WHENEVER. WHEREVER.
We'll be there.

DELIVERED BY HAND

May 18, 2021

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

Dear Ms. Blundon:

Re: Newfoundland Power's 2022 Capital Budget Application

A. 2022 Capital Budget Application

Enclosed are the original and 9 copies of Newfoundland Power Inc.'s (the "Company") *2022 Capital Budget Application* and supporting materials (the "Filing").

The Filing outlines a proposed 2022 Capital Budget totaling $109,651,000. Included in that total are 2022 capital expenditures of $245,000 previously approved in Order No. P.U. 37 (2020) (the "2021 Capital Order") and $15,826,000 previously approved in Order No. P.U. 12 (2021). These previously approved expenditures relate to multi-year projects proposed in the *2021 Capital Budget Application*. The Filing also outlines multi-year projects commencing in 2022 that include proposed 2023 capital expenditures totaling $13,526,000 and proposed 2024 capital expenditures totaling $4,276,000.

In addition, the Filing seeks approval of a 2020 rate base in the amount of $1,181,897,000.

B. Compliance Matters

B.1 Board Orders

In the 2021 Capital Order, the Board required a progress report on 2021 capital expenditures be provided with the Filing. In Order No. P.U. 35 (2003) (the "2004 Capital Order"), the Board required a 5-year capital plan 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.
55 Kenmount Road • P.O. Box 8910 • St. John's, NL A1B 3P6
PHONE (709) 737-5364 • FAX (709) 737-2974 • **khopkins@newfoundlandpower.com**

These requirements are specifically addressed in the Filing in the:

(i) *2021 Capital Expenditure Status Report*, which meets the requirements of the 2021 Capital Order;

(ii) *2022 Capital Plan*, which meets the requirements of the 2004 Capital Order; and

(iii) *Report 8.1 Rate Base: Additions, Deductions & Allowances*, which meets the requirements of the 2003 Rate Order.

B.2 The Guidelines

The Filing complies with the Board's *Capital Budget Application Guidelines* (the "Guidelines") and remains reasonably consistent with past filings.

The Guidelines provide direction on the categorization of capital expenditures. Attachment A of the *2022 Capital Plan* categorizes the 2022 Capital Budget by definition, classification, and materiality segmentation, as required by the Guidelines. Schedule B to the Application provides the categorization of each project.

In correspondence dated March 9, 2020, the Board outlined changes to the process for 2021 capital budget applications. Specifically, the Board directed that capital budget applications should contain: (i) additional information related to the process for assessing deferral opportunities and why specific projects cannot be deferred; and (ii) information related to the revenue requirement impacts of the capital projects proposed.

In correspondence dated February 18, 2021, the Board directed that these requirements would remain in place for 2022 capital budget applications. These requirements are specifically addressed in Section 2.0 of the *2022 Capital Plan* and Schedule B to the Application.

C. Filing Details and Circulation

The enclosed materials have been provided in binders with appropriate tabbing.

A copy of the Filing has been forwarded directly to Ms. Shirley Walsh, Senior Legal Counsel of Newfoundland and Labrador Hydro, and Mr. Dennis Browne, the Consumer Advocate.

A PDF of the Filing is available to the Board and interested parties via Newfoundland Power's stranded website at https://ftp.nfpower.nf.ca/. Access information for the stranded website for all interested parties has been emailed directly to them.

The Filing is also posted on the Company's website (newfoundlandpower.com). Interested parties may contact Newfoundland Power directly for assistance if they have any issues accessing the website.

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 truly,

Kelly Hopkins
Corporate Counsel

Enclosures

c. Shirley Walsh
Newfoundland and Labrador Hydro

Dennis Browne, Q.C.
Browne Fitzgerald Morgan & Avis

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PHONE (709) 737-5364 • FAX (709) 737-2974 • **khopkins@newfoundlandpower.com**

Newfoundland Power Inc.
2022 Capital Budget Application

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APPLICATION

SUPPORTING MATERIALS

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 2022 Capital Budget of $109,651,000;
(b) approving certain capital expenditures related to multi-year projects commencing in 2022; and
(c) fixing and determining a 2020 rate base of $1,181,897,000.

2022 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 2022 Capital Budget of $109,651,000;
(b) approving certain capital expenditures related to multi-year projects commencing in 2022; and
(c) fixing and determining a 2020 rate base of $1,181,897,000.

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 2022 Capital Budget in the amount of $109,651,000 which includes forecast 2022 capital expenditures previously approved in Order No. P.U. 37 (2020), Order No. P.U. 12 (2021), 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 2022. 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 2022 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. 37 (2020);

   (b) ongoing projects for which capital expenditures were approved in Order No. P.U. 12 (2021); and

(c) projects which will commence as part of the 2022 Capital Budget but will not be completed in 2022.

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

6. Schedule D to this Application shows Newfoundland Power's actual average rate base for 2020 of $1,181,897,000.

7. Communication with respect to this Application should be forwarded to the attention of Kelly C. Hopkins and Liam P. O'Brien, 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 2022 Capital Budget in the amount of $109,651,000 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 2023 and 2024 of improvements and additions to its property in the amount of $17,802,000 as set out in Schedule C to the Application; and

(c) pursuant to Section 78 of the Act, fixing and determining Newfoundland Power's average rate base for 2020 in the amount of $1,181,897,000 as set out in Schedule D to the Application.

DATED at St. John's, Newfoundland and Labrador, this 18th day of May, 2021.

NEWFOUNDLAND POWER INC.

Kelly C. Hopkins and Liam P. O'Brien
Counsel to Newfoundland Power Inc.
P.O. Box 8910 55 Kenmount Road
St. John's, NL A1B 3P6

Telephone: (709) 737-5364
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 2022 Capital Budget of $109,651,000;
(b) approving certain capital expenditures related to multi-year projects commencing in 2022; and
(c) fixing and determining a 2020 rate base of $1,181,897,000.

AFFIDAVIT

I, Byron Chubbs of Paradise in the Province of Newfoundland and Labrador, make oath and say as follows:

1. That I am Vice-President, Engineering and Energy Supply 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 18th day of May, 2021:

Barrister

Byron Chubbs

2022 CAPITAL BUDGET SUMMARY

Asset Class	**Budget ($000s)**
1. Generation - Hydro	2,462
2. Generation - Thermal	307
3. Substations	11,639
4. Transmission	12,892
5. Distribution	47,744
6. General Property	2,660
7. Transportation	3,089
8. Telecommunications	564
9. Information Systems	21,044
10. Unforeseen Allowance	750
11. General Expenses Capitalized	6,500
Total	**$ 109,651**

2022 CAPITAL PROJECTS (BY ASSET CLASS)

Capital Projects	Budget ($000s)	Description[1]
1. Generation – Hydro		
Hydro Facility Rehabilitation	2,062	2
Sandy Brook Plant Penstock Replacement[2]	400	5
Total Generation – Hydro	**$ 2,462**	
2. Generation – Thermal		
Thermal Plant Facility Rehabilitation	307	8
Total Generation – Thermal	**$ 307**	
3. Substations		
Substation Refurbishment and Modernization	7,049	11
Replacements Due to In-Service Failures	3,691	13
PCB Bushing Phase-out	899	15
Total Substations	**$ 11,639**	
4. Transmission		
Transmission Line Rebuild[3]	10,494	18
Transmission Line Maintenance and 3rd Party Relocations	2,398	21
Total Transmission	**$ 12,892**	

1 Project descriptions can be found in Schedule B at the page indicated.
2 This is the 1st year of a 2 year project as identified in Schedule C of this Application.
3 This includes the 1st year of a 3 year project to rebuild transmission line 94L as identified in Schedule C of this Application.

2022 CAPITAL PROJECTS (BY ASSET CLASS)

Capital Projects	Budget ($000s)	Description[4]
5. Distribution		
Extensions	10,333	24
Meters	818	26
Services	3,038	29
Street Lighting	2,507	32
Street Lighting – LED Replacement Program	5,428	34
Transformers	5,958	36
Reconstruction	5,902	38
Rebuild Distribution Lines	4,333	40
Relocate/Replace Distribution Lines for Third Parties	3,370	43
Distribution Reliability Initiative	350	46
Feeder Additions for Load Growth	1,690	48
Distribution Feeder Automation	893	50
Trunk Feeders – Humber 4.16 kV Conversion	1,355	52
Electric Vehicle Charging Network	1,530	54
Allowance for Funds Used During Construction	239	57
Total Distribution	**$ 47,744**	
6. General Property		
Tools and Equipment	598	60
Additions to Real Property	716	63
Clarenville Area Office Building Refurbishment	854	65
Physical Security Upgrades	492	67
Total General Property	**$ 2,660**	
7. Transportation		
Replace Vehicles and Aerial Devices 2022-2023[5]	3,089	70
Total Transportation	**$ 3,089**	

4 Project descriptions can be found in Schedule B at the page indicated.
5 This is the 1st year of a 2 year project as identified in Schedule C of this Application.

2022 CAPITAL PROJECTS (BY ASSET CLASS)

Capital Projects	Budget ($000s)	Description[6]
8. Telecommunications		
Replace/Upgrade Communications Equipment	114	74
St. John's Teleprotection System Replacement[7]	450	76
Total Telecommunications	**$ 564**	
9. Information Systems		
Application Enhancements	1,007	79
System Upgrades[8]	802	81
Personal Computer Infrastructure	615	83
Shared Server Infrastructure	613	86
Network Infrastructure	508	88
Cybersecurity Upgrades	865	90
Customer Service System Replacement[9]	15,826	92
Workforce Management System Replacement[10]	808	94
Total Information Systems	**$ 21,044**	
10. Unforeseen Allowance		
Allowance for Unforeseen Items	750	97
Total Unforeseen Allowance	**$ 750**	
11. General Expenses Capitalized		
General Expenses Capitalized	6,500	99
Total General Expenses Capitalized	**$ 6,500**	

6 Project descriptions can be found in Schedule B at the page indicated.
7 This is the 1st year of a 2 year project as identified in Schedule C of this Application.
8 This includes the 2nd year of the Microsoft Enterprise Agreement as identified in Schedule C of this Application
9 This is the 2nd year of the *Customer Service System Replacement* as identified in Schedule C of this Application.
10 This is the 1st year of a 2 year project as identified in Schedule C of this Application.

2022 CAPITAL PROJECTS SUMMARY

2022 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 interdependant 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 an 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:
   (i) Expenditures under $200,000;
   (ii) Expenditures between $200,000 and $500,000; and
   (iii) Expenditures over $500,000

This 2022 Capital Project Summary provides a summary of the planned capital expenditures contained in Newfoundland Power Inc.'s ("Newfoundland Power" or the "Company") *2022 Capital Budget Application* by definition (pages ii to iii), classification (pages v to vi), and segmentation by materiality (pages vii to viii). In addition, each project description in *Schedule B* indicates the definitions, classifications and forecast costs, as provided for in the Guidelines.

Summary of
2022 Capital Projects by Definition
($000s)

Clustered	**$18,898**	**Page**
Distribution	**1,355**	
Trunk Feeders – Humber 4.16 kV Conversion	1,355	52
Substations	**7,049**	
Substation Refurbishment and Modernization	7,049	11
Transmission	**10,494**	
Transmission Line Rebuild	10,494	18

Pooled	**$62,930**	**Page**
Distribution	**46,389**	
Extensions	10,333	24
Meters	818	26
Services	3,038	29
Street Lighting	2,507	32
Street Lighting - LED Replacement Program	5,428	34
Transformers	5,958	36
Reconstruction	5,902	38
Rebuild Distribution Lines	4,333	40
Relocate/Replace Distribution Lines for Third Parties	3,370	43
Distribution Reliability Initiative	350	46
Feeder Additions for Load Growth	1,690	48
Distribution Feeder Automation	893	50
Electric Vehicle Charging Network	1,530	54
Allowance for Funds Used During Construction	239	57
General Property	**2,660**	
Tools and Equipment	598	60
Additions to Real Property	716	63
Clarenville Area Office Building Refurbishment	854	65
Physical Security Upgrades	492	67
Generation - Hydro	**2,062**	
Hydro Facility Rehabilitation	2,062	2

Project Clustering

Clustered expenditures are those that would logically be undertaken together. Clustered expenditures are either interdependent or related. Interdependent items are necessarily linked together, as one item triggers the other. Related items are not necessarily linked to each other, but are nonetheless logically undertaken together.

In 2022, the following projects have expenditures that are clustered:

1. In 2022, Humber Substation will be converted to 12.5 kV with a *Substation Refurbishment and Modernization* Substations project. A *Trunk Feeders – Humber 4.16 kV Conversion* Distribution project to convert the distribution feeders out of Humber Substation, as well as to construct a new distribution feeder out of Humber Substation is also being completed. The *Substation Refurbishment and Modernization* Substations project and the *Trunk Feeders – Humber 4.16 kV Conversion* Distribution project are interdependent and therefore clustered.

2. In 2022, 138 kV circuit breakers will be installed at Glovertown Substation on transmission lines 121L and 124L within the *Substation Refurbishment and Modernization* Substations project. The *Transmission Line Rebuild* Transmission project on 124L will reconfigure the transmission line to terminate at Glovertown Substation in 2022. The *Substation Refurbishment and Modernization* Substations project and the *Transmission Line Rebuild* Transmission project are interdependent and therefore clustered.

Summary of
2022 Capital Projects by Classification
($000s)

Normal Capital	**$100,787**	**Page**
Distribution	**40,786**	
Extensions	10,333	24
Meters	818	26
Services	3,038	29
Street Lighting	2,507	32
Transformers	5,958	36
Reconstruction	5,902	38
Rebuild Distribution Lines	4,333	40
Relocate/Replace Distribution Lines for Third Parties	3,370	43
Distribution Reliability Initiative	350	46
Feeder Additions for Load Growth	1,690	48
Distribution Feeder Automation	893	50
Trunk Feeders – Humber 4.16 kV Conversion	1,355	52
Allowance for Funds Used During Construction	239	57
General Expenses Capitalized	**6,500**	
General Expenses Capitalized	6,500	99
General Property	**2,660**	
Tools and Equipment	598	60
Additions to Real Property	716	63
Clarenville Area Office Building Refurbishment	854	65
Physical Security Upgrades	492	67
Generation - Hydro	**2,462**	
Hydro Facility Rehabilitation	2,062	2
Sandy Brook Plant Penstock Replacement	400	5
Generation – Thermal	**307**	
Thermal Plant Facility Rehabilitation	307	8
Information Systems	**20,037**	
System Upgrades	802	81
Personal Computer Infrastructure	615	83
Shared Server Infrastructure	613	86
Network Infrastructure	508	88
Cybersecurity Upgrades	865	90
Customer Service System Replacement	15,826	92
Workforce Management System Replacement	808	94

Normal Capital (continued)		Page
Substations	**10,740**	
Substation Refurbishment and Modernization	7,049	11
Replacements Due to In-Service Failures	3,691	13
Telecommunications	**564**	
Replace/Upgrade Communications Equipment	114	74
St. John's Teleprotection System Replacement	450	76
Transmission	**12,892**	
Transmission Line Rebuild	10,494	18
Transmission Line Maintenance and 3rd Party Relocations	2,398	21
Transportation	**3,089**	
Replace Vehicles and Aerial Devices 2022-2023	3,089	70
Unforeseen Allowance	**750**	
Allowance for Unforeseen Items	750	97

Justifiable	$7,965	Page
Distribution	**6,958**	
Street Lighting - LED Replacement Program	5,428	34
Electric Vehicle Charging Network	1,530	54
Information Systems	**1,007**	
Application Enhancements	1,007	79

Mandatory	$899	Page
Substations	**899**	
PCB Bushing Phase-out	899	15

Summary of
2022 Capital Projects by Materiality
($000s)

Large – Greater than $500	**$107,299**	**Page**
Distribution	**47,155**	
Extensions	10,333	24
Meters	818	26
Services	3,038	29
Street Lighting	2,507	32
Street Lighting - LED Replacement Program	5,428	34
Transformers	5,958	36
Reconstruction	5,902	38
Rebuild Distribution Lines	4,333	40
Relocate/Replace Distribution Lines for Third Parties	3,370	43
Feeder Additions for Load Growth	1,690	48
Distribution Feeder Automation	893	50
Trunk Feeders – Humber 4.16 kV Conversion	1,355	52
Electric Vehicle Charging Network	1,530	54
General Expenses Capitalized	**6,500**	
General Expenses Capitalized	6,500	99
General Property	**2,168**	
Tools and Equipment	598	60
Additions to Real Property	716	63
Clarenville Area Office Building Refurbishment	854	65
Generation - Hydro	**2,062**	
Hydro Facility Rehabilitation	2,062	2
Information Systems	**21,044**	
Application Enhancements	1,007	79
System Upgrades	802	81
Personal Computer Infrastructure	615	83
Shared Server Infrastructure	613	86
Network Infrastructure	508	88
Cybersecurity Upgrades	865	90
Customer Service System Replacement	15,826	92
Workforce Management System Replacement	808	94
Substations	**11,639**	
Substation Refurbishment and Modernization	7,049	11
Replacements Due to In-Service Failures	3,691	13
PCB Bushing Phase-out	899	15

Large – Greater than $500 (continued)		**Page**
Transmission	**12,892**	
Transmission Line Rebuild	10,494	18
Transmission Line Maintenance and 3rd Party Relocations	2,398	21
Transportation	**3,089**	
Replace Vehicles and Aerial Devices 2022-2023	3,089	70
Unforeseen Allowance	**750**	
Allowance for Unforeseen Items	750	97

Medium – Between $200 and $500	**$2,238**	**Page**
Distribution	**589**	
Distribution Reliability Initiative	350	46
Allowance for Funds Used During Construction	239	57
General Property	**492**	
Physical Security Upgrades	492	67
Generation – Hydro	**400**	
Sandy Brook Plant Penstock Replacement	400	5
Generation – Thermal	**307**	
Thermal Plant Facility Rehabilitation	307	8
Telecommunications	**450**	
St. John's Teleprotection System Replacement	450	76

Small – Under $200	**$114**	**Page**
Telecommunications	**114**	
Replace/Upgrade Communications Equipment	114	74

GENERATION - HYDRO

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

Project Cost: **$2,062,000**

Project Description

This Generation Hydro project is necessary to improve the operation of various hydro plants or to replace plant components due to in-service failures. The project involves the replacement or refurbishment of deteriorated plant components that have been identified through routine inspections, operating experience and engineering studies.

The 2022 project includes the following items:

1. Equipment replacements due to in-service failures ($610,000);
2. Replacement of Morris Head Gate and Intake Gatehouse ($465,000);
3. Generation Control Systems Upgrades ($339,000);
4. Replacement of Petty Harbour Surge Tank Cladding ($347,000); and
5. Overhaul of Petty Harbour Unit #2 Turbine ($301,000).

The replacement or refurbishment of deteriorated components at individual plants is not interdependent 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 2022 proposed expenditures are included in report *1.1 2022 Facility Rehabilitation*.

Justification

Newfoundland Power operates 23 hydro plants that range in age from 22 to 121 years old. These facilities provide relatively inexpensive energy to customers served by the Island Interconnected System.

Maintaining the Company's hydroelectric production reduces the need for additional, more expensive generation to supply customers. The value of this production consists primarily of: (i) reduced marginal energy costs; and (ii) avoidance of the need to add generation capacity.[1] Based on Newfoundland and Labrador Hydro's 2020 marginal cost update, the energy-related value of the production from the Company's hydro facilities is estimated at $18,573,000 annually, while the capacity-related value is estimated at $18,482,000 annually.[2]

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[1] The Island Interconnected System's need for new capacity additions is being reviewed by the Board. Newfoundland and Labrador Hydro's most recent assessment shows that the system has limited capacity to meet future load growth.

[2] These estimates are calculated to reflect post Muskrat Falls marginal costs using the 2022 marginal cost values for energy and capacity.

Newfoundland Power maintains reliable operation of its hydro facilities through a combination of annual inspection and maintenance activities and replacement and refurbishment projects. Replacement and refurbishment projects are identified annually based on plant condition and facility requirements. These projects are necessary to ensure the continued operation of hydro facilities in a safe, reliable and environmentally compliant manner. The alternative to maintaining the Company's generation facilities would be to retire them.

For 2022, maintaining the reliable operation of Newfoundland Power's hydro facilities requires upgrading generation control systems, responding to in-service equipment failures, and replacing and overhauling deteriorated or substandard components at the Morris and Petty Harbour hydro plants.

This project is justified on the obligation to provide reliable service to customers at least cost and cannot be deferred.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2022 and a projection of expenditures through 2026.

Table 1
Projected Expenditures
($000s)

Cost Category	**2022**	**2023**	**2024 - 2026**	**Total**
Material	1,252	-	-	-
Labour – Internal	305	-	-	-
Labour – Contract	-	-	-	-
Engineering	335	-	-	-
Other	170	-	-	-
Total	**$2,062**	**$2,071**	**$5,896**	**$10,029**

Costing Methodology

Table 2 shows the annual expenditures for this project for the most recent 5-year period, as well as the projected expenditure for 2022.

Table 2
Expenditure History
(000s)

Year	**2017**	**2018**	**2019**	**2020**	**2021F**	**2022B**
Total	$1,564	$2,348	$1,584	$1,428	$1,806	$2,062

The budget estimate for this project is based on engineering estimates for the individual budget items and an assessment of historical expenditures for the equipment replacements due to in-service failures.

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: **Sandy Brook Plant Penstock Replacement (Other, Multi-Year)**

Project Cost: **$400,000**

Project Description

This Generation Hydro project involves the replacement of the penstock at the Company's Sandy Brook hydroelectric development located on a tributary of the Exploits River, approximately 13 km southwest of the Town of Grand Falls-Windsor.

The plant was placed into service in 1963 and contains one generating unit. The plant has undergone a number of upgrades to the original structures, plant and equipment over approximately 60 years in service. The normal annual production of the plant is approximately 27.6 GWh of energy, or about 6.3% of Newfoundland Power's total hydroelectric generation.

The project is a multi-year project and will be executed over 2 years, with the engineering design and procurement for the penstock and site preparation work completed in 2022. The installation of the replacement penstock will take place in 2023.

Details on 2022 and 2023 proposed expenditures are included in report *1.2 Sandy Brook Plant Penstock Replacement* filed as part of this application.

Justification

Engineering assessments of the original 1963 penstock have identified that it is deteriorated and requires replacement. Deficiencies have been noted with all components of the woodstave penstock including saddles, steel bands, wood staves, and site drainage. Completing this replacement project is necessary to ensure the continued operation of the Sandy Brook plant.

An economic analysis has been completed for the continued operation of the Sandy Brook plant, assuming the 2022 project is undertaken.[3] The results of the economic analysis show that the continued operation of Sandy Brook plant is economical over the long term. The analysis shows the levelized cost of production is 3.22 ¢/kWh. The benefit of the plant production is 10.21¢/kWh for fully dispatchable and 7.04 ¢/kWh for a run of river plant. This indicates that continued operation of the plant is economically justified. Investing in the life extension of Sandy Brook plant ensures the continued availability of 27.6 GWh of energy annually to the Island Interconnected System.

This project is justified on the obligation to provide reliable service to customers at least cost and cannot be deferred.

[3] Details of the economic analysis are included in Appendix A in report *1.2 Sandy Brook Plant Penstock Replacement*. The analysis includes estimates for work to be completed over the next 50 years including expenditures in 2022 and 2023.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2022 and a projection of expenditures through 2026.

Table 1
Multi-Year Projected Expenditures
($000s)

Cost Category	2022	2023	2024 - 2026	Total
Material	290	4,491	-	4,781
Labour – Internal	9	9	-	18
Labour – Contract	-	-	-	-
Engineering	71	54	-	125
Other	30	140	-	170
Total	**$400**	**$4,694**	**$0**	**$5,094**

Costing Methodology

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

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

Future Commitments

This is a multi-year project which will be undertaken in 2022 and 2023.

GENERATION - THERMAL

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

Project Cost: **$307,000**

Project Description

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

The 2022 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, $307,000 is estimated to be the cost of refurbishing or replacing thermal plant structures and equipment in 2022.

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

Justification

Newfoundland Power maintains 44.5 MW of thermal generation consisting of gas turbine and diesel units. These units are used to provide emergency generation, both locally and for the Island Interconnected System, and to minimize customer outages during scheduled maintenance on transmission, distribution or substation assets.

Replacement and refurbishment requirements are identified during annual inspections and maintenance activities. In-service failures are addressed as they occur to ensure the continued operation of thermal generation facilities in a safe, reliable and environmentally compliant manner.

This project is justified on the obligation to provide reliable service to customers at least cost and cannot be deferred.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2022 and a projection of expenditures through 2026.

Table 1 Projected Expenditures ($000s)				
Cost Category	**2022**	**2023**	**2024 - 2026**	**Total**
Material	194	-	-	-
Labour – Internal	54	-	-	-
Labour – Contract	-	-	-	-
Engineering	41	-	-	-
Other	18	-	-	-
Total	**$307**	**$311**	**$961**	**$1,579**

Costing Methodology

Table 2 shows the annual expenditures for this project for the most recent 5-year period, as well as the projected expenditure for 2022.

Table 2 Expenditure History (000s)						
Year	**2017**	**2018**	**2019**	**2020**	**2021F**	**2022B**
Total	$242	$408	$165	$333	$330	$307

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

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

Future Commitments

This is not a multi-year project.

SUBSTATIONS

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

Project Cost: **$7,049,000**

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 report *2.1 2022 Substation Refurbishment and Modernization*.

This project is necessary for the planned replacement and modernization of deteriorated and substandard substation infrastructure, such as breakers, bus structures, equipment foundations, fencing, grounding, potential transformers, protective relaying, support structures, switches and transformers. Infrastructure to be replaced is identified as a result of inspections, engineering assessments and operating experience.

In 2022, this project will refurbish and modernize the Tors Cove, Glovertown, and Humber substations. The 2022 project also includes upgrading communications gateways that connect digital devices in substations to the Supervisory Control and Data Acquisition system, as well as upgrading ground grids in identified substations.

The *Substation Refurbishment and Modernization* and the *Trunk Feeders – Humber 4.16 kV Conversion* projects at Humber Substation are interdependent and are therefore clustered.

The *Substation Refurbishment and Modernization* and the *Transmission Line Rebuild* projects at Glovertown Substation are interdependent and are therefore clustered.

Details on proposed expenditures are included in report *2.1 2022 Substation Refurbishment and Modernization* filed as part of this Application.

Justification

Newfoundland Power operates 131 substations. These substations range in age from 2 years to greater than 100 years. Failure of critical substation equipment can result in outages to thousands of customers at once.

The annual *Substation Refurbishment and Modernization* project provides a structured, long-term approach to maintaining approximately 4,000 pieces of critical substation equipment. Addressing deteriorated and substandard equipment reduces in-service failures and ensures compliance with current industry standards.

Refurbishment and modernization of Tors Cove, Glovertown and Humber substations in 2022 is necessary to ensure continued reliable operation of substation equipment.

This project is justified on the obligation to provide reliable service to customers at least cost and cannot be deferred.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2022 and a projection of expenditures through 2026. Appendix A of report *2.1 2022 Substation Refurbishment and Modernization* details the work planned for each of the next 5 years.

Table 1
Projected Expenditures
($000s)

Cost Category	2022	2023	2024 - 2026	Total
Material	5,632	-	-	-
Labour – Internal	208	-	-	-
Labour – Contract	-	-	-	-
Engineering	1,009	-	-	-
Other	200	-	-	-
Total	**$7,049**	**$12,793**	**$41,018**	**$60,860**

Costing Methodology

Table 2 shows the annual expenditures for this project for the most recent 5-year period, as well as the projected expenditure for 2022.

Table 2
Expenditure History
(000s)

Year	2017	2018	2019	2020	2021F	2022B
Total	$10,777	$7,917	$7,384	$10,018	$5,153	$7,049

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: **$3,691,000**

Project Description

This Substations project is necessary to replace substation equipment that has been removed from service due to storm damage, lightning strikes, vandalism, electrical or mechanical failure, corrosion damage, technical obsolescence or 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 interdependent. However, they are similar in nature and justification. The expenditures are therefore pooled for consideration as a single capital project.

Justification

Newfoundland Power operates 131 substations containing approximately 4,000 pieces of critical electrical equipment. Failure of critical substation equipment can result in outages to thousands of customers at once. Addressing in-service failures of substation equipment in a timely manner is necessary to maintain the condition of the Company's substations and provide reliable service to customers.

This project is justified on the obligation to provide reliable service to customers at least cost and cannot be deferred.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2022 and a projection of expenditures through 2026.

Table 1
Projected Expenditures
($000s)

Cost Category	2022	2023	2024 - 2026	Total
Material	2,564	-	-	-
Labour – Internal	745	-	-	-
Labour – Contract	-	-	-	-
Engineering	289	-	-	-
Other	93	-	-	-
Total	**$3,691**	**$3,753**	**$11,652**	**$19,096**

Costing Methodology

Table 2 shows the annual expenditures for this project for the most recent 5-year period, as well as projected expenditures for 2022.

Table 2
Expenditure History
(000s)

Year	**2017**	**2018**	**2019**	**2020**	**2021F**	**2022B**
Total	$2,230	$3,861	$4,532	$3,684	$3,413	$3,691

The major equipment items comprising a substation include substation transformers, circuit breakers, reclosers, voltage regulators, potential transformers and battery banks. In total, Newfoundland Power's substations have approximately 180 substation transformers, 420 circuit breakers, 180 reclosers, 50 voltage regulators, 450 potential transformers, 100 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 respond quickly to in-service failures. The size of the pool is based on past experience and engineering judgment, 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 an 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: **$899,000**

Project Description

This Substations project is necessary 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").[4]

Inspections completed before the end of 2014 identified 24 substation transformers with bushings having PCB concentrations greater than 50 ppm and less than 500 ppm. Similarly, inspections completed before the end of 2014 identified 42 bulk oil circuit breakers with PCB concentrations greater than 50 ppm and less than 500 ppm. These transformer bushings and circuit breakers will be replaced by 2025 to ensure compliance with government regulations regarding the phase out of PCBs in substation equipment.[5]

In 2022, the Company will replace bushings on 1 substation transformer and replace 8 bulk oil circuit breakers.

Justification

Substation equipment with PCB concentrations greater than 50 ppm must be addressed by 2025 as per the *PCB Regulations*. The *PCB Bushing Phase-out* project is necessary to meet the requirements outlined in these regulations.

This is a mandatory project justified on the requirement to meet the Government of Canada's *PCB Regulations* and cannot be deferred.

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4 Government of Canada PCB Regulation (SOR/2008-273) requires that substation transformer bushings, breakers and instrument transformers with PCB concentrations of greater than 50 ppm be removed from service by the end of 2025.

5 Commencing in 2017, Newfoundland Power initiated an 8 year program to remove from service substation equipment with PCB concentrations between 50 ppm and 500 ppm.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2022 and a projection of expenditures through 2026.

Table 1
Projected Expenditures
($000s)

Cost Category	2022	2023	2024 – 2026	Total
Material	628	-	-	-
Labour – Internal	38	-	-	-
Labour – Contract	-	-	-	-
Engineering	216	-	-	-
Other	17	-	-	-
Total	**$899**	**$855**	**$2,128**	**$3,882**

Costing Methodology

Table 2 shows the annual expenditures for this project for the most recent 5-year period, as well as the projected expenditure for 2022.

Table 2
Expenditure History
(000s)

Year	2017	2018	2019	2020	2021F	2022B
Total	$849	$884	$934	$739	$717	$899

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 (Clustered, Multi-Year)**

Project Cost: **$10,494,000**

Project Description

This Transmission project is necessary to replace deteriorated and deficient transmission line infrastructure. The rebuilding of the Company's oldest, most deteriorated transmission lines is in accordance with the program outlined in report *3.1 Transmission Line Rebuild Strategy* filed with the *2006 Capital Budget Application*.

The 2022 project involves:

1. Rebuilding the remaining 26.7 kilometre section of Transmission Line 124L from Terra Nova Substation to Gambo Substation. The project will include the rebuild of 23.6 kilometres of transmission line infrastructure, the dismantling of 3.1 kilometres of transmission line infrastructure, and the construction of a new 5.4 kilometre section of transmission line infrastructure into Glovertown Substation. ($6,021,000)

2. Rebuilding a 21 kilometre section of Transmission Line 94L. Transmission Line 94L operates between Blaketown Substation and Riverhead Substation.[6] (4,473,000)

The *Transmission Line Rebuild* Transmission project to rebuild Transmission Line 124L and the *Substation Refurbishment and Modernization* Substation project at Glovertown Substation are interdependent and are therefore clustered.

Details on the proposed 2022 rebuild project are included in report *3.1 2022 Transmission Line Rebuild*.

Justification

Newfoundland Power operates 107 transmission lines interconnecting substation, distribution and generation assets throughout its service territory. These transmission lines are the backbone of the Company's electrical system. A single transmission line outage can cause outages to thousands of customers.

On a total kilometre basis, 54% of Newfoundland Power's transmission lines are in excess of 40 years of age. Many of these lines are experiencing pole, crossarm, conductor, insulator and hardware deterioration.

Each transmission line is inspected annually to identify deterioration and deficiencies. Engineering assessments determine whether routine maintenance or the replacement of any

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[6] This is a multi-year project with expenditures planned for 2022 through 2024. Details of the planned expenditures can be found in Schedule C of this Application.

section of line is required to maintain the strength and integrity of the line. Maintaining the strength and integrity of transmission lines is necessary to provide reliable service to customers.

This project is justified on the obligation to provide reliable service to customers at least cost and cannot be deferred.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2022 and a projection of expenditures through 2026. Appendix A of report *3.1 2022 Transmission Line Rebuild* details the transmission line rebuilds planned for each year.

Table 1
Projected Expenditures
($000s)

Cost Category	2022	2023	2024 - 2026	Total
Material	3,685	-	-	-
Labour – Internal	211	-	-	-
Labour – Contract	4,823	-	-	-
Engineering	153	-	-	-
Other	1,622	-	-	-
Total	**$10,494**	**$10,044**	**$34,985**	**$55,523**

Costing Methodology

Table 2 shows the annual expenditures for this project for the most recent 5-year period, as well as projected expenditures for 2022. Annual expenditures are a function of the number of lines rebuilt, the distance covered and the construction standard used in the original design.

Table 2
Expenditure History
(000s)

Year	2017	2018	2019	2020	2021F	2022B
Total	$4,229	$5,588	$9,342	$7,809	$6,170	$10,494

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

The rebuild of transmission line 94L is a multi-year project which will be undertaken in 2022, 2023, and 2024. Table 3 details the 2022 through 2024 project expenditures for this multi-year project.

Table 3
94L Multi-Year Projected Expenditures
($000s)

Cost Category	2022B	2023B	2024B	Total
Material	1,579	1,486	1,482	4,547
Labour – Internal	90	86	86	262
Labour – Contract	2,050	1,970	1,970	5,990
Engineering	65	62	62	189
Other	689	742	676	2,107
Total	**$4,473**	**$4,346**	**$4,276**	**$13,095**

This is not otherwise a multi-year project.

Project Title: **Transmission Line Maintenance and 3rd Party Relocations (Pooled)**

Project Cost: **$2,398,000**

Project Description

This Transmission project is necessary to replace deteriorated transmission line infrastructure and to accommodate 3rd party requests to relocate or replace transmission lines.

The 2022 project involves:

1. Replacing transmission line poles, crossarms, conductors, insulators and hardware. Equipment replacements can result from deficiencies identified during inspections and engineering reviews, or in-service and imminent failures.

2. Accommodating 3rd party requests to relocate or replace transmission structures. The relocation or replacement of transmission lines results from: (i) work initiated by municipal, provincial and federal governments; (ii) work initiated by other users, such as Bell Aliant, Eastlink and Rogers Communications; and (iii) requests from customers.

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

Justification

Newfoundland Power operates over 2,000 kilometres of transmission lines. The Company's transmission line maintenance includes annual inspections and engineering reviews to assess plant condition and the requirement to replace deteriorated structures and equipment. The replacement of deteriorated structures and equipment is required annually to maintain overall plant condition. Project costs for 2022 are based on recent requirements for addressing transmission line deterioration.

Responding to 3rd party requests to relocate or replace transmission structures is necessary to maintain safe and adequate facilities. The relocation or replacement of transmission lines is governed by the provisions of agreements in place with the requesting parties. Requests by customers are governed by the Company's policy respecting Contributions in Aid of Construction.

The maintenance component of this project is justified on the obligation to provide reliable service to customers at least cost and cannot be deferred.

The 3rd party requests component of this project is justified on the obligation to maintain safe and adequate facilities and cannot be deferred.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2022 and a projection of expenditures through 2026.

Table 1
Projected Expenditures
($000s)

Cost Category	**2022**	**2023**	**2024 - 2026**	**Total**
Material	1,632	-	-	-
Labour – Internal	115	-	-	-
Labour – Contract	339	-	-	-
Engineering	152	-	-	-
Other	160	-	-	-
Total	**$2,398**	**$2,442**	**$7,603**	**$12,443**

Costing Methodology

Table 2 shows the annual expenditures for this project for the most recent 5-year period, as well as the projected expenditure for 2022.[7]

Table 2
Expenditure History
(000s)

Year	**2017**	**2018**	**2019**	**2020**	**2021F**	**2022B**
Total	$2,134	$2,747	$2,214	$2,139	$2,238	$2,398

Annual expenditures are a function of the number of deficiencies identified and the number of 3rd party requests received. Budget estimates are based on an assessment of historical expenditures.

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

Future Commitments

This is not a multi-year project.

7 These expenditures were included as part of the *Transmission Line Rebuild* project in capital budget applications prior to 2021.

DISTRIBUTION

Project Title: **Extensions (Pooled)**

Project Cost: **$10,333,000**

Project Description

This Distribution project involves the construction of both primary and secondary distribution lines to connect new customers to the electrical 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

Providing equitable access to an adequate supply of power requires connecting new customers to the electrical system and addressing increases in customers' electrical loads. This project is necessary to ensure these requirements are met in 2022.

This project is justified on the obligation to provide customers with equitable access to an adequate supply of power and cannot be deferred.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2022 and a projection of expenditures through 2026.

Table 1
Projected Expenditures
($000s)

Cost Category	2022	2023	2024 - 2026	Total
Material	3,207	-	-	-
Labour – Internal	3,041	-	-	-
Labour – Contract	2,431	-	-	-
Engineering	1,320	-	-	-
Other	334	-	-	-
Total	**$10,333**	**$10,386**	**$31,599**	**$52,318**

Costing Methodology

Table 2 shows the annual expenditures and unit costs for this project for the most recent 5-year period, as well as a projected unit cost for 2022.

Table 2
Expenditure History and Unit Cost Projection

Year	2017	2018	2019	2020	2021F	2022B
Total (000s)	$13,371	$11,274	$13,379	$10,561	$9,556	$10,333
Adjusted Costs (000s)[1]	$14,296	$11,811	$13,798	$10,735	-	-
New Customers	3,271	2,781	2,379	2,062	2,096	2,038
Unit Costs ($/customer)[1]	$4,371	$4,247	$5,800	$5,206	$4,559	$5,070

[1] 2021 dollars.

The project cost for connecting new customers is calculated on the basis of historical data. Historical annual expenditures over the most recent 5-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: **$818,000**

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 2022.

Table 1
2022 Proposed Meter Acquisition

Program	Number of Meters
Energy Only Domestic Meters	4,886
Other Energy Only and Demand Meters	1,844

The expenditures for individual meters are not interdependent, but are similar in nature and justification. They have therefore been pooled for consideration as a single capital project.

Since 2016, Newfoundland Power has used AMR metering technology as per report *4.4 2016 Metering Strategy* included in the *2016 Capital Budget Application*. All new and replacement meters in 2022 will also be AMR technology to integrate with current technology.

Justification

Providing equitable access to an adequate supply of power requires connecting new customers to the electrical system. The installation of meters to serve new customers is necessary to ensure this requirement is met in 2022.

Revenue metering of electrical service is regulated under the *Electricity and Gas Inspection Act (Canada)*. The replacement component of this project ensures compliance with this legislation and that deteriorated or failed meters are removed from service.

The new component of this project is justified on the obligation to provide customers with equitable access to an adequate supply of power and cannot be deferred.

The replacement component of this project is justified on the obligation to provide reliable service to customers at least cost and cannot be deferred.

Projected Expenditures

Table 2 provides a breakdown of the proposed expenditures for 2022 and a projection of expenditures through 2026.

Table 2
Projected Expenditures
($000s)

Cost Category	2022	2023	2024 - 2026	Total
Material	685	-	-	-
Labour – Internal	116	-	-	-
Labour – Contract	17	-	-	-
Engineering	-	-	-	-
Other	-	-	-	-
Total	**$818**	**$849**	**$2,742**	**$4,409**

Costing Methodology

Table 3 shows the annual expenditures for the most recent 5-year period, as well as a projection for 2022.

Table 3
Expenditure History and Unit Cost Projection

Year	2017	2018	2019	2020	2021F	2022B
Meter Requirements						
New Connections	3,271	2,781	2,379	2,062	2,096	2,038
GROs/CSOs	4,042	563	839	1,269	1,449	2,192
Replacements	36,681[2]	2,021	1,204	1,224	2,500	2,500
Total	43,994	5,365	4,422	4,292	6,045	6,730
Meter Costs						
Actual (000s)	$3,625	$644	$481	$582	$680	$818
Adjusted[1] (000s)	$3,818	$668	$494	$590	-	-
Unit Costs[1]	$ 87	$ 125	$ 112	$ 130	$ 113	$ 120

1 2021 dollars.
2 The Company achieved 100% penetration of AMR meters at the end of 2017. The 2022 metering budget is approximately $3 million less than expenditures prior to 2018.

The project cost for meters is calculated on the basis of historical data. Historical annual expenditures over the most recent 5-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: **$3,038,000**

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 a 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

Providing equitable access to an adequate supply of power requires connecting new customers to the electrical system and addressing increases in customers' electrical loads. The installation of service wires for new customers or customers with increased electrical loads is necessary to ensure these requirements are met in 2022.

Providing reliable service requires replacing deteriorated, damaged or failed service wires serving existing customers. This project is necessary to ensure this requirement is met in 2022.

The new component of this project is justified on the obligation to provide customers with equitable access to an adequate supply of power and cannot be deferred.

The replacement component of this project is justified on the obligation to provide reliable service to customers at least cost and cannot be deferred.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2022 and a projection of expenditures through 2026.

Table 1
Projected Expenditures
($000s)

Cost Category	2022	2023	2024 - 2026	Total
Material	923	-	-	-
Labour – Internal	1,657	-	-	-
Labour – Contract	154	-	-	-
Engineering	265	-	-	-
Other	39	-	-	-
Total	**$3,038**	**$3,066**	**$9,401**	**$15,505**

Costing Methodology

Table 2 shows the annual expenditures and unit costs for *new* services for the most recent 5-year period, as well as a projected unit cost for 2022.

Table 2
Expenditure History and Unit Cost Projection
New Services

Year	2017	2018	2019	2020	2021F	2022B
Total (000s)	$2,748	$3,233	$2,769	$2,283	$2,226	$2,470
Adjusted Costs (000s)[1]	$2,941	$3,389	$2,858	$2,322	-	-
New Customers	3,271	2,781	2,379	2,062	2,096	2,038
Unit Costs ($/customer)[1]	$899	$1,219	$1,201	$1,126	$ 1,062	$1,212

[1] 2021 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 5-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 5-year period, as well as a projected cost for 2022.

Table 3
Expenditure History and Average Cost Projection
Replacement Services
(000s)

Year	2017	2018	2019	2020	2021F	2022B
Total	\$607	\$577	\$321	\$607	\$573	\$568
Adjusted Costs[1]	\$650	\$605	\$332	\$617	-	-

[1] 2021 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: **$2,507,000**

Project Description

This Distribution project involves the installation of new street lighting fixtures and the replacement of overhead and underground wiring, where necessary. A street light fixture includes the light head and photocell as well as the pole mounting bracket and other hardware. The project is driven by customer requests for street lighting.

In 2019, the Company adopted LED technology as its new service standard for all new and replacement street lighting installations. The adoption of this standard followed the approval of LED street lighting rates for customers in Order No. P.U. 2 (2019).

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

Justification

Street lighting is an established service offering of the Company. Providing equitable access to this service requires responding to customers' requests for street light installations. This project is necessary to ensure this requirement is met in 2022.

This project is justified on the obligation to provide equitable access to an adequate supply of power and cannot be deferred.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2022 and a projection of expenditures through 2026.

Table 1
Projected Expenditures
($000s)

Cost Category	2022	2023	2024 - 2026	Total
Material	1,382	-	-	-
Labour – Internal	875	-	-	-
Labour – Contract	190	-	-	-
Engineering	36	-	-	-
Other	24	-	-	-
Total	**$2,507**	**$2,557**	**$7,984**	**$13,048**

Street lighting capital expenditures for the period 2022 to 2026 include the installation of new street lighting fixtures and the replacement of overhead and underground wiring. The capital expenditures associated with replacement street lighting is now included in the *Street Lighting - LED Replacement Program* capital project.

Costing Methodology

Table 2 shows the annual expenditures for new street lights for the most recent 5-year period, as well as the projected cost for 2022.

Table 2
Expenditure History
(000s)

Year	**2017**	**2018**	**2019**	**2020**	**2021F**	**2022B**
Total	$1,319	$2,535	$2,678	$2,608	$1,979	$2,283[2]
Adjusted Costs[1]	$1,398	$2,649	$2,754	$2,645	-	-

1 2021 dollars.
2 Excludes $225,000 associated with the replacement of overhead and underground wiring.

Previously, the costing methodology for estimating the budget requirement for street lights used inflation adjusted unit costs and forecast new customer connections. In recent years, Newfoundland Power has experienced significant variances between budgets and actual expenditures.[8] As a result, the Company has reassessed its *Street Lighting* costing methodology for 2022.[9]

In 2022, the process for estimating the budget requirement for street lights is based on historical average. Historical annual expenditures related to new street lights over the most recent 5-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.

8 Over the past 3 years, the average variance from budget to actual capital expenditures has been 50%.
9 The *Capital Budget Application Guidelines* state in Section C, Subsection 1 – Capital Expenditure Report, "Should the overall variance in any two years exceed 10% of the budgeted total the report should address whether there should be changes to the forecasting or capital budgeting process which should be considered."

Project Title: **Street Lighting – LED Replacement Program (Pooled)**

Project Cost: **$5,428,000**

Project Description

This Distribution project is the 2nd year of a 6-year program to replace all High Pressure Sodium ("HPS") street light fixtures with LED fixtures.

All expenditures required to replace existing HPS fixtures are included in this project. The expenditures are pooled for consideration as a single capital project.

Details on the LED replacement program can be found in the *2021 Capital Budget Application* report *LED Street Lighting Replacement Plan.*

Justification

Newfoundland Power adopted LED street lighting as its new service standard following the approval of customer rates in Order No. P.U. 2 (2019).

Current customer rates for LED street lights are between 9% and 39% less for customers than equivalent HPS rates. Lower customer rates are the result of lower energy and maintenance costs for LED street lights. LED street lights also provide more reliable and better quality lighting for customers.

In 2021, Newfoundland Power developed a plan to accelerate the installation of LED street lights for customers. The plan will continue in 2022 and ensure all customers are provided with the lower rates of LED street lights within 6 years.

The total cost of executing the plan is estimated at approximately $32.8 million. An economic analysis determined the plan will reduce energy and maintenance costs to customers by approximately $52 million over 20 years. This results in lower overall costs for customers over the long term.

The plan is consistent with current Canadian utility practice and has received the support of the largest municipal organization in the province, Municipalities Newfoundland and Labrador.

This project is justified on the obligation to provide reliable service to customers at least cost and cannot be deferred.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2022 and a projection of expenditures through 2026.

Table 1
Projected Expenditures
($000s)

Cost Category	2022	2023	2024 - 2026	Total
Material	4,128	-	-	-
Labour – Internal	1,300	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	-	-	-	-
Total	**$5,428**	**$5,453**	**$16,510**	**$27,391**

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: **Transformers (Pooled)**

Project Cost: **$5,958,000**

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

Providing equitable access to an adequate supply of power requires connecting new customers to the electrical system. This project is necessary to ensure this requirement is met in 2022.

Providing reliable service requires replacing deteriorated or failed transformers serving existing customers. This project is necessary to ensure this requirement is met in 2022.

The new component of this project is justified on the obligation to provide customers with equitable access to an adequate supply of power and cannot be deferred.

The replacement component of this project is justified on the obligation to provide reliable service to customers at least cost and cannot be deferred.

Projected Expenditures

Table 1 provides the breakdown of the proposed expenditures for 2022 and a projection of expenditures through 2026.

Table 1
Projected Expenditures
($000s)

Cost Category	2022	2023	2024 - 2026	Total
Material	5,958	-	-	-
Labour – Internal	-	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	-	-	-	-
Total	**$5,958**	**$6,019**	**$18,445**	**$30,422**

Costing Methodology

Table 2 shows the annual expenditures for this project for the most recent 5-year period, as well as the projected expenditure for 2022.

Table 2
Expenditure History
(000s)

Year	**2017**	**2018**	**2019**	**2020**	**2021F**	**2022B**
Total	\$5,835	\$5,782	\$5,696	\$5,628	\$5,945	\$5,958
Adjusted Costs[1]	\$6,082	\$5,963	\$5,813	\$5,686	-	-

[1] 2021 dollars.

The process of estimating the budget requirement for transformers is based on an historical average. Historical annual expenditures related to distribution transformers over the most recent 5-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: **$5,902,000**

Project Description

This Distribution project involves the replacement of deteriorated or damaged distribution structures and electrical equipment. This project comprises high-priority deficiencies that are identified during the budget year or recognized during follow-up on operational problems, including power interruptions and customer trouble calls.

This project differs from the *Rebuild Distribution Lines* project, which involves the planned rebuilding of sections of lines or the selective replacement of various line components based on preventive maintenance inspections or engineering reviews.

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

Justification

Newfoundland Power operates over 10,000 kilometres of distribution lines to serve customers throughout its service territory. Addressing deteriorated distribution structures and equipment is required to maintain plant condition. High-priority deficiencies must be addressed in a timely manner to maintain the safe and reliable operation of the electrical system. Project costs for 2022 are based on recent requirements for addressing high-priority deficiencies.

This project is justified on the obligation to provide reliable service to customers at least cost and cannot be deferred.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2022 and a projection of expenditures through 2026.

Table 1
Projected Expenditures
($000s)

Cost Category	**2022**	**2023**	**2024 - 2026**	**Total**
Material	1,397	-	-	-
Labour – Internal	2,376	-	-	-
Labour – Contract	1,332	-	-	-
Engineering	596	-	-	-
Other	201	-	-	-
Total	**$5,902**	**$6,052**	**$19,100**	**$31,054**

Costing Methodology

Table 2 shows the annual expenditures and costs in current dollars for the most recent 5-year period, as well as the projected expenditure for 2022.

Table 2
Expenditure History
(000s)

Year	**2017**	**2018**	**2019**	**2020**	**2021F**	**2022B**
Total	$4,575	$5,903	$5,579	$6,275	$5,567	$5,902
Adjusted Costs[1]	$4,917	$6,199	$5,766	$6,384	-	-

[1] 2021 dollars.

The process of estimating the budget requirement for *Reconstruction* is based on an historical average. Historical annual expenditures related to unplanned repairs to distribution feeders over the most recent 5-year period, including the current year, are expressed in current-year dollars ("Adjusted Costs"). The estimate for the budget year is calculated by taking the average of the Adjusted Costs and inflating it using the GDP Deflator for Canada.

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

Future Commitments

This is not a multi-year project.

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

Project Cost: **$4,333,000**

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 2022 will be performed on the following 43 of the Company's feeders:

BCV-03	CHA-03	HUM-08	NCH-03	SJM-10	VIR-01	WES-01
BLK-01	GBE-01	HUM-09	OPL-01	SPR-03	VIR-02	
BRB-04	GBS-02	JON-01	OPL-02	SPR-04	VIR-03	
BVA-01	GDL-01	LAU-01	OPL-03	SUM-02	VIR-04	
BVA-02	GDL-07	LAU-02	ROB-02	TNS-01	VIR-05	
BVA-03	HAR-01	LEW-02	SJM-02	VIC-01	VIR-06	
CHA-01	HOW-01	MIL-01	SJM-03	VIC-02	WBC-01	

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

Justification

Newfoundland Power operates approximately 10,000 kilometres of distribution lines to serve customers throughout its service territory. The Company implements an annual inspection program to identify deteriorated structures and equipment throughout its distribution system. Deterioration is addressed under this project through either the planned rebuilding of sections of line or the selective replacement of line components. Project costs for 2022 are based on recent requirements for addressing deterioration on the distribution system.

This project is justified on the obligation to provide reliable service to customers at least cost and cannot be deferred.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2022 and a projection of expenditures through 2026.

Table 1
Projected Expenditures
($000s)

Cost Category	2022	2023	2024 - 2026	Total
Material	1,802	-	-	-
Labour – Internal	2,008	-	-	-
Labour – Contract	262	-	-	-
Engineering	44	-	-	-
Other	217	-	-	-
Total	**$4,333**	**$4,439**	**$13,988**	**$22,760**

Costing Methodology

Table 2 shows the annual expenditures for this project for the most recent 5-year period, as well as the projected expenditure for 2022.

Table 2
Expenditure History
(000s)

Year	2017	2018	2019	2020	2021F	2022B
Total	$3,269	$4,429	$4,371	$4,477	$3,965	$4,333
Adjusted Costs[1]	$3,502	$4,646	$4,514	$4,556	-	-

[1] 2021 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 2022 are ongoing throughout 2021. Complete inspection data will not be available until late 2021. The process of estimating the budget requirement for *Rebuild Distribution Lines* is based on an historical average. Historical annual expenditures related to rebuilding distribution feeders over the most recent 5-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: **Relocate/Replace Distribution Lines for Third Parties (Pooled)**

Project Cost: **$3,370,000**

Project Description

This Distribution project is necessary to accommodate 3rd party requests to relocate or replace 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 users, such as Bell Aliant, Eastlink and Rogers Communications; 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. The relocation or replacement of facilities for customers is governed by the Company's policy respecting Contributions in Aid of Construction.

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

Justification

Maintaining safe and adequate facilities requires responding to 3rd party requests to relocate or replace distribution lines.

This project is justified on the obligation to maintain safe and adequate facilities and cannot be deferred.

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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.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2022 and a projection of expenditures through 2026.

Table 1
Projected Expenditures
($000s)

Cost Category	2022	2023	2024 - 2026	Total
Material	1,188	-	-	-
Labour – Internal	1,084	-	-	-
Labour – Contract	690	-	-	-
Engineering	347	-	-	-
Other	61	-	-	-
Total	**$3,370**	**$3,445**	**$10,808**	**$17,623**

Costing Methodology

Table 2 shows the annual expenditures for this project for the most recent 5-year period, as well as the projected expenditure for 2022.

Table 2
Expenditure History
(000s)

Year	2017	2018	2019	2020	2021F	2022B
Total	$2,445	$3,177	$5,192	$2,745	$3,155	$3,370
Adjusted Costs[1]	$2,577	$2,619[2]	$5,363	$2,793	-	-

1 2021 dollars
2 Excludes $681,000 associated with Rogers Communications fibre build in St. John's area.

The 2022 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 5-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: **Distribution Reliability Initiative (Pooled)**

Project Cost: **$350,000**

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.[11] 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 location-specific design and construction standards.

In 2019, Newfoundland Power implemented a new Outage Management System. The new system, called Responder, is capable of providing outage data with much greater granularity. This allows Newfoundland Power to not only identify worst performing feeders but to isolate specific sections of feeders or even specific customers who are experiencing poor reliability performance. The system allows Newfoundland Power's technical staff to more accurately pinpoint areas where reliability is a concern.

In 2022, the Company has identified a section of distribution feeder BCV-04 where reliability performance can be improved by focused work on a 2 km section exposed to high winds and salt contamination.

Details on 2022 proposed expenditures are included in report *4.1 Distribution Reliability Initiative* filed as part of this application.

Justification

Under the *Distribution Reliability Initiative*, individual feeder projects are identified and 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. Engineering assessments are completed to determine whether targeted capital investments would improve the reliability experienced by customers served by these feeders.

The *Distribution Reliability Initiative* improves reliability in areas where customers experience poor reliability performance. Targeting capital expenditures in these areas is consistent with maintaining an overall acceptable level of service reliability for all customers.

This project is justified on the obligation to provide reliable service to customers at least cost and cannot be deferred.

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

Projected Expenditures

Table 2 provides the breakdown of the proposed expenditures for 2022 and a projection of expenditures through 2026.

Table 2
Projected Expenditures
($000s)

Cost Category	**2022**	**2023**	**2024 - 2026**	**Total**
Material	96	-	-	-
Labour – Internal	126	-	-	-
Labour – Contract	90	-	-	-
Engineering	23	-	-	-
Other	15	-	-	-
Total	**$350**	**$1,000**	**$4,700**	**$6,050**

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: **Feeder Additions for Load Growth (Pooled)**

Project Cost: **$1,690,000**

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 2022, the *Feeder Additions for Load Growth* project will include the upgrading of the following distribution feeders:

1. A section of Pulpit Rock feeder PUL-03 will be upgraded from 2-phase to 3-phase in order to address an overload condition that has developed as a result of customer connection growth, as well as large home renovations and electrical service upgrades in the areas of Bauline Line, Middle Three Island Pond Cabin Area, Bauline Line Extension and Pondside Subdivision. ($560,000)

2. A section of Virginia Waters feeder VIR-01 will be upgraded from single-phase to 3-phase in order to address an overload condition that has developed as a result of customer connection growth as well as large home renovations and electrical service upgrades in the area of Marine Drive and Doran's Lane. ($350,000)

3. A section of Springfield feeder SPF-01 will be upgraded from single-phase to 3-phase, and an additional section will be upgraded from 2-phase to 3-phase in order to address an overload condition that has developed as a result of residential development in the community of North River, Halls Town and the cabin area along North River Road. ($600,000)

4. A section of Harmon feeder HAR-02 will be reconductored in order to address an overload condition that has developed as a result of the addition of a new large load customer on the feeder. ($180,000)

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

Justification

Providing equitable access to an adequate supply of power requires connecting new customers to the electrical system and addressing increases in customers' electrical loads. This project is necessary to ensure these requirements are met in 2022.

This project is justified on the obligation to provide customers with equitable access to an adequate supply of power and cannot be deferred.

Projected Expenditures

Table 1 provides the breakdown of the proposed expenditures for 2022 and a projection of expenditures through 2026.

Table 1
Projected Expenditures
($000s)

Cost Category	2022	2023	2024 - 2026	Total
Material	395	-	-	-
Labour – Internal	508	-	-	-
Labour – Contract	327	-	-	-
Engineering	168	-	-	-
Other	292	-	-	-
Total	**$1,690**	**$4,682**	**$9,061**	**$15,433**

Costing Methodology

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

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

Future Commitments

This is not a multi-year project.

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

Project Cost: **$893,000**

Project Description

This Distribution project is necessary to increase automation in the Company's distribution system. Increased automation in the distribution system improves customer service through reduced restoration times following both local and system-wide outages.[12]

Increasing automation of distribution feeders will involve the addition of new equipment to the distribution system or the replacement of some older equipment in service with modern, communications-capable equipment. The increase in automation will include the addition of technologies, such as automated downline reclosers and fault indicators. These devices reduce outage response and restoration time, as sections of feeders no longer need to be patrolled to identify the cause of outages. Details on the various customer and operational benefits associated with the continued deployment of automated equipment throughout the Company's distribution system can be found in the *2020 Capital Budget Application* report *4.5 Distribution Feeder Automation*.

Table 1 lists the downline automated reclosers proposed to be installed in 2022.

Table 1
2022 Downline Automated Recloser Installations

Feeders	Number of Devices	Deployment Scenario[13]
GOU-02	1	Scenario 1
GDL-08	1	Scenario 1
GOU-02/GDL-08 TIE	1	Scenario 3
GDL-04	1	Scenario 1
GDL-05	1	Scenario 1
CLV-01	1	Scenario 1
MKS-01	1	Scenario 1
BLK-01	2	Scenario 2
GFS-06	1	Scenario 2
SUM-01	1	Scenario 2
PAB-03	2	Scenario 2
PAB-05	1	Scenario 2
GBS-01	1	Scenario 2
LGL-02	1	Scenario 2

12 Increasing the level of automation in the distribution system is consistent with Recommendation 2.4 of The Liberty Consulting Group's *Report on Island Interconnected System to Interconnection with Muskrat Falls addressing Newfoundland Power*, December 17, 2014.

13 Deployment scenarios as defined in the *2020 Capital Budget Application* report *4.5 Distribution Feeder Automation*.

Justification

The deployment of automated distribution equipment will enhance the Company's response to customer outages in all operating conditions, including local and system-wide outages. Distribution feeder automation is recognized in the electric utility industry as providing both reliability and efficiency benefits for customers.

This project is justified on the obligation to provide reliable service to customers at least cost and cannot be deferred.

Projected Expenditures

Table 2 provides the breakdown of the proposed expenditures for 2022 and a projection of expenditures through 2026.

Table 2
Projected Expenditures
($000s)

Cost Category	**2022**	**2023**	**2024 - 2026**	**Total**
Material	536	-	-	-
Labour – Internal	81	-	-	-
Labour – Contract	77	-	-	-
Engineering	88	-	-	-
Other	111	-	-	-
Total	**$893**	**$955**	**$2,976**	**$4,824**

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: **Trunk Feeders – Humber 4.16 kV Conversion (Clustered)**

Project Cost: **$1,355,000**

Project Description

This Distribution project involves the conversion of the 4.16 kV distribution system at Humber ("HUM") Substation to 12.5 kV. This Distribution project is necessary to address identified substation deficiencies thereby maintaining safe, reliable service to customers into the future.[14]

The project includes conversion of the 4.16 kV distribution feeders to 12.5 kV and construction of a new feeder, HUM-10, to supply the loads associated with the former 4.16 kV system. Components that require upgrading to support voltage conversion include distribution pole top transformers, insulators and lightning arrestors.

In addition to installing 12.5 kV compatible components, additional upgrades will be required to accommodate the final configuration, as well as minimize the customer impact during the project. Associated work will include upgrading sections of feeders to support reconfigured distribution feeder trunks; establishing appropriate feeder tie points for facilitating conversion; and replacement of protective fusing to accommodate changes in voltage and configuration.

Details on the proposed expenditures are included in report *2.1 2022 Substation Refurbishment and Modernization; Appendix B Humber Substation 4.16 kV Infrastructure Replacement*.

The *Trunk Feeders – Humber 4.16 kV Conversion* and the *Substation Refurbishment and Modernization* projects at Humber Substation are interdependent and are therefore clustered.

Justification

Engineering condition assessments have identified a number of components in Humber Substation, including the 4.16 kV switchgear, power transformer HUM-T3, and high voltage switches are approaching the end of their service life. The least cost alternative identified is to dismantle the existing 4.16 kV infrastructure and replace it with 12.5 kV infrastructure. Upgrading the 4.16 kV distribution system in downtown Corner Brook will also improve operational flexibility through the creation of tie points to the existing 12.5 kV distribution system adjacent to the distribution system being converted.

This project is justified on the obligation to provide reliable service to customers at least cost and cannot be deferred.

[14] The 4.16 kV equipment at the Company's Humber Substation is deteriorated and requires replacement.

Projected Expenditures

Table 1 provides the breakdown of the proposed expenditures for 2022 and a projection of expenditures through 2026.

Table 1
Projected Expenditures
($000s)

Cost Category	**2022**	**2023**	**2024 - 2026**	**Total**
Material	152	-	-	-
Labour – Internal	514	-	-	-
Labour – Contract	370	-	-	-
Engineering	205	-	-	-
Other	114	-	-	-
Total	**$1,355**	**-**	**-**	**$1,355**

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: **Electric Vehicle Charging Network (Pooled)**

Project Cost: **$1,530,000**

Project Description

In 2021, Newfoundland Power will commence the implementation of the *Electrification, Conservation and Demand Management Plan: 2021-2025.* The plan includes the construction and installation of an electric vehicle charging network over a 5-year period, commencing with installation of 10 chargers in 2021.[15]

In 2022, the project includes the construction and installation of 10 additional electric vehicle charging stations. Each charging station will include a 50 kW fast charger, commonly referred to as Direct Current Fast Chargers.

The locations of charging sites in 2022 were selected based on specific criteria. These criteria include: (i) location along highways and major transportation routes; (ii) the location of current and planned charging sites; (iii) the distance between charging sites; and (iv) proximity to amenities and points of interest. These criteria are consistent with Federal Government recommendations.

[15] Details on the 5-year electric vehicle charging network are included in the *Electrification, Conservation and Demand Management Plan: 2021-2025*, as well as the *2021 Supplemental Capital Expenditures: Electric Vehicle Charging Network Application* filed as part of the plan with the Board on December 23rd, 2020.

Figure 1 provides the locations selected for electric vehicle charging sites in 2022.

Figure 1: 2022 Electric Vehicle Charging Site Locations

The locations selected for electric vehicle charging sites in 2022 are: Baie Verte; Clarenville; Steady Brook; Doyles; Grand Falls-Windsor; Heart's Delight - Islington; Lumsden; Placentia; St. John's and Twillingate. The specific sites for each location will be selected through a public application process.[16]

Justification

Execution of the *Electric Vehicle Charging Network* project is necessary to facilitate the successful delivery of customer electrification programs outlined in Newfoundland Power's *Electrification, Conservation and Demand Management Plan: 2021-2025*. The successful delivery of electrification programs will provide a rate mitigating benefit to customers over the longer term, primarily through transportation electrification.

[16] For each location, Newfoundland Power will select a site host through a public application process.

Transportation electrification requires the installation of adequate charging infrastructure for electric vehicles. The availability of charging infrastructure in Newfoundland and Labrador is currently insufficient to support the widespread adoption of electric vehicles.

The proposed expenditures included in this project are justified based on a cost benefit analysis included in Appendix A in the *2021 Supplemental Capital Expenditures: Electric Vehicle Charging Network Application*.[17]

Projected Expenditures

Table 1 provides the breakdown of the proposed expenditures for 2022 and a projection of expenditures through 2026.

Table 1
Projected Expenditures
($000s)

Cost Category	2022	2023	2024 - 2026	Total
Material	1,393	-	-	-
Labour – Internal	-	-	-	-
Labour – Contract	-	-	-	-
Engineering	38	-	-	-
Other	99	-	-	-
Total	**$1,530**	**$460**	**$771**	**$2,761**

Costing Methodology

The budget estimate for this project is based on an engineering cost estimate of the required work.

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

Future Commitments

This is not a multi-year project. Future expenditures will be presented in the appropriate annual capital budget application.

[17] Newfoundland Power intends to apply for federal funding for the construction of the Electric Vehicle Charging Network in 2022. If approved, this funding will reduce the overall capital costs borne by customers.

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

Project Cost: **$239,000**

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 3 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

AFUDC is required to implement the Company's capital program and is justified on the same basis as the distribution capital projects to which it relates.

Projected Expenditures

Table 1 provides the breakdown of the proposed expenditures for 2022 and a projection of expenditures through 2026.

Table 1
Projected Expenditures
($000s)

Cost Category	2022	2023	2024 - 2026	Total
Material	-	-	-	-
Labour – Internal	-	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	239	-	-	-
Total	**$239**	**$243**	**$749**	**$1,231**

Costing Methodology

Table 2 shows the annual expenditures for this project for the most recent 5-year period, as well as the projected expenditure for 2022.

Table 2
Expenditure History
(000s)

Year	2017	2018	2019	2020	2021F	2022B
Total	$179	$177	$215	$234	$205	$239

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: **$598,000**

Project Description

This General Property project is necessary to add or replace tools and equipment used in providing safe and reliable electrical service. Tools and equipment are used by power line technicians ("PLT"), engineering technologists, engineers and tradespersons. The majority of these tools are used in normal day-to-day operations. Additionally, 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 ($299,000)*: This item includes the replacement of tools and equipment used by PLTs 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 ($175,000)*: This item includes engineering test equipment and tools used by electrical and mechanical maintenance personnel and engineering technologists. 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. This category also consists of the purchase of a universal relay test set at an estimated cost of $100,000.

3. *Office Furniture ($124,000)*: 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.

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

Justification

Maintaining suitable tools and equipment is required to respond to customer outages and to operate and maintain the electrical system. This project is necessary to ensure this requirement is met in 2022.

This project is justified on the obligation to provide reliable service to customers at least cost and cannot be deferred.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2022 and a projection of expenditures through 2026.

Table 1
Projected Expenditures
($000s)

Cost Category	2022	2023	2024 - 2026	Total
Material	598	-	-	-
Labour – Internal	-	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	-	-	-	-
Total	**$598**	**$654**	**$1,543**	**$2,795**

Costing Methodology

Table 2 shows the annual expenditures for this project for the most recent 5-year period, as well as the projected expenditure for 2022.

Table 2
Expenditure History
(000s)

Year	2017	2018	2019	2020	2021F	2022B
Total	$499	$485	$451	$496	$486	$498[1]

1 Excludes universal relay test set ($100,000).

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. 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: $716,000

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 water line replacement, sewer interceptor installation and correcting major drainage problems.

The 2022 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 historical expenditures for the previous 5-year period, $383,000 is required for 2022.

In addition to the historical expenditure component, this project also consists of the refurbishment of identified deteriorated transformer storage racks at Company service centres at an estimated cost of $150,000, the refurbishment of Company washrooms at an estimated cost of $113,000,[18] and the installation of electric vehicle chargers for Company electric vehicle fleet at an estimated cost of $70,000.[19]

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

Justification

Newfoundland Power maintains office buildings and other facilities throughout its service territory to ensure a reasonable response to customer outages and customer-driven work requests. These facilities deteriorate and components fail over time. Upgrading, refurbishing and replacing building components is necessary annually to maintain these facilities in safe and adequate condition. Project costs for 2022 are estimated based on recent and identified requirements for addressing deteriorated building components.

This project is justified on the obligation to maintain safe and adequate facilities and cannot be deferred.

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[18] As a result of the COVID -19 pandemic, it is recognized that improvements to washrooms are required to improve sanitary conditions. In addition, Company buildings generally predate modern accessibility, inclusivity and diversity regulations and expectations. To promote sanitary conditions, touchless fixtures will be provided for faucets and toilets. Doors, equipped with operators to provide hands free operation and improve accessibility, will be able to be opened without touching handles.

[19] Electric Vehicle (EV) charging stations will be installed at various Company properties to support the use of EVs for Company functions such as meter reading and other field services.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2022 and a projection of expenditures through 2026.

Table 1
Projected Expenditures
($000s)

Cost Category	2022	2023	2024 – 2026	Total
Material	586	-	-	-
Labour – Internal	18	-	-	-
Labour – Contract	-	-	-	-
Engineering	75	-	-	-
Other	37	-	-	-
Total	**$716**	**$971**	**$1,957**	**$3,644**

Costing Methodology

Table 2 shows the annual expenditures for this project for the most recent 5-year period, as well as the projected expenditure for 2022.

Table 2
Expenditure History
(000s)

Year	2017	2018	2019	2020	2021F	2022B
Total	$467	$412[1]	$353[2]	$335[2]	$372[3]	$383[4]

1 Excludes Duffy Place backflow prevention ($224,000) and 2 UPS battery bank replacements ($123,000).
2 Excludes refurbishment of deteriorated transformer storage racks ($150,000).
3 Excludes refurbishment of deteriorated transformer storage racks ($150,000) and Duffy Place battery bank ($75,000).
4 Excludes refurbishment of deteriorated transformer storage racks ($150,000), Company washrooms ($113,000), and the installation of EV chargers at Company buildings ($70,000).

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: **Clarenville Area Office Building Refurbishment (Pooled)**

Project Cost: **$854,000**

Project Description

In 2022, the Company will upgrade the HVAC system and replace the built-up roofing system at the Clarenville Area Office Building (the "Facility"). The Facility is Newfoundland Power's centre of operations for the Clarenville Area (the "Area"). The Area's service territory extends from Southern Harbour in the east to Port Blandford in the west and includes the Bonavista Peninsula. Staff based out of the Facility also assist with Company operations on the Burin Peninsula. In total, the Facility serves approximately 30,000 customers, representing 11% of all customers served by the Company.[20]

The Facility provides support for 22 employees and equipment necessary for operations in the Area. This includes area customer service staff, line crews, maintenance and planning staff, a materials handler, and associated management staff. The Facility also supports corporate functions, such as emergency material storage needed for regional storm response.

Condition assessments of the HVAC system and roofing system have identified significant deterioration on each system. Capital improvements are necessary at this time to ensure the Company can continue to provide safe and reliable service to its customers in the Area.

Details on the proposed expenditures are included in report *5.1 Clarenville Area Office Building Refurbishment*.

Justification

Newfoundland Power maintains office buildings and other facilities throughout its service territory to ensure a reasonable response to customer outages and customer-driven work requests. These facilities deteriorate and components fail over time. Upgrading, refurbishing and replacing building components is necessary to maintain these facilities in safe and adequate condition.

This project is justified on the obligation to maintain safe and adequate facilities and cannot be deferred.

[20] Approximately 1,500 customer visits occur annually at the Clarenville Area Office Building.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2022 and a projection of expenditures through 2026.

Table 1
Projected Expenditures
($000s)

Cost Category	2022	2023	2024 – 2026	Total
Material	680	-	-	-
Labour – Internal	4	-	-	-
Labour – Contract	-	-	-	-
Engineering	122	-	-	-
Other	48	-	-	-
Total	**$854**	-	-	**$854**

Costing Methodology

The budget estimate for this project is based on detailed engineering estimates for the work identified.

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

Future Commitments

This is not a multi-year project.

Project Title: **Physical Security Upgrades (Pooled)**

Project Cost: **$492,000**

Project Description

This General Property project consists of capital expenditures necessary for the refurbishment and upgrading of security infrastructure at Company locations.[21]

Since 2016, there have been 24 substation break-ins. This results in significant safety risk to Newfoundland Power staff and the general public in addition to property damage. Most substation break-ins result in the theft of bare copper wire due to the scrap value of copper.

Security upgrades will be performed in 10 substations to deter the entry of unauthorized persons and reduce the likelihood of copper theft occurring. Substation security upgrades will include the installation of surveillance and alarm systems to deter theft and vandalism.

Company offices contain equipment and information that needs to be effectively secured from intrusion and theft. In addition, 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.

Security upgrades will be performed at 3 Company facilities and will include upgrades to the security infrastructure, including improvements in public entrances, access control, surveillance and lighting upgrades, and the addition of security fencing, access control gates and security surveillance systems.

Security upgrades will be performed at 8 of the Company's hydro plant facilities to deter unauthorized entry and to provide Company personnel with access to video streaming to check on remote facilities in the event of a security or fire alarm.

Based on engineering estimates, $492,000 is required for physical security upgrades in 2022.

Justification

Newfoundland Power maintains office buildings, substations and other facilities throughout its service territory to support the delivery of service to customers. Maintaining the security of these facilities is necessary to ensure the safety of employees and the general public. It is also necessary to prevent the theft or damage of materials required to provide service to customers.

[21] Prior to 2019, corporate security upgrades for office buildings and storage sites were included in the *Additions to Real Property* General Property project. Substation security was included in the *Substation Refurbishment and Modernization* Substations project. Combining all physical security upgrades in a single project is intended to focus Company security efforts.

This project is justified on the obligation to maintain safe and adequate facilities and cannot be deferred.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2022 and a projection of expenditures through 2026.

Table 1
Projected Expenditures
($000s)

Cost Category	**2022**	**2023**	**2024 - 2026**	**Total**
Material	380	-	-	-
Labour – Internal	18	-	-	-
Labour – Contract	-	-	-	-
Engineering	78	-	-	-
Other	16	-	-	-
Total	**$492**	**$796**	**$1,120**	**$2,408**

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: **Replace Vehicles and Aerial Devices 2022 – 2023 (Other, Multi-Year)**

Project Cost: **$3,089,000**

Project Description

This Transportation multi-year project involves the addition and necessary replacement of heavy/medium duty fleet, light duty fleet, passenger and off-road vehicles. The long delivery times associated with the purchase of heavy/medium fleet vehicles have reached the point where these vehicles can no longer be ordered and delivered in a calendar year.[22] A multi-year project will address long delivery times.

Table 1 summarizes the units to be replaced in 2022 and 2023 under this project.

Table 1
2022-2023 Proposed Vehicle Replacements

Category	2022 No. of Units	2023 No. of Units
Heavy/Medium Duty Fleet Vehicles	-	5
Light Duty Fleet Vehicles	4	-
Passenger Vehicles	32	-
Off-road Vehicles[1]	14	-
Total	**50**	**5**

[1] The Off-road Vehicles category includes snowmobiles, ATVs, trailers and specialized mobile equipment.

In 2022, the Company has identified 4 light duty fleet, 32 passenger and 14 off-road vehicles for replacement. In 2023, there are 5 heavy and medium duty fleet vehicles that are anticipated to meet the age, mileage and condition parameters that indicate replacement is necessary. Detailed evaluation of the units to be replaced will take place to confirm they have reached the end of their service lives.

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

[22] In recent years the Company has had to carry forward the cost associated with the purchase of heavy/medium fleet vehicles. In 2020 and 2021, this issue has worsened as a result of the global pandemic.

Justification

Providing reliable service to customers across the Company's 70,000 km² service territory requires maintaining an adequate fleet of vehicles to respond to customer outages and maintain the electrical system. Project costs for 2022 and 2023 are estimated based on the number of vehicles expected to require replacement in those years.

This project is justified on the obligation to provide reliable service to customers at least cost and cannot be deferred.

Projected Expenditures

Table 2 provides a breakdown of the proposed expenditures for 2022 and a projection of expenditures through 2026 for the *Replace Vehicles and Aerial Devices 2022-2023* capital project.

Table 2
Projected Multi-Year Expenditures
($000s)

Cost Category	2022	2023	2024 - 2026	Total
Material	2,979	2,059	-	5,038
Labour – Internal	106	73	-	179
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	4	3	-	7
Total	**$3,089**	**$2,135**	-	**$5,224**

Costing Methodology

Table 3 shows the annual expenditures for the *Replace Vehicles and Aerial Devices* project for the most recent 5-year period, as well as the projected expenditure in 2022 for the *Replace Vehicles and Aerial Devices 2022-2023* project.

Table 3
Expenditure History
(000s)

Year	2017	2018	2019	2020	2021F	2022B
Total	$3,824	$3,594	$4,223	$3,869	$4,032	$3,089

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

Evaluation for replacement is initiated when individual vehicles reach a threshold age or level of usage. Heavy/medium and light duty 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 these thresholds are evaluated on a number of criteria, such as overall condition, maintenance history and immediate repair requirements. This determines whether they have reached the end of their useful service lives.

Based on these criteria, each unit proposed for replacement is forecast to reach the end of its service life and require replacement in 2022 or 2023.

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

Future Commitments

This is a multi-year project to be completed in 2022 and 2023. Heavy and medium duty fleet vehicles will be ordered in 2022 with delivery anticipated in 2023. Light duty fleet, passenger and off-road vehicles will be ordered and delivered in 2022.

TELECOMMUNICATIONS

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

Project Cost: **$114,000**

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. These voice, monitoring and control systems allow the Company to provide acceptable levels of customer service and achieve operational efficiencies.

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 communication 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.

The 2022 project involves the replacement and/or upgrade of communications equipment, including radio communications equipment associated with electrical system operations, and data communications equipment providing remote monitoring and control capabilities associated with the Company's SCADA system.

Justification

Providing reliable service to customers requires the effective deployment of field crews, along with the safe and effective operation of the electrical system. Maintaining adequate communications equipment is necessary to ensure these requirements are met in 2022.

This project is justified on the obligation to provide reliable service to customers at least cost and cannot be deferred.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2022 and a projection of expenditures through 2026.

Table 1
Projected Expenditures
($000s)

Cost Category	2022	2023	2024 - 2026	Total
Material	70	-	-	-
Labour – Internal	11	-	-	-
Labour – Contract	-	-	-	-
Engineering	23	-	-	-
Other	10	-	-	-
Total	**$114**	**$116**	**$364**	**$594**

Costing Methodology

Table 2 shows the annual expenditures and costs in current dollars for the most recent 5-year period, as well as the projected expenditure for 2022.

Table 2
Expenditure History
(000s)

Year	2017	2018	2019	2020	2021F	2022B
Total	$111	$98	$112	$112	$112	$114
Adjusted Cost[1]	$117	$102	$115	$114	-	-

[1] 2021 dollars.

The process of estimating the budget requirement for communications equipment is based on an historical average. Historical annual expenditures related to upgrading and replacing communications equipment over the most recent 5-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: **St. John's Teleprotection System Replacement (Other, Multi-Year)**

Project Cost: **$450,000**

Project Description

This Telecommunications project involves the replacement of the Company's St. John's teleprotection system used to protect the 66 kV transmission network serving substations in the St. John's area. The existing teleprotection system has been in service for 20 years and has reached the end of its service life. The teleprotection system provides communications for the differential protection relays at both ends of the associated transmission lines interconnecting the substations, protecting employees and the public from energized failures of transmission line infrastructure.

The St. John's teleprotection system is critical to the safe and reliable operation of both the Holyrood Thermal Generating Station ("HTGS") and the Labrador Island Link ("LIL"). In 1991, Newfoundland Power and Newfoundland and Labrador Hydro ("Hydro") jointly completed a critical clearing time study.[23] The study determined that faults with excessive clearing times on the St. John's 66 kV transmission network could cause severe voltage depressions on the HTGS station service equipment resulting in the potential loss of generation.

In 2021, TransGrid Solutions Inc. at the direction of Hydro, completed a study of critical clearing times on Newfoundland Power's 138 kV and 66 kV transmission systems following the introduction of the LIL. Study results confirmed the need to maintain critical clearing times for the St. John's 66 kV transmission system when the HTGS is no longer operational and the LIL begins supplying the Island Interconnected System.[24]

The Company plans to replace the St. John's teleprotection system as a multi-year project starting in 2022. Details on the proposed expenditures are included in report 6*.1 St. John's Teleprotection System Replacement.*

Justification

The critical nature of the teleprotection system, and the potential of a teleprotection failure causing outages to both the HTGS and the LIL, makes the replacement of the existing equipment necessary in 2023.

A reliable teleprotection system is essential for the provision of safe and reliable service to customers.

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[23] *Eastern System Critical Clearing Time Study– Island Interconnected Transmission System*, dated August 8, 1991, jointly prepared by Newfoundland & Labrador Hydro and Newfoundland Power.
[24] Study results were presented in Technical Note TN1205.81.06 filed by Hydro with the Board on March 31, 2021.

This project is justified on the obligation to provide reliable service to customers at least cost and cannot be deferred.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2022 and a projection of expenditures through 2026.

Table 1
Projected Multi-Year Expenditures
($000s)

Cost Category	2022	2023	2024 - 2026	Total
Material	200	566	-	766
Labour – Internal	25	100	-	125
Labour – Contract	-	104	-	104
Engineering	150	240	-	390
Other	75	140	-	215
Total	**$450**	**$1,150**	**$0**	**$1,600**

Costing Methodology

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

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

Future Commitments

This is a multi-year project with expenditures in 2022 and 2023.

INFORMATION SYSTEMS

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

Project Cost: **$1,007,000**

Project Description

This Information Systems project is necessary to enhance the functionality of the Company's software applications. 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 for 2022 include enhancement of: (i) the digital forms application for work observations, contractor inspections and tailboard meetings; (ii) technology service management; (iii) the customer energy conservation website and (iv) the Great Plains financial system.

The application enhancements proposed for 2022 are not interdependent, but are similar in nature and justification. They are therefore pooled for consideration as a single capital project.

Details on proposed expenditures are included in report *7.1 2022 Application Enhancements*.

Justification

The proposed enhancements included in this project are justified on the basis of improving customer service and operational efficiencies. Cost benefit analyses, where appropriate, are provided in report *7.1 2022 Application Enhancements*.

This project is justified on the obligation to provide reliable service to customers at least cost and cannot be deferred.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2022 and a projection of expenditures through 2026.

Table 1
Projected Expenditures
($000s)

Cost Category	2022	2023	2024 - 2026	Total
Material	120	-	-	-
Labour – Internal	587	-	-	
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	300	-	-	
Total	**$1,007**	**$1,050**	**$3,150**	**$5,207**

Costing Methodology

Table 2 shows the annual expenditures for this project for the most recent 5-year period, as well as the projected expenditure for 2022.

Table 2
Expenditure History
(000s)

Year	2017	2018	2019	2020	2021F	2022B
Total	$820	$891	$879	$1,481	$978	$1,007

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 to provide competitive bids, all materials and services will be negotiated with the sole-source supplier to ensure they are least cost.

Future Commitments

This is not a multi-year project.

Project Title: System Upgrades (Pooled, Multi-Year)

Project Cost: $802,000

Project Description

This Information Systems project involves upgrades to third-party software products that comprise the Company's information systems.

For 2022, the project includes upgrades to the Company's SCADA System, System Control Reporting System, Database Management Software, as well as various minor upgrades.

This project also includes the Microsoft Enterprise Agreement.[25] 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 report *7.2 2022 System Upgrades*.

Justification

Newfoundland Power maintains a network of computers, servers, information systems and other hardware and software. This technology infrastructure is used to operate the Company's electrical system, manage field operations and provide customer service delivery in an effective and efficient manner.

System upgrades in 2022 are primarily driven by the expiration of support arrangements with 3rd party software vendors. Completing system upgrades ensures continuity in vendor support, which reduces risks of system failure and cybersecurity breaches. Upgrades are also required in 2022 to improve system performance.

This project is justified on the obligation to provide reliable service to customers at least cost and cannot be deferred.

[25] The Microsoft Enterprise Agreement was approved as a multi-year project in Order No. P.U. 37 (2020).

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2022 and a projection of expenditures through 2026.

Table 1
Projected Expenditures
($000s)

Cost Category	2022	2023	2024 - 2026	Total
Material	250	-	-	-
Labour – Internal	367	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	185	-	-	-
Total	**$802**	**$1,175**	**$8,810**	**$10,787**

Costing Methodology

Table 2 shows the annual expenditures for this project for the most recent 5-year period, as well as the projected expenditure for 2022.

Table 2
Expenditure History
(000s)

Year	2017	2018	2019	2020	2021F	2022B
Total	$1,676	$1,133	$933	$2,830	$2,410	$802

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 to provide competitive bids, all materials and services will be negotiated with the sole-source supplier to ensure they are least cost.

Future Commitments

This project includes the Microsoft Enterprise Agreement in 2022 as a multi-year project. This is not otherwise a multi-year project.

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

Project Cost: **$615,000**

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 service lives.

In 2022, a total of 146 PCs will be purchased. The Company plans to increase its number of mobile PCs by replacing 66 retired desktop units with mobile units. This will enable greater flexibility of the work force to work remotely.[26] The increase in the number of mobile PCs has an average incremental cost of approximately $600 per device, for a total of approximately $40,000.

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 service lives. In 2022, the purchase of peripheral equipment used to scan inventory barcodes are being replaced as they are at the end of their service lives.

Individual PCs and peripheral equipment are not interdependent. However, they are similar in nature and justification, and are therefore pooled for consideration as a single capital project.

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

Newfoundland Power is currently able to achieve an approximate 5-year lifecycle for its PCs before they require replacement.

[26] Examples of providing greater flexibility of the work force to work remotely are: (i) replacing a traditional office employee's desktop (for example a finance employee) with a laptop to enable them to work effectively from home or in the office; and (ii) replacing a call center agent's desktop with a laptop to enable them to work from home and be mobilized quicker in larger outage events, allowing them to log in remotely and receive customer calls much faster from home.

Table 1 outlines the PC additions and retirements for 2020 and 2021, as well as the proposed additions and retirements for 2022.

Table 1
PC Additions and Retirements
2020 – 2022B

	2020			**2021F**			**2022B**		
	Add	**Retire**	**Total**	**Add**	**Retire**	**Total**	**Add**	**Retire**	**Total**
Desktop	21	60	379	0	60	319	12	78	253
Mobile	160	121	361	145	85	421	134	68	487
Total	**181**	**181**	**740**	**145**	**145**	**740**	**146**	**146**	**740**

Justification

Newfoundland Power maintains a network of computers, servers, information systems and other hardware and software. This technology infrastructure is used to operate the Company's electrical system, manage field operations and provide customer service delivery in an effective and efficient manner. The replacement of personal computers and associated equipment is necessary when it reaches the end of its useful service life.

This project is justified on the obligation to provide reliable service to customers at least cost and cannot be deferred.

Projected Expenditures

Table 2 provides a breakdown of the proposed expenditures for 2022 and a projection of expenditures through 2026.

Table 2
Projected Expenditures
($000s)

Cost Category	**2022**	**2023**	**2024 - 2026**	**Total**
Material	475	-	-	-
Labour – Internal	105	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	35	-	-	-
Total	**$615**	**$585**	**$1,800**	**$3,000**

Costing Methodology

Table 3 shows the annual expenditures for this project for the most recent 5-year period, as well as the projected expenditure for 2022.

Table 3
Expenditure History
(000s)

Year	**2017**	**2018**	**2019**	**2020**	**2021F**	**2022B**
Total	$493	$480	$500	$648	$495	$615

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 3-year period is 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: **$613,000**

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 are critical to ensuring these applications operate effectively at all times.

In 2022, the Company will upgrade existing server infrastructure to accommodate growth in information storage needs, to extend the service life of existing shared servers and improve performance of Company applications. It also includes upgrading the associated shared server operating systems to the current, vendor-supported versions. Additional server infrastructure is also required to support Newfoundland Power's SCADA System. This is critical infrastructure that allows the Company to monitor and control the electricity system.

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

The shared server infrastructure requirements for 2022 are not interdependent. However, they are similar in nature and justification, and are therefore pooled for consideration as a single capital project.

Justification

Newfoundland Power maintains a network of computers, servers, information systems and other hardware and software. This technology infrastructure is used to operate the Company's electrical system, manage field operations and provide customer service delivery in an effective and efficient manner. The addition, upgrade and replacement of shared server infrastructure is necessary to ensure the effective operation of the Company's systems and technologies.

This project is justified on the obligation to provide reliable service to customers at least cost and cannot be deferred.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2022 and a projection of expenditures through 2026.

Table 1
Projected Expenditures
($000s)

Cost Category	2022	2023	2024 - 2026	Total
Material	325	-	-	-
Labour – Internal	248	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	40	-	-	-
Total	**$613**	**$586**	**$3,100**	**$4,299**

Costing Methodology

Table 2 shows the annual expenditures for this project for the most recent 5-year period, as well as the projected expenditure for 2022.

Table 2
Expenditure History
(000s)

Year	2017	2018	2019	2020	2021F	2022B
Total	$707	$635	$879	$1,275	$538	$613

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 to provide competitive bids, all materials and services will be negotiated with the sole-source supplier to ensure they are least cost.

Future Commitments

This is not a multi-year project.

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

Project Cost: **$508,000**

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 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 2022, this project includes the purchase and implementation of network and video conference equipment that has reached the end of its service life and to increase overall network availability and disaster recovery capabilities.

The individual network infrastructure requirements for 2022 are not interdependent. 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 service lives.

This project is justified on the obligation to provide reliable service to customers at least cost and cannot be deferred.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2022 and a projection of expenditures through 2026.

Table 1
Projected Expenditures
($000s)

Cost Category	2022	2023	2024 - 2026	Total
Material	270	-	-	-
Labour – Internal	188	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	50	-	-	-
Total	**$508**	**$386**	**$1,375**	**$2,269**

Costing Methodology

Table 2 shows the annual expenditures for this project for the most recent 5-year period, as well as the projected expenditure for 2022.

Table 2
Expenditure History
(000s)

Year	2017	2018	2019	2020	2021F	2022B
Total	$407	$439	$338	$487	$363	$508

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

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

Future Commitments

This is not a multi-year project.

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

Project Cost: **$865,000**

Project Description

This Information Systems project involves upgrades to the Company's cybersecurity infrastructure.

Electrical system assets are operated using a combination of physical and technology infrastructure. Physical infrastructure includes components such as protection and control systems. Technology infrastructure includes components such as networks, software and data. Protecting this infrastructure from threats, including cybersecurity threats, is critically important to the day-to-day provision of safe and reliable service to customers.

The risk of cybersecurity threats has increased materially for utilities. Increased risks result from the widespread use of operations technology within utilities and the continual evolution and sophistication of cybersecurity threats. Ensuring cybersecurity infrastructure is adequately designed to address potential vulnerabilities and respond to threats is increasingly important to the safe and reliable operation of the electrical system.

Newfoundland Power completes annual assessments to identify measures to improve the Company's cybersecurity infrastructure. Proposed 2022 capital expenditures include new technologies to reduce risk and enhance security at Newfoundland Power in the following areas: Network Security, Endpoint Security, Logging, Alerting and Event Management.

The individual requirements for 2022 are not interdependent. However, they are similar in nature and justification, and are therefore pooled for consideration as a single capital project.

Justification

The security and availability of critical infrastructure enables Newfoundland Power to provide safe and reliable service to customers at least cost. This project is consistent with the Company's Cybersecurity Risk Management Program and will enable Newfoundland Power to improve its cybersecurity infrastructure to prevent and respond to rapidly evolving cybersecurity threats.

This project is justified on the obligation to maintain safe and adequate facilities and cannot be deferred.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2022 and a projection of expenditures through 2026.

Table 1
Projected Expenditures
($000s)

Cost Category	2022	2023	2024 - 2026	Total
Material	380	-	-	-
Labour – Internal	330	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	155	-	-	-
Total	**$865**	**$800**	**$2,400**	**$4,065**

Costing Methodology

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 to provide competitive bids, all materials and services will be negotiated with the sole-source supplier to ensure they are least cost.

Future Commitments

This is not a multi-year project.

Project Title: **Customer Service System Replacement (Other, Multi-year)**

Project Cost: **$15,826,000**

Project Description

This Information Systems project is a multi-year project to replace the Company's existing Customer Service System ("CSS").[27]

Newfoundland Power plans to replace CSS with a modern, commercially available solution over 3 years commencing in 2021. Details on this project are provided in the *Customer Service Continuity Plan* filed as part of the *2021 Capital Budget Application.*

Justification

Least cost customer service delivery is a principal objective of Newfoundland Power.

An independent assessment of alternatives determined that implementing a modern Customer Information System ("CIS") is the only viable alternative to ensure continuity in Newfoundland Power's customer service delivery. A modern CIS would support the Company's existing business processes, provide opportunities to improve the customer experience, and align the Company with current industry practice.

Newfoundland Power's plan for implementing a modern CIS is consistent with industry best practices. Implementing this plan will enable the Company to continue providing responsive and efficient service to customers over the longer term.

This project is justified on the obligation to provide reliable service to customers at least cost and cannot be deferred.

[27] This project was approved in Order No. P.U. 12 (2021).

Projected Expenditures

Table 1 provides a breakdown of the proposed multi-year expenditures for 2022-2023.

Table 1
Projected Multi-year Expenditures
($000s)

Cost Category	2022	2023	2024 - 2026	Total
Material	10,357	3,685	-	14,042
Labour – Internal	4,133	1,237	-	5,370
Labour – Contract	-	-	-	-
Engineering	1,336	995	-	2,331
Other	-	-	-	-
Total	**$15,826**	**$5,917**	**$0**	**$21,743**

Costing Methodology

The project cost estimate is consistent with the *Customer Service Continuity Plan* filed as part of Newfoundland Power's *2021 Capital Budget Application.*

The Company has contracted a third-party procurement advisor for this project. The procurement advisor will assist in undertaking a competitive Request for Proposals process by: (i) developing functional and technical specifications for the replacement system; (ii) providing best practices in evaluating vendors' proposals; and (iii) providing industry expertise during contract negotiations. The use of a procurement advisor will reduce execution risks for this once-in-a-generation project.

The Company will complete procurement in 2 phases. The first phase will focus on procuring a commercial solution from an established software vendor. The second phase will focus on contracting a third-party system integrator to provide the technical expertise required to implement the solution. A 2-phase procurement approach is consistent with industry best practice

Future Commitments

The Customer Service System Replacement project is a multi-year project approved in Order No. P.U. 12 (2021) and will be undertaken in 2021, 2022 and 2023.

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

Project Cost: **$808,000**

Project Description

This Information Systems project is a multi-year project to replace the Company's current Workforce Management System ("WFMS").[28] The existing WFMS, known as Click, was deployed in 2011 and will become obsolete in 2023.[29]

Newfoundland Power proposes to replace the existing system with a commercially available product. Details on this project are included in report *7.3 Workforce Management System Replacement*.

Justification

The replacement of WFMS in 2022 is primarily driven by the expiration of vendor support for the current system.

Implementation of a new WFMS will address the software obsolescence of the current system and ensure continuity in vendor support, which reduces risks of system failure. The replacement of Click with an alternative system is in line with industry best practice, and will allow the Company to maintain its service performance in field operations, including but not limited to outage response, new service connections, and street light repair.

This project is justified on the obligation to provide reliable service to customers at least cost and cannot be deferred.

[28] This is a multi-year project with expenditures planned for 2022 through 2023. Details of the planned expenditures can be found in Schedule C of this Application.

[29] In August 2020, the vendor advised that the development of Click has ended and support for Click will expire on December 31, 2023.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2022 and 2023, along with a projection of expenditures through 2026.

Table 1
Projected Multi-year Expenditures
($000s)

Cost Category	2022	2023	2024 - 2026	Total
Material	150	250	-	400
Labour – Internal	418	266	-	684
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	240	685	-	925
Total	**$808**	**$1,201**	**$0**	**$2,009**

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 2022 and 2023.

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*.

This project is justified on the obligation to provide reliable service to customers at least cost and cannot be deferred.

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: **$6,500,000**

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 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).

GEC is required to implement the Company's capital program and is justified on the same basis as the capital projects to which it relates.

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. In Order No. P.U. 2 (2019), the Board approved a revised capitalization methodology for pension costs as part of 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.
2022 Capital Budget
Multi-Year Projects Approved in Previous Years

				Expenditure ($000s)			
Class	**Project Description**	**CBA/ Board Order**		**2021**	**2022**	**2023**	**Total**
Information Systems	Microsoft Enterprise Agreement[1]	2021 CBA P.U. 37 (2020)	Approved	245	245	245	735
			Actual/Forecast	245	245	245	735
Information Systems	Customer Service System Replacement[2]	2021 CBA P.U. 12 (2021)	Approved	9,903	15,826	5,917	31,646
			Actual/Forecast	9,903	15,826	5,917	31,646
			Total Approved	**$10,148**	**$16,071**	**$6,162**	**$32,381**
			Total Actual/Forecast	**$10,148**	**$16,071**	**$6,162**	**$32,381**

1 A detailed project description can be found in the *2021 Capital Budget Application*, Volume 1, Schedule B pages 82 to 83, and Volume 2, *6.2 2021 System Upgrades.*
2 A detailed project description can be found in the *2021 Capital Budget Application*, Volume 1, Schedule B pages 93 to 94, and Volume 1, *Customer Service Continuity Plan.*

Newfoundland Power Inc.
2022 Capital Budget
Multi-Year Projects Commencing in 2022

Class	**Project Description**	**CBA**		**Expenditure ($000s)** 2022	2023	2024	Total
Generation – Hydro	Sandy Brook Plant Penstock Replacement[3]	2022 CBA	Budget	400	4,694		5,094
Transmission	Transmission Line 94L Rebuild[4]	2022 CBA	Budget	4,473	4,346	4,276	13,095
Transportation	Replace Vehicles and Aerial Devices 2022-2023[5]	2022 CBA	Budget	3,089	2,135		5,224
Telecommunications	St. John's Teleprotection System Replacement[6]	2022 CBA	Budget	450	1,150		1,600
Information Systems	Workforce Management System Replacement[7]	2022 CBA	Budget	808	1,201		2,009
			Total	**$9,220**	**$13,526**	**$4,276**	**$27,022**

3 A detailed project description can be found in the *2022 Capital Budget Application*, Schedule B pages 5 to 6, and report *1.2 Sandy Brook Plant Penstock Replacement.*
4 A detailed project description can be found in the *2022 Capital Budget Application*, Schedule B pages 18 to 20, and report *3.1 2022 Transmission Line Rebuild.*
5 A detailed project description can be found in the *2022 Capital Budget Application*, Schedule B pages 70 to 72.
6 A detailed project description can be found in the *2022 Capital Budget Application*, Schedule B pages 76 to 77, and report *6.1 St. John's Teleprotection System Replacement.*
7 A detailed project description can be found in the *2022 Capital Budget Application*, Schedule B pages 94 to 95, and report *7.3 Workforce Management System Replacement.*

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

	2020	2019
Net Plant Investment		
Plant Investment	2,020,501	1,954,715
Accumulated Depreciation	(828,004)	(790,243)
Contributions in Aid of Construction	(44,357)	(44,616)
	$1,148,140	$1,119,856
Additions to Rate Base		
Deferred Pension Costs	89,900	91,824
Deferred Credit Facility Issue Costs	46	61
Cost Recovery Deferral – Hearing Costs	247	494
Cost Recovery Deferral – Conservation	17,049	17,371
Customer Finance Programs	2,098	2,494
Demand Management Incentive Account	1,002	1,881
	$110,342	$114,125
Deductions from Rate Base		
Weather Normalization Reserve	3,734	(5,654)
Other Post-Employment Benefits	66,739	61,791
Customer Security Deposits	1,212	1,420
Accrued Pension Obligation	5,258	5,104
Accumulated Deferred Income Taxes	12,683	10,088
2019 Cost Recovery Deferral	613	1,226
	$90,239	$73,975
Year End Rate Base	1,168,243	1,160,006
Average Rate Base Before Allowances	1,164,124	1,137,174
Rate Base Allowances		
Materials and Supplies Allowance	7,270	6,475
Cash Working Capital Allowance	10,503	9,907
Average Rate Base at Year End	$1,181,897	$1,153,556

2021 Capital Expenditure Status Report

May 2021

Newfoundland Power Inc.

2021 Capital Expenditure Status Report

Compliance Matter

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. 37 (2020):

> *Unless otherwise directed by the Board, Newfoundland Power shall provide, in conjunction with the 2022 capital budget application, a status report on the 2021 capital budget expenditures showing for each project:*
> - *(i) the approved budget for 2021;*
> - *(ii) the expenditures prior to 2021;*
> - *(iii) the 2021 expenditures to the date of the application;*
> - *(iv) the remaining projected expenditures for 2021;*
> - *(v) the variance between the projected total expenditures and the approved budget; and*
> - *(vi) an explanation of the variance.*

Overview

Page 1 of the 2021 Capital Expenditure Status Report outlines the forecast variances from budget of the capital expenditures approved by the Board. The detailed tables on pages 3 to 13 provide additional detail on capital expenditures in 2021 which were approved in Order Nos. P.U. 37 (2020), P.U. 10 (2021) and P.U. 12 (2021). The detailed tables also include information on those capital projects approved for 2020 (and approved in Order No. P.U. 5 (2020)) that were not completed prior to 2021.

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 2021 Capital Expenditure Status Report. These variance criteria are as outlined in the *Capital Budget Application Guidelines*.

The variances contained in Appendix A relate to forecast reductions in gross new customer connections by approximately 12% from 2,379 to 2,096.

Newfoundland Power will provide updated information to the Board in its regular reporting and upon request of the Board.

Newfoundland Power Inc.

2021 Capital Budget Variances
($000s)

Approved by Order
Nos. P.U. 37 (2020), P.U 10
(2021) & P.U. 12 (2021)

	Budget	Forecast	Variance
Generation – Hydro	11,180	11,180	-
Generation - Thermal	330	330	-
Substations	14,280	14,280	-
Transmission	9,751	9,751	-
Distribution	45,875	44,229	(1,646)[1]
General Property	2,776	2,776	-
Transportation	4,032	4,032	-
Telecommunications	462	462	-
Information Systems	15,362	15,362	-
Unforeseen Items	750	750	-
General Expenses Capitalized	6,500	6,500	-
Total	$111,298	$109,811	($1,646)
Projects carried forward from prior years		$11,639[2]	

[1] The decrease is due to a reduction in the forecast number of customer connections. Details can be found in the notes provided in Appendix A.

[2] Forecast 2021 expenditures associated with projects carried forward from prior years.

2021 Capital Expenditure Status Report
($000s)

	Capital Budget			Actual Expenditure			Forecast			
	2020	2021	Total	2020	YTD 2021	Total To Date	Remainder 2021	Total 2021	Overall Total	Variance
	A	B	C	D	E	F	G	H	I	J
2021 Projects	$ -	$ 111,298	$ 111,298	$ -	$ 17,412	$ 17,412	$ 92,240	$ 109,652	$ 109,652	$ (1,646)
2020 Projects	44,860	-	44,860	33,022	372	33,394	11,267	11,639	44,661	(199)
Grand Total	**$ 44,860**	**$ 111,298**	**$ 156,158**	**$ 33,022**	**$ 17,784**	**$ 50,806**	**$ 103,507**	**$ 121,291**	**$ 154,313**	**$ (1,845)**

Column A	Approved Capital Budget for 2020
Column B	Approved Capital Budget for 2021
Column C	Total of Columns A and B
Column D	Actual Capital Expenditures for 2020 YTD
Column E	Actual Capital Expenditures for 2021 YTD
Column F	Total of Columns D and E
Column G	Forecast for Remainder of 2021
Column H	Total of Columns E and G
Column I	Total of Columns F and G
Column J	Column I less Column C

2021 Capital Expenditure Status Report
($000s)

Category: Generation - Hydro

	Capital Budget			Actual Expenditure			Forecast				
	2020	2021	Total	2020	YTD 2021	Total To Date	Remainder 2021	Total 2021	Overall Total	Variance	Notes*
	A	B	C	D	E	F	G	H	I	J	
2021 Projects											
Facility Rehabilitation	$ -	$ 1,806	$ 1,806	$ -	$ 193	$ 193	$ 1,613	$ 1,806	$ 1,806	$ -	
Topsail Hydro Plant Penstock	-	9,374	9,374	-	-	-	9,374	9,374	9,374	-	
Total - 2021 Generation Hydro	**$ -**	**$ 11,180**	**$ 11,180**	**$ -**	**$ 193**	**$ 193**	**$ 10,987**	**$ 11,180**	**$ 11,180**	**$ -**	
2020 Projects											
Facility Rehabilitation	$ 1,519	$ -	$ 1,519	$ 1,368	$ -	$ 1,368	$ 60	$ 60	$ 1,428	$ (91)	
Petty Harbour Plant Refurbishment	3,662	-	3,662	337	40	377	3,285	3,325	3,662	-	
Rattling Brook Plant Refurbishment	1,183	-	1,183	100	12	112	1,071	1,083	1,183	-	
Topsail Hydro Plant Refurbishment	485	-	485	319	99	418	70	169	488	3	
Total Generation Hydro	**$ 6,849**	**$ 11,180**	**$ 18,029**	**$ 2,124**	**$ 344**	**$ 2,468**	**$ 15,473**	**$ 15,817**	**$ 17,941**	**$ (88)**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2020
Column B	Approved Capital Budget for 2021
Column C	Total of Columns A and B
Column D	Actual Capital Expenditures for 2020 YTD
Column E	Actual Capital Expenditures for 2021 YTD
Column F	Total of Columns D and E
Column G	Forecast for Remainder of 2021
Column H	Total of Columns E and G
Column I	Total of Columns F and G
Column J	Column I less Column C

2021 Capital Expenditure Status Report
($000s)

Category: Generation - Thermal

	Capital Budget			Actual Expenditure			Forecast				
	2020	2021	Total	2020	YTD 2021	Total To Date	Remainder 2021	Total 2021	Overall Total	Variance	Notes*
	A	B	C	D	E	F	G	H	I	J	
2021 Projects											
Facility Rehabilitation Thermal	$ -	$ 330	$ 330	$ -	$ 114	$ 114	$ 216	$ 330	$ 330	$ -	
Total - 2021 Generation Thermal	**$ -**	**$ 330**	**$ 330**	**$ -**	**$ 114**	**$ 114**	**$ 216**	**$ 330**	**$ 330**	**$ -**	
2020 Projects											
Purchase Mobile Generation (2019 - 2020)	$ 13,915	$ -	$ 13,915	$ 13,257	$ 102	$ 13,359	$ -	$ 102	$ 13,359	$ (556)	
Total Generation Thermal	**$ 13,915**	**$ 330**	**$ 14,245**	**$ 13,257**	**$ 216**	**$ 13,473**	**$ 216**	**$ 432**	**$ 13,689**	**$ (556)**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2020
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Column H	Total of Columns E and G
Column I	Total of Columns F and G
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2021 Capital Expenditure Status Report
($000s)

Category: Substations

	Capital Budget			Actual Expenditures			Forecast				
	2020	2021	Total	2020	YTD 2021	Total To Date	Remainder 2021	Total 2021	Overall Total	Variance	Notes*
2021 Projects	A	B	C	D	E	F	G	H	I	J	
Substation Refurbishment and Modernization	$ -	$ 5,153	$ 5,153	$ -	$ 607	$ 607	$ 4,546	$ 5,153	$ 5,153	$ -	
Replacements Due to In-Service Failures	-	3,413	3,413	-	596	596	2,817	$ 3,413	3,413	-	
PCB Bushing Phase-out	-	717	717	-	-	-	717	$ 717	717	-	
Additions Due to Load Growth	-	4,997	4,997	-	39	39	4,958	$ 4,997	4,997	-	
Total 2021 Substations	**$ -**	**$ 14,280**	**$ 14,280**	**$ -**	**$ 1,242**	**$ 1,242**	**$ 13,038**	**$ 14,280**	**$ 14,280**	**$ -**	
2020 Projects											
Substation Feeder Termination	$ 290	$ -	$ 290	$ 76	$ 1	$ 77	$ 213	$ 214	$ 290	$ -	
Total - Substations	**$ 290**	**$ 14,280**	**$ 14,570**	**$ 76**	**$ 1,243**	**$ 1,319**	**$ 13,251**	**$ 14,494**	**$ 14,570**	**$ -**	

* See Appendix A for notes containing variance explanations.

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2021 Capital Expenditure Status Report
($000s)

Category: Transmission

	Capital Budget			Actual Expenditure			Forecast				
	2020	2021	Total	2020	YTD 2021	Total To Date	Remainder 2021	Total 2021	Overall Total	Variance	Notes*
	A	B	C	D	E	F	G	H	I	J	
2021 Projects											
Rebuild Transmission Lines	$ -	$ 6,170	$ 6,170	$ -	$ 242	$ 242	$ 5,928	$ 6,170	$ 6,170	$ -	
Transmission Line Maint. & Relocates for 3rd Parties	$ -	$ 2,238	$ 2,238	$ -	$ 39	$ 39	$ 2,199	$ 2,238	$ 2,238	$ -	
Transmission Line Extension 35L	$ -	$ 1,343	$ 1,343	$ -	$ 4	$ 4	$ 1,339	$ 1,343	$ 1,343	$ -	
Total - 2021 Transmission	**$ -**	**$ 9,751**	**$ 9,751**	**$ -**	**$ 285**	**$ 285**	**$ 9,466**	**$ 9,751**	**$ 9,751**	**$ -**	
2020 Projects											
Rebuild Transmission Lines	$ 9,623	$ -	$ 9,623	$ 8,002	$ -	$ 8,002	$ 1,946	$ 9,948	$ 9,948	$ 325	
Total - Transportation	**$ 9,623**	**$ 9,751**	**$ 19,374**	**$ 8,002**	**$ 285**	**$ 8,287**	**$ 11,412**	**$ 19,699**	**$ 19,699**	**$ 325**	

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2021 Capital Expenditure Status Report
($000s)

Category: Distribution

	Capital Budget			Actual Expenditure			Forecast				
	2020	2021	Total	2020	YTD 2021	Total To Date	Remainder 2021	Total 2021	Overall Total	Variance	Notes*
	A	B	C	D	E	F	G	H	I	J	
2021 Projects											
Extensions	$ -	$ 10,891	$ 10,891	$ -	$ 2,441	$ 2,441	$ 7,115	$ 9,556	$ 9,556	$ (1,335)	1
Meters	-	680	680	-	547	547	133	680	680	-	
Services	-	3,110	3,110	-	725	725	2,074	2,799	2,799	(311)	2
Street Lighting	-	1,979	1,979	-	616	616	1,363	1,979	1,979	-	
Street Light - LED Replacement Program	-	5,402	5,402	-	2,046	2,046	3,356	5,402	5,402	-	
Transformers	-	5,945	5,945	-	2,096	2,096	3,849	5,945	5,945	-	
Reconstruction	-	5,567	5,567	-	1,388	1,388	4,179	5,567	5,567	-	
Rebuild Distribution Lines	-	3,965	3,965	-	1,300	1,300	2,665	3,965	3,965	-	
Relocate/Replace Distribution Lines for Third Parties	-	3,155	3,155	-	793	793	2,362	3,155	3,155	-	
Trunk Feeders	-	800	800	-	19	19	781	800	800	-	
Feeder Additions for Growth	-	2,655	2,655	-	173	173	2,482	2,655	2,655	-	
Distribution Reliability Initiative	-	700	700	-	29	29	671	700	700	-	
Distribution Feeder Automation	-	821	821	-	38	38	783	821	821	-	
Allowance for Funds Used During Construction	-	205	205	-	59	59	146	205	205	-	
Total - Distribution 2021	**$ -**	**$ 45,875**	**$ 45,875**	**$ -**	**$ 12,270**	**$ 12,270**	**$ 31,959**	**$ 44,229**	**$ 44,229**	**$ (1,646)**	
2020 Projects											
Trunk Feeders	$ 2,820	$ -	$ 2,820	$ 707	-	$ 707	$ 2,050	$ 2,050	$ 2,757	$ (63)	
Feeder Additions for Growth	2,302	-	2,302	1,718	-	1,718	442	442	2,160	(142)	
Total Distribution	**$ 5,122**	**$ 45,875**	**$ 50,997**	**$ 2,425**	**$ 12,270**	**$ 14,695**	**$ 34,451**	**$ 46,721**	**$ 49,146**	**$ (1,851)**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2020
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2021 Capital Expenditure Status Report
($000s)

Category: General Property

	Capital Budget			Actual Expenditure			Forecast				
	2020	2021	Total	2020	YTD 2021	Total To Date	Remainder 2021	Total 2021	Overall Total	Variance	Notes*
	A	B	C	D	E	F	G	H	I	J	
2021 Projects											
Tools and Equipment	$ -	$ 486	$ 486	$ -	$ 65	$ 65	$ 421	$ 486	$ 486	$ -	
Additions to Real Property	-	598	598	-	42	42	556	598	598	-	
Company Building Renovations	-	1,392	1,392	-	72	72	1,320	1,392	1,392	-	
Physical Security Upgrades	-	300	300	-	10	10	290	300	300	-	
									-		
Total - 2021 General Property	**$ -**	**$ 2,776**	**$ 2,776**	**$ -**	**$ 189**	**$ 189**	**$ 2,587**	**$ 2,776**	**$ 2,776**	**$ -**	
2020 Projects											
Company Building Renovations	$ 1,172	$ -	$ 1,172	$ 1,116	$ -	$ 1,116	$ 90	$ 90	$ 1,206	$ 34	
Total - General Property	**$ 1,172**	**$ 2,776**	**$ 3,948**	**$ 1,116**	**$ 189**	**$ 1,305**	**$ 2,677**	**$ 2,866**	**$ 3,982**	**$ 34**	

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Column J	Column I less Column C

2021 Capital Expenditure Status Report
($000s)

Category: Transportation

	Capital Budget			Actual Expenditure			Forecast				
	2020	2021	Total	2020	YTD 2021	Total To Date	Remainder 2021	Total 2021	Overall Total	Variance	Notes*
	A	B	C	D	E	F	G	H	I	J	
2021 Projects											
Purchase Vehicles and Aerial Devices	$ -	$ 4,032	$ 4,032	$ -	$ -	$ -	$ 4,032	$ 4,032	$ 4,032	$ -	
Total - 2021 Transportation	**$ -**	**$ 4,032**	**$ 4,032**	**$ -**	**$ -**	**$ -**	**$ 4,032**	**$ 4,032**	**$ 4,032**	**$ -**	
2020 Projects											
Purchase Vehicles and Aerial Devices	$ 3,869	$ -	$ 3,869	$ 2,254	$ 118	$ 2,372	$ 1,497	$ 1,615	$ 3,869	$ -	
Total - Transportation	**$ 3,869**	**$ 4,032**	**$ 7,901**	**$ 2,254**	**$ 118**	**$ 2,372**	**$ 5,529**	**$ 5,647**	**$ 7,901**	**$ -**	

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Column A	Approved Capital Budget for 2020
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2021 Capital Expenditure Status Report
($000s)

Category: Telecommunications

Project	Capital Budget 2021 A	Capital Budget Total B	Actual Expenditures YTD 2021 C	Actual Expenditures Total To Date D	Forecast Remainder 2021 E	Forecast Total 2021 F	Forecast Overall Total G	Variance H	Notes*
2021 Projects									
Replace/Upgrade Communications Equipment	$ 112	$ 112	$ 42	$ 42	$ 70	$ 112	$ 112	$ -	
Fibre Optic Cable Builds	$ 350	$ 350	$ 2	$ 2	$ 348	$ 350	$ 350	$ -	
Total - Telecommunications	**$ 462**	**$ 462**	**$ 44**	**$ 44**	**$ 418**	**$ 462**	**$ 462**	**$ -**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2021
Column B	Total of Column A
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Column D	Total of Column C
Column E	Forecast for Remainder of 2021
Column F	Total of Columns C and E
Column G	Total of Column F
Column H	Column G less Column B

2021 Capital Expenditure Status Report
($000s)

Category: Information Systems

	Capital Budget			Actual Expenditure			Forecast				
	2020	2021	Total	2020	YTD 2021	Total To Date	Remainder 2021	Total 2021	Overall Total	Variance	Notes*
	A	B	C	D	E	F	G	H	I	J	
2021 Projects											
Application Enhancements	$ -	$ 978	$ 978	$ -	$ 189	$ 189	$ 789	$ 978	$ 978	$ -	
System Upgrades	-	2,410	2,410	-	655	655	1,755	2,410	2,410	-	
Personal Computer Infrastructure	-	495	495	-	99	99	396	495	495	-	
Shared Server Infrastructure	-	538	538	-	46	46	492	538	538	-	
Network Infrastructure	-	363	363	-	53	53	310	363	363	-	
Cybersecurity Upgrades	-	675	675	-	219	219	456	675	675	-	
Customer Service System Replacement		9,903	9,903	-	-	-	9,903	9,903	9,903	-	
Total - 2021 Information Systems	**$ -**	**$ 15,362**	**$ 15,362**	**$ -**	**$ 1,261**	**$ 1,261**	**$ 14,101**	**$ 15,362**	**$ 15,362**	**$ -**	
2020 Projects											
Application Enhancements	$ 1,428	$ -	$ 1,428	$ 1,346	$ -	$ 1,346	$ 135	$ 135	$ 1,481	$ 53	
System Upgrades	2,592	-	2,592	2,422	-	2,422	408	408	2,830	238	
Total - Information Systems	**$ 4,020**	**$ 15,362**	**$ 19,382**	**$ 3,768**	**$ 1,261**	**$ 5,029**	**$ 14,644**	**$ 15,905**	**$ 19,673**	**$ 291**	

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2021 Capital Expenditure Status Report
($000s)

Category: Unforeseen Allowance

	Capital Budget		Actual Expenditures		Forecast				
Project	**2021**	**Total**	**YTD 2021**	**Total To Date**	**Remainder 2021**	**Total 2021**	**Overall Total**	**Variance**	**Notes***
	A	**B**	**C**	**D**	**E**	**F**	**G**	**H**	
2021 Projects									
Allowance for Unforeseen Items	$ 750	$ 750	$ -	$ -	$ 750	$ 750	$ 750	$ -	
Total - Unforeseen Items	**$ 750**	**$ 750**	**$ -**	**$ -**	**$ 750**	**$ 750**	**$ 750**	**$ -**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2021
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Column F	Total of Columns C and E
Column G	Total of Column F
Column H	Column G less Column B

2021 Capital Expenditure Status Report
($000s)

Category: General Expenses Capitalized

Project	Capital Budget 2021 A	Capital Budget Total B	Actual Expenditures YTD 2021 C	Actual Expenditures Total To Date D	Forecast Remainder 2021 E	Forecast Total 2021 F	Forecast Overall Total G	Variance H	Notes*
2021 Projects									
General Expenses Capitalized	$ 6,500	$ 6,500	$ 1,814	$ 1,814	$ 4,686	$ 6,500	$ 6,500	$ -	
Total - General Expenses Capitalized	**$ 6,500**	**$ 6,500**	**$ 1,814**	**$ 1,814**	**$ 4,686**	**$ 6,500**	**$ 6,500**	**$ -**	

* See Appendix A for notes containing variance explanations.

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Column A	Approved Capital Budget for 2021
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Distribution

1. *Extensions:*

   Budget: $10,891,000 Forecast: $9,556,000 Variance: ($1,335,000)

   The forecast expenditure for Extensions is expected to be approximately 12% below the budgeted amount. The reduction reflects a 12% decrease in anticipated new customer connections. In 2021, the forecast number of new customer connections is expected to drop from 2,379 to 2,096.

2. *Services:*

   Budget: $3,110,000 Forecast: $2,799,000 Variance: ($311,000)

   The forecast expenditure for Services is expected to be approximately 10% below the budgeted amount. The reduction reflects an anticipated drop in new customer connections from 2,379 to 2,096.

2022 Capital Plan

May 2021

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1.0 Executive Summary

Newfoundland Power Inc.'s ("Newfoundland Power" or the "Company") annual capital planning enables the provision of safe, reliable and least-cost service to customers.

The value of the Company's investments to customers can be observed over the long term and short term. Over the last 2 decades, Newfoundland Power's investment in the electricity system has improved the reliability experienced by customers, while reducing the Company's contribution to customer rates on an inflation-adjusted basis. Since 2016, customer rates have not increased due to changes in Newfoundland Power's costs and reliability has been maintained.

In comparison to other Atlantic Canadian utilities, Newfoundland Power has had the lowest rate of growth in transmission and distribution investment over the decade ending 2019. At the same time, the Company's customers experienced the best service reliability in Atlantic Canada.

Newfoundland Power's capital investments are also consistent with good utility practice. This was confirmed in the last independent review of the Company's engineered operations completed in 2014.

Newfoundland Power's *2022 Capital Budget Application* proposes investments totalling approximately $109.6 million.

The capital budget proposed for 2022 is consistent with the level of expenditure over the last 5-year period. Approximately 69% of proposed 2022 expenditures are driven by the need to replace deteriorated and failed plant, and the obligation to serve new customers and customers' increased electricity usage.

Newfoundland Power's 5-year capital plan forecasts average expenditures of approximately $123 million annually through 2026.

This includes 2 plans to guide certain capital projects continuing in 2022. These are: (i) the *LED Street Lighting Replacement Plan,* which will provide net cost savings for customers over the next 20 years; and (ii) the *Customer Service Continuity Plan*, which will replace the Company's nearly 30-year-old Customer Service System.

Each of these plans is consistent with sound public utility practice. These plans, and other capital investments proposed for 2022, will enable the Company to continue providing safe and reliable service to customers at least cost.

2.0 Capital Planning at Newfoundland Power

2.1 Planning and Deferring Capital Investments

2.1.1 Public Policy Context

Newfoundland Power is the primary distributor of electricity in the province of Newfoundland and Labrador. The Company serves approximately 87% of all customers in the province.

Newfoundland Power's operations, including its capital investments, are regulated by the Newfoundland and Labrador Board of Commissioners of Public Utilities (the "Board") pursuant to the *Public Utilities Act* and the *Electrical Power Control Act, 1994*.[1]

The *Public Utilities Act* requires a public utility to provide services and facilities that are reasonably safe and adequate and just and reasonable.[2]

The *Electrical Power Control Act, 1994* contains the provincial power policy. Among other provisions, the provincial power policy requires that power be delivered to customers at the lowest possible cost consistent with reliable service.[3]

The Board has provided specific directions regarding the preparation of annual capital budget applications. These include: (i) the Capital Budget Application Guidelines (the "Guidelines");[4] (ii) the requirement to file a 5-year capital plan;[5] and (iii) the requirement to provide certain additional information regarding the deferral and revenue requirement impact of proposed capital projects.[6]

Newfoundland Power's *2022 Capital Budget Application* is consistent with the *Public Utilities Act*, the *Electrical Power Control Act, 1994*, and all applicable policies and directives of the Board.

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1 Section 41 of the *Public Utilities Act* requires, among other provisions, that a public utility submit an annual capital budget of proposed improvements or additions to its property to the Board for its approval.

2 See Section 37(1) of the *Public Utilities Act.*

3 See Sections 3(b)(i), 3(b)(ii) and 3(b)(iii) of the *Electrical Power Control Act, 1994*.

4 The Guidelines were established by the Board as Policy No. 1900.6 issued in October 2007. Appendix A to this plan provides a summary of Newfoundland Power's compliance with the Guidelines as it relates to its *2022 Capital Budget Application.*

5 In Order No. P.U. 35 (2003), the Board required that future capital budget applications include an updated 5-year plan for maintaining the predictability and stability of the capital budget and the capital works program (see page 31). Appendix B to this plan provides Newfoundland Power's 5-year capital plan.

6 On February 27, 2020, the Board directed that the *2021 Capital Budget Application* should include additional information regarding the deferral and revenue requirement impact of proposed capital projects. In February 2021, the Board concluded that the additional requirements established for the *2021 Capital Budget Application* would remain in place for the *2022 Capital Budget Application*.

2.1.2 Capital Planning Process

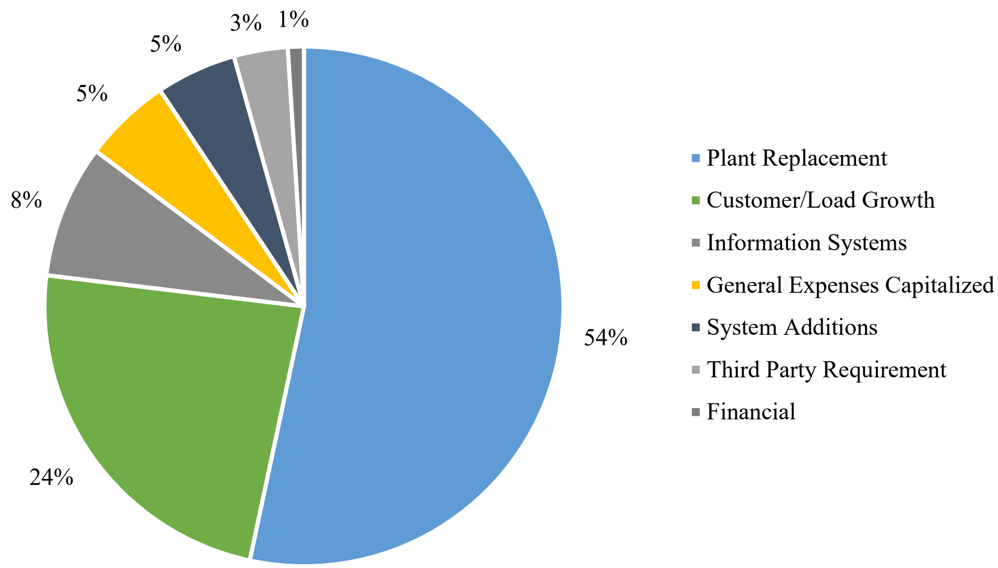
Newfoundland Power's 5-year capital plan provides the basis of its annual capital budgeting. The 5-year plan includes: (i) a proposed capital budget for the upcoming year for approval by the Board; and (ii) a forecast of capital expenditures over the subsequent 4-year period.

The 5-year capital plan is reviewed and updated annually. The updated plan is filed with the Board as part of the Company's annual capital budget applications.

The annual review and updating of the 5-year capital plan is a comprehensive planning process based on sound engineering and objective data.

Figure 1 shows the Company's total Capital Budget expenditure by origin, or root cause for the 5-year period 2017 to 2021F.

Figure 1
2017 to 2021F Capital Expenditures by Origin



Each year, approximately ½ of annual capital expenditures are driven by the need to replace deteriorated or deficient plant, or plant that fails in service. The replacement of deteriorated, deficient or failed plant is necessary to provide safe and reliable service to customers. The 5-year capital plan is updated annually to reflect the most recent information available on plant condition. This includes information obtained through the Company's annual inspection and maintenance programs,[7] engineering reviews conducted as part of long-term asset management strategies,[8] and recent operating experience.

Approximately ¼ of annual capital expenditures are driven by the need to serve new customers and to respond to system load growth. The 5-year capital plan is updated annually to reflect the most recent customer, energy and demand forecasts.[9] This ensures the electrical system is adequately designed to meet customers' service requirements.

The remaining ¼ of annual capital expenditures include information systems, system additions, third-party requirements, General Expenses Capitalized and financing costs. The 5-year capital plan is updated annually to reflect the most recent information available for these projects, such as risk assessments for Company information systems.

This comprehensive planning process determines the necessity, scope and timing of each proposed capital project. As projects move from the forecast period to the budget year, they are assessed in detail to determine the least-cost alternative to meet a particular requirement.

Overall, Newfoundland Power's capital planning process ensures all proposed projects are consistent with its obligation to provide safe and reliable service to customers at least cost.

2.1.3 Deferral in the Planning Process

The Board's Guidelines require an assessment of all available alternatives for capital projects, including whether a project can be deferred.[10] Newfoundland Power assesses the deferral of capital projects at multiple points throughout its capital planning process.

Before any expenditure is included in Newfoundland Power's 5-year capital plan, the Company assesses whether the expenditure is necessary to: (i) meet federal or provincial laws; (ii) provide customers with equitable access to an adequate supply of power; (iii) provide reliable service to customers at least cost; or (iv) maintain safe and adequate facilities in serving customers.[11]

Whether capital expenditures are necessary to meet these requirements is determined based on objective data, including inspection data, condition assessments and forecast customer requirements. Capital expenditures that are not necessary to meet these requirements are not included in the 5-year capital plan. These expenditures are, in effect, deferred.

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7 Substations are inspected 8 times each year, transmission lines are inspected annually, and distribution lines are inspected on a 7-year cycle.

8 Examples of long-term asset management strategies include the Company's: (i) *Substation Strategic Plan*; (ii) *Transmission Line Rebuild Strategy*; and (iii) *Distribution Reliability Initiative*.

9 Forecast inflation and new customer connections are developed with economic inputs from the Conference Board of Canada.

10 The Guidelines require that all reasonable alternatives, including deferral, be considered for all Normal and Justifiable expenditures. See page 6 of the Guidelines.

11 These requirements are established in the provincial power policy. See Section 3 of the *Electrical Power Control Act, 1994.*

Expenditures that are included as projects in the 5-year capital plan are routinely updated based on new data or information. This may result in a project being advanced to an earlier year, deferred to a later year, or removed entirely from the 5-year capital plan. Examples of new data or information that can result in the deferral of capital projects include:

(i) Updated customer, energy and demand forecasts. A reduced forecast will tend to result in the deferral of a planned substation or distribution upgrade.
(ii) Updated condition assessments of equipment. A piece of equipment that is inspected and found to be in adequate condition will tend to result in the deferral of a refurbishment or replacement project.
(iii) Updated assessments of potential customer benefits. Changes in system costs or technologies may result in a project no longer being economic for customers and therefore being deferred.

The Company considers this information in evaluating all available alternatives for meeting a particular requirement. This can include alternatives that do not require capital investments, such as transferring customer load to an adjacent substation when overload conditions arise. It can also include investing in the life extension of an electrical system asset to delay the need for a larger, one-off capital investment. Each of these alternatives can, in effect, result in the deferral of a capital project.

2.1.4 Deferred Capital Projects

Table 1 provides examples of capital projects proposed for 2022 that were previously deferred through Newfoundland Power's capital planning process.

Table 1
2022 Capital Projects Deferred from Previous Years

Project	Description
Sandy Brook Hydro Plant Penstock Replacement	Newfoundland Power's Sandy Brook hydro plant has provided reliable supply to customers since 1963. The replacement of the woodstave penstock was originally planned for 2020.[12] The project was deferred to allow for an updated condition assessment of the penstock. Recent condition assessments have indicated that the condition of the penstock has deteriorated, and requires replacement. The replacement of the woodstave penstock is proposed as a multi-year project commencing in 2022 and completed in 2023.[13]
St. John's Teleprotection System Replacement	Newfoundland Power's existing teleprotection system associated with the St. John's 66 kV transmission line network is 20 years old and at the end of its useful life. The replacement of this system was originally planned for 2021.[14] This project was deferred to allow further study of system protection requirements following the commissioning of the Muskrat Falls project. A study of system protection requirements confirmed that the system is required following the commissioning of the Muskrat Falls project. Maintaining the existing teleprotection system is no longer feasible. The replacement of the teleprotection system is proposed as a multi-year project commencing in 2022 and completed in 2023.[15]

[12] The 2019 5-year capital plan filed with the *2019 Capital Budget Application* included the replacement of the Sandy Brook Penstock in 2020.

[13] For more information, see the *2022 Capital Budget Application, Report 1.2 Sandy Brook Plant Penstock Replacement.*

[14] The 2020 5-year capital plan filed with the *2020 Capital Budget Application* included the replacement of the St. John's Teleprotection System in 2021.

[15] For more information, see the *2022 Capital Budget Application, Report 6.1 St. John's Teleprotection System Replacement.*

Table 2 provides examples of capital projects originally planned for 2022 that have been deferred to subsequent years.

Table 2
Capital Projects Deferred from 2022 to Subsequent Years

Project	Description
Mobile Hydro Plant Refurbishment	The electrical, mechanical, and civil systems at Newfoundland Power's Mobile Hydro Plant require refurbishment. The refurbishment of this plant was originally planned for 2022. This project has been deferred to 2023 to allow further assessment of the condition of the plant and associated infrastructure.
Corner Brook Feeder Load Growth	Distribution feeder additions in the City of Corner Brook were originally planned for 2022 to address forecast load growth associated with the construction of the new hospital. A review of the load requirements and revised construction schedule for the new hospital was completed in late 2020 and determined that the existing distribution system in the Corner Brook area has available capacity to supply the increased load requirements until 2023. As a result, this project has been deferred to 2023 to be consistent with the load requirements of the new hospital.

2.1.5 Observations

Newfoundland Power's capital planning process is based on sound engineering and is consistent with the Company's obligation to provide safe and reliable service to customers at least cost.

The deferral of capital projects is thoroughly considered at multiple points throughout the capital planning process. This is consistent with the Board's Guidelines and routinely results in the deferral of specific capital projects.

2.2 Capital Investment and Customer Service

2.2.1 Capital Investment in Context

Newfoundland Power's service territory is approximately 70,000 km^2. The Company owns and operates over 10,000 kilometres of distribution line, 2,000 kilometres of transmission line, 131 substations and 29 generating plants to serve customers throughout its service territory. On average, these assets have been in service for approximately 30 years.

The reliability experienced by customers reflects both: (i) the general condition of the electrical system; and (ii) the Company's operational response when customer outages occur.

Newfoundland Power's electrical system is constructed and maintained to meet national standards and local climatic conditions.[16] The Company deploys a skilled workforce throughout its service territory to respond to equipment failures and customer outages, including Powerline Technicians, Technologists and Professional Engineers. Annual capital investments are necessary to maintain both electrical system condition and the Company's operational response capabilities.

The most recent independent review of Newfoundland Power's engineered operations was conducted by The Liberty Consulting Group ("Liberty") in 2014. Liberty found that:

> *"Newfoundland Power's planning and design of its system, its asset management practices, its system operations, its outage management and emergency practices and its customer communications processes all conform to good utility practices."*[17]
>
> *"Its transmission and distribution systems operate effectively in ensuring adequate service reliability. Effective maintenance and capital programs, that appropriately recognize the age of its assets, have contributed materially to improved reliability."* [18]

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16 The primary engineering standard for distribution and transmission systems is Canadian Standards Association ("CSA") standard *C22.3 No.1-15 Overhead Systems*.

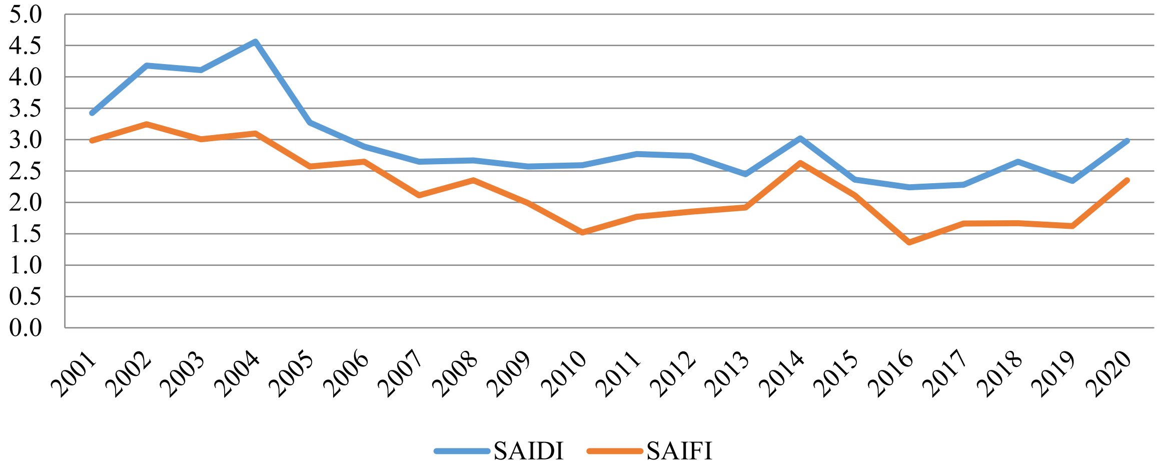
17 Liberty, *Executive Summary of Report on Island Interconnected System to Interconnection with Muskrat Falls addressing Newfoundland Power Inc.*, December 17, 2014, page ES-1.

18 Ibid., page ES-2.

2.2.2 Customer Service Outcomes

Figure 2 shows the duration ("SAIDI") and frequency ("SAIFI") of outages to Newfoundland Power's customers over the period 2001 to 2020 under normal operating conditions.[19]

Figure 2
SAIDI and SAIFI
2001 to 2020



Over the period 2001 to 2020, the duration of customer outages was reduced by approximately 13%.[20] The frequency of customer outages was reduced by approximately 21% over the same period.[21]

The duration and frequency of customer outages has remained reasonably consistent since 2009. The duration of customer outages has ranged from approximately 2.2 to 3.0 hours per year under normal operating conditions. The frequency of customer outages has ranged from approximately 1.4 to 2.6 outages per year.

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[19] Newfoundland Power calculates its SAIDI ("System Average Interruption Duration Index") and SAIFI ("System Average Interruption Frequency Index") in accordance with Canadian Electricity Association ("CEA") Guidelines. SAIDI is calculated by dividing the total number of customer outage minutes by the total number of customers served. SAIFI is calculated by dividing the total number of customer interruptions by the total number of customers served. The data shown in Figure 2 does not include customer outages due to significant events or loss of supply from Newfoundland and Labrador Hydro.

[20] Newfoundland Power's SAIDI was 3.42 in 2001 and 2.98 in 2020 ((3.42 – 2.98) / 3.42 = 0.13, or 13%).

[21] Newfoundland Power's SAIFI was 2.99 in 2001 and 2.35 in 2020 ((2.99 – 2.35) / 2.99 = 0.21, or 21%).

Current levels of service reliability have been viewed as acceptable by Newfoundland Power for about a decade.[22]

2.2.3 Observations

Newfoundland Power's engineered operations are consistent with good utility practice.

The Company's capital investments and operational response have improved the service reliability experienced by customers over the long term. The Company has focused on maintaining current levels of service reliability for customers over the last decade.

2.3 Capital Investment and Customer Costs

2.3.1 General

In February 2020, the Board directed that the *2021 Capital Budget Application* should include information on the revenue requirement impact of proposed capital projects. In February 2021, the Board concluded that the additional requirements established for the *2021 Capital Budget Application* would remain in place for the *2022 Capital Budget Application*.[23]

Revenue requirement is the aggregate amount of forecast revenue required by a utility in a year to cover its cost of serving customers, including operating costs, taxes and allowed return on rate base.[24] The forecast revenue requirement is the primary determinant of customer rates. Customers' rates also reflect the Company's customer, energy and demand forecasts and Board-approved rate structures.[25]

Newfoundland Power's revenue requirements and customer rates are interrogated by the Board on a triennial basis in the context of general rate applications ("GRA").

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22 In Newfoundland Power's *2010 General Rate Application*, the Company stated it considered then current levels of service reliability to be satisfactory (see Volume 1 (1st Revision), Section 2: Customer Operations, Page 2-8, Line 6). Similarly, the Company has characterized its electrical system performance as reliable in its *2013/2014 General Rate Application* (see Volume 1, Section 1: Introduction, Page 1-3, Line 10), its *2016/2017 General Rate Application* (see Volume 1 (1st Revision), Section 1: Introduction, Page 1-3, Line 11), and its *2019/2020 General Rate Application* (see Volume 1, Section 1: Introduction, Page 1-3, Line 21).

23 See correspondence from the Board dated February 18, 2021, regarding further interim changes for 2022 capital budget applications.

24 See Order No. P.U. 7 (2002-2003), page 31.

25 See Order No. P.U. 40 (2005), page 13.

The Board has previously recognized the complex relationship between capital investments, revenue requirements and customer rates. In Order No. P.U. 40 (2005), the Board stated:

> *"NP undertakes a capital program and incurs capital expenditures each year and these expenditures impact the revenue requirement in other ways, in addition to depreciation. The portion of capital expenditures incurred for example as a result of customer growth will be offset somewhat by higher revenues from increased energy sales. Other capital expenditures may impact maintenance expenses…these expenses are properly dealt with in the context of a general rate application."* [26]

The Board has also stated that:

> *"From a regulatory perspective, efficient operations, fully justified capital expenditures and a low cost capital structure all combine to minimize revenue requirement, and hence provide least cost electricity to ratepayers."* [27]

Newfoundland Power shares the Board's view that fully justified capital expenditures are part and parcel of delivering least-cost service to customers.

2.3.2 Revenue Requirement Perspective

On a *pro forma* basis, the Company's 2022 revenue requirement is estimated to increase by approximately $2 million as a result of the capital projects proposed for 2022. This *pro forma* estimate includes increases in depreciation, return on rate base and income tax, as well as reduced operating costs as a result of the *LED Street Lighting Replacement Plan*.[28]

The *pro forma* estimate is, however, practically limited. It does not include potentially higher revenues from customer growth projects, or the long-term effect that fully justified capital expenditures have on minimizing aggregate costs and thus revenue requirements.[29]

To illustrate these practical limitations, Newfoundland Power assessed its revenue requirements and capital investments since its 2013/2014 GRA.

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[26] Customer rates are stated in unit costs. For example, energy charges are priced on a ¢/kWh basis.

[27] See Order No. P.U. 7 (2002-2003), page 31.

[28] The proposed *LED Street Lighting Replacement Plan* is forecast to reduce operating costs in 2022 by approximately $2 million on a *pro forma* basis. See the *2021 Capital Budget Application, Volume 1, LED Street Lighting Replacement Plan,* Appendix B, page B-5.

[29] For example, the systematic replacement of deteriorated plant (i.e. during regular work hours) tends to reduce the cost of making emergency repairs due to equipment failures (i.e. during overtime hours). Other capital expenditures enable efficiencies through technology. These effects will also tend to decrease future revenue requirements.

Table 3 shows Newfoundland Power's actual and inflation-adjusted contribution to revenue requirement in 2014 and 2021.[30]

Table 3
Newfoundland Power
Contribution to Revenue Requirement
($millions)

	2014	2021[31]	Change
Actual	212.9[32]	226.5	6%
Inflation-Adjusted[33]	232.2	226.5	-2%

Since 2014, Newfoundland Power's contribution to revenue requirement has increased by approximately 6%. On an inflation-adjusted basis, the Company's contribution to revenue requirement has decreased by approximately 2%.

While Newfoundland Power's contribution to revenue requirement has decreased slightly, the Company's annual capital investments have averaged approximately $100 million per year over this period.

2.3.3 Customer Rates Perspective

To more broadly assess the long-term impact of Newfoundland Power's operations on customer costs, the Company analyzed its contribution to customer rates over the last 2 decades.

30 Based on the Company's test year revenue requirements, excluding purchased power costs. Purchased power costs from Newfoundland and Labrador Hydro account for approximately 70% of the Company's overall revenue requirement.

31 Newfoundland Power's 2020 revenue requirement was $673.8 million. Excluding purchased power costs of $447.3 million, it was $226.5 million. See the Company's 2019/2020 GRA, Exhibit 7 (Revised), page 2.

32 Newfoundland Power's 2014 revenue requirement was $612.1 million. Excluding purchased power costs of $399.2 million, it was $212.9 million. See the Company's application filed in compliance with Order No. P.U. 13 (2013), Schedule 1, Appendix E, page 2.

33 Inflation adjusted based on the GDP Deflator for Canada.

Table 4 compares Newfoundland Power's total contribution to average customer rates in ¢/kWh in 2000 and 2021.

Table 4
Newfoundland Power
Contribution to Customer Rates
(¢/kWh)

	2000	2021[34]	Change
Actual	3.53	4.14	17%
Inflation-Adjusted[35]	5.23	4.14	-21%

Newfoundland Power's contribution to average customer rates has increased by approximately 17% over the last 2 decades. On an inflation-adjusted basis, the Company's contribution to average customer rates decreased by 21%.

2.3.4 Observations

The relationship between Newfoundland Power's capital expenditures and its revenue requirements or customer rates is not a direct one.

The Company's revenue requirements have remained relatively stable over the past 6 years. Customer rates have not changed as a result of a Newfoundland Power GRA since July 1, 2016.[36] Over the longer term, the Company's contribution to average customer rates decreased by 21% on an inflation-adjusted basis.

Newfoundland Power's approach to capital planning tends to minimize overall costs to customers over the longer term. This is consistent with the least-cost delivery of reliable service to customers.

34 Based on Newfoundland Power's 2020 test year revenue requirement which is reflected in current customer rates. The Company's base rates are not expected to change in 2021.
35 Inflation adjusted based on the GDP Deflator for Canada.
36 On July 1, 2016, customer rates increased by 1.2% as a result of Newfoundland Power's 2016/2017 GRA. Customer rates did not change as a result of its 2019/2020 GRA.

2.4 Atlantic Canada Comparison: Capital Investment and Service Outcomes

2.4.1 Comparison

The 4 primary distributors of electricity in Atlantic Canada are: (i) Newfoundland Power; (ii) Nova Scotia Power; (iii) NB Power; and (iv) Maritime Electric. Each of these utilities serves customers in a mix of urban and rural areas.[37]

Newfoundland Power compared its capital investment and service outcomes to the other 3 Atlantic Canadian utilities over the 10-year period 2010 to 2019.

Table 5 shows: (i) the capital investment of Newfoundland Power in transmission and distribution ("T&D") assets; (ii) the average investment of the other 3 Atlantic Canadian utilities over the period 2010 to 2019; and (iii) the cumulative rate of growth in T&D capital investment.[38]

Table 5
Capital Investment
Property Plant and Equipment – T&D
($millions)

Utility	2010	2019	Growth
Newfoundland Power	$999	$1,424	43%
Average of Other Atlantic Canadian Utilities[39]	$1,166	$1,774	52%

Newfoundland Power's investment in T&D assets has increased at a rate 9% less than the average of other Atlantic Canadian utilities over the 10-year period ending 2019. The Company's capital investment in T&D assets has, in fact, increased at the lowest rate of any Atlantic Canadian utility.[40] At the same time, Newfoundland Power experienced the highest rate of growth in customers served of these utilities.[41]

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[37] NB Power, Nova Scotia Power, Maritime Electric, and Newfoundland Power are all members of the CEA and are considered Region 2 utilities. Region 2 utilities are those that serve a mix of urban and rural areas.

[38] Table 5 reflects the average Property, Plant and Equipment in T&D assets of NB Power, Nova Scotia Power and Maritime Electric over the period 2010 to 2019. Property, Plant and Equipment is the gross cost of utility assets determined in accordance with generally accepted accounting principles. This information is based on the audited and publicly available financial statements of each utility.

[39] The aggregate investment of NB Power, Nova Scotia Power and Maritime Electric was $3,498 million in 2010 ($3,498 million / 3 = $1,166 million) and $5,322 million in 2019 ($5,322 million / 3 = $1,774 million).

[40] Over the period 2010 to 2019, increases in Property, Plant and Equipment (T&D) range from 48% to 59% for the other Atlantic Canadian utilities.

[41] Over the period 2010 to 2019, the total number of residential and commercial customers served by Newfoundland Power increased by approximately 11%. This compares to customer growth of between 2% and 7% for other Atlantic Canadian utilities, as shown in annual CEA filings.

Table 6 compares the duration of outages experienced by Newfoundland Power's customers to the average of other Atlantic Canadian utilities over the period 2010 to 2019.[42]

Table 6
Atlantic Canadian Utilities
Annual Duration of Customer Outages
(2010-2019)

Utility	Average SAIDI
Newfoundland Power	2.54
Other Atlantic Canadian Utilities	4.66

Over the 10-year period ending 2019, Newfoundland Power's customers have experienced approximately ½ the duration of customer outages in comparison to customers of other Atlantic Canadian utilities.[43]

2.4.2 Observations

The Company's capital investments have increased at the lowest rate of any Atlantic Canadian utility over the 2010 to 2019 period. At the same time, Newfoundland Power's customers have experienced better-than-average reliability compared to the remainder of Atlantic Canada.

Newfoundland Power's capital investments appear reasonable in comparison to other Atlantic Canadian utilities.

3.0 2022 Capital Budget

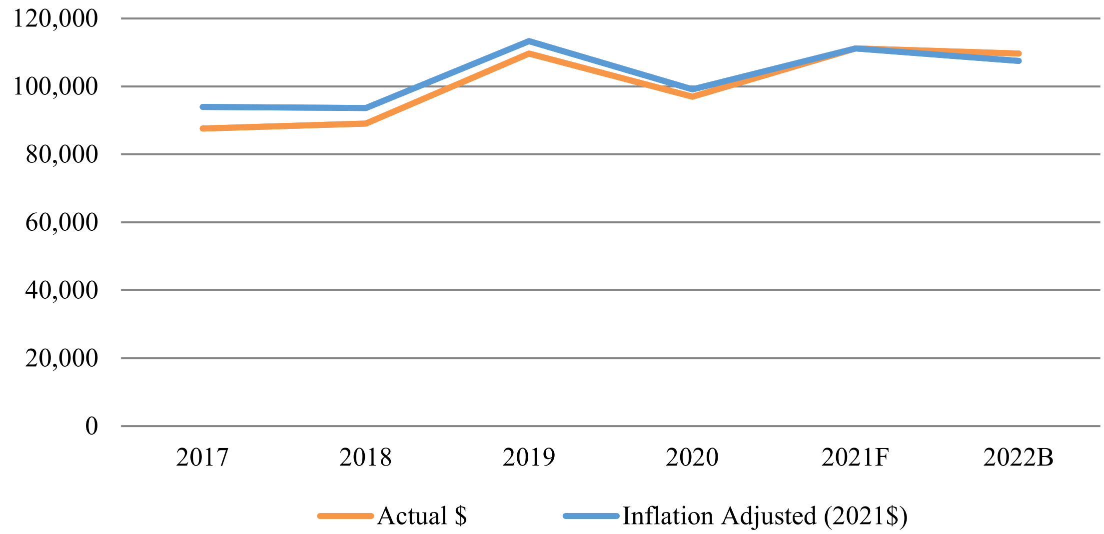
3.1 2022 Budget Overall

Newfoundland Power's *2022 Capital Budget Application* proposes 40 projects totaling approximately $109.6 million.

[42] Table 6 does not include customer outages due to significant events or loss of supply.
[43] 2.54 / 4.66 = 0.55, or 55%. The average SAIDI for the other Atlantic Canadian utilities ranged from 3.9 to 5.4 over this period which, in all cases, is higher than that of Newfoundland Power.

Figure 3 compares Newfoundland Power's proposed 2022 Capital Budget to capital expenditures over the most recent 5-year period, including the 2021 forecast on an actual and inflation adjusted basis.[44]

Figure 3
Capital Expenditures 2017 to 2022B
($000s)



Newfoundland Power's proposed 2022 Capital Budget of $109.6 million is reasonably consistent with expenditures over the last 5 years on an inflation-adjusted basis.[45]

3.2 2022 Budget by Origin

Newfoundland Power's capital expenditures are primarily driven by the replacement of aging infrastructure and its obligation to serve new customers and respond to system load growth.

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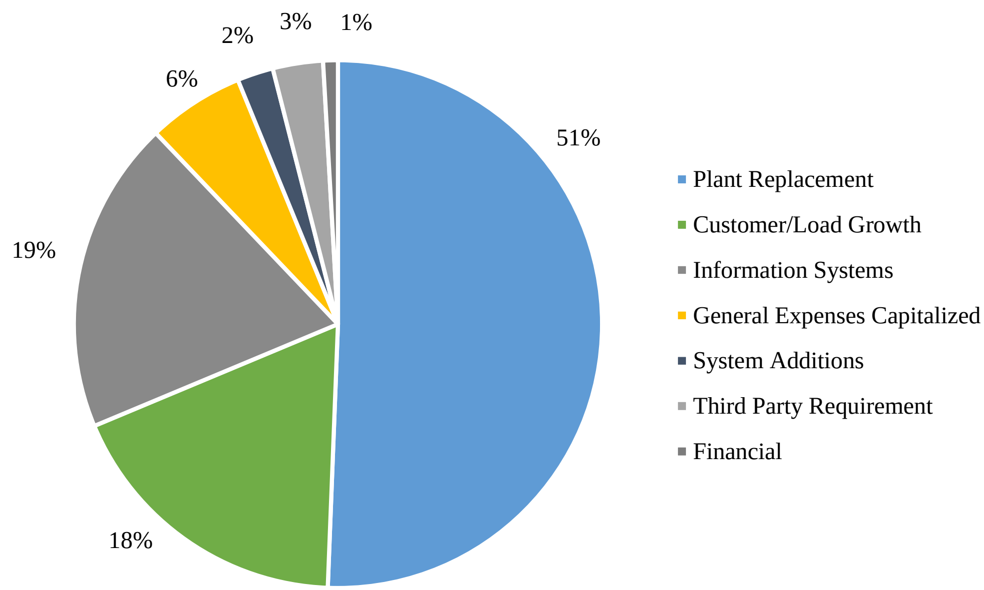
44 Historical capital expenditures are inflation-adjusted using the GDP Deflator for Canada for non-labour expenditures and its bargaining unit contracts for labour expenditures. In Order No. P.U. 36 (1998-99), the Board ordered the adoption of the GDP Deflator for Canada as an appropriate inflation index for forecasting Newfoundland Power's non-labour expenses.

45 In 2022, capital expenditures of $109.6 million include $15.8 million associated with the multi-year project to replace the Company's Customer Service System. Without this once-in-a-generation project, 2022 capital expenditures would total approximately $94 million. Capital expenditures totaled approximately $94 million in 2017 when adjusted for inflation.

Figure 4 shows the Company's 2022 Capital Budget by origin, or root cause.

Figure 4
2022 Capital Plan by Origin



Approximately 51% of proposed 2022 expenditures are driven by the replacement of existing plant. These expenditures are required to maintain the condition of the electrical system and provide reliable service to customers.

Approximately 18% of proposed 2022 expenditures are driven by connecting new customers and responding to system load growth. These expenditures are required to provide customers with equitable access to an adequate supply of power.

Approximately 19% of proposed 2022 expenditures are driven by Information Systems. These expenditures include $15.8 million associated with the Customer Service System Replacement project.[46]

The remaining expenditures proposed for 2022 relate to System Additions, General Expenses Capitalized ("GEC"), Third Party Requirements, and Financial costs associated with the proposed investments.[47]

46 This project was approved in Order No. P.U. 12 (2021).
47 Financial costs include the Allowance for Funds Used During Construction ("AFUDC") and the Unforeseen Allowance.

3.3 2022 Budget by Asset Class

3.3.1 Overview

Table 7 provides the 2022 Capital Budget by asset class.

Table 7
2022 Capital Budget by Asset Class
($000s)

Asset Class	Budget	Percentage
Distribution	$47,744	43%
Substations	11,639	11%
Transmission	12,892	12%
Generation	2,769	2%
Information Systems	21,044	19%
Transportation	3,089	3%
General Property	2,660	2%
Telecommunications	564	1%
Allowance for Unforeseen	750	1%
General Expenses Capitalized	6,500	6%
Total	**$109,651**	**100%**

3.3.2 Distribution

Distribution expenditures account for the greatest percentage of the 2022 Capital Budget, at approximately $47.7 million, or 44% of the total budget.

The Company operates approximately 10,000 kilometres of distribution line serving approximately 271,000 customers. Distribution capital expenditures are primarily driven by: (i) preventative and corrective maintenance on aged and deteriorated distribution structures; and (ii) the need to serve new customers and address system load growth.

Distribution expenditures in 2022 include the 2nd year of the *LED Street Lighting Replacement Plan*.

3.3.3 Substations

Substations expenditures total approximately $11.6 million in 2022, or 11% of the budget.

The Company operates 131 substations containing approximately 4,000 pieces of critical electrical equipment. Substations expenditures are primarily driven by: (i) the maintenance and refurbishment of substation assets; and (ii) system load growth.

Substations expenditures in 2022 include the refurbishment of the Tors Cove, Glovertown, and Humber substations, upgrading of ground grids in identified substations, and the mandatory phase-out of substation equipment with PCBs.[48]

3.3.4 Transmission

Transmission expenditures total approximately $12.9 million in 2022, or 12% of the budget.

The Company operates approximately 2,000 kilometres of transmission lines. Transmission lines are the backbone of the electrical system serving customers. Transmission expenditures are primarily driven by: (i) rebuilding aging and deteriorated transmission lines; and (ii) preventive capital maintenance of transmission line structures.

In 2022, the Company will rebuild 2 transmission lines, 124L in Central Newfoundland,[49] and 94L in Eastern Newfoundland.[50]

3.3.5 Generation

Generation expenditures total approximately $2.8 million in 2022, or 3% of the budget.

Generation expenditures in 2022 include the 1st year of a multi-year project to replace the woodstave penstock at the Company's Sandy Brook hydro plant.

Newfoundland Power operates 23 hydroelectric plants, 4 gas turbines and 2 diesel plants. These assets operate to provide a reliable supply of electricity to customers at least cost. Generation expenditures are primarily driven by: (i) preventative and corrective maintenance on aged and deteriorated assets; and (ii) specific capital projects, such as plant refurbishments.

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48 The refurbishment of Glovertown Substation is clustered with a project to rebuild transmission line 124L. The refurbishment of Humber Substation is clustered with a project to refurbish the 4.16 kV distribution system out of Humber Substation. The phase-out of substation equipment with PCBs is required by Government of Canada regulations.

49 Transmission Line 124L is a 138 kV H-Frame line running between Gambo Substation and Clarenville Substation. The line was originally constructed in 1964 and is approximately 86 kilometres in length. In 2022, the Company plans to rebuild 29 kilometres of the line to address deteriorated poles and ball link eye bolts. See the *2022 Capital Budget Application, Report 3.1 2022 Transmission Line Rebuild.*

50 Transmission Line 94L is a 66 kV H-Frame radial line running between Blaketown Substation and Riverhead Substation. The line was originally constructed in 1969 and is approximately 58 kilometres in length. In 2022, the Company plans to rebuild 21 kilometres of the line to address deteriorated poles and clamps. See the *2022 Capital Budget Application, Report 3.1 2022 Transmission Line Rebuild.*

3.3.6 Information Systems

Information Systems expenditures total approximately $21 million in 2022, or 19% of the budget.

Information Systems expenditures in 2022 include the 2nd year of a multi-year project to replace the Company's Customer Service System, and the 1st year of a multi-year project to replace the Company's Workforce Management System.

The remaining Information Systems expenditures are driven by: (i) the replacement of shared server and network infrastructure, personal computers and peripheral equipment; (ii) upgrades to existing applications, which are primarily driven by third-party vendors; and (iii) enhancements to existing applications to provide improved performance or functionality.

The remaining 13% of proposed 2022 capital expenditures relate to Transportation,[51] General Property,[52] Telecommunications,[53] the Allowance for Unforeseen and GEC.

4.0 Five-Year Capital Plan: 2022-2026

4.1 Planned Expenditures Overall

Newfoundland Power's capital planning process is a deliberate effort to balance customer requirements, reliability, productivity, safety and environmental concerns with prudent capital investments. Prudent capital investments are necessary to meet the Company's obligation to provide safe and reliable service to customers at least cost.

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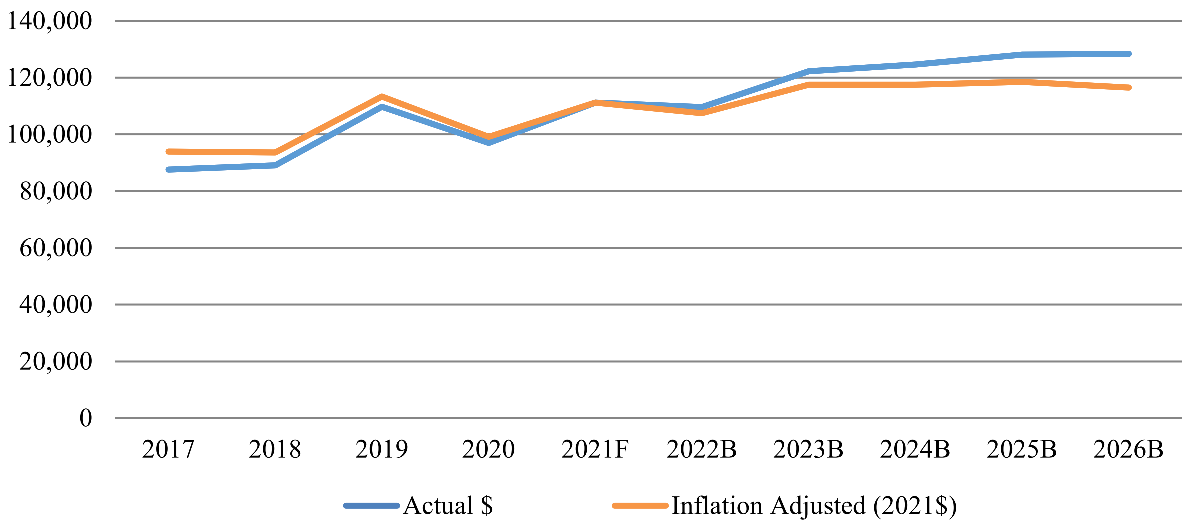
[51] The Transportation asset class includes heavy fleet, passenger and off-road vehicles. The replacement of these vehicles can be influenced by a number of factors, including kilometres traveled, vehicle condition, and operating experience and maintenance expenditures. The Company's replacement criteria for vehicles are described in *Report 5.1 Vehicle Replacement Criteria* filed as part of its *2016 Capital Budget Application*.

[52] The General Property asset class includes capital expenditures for: (i) the addition or replacement of tools and equipment utilized by line and engineering staff; (ii) the replacement or addition of office furniture and equipment; (iii) additions to real property necessary to maintain buildings and facilities; and (iv) the refurbishment of Company buildings and related security infrastructure.

[53] The Telecommunications asset class includes the replacement or upgrading of various telecommunications 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.

Figure 5 shows Newfoundland Power's capital expenditures over the period 2017 to 2026 on an actual and inflation-adjusted basis.

Figure 5
Capital Expenditures 2017 to 2026B
($000s)



Capital expenditures are forecast to average approximately $122.6 million annually over the period 2022 to 2026. This compares to approximately $98.9 million annually over the previous 5-year period, or $102 million annually on an inflation adjusted basis.

The forecast increase in annual expenditures is primarily attributable to implementation of the *LED Street Lighting Replacement Plan* which accounts for approximately $5.5 million in capital expenditures annually throughout the 5-year period. The *Customer Service Continuity Plan* accounts for approximately $10.9 million annually over the first 2 years of the 5-year period. In addition, the Company plans expenditures of $17.4 million in 2024 and 2025 to address backup thermal generation requirements.

4.2 Planned Expenditures by Origin

The replacement of existing plant and the requirement to serve new customers and address system load growth will continue to be the largest drivers of Newfoundland Power's capital expenditures over the next 5 years.

Table 8 compares forecast capital expenditures over the next 5 years to the most recent 5-year period.

Table 8
Capital Plan Comparison

	2017 - 2021	2022 - 2026	Change
Plant Replacement	54%	61%	7%
Customer/Load Growth	24%	19%	-5%
Information Systems	8%	9%	1%
System Additions	5%	2%	-3%
General Expenses Capitalized	5%	5%	0%
Third Party Requirement	3%	3%	0%
Financial	1%	1%	0%
Total	**100%**	**100%**	

The drivers of capital expenditures under the *Five-Year Capital Plan: 2022-2026* are consistent with recent experience. Approximately 60% of forecast capital expenditures over next 5 years are driven by the replacement of existing plant. This compares to approximately 54% over the most recent 5-year period.

The increase in expenditures related to plant replacement are offset by decreases in:
(i) expenditures required to connect new customers and address system load growth; and (ii) a forecast reduction in system additions.

4.3 Planned Expenditures by Asset Class

4.3.1 Overview

Table 9 provides the *Five-Year Capital Plan: 2022-2026* annually by asset class.

Table 9
5-Year Capital Plan by Asset Class
($000s)

Asset Class	**2022**	**2023**	**2024**	**2025**	**2026**
Distribution	$47,744	$51,456	$52,857	$54,117	$55,405
Substations	11,639	17,581	20,057	19,873	20,908
Transmission	12,892	12,486	13,574	14,023	18,991
Generation	2,769	11,527	14,751	17,326	9,002
Information Systems	21,044	11,700	6,245	8,900	9,240
Transportation	3,089	4,239	4,623	4,464	4,386
General Property	2,660	4,816	3,448	1,762	2,923
Telecommunications	564	1,266	1,869	371	294
Allowance for Unforeseen	750	750	750	750	750
GEC	6,500	6,500	6,500	6,500	6,500
Total	**$109,651**	**$122,321**	**$124,674**	**$128,086**	**$128,399**

Capital expenditures are forecast to remain reasonably stable in the majority of asset classes over the next 5 years. The highest degree of variability is observed in the Information Systems, Generation and Telecommunication asset classes. In each case, this variability is attributable to large-scale, one-time capital projects, as described below under each of these asset classes.

Table 10 provides total planned capital expenditures by asset class for the period 2022 to 2026.

Table 10
5-Year Capital Plan
Percentage of Expenditures by Asset Class
($000s)

Asset Class	2022-2026	Percentage of Total
Distribution	$261,579	43%
Substations	90,058	15%
Transmission	71,966	12%
Generation	55,375	9%
Information Systems	57,129	9%
Transportation	20,801	3%
General Property	15,609	2%
Telecommunications	4,364	1%
Allowance for Unforeseen	3,750	1%
GEC	32,500	5%
Total	**$613,131**	**100%**

The Distribution asset class is expected to continue as the largest driver of capital expenditures over the next 5 years. Approximately 43% of planned capital expenditures over the next 5 years relate to Distribution assets.

Tables 11 through 19 provide actual, forecast and budget expenditures by asset class over the period 2017 to 2026.

4.3.2 Distribution

Table 11 provides Distribution capital expenditures over the period 2017 to 2026.

Table 11
Distribution Capital Expenditures
($000s)

Actual/Forecast					**Average**
2017	**2018**	**2019**	**2020**	**2021F**	**2017-2021**
45,879	42,333	46,801	44,897	45,767	45,135

Budget					**Average**
2022B	**2023B**	**2024B**	**2025B**	**2026B**	**2022-2026**
47,744	51,456	52,857	54,117	55,405	52,316

Distribution capital expenditures are forecast to average approximately $52.3 million annually over the period 2022 to 2026. This compares to an average of approximately $45.1 million annually over the previous 5-year period.

Increased Distribution expenditures are primarily attributable to the *LED Street Lighting Replacement Plan*, with expenditures averaging approximately $5.5 million annually over the period.

Other expenditures are forecast to remain reasonably stable.

Expenditures related to Newfoundland Power's capital maintenance programs for its distribution assets are forecast to remain reasonably stable. Both the Rebuild Distribution Lines[54] and Reconstruction[55] capital projects are planned to continue at a combined average cost of approximately $5.1 million annually. Expenditures related to the *Distribution Reliability Initiative* are also expected to remain stable, averaging approximately $1.2 million annually.[56]

[54] The Company's inspection and maintenance practices are principally designed to extend the lives of the existing assets. The Company plans to perform preventive capital maintenance on approximately 43 distribution feeders per year over the planning period.

[55] 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.

[56] Each year, Newfoundland Power assesses and ranks the reliability performance of over 300 distribution feeders and completes targeted capital investments, when appropriate, as part of the Distribution Reliability Initiative. See the *2022 Capital Budget Application, Report 4.1 Distribution Reliability Initiative.*

Table 12 provides the forecast number of new customer connections and the total capital expenditures associated with those connections over the next 5 years.[57]

Table 12
Forecast New Customer Connections
(2022-2026)

	2022	2023	2024	2025	2026
New Customer Connections	2,038	2,002	1,965	1,925	1,928
Average Cost/Connection	$8,898	$9,128	$9,368	$9,622	$9,811
Capital Expenditure (000s)	$18,134	$18,274	$18,409	$18,522	$18,915

Over the period 2022 to 2026, capital expenditures for new customer connections are forecast to be within the range of $18.1 million to $18.9 million annually.

While customer connections are forecast to decline, additional expenditures are forecast to address load growth in certain areas. This includes load growth associated with the electrification of heating systems and the electrification of heating systems in provincial buildings. Forecast Distribution expenditures over the next 5 years include approximately $3 million to respond to load growth driven by provincial electrification efforts.

4.3.3 Substations

Table 13 provides Substations expenditures over the period 2017 to 2026.

Table 13
Substation Capital Expenditures
($000s)

		Actual/Forecast			Average
2017	**2018**	**2019**	**2020**	**2021F**	**2017-2021**
15,477	12,662	17,133	14,732	14,280	14,857
		Budget			**Average**
2022B	**2023B**	**2024B**	**2025B**	**2026B**	**2022-2026**
11,639	17,581	20,057	19,873	20,908	18,012

57 Costs to connect new customers to the electricity system are included in the Extensions, Transformers, Services, Meters and Street Lighting distribution projects.

Substations expenditures are forecast to average approximately $18 million annually over the period 2022 to 2026. This compares to an average of approximately $14.9 million annually over the previous 5-year period.

Substations expenditures over the planning period continue to be driven by the *Substation Strategic Plan,* as filed with the Company's *2007 Capital Budget Application*. Forecast expenditures over the next 5 years include the refurbishment and modernization of 24 substations, including Gander Bay Substation in 2024 and Goulds Substation in 2026.[58] Further engineering assessments of these substations will be completed prior to the proposal of specific capital projects.

In total, 2 new substation transformers are forecast to be required over the 2022 to 2026 period to accommodate customer load growth.[59] Both transformers are forecast to be required for load growth in the St. John's area.[60]

4.3.4 Transmission

Table 14 provides Transmission capital expenditures for the period 2017 to 2026.

Table 14
Transmission Capital Expenditures
($000s)

		Actual/Forecast			**Average**
2017	**2018**	**2019**	**2020**	**2021F**	**2017-2021**
6,224	7,806	11,940	9,948	9,751	9,134

		Budget			**Average**
2022B	**2023B**	**2024B**	**2025B**	**2026B**	**2022-2026**
12,892	12,486	13,574	14,023	18,991	14,393

58 The *Five-Year Capital Plan: 2022-2026* currently includes refurbishment and modernization of the Bay L'Argent, Blaketown, Botwood, Broad Cove, Deer Lake, Gambo, Gander Bay, Glovertown, Goulds, Grand Falls, Hardwoods, Humber, Islington, Laurentian, Linton Lake, Lockston, Memorial University, Mobile, Molloy's Lane, Morris Plant, Port Blandford, Stamps Lane, Tors Cove, and Walbournes Substations.

59 By comparison, in the period 2017 through 2021, Newfoundland Power has purchased 3 new power transformers and relocated 1 power transformer 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.

60 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.

Transmission capital expenditures are forecast to average approximately $14.4 million annually over the period 2022 to 2026. This compares to an average of approximately $9.1 million annually over the previous 5-year period.

Increased Transmission expenditures are driven by an increase in the kilometres of transmission line forecast to be rebuilt annually as part of the *Transmission Line Rebuild Strategy.*[61] As of 2021, execution of this strategy is approximately 76% complete.

Forecast Transmission expenditures also include capital maintenance of transmission line structures.

4.3.5 Generation

Table 15 provides Generation capital expenditures for the period 2017 to 2026.

Table 15
Generation Capital Expenditures
($000s)

		Actual/Forecast			**Average**
2017	**2018**	**2019**	**2020**	**2021F**	**2017-2021**
6,402	8,934	11,932	7,095	11,510	9,175
		Budget			**Average**
2022B	**2023B**	**2024B**	**2025B**	**2026B**	**2022-2026**
2,769	11,527	14,751	17,326	9,002	11,075

Generation capital expenditures are forecast to average approximately $11.1 million annually over the period 2022 to 2026. This compares to an average of approximately $9.2 million annually over the previous 5-year period.

The *Five-Year Capital Plan: 2022-2026* includes the penstock replacement at the Sandy Brook hydro plant in 2022 and 2023. It also includes the planned purchase of a 2nd mobile gas turbine to replace the existing Greenhill and Wesleyville gas turbines in 2024 and 2025.[62] All Generation projects involving plant refurbishment or upgrades are justified using marginal cost-based analysis.

61 The lines remaining to be completed in the 2022 to 2026 period include 3 long 138 kV H-frame construction transmission lines. The extended line length for these rebuilds, and the 138 kV H-frame construction, are the primary drivers for the increase in transmission expenditures.

62 See *Section 4.4 Risks to Planned Expenditures* for more information on the planned purchase of a 2nd mobile gas turbine.

4.3.6 Information Systems

Table 16 provides Information Systems capital expenditures for the period 2017 to 2026.

Table 16
Information Systems Capital Expenditures
($000s)

		Actual/Forecast			**Average**
2017	**2018**	**2019**	**2020**	**2021F**	**2017-2021**
4,314	6,620	7,615	7,282	15,362	8,239

		Budget			**Average**
2022B	**2023B**	**2024B**	**2025B**	**2026B**	**2022-2026**
21,044	11,700	6,245	8,900	9,240	11,426

Information Systems capital expenditures are forecast to average approximately $11.4 million annually over the period 2022 to 2026. This compares to an average of approximately $8.2 million annually over the previous 5-year period.

Increased Information Systems expenditures are primarily driven by the *Customer Service Continuity Plan* at a cost of approximately $31.6 million over 3 years starting in 2021. Expenditures also include upgrades to the Company's Geographic Information System and Outage Management System in 2025 and 2026.

4.3.7 Transportation

Table 17 provides Transportation capital expenditures for the period 2017 to 2026.

Table 17
Transportation Capital Expenditures
($000s)

		Actual/Forecast			Average
2017	**2018**	**2019**	**2020**	**2021F**	**2017-2021**
3,776	3,594	4,223	3,869	4,032	3,899
		Budget			**Average**
2022B	**2023B**	**2024B**	**2025B**	**2026B**	**2022-2026**
3,089	4,239	4,623	4,464	4,386	4,160

Transportation capital expenditures are forecast to average approximately $4.2 million annually over the period 2022 to 2026. This compares to an average of approximately $3.9 million annually over the previous 5-year period.

The increase in Transportation capital expenditures from 2022 through 2026 is principally a reflection of inflation and the number of heavy fleet and passenger vehicles forecast to be replaced over the period.[63] Commencing in 2022, the Company will move to a multi-year project approach to vehicle replacement. This new multi-year approach is a result of long delivery times associated with the purchase of heavy fleet vehicles experienced in recent years.

[63] The Company operates 75 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 and off-road vehicles would be replaced annually.

4.3.8 General Property

Table 18 provides General Property capital expenditures for the period 2017 to 2026.

Table 18
General Property Capital Expenditures
($000s)

	Actual/Forecast				**Average**
2017	**2018**	**2019**	**2020**	**2021F**	**2017-2021**
1,456	2,722	3,561	2,473	2,776	2,598

		Budget			**Average**
2022B	**2023B**	**2024B**	**2025B**	**2026B**	**2022-2026**
2,660	4,816	3,448	1,762	2,923	3,122

General Property capital expenditures are forecast to average approximately $3.1 million annually over the period 2022 to 2026. This compares to an average of approximately $2.6 million annually over the previous 5-year period.

General Property capital expenditures are driven by the need to address deterioration in Company-owned buildings throughout its service territory. Many of Newfoundland Power's area offices are over 25 years old and certain components require replacement. The increase in expenditures over the 2022 to 2026 period is attributable to refurbishments required in the Company's head office in St. John's and area offices in Clarenville and Gander.

4.3.9 Telecommunications

Table 19 provides Telecommunications capital expenditures for the period 2017 to 2026.

Table 19
Telecommunications Capital Expenditures
($000s)

		Actual/Forecast			**Average**
2017	**2018**	**2019**	**2020**	**2021F**	**2017-2021**
112	325	312	112	462	265

		Budget			**Average**
2022B	**2023B**	**2024B**	**2025B**	**2026B**	**2022-2026**
564	1,266	1,869	371	294	873

Telecommunications capital expenditures are forecast to average approximately $0.9 million annually over the period 2022 to 2026. This compares to an average of approximately $0.3 million annually over the previous 5-year period.

The increase in Telecommunications capital expenditures over the planning period is primarily driven by: (i) the replacement of the St. John's teleprotection system in 2022 and 2023 at a cost of approximately $1.6 million;[64] and (ii) the replacement of the Company's current VHF radio mobile system in 2024 at a cost of approximately $1.8 million.[65]

[64] Newfoundland Power's existing teleprotection system, used to monitor and protect the St. John's 66 kV transmission line network, is 20 years old and at the end of its useful life. A reliable teleprotection system ensures that transmission line faults are detected and addressed within the critical clearing times established for system stability.

[65] Newfoundland Power's VHF mobile radio communications uses a system provided by Bell Mobility. Other users of this system include Newfoundland and Labrador Hydro and some departments of the Provincial Government. The Provincial Government has started a process to transition away from the current VHF radio system to a new province-wide public safety radio system. Newfoundland Power is investigating options to provide its field staff with mobile radio communications in the event the current Bell Mobility VHF technology is retired.

4.3.10 Unforeseen Allowance

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

The Unforeseen Allowance constitutes $750,000 in annual capital expenditures over the period 2022 to 2026.

4.3.11 General Expenses Capitalized

GEC 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 capitalizing general expenses.

GEC is expected to average $6.5 million annually over the period 2022 to 2026. This compares to an average of $5.4 million annually over the previous 5-year period. This increase is attributable to a change in the accounting of pension expense, as approved in Order No. P.U. 2 (2019).

4.4 Risks to Planned Expenditures

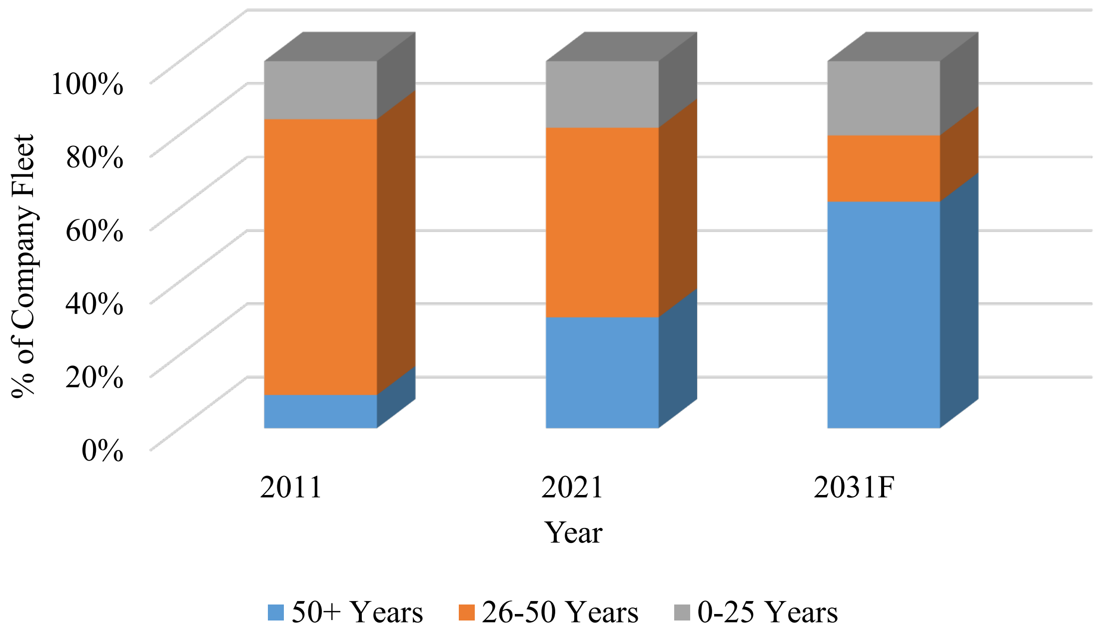
While Newfoundland Power targets stability in its annual capital expenditures, the nature of the utility's obligation to provide safe and reliable service at least cost will not, in all circumstances, facilitate such stability. The Company has identified some risks to the stability of its capital expenditures through 2026.

Newfoundland Power has an obligation to serve customers in its service territory. The capital expenditures required to provide such service are dependent upon customer and load growth. New home construction has decreased considerably and is expected to deteriorate further over the forecast period. Should customer and load growth vary from forecast, so too will the capital expenditures that are sensitive to growth.

The age of certain critical electrical system assets presents another risk to the Company's capital planning. This includes the age of existing power transformers.

Figure 6 shows power transformer age for transformers located across the Company's service territory.

Figure 6
Age of Company Transformer Fleet



In 2011, 9% of the Company's power transformers were over 50 years in service.[66] In 2021, approximately 33% of the Company's power transformers are over 50 years in service. In 2031, the Company forecasts approximately 62% of power transformers will be over 50 years in service. In most substations, a single power transformer is used to supply customers. In the event of an in-service failure, a portable substation is required as a temporary solution until a replacement power transformer can be sourced and installed.[67]

Over the next decade, as the number of in-service power transformers over the age of 50 increases, the risk of more in-service failures increases. Going forward, the Company's capital plan will need to address the aging power transformer fleet.

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[66] Figure 1 on page 2 of report *2.4 Portable Substation Study*, June 2011, filed as part of Newfoundland Power's *2012 Capital Budget Application* provides the age distribution of the Company's power transformer fleet in 2011.

[67] In-service failures of power transformers, such as those that occurred with the Salt Pond transformer in 2002, Pierre's Brook transformer in 2008, Kenmount and Horse Chops transformers in 2009, and Riverhead transformer in 2017 may necessitate unplanned capital expenditures. Additionally, recent in-service failures of power transformers in Bonavista and Stamps Lane were addressed through the *In-Service Failure* capital project. The Bonavista transformer was repaired and the Stamps Lane transformer was replaced with a spare unit of similar vintage.

Additionally, Newfoundland Power's Greenhill and Wesleyville gas turbines are aged 46 years and 52 years, respectively. Recent inspections have identified required refurbishment work on both gas turbines. The Company is finalizing a system planning study to inform the long-term plan for these gas turbines.

The plan for these assets will be informed by the Board's ongoing review of the Island Interconnected System's need for new capacity additions. Newfoundland and Labrador Hydro's most recent assessment shows that the system has limited capacity to meet future load growth.[68] Due to uncertainty surrounding future capacity requirements, the Company has not included expenditures to refurbish these gas turbines in the 5-year outlook. Rather, the Company is forecasting to purchase a 2nd mobile gas turbine. The mobile gas turbine would replace some of the capacity lost if either of the Greenhill or Wesleyville gas turbines were decommissioned.

Upon commissioning, the Muskrat Falls Project will be the largest source of electricity supply to Newfoundland Power's customers. The reliability of supply from the Muskrat Falls Project is currently under review by the Board. This includes the reliability of the Labrador Island Link and the adequacy of generation resources on the Island Interconnected System.

It is currently uncertain what effect, if any, the reliability of the Muskrat Falls Project may have on Newfoundland Power's capital expenditures. For example, an increased risk of rotating outages may require more advanced software or increased electrical system automation. Additional backup generation may require upgrades to the Company's transmission lines, substations or protection equipment.

The 5-year outlook does not currently include any capital expenditures related to the reliability supply following commissioning of the Muskrat Falls Project.

Capital expenditures can also be impacted by major storms or weather events. In March 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.

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68 See Newfoundland and Labrador Hydro's *Marginal Cost Study Update – 2018 Summary Report*, dated November 15, 2018, pages 3-4.

Attachment A

Guidelines Compliance Summary

1.0 General

Newfoundland Power organizes its annual capital budget applications in a manner consistent with the Guidelines. The Guidelines require capital projects to be organized by:

(i) **Definition** as either *Clustered* expenditures that are logically undertaken together, *Pooled* expenditures that are neither inter-dependent nor related, but are logically grouped together, or *Other* expenditures;
(ii) **Classification** as either *Mandatory* expenditures required by legislation, Board Order, safety issues, or risk to the environment, *Normal* expenditures required based on identified need or historical pattern of repair or replacement, or *Justified* expenditures based on the positive impact on the utility's operations; and
(iii) **Materiality**, which requires segmentation of expenditures under $200,000, between $200,000 and $500,000, and over $500,000.

Newfoundland Power's *2022 Capital Budget Application* proposes 40 capital projects. Tables A-1 through A-4 summarize the organization of 2022 projects, as detailed in Schedule B.

2.0 Definition

Table A-1 summarizes proposed 2022 capital projects by Definition.

Table A-1
2022 Capital Projects
By Definition

Definition	Number of Projects	Budget ($000s)
Pooled	30	62,930
Clustered	3	18,898
Other	7	27,823
Total	**40**	**$109,651**

A total of 30 projects are Pooled, accounting for 57% of total expenditures.

There are 3 Clustered projects, accounting for 17% of total expenditures: (i) *Substations Refurbishment and Modernization* is clustered with *Transmission Line Rebuilds* to add 138 kV circuit breakers at Glovertown Substation on transmission lines 121L and 124L and to reconfigure transmission line 124L to terminate at Glovertown Substation; and (ii) *Substations Refurbishment and Modernization* is clustered with *Trunk Feeders – Humber 4.16 kV Conversion* to refurbish and convert the 4.16 kV distribution system to 12.5 kV at Humber Substation.

3.0 Classification

Table A-2 summarizes Newfoundland Power's proposed 2022 capital projects by Classification.

Table A-2
2022 Capital Projects
By Classification

Definition	Number of Projects	Budget ($000s)
Normal	36	100,787
Mandatory	1	899
Justifiable	3	7,965
Total	**40**	**$109,651**

A total of 36 projects are classified as Normal, accounting for 92% of total expenditures. The *PCB Bushing Phase-out* Substations project is required by Government of Canada Regulations and is the only Mandatory project in 2022. Three projects are classified as Justifiable: (i) the *Applications Enhancement* Information Systems project; (ii) the *LED Streetlight Replacement* Distribution project; and (iii) the *Electric Vehicle Charging Network* Distribution project. All projects are justified with net present value analyses.

Table A-3 summarizes proposed 2022 capital projects by Costing Method.

Table A-3
2022 Capital Projects
By Costing Method

Definition	Number of Projects	Budget ($000s)
Identified Need	23	58,079
Historical Pattern	17	51,572
Total	**40**	**$109,651**

Approximately 53% of total expenditures are based on Identified Need, while approximately 47% of total expenditures are based on historical patterns.

4.0 Materiality

Table A-4 summarizes 2022 capital projects by Materiality.

Table A-4
2022 Capital Projects
By Materiality

Definition	Number of Projects	Budget ($000s)
Under $200,000	1	114
$200,000 - $500,000	6	2,238
Over $500,000	33	107,299
Total	**40**	**$109,651**

A total of 33 projects are budgeted at over $500,000, accounting for 98% of total expenditures.

Twenty projects are budgeted at over $1,000,000, accounting for 89% of total expenditures.

Attachment B

Five-Year Capital Plan: 2022-2026

Five-Year Capital Plan: 2022-2026
By Asset Class
($000s)

Asset Class	**2022**	**2023**	**2024**	**2025**	**2026**
Distribution	47,744	51,456	52,857	54,117	55,405
Substations	11,639	17,581	20,057	19,873	20,908
Transmission	12,892	12,486	13,574	14,023	18,991
Generation	2,769	11,527	14,751	17,326	9,002
Information Systems	21,044	11,700	6,245	8,900	9,240
Transportation	3,089	4,239	4,623	4,464	4,386
General Property	2,660	4,816	3,448	1,762	2,923
Telecommunications	564	1,266	1,869	371	294
Allowance for Unforeseen	750	750	750	750	750
GEC	6,500	6,500	6,500	6,500	6,500
Total	**$109,651**	**$122,321**	**$124,674**	**$128,086**	**$128,399**

Distribution
Five-Year Capital Plan: 2022-2026
($000s)

Project	2022	2023	2024	2025	2026
AFUDC	239	243	246	250	253
Distribution Feeder Automation	893	955	983	995	998
Distribution Reliability Initiative	350	1,000	1,200	1,500	2,000
EV Charging Network	1,530	460	460	311	-
Extensions	10,333	10,386	10,432	10,460	10,707
Feeder Additions for Growth	1,690	4,682	2,746	3,329	2,986
Meters	818	849	851	827	1,064
Rebuild Distribution Lines	4,333	4,439	4,549	4,661	4,778
Reconstruction	5,902	6,052	6,206	6,365	6,529
Relocations for Third Parties	3,370	3,445	3,522	3,602	3,684
Services	3,038	3,066	3,093	3,116	3,192
Street lights	7,935	8,610	8,686	8,764	8,844
Transformers	5,958	6,019	6,083	6,147	6,215
Trunk Feeders	1,355	1,250	3,800	3,790	4,155
Total	**$47,744**	**$51,456**	**$52,857**	**$54,117**	**$55,405**

Substations
Five-Year Capital Plan: 2022-2026
($000s)

Project	**2022**	**2023**	**2024**	**2025**	**2026**
Additions Due to Load Growth	-	-	3,000	-	2,500
PCB Strategy	899	855	1,155	973	-
Replacement Due to In-Service Failures	3,691	3,753	3,818	3,883	3,951
Substation Feeder Termination	-	180	-	540	-
Substation Refurbishment & Modernization	7,049	12,793	12,084	14,477	14,457
Total	**$11,639**	**$17,581**	**$20,057**	**$19,873**	**$20,908**

Transmission
Five-Year Capital Plan: 2022-2026
($000s)

Project	**2022**	**2023**	**2024**	**2025**	**2026**
Transmission Line Additions	-	-	-	-	4,000
Transmission Line Maintenance & 3rd Party	2,398	2,442	2,487	2,534	2,582
Transmission Line Rebuild	10,494	10,044	11,087	11,489	12,409
Total	**$12,892**	**$12,486**	**$13,574**	**$14,023**	**$18,991**

Generation
Five-Year Capital Plan: 2022-2026
($000s)

Project	**2022**	**2023**	**2024**	**2025**	**2026**
Facilities Rehabilitation Hydro	2,062	2,071	1,991	2,149	1,756
Facilities Rehabilitation Thermal	307	311	316	320	325
Cape Broyle Upgrades	-	-	-	660	2,925
Lookout Brook Plant Upgrade	-	-	307	923	2,383
Mobile Plant Upgrades	-	3,005	4,239	-	-
Morris Plant Upgrades	-	-	-	-	1,263
Pitman's Pond Upgrade	-	-	-	-	350
Sandy Brook Upgrades	400	6,140	-	-	-
Tors Cove Plant Upgrade	-	-	428	3,384	-
Gas Turbine Replacement	-	-	7,470	9,890	-
Total	**$2,769**	**$11,527**	**$14,751**	**$17,326**	**$9,002**

Information Systems
Five-Year Capital Plan: 2022-2026
($000s)

Project	**2022**	**2023**	**2024**	**2025**	**2026**
Application Enhancements	1,007	1,050	1,050	1,050	1,050
Customer Service System	15,826	5,917	-	-	-
Cybersecurity Upgrades	865	800	800	800	800
Network Infrastructure	508	386	400	475	500
Operations Technology	-	-	-	2,750	1,000
PC Infrastructure	615	585	595	600	605
Shared Server Infrastructure	613	586	650	1,000	1,450
System Upgrades	802	1,175	2,750	2,225	3,835
Workforce Management System Replacement	808	1,201	-	-	-
Total	**$21,044**	**$11,700**	**$6,245**	**$8,900**	**$9,240**

Transportation
Five-Year Capital Plan: 2022-2026
($000s)

Project	**2022**	**2023**	**2024**	**2025**	**2026**
Replace Vehicles and Aerial Devices 2022 - 2023	3,089	2,135	-	-	-
Replace Vehicles and Aerial Devices 2023 - 2024	-	2,104	2,369	-	-
Replace Vehicles and Aerial Devices 2024 - 2025	-	-	2,254	2,423	-
Replace Vehicles and Aerial Devices 2025 - 2026	-	-	-	2,041	3,010
Replace Vehicles and Aerial Devices 2026 - 2027	-	-	-	-	1,376
Total	**$3,089**	**$4,239**	**$4,623**	**$4,464**	**$4,386**

General Property
Five-Year Capital Plan: 2022-2026
($000s)

Project	**2022**	**2023**	**2024**	**2025**	**2026**
Additions to Real Property	716	971	806	548	603
Physical Security Upgrades	492	796	520	300	300
Company Building Renovations	854	2,395	1,613	400	1,500
Tools and Equipment	598	654	509	514	520
Total	**$2,660**	**$4,816**	**$3,448**	**$1,762**	**$2,923**

Telecommunications
Five-Year Capital Plan: 2022-2026
($000s)

Project	**2022**	**2023**	**2024**	**2025**	**2026**
Fibre Optic Cable Build	-	-	-	250	170
Radio System Replacement	-	-	1,750	-	-
Replace / Upgrade Communications Equipment	114	116	119	121	124
St. John's Teleprotection System Replacement	450	1,150	-	-	-
Total	**$564**	**$1,266**	**$1,869**	**$371**	**$294**

Unforeseen Allowance
Five-Year Capital Plan: 2022-2026
($000s)

Project	**2022**	**2023**	**2024**	**2025**	**2026**
Allowance for Unforeseen	750	750	750	750	750
Total	**$750**	**$750**	**$750**	**$750**	**$750**

General Expenses Capitalized
Five-Year Capital Plan: 2022-2026
($000s)

Project	**2022**	**2023**	**2024**	**2025**	**2026**
GEC	6,500	6,500	6,500	6,500	6,500
Total	**$6,500**	**$6,500**	**$6,500**	**$6,500**	**$6,500**

2022 Facility Rehabilitation

May 2021

Prepared by:
Monty Hunter, P. Eng.

REGISTERED PROFESSIONAL ENGINEER
M. G. HUNTER
SIGNATURE
May 5, 2021
PROVINCE OF NEWFOUNDLAND

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NEWFOUNDLAND POWER
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1.0 Introduction

The *2022 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 Inc. ("Newfoundland Power" or the "Company") has 23 hydroelectric facilities that generate a combined normal annual production of 434.8 GWh.[1] Maintaining the Company's hydro generation production realizes customer benefits provided by the electricity generated at the facilities. The value of electricity production consists primarily of: (i) reduced marginal energy costs; and (ii) avoidance of the need to add generation capacity.[2] The alternative to maintaining these facilities is to retire them.

The *2022 Facility Rehabilitation* project cost totals $2,062,000 and is comprised of: (i) Hydroelectric Infrastructure Rehabilitation; (ii) Generation Control System Upgrades; and (iii) Generation Equipment Replacements Due to In-Service Failures.

2.0 Hydroelectric Infrastructure Rehabilitation ($1,113,000)

Newfoundland Power's 23 hydroelectric facilities range in age from 22 to 121 years and have many components, including access roads, bridges, penstocks, surge tanks, powerhouses, generating equipment, control equipment ancillary buildings and tailraces. Based on the age of the components in the Company'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 projects noted are justified on the basis of the need to restore the structures to an appropriate level of safety and integrity, and to allow for continued operation of hydroelectric facilities in a safe and reliable manner.

Specific work to be completed in 2022 includes:

2.1 Morris Head Gate and Intake Gatehouse Replacement ($465,000)

The Morris powerhouse, commissioned in 1983, is located upstream of Mobile First Pond near the community of Mobile on the Southern Shore of the Avalon Peninsula. The plant has a capacity of 1,135 kW under a net head of 30.0 m, and normal annual production of 6.6 GWh.

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1 For 2021, adjusted normal annual hydroelectric production for Newfoundland Power has been set at 434.8 GWh as set forth in the letter to the Board on January 29, 2021.

2 Based on Hydro's 2020 marginal cost update as provided to Newfoundland Power on April 9, 2020, the energy-related value of the production from the Company's hydro facilities is estimated at $18,573,000 annually, while the capacity-related value is estimated at $18,482,000 annually. These estimates are calculated to reflect post Muskrat Falls marginal costs using the 2022 marginal cost values for energy and capacity.

The intake to the plant penstock is comprised of a concrete foundation, trash rack, head gate and wood frame gatehouse building.[3] The head gate is used to control water entry into the penstock so it can be drained for safe maintenance of the turbine generator or in the event of a rupture of the penstock itself. The head gate is original construction, and is constructed from a number of 267 mm x 267 mm timbers, bolted together by 20 mm diameter threaded rods (Figure 1). The operator stem is affixed to the top of the head gate via a hollow structural steel section. The head gate is raised and lowered using a manual operator (Figure 2). A wood frame gatehouse is built over the intake structure to protect the operator mechanism from exposure to the elements and to house telemetry equipment used to monitor the reservoir level. With the exception of routine maintenance, no major work has been undertaken on the intake since the original construction in 1983.

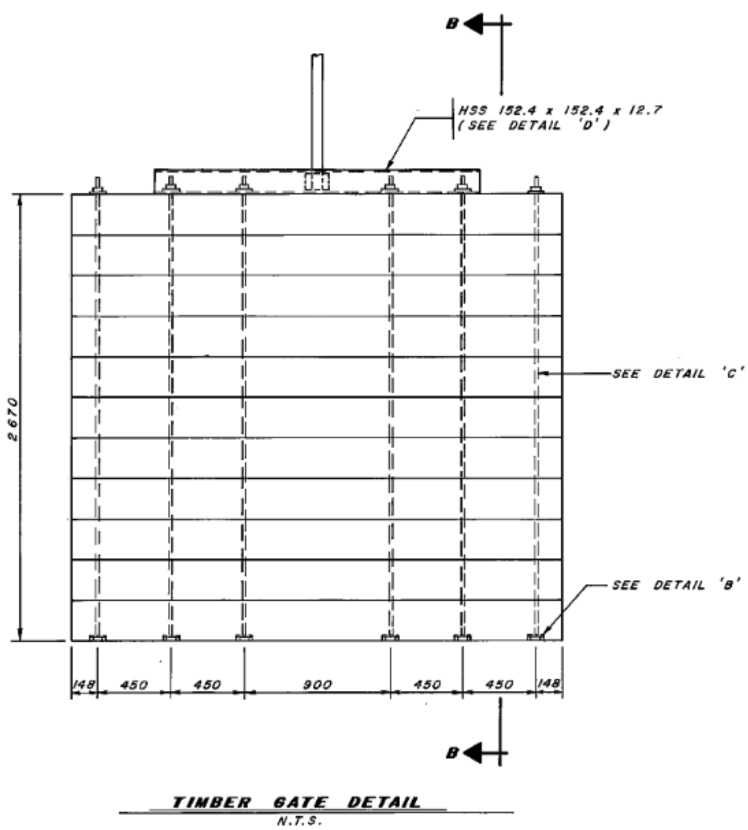

Figure 1: Morris Head Gate Drawing

In 2020, following maintenance on the turbine, the operator stem detached from the top of the head gate while it was being opened (Figure 3). This was determined to have occurred as a result of corrosion and deterioration of the structural steel on top of the gate. To allow the plant to continue operating, the head gate is currently being held in the open position with secure straps. In the event of an emergency, the gate can be closed; but it likely would not be able to be

[3] A penstock is a large diameter pipe used to convey water from the forebay intake to the turbine-generator located in the powerhouse.

opened again as the gate stem is no longer attached. Attempting to lift the gate using straps or jacks will likely lead to it becoming jammed in place, obstructing the flow of water and leaving the plant out of service indefinitely.

Figure 2: Head Gate Operator

Figure 3: Failed Gate Stem Connection

The intake gatehouse is in poor condition due to weathering and age-related deterioration (Figures 4 & 5).

Figure 4: Intake Gatehouse Deterioration

Figure 5: Deteriorated Eaves

To ensure the penstock can be safely drained and isolated in the event of an emergency, or when repairs or maintenance on the turbine or the penstock is necessary, an operable, secure intake gate is required. Standard safety practice is to provide 2 points of isolation with a gap between. In this case, the 2 points of isolation are the head gate and the unit inlet valve. Not having an operable head gate creates an unsafe work environment.

Due to the age and condition of the head gate, it will be replaced. To provide a safe and durable installation, a new stainless steel head gate with surface-mounted slides will be installed. An electric operator will be installed to raise and lower the gate. To facilitate the work, a cofferdam will be installed upstream of the intake structure. While the intake is dewatered, any necessary concrete rehabilitation will be completed.

To remove the existing head gate, the intake gatehouse will need to be removed to provide access for a crane. Due to the poor condition of the gatehouse, it cannot be removed without additional damage and deterioration. The old gatehouse will be replaced with a new structure with a removable roof. This will provide easy access to the head gate to facilitate future repairs and major maintenance.

Replacing the head gate and gatehouse is justified on the need to maintain the plant in a safe and reliable condition.

2.2 Petty Harbour Surge Tank Cladding Replacement ($347,000)

Newfoundland Power's Petty Harbour plant is located on the east coast of the Avalon Peninsula. The powerhouse is situated in the community of Petty Harbour-Maddox Cove. There are 3 horizontal Francis turbines and generators in the plant. The first unit was commissioned in 1900 and the other units were commissioned in 1908 and 1926. The total installed capacity of the 3 units is 5,300 kW under a net head of 57.9 meters. The normal annual production at Petty Harbour plant is estimated at 16.3 GWh per year.

The plant has a 12.2 metre high surge tank (Figure 6) located on the hill behind the plant. The surge tank is used to control pressure increases in the penstock during load rejections. When one or all of the online generators trip offline due to the operation of protective devices, the turbine control gates close to stop unit rotation. The water flowing in the penstock is diverted into the surge tank to prevent a significant increase in penstock pressure. Unmitigated, a significant increase in pressure would cause failure of the penstock.

In 2010, major upgrade work was performed on the surge tank including: tank and riser refurbishment; upgrade of lap joints and riser inlet connections; interior and exterior access ladder replacement and the addition of fall arrest systems; and concrete foundation refurbishment. This work required the removal of the existing wooden cladding, which was replaced with a system of vertical standing seam aluminum cladding over new exterior insulation. Exterior insulation and heaters are used to prevent the water in the tank from freezing to the steel sides, which would render the surge tank ineffective.

During weather conditions experienced in March and April 2018, winds reached gusts of 115 km/h, causing a section of the surge tank cladding to come loose.[4] This was repaired in place at the time by using rope access techniques.[5] After the January 2020 "Snowmageddon" event, with winds in excess of 140 km/h, additional damage occurred (Figure 7). During this second wind event, some of the cladding became detached and was taken away by the wind. A large section of the cladding is now missing. The remaining cladding is in poor condition and is being temporarily held in place by nylon strapping (Figure 8). The cladding requires full replacement due to the extent of the wind damage.

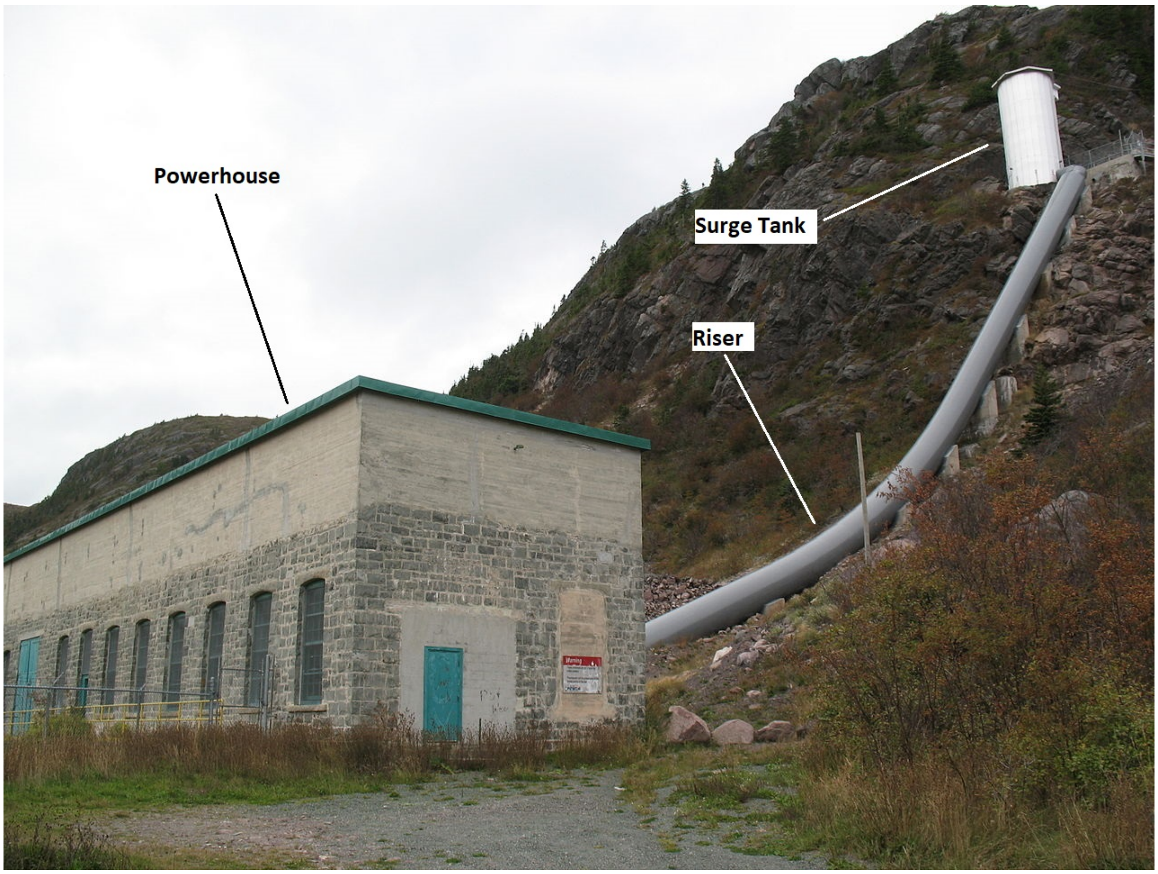

Figure 6: Petty Harbour Plant and Surge Tank

[4] Recorded at the meteorological station at St. John's International Airport.
[5] This involved tying off to the top of the tank and rappelling to the area that required attention.

Figure 7: Damage Resulting from "Snowmageddon"

Figure 8: Temporary Repair

The insulation is a critical component to ensure the proper operation of the surge tank. The cladding protects the insulation from deterioration. Unless the cladding is replaced, the exterior insulation will continue to deteriorate. In addition, cladding pieces coming loose in windy conditions pose a significant safety hazard to employees and the general public. The probability of further wind damage, and the consequence associated with the safety hazards, is too great to defer this project.

Replacing the surge tank cladding involves installing full height scaffolding around the exterior of the tank to provide access and a safe work platform. The damaged cladding and insulation will be removed. A new cladding system will be installed with a robust anchoring system. The new anchoring system will be supplemented by stainless steel exterior banding to withstand extreme wind events.

Rehabilitation of the Petty Harbour surge tank is justified on the need to maintain the structure in a safe condition, thus ensuring the continued operation of Petty Harbour plant.

2.3 Petty Harbour Unit 2 Turbine Overhaul ($301,000)

The Petty Harbour Unit 2 hydroelectric turbine generator (Figure 9) was installed in 1907. Unit 2 was upgraded in 1984 to 1,350 kW with the replacement of the turbine runner and generator.[6] Many of the original internal components of the turbine remained, including the control wicket gates, arms and linkages.[7] The design of the turbine is such that most of the operating components are internal to the spiral case and cannot be accessed without full disassembly.[8]

In 2004, 20 years after the Unit 2 was upgraded, the turbine had deteriorated to the point where the wicket gates could no longer seal sufficiently to stop the unit from rotating following a shutdown. The only way to achieve a full stop was to close the inlet valve, which is a slower operation. To limit overspeed during shutdown, which can stress the rotating components, the wicket gates were restricted to less than 80% opening, with a corresponding full load reduction from 1,350 kW to less than 1,000 kW.[9] In 2006, a mid-life overhaul repaired the wicket gates using a metal resurfacing component. In addition, operating linkages were cleaned, the operating ring refurbished, and new bolting hardware installed. This returned Unit 2 to its 1,350 kW load capacity.

Following the 2006 refurbishment, the unit continued to operate as intended. In 2020, however, the wicket gate issue redeveloped.[10] In addition, the operating ring, which is internal to the scroll case, now binds during operation. When this happens, load cannot be varied without manual intervention.[11] Additionally, the access port where the operating arm enters the turbine is leaking (Figure 10). In order to diagnose and rectify the impaired operation, the unit will be dismantled, and any worn or deteriorated components refurbished or replaced as appropriate.

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[6] A runner is the rotating part of the turbine that converts the falling water into energy.

[7] Wicket gates are components of a water turbine used to control the flow of water that enters the turbine runner**.** They also close quickly when a unit trips to limit overspeed.

[8] The spiral case encloses the water containing parts of the turbine such as the wicket gates and runner.

[9] This reduces the amount of water going through the turbine and lowers the resultant overspeed when the unit trips off line.

[10] Upon shutdown, the rotation remains at 170 rpm compared to its full speed rating of 450 rpm.

[11] The turbine operating ring opens and closes the wicket gates in unison by means of mechanical linkages.

Figure 9: Unit 2 Turbine

Figure 10: Operating Arm Leakage

Delaying the refurbishment of Unit 2, would result in further deterioration which would impair the ability of the unit to carry full load. Impaired operation also presents a safety hazard. If the gates and operating ring were to become jammed, the resulting inability to close the gates in the event of a unit trip could cause an overspeed condition while the inlet valve is closing, with potential destructive consequences for the rotating components.

There are 3 units in the Petty Harbour plant, 2 of which are automated.[12] Not completing the overhaul and removing Unit 2 from service would limit total generation from the plant, and reduce the ability to optimize water use and provide system support when requested by Newfoundland and Labrador Hydro.[13]

Rehabilitation of the Petty Harbour Unit 2 turbine is justified on the need to maintain the plant components in a safe and efficient operating condition.

3.0 Generation Control System Upgrades ($339,000)

In the early 2000s, Newfoundland Power began upgrading its hydroelectric facilities' protection and control systems. This included modernizing the protection, governor, generator excitation system and unit controls by converting from older technology to modern digital systems.[14]

The Company will have 8 generating plants that use the Rockwell Automation 1407 Combined Generator Control Module ("CGCM") by the end of 2021. The CGCM combines excitation control, generator protection, synchronization control, and full-featured metering in a single compact product. The CGCM, when used in conjunction with a Rockwell programmable logic controller ("PLC"), provides an integrated platform for generator control and system supervision.[15]

In recent years, Newfoundland Power has experienced CGCM communication card failures in 6 modules manufactured before 2010. These modules have been replaced as they fail. However, for recent failures, the Company has been unable to obtain a replacement module from the vendor. In February 2019, the vendor announced that the product had been discontinued and is no longer manufactured.

There is no direct replacement for the CGCM. Replacement will require redesign of the control system, including engineering, installation and commissioning. In addition, the PLCs will be upgraded at the same time due to obsolescence issues and a lack of spare parts.[16]

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12 Unit 2 is one of the automated units. Unit 1 is original to the plant circa 1910 and is strictly manual control. It is put on line during high flow periods with the other 2 units remotely controlled to efficiently use the available water.

13 Newfoundland Power's System Control Centre monitors and controls the electrical system including its 23 hydro plants. During winter operations, Newfoundland and Labrador Hydro routinely requests units to be put on line for peak and system requirements.

14 Replacement parts for the older electromechanical technology were no longer available to maintain this vintage of equipment. Additionally, the expertise necessary to work on the older technology was no longer being taught to the current generation of technologists, resulting in a technical skills gap.

15 As the CGCM module is installed in the PLC chassis, it can be configured through the PLC programming interface making it highly customizable for the purpose intended.

16 The models of PLC used in the protection and control system upgrades over the past 20 years are reaching end of life and have been replaced with other models. Upgrading to the currently supported models will ensure the continued reliable operation of the Company's hydroelectric facilities.

In 2019, Newfoundland Power identified the generation facilities with obsolete CGCMs and PLCs, and developed a multi-year plan to replace the obsolete components. The multi-year plan, started in the 2020 Capital Budget Application, involves the replacement of approximately 2 systems per year. The replacement plan will also establish CGCM and PLC spare inventory to accommodate failures of the units that remain in service over the replacement period. In 2022, the control systems to be replaced are located at the Lookout Brook and Sandy Brook hydroelectric plants.

Table 1 outlines the forecast capital expenditures to complete the generator control systems upgrade plan.

Table 1
Generator Control System Upgrades Plan
($000s)

	2020	**2021F**	**2022B**	**2023**	**2024**	**2025**
Total	340	350	339	401	315	353

4.0 Generation Equipment Replacements Due to In-Service Failures ($610,000)

Equipment and infrastructure at generating facilities routinely require upgrading or replacement to ensure reliable operation 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: (i) emergency replacements, where components fail and require immediate replacement to return a unit to service; or (ii) observed deficiencies, where components are identified for replacement due to imminent failure, or for safety or environmental reasons.

Table 2 provides the annual expenditures for replacements due to in-service failures for the most recent 5-year period, as well as estimated expenditures for 2022.

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

	2017	2018	2019	2020	2021F	2022B
Total	571	578	573	594	606	610
Adjusted Costs[17]	602	601	589	603	606	-

The project cost for the replacement of equipment due to in-service failures is calculated on the basis of historical data. The historical annual expenditures over the most recent 5-year period are converted to current-year dollars (the "Adjusted Cost"). The 2022 budget estimate is based on the 5-year average of the Adjusted Cost.

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.

5.0 2022 Project Cost

Table 3 provides a breakdown of the proposed expenditures for 2022 by cost category.

Table 3
Project Cost
($000s)

Cost Category	Infrastructure Rehabilitation	Control System Upgrades	In-Service Failures	Total
Material	721	127	404	1,252
Labour - Internal	154	34	117	305
Labour - Contract	-	-	-	-
Engineering	174	130	31	335
Other	64	48	58	170
Total	**$1,113**	**$339**	**$610**	**$2,062**

[17] 2021 dollars.

6.0 Conclusion

The projects described in this report are required to ensure Newfoundland Power's hydroelectric facilities continue to be operated in a safe, least-cost, and reliable manner.

In 2022, capital improvements are required to replace the Morris plant head gate and intake gatehouse, replace the Petty Harbour plant surge tank exterior cladding, refurbish the Petty Harbour Unit 2 turbine, upgrade the generation control systems at 2 plants, and replace equipment due to in-service failures.

The total 2022 budget for facility rehabilitation is estimated at $2,062,000.

Sandy Brook Plant
Penstock Replacement

May 2021

Prepared by:
Alex Hawco, P. Eng.

LICENSED PROFESSIONAL ENGINEER
08900
ALEX C. HAWCO
SIGNATURE
MAY 5th, 2021
DATE
NEWFOUNDLAND & LABRADOR

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1.0 Introduction

Newfoundland Power's (the "Company") Sandy Brook hydroelectric development (the "Sandy Brook Plant" or the "Plant") is located on a tributary of the Exploits River, approximately 13 kilometres southwest of the Town of Grand Falls-Windsor.

The Plant was placed into service in 1963 and contains one (1) vertical hydro generating unit with a capacity of 6.31 MW at a rated net head of 33.5 metres. The normal annual production of the Plant is approximately 27.6 GWh, or 6.3% of the total 2021 normal hydroelectric production of Newfoundland Power.[1] The Plant has provided 58 years of reliable energy production.

This report provides an assessment of the current condition of the penstock as well as the project scope of work and budget.

2.0 Background

The 336 metre long, 2.6 metre diameter wood stave penstock was installed in 1963.[2] The penstock is comprised of 2 sections. The 251 metre long upstream section extends from the intake to the surge tank.[3] The 85 metre long downstream section begins at the downstream side of the surge tank and terminates at the powerhouse. The penstock sits above ground for its entire length and is connected to the intake, surge tank and plant using steel thimbles.[4]

Figure 1 outlines the lower reaches of the Sandy Brook development.

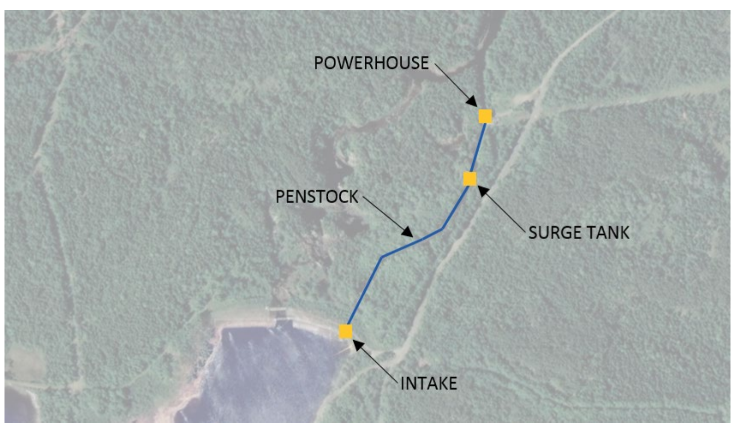

Figure 1: Map of Sandy Brook Development

[1] For 2021, the adjusted normal annual hydroelectric production for Newfoundland Power has been set at 434.8 GWh of energy.

[2] A penstock is a pipeline that conveys water from the intake to the hydro turbine. Woodstave penstocks consist of wooden staves wrapped by steel bands and are supported on timber saddles.

[3] A surge tank is a pressure control device that dampens pressure variances due to changes in load.

[4] Woodstave penstocks are connected to steel thimbles by wrapping the wood staves around the steel and tensioning the steel bands around the wood staves to form a friction connection.

3.0 Penstock Condition Assessment

In 2020, Newfoundland Power engaged Kleinschmidt Canada Inc.[5] ("Kleinschmidt") to complete a visual inspection and condition assessment of the existing penstock.[6] A summary of the report results are described in this section.

Saddles

The penstock saddles are constructed of rough cut timber treated with creosote.[7] The penstock is supported on 94 saddles, with ⅓ having moderate to severe cracking present. Cracking has most likely occurred due to movement and displacement of the penstock as the wood is otherwise in good condition with no indication of premature rot (Figure 2). However, due to the extensive cracking present, the overall condition of the saddles is considered to be poor.

Figure 2: Cracked Saddle

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5 Kleinschmidt Canada Inc. provides engineering, regulatory, and environmental consulting services to energy companies and government agencies across North America.

6 The detailed inspection report can be found in Appendix B, *Penstock Inspection Report – Sandy Brook Hydroelectric Development.*

7 Creosote is a distillate of coal tar and was used as a preservative.

Steel Bands

Two different diameter steel bands are used to secure the penstock's wooden staves. In the section between the intake and the surge tank the steel bands are 19 mm (3/4 inch) diameter. In the section between the surge tank and the powerhouse the steel bands are 22 mm (7/8 inch) diameter. Band spacing varies from 254 mm (10 inches) near the intake to less the 127 mm (5 inches) near the powerhouse as internal pressure increases.[8] Overall the steel bands are in good condition with only minor corrosion present (Figure 3).

Figure 3: Steel Bands

[8] The pressure in a penstock increases as it approaches the powerhouse.

Wood Staves

The wood staves are nominally 95 mm (3.75 inches) x 127 mm (5 inches) of an unknown wood species. Historically, wooden staves were recoated with creosote annually. In recent years, creosote has not been reapplied due to health and environmental concerns.[9] Discontinuing the creosote treatment has contributed to deterioration of the wooden staves.

The entire length of the penstock is experiencing joint leakage between staves and brooming at the stave ends (Figure 4).[10] Joint leakage is most prominent at the spring line, indicating that ovaling of the pipe has developed (Figure 5).[11]

Figure 4: Stave Brooming

Figure 5: Spring Line Leakage

The wooden staves are also showing signs of severe quality loss and excessive decay (Figure 6).[12] Leakage during winter months creates large build ups of ice (Figure 7). Ice buildup can cause (i) penstock jacking if located under the penstock, (ii) eccentric loading if the ice buildup is more prominent on one side of the penstock, and (iii) impact damage or rupture if large chunks of ice break off and fall on the penstock.

9 Creosote is a suspected cancer hazard (Material Safety Data Sheet – Creosote Oil) and the Government of Newfoundland and Labrador *Policy for Use of Creosote Treated Wood In and Near Fresh Water* will not approve its use in or near a body of fresh water.

10 Brooming is the delamination at the end of staves.

11 The spring line is the horizontal line at the midpoint of the vertical axis of a penstock.

12 Kleinschmidt conducted an assessment of wood decay using a blunt tip probe. The assessment indicated a significant amount of decay and poor condition of the wood staves.

Figure 6: Stave Rot

Figure 7: Ice Buildup

Site Drainage

The site drainage system consists of a free draining granular saddle foundation and ditching on both sides of the penstock. Water from leakage and local rainfall accumulates in the penstock right of way, resulting in material loss occurring around some saddles. If left unmitigated, the leakage flow will further deteriorate the saddle foundations resulting in foundation failure (Figures 8, 9 and 10). Additionally, when large amounts of water reach the powerhouse wall it collects and enters the building flooding the powerhouse floor (Figure 11).

Figure 8: Penstock Drainage

Figure 9: Penstock Entering Powerhouse

Figure 10: Leakage Along Length of Penstock

Figure 11: Water in Powerhouse

4.0 Project Justification

Kleinschmidt has determined that failure of the penstock is likely due to wood stave collapse and/or loss of support from the saddles due to excessive cracking in the timbers. Due to the increased probability of penstock failure related to its current condition and significant consequences associated with failure, the replacement of the penstock at this time cannot be deferred.

Penstock failure presents a significant safety risk to employees, the general public and wildlife in the vicinity and downstream of the penstock. As the penstock ages and continues to deteriorate the probability of failure increases. If the penstock were to fail, flooding of the powerhouse and surrounding area will occur resulting in significant damage to the powerhouse structure and equipment within the Plant. Plant refurbishment after a penstock failure would result in a longer outage with increased spill and additional costs due to powerhouse and equipment damage.

Significant environmental damage would also result from the fast flowing water escaping from the failed penstock. The Plant is located on a tributary of the Exploits River. The Exploits River is a sensitive ecological environment and has a significant population of Atlantic salmon. Failure of the penstock would result in debris and sedimentation entering the Exploits River potentially causing harm to the Atlantic salmon population.

5.0 Project Description

5.1 Scope of Work

The project scope of work includes the penstock replacement as a multi-year project in 2022 and 2023. The engineering for the penstock replacement, right of way clearing and geotechnical study will be completed in 2022. This would include creating engineering specifications, tendering packages and issuance of contracts required for the project.

In 2023, the penstock replacement project will be completed during a 24 week outage at the Plant commencing in the summer season when there are lower inflows.

5.2 Project Execution

To complete the penstock replacement on schedule the following tasks will be executed in 2022: (i) right of way clearing, (ii) survey, (iii) geotechnical and environmental sampling, (iv) engineering design of the penstock, and (v) procurement of long lead time materials.

The execution of all onsite work will begin in the 2nd quarter of 2023, with completion during the 4th quarter

Table 1 shows the proposed schedule for the project.

Table 1
Project Schedule

Date	Description
Mar – Oct 2022	Complete detailed engineering design and tender package
May – June 2022	Right of way clearing and survey
June – July 2022	Complete geotechnical study and environmental review
Aug – Dec 2022	Tender and award penstock contract
Jan – May 2023	Penstock pipe manufacture
June – Oct 2023	Construction on site
Nov 2023	Test and commission systems, return to service

5.3 Project Cost Breakdown

The total cost for the penstock replacement project is estimated at $5,094,000, which includes $400,000 in 2022, followed by $4,694,000 in 2023.

Table 2 below summarizes the project costs by cost category and year.

Table 2
Project Cost
($000)

Cost Category	2022	2023	Total
Material	290	4,491	$4,781
Labour - Contract	-	-	-
Labour - Internal	9	9	$18
Engineering	71	54	$125
Other	30	140	$170
Total	**$400**	**$4,694**	**$5,094**

6.0 Economic Analysis

Appendix A provides an economic analysis for the continued operation of the Plant assuming that the planned capital refurbishment is undertaken. The results of the economic analysis show that the continued operation of the Plant is economical over the long term. Investing in the life extension of the Plant ensures the continued availability of 27.6 GWh of energy annually to the Island Interconnected System.

The analysis includes estimates for work to be completed over the next 50 years including expenditures in 2022 and 2023. The analysis shows that the benefits to customers of continued operation of the Sandy Brook Plant are greater than the cost of production. The net benefit of the plant production is 10.21¢/kWh for fully dispatchable and 7.04 ¢/kWh for a run of river plant.[13] The levelized cost of production is 3.22¢/kWh.[14] This indicates that continued operation of the Plant is economically justified and is least cost for customers.

7.0 Conclusion

The Sandy Brook penstock is original to the Plant and approaching 58 years in service. The penstock wooden staves are in poor condition and the saddles are experiencing severe cracking. Due to the advanced age, condition, and consequence of failure, penstock replacement is required.

The results of the economic analysis conclude that continued operation of the Plant, including the planned upgrades, is economically viable over the long term. This project will allow Newfoundland Power to continue to operate the Sandy Brook Plant into the future, providing least-cost, reliable energy for customers.

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[13] See Table 3 of Appendix A.

[14] The cost presented is based on a normal Capital Cost Allowance (CCA). Penstocks may be eligible for accelerated CCA, in which case the cost of production is estimated to be 3.06¢/kWh.

Appendix A

Sandy Brook Plant
Economic Evaluation

Sandy Brook Plant
Economic Evaluation

May 2021

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1.0 Introduction

This economic analysis examines the future viability of generation at Newfoundland Power's Sandy Brook hydroelectric plant (the "Plant"). The continued long-term operation of the Plant is reliant on the completion of capital improvements in 2022 and 2023.

This analysis compares the cost of continued operation of the Plant to the benefit of the power produced from the Plant. The analysis includes a study period of 50 years, the expected service life of the new penstock, and expresses the results in terms of the levelized cost of energy.

2.0 Costs

2.1 Capital Costs

All significant capital expenditures for the Plant over the next 25 years are shown in Table 1.

Table 1
Sandy Brook Hydroelectric Plant
Capital Expenditures
($000s)

Year	Expenditure
2022	505
2023	6,586
2031	35
2034	325
2036	370
2046	1,225
2047	300
Total	**$9,346**

The estimated capital expenditure for the Plant is $9,346,000 over the next 25 years.[1] A more comprehensive breakdown of capital costs is provided in Attachment A.

[1] Capital expenditures beyond the initial 25 years are included in the analysis and are broadly indicative of the expenditures anticipated.

2.2 Operating Costs

Operating costs for the Plant are estimated to be approximately $223,000 per year.[2] The operating cost represents both direct charges for operations and maintenance at the Plant, as well as indirect costs such as those related to managing the environment, safety, dam safety inspections and staff training. This estimate is primarily based on recent historical operating experience. A summary of operating costs is provided in Attachment B. The annual operating cost also includes a water power rental rate.[3] This fee is paid annually to the Provincial Department of Environment, Climate Change and Municipalities based on yearly hydro plant generation/output. This charge is reflected in the historical annual operating costs for the Plant.

3.0 Customer Benefits

3.1 General

The customer benefits of the continued operation of the Plant are provided by the electricity generated by the Plant. The value of electricity production consists primarily of: (i) reduced marginal energy cost; and (ii) avoidance of the need to add generation capacity.

3.2 Marginal Energy Cost

The Island Interconnected System is connected to the North American power grid through the Labrador Island Link and the Maritime Link. Once the Muskrat Falls Hydroelectric Generation Plant is fully operational, there will be excess power available to export to customers in other jurisdictions on the North American Grid.

A marginal cost study completed by Newfoundland and Labrador Hydro ("Hydro") provides estimates of the opportunity cost of selling to other jurisdictions (the "Marginal Cost Update").[4] The marginal cost estimates vary by time of day and by season. To recognize these time-varying characteristics, Newfoundland Power has summarized the costs by winter on-peak, winter off-peak and non-winter marginal energy costs. Attachment C to this report provides the forecast marginal costs for the period 2022 to 2042.

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2 Reflects 2022 dollars.

3 The water power rental rate increased from $0.80/MWh in 2015 to $2.50/MWh in 2016, and is increased annually by the Consumer Price Index. The additional cost is added to the annual operating cost.

4 Based on Hydro's 2020 marginal cost update as provided to Newfoundland Power on April 9, 2020.

Table 2 provides a breakdown of the normal production of the Plant.

Table 2
Normal Production from Sandy Brook Hydro Plant

Marginal Cost Period	Normal Production (GWh)	Production (%)	Average Normal Production (MW)
Non-Winter Period (All hours)	19.01	69	5.09
Winter Period			
On-Peak	4.41	16	5.03
Off-Peak	4.13	15	4.24
Annual Production	**27.55**	**100**	**4.93**

Table 2 shows that the average normal production during the on-peak winter period is 5.03 MW. This is 80% of the maximum winter capacity of 6.31 MW.[5] It is during the on-peak winter period in which the benefits of electricity production are highest.[6]

3.3 Value of Avoided New Capacity Additions

The Island Interconnected System's need for new capacity additions is being reviewed by the Board of Commissioners of Public Utilities of Newfoundland and Labrador (the "Board").[7] Hydro's most recent assessment shows that the system has limited capacity to meet future load growth.[8] Maintaining the Plant's production avoids or postpones the need to introduce new sources of generation. The Marginal Cost Update provides estimates of the marginal cost of generation capacity in terms of cost per MWh and cost per kW of peak demand. These figures are provided in Attachment C.

The Plant can provide 6.3 MW of capacity during the winter. The value of this capacity is dependent on the amount of storage, the timing of rainfall, how the Plant is dispatched, and the potential that the Plant is out of service when required to meet customer demand.

5 The maximum winter capacity is based on the typical production from the Plant during the Company's annual generation capacity test. The generation capacity test is required by Hydro's Utility Rate.

6 See Attachment C.

7 The Board's ongoing review of Hydro's Reliability and Resource Adequacy Study may impact the need for capacity additions.

8 See Hydro's *Marginal Cost Study Update – 2018 Summary Report*, dated November 15, 2018, page 3-4.

To assess the value of capacity for the Plant, Newfoundland Power has completed an evaluation under 2 assumptions: (i) evaluating the historic production patterns to assess its value as a *run of river* hydro plant; and (ii) evaluating the Plant as a *fully dispatchable* plant.

A *run of river* plant has very little storage and provides minimum flexibility for the Company to schedule production for periods of greatest value.[9] The capacity value from a run of river plant is dependent on the extent to which timing of the river flow will correspond to periods when the value of electricity is the greatest. Evaluation of a run of river plant is completed by applying the production for each marginal cost time period to the appropriate marginal generation capacity cost.

Fully dispatchable generation, on the other hand, has sufficient storage to allow it to produce at its full rated capacity for all potential periods of need. This would be similar to a gas turbine, which can be dispatched at any time to provide its rated capacity to support customer demand. The capacity of a fully dispatchable plant is primarily reflective of its rated capacity and the likelihood it is not available for service.

Newfoundland Power's facilities vary between being run of river and fully dispatchable. The Plant has total available storage of 2.6 GWh. This level of storage represents about 17 days of production at a production rate of 6.31 MW. However, storage levels are often not full, and there are practical limitations of managing the flow of the water from storage to the forebay. These practical considerations limit the Company's ability to maintain continuous production at rated capacity for extended periods of time.

The results of the evaluation are provided in Section 4.0.

4.0 Economic Evaluation Results

An overall financial analysis of the costs and benefits of the Plant's production has been completed using the levelized cost of energy approach. The levelized cost of energy expresses the costs and benefits in terms of a ¢ per kWh of production. The detailed results of the calculated levelized costs and benefits are provided in Attachment D of this report.[10]

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9 As examples, periods of greatest value for production include during generation shortages and peak demand periods.

10 The financial assumptions used in the economic evaluation are provided in Attachment E.

Table 3 provides a comparison of the estimated levelized costs and benefits of the Plant's production.

Table 3
Economic Evaluation Results

	50 Year Levelized Value[11]	**Net benefit**
Cost of Plant Production	**3.22 ¢/kWh**	
Benefits of Production (Run of River)		
Value of Energy	5.67 ¢/kWh	
Value of Capacity	4.59 ¢/kWh	
Total	**10.26 ¢/kWh**	**7.04 ¢/kWh**
Benefits of Production (Fully Dispatchable)		
Value of Energy	5.67 ¢/kWh	
Value of Capacity	7.76 ¢/kWh	
Total	**13.43 ¢/kWh**	**10.21 ¢/kWh**

Table 3 shows that the benefits of the Plant's production will exceed its cost of production by between 7.04 and 10.21 ¢ per kWh.[12] In order for the benefits to be less than the costs, the benefits would need to be reduced by between 65% and 76% based on the fully dispatchable and run of river assumptions, respectively. The large differences between costs and benefits suggest any reasonable variance in the estimates of the costs and benefits will support the continued operation of the Plant.

5.0 Conclusion

The results indicate that continued operation of the Plant is economically justified. Investing in the current upgrades of the Plant guarantees the continued availability of low-cost energy to the Island Interconnected System. The project will benefit customers by providing least-cost, reliable energy into the future.

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[11] See Attachment D.

[12] The range presented is based on a normal Capital Cost Allowance (CCA). Penstocks may be eligible for an accelerated CCA, in which case the benefits of the Plant's production will exceed its cost of production by between 7.20 and 10.37 ¢ per kWh.

Attachment A

Summary of Capital Costs

Sandy Brook Hydro Plant Economic Analysis
Summary of Capital Costs (2022-2047)
($000s)

Description	2022	2023	2031	2034	2036	2046	2047
Civil							
Dam, Spillways and Gates	-	246	-	300	-	-	300
Penstock	400	4,694	-	-	-	-	-
Surge Tank	-	200	-	-	-	-	-
Powerhouse	-	-	-	-	200	-	-
Mechanical							
Turbine	-	-	-	-	-	1,140	-
Governor	-	-	-	-	-	50	-
Powerhouse Systems	-	-	-	-	50	-	-
Electrical							
Generator Refurbishment	-	1,446	-	-	-	-	-
Control Systems	105	-	-	-	120	-	-
Switchgear	-	-	-	-	-	-	-
AC/DC Systems	-	-	-	25	-	-	-
Battery/Charger	-	-	35	-	-	35	-
Total ($2022)	**$505**	**$6,586**	**$35**	**$325**	**$370**	**$1,225**	**$300**

Attachment B

Summary of Operating Costs

Sandy Brook Hydro Plant
Economic Evaluation
Summary of Operating Costs
($2022)

	Amount
2016	$126,415
2017	$144,626
2018	$142,738
2019	$164,865
2020	$151,873
Average[1]	**$146,103**
Water Power Rental[2]	$76,589
Total Average Operating Cost	**$222,692**

[1] Cost excludes the water power rental rate.

[2] Calculated using the current water power rental rate ($2.50/MWh – 2016 base plus CPI Inflator) multiplied by the normal annual output of the plant.

Attachment C

Marginal Costs Estimates

Marginal Cost Projections 2022-2042
Island Interconnected System
At Hydro's Delivery Point to Newfoundland Power

	Energy Supply Costs			Capacity Costs			
	Winter		Non-Winter	Winter		Non-Winter	
Year	Peak Period	Off Peak Period	All hours	Peak Period	Off Peak Period	All hours	Generation
	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh	$/kW·yr
2022	72.86	59.51	26.51	130.91	63.55	1.36	285.71
2023	64.53	52.15	23.71	135.54	65.82	1.39	292.15
2024	63.45	52.15	24.84	138.56	67.28	1.42	299.70
2025	62.10	51.90	26.66	141.64	68.78	1.46	306.61
2026	68.69	58.72	27.27	144.79	70.31	1.49	312.30
2027	70.98	61.18	28.18	148.01	71.88	1.52	318.75
2028	73.54	64.20	31.27	151.31	73.48	1.56	326.38
2029	77.18	66.56	36.53	154.68	75.11	1.59	334.79
2030	78.52	67.72	37.16	157.36	76.42	1.62	340.60
2031	79.90	68.90	37.81	160.12	77.75	1.65	346.56
2032	81.28	70.10	38.47	162.89	79.10	1.67	352.57
2033	82.69	71.31	39.13	165.71	80.47	1.70	358.66
2034	84.11	72.54	39.81	168.56	81.85	1.73	364.83
2035	85.55	73.78	40.49	171.45	83.26	1.76	371.09
2036	87.03	75.05	41.19	174.41	84.69	1.79	377.49
2037	88.51	76.33	41.89	177.39	86.14	1.82	383.93
2038	90.03	77.65	42.61	180.43	87.62	1.85	390.53
2039	91.56	78.96	43.33	183.50	89.11	1.89	397.16
2040	93.13	80.32	44.08	186.64	90.63	1.92	403.97
2041	94.73	81.69	44.83	189.84	92.19	1.95	410.89
2042	96.35	83.09	45.60	193.09	93.76	1.98	417.93

Notes:

1. 2020-2029 based on the marginal cost projections provided by Hydro on April 9, 2020.
2. 2030-2042 marginal cost projections are escalated based on Conference Board of Canada GDP deflator, long term projection dated December 5, 2019.

Attachment D

Calculation of Levelized Costs and Benefits

Levelized Present Worth Analysis of the Cost of Future Plant Production

Weighted Average Incremental Cost of Capital **5.81%**
PW Year **2022**

Year	Year	Generation Hydro 64.4yrs 8% CCA	Generation Hydro 64.4yrs 100% CCA	Capital Revenue Requirement	Operating Costs	Operating Benefits	Net benefit	Present Worth Benefit +ve	Cumulative Present Value Benefit +ve	Present Worth of Sunk Costs	Total Present Worth Benefit +ve	Rev Rqmt (¢/kWhr)	Levelized Rev Rqmt (¢/kWhr) 50 years
1	2022	**105,000**	**0**	8,712	**0**	**0**	-8,712	-8,712	-8,712	0	-8,712	0.032	-
2	2023	**6,986,000**	**0**	589,109	**226,403**	0	-815,512	-770,733	-779,445	-8,267,837	-9,047,282	2.960	3.22
3	2024	**0**	**0**	638,892	**230,032**	0	-868,924	-776,119	-1,555,564	-7,697,182	-9,252,746	3.154	3.22
4	2025	**0**	**0**	620,739	**233,617**	0	-854,356	-721,205	-2,276,769	-7,173,185	-9,449,954	3.101	3.22
5	2026	**0**	**0**	603,442	**237,807**	0	-841,249	-671,147	-2,947,916	-6,691,760	-9,639,676	3.054	3.22
6	2027	**0**	**0**	586,932	**242,000**	0	-828,932	-625,008	-3,572,924	-6,249,218	-9,822,142	3.009	3.22
7	2028	**0**	**0**	571,147	**246,264**	0	-817,411	-582,479	-4,155,403	-5,842,225	-9,997,627	2.967	3.22
8	2029	**0**	**0**	556,028	**250,591**	0	-806,619	-543,227	-4,698,630	-5,467,761	-10,166,391	2.928	3.22
9	2030	**0**	**0**	541,523	**254,940**	0	-796,462	-506,934	-5,205,564	-5,123,091	-10,328,656	2.891	3.22
10	2031	**40,769**	**0**	530,964	**259,398**	0	-790,361	-475,429	-5,680,993	-4,803,699	-10,484,692	2.869	3.22
11	2032	**0**	**0**	517,833	**263,898**	0	-781,731	-444,416	-6,125,409	-4,509,309	-10,634,719	2.837	3.22
12	2033	**0**	**0**	504,783	**268,455**	0	-773,239	-415,451	-6,540,860	-4,238,096	-10,778,956	2.807	3.22
13	2034	**398,532**	**0**	525,245	**273,077**	0	-798,322	-405,375	-6,946,235	-3,971,385	-10,917,620	2.898	3.22
14	2035	**0**	**0**	515,903	**277,763**	0	-793,666	-380,882	-7,327,117	-3,723,802	-11,050,919	2.881	3.22
15	2036	**469,462**	**0**	542,013	**282,556**	0	-824,569	-373,984	-7,701,101	-3,477,971	-11,179,073	2.993	3.22
16	2037	**0**	**0**	532,929	**287,375**	0	-820,304	-351,620	-8,052,722	-3,249,533	-11,302,255	2.978	3.22
17	2038	**0**	**0**	519,641	**292,310**	0	-811,951	-328,929	-8,381,651	-3,039,022	-11,420,673	2.947	3.22
18	2039	**0**	**0**	506,743	**297,275**	0	-804,017	-307,830	-8,689,481	-2,845,008	-11,534,489	2.918	3.22
19	2040	**0**	**0**	494,204	**302,375**	0	-796,579	-288,236	-8,977,717	-2,666,184	-11,643,901	2.891	3.22
20	2041	**0**	**0**	481,995	**307,553**	0	-789,548	-270,005	-9,247,721	-2,501,355	-11,749,076	2.866	3.22
21	2042	**0**	**0**	470,090	**312,820**	0	-782,910	-253,033	-9,500,755	-2,349,424	-11,850,178	2.842	3.22
22	2043	**0**	**0**	458,465	**318,177**	0	-776,642	-237,225	-9,737,980	-2,209,386	-11,947,365	2.819	3.22
23	2044	**0**	**0**	447,097	**323,626**	0	-770,723	-222,490	-9,960,470	-2,080,319	-12,040,789	2.798	3.22
24	2045	**0**	**0**	435,965	**329,168**	0	-765,134	-208,748	-10,169,218	-1,961,377	-12,130,595	2.777	3.22
25	2046	**1,841,718**	**0**	577,863	**334,805**	0	-912,668	-235,327	-10,404,545	-1,812,378	-12,216,922	3.313	3.22
26	2047	**458,757**	**0**	618,409	**340,539**	0	-958,948	-233,683	-10,638,228	-1,661,680	-12,299,907	3.481	3.22
27	2048	**0**	**0**	606,448	**346,371**	0	-952,819	-219,440	-10,857,668	-1,522,011	-12,379,679	3.459	3.22
28	2049	**0**	**0**	590,417	**352,302**	0	-942,720	-205,192	-11,062,860	-1,393,501	-12,456,361	3.422	3.22
29	2050	**0**	**0**	574,803	**358,336**	0	-933,139	-191,954	-11,254,815	-1,275,259	-12,530,073	3.387	3.22
30	2051	**0**	**0**	559,571	**364,472**	0	-924,044	-179,646	-11,434,461	-1,166,471	-12,600,932	3.354	3.22
31	2052	**0**	**0**	544,692	**370,714**	0	-915,406	-168,195	-11,602,655	-1,066,390	-12,669,046	3.323	3.22
32	2053	**0**	**0**	530,137	**377,062**	0	-907,199	-157,534	-11,760,190	-974,333	-12,734,522	3.293	3.22
33	2054	**0**	**0**	515,879	**383,520**	0	-899,399	-147,604	-11,907,793	-889,670	-12,797,463	3.265	3.22
34	2055	**0**	**0**	501,896	**390,088**	0	-891,984	-138,349	-12,046,142	-811,825	-12,857,967	3.238	3.22
35	2056	**0**	**0**	488,166	**396,768**	0	-884,933	-129,719	-12,175,861	-740,266	-12,916,127	3.212	3.22
36	2057	**0**	**0**	474,667	**403,563**	0	-878,230	-121,667	-12,297,528	-674,508	-12,972,035	3.188	3.22
37	2058	**0**	**0**	461,382	**410,474**	0	-871,856	-114,152	-12,411,680	-614,099	-13,025,779	3.165	3.22
38	2059	**0**	**0**	448,293	**417,503**	0	-865,797	-107,134	-12,518,814	-558,627	-13,077,441	3.143	3.22
39	2060	**0**	**0**	435,386	**424,653**	0	-860,039	-100,578	-12,619,392	-507,710	-13,127,102	3.122	3.22
40	2061	**0**	**0**	422,644	**431,925**	0	-854,569	-94,451	-12,713,842	-460,998	-13,174,840	3.102	3.22
41	2062	**0**	**0**	410,056	**439,322**	0	-849,378	-88,722	-12,802,565	-418,165	-13,220,730	3.083	3.22
42	2063	**0**	**0**	397,608	**446,845**	0	-844,453	-83,364	-12,885,929	-378,914	-13,264,842	3.065	3.22
43	2064	**0**	**0**	385,290	**454,498**	0	-839,787	-78,351	-12,964,280	-342,966	-13,307,247	3.048	3.22
44	2065	**0**	**0**	373,090	**462,281**	0	-835,371	-73,660	-13,037,940	-310,069	-13,348,009	3.032	3.22
45	2066	**0**	**0**	361,001	**470,198**	0	-831,199	-69,267	-13,107,208	-279,985	-13,387,192	3.017	3.22
46	2067	**0**	**0**	349,012	**478,250**	0	-827,262	-65,154	-13,172,362	-252,497	-13,424,859	3.003	3.22
47	2068	**0**	**0**	337,116	**486,440**	0	-823,556	-61,301	-13,233,662	-227,404	-13,461,066	2.989	3.22
48	2069	**0**	**0**	325,306	**494,770**	0	-820,076	-57,690	-13,291,352	-204,520	-13,495,872	2.977	3.22
49	2070	**0**	**0**	313,574	**503,243**	0	-816,817	-54,305	-13,345,657	-183,672	-13,529,330	2.965	3.22
50	2071	**0**	**0**	301,914	**511,861**	0	-813,775	-51,132	-13,396,790	-164,702	-13,561,492	2.954	3.22

Value of the Opportunity Cost of Energy
Based on Normal Production

Year	Marginal Energy Costs	Total Present Worth	Cumulative present Worth	Value of Export Sales (¢/kWhr)	Levelizied Value of Export Energy (¢/kWhr)
2022	-	-	-	-	-
2023	950,700	898,497	898,497	3.45	5.67
2024	967,403	864,080	1,762,578	3.51	5.67
2025	994,898	839,844	2,602,422	3.61	5.67
2026	1,063,799	848,697	3,451,118	3.86	5.67
2027	1,101,348	830,407	4,281,526	4.00	5.67
2028	1,183,999	843,706	5,125,231	4.30	5.67
2029	1,309,672	882,014	6,007,245	4.75	5.67
2030	1,332,398	848,048	6,855,293	4.84	5.67
2031	1,355,698	815,498	7,670,791	4.92	5.67
2032	1,379,216	784,089	8,454,879	5.01	5.67
2033	1,403,036	753,833	9,208,712	5.09	5.67
2034	1,427,190	724,705	9,933,417	5.18	5.67
2035	1,451,680	696,665	10,630,082	5.27	5.67
2036	1,476,730	669,772	11,299,854	5.36	5.67
2037	1,501,918	643,792	11,943,646	5.45	5.67
2038	1,527,711	618,890	12,562,536	5.55	5.67
2039	1,553,655	594,840	13,157,376	5.64	5.67
2040	1,580,312	571,824	13,729,200	5.74	5.67
2041	1,607,376	549,680	14,278,880	5.83	5.67
2042	1,634,902	528,394	14,807,273	5.93	5.67
2043	1,662,900	507,932	15,315,205	6.04	5.67
2044	1,691,377	488,262	15,803,466	6.14	5.67
2045	1,720,343	469,354	16,272,820	6.24	5.67
2046	1,749,804	451,178	16,723,999	6.35	5.67
2047	1,779,769	433,706	17,157,705	6.46	5.67
2048	1,810,248	416,911	17,574,616	6.57	5.67
2049	1,841,249	400,766	17,975,383	6.68	5.67
2050	1,872,781	385,247	18,360,629	6.80	5.67
2051	1,904,852	370,328	18,730,957	6.91	5.67
2052	1,937,473	355,987	19,086,945	7.03	5.67
2053	1,970,653	342,202	19,429,146	7.15	5.67
2054	2,004,400	328,950	19,758,096	7.28	5.67
2055	2,038,726	316,211	20,074,307	7.40	5.67
2056	2,073,640	303,966	20,378,273	7.53	5.67
2057	2,109,151	292,195	20,670,468	7.66	5.67
2058	2,145,271	280,880	20,951,348	7.79	5.67
2059	2,182,009	270,003	21,221,350	7.92	5.67
2060	2,219,376	259,547	21,480,897	8.06	5.67
2061	2,257,383	249,496	21,730,393	8.19	5.67
2062	2,296,041	239,834	21,970,227	8.33	5.67
2063	2,335,361	230,547	22,200,774	8.48	5.67
2064	2,375,354	221,619	22,422,393	8.62	5.67
2065	2,416,033	213,037	22,635,429	8.77	5.67
2066	2,457,408	204,787	22,840,216	8.92	5.67
2067	2,499,491	196,856	23,037,072	9.07	5.67
2068	2,542,295	189,233	23,226,305	9.23	5.67
2069	2,585,833	181,905	23,408,210	9.39	5.67
2070	2,630,115	174,861	23,583,071	9.55	5.67
2071	2,675,156	168,089	23,751,160	9.71	5.67

Value of Avoided Capacity

Based on Normal Production (Run - of River Assumption)

Year	Marginal Capacity Cost	Total Present Worth	Cumulative present Worth	Value of Avoided Generation Capacity (¢/kWhr)	Levelizied Value of capacity (¢/kWhr)
2022	-	-	-	-	-
2023	895,926	846,731	846,731	3.25	4.59
2024	915,858	818,041	1,664,771	3.32	4.59
2025	936,240	790,327	2,455,098	3.40	4.59
2026	957,080	763,557	3,218,655	3.47	4.59
2027	978,389	737,697	3,956,352	3.55	4.59
2028	1,000,179	712,718	4,669,070	3.63	4.59
2029	1,022,460	688,588	5,357,657	3.71	4.59
2030	1,040,202	662,070	6,019,727	3.78	4.59
2031	1,058,392	636,658	6,656,385	3.84	4.59
2032	1,076,752	612,137	7,268,522	3.91	4.59
2033	1,095,349	588,516	7,857,039	3.98	4.59
2034	1,114,205	565,776	8,422,815	4.04	4.59
2035	1,133,325	543,885	8,966,700	4.11	4.59
2036	1,152,881	522,890	9,489,591	4.18	4.59
2037	1,172,546	502,608	9,992,198	4.26	4.59
2038	1,192,682	483,167	10,475,365	4.33	4.59
2039	1,212,937	464,391	10,939,757	4.40	4.59
2040	1,233,748	446,422	11,386,179	4.48	4.59
2041	1,254,876	429,134	11,815,313	4.55	4.59
2042	1,276,366	412,516	12,227,829	4.63	4.59
2043	1,298,224	396,542	12,624,371	4.71	4.59
2044	1,320,457	381,186	13,005,556	4.79	4.59
2045	1,343,070	366,424	13,371,981	4.88	4.59
2046	1,366,070	352,234	13,724,215	4.96	4.59
2047	1,389,464	338,594	14,062,809	5.04	4.59
2048	1,413,259	325,482	14,388,291	5.13	4.59
2049	1,437,461	312,878	14,701,169	5.22	4.59
2050	1,462,078	300,762	15,001,931	5.31	4.59
2051	1,487,116	289,115	15,291,045	5.40	4.59
2052	1,512,583	277,919	15,568,964	5.49	4.59
2053	1,538,486	267,156	15,836,121	5.58	4.59
2054	1,564,833	256,811	16,092,931	5.68	4.59
2055	1,591,631	246,866	16,339,797	5.78	4.59
2056	1,618,888	237,306	16,577,103	5.88	4.59
2057	1,646,612	228,116	16,805,219	5.98	4.59
2058	1,674,810	219,282	17,024,502	6.08	4.59
2059	1,703,492	210,791	17,235,293	6.18	4.59
2060	1,732,664	202,628	17,437,920	6.29	4.59
2061	1,762,336	194,781	17,632,702	6.40	4.59
2062	1,792,517	187,238	17,819,940	6.51	4.59
2063	1,823,214	179,987	17,999,927	6.62	4.59
2064	1,854,437	173,017	18,172,945	6.73	4.59
2065	1,886,194	166,317	18,339,262	6.85	4.59
2066	1,918,496	159,877	18,499,139	6.96	4.59
2067	1,951,350	153,686	18,652,825	7.08	4.59
2068	1,984,767	147,734	18,800,559	7.20	4.59
2069	2,018,757	142,013	18,942,572	7.33	4.59
2070	2,053,328	136,514	19,079,085	7.45	4.59
2071	2,088,492	131,227	19,210,313	7.58	4.59

Value of Avoided Capacity

Assuming Fully Dispatchable with same plant availability as Gas Turbine

Plant Effective Capacity reflecting 95% FOR and a 16.0% Reserve Margin

Year	Effective Capacity	Marginal Capacity Cost	Total Present Worth	Cumulative Present Worth	Value of Avoided Generation Capacity	Levelizied Value of capacity
	MW	$	$	$	(¢/kWhr)	(¢/kWhr)
2022	-	-	-	-	-	-
2023	5.17	1,509,723	1,426,824	1,426,824	5.48	7.76
2024	5.17	1,548,771	1,383,356	2,810,180	5.62	7.76
2025	5.17	1,584,485	1,337,544	4,147,724	5.75	7.76
2026	5.17	1,613,890	1,287,559	5,435,282	5.86	7.76
2027	5.17	1,647,216	1,241,987	6,677,269	5.98	7.76
2028	5.17	1,686,629	1,201,875	7,879,144	6.12	7.76
2029	5.17	1,730,085	1,165,146	9,044,290	6.28	7.76
2030	5.17	1,760,106	1,120,276	10,164,566	6.39	7.76
2031	5.17	1,790,886	1,077,277	11,241,843	6.50	7.76
2032	5.17	1,821,952	1,035,786	12,277,629	6.61	7.76
2033	5.17	1,853,419	995,818	13,273,447	6.73	7.76
2034	5.17	1,885,326	957,339	14,230,786	6.84	7.76
2035	5.17	1,917,678	920,298	15,151,084	6.96	7.76
2036	5.17	1,950,769	884,773	16,035,857	7.08	7.76
2037	5.17	1,984,043	850,453	16,886,310	7.20	7.76
2038	5.17	2,018,115	817,558	17,703,868	7.33	7.76
2039	5.17	2,052,387	785,787	18,489,655	7.45	7.76
2040	5.17	2,087,602	755,382	19,245,037	7.58	7.76
2041	5.17	2,123,353	726,130	19,971,168	7.71	7.76
2042	5.17	2,159,715	698,011	20,669,179	7.84	7.76
2043	5.17	2,196,701	670,981	21,340,159	7.97	7.76
2044	5.17	2,234,320	644,997	21,985,156	8.11	7.76
2045	5.17	2,272,583	620,019	22,605,175	8.25	7.76
2046	5.17	2,311,501	596,009	23,201,185	8.39	7.76
2047	5.17	2,351,086	572,929	23,774,113	8.53	7.76
2048	5.17	2,391,349	550,742	24,324,856	8.68	7.76
2049	5.17	2,432,301	529,415	24,854,270	8.83	7.76
2050	5.17	2,473,954	508,913	25,363,183	8.98	7.76
2051	5.17	2,516,321	489,206	25,852,389	9.13	7.76
2052	5.17	2,559,414	470,261	26,322,650	9.29	7.76
2053	5.17	2,603,244	452,050	26,774,700	9.45	7.76
2054	5.17	2,647,825	434,545	27,209,245	9.61	7.76
2055	5.17	2,693,169	417,717	27,626,962	9.78	7.76
2056	5.17	2,739,290	401,541	28,028,503	9.94	7.76
2057	5.17	2,786,201	385,991	28,414,494	10.11	7.76
2058	5.17	2,833,915	371,044	28,785,538	10.29	7.76
2059	5.17	2,882,446	356,675	29,142,213	10.46	7.76
2060	5.17	2,931,809	342,863	29,485,076	10.64	7.76
2061	5.17	2,982,016	329,586	29,814,661	10.82	7.76
2062	5.17	3,033,084	316,822	30,131,484	11.01	7.76
2063	5.17	3,085,026	304,553	30,436,037	11.20	7.76
2064	5.17	3,137,857	292,760	30,728,797	11.39	7.76
2065	5.17	3,191,594	281,423	31,010,219	11.58	7.76
2066	5.17	3,246,250	270,524	31,280,744	11.78	7.76
2067	5.17	3,301,843	260,048	31,540,792	11.98	7.76
2068	5.17	3,358,387	249,978	31,790,770	12.19	7.76
2069	5.17	3,415,900	240,298	32,031,068	12.40	7.76
2070	5.17	3,474,398	230,992	32,262,060	12.61	7.76
2071	5.17	3,533,897	222,047	32,484,107	12.83	7.76

Attachment E

Economic Analysis Financial Assumptions

Economic Evaluation
Major Inputs and Assumptions

Specific assumptions include:

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

Operating Costs: Operating costs were assumed to be in 2022 dollars escalated yearly using the GDP Deflator for Canada.

Average Incremental Cost of Capital:

	Capital Structure	Return	Weighted Cost
Debt	55.00%	3.608%	1.98%
Common Equity	45.00%	8.500%	3.83%
Total	**100.00%**		**5.81%**

CCA Rates:

Class	Rate	Details
17.1 & 47	8.00%	All generating, transmission, substation and distribution equipment not otherwise noted.
43.2	50.00%	Expenditures related primarily to new generation or additions/alterations that increase the capacity of generating facilities.

Escalation Factors: Conference Board of Canada GDP deflator, medium term forecast data February 24, 2021 and long term forecast dated December 5, 2019.

Supporting Documents: Newfoundland and Labrador Hydro's Marginal Cost Study 2018 Update with further update provided to Newfoundland Power on April 9, 2020.

Appendix B

Penstock Inspection Report

PENSTOCK INSPECTION SUMMARY REPORT

SANDY BROOK HYDROELECTRIC DEVELOPMENT

Prepared for:

Newfoundland Power Inc.
St. John's, Newfoundland and Labrador

Prepared by:

Kleinschmidt

Dartmouth, Nova Scotia
www.KleinschmidtGroup.com

April 2021

Penstock Inspection Summary Report

Sandy Brook Hydroelectric Development

Prepared for:

Newfoundland Power Inc.
St. John's, Newfoundland and Labrador

Prepared by:

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April 2021

PENSTOCK INSPECTION SUMMARY REPORT

SANDY BROOK HYDROELECTRIC DEVELOPMENT

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1.0 INTRODUCTION

1.1 PROJECT DESCRIPTION

Newfoundland Power Inc. (Newfoundland Power)'s Sandy Brook Hydroelectric Development (the Project) is part of the Exploits River system. The Project is located 13 km south-west of Grand-Falls-Windsor in Newfoundland and Labrador and was constructed in 1963. The purpose of the Project is electric power generation. Original construction included a diversion dam, wood stave penstock, surge tank and powerhouse.

The wood stave penstock is approximately 336 m (1,100 feet) long with an internal diameter of 2.6 m (8.5 feet). There is a steel penstock section at the surge tank and a welded steel section at the downstream end as the penstock transitions into the powerhouse.

1.2 INSPECTION SCOPE

Kleinschmidt Associates Canada Inc. (Kleinschmidt) inspected the exterior portion of the wood stave penstock. The interior of the water conveyance system and control structures were not part of the inspection scope.

The purpose of the inspection was to determine the condition of the penstock and its suitability to ensure continued safe operation.

1.3 INSPECTION TEAM

Chris Vella, P. Eng., Senior Structural Engineer with Kleinschmidt performed the inspection, assisted by Sarah Bungay, Project Coordinator. Michael Brown of Newfoundland Power accompanied the team during the inspection.

1.4 INSPECTION PROCEDURES

1.4.1 MODES OF FAILURE – WOOD STAVE PENSTOCK

It is important to understand the modes of failure of a wood stave penstock such that the inspection focuses on the important elements.

The modes of failure include:

- Steel band corrosion
- Excessive band spacing
- Steel band elongation
- Wood Stave collapse – advanced wood decay; and
- Loss of shell supports and foundations:
    - Support and foundation damage or deterioration; and
    - Foundation movement or loss of bedding material.

These failure modes are discussed in more detail in Reference 2 and form the basis of observations in the following discussions.

1.4.2 INSPECTION DESCRIPTION

Kleinschmidt inspected the penstock on November 4, 2020. The inspection team completed a safety orientation with Newfoundland Power personnel upon arrival to the Project location. The weather was sunny with an approximate temperature of zero degrees Celsius. There was roughly 5 cm of snow on the ground at the start of the inspection with some icy conditions. The operating penstock had significant leakage that somewhat hampered the inspection (Photos 1 and 2). The inspection started at the powerhouse and progressed upstream along the right side of the penstock to the dam and returned to the powerhouse along the left side. Penstock saddles were consecutively numbered beginning at the surge tank and progressing upstream.

References to left and right are from the point of view of looking downstream. Points around the penstock are located by clock positions from this same point of view. The reference baseline for inspection used saddle numbering tracked during the inspection.

A number of photographs were taken to document the condition of the penstock and a representative sample can be found in Appendix A.

The inspection included observation of vibration, geometry, alignment, movement, settlement, type and condition of materials, type of joints, and type and location of supports.

2.0 INSPECTION FINDINGS

2.1 DEFINITIONS

Definitions for qualitative terminology are as described in Table 2-1.

TABLE 2-1 DEFINITIONS

TERM	DEFINITION
Excellent	New or near new condition with no visible deterioration
Good	General or light deterioration where performance is not affected
Fair	Medium deterioration or defects
Poor	Significant deterioration or defects
Very Poor	Severe deterioration or defects

2.2 OBSERVATIONS

The following summarizes Kleinschmidt's observations of the steel bands, wood stave shell, saddles, and foundations. Detailed inspection notes can be found in Appendix C.

Steel Bands

1) Bands were 22 mm (7/8 inch) in diameter downstream of the surge tank and 19 mm (3/4 inch) in diameter upstream of the surge tank. This matches the drawings (Figure 2, Appendix B).
2) Band spacing varied from about 254 mm (10 inches) to 203 mm (8 inches) from the dam to the surge tank, and from 127 mm (5 inches) decreasing to less than 5 inches from the surge tank to the powerhouse. The spacing appears to match the spacing noted in Figure 5 in Appendix B which shows the design band spacing. The band spacing is conventional and what we expect for this type of penstock. An analysis of the spacing was not performed.
3) Steel bands were in good condition with very light corrosion on the bands and light corrosion on the threads and around the nut (Photos 3 to 6).
4) There was one disconnected steel band about 4 cradles downstream of the surge tank (Photo 7). The nut was still on and the band did not appear broken or cracked in any way. Disconnection of a band can occur from pipe vibration, ovaling (common on older pipes), or excessive stress that stretches the bands.

Wood Stave Shell

1) Wood staves were measured to be about 95 mm (3 ¾ inch) thick by 127 mm (5 inches) wide. This thickness is what is expected for a penstock greater than 2,286 mm (90 inches) in diameter (Ref. 1).

2) There is a significant amount of seam leakage between the surge tank and the powerhouse on both sides (Photo 2) and upstream of the surge tank the leakage gets less as the pressure decreases moving upstream. Much of the seam leakage is located near the spring line which is an indicator of ovaling. Deteriorating and moving supports or softening wood staves can lead to ovaling. Excessive leakage is also an indication of poor wood condition. Little leakage was noted from the top or bottom of the pipe. Seam leakage is normally improved by tightening the bands; however, this may crush the wood and is a particular concern with older penstocks with decaying wood. Wedging tends to be the next method for dealing with seam leakage and significant wedging has been completed on this penstock (Photo 8).
3) There are several areas of spot or knot wedges, where wedges are not driven into a seam but into a hole away from the seams (Photos 9 and 10).
4) There are a few locations where a jet of water is coming out (Photos 11 to 13) causing foundation and stave erosion.
5) A 22 mm (1 inch) long steel blunt tip probe was used at intermittent locations along the penstock. The probe was pushed into the wood to assess penetration and softness. If wood staves are in good condition, no penetration of the blunt tip probe will be observed. Most of the wood staves between the surge tank and the powerhouse and many of the wood staves upstream of the surge tank are soft, allowing for up to the full depth of the probe to penetrate. Probe penetration generally varied between ¼ inch deep to a full 25mm (1 inch) deep along the length of the penstock. This indicates a significant amount of wood decay and poor condition of the wood staves.
6) The wood staves have a significant amount of brooming (splintering and delamination) at band and joint locations consistently along the length of the penstock (Photos 14 to 17). This is caused by crushing of the wood by the bands and is prominent in deteriorating wood that has reduced strength and bearing capacity.

Saddles and Foundations

1) Approximately 31 saddles have noted cracks and a list of cracked saddles can be found in Appendix C. Typical cracks can be seen in Photos 18, 19, 21, and 22. The cracks appear to be related to overstress due to movement and not necessarily to weakening wood. The saddle wood was found to be solid with little to no penetration noted when tested with the probe.
2) Saddle 36 counting down from the dam on the left side has a crack and was leaning (Photo 23). A saddle on the right side about 100 m (328 feet) upstream of the surge tank was also leaning. These displaced saddles indicate excessive stress in the saddles and potential movement of the penstock.
3) In general, the foundation of the saddles were in good condition (Photos 25 and 26); however, Saddle 34 (counting down from the dam on the left side) shows loss of bedding material (Photo 11) as does Saddle 27 (Photo 27).
4) Foundation/bedding material was generally in good condition (Photo 24). The material was a good size, free draining, stable, and generally well graded with no vegetation growing from the foundation material within 1,219 mm (4 feet) of the penstock.

3.0 FAILURE MODE ANALYSIS

Based on the condition assessment completed above the following analysis of possible failure modes has been completed.

Definitions for qualitative terminology are as described in Table 3-1.

TABLE 3-1 DEFINITIONS

TERM	DEFINITION
Likely	Sign of failure present
Possible	No immediate sign of failure but may occur if conditions continue to degrade
Unlikely	No sign of failure present

Steel Band Corrosion

Steel bands are in good condition with only very light corrosion present. Failure due to steel band corrosion is unlikely.

Excessive Band Spacing

Steel band spacing is adequate and is what is to be expected of a penstock of this type. Failure due to excessive band spacing is unlikely.

Steel Band Elongation

Steel band tightening has been completed since penstock construction to try to mitigate leakage. Band tightening may have caused band elongation. Failure due to steel band elongation is possible.

Wood Stave Collapse

The wooden staves are in poor condition as confirmed by the stave softness testing completed with the blunt tip probe. Excessive deterioration of the wood stave condition was observed. The loss of one or two wood staves, especially from the crown of the penstock, could cause a catastrophic failure of the entire length. Failure due to stave collapse is likely.

Loss of Shell Supports

Penstock saddles have significant cracking and some observed movement. Penstock foundation material is in good condition with a few minor areas of deterioration. Failure due to loss of shell supports is possible.

4.0 CONCLUSIONS

The penstock wood staves and saddles are in poor condition. Based on the modes of failure studied in this report, Kleinschmidt's opinion is that failure due to wood stave collapse is likely. Kleinschmidt recommends that the penstock be replaced.

This report was prepared by Kleinschmidt who inspected the penstock in November 2020. Inspection observations, evaluations and conclusions in this report are those of Kleinschmidt. The finding of the report were made independently of Newfoundland Power, their subsidiaries, employees, and representatives.

REPORT SIGNATURE PAGE

KLEINSCHMIDT ASSOCIATES CANADA INC.

REGISTERED PROFESSIONAL ENGINEER
PEG Newfoundland and Labrador
CHRISTOPHER M. VELLA
SIGNATURE
April 23, 2021
DATE
NEWFOUNDLAND & LABRADOR

PROVINCE OF NEWFOUNDLAND AND LABRADOR
PEG Newfoundland and Labrador
PERMIT HOLDER
This Permit Allows
KLEINSCHMIDT ASSOCIATES CANADA INC.
To practice Professional Engineering in Newfoundland and Labrador.
Permit No. as issued by PEGNL N0708
which is valid for the year 2021

Chris M. Vella, P.Eng.
Senior Structural Engineer

CMV:SCB

APPENDIX A

PHOTOGRAPHS

PHOTO 1 **LOOKING UPSTREAM FROM POWERHOUSE ALONG RIGHT SIDE OF PENSTOCK**

PHOTO 2 **RIGHT SIDE OF PENSTOCK NEAR POWERHOUSE**

PHOTO 3 **TYPICAL BANDING RIGHT SIDE DOWNSTREAM OF SURGE TANK**

PHOTO 4 **TYPICAL BANDING LEFT SIDE UPSTREAM OF SURGE TANK**

PHOTO 5 **TYPICAL BANDING LEFT SIDE DOWNSTREAM OF SURGE TANK**

PHOTO 6 **TYPICAL BANDING BOLT**

PHOTO 7 DETATCHED BAND RIGHT SIDE, ADJACENT 4TH SADDLE DOWN FROM SURGE TANK

PHOTO 8 LOOKING DOWNSTREAM ALONG LEFT SIDE NEAR PH. NOTE WEDGES.

PHOTO 9 **SEAM AND SPOT WEDGES UPSTREAM OF SURGE TANK**

PHOTO 10 **SEAM AND SPOT WEDGES DOWNSTREAM OF SURGE TANK**

PHOTO 11 WATER JET ON LEFT ADJACENT SADDLE 34 NUMBERED FROM DAM

PHOTO 12 WATER JET ON LEFT JUST DOWNSTREAM OF SADDLE 75, NUMBERED FROM DAM

Photo 13 **Water jet on right 30 meters downstream of surge tank**

Photo 14 **Typical bands and wood staves near powerhouse. Some crushing and brooming of wood staves**

PHOTO 15 **BENT AND CRUSHED WOOD NEAR SURGE TANK LEFT SIDE**

PHOTO 16 **CRUSHED AND BROOMING WOOD NEAR SURGE TANK RIGHT SIDE**

PHOTO 17 BENT AND CRUSHED WOOD NEAR SURGE TANK LEFT SIDE

PHOTO 18 SPLIT SADDLE 4TH DOWNSTREAM OF SURGE TANK ON RIGHT SIDE

PHOTO 19 **SPLIT SADDLE 15 DOWN FROM DAM ON LEFT SIDE. TYPICAL CRACK.**

PHOTO 20 **SPLIT VERTICAL 46 DOWN FROM DAM ON LEFT SIDE**

PHOTO 21 **SPLIT SADDLE 69 DOWN FROM DAM ON LEFT SIDE**

PHOTO 22 **SADDLE 100 M UPSTREAM OF SURGE TANK ON RIGHT SIDE. SEPARATION OF SADDLE VERTICAL FROM PENSTOCK**

PHOTO 23 **SADDLE 36 FROM DAM ON LEFT SIDE – SADDLE IS CRACKED AND LEANING**

PHOTO 24 **140 DEGREE SADDLE STYLE NEAR THE POWERHOUSE. TYPICAL BEDDING MATERIAL**

PHOTO 25 **TYPICAL SADDLE FOUNDATION**

PHOTO 26 **SADDLE FOOTING 3RD UPSTREAM OF POWERHOUSE (TYPICAL CONDITION)**

PHOTO 27 SADDLE 27 NUMBERED DOWN FROM DAM ON LEFT SIDE. NOTE FOUNDATION EROSION STARTING

PHOTO 28 WATER POUR FROM CONCRETE FOUNDATION BLOCK

APPENDIX B

DRAWINGS

FIGURE 1


DRESSER COUPLING (WITHOUT PIPE STOP) TO BE SUPPLIED COMPLETE WITH BOLTS AND GASKETS
1" CLEAR APPROX.
24-RIBS 1" THICK EQUALLY SPACED
TURBINE INLET PIPE BY OTHERS
REMOVABLE CONNECTING SECTION TO TURBINE INLET PIPE
PLAN
(SHOWN WITH CONNECTING SECTION IN PLACE AND DRESSER TYPE COUPLING)
TYPICAL FLANGE DETAIL
SCALE: 1½"=1'-0"
BOLT CIRCLE 87½" DIA.
1¼" DRILL - 48 HOLES FOR 1¼" BOLTS EQUALLY SPACED STRADDLING ℄
OUTLINE OF 120° CONCRETE SADDLE
FIELD JOINT
BOLTED HEAD
℄ PENSTOCK & DISTRIBUTOR EL. 299-0
13'-0" TO ℄ UNIT
15'-0" TO ℄ UNIT
NO PROTECTIVE COATING
6" DIA. STEEL ELBOW WELDED TO PENSTOCK
THIS ELBOW BY OTHERS
WELDED JOINT (TERMINATION OF PENSTOCK CONTRACT)
SECTION A-A
(SHOWN WITH BOLTED HEAD IN PLACE)
20'-0" PROTECTIVE COATING TOP 240°
1" STIFFENERS - 24 REQ'D PER FLANGE
FULL FACE CLOTH-INSERTED RUBBER GASKET
A.S.M.E. FLANGED AND DISHED HEAD (LUKENS OR EQUAL)
DETAIL "X"
SCALE: 3"=1'-0"
NOTES:
1. THIS DRAWING SHALL BE READ IN CONJUNCTION WITH SPECIFICATION E-16917/NL 794-2
2. MATERIALS:
(a) ALL PLATE STEEL SHALL COMPLY WITH ASTM A-285 GRADE "C" FIREBOX QUALITY.
(b) ALL STRUCTURAL SHAPES SHALL COMPLY WITH C.S.A. G 40-4.
(c) ALL BOLTS SHALL COMPLY WITH ASTM A-307
3. DESIGN PRESSURE FOR PENSTOCK = 79 PSI = 180' HEAD (INCL. 50% WATERHAMMER)
4. VESSELS, 1962
℄ PIPE
FIELD WELD JOINT
DETAIL "X"
FOR DRESSER TYPE COUPLING SEE PLAN
ASME FLANGED AND DISHED HEAD (LUKENS OR EQUAL) ⅜" PLATE
STEEL WIRE SCREEN
WELDED TO PENSTOCK
6" ⌀ STEEL ELBOW
BEVEL PIPE END FOR WELDING
ELEVATION SHOWING TRUE ANGLE OF BEND
BOLTED HEAD
REMOVABLE CONNECTING SECTION TO TURBINE INLET PIPE
SECTION B-B
PIPE END TO BE PREPARED FOR DRESSER TYPE COUPLING. THE DISTANCE TO BE FREE FROM INDENTATIONS; OUTSIDE CIRCUMFERENCE TO BE 254⅝ ±⅛" OUTSIDE DIAM. TO BE 80⅞" WITH + 3/32" OR -1/32" TOLERANCE.
N L - 19269
F6 Sandy Brook Waterworks
Drawing received with NECo. memo No. 142 of March 26, 1963
APPROVED FOR CONSTRUCTION
MONTREAL ENGINEERING CO. LTD.
NEWFOUNDLAND LIGHT & POWER COMPANY LTD.
SANDY BROOK DEVELOPMENT
PENSTOCK STEEL ELBOW
DWG. No. NL 19269
REV. C FEB 28 63 D.K. OUTLINE OF CONCRETE ENCASEMENT CHANGED. DIMENSIONS OF BOLTED HEAD CHANGED.
REV. B JAN 7 1963 PLASTIC DEWATERING CHANGED TO 6" ⌀ LONG R ELBOW
REV. A 14 DEC 62 APPROVED FOR CONSTRUCTION

24 X

FIGURE 2

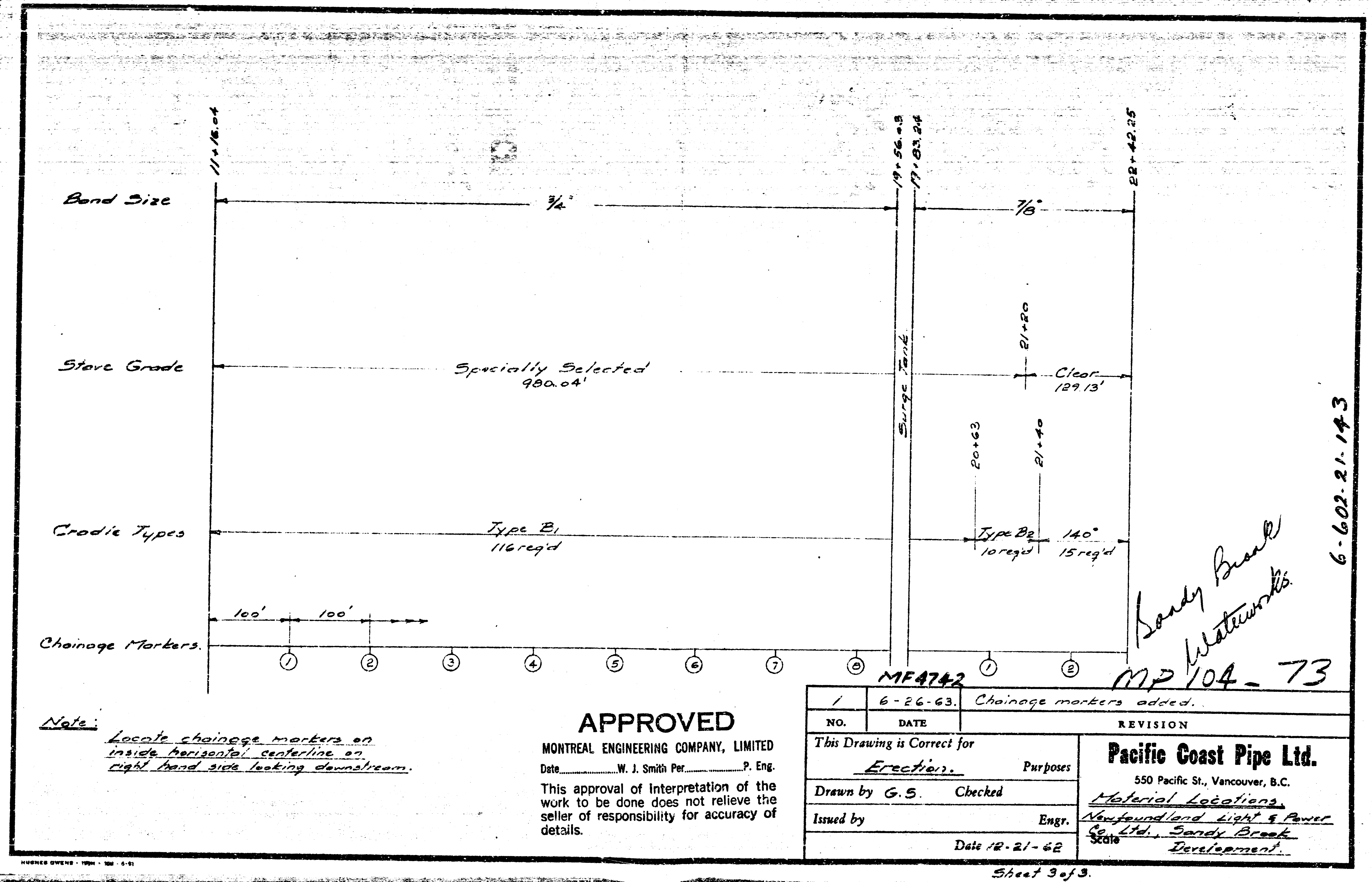
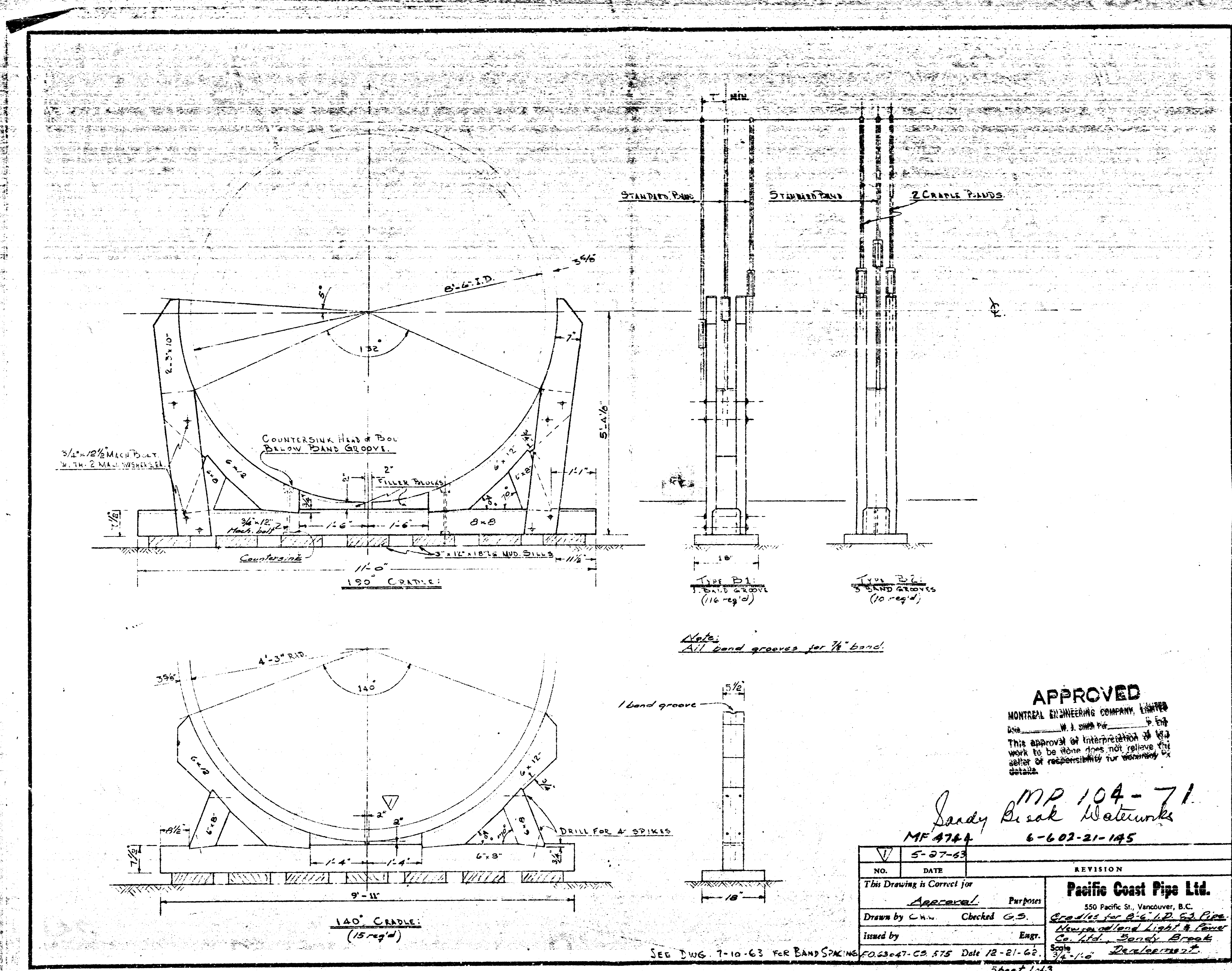

11+16.04
19+56.03
19+83.24
22+42.25
Band Size
3/4"
7/8"
Stave Grade
Specially Selected
980.04'
21+20
Clear
129.13'
Surge Tank
Cradle Types
Type B1
116 req'd
20+63
21+40
Type B2
10 req'd
140°
15 req'd
100'
100'
Chainage Markers.
MF4742
Sandy Brook Waterworks.
6-602-21-143
MP 104 - 73
1
6-26-63.
Chainage markers added.
NO.
DATE
REVISION
Note:
Locate chainage markers on inside horizontal centerline on right hand side looking downstream.
APPROVED
MONTREAL ENGINEERING COMPANY, LIMITED
Date W. J. Smith Per P. Eng.
This approval of Interpretation of the work to be done does not relieve the seller of responsibility for accuracy of details.
This Drawing is Correct for Erection. Purposes
Drawn by G.S. Checked
Issued by Engr.
Date 12-21-62
Pacific Coast Pipe Ltd.
550 Pacific St., Vancouver, B.C.
Material Locations, Newfoundland Light & Power Co. Ltd., Sandy Brook Development.
Scale
Sheet 3 of 3.

FIGURE 3



8'-6" I.D.
132°
Countersink Head & Bolt Below Band Groove.
3/4" x 12 1/2" Mach Bolt with 2 Malleable Washers.
Filler Blocks
5'-4 1/8"
11'-0"
180° Cradle.
Standard Band
2 Cradle Bands.
Type B1.
(116 req'd)
Type B2.
3 Band Grooves
(10 req'd)
Note:
All band grooves for 7/8" band.
4'-3" Rad.
140°
1 band groove
Drill for 4 spikes
9'-11"
140° Cradle.
(15 req'd)
See Dwg. 7-10-63 for Band Spacing
APPROVED
MONTREAL ENGINEERING COMPANY, LIMITED
This approval or interpretation of the work to be done does not relieve the seller of responsibility for accuracy of details.
MP 104-71
Sandy Brook Waterworks
MF 4744
6-602-21-145
5-27-63
No. Date Revision
This Drawing is Correct for Approval Purposes
Drawn by C.H.L. Checked G.S.
Issued by Engr.
F.O. 63047-C3 575 Date 12-21-62.
Pacific Coast Pipe Ltd.
550 Pacific St., Vancouver, B.C.
Cradles for 8'-6" I.D. C.S. Pipe Newfoundland Light & Power Co. Ltd. Sandy Brook Development
Scale 3/4" = 1'-0"
Sheet 1/3

FIGURE 4

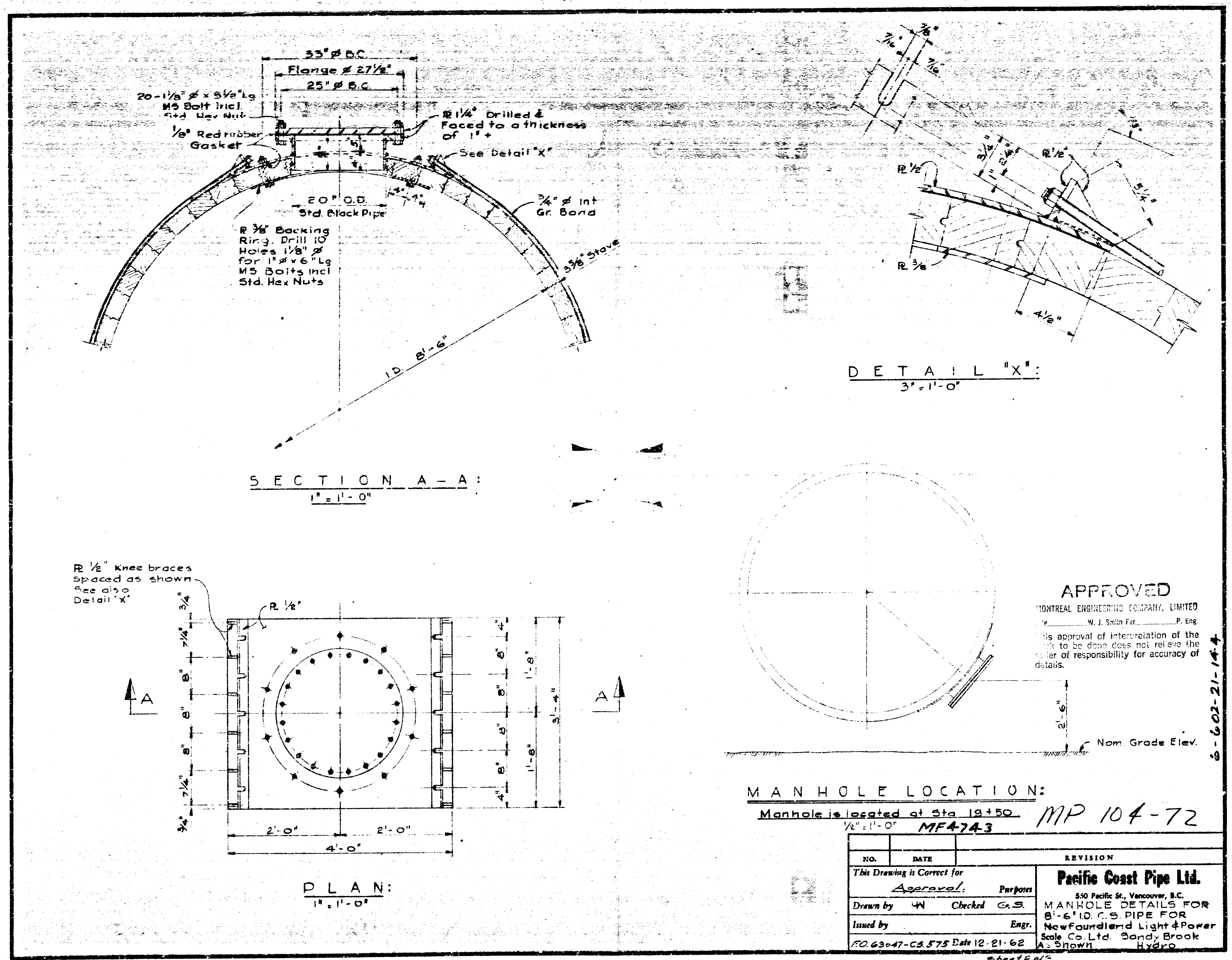

33" ⌀ B.C.
Flange ⌀ 27½"
25" ⌀ B.C.
20-1⅛" ⌀ x 5½" Lg MS Bolt Incl. Std. Hex Nut
⅛" Red rubber Gasket
R 1¼" Drilled & Faced to a thickness of 1" +
See Detail "X"
20" O.D. Std. Black Pipe
¾" ⌀ Int Gr. Band
R ⅜" Backing Ring. Drill 10 Holes 1⅛" ⌀ for 1" ⌀ x 6" Lg MS Bolts incl Std. Hex Nuts
3⅝" Stave
I.D. 8'-6"
SECTION A-A:
1" = 1'-0"
DETAIL "X":
3" = 1'-0"
R ½" Knee braces spaced as shown. See also Detail "X"
R ½"
A
A
2'-0"
2'-0"
4'-0"
1'-8"
1'-8"
3'-4"
PLAN:
1" = 1'-0"
APPROVED
MONTREAL ENGINEERING COMPANY, LIMITED
W. J. Smith P. Eng.
This approval of interpretation of the work to be done does not relieve the ... of responsibility for accuracy of details.
2'-6"
Nom. Grade Elev.
MANHOLE LOCATION:
Manhole is located at Sta. 19+50
½" = 1'-0"
MF4743
MP 104-72
6-602-21-144
NO. DATE REVISION
This Drawing is Correct for Approval Purposes
Drawn by HW Checked G.S.
Issued by Engr.
P.O. 63047-CS.575 Date 12-21-62
Pacific Coast Pipe Ltd.
550 Pacific St., Vancouver, B.C.
MANHOLE DETAILS FOR 8'-6" I.D. C.S. PIPE FOR Newfoundland Light & Power Co. Ltd. Sandy Brook Hydro
Scale As Shown
Sheet 6 of 6

FIGURE 5

3/4" Bands

Chainage 11+16·04

3' Overlap

5' 8"

Cradles @ 8' Centers All Type B1

Cradle No.	No. of Bands	Spacing
(start)	9	4"
– 1	6	10"
1–2	10	9·6"
2–3	10	9·6"
3–4	10	9·6"
4–5	10	9·6"
5–6	10	9·6"
6–7	10	9·6"
7–8	10	9·6"
8–9	10	9·6"
9–10	10	9·6"
10–11	10	9·6"
11–12	10	9·6"
12–13	10	9·6"
13–14	10	9·6"
14–15	10	9·6"
15–16	10	9·6"
16–17	10	9·6"
17–18	10	9·6"
18–19	10	9·6"
19–20	10	9·6"
20–21	10	9·6"
21–22	10	9·6"
22–23	10	9·6"
23–24	10	9·6"
24–25	10	9·6"
25–26	10	9·6"
26–27	10	9·6"
27–28	10	9·6"
28–29	10	9·6"
29–30	10	9·6"
30–31	10	9·6"
31–32	10	9·6"
32–33	10	9·6"
33–34	10	9·6"
34–35	10	9·6"
35–36	10	9·6"
36–37	10	9·6"
37–38	10	9·6"
38–39	10	9·6"
39–40	10	9·6"
40–41	10	9·6"
41–42	10	9·6"
42–43	10	9·6"
43–44	10	9·6"
44–45	10	9·6"
45–46	10	9·6"
46–47	10	9·6"
47–48	10	9·6"
48–49	10	9·6"
49–50	10	9·6"
50–51	10	9·6"
51–52	10	9·6"
52–53	10	9·6"
53–54	10	9·6"
54–55	10	9·6"
55–56	10	9·6"
56–57	10	9·6"
57–58	10	9·6"
58–59	10	9·6"
59–60	10	9·6"
60–61	10	9·6"
61–62	10	9·6"
62–63	10	9·6"
63–64	10	9·6"
64–65	10	9·6"
65–66	10	9·6"
66–67	10	9·6"
67–68	10	9·6"
68–69	10	9·6"
69–70	10	9·6"
70–71	10	9·6"
71–72	10	9·6"
72–73	10	9·6"
73–74	10	9·6"
74–75	10	9·6"
75–76	11	8·72"
76–77	11	8·72"
77–78	11	8·72"
78–79	11	8·72"
79–80	11	8·72"
80–81	11	8·72"
81–82	11	8·72"
82–83	11	8·72"
83–84	11	8·72"
84–85	11	8·72"
85–86	11	8·72"
86–87	11	8·72"
87–88	11	8·72"
88–89	12	8"
89–90	12	8"
90–91	12	8"
91–92	12	8"
92–93	12	8"
93–94	12	8"
94–95	12	8"
95–96	12	8"
96–97	12	8"
97–98	12	8"
98–99	12	8"
99–100	12	8"
100–101	12	8"
101–102	12	8"
102–103	12	8"
103–104	12	8"
104–	8	7½"
(end)	8	4"

3' Overlap

Chainage 19+56·03

7/8" Bands

3' Overlap

Chainage 19+83·24

Type B1 Cradles (105–113); Type B2 Cradles (114–123); 140° Cradles (124–137)

Cradle No.	No. of Bands	Spacing
(start)	9	4"
– 105	6	10"
105–106	10	9·6"
106–107	11	8·72"
107–108	11	8·72"
108–109	12	8"
109–110	12	8"
110–111	12	8"
111–112	13	7·38"
112–113	13	7·38"
113–114	14	6·85"
114–115	14	6·56" 4·06
115–116	14	4·06 6·27" 4·06
116–117	14	4·06 6·27" 4·06
117–118	15	4·06 5·86 4·06
118–119	15	4·06 5·86" 4·06
119–120	15	4·06 5·86 4·06
120–121	16	4·06 5·49" 4·06
121–122	16	4·06 5·49" 4·06
122–123	17	4·06 5·17" 4·06
123–124	18	4·06 5·10"
124–125	19	5·05"
125–126	19	5·05"
126–127	20	4·8"
127–128	20	4·8"
128–129	21	4·57"
129–130	21	4·57
130–131	22	4·37"
131–132	23	4·17"
132–133	23	4·17"
133–134	24	4"
134–135	25	3·84"
135–136	25	3·84"
136–137	26	3·69"
137–	7	3·61"
(end)	10	3·56"

2·14'

3' Overlap

Chainage 22+42·25

V.A.A.
N L P Co

APPROVED
MONTREAL ENGINEERING COMPANY, LIMITED
Date........ W. J. Smith Per........ P. Eng.
This approval of interpretation of the work to be done does not relieve the seller of responsibility for accuracy of details.

MP 104-116
Sandy Brook Waterworks.

NEWFOUNDLAND LIGHT AND POWER Co.
SANDY BROOK HYDRO-ELECTRIC DEVELOPMENT.

MF4771 6-602-21-169

NO.	DATE	REVISION

This Drawing is Correct for Construction Purposes
Drawn by WG Checked G.S.
Issued by Engr.
Date 7-10-63

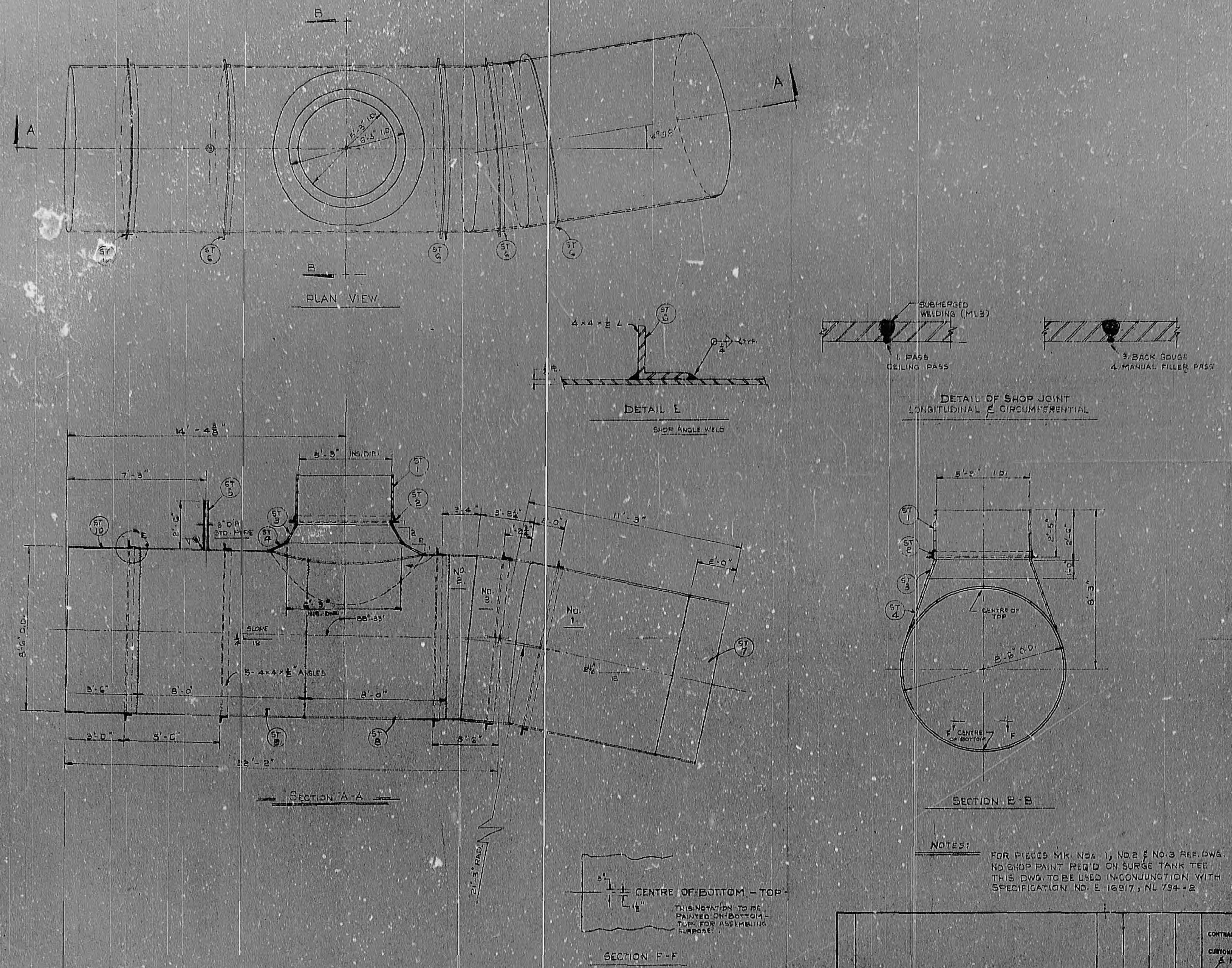
Pacific Coast Pipe Ltd.
550 Pacific St., Vancouver, B.C.
CS 575 Sandy Brook
Bond Spacing Details
Scale

Sheet 2 of 2

HUGHES OWENS

FIGURE 6

SHIP ASS'Y	MARK	QUAN.	DESCRIPTION	WEIGHT	REMARKS OR REF. DWGS.
			SURGE TANK TEE		
			MAT'L LISTED FOR ONE ONLY 1 REQ'D		
	ST 1	1	3/8 PL. 2'-6" × 16'-7 1/8" LG.	640	ASTM A285 C
	ST 2	1	4 × 4 × 1/2" ANGLE × 16'-8 3/4"	214	ASTM-A7
	ST 3	1	3/8 PL × 50 SQ. FT.	765	ASTM A285 C
	ST 4	1	3/8 PL. × 90 SQ. FT.	1,377	"
	ST 5	1	3" DIA. STD. PIPE × 2'-6" LG.	8	S/O
	ST 6	5	4 × 4 × 1/2" ANGLE × 26'-0" LG.	1,660	ASTM A7
	ST 7	1	3/8 PL. 2'-0" × 26'-7 1/4" LG.	818	ASTM A7
	ST 8	1	3/8 PL 8'-0" × 26'-7 1/4" LG.	3,234	ASTM A285 C
	ST 9	1	3/8 PL 8'-0" × 26'-7 1/4" LG.	3234	"
	ST 10	1	3/8 PL 3'-6" × 26'-7 1/4" LG.	1,432	
	ST 11				
			WGT.	13,502	



NOTES:

FOR PIECES MK. Nos. 1, No. 2 & No. 3 REF. DWG.
NO SHOP PAINT REQ'D ON SURGE TANK TEE
THIS DWG. TO BE USED IN CONJUNCTION WITH
SPECIFICATION NO. E 16917, NL 794-2

APPROVED
MONTREAL ENGINEERING COMPANY, LIMITED
Date ____ W. J. Smith Per ____ P. Eng.
This approval of interpretation of the work to be done does not relieve the seller of responsibility for accuracy of details.

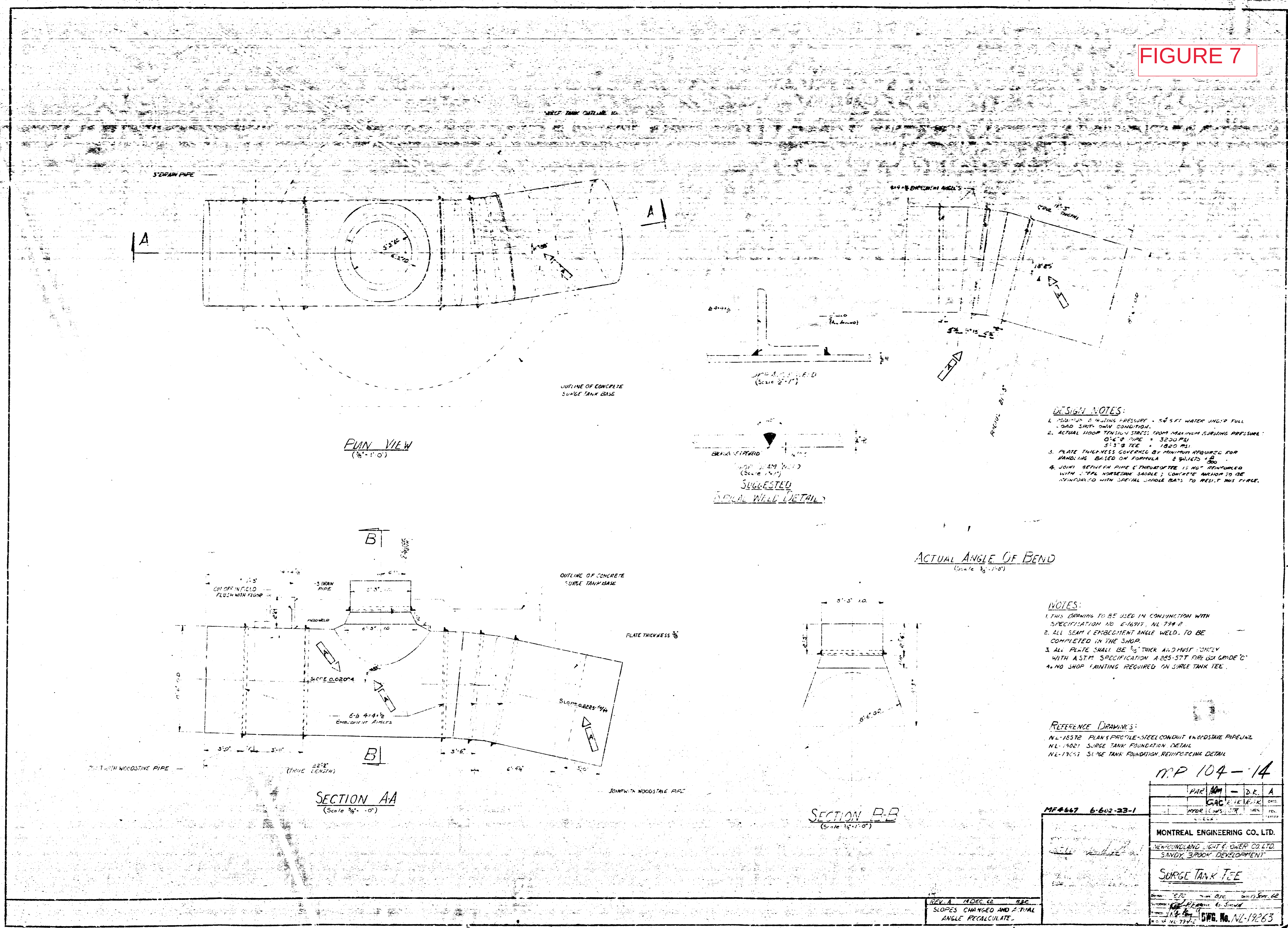
MP 104-66
Sandy Brook Waterworks.
MF 4749
6-602-21-150

	DESCRIPTION OF REVISION	DATE	BY	CHK'D	APP'D
1	ANGLE CHANGED	18/3			

CONTRACT NO. S/5920 REQ'D 1
CUSTOMER NEWFOUNDLAND LIGHT & POWER CO. LTD.
CUST'S UNIT NO. NL-19263

MCNAMARA INDUSTRIES LTD., ST. JOHN'S, NFLD.
DESCRIPTION SURGE TANK TEE
SANDY BROOK HYDRO ELECTRIC DEVELOPEMENT...
GEN. ASS'Y REF.
DWG. No. DM-745-3 REV. 1
SCALE 3/8"=1'-0" DWN. JAN
DATE 1963 JAN 23/63
15/2
CHAS. BRUNING 307

FIGURE 7



PLAN VIEW
SUGGESTED
ACTUAL ANGLE OF BEND
SECTION AA
SECTION B-B
NOTES:
1. THIS DRAWING TO BE USED IN CONJUNCTION WITH SPECIFICATION NO. E-16917, NL-794-2.
2. ALL SEAM & EMBEDMENT ANGLE WELD. TO BE COMPLETED IN THE SHOP.
3. ALL PLATE SHALL BE 3/8" THICK AND MUST COMPLY WITH A.S.T.M. SPECIFICATION A-285-57T FIRE BOX GRADE "C"
4. NO SHOP PAINTING REQUIRED ON SURGE TANK TEE.
REFERENCE DRAWINGS:
NL-18572 PLAN & PROFILE-STEEL CONDUIT & WOODSTAVE PIPELINE
NL-19021 SURGE TANK FOUNDATION DETAIL
NL-19057 SURGE TANK FOUNDATION REINFORCING DETAIL
MP 104-14
MF4667 6-602-23-1
MONTREAL ENGINEERING CO., LTD.
NEWFOUNDLAND LIGHT & POWER CO. LTD.
SANDY BROOK DEVELOPMENT
SURGE TANK TEE
SLOPES CHANGED AND ACTUAL ANGLE RECALCULATE
DWG. No. NL-19263

APPENDIX C

FIELD NOTES SUMMARY

SANDY BROOK WOOD STAVE PENSTOCK OBSERVATIONS AND FIELD NOTES

SADDLE NUMBER[1] / MEASUREMENT	OBSERVATION NOTES
Heading Upstream Along River Right Side	
Powerhouse to Surge Tank	
	Significant water spray and leakage hindering inspection
	Wood stave has light erosion near powerhouse
	¼ inch penetration with pointer in a few localized spots
	Foundation looks good, saddles/footings look good
	Penetration varies up to 1-inch (maximum length of pointer)
	A few areas of brooming on boards
4th the down from tank	Broken band, 4th saddle from the surge tank
3rd and 4th down from tank	Split angle
Surge Tank to Dam	
	Manhole at 4:00 position, saddle at upstream of bridgestone
4	¼ inch penetration – 4 saddles up from surge tank
100 m	Line of cracking
150 m	Badly cracked angle – may need repair
150 m	Cracked saddle footing
5	5 saddles up – cracked footing
200 m	Full 1-inch penetration (@ 200 m)
	Start of last bend before the dam there is a crack in saddle
Heading Downstream Along River Left Side	
Dam to Surge Tank	
	7 ft down from dam, broken saddle
	At dam, 10-inch spacing between bars, 8-foot saddle spacing
	8’-6” diameter penstock
6	Cracked footing
8	Crack at saddle
11	Crack at saddle
12	Crack at saddle
13	Crack at saddle
15	Crack at saddle
16	Crack at saddle
23	Crack at footing

[1] Saddle numbers restart after each section noted herein.

Saddle Number[1] / Measurement	Observation Notes
25	Crack at footing
26	Crack at footing
27	Crack at footing (as well as loss of rock support)
33	Crack at saddle
34	Foundation erosion at 34, loss of material
36	Crack at saddle and leaning
38	Crack at saddle
43	Crack at saddle
46	Crack at saddle
47	Crack at saddle
51	Crack at saddle
53 and 54	Full penetration of pointer (1 inch) between 53 and 54
57	Crack at saddle
59	Crack at saddle
64	Crack at saddle
71	Crack at saddle
75	Crack at saddle
79 and 80	Gush between 79 and 80
88	Crack at saddle
94	Last saddle in section recorded from dam to surge tank
Surge Tank to Powerhouse	
19	Start of downstream section, surge tank to powerhouse. Start of short saddles
20	Split
	8 ft spacing on new section of saddles
	8 inch spacing of steel bands reducing to 6 inch closer to PH
29	Split
30	Crack at saddle
	Most of wood in the downstream section is soft
33	Last saddle in section recorded.

2022 Substation Refurbishment and Modernization

May 2021

Prepared by:
Adam Wong, P. Eng.

REGISTERED PROFESSIONAL ENGINEER
PEG Newfoundland and Labrador
ADAM E.H. WONG
Adam Wong
SIGNATURE
May 5, 2021
DATE
NEWFOUNDLAND & LABRADOR

WHENEVER. WHEREVER.
We'll be there.

NEWFOUNDLAND POWER
A FORTIS COMPANY

Table of Contents

1.0 Substation Refurbishment and Modernization Strategy

Newfoundland Power Inc. ("Newfoundland Power" or the "Company") operates 131 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.

The *Substation Refurbishment and Modernization Plan* is coordinated with the maintenance cycle for major substation equipment and replacement activities. Such coordination minimizes service interruptions to customers and ensures the optimal use of resources. This approach is consistent with the least-cost delivery of reliable service to customers. 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 an element of the *Substation Strategic Plan* filed with the *2007 Capital Budget Application*.

2.0 2022 Substation Refurbishment and Modernization Projects

The *2022 Substation Refurbishment and Modernization* project includes the planned refurbishment and modernization of 3 substations. This substation work is estimated to cost a total of $6,416,000 comprising approximately 91% of the total 2022 project cost. The remaining project cost includes $446,000 associated with Grounding Grid Upgrades to upgrade substation grounding systems, and $187,000 associated with Substation Monitoring Upgrades to upgrade substation communication systems.

Table 1 outlines the expenditures for the *2022 Substation Refurbishment and Modernization* projects.

Table 1
2022 Substation Refurbishment and Modernization Projects
($000s)

Project	**Budget**
Humber Substation	2,858
Tors Cove Substation	1,813
Glovertown Substation	1,745
Ground Grid Upgrades	446
Substation Monitoring Upgrades	187
Total	**$7,049**

The locations of the substations undergoing refurbishment and modernization in 2022 are shown in Figure 1.

Figure 1: Location of 2022 Substation Refurbishment and Modernization Projects

The Humber ("HUM") Substation refurbishment and modernization project is being completed in 2022 to refurbish and modernize deteriorated substation components. Associated with the HUM Substation refurbishment and modernization project is the dismantling of the existing 4.16 kV substation infrastructure and conversion of the HUM 4.16 kV distribution system to operate at 12.5 kV. This project will result in a significant reduction in substation equipment including a power transformer, a 66kV air break switch and the replacement of four 4.16 kV breakers with a single 12.5 kV recloser.[2]

The Tors Cove ("TCV") Substation refurbishment and modernization project is being completed in 2022 to replace the 71 year old power transformer which has reached the end of its service life, and the relocation of the TCV Substation to a new site.

The Glovertown ("GLV") Substation refurbishment and modernization project is being completed in 2022 to install two 138 kV circuit breakers in coordination with the *Transmission Line Rebuild* project for Transmission Line 124L.[3]

The Ground Grid Upgrade project is an addition to the original *Substation Refurbishment and Modernization Plan*. It is being implemented in 2022 to ensure substation ground grids are compliant with *ANSI/IEEE Standard 80-2013 Guide for Safety in AC Substation Grounding*. Prior to 2022, the Company addressed ground grid upgrades primarily at substations included in the refurbishment and modernization projects. In order to address deficiencies identified in an assessment carried out in 2020, additional ground grid projects will be undertaken in 2022 and subsequent years.

The Substation Monitoring Upgrades are undertaken as required to effectively manage an increased volume of electrical system data collected by the Company's Supervisory Control and Data Acquisition ("SCADA") system. Upgrades typically increase the functionality of the equipment and software, and remedy known deficiencies and cybersecurity vulnerabilities to ensure continued effective electrical system control and operations.

3.0 2022 Substation Projects ($6,416,000)

3.1 Humber Substation ($2,858,000)

HUM Substation was built in 1954 as a transmission and distribution substation. The substation is supplied by Newfoundland Power 66 kV transmission lines 356L from Massey Drive ("MAS") Terminal Station and 359L from Bayview ("BVS") Substation. The substation is located in the downtown core of the City of Corner Brook on a small piece of land adjacent to the Lewin Parkway and the Corner Brook Pulp & Paper Ltd. paper mill as shown in Figure 2.

---

[2] Appendix B includes the details on the dismantling of the 4.16 kV substation infrastructure and the conversion of the HUM 4.16 kV distribution system to operate at 12.5 kV in report *Humber Substation 4.16 kV Infrastructure Replacement.*

[3] The *2022 Transmission Line 124L* project includes the rebuilding of transmission line 124L which connects Gambo ("GAM") Substation to Clarenville ("CLV") Substation. For details, see the *2022 Capital Budget Application, Volume 2, Report 3.1 2022 Transmission Line Rebuild*.

Figure 2: HUM Substation

HUM Substation includes 66 kV transmission infrastructure along with both 4.16 kV and 12.5 kV distribution infrastructure to supply customers. To supply the 4.16 kV and 12.5 kV infrastructure the substation has 2 power transformers, 66 kV to 4.16 kV (7.46 MVA) HUM-T2 and 66 kV to 12.5 kV (13.3 MVA) HUM-T3. The 2 power transformers provide HUM Substation with a total transformer capacity of 20.76 MVA. The distribution system in Corner Brook is supplied from both the 4.16 kV and 12.5 kV substation infrastructure.

4.16 kV Infrastructure

In addition to HUM-T2, the 4.16 kV infrastructure includes 4.16 kV metal clad distribution switchgear and four 4.16 kV feeder exits. Four 4.16 kV feeder cables exit the substation via underground paper insulated, lead covered ("PILC") cables, crossing congested utility and transportation corridors to connect with the overhead sections of the feeders. Of the 4 feeder exits, only 3 feeder exits normally serve customers.[4]

In recent years, deteriorated and failed components on the 4.16 kV distribution system have been replaced with components compatible with a future 12.5 kV voltage conversion. Much of the remaining 4.16 kV rated distribution infrastructure was installed in the 1950s and 1960s, and is nearing the end of the equipment's expected service life.

The report *Humber Substation 4.16 kV Infrastructure Replacement* included in Appendix B includes more detail on the 4.16 kV infrastructure condition assessment. The report has determined that the least-cost alternative to refurbish and modernize HUM Substation involves dismantling the existing 4.16 kV distribution equipment and replacing it with 12.5 kV equipment.

[4] One of the feeder exits does not normally supply customers but provides a spare breaker and substation exit to the HUM-04 distribution feeder. HUM-04 is remote from the other two 4.16 kV distribution feeders and cannot be used to transfer customers to another feeder for maintenance or emergency repairs.

12.5 kV Infrastructure

In addition to HUM-T3, the 12.5 kV infrastructure includes a transformer breaker, 12.5 kV bus structure, two 12.5 kV reclosers and associated distribution feeder exits. The 12.5 kV feeders exit the substation aerially and are double circuited for the first 1.2 kilometres through the congested downtown area.[5]

Engineering condition assessments have determined the 12.5 kV steel structures, foundations, buses, and insulators as shown in Figure 3 are all in good condition.

Figure 3: HUM-12.5 kV Low Voltage Distribution Bus Structure

The majority of the switches on the 12.5 kV bus structure are in excess of 34 years in service and are in a deteriorated condition primarily as a result of corrosion.[6] This includes 2 distribution side break switches, and 2 sets of distribution hook stick operated switches. The deteriorated switches will be replaced.

---

5 12.5 kV equipment was first installed in 1982 to address load growth in the area and replace deteriorated 4.16 kV components including HUM-T1. Since that time, incremental conversions have occurred to accommodate the 12.5 kV network or when completing routine work such as feeder rebuild.

6 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 a switch, its operation contributes to 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, which causes heating, arcing and eventually switch failure.

All low-voltage equipment does not have standard varmint protection installed.[7]

66 kV Infrastructure

The 66 kV bus structure is a non-standard configuration, and is reflective of the substation site constraints. The steel structure and foundations are in good condition with some surficial corrosion present on the steel structure, as shown in Figure 4. The corrosion is not presently impacting the structural integrity.

Figure 4: 66 kV Bus Structure, T2 and T3

The majority of the switches on the 66 kV bus structures are in excess of 39 years in service and are in a deteriorated condition primarily as a result of corrosion. This includes 3 transmission side break switches, and a transmission air break switch. The deteriorated switches will be replaced.

[7] 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. In the *Report on Island Interconnected System to Interconnection with Muskrat Falls addressing Newfoundland Power, December 17th, 2014*, Conclusion 2.10 states that "The use of insulated coverings, guards and insulated leads have been effective in preventing animal-caused damage and outages."

The 66 kV copper bus is in good condition with a mix of vintage and modern 66 kV bus insulators. On December 20, 2019, a failure of a vintage 66 kV centre phase bus insulator occurred, as illustrated in Figure 5.[8] All remaining vintage insulators will be replaced.

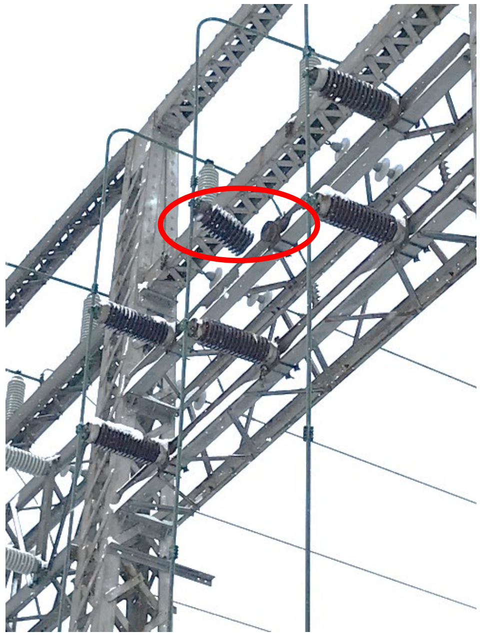


Figure 5: Broken Insulator on 356L Bus

Power Transformers

HUM-T2 power transformer was manufactured by Canadian General Electric in 1968, and installed in HUM Substation in 1999.[9] HUM-T2 is a 66 kV to 4.16 kV (7.46 MVA) power transformer supplying the 4.16 kV distribution system in the City. See report *Humber Substation 4.16 kV Infrastructure Replacement* included in Appendix B for a detailed assessment of this transformer.

The automatic on-load tap changer ("OLTC") on HUM-T2 is a GE model LRT-68. This OLTC does not have support available from the manufacturer therefore sourcing replacement parts is difficult. The transformer bushings have polychlorinated biphenyl ("PCB") contamination ranging from 100 to 490 parts per million ("ppm") in the individual bushings. The OLTC compartment oil has 56 ppm PCB. There is evidence of cracked welds on this transformer tank that are leaking oil.

The Company has four 4.16 kV distribution systems in service. These systems are located at Stamps Lane Substation in St. John's, Petty Harbour Substation, Grand Falls 4.16 kV Substation and HUM Substation. There is only one portable substation, Unit P1, which can transform

8 The failure tripped transmission line 356L. There was no customer impact as the transmission system was operating in a looped configuration at the time.

9 Prior to being installed at HUM Substation, transformer HUM-T2 was installed at Port aux Basques Substation.

66 kV to 4.16 kV.[10] The Company does not have a spare 66 kV to 4.16 kV transformer in inventory. If HUM-T2 were to fail in service there would be an extended customer outage until Portable Substation P1 can be mobilized to HUM Substation. Portable Substation P1 would have to remain in service at HUM Substation until a replacement unit could be manufactured.

In 2020, Newfoundland Power engaged van Kooy Transformer Consulting Services Inc. (the "Consultant") to perform an independent transformer condition assessment on HUM-T2.[11] Based on the results of this assessment, the Consultant concluded HUM-T2 is at the end of its service life. The Consultant recommended replacing HUM-T2 in 2022 due to its age, physical deterioration, tap-changer operational concerns and the PCB contaminants in the transformer bushings.

HUM-T3 power transformer was manufactured by Westinghouse in 1974, and installed in HUM Substation in 1984 (see Figure 6).[12] During November 2018, HUM-T3 tap changer experienced issues with internal gassing. There was no significant customer impact, as customer load was transferred to surrounding 12.5 kV substations to avoid an outage.

Figure 6: HUM-T3

10 See *Portable Substation Study, June 2011* filed with the 2012 Capital Budget Application, Appendix C, page C-4 for details on portable substation backup capability.

11 The Consultant has more than 35 years of experience in the transformer services industry. Newfoundland Power has been using the Consultant in various aspects of its power transformer asset management program since 2002. The transformer condition assessment completed by the Consultant is included in Attachment B to Appendix B.

12 Prior to being installed at HUM Substation transformer HUM-T3 was installed at Chamberlains Substation.

The automatic OLTC on HUM-T3 is a Westinghouse type UTT. This OLTC has support available from the manufacturer yet sourcing some replacement parts is difficult. The transformer bushings have low concentrations of PCB contamination.

Protection Relays
The transmission line protection is provided by microprocessor-based digital relays that are in good condition.

The feeder protection for three of the four 4.16 kV feeders that remain in service are early vintage microprocessor-based digital relays. A number of these early vintage digital relays have failed in recent years with 8 of these relays in various Company substations requiring replacement within the past 5 years. The protection relays for the spare 4th feeder as well as for HUM-T2 and HUM-T3 are vintage electromechanical type and are 42 years old.[13] The age and general deterioration of these relays indicate that they are at the end of their service life.

Site Condition
Humber Substation is located in downtown Corner Brook on a small piece of land adjacent to the Lewin Parkway and the Corner Brook Pulp & Paper Ltd. paper mill. Currently the site contains equipment for two 66 kV transmission lines, two 12.5 kV distribution feeders and three 4.16 kV distribution feeders. The 4.16 kV equipment and the substation protection and control equipment is located in a building located on the site which was constructed as part of the original construction of the substation. The building envelope has deteriorated components including the windows, doors and roofing. There is also asbestos in some of the interior construction materials. The small site footprint necessitated nonstandard bus structures and limited clearance between energized equipment and the building.

A grounding study will be completed and the ground grid for the substation will be extended to cover the expanded substation yard and new equipment.[14]

Scope of Work
The 2022 scope of work at HUM Substation involves the following:

(i) Dismantle the existing 4.16 kV distribution equipment,[15]
(ii) Remove from service power transformer HUM-T2,

[13] 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. 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, examined Newfoundland Power's practice of replacing multiple obsolete electromechanical relays with a single modern microprocessor controlled relay and concluded that the Company uses reasonable practices that conform to industry practice.

[14] 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.

[15] Dismantling the existing 4.16 kV substation equipment and replacing it with 12.5 kV equipment will have to be coordinated with the conversion of the 4.16 kV distribution feeders. A description of the 4.16 kV conversion distribution project can be found in Appendix B.

(iii) Replace power transformer HUM-T3 with a new 25 MVA unit,[16]
(iv) Construct a new spill containment foundation for the new transformer,
(v) Install a new 12.5 kV distribution feeder HUM-10, including a new recloser and associated switches,
(vi) Install associated protection and control equipment to accommodate the new power transformer and distribution feeder HUM-10,
(vii) Dismantle the existing building to accommodate the installation of a smaller control building which will improve clearances between energized equipment and the building,
(viii) Replace all deteriorated 66 kV and 12.5 kV switches,
(ix) Replace all remaining vintage 66 kV vintage bus insulators,
(x) Extend the ground grid to cover substation equipment extension, and
(xi) Complete standard varmint protection on all 12.5 kV equipment.

3.2 Tors Cove Substation ($1,813,000)

TCV Substation was built in 1941 (see Figure 7) as part of the Tors Cove Hydro Plant (the "Plant") development. One 66 kV to 6.9 kV power transformer, TCV-T1 (7.5 MVA), connects the Plant to Transmission Line 11L, and on to the Company's Mobile ("MOB") Substation 5 kilometres away.

Figure 7: TCV Substation

[16] A portable substation will be required to offload the existing substation to accommodate power transformer replacement and dismantling of the 4.16 kV equipment.

Power Transformer

TCV-T1 is a 71 year old 66 kV to 6.9 kV, 7.5 MVA power transformer connecting the Plant to the Island Interconnected System. This transformer is heavily deteriorated with severe rusting (see Figure 8). TCV-T1 is one of the 2 oldest transformers in the Company's transformer fleet, and has reached the end of its service life. TCV-T1 will be replaced with a new 66 kV to 6.9 kV, 7.5 MVA power transformer as recommended in Appendix C of this report.

Figure 8: Severe Rust on TCV-T1 Transformer

The existing spill containment pan protects against environmental damage in the event of an oil spill from transformer T1.[17] A new concrete spill containment foundation will be constructed for the replacement transformer.[18]

Transformer Protection

The TCV-T1 transformer currently relies on Mobile Substation 5 kms away for protection.[19] Three single-phase 66 kV disconnect switches equipped with fuses will be installed to protect the new transformer at TCV. A new 66 kV air break switch and 6.9 kV hook stick operated switches will also be installed.

[17] The Witless Bay Ecological Reserve is located offshore adjacent to the Plant.

[18] *IEEE Standard 980-2013 Guide for Containment and Control of Oil Spills in Substations* recommends spill containment to prevent or mitigate the environmental impacts of an oil release or spill. These impacts can range from the clean-up costs associated with a spill to the contamination of a water supply. Additionally, *IEEE Standard 979-2012 Guide for Substation Fire Protection* recommends spill containment to minimize the surface area of a spill. This provides fire protection benefits.

[19] A fault on TCV-T1 transformer would have to be detected and cleared by the relay protection for transmission line breaker MOB-11L-B located at MOB Substation.

66 kV and 6.9 kV Bus Structures
Engineering assessments have determined that the 66 kV and 6.9 kV wood pole structures are splitting and include deteriorated crossarms (see Figure 9). The 66 kV and 6.9 kV wood pole structures will be replaced by new steel structures.

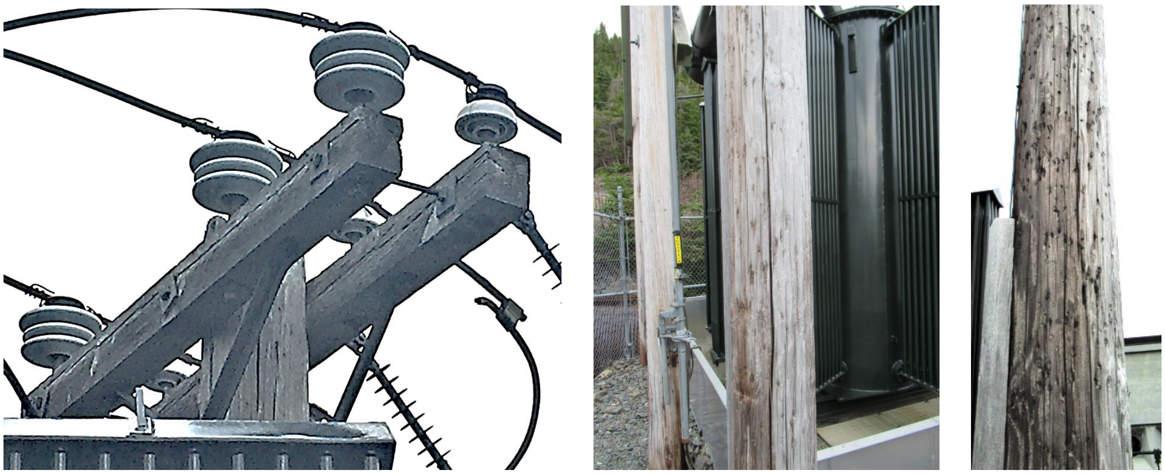


Figure 9: TCV Deteriorated Wood Poles and Cross Arms

Site Conditions
The existing site layout does not meet current design standards. The existing site cannot accommodate the new transformer, spill containment foundation, and structures due to inadequate clearances. The existing site is in poor condition and the grading and proximity to the plant building and the penstock do not allow for the required expansion. The substation yard will therefore be relocated to allow for proper design clearances.

The existing concrete foundations and retaining wall are deteriorated (see Figures 10 and 11).

Figure 10: TCV Deteriorated Concrete Foundations

Figure 11: TCV Deteriorated Concrete Retaining Walls

A partially cleared site approximately 50 metres from the existing substation will be prepared and fenced for the relocated substation. The new transformer and new 66 kV and 6.9 kV steel structures will be located in the new substation. New wood structures will be constructed in the existing yard to transition the 6.9 kV conductors from the Plant to the new substation.

The ground grid installed for the new substation will be properly designed for the safety of employees and the public inside the substation.[20]

Scope of Work
The 2022 scope of work at TCV Substation involves the following:

(i) Remove from service power transformer TCV-T1,
(ii) Dismantle the existing substation,
(iii) Install new substation yard, including fencing,
(iv) Install new ground grid,
(v) Install 66 kV and 6.9 kV bus structures, including disconnect switches,
(vi) Install new concrete spill containment foundation, and
(vii) Install new power transformer.

3.3 Glovertown Substation ($1,745,000)

GLV Substation was built in 1976 as a distribution and transmission substation (see Figure 12). The transmission portion of the substation includes one 138 kV transmission line termination for Transmission Line 121L.[21] The 25 kV distribution bus structure is energized by a single 138 kV to 25 kV 20 MVA power transformer, GLV-T1. There are two 25 kV distribution feeders, GLV-01 and GLV-02, serving approximately 2,730 customers in the Glovertown and Eastport Peninsula area.

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[20] 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.

[21] Transmission line 121L extends from a tap at Alexander Bay Switchyard from Transmission Line 124L which connects GAM Substation to CLV Substation.

The GLV Substation refurbishment and modernization project is being clustered with the *Transmission Line 124L Rebuild Project,* which will result in the termination of Transmission Line 124L at GLV Substation.[22]

Figure 12: GLV Substation

Power Transformer

The existing transformer GLV-T1 does not have spill containment. A new spill containment foundation will be constructed for transformer GLV-T1 to protect against environmental damage in the event of an oil spill from the unit.[23]

138 kV and 25 kV Bus Structures

Engineering assessments have determined that the 138 kV and 25 kV steel structures, foundations, buses, and insulators are all in good condition. As the existing 138 kV steel structure cannot accommodate two 138 kV circuit breakers, a yard extension and 138 kV steel

[22] The 2022 Transmission Line 124L project includes the rebuilding of Transmission Line 124L which connects GAM Substation to CLV Substation. For details, see the *2022 Capital Budget Application, Report 3.1 2022 Transmission Line Rebuild*. The termination of 124L at GLV Substation will result in 2 separate transmission lines entering the GLV Substation and the conversion of the existing radial tap 121L from Transