WHENEVER. WHEREVER.
We'll be there.

NEWFOUNDLAND POWER
A FORTIS COMPANY

DELIVERED BY HAND

July 7, 2017

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 2018 Capital Budget Application

A. 2018 Capital Budget Application

Enclosed are the original and 10 copies of Newfoundland Power Inc.'s (the "Company") 2018 Capital Budget Application and supporting materials (the "Filing").

The Filing outlines a proposed 2018 Capital Budget totaling $83,876,000. Included in that total are 2018 capital expenditures of $1,431,000 previously approved in Order No. P.U. 39 (2016) (the "2017 Capital Order"). Those previously approved expenditures relate to multi-year projects proposed in the 2017 Capital Budget Application. The Filing also outlines multi-year projects commencing in 2018 that include proposed 2019 capital expenditures totaling $17,314,000, proposed 2020 capital expenditures totaling $3,845,000, and proposed 2021 capital expenditures totaling $3,750,000. In addition, the Filing seeks approval of a 2016 rate base in the amount of $1,061,044,000.

B. Compliance Matters

B.1 Board Orders

In the 2017 Capital Order, the Board required a progress report on 2017 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. *2017 Capital Expenditure Status Report*: this meets the requirements of the 2017 Capital Order;

2. *2018 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 *2018 Capital Plan* provides a breakdown of the overall 2018 Capital Budget by definition, classification, and materiality segmentation as described in the Guidelines. Pages i through vii 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. Dennis Browne, 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. Tracey Pennell
Newfoundland and Labrador Hydro

Dennis Browne, QC
Browne Fitzgerald Morgan & Avis

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Newfoundland Power Inc.
2018 Capital Budget Application
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Application

Application

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Schedule D *Computation of Average Rate Base*

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1.2 Purchase Mobile Generation

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2.1 2018 Substation Refurbishment and Modernization

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Distribution
4.1 Distribution Reliability Initiative
4.2 Feeder Additions for Load Growth
4.3 CLV-01 Distribution Feeder Refurbishment

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5.1 2018 Application Enhancements
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Deferred Charges
6.1 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 2018 Capital Budget of $83,876,000;

(b) approving certain capital expenditures related to multi-year projects commencing in 2018; and

(c) fixing and determining a 2016 rate base of $1,061,044,000

2018 Capital Budget Application

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

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

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

(a) approving a 2018 Capital Budget of $83,876,000;

(b) approving certain capital expenditures related to multi-year projects commencing in 2018; and

(c) fixing and determining a 2016 rate base of $1,061,044,000

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 2018 Capital Budget in the amount of $83,876,000, which includes forecast 2018 capital expenditures previously approved in Order No. P.U. 39 (2016) and also includes an estimated amount of $2,500,000 in contributions in aid of construction that the Applicant intends to demand from its customers in 2018. 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 2018 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. 39 (2016); and

    (b) projects which will commence as part of the 2018 Capital Budget but will not be completed in 2018.

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

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 2016 of $1,061,044,000.

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 2018 Capital Budget in the amount of $83,876,000 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 2019 of improvements and additions to its property in the amount of $17,314,000, as set out in Schedule C to the Application;

   (c) pursuant to Section 41 of the Act, approving Newfoundland Power's purchase and construction in 2020 of improvements and additions to its property in the amount of $3,845,000, as set out in Schedule C to the Application;

   (d) pursuant to Section 41 of the Act, approving Newfoundland Power's purchase and construction in 2021 of improvements and additions to its property in the amount of $3,750,000, as set out in Schedule C to the Application; and

   (e) pursuant to Section 78 of the Act, fixing and determining Newfoundland Power's average rate base for 2016 in the amount of $1,061,044,000 as set out in Schedule D to the Application.

DATED at St. John's, Newfoundland and Labrador, this 7th day of July, 2017.

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 2018 Capital Budget of $83,876,000;

(b) approving certain capital expenditures related to multi-year projects commencing in 2018; and

(c) fixing and determining a 2016 rate base of $1,061,044,000

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 7th day of July, 2017:

Barrister

Gary Murray

2018 CAPITAL BUDGET SUMMARY

Asset Class	Budget (000s)
1. Generation - Hydro	$ 2,119
2. Generation - Thermal	6,301
3. Substations	12,788
4. Transmission	7,168
5. Distribution	38,857
6. General Property	1,763
7. Transportation	3,362
8. Telecommunications	198
9. Information Systems	6,570
10. Unforeseen Allowance	750
11. General Expenses Capitalized	4,000
Total	**$ 83,876**

2018 CAPITAL PROJECTS (BY ASSET CLASS)

Capital Projects	Budget (000s)	Description[1]
1. Generation – Hydro		
Facility Rehabilitation	$ 2,119	2
Total Generation – Hydro	**$ 2,119**	
2. Generation – Thermal		
Facility Rehabilitation Thermal	$ 301	5
Purchase Mobile Generation[2]	$ 6,000	7
Total Generation – Thermal	**$ 6,301**	
3. Substations		
Substations Refurbishment and Modernization	$ 8,001	10
Replacements Due to In-Service Failures	3,814	12
PCB Bushing Phase-out	973	14
Total Substations	**$ 12,788**	
4. Transmission		
Transmission Line Rebuild[3]	$ 7,168	17
Total Transmission	**$ 7,168**	

1 Project descriptions can be found in Schedule B at the page indicated.
2 This is a multi-year project with future commitments identified in Schedule C of this Application.
3 This is a multi-year project with future commitments identified in Schedule C of this Application.

2018 CAPITAL PROJECTS (BY ASSET CLASS)

Capital Projects	Budget (000s)	Description[4]
5. Distribution		
Extensions	$ 11,738	21
Meters	546	23
Services	3,200	26
Street Lighting	1,814	29
Transformers	6,084	32
Reconstruction	5,366	34
Rebuild Distribution Lines	3,844	36
Relocate/Replace Distribution Lines for Third Parties	2,317	39
Trunk Feeders	798	41
Feeder Additions for Load Growth[5]	539	43
Distribution Reliability Initiative[6]	1,789	45
Distribution Feeder Automation	612	48
Allowance for Funds Used During Construction	210	50
Total Distribution	**$ 38,857**	
6. General Property		
Tools and Equipment	$ 479	53
Additions to Real Property	671	56
Company Buildings Renovations – Carbonear Parking Lot	298	58
Security Fencing Refurbishment	315	60
Total General Property	**$ 1,763**	
7. Transportation		
Purchase Vehicles and Aerial Devices	$ 3,362	63
Total Transportation	**$ 3,362**	

4 Project descriptions can be found in Schedule B at the page indicated.
5 This is a multi-year project with future commitments identified in Schedule C of this Application.
6 This is a multi-year project that includes $1,431,000 in expenditures approved in Order No. P.U. 39 (2016).

2018 CAPITAL PROJECTS (BY ASSET CLASS)

Capital Projects	Budget (000s)	Description[7]
8. Telecommunications		
Replace/Upgrade Communications Equipment	$ 99	67
Fibre Optic Network	99	69
Total Telecommunications	**$ 198**	
9. Information Systems		
Application Enhancements	$ 858	72
System Upgrades[8]	1,343	74
Personal Computer Infrastructure	472	76
Shared Server Infrastructure	648	79
Network Infrastructure	467	81
Outage Management System[9]	2,360	83
Human Resource Management System Replacement[10]	422	85
Total Information Systems	**$ 6,570**	
10. Unforeseen Allowance		
Allowance for Unforeseen Items	$ 750	88
Total Unforeseen Allowance	**$ 750**	
11. General Expenses Capitalized		
General Expenses Capitalized	$ 4,000	90
Total General Expenses Capitalized	**$ 4,000**	

[7] Project descriptions can be found in Schedule B at the page indicated.
[8] This is a multi-year project with future commitments for the Microsoft Enterprise Agreement identified in Schedule C of this Application.
[9] This is a multi-year project with future commitments identified in Schedule C of this Application.
[10] This is a multi-year project with future commitments identified in Schedule C of this Application.

2018 CAPITAL PROJECTS SUMMARY

2018 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 on identified need or on a historical pattern of repair and replacement. Justifiable capital expenditures are those which are justified based on 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 2018 Capital Project Summary provides a summary of the planned capital expenditures contained in Newfoundland Power's (the "Company") 2018 Capital Budget Application by definition (pages ii to iii), classification (pages iv to v), and segmentation by materiality (pages vi to vii), 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
2018 Capital Projects by Definition
(000's)

Clustered	**$0**	**Page**

Pooled	**$69,149**	**Page**
Distribution	**38,059**	
AFUDC	210	50
Distribution Reliability Initiative	1,789	45
Distribution Feeder Automation	612	48
Extensions	11,738	21
Feeder Additions for Load Growth	539	43
Meters	546	23
Rebuild Distribution Lines	3,844	36
Reconstruction	5,366	34
Relocate/Replace Distribution Lines for Third Parties	2,317	39
Services	3,200	26
Street Lighting	1,814	29
Transformers	6,084	32
General Property	**1,465**	
Additions to Real Property	671	56
Tools and Equipment	479	53
Security Fencing Refurbishment – St. John's	315	60
Generation	**2,420**	
Facility Rehabilitation	2,119	2
Facility Rehabilitation Thermal	301	5
Information Services	**3,788**	
Application Enhancements	858	72
Network Infrastructure	467	81
Personal Computer Infrastructure	472	76
Shared Server Infrastructure	648	79
System Upgrades	1,343	74
Substations	**12,788**	
Substations Refurbishment and Modernization	8,001	10
Replacements Due to In-Service Failures	3,814	12
PCB Bushing Phase-out	973	14
Telecommunications	**99**	
Replace/Upgrade Communications Equipment	99	67
Transmission	**7,168**	
Transmission Lines Rebuild	7,168	17
Transportation	**3,362**	
Purchase Vehicles and Aerial Devices	3,362	63

Other	**$14,727**	**Page**
Distribution	**798**	
Trunk Feeders	798	41
General Expenses Capitalized	**4,000**	
General Expenses Capitalized	4,000	90
General Property	**298**	
Company Building Renovations – Carbonear	298	58
Generation	**6,000**	
Purchase Mobile Generation	6,000	7
Information Services	**2,782**	
Outage Management System	2,360	83
Human Resource Management System	422	85
Telecommunications	**99**	
Fibre Optic Cable	99	69
Unforeseen Allowance	**750**	
Allowance for Unforeseen Items	750	88

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 2018, there are no projects that have expenditures which are clustered.

Summary of 2018 Capital Projects by Classification (000's)

Normal Capital	**$82,045**	**Page**
Distribution	**38,857**	
AFUDC	210	50
Distribution Feeder Automation	612	48
Distribution Reliability Initiative	1,789	45
Extensions	11,738	21
Feeder Additions for Load Growth	539	43
Meters	546	23
Rebuild Distribution Lines	3,844	36
Reconstruction	5,366	34
Relocate/Replace Distribution Lines for Third Parties	2,317	39
Services	3,200	26
Street Lighting	1,814	29
Transformers	6,084	32
Trunk Feeders	798	41
General Expenses Capitalized	**4,000**	
General Expenses Capitalized	4,000	90
General Property	**1,763**	
Additions to Real Property	671	56
Tools and Equipment	479	53
Company Building Renovations – Carbonear	298	58
Security Fencing Refurbishment – St. John's	315	60
Generation	**8,420**	
Facility Rehabilitation	2,119	2
Facility Rehabilitation Thermal	301	5
Purchase Mobile Generation	6,000	7
Information Systems	**5,712**	
Network Infrastructure	467	81
Personal Computer Infrastructure	472	76
Shared Server Infrastructure	648	79
System Upgrades	1,343	74
Outage Management System	2,360	83
Human Resource Management System	422	85
Substations	**11,815**	
Substations Refurbishment and Modernization	8,001	10
Replacements Due to In-Service Failures	3,814	12

Normal Capital (continued)		**Page**
Telecommunications	**198**	
Replace/Upgrade Communications Equipment	99	67
Fibre Optic Network	99	69
Transmission	**7,168**	
Transmission Line Rebuild	7,168	17
Transportation	**3,362**	
Purchase Vehicles and Aerial Devices	3,362	63
Unforeseen Allowance	**750**	
Allowance for Unforeseen Items	750	88

Justifiable	**$858**	**Page**
Information Systems	**858**	
Application Enhancements	858	72

Mandatory	**$973**	**Page**
Substations	**973**	
PCB Bushing Phase-out	973	14

Summary of
2018 Capital Projects by Materiality
(000's)

Large – Greater than $500	$80,714	Page
Distribution	**38,647**	
Distribution Feeder Automation	612	48
Distribution Reliability Initiative	1,789	45
Extensions	11,738	21
Feeder Additions for Load Growth	539	43
Meters	546	23
Rebuild Distribution Lines	3,844	36
Reconstruction	5,366	34
Relocate/Replace Distribution Lines for Third Parties	2,317	39
Services	3,200	26
Street Lighting	1,814	29
Transformers	6,084	32
Trunk Feeders	798	41
General Expenses Capitalized	**4,000**	
General Expenses Capitalized	4,000	90
General Property	**671**	
Additions to Real Property	671	56
Generation	**8,119**	
Facility Rehabilitation	2,119	2
Purchase Mobile Generation	6,000	7
Information Systems	**5,209**	
Application Enhancements	858	72
Shared Server Infrastructure	648	79
System Upgrades	1,343	74
Outage Management System	2,360	83
Substations	**12,788**	
Replacements Due to In-Service Failures	3,814	12
Substations Refurbishment and Modernization	8,001	10
PCB Bushing Phase-out	973	14
Transmission	**7,168**	
Transmission Line Rebuild	7,168	17
Transportation	**3,362**	
Purchase Vehicles and Aerial Devices	3,362	63
Unforeseen Allowance	**750**	
Allowance for Unforeseen Items	750	88

Medium – Between \$200 and \$500	**\$2,964**	**Page**
Distribution	**210**	
AFUDC	210	50
General Property	**1,092**	
Tools and Equipment	479	53
Company Building Renovations – Carbonear	298	58
Security Fencing Improvements – St. John's	315	60
Generation	**301**	
Facility Rehabilitation Thermal	301	5
Information Systems	**1,361**	
Network Infrastructure	467	81
Personal Computer Infrastructure	472	76
Human Resource Management System	422	85

Small – Under \$200	**\$198**	**Page**
Telecommunications	**198**	
Replace/Upgrade Communications Equipment	99	67
Fibre Optic Network	99	69

GENERATION - HYDRO

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

Project Cost: **$2,119,000**

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 2018 project includes the following items:

- Refurbishment of Second Storage Pond Dam ($351,000);
- Rehabilitation of Horsechops tailrace tunnel ($291,000);
- Replacement of Tors Cove access road bridges ($302,000);
- Replacement of Rocky Pond turbine bearing ($438,000);
- Refurbishment of Rocky Pond powerhouse ($169,000); and
- Equipment replacements due to in-service failures ($568,000).

The refurbishment, 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 2018 proposed expenditures are included in ***1.1*** *2018 Facility Rehabilitation*.

Justification

The Company's 23 hydro plants range in age from 18 to 117 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 Generating Station would require approximately 710,000 barrels of fuel annually. At an oil price of $81.40 per barrel, this translates into approximately $58 million in annual fuel savings.[1]

[1] The price forecast per barrel of oil used at Holyrood as per Rate Stabilization Plan – Fuel Price Projection Update letter dated April 18, 2017.

All expenditures on individual hydro plants, such as the replacement of dam structures, runners, or forebays, are justified on the basis of maintaining access to hydro 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 2018 and a projection of expenditures through 2022.

Table 1
Projected Expenditures
(000s)

Cost Category	2018	2019	2020 - 2022	Total
Material	1,457	-	-	-
Labour – Internal	292	-	-	-
Labour – Contract	-	-	-	-
Engineering	185	-	-	-
Other	185	-	-	-
Total	**$2,119**	**$1,533**	**$4,733**	**$8,385**

Costing Methodology

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

Table 2
Expenditure History
(000s)

Year	2013	2014	2015	2016	2017F
Total	$1,449	$1,825	$1,545	$1,689	$1,607

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.

GENERATION - THERMAL

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

Project Cost: **$301,000**

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 2018 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 on historical information, $301,000 is estimated to be the cost of refurbishment or replacement of thermal plant structures in 2018.

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 on transmission and distribution lines or substation assets. 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 2018 and a projection of expenditures through 2022.

Table 1
Projected Expenditures
(000s)

Cost Category	2018	2019	2020 - 2022	Total
Material	$165	-	-	-
Labour – Internal	60	-	-	-
Labour – Contract	-	-	-	-
Engineering	60	-	-	-
Other	16	-	-	-
Total	**$301**	**$308**	**$966**	**$1,575**

Costing Methodology

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

Table 2
Expenditure History
(000s)

Year	2013	2014	2015	2016	2017F
Total	$201	$331	$228	$424	$234

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.

Project Title: **Purchase Mobile Generation (Other, Multi-Year)**

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

Project Description

This Generation Thermal project is necessary for the replacement of the existing Mobile Gas Turbine ("MGT"), which has reached the end of its mobile service life. The existing MGT is 43 years old and, while the generating equipment can provide some additional years of service, the condition of the trailers' chassis and equipment enclosures have deteriorated to the point where replacement is the only viable option.[2]

The Company's mobile generation serves 3 main roles: (i) emergency generation during long duration customer outages; (ii) temporary generation to minimize customer outages during planned construction projects; and (iii) system support during times of high demand or low generation reserve. The availability of mobile generation can greatly improve the reliability of electrical service to customers when responding to extended customer outages. Also, mobile generation provides flexibility to operating and maintenance staff for planned outages associated with transmission, substation and distribution maintenance.

This is a multi-year project. In 2018, the Company will issue a Request for Proposals for both new and refurbished mobile gas turbine units in the 3.5 to 7.5 MW range, leading to the delivery a new mobile generator in 2019.

Details on the proposed expenditures for the purchase of a new mobile generator are included in ***1.2*** *Purchase Mobile Generation*.

Justification

A detailed engineering assessment has been completed on the existing MGT and, given the overall poor condition of the chassis and enclosures, it is recommended that the unit be retired from mobile service over the next 2 to 3 years. The existing MGT operates multiple times every year in support of planned and unplanned, long duration outages. If the MGT is not replaced as planned, the Company would not be able to deploy mobile generation in some situations and reliability would be negatively impacted.[3]

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[2] Following the commissioning of a new mobile generator, the existing MGT will be installed at a permanent location to continue to provide standby and emergency generation for the remainder of its service life.

[3] For example, in 2015, Newfoundland Power deployed the MGT in 4 locations to avoid extensive customer outages: Trepassey, Abrahams Cove, Lewisporte and Twillingate. In these cases, approximately 28 million customer outage minutes were avoided. Similarly, in Port aux Basques in the summer of 2015 it was used along with the mobile and Port aux Basques diesel generators, as well as the Rose Blanche hydro plant, to avoid 6 million customer outage minutes during Hydro's annual maintenance on the TL214 and TL215 transmission system.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2018 and a projection of expenditures through 2022.

Table 1

Projected Expenditures
(000s)

Cost Category	2018	2019	2020 - 2022	Total
Material	$4,731	$5,869	-	-
Labour – Internal	35	195	-	-
Labour – Contract	-	-	-	-
Engineering	154	231	-	-
Other	1,080	1,620	-	-
Total	**$6,000**	**$7,915**	**-**	**$13,915**

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 a multi-year project to be completed over 2 years commencing in 2018.

SUBSTATIONS

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

Project Cost: **$8,001,000**

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** 2018 Substation Refurbishment and Modernization*.

The Company has 130 substations ranging in age from 15 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 2018, this project will refurbish and modernize the following substations:

- Harbour Grace Substation
- Bayview Substation

In addition to the substations listed above, the 2018 project includes the upgrading of automation equipment in substations, including the automation of distribution feeder breakers and reclosers.[4] Also, the 2018 project includes the upgrading of security infrastructure at selected substations.

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

Justification

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

[4] At the end of 2016, approximately 82% of distribution feeder breakers and reclosers located in Company substations were automated through the SCADA system. By the end of 2017, there will be 269 distribution feeders automated, representing approximately 88% of all distribution feeders. By the end of 2018, there will be 281 distribution feeders automated, representing approximately 92% of all distribution feeders.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2018 and a projection of expenditures through 2022. Appendix A of ***2.1*** *2018 Substation Refurbishment and Modernization* details the work planned for each year.

Table 1
Projected Expenditures
(000s)

Cost Category	**2018**	**2019**	**2020 - 2022**	**Total**
Material	$6,109	-	-	-
Labour – Internal	317	-	-	-
Labour – Contract	-	-	-	-
Engineering	1,362	-	-	-
Other	213	-	-	-
Total	**$8,001**	**$8,713**	**$24,479**	**$41,193**

Costing Methodology

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

Table 2
Expenditure History
(000s)

Year	**2013**	**2014**	**2015**	**2016**	**2017F**
Total	$3,570	$6,411	$10,938	$7,044	$8,425

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: **$3,814,000**

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 2018 and a projection of expenditures through 2022.

Table 1
Projected Expenditures
(000s)

Cost Category	2018	2019	2020 - 2022	Total
Material	$2,649	-	-	-
Labour – Internal	770	-	-	-
Labour – Contract	-	-	-	-
Engineering	299	-	-	-
Other	96	-	-	-
Total	**$3,814**	**$3,901**	**$12,219**	**$19,934**

Costing Methodology

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

Table 2
Expenditure History
(000s)

Year	**2013**	**2014**	**2015**	**2016**	**2017F**
Total	$3,485	$4,797	$3,116	$2,561	$3,851

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 180 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: **PCB Bushing Phase-out (Pooled)**

Project Cost: **$973,000**

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").[5]

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.[6] Expenditures are now required to address the phase-out of PCBs in equipment with concentrations greater than 50 ppm and less than 500 ppm.

Inspections competed before the end of 2014 identified 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.

Similarly, inspections have identified 42 bulk oil circuit breakers with PCB concentrations greater than 50 ppm and less than 500 ppm. These circuit breakers will be replaced by 2025.

In 2018, the Company will replace bushings on 2 substation transformers and replace 5 bulk oil circuit breakers.

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*.

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5 Government of Canada Regulations required that, by the end of 2025, substation transformer bushings, breakers and instrument transformers with PCB concentrations of greater than 50 ppm be removed from service.

6 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*.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2018 and a projection of expenditures through 2022.

Table 1

Projected Cost (000s)

Cost Category	2018	2019	2020 - 2022	Total
Material	$641	-	-	-
Labour – Internal	36	-	-	-
Labour – Contract	-	-	-	-
Engineering	270	-	-	-
Other	26	-	-	-
Total	**$973**	**$987**	**$3,248**	**$5,208**

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.

TRANSMISSION

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

Project Cost: **$7,168,000**

Project Description

This Transmission project is necessary to replace deteriorated transmission line infrastructure. The 2018 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 2018 transmission line rebuild work will take place on transmission lines 302L, and 363L. Transmission line 302L operates between Salt Pond Substation and Laurentian Substation on the Burin Peninsula.[7] Transmission line 363L operates between Baie Verte Junction Substation on the Trans-Canada Highway and Seal Cove Road Substation located in Baie Verte.[8] ($5,068,000)

   Details on the proposed 2018 rebuilds are included in ***3.1*** *2018 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. Based on historical information from the most recent five-year period, $2,100,000 is required for 2018.

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

The Company has 107 transmission lines interconnecting substations and hydro plants across its service territory. Approximately 60% of the total kilometres of line construction 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.

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[7] This is a multi-year project with expenditures planned for 2018 and 2019. Details of the planned expenditures can be found in Schedule C of this Application.

[8] This is a multi-year project with expenditures planned for 2018, 2019, 2020 and 2021. Details of the planned expenditures can be found in Schedule C of this Application.

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 2018 and a projection of expenditures through 2022. Appendix A of ***3.1*** *2018 Transmission Line Rebuild* details the transmission line rebuilds planned for each year.

Table 1

Projected Expenditures
(000s)

Cost Category	**2018**	**2019**	**2020 - 2022**	**Total**
Material	$2,510	-	-	-
Labour – Internal	280	-	-	-
Labour – Contract	3,408	-	-	-
Engineering	226	-	-	-
Other	744	-	-	-
Total	**$7,168**	**$10,964**	**$30,550**	**$48,682**

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	**2013**	**2014**	**2015**	**2016**	**2017F**
Total	$5,081	$4,664	$6,391	$4,944	$6,711

The budget estimates for rebuilding and upgrade projects are based on engineering cost estimates. The budget estimates for addressing deficiencies identified during inspections 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 302L is a multi-year project planned for 2018 and 2019. Table 3 details the 2018 and 2019 project expenditures for this multi-year project.

Table 3
302L Multi-Year Projected Expenditures
(000s)

Cost Category	2018B	2019B	Total
Material	$600	$841	$1,441
Labour – Internal	72	86	158
Labour – Contract	1,118	1,803	2,921
Engineering	70	86	156
Other	208	248	456
Total	**$2,068**	**$3,064**	**$5,132**

The rebuilding of transmission line 363L is a multi-year project planned for 2018 through 2021. Table 4 details the 2018 through 2021 project expenditures for this multi-year project.

Table 4
363L Multi-Year Projected Expenditures
(000s)

Cost Category	2018B	2019B	2020B	2021B	Total
Material	$1,040	$1,035	$1,208	$1,250	$4,533
Labour – Internal	150	150	180	200	680
Labour – Contract	1,300	1,300	1,600	1,670	5,870
Engineering	130	130	150	160	570
Other	380	385	462	470	1,697
Total	**$3,000**	**$3,000**	**$3,600**	**$3,750**	**$13,350**

DISTRIBUTION

Project Title: **Extensions (Pooled)**

Project Cost: **$11,738,000**

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' increased electrical loads. 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 2018 and a projection of expenditures through 2022.

Table 1
Projected Expenditures
(000s)

Cost Category	2018	2019	2020 - 2022	Total
Material	$3,664	-	-	-
Labour – Internal	3,452	-	-	-
Labour – Contract	2,764	-	-	-
Engineering	1,481	-	-	-
Other	377	-	-	-
Total	**$11,738**	**$11,315**	**$33,739**	**$56,792**

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 2018.

Table 2
Expenditure History and Unit Cost Projection

Year	2013	2014	2015	2016	2017F	2018B
Total (000s)	$ 13,434	$ 15,467	$ 15,423	$ 13,008	$ 11,834	$ 11,738
Adjusted Costs (000s)[1]	$ 15,186	$ 15,138	$ 16,355	$ 13,527	$ 11,834	-
New Customers	5,280	4,308	3,786	3,528	2,867	2,782
Unit Costs ($/customer)[1]	$ 2,876	$ 3,514	$ 4,320	$ 3,834	$ 4,128	$ 4,219

[1] 2017 dollars

The project cost for the connection of new customers is calculated on the basis of historical data. Historical annual expenditures over the most recent five-year period, including the current year, 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: **$546,000**

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 2018.

Table 1
2018 Proposed Meter Acquisition

Program	Number of Meters
Energy Only Domestic Meters	4,998
Other Energy Only and Demand Meters	77

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 2015, 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*. Based on the *2016 Metering Strategy* the Company will:

- Continue with the objectives outlined in the *2013 Metering Strategy* with respect to accuracy and 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.

The Company is on schedule to achieve 100% penetration of AMR meters by the end of 2017. As a result, the metering budget is significantly less than expenditures in previous periods.[9]

[9] Once the newer AMR meters reach an age where they are subject to the sampling regulations, metering requirements, and expenditures, are expected to increase.

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)*.

Projected Expenditures

Table 2 provides a breakdown of the proposed expenditures for 2018 and a projection of expenditures through 2022.

Table 2

Projected Expenditures
(000s)

Cost Category	2018	2019	2020 - 2022	Total
Material	$480	-	-	-
Labour – Internal	55	-	-	-
Labour – Contract	11	-	-	-
Engineering	-	-	-	-
Other	-	-	-	-
Total	**$546**	**$530**	**$1,551**	**$2,627**

Costing Methodology

Table 3 shows the annual expenditures for the most recent five-year period, as well as a projection for 2018.

Table 3
Expenditure History and Unit Cost Projection

Year	2013	2014	2015	2016	2017F	Avg	2018B
Meter Requirements							
New Connections	5,280	4,308	3,786	3,528	2,867		2,782
GROs/CSOs	18,805	20,009	18,856	3,670	7,326		575
Replacements	6,218	8,825	12,894	41,020	35,323		2,218
Total	30,303	33,142	35,536	48,218	45,516		5,575
Meter Costs							
Actual (000s)	$3,109	$3,003	$3,108	$4,496	$4,391		$546
Adjusted[1] (000s)	$3,326	$3,152	$3,194	$4,603			
Unit Costs[1]	$ 110	$ 95	$ 90	$ 95	$ 96	$ 97	$ 98

[1] 2017 dollars

The project cost for meters is calculated on the basis of historical data. Historical annual expenditures over the most recent five-year period, including the current year, are expressed in current year dollars ("Adjusted Meter Costs"). 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. 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: **$3,200,000**

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 loads.

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 2018 and a projection of expenditures through 2022.

Table 1
Projected Expenditures
(000s)

Cost Category	2018	2019	2020 - 2022	Total
Material	$963	-	-	-
Labour – Internal	1,775	-	-	-
Labour – Contract	156	-	-	-
Engineering	268	-	-	-
Other	38	-	-	-
Total	**$3,200**	**$3,123**	**$9,420**	**$15,743**

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 2018.

Table 2

Expenditure History and Unit Cost Projection
New Services

Year	2013	2014	2015	2016	2017F	2018B
Total (000s)	$3,608	$3,300	$3,183	$3,174	$2,837	$2,568
Adjusted Costs (000s)[1]	$4,091	$3,623	$3,381	3,492	2,837	-
New Customers	5,280	4,308	3,786	3,528	2,867	2,782
Unit Costs ($/customer)[1]	$ 775	$ 841	$ 893	$ 990	$ 989	$ 923

[1] 2017 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 2018.

Table 3

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

Year	2013	2014	2015	2016	2017F	2018B
Total	$672	$544	$544	$565	$727	$632
Adjusted Costs[1]	$762	$597	$587	$400	$727	-

[1] 2017 dollars

The process of estimating the budget requirement for *replacement* services is similar to that for *new* services, except the budget estimate is based on the historical average of the total cost of replacement services, as opposed to a unit cost.

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

Future Commitments

This is not a multi-year project.

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

Project Cost: **$1,814,000**

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.

Newfoundland Power plans to install additional LED street lights to field test its draft LED street light specification and expand upon the experience the Company has gained with the limited number of LED streetlights it has in service. The 2018 LED deployment is targeted to new residential and commercial developments where street lighting design will be specifically focused on LED technology. Installation of additional LED street light fixtures will provide a reasonable basis for a technical assessment of the lighting design as well as provide an opportunity for customer feedback to assist in the development of an LED streetlight specific rate design.

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 2018 and a projection of expenditures through 2022.

Table 1 **Projected Expenditures** **(000s)**				
Cost Category	**2018**	**2019**	**2020 - 2022**	**Total**
Material	$983	-	-	-
Labour – Internal	645	-	-	-
Labour – Contract	140	-	-	-
Engineering	27	-	-	-
Other	19	-	-	-
Total	**$1,814**	**$1,786**	**$5,419**	**$9,019**

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 2018.

Table 2 **Expenditure History and Unit Cost Projection** **New Street Lights**						
Year	**2013**	**2014**	**2015**	**2016**	**2017F**	**2018B**
Total (000s)	$1,889	$2,265	$1,906	$1,274	$1,335	$1,174
Adjusted Costs (000s)[1]	$2,088	$1,738[2]	$1,584[3]	$1,316	$1,335	-
New Customers	5,280	4,308	3,786	3,528	2,867	2,782
Unit Costs ($/customer)[1]	$ 395	$ 403	$ 418	$ 373	$ 466	$ 422

1 2017 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 2018.

Table 3

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

Year	**2013**	**2014**	**2015**	**2016**	**2017F**	**2018B**
Total	$703	$482	$623	$453	$714	$640
Adjusted Costs[1]	$775	$519	$653	$468	$714	

[1] 2017 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: **$6,084,000**

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 2018 and a projection of expenditures through 2022.

Table 1
Projected Expenditures
(000s)

Cost Category	2018	2019	2020 - 2022	Total
Material	$6,084	-	-	-
Labour – Internal	-	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	-	-	-	-
Total	**$6,084**	**$5,683**	**$16,067**	**$27,834**

Costing Methodology

Table 2 shows the annual expenditures for the most recent five-year period, as well as an estimate for 2018.

Table 2
Expenditure History and Budget Estimate
(000s)

Year	**2013**	**2014**	**2015**	**2016**	**2017F**	**2018B**
Total	$6,710	$7,106	$7,462	$4,956	$5,353	$6,084
Adjusted Costs[1]	$ 7,086	$7,386	$7,612	$5,055	$5,353	

[1] 2017 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: **$5,366,000**

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 until 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 2018 and a projection of expenditures through 2022.

Table 1

Projected Expenditures (000s)

Cost Category	2018	2019	2020 - 2022	Total
Material	$1,270	-	-	-
Labour – Internal	2,160	-	-	-
Labour – Contract	1,211	-	-	-
Engineering	542	-	-	-
Other	183	-	-	-
Total	**$5,366**	**$5,494**	**$17,268**	**$28,128**

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 2018.

Table 2
Expenditure History and Budget Estimate
(000s)

Year	2013	2014	2015	2016	2017F	2018B
Total	$4,643	$5,041	$5,059	$4,876	$4,908	$5,366
Adjusted Costs[1]	$5,249	$5,522	$5,365	$5,071	$4,908	

1 2017 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: **$3,844,000**

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 that consist of either the complete rebuilding of deteriorated distribution line sections 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 2018 will be performed on the following 44 of the Company’s 305 feeders:

CAR-02	GBY-03	KBR-04	MOL-02	PAB-05	TRP-01
CAT-02	GLV-01	KEN-05	MOL-04	SCR-01	TWG-02
CLV-03	GOU-03	LET-01	MOL-05	SCR-02	WAL-04
DLK-04	GRH-03	LEW-01	MOL-06	SLA-02	WAL-05
GAN-01	HGR-01	LEW-03	MOL-08	SLA-03	
GAN-02	HWD-06	LEW-04	MOL-09	SPF-02	
GAL-04	HWD-07	MMT-01	MSY-02	SPF-03	
GAR-01	HWD-09	MOL-01	OXP-01	STX-01	

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 2018 and a projection of expenditures through 2022.

Table 1
Projected Expenditures
(000s)

Cost Category	2018	2019	2020 - 2022	Total
Material	$1,615	-	-	-
Labour – Internal	1,768	-	-	-
Labour – Contract	231	-	-	-
Engineering	38	-	-	-
Other	192	-	-	-
Total	**$3,844**	**$3,934**	**$12,394**	**$20,172**

Costing Methodology

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

Table 2
Expenditure History
(000s)

Year	2013	2014	2015	2016	2017F
Total	$2,958	$4,338	$4,137	$2,846	$4,023
Adjusted Costs[1]	$3,195	$4,594	$4,297	$2,846	

[1] 2017 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.

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 on which work is to take place in 2018 are ongoing throughout 2017. Complete inspection data will not be available until late 2017. Therefore, the 2018 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: **$2,317,000**

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: (i) work initiated by municipal, provincial and federal governments; (ii) work initiated by other pole users, such as Bell Aliant, Eastlink and Rogers Cable; or (iii) requests from customers.[10]

The Company's response to requests for relocation and replacement of distribution facilities by governments and other service providers is governed by the provisions of agreements in place with the requesting parties. Relocation or replacement of facilities by customers is 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 2018 and a projection of expenditures through 2022.

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

Table 1 Projected Expenditures (000s)				
Cost Category	**2018**	**2019**	**2020 - 2022**	**Total**
Material	$812	-	-	-
Labour – Internal	740	-	-	-
Labour – Contract	487	-	-	-
Engineering	237	-	-	-
Other	41	-	-	-
Total	**$2,317**	**$2,371**	**$7,442**	**$12,130**

Costing Methodology

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

Table 2 Expenditure History (000s)					
Year	**2013**	**2014**	**2015**	**2016**	**2017F**
Total	$2,586	$2,077	$2,118	$2,454	$2,266
Adjusted Costs[1]	$2,879	$2,248	$2,226	$2,541	

[1] 2017 dollars

The budget estimate is based on historical expenditures. Generally, these expenditures are associated with a number of small projects that cannot be 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 (Other)**

Project Cost: **$798,000**

Project Description

This Distribution project includes the replacement of deteriorated distribution infrastructure on feeder CLV-01. Distribution feeder CLV-01 is 1 of 3 distribution feeders originating from the Clarenville Substation ("CLV") located on the Trans-Canada Highway in the Town of Clarenville. It supplies electricity to approximately 1,000 customers in the Clarenville South, Deep Bight and Adeytown areas.

The CLV-01 *Trunk Feeders* project involves the replacement of deteriorated poles, conductor and hardware on the 3-phase section of feeder along Marine Drive, Clarenville. The purpose of the project is to prevent outages and failures due to aging and deteriorated hardware.

Details on the proposed expenditures are included in ***4.3*** *CLV-01 Distribution Feeder Refurbishment*.

Justification

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

Inspections of distribution feeder CLV-01 have identified deterioration due to decay, substandard conductor and clearances, 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.

Projected Expenditures

Table 1 provides the breakdown of the proposed expenditures for 2018 and a projection of expenditures through 2022.

Table 1 **Projected Expenditures** **(000s)**				
Cost Category	**2018**	**2019**	**2020 - 2022**	**Total**
Material	$144	-	-	-
Labour – Internal	170	-	-	-
Labour – Contract	184	-	-	-
Engineering	106	-	-	-
Other	194	-	-	-
Total	**$798**	**-**	**-**	**$798**

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 Load Growth (Pooled, Multi-Year)**

Project Cost: **$539,000**

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 2018, the *Feeder Additions for Load Growth* project will include the upgrading of the following distribution feeders:

1. Blaketown Substation feeder BLK-02 serves approximately 1,800 customers from Whitbourne to Brigus Junction. An analysis of the BLK-02 distribution feeder was completed using a distribution feeder computer modelling application.[11] The results show that BLK-02 distribution feeder exceeds the Company's planning criteria for both maximum current on a single-phase distribution line and for maximum neutral current on an unbalanced 3-phase distribution line. The Company proposes to complete the work over 2 years. ($319,000 in 2018 and $665,000 in 2019)

2. Broad Cove Substation feeder BCV-03 serves approximately 1,200 customers in the Town of Portugal Cove-St. Philip's. An analysis of the BLK-02 distribution feeder has identified a 0.7 km section of this feeder from BCV Substation to the intersection of Thorburn Road and St. Thomas Line is overloaded. This project will address overloaded conductor on the 0.7 km section of this distribution feeder. ($220,000 in 2018)

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

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.

[11] Actual load measurements were taken to verify the results of the computer simulation.

Projected Expenditures

Table 1 provides the breakdown of the proposed expenditures for 2018 and a projection of expenditures through 2022.

Table 1

Projected Expenditures
(000s)

Cost Category	2018	2019	2020 - 2022	Total
Material	$117	$69	-	-
Labour – Internal	119	231	-	-
Labour – Contract	103	57	-	-
Engineering	74	87	-	-
Other	126	221	-	-
Total	**$539**	**$665**	**-**	**$1,204**

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

The BLK-02 *Feeder Additions for Load Growth* item is planned to be completed in 2018 and 2019.

Project Title: Distribution Reliability Initiative (Pooled, Multi-Year)

Project Cost: $1,789,000

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.[12] The upgrading work is typically determined through assessments of past service problems, knowledge of local environmental conditions (such as salt contamination, wind and ice loading), and application of location-specific design and construction standards.

In the past, Newfoundland Power identified worst performing feeders on the basis of SAIDI, SAIFI and customer minutes.[13] These indices determine reliability performance based on the customer impact of outages. In 2012, the Canadian Electricity Association began capturing and reporting on 2 additional indices: CIKM and CHIKM.[14] These indices determine 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 2018 project involves work on feeders KEN-03, SUM-02 and TRP-01. Table 1 shows the number of customers affected and the average unscheduled interruption statistics by feeder for the five-year period ending December 31, 2016. These statistics exclude interruptions due to any causes other than distribution system failure. An analysis of these feeders' performance is contained in report ***4.1*** *Distribution Reliability Initiative*.

Table 1

Distribution Interruption Statistics
Five-Year Average to December 31, 2016

Feeder	Customers	SAIFI	SAIDI	CHIKM	CIKM
KEN-03	2,317	1.69	2.69	241	151
SUM-02	609	3.68	10.59	81	28
TRP-01	605	2.76	5.90	32	15
Company Average		**1.43**	**1.71**	**56**	**49**

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12 These feeders are sometimes referred to in the industry as *worst performing feeders*.

13 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.

14 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 the worst-performing feeders experience power interruptions more often, or of longer duration, than the Company average 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.[15]

Projected Expenditures

Table 2 provides the breakdown of the proposed expenditures for 2018 and a projection of expenditures through 2022.

Table 2
Projected Expenditures
(000s)

Cost Category	2018	2019	2020 - 2022	Total
Material	$474	-	-	-
Labour – Internal	500	-	-	-
Labour – Contract	170	-	-	-
Engineering	210	-	-	-
Other	435	-	-	-
Total	**$1,789**	**$1,500**	**$4,500**	**$7,789**

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.

[15] Chart 6 of the 2018 Capital Plan shows a 58% improvement in SAIDI and 67% improvement in SAIFI over the period from 2000 to 2016.

Future Commitments

The DRI work proposed for distribution feeders SUM-02 and TRP-01 in 2017 and 2018 were approved in Order No. P.U. 39 (2016).

The Distribution Reliability work for SUM-02 is a multi-year project with expenditures planned for 2017 and 2018. Table 3 details the 2017 and 2018 expenditures for SUM-02.

Table 3
SUM-02 Multi-Year Projected Expenditures
(000s)

Cost Category	2017F	2018B	Total
Material	$208	$265	$473
Labour – Internal	241	307	548
Labour – Contract	54	69	123
Engineering	97	123	220
Other	191	243	434
Total	**$791**	**$1,007**	**$1,798**

The Distribution Reliability work for TRP-01 is a multi-year project with expenditures planned for 2017 and 2018. Table 4 details the 2017 and 2018 expenditures for TRP-01.

Table 4
TRP-01 Multi-Year Projected Expenditures
(000s)

Cost Category	2017F	2018B	Total
Material	$106	$106	212
Labour – Internal	81	81	162
Labour – Contract	83	83	166
Engineering	49	49	98
Other	105	105	210
Total	**$424**	**$424**	**$848**

The Distribution Reliability work for KEN-03 is planned to be completed in 2018.

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

Project Cost: **$612,000**

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 efficiency of restoration following both local and system wide outages.[16] 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, thereby reducing the duration of the outage for customers upstream of the fault location. In addition, installation of automated reclosers improves the Company's capability to deal with cold load pickup.

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 2018, a downline automated recloser will be installed on each of the following distribution feeders:

St. John's	Eastern	Central	Western
CHA-01	BRB-01	LEW-01[17]	DLK-03
CHA-02	MIL-02		
CHA-03			
HWD-07			
HWD-09			

[16] 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*, December 17, 2014.

[17] LEW-01-R2 will be a single-phase recloser. All other downline reclosers will be 3-phase reclosers.

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, including local and system-wide outages.

Projected Expenditures

Table 1 provides the breakdown of the proposed expenditures for 2018 and a projection of expenditures through 2022.

Table 1

Projected Expenditures
(000s)

Cost Category	2018	2019	2020 - 2022	Total
Material	$324	-	-	-
Labour – Internal	72	-	-	-
Labour – Contract	24	-	-	-
Engineering	96	-	-	-
Other	96	-	-	-
Total	**$612**	**$490**	**$960**	**$2,062**

Costing Methodology

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

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

Future Commitments

This is not a multi-year project.

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

Project Cost: **$210,000**

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 2018 and a projection of expenditures through 2022.

Table 1

Projected Expenditures
(000s)

Cost Category	2018	2019	2020 - 2022	Total
Material	-	-	-	-
Labour – Internal	-	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	$210	-	-	-
Total	**$210**	**$215**	**$672**	**$1,097**

Costing Methodology

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

Table 2
Expenditure History and Budget Estimate
(000s)

Year	2013	2014	2015	2016	2017F
Total	$196	$208	$214	$197	$209

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: **$479,000**

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 ($125,000)*: 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 ($129,000)*: 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.[18]

[18] 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 2018 and a projection of expenditures through 2022.

Table 1

Projected Expenditures
(000s)

Cost Category	2018	2019	2020 - 2022	Total
Material	$479	-	-	-
Labour – Internal	-	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	-	-	-	-
Total	**$479**	**$489**	**$1,528**	**$2,496**

Costing Methodology

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

Table 2
Expenditure History
(000s)

Year	**2013**	**2014**	**2015**	**2016**	**2017F**
Total	$443	$440	$328	$443[1]	$475

[1] Excludes cost of a load cell and tools for a new line truck. ($113,000)

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 is 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 will be obtained through competitive tendering.

Future Commitments

This is not a multi-year project.

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

Project Cost: **$671,000**

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 2018 project consists of the upgrading, refurbishment or replacement of equipment and facilities due to organizational changes, damage, deterioration, corrosion and in-service failure. Based on recent historical information, $341,000 is required for 2018. This project also includes corporate security upgrades to the Company's security infrastructure, including improvements in public entrances, access control, surveillance and lighting of Company facilities. Based on an engineering estimate, $100,000 is required for corporate security upgrades in 2018. The Duffy Place facility requires backflow prevention for its water supply at an estimated cost of $200,000. Upgrades to energy efficient lighting in buildings is estimated at $30,000 for 2018.

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 other facilities, and to operate them in a safe and efficient manner.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2018 and a projection of expenditures through 2022.

Table 1 **Projected Expenditures** **(000s)**				
Cost Category	**2018**	**2019**	**2020 - 2022**	**Total**
Material	$561	-	-	-
Labour – Internal	39	-	-	-
Labour – Contract	-	-	-	-
Engineering	42	-	-	-
Other	29	-	-	-
Total	**$671**	**$479**	**$1,391**	**$2,541**

Costing Methodology

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

Table 2 **Expenditure History** **(000s)**					
Year	**2013**	**2014**	**2015**	**2016**	**2017F**
Total	$401[1]	$271[2]	$307[3]	$293[4]	$371[5]

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 ($98,000).
5 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 – Carbonear Parking Lot (Other)**

Project Cost: **$298,000**

Project Description

This General Property project involves the resurfacing of the 40-year old asphalt parking lot at Newfoundland Power's Regional Facility at 30 Goff Avenue in Carbonear. The Carbonear service building is the Company's main facility for the Avalon operating area. The asphalt parking lot is original to the 1977 construction of the building. Approximately 5,400 m^2 of asphalt will be replaced and deteriorated curbs and catch basins refurbished or replaced, as required.

Justification

The project is justified based on the age and the deterioration of the existing Carbonear parking lot. Justifications for company building renovations are based on inspections completed by professional engineers or independent experts.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2018 and a projection of expenditures through 2022.

Table 1
Multi-year Projected Expenditures
(000s)

Cost Category	2018	2019	2020 - 2022	Total
Material	$242	-	-	-
Labour – Internal	9	-	-	-
Labour – Contract	-	-	-	-
Engineering	26	-	-	-
Other	21	-	-	-
Total	**$298**	-	-	**$298**

Costing Methodology

The budget estimate for this project is based on an 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 not a multi-year project.

Project Title: **Security Fencing Refurbishment – St. John's (Pooled)**

Project Cost: **$315,000**

Project Description

This General Property project consists of capital expenditures necessary for the refurbishment of the security fencing at Company locations. Newfoundland Power has a number of sites where electrical equipment and hazardous materials are stored. These sites are vulnerable to theft, vandalism and trespassing. These sites are secured by perimeter fencing and controlled access gates. As this infrastructure ages, it requires refurbishment to ensure safe and secure operation of the sites.

In 2018, the Company will refurbish security fencing at 2 storage yards in the St. John's area.

1. *Equipment Maintenance Centre - EMC ($216,000)*
   The perimeter galvanized steel fence at the EMC is in poor condition and in need of refurbishment. The fence needs to be replaced with an 8-foot high fence topped with a barbed wire outrigger. No trespassing signage will be installed on the fence.

   The main entrance to the EMC is a swing gate that is not motorized and does not have separate pedestrian access. A motorized vehicle gate and a smaller personnel gate with secure access control will replace the existing vehicle swing gate. Both gates will be opened using the Company's standard access control cards issued to employees and approved contractors.

2. *Central Stores ($99,000)*
   A section of the perimeter galvanized steel fence at Central Stores is in poor condition and in need of refurbishment. The barbed wire outrigger along the north side is in need of replacement. The locking mechanism on the vehicle swing gates will be replaced with a more robust design. No trespassing signage will be installed on the fence.

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 necessary to maintain and operate Company storage sites in a safe and efficient manner. Secure storage sites will ensure that the Company's inventory of materials and spare equipment are not stolen or damaged. Securing the sites will also prevent the general public from being injured if they enter the property without proper supervision.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2018 and a projection of expenditures through 2022.

Table 1
Projected Expenditures
(000s)

Cost Category	2018	2019	2020 - 2022	Total
Material	$259	-	-	-
Labour – Internal	16	-	-	-
Labour – Contract	-	-	-	-
Engineering	21	-	-	-
Other	19	-	-	-
Total	**$315**	-	-	**$315**

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: **$3,362,000**

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 service lives.

Table 1 summarizes the units to be replaced in 2018.

Table 1
2018 Proposed Vehicle Replacements

Category	**No. of Units**
Heavy Fleet Vehicles	7
Passenger Vehicles[1]	23
Off-road Vehicles[2]	4
Total	**34**

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 2018, there are 7 heavy fleet vehicles that meet the age, mileage and condition parameters that indicate replacement is necessary. Also in 2018, the Company has identified 23 passenger and 4 off-road 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 2018 and a projection of expenditures through 2022.

Table 2
Projected Expenditures
(000s)

Cost Category	2018	2019	2020 - 2022	Total
Material	$3,362	-	-	-
Labour – Internal	-	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	-	-	-	-
Total	**$3,362**	**$3,429**	**$11,051**	**$17,842**

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

Table 3
Expenditure History
(000s)

Year	2013	2014	2015	2016	2017F
Total	$3,220	$2,872	$3,080	$3,377	$3,456

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 service life and require replacement in 2018.

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: **$99,000**

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 achieve operational efficiencies. The 2018 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 Company's Supervisory Control and Data Acquisition ("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 on local conditions and available service offerings from telecommunications providers. 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 providers. As a result the equipment must be upgraded or replaced.

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 2018 and a projection of expenditures through 2022.

Table 1 **Projected Expenditures** **(000s)**				
Cost Category	**2018**	**2019**	**2020 - 2022**	**Total**
Material	$61	-	-	-
Labour – Internal	10	-	-	-
Labour – Contract	-	-	-	-
Engineering	19	-	-	-
Other	9	-	-	-
Total	**$99**	**$102**	**$318**	**$519**

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	**2013**	**2014**	**2015**	**2016**	**2017F**
Total	$82	$97	$78	$109	$98
Adjusted Cost[1]	$90	$103	$81	$112	

[1] 2017 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, 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 determine the budget estimate. To ensure consistency from year to year, expenditures related to planned projects are excluded from the calculation of the historical average.

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

Future Commitments

This is not a multi-year project.

Project Title: **Fibre Optic Network (Other)**

Project Cost: **$99,000**

Project Description

This Telecommunications project involves the addition of a new fibre optic link in the Company's fibre optic network connecting its substations and office in the City of Corner Brook.

The Company currently operates more than 36 fibre optic links. These fibre optic links are used for corporate data, substation, voice and SCADA communications, protective relay communications, as well as data communications between Newfoundland Power's and Newfoundland and Labrador Hydro's control centres.[19] In 2018, the Company will build a fibre optic cable link between Humber substation and Bayview substation in Corner Brook.[20]

Included in the Company's five-year *Substation Refurbishment and Modernization Plan*, the protection system on the 66 kV transmission lines interconnecting the 4 Corner Brook substations will be upgraded. As part of this protection upgrade, the Company will undertake a program to install fibre optic cables between all 4 substations in the City of Corner Brook.

The individual budget items are similar in nature and are therefore pooled for consideration as a single capital project.

Justification

Reliable communications equipment is essential to the provision of safe, reliable electrical service.

Fibre optic cables are used to provide communications between digital protective relays in selected substations. The communication established between relays monitors the substation equipment at both ends of the associated transmission lines interconnecting the substations, protecting employees and the public from energized failures of transmission line infrastructure. Also, the fibre optic cables provide SCADA communications between the substations and the System Control Centre, allowing for the remote monitoring and control of all critical substation equipment.

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[19] The Company's fibre optic network in St. John's includes a cable to Newfoundland and Labrador Hydro's Energy Management Centre. This fibre cable carries the Inter Control Centre Protocol ("ICCP") link, which is used to exchange real-time power system data between the 2 SCADA systems.

[20] This fibre optic link will allow for the connection of corporate and SCADA data traffic to these substations, thereby reducing the number of leased circuits used for SCADA communications in Corner Brook. Also, the link will carry data communications between digital protection relays in the substation to improve clearing times for faults on the 66 kV transmission system.

The communications transmitted by the fibre optic cables, for both protection and remote control functionality, are essential for the provision of safe and reliable service to customers.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2018 and a projection of expenditures through 2022.

Table 1

Projected Expenditures
(000s)

Cost Category	2018	2019	2020 - 2022	Total
Material	$79	-	-	-
Labour – Internal	4	-	-	-
Labour – Contract	-	-	-	-
Engineering	12	-	-	-
Other	4	-	-	-
Total	**$99**	**-**	**$489**	**$588**

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 will be obtained through competitive tendering.

Future Commitments

This is not a multi-year project.

INFORMATION SYSTEMS

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

Project Cost: **$858,000**

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 the provision of service to customers, the effective operation of the electrical system, and compliance with regulatory and financial reporting requirements.

The application enhancements proposed in 2018 include: (i) replacement of the Company's Safety and Environment Management System application; (ii) the introduction of mobile field payment devices; (iii) enhancements to accommodate the introduction of a second area code for Newfoundland and Labrador; and (iv) enhancements to the energy conservation website.

The application enhancements proposed for 2018 are not inter-dependent, but are similar in nature and justification and are therefore pooled for consideration as a single capital project.

Details on proposed expenditures are included in ***5.1*** *2018 Application Enhancements*.

Justification

The proposed enhancements included in this project are justified on the basis of improving customer service and operational efficiencies, and achieving compliance with regulatory and legislative requirements.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2018 and a projection of expenditures through 2022.

Table 1 **Projected Expenditures** **(000s)**				
Cost Category	**2018**	**2019**	**2020 - 2022**	**Total**
Material	$75	-	-	-
Labour – Internal	548	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	235	-	-	-
Total	**$858**	**$1,000**	**$3,000**	**$4,858**

Costing Methodology

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

Table 2 **Expenditure History** **(000s)**					
Year	**2013**	**2014**	**2015**	**2016**	**2017F**
Total	$1,473	$1,382	$1,301	$1,143	$1,003

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 the sole-source supplier to ensure least cost.

Future Commitments

This is not a multi-year project.

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

Project Cost: **$1,343,000**

Project Description

This Information Systems project involves upgrades to third-party software products that comprise the Company's information systems. Such upgrades are necessary to ensure continued vendor support, to improve compatibility with software or hardware upgrades, or to take advantage of newly developed functionality.

For 2018, the project includes upgrades to the Company's Geographic Information System, Supervisory Control and Data Acquisition system, and components of the Customer Service System, as well as improvements to the disaster recovery capabilities of the Avaya contact centre solution.

This project also includes the Microsoft Enterprise Agreement. This agreement covers the purchase of Microsoft software products and provides access to the latest versions of each product purchased under the agreement. Details on the multi-year expenditures associated with the Microsoft Enterprise Agreement are included in *Schedule C* to this Application.

Details on proposed expenditures are included in ***5.2** 2018 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 2018 and a projection of expenditures through 2022.

Table 1 **Projected Expenditures** **(000s)**				
Cost Category	**2018**	**2019**	**2020 - 2022**	**Total**
Material	$550	-	-	-
Labour – Internal	533	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	260	-	-	-
Total	**$1,343**	**$1,848**	**$4,482**	**$7,673**

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	**2013**	**2014**	**2015**	**2016**	**2017F**
Total	$1,269	$1,066	$1,163	$1,664	$1,676

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 the sole-source supplier to ensure least cost.

Future Commitments

This project includes provision in 2018 for the renewal of the Microsoft Enterprise Agreement, which is included in Schedule C. This is not otherwise a multi-year project.

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

Project Cost: **$472,000**

Project Description

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

In 2018, a total of 116 PCs will be purchased, consisting of 30 desktop computers and 86 mobile computers. This project also includes the purchase of peripheral equipment, such as monitors, mobile devices, and workgroup 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 five-year lifecycle for its PCs before they require replacement.

Table 1 outlines the PC additions and retirements for 2016 and 2017, as well as the proposed additions and retirements for 2018.

Table 1
PC Additions and Retirements
2016 – 2018B

	2016			2017F			2018B		
	Add	**Retire**	**Total**	**Add**	**Retire**	**Total**	**Add**	**Retire**	**Total**
Desktop	51	68	424	70	89	405	30	30	405
Mobile	65	48	325	95	98	322	86	86	322
Total	**116**	**116**	**749**	**165**	**187**	**727**	**116**	**116**	**727**

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 service life.

Projected Expenditures

Table 2 provides a breakdown of the proposed expenditures for 2018 and a projection of expenditures through 2022.

Table 2
Projected Expenditures
(000s)

Cost Category	2018	2019	2020 - 2022	Total
Material	$325	-	-	-
Labour – Internal	102	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	45	-	-	-
Total	**$472**	**$477**	**$1,518**	**$2,467**

Costing Methodology

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

Table 3
Expenditure History
(000s)

Year	2013	2014	2015	2016	2017F
Total	$411	$455	$488	$470	$485

The 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, workgroup 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: **$648,000**

Project Description

This Information Systems project includes the addition, upgrade and replacement of computer hardware components and related technology associated with shared server infrastructure and peripheral equipment. The Company's shared servers are used for the routine operation, testing, and disaster recovery of the Company's corporate applications. Management of these shared servers and their components is critical to ensuring these applications operate effectively at all times.

The project is necessary to ensure the secure operation of the Company's shared sever infrastructure, and to complete lifecycle replacement of equipment that is at the end of its expected service life.

For 2018, the project includes:

1. Implementation of a Web Application Firewall for corporate web applications accessible via the Internet;
2. Implementation of a security monitoring and alerting service for the Company's Supervisory Control and Data Acquisition ("SCADA") infrastructure;
3. Lifecycle replacement of the corporate secure remote access solution, which allows Company employees to securely access Company applications and systems while not physically in a Company office; and
4. Lifecycle replacement of high-volume printing equipment in the Company's production centre, which is required for customer billing and other functions.

The shared server infrastructure requirements for 2018 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 ***5.3*** *2018 Shared Server Infrastructure*.

Justification

This project is justified on the basis of maintaining current levels of customer service and operational efficiencies, while protecting corporate and customer information on the Company's shared server infrastructure.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2018 and a projection of expenditures through 2022.

Table 1

Projected Expenditures
(000s)

Cost Category	2018	2019	2020 - 2022	Total
Material	$360	-	-	-
Labour – Internal	248	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	40	-	-	-
Total	**$648**	**$879**	**$2,798**	**$4,325**

Costing Methodology

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

Table 2

Expenditure History
(000s)

Year	2013	2014	2015	2016	2017F
Total	$941	$832	$997	$847	$661

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 the sole-source supplier to ensure least cost.

Future Commitments

This is not a multi-year project.

Project Title: **Network Infrastructure (Pooled)**

Project Cost: **$467,000**

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 throughout the Company, enabling the transport of Supervisory Control and Data Acquisition ("SCADA"), corporate and customer service data. In addition to traditional wired network technologies, the Company has increased its use of wireless communications technologies in recent years.

For 2018, 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. Also in 2018, the Company will improve the security of SCADA circuits that use public networks for primary and backup communications, and better management of mobile computers in Company vehicles that also use public networks to communicate securely with corporate information systems.

The individual network infrastructure requirements for 2018 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 2018 and a projection of expenditures through 2022.

Table 1
Projected Expenditures
(000s)

Cost Category	2018	2019	2020 - 2022	Total
Material	$214	-	-	-
Labour – Internal	178	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	75	-	-	-
Total	**$467**	**$344**	**$1,094**	**$1,905**

Costing Methodology

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

Table 2
Expenditure History
(000s)

Year	2013	2014	2015	2016	2017F
Total	$218	$345	$307	$312	$388

The budget for this project is based on cost estimates for the individual budget items based on past experiences and pricing. The historical average cost for the past 5 years is approximately $314,000. The improvements required in 2018 for the secure use of public networks used by the SCADA system and remote management of mobile computers is an additional $153,000.

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 the 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: **$2,360,000**

Project Description

This Information Systems project is a multi-year project to replace the Company's existing Outage Management System ("OMS"). The existing OMS was deployed in 2003 and is now functionally obsolete.[21] Following a review of commercial OMS products and current Canadian utility practice, the Company has determined the most appropriate approach to modernizing its OMS is to replace the existing system with a commercially available product that offers enhanced functionality.

The replacement aspect of the project includes integrating the new OMS with the Company's recently implemented SCADA system and GIS. This will make real-time electrical system information available to Company employees when responding to customer outages. Three additional enhancements will also be included as part of the new OMS. Each of these enhancements will improve the Company's ability to respond to customer outages. The 3 enhancements are: (i) automated outage assessment, which will improve the Company's ability to analyze the cause and location of outages; (ii) integrated dispatch and follow up, which will expedite outage response; and (iii) coordinated customer communications, which will ensure customers receive more timely and accurate information concerning outages.

This is a multi-year project, with total project cost of $3,570,000 over 2 years, starting 2018.

Details on the 2018 OMS replacement and enhancement project are included in report ***5.5*** *Outage Management System Replacement & Enhancement.*

Justification

The OMS is a cornerstone of reliability management at Newfoundland Power. Implementation of a new OMS will address the functional obsolescence of the Company's existing system. The inclusion of enhanced functionality will: (i) ensure crews are dispatched more quickly, thereby reducing the duration of customer outages; (ii) improve the accuracy and timeliness of customer communications during outages; and (iii) reduce or eliminate manual processes, which will ensure the Company can continue to manage outages in a cost-effective way.

This project is justified on the basis of improving reliability performance and customer service.

[21] Newfoundland Power's existing OMS was developed internally and cannot integrate with the Company's Supervisory Control and Data Acquisition ("SCADA") system or Geographic Information System ("GIS"). This practically requires Company employees to assess and respond to outages without the benefit of real-time information. The existing OMS is therefore considered functionally obsolete.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2018 and a projection of expenditures through 2022.

Table 1

Projected Expenditures (000s)

Cost Category	2018	2019	2020 - 2022	Total
Material	$1,665	$505	-	$2,170
Labour – Internal	640	650	-	1,290
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	55	55	-	110
Total	**$2,360**	**$1,210**	-	**$3,570**

Costing Methodology

The budget for this project is based on cost estimates obtained through a Request for Proposals process for the new OMS.

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 to be completed in 2018 and 2019.

Project Title: **Human Resource Management System Replacement (Other, Multi-year)**

Project Cost: **$422,000**

Project Description

Newfoundland Power manages a workforce of approximately 686 regular and temporary employees. In addition, the Company has approximately 775 retirees. As part of its Human Resource Management System ("HRMS"), the Company currently uses a combination of software applications to ensure effective human resource management.[22]

The core component in the Company's HRMS is the 15-year-old Empower application. Empower is now functionally obsolete and at the end of its service life. The Company was recently informed by the vendor that the application is no longer being advanced, improved or supported. Starting in 2018, the Company will commence a 2-year project to replace the existing HRMS with a commercially available application.

This is a multi-year project, with total project cost of $1,637,000 over 2 years.

Details on proposed expenditures are included in the report ***5.4** Human Resource Management System Replacement.*

Justification

The acquisition of a commercially available HRMS is necessary to address the functional obsolescence of the Empower application. In addition, implementing a replacement HRMS application will ensure an appropriate level of vendor support, improve the Company's ability to update the system, and achieve operational efficiencies through a reduction in manual data entry. Overall, the replacement application will better enable the Company to effectively manage its workforce and retirees.

[22] The Company's HRMS is provided through a variety of different software applications and tools that deliver the required functionality. In addition to the Empower application, the existing HRMS incorporates a number of in-house developed applications, workflows, spreadsheets, databases and reports.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2018 and 2019, along with a projection of expenditures through 2022.

Table 1
Projected Expenditures (000s)

Cost Category	2018	2019	2020 - 2022	Total
Material	$17	$360	-	-
Labour – Internal	305	400	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	100	455	-	-
Total	**$422**	**$1,215**	-	**$1,637**

Costing Methodology

The budget for this project is based on cost estimates provided by potential suppliers and an estimate for the internal effort required to complete the project.

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 to be completed in 2018 and 2019.

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 that 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.
2018 Capital Budget
Multi-Year Projects Approved in Previous Years

Class	Project Description	CBA/ Board Order		Expenditure (000s) 2017	2018	2019	2020	Total
Distribution	Distribution Reliability Initiative[1]	2017 CBA P.U. 39 (2016)	Approved	$1,215	$1,431			$2,646
			Forecast	$1,215	$1,431			$2,646

[1] 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.
2018 Capital Budget
Multi-Year Projects Commencing in 2018

Class	Project Description	CBA/ Board Order		Expenditure (000s) 2018	2019	2020	2021	Total
Generation Thermal	Purchase Mobile Generation[2]	2018 CBA	Budget	$6,000	$7,915			$13,915
Transmission	Transmission Line Rebuild[3]	2018 CBA	Budget	5,068	6,064	3,600	3,750	18,482
Distribution	Feeder Additions for Growth[4]	2018 CBA	Budget	319	665			984
Information Systems	Microsoft Enterprise Agreement[5]	2018 CBA	Budget	245	245	245		735
Information Systems	Outage Management System[6]		Budget	2,360	1,210			3,570
Information Systems	Human Resource Management System Replacement[7]	2018 CBA	Budget	422	1,215			1,637
			Total	**$14,414**	**$17,314**	**$3,845**	**$3,750**	**$39,323**

[2] A detailed project description can be found in the 2018 Capital Budget Application, Schedule B pages 7 to 8 of 90, and report ***1.2*** *Purchase Mobile Generation.*
[3] A detailed project description can be found in the 2018 Capital Budget Application, Schedule B pages 17 to 19 of 90, and report ***3.1*** *2018 Transmission Line Rebuild.*
[4] A detailed project description can be found in the 2018 Capital Budget Application, Schedule B pages 43 to 44 of 90, and report ***4.2*** *Feeder Additions for Growth.*
[5] A detailed project description can be found in the 2018 Capital Budget Application, Schedule B pages 74 and 75 of 90, and report ***5.2*** *2018 System Upgrades.*
[6] A detailed project description can be found in the 2018 Capital Budget Application, Schedule B pages 83 and 84 of 90, and report ***5.5*** *Outage Management System Replacement & Enhancement.*
[7] A detailed project description can be found in the 2018 Capital Budget Application, Schedule B pages 85 and 86 of 90, and report ***5.4*** *Human Resource Management System Replacement.*

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

	2016	2015
Net Plant Investment		
Plant Investment	1,741,193	1,665,762
Accumulated Depreciation	(694,843)	(668,641)
Contributions in Aid of Construction	(36,094)	(34,238)
	1,010,256	962,883
Additions to Rate Base		
Deferred Pension Costs	94,775	98,829
Deferred Credit Facility Costs	94	56
Cost Recovery Deferral – Seasonal/TOD Rates	-	49
Cost Recovery Deferral – Hearing Costs	682	-
Cost Recovery Deferral – Conservation	11,304	7,463
Weather Normalization Reserve	1,721	4,411
Customer Finance Programs	1,341	1,211
	109,917	112,019
Deductions from Rate Base		
Other Post-Employment Benefits	46,083	39,208
Customer Security Deposits	786	1,286
Accrued Pension Obligation	5,285	4,955
Accumulated Deferred Income Taxes	2,186	1,268
2016 Cost Recovery Deferral	1,445	-
Excess Earnings Account	-	49
	55,785	46,766
Year End Rate Base	1,064,388	1,028,136
Average Rate Base Before Allowances	1,046,262	1,006,063
Rate Base Allowances		
Materials and Supplies Allowance	6,464	6,280
Cash Working Capital Allowance	8,318	6,739
Average Rate Base at Year End	1,061,044	1,019,082

2018 Capital Plan

July 2017

WHENEVER. WHEREVER.
We'll be there.

NEWFOUNDLAND POWER
A FORTIS COMPANY

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Appendix A: 2018-2022 Capital Plan

1.0 Introduction

Newfoundland Power's *2018 Capital Plan* provides an overview of the Company's 2018 capital budget, together with an outlook for capital expenditure through 2022.

Newfoundland Power's 2018 capital budget totals $83,876,000.

For the 5 years from 2018 through 2022, Newfoundland Power plans to make capital investments totaling approximately $470 million. This is $11 million, or about 2%, lower than the 5-year outlook presented in the Company's *2017 Capital Plan*.

Changes in customer requirements are a primary influence on the Company's lower capital planning forecast. For example, *2018 Capital Plan* expenditures in the *Substation Additions Due to Load Growth* capital project are forecast to decline by approximately 27% from what was estimated in the *2017 Capital Plan* due, in part, to lower projected growth in customer load. Over the previous 5-year period, the capital expenditures in the *Substation Additions Due to Load Growth* capital project were approximately $19.9 million or $12.4 million more than what is forecast in the *2018 Capital Plan*.

Similarly, forecast Distribution capital expenditure for the 5 years from 2018 through 2022 are reduced. The *2018 Capital Plan* forecast for Distribution capital expenditure is approximately 7.5% lower than the 5-year outlook presented in the Company's *2017 Capital Plan.* This reduction is also largely reflective of reduced forecast customer requirements.

Technological change has also influenced Newfoundland Power's capital planning forecast for Distribution. Part of the reduction in the Distribution capital forecast over the 2018 to 2022 period reflects the forecast conclusion of the Company's accelerated deployment of AMR meters in 2017.[1] Reduced expenditures for AMR meters result in reduced Distribution expenditures during the 2018 to 2022 period.[2]

Stability and predictability in capital planning are 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 *2018 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*.

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1 AMR meter denotes Automated Meter Reading meters.

2 Over the 5-year period from 2013 to 2017, capital expenditures for meters totaled approximately $18 million. Forecast capital expenditures for meters for the 5-year period 2018 to 2022 are approximately $3 million.

2.0 2018 Capital Budget

Newfoundland Power's 2018 capital budget is $83,876,000.

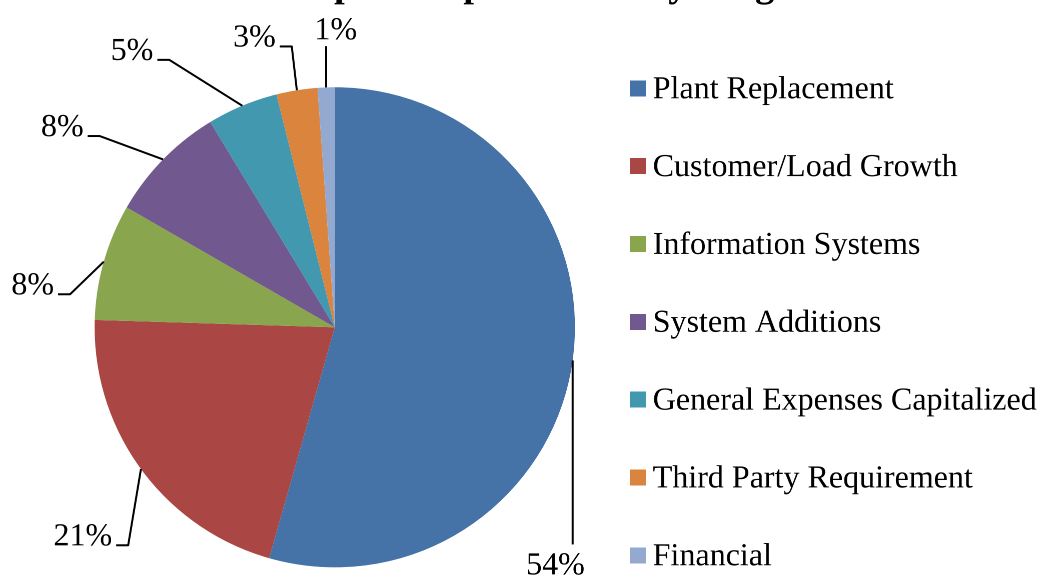
This section of the 2018 Capital Plan provides an overview of the 2018 capital budget by origin (root cause) and asset class. In addition, this section summarizes 2018 capital projects by the various categories set out in the Board's October 2007 Capital Budget Application Guidelines.

2.1 2018 Capital Budget Overview

Newfoundland Power's 2018 Capital Budget contains 36 projects totalling approximately $83.6 million.

Chart 1 shows the 2018 capital budget by origin, or root cause.

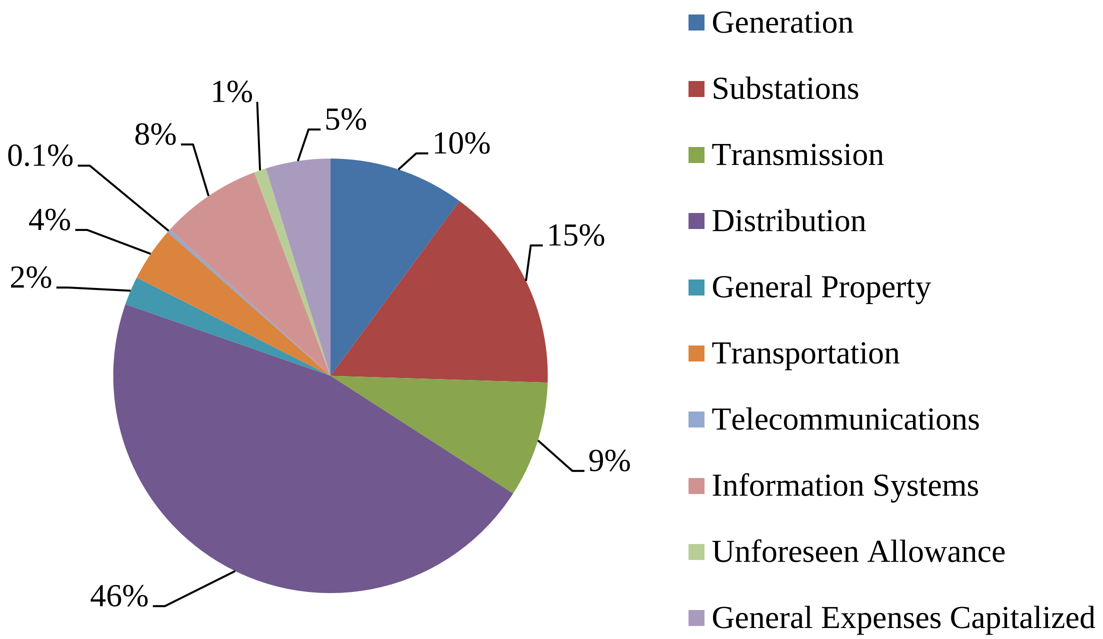
Chart 1
2018 Capital Expenditures by Origin



Approximately 54% of proposed 2018 capital expenditure is related to the replacement of plant. A further 21% of proposed 2018 capital expenditure is required to meet the Company's obligation to serve new customers and meet the requirement for increased system capacity. Information Systems account for 8% of proposed 2018 capital expenditures. The remaining 17% of forecast capital expenditures for 2018 relates to System Additions, General Expenses Capitalized, Third Party Requirements, and Financial Costs (allowance for funds used during construction).[3] The allocation of 2018 capital expenditures is broadly consistent with capital budgets for the past 5 years.

Chart 2 shows the 2018 capital budget by asset class.

Chart 2
2018 Capital Expenditures by Asset Class



As in past years, Distribution capital expenditure accounts for the greatest percentage of overall expenditure at $38.9 million, or 46% of the 2018 capital budget. Substations capital expenditure accounts for $12.8 million, or 15% of the 2018 capital budget. Generation capital expenditure accounts for $8.4 million, or 10% of the 2018 capital budget. Transmission capital expenditure accounts for $7.2 million, or 9% of the 2018 capital budget. Information Systems capital expenditure accounts for $6.6 million, or 8% of the 2018 capital budget. Together, expenditure for these 5 asset classes comprises 88% of the Company's 2018 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. Distribution capital expenditures in 2018 and beyond are expected to reflect reduced new customer connections. The 2018 estimate of 2,782 gross new customer connections is the lowest it has been since 1999 when 2,737 new customers were connected.

3 The purchase of new mobile generation is initially considered a system addition as the Company intends to permanently locate the existing mobile gas turbine and continue to operate the generator until the end of its service life.

The Company will continue with the rebuilding of the oldest, most deteriorated transmission lines in its system. In 2018, the Company will commence multi-year projects to rebuild Transmission lines 302L on the Burin Peninsula and 363L on the Baie Verte Peninsula.

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 2018 Capital Budget Application complies with the CBA Guidelines.

The 2018 Capital Budget Application includes 36 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 2018 capital budget, along with a summary of costs segmented by materiality.

2018 Capital Projects by Definition

Table 1 summarizes Newfoundland Power's proposed 2018 capital projects by definition, as set out in the CBA Guidelines.

Table 1
2018 Capital Projects
By Definition

Definition	**Number of Projects**	**Budget (000s)**
Pooled	28	$69,149
Clustered[4]	0	0
Other	8	14,727
Total	**36**	**$83,876**

There are a total of 28 *pooled* projects, accounting for 82% of total expenditures.

[4] There are no Clustered projects in 2018.

2018 Capital Projects by Classification

Table 2 summarizes Newfoundland Power's proposed 2018 capital projects by classification, as set out in the CBA Guidelines.

Table 2
2018 Capital Projects
By Classification

Classification	**Number of Projects**	**Budget (000s)**
Normal	34	$82,045
Mandatory	1	973
Justifiable	1	858
Total	**36**	**$83,876**

There are 34 *normal* projects accounting for 98% of total expenditures.

2018 Capital Projects by Costing Method

Table 3 summarizes Newfoundland Power's proposed 2018 capital projects by costing method (i.e., identified need vs. historical pattern), as set out in the CBA Guidelines.

Table 3
2018 Capital Projects
By Costing Method

Method	**Number of Projects**	**Budget (000s)**
Identified Need	20	$38,643
Historical Pattern	16	45,233
Total	**36**	**$83,876**

Projects with costing method based on *identified need* account for 46% of total expenditures, while those based on *historical pattern* account for 54% of total expenditures.

2018 Capital Projects by Materiality

Table 4 segments Newfoundland Power's proposed 2018 capital projects by materiality, as set out in the CBA Guidelines.

Table 4
2018 Capital Projects
Segmentation by Materiality

Segment	**Number of Projects**	**Budget (000s)**
Under $200,000	2	$198
$200,000 - $500,000	8	2,964
Over $500,000	26	80,714
Total	**36**	**$83,876**

There are 26 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 2018 through 2022 includes forecast average annual capital expenditure of $94.0 million. Over the 5-year period 2013 through 2017, the average annual capital expenditure is expected to be $96.1 million.

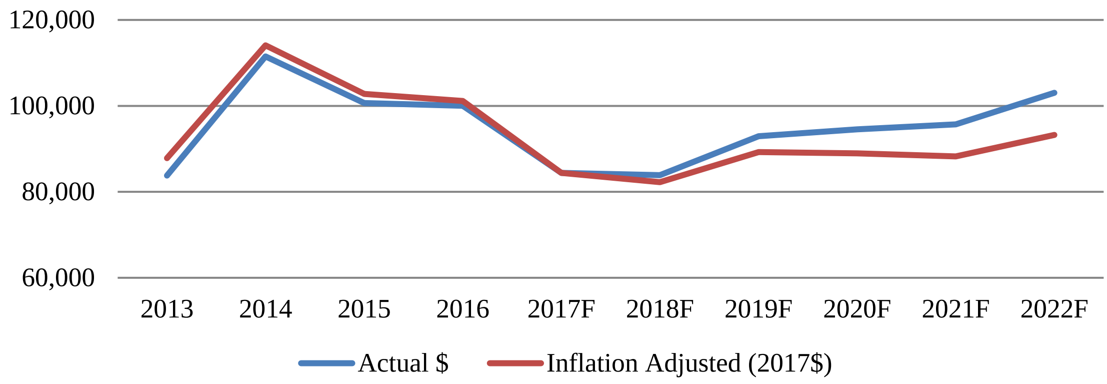
The forecast annual capital expenditure reflects inflation and requirements for specific projects related to the replacement of deteriorated plant and equipment, meeting customer and load growth, replacing the Company's Outage Management and Customer Service systems, and new mobile generation. Average annual expenditures through the forecast period are estimated to be approximately 2% less than in the period 2013 through 2017 primarily due to reduced forecast customer requirements.

3.1 Capital Expenditures: 2013-2022

The Company plans to invest $470 million in plant and equipment during the 2018 through 2022 period. On an annual basis, capital expenditures are expected to average approximately $94.0 million and range from a low of $83.9 million in 2018, to a high of $103.0 million in 2022.

Chart 3 shows actual capital expenditures for the period 2013 through 2016, and forecast capital expenditures for the period 2017 through 2022. For comparison purposes, the annual capital expenditures are also expressed in 2017 dollars to remove the effects of inflation.

Chart 3
Capital Expenditures
2013 to 2022F
($000s)



Overall, planned capital expenditures for the 5-year period from 2018 through 2022 are expected to be lower than those in the 5-year period from 2013 through 2017. Forecast requirements for the 5-year period from 2018 through 2022 include additional power transformers due to forecast load growth, new transmission lines on the Northeast Avalon Peninsula, reconfiguration of the 138 kV transmission system from Grand Falls to Gander, new mobile generation, gas turbine refurbishment, and the replacement of important information technology, such as the Company's Outage Management System and Customer Service System.

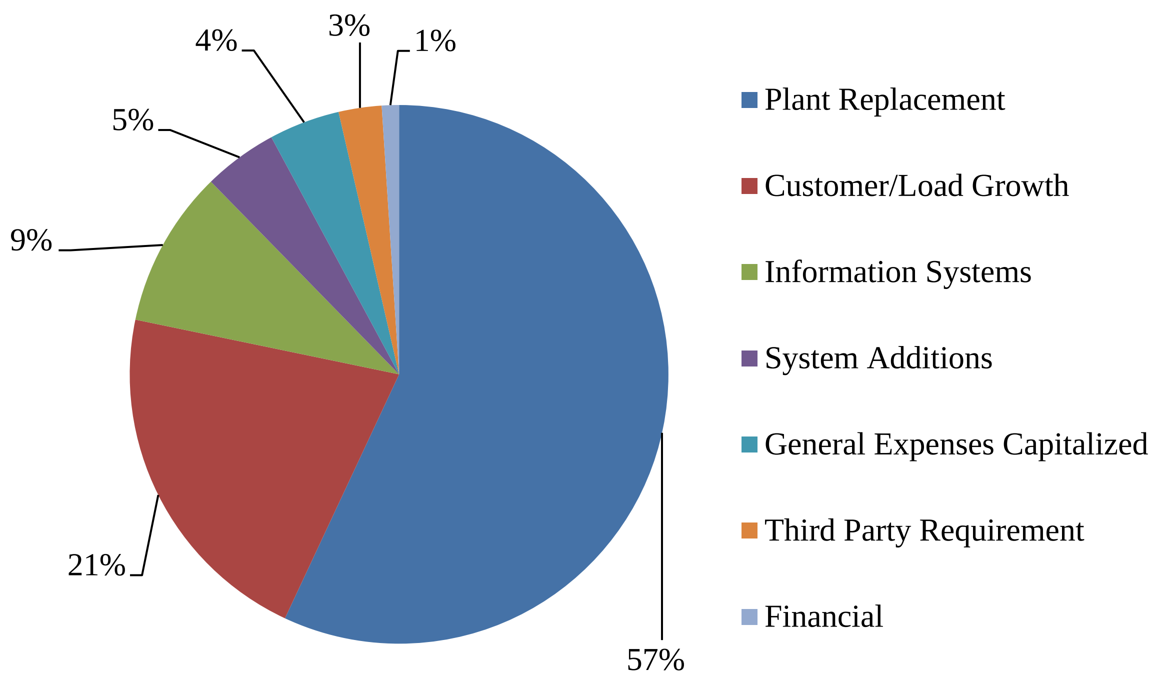
The replacement of plant has been, and is expected to continue to be, the largest driver of Newfoundland Power's capital budget, accounting for 56% of total expenditure for the 10-year period from 2013 through 2022. Over the same 10-year period, capital expenditures to meet increased customer connections and electricity sales account for 26% of total expenditures.

3.2 2018-2022 Capital Expenditures

3.2.1 Overview

Chart 4 shows aggregate forecast capital expenditures by origin for the period 2018 through 2022.

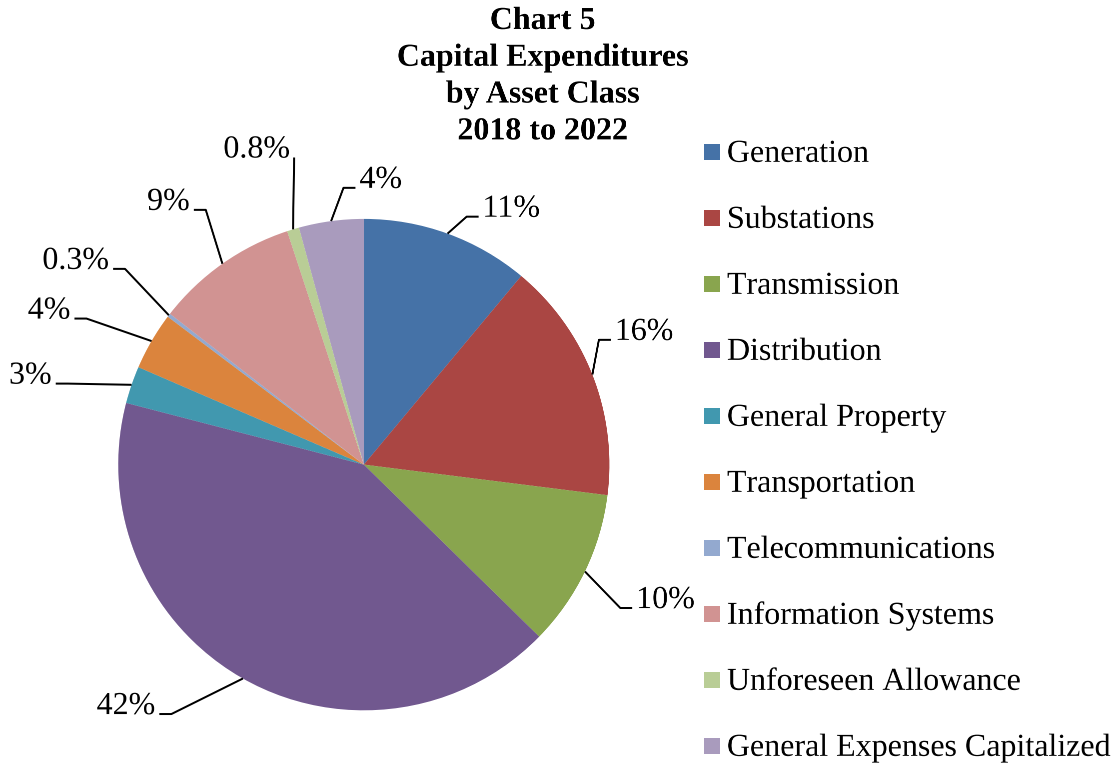
Chart 4
Capital Expenditures
by Origin
2018 to 2022



Plant Replacement accounts for 57% of all planned expenditures over the 5-year period from 2018 through 2022. This is greater than the average of 54% in the previous 5-year period from 2013 through 2017. Capital expenditure related to Customer and Load Growth accounts for 21% of planned expenditures over the 5-year period from 2018 through 2022. This is less than the average of 31% in the previous 5-year period from 2013 through 2017. Capital expenditure related to Information Systems accounts for 9% of planned expenditures over the 5-year period from 2018 through 2022. This is greater than the average of 6% in the previous 5-year period from 2013 through 2017.

The remaining 13% of total capital expenditures for the 2018 through 2022 period relate to a variety of origins, including System Additions, General Expenses Capitalized, Third Party Requirements, and Financial Costs.

Chart 5 shows aggregate forecast capital expenditures for the period 2018 through 2022 by asset class.



The Distribution asset class accounts for 42% of all planned expenditures over the next 5 years, followed by Substations (16%), Generation (11%) and Transmission (10%). The remaining 6 asset classes account for 21% of total capital expenditures for the 2018 through 2022 period.

Overall, planned expenditures for the period 2018 through 2022 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 new mobile generation over the forecast period. The Company has also included the replacement of its Customer Service System in the 5-Year Capital Plan, which increases Information Systems expenditures in 2021 and 2022.

A summary of planned capital expenditures by asset class and by project for 2018 to 2022 is provided in Appendix A.

3.2.2 Generation

Generation capital expenditures will average approximately $10.4 million per year from 2018 through 2022, which is greater than the annual average of $8.6 million from 2013 through 2017.[5]

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

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

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. For example, the following major capital projects are planned:

- In 2018 and 2019, the Company plans to purchase a mobile generator at an estimated cost of $13.9 million. The mobile generator will be used for both emergency generation and to minimize customer outages during planned work.[6]

- In 2019, the Company plans to replace a section of the Topsail woodstave penstock at an estimated cost of $2.3 million.

- In 2020 and 2021, the Company plans to refurbish the Greenhill gas turbine facility at an estimated cost of $7.8 million.

- In 2020 and 2021, the Company plans to replace the turbine runners on both units at the Rattling Brook hydro plant at an estimated cost of $2.2 million.

- In 2021, the Company plans to refurbish the generator and surge tank, and replace the penstock at the Sandy Brook hydro plant at an estimated cost of $4.9 million.

- In 2021 and 2022, the Company plans to upgrade the Wesleyville gas turbine facility. The Company will explore replacement options in advance of the project.

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5 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 refurbishment of Sandy Brook hydro plant.

6 The existing mobile gas turbine will be 45 years old in 2018.

3.2.3 Transmission

Transmission capital expenditures are expected to average $9.7 million annually from 2018 through 2022, compared with $5.7 million annually from 2013 through 2017. The increase in annual expenditure is related to an increase in the kilometres of transmission line to be rebuilt each year, the addition of 2 new transmission lines on the Northeast Avalon Peninsula, and the reconfiguration of the 138 kV transmission system in Central Newfoundland.

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

- preventive capital maintenance;
- rebuilding aging transmission lines; 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 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** 2018 Transmission Line Rebuild* included with the 2018 Capital Budget Application.

In 2018, the Company will rebuild 2 transmission lines, 1 each on the Baie Verte and Burin peninsulas. Transmission line 363L is a 138 kV H-Frame line running between Baie Verte Junction Substation on the Trans-Canada Highway and Seal Cove Road Substation located in Baie Verte. The line was originally constructed in 1963 and includes approximately 62 km of original construction. Transmission line 302L is a 66 kV single-pole line running between Salt Pond Substation in Burin and Laurentian Substation in St. Lawrence. The line was originally constructed in 1959 and includes approximately 27 km of original construction.

The 112 km of 66 kV transmission lines from Grand Falls to Gander are approaching the end of their service life and must be either rebuilt or retired from service. The 66 kV transmission system interconnects 4 substations serving customers in Central Newfoundland.[7] In its current configuration, the estimated cost to rebuild 66 kV transmission lines 101L and 102L is $20 million. The alternative to rebuilding the 66 kV transmission lines is to extend the existing 138 kV transmission system in Central Newfoundland to include Rattling Brook and Lewisporte substations.[8] The estimated cost to extend the existing 138 kV transmission system and to

[7] The 66 kv transmission system between Grand Falls and Gander supplies substations at Rattling Brook, Notre Dame Junction, Lewisporte and Roycefield Mine. The transmission lines are designated 101L, 102L, 103L and 104L.

[8] This alternative would retire the Notre Dame substation, and continue to serve Roycefield Mine at 66 kV when they return to production.

upgrade Rattling Brook and Lewisporte substations is $18 million.[9] Extending the 138 kV transmission system is the least-cost alternative for providing reliable service to customers in Central Newfoundland. The extension of the 138 kV transmission system will commence in 2019, with the substation upgrades commencing in 2020.

In 2020, 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 2020 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.

3.2.4 Substations

Substations capital expenditures are expected to average $15.0 million annually from 2018 through 2022, which is less than the average of $17.7 million annually from 2013 through 2017. The reduction in annual expenditure is related to fewer load growth-related power transformer additions over the forecast period. Otherwise, the forecast level of expenditure is driven by substation refurbishment and modernization and the automation of 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:

- preventive capital maintenance and modernization;
- breakdown capital maintenance;
- government regulations regarding the elimination of polychlorinated biphenyls (“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 *Substation Refurbishment and Modernization Plan* 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 plan is included in the report ***2.1** 2018 Substation Refurbishment and Modernization* filed with the 2018 Capital Budget Application.

[9] Included in the $18 million estimate is $4 million to rebuild transmission line 102L from Gander to the location west of Glenwood where transmission line 104L to Roycefield Mine taps into 102L. The need to complete this rebuild will be dependent upon future loads at the mine if and when it re-establishes production.

The *2018 Substation Refurbishment and Modernization* project also includes the automation of 12 distribution feeders. The requirement for increased automation was highlighted during the system events of January 2-8, 2014, which involved lengthy customer outages and successive rotating power outages, revealing control limitations on the Company's transmission and distribution systems.[10] At year-end 2018, SCADA control and monitoring will be implemented on approximately 92% of Newfoundland Power's transmission lines and approximately 92% of distribution feeders.[11] The 5-Year Capital Plan includes projects to complete the automation of the remaining distribution feeders by the end of 2019.

Over the 2018 to 2022 forecast period, there is a requirement to install 3 substation transformers to accommodate load growth.[12] Commencing in 2020 and continuing through 2022, 3 additional substation transformers will be required for the Avalon Peninsula and Western Newfoundland.[13]

Government of Canada's regulations require that equipment with PCB concentrations greater than 50 mg/kg and less than 500 mg/kg must be removed from service by 2025. The 5-Year Capital Plan includes expenditures of approximately $5.2 million to address PCB concentrations greater than 50 mg/kg and less than 500 mg/kg in advance of the 2025 deadline.

3.2.5 Distribution

Distribution capital expenditures from 2018 through 2022 are expected to average approximately $39.2 million annually, compared to an average of $48.1 million annually from 2013 through 2017. This decrease is largely attributable to lower expenditures related to customer growth and lower expenditure for meters, with the deployment of AMR meters completed in 2017.

The Company operates approximately 10,000 km of distribution lines serving approximately 265,000 customers. Distribution capital expenditures are primarily driven by:

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

The number of new customer connections is forecast to decrease over the planning period when compared to the 2013 to 2017 period. Over the 5-year period from 2018 to 2022, the number of

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[10] 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.

[11] 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.

[12] By comparison, in the period 2013 through 2017, 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.

[13] 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.

new customer connections is forecast to decrease by 13%. The associated decrease in capital expenditures is primarily due to this reduction in the number of forecast new customer connections. Costs to connect new customers to the electricity system are included in the distribution projects *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

	2018	**2019**	**2020**	**2021**	**2022**
New Customer Connections	2,782	2,619	2,527	2,506	2,424
Average Cost/Connection	$6,162	$6,297	$6,433	$6,571	$6,706
Capital Expenditure (000s)	$17,144	$16,491	$16,255	$16,467	$16,256

Over the period 2018 to 2022, the expenditure associated with new customer connections is forecast to be within the range of $16.3 million to $17.1 million, or approximately 17.6% 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 2018 through 2022 are expected to total approximately $9.0 million over the next 5 years.[14]

Distribution capital expenditures are required to relocate or replace distribution lines to meet third party requests from governments, telecommunications companies and individual customers. In 2018, the expenditures associated with third party requests are estimated at $2.3 million. Over the 5-year period from 2018 through 2022, these expenditures are forecast to remain stable and average approximately $2.4 million annually.

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*. Over the period 2018 to 2022, distribution capital expenditures for meters will be substantially reduced and average $525,000 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

[14] Capital expenditures for the *Feeder Additions for Load Growth* project for the 5-year period 2013 to 2017 were approximately $7.9 million.

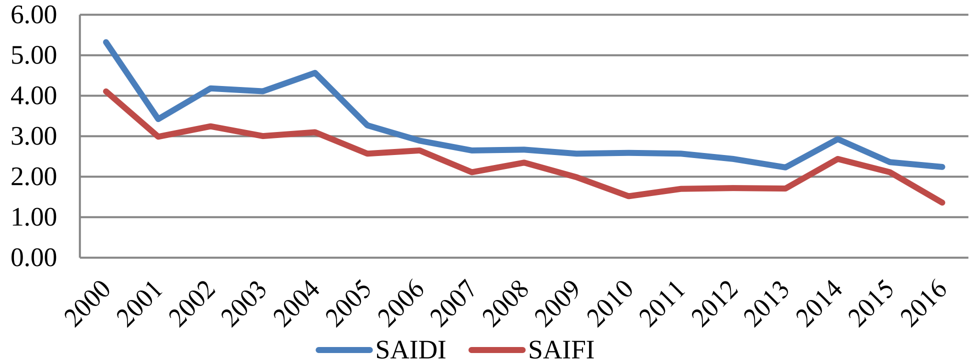
annual *Rebuild Distribution Lines* project. The Company plans to perform preventive capital maintenance on approximately 43 distribution feeders per year over the planning period.

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 the *Distribution Reliability Initiative* project.

Chart 6 shows SAIDI, or System Average Interruption Duration Index, and SAIFI, or System Average Interruption Frequency Index, for the years 2000 through 2016. Chart 6 has been adjusted to remove the effects of severe weather and system events.[15]

Chart 6
SAIDI and SAIFI
2000 - 2016



Newfoundland Power considers current levels of service reliability on a system-wide basis to be satisfactory.

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[15] 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 Central Newfoundland winter storm in November 2013 and the December 16, 2016 severe wind storm in Western Newfoundland. These exclusions are consistent with the Canadian Electricity Association approved definitions.

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.[17] In 2017, reliability rebuilds were initiated on distribution feeders SUM-02 in Central Newfoundland, and TRP-01 on the Avalon Peninsula. These reliability rebuilds will be completed in 2018. In addition, in 2018 a reliability rebuild will be undertaken on distribution feeder KEN-03, serving customers in the Cowan Heights area of St. John's. Details on the project expenditure can be found in the report ***4.1** Distribution Reliability Initiative*.

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 is a cost-effective way of further improving distribution reliability.[18] In 2018, 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 improve reliability performance when used to isolate faulted segments downstream from undamaged upstream sections of feeder.

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 Capital 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 alternatives to replace its infrastructure that did not involve excavating Water Street. As a result, the Company revised its plans to include only the replacement of 2 sections of existing duct bank in 2020 and 2021.[19]

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 related security infrastructure; and
- backup electricity generation at Company buildings.

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[16] In 2012, the Canadian Electricity Association began capturing and reporting on 2 additional indices: (i) Customer Hours of Interruption per Kilometer ("CHIKM"); and (ii) Customers Interrupted per Kilometer ("CIKM").

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

[18] Recommendation 2.4 of Liberty Consulting Group'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.

[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 Load 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 $2.3 million annually from 2018 through 2022, which is similar to the average of $2.1 million for the period from 2013 through 2017. 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 2018 through 2022 are expected to increase to an average of approximately $3.6 million annually, compared to an average of $3.2 million annually from 2013 through 2017. 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 2018 through 2022 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 $221,000 annually from 2018 through 2022, less than the annual average of $302,000 from 2013 through 2017.[20] Over the next 5-year period, the Telecommunications capital expenditures are largely associated with the installation of new fibre optic cables in the City of 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.

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

Information Systems capital expenditures from 2018 through 2022 are expected to increase to an average of approximately $8.9 million annually, compared to an average of $5.8 million annually from 2013 through 2017. The increase is largely driven by the replacement of corporate systems, such as the Outage Management System commencing in 2018 and the Customer Service System commencing in 2021.

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 2018 through 2022.

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 2018 through 2022.

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 all circumstances, necessarily facilitate such stability. The Company has identified some risks to such stability in the period 2018 through 2022.

Newfoundland Power has an obligation to serve customers in its service territory. The capital expenditure required to provide such service is impacted by customer and load growth. New home construction on the Northeast Avalon Peninsula has decreased 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.[21] The extent of change in new customer connections required over the course of this 5-year forecast can have a material impact on capital expenditures.

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 materially vary from forecast, the capital expenditure for the required transformers (each in the order of $2 million to $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, such as occurred with the

[21] Forecast gross new customer connections have declined to levels not seen for the past 20 years.

Riverhead, Kenmount, Horsechops, Pierre's Brook and Salt Pond power transformers, will necessitate capital expenditures.[22]

Newfoundland Power's gas turbines range in age from 42 years to 48 years. These gas turbines had a significant increase in usage during the 2013/2014 winter season. Condition assessments 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 forecast has identified refurbishment work on the Greenhill and Wesleyville gas turbine systems. An in-service failure of either gas turbine system will necessitate a change to this plan.

The Company continues to take steps to reduce risks associated with the operation of its Customer Service System, which has been in service since 1991.[23] In recent years, 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 technology should be supported throughout this capital plan period, commencing in 2021, the Company has included a project to commence the replacement of its Customer Service System. 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 5-6, 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.

The Board is currently conducting an investigation into the adequacy of reliability of electricity supply on the Island of Newfoundland. It is currently uncertain what, if any, impact the results of this investigation may have on Newfoundland Power's capital expenditures. Accordingly, this 5-Year Capital Plan does not include expenditures which may be required as a result of the matters currently under investigation by the Board.

[22] Replacement of the Riverhead power transformer was approved in Board Order No. P.U. 6 (2017). Replacement of the Horsechops power transformer was approved as part of the 2009 Capital Budget Application in Board Order No. P.U. 27 (2008). Replacement of the Pierre's Brook power transformer was approved in Board Order No. P.U. 3 (2008). Replacement of the Salt Pond power transformer was approved in Board Order No. P.U. 15 (2002-2003). Kenmount power transformer failed in-service in March 2009 and its refurbishment was approved in Board Order No. P.U. 29 (2009).

[23] The Company's existing Customer Service System originally cost in excess of $10 million. A replacement system is estimated to cost in the range of $15 million to $20 million.

Appendix A
2018-2022 Capital Plan

Newfoundland Power Inc.
2018-2022 Capital Plan
(000s)

Asset Class	2018	2019	2020	2021	2022
Generation	$8,420	$12,091	$7,737	$15,391	$8,403
Substations	$12,788	$13,891	$17,089	$14,690	$16,377
Transmission	$7,168	$10,964	$11,001	$9,274	$10,275
Distribution	$38,857	$38,355	$41,030	$38,416	$39,376
General Property	$1,763	$2,397	$2,454	$1,755	$3,133
Transportation	$3,362	$3,429	$3,993	$3,780	$3,278
Telecommunications	$198	$102	$104	$360	$343
Information Systems	$6,570	$6,973	$6,394	$7,299	$17,099
Unforeseen Allowance	$750	$750	$750	$750	$750
General Expenses Capitalized	$4,000	$4,000	$4,000	$4,000	$4,000
Total	**$83,876**	**$92,952**	**$94,552**	**$95,715**	**$103,034**

Newfoundland Power Inc.
2018-2022 Capital Plan
(000s)

GENERATION

Project	2018	2019	2020	2021	2022
Facility Rehabilitation – Hydro	$2,119	$1,533	$1,556	$1,577	$1,600
Facility Rehabilitation - Thermal	$301	$308	$315	$322	$329
Purchase Mobile Generation	$6,000	$7,915	$0	$0	$0
Topsail Plant Upgrades	$0	$2,335	$0	$0	$0
Tors Cove Plant Refurbishment	$0	$0	$2,310	$0	$0
Rattling Brook Plant Refurbishment	$0	$0	$1,106	$1,132	$0
Greenhill Plant Upgrades	$0	$0	$2,450	$5,310	$0
Sandy Brook Plant Refurbishment	$0	$0	$0	$4,868	$0
Enclosure for MGT	$0	$0	$0	$600	$0
Petty Harbour Plant Refurbishment	$0	$0	$0	$0	$3,111
Lookout Brook Plant Refurbishment	$0	$0	$0	$0	$702
Wesleyville Plant Refurbishment	$0	$0	$0	$1,582	$2,661
Total - Generation	**$8,420**	**$12,091**	**$7,737**	**$15,391**	**$8,403**

Newfoundland Power Inc.
2018-2022 Capital Plan
(000s)

SUBSTATIONS

Project	2018	2019	2020	2021	2022
Substations Refurbishment and Modernization	$8,001	$8,713	$8,972	$6,909	$8,598
Replacements Due to In-Service Failure	$3,814	$3,901	$3,987	$4,075	$4,157
Additions Due to Load Growth	$0	$0	$2,500	$2,500	$2,500
Substation Feeder Terminations	$0	$290	$510	$200	$0
PCB Bushing Phase Out	$973	$987	$1,120	$1,006	$1,122
Total – Substations	**$12,788**	**$13,891**	**$17,089**	**$14,690**	**$16,377**

Newfoundland Power Inc.
2018-2022 Capital Plan
(000s)

TRANSMISSION

Project	2018	2019	2020	2021	2022
Rebuild Transmission Lines	$5,068	$8,864	$7,421	$4,508	$8,275
Transmission Line Reconstruction	$2,100	$2,100	$2,000	$2,000	$2,000
Transmission Line Additions	$0	$0	$1,580	$2,766	$0
Total – Transmission	**$7,168**	**$10,964**	**$11,001**	**$9,274**	**$10,275**

Newfoundland Power Inc.
2018-2022 Capital Plan
(000s)

DISTRIBUTION

Project	2018	2019	2020	2021	2022
Extensions	$11,738	$11,315	$11,175	$11,344	$11,220
Meters	$546	$530	$521	$519	$511
Services	$3,200	$3,123	$3,108	$3,162	$3,150
Street Lighting	$1,814	$1,786	$1,785	$1,817	$1,817
Transformers	$6,084	$5,683	$5,457	$5,406	$5,204
Reconstruction	$5,366	$5,494	$5,624	$5,757	$5,887
Rebuild Distribution Lines	$3,844	$3,934	$4,024	$4,166	$4,204
Relocations For Third Parties	$2,317	$2,371	$2,426	$2,481	$2,535
Distribution Reliability Initiative	$1,789	$1,500	$1,500	$1,500	$1,500
Distribution Feeder Automation	$612	$490	$390	$320	$250
Feeder Additions for Load Growth	$539	$1,627	$3,468	$832	$2,520
Trunk Feeders	$798	$287	$0	$0	$350
St. John's Underground Refurbishment	$0	$0	$1,332	$888	$0
Allowance for Funds Used During Construction	$210	$215	$220	$224	$228
Total – Distribution	**$38,857**	**$38,355**	**$41,030**	**$38,416**	**$39,376**

Newfoundland Power Inc.
2018-2022 Capital Plan
(000s)

GENERAL PROPERTY

Project	2018	2019	2020	2021	2022
Tools and Equipment	$479	$489	$499	$510	$519
Additions to Real Property	$671	$479	$456	$464	$471
Renovations to Company Buildings	$298	$1,429	$1,499	$781	$2,143
Fencing Refurbishment	$315	$0	$0	$0	$0
Total – General Property	**$1,763**	**$2,397**	**$2,454**	**$1,755**	**$3,133**

Newfoundland Power Inc.
2018-2022 Capital Plan
(000s)

TRANSPORTATION

Project	2018	2019	2020	2021	2022
Replace Vehicles and Aerial Devices	$3,362	$3,429	$3,993	$3,780	$3,278
Total – Transportation	**$3,362**	**$3,429**	**$3,993**	**$3,780**	**$3,278**

Newfoundland Power Inc.
2018-2022 Capital Plan
(000s)

TELECOMMUNICATIONS

Project	2018	2019	2020	2021	2022
Replace/Upgrade Communications Equipment	$99	$102	$104	$106	$108
Fibre Optic Cable	$99	$0	$0	$254	$235
Total – Telecommunications	**$198**	**$102**	**$104**	**$360**	**$343**

Newfoundland Power Inc.
2018-2022 Capital Plan
(000s)

INFORMATION SYSTEMS

Project	2018	2019	2020	2021	2022
Application Enhancements	$858	$1,000	$1,000	$1,000	$1,000
System Upgrades	$1,343	$1,848	$1,742	$1,495	$1,245
Personal Computer Infrastructure	$472	$477	$492	$506	$520
Shared Server Infrastructure	$648	$879	$906	$933	$959
Network Infrastructure	$467	$344	$354	$365	$375
Geographic Information System	$0	$0	$1,000	$0	$0
Outage Management System	$2,360	$1,210	$0	$0	$0
Customer Service System	$0	$0	$0	$3,000	$13,000
Human Resource Management System	$422	$1,215	$0	$0	$0
Call Centre Technology	$0	$0	$900	$0	$0
Total – Information Systems	**$6,570**	**$6,973**	**$6,394**	**$7,299**	**$17,099**

Newfoundland Power Inc.
2018-2022 Capital Plan
(000s)

UNFORESEEN ALLOWANCE

Project	2018	2019	2020	2021	2022
Allowance for Unforeseen Items	$750	$750	$750	$750	$750
Total - Unforeseen Allowance	**$750**	**$750**	**$750**	**$750**	**$750**

Newfoundland Power Inc.
2018-2022 Capital Plan
(000s)

GENERAL EXPENSES CAPITALIZED

Project	2018	2019	2020	2021	2022
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**

2017 Capital Expenditure Status Report

July 2017

WHENEVER. WHEREVER.
We'll be there.

NEWFOUNDLAND POWER
A FORTIS COMPANY

Newfoundland Power Inc.

2017 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. 39 (2016).

Page 1 of the 2017 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 2017, which were approved in Order No. P.U. 39 (2016), Order No. P.U. 6 (2017) and Order No. P.U. 19 (2017). The detailed tables also include information on those capital projects approved for 2016 (and approved in Order No. P.U. 28 (2015)) that were not completed prior to 2017.

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 2017 Capital Expenditure Status Report. These variance criteria are as outlined in the *Capital Budget Application Guidelines*.

Newfoundland Power Inc.

2017 Capital Budget Variances
(000s)

	Approved by Order Nos. P.U. 39 (2016) P.U. 19 (2017) and P.U.6 (2017)	Forecast	Variance
Generation – Hydro	$7,026	$7,026	-
Generation - Thermal	234	234	-
Substations	18,239	17,789	(450)
Transmission	6,711	6,711	-
Distribution	48,217	45,027	(3,190)
General Property	1,502	1,502	-
Transportation	3,456	3,456	-
Telecommunications	98	98	-
Information Systems	5,288	4,413	(875)
Unforeseen Items	750	750	-
General Expenses Capitalized	4,000	4,000	-
Total	$95,521	$91,006	($4,515)
Projects carried forward from 2016		$7,581[1]	

1 Forecast 2017 expenditures associated with projects carried forward from 2016.

2017 Capital Expenditure Status Report
(000s)

	Capital Budget			Actual Expenditure			Forecast			
	2016	2017	Total	2016	YTD 2017	Total To Date	Remainder 2017	Total 2017	Overall Total	Variance
	A	B	C	D	E	F	G	H	I	J
2017 Projects	$ -	$ 95,521	$ 95,521	$ -	$ 25,547	$ 25,547	$ 65,459	$ 91,006	91,006	$ (4,515)
2016 Projects	51,419	-	51,419	40,116	2,156	42,272	5,425	7,581	47,697	(3,722)
Grand Total	**$ 51,419**	**$ 95,521**	**$ 146,940**	**$ 40,116**	**$ 27,703**	**$ 67,819**	**$ 70,884**	**$ 98,587**	**$ 138,703**	**$ (8,237)**

Column A	Approved Capital Budget for 2016
Column B	Approved Capital Budget for 2017
Column C	Total of Columns A and B
Column D	Actual Capital Expenditures for 2016
Column E	Actual Capital Expenditures for 2017 YTD
Column F	Total of Columns D and E
Column G	Forecast for Remainder of 2017
Column H	Total of Columns E and G
Column I	Total of Columns F and G
Column J	Column I less Column C

2017 Capital Expenditure Status Report
(000s)

Category: Generation - Hydro

	Capital Budget			Actual Expenditure			Forecast				
Project	**2016**	**2017**	**Total**	**2016**	**YTD 2017**	**Total To Date**	**Remainder 2017**	**Total 2017**	**Overall Total**	**Variance**	**Notes***
	A	B	C	D	E	F	G	H	I	J	
2017 Projects											
Facility Rehabilitation	$ -	$ 1,607	$ 1,607	$ -	$ 97	$ 97	$ 1,510	$ 1,607	$ 1,607	$ -	
Public Safety Around Dams	-	662	662	-	46	46	616	662	662	-	
Tors Cove Plant Refurbishment	-	1,476	1,476	-	39	39	1,437	1,476	1,476	-	
Rose Blanche Plant Refurbishment	-	3,281	3,281	-	81	81	3,200	3,281	3,281	-	
Total - 2017 Generation Hydro	**$ -**	**$ 7,026**	**$ 7,026**	**$ -**	**$ 263**	**$ 263**	**$ 6,763**	**$ 7,026**	**$ 7,026**	**$ -**	
2016 Projects											
Facility Rehabilitation (2016)	$ 1,462	$ -	$ 1,462	$ 1,252	$ 20	$ 1,272	$ 417	$ 437	$ 1,689	$ 227	1
Facility Rehabilitation (2015)	1,586	-	1,586	1,379	-	1,379	170	170	1,549	(37)	
Public Safety Around Dams	883	-	883	559	-	559	200	200	759	(124)	2
Pierre's Brook Plant Refurbishment	15,762	-	15,762	14,793	214	15,007	-	214	15,007	(755)	
Total - Generation Hydro	**$ 19,693**	**$ 7,026**	**$ 26,719**	**$ 17,983**	**$ 497**	**$ 18,480**	**$ 7,550**	**$ 8,047**	**$ 26,030**	**$ (689)**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2016
Column B	Approved Capital Budget for 2017
Column C	Total of Columns A and B
Column D	Actual Capital Expenditures for 2016
Column E	Actual Capital Expenditures for 2017 YTD
Column F	Total of Columns D and E
Column G	Forecast for Remainder of 2017
Column H	Total of Columns E and G
Column I	Total of Columns F and G
Column J	Column I less Column C

2017 Capital Expenditure Status Report
(000s)

Category: Generation - Thermal

Project	Capital Budget 2017	Capital Budget Total	Actual Expenditures YTD 2017	Actual Expenditures Total To Date	Forecast Remainder 2017	Forecast Total 2017	Forecast Overall Total	Variance	Notes*
	A	B	C	D	E	F	G	H	
2017 Projects									
Facility Rehabilitation Thermal	$ 234	$ 234	$ 123	$ 123	$ 111	$ 234	$ 234	$ -	
Total - 2017 Generation Thermal	**$ 234**	**$ 234**	**$ 123**	**$ 123**	**$ 111**	**$ 234**	**$ 234**	**$ -**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2017
Column B	Total of Column A
Column C	Actual Capital Expenditures for 2017 YTD
Column D	Total of Column C
Column E	Forecast for Remainder of 2017
Column F	Total of Columns C and E
Column G	Total of Column F
Column H	Column G less Column B

2017 Capital Expenditure Status Report
(000s)

Category: Substations

Project	Capital Budget 2016	Capital Budget 2017	Capital Budget Total	Actual Expenditure 2016	Actual Expenditure YTD 2017	Actual Expenditure Total To Date	Forecast Remainder 2017	Forecast Total 2017	Forecast Overall Total	Variance	Notes*
	A	B	C	D	E	F	G	H	I	J	
2017 Projects											
Substation Refurbishment and Modernization	$ -	$ 10,521	$ 10,521	$ -	$ 1,461	$ 1,461	$ 8,610	$ 10,071	$ 10,071	$ (450)	
Replacements Due to In-Service Failures	-	3,851	3,851	-	1,019	1,019	2,832	$ 3,851	3,851	-	
Additions Due to Load Growth	-	2,574	2,574	-	230	230	2,344	$ 2,574	2,574	-	
PCB Bushing Phaseout		1,009	1,009	-	-	-	1,009	$ 1,009	1,009	-	
Substation Feeder Termination	-	284	284	-	59	59	225	$ 284	284	-	
Total - 2017 Substations	$ -	$ 18,239	$ 18,239	$ -	$ 2,769	$ 2,769	$ 15,020	$ 17,789	$ 17,789	$ (450)	
2016 Projects											
Substation Refurbishment and Modernization	$ 7,871	$ -	$ 7,871	$ 5,980	$ 95	$ 6,075	$ 969	$ 1,064	$ 7,044	$ (827)	3
Total - Substations	**$ 7,871**	**$ 18,239**	**$ 26,110**	**$ 5,980**	**$ 2,864**	**$ 8,844**	**$ 15,989**	**$ 18,853**	**$ 24,833**	**$ (1,277)**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2016
Column B	Approved Capital Budget for 2017
Column C	Total of Columns A and B
Column D	Actual Capital Expenditures for 2016
Column E	Actual Capital Expenditures for 2017 YTD
Column F	Total of Columns D and E
Column G	Forecast for Remainder of 2017
Column H	Total of Columns E and G
Column I	Total of Columns F and G
Column J	Column I less Column C

2017 Capital Expenditure Status Report
(000s)

Category: Transmission

Project	Capital Budget 2016 (A)	Capital Budget 2017 (B)	Capital Budget Total (C)	Actual Expenditure 2016 (D)	Actual Expenditure YTD 2017 (E)	Actual Expenditure Total To Date (F)	Forecast Remainder 2017 (G)	Forecast Total 2017 (H)	Forecast Overall Total (I)	Variance (J)	Notes*
2017 Projects											
Rebuild Transmission Lines	$ -	$ 6,711	$ 6,711	$ -	$ 835	$ 835	$ 5,876	$ 6,711	$ 6,711	$ -	
Total - 2017 Transmission	$ -	$ 6,711	$ 6,711	$ -	$ 835	$ 835	$ 5,876	$ 6,711	$ 6,711	$ -	
2016 Projects											
Rebuild Transmission Lines	$ 6,067	$ -	$ 6,067	$ 4,046	$ 116	$ 4,162	$ 782	$ 898	$ 4,944	$ (1,123)	4
Total - Transmission	**$ 6,067**	**$ 6,711**	**$ 12,778**	**$ 4,046**	**$ 951**	**$ 4,997**	**$ 6,658**	**$ 7,609**	**$ 11,655**	**$ (1,123)**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2016
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Column E	Actual Capital Expenditures for 2017 YTD
Column F	Total of Columns D and E
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Column H	Total of Columns E and G
Column I	Total of Columns F and G
Column J	Column I less Column C

2017 Capital Expenditure Status Report
(000s)

Category: Distribution

	Capital Budget			Actual Expenditure			Forecast				
Project	**2016**	**2017**	**Total**	**2016**	**YTD 2017**	**Total To Date**	**Remainder 2017**	**Total 2017**	**Overall Total**	**Variance**	**Notes***
	A	B	C	D	E	F	G	H	I	J	
2017 Projects											
Extensions	$ -	$ 13,017	$ 13,017	$ -	$ 4,604	$ 4,604	$ 8,413	$ 13,017	$ 13,017	$ -	
Meters	-	4,391	4,391	-	2,363	2,363	2,028	4,391	4,391	-	
Services	-	3,564	3,564	-	1,163	1,163	2,401	3,564	3,564	-	
Street Lighting	-	2,049	2,049	-	746	746	1,303	2,049	2,049	-	
Transformers	-	6,103	6,103	-	3,842	3,842	1,511	5,353	5,353	(750)	5
Reconstruction	-	4,908	4,908	-	2,017	2,017	2,891	4,908	4,908	-	
Rebuild Distribution Lines	-	4,023	4,023	-	810	810	3,213	4,023	4,023	-	
Relocate/Rebuild Distribution Lines for Third Parties	-	2,266	2,266	-	687	687	1,579	2,266	2,266	-	
Trunk Feeders	-	1,834	1,834	-	93	93	1,741	1,834	1,834	-	
Feeder Additions for Growth	-	1,430	1,430	-	356	356	1,074	1,430	1,430	-	
Distribution Reliability Initiative	-	1,415	1,415	-	632	632	783	1,415	1,415	-	
Distribution Feeder Automation	-	568	568	-	-	-	568	568	568	-	
St. John's Main Underground Refurbishment	-	2,440	2,440	-	-	-	-	-	-	(2,440)	6
Allowance for Funds Used During Construction	-	209	209	-	71	71	138	209	209	-	
		-									
Total - 2017 Distribution	$ -	$ 48,217	$ 48,217	$ -	$ 17,384	$ 17,384	$ 27,643	$ 45,027	$ 45,027	$ (3,190)	
2016 Projects											
Trunk Feeders	$ 1,607	$ -	$ 1,607	$ 1,134	$ 79	$ 1,213	$ 98	$ 177	$ 1,311	$ (296)	7
Distribution Reliability Initiative	1,463	-	1,463	359	164	523	586	750	1,109	(354)	8
Distribution Feeder Automation	565	-	565	265	33	298	170	203	468	(97)	
St. John's Main Underground Refurbishment	1,950	-	1,950	326	125	451	1,319	1,444	1,770	(180)	
Total - Distribution	**$ 5,585**	**$ 48,217**	**$ 53,802**	**$ 2,084**	**$ 17,785**	**$ 19,869**	**$ 29,816**	**$ 47,601**	**$ 49,685**	**$ (4,117)**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2016
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Column E	Actual Capital Expenditures for 2017
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Column G	Forecast for Remainder of 2017
Column H	Total of Columns E and G
Column I	Total of Columns F and G
Column J	Column I less Column C

2017 Capital Expenditure Status Report
(000s)

Category: General Property

	Capital Budget		Actual Expenditures		Forecast				
Project	**2017**	**Total**	**YTD 2017**	**Total To Date**	**Remainder 2017**	**Total 2017**	**Overall Total**	**Variance**	**Notes***
	A	**B**	**C**	**D**	**E**	**F**	**G**	**H**	
2017 Projects									
Tools and Equipment	$ 475	$ 475	$ 206	$ 206	$ 269	$ 475	$ 475	$ -	
Additions to Real Property	471	471	89	89	382	471	471	-	
Company Buildings Renovations - Stephenville	351	351	8	8	343	351	351	-	
Standby and Emergency Power - Stephenville	205	205	9	9	196	205	205		
Total - General Property	**$ 1,502**	**$ 1,502**	**$ 312**	**$ 312**	**$ 1,190**	**$ 1,502**	**$ 1,502**	**$ -**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2017
Column B	Total of Column A
Column C	Actual Capital Expenditures for 2017 YTD
Column D	Total of Column C
Column E	Forecast for Remainder of 2017
Column F	Total of Columns C and E
Column G	Total of Column F
Column H	Column G less Column B

2017 Capital Expenditure Status Report
(000s)

Category: Transportation

Project	Capital Budget 2016	Capital Budget 2017	Capital Budget Total	Actual Expenditure 2016	Actual Expenditure YTD 2017	Actual Expenditure Total To Date	Forecast Remainder 2017	Forecast Total 2017	Forecast Overall Total	Variance	Notes*
	A	B	C	D	E	F	G	H	I	J	
2017 Projects											
Purchase Vehicles and Aerial Devices	$ -	$ 3,456	$ 3,456	$ -	$ 675	$ 675	$ 2,781	$ 3,456	$ 3,456	$ -	
Total - 2017 Transportation	**$ -**	**$ 3,456**	**$ 3,456**	**$ -**	**$ 675**	**$ 675**	**$ 2,781**	**$ 3,456**	**$ 3,456**	**$ -**	
2016 Projects											
Purchase Vehicles and Aerial Devices	$ 3,258	$ -	$ 3,258	$ 2,353	$ 1,024	$ 3,377	$ -	$ 1,024	$ 3,377	$ 119	
Total - Transportation	**$ 3,258**	**$ 3,456**	**$ 6,714**	**$ 2,353**	**$ 1,699**	**$ 4,052**	**$ 2,781**	**$ 4,480**	**$ 6,833**	**$ 119**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2016
Column B	Approved Capital Budget for 2017
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Column E	Actual Capital Expenditures for 2017 YTD
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Column H	Total of Columns E and G
Column I	Total of Columns F and G
Column J	Column I less Column C

2017 Capital Expenditure Status Report
(000s)

Category: Telecommunications

Project	Capital Budget 2016	Capital Budget 2017	Capital Budget Total	Actual Expenditure 2016	Actual Expenditure YTD 2017	Actual Expenditure Total To Date	Forecast Remainder 2017	Forecast Total 2017	Forecast Overall Total	Variance	Notes*
	A	B	C	D	E	F	G	H	I	J	
2017 Projects											
Replace/Upgrade Communications Equipment	$ -	$ 98	$ 98	$ -	$ 2	$ 2	$ 96	$ 98	$ 98	$ -	
Total - 2017 Telecommunications	**$ -**	**$ 98**	**$ 98**	**$ -**	**$ 2**	**$ 2**	**$ 96**	**$ 98**	**$ 98**	**$ -**	
2016 Projects											
Fibre Optic Network	$ 409	$ -	$ 409	$ 102	$ -	$ 102	$ 150	$ 150	$ 252	$ (157)	9
Total - Telecommunications	**$ 409**	**$ 98**	**$ 507**	**$ 102**	**$ 2**	**$ 104**	**$ 246**	**$ 248**	**$ 350**	**$ (157)**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2016
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Column D	Actual Capital Expenditures for 2016
Column E	Actual Capital Expenditures for 2017 YTD
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Column H	Total of Columns E and G
Column I	Total of Columns F and G
Column J	Column I less Column C

2017 Capital Expenditure Status Report
(000s)

Category: Information Systems

	Capital Budget			Actual Expenditure			Forecast				
Project	**2016**	**2017**	**Total**	**2016**	**YTD 2017**	**Total To Date**	**Remainder 2017**	**Total 2017**	**Overall Total**	**Variance**	**Notes***
	A	B	C	D	E	F	G	H	I	J	
2017 Projects											
Application Enhancements	$ -	$ 1,003	$ 1,003	$ -	$ 71	$ 71	$ 932	$ 1,003	$ 1,003	$ -	
System Upgrades	-	1,676	1,676	-	781	781	895	1,676	1,676	-	
Personal Computer Infrastructure	-	485	485	-	259	259	226	485	485	-	
Shared Server Infrastructure	-	661	661	-	196	196	465	661	661	-	
Network Infrastructure	-	388	388	-	119	119	269	388	388	-	
Geographic Information System Improvement	-	200	200	-	104	104	96	200	200	-	
Outage Management System Replacement	-	875	875	-	-	-	-	-	-	(875)	10
Total - 2017 Information Systems	**$ -**	**$ 5,288**	**$ 5,288**	**$ -**	**$ 1,530**	**$ 1,530**	**$ 2,883**	**$ 4,413**	**$ 4,413**	**$ (875)**	
2016 Projects											
SCADA System Replacement	$ 5,675	$ -	$ 5,675	$ 5,335	$ -	$ 5,335	$ 276	$ 276	$ 5,611	$ (64)	
Application Enhancements	1,143	-	1,143	989	93	1,082	61	154	1,143	-	
System Upgrades	1,718	-	1,718	1,244	193	1,437	227	420	1,664	(54)	
Total - Information Systems	**$ 8,536**	**$ 5,288**	**$ 13,824**	**$ 7,568**	**$ 1,816**	**$ 9,384**	**$ 3,447**	**$ 5,263**	**$ 12,831**	**$ (993)**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2016 and prior year
Column B	Approved Capital Budget for 2017
Column C	Total of Columns A and B
Column D	Actual Capital Expenditures for 2016 and prior year
Column E	Actual Capital Expenditures for 2017 YTD
Column F	Total of Columns D and E
Column G	Forecast for Remainder of 2017
Column H	Total of Columns E and G
Column I	Total of Columns F and G
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2017 Capital Expenditure Status Report
(000s)

Category: Unforeseen Allowance

Project	Capital Budget 2017 A	Capital Budget Total B	Actual Expenditures YTD 2017 C	Actual Expenditures Total To Date D	Forecast Remainder 2017 E	Forecast Total 2017 F	Forecast Overall Total G	Variance H	Notes*
2017 Projects									
Allowance for Unforeseen Items	$ 750	$ 750	$ -	$ -	$ 750	$ 750	$ 750	$ -	
Total - 2017 Unforeseen Items	**$ 750**	**$ 750**	**$ -**	**$ -**	**$ 750**	**$ 750**	**$ 750**	**$ -**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2017
Column B	Total of Column A
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Column D	Total of Column C
Column E	Forecast for Remainder of 2017
Column F	Total of Columns C and E
Column G	Total of Column F
Column H	Column G less Column B

2017 Capital Expenditure Status Report
(000s)

Category: General Expenses Capitalized

Project	Capital Budget 2017	Capital Budget Total	Actual Expenditures YTD 2017	Actual Expenditures Total To Date	Forecast Remainder 2017	Forecast Total 2017	Forecast Overall Total	Variance	Notes*
	A	B	C	D	E	F	G	H	
2017 Projects									
General Expenses Capitalized	$ 4,000	$ 4,000	$ 1,654	$ 1,654	$ 2,346	$ 4,000	$ 4,000	$ -	
Total - 2017 General Expenses Capitalized	**$ 4,000**	**$ 4,000**	**$ 1,654**	**$ 1,654**	**$ 2,346**	**$ 4,000**	**$ 4,000**	**$ -**	

* See Appendix A for notes containing variance explanations.

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Column A	Approved Capital Budget for 2017
Column B	Total of Column A
Column C	Actual Capital Expenditures for 2017 YTD
Column D	Total of Column C
Column E	Forecast for Remainder of 2017
Column F	Total of Columns C and E
Column G	Total of Column F
Column H	Column G less Column B

Generation - Hydro

1. *Facility Rehabilitation (2016 Project):*

Budget: $1,462,000 Actual: $1,689,000 Variance: $227,000

The *Facility Rehabilitation* project consists of the refurbishment or replacement of hydro plant structures and equipment due to damage, deterioration, corrosion and in-service failure. The 2016 expenditure was $227,000 higher than budget. The estimate for the generation equipment replacements due to in-service failures aspect of the project is based on a historical average. The variance is primarily due to equipment replacements necessary due to in-service failures being $198,000 higher than the historical average.

2. *Public Safety Around Dams(2016 Project):*

Budget: $883,000 Actual: $759,000 Variance: ($124,000)

Actual expenditure on the *Public Safety Around Dams* project was $124,000 below the budget estimate. This was mainly due to contractor costs being lower than expected.

Substations

3. Substation Refurbishment and Modernization (2016 Project):

Budget: $7,871,000 Actual: $7,044,000 Variance: ($827,000)

Actual expenditure on the *Substation Refurbishment and Modernization* project was $827,000 below the budget estimate. The cost estimates were based on historical contractor costs. Due to lower than anticipated substation maintenance requirements during the year, much of the construction and commissioning work was completed by Company personnel at lower than forecast cost.

Transmission

4. *Rebuild Transmission Lines (2016 Project):*

Budget: $6,067,000 Actual: $4,944,000 Variance: ($1,123,000)

Actual capital expenditure on the *Rebuild Transmission Lines* project was $1,123,000 lower than the budget estimate. The 2016 project estimate included an amount to build a corduroy road.[1] However, the corduroy road was completed during the 2015 portion of the project, and no additional expenditures were required in 2016. This resulted in a reduction of approximately $550,000 in the 2016 expenditure. The project also includes an amount to correct deficiencies identified through inspections. This expenditure is budgeted based on historical averages. Correcting identified deficiencies in 2016 cost $300,000 less than the historical average. Lower than expected contractor pricing also contributed to this variance.

[1] A corduroy road or log road is constructed by placing logs perpendicular to the direction of travel over a wet or boggy area. The use of the corduroy road minimizes the impact of travel on the environment while making passage to and from the work site safe for workers and vehicles.

Distribution

5. *Transformers:*

Budget: $6,103,000 Forecast: $5,353,000 Variance: ($750,000)

The transformer budget estimate is based on the historical average cost over the past 5 years. In 2017, the actual expenditure is forecast to be below the 5-year average. The reduction is largely due to the reduction in forecast new customer connections. The original budget was based on 3,417 new customer connections. The revised forecast is for 3,032 new customer connections, an 11% reduction.

6. *St. John's Main Underground Refurbishment:*

Budget: $2,440,000 Forecast: $0 Variance: ($2,440,000)

The *St. John's Main Underground Refurbishment* project involves 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 part of the 2016 Capital Budget Application as a multi-year project in Order No. P.U. 28 (2015).

The underground distribution infrastructure originating from SJM passes under property owned by a third-party. Negotiations with the owner took longer than anticipated, resulting in delays getting the project started in 2016. As a result, the work originally planned for 2016 will take place in 2017. In turn, this will result in the 2017 planned work being delayed to 2018.

7. *Trunk Feeders (2016 Project):*

Budget: $1,607,000 Actual: $1,311,000 Variance: ($296,000)

Actual capital expenditure in the *Trunk Feeders* project was $296,000 lower than the budget estimate. The reduction was principally due to the elimination of a requirement to upgrade the vault at the old Battery Hotel when the property was purchased by MUN, who elected to utilize an aerial service rather than continue to be served by underground lines.

8. *Distribution Reliability Initiative (2016 Project):*

Budget: $1,463,000 Actual: $1,109,000 Variance: ($354,000)

The expenditure requirements for HWD-07 and GFS-02 were $250,000 and $80,000, respectively, lower than anticipated. The lower expenditure requirement was a result of work carried out on these feeders under the *Reconstruction* and *Relocate/Replace Distribution Lines for Third Parties* projects subsequent to the preparation of the 2016 Capital Budget Application.

Telecommunications

9. *Fibre Optic Network (2016 Project):*

Budget: $409,000 Actual: $252,000 Variance: ($157,000)

The project involved the installation of a fiber optic cable for communications route diversity between Company locations in St. John's. The final route identified during detailed engineering was shorter than the route used to prepare the budget estimate. This resulted in a reduced material and labour requirement for the project.

Information Systems

10. *Outage Management System Replacement (2016 Multi-year Project):*

Budget: $875,000 Actual: $0 Variance: ($875,000)

In Order No. P.U. 28 (2015), the Board approved the Company's proposal to replace its existing Outage Management System ("OMS") with a commercially available product with a 2017 estimated cost of $875,000. This replacement project only included integrating the new OMS with Newfoundland Power's SCADA system and GIS as part of a phased approach to replacing its functionally obsolete OMS. The 2016 multi-year project did not include enhanced functionality, such as the ability to automatically predict outage cause and location.

The Company issued a Request for Proposals in Q1 2017 for a replacement OMS with enhanced functionality. The inclusion of enhanced functionality reflected a combination of: (i) an assessment of the existing commercial OMS marketplace; and (ii) delays in progress on the OMS replacement project approved in Order No. P.U. 28 (2015). Combining OMS replacement and enhancement now best meets Newfoundland Power's outage management requirements and is consistent with the 5-year OMS replacement and enhancement timeline envisaged in 2014.[2]

The 2018 Capital Budget Application includes a revised multi-year project proposal that includes an enhanced scope and revised budget to replace the 2016 multi-year project.

[2] The Board's *Investigation and Hearing into Supply Issues and Power Outages on the Island Interconnected System* completed in 2014 included an assessment of Newfoundland Power's plan to replace its existing OMS with a commercial alternative within 5 years.

2018 Facility Rehabilitation

July 2017

Prepared by:

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REGISTERED PROFESSIONAL ENGINEER
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SIGNATURE
Jun 23, 2017
PROVINCE OF NEWFOUNDLAND

WHENEVER. WHEREVER.
We'll be there.

NEWFOUNDLAND POWER
A FORTIS COMPANY

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1.0 Introduction

The *2018 Facility Rehabilitation* project is necessary for the replacement or rehabilitation of deteriorated hydroelectric facility components that have been identified through routine inspections, operating experience and engineering studies. The project includes expenditures necessary to ensure the safe, reliable and environmentally compliant operation of various hydroelectric facilities, or to replace equipment due to in-service failures.

Newfoundland Power (the "Company") has 23 hydroelectric facilities that generate a combined normal annual production of 438.6 GWh.[1] Maintaining these facilities reduces the need for additional, more expensive generation on the Island Interconnected System. The alternative to maintaining these facilities is to retire them.

The *2018 Facility Rehabilitation* project totals $2,119,000 and is comprised of: (i) Hydroelectric Dam and Spillway Rehabilitation; (ii) Other Hydroelectric Infrastructure Rehabilitation; (iii) Rocky Pond Plant Refurbishment; and (iv) Generation Equipment Replacements Due to In-Service Failures.

2.0 Hydroelectric Dam and Spillway Rehabilitation

Cost: $351,000

The Company has over 150 dam structures throughout its 23 hydroelectric facilities. Based on the age of the structures in Newfoundland Power's system, deterioration of earth-filled, timber crib, and concrete dams is to be expected.

Each year, refurbishment of deteriorated components at various dam structures is required to ensure an appropriate level of dam safety is maintained, as per the guidelines established by the Canadian Dam Association.[2] The project is justified on the basis of needing to restore the structures to an appropriate safety level, based on current site conditions, and to allow for continued operation of the hydroelectric system in a safe and reliable manner.

Specific work to be completed in 2018 includes:

1. *Second Storage Pond Dam ($351,000)*

   The Second Storage Pond Dam is a 64 m long, rock-filled, timber-faced dam. It was originally constructed around 1920, early in the life of the Port Union development. Significant improvements in the past include partial replacement of the timbers, and improvements in 1986 to increase flood-carrying capacity and to partially replace the timbers. In 1999, additional rock ballast was added to increase stability and upstream improvements were undertaken to limit leakage.

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[1] Normal annual production was established as 438.6 GWh in Newfoundland Power's Normal Hydroelectric Production for 2017 in a letter dated February 22, 2017.

[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.

The upstream timbers and the associated plastic liner provide an impervious boundary to limit leakage through the structure. The timbers on the crest support the upstream timbers and protect the underlying material from erosion to ensure overall stability and, when water levels allow, provide a path for inspection. The timbers range in age from 18 to 31 years and are in fair to poor condition. Figures 1 and 2 show timbers in poor condition and Figure 3 shows misalignment as a result of shifting that has occurred over time.

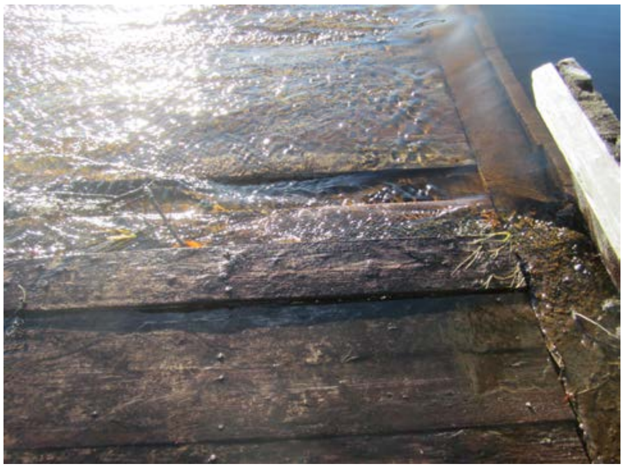

Figure 1: Delaminated Timbers

Figure 2: Delaminated Timbers

Figure 3: Misaligned Upstream Face

Figure 4: Downstream Ballast

Replacement of the upstream timbers with galvanized sheet steel pilings on the upstream face will ensure the structure remains watertight, stable and safe under flood conditions. The timber on the crest will be removed and replaced with additional rock fill that will be graded such that it will prevent erosion and permit safe inspection by Newfoundland Power staff. The rock ballast on the downstream face is in good condition and will be integrated into the refurbished structure (see Figure 4).

3.0 Other Hydroelectric Infrastructure Rehabilitation

Cost: $593,000

The Company's 23 hydroelectric facilities range in age from 18 to 117 years and have many components, including access roads, bridges, penstocks, surge tanks, powerhouses, ancillary buildings and tailraces. Based on the age of the components in Newfoundland Power's system, deterioration is to be expected.

Each year, refurbishment of deteriorated components at various hydroelectric facilities is required to ensure integrity of the components and the safe and reliable operation of the facilities. The project is justified on the basis of needing to restore the structures to an appropriate level of safety and integrity, based on the current site conditions, and to allow for continued operation of the hydroelectric system in a safe and reliable manner.

Specific work to be completed in 2018 includes:

1. *Horsechops Tailrace Tunnel Rehabilitation ($291,000)*

   The Horsechops tailrace tunnel was constructed in 1980 to replace a rock crib retaining wall constructed in 1954 as part of the original development.[3] The tunnel consists of 2 types of large diameter, corrugated steel culvert with a total length of approximately 32 m. Approximately one-third of the tunnel is constructed as an elliptical steel culvert, while the remainder is constructed as a steel arch culvert supported on concrete foundations. The tunnel has not received significant upgrades since 1980.

   An internal inspection of the tunnel structure was completed in 2016 after 2 sink holes developed – 1 on each side of the tunnel, as show in Figure 5 and Figure 6.[4] The inspection revealed the elliptical steel culvert is in poor condition. Longitudinal cracks have developed in some of the structural plates and corrosion is prevalent, with holes starting to appear, as shown in Figure 7. The transition between the elliptical steel culvert and the concrete building foundation has failed and is no longer sealed. Rocks are currently exposed and finer fills have washed out, undermining the culvert and causing voids on the sides.[5] Figure 8 shows the undermined culvert, a section of the failed transition, and exposed rocks. The downstream transition where the elliptical steel culvert transitions to the steel arch culvert has also deteriorated and is similarly separated.

[3] A tailrace is the water conveying channel downstream of a hydroelectric turbine.
[4] The sink holes have been temporarily stabilized to permit planned replacement.
[5] Corrugated steel culverts rely on well compacted backfill to retain their structural strength.

Figure 5: Left Side Sinkhole

Figure 6: Right Side Sinkhole

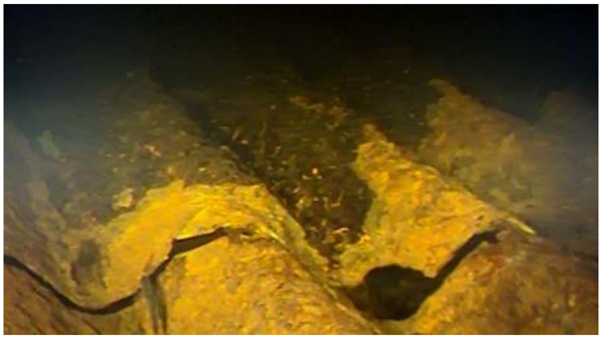

Figure 7: Cracked and Corroded Section

Figure 8: Failed Culvert to Concrete Connection

The elliptical steel culvert and the associated transitions on both ends are in poor condition and require replacement to ensure safe, reliable production at Horsechops.[6] Replacement will include the removal of the existing elliptical steel culvert and granular fill material, and the installation of a new fill retaining system. The remaining steel arch culvert is in fair condition and does not require replacement at this time.

2. *Tors Cove Access Road Bridge Replacements ($302,000)*

The Tors Cove powerhouse is accessed via a gravel road extending from an unnamed residential street in Tors Cove. An 8.5 m long steel bridge with a timber deck crosses the penstock, permitting access to the powerhouse and the plant substation.[7] Beyond the first bridge, a second 11.6 m long steel bridge of similar construction crosses the spill channel, permitting access to the surge tank and a portion of the penstock. Both bridges were constructed in 1987. They are now in poor condition and require replacement.

[6] Unplanned failure of the culvert would cause significant siltation and stop generation until the debris could be removed and the culvert replaced.

[7] A large loading door is accessible before the bridge. It is not practical for normal entry.

The concrete abutments for both bridges were constructed in 1941 as part of the original development of the Tors Cove system, and modified in 1987 to suit the replacement of the bridges.[8] The 1941 concrete is deteriorated, exhibiting significant cracking as shown in Figure 9 and Figure 10.

Figure 9: Abutment (Bridge 1)

Figure 10: Abutment (Bridge 2)

Due to the close proximity to the salt water, corrosion of the bridges has accelerated beyond what would typically be expected. The steel structural members of both bridges are heavily corroded and are scaling, as shown in Figure 11 and Figure 12. The timber deck and railings have been maintained in good condition to ensure the safety of employees and the public.[9] However, the loading capacity of the bridges is now below current standards.[10]

Figure 11: Deteriorated Steel (Bridge 1)

Figure 12: Deteriorated Steel (Bridge 2)

8 An abutment is the structure on which the ends of a bridge rests.

9 In addition to Company employees, the bridges are crossed frequently by ATVs and hikers accessing the East Coast Trail.

10 Design of a new structure would be governed by CSA-S6-14 - Canadian Highway Bridge Design Code.

The abutments and structural steel of both bridges are in poor condition and require replacement to meet capacity requirements and ensure the Company's ability to access and maintain its assets. The timber deck and railings will also be replaced as part of the bridge replacements.[11]

4.0 Rocky Pond Plant Refurbishment

Cost: $607,000

The Company's Rocky Pond and Tors Cove hydroelectric development is comprised of 2 generating plants: Rocky Pond and Tors Cove. These plants are located on the Southern Shore of the Avalon Peninsula, approximately 40 km south of the City of St. John's. Rocky Pond Plant was commissioned in 1942 with a 3,750 kVA generator coupled to a 4,200 hp Francis turbine operating under a rated net head of 32.6 m. The plant has a capacity of 3.25 MW and a normal annual production of approximately 14.45 GWh, or 3.3% of the total hydroelectric production of Newfoundland Power. The development has provided 75 years of reliable energy production.

The proposed project for Rocky Pond Plant involves the replacement of the turbine bearing. This will include disassembly of the generator, replacing the turbine bearing, realigning the shaft, replacing any worn components, cleaning the rotor and stator, and rewedging stator windings as required. Additionally, the powerhouse exterior is in need of an upgrade so it can continue to provide safe and secure housing of the generator and associated equipment.

Specific work to be completed in 2018 includes:

1. *Turbine Bearing Replacement ($438,000)*

The water cooled turbine bearing for generator G1 is worn and requires replacement. In addition, the 20 year old cooling coils on the generator thrust and lower guide bearings will be replaced at the same time. The cause of the excessive wear on the turbine bearing is related to the generator shaft being misaligned due to the generator and turbine shaft coupling faces not being parallel and the turbine shaft coupling face not being perpendicular to the shaft centreline. In 2009, when the unit was last disassembled, in-situ machining was attempted on site to correct the long standing misalignment issue. The onsite machining did not sufficiently correct the misalignment, and it was determined that the shaft would need to be sent to a specialized machine shop to achieve the required tolerances to correct the misalignment. As there was insufficient time before winter to send the shaft to a machine shop, temporary measures were put in place using shims between the coupling faces to return the generator to service. However, the residual runout at the turbine bearing is not optimal, thereby leading to additional wear on the bearing components. Replacing the bearing at this time, and realigning the shaft, will ensure a more costly shaft refurbishment is not required in the future.

[11] It is not possible to salvage the timber deck and railings as the new bridges will be configured differently.

The generator rotor will be removed to permit access to the shafts and turbine bearing. During the disassembly the rotor and stator will be cleaned and the stator windings re-wedged.

Figure 13 shows the generator shaft and Figure 14 shows the turbine bearing.

Figure 13: Generator Shaft

Figure 14: Turbine Bearing

2. *Powerhouse Refurbishment ($169,000)*

The powerhouse is of concrete construction with an exterior parging and paint finish. The parging is failing due to cracking and freeze-and-thaw failures caused by water ingress, as shown in Figure 15. The exterior will be scaled to remove loose parging material and a metal cladding will be installed to protect the building structure.

Figure 15: Powerhouse Parging Failure

5.0 Generation Equipment Replacements Due to In-Service Failures

Cost: $568,000

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

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 1 of 2 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 2013.

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

Year	2013	2014	2015	2016	2017F
Total	$399	$590	$524	$582	$552

Based on recent expenditures and engineering judgement, $568,000 is estimated to be required in 2018 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 support the continued operation of generating facilities in a safe and reliable manner.

6.0 Concluding

This project, for which there is no feasible alternative, is required to ensure the continued provision of safe, reliable generating facility operations. A 2018 budget of $2,119,000 for Facility Rehabilitation is recommended as follows:

- $351,000 for Hydro Dam and Spillway Rehabilitation;
- $593,000 for Other Hydroelectric Infrastructure Rehabilitation;
- $607,000 for Rocky Pond Plant Refurbishment; and
- $568,000 for Generation Equipment Replacements Due to In-Service Failures.

Purchase Mobile Generation

July 2017

Prepared by:

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M. G. HUNTER
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June 23, 2017
PROVINCE OF NEWFOUNDLAND

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Appendix A: Mobile Gas Turbine Condition Assessment – December 2015

1.0 Introduction

Newfoundland Power owns one mobile gas turbine ("MGT"), which is rated at 6,750 kW and one mobile diesel generator, which is rated at 2,500 kW. A condition assessment done on the MGT in 2015 recommended that it soon be retired from mobile operation due to the deteriorating condition of the trailer chassis.[1] In addition to the issues with the trailer chassis, prime mover components, namely the Orenda gas generator and power turbine, are no longer manufactured. The dwindling number of similar units in service has resulted in fewer overhaul facilities with the necessary expertise to refurbish this equipment.

The existing MGT has been traditionally used for: (i) support for customer outages; (ii) construction projects; and (iii) system support. The availability of mobile generation can ensure the reliability of electrical service to customers and provide flexibility to operating and maintenance staff when responding to extended customer outages in both planned and unplanned situations.

The existing MGT is 43 years old and approaching the end of its service life. This report provides an assessment of the benefits of maintaining mobile generation and options for replacing the MGT.

2.0 Function of Mobile Generation

2.1 Support for Customer Outages

Mobile generation serves 2 main reliability roles: emergency generation and system backup generation. Emergency generation is the capability to provide power to an area of the system that has sustained severe damage where it is expected to take more than 48 hours to repair the damage.[2]

System backup generation is a benefit provided to areas that have below average reliability and few economical options for improving reliability performance through traditional means. Mobile generation can serve as end-of-line generation for customers served by radial distribution or transmission lines. In this case, when not required for construction projects or long-duration emergency outages, mobile generation is stored at a location that would reduce outage time in the event of issues with the radial lines.

The existing MGT had been historically stationed at the Grand Bay Substation in Port aux Basques during the winter months due to the risk of outages on Newfoundland and Labrador Hydro's ("Hydro") TL214 and TL215 – the 2 radial transmission lines that supply the Port aux Basques area. Reliability improvements have been made to transmission lines TL214 and TL215 by Hydro and, as a result, the MGT has been stationed elsewhere during the winter months.[3]

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1 A copy of the MGT condition assessment is included as Appendix A to this report.

2 The MGT typically takes 48 hours to dismantle, transport, reassemble and prepare for generation. The existing MGT has been deployed several times over its service life to Bonavista, Bell Island and the Trepassey areas due to transmission line issues caused by severe weather events.

3 The MGT returns to Grand Bay Substation for planned annual maintenance outages on the Hydro transmission lines.

Most recently, the MGT has been stationed on the Avalon Peninsula during the winter months. For portions of the 2012-13 and 2013-14 winter seasons, prior to the installation of the black start diesel generators at Hydro's Holyrood Thermal Generating Station, the MGT was stationed at Holyrood to support station service requirements. The MGT was then stationed at Whitbourne during the winter of 2014-15 and 2015-16. The rationale for locating the MGT at Whitbourne was that it is more central for emergency dispatch, as well as being able to provide generation support, if required, to the Avalon Peninsula during times of high demand or low generation. In December 2016, the MGT returned to Port aux Basques to provide generation support following the loss of a single turbine at the Rose Blanche Hydroelectric Plant.[4]

2.2 Construction Projects

Mobile generation is used during selected construction projects to minimize the number and duration of customer outages. Depending on the location and amount of line or substation work involved, mobile generation is an alternative to hot-line work to minimize the duration of customer outages. Otherwise, hot-line work methods must be employed if customer outages are to be avoided.[5]

For example, to replace structures on a radial transmission line serving remote, rural communities, mobile generation may be able to supply these customers while the transmission line is de-energized, allowing work to proceed. In this situation, customers would typically experience a brief switching outage in the morning and evening of each day that construction proceeds. Otherwise, customers would experience long duration daily outages for the planned construction until the project is completed.

In 2015, Newfoundland Power deployed the MGT in 4 locations to avoid hot-line work and extensive customer outages: Trepassey, Abrahams Cove, Lewisporte and Twillingate. In these cases, approximately 28 million customer outage minutes were avoided. The MGT also operates regularly at Port aux Basques where it is used along with the mobile and Port aux Basques diesel generators, as well as the Rose Blanche hydro plant, during Hydro's annual maintenance on transmission lines TL214 and TL215. In 2015, in Port Aux Basques it was used to avoid approximately 6 million customer outage minutes and in 2016 it was used to avoid approximately 4 million customer outage minutes. It was also used at the Pulpit Rock Substation (Torbay) to complete scheduled transmission line maintenance in 2016, avoiding approximately 725,000 customer outage minutes.

2.3 System Support

Mobile generation can be used to provide generation and voltage support to the Island Interconnected System during times of high demand or low generation reserve.

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4 It is anticipated that the MGT will remain in Port aux Basques for the winter of 2017/2018 as the refurbishment of the Rose Blanche turbine will not be completed prior to the onset of winter.

5 Working on energized equipment requires the use of hot-line work methods, which have inherent safety risks and additional costs associated with extended time to complete certain construction projects.

As noted by the historical operation in Figure 1, the existing MGT has been utilized significantly to provide system support at the request of Hydro. In addition, in areas where voltage problems may occur, the MGT has been dispatched to provide voltage support.

3.0 Historical Operation of MGT

A review of the past 10 years of operation indicates that the average annual generation for the MGT is 488 MWh at an average load of 3.51 MW. The past 5 years of operation had an average annual generation of 639 MWh at an average load of 3.96 MW. A summary of the historic operation of the MGT over the 10 and 5-year periods is shown in Figure 1.

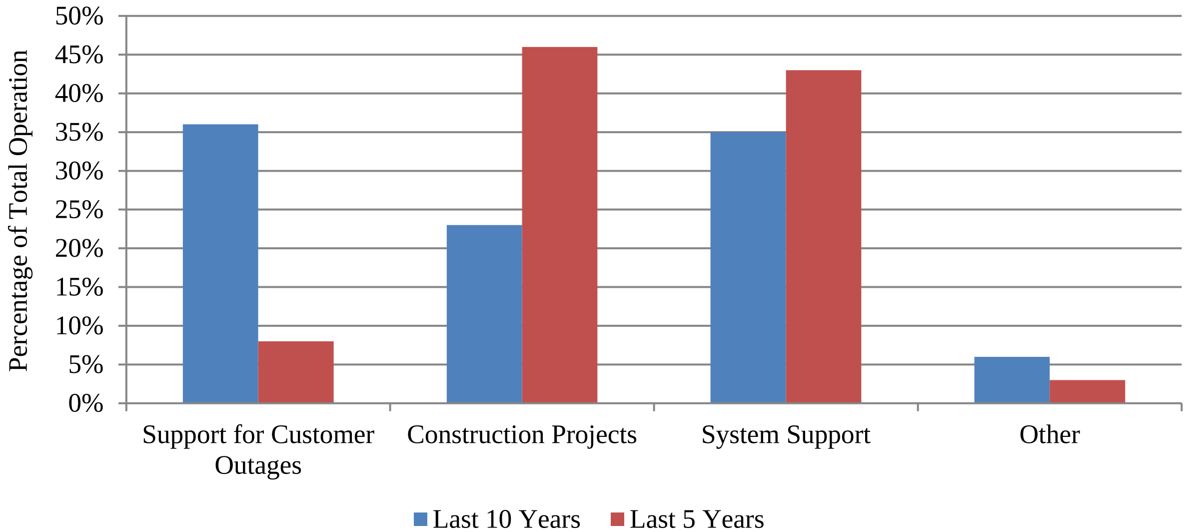

Figure 1: Historical Operation of MGT by Function

The use of the MGT for system support has increased in the last 5 years. This can be attributed to it being located on the Avalon Peninsula during this period, and the more frequent requests by Hydro for generation support related to the Avalon Peninsula reserve requirements. The use of the MGT to support customer outages has been less in the last 5 years than it was during the past 10 years. This is related to the timing of storms that caused damage to the Company's transmission and distribution systems.[6]

[6] For example, in March 2010, the MGT was stationed at Catalina on the Bonavista Peninsula and at Old Perlican on the Avalon Peninsula to provide emergency generation following a severe ice storm. During these outages the MGT operated for 123 hours producing 442 MWh of generation.

4.0 Existing MGT Condition

In 2015, a condition assessment was completed on the major components of the existing MGT.[7]

The gas generator was last overhauled in 2003. This component and the power turbine are no longer supported by the original equipment manufacturer. The instrumentation and controls were also upgraded in 2003 with the addition of programmable logic controls, digital synchronizer, voltage regulator and relays, as well as new field sensors, such as vibration and exhaust gas temperature sensors. The switchgear and power transformer are original, but underwent major overhauls in 2003.

The trailers that house the gas turbine components are deteriorating. The undercarriage is susceptible to heavy corrosion with major repairs done in 2010. In late 2016, extensive chassis and axle repairs to the two trailers were again necessary to make the MGT roadworthy. The undercarriage continues to deteriorate. The enclosures are also in very poor condition with water leaks into the trailers occurring.[8]

As a result of the poor condition of the trailers that support and house the gas turbine components, the existing MGT will be retired from mobile service over the next 3 years and then moved to a permanent location until the other major components reach the end of their service lives, which is anticipated to be between 5 and 10 years for each of the various subsystems.[9]

5.0 Mobile Generation Options

Utility-sized mobile generation units are typically provided using 2 types of technology: diesel generators and gas turbines. The appropriate choice of technology depends on several factors.

Diesel generation technology is well proven. Newfoundland Power has 2 diesel generators, including a 2.5 MW stationary unit located at Port aux Basques Substation and a 2.5 MW mobile unit (MD3) purchased in 2003. In addition, Hydro has several large stationary units located on both rural interconnected and isolated networks.[10] As a result, the resources to operate, service and maintain utility-sized diesel generators are readily available in the province.

Due to their inherent high rotating inertia, diesel generators have good load pickup capability. The major disadvantages of mobile diesel units are their physical size and weight. The largest practical size of a mobile diesel is 2.0 MW to 2.5 MW. Newfoundland Power's rural feeders typically have peak loads in the 3.0 MW to 4.5 MW ranges, so multiple diesel units would be required to serve most locations. Operating multiple diesel generators in parallel increases the complexity of necessary control equipment and operation.

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7 A copy of the MGT condition assessment is included as Appendix A to this report.
8 Pictures 13 through 25 of Attachment B to Appendix A show the extent of the deterioration that exists on the undercarriage and enclosure.
9 Table 3 of Appendix A includes information on the remaining service life of the various subsystems that comprise the MGT.
10 Hydro also has a number of black-start diesel generators at the Holyrood Thermal Generating Station capable of providing support to the Island Interconnected System.

Gas turbines are more compact than diesels for the same load generating capacity and are better suited for applications where the load requirements exceed 2.5 MW. Newfoundland Power has operated gas turbines for many years, including the existing MGT along with the Wesleyville and Greenhill gas turbine facilities. Gas turbines are more complex to operate and maintain than diesel generators, but Newfoundland Power has experienced personnel qualified to operate and maintain gas turbines. As well, out-of-province expertise is readily available to assist, if required.

In some situations, the load pickup capability of a gas turbine is more limited than that of a diesel generator, but this may be managed by sectionalizing the distribution system to operate within the unit's limitations.

Given the size of the loads typically required, based on historical operation of the existing MGT, a new mobile gas turbine will be purchased to replace the existing unit.

The criteria for the new gas turbine will be:

- Fully self-contained and able to be set up with minimum site preparation;
- Capable of burning locally available No. 2 diesel fuel;
- Have black start capability (i.e., no external AC power available);
- Able to operate isolated (isochronous) or in parallel with the provincial power grid;
- Complete with a step-up transformer capable of providing 60 Hz power at both 12,500 and 25,000 volts through the use of field-selectable taps;
- Compliant with current industry, regulatory, environmental and safety performance standards; and
- Capable of travelling the province's roads and bridges.[11]

6.0 2018 Project

6.1 Project Description

Potential suppliers have been identified to determine the available unit sizes and approximate purchase cost. There are units available in the 3.5 MW to 7.5 MW range, which is suitable for most applications. High-level pricing was obtained and internal costs added to determine a probable cost range. The unit supply costs obtained were in US dollars and are susceptible to the changing currency rate. For the units identified, the estimated costs are between $12,000,000 and $14,000,000, for an all-in, per-kW cost of $2,600/kW to $2,770/kW.[12] Deliveries for the new unit, from date of ordering, would be approximately 12 months. Engineering, procurement, and commissioning is expected to be done over an 18-month to 24-month period.

An alternative to procuring a new unit would be to procure 10 to 15-year-old, zero-hour rated, refurbished unit. This may result in lower equipment cost, but a full evaluation of the equipment would be necessary. All major components would need to be commercially available and supported by the original equipment manufacturer. As well, all controls, protection and

[11] The maximum allowable weight per single axle is 9,000 kg and 17,500 kg per tandem axle.
[12] All cost estimates are in Canadian dollars.

switchgear would need to be upgraded to modern standards. Trailer sub frames and enclosures would need to be in excellent condition and suitable for the provincial climate and road conditions.[13]

A Request for Proposals will be prepared for both new and refurbished portable gas turbine units in the 3.5 MW to 7.5 MW range.

An analysis will be completed to determine the optimum location for stationing the new MGT when it is not required for immediate service so it can provide system backup generation. This will be done by considering the potential reliability improvements that could be achieved at various substations if the unit were located there. This will be balanced against accessibility for dispatch to other areas of the system, should it be required for emergency service.

6.2 Project Cost

The total project cost for the supply of a new mobile gas turbine is estimated at $13,915,000. Table 1 below summarizes the cost breakdown.

Table 1
Project Cost
(000s)

Cost Category	2018	2019	Total
Material	$4,731	$5,869	$10,600
Labour - Internal	35	195	230
Labour - Contract	-	-	-
Engineering	154	231	385
Other	1,080	1,620	2,700
Total	**$6,000**	**$7,915**	**$13,915**

7.0 Conclusion

A detailed engineering assessment has been completed of the existing MGT and, given the overall poor condition of the chassis and enclosures, the unit will be retired from mobile service within the next 3 years.

A new mobile gas turbine system in the 3.5 MW to 7.5 MW size range is required to provide support for customer outages, construction projects, and system support to the Island Interconnected System.

Based upon the condition of the existing MGT and the considerations outlined in this report, the project will proceed over the 2018-19 timeframe.

[13] The opportunity to purchase a refurbished unit will depend upon the availability of such units at the time the RFP is released. The market for these type units is small and the availability of suitable units cannot be easily predicted.

Appendix A:
Mobile Gas Turbine
Condition Assessment

December 2015

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Attachment A MGT Single Line Diagram
Attachment B Photographs of the MGT
Attachment C Maintenance History
Attachment D MGT Inspection

1.0 Introduction

The mobile gas turbine ("MGT") is a 6,750 kW combustion turbine assembled on 2 trailers. One trailer houses the gas generator, power turbine, speed reduction gearbox and AC generator. The second trailer houses the unit switchgear, controls, batteries and chargers, power transformer, recloser and auxiliary power unit. Fuel for the gas turbine is provided either by a separate stationary dyked storage tank in some areas or by leased tanker trucks in other areas. The single line diagram for the existing MGT is provided in Attachment A.

The MGT is utilized for emergency power in the event of system outages following storms or other significant events. It is also used during construction projects on transmission and distribution lines to reduce the need for hot-line work and to minimize outages to customers during construction projects.

The typical life expectancy of a gas turbine is 25 years. The MGT was purchased in 1974 and has undergone several upgrades, including gas generator overhauls and control system upgrades. This has extended the unit's service life.[1]

Deterioration and aging of the non-gas turbine components are becoming the determining factors on the unit's service life. A review of the various components has been undertaken to provide a recommendation for the MGT's future.

2.0 Description

2.1 Gas Generator

The gas generator is an Orenda OT-390 Model 2G originally manufactured by Hawker Siddeley, Orenda Aerospace division. The unit has undergone 2 overhauls: 1 in 1990 by Hawker Siddeley and the most recent in 2003 by S&S Turbine Services Ltd. At the time of the 2003 overhaul, the unit was found to be in good overall condition. The most recent boroscope inspection was done in March 2015 by S&S Turbine Services during a vibration investigation. Generally, the unit was found to be in good condition.[2]

2.2 Power Turbine

The power turbine (Orenda, OT-3, Model 6) was also manufactured by Hawker Siddeley, specifically for use with the gas generator. During the gas generator refurbishment in 2003, the stage 2 turbine nozzles were replaced with refurbished parts. In 2010, the power turbine inlet duct underwent repairs.

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[1] The MGT's maintenance history is included in Attachment C.

[2] The S&S Turbine Services March 2015 inspection report is included in Attachment D.

2.3 Speed Reduction Gearbox

The speed reduction gearbox was manufactured by Philadelphia Gear. The gearbox reduces the output speed of the power turbine from 7,200 rpm to 3,600 rpm required by the AC generator to operate at synchronous speed. The gearbox also drives the power turbine lubricating pump.

There is no record of any major maintenance being required on this component and it has operated reliably.

2.4 AC Generator

The AC generator was manufactured by Electric Machinery Manufacturing Company and operates at 4,160 volts at 3,600 rpm. There has been no major maintenance done on the generator over its life. Generator service life is typically 30 to 40 years. Normal testing has not indicated any issues with the AC generator.

2.5 Instrumentation/Controls

The original controls were replaced in 2003 by Allan Bradley programmable logic controller based controls, synchronizer and digital voltage regulator.[3] New digital relays, vibration monitoring system, exhaust gas temperature thermocouples and speed sensing were installed. New power cables and a new motor control centre were installed.

2.6 Switchgear

The switchgear, including the unit breaker, is original equipment. The last major maintenance performed on the switchgear was completed during the 2003 MGT overhaul.

2.7 Auxiliary Power Unit

The auxiliary power unit is a 40 kW, 208 volt, 3-phase Kohler diesel generator used to provide station service and for starting the gas turbine under black start conditions. The original auxiliary power unit was replaced in 1995 with the current unit. No major maintenance has been done on the Kohler diesel generator. The exterior enclosure is exhibiting rust, as are some minor components of the engine auxiliaries.

2.8 Power Transformer

The power transformer is original, manufactured by Federal Pioneer, and is rated at 7.5 MVA. The transformer can be configured to operate at 2 different voltages: 25 kV and 12.5 kV. Most frequently, it is used at the 12.5 kV voltage level.

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[3] The Allan Bradley programmable logic controller based controls, synchronizer, and digital voltage regulator are standard technologies used by Newfoundland Power in all of its gas turbines and hydro plants that have been refurbished since 2000. Standardizing on these digital technologies, and their most recent upgrades, has reduced the cost of training and spares inventory to support these critical control systems.

The last major maintenance performed on the power transformer was completed during the 2003 unit overhaul. Other than regular maintenance, the power transformer has not undergone any major upgrades since 2003.

2.9 Trailers

The gas turbine components are mounted on 2 trailers originally manufactured by Bartlett Trailer Corporation. The undercarriage structures have experienced heavy corrosion. The undercarriage was assessed by Hatch in 2010. As a result of the assessment, the cross members were replaced and undercoating repaired. Also in 2010, the trailer suspension, wheels and brakes of both trailers were inspected and repairs were made where necessary.

The repairs done are considered a short-term measure to keep the unit operational. Recent inspections indicated that the chassis still appears to be in reasonable condition, but the undercoating is starting to deteriorate again and, as a result, the underlying steel components are exposed to the elements and corrosion is prevalent throughout.[4]

The enclosures on the trailers that house the equipment are in very poor condition. There is some damage to the enclosure envelope, allowing water to leak into the enclosures, which could jeopardize the equipment inside. Where possible, leaks are repaired, but often reoccur once the unit is moved. The doors and sills are in particularly poor condition.

In addition to the condition of the trailers, there is a safety concern associated with accessing the tops of the trailers to install the power cables, remove covers and install the exhaust stacks. The existing roof-mounted railing system was retrofitted to the trailers and is of the collapsible type, which is stored for transportation. The railing system is slight. It is not possible to install a more rigid system as the enclosures do not have adequate structure to which the railings can be attached. Maintenance staff currently uses a boom truck to connect fall arrest lanyards or, where there is inadequate room for this, scaffolding is erected to provide a safety barrier.

[4] Attachment B has numerous photographs showing the condition of the undercarriage.

3.0 Operating History

The annual production of the MGT over the past 10 years is shown in Table 1.

Table 1
Annual Production

Year	Generation (kWh)	Run Time (hours)	Avg. Generation Load (kW)
2006	155,183	36.95	4,199.8
2007	98,489	34.62	2,844.9
2008	652,193	215.42	3,027.5
2009	189,620	66.76	2,840.3
2010	614,866	172.44	3,565.7
2011	126,928	42.65	2,974.4
2012	388,811	125.23	3,104.8
2013	241,828	73.75	3,279.0
2014[5]	960,984	195.60	4,913.0
2015[6]	1,160,140	338.27	3,429.6
Average	**473,137**	**130.17**	**3,418.07**

The average annual production over the past 10 years was 473 MWh, with an average load supplied of 3.42 MW.

4.0 Incapability Factor

A unit's incapability factor ("ICBF") is the ratio of the total equivalent outage time to the number of hours the unit has been in service. The total equivalent outage time includes the total forced outage time, planned outage time, and maintenance time, as well as adjusted derated times. Adjusted derated time is the time transformed into an equivalent outage time. For example, if a generating unit is derated to 80 per cent of its maximum capability for 5 hours, which would be equivalent to a full outage for 1 hour (i.e., 20 per cent of 5 hours equals 1 hour).

[5] Increased generation and run time hours related to system support are the result of requests by Newfoundland and Labrador Hydro for additional supply.
[6] Increased generation and run time hours related to use for construction projects on 94L, 114L, 140L and 410L.

The ICBF was determined for the MGT over the period 2007 to 2015. The Canadian Electrical Association ("CEA") provided data for the period 2008 to 2012 for comparison. Table 2 compares the ICBF of the MGT with the CEA average.

Table 2
Incapability Factor

Plant	ICBF
MGT	0.14%
CEA Average	13.8%

The ICBF is very good, but consideration should be given to the fact that the unit is mostly on standby and, relatively speaking, has had very little operation. There have also been no major overhauls or repairs carried out over the period from 2007 to 2015.

5.0 Industry Trends

5.1 Orenda Gas Generator

There were approximately 150 Orenda hot gas generators produced for use in gas turbine packages for gas compression, oil pumping and electricity generation. Repair and overhaul services for the units appear limited. They are currently provided by Magellan Aerospace and S&S Turbines.

5.2 Power Turbine

The power turbine is no longer manufactured but is supported by Magellan Aerospace and S&S Turbines. As with the hot gas generator, replacement components are either salvaged or fabricated.

5.3 Speed Reduction Gearbox

The gearbox was manufactured by Philadelphia Gear and the company is still in operation. As well, there are numerous third-party manufacturers that could perform overhaul and maintenance services. As the gearbox was custom made for the application, any replacements would either have to be salvaged or fabricated.

5.4 AC Generator

The manufacturer of the generator, Electric Machinery Manufacturing Company, is still in business. As well, as the generator is not particularly specialized, it can be replaced or maintained by a number of third-party generator manufacturers or maintenance facilities.

5.5 Enclosures and Trailers

The enclosures and trailer components were specifically designed and manufactured for the application. The original manufacturer is no longer in business. It is possible that replacements may be reverse engineered, but given the vintage of the unit and available technical information, it may prove difficult.

5.6 Balance of Plant

The balance of plant systems are not proprietary in nature and may be replaced or maintained as required.

6.0 Remaining Service Life

The 2015 Depreciation Study estimated the remaining life of the various components. Table 3 includes those estimates.

Table 3
Remaining Service Life

Component	Years
Engine	10
Power Turbine (incl. gearbox)	5
Generator	5
Governor	10
Enclosure	5
Building Services	5
Instrumentation & Controls	10
Switchgear	5
Trailers	3
Balance of Plant	5

7.0 Environmental

The MGT has a 470 litre day tank used to fuel the hot gas generator. This is refilled by a tanker truck or from a dyked steel storage tank depending on location. The day tank is single-walled and original.

The unit lube oil tank has a capacity of 1,100 litres and is single-walled.

The auxiliary power unit has a fuel tank capacity of 20 litres and is single-walled.

The power transformer contains 2,700 litres of insulating oil. This is a single-walled component.

Given the vintage of the MGT, it is unlikely to meet current emission standards, particularly for Nitrous Oxide. As the unit is only used for emergency purposes and construction projects, it would be unlikely to emit any significant amount of contaminants.

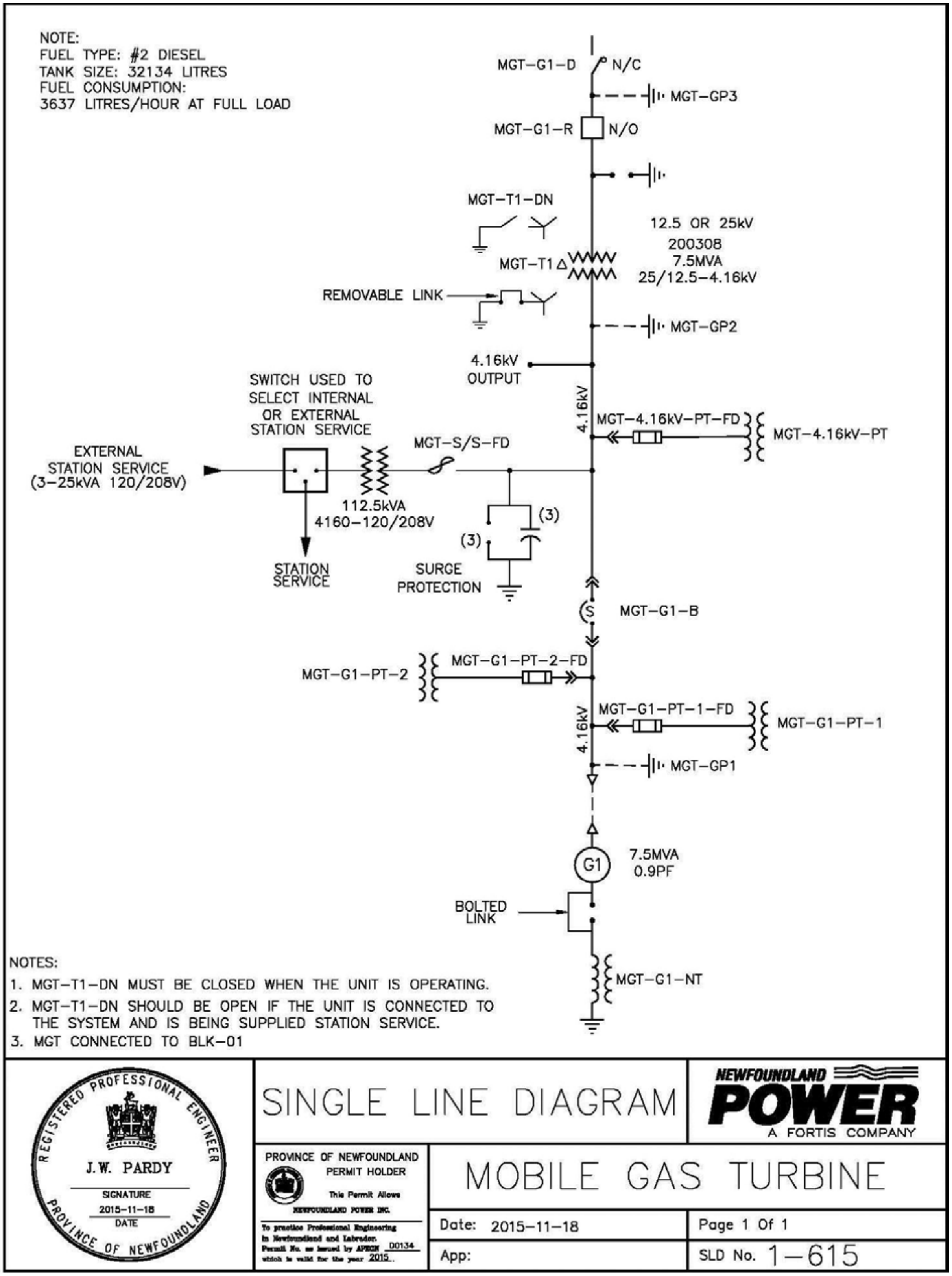
Determination of the various levels of air pollutants from the MGT would require source testing and air dispersion modeling. The modeling would be site specific due to the impact of local topography. For a mobile unit, air dispersion modeling would be impractical.

8.0 Recommendations

Given the current condition of the rolling components, the MGT should be retired from mobile service over the next 3 years.

The remaining service lives of the other parts of the MGT are estimated to range from 5 to 10 years, so it may be stationed at a fixed location until it is fully retired from service. A review of siting should be undertaken to identify the most appropriate location based on potential reliability considerations.

Attachment A:
MGT Single Line Diagram


NOTE:
FUEL TYPE: #2 DIESEL
TANK SIZE: 32134 LITRES
FUEL CONSUMPTION:
3637 LITRES/HOUR AT FULL LOAD
MGT-G1-D
N/C
MGT-GP3
MGT-G1-R
N/O
MGT-T1-DN
12.5 OR 25kV
200308
7.5MVA
25/12.5-4.16kV
MGT-T1
REMOVABLE LINK
MGT-GP2
4.16kV
OUTPUT
SWITCH USED TO
SELECT INTERNAL
OR EXTERNAL
STATION SERVICE
4.16kV
MGT-4.16kV-PT-FD
MGT-4.16kV-PT
EXTERNAL
STATION SERVICE
(3-25kVA 120/208V)
MGT-S/S-FD
112.5kVA
4160-120/208V
(3)
(3)
STATION
SERVICE
SURGE
PROTECTION
MGT-G1-B
MGT-G1-PT-2-FD
MGT-G1-PT-2
MGT-G1-PT-1-FD
MGT-G1-PT-1
4.16kV
MGT-GP1
G1
7.5MVA
0.9PF
BOLTED
LINK
MGT-G1-NT
NOTES:
1. MGT-T1-DN MUST BE CLOSED WHEN THE UNIT IS OPERATING.
2. MGT-T1-DN SHOULD BE OPEN IF THE UNIT IS CONNECTED TO THE SYSTEM AND IS BEING SUPPLIED STATION SERVICE.
3. MGT CONNECTED TO BLK-01
REGISTERED PROFESSIONAL ENGINEER
J.W. PARDY
SIGNATURE
2015-11-18
DATE
PROVINCE OF NEWFOUNDLAND
SINGLE LINE DIAGRAM
NEWFOUNDLAND POWER
A FORTIS COMPANY
PROVINCE OF NEWFOUNDLAND
PERMIT HOLDER
This Permit Allows
NEWFOUNDLAND POWER INC.
To practice Professional Engineering in Newfoundland and Labrador.
Permit No. as issued by APEGN D0134 which is valid for the year 2015.
MOBILE GAS TURBINE
Date: 2015-11-18
Page 1 Of 1
App:
SLD No. 1-615

Attachment B:
Photographs of the MGT

Picture 1: General View

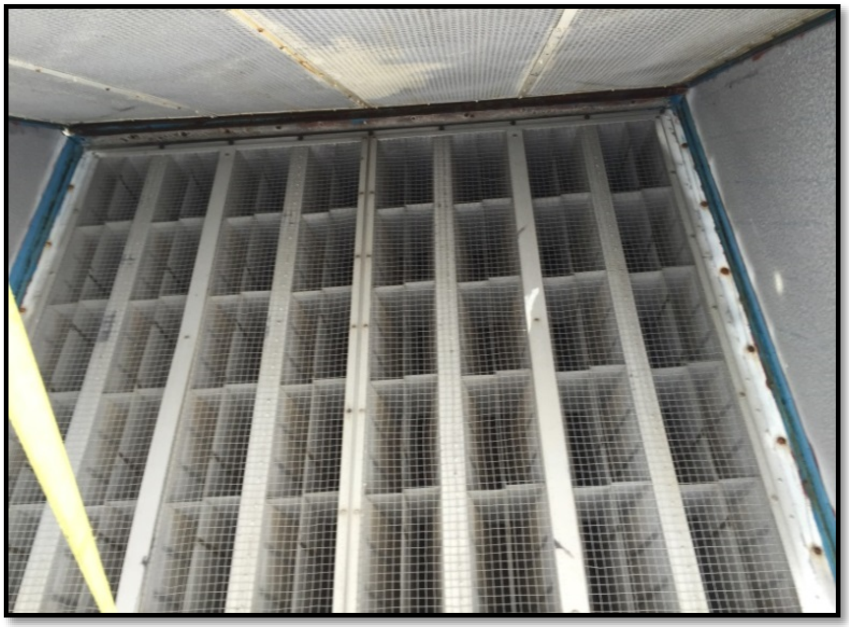
Picture 2: Turbine Trailer

Picture 3: Control Trailer

Picture 4: Transformer

Picture 5: Exhaust Stacks

Picture 6: APU Enclosure

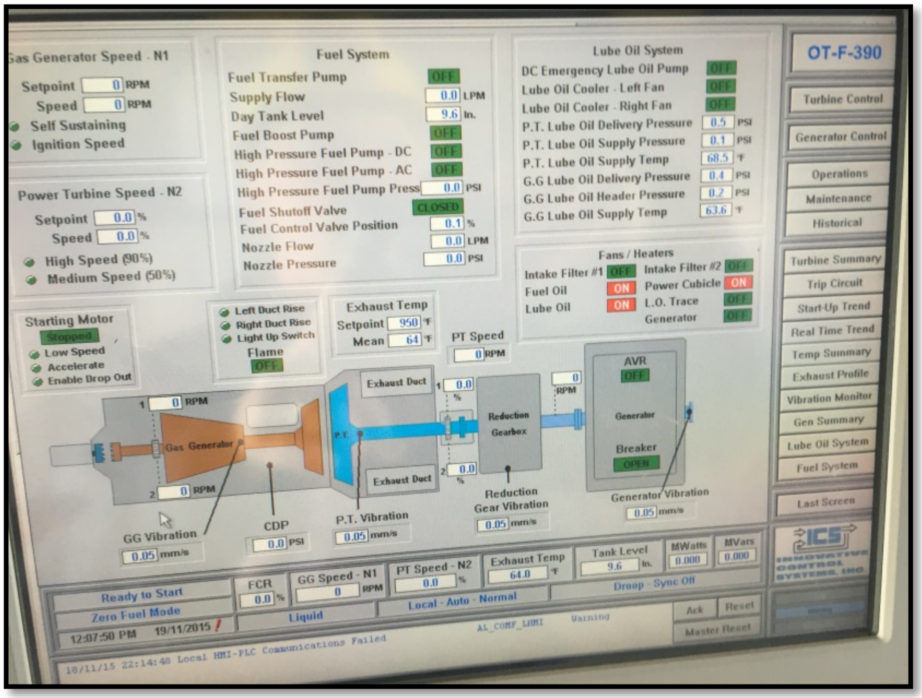


Picture 7: HGG Air Intake

Picture 8: Gas Generator

Picture 9: Controls

Picture 10: Generator



Picture 11: Control Screen

Picture 12: Motor Control Center

Picture 13: Enclosure – Old Repair

Picture 14: Enclosure Condition

Picture 15: Enclosure Door Hinge

Picture 16: Enclosure Door

Picture 17: Chassis

Picture 18: Chassis

Picture 19: Support Leg

Picture 20: Undercarriage

Picture 21: Undercarriage Frame

Picture 22: Undercarriage Frame

Picture 23: Undercarriage

Picture 24: Undercarriage

Picture 25: Undercarriage

Attachment C:
Maintenance History

Maintenance History

The following is a list of major maintenance and life extension activities undertaken on the Mobile Gas Turbine over the past 30 years.

1990	Gas Generator Overhaul/Repair
1992	Trailer Roof Replacement
1994	Air Lift Axle Replacement
1994	Auxiliary Power Unit Replacement
1999	Control Improvements
2001	New Gas Generator Burners/Igniters
2002-03	Gas Generator Overhaul
2002-03	Control System Replacement, Transformer Overhaul, and Recloser Added
2009	Lube Oil Cooler Replacement
2010	Fire Suppression System Upgrade
2010	Gas Generator Combustion Chamber Refurbishment
2010	Trailer Structural Refurbishment
2015	Condition Assessment
2015	S&S Turbines investigated vibration issue

Attachment D:
MGT Inspection

March 16, 2015

S&S Turbine Services LTD.

Field Service Report

Newfoundland Power

Model OT-F-390

Sn 5907

March 10, 2015 S&S Turbines LTD. attended 96 Markland Road Whitbourne, NL. to aid staff in determining the cause of vibration and shut down on loading of portable generator.

The unit would start and ramp to sync speed normally. Over all vibration increased with loading above 0.7 MW and unit shut down by 1.2 MW. Alarm / Shut down points were observed at 30 and 40 mm/s PK-PK respectively.

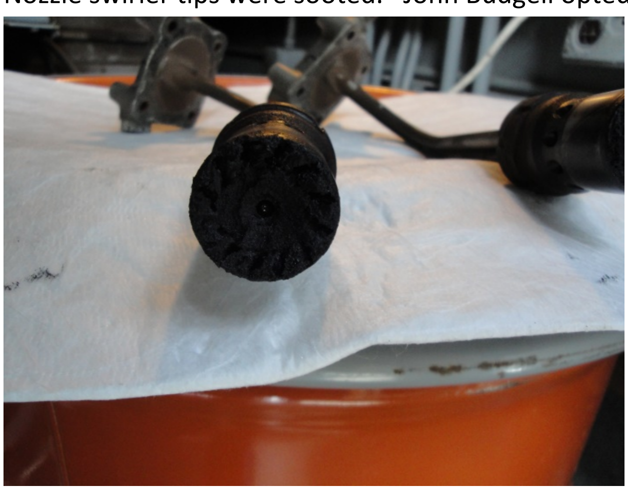
Prior to arriving John Budgell had verified vibration with a portable analyzer. An FFT Spectrum taken at Alarm conditions indicated predominant 1X with a large 2X component.

Observations

Upon arrival the generator skid appeared not to be plumb. The trailer was sloping rear to front with a noticeable wave in the support of the port side of the skid.

- Intake screen was removed to inspect Bellmouth and Compressor forward.
    - Silencer cabinet corroded with perforations.
    - Stage 1 and 2 blading and stators were slightly corroded with no evidence of impact damage.
    - Verified Stage 1 and Stage 2 blades were free to move.
    - Bellmouth touching rear intake wall at bottom.
    - Witness marking on engine side of engine / intake seal indicating engine had moved downward relative rear intake wall.

- Fuel Nozzles were numbered and removed to allow bore scope inspection of combustors and turbine nozzles.
  - Nozzle swirler tips were sooted. John Budgell opted to change out with spare set.



- Removed Combustor #5 to better inspect compressor OGV and stage 10 compressor blading.
    - Found slight impact damage approximately mid blade on the trailing edge of 2 consecutive stage 10 compressor blades.

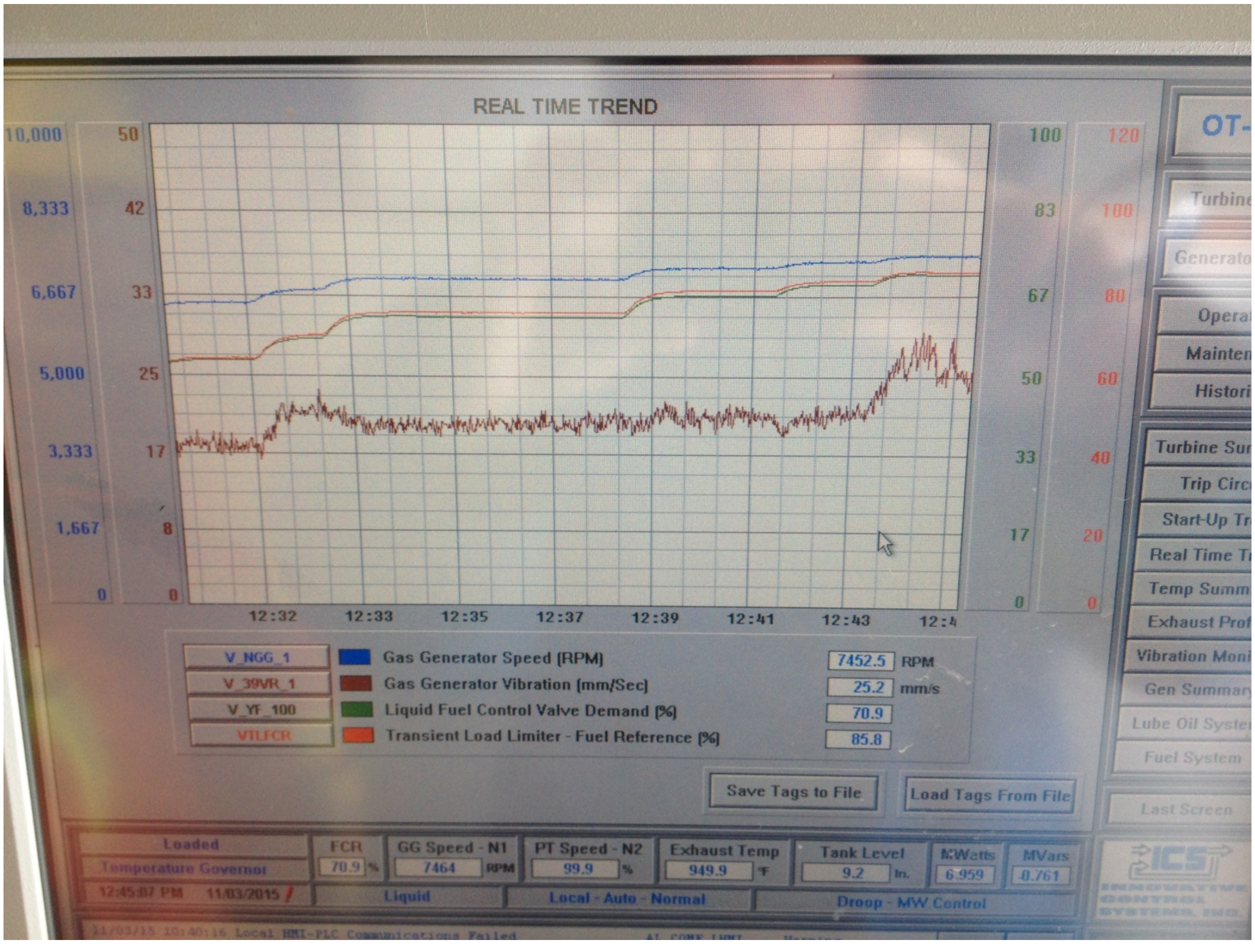
- Combustor liner, turbine nozzles and blading appear in serviceable condition.

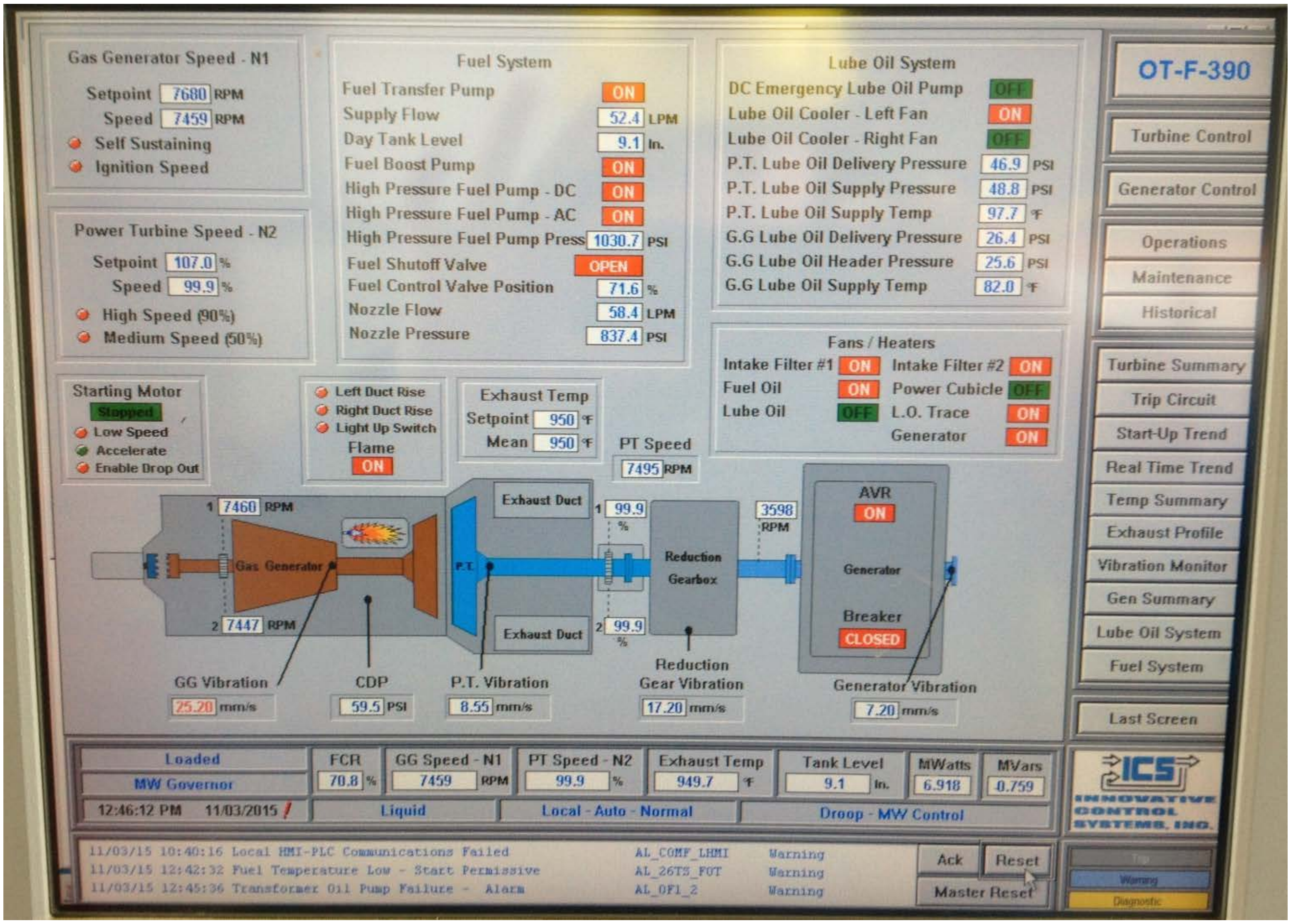
- Completed Bore scope inspection of remaining combustors.
    - All combustor liners, turbine nozzles appear in serviceable condition.

- Newfoundland Power Technicians removed main magnetic plug and all oil scavenge screens. Plug was clean. #2 and #3 scavenge screens had no notable debris.

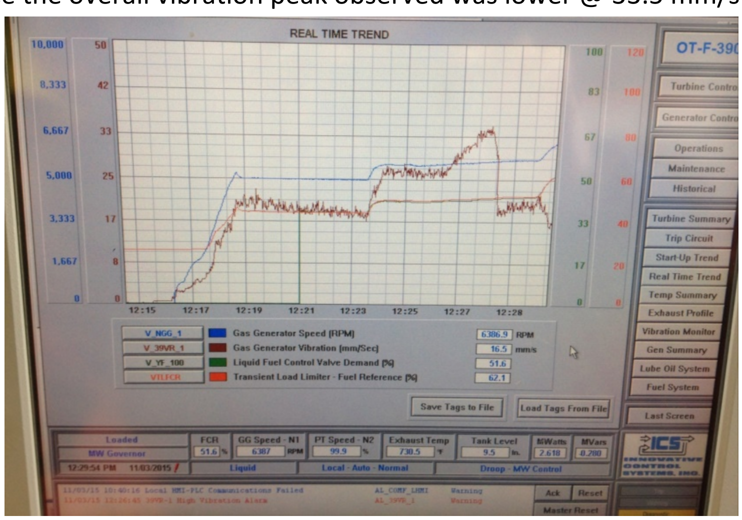
- Replaced Inlet screen, oil lines and magnetic plug, #5 combustor and fuel nozzles. Secured, lock wired and checked all disturbed hardware. Vacuumed debris from intake.
- Used a 4’ bubble level to survey the installation of the generator trailer. Found the forward supports slightly off level from side to side. Lowered port forward support more than 1/8” and then lowered both the port and starboard forward supports 1/4".
- Cold rolled unit on starter to verify oil pressure, listen for rubs and bearing noise.
- Started unit and checked again for oil and fuel leaks. Physically felt unit to verify smooth operation at all 3 bearing sumps.
- When loading the engine overall vibration levels increased to 30 mm/s Pk-Pk or alarm levels at approximately 0.8 MW rising to 36.5 mm/s Pk-Pk 0.9 MW or 5400 RPM Gas generator speed.

- In an effort to raise over all vibration levels to near shut down level for analysis we increased the load on the generator. Above 0.9 MW vibration fell to approximately 17 mm/s Pk-Pk.
- Increased load to EGT limit of the engine.
    - Used Pruftechnik portable analyser to verify vibration monitoring equipment and take FFT spectrum at all 3 engine bearing supports.
    - On the mount next to the engine vibration probe the Pruftechnik analyser indicated.
      Gas Generator 7440 RPM
      1X Peak @ 19.8 mm/s Pk-Pk
      Overall @ 22.7 mm/s Pk-Pk





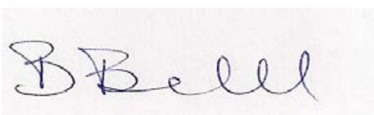
- Reduced load to observe descending vibration characteristics.
  - Observed no increase in vibration levels as load on engine decreased.
- Over the course of the test run we had full load shut down due to low fuel level and a normal unload shutdown. Both roll downs were monitored for rub and bearing noise. During the second load sequence the overall vibration peak observed was lower @ 33.5 mm/s Pk-Pk.



Conclusion

We were unable to duplicate the shutdown conditions on loading at this time. However the vibration spectrum information gathered previously by John Budgell indicating a large 2X component of the overall vibration reading leads to S&S Turbines Services LTD. to recommend the following.

1. Generator skid supports to be leveled with a quality sight level any time the generator is relocated and verify level seasonally.
2. Once generator skid has been verified level. Check alignment of all components of the generator in particular engine to PT. Ensure alignment is with in manufacturer's specification.
3. Ensure there is no contact or binding such as observed at the bell mouth to intake silencer rear wall.



Bill Burchell

S&S Turbine Services LTD.

2018 Substation Refurbishment and Modernization

July 2017

Prepared by:

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PEG Newfoundland and Labrador
ADAM E.H. WONG
Adam Wong
SIGNATURE
June 23, 2017
DATE
NEWFOUNDLAND & LABRADOR

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Appendix A: Substation Refurbishment and Modernization Plan
5-Year Forecast 2018 to 2022

1.0 Substation Refurbishment and Modernization Strategy

Newfoundland Power (the "Company") has 130 substations located throughout its service territory. These include: (i) generation substations that connect generating plants to the electrical system; (ii) transmission substations that connect transmission lines of different voltages; and (iii) distribution substations that connect the low-voltage distribution system to the high-voltage transmission system.

Substations are critical to electrical system reliability; an unplanned substation outage can affect thousands of customers. The Company's substation maintenance program and the *Substation Refurbishment and Modernization Plan* ensure the delivery of reliable, least-cost electricity to customers in a safe and environmentally responsible manner.[1]

The *Substation Refurbishment and Modernization Plan* was first established in 2007. The plan is reviewed and updated annually to provide a structured approach for the overall refurbishment and modernization of substations. The annual review identifies projects based on: (i) the condition of the infrastructure and equipment; (ii) the need to upgrade and modernize protection and control systems; and (iii) other relevant work, such as necessary security upgrades. In 2015, an initiative to accelerate substation feeder automation was incorporated into the *Substation Refurbishment and Modernization Plan*. This initiative will ensure all distribution feeders are automated by the end of 2019.[2] Feeder automation will enhance system reliability and reduce the duration of distribution feeder outages.

The *Substation Refurbishment and Modernization Plan* is coordinated with the maintenance cycle for major substation equipment and replacement activities. Such coordination minimizes customer service interruptions and ensures the optimum use of resources. This approach is consistent with the least-cost delivery of reliable service. Additionally, substation refurbishment and modernization typically requires power transformers to be removed from service. If customer outages are to be avoided, the timing of the work must be coordinated with the availability of a portable substation. Due to capacity limitations of portable substations, this work is often 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.

---

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

2 By the end of 2018, there will be 281 distribution feeders automated, representing approximately 92% 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 2018 Substation Refurbishment and Modernization Projects

For 2018, Substation Refurbishment and Modernization Projects include planned refurbishment and modernization of 2 substations. This substation work is estimated to cost a total of $6,790,000, comprising approximately 85% of the total 2018 project cost. The remaining project cost includes: (i) $886,000 for Substation Feeder Automation to automate 9 distribution feeders; (ii) $175,000 associated with Substation Monitoring and Operations to upgrade substation communication systems; and (iii) $150,000 for upgrades related to Substation Security.

Table 1 identifies expenditures for the 2018 Substation Refurbishment and Modernization Projects.

Table 1
2018 Substation Refurbishment and Modernization Projects
(000s)

Project	Budget
Harbour Grace (HGR) Substation	$3,873
Bayview (BVS) Substation	$2,917
Substation Feeder Automation	$886
Substation Monitoring and Operations	$175
Substation Security	$150
Total	**$8,001**

2.1 2018 Substation Projects ($6,790,000)

The locations of the 2 substations undergoing refurbishment and modernization projects in 2018 are shown on the map below (see Figure 1).

Figure 1: 2018 Substation Refurbishment and Modernization Projects

Harbour Grace Substation ($3,873,000)

Harbour Grace Substation ("HGR") was built in 1966 as both a transmission and distribution substation. The transmission portion of the substation contains two 66 kV transmission lines.[3] The 12.5 kV distribution bus structure is energized by two 66 kV to 12.5 kV power transformers: HGR-T1 (10 MVA) and HGR-T2 (6.7 MVA). There are three 12.5 kV distribution feeders (HGR-01, HGR-02, and HGR-03) serving approximately 1,800 customers in the Harbour Grace area.

Engineering assessments have determined that the 66 kV and 12.5 kV wood pole structures including most crossarms are in a deteriorated condition and are splitting (see Figure 2). The wood pole structures will be replaced by steel structures.

Figure 2: HGR Deteriorated Wood Poles and Cross Arms

The concrete foundations for the breakers, reclosers, and transformers are also in a deteriorated condition (see Figure 3). New concrete foundations will be required for the steel structures and associated equipment.

3 The two 66 kV transmission lines are 57L to Upper Island Cove Substation and 68L to Carbonear Substation.

Figure 3: HGR Deteriorated Concrete Foundations

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

[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.

The 3 distribution feeders are protected and controlled using hydraulic reclosers that range in age from 31 to 50 years old (see Figure 4).[6] The hydraulic reclosers are not capable of automation through the System Control and Data Acquisition system ("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 provide a means of automated restoration of service, reducing the duration of customer outages. With feeder automation, the 3 HGR distribution feeders will be added to the provincial under-frequency load shedding scheme.[7]

Figure 4: HGR Hydraulic Reclosers

A spill containment foundation will be constructed for transformers HGR-T1 and HGR-T2 to protect against environmental damage in the event of an oil spill from the units.

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

7 Most automated distribution feeders are included in the provincial under-frequency load shedding scheme. Under-frequency load shedding is required when there is a significant loss of generation on the Island Interconnected System. By de-energizing selected distribution feeders, the system is quickly able to match load with generation to avoid the collapse of the power system. By increasing the number of distribution feeders in the provincial scheme, the number of times each individual feeder is de-energized is reduced.

Power transformers HGR-T1, installed in 1970, and HGR-T2, installed in 1971, will be refurbished and upgrades made to the transformers' auxiliary protection (see Figure 5). The existing 47-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 transformers.

Figure 5: Existing HGR-T1 and HGR-T2

The protection and control of substation assets will be modernized by installing microprocessor-based digital relays to monitor and control substation assets. Circuit breakers monitored and controlled by digital protection relays will be installed to replace the existing fused protection on transformers T1 and T2. Also, the 2 transmission line breakers 57L-B and 68L-B will be monitored and controlled by digital protection relays. This will improve automation capabilities and reduce the duration of substation outages.

The existing 45-year-old control building at HGR cannot accommodate the new relay and communication panels required to complete the protection upgrades. The building is deteriorated and does not meet current standards (see Figure 6).[8] A new control building will be constructed to permit installation of new protection and communications panels, with minimum disruption to the existing protections scheme and minimal impact on the integrity of the electrical system during construction. The protection upgrade will also include replacement of all existing protection panels and control cables.

8 There is corrosion present on both the metal roof panels and siding. There is insufficient clearance between the control building and the power transformer.

Figure 6: HGR Building

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]

Bayview Substation ($2,917,000)

Bayview Substation ("BVS") was built in 1971 as both a transmission and distribution substation. The transmission portion of the substation contains three 66 kV transmission lines.[11] The 12.5 kV distribution bus structure is energized by two 66 kV to 12.5 kV power transformers: BVS-T1 (20 MVA) and BVS-T2 (15 MVA). There are five 12.5 kV distribution feeders (BVS-01, BVS-02, BVS-03, BVS-04, and BVS-05) serving approximately 3,400 customers in the Corner Brook area.

Engineering assessments have determined that the 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 5 pier foundations and 1 breaker foundation that need to be refurbished (see Figure 7).

---

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 80-2013 Guide for Safety in AC Substation Grounding*. This standard is considered industry best practice for designing substation ground grids.

11 The 66 kV transmission lines are 357L to Massey Drive Substation, 358L to Gillams Substation and 359L to Humber Substation.

Figure 7: BVS Deteriorated Concrete Foundation

Most of the switches on the 66 kV and 12.5 kV bus structures are in excess of 30 years in service and will be replaced due to their mechanical condition and age.[12] This includes 6 side break switches and 2 transformer air break switches (BVS-T1-A and BVS-T2-A). The transformer air break switches will be replaced with motorized air break switches complete with ground switches.[13]

Power transformers BVS-T1, installed in 1976, and BVS-T2, installed in 1969, will be refurbished and upgrades made to the transformers' auxiliary protection (see Figure 8). 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 transformers.

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.

Figure 8: BVS-T1 and BVS-T2

Spill containment foundations will be constructed for transformer BVS-T1 and BVS-T2 to protect against environmental damage in the event of an oil spill from the units. A transformer will be relocated and the steel structure extended in order to maintain appropriate clearances to meet existing standards.

The relays for the 3 transmission lines, 1 transformer and 1 bus protection are vintage electromechanical type and are original to the 1982 building construction (see Figure 9). Electromechanical relays operate by using torque-producing coils energized by current and voltage inputs, which open or close contacts based on mechanically calibrated thresholds. At present, there are 18 electromechanical relays installed in 4 individual protection panels inside the substation control building. These relays are used for the protection of 1 transformer (BVS-T1), the 66 kV bus, and 3 transmission lines, and are approximately 35 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.[14] The protection upgrades on the transmission lines are also required to address critical clearing times.[15]

---

[14] 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.

[15] As outlined in the *2018 Capital Plan*, the 4 Corner Brook substations will communicate with each other via fibre optic cable to allow for differential transmission line protection, which will address critical clearing times. The Telecommunications projects to install the fibre optic cables are included elsewhere in the Company's *2018 Capital Plan*. These projects will be justified in future capital budget applications.

Figure 9: BVS Control Building

The protection and control of substation assets will be modernized by replacing the obsolete electromechanical relays with microprocessor-based digital relays, reducing the total protection relay device count from 18 electromechanical relays to 4 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.

The existing 35-year-old control building at BVS has insufficient space to accommodate both the existing and the new protection and communication panels required to complete the protection upgrades. The building is deteriorated and does not meet current standards. A new control building will be constructed to permit installation of the new protection and communications panels, with minimum disruption to the existing protections scheme and minimal impact to the integrity of the electrical system during construction. The protection upgrade will also include replacement of all existing protection and control cables.

The communications equipment will be upgraded. This includes a Gateway that will be installed to enhance SCADA system remote control and monitoring of the power system protection equipment. The Gateway will integrate all substation devices that provide monitoring, protection and control of the transmission lines, distribution feeders and substation transformers into the SCADA system. The enhancement will allow for remote administration of upgraded devices.

All low-voltage equipment will have standard varmint protection installed.[16]

---

[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."

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]

2.2 Substation Feeder Automation - SFA ($886,000)

At the end of 2018, approximately 92% of distribution feeders will be automated at the substation breaker or recloser. Under the current plan, this percentage will increase to 100% by the end of 2019. Automation of distribution feeders at the substation breaker or recloser reduces restoration time during 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 2018, the Company plans to automate an additional 12 distribution feeders.[18] The refurbishment and modernization of HGR will automate 3 distribution feeders.[19] The additional 9 distribution feeders are located in Dunville (2), New Chelsea (2), New Harbour (2), Port Blandford (1) and Upper Island Cove (2).

2.3 Substation Monitoring and Operations – SMU ($175,000)

Over the past decade, there has been a substantial increase of computer-based digital equipment in electrical system control and operations. Periodic upgrades of this equipment are necessary to ensure continued effective electrical system control and operations.

In 2018, hardware and software upgrades are planned to the communications gateways that connect multiple digital devices in substations to the SCADA system. This work will incorporate manufacturers' upgrades to gateways and other computer-based equipment located in Company substations.

These upgrades are required to effectively manage increased volumes of electrical system data. Upgrades typically increase the functionality of the equipment and software, and remedy known deficiencies.

---

[17] Newfoundland Power designs substation ground grids using the *ANSI/IEEE Standard 80-2013 Guide for Safety in AC Substation Grounding*. This standard is considered industry best practice for designing substation ground grids.

[18] The Company plans to automate *all* distribution feeders by 2019. The Substation Feeder Automation item has been included in all *Substation Refurbishment and Modernization* projects since the 2015 Capital Budget Application.

[19] The 5 distribution feeders at BVS were previously automated.

2.4 Substation Security - SSU ($150,000)

In recent years, there have been a number of unauthorized persons entering Newfoundland Power substations to commit vandalism or theft. This results in damaged property and presents a significant safety risk to Newfoundland Power staff and the public when substation grounding has been altered or removed.

Security upgrades will be performed in selected substations to deter the entry of unauthorized persons and reduce the likelihood of theft occurring.

Appendix A
Substation Refurbishment and Modernization Plan
5-Year Forecast 2018 to 2022

Substation Refurbishment and Modernization Plan 5-Year Forecast 2018 to 2022 ($000s)									
2018		**2019**		**2020**		**2021**		**2022**	
SUB	**Cost**	**SUB**	**Cost**	**SUB**	**Cost**	**SUB**	**Cost**	**SUB**	**Cost**
BVS	$2,917	LEW	$3,713	BVA	$2,600	HUM	$1,925	DUN	$2,698
HGR	$3,873	PEP	$2,831	BCV	$1,093	MSY	$1,529	MOL	$4,675
SFA	$886	SFA	$1,789	GOU	$4,844	RBK	$3,015	WAL	$780
SMU	$175	SMU	$180	SMU	$185	SMU	$190	SMU	$195
SSU	$150	SSU	$200	SSU	$250	SSU	$250	SSU	$250
	$8,001		**$8,713**		**$8,972**		**$6,909**		**$8,598**

Note: SUB: Substation - Refer to the Electrical System handbook included with the 2006 Capital Budget Application for 3-letter substation designations.

2018 Transmission Line Rebuild

July 2017

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Appendix C: Photographs of Transmission Lines 363L and 302L

1.0 Transmission Line Rebuild Strategy

Newfoundland Power's transmission lines are the backbone of the electricity network 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 2018 Transmission Line Rebuild Projects

In 2018, the Company will rebuild sections of 2 transmission lines totalling 25 km, with an average age of 57 years.[1] Appendix B contains maps of each of the lines to be rebuilt. Appendix C contains photographs of the existing lines.

The transmission line sections to be rebuilt in 2018 are included in Table 1.

Table 1
2018 Transmission Line Rebuilds

Transmission Line	Distance to be Rebuilt	Year Constructed
363L	14 km	1963
302L	11 km	1959

These transmission line sections 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 these sections of line will improve the overall reliability of the transmission system that serves customers in the Baie Verte and Burin peninsulas.

1 This 25 km represents approximately 1.25% of the total 2,000 km of transmission lines owned and maintained by Newfoundland Power.

2.1 Transmission Line 363L ($3,000,000 in 2018, $3,000,000 in 2019, $3,600,000 in 2020 and $3,750,000 in 2021)

Transmission line 363L is a 138 kV H-Frame line running between Baie Verte Junction Substation ("BVJ") on the Trans-Canada Highway, and Seal Cove Road Substation ("SCR") located in Baie Verte.[2] The line was originally constructed in 1963, and includes approximately 62 km of original construction consisting of 478 two-pole and three-pole H-Frame structures, with non-standard 266.8 ACSR transmission line conductor.[3]

Transmission line 363L was constructed by Bowaters Power and later purchased by Newfoundland Power. Construction standards, materials, and hardware used in the construction of the line are not to Newfoundland Power's standards. This requires Newfoundland Power to maintain low levels of emergency stock equipment solely for this line. As a result, there is a risk that any larger-scale damage to this line would result in an extended outage, should material requirements exceed emergency stock levels. This risk escalates as the transmission line ages and further deteriorates.

Crossarms used in the construction of 363L were 27-foot-long, red pine spar arms.[4] These spar arms have increasingly been identified on inspections as requiring replacement due to deterioration. Non-standard pole spacing complicates their replacement using standard Newfoundland Power crossarms, which have to be field-drilled prior to installation. A broken spar arm was the cause of an outage to the area during the winter of 2015 and a number of arms were replaced at that time.[5] However, the remaining arms are of the same vintage and continue to be an issue.

Transmission line 363L is a radial line that serves as the only supply to Newfoundland Power and Newfoundland Hydro customers on the Baie Verte Peninsula. This makes 363L critical for both the residents of the area, as well as some mining operations. It is also located across country with few access points from the local highway. Site access complicates maintenance efforts; as a result, maintenance either requires extended outages or mobile generation to supply the customers of the Baie Verte Peninsula. The other option is the use of hot-line work methods, which are expensive and time consuming because of work safety requirements associated with energized 138 kV lines.[6]

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

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2 BVJ is part of a jointly owned substation with Newfoundland and Labrador Hydro's Indian River Substation ("IRV").

3 ACSR, or Aluminum Conductor Steel Reinforced, is a bare overhead conductor constructed with aluminum outer strands and a steel core to support the weight of the cable.

4 Spar arms are effectively short poles used as crossarms on large H-frame structures.

5 See Appendix C, Figures 5 & 6 for pictures of crossarms replaced in 2015.

6 Working on energized equipment requires the use of hot-line work methods, which involve the use of special insulated tools. See Appendix C, Figure 8 for a picture of Newfoundland Power crews completing maintenance on 363L using hot-line work methods.

components are in advanced stages of deterioration and require replacement.[7] The most recent inspection in 2017 also identified conductor damage requiring immediate repair.[8]

Major maintenance activities have been completed on this line in 2007, 2012 and 2016 in order to extend the life of the line and ensure safe, reliable operation. The maintenance history of 363L is shown in Table 2.

Table 2
10-Year Maintenance History of 363L

	Year Completed			
Repair Type	**2007**	**2012**	**2016**	**Total**
Hardware	1	44	0	45
Insulator	8	131	0	139
Poles	0	0	1	1
Crossarms	0	20	7	27
Total Repairs	**9**	**195**	**8**	**212**
Total Estimated Cost	**$45,000**	**$961,000**	**$180,000**	**$1,186,000**

Each subsequent inspection cycle identifies further deterioration and deficiency. There are currently 406 deficiencies identified, including 374 deteriorated crossarms. The transmission line has reached a point where continued maintenance is no longer feasible and it must be rebuilt to continue its safe, reliable operation.

Based on its age, deteriorated condition and criticality, the line will be rebuilt over 4 years starting in 2018. A 14 km section of the transmission line will be rebuilt in 2018 at an estimated cost of $3,000,000.

In 2019, a further 14 km section will be rebuilt at an estimated cost of $3,000,000. In 2020, a 17 km section will be rebuilt at an estimated cost of $3,600,000. In 2021, the final 18 km section will be rebuilt at an estimated cost of $3,750,000.[9]

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7 Figures 1 through 6 of Appendix C shows examples of deterioration on 363L, such as pole checks and deteriorated crossarms.
8 Figure 7 of Appendix C shows conductor damage on 363L identified and repaired in 2017.
9 Figure 1 of Appendix B shows the route taken by 363L and identifies the sections to be rebuilt in 2018 to 2021.

2.2 Transmission Line 302L ($2,068,000 in 2018 and $3,064,000 in 2019)

Transmission line 302L is a 66 kV single-pole line running between Salt Pond Substation (“SPO”) in Burin and Laurentian Substation (“LAU”) in St. Lawrence. The line was originally constructed in 1959, with the exception of a 2.4 km section extending into LAU, which was constructed in 1974. Approximately 26.6 km of original vintage line consisting of 315 single-pole structures with non-standard 4/0 ACSR conductor, remain in service.

Due to the age and condition of the line, it is susceptible to damage when exposed to severe wind, ice or snow loading. This line was built to weather loading criteria that are below the standard currently used to construct new lines in this area.[10] Over the life of the line there have been instances of ice accumulation greater than the design values, which have resulted in broken poles, conductor and other damage.[11]

Transmission line 302L is the most heavily loaded line in the Burin transmission system. As one of two lines feeding LAU, 302L is integral in bringing power generated by the St. Lawrence Wind Farm onto the grid. The new fluorspar mine in St. Lawrence will be adding an estimated load of 8 MW to LAU over the next couple of years, which will further increase the area’s reliance on 302L.

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.[12]

The transmission line has reached a point where continued maintenance is no longer feasible and it must be rebuilt to continue its safe, reliable operation.

Based on the age, deteriorated condition and weather loadings, along with system loading constraints and required conductor replacement, 302L will be rebuilt to current weather loading standards using 477 ASC conductor.[13]

A 11 km section of the transmission line is proposed to be rebuilt in 2018 at an estimated cost of $2,068,000. In 2019, the remaining 16 km section will be rebuilt at an estimated cost of $3,064,000.

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[10] Newfoundland Power follows CSA Standard C22.3 No. 1 “Overhead Systems” (2015) for transmission line construction.

[11] Figures 12 and 14 of Appendix C show examples of weather loading damage experienced on 302L.

[12] Figures 9 through 11 of Appendix C shows examples of deterioration on 302L, such as pole checks, deteriorated crossarms, and damaged conductor.

[13] ASC, or Aluminum Stranded Conductor, is a bare overhead conductor constructed with aluminum strands.

3.0 Concluding

In 2018, the Company will rebuild sections of 363L and 302L. Each of these transmission lines has structures experiencing deterioration of the poles, crossarms, hardware, and conductor. Recent inspections and engineering assessments have determined the transmission lines have reached a point where continued maintenance is no longer feasible and they must be rebuilt to continue providing safe, reliable electrical service.

Appendix A:
Transmission Line Rebuild Strategy Schedule

Transmission Line Rebuilds 2018 – 2022 ($000s)						
Line	**Year Built**	**2018**	**2019**	**2020**	**2021**	**2022**
302L SPO-LAU	1959	2,068	3,064			
363L BVJ-SCR	1963	3,000	3,000	3,600	3,750	
136L-LEW[14]	1981		2,800	3,000		
136L-RBK[14]	1981				320	
403L ROB TAP	1960			821		
105L GFS-SBK	1963					2,713
35L KEN-OXP	1965				438	
49L HWD-CHA	1966					605
55L BLK-CLK	1971					4,957
TOTAL		**5,068**	**8,864**	**7,421**	**4,508**	**8,275**

[14] Extending 136L to Lewisporte Substation and Rattling Brook Plant, along with upgrading the substation and plant to 138 kV standard, is part of a larger project to retire the 66 kV transmission network in Central Newfoundland.

Appendix B:
Maps of Transmission Lines
363L and 302L

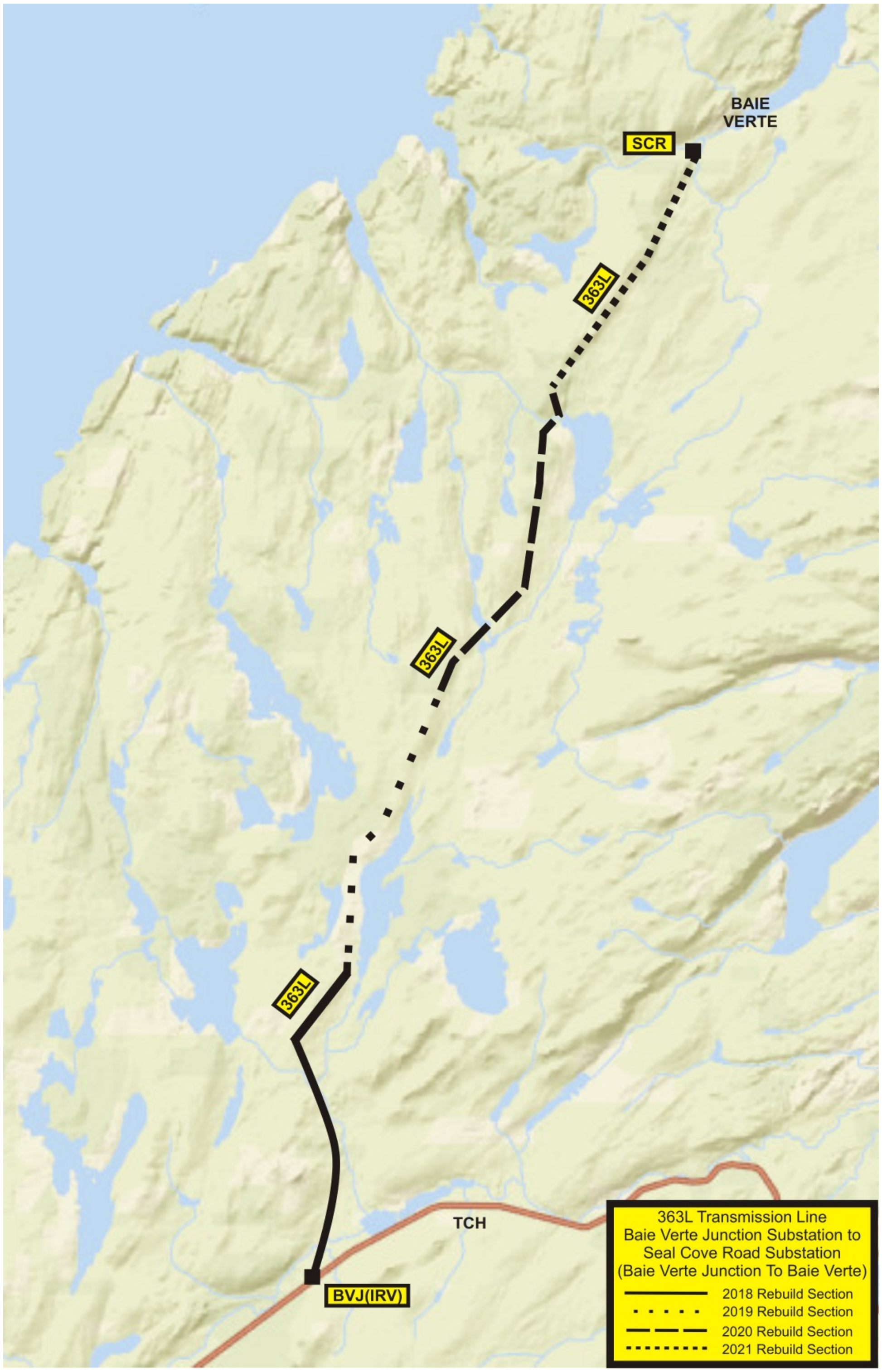

Figure 1: Map of 363L Route

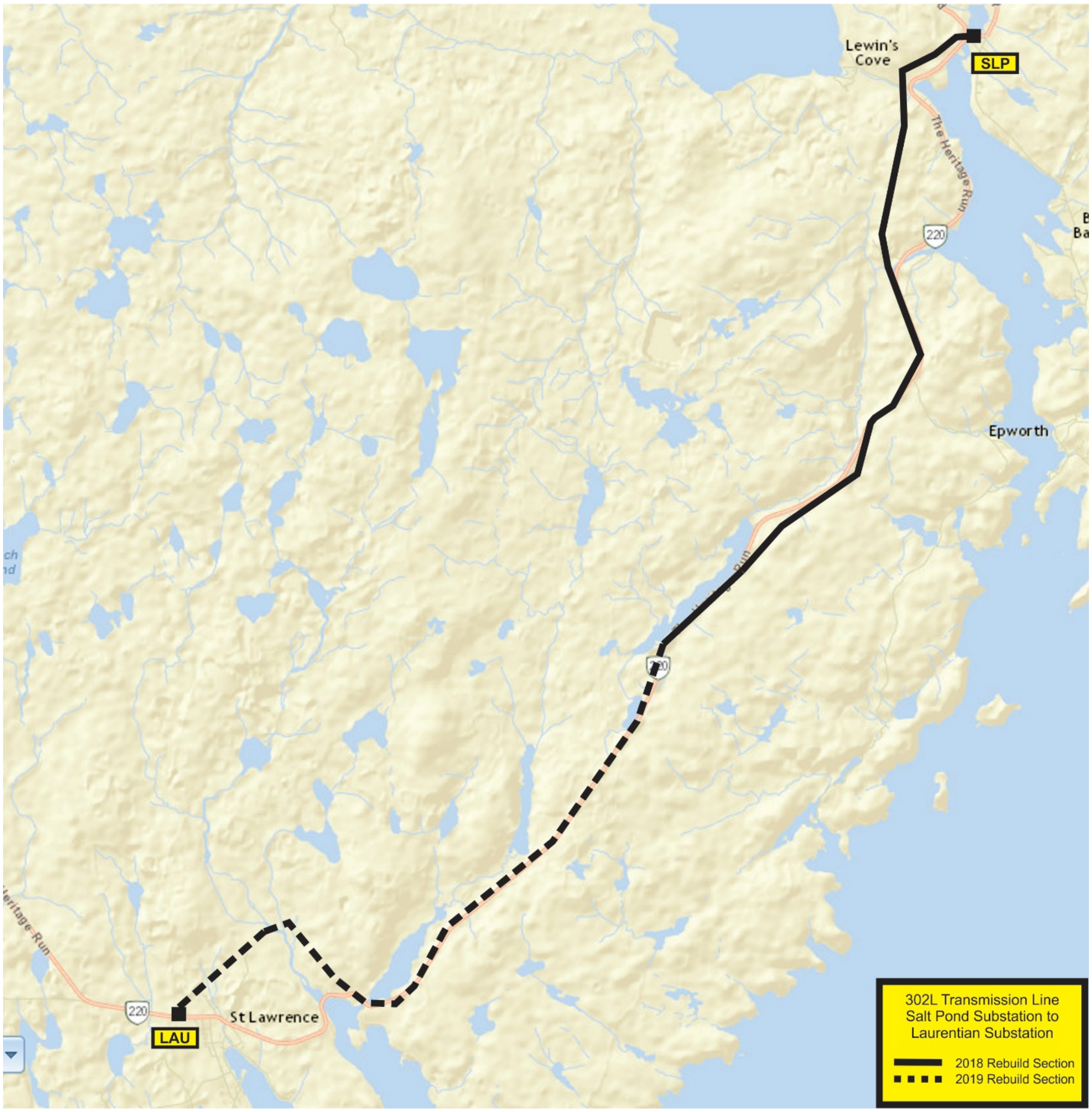

Figure 2: Map of 302L Route

Appendix C:
Photographs of Transmission Lines
363L and 302L

Transmission Line 363L

Figure 1: Check in Left Pole Near Crossbrace Attachment

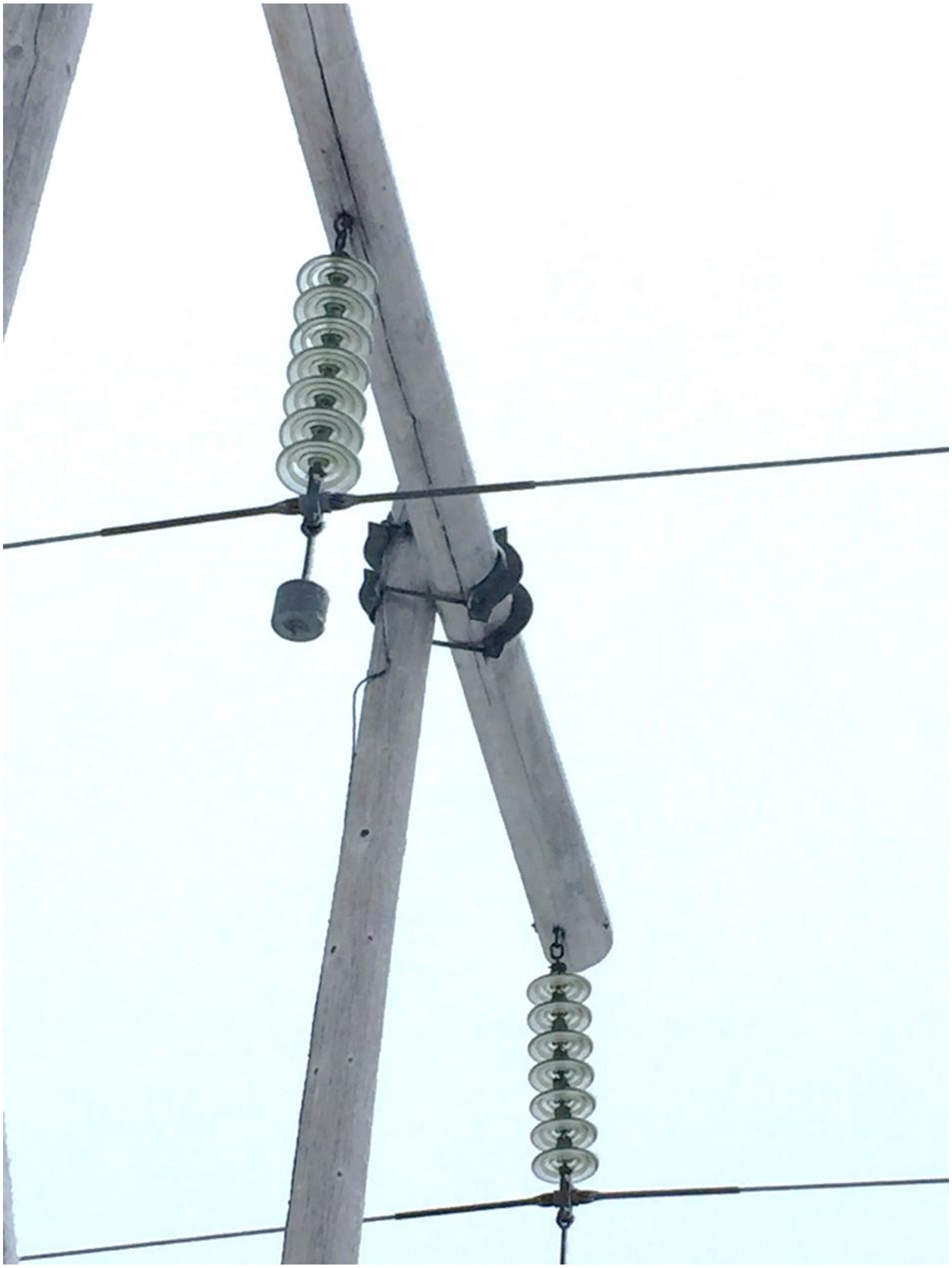

Figure 2: Check in Pole Crossarm

Figure 3: Structure Twisted as a Result of Storm Loading

Figure 4: Severe Checks in Pole

Figure 5: Early Stages of Decay in Pole Crossarm Replaced in 2015

Figure 6: Significant Decay in Pole Crossarm Replaced in 2015

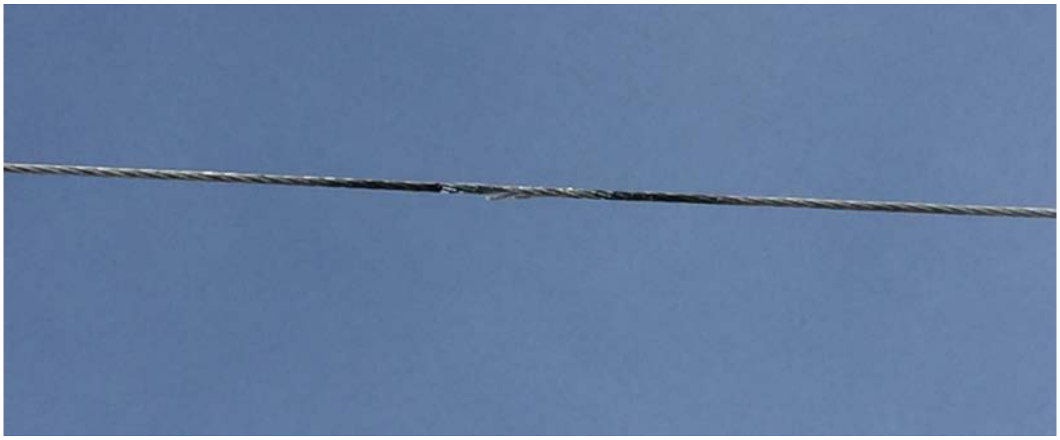

Figure 7: Conductor Damage Identified During 2017 Inspection

Figure 8: Replacement of Insulators on 363L Using Hot-Line Work Method

Transmission Line 302L

Figure 9: Significant Checks in Pole

Figure 10: Decay at End of Wooden Crossarm

Figure 11: Structure Damage Due to Conductor Failure

Figure 12: Line Failure During Severe Icing Event

Figure 13: Failed Conductor on 302L

Figure 14: Extreme Ice Loading Experienced on 302L

Distribution Reliability Initiative

July 2017

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WHENEVER. WHEREVER.
We'll be there.

NEWFOUNDLAND POWER
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1.0 Introduction

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 *Distribution Reliability Initiative* is a capital project focusing on the reconstruction of the worst-performing distribution feeders. Customers served by these feeders experience more frequent and longer duration outages than average.

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, completing 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 on the engineering assessments completed as part of the process.

2.0 Background

Historically, 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 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

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[1] System Average Interruption Duration Index (SAIDI) is calculated by dividing the number of customer-outage-hours (e.g., a 2-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 typically have fewer customers than larger feeders and, as a result, outages of similar duration will involve fewer 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 kilometers of line. Customer Hours of Interruption per Kilometer (CHIKM) is calculated by dividing the number of customer-outage-hours by the kilometers 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 2012 to 2016, 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 identified for 3 distribution feeders in 2018. Work on SUM-02 and TRP-01 feeders is starting in 2017 and will be completed in 2018.[5] Work on KEN-03 will be completed in 2018.

A detailed engineering assessment of distribution feeders SUM-02 and TRP-01 was included in Appendix C and Appendix D of the 2017 Capital Budget Application report for the *Distribution Reliability Initiative*. A detailed engineering assessment of KEN-03 is included in Appendix C to this report.

Table 1 summarizes the reliability data for each of the distribution feeders identified and compares those data to Company averages.

Table 1
Distribution Interruption Statistics
5-Year Average to December 31, 2016

Feeder	Customers	SAIFI	SAIDI	CHIKM	CIKM
SUM-02	609	3.68	10.59	81	28
TRP-01	605	2.76	5.90	32	15
KEN-03	2,317	1.69	2.69	241	151
Company Average	**842**	**1.43**	**1.71**	**56**	**49**

[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] A multi-year capital project was approved in Order No. P.U. 39 (2016) for reliability rebuilds on distribution feeders SUM-02 and TRP-01.

Table 1 shows that distribution feeders SUM-02 and TRP-01 are outliers from the Company average for SAIFI and SAIDI.[6] KEN-03 is an urban feeder with an abnormally high CHIKM and CIKM.[7] An analysis of the outage data reveals that equipment failure has been the cause of most of the outages experienced on KEN-03.

4.0 Project Cost

The estimate to complete the 2018 work associated with the *2018 Distribution Reliability Initiative* project is $1,789,000. Table 2 provides a detailed breakdown of the 2018 project cost by distribution feeder.[8]

Table 2
2018 Project Cost

Description	SUM-02	TRP-01	KEN-03	Total
Engineering	$123,000	$49,000	$38,000	$210,000
Labour - Contract	69,000	83,000	18,000	170,000
Labour - Internal	307,000	81,000	112,000	500,000
Material	265,000	106,000	103,000	474,000
Other	243,000	105,000	87,000	435,000
Total	**$1,007,000**	**$424,000**	**$358,000**	**$1,789,000**

6 The SAIFI for SUM-02 is 2.6 times the Company average and TRP-01 is 1.9 times the Company average. The SAIDI for SUM-02 is 6.2 times the Company average and TRP-01 is 3.5 times the Company average.

7 The CHIKM for KEN-03 is 4.3 times the Company average and CIKM is 3.1 times the Company average.

8 Order No. P.U. 39 (2016) approved *Distribution Reliability Initiative* work for 2018 on feeders SUM-02 and TRP-01 for $1,431,000 which is included here in the 2018 amount.

Appendix A:
Distribution Reliability Data:
Worst-Performing Feeders

Unscheduled Distribution-Related Outages Five-Year Average 2012-2016 Sorted By Customer Minutes of Interruption				
Feeder	**Annual Customer Interruptions**	**Annual Customer Minutes of Interruption**	**Annual Distribution SAIFI**	**Annual Distribution SAIDI**
SUM-01	4,014	580,683	3.72	5.36
DUN-01	3,368	514,248	3.25	8.35
SCV-01	1,565	501,395	0.90	4.99
SCR-01	2,465	414,141	2.53	7.07
LEW-02	3,276	409,022	2.19	4.57
DOY-01	4,029	399,624	2.34	3.88
SUM-02	6,675	390,030	3.68	10.59
KEN-03	3,862	369,857	1.69	2.69
GFS-02	5,225	369,789	3.13	3.71
LAU-01	2,133	350,506	3.02	8.25
BLK-01	4,136	342,978	2.36	3.31
HWD-07	4,466	342,556	1.66	2.17
BOT-01	2,815	334,612	1.64	3.28
SJM-11	245	333,315	3.95	3.82
BCV-02	2,397	295,974	1.53	3.18
Company Average	**1,223**	**88,127**	**1.43**	**1.71**

Unscheduled Distribution-Related Outages Five-Year Average 2012-2016 Sorted By Distribution SAIFI				
Feeder	**Annual Customer Interruptions**	**Annual Customer Minutes of Interruption**	**Annual Distribution SAIFI**	**Annual Distribution SAIDI**
BHD-01	6,752	260,194	7.15	4.59
SCT-02	1,730	96,341	6.68	6.24
TWG-01	4,074	192,955	5.45	4.36
TWG-02	3,673	156,477	5.17	3.68
SCT-01	3,645	127,884	5.17	3.04
RVH-02	795	84,528	5.13	9.17
TWG-03	1,421	42,799	5.09	2.57
ABC-02	4,984	260,703	4.84	4.22
SJM-11	245	333,315	3.95	3.82
MOB-01	6,302	199,652	3.85	2.06
SUM-01	4,014	580,683	3.72	5.36
SUM-02	6,675	390,030	3.68	10.59
RVH-01	2,719	62,253	3.66	1.39
GBY-03	2,726	267,730	3.58	5.84
ABC-01	2,715	63,159	3.44	1.55
Company Average	**1,223**	**88,127**	**1.43**	**1.71**

Unscheduled Distribution-Related Outages Five-Year Average 2012-2016 Sorted By Distribution SAIDI				
Feeder	**Annual Customer Interruptions**	**Annual Customer Minutes of Interruption**	**Annual Distribution SAIFI**	**Annual Distribution SAIDI**
SUM-02	6,675	390,030	3.68	10.59
RVH-02	795	84,528	5.13	9.17
DUN-01	3,368	514,248	3.25	8.35
LAU-01	2,133	350,506	3.02	8.25
SCR-01	2,465	414,141	2.53	7.07
SCT-02	1,730	96,341	6.68	6.24
GBY-01	1,930	233,393	3.08	6.20
LGL-01	700	129,201	1.96	6.08
TRP-01	1,442	215,945	2.76	5.90
GBY-03	2,726	267,730	3.58	5.84
LGL-02	1,659	207,818	2.66	5.56
GBS-02	1,289	153,375	2.78	5.53
SUM-01	4,014	580,683	3.72	5.36
OPL-01	1,047	136,919	2.28	5.01
FER-01	2,196	194,634	3.38	5.00
Company Average	**1,223**	**88,127**	**1.43**	**1.71**

Unscheduled Distribution-Related Outages Five-Year Average 2012-2016 Sorted By Distribution CHIKM	
Feeder	**Annual Distribution CHIKM**
GFS-02	531
MOL-04	286
MOL-09	285
KBR-10	281
SLA-13	263
SLA-10	255
SJM-06	255
KEN-03	242
SLA-09	238
SJM-13	232
VIR-04	216
SPR-02	216
HWD-07	215
MOL-06	188
KEN-04	178
Company Average	**56**

Unscheduled Distribution-Related Outages Five-Year Average 2012-2016 Sorted By Distribution CIKM	
Feeder	**Annual Distribution CIKM**
GFS-02	450
SJM-06	256
KBR-10	213
MOL-09	201
KEN-01	195
TWG-02	191
MOL-04	190
KEN-04	189
TWG-01	187
MOL-05	186
HWD-07	168
GFS-05	165
HWD-08	165
SJM-04	163
GAN-03	156
Company Average	**49**

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 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 and a significant outage in 2016 due to broken conductor. These will be addressed through the *Rebuild Distribution Lines* project. No additional work required at this time.
BCV-02	The poor reliability was related to an underwater cable issue. The cable was replaced in 2014. No work is required at this time.
BHD-01	Reliability historically has been good. The 2015 and 2016 reliability statistics were driven by wind-related incidents. No work is required at this time but the feeder will continue to be monitored.
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. Vegetation issues were addressed and no additional 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, 2015 and 2016. Work was completed under the *2014 Feeder Additions for Load Growth* project to address the unbalanced load issue. No additional 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 caused problems. Poor reliability statistics in 2016 were caused by high winds. A downline automated recloser was 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 additional work is required at this time.
GAN-03	Poor reliability statistics were driven by a damaged insulator in 2015. No work is required at this time.
GBS-02	Wind and sleet caused several reliability issues in 2014 and 2015. Some work was done in 2016 under the *Rebuild Distribution Lines* program. No additional 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 an isolated weather event in 2013. A bird caused an outage in 2014, lightning caused an outage in 2015 and a broken insulator caused problems in 2016. No additional 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 was upgraded as part of the *2016 Distribution Reliability Initiative* project. No additional work is required at this time.
GFS-05	Poor reliability statistics were principally due to a single tree-related incident in 2016. No work is required at this time.
HWD-07	This feeder had significant upgrades as part of the *2016 Distribution Reliability Initiative* project. No additional work is required at this time.
HWD-08	Poor reliability statistics were principally due to high winds and an underground cable fault in 2014. No work is required at this time
KBR-10	Sections of this feeder had significant upgrades as part of the *2015 Distribution Reliability Initiative* project. Historically this feeder had poor reliability statistics due to the condition of the aerial cable along Kings Bridge Road. The aerial cable has now been replaced. No additional 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	Poor reliability statistics are related to conductor issues, which have become more frequent in recent years. Outages have also occurred as a result of the feeder's porcelain cutouts and 2-piece insulators, which have a history of failing. Work is required in 2018.
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 was added to the feeder in 2016 as part of the *Distribution Feeder Automation* project. No additional 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.
LEW-02	Poor reliability statistics were driven by a wind-related event and a vehicle accident in 2016. No work is required at this time.

Worst-Performing Feeders Summary of Data Analysis	
Feeder	**Comments**
LGL-01	Weather-related outages, including damage from wind in 2013 and 2014, resulted in poor reliability statistics. No work is required at this time.
LGL-02	Poor reliability statistics were driven by salt spray, a broken conductor in 2013 and sleet in 2015. No work is required at this time.
MOB-01	Reliability has generally been good. A broken pole and crossarm related to a vehicle accident in 2013 was the primary reasons for the poor reliability statistics experienced in recent years. Approximately 5 km of the feeder was upgraded as part of the *2015 Feeder Additions for Growth* project. No additional 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 will continue to be monitored to determine if it should be considered for rebuilding in a future capital budget.
MOL-05	Poor reliability statistics were due to broken insulators in 2013, 2014 and 2016. No work is required at this time.
MOL-06	Poor reliability statistics were due to a single tree incident in 2013. No work is required at this time.
MOL-09	This feeder was included in the *2015 Distribution Reliability Initiative* project to address poor reliability statistics. The feeder also had multiple outages on long taps due to equipment failure. No work is required at this time.
OPL-01	Poor reliability statistics were due to a broken insulator and a fire at a fish plant in 2016. No work is required at this time.
RVH-01	Poor reliability statistics were due to a wind-related issue in 2016. No work is required at this time.
RVH-02	Poor reliability statistics were due to several equipment failures in 2015. This feeder is one of the Company’s worst performing from a SAIDI and SAIFI perspective. Work is being carried out on this feeder in the *2017 Distribution Reliability Initiative* project.
SCR-01	The feeder had significant reliability issues in 2016. Broken insulator, birds, trees and vandalism. This feeder will continue to be monitored to determine if it should be considered for rebuilding in a future capital budget.
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, 2014 and 2016. 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.

Worst-Performing Feeders Summary of Data Analysis	
Feeder	**Comments**
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 third 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-11	Reliability has generally been good. Damages by a third 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 poor reliability statistics. This feeder will continue to be monitored to determine if it should be considered for rebuilding in a future capital budget.
SLA-09	Historically poor reliability statistics are due to underground cable faults. This feeder is one of the Company's worst performing from an interruption per kilometer perspective. Work was carried out under the *2016 Distribution Reliability Initiative* project. No additional work is required at this time.
SLA-10	Poor reliability statistics were caused by 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 a weather event in 2012 and several incidents of broken conductor in 2014 and 2015. Work is being carried out in 2017 and 2018 as part of the *Distribution Reliability Initiative* project.
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 being carried out on this feeder in 2017 and 2018 as part of the *Distribution Reliability Initiative* project.

Worst-Performing Feeders Summary of Data Analysis	
Feeder	**Comments**
TWG-01	Feeder has good reliability. Poor reliability statistics were caused by a lightning-related event in 2013 and a failed insulator in 2016. No work is required at this time.
TWG-02	Feeder has good reliability. Poor reliability statistics were caused by a broken conductor incident in 2012 and a failed insulator in 2016. No work is required at this time.
TWG-03	Feeder has good reliability. Poor reliability statistics were caused by a single wind-related event in 2013. No work is required at this time.
VIR-04	Feeder has good reliability. Poor reliability statistics were caused by wind and conductor issues in 2012 and a vehicle accident in 2016. No work is required at this time.

Appendix C:
Kenmount KEN-03 Feeder Study

June 2017

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Attachment 1: Map Showing Areas Served by KEN-03
Attachment 2: Photographs of KEN-03

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 infrastructure, the risk of failure, and the potential impact to customers in the event of a failure.

The *Distribution Reliability Initiative* has identified KEN-03 as one of the worst-performing feeders on Newfoundland Power's distribution system. An engineering assessment of the feeder was carried out in 2017. This report summarizes the findings of that assessment and presents a plan to improve reliability on the feeder.

2.0 KEN-03 Feeder

KEN-03 is one of 5 distribution feeders originating from the Kenmount Substation ("KEN").[1] The feeder has a tie to KEN-01 and KEN-04 feeders, which allows for both permanent and temporary load transfers between these feeders and adjacent substations during unplanned or planned outages.

KEN-03 is a 25 kV distribution feeder that was originally constructed in the mid-1960s. It currently serves approximately 2,317 customers. The feeder leaves the substation located on Kenmount Road and heads west along Kenmount Road, then south across Kenmount Road and through 1.6 km of wooded area over Kenmount Hill to Blackmarsh Road. The feeder then extends along Blackmarsh Road, Canada Drive and Frecker Drive with numerous single-phase taps branching out into the residential neighbourhood of Cowan Heights.

The majority of the 3-phase, 5 km main trunk section of KEN-03 is constructed with 477 ASC conductors. The 3-phase main trunk along Canada Drive includes a 0.5 km section constructed with #4/0 AASC conductors. There is also a 0.5 km 3-phase section of #2/0 ACSR conductors feeding customers on Georges Pond Road.[2] All the single-phase sections are constructed with 1/0 AASC.

3.0 Engineering Assessment

Inspections have identified deteriorated hardware and conductor, obsolete insulators and decayed or damaged cross arms. It has also been identified that over 50 porcelain cutouts are present on the feeder.[3] There is also a significant quantity of 2-piece insulators still in use on the main trunk section of the feeder. Two-piece insulators have a documented high failure rate related to

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1 Attachment 1 is a map showing the areas served by KEN-03.

2 Aluminum conductor steel reinforced ("ACSR") 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.

3 Porcelain cutouts deteriorate when exposed to harsh weather conditions over time and are likely to crack and fail when operated and therefore reduce feeder reliability and create safety concerns for the general public and line staff.

cement growth and are a particular concern on heavily loaded urban feeders.[4] Component failure during high winds has been an issue over the past couple of years.

There are a number of locations where the existing conductor has been sleeved to extend the distribution line to adjacent structures.[5] The physical condition of the overhead conductors makes it highly likely that there will be further failures. Due to the age and condition of the insulators, cutouts and conductor, the feeder is becoming more susceptible to damage when exposed to severe wind, ice and snow loading.

Table 1 summarizes the reliability data for KEN-03 for the most recent 5-year period.

Table 1
KEN-03 Distribution Interruption Statistics
5-Year Average to December 31, 2016

	Customers	SAIFI	SAIDI	CHIKM	CIKM
KEN-03	2,317	1.69	2.69	241	151
Company Average	842	1.43	1.71	56	49

Table 1 shows that KEN-03 is an outlier from the Company average for SAIDI, CHIKM and CIKM.[6] 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

KEN-03 is a critical part of the Company's 25 kV distribution system in the St. John's west area. The primary contributor to the poor reliability of this feeder is the deteriorated conductor and equipment failure of components such as porcelain cutouts and 2-piece insulators.

To improve the reliability performance of KEN-03, the following work is required:

(i) all deteriorated cross arms and insulators on KEN-03 will be replaced with V-brace cross arms and 25 kV clamp top insulators, involving approximately 230 structures;
(ii) any substandard or deteriorated conductor on KEN-03 will be replaced; and

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4 Since the 1960s the term "cement growth" has been used to categorize a problem with premature failure of porcelain insulators. The cement joining the 2 insulating discs grows over time placing stress on the porcelain that fails in tension to cracking.

5 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 Attachment 2, Figure 2.

6 The SAIDI for KEN-03 is 1.6 times the Company average, while CIKM is 3.1 times the Company average and CHIKM is 4.3 times the Company average.

(iii) all remaining porcelain cutouts will be replaced.

The required work will be completed in 2018 at a total project cost estimated at $358,000.

Attachment 1:
Map Showing Areas Served by KEN-03

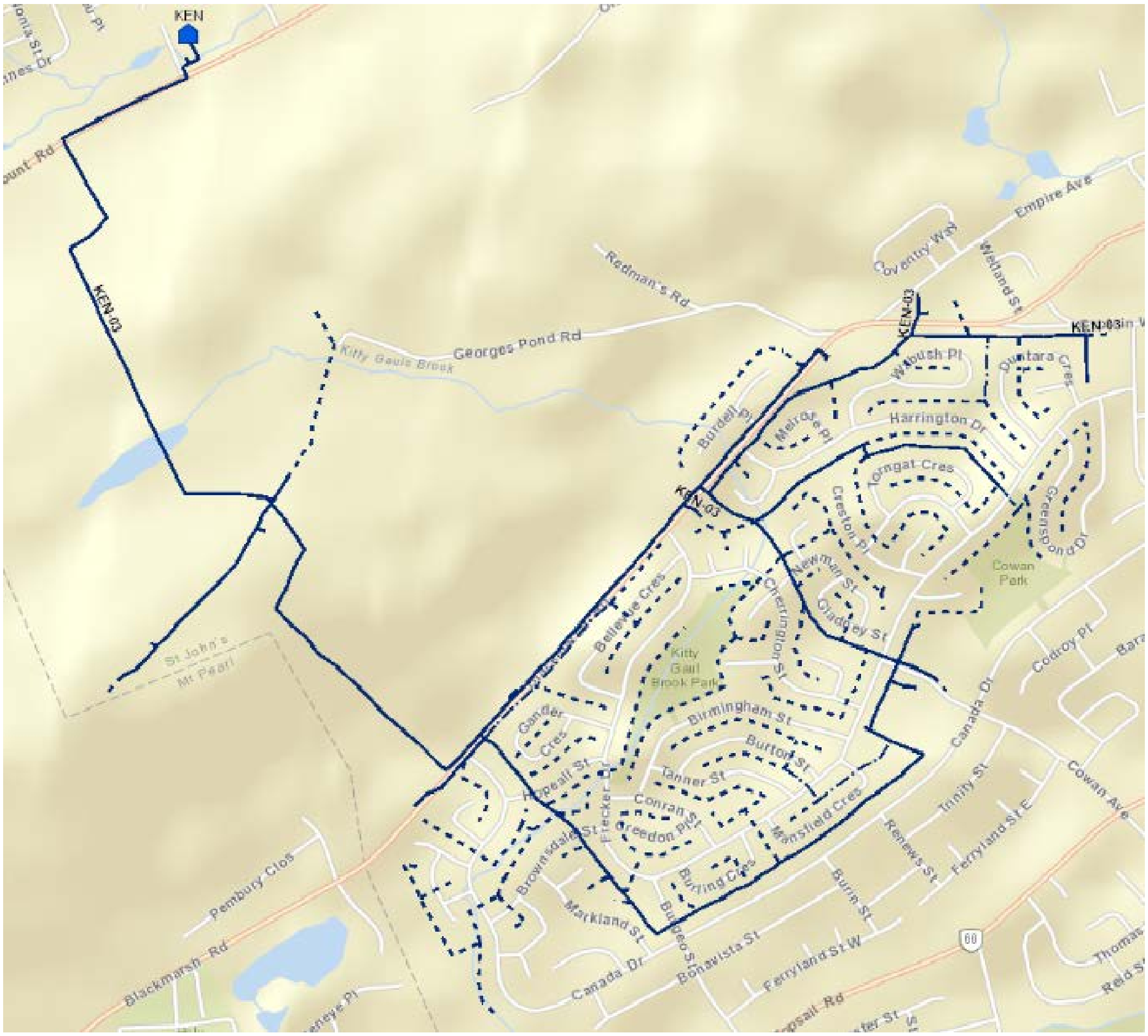

Figure 1 – Map of KEN-03

Attachment 2:
Photographs of KEN-03

Figure 1 – Porcelain Cutout

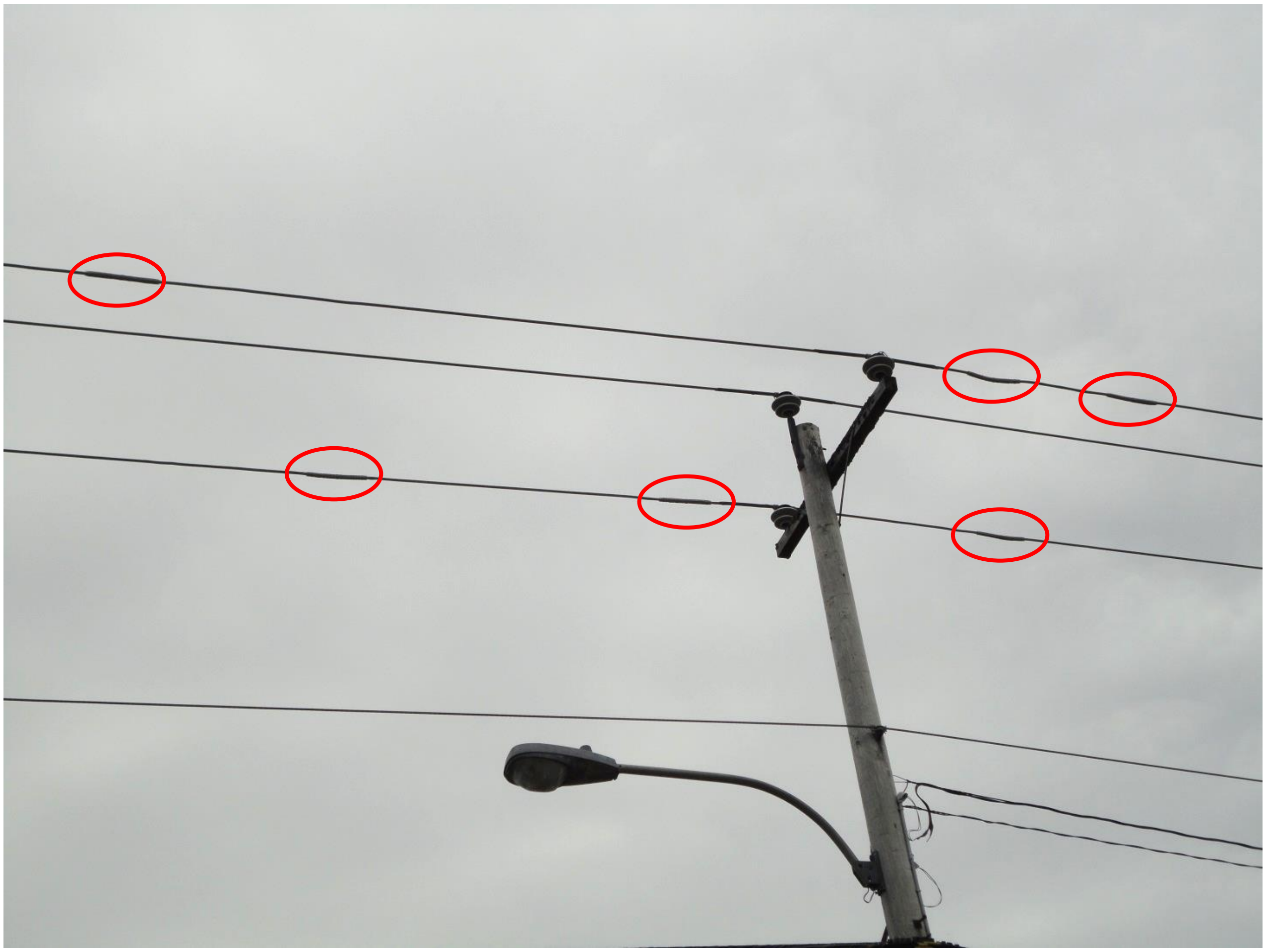

Figure 2 – Sleeved Conductor

Figure 3 – Previously Failed 2-Piece Insulator

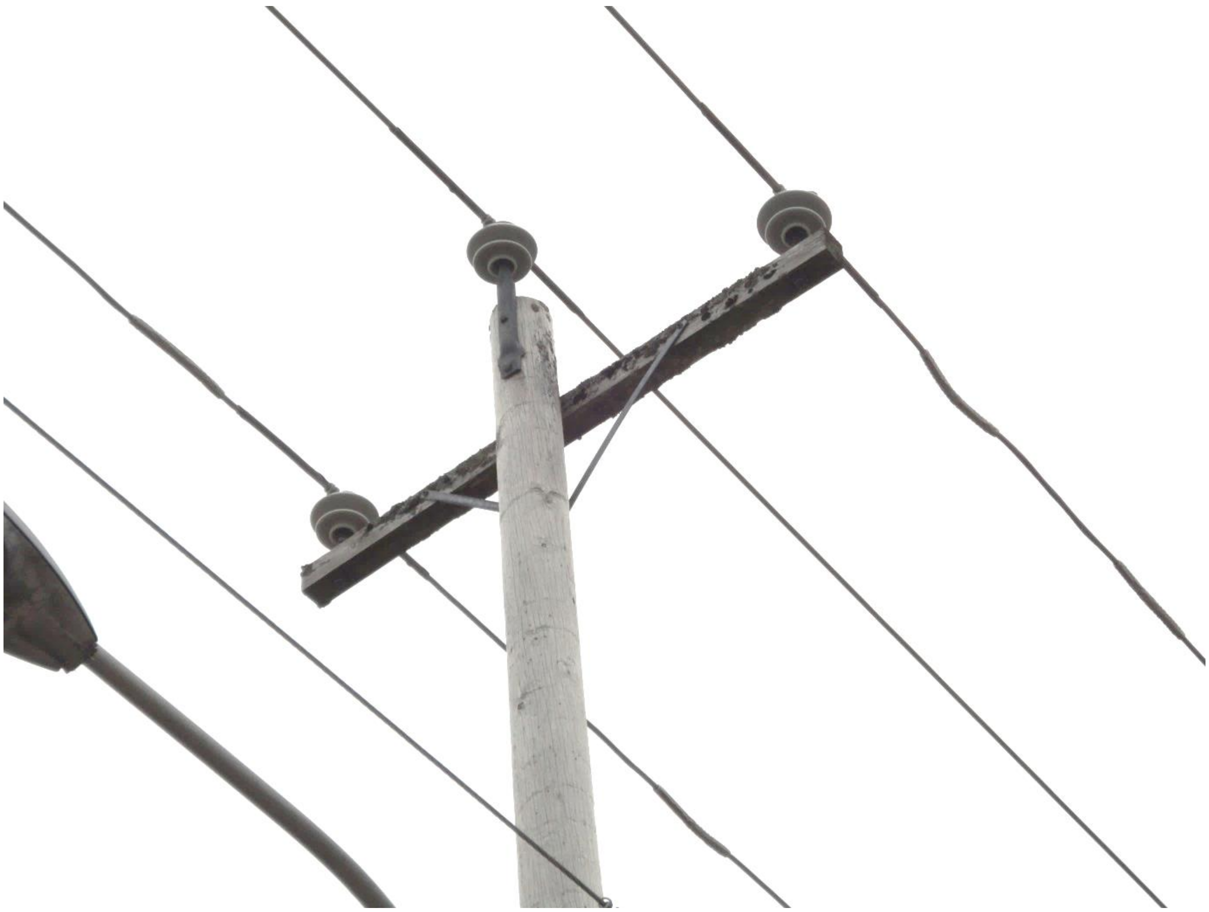

Figure 4 – 2-Piece Insulators, Deteriorated Crossarm and Conductor Sleeves

Feeder Additions for Load Growth

July 2017

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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 concern Broad Cove Substation ("BCV") feeder BCV-03 and Blaketown Substation ("BLK") feeder BLK-02, both of which can be attributed to customer growth in each area.

2.0 Overloaded Conductors

2.1 General

Overloaded sections of conductor on a distribution line are at risk of failure. Failures are caused by overheating of the conductor as the load current 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. Conductor overloads can also have a negative impact on customer outage durations during restoration activities due to increased conductor loading associated with cold load.

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 of offloading overloaded conductors onto surrounding feeders.

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[1] Feeder balancing involves transferring load from 1 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 1 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.

Alternative #1 – Feeder Balancing
In some cases, a conductor may be overloaded on only 1 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 increasing the number of phases on a section or sections of a feeder. Feeder balancing 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, 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

BCV-03 Feeder Upgrade ($220,000)

BCV is located on Pendergast Road in the Town of Portugal Cove-St. Philip's. There are four 12.5 kV distribution feeders terminated at BCV, serving approximately 4,500 customers. BCV-03 distribution feeder leaves BCV and extends southward along Thorburn Road, serving approximately 1,200 primarily residential customers in the Town of Portugal Cove-St. Philip's.

An analysis of BCV-03 was completed using a distribution feeder computer modelling application, and was verified using actual load measurements. This analysis showed a 0.7 km section of this feeder is overloaded. The overloaded section is from BCV to the intersection of Thorburn Road and St. Thomas Line and was evaluated using all 4 available alternatives identified in section 2.2. The conductor on this section is 4/0 AASC and is rated for 356 amps per phase. The balanced 2017 forecasted peak load on each of the phases in this section is 390 amps per phase.

The overload condition on BCV-03 can be attributed to residential growth in the community of Portugal Cove-St. Philip's.[3] Continued growth is expected as development in this area has increased.

[3] Over the past 10 years, the BCV-03 distribution feeder has experienced a 40% growth in customers.

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 existing tie points between BCV-03 and any other feeder that would allow load to be transferred.

The only viable options to address the overload condition on BCV-03 are to upgrade the conductor or construct a new feeder. The least-cost option is to upgrade a 0.7 km section of the feeder to #477 ASC conductor, which has a rating of 590 amps per phase.[4]

BLK-02 Feeder Upgrade (2018 - $319,000, 2019 - $665,000)

BLK is located 1.0 km east of the community of Whitbourne on the Trans-Canada Highway ("TCH"). BLK-02 feeder serves approximately 1,800 customers, consisting of mostly single-phase domestic services supplied via many long, single-phase taps.[5] The load on these single-phase taps has increased due to the addition of new line extensions to cottage developments contributing to significant customer and load growth.[6]

The capacity of a single-phase tap is limited by the performance of feeder protection back on the 3-phase trunk feeder.[7] A heavily loaded single-phase tap can result in unbalanced loads on the 3 phases of a feeder, and subsequent undesirable operation of the feeder protection at the substation.[8] This results in unnecessary outages to customers and extended time for restoring service. The unbalanced load condition can occur during peak load, cold load pickup, or when a protection fuse operates on a single-phase tap.[9] Eliminating the unbalanced condition caused by growth on single-phase feeder taps will result in a more reliable distribution system.

An analysis of BLK-02 was completed using a distribution feeder computer modelling application, and was verified using actual load measurements. This analysis showed the BLK-02 distribution feeder exceeds the Company's planning criteria for both maximum current on a single-phase distribution line and for maximum neutral current on an unbalanced 3-phase distribution line. There are no adjacent distribution lines that could be extended, at a reasonable cost, to offload the existing feeder. Similarly, the cost of constructing a new feeder is prohibitive.

Compared to extending an adjacent distribution line, or constructing a new feeder, the least-cost alternative to address this overload condition is to: (i) upgrade 2.0 km of single-phase distribution line to 2 phases from the TCH at Brigus Junction into the Middle Gull Pond cabin

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4 The single line diagram for BVC-03 is included in Appendix B.

5 The total circuit length of BLK-02 is approximately 150 km. This length consists of 12 km of 3-phase distribution line, 13 km of 2-phase distribution line, and 125 km of single-phase distribution line. The single line diagram for BLK-02 is included in Appendix B.

6 Over the past 10 years, customer growth on BLK-02 has increased by approximately 43%. BLK-02 currently ranks as the Company's 10th largest out of 305 feeders in terms of the number of customers.

7 Newfoundland Power's planning criteria for maximum current on a single-phase distribution line is 85 amps.

8 To detect faults, such as when a conductor breaks and falls to the ground, protection schemes are based on detecting the short circuit current on the phase that has the fault and/or by detecting the differences between the current levels (unbalanced current) on each of the 3 phases and the neutral conductor on a distribution feeder. To ensure that a line-to-ground fault is detected on a distribution feeder, the protection settings are established based on a minimal amount of short circuit and/or unbalanced current.

9 Newfoundland Power's planning criteria for maximum neutral current on an unbalanced 3-phase distribution feeder is 50 amps.

area; and (ii) upgrade 11.5 km of 2-phase distribution line to 3-phase along the TCH from Ocean Pond to Brigus Junction.

The Company proposes to complete this work over 2 years. In 2018, the 2.0 km section of the existing single-phase line from Brigus Junction to Middle Gull Pond cabin area will be upgraded to 2-phase to resolve the overload condition on the existing single-phase line.[10] Approximately 50% of the existing single-phase load beyond the 2-phase extension will be placed on each of the 2 phases effectively balancing the load on each phase. By reducing the load current on each of the 2 phases, fuse protection will be installed on each single-phase tap.[11]

In 2019, the 11.5 km section of 2-phase along the Trans-Canada Highway from Ocean Pond to Brigus Junction will be upgraded to 3-phase. This will permit balanced loading on all 3-phases of the entire distribution feeder and address the issue of high neutral current. Balancing the line across all 3 phases will allow for the implementation of standardized protection settings to provide safe and reliable service to customers on BLK-02.

3.0 Project Cost

The *Feeder Additions for Load Growth* work on distribution feeder BCV-03 will be completed in 2018. The Company will complete the *Feeder Additions for Load Growth* work over 2 years for distribution feeder BLK-02.

The estimate to complete the 2018 work associated with the *Feeder Additions for Load Growth* project is $539,000. Table 1 provides a detailed breakdown of the 2018 project cost by distribution feeder.

Table 1
2018 Project Costs

Description	**BCV-03**	**BLK-02**	**Total**
Engineering	$33,000	$41,000	$74,000
Labour - Contract	22,000	81,000	103,000
Labour - Internal	64,000	55,000	119,000
Material	49,000	68,000	117,000
Other	52,000	74,000	126,000
Total	**$220,000**	**$319,000**	**$539,000**

[10] The overload condition on the existing single-phase line violates the Company's planning criteria for maximum current on a single-phase distribution line.

[11] Fuse protection on single-phase taps effectively isolate faults to just those customers downstream of the fuse. Otherwise, faults on these taps would cause protection devices further upstream to operate causing an outage to a larger number of customers.

The estimate to complete the 2019 work associated with BLK-02 in the *Feeder Additions for Load Growth* project is $665,000. Table 2 provides a detailed breakdown of the 2019 project cost.

Table 2
2019 Project Costs

Description	**BLK-02**
Engineering	$87,000
Labour - Contract	57,000
Labour - Internal	231,000
Material	69,000
Other	221,000
Total	**$665,000**

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.

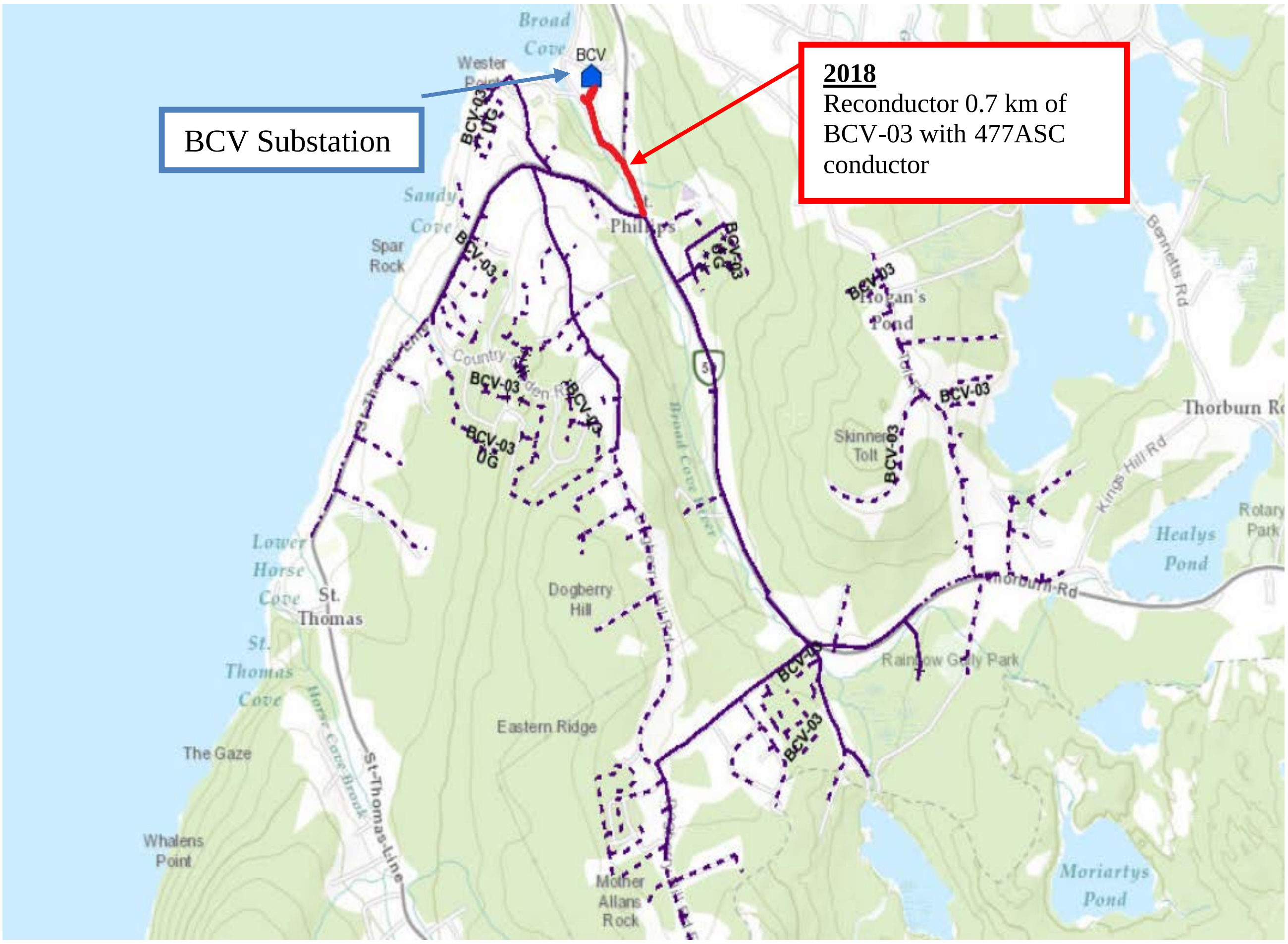
3 The planning rating is theoretically 75% of the winter conductor ampacity. In practice, the actual percentage will be something less due to: (i) the age and physical condition of the conductor; (ii) the number of customers on the feeder; (iii) the ability to transfer load to adjacent feeders; and (iv) operational considerations, including the geographic layout and the distribution of customers on the feeder.

4 Cold load pickup (“CLPU”): 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.

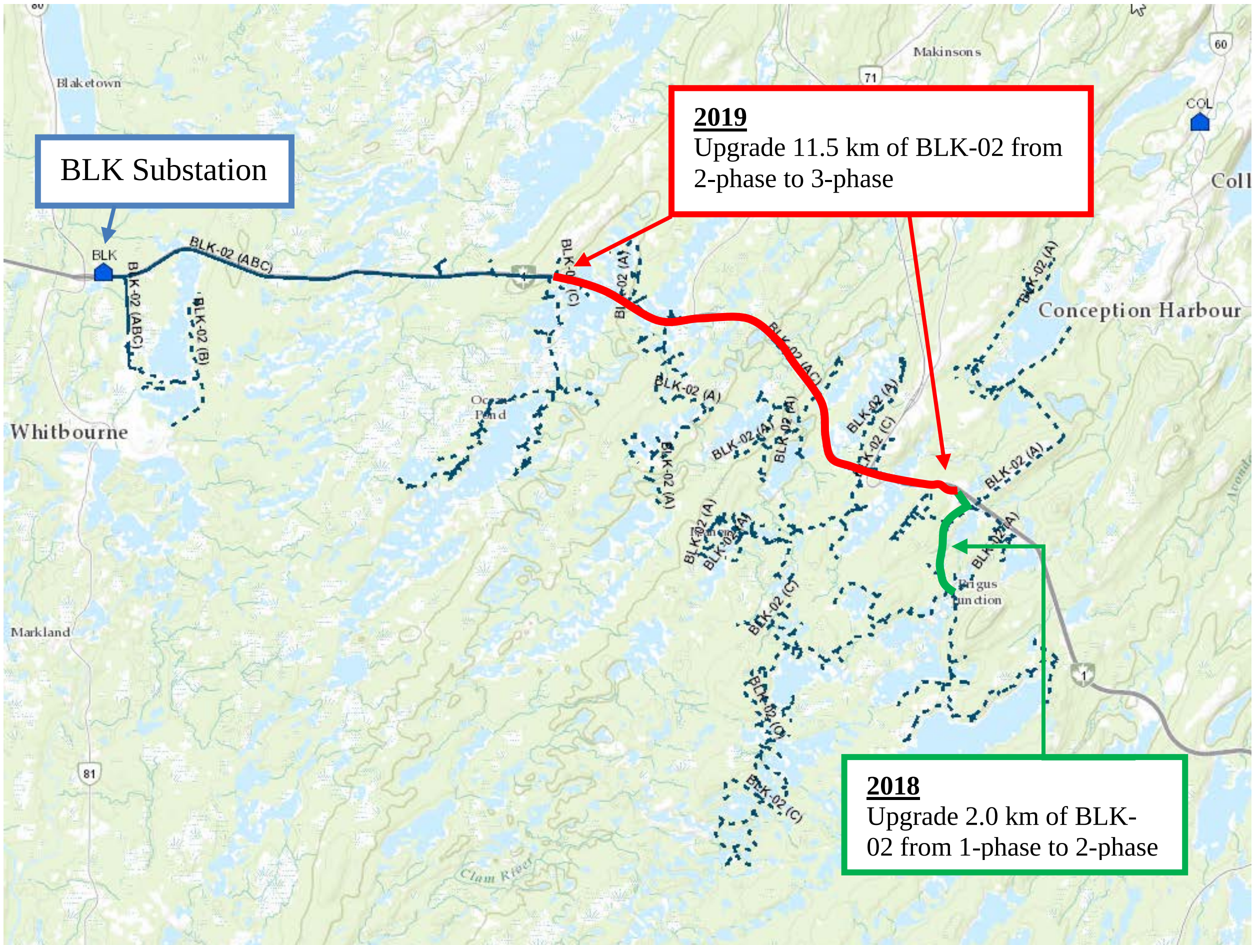
5 Sectionalizing factor: Two-stage sectionalizing is used during CLPU conditions to increase the Planning Rating of aerial conductors. Restoring power to one section of the feeder at a time reduces the overall effect of CLPU. The sectionalizing factor is the fraction of the load that is restored in the 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

<u>BCV-03 Distribution Feeder Upgrade</u>



<u>BLK-02 Distribution Feeder Upgrade</u>



CLV-01
Distribution Feeder Refurbishment

July 2017

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Appendix A: CLV Feeder Schematic Diagram
Appendix B: CLV-01 Distribution System Photographs

1.0 Introduction

Distribution feeder CLV-01 is 1 of 3 distribution feeders originating from the Clarenville Substation ("CLV") located on the Trans-Canada Highway ("TCH") in the Community of Clarenville. It supplies electricity to approximately 1,000 customers in the Clarenville South, Deep Bight and Adeytown areas. Figure 1 is a map showing the location of CLV-01.

Figure 1: Location of CLV Substation

The *CLV-01 Distribution Feeder Refurbishment* project involves the replacement of deteriorated poles, conductor and hardware on the 3-phase section of feeder along Marine Drive, Clarenville.

The purpose of the project is to prevent outages and failures due to aging and deteriorated infrastructure.[1]

This report outlines the capital expenditures required to address the deteriorated infrastructure that exists along Marine Drive on the CLV-01 distribution feeder. The refurbishment of the deteriorated infrastructure will improve reliability and safety performance of this section of the distribution feeder.

2.0 Background

CLV-01 is a 12.5 kV distribution feeder that was originally constructed in the late 1960s and serves approximately 1,000 customers. The feeder extends from CLV, on the north side of the TCH, and supplies the south side of Clarenville, including a 3-phase section of CLV-01 that runs along Marine Drive, starting at its intersection with Memorial Drive, and ending at its tie point with CLV-02. CLV-01 also extends east to the communities of Deep Bight and Adeytown.[2] This section of CLV-01 serves a marine dry-dock, fish plant and the provincial government building for the Clarenville area.

The 3-phase main trunk section of CLV-01 along Memorial Drive is primarily constructed of 1960s vintage overhead line infrastructure. This section is 3 km long and is constructed using #4 copper primary conductor. The #4 copper primary conductor is deteriorated and is more than 50 years old.[3]

CLV-01 was inspected in 2015 as per Newfoundland Power's distribution inspection and maintenance practices. This inspection identified a significant number of deficiencies in the Marine Drive section including two-piece insulators, porcelain cutouts, and lack of lightning arrestors on transformers, damaged and deteriorated poles and crossarms.[4] The inspection also identified several areas of concern where substandard design clearances exist. At that time, it was determined that the capital expenditures required to refurbish this section of CLV-01 were beyond the scope of the *2016 Rebuild Distribution Lines* capital project and would require a separate capital project to correct the deficiencies along the Marine Drive section of the feeder. Therefore, work completed on the Marine Drive section of CLV-01 feeder under the *2016 Rebuild Distribution Lines* capital project was limited to the high-priority deficiencies that required attention in the 2016 planning year.[5]

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1 Rebuilding the 3-phase section of CLV-01 will also increase feeder capacity to improve the feeder's load transfer capability to and from the surrounding CLV feeders. Additional capacity to transfer load from CLV-01 feeder to adjacent CLV-02 and CLV-03 feeders will have a positive impact on the duration and frequency of both planned and unplanned outages.

2 Appendix A includes a schematic of the CLV 12.5 kV distribution system.

3 The #4 copper conductor is no longer a standard conductor for the Company's distribution feeders.

4 The *Rebuild Distribution Lines Update* included in the 2013 Capital Budget Application describes the Company's targeted replacement program for lightning arrestors, CP8080 and 2-piece insulators, current limiting fuses, automatic sleeves, porcelain cutouts and transformers.

5 The *Rebuild Distribution Lines* capital project is an annual preventative maintenance project based on condition assessments as per Newfoundland Power's 7-year inspection cycle for distribution feeders.

CLV-01 is 1 of 3 distribution feeders originating from CLV. The feeder has a tie point to the CLV-02 feeder, which also has a tie with the CLV-03 feeder. These tie points allow for the flexibility of both permanent and temporary load transfers between the 3 distribution feeders. However, the deteriorated condition of conductor and hardware on the 3-phase section of CLV-01 along Marine Drive restricts load transfers during planned and unplanned work.[6]

3.0 CLV-01 Distribution Feeder Refurbishment

Based on the inspection of the CLV-01 distribution system completed in 2015 the following upgrade of the Marine Drive section of the feeder is proposed:

- Replace the 50-year-old #4 copper primary conductor with #4/0 Aluminum Alloy Stranded Conductor ("AASC");
- Eliminate all non-standard distribution structures and substandard clearance issues;
- Replace all deteriorated poles and structures of 1960 vintage and older; and
- Replace all deteriorated secondary conductors and service drops.

The *CLV-01 Distribution Feeder Refurbishment* project will see all identified deficiencies resolved and the complete section brought up to current Newfoundland Power distribution standards. This project will also provide additional load transfer capacity with the tie point to CLV-02.[7]

4.0 Project Cost

The total project cost is estimated at $798,000. Table 1 provides the project cost breakdown for the CLV-01 Trunk Feeder project.

Table 1
CLV-01 Project Costs

Description	**Amount**
Engineering	$106,000
Labour - Contract	184,000
Labour - Internal	170,000
Material	144,000
Other	194,000
Total	**$798,000**

6 A load study completed in the winter of 2016 indicates peak load on the #4 Copper primary conductor on this section of CLV-01 of 95 amps. The planning rating for #4 copper is 102 amps, restricting load transfers for planned and unplanned work.

7 Upgrading the existing #4 copper primary conductor to #4/0 AASC will increase the planning rating of the conductor from 2.2 MVA to 5.1 MVA. This will allow both permanent and temporary load transfers between these feeders during unplanned or planned outages.

5.0 Concluding

The *CLV-01 Distribution Feeder Refurbishment* Trunk Feeder project for 2018 includes distribution system upgrades to CLV-01 distribution feeder to replace deteriorated and non-standard infrastructure identified through inspections. The refurbishment of the deteriorated infrastructure will improve reliability and safety performance of this section of the distribution feeder.

Appendix A:
CLV Feeder Schematic Diagram


CLV-01 TO CLV-02
TIE POINT
CLV-02 TO CLV-03
TIE POINT
CLV-01
REBUILD
SECTION
CLV-02
CLV-03
CLV-01
CLV
DEEP BIGHT/ADEYTOWN

Appendix B:
CLV-01 Distribution System Photographs

Figure 1: Deteriorated Non-Standard Structure

Figure 2: Deteriorated Section (Poles Leaning)

Figure 3: Worn Conductor Burnt Off Under Hot-Line Tap (Outage March 2015)

Figure 4: Splice in #4 Copper Primary Conductor

Figure 5: Hidden Splice on Insulator (Potential Hazard)

Figure 6: Deteriorated Line/Substandard Clearances

Figure 7: Non-Standard Structure

Figure 8: Non-Standard Secondary/Deteriorated Structure

Figure 9: Non-Standard Construction/Substandard Clearances

Figure 10: Deteriorated Leaning Pole

Figure 11: Deteriorated Leaning Pole

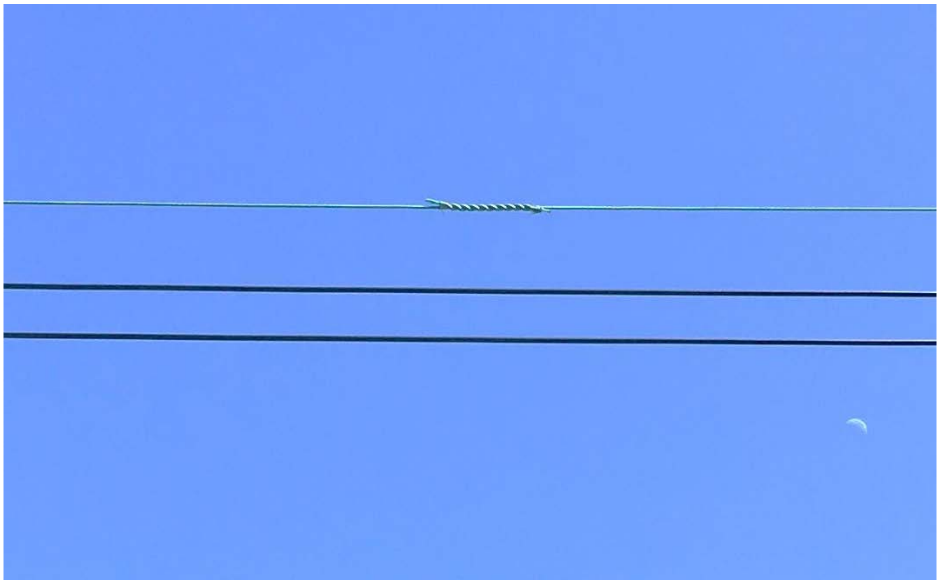

Figure 12: Splice in #4 Copper Primary Conductor

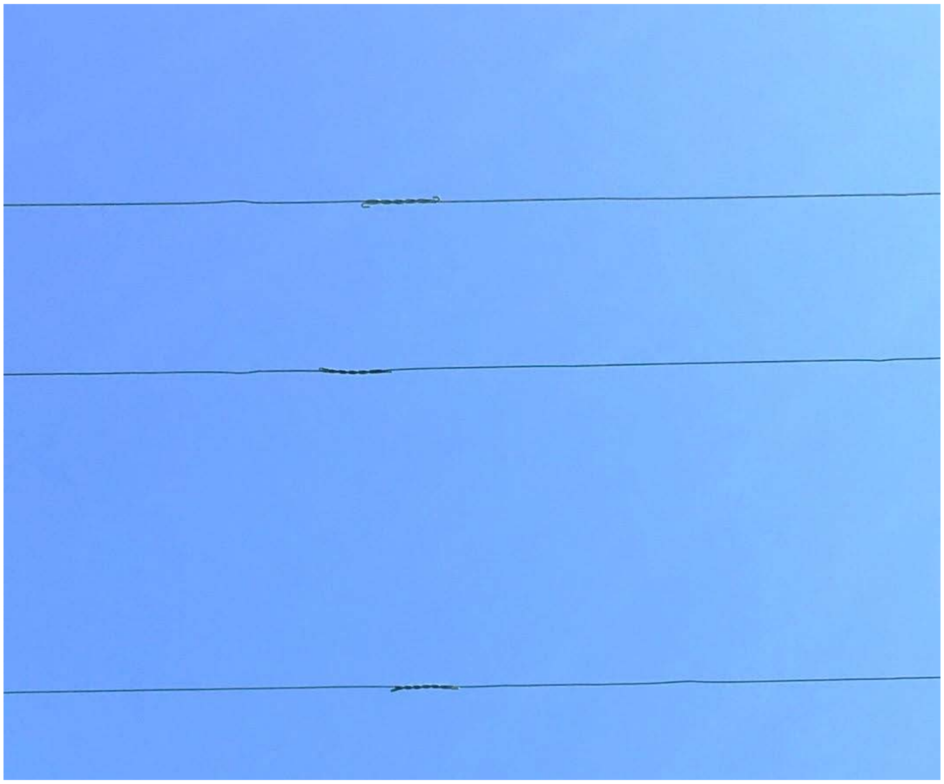

Figure 13: 3 Splices in #4 Copper Primary Conductor

Figure 14: Deteriorated Pole with Checks

Figure 15: Leaning Non-Standard Structure

2018 Application Enhancements

July 2017

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1.0 Introduction

Newfoundland Power (the "Company") operates and supports over 100 corporate applications. These include third-party software products, such as the Microsoft Dynamics Great Plains ("Dynamics GP") financial system, the ClickSoftware work scheduling and dispatch system, as well as internally developed software, such as the Customer Service System ("CSS") and the Technical Work Request system. These applications help employees work more effectively and efficiently in their daily duties.

The Company's *2018 Application Enhancements* fall into 3 categories: (i) Business Support System Enhancements; (ii) CSS Enhancements; and (iii) Internet Enhancements.[1] In addition, the Company budgets for various minor enhancements needed 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 2018.

2.0 Business Support System Enhancements

This category includes enhancements necessary to support the Company's business applications. Business applications include the Dynamics GP financial management application, the Safety and Environment Management System ("S&EMS") application, and various other applications used to manage the financial, human resources, and inventory areas of the Company.

For 2018, replacement of the Company's S&EMS application is proposed.

Table 1 summarizes the estimated cost associated with this replacement.

[1] The 4th category for application enhancements is "Operations and Engineering Systems Enhancements." No application enhancements are proposed for this category in 2018.

Table 1
Business Support System Enhancements
Project Expenditures
(000s)

Cost Category	2018 Estimate
Material	$40
Labour – Internal	46
Labour – Contract	-
Engineering	-
Other	90
Total	**$176**

2.1 Safety and Environment Management System Upgrade ($176,000)

Description

The Company's current S&EMS application is known as "Prevent." Prevent is an internally developed, web-based application that is used by operations personnel on a daily basis to manage safety and environmental requirements. Prevent archives and tracks safety, security and environmental incidents.[2] This functionality is critical to meeting the requirements of: (i) Occupational Health and Safety Assessment Series ("OHSAS") 18001; and (ii) the International Organization of Standards ("ISO") 14001.[3]

Prevent has been in service for approximately 10 years. The application has reached the end of its service life and must be replaced.[4]

The Company will replace Prevent with a commercially available product that will continue to allow it to meet the requirements of OHSAS 18001 and ISO 14001. This will support the Company's overall system for safety and environmental management.

Operating Experience

The safety of the general public, employees and contractors is a high priority for the Company. As part of an effective system for safety and environmental management, the Company inventories and assesses the risk of activities that present potential hazards to the general public, employees, contractors and the environment.

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2 Safety, security and environmental incidents include accidents, injuries, spills, near miss situations, public contacts, non-conformance to safety procedures, opportunities for improvement and inquiries from third parties.

3 OHSAS 18001 is an internationally recognized specification for health and safety management systems. ISO 14001 is an internationally recognized environmental management certification. The Company has adopted both of these standards as part of its system for safety and environmental management.

4 In addition to Prevent, the Company's relies on SharePoint and Microsoft Excel to manage document control, emergency preparedness, and other safety and environmental requirements.

The Company continually evaluates the effectiveness of its policies, procedures and systems to ensure a safe and healthy workplace. Risk and environmental assessments, control procedures and legal aspects are monitored and updated on an annual basis in order to meet the requirements of OHSAS 18001 and ISO 14001. Employees and contractors must identify and assess new hazards as they occur, and keep a complete record of the process, including training and compliance records. Incidents are archived in the S&EMS application and retrieved for post-event analysis and training opportunities.

In 2018, the Company will replace the Prevent application and purchase a new, commercially available S&EMS application. The project will include:

(i) Migrating the existing Prevent data to the new S&EMS application;

(ii) Including the S&EMS aspects currently archived in Excel files in the new S&EMS application database;

(iii) Implementing a dashboard customized to the individual user that presents the most recent incidents relative to their job responsibilities;

(iv) Implementing an emergency preparedness module to track all emergency contact information, and automating the electronic notification process for government and community agencies in the event of an emergency;

(v) Improving incident workflow in the S&EMS application by providing the ability to enter information from computing devices onsite when inspections or investigations are taking place; and

(vi) Improving system reporting capabilities.

Justification

Replacement of Prevent will improve the Company's ability to manage the requirements of OHSAS 18001 and ISO 14001. This project is justified on the basis of ensuring compliance with regulatory and legislative requirements.

3.0 Customer Service System Enhancements

This category includes application enhancements necessary to support customer service delivery, including the various forms of communication used by customers to interact with the Company. For 2018, enhancements are proposed to introduce mobile electronic payment devices in the field and to address the introduction of a second area code for Newfoundland and Labrador.

Table 2 summarizes the estimated cost associated with this item.

Table 2
Customer Service System Enhancements
Project Expenditures
(000s)

Cost Category	2018 Estimate
Material	$25
Labour – Internal	268
Labour – Contract	-
Engineering	-
Other	37
Total	**$330**

3.1 Field Collections by Electronic Payment ($167,000)

Description

Newfoundland Power Field Service Representatives ("FSRs") can meet with customers as a last attempt to collect their outstanding account balance. This contact often results in cash payments taken at the customer residence to avoid disconnection of the customer's electricity service.

The introduction of mobile electronic payment devices will provide the opportunity to collect debit ("Interac") payments in the field. The devices will be tested to ensure their secure operation and configured to integrate with the Company's CSS. This integration will allow payments to be automatically credited against a customer's account, preventing any further collection action.[5]

Operating Experience

It is anticipated that an average of 10 field cash transactions per day would be completed using the mobile electronic payment devices. In addition, there are between 20 and 30 walk-in office cash payments daily, some of which could also be completed by using the electronic payment devices if the customer prefers this method of payment.

The purpose of the FSR's customer visit is to receive payment to prevent the disconnection of the customer's electricity service. Frequently, the customer does not have the necessary amount of cash on hand that is required to prevent the disconnection of their electricity service. As a result, a follow-up visit is required.

[5] The integration of mobile electronic payment devices into CSS will be similar to work completed previously when the Company first began receiving customer payments through chartered banks.

Electronic payments are commonplace today and most customers prefer to pay electronically. Requiring cash payment is often an inconvenience to most Customers, resulting in additional customer frustration, and potentially resulting in unnecessary disconnection of the customer's electrical service.

Justification

Providing customers with additional payment options at their residence is the primary justification of this project. Allowing customers to use electronic payment to address outstanding account balances improves payment flexibility and increases the likelihood that the customer will be able to make a payment when the FSR visits the customer.

Twenty mobile units will be required for FSRs and to provide adequate backup equipment in the closest area office. The backup units will be used by front-line customer service staff to accept debit payments from customers with overdue account balances who visit a Company office.

3.2 Introduction of New Area Code and Ten-Digit Dialing ($163,000)

Description

Area code 709 covers the entire province of Newfoundland and Labrador. On April 22, 2016, the Canadian Numbering Administrator provided notice that they forecast all available 709 telephone numbers will be exhausted by March 2019. As a result, on February 2, 2017, the Canadian Radio-television and Telecommunications Commission ("CRTC") decided to introduce a new area code for the province.

Starting on August 17, 2018, the adoption of 10-digit dialing commences (i.e. the area code followed by the 7-digit telephone number). Calls made using only the 7-digit telephone number will hear a voice message reminding them the full 10-digit telephone number must be used. Starting on November 10, 2018, calls made using only the 7-digit telephone number will not be completed by the telephone network. Effective November 24, 2018, area code 879 will come into full effect, with new telephone numbers assigned to the 879 area code.

Operating Experience

The Company uses customer telephone numbers in several applications that will need to be assessed for the area code changes and updated to ensure a seamless transition. These applications include the Company's Customer Service System ("CSS"), the Telvox automated outbound dialing system, the customer service website, Outage Management System and the Technical Work Request system.

The most significant of these applications is CSS, which includes the customer information database. When this system was implemented over 25 years ago, 10-digit dialing was not considered when designing screens that accepted and displayed customers' telephone numbers. To update the CSS, the system must be revised to ensure the area code portion of customer telephone numbers are properly accepted, displayed and integrated with external systems.

Justification

The ability to capture accurate telephone numbers is essential to providing service to customers. Several of the Company's corporate applications do not provide the flexibility for capturing or displaying area code information. Ensuring the Company's applications have this capability through the transition to a second area code will ensure the Company continues to provide customer service using the appropriate customer contact information.

4.0 Internet Enhancements

This category includes 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. Applications in this category include the Company's customer service website, and the takeCHARGE website.[6]

For 2018, enhancements to the takeCHARGE website are proposed in order to reflect planned changes in the Company's energy conservation initiatives.

Table 3 summarizes the estimated cost associated with this item.

Table 3
Internet Enhancements
Project Expenditures
(000s)

Cost Category	2018 Estimate
Material	-
Labour – Internal	$40
Labour – Contract	-
Engineering	-
Other	20
Total	**$60**

[6] The takeCHARGE website supports the joint Newfoundland and Labrador Hydro and Newfoundland Power customer energy conservation initiative.

4.1 Energy Conservation Website Enhancements ($60,000)

Description

Each year, the Company's energy conservation initiatives under takeCHARGE are updated according to the Company's *5-Year Energy Conservation Plan: 2016-2020.* Enhancements to the takeCHARGE website are therefore required annually to ensure customers have access to up-to-date information on current energy conservation initiatives. In 2018, specific enhancements are anticipated to include expansion of customer self-service tools, calculators and email communication.

Operating Experience

In 2008, Newfoundland and Labrador Hydro and Newfoundland Power launched a joint energy conservation initiative called takeCHARGE, which included a website. This website serves as the primary communication channel through which customers are directed for information on energy conservation and current programs, including available rebates and eligibility details, as well as energy efficiency education and awareness resources.

In 2016, there were over 241,000 visits to the takeCHARGE website. This is consistent with promotion of this website as the primary resource for customer inquiries and information on energy conservation. It also reflects the broad trend towards increased customer expectations for self-service options, particularly through mobile devices.

Justification

Website enhancements are justified based on ensuring customers have access to up-to-date, user-friendly information and resources on energy conservation and related initiatives. As energy conservation initiatives and associated incentives evolve according to the Company's *5-Year Energy Conservation Plan: 2016-2020*, it is necessary to ensure the takeCHARGE website and tools are updated to reflect the new initiatives and improved information resources.

Ensuring customers have access to energy conservation tools and information is integral to the Company's customer energy conservation initiative. In addition to providing up-to-date, accurate information, the proposed enhancements will ensure customers can access the takeCHARGE website independent of location, time of day, or type of device used. This supports continued efficiency in the Company's response to customer expectations in this area.

5.0 Various Minor Enhancements ($292,000)

Description

The purpose of this item is to complete enhancements to the Company's corporate 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. Based on recent expenditures, $292,000 is estimated to be required in 2018 to address various minor enhancements to Company applications.

Operating Experience

Examples of work that would be completed under this budget item include modifications to customer, operations and engineering applications. This work is often required as a result of unforeseen circumstances that occur throughout the year that cannot be deferred to future capital budget applications.

Some recent examples include new regulatory matters, such as the customer net meter billing option, and externally requested changes to how Newfoundland Power conducts business with third parties, such as Bell Aliant and pole contractors.

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.

2018 System Upgrades

July 2017

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1.0 Introduction

Newfoundland Power (the "Company") depends on the effective implementation and ongoing operation of its information systems in order to continue providing least-cost service to customers. Over time, these systems must be upgraded to ensure continued vendor support, to improve compatibility with software or hardware upgrades, or to take advantage of newly developed functionality and security improvements.

This project consists of system upgrades and continuation of the Microsoft Enterprise Agreement.

2.0 2018 System Upgrades ($1,098,000)

These upgrades involve third-party software products that comprise the Company's information systems. For 2018, upgrades are proposed for the Company's Geographic Information System ("GIS"), Supervisory Control and Data Acquisition system ("SCADA system"), Customer Service System ("CSS"), and business continuity improvements related to the Avaya contact centre solution.

Table 1 summarizes the cost associated with these items.

Table 1
System Upgrades
Project Expenditures
($000s)

Cost Category	**2018 Estimate**
Material	305
Labour – Internal	533
Labour – Contract	-
Engineering	-
Other	260
Total	**1,098**

2.1 Description

Upgrades to third-party software products ensure the Company's information systems continue to function in a stable and reliable manner with the appropriate level of vendor support. Each year, the Company's systems are reviewed to determine if upgrades are required.

For 2018, upgrades include:

Geographic Information System Upgrade ($352,000)

This item involves upgrading the Company's GIS to the most current, vendor-supported version of the product.

The GIS was initially implemented in 2013. The version currently used by the Company will no longer be supported by the vendor commencing in June 2017. The GIS is used to manage field assets and locations, including the distribution network model, poles and customer locations. This information is critical to operate and maintain the electrical system.

Modifications were made to the GIS to meet Company requirements and integrate with other Company systems, including the Technical Work Request system and the Workforce Management System.[1] These modifications will be transferred to the new version.

The proposed upgrade will ensure continued support by the vendor, contributing to the consistent and effective operation of the GIS. It will also improve the overall performance of the GIS.

Supervisory Control and Data Acquisition System Upgrade ($136,000)

This item involves upgrading the SCADA system to ensure System Operations benefits from the latest enhancements and functionality, and to ensure the system continues to be fully supported by the vendor.

This system was implemented in 2016. It is a critical component of the Company's System Operations that monitors and controls the electrical system on a real-time basis. Frequent upgrades of SCADA systems have become industry best practice.

The proposed upgrade will ensure consistent and effective operation of the Company's SCADA system and apply the latest security updates and features available for the system. The upgrade will also ensure that integrations to other enterprise systems will continue to function properly.

Customer Service System Components Upgrade ($293,000)

This item involves the upgrade of software development tools and related components used to operate the Company's CSS and other information systems. These are: (i) the database management software from Oracle, which is used to store relevant customer information; (ii) the PowerHouse and Axiant programming tools from Unicom Global, which are used to develop,

[1] The Technical Work Request system is used to record and plan customer work requests, such as the need to replace a frayed service wire. The Workforce Management System is used to dispatch field staff and monitor ongoing field work. Each of these systems requires information on the location of electrical system assets and customers. This information is provided through integration with the Company's GIS.

support and enhance the Company's CSS; and (iii) the OpenVMS server operating system, which is the software through which the Company's CSS is operated.[2]

These upgrades are required because the Company's current version of the Oracle database management software is no longer supported by the vendor.[3] The database software will be upgraded to the most current, vendor-supported version. The PowerHouse and Axiant programming tools and the OpenVMS server operating system will also be upgraded to ensure continued compatibility with the new database software. Overall, these upgrades will enable the Company to sustain an acceptable level of support and maintenance for the CSS and other information systems that rely on these tools and related components.[4]

Business Continuity Improvements ($317,000)

This item involves improving the Company's disaster recovery capabilities related to its Avaya call centre solution.

Avaya is an enterprise contact centre vendor and provides many of the technology components used at the Company's Customer Contact Centre ("CCC"). The primary purpose of the Avaya contact centre solution is to process incoming customer calls by:

- Connecting the Company's CCC infrastructure to incoming calls from customers via the Bell network;
- Distributing incoming calls to specific groups of customer service representatives based on their skill set and the menu option selected by the customer;
- Using automation to satisfy a customer call by means of the self-service capabilities; and
- Reporting and analyzing the types of calls received and how effective the CCC is at handling these calls.

The existing Avaya contact centre solution has a primary system and a backup system. These systems are co-located in 2 separate Newfoundland Power data centres. Currently, when an interruption is experienced on the primary system, manual intervention is required by the vendor or Newfoundland Power staff to switch over to the backup system. This results in downtime for the CCC and affects the Company's ability to continuously communicate with its customers.

The proposed upgrade will build on the existing foundation to ensure that, in the event of an interruption, the system will automatically switch over to the backup system without manual intervention. Automatic recovery will ensure the CCC can continue to provide uninterrupted service to customers who are contacting Newfoundland Power during or after regular business hours.

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2 Unicom Global acquired the Cognos development tools from IBM Corporation, including PowerHouse, Axiant 4GL and PowerHouse Web, in December 2013.

3 The last upgrade required to ensure a sustainable level of vendor support for the Oracle database software occurred in 2010.

4 These upgrades reduce uncertainty associated with the operation of the Company's CSS, which has been in service since 1991, until the system's eventual replacement.

2.2 Operating Experience

System upgrades help ensure the reliability and effectiveness of the Company's information systems and mitigate risks associated with technology-related issues. The timing of the upgrades is based on a review of the risks and operational experience of the systems being considered for upgrade. New versions of third-party software products are generally designed to address known deficiencies, thereby improving performance, and allow the Company to take advantage of functional or technical enhancements.

2.3 Justification

Investments in the GIS, SCADA system, and CSS components will ensure continued vendor support. Unstable and unsupported software products can negatively impact security, operating efficiencies and customer service.

Investments in the Avaya contact centre solution will improve business continuity planning and ensure the Company provides continuous customer service during interruptions to the primary system.

3.0 The Microsoft Enterprise Agreement ($245,000)

3.1 Description

This agreement covers the purchase of Microsoft software products and provides access to the latest versions of each software product purchased under this agreement at least-cost.

The Microsoft Enterprise Agreement is a fixed-price, annual agreement based on the number of eligible employees that utilize Microsoft software products on Company-assigned personal computers.[5] Under this agreement, the Company distributes its purchasing costs for these licenses over 3 years, as outlined in Schedule C. This achieves overall cost savings.

3.2 Operating Experience

The Company has had the Microsoft Enterprise Agreement in place providing access to the latest versions of software products for over 15 years.[6] The terms of the agreements are typically 3 years, with requirements reviewed and adjusted annually. The current agreement expires on May 31, 2018.

3.3 Justification

The Microsoft Enterprise Agreement is the least-cost option to ensure access to current Microsoft software products.

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[5] Personal computers include desktops, laptops, tablets and other mobile computing devices.

[6] The agreement covers software products such as Microsoft Windows, Microsoft Office, Outlook, SharePoint, SQL Server, and other products used by employees in the completion of their normal duties.

2018 Shared Server Infrastructure

July 2017

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1.0 Introduction

Newfoundland Power's (the "Company") shared server infrastructure consists of over 100 shared servers that are used for routine operation, testing, and disaster recovery of the Company's corporate applications. The Company relies on these shared servers to ensure the efficient operation and support of its systems and applications.[1]

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 and peripheral equipment.

Table 1 summarizes the cost associated with these items.

Table 1
Shared Server Infrastructure Upgrades
Project Expenditures
($000s)

Cost Category	2018 Estimate
Material	360
Labour – Internal	248
Labour – Contract	-
Engineering	-
Other	40
Total	**648**

For 2018, this project includes 3 items to enhance the secure operation of the Company's shared server infrastructure (total estimated cost of $423,000):

1. Implementation of a Web Application Firewall for corporate web applications accessible via the Internet;
2. Implementation of a security monitoring and alerting service for the Company's Supervisory Control and Data Acquisition ("SCADA") infrastructure; and

[1] The Company's systems and applications fall into 4 categories: (i) Business Support Systems, (ii) Customer Service Systems, (iii) Internet, and (iv) Operations and Engineering Systems.

3. Lifecycle replacement of the corporate secure remote access solution, which allows Company employees to securely access Company applications and systems, while not physically in a Company office.

For 2018, this project also includes the lifecycle replacement of high-volume printing equipment in the Company's production centre at a total estimated cost of $225,000.[2]

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 and peripheral equipment. Shared servers and peripheral equipment are critical to ensuring the efficient operation of the Company and the provision of service to customers.

Factors considered in determining when to upgrade, replace or add shared server components or peripheral equipment include:

(i) Level of support provided by the vendor;
(ii) Current performance of the components;
(iii) Ability of the components to meet future growth;
(iv) Cost of maintaining and operating the components;
(v) Cost of replacing or upgrading the components versus operating the current components;
(vi) Criticality of the equipment or the applications running on the shared servers; and
(vii) Business or customer impact, should the component fail.

Gartner Inc. has indicated that 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 servers is about 7 years.

In order to ensure the high availability of its applications, and to minimize the vulnerability of its computer systems to external interference, the Company invests in system availability, 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 compromise customer and corporate information.

Additionally, Newfoundland Power relies on high-volume printing equipment in the Company's production centre to, among other functions, produce materials for communicating with customers. This includes: (i) 2 high-volume production printers used to print customer bills, customer correspondence, and reports; (ii) 1 high-volume colour copier used for large-scale printing, such as customer information brochures, major regulatory filings, internal training manuals, booklets, posters, energy conservation materials and business cards; and (iii) 1 production printer for disaster recovery purposes for bill printing.

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[2] The existing high-volume printing equipment has been in service for 6 years, with the lease scheduled to end in January 2018.

[3] Gartner Inc. is a leading provider of research and analysis on the global information technology industry.

The 5-year lease for high-volume printing equipment in the production centre was scheduled to end in January 2017, but was extended for 1 additional year. Given the current lease is scheduled to end in January 2018, lifecycle replacement of the printing equipment is now required.

4.0 Justification

The need to replace, upgrade and modernize information technology infrastructure is fundamentally the same as the need to replace, upgrade and modernize the components of the Company's electrical system infrastructure as it deteriorates. Instability within shared server infrastructure and peripheral equipment has the potential to impact large numbers of employees and customers. Investments in shared server infrastructure and peripheral equipment are therefore critical to the Company's overall operations and the provision of least-cost service to customers.

Investments are based on evaluating the alternatives of modernizing or replacing technology components and selecting the least-cost alternative.

Improving the security of the Company's shared server infrastructure will enhance the protection of corporate and customer information, and ensure security of system operations through the SCADA infrastructure.

Completing lifecycle replacement of high-volume printing equipment in the Company's production centre will support timely and effective customer communications, including billing and related materials.

Human Resource Management System Replacement

July 2017

Prepared By:

Sherina Wall
John Pope

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Appendix A: Letter from NorthGateArinso to Newfoundland Power

Appendix B Letter from MediSolution to Newfoundland Power

1.0 Introduction

Newfoundland Power (the "Company") manages a workforce of approximately 686 regular and temporary employees. In addition, the Company has approximately 775 retirees.[1]

The Company's Human Resource Management System ("HRMS") currently includes a combination of software applications and tools to ensure effective human resource management.

A core component of the Company's HRMS is the 15-year-old Empower application. Empower is a third-party human resource application implemented by Newfoundland Power in 2002. Key functions of Empower include benefit management, compensation, personnel records, and time and attendance management. The Company's version of Empower is now functionally obsolete and will no longer be advanced, improved or supported by its vendor.[2]

The Company intends to commence a 2-year replacement project for the Empower application. In 2018, the Company will evaluate integrated HRMS products to select the most cost-effective solution to meet the Company's specific business requirements. Procurement will take place in late 2018 and implementation will follow in 2019.

2.0 Existing HRMS

The Company's HRMS carries out a variety of functions related to the management of employees and retirees. In addition to the Empower application, the Company's existing HRMS delivers this functionality through various in-house developed applications, workflows, spreadsheets, databases and reports.[3]

Table 1 illustrates how the various functionality required by the HRMS is currently provided.

---

[1] The Company anticipates that approximately 130 employees will retire in the next 5 years. This is comparable to the 150 retirements that occurred over the most recent 5-year period, which significantly contributed to the 36% increase in the number of new hires during the same timeframe. Based on the number of anticipated retirements over the next 5 years, the Company expects the number of new hires to be similar to recent experience.

[2] See Appendix A, Letter from NorthGateArinso to Newfoundland Power.

[3] In-house developed applications and workflows include timesheet entry and approval, recruitment, employee records management, performance management, and employee/supervisor self-service. Spreadsheets are currently being utilized for employee pension estimators, voluntary relocation program, clothing allowance and apprenticeship programs. A Microsoft Access database is used to manage the employee grievance and disciplinary processes.

Table 1
Delivery of HRMS Functionality

Functionality	**Empower**	**Dynamics GP**	**Microsoft Excel Spreadsheet**	**In-House Applications**[4]	**Other**[5]
Apprenticeship Program			×		
Benefit Management	×		×	×	
Career Development			×		
Compensation	×	×	×		×
Corporate Allowances		×	×		
Disability Management (ESRTW)			×		
Education Tracking	×			×	
Employee Change Management				×	
Employee Discipline				×	
Employee Self-Service				×	
IT Access Control				×	
Organization Chart					×
Pension Calculator			×		
Performance Management				×	
Personnel Records	×			×	
Recruitment				×	
Reporting	×	×	×		×
Time and Attendance Management	×	×	×	×	
Training and Learning			×		×
Union Grievances				×	
Workforce Planning			×		

As shown in Table 1, the Company uses a wide range of applications and tools to provide the required HRMS functionality. This approach was largely required due to a lack of vendor-supplied updates to the Empower system in recent years.

The Empower application has provided core functionality in the Company's HRMS since 2002, but is now functionally obsolete. The Company was recently informed by the vendor that the application will no longer be advanced, improved or supported. The vendor recommended the Company either migrate to a new product offering or manage the support of Empower locally.

[4] In-house applications are created using Microsoft .Net programming, SharePoint framework and Microsoft Access databases.
[5] Other applications include 3rd party products such as the safety and environment management application, OrgPlus organizational chart management application and reporting applications such as Crystal Reporting, Impromptu Reporting and SRS Reporting.

Due to the high level of customization of the Company's Empower implementation, there are no third-party vendors available to provide support or enhancements.[6] It is therefore necessary to purchase a replacement application.

3.0 Project Description

Starting in 2018, the Company will commence a 2-year project to replace the Empower application with another commercially available application.

In 2016, the Company initiated a Request for Information process to 7 HRMS vendors to determine the functionality available in current applications, as well as cost estimates. Responses were received from 4 HRMS vendors.

Cost estimates based on vendor responses, as well as the anticipated level of internal effort required to execute the project, are shown in Table 2.

Table 2
2018-2019 Project Cost
($000s)

Cost Category	2018 Cost	2019 Cost
Material	17	360
Labour – Internal	305	400
Labour – Contract	-	-
Engineering	-	-
Other	100	455
Total	**422**	**1,215**

Vendor responses showed that HRMS applications commercially available today have advanced significantly since Empower was implemented in 2002. The functionality of current generation HRMS applications includes: (i) personnel records; (ii) compensation; (iii) benefits management; (iv) workforce planning; (v) recruitment; (vi) career development; (vii) performance management; (viii) attendance management; and (ix) training and learning. The Company currently uses a number of applications and tools to provide this functionality. Today's commercially available applications also have increased self-service functions, allowing employees and retirees to directly access their personal information and complete transactions.[7]

Implementation of a new HRMS is required to address the functional obsolescence of the Empower application. Additionally, implementation of a new application with increased

---

6 See Appendix B, *Letter from MediSolution to Newfoundland Power*.

7 Self-service options include: (i) viewing and approving transactions, such as timesheets, onboarding checklists, and job applications; (ii) viewing and modifying personal information, such as paystubs, subordinate reports, and personal profile changes; and (iii) accessing Company information online or remotely from a mobile device.

functionality will allow the Company to modernize its overall HRMS by streamlining the system and reducing the number of applications and tools currently required to deliver the necessary functionality. This will reduce the complexity of completing updates to the HRMS.[8] It will also reduce the amount of manual data entry required across the system.[9]

4.0 Operating Experience

The Company relies on its HRMS to effectively support its employees and retirees. Replacing the obsolete Empower application will improve the efficient and effective delivery of various functions related to human resource management.

Implementing a comprehensive, commercially available HRMS application will address the following issues within the current system:

(i) A lack of vendor support, which is needed to ensure the effective operation and maintenance of the application;
(ii) A large number of supplementary applications and tools are used to provide the required functionality, making it difficult to complete necessary upgrades; and
(iii) A lack of automation within the system, which creates inefficiencies associated with the amount of manual data entry and quality assurance required.

5.0 Justification

The Company's version of the Empower application is functionally obsolete and is no longer being advanced, improved or supported by the vendor. Replacement of the application with a commercially available alternative is required in order to continue providing effective and efficient human resource management for the Company's 1,461 employees and retirees.

In selecting a replacement HRMS application, the Company will evaluate commercially available products to determine the most cost-effective solution to deliver the required functionality.

8 The applications and tools that deliver the Company's HRMS functionality must share data and communicate with each other. As such, upgrades to one product often necessitate minor upgrades to the other applications and tools. This increases the complexity of each upgrade required to respond to emerging business needs. A reduction in the number of tools and applications will improve the Company's ability to update the system.

9 A significant amount of manual data entry is currently required across the various applications and tools that comprise the HRMS. This increases the possibility for errors, thereby requiring a significant effort to ensure data quality. A modern HRMS with a fully integrated database will reduce the possibility of errors and the effort required for quality assurance, which will create efficiencies.

Appendix A
Letter from NorthGateArinso to Newfoundland Power

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Mr R Blackmore
Manager, Information Services
New Found Land Power
55 Kenmount Road
St. John's
NL
A1B 3P6

18th April 2016

Dear Robert,

The Empower System

I can confirm that Empower is within our Heritage offering at NGA and ResourceLink is now is our UK flagship offering, I can also confirm that there will be no more development in the Empower product from NGA in the UK.

Our client base have a couple of options, one is migrate to ResourceLink but some still have the option to remain on Empower and manage their support of the application locally.

Trust this is in order.

Yours Sincerely

Mark Debono
New Business Sales Manager

Appendix B
Letter from MediSolution to Newfoundland Power

MediSolution

5915 Airport Road, Suite 810
Mississauga, Ontario L4V 1T1

May 18, 2017

Mr. Robert Blackmore
Manager Information Services
Newfoundland Power
55 Kenmount Road
St. John's, Newfoundland A1B 3P6

Dear Robert,

Re: Empower HR Solution

MediSolution understands Newfoundland Power's (NP's) current situation with regards to the use of the Empower (HRWare 2.04, PowerTool 5.9.2) HR software integrated with Microsoft Dynamics GP Payroll product and future need to upgrade the technology platform adopting new features available today in the market.

While MediSolution continues to support its Healthcare customers and evolve the Empower product, we recognize that the NP version of the Empower module and interface to GP Payroll has been customized to meet specific NP requirements. This being said, MediSolution is unable to ensure that new software changes required to meet NP's future business processes will not impact the integration between Empower HR and the Microsoft Dynamics Payroll solution. It is our understanding that HRWare developed the interface specifically for NP and MediSolution does not have access to the source code and logic of this interface to effectively support changes.

MediSolution thanks NP for your continued business and look forward to continuing to support NP with your initiatives.

Yours sincerely,

L Cardinal

Lynne Cardinal
Director of Operations

cc/ John Pope
Sherry Mayer
Doug Smith

Outage Management System Replacement & Enhancement

July 2017

Prepared By:

Jack Casey, P. Eng.
Chris Wells

REGISTERED PROFESSIONAL ENGINEER
J. W. CASEY
SIGNATURE
PROVINCE OF NEWFOUNDLAND

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Appendix A Outage Management System Replacement & Enhancement Plan, July 2017

1.0 Introduction

For 2018, Newfoundland Power (the "Company") is seeking approval of a multi-year project to replace its existing Outage Management System ("OMS"). The existing OMS was deployed in 2003 and is now functionally obsolete.[1] Following a review of commercial OMS products and current Canadian utility practice, the Company has determined the most appropriate approach to modernizing its OMS is to replace the existing system with a commercially available product that offers enhanced functionality.

Newfoundland Power plans to include 3 enhancements with its new OMS. Each of these enhancements will improve the Company's ability to respond to customer outages. The 3 enhancements are: (i) automated outage assessment, which will improve the Company's ability to analyze the cause and location of outages; (ii) integrated dispatch and follow up, which will expedite outage response; and (iii) coordinated customer communications, which will ensure customers receive more timely and accurate information concerning outages.

2.0 Background

The OMS is a cornerstone of reliability management at Newfoundland Power. The OMS plays central roles in outage assessment, outage response, and customer communications. While the importance of the OMS increases substantially in major electrical system events, it is essential to least-cost, reliable service delivery on a daily basis. Once implemented, the *Outage Management System Replacement & Enhancement Plan, July 2017* (the "*OMS Plan*") will improve Newfoundland Power's reliability performance in responding to both major electrical system events and more routine outages.[2]

Newfoundland Power's outage management practices were extensively reviewed during the Newfoundland and Labrador Board of Commissioners of Public Utilities' (the "Board") *Investigation and Hearing into Supply Issues and Power Outages on the Island Interconnected System*. Part of that review included an assessment of Newfoundland Power's plan to replace and enhance its existing OMS with a commercial alternative within 5 years. In 2014, the Board's consultant for this review concluded that, while the existing OMS had served adequately, the Company's move to a commercially provided replacement in 5 years was appropriate.

2.1 2016 Project

In 2014, Newfoundland envisaged that OMS replacement and enhancement would occur in stages over 5 years. Replacement of the existing OMS would be undertaken first, followed by appropriate enhancements.

---

[1] Newfoundland Power's existing OMS was developed internally and cannot integrate with the Company's Supervisory Control and Data Acquisition ("SCADA") system or Geographic Information System ("GIS"). This practically requires Company employees to assess and respond to outages without the benefit of real-time information. The existing OMS is therefore considered functionally obsolete.

[2] Appendix A provides the *Outage Management System Replacement & Enhancement Plan, July 2017*.

In Order No. P.U. 28 (2015), the Board approved the Company's proposal to replace its existing OMS with a commercially available product by 2017 at an estimated cost of $949,000.[3] This replacement project only included integrating the new OMS with Newfoundland Power's SCADA system and GIS. It did not include enhanced functionality, such as the ability to automatically predict outage cause and location. Such functionality was indicated to be *potential future* enhancements.

During the 2nd half of 2016, the Company was required to reassess its information technology priorities, primarily in light of the programming requirements associated with Newfoundland and Labrador Hydro's Rate Stabilization Plan Surplus Refund. This reassessment delayed meaningful progress on planning for the OMS replacement project until December 2016.

At the end of the 1st quarter of 2017, the Company issued a Request for Proposals relating to OMS replacement and enhancement options. The inclusion of enhancement options reflected a combination of: (i) an assessment of the existing commercial OMS marketplace; and (ii) delays in progress on the OMS replacement project approved in Order No. P.U. 28 (2015). The responses to the Request for Proposals indicate that combining OMS replacement and enhancement now best meets Newfoundland Power's outage management requirements. Such an approach is also consistent with the 5-year OMS replacement and enhancement timeline envisaged in 2014.

2.2 2018 Project

The *OMS Plan* provides for both the replacement and enhancement of Newfoundland Power's existing OMS. The existing OMS is functionally obsolete. The planned replacement and enhancement of Company's existing OMS with a commercial alternative is consistent with current Canadian utility practice.

The replacement aspect of the project includes integration of the OMS with the Company's recently implemented SCADA system and GIS. This will make real-time electrical system information available to Company employees when responding to customer outages. System operators, dispatchers, customer service representatives and field staff will have more accurate information on the cause of outages and which customers are without electricity. This will enable the Company to respond to customer outages more quickly and improve the quality of information provided to customers.

The project also includes 3 additional enhancements to the Company's outage response capabilities. These are: (i) automated outage assessment; (ii) integrated dispatch and follow up; and (iii) coordinated customer communications.

[3] See the 2017 Capital Expenditures Status Report, Appendix A, page 7 of 7.

3.0 Project Description

3.1 Project Scope

In 2019, the Company will deploy a replacement OMS with enhanced functionality. This enhanced functionality will improve the Company's outage management capabilities and directly benefit the Company's customers.

The 3 enhancements to be included in the new OMS are as follows:

(i) Automated outage assessment will replace the manual assessment process currently used by the Company when identifying the likely cause and location of outages. The OMS will automatically group related outage reports received from customers and outages detected through the SCADA system. The automated outage assessment process will be more accurate and faster than the current manual process. Overall, this will expedite the Company's response to customer outages.

(ii) Integrated dispatch and follow up will create efficiencies in deploying crews to restore service to customers. The new OMS will integrate directly with 4 operational technologies used to schedule crews, monitor restoration activities, and complete any required follow-up work.[4] This will allow information to flow instantaneously between the systems. Overall, this will ensure all required work to restore and maintain service to customers is appropriately planned and completed.

(iii) Coordinated customer communications will ensure the Company's customers receive timely and accurate information concerning outages. The new OMS will directly integrate with the Company's website, customer app, call centre technology, and outage alert service.[5] This will ensure updates to these channels occur quickly by bypassing the manual process currently required. The new OMS will also include an internal communications dashboard that displays information such as the number of customer experiencing outages, the status of restoration work, and estimated restoration times. This will provide Company employees with up-to-date and accurate information when responding to customer inquiries.

Each of these enhancements is described in detail in the *OMS Plan* included as Appendix A.

---

[4] The Company uses 2 technologies to dispatch field staff to respond to outages: (i) the Workforce Management System is used to schedule staff and provide field updates on restoration work; and (ii) the Automatic Vehicle Location ("AVL") system is used to identify the nearest available crew for dispatching. Two other technologies are used to record and plan follow-up work that may be required after an outage: (i) the Work Order Management System is primarily used to record and manage customer work requests; and (ii) the Asset Management System is used to facilitate the Company's overall inspection, maintenance, and replacement programs for its electrical system equipment.

[5] The Company's customers can sign up to receive outage alerts via SMS text or email.

3.2 Project Cost

Newfoundland Power is seeking approval of $2,360,000 in 2018 and $1,210,000 in 2019 to implement its *OMS Plan*.

Table 1 summarizes the forecast capital expenditures for this multi-year project.

Table 1
2018-2019 Project Cost
($000s)

Cost Category	**2018**	**2019**	**Total**
Material	$1,665	$505	$2,170
Labour – Internal	640	650	1,290
Labour – Contract	-	-	-
Engineering	-	-	-
Other	55	55	110
Total	**$2,360**	**$1,210**	**$3,570**

3.3 Project Schedule

Table 2 provides the schedule for implementing the *OMS Plan*.

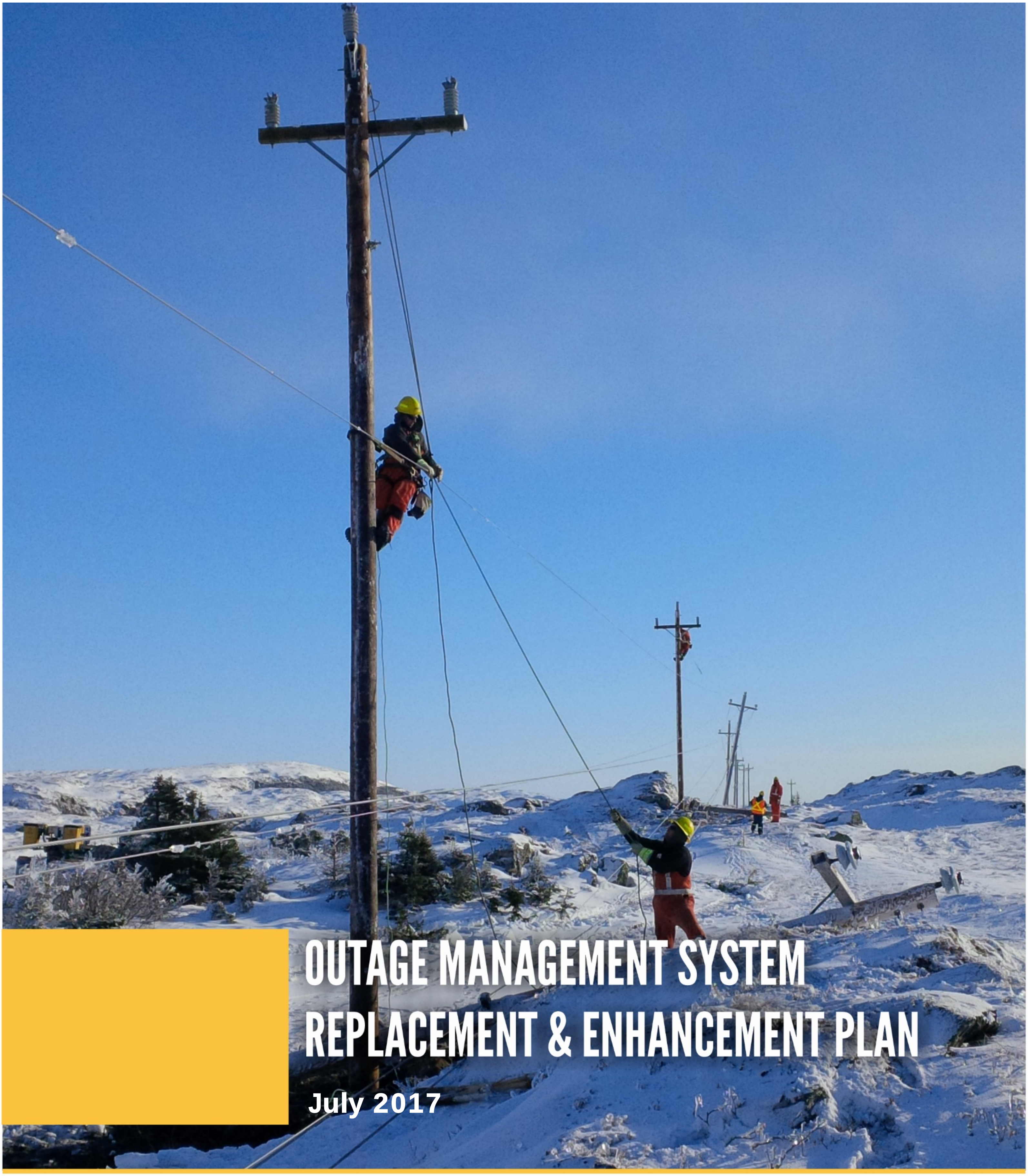
Table 2
Project Schedule

Milestone	**Completion Date**
Proposal evaluation	November 2017
Contract awarded	February 2018
Project design	June 2018
System development	November 2018
System testing	March 2019
Employee training	May 2019
System implementation	June 2019

4.0 Concluding

Because outages are inevitable on electrical systems, effective outage management processes are broadly accepted to be a critical component of overall utility management. Implementation of Newfoundland Power's *OMS Plan* will address the functional obsolescence of its existing system and improve the Company's ability to respond to outages. As a result of the enhancements outlined in the plan, crews will be dispatched more quickly and customers will experience outages of reduced duration. The accuracy and timeliness of customer communications during outages will be improved. Additionally, the reduction or elimination of manual processes will ensure the Company can continue to manage outages in a cost-effective way.

Appendix A
Outage Management System Replacement & Enhancement Plan



OUTAGE MANAGEMENT SYSTEM REPLACEMENT & ENHANCEMENT PLAN

July 2017

WHENEVER. WHEREVER.
We'll be there.

NEWFOUNDLAND POWER
A FORTIS COMPANY

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1. EXECUTIVE SUMMARY

The Outage Management System ("OMS") is a cornerstone of reliability management at Newfoundland Power (the "Company"). The OMS plays central roles in outage assessment, outage response, and customer communications. While the importance of the OMS increases substantially in major electrical system events, it is essential to least-cost, reliable service delivery in all conditions. This includes normal day-to-day operations. Once implemented, the *Outage Management System Replacement & Enhancement Plan, July 2017* will improve Newfoundland Power's reliability performance in responding to both major electrical system events and more routine outages.

The Company modernizes its operational technologies on an ongoing basis. The existing OMS was deployed in 2003 and is now functionally obsolete. Newfoundland Power has been planning its replacement for a number of years. Following a review of commercial OMS products and current Canadian utility practice, the Company has determined the most appropriate approach to modernizing its OMS is to replace the existing system with a commercially available product that offers enhanced functionality. This *Outage Management System Replacement & Enhancement Plan, July 2017* describes the existing OMS, Newfoundland Power's assessment of OMS options and benefits, and the plan to replace and enhance the existing OMS by 2019.

Newfoundland Power's outage management practices were extensively reviewed during the Newfoundland and Labrador Board of Commissioners of Public Utilities' (the "Board") *Investigation and Hearing into Supply Issues and Power Outages on the Island Interconnected System*. Part of that review included an assessment of Newfoundland Power's plan to replace its existing OMS with a commercial alternative within 5 years. In 2014, the Board's consultant for this review concluded that, while the existing OMS had served adequately, the Company's move to a commercially provided replacement in 5 years was appropriate. Completion of the *Outage Management System Replacement & Enhancement Plan, July 2017* will achieve this objective.

Newfoundland Power plans to address the functional obsolescence of its existing OMS by replacing it with a commercially available product that provides 3 enhancements. These enhancements are: (i) automated outage assessment, which will improve the Company's ability to analyze the cause and location of outages; (ii) integrated dispatch and follow up, which will expedite outage response; and (iii) coordinated customer communications, which will ensure customers receive more timely and accurate information concerning outages.

The estimated cost to implement the *Outage Management System Replacement & Enhancement Plan, July 2017* is $3,570,000. Deployment of the new OMS is planned for June 2019.

2. OUTAGE MANAGEMENT AT NEWFOUNDLAND POWER

a. Outage Management Process

The electrical system serving Newfoundland Power's customers typically experiences approximately 6,500 outages per year. These include planned outages to complete electrical system maintenance and capital projects, as well as unplanned outages caused by equipment failure or severe weather. Virtually all outages result in a customer or customers seeking information from Newfoundland Power. This may range from a few telephone calls on a planned outage to perform system maintenance, to over a million customer contacts during a series of electrical system events, such as those that occurred in January 2014.

Because outages are inevitable on electrical systems, effective outage management processes are broadly accepted to be a critical component of overall utility management.

For unplanned outages, Newfoundland Power's outage management process typically starts with an outage report from a customer or customers. Currently, the assessment of the likely cause and location of the outage is a manual process. This assessment informs the Company's initial response.

Field staff are typically dispatched to first verify the cause and location of the outage and then commence restoring service to customers. Required follow-up work, such as the need to replace a temporary repair with a permanent solution, is logged to be completed at a future time. Scheduling of follow-up work is a manual process.

Communications with customers are typical throughout an outage. These communications largely focus on the cause of the outage and the estimated time of service restoration. The Company currently provides multiple channels for customers to receive outage-related information. These include telephone, website, customer app, SMS text, and email. Updating outage-related information is a manual process.

b. Existing OMS

The Company's existing OMS is at the centre of its outage management process. It is used to create and track outage reports received from customers.

The existing OMS was developed internally and deployed in 2003. It cannot be functionally upgraded. This functional limitation restricts the ability of Newfoundland Power to improve its outage response capabilities.

For example, current commercial OMS products typically can be substantially or fully integrated with real-time control systems, such as the Company's Supervisory Control and Data Acquisition ("SCADA") system. Increased availability of such real-time information concerning the status of the electrical system improves a utility's response to outages. Newfoundland Power's existing OMS cannot be integrated with its SCADA system. This practically requires Company employees to manually assess the cause and location of outages without the benefit of real-time information.

To address the functional obsolescence of its existing OMS, Newfoundland Power intends to replace it with a commercial OMS product capable of integrating with its existing operational technologies, including its SCADA system and Geographic Information System ("GIS").[1] This increased integration will, in turn, provide enhanced functionality in the new OMS. The enhanced functionality includes the automatic assessment of outage cause and location and the automatic coordination of customer communications.

3. ASSESSING OMS OPTIONS

a. Commercial OMS Products

Commercial OMS products are mature technologies that are widely used in the utility industry. The functionality provided by commercial OMS products has evolved over the years as vendors continued to invest in and improve their products. These products have evolved beyond basic reporting systems; they have become "functionally rich and capable of addressing the majority of 'traditional' OMS needs out of the box."[2]

The enhanced functionality provided by commercial OMS products is largely dependent on integration with other systems used to operate and maintain the electrical system, such as a SCADA system and GIS. Integration establishes a connection between the different systems allowing information to be shared instantaneously. For example, by integrating an OMS with a dispatching system, outage reports can flow automatically from the OMS to dispatchers to ensure field staff are quickly deployed to restore service to customers. Such enhanced functionality increases the quality of information available when responding to customer outages and improves response times by reducing or eliminating manual processes. Industry experience indicates that implementing an OMS with enhanced functionality can achieve reductions in outage duration.[3]

As part of the *Investigation and Hearing into Supply Issues and Power Outages on the Island Interconnected System* in 2014, the Liberty Consulting Group ("Liberty") examined the Company's outage management performance. Liberty found "Newfoundland Power's approach,

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[1] The Company's GIS stores location-related information on electrical system assets and customers. The GIS and SCADA system are integrated to ensure system operators have real-time information on the status of electrical system assets, and the location of customers relative to those assets. This information is critical to understanding the impact of outages on customers and organizing the Company's response.

[2] See Gartner Inc.'s *MarketScope for Outage Management,* May 24, 2013, page 8.

[3] See the Institute of Electrical and Electronics Engineers' *Effect of Outage Management System Implementation on Reliability Indices,* 2006, page 1.

organization, staffing and practices… are effective."[4] They also noted the Company "is appropriately moving to a commercially provided replacement."[5] Liberty stated this approach, in addition to replacement of the Company's SCADA system, "should improve the effectiveness of its system operations."[6]

b. OMS Enhancements

Newfoundland Power has assessed the enhanced functionality available from commercial OMS products to determine how its new OMS could improve the effectiveness of its operations. The Company has identified 3 enhancements that will be included in the initial implementation of its new OMS.

Table 1 provides a brief description of these enhancements.

Table 1:
OMS Enhancements

Functionality	Description	System Integration
Automated Outage Assessment	Uses information on the location and status of electrical system assets to automatically group customer outage reports and determine the likely cause and location of an outage.	• GIS • SCADA system
Integrated Dispatch and Follow Up	Provides a consolidated view for systems used to plan, schedule and monitor restoration activities, including follow-up work.	• Workforce Management System • Automatic Vehicle Location System • Asset Management System • Work Order Management System
Coordinated Customer Communications	Automatically provides outage-related information to customer communication channels. Consolidates and displays outage-related information on an internal communications dashboard for employees.	• Website • Call centre technology • SMS text message and email alerts • Customer Service System

4 See the Board's *Phase One Report on the Investigation and Hearing Into Supply Issues and Power Outages on the Island Interconnected System,* September 29, 2016, page 34.

5 See Liberty Consulting Group's *Report on Island Interconnected System to Interconnection with Muskrat Falls addressing Newfoundland Power Inc.*, December 17, 2014, page 73.

6 See Liberty Consulting Group's *Report on Island Interconnected System to Interconnection with Muskrat Falls addressing Newfoundland Power Inc.*, December 17, 2014, page 62.

Implementing a new OMS with these enhancements at this time will enable Newfoundland Power to take fuller advantage of operational technologies implemented over the past few years. These include: (i) the Workforce Management System implemented in 2011; (ii) the GIS implemented in 2013; and (iii) the SCADA system implemented in 2016. This sequencing in the Company's overall modernization of its operational technologies has been planned and purposeful.

Other enhanced functionality will be considered in the future, as appropriate. These include enhancements that automatically estimate customer restoration times and predict system maintenance requirements. Both of these enhancements require an inventory of past practice as a basis for estimation or prediction, which does not currently exist. Such an inventory is expected to be established over time as data collection will commence when the new OMS is deployed in 2019. Once sufficient data is available to allow a reasonable assessment of the costs and benefits, consideration of these enhancements can be undertaken.

c. Current Canadian Utility Practice

Newfoundland Power consulted with Canadian utilities from January to March 2017 to understand their approach to OMS implementation. The Company conducted a survey from April to May 2017 through the Canadian Electricity Association to validate its findings.

In total, 8 Canadian utilities responded to the survey. The results showed:

(i) Commercial OMS products are the industry standard. All 8 utilities have completed new installations or upgrades within the last 5 years.

(ii) Implementation timeframes vary. Timeframes for new installations ranged from between "6 to 9 months" and 26 months, likely reflecting variations in project scope and complexity.

(iii) Enhanced functionality was pursued by all 8 utilities. All 8 utilities implemented automated outage assessment by integrating their OMS with their GIS. They all implemented some level of integrated dispatch and follow up, as well as coordinated customer communications.

Newfoundland Power has determined its approach of implementing a commercial OMS product with enhanced functionality is consistent with current Canadian utility practice. Appendix A provides the detailed results of the survey.

4. PROJECT SCOPE

a. Overview

Project History

In 2014, Newfoundland Power planned to replace and enhance its existing OMS within 5 years.[7] Initially, it was envisaged that replacement and enhancement would occur in stages. Replacement would be undertaken first, followed by appropriate enhancements.

In Order No. P.U. 28 (2015), the Board approved the Company's proposal to replace its existing OMS with a commercially available product by 2017 at an estimated cost of $949,000. This project only envisaged integrating the new OMS with Newfoundland Power's SCADA system and GIS. It did not include functions such as the automatic assessment of outage cause and location, integration with dispatch and follow up technologies, or coordination of customer outage communications. These were indicated to be *potential future* enhancements.[8]

During the 2nd half of 2016, Newfoundland Power was required to reassess its information technology priorities, primarily in light of the programming requirements associated with Newfoundland and Labrador Hydro's Rate Stabilization Plan Surplus Refund.[9] This reassessment delayed meaningful progress on planning for the OMS replacement project until December 2016.

At the end of the 1st quarter of 2017, the Company issued a Request for Proposals relating to OMS replacement and enhancement options. The inclusion of enhancement options reflected a combination of: (i) an assessment of the existing commercial OMS marketplace; and (ii) delays in progress on the OMS replacement project approved in Order No. P.U. 28 (2015). The responses to the Request for Proposals indicate that combining OMS replacement and enhancement now best meets Newfoundland Power's outage management requirements. Such an approach is also consistent with the 5-year OMS replacement and enhancement timeline envisaged in 2014.

These considerations have informed the creation of the *Outage Management System Replacement & Enhancement Plan, July 2017*.

Project Description

The *Outage Management System Replacement & Enhancement Plan, July 2017* provides for both the replacement and enhancement of Newfoundland Power's existing OMS. The existing OMS is

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7 This plan was discussed in depth with the Board's consultants during the Board's *Investigation of Supply Issues and Power Outages on the Island Interconnected System.* See *Report on Island Interconnected System to Interconnection with Muskrat Falls addressing Newfoundland Power Inc.* December 17, 2014, page 69-73.

8 See the 2016 Capital Budget Application report ***6.4*** *Outage Management System Replacement*.

9 Newfoundland Power filed its application for approval of a refund plan on June 30, 2016; the Board approved the plan in Order No. P.U. 35 (2016) on September 2, 2016.

functionally obsolete and incapable of integration with the Company's SCADA system and GIS. This limits the ability of the Company to respond effectively to customer outages. The planned enhancement of Newfoundland Power's existing OMS capabilities are consistent with current Canadian practice in electric utility outage management.

The replacement aspect of the project includes the integration of the OMS with the Company's recently implemented SCADA system and GIS. This will make real-time electrical system information from the SCADA system and locational detail from the GIS available when responding to customer outages. The project also includes 3 additional enhancements to the Company's outage response capabilities. These are: (i) automated outage assessment; (ii) integrated dispatch and follow up; and (iii) coordinated customer communications. Each of these enhancements is described further in this section of the *Outage Management System Replacement & Enhancement Plan, July 2017.*

Appendix C provides conceptual diagrams that show how the Company's approach to system integration will differ once the new OMS is implemented.

Appendix D provides technical considerations for implementation.

b. Automated Outage Assessment

Existing

Once an outage report is received from a customer, Company employees must assess the likely cause and location of the outage before restoration work can begin. This is currently a manual process. Staff monitor outage reports as they are created in the OMS and manually group related outages. By manually grouping related outages, the Company can sometimes identify the likely cause of the outage. When the outage is isolated and the cause is relatively simple, such as a failed transformer or switch, the time to complete the manual process is relatively brief. During major electrical system events, manual assessment can become increasingly complex and involve hundreds or thousands of customer outage reports. In these situations, the impact of the manual process on response time can be more substantial.

Future

The Company's new OMS will have a predictive engine that will automatically group related outage reports to identify the electrical system asset likely causing the outage and the number of customers affected. This functionality requires the OMS to have up-to-date and accurate information on the location of electrical system assets and the customers connected to those assets. The new OMS will receive this information through integration with the Company's GIS.

The Company's OMS will also integrate with its SCADA system. The SCADA system contains real-time information on whether electrical system assets are experiencing outages. Outages detected through the SCADA system will instantaneously flow to the new OMS. Outage reports received from customers that are associated with a SCADA-detected outage will be automatically grouped in the OMS. The OMS will identify which customer outages are related, allowing the Company to organize its response accordingly.

The automated assessment process will be faster and more accurate than the manual assessment process currently used by the Company. This will allow field staff to be dispatched more quickly and with more accurate information on the cause and location of outages. Field assessments will become more efficient as a result.[10] For example, if an outage is experienced on a distribution feeder spanning several kilometers, field staff will have a map indicating the location of the electrical system asset that must be assessed, such as a failed transformer or switch. Overall, automated outage assessment will reduce the amount of time between when an outage is reported and when service is restored to customers.

c. Integrated Dispatch and Follow Up

Existing

Human and physical resources are available throughout the Company's service territory to respond to outages during and after normal business hours. The dispatch and follow up associated with customer outage response is primarily managed with the assistance of 4 operational technologies.

The Company uses 2 technologies to dispatch field staff to respond to outages: (i) the Workforce Management System is used to schedule staff and provide field updates on restoration work; and (ii) the Automatic Vehicle Location ("AVL") system is used to identify the nearest available crew for dispatching. Two other technologies are used to record and plan follow-up work that may be required after an outage: (i) the Work Order Management System is primarily used to record and manage customer work requests; and (ii) the Asset Management System is used to facilitate the Company's overall inspection, maintenance, and replacement programs for its electrical system equipment.[11]

Newfoundland Power's existing OMS has a limited degree of integration with these 4 technologies. Only the Workforce Management System and Asset Management System

[10] In the Company's approximately 70,000 km^2 service territory, long drives to restore service following an outage are not uncommon. When line crews and technical staff are required to spend more time in the field locating the source of an outage, the cost of response increases accordingly. The improved efficiency of field assessments will be reflected in Newfoundland Power's day-to-day cost of responding to customer outages. The approximate overtime cost of a 2-person line crew is $220/hr; the approximate overtime cost of a technologist is $100/hr. So, for example, reducing the response time required to locate an outage at night using a line crew and a technologist by just 2 hours would yield savings of approximately $640 (($220 + $100) x 2 = $640) for a single routine outage call.

[11] The Company's Workforce Management System is comprised of two pieces of software: (i) ClickSchedule is used to dispatch crews; and (ii) ClickMobile is used to provide field updates for ongoing work. The Company's Work Order Management System is referred to as the "Technical Work Request System" and the Asset Management System is referred to as "Avantis."

currently integrate with the Company's existing OMS. This achieves efficiencies in dispatching and completing Company-identified follow-up work. However, the existing integration does not permit the OMS to assist in identifying the nearest available crew for response or in managing follow-up work from customer requests.

Future

The new OMS will fully integrate the Company's existing dispatch and vehicle location technologies. Dispatchers will have a single map in the OMS that shows the location of crews and outages. This will allow the speedier assignment of work to the nearest available crew. Overall, fully integrated dispatch processes will enable the Company to respond more efficiently to customer outages. It will also enable Newfoundland Power to more fully capture the efficiencies available through the automated outage assessment.

The new OMS will also fully integrate the Company's existing work and asset management technologies. This will result in more complete automation of all follow-up work related to customer outages by ensuring all customer work requests are appropriately recorded and, ultimately, completed.

d. Coordinated Customer Communications

Existing

The Company currently provides multiple channels to ensure its customers can obtain outage-related information. Customers can: (i) call the Company to obtain information via the automated High Volume Call Answering system or by speaking with a customer service representative; (ii) visit the Company's website or use the customer app; and (iii) sign up to receive outage alerts via email or SMS text message.[12] These communication channels are manually updated with outage-related information as circumstances require.[13]

In 2013, the Company created the Communications Hub, which is a team of employees assembled to improve customer communication during major electrical system events. The Communications Hub manually assembles outage-related information for communication to customers and other interested parties (e.g. municipalities). This information includes OMS outage reports, real-time SCADA data, GIS data, and available dispatch and field crew data. This information is then disseminated to customers via a number of communication channels.

12 After hours, calls are answered by system operators at the System Control Centre.

13 The updating is done via the Company's internally developed Informer application. Once information is manually entered into the application, the application then updates all communication channels to ensure consistency.

Future

The new OMS will include 2 key features to automatically coordinate customer communications: (i) an internal communications dashboard; and (ii) direct integration with the Company's communication channels.

The internal communications dashboard will automatically consolidate all outage-related information.[14] The dashboard will display information on the number of customers affected, the status of restoration work, and estimated restoration times. System operators, dispatchers, customer service representatives and other staff will have access to the dashboard during and after regular business hours. This will provide Company employees with a consolidated view of outage-related information when responding to customer inquiries. During major electrical system events, the Communications Hub will spend less time manually assembling outage-related information and more time ensuring customers and other interested parties are well informed.

The new OMS will also integrate directly with the Company's website, customer app, and outage alert service.[15] Updates to these communications channels will occur automatically, eliminating the manual processes currently required. The Company's customers will receive more accurate and timely information as a result.[16]

5. PROJECT BENEFITS

The operational improvements resulting from implementing a new OMS with automated outage assessment, integrated dispatch and follow up, and coordinated customer communications will directly benefit the Company's customers.

Reduced Outage Duration

Through the automated assessment process and integrated dispatch and follow up, the Company's response time to outages will be improved. Field staff will be dispatched more quickly and be equipped with more accurate information on the likely cause and location of outages. As a result, restoration work will be completed sooner and customers will experience outages of reduced duration.

Improved Customer Communication

The internal communications dashboard will automatically consolidate and display outage-related information, providing a key tool for employees when responding to customer inquiries, the media, and other interested parties. Direct integration with the Company's communication

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[14] Figure B-2 of Appendix B provides a sample screenshot of an internal communications dashboard.

[15] The High Volume Call Answering service is a legacy system hosted on the Bell network. Due to the system's technical complexities, the Informer application will initially be used to continue updating this service.

[16] The Company's website currently includes a map that provides information on the number of outages being experienced in the Company's operating areas. Figure B-3 of Appendix B provides a sample screenshot of a more detailed customer map that can be implemented as part of a commercial OMS product.

channels will ensure outage-related information flows quickly from the OMS to customers. Overall, customers will experience improvements in both the accuracy and timeliness of information during outages.

Cost Efficiencies

The new OMS will reduce or eliminate several manual processes. These include the manual effort currently required to assess outages and gather outage-related information. A reduction in manual processes and an improvement in the quality of information available to staff will allow the Company to optimize its use of resources during outages. The resulting efficiencies will ensure the Company continues to manage outages in a cost-effective way.

6. PROJECT COSTS & SCHEDULE

a. Project Costs

The total estimated cost of implementing a new OMS with the enhancements described in this report is $3,570,000. This estimate is based on cost estimates provided by vendors through a Request for Proposals process initiated in March 2017. Material costs include licensing fees and vendor project implementation services. Labour includes project management, system design, testing and user training.

Table 2:
2018-2019 Project Cost
($000s)

Cost Category	2018 Budget	2019 Budget	Total Budget
Material	$1,665	$505	$2,170
Labour	640	650	1,290
Other	55	55	110
Total	**$2,360**	**$1,210**	**$3,570**

Through the Request for Proposals process, the Company will select the least-cost option that effectively meets its requirements.

b. Project Schedule

In March 2017, Newfoundland Power requested and subsequently received proposals from 4 OMS vendors based on the project scope outlined in this report. A detailed proposal evaluation process will be completed to ensure the selected vendor can successfully meet the Company's requirements. Pending Board approval, implementation of the new OMS is scheduled for June 2019.[17]

Table 3:
Project Schedule

Milestone	Completion Date
Proposal evaluation	November 2017
Contract awarded	February 2018
Project design	June 2018
System development	November 2018
System testing	March 2019
Employee training	May 2019
System implementation	June 2019

[17] The Company will avoid implementing its new OMS during peak outage season.

Appendix A: Survey of Canadian Utility Practice

Table A-1 outlines the results of Newfoundland Power's survey of Canadian utilities' OMS implementations. The survey was conducted from April to May 2017 through the Canadian Electricity Association.

Table A-1:
Survey of Canadian Utilities' Outage Management Systems

Question	Utility 1	Utility 2	Utility 3	Utility 4	Utility 5	Utility 6	Utility 7	Utility 8
Q1. Do you use a commercial OMS or internally developed OMS?	Commercial	Commercial	Commercial	Commercial	Commercial	Commercial	Commercial	Commercial
Q2. When was your OMS last replaced or upgraded?	Installed in 2016	Replaced within last 5 years	Upgraded in 2012	Installed in 2014	Plans to upgrade within next 2 years	Currently upgrading	Replaced within last 5 years	Installed in 2012
Q3. What was the project implementation timeframe?	9 to 12 months	26 months	Less than 6 months (upgrade)	6 to 9 months	18 to 24 months	18 months	9 to 12 months	12 to 18 months
Q4. What integrations were completed as part of the implementation?								
SCADA System	--	--	Yes	--	Yes	Yes	Yes	Yes
Geographic Information System	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Workforce Management System	--	--	Yes	--	Yes	Yes	Yes	Yes
Work Order Management System	Yes	Yes	--	--	--	Yes	Yes	Yes
Asset Management System	--	--	--	--	--	Yes	Yes	--
Customer Information System	Yes	Yes	Yes	--	Yes	Yes	--	Yes
Customer Website	Yes	Yes	Yes	Yes	Yes	--	Yes	--
Interactive Voice Response	--	Yes	Yes	Yes	--	--	Yes	Yes
Internal Dashboard/Intranet	Yes	Yes	Yes	--	Yes	Yes	--	Yes

Appendix B: Sample Screenshots of Commercial OMS Products

The following are sample screenshots of commercial OMS products that broadly resemble some of the features that will be included in Newfoundland Power's new OMS.

Figure B-1: Example of Interface for Call Taking

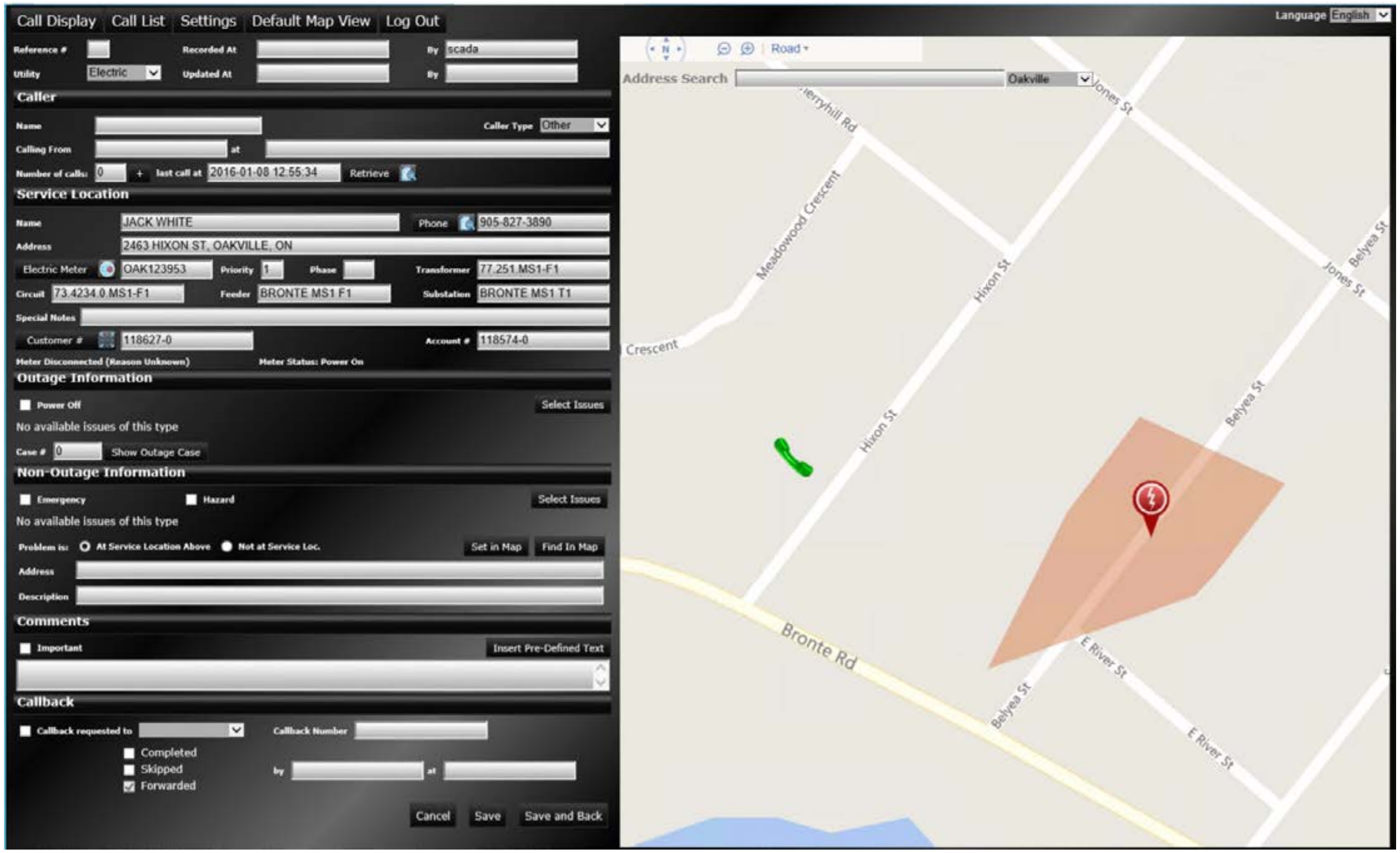


Figure B-2: Example of Internal Communications Dashboard

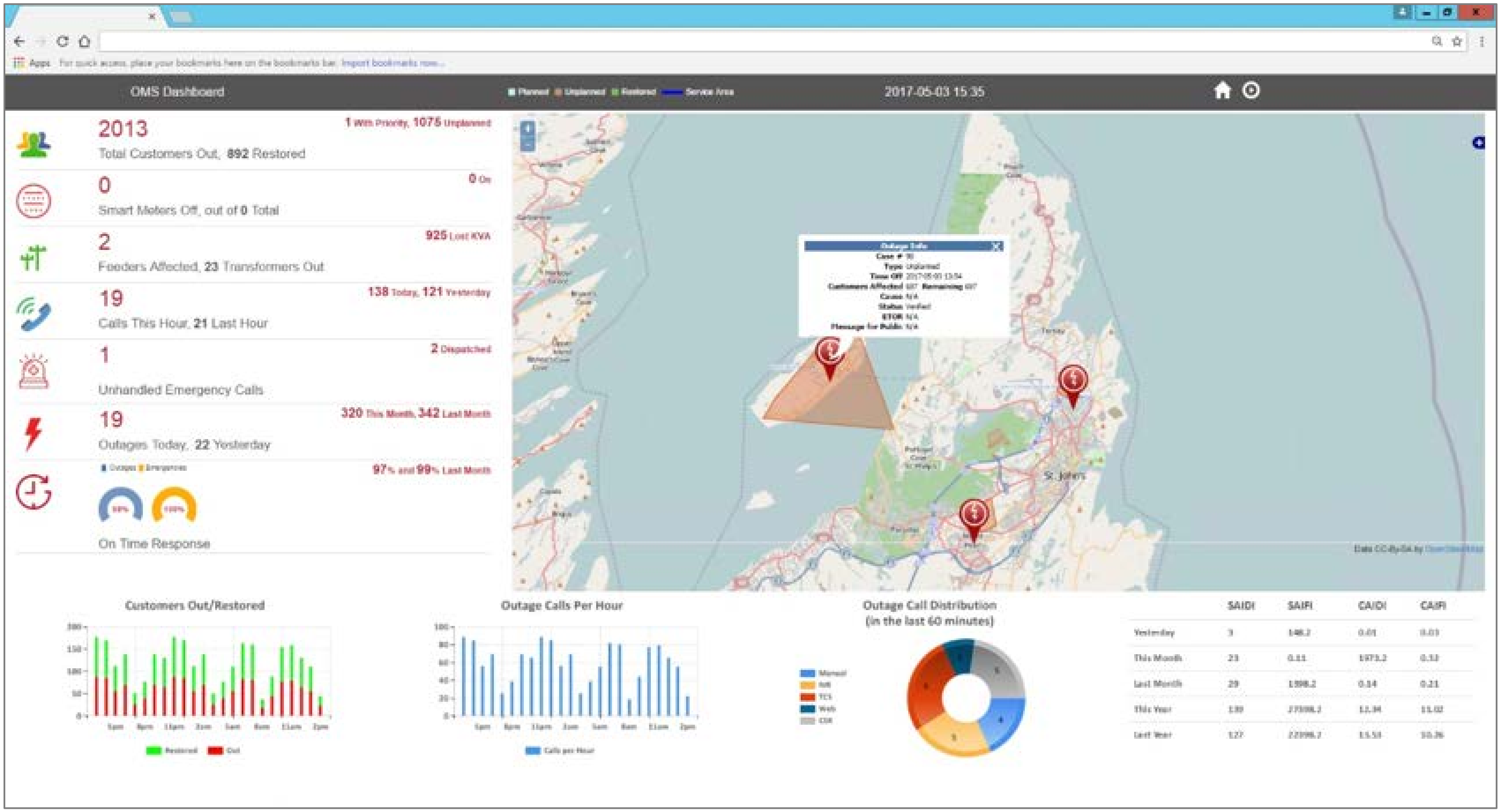
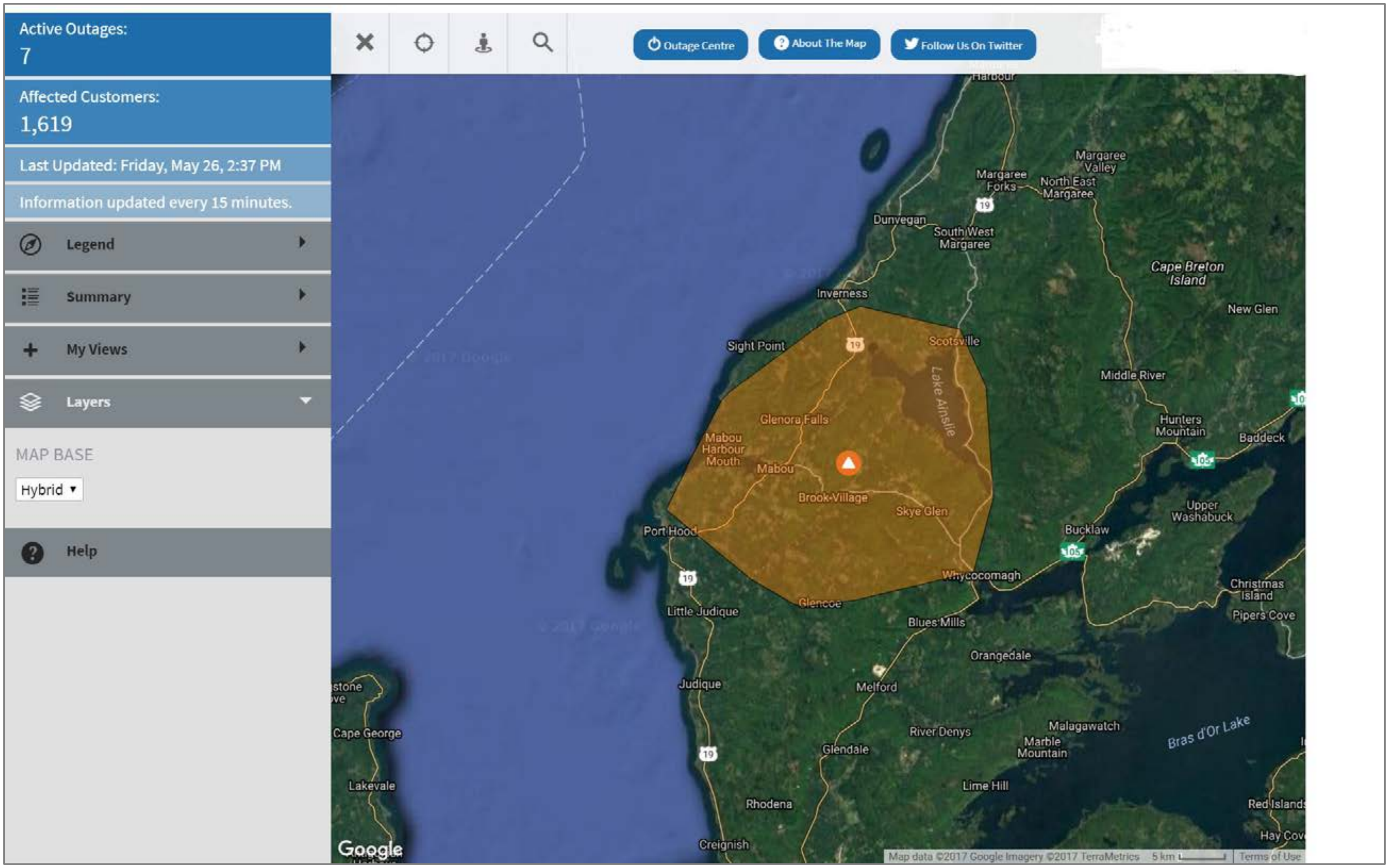


Figure B-3: Example of Customer-Facing Website Map



Appendix C: System Integration Diagrams

Figures C-1 and C-2 are conceptual diagrams of Newfoundland Power's approach to system integration currently, and with the implementation of a new OMS.

Figure C-1: Current OMS System Integrations

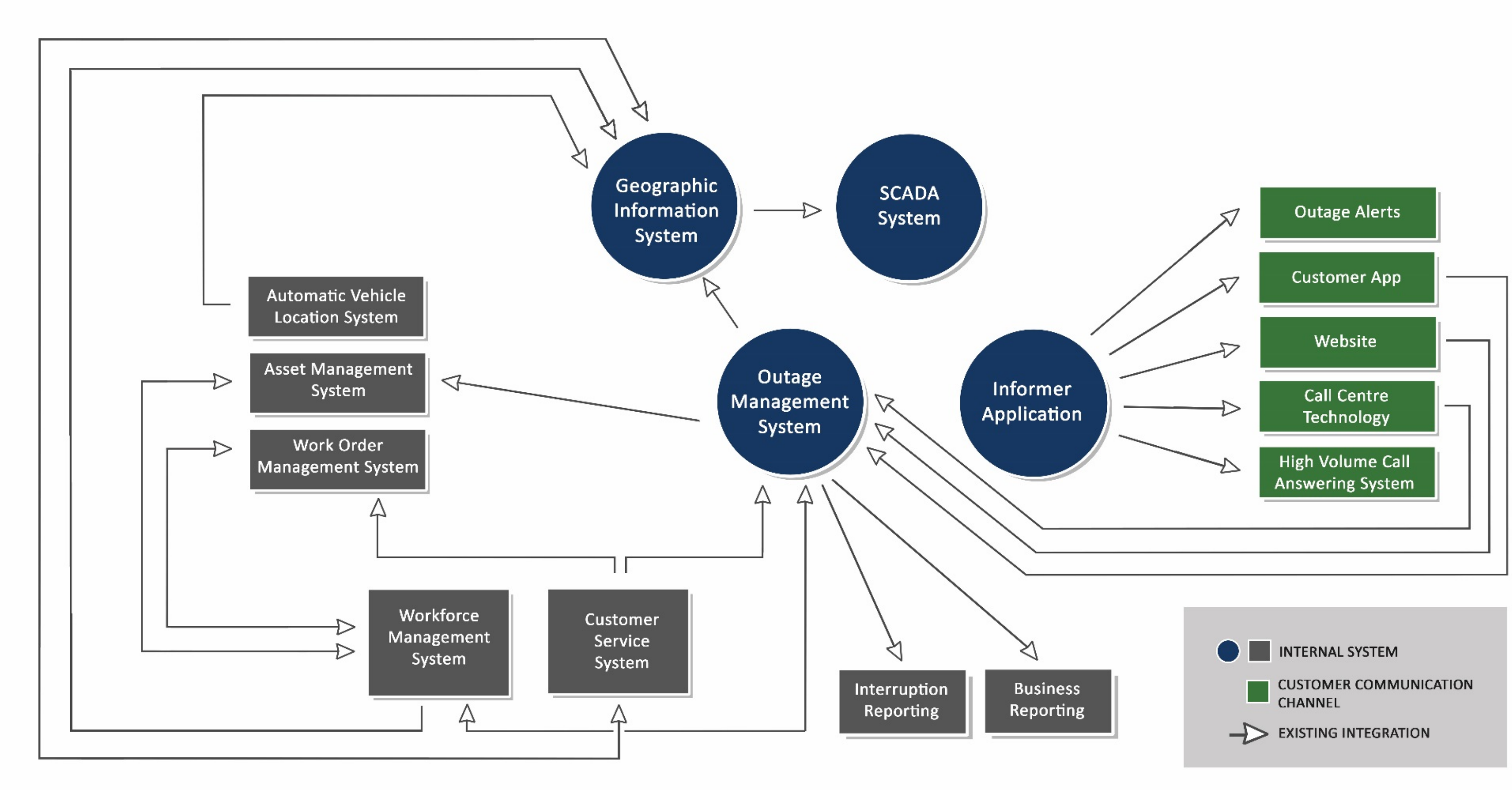
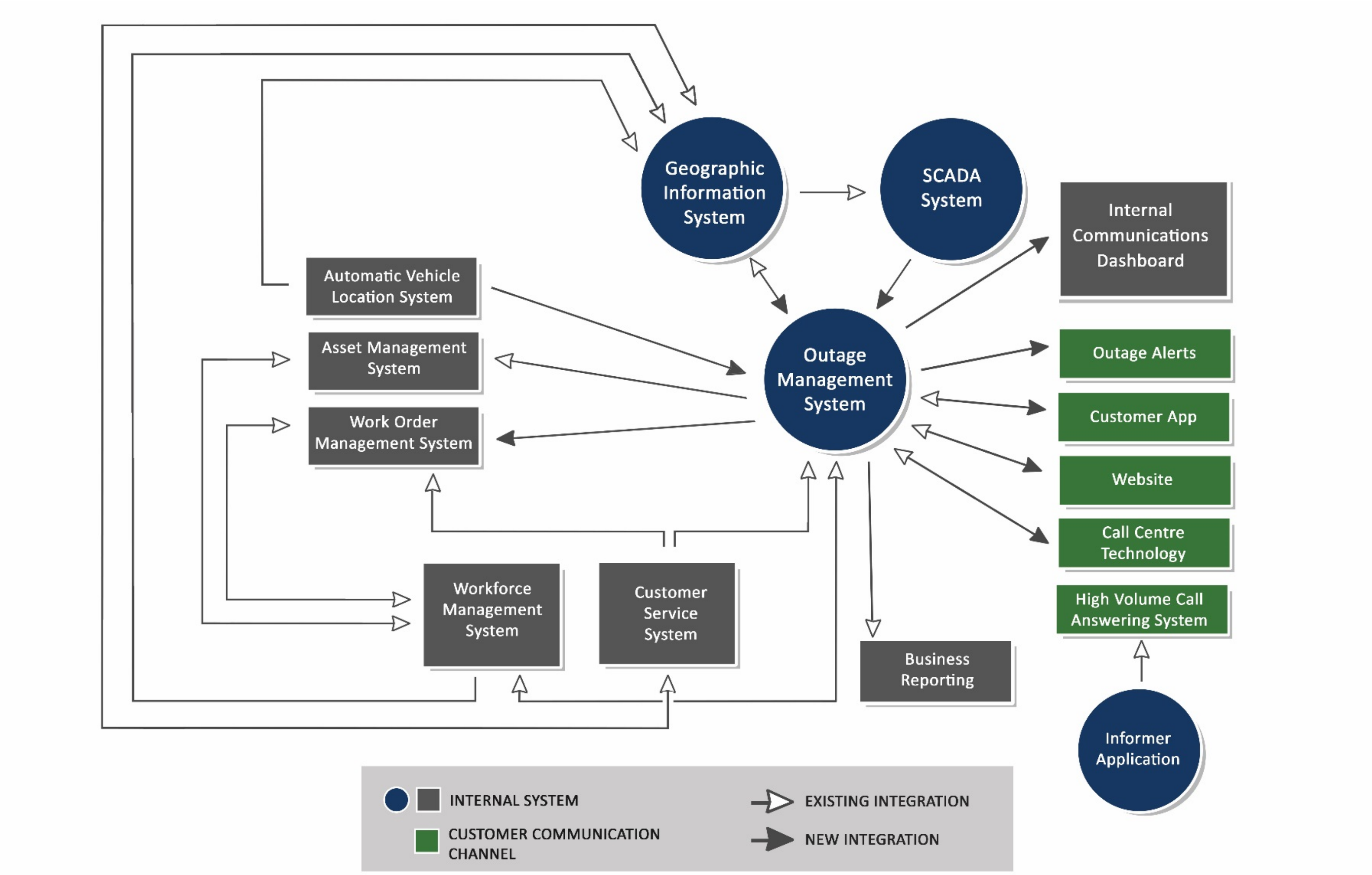


Figure C-2: System Integrations with Implementation of a New OMS



Appendix D: Technical Considerations

In implementing a commercial OMS product with the enhanced functionality described in this report, Newfoundland Power will consider the following technical challenges during vendor selection and project design:

- Integration with Legacy Systems – Several of the Company's existing operational technologies, such as its Customer Service System, are legacy systems. Integration with such systems will require significant technical expertise and oversight to ensure their integrity and performance.

- Cellular Connectivity – Newfoundland Power's service territory is large with intermittent telecommunications connectivity. Mobile solutions designed for urban areas experience difficulty maintaining connectivity in the Company's rural service territory. Any OMS product would require design and testing to ensure it can tolerate low cellular connectivity.

- High Availability – The OMS must perform well under normal operating conditions and major electrical system events. During such events, a significant volume of data is constantly moving between the SCADA system, GIS, hundreds of computers, communication channels and databases. Through testing and simulations, the Company will ensure the vendor design supports high availability.

- Efficient Connectivity Model – Developing a connectivity model (i.e. a model that relates outages to specific electrical system assets and customers) requires efficient integration between the OMS and GIS. The Company will work with its vendor to design a process to minimize the time required to extract the GIS map to ensure the connectivity model is efficiently updated.

- Support and Maintenance – Corrective and preventative maintenance procedures will be defined to ensure any concerns with the OMS software are addressed before they affect the operation of the software. Company employees will be trained to troubleshoot and maintain the system. Vendor support will also be available 24 hours a day.

- Disaster Recovery – The Company will work with the vendor to define a strategy to ensure the secure operation and performance of the OMS. A technical plan will be developed to guarantee the Company's outage management process can continue in the event a critical OMS component fails. Acceptance testing, simulations and training will be required.

- User Training – Extensive user training with employees throughout the Company, such as system operators, dispatchers and customer service representatives, will be required to ensure the effective operation of the new OMS and associated processes. Over 200 Company employees will be trained to use the new OMS.

Rate Base:
Additions, Deductions & Allowances

July 2017

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1.0 Introduction

1.1 General

In the 2018 Capital Budget Application (the "Application"), Newfoundland Power seeks final approval of its 2016 average rate base. This is consistent with current regulatory practice before the Board.

Newfoundland Power's 2016 average rate base of $1,061,044,000 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 affects 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 to 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 2017 and 2018 forecast rate base additions and deductions reflect the Company's most recent forecasts and estimates. 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 2015 and 2016, and the forecast additions for 2017 and 2018.

Table 1
Additions to Rate Base
2015-2018F
($000s)

	2015	**2016**	**2017F**	**2018F**
Deferred Pension Costs	98,829	94,775	92,003	91,199
Deferred Credit Facility Issue Costs	56	94	74	54
Cost Recovery Deferral – Seasonal/TOD Rates	49	-	-	-
Cost Recovery Deferral – Hearing Costs	-	682	341	-
Cost Recovery Deferral – Conservation	7,463	11,304	14,744	16,286
Weather Normalization Reserve	4,411	1,721	807	-
Customer Finance Programs	1,211	1,341	1,136	1,136
Total Additions	112,019	109,917	109,105	108,675

Additions to rate base were approximately $109.9 million in 2016. This is approximately $2.1 million lower than 2015. The lower additions to rate base in 2016 reflects a decrease in deferred pension costs and the balance in the weather normalization account. These decreases are partially 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.

2.2 Deferred Pension Costs

The difference between pension plan *funding* and pension plan *expense* associated with the Company's defined benefit pension plan is captured as a deferred pension cost in accordance with Order No. P.U. 17 (1987).[1]

Table 2 shows details of changes in Newfoundland Power's deferred pension costs from 2015 through 2018F.

Table 2
Deferred Pension Costs
2015-2018F
($000s)

	2015	**2016**	**2017F**	**2018F**
Deferred Pension Costs, January 1st	103,939	98,829	94,775	92,003
Pension Plan Funding[2]	10,213	3,249	3,363	3,253
Pension Plan Expense	(15,323)	(7,303)	(6,135)	(4,057)
Deferred Pension Costs, December 31st	98,829	94,775	92,003	91,199

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.

In the 2016/2017 General Rate Application, the amortization of credit facility costs associated with the balance as of December 31, 2015 of $56,000 was included as a component of the Company's cost of capital for 2016 and 2017 for revenue requirement purposes. As these costs are reflected in customer rates, they are not included in rate base for those years.

In August 2016, the committed credit facility was renegotiated to extend its maturity date to August 2021. Costs related to this amendment totalled $101,000 and are being amortized over the 5-year life of the agreement, beginning in 2016. For 2016 to 2018, the unamortized credit facility costs assocated with this amount are included in rate base as these costs have not yet been reflected in the Company's revenue requirements.

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1 Deferred pension costs were approved for inclusion in average rate base in Order No. P.U. 19 (2003).
2 Pension funding for 2015 includes special funding payments of $7.0 million. There are no special funding payments forecast for 2016 to 2018.

Table 3 shows details of Newfoundland Power's amortization of deferred credit facility issue costs for 2015 through 2018F.

Table 3
Deferred Credit Facility Issue Costs
2015-2018F
($000s)

	2015	2016	2017F	2018F
Balance, January 1st	72	56	94	74
Cost – Reduction	-	(56)	-	-
Cost – Addition	-	101	-	-
Amortization	(16)	(7)	(20)	(20)
Balance, December 31st	56	94	74	54

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.[3]

[3] 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 4 shows details of the Optional Seasonal Rate Revenue and Cost Recovery Account for 2015 through 2018F.

Table 4
Seasonal/TOD Rates
2015-2018F
($000s)

	2015	**2016**	**2017F**	**2018F**
Balance, January 1st	68	49	-	-
Additions	49	-	-	-
Reductions	(68)	(49)	-	-
Balance, December 31st	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 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 5 shows details of the changes in Newfoundland Power's deferred hearing costs from 2015 through 2018F.

Table 5
Deferred Hearing Costs
2015-2018F
($000s)

	2015	**2016**	**2017F**	**2018F**
Balance, January 1st	322	-	682	341
Cost	-	853	-	-
Amortization	(322)	(171)	(341)	(341)
Balance, December 31st	-	682	341	-

2.6 Cost Recovery Deferral – Conservation

Table 6 shows details of the forecast amortizations of the deferred cost recovery related to conservation for 2015 through 2018F.

Table 6
Cost Recovery Deferral – Conservation
2015-2018F
($000s)

	2015	**2016**	**2017F**	**2018F**
Balance, January 1st	4,937	7,463	11,304	14,744
Cost	3,274	5,040	5,359	4,227
Amortization	(748)	(1,199)	(1,919)	(2,685)
Balance, December 31st	7,463	11,304	14,744	16,286

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.

2.7 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.[4]

[4] 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 7 shows details of changes in the balance of the Weather Normalization Reserve from 2015 through 2018F.

Table 7
Weather Normalization Reserve
2015-2018F
($000s)

	2015	**2016**	**2017F**	**2018F**
Balance, January 1st	(1,640)	4,411	1,721	807
Operation of the reserve	4,411	1,721	807	-
Transfers to the RSA	(33)	(4,411)	(1,721)	(807)
Amortization	1,673	-	-	-
Balance, December 31st	4,411	1,721	807	-

The disposition of the December 31, 2016 balance in the Weather Normalization Reserve Account to the RSA as of March 31, 2017, was approved by the Board in Order No. P.U. 12 (2017).

2.8 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 8 shows details of changes to balances related to customer finance programs for 2015 through 2018F.

Table 8
Customer Finance Programs
2015-2018F
($000s)

	2015	**2016**	**2017F**	**2018F**
Balance, January 1st	1,136	1,211	1,341	1,136
Change	75	130	(205)	-
Balance, December 31st	1,211	1,341	1,136	1,136

3.0 Deductions from Rate Base

3.1 Summary

Table 9 summarizes Newfoundland Power's deductions from rate base for 2015 and 2016, and the Company's forecasts for 2017 and 2018.

Table 9
Deductions from Rate Base
2015-2018F
($000s)

	2015	2016	2017F	2018F
Other Post Employment Benefits ("OPEBs")	39,208	46,083	52,061	56,988
Customer Security Deposits	1,286	786	700	700
Accrued Pension Obligation	4,955	5,285	5,603	5,886
Accumulated Deferred Income Taxes	1,268	2,186	4,130	5,824
Cost Over Recovery – 2016 Revenue Surplus	-	1,445	722	-
Demand Management Incentive Account	-	-	(1,022)	-
Excess Earnings Account	49	-	-	-
Total Deductions	46,766	55,785	62,194	69,398

Deductions from rate base were approximately $55.8 million in 2016. Newfoundland Power's total deductions from rate base in 2016 were approximately $9.0 million higher than 2015 primarily due to the increase in the OPEBs liability from 2015. The increase in the OPEBs liability primarily reflects the amortization of the OPEBs regulatory asset[5] and amortization of the employee future benefits regulatory asset[6] related to OPEBs.

This section outlines the deductions from rate base in further detail.

3.2 Other Post Employment Benefits

Newfoundland Power's OPEBs are comprised of retirement allowances for retiring employees, as well as health, medical and life insurance for retirees and their dependents.

[5] 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.

[6] 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.

Table 10 shows details of the changes related to the net OPEBs liability from 2015 through 2018F.

Table 10
Other Post Employment Benefits
2015-2018F
($000s)

	2015	2016	2017F	2018F
Regulatory Asset	47,328	45,875	42,207	39,474
OPEBs Liability	86,536	91,958	94,268	96,462
Net OPEBs Liability	39,208	46,083	52,061	56,988

3.3 Customer Security Deposits

Customer security deposits are provided by customers in accordance with the Schedule of Rates, Rules and Regulations.

Table 11 shows details on the changes in customer security deposits from 2015 through 2018F.

Table 11
Customer Security Deposits
2015-2018F
($000s)

	2015	2016	2017F	2018F
Balance, January 1st	660	1,286	786	700
Change	626	(500)	(86)	-
Balance, December 31st	1,286	786	700	700

3.4 Accrued Pension Obligation

Accrued pension obligation is the cumulative costs of Newfoundland Power's unfunded pension plans net of associated benefit payments.

Table 12 shows details of changes related to accrued pension obligation for 2015 through 2018F.

Table 12
Accrued Pension Obligation
2015-2018F
($000s)

	2015	2016	2017F	2018F
Balance, January 1st	4,635	4,955	5,285	5,603
Change	320	330	318	283
Balance, December 31st	4,955	5,285	5,603	5,886

3.5 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,[7] pension costs[8] and other employee future benefit costs.[9]

Table 13 shows details of changes in the accumulated deferred income taxes from 2015 through 2018F.

Table 13
Accumulated Deferred Income Taxes
2015-2018F
($000)

	2015	2016	2017F	2018F
Balance, January 1st	2,529	1,268	2,186	4,130
Change	(1,261)	918	1,944	1,694
Balance, December 31st	1,268	2,186	4,130	5,824

[7] 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.

[8] 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.

[9] 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).

3.6 Cost Over Recovery – 2016 Revenue Surplus

The Board's determination 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 provided for credit of the 2016 Revenue Surplus through a regulatory amortization beginning on July 1, 2016 and concluding on December 31, 2018.

Table 14 shows the 2016 revenue surplus amortization for 2015 through 2018F.

Table 14
Cost Over Recovery – 2016 Revenue Surplus
2015-2018F
($000s)

	2015	2016	2017F	2018F
Balance, January 1st	-	-	1,445	722
Credit	-	1,806	-	-
Amortization	-	(361)	(723)	(722)
Balance, December 31st	-	1,445	722	-

3.7 Demand Management Incentive Account

In Order No. P.U. 32 (2007), the Board approved the Demand Management Incentive Account (the "DMI Account") to replace the Purchase Power Unit Cost Variance Reserve.

Table 15 shows details of the DMI Account from 2015 through 2018F.

Table 15
DMI Account
2015-2018F
($000s)

	2015	2016	2017F	2018F
Balance, January 1st	446	-	-	(1,022)
Transfers to the RSA	(446)	-	-	1,022
Operation of DMI	-	-	(1,022)	-
Balance, December 31st	-	-	(1,022)	-

3.8 Excess Earnings Account

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.[10]

In the Company's 2016/2017 General Rate Application, the 2013 excess earnings amount was included in the Company's 2016 revenue requirement.[11] Accordingly, there is no balance in the excess earnings account as of December 31, 2016.

Table 16 shows details of the Excess Earnings Account from 2015 through 2018F.

Table 16
Excess Earnings Account
2015-2018F
($000s)

	2015	2016	2017F	2018F
Balance, January 1st	49	49	-	-
Change	-	(49)	-	-
Balance, December 31st	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.

[10] 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).

[11] The Company's 2016 and 2017 revenue requirements were approved in Order No. P.U. 25 (2016).

Table 17 shows details on changes in the cash working capital allowance from 2015 through 2018F.

Table 17
Rate Base Allowances
Cash Working Capital Allowance[12]
2015-2018F
($000s)

	2015	2016	2017F	2018F
Gross Operating Costs	500,372	513,878	521,587	516,902
Income Taxes	11,622	12,204	15,853	18,236
Municipal Taxes Paid	17,538	17,561	16,177	19,012
Non-Regulated Expenses	(1,799)	(2,379)	(2,636)	(2,291)
Total Operating Expenses	527,733	541,264	550,981	551,859
Cash Working Capital Factor	1.690%	1.336%	1.353%	1.353%
	8,919	7,231	7,455	7,467
HST Adjustment	(2,180)	1,087	960	960
Cash Working Capital Allowance	6,739	8,318	8,415	8,427

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.[13]

[12] The cash working capital allowance for 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 through 2018 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).

[13] 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 18 shows details on changes in the materials and supplies allowance from 2015 through 2018F.

Table 18
Rate Base Allowances
Materials and Supplies Allowance
2015-2018F
($000s)

	2015	2016	2017F	2018F
Average Materials and Supplies	8,107	8,142	7,819	7,996
Expansion Factor[14]	22.53%	20.61%	20.61%	20.61%
Expansion	1,827	1,678	1,611	1,648
Materials and Supplies Allowance	6,280	6,464	6,208	6,348

[14] The expansion factor is based on a review of actual inventories used for expansion projects. The calculation of the 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 through 2018, based upon an expansion factor of 20.61%, was approved by the Board in Order No. P.U. 18 (2016).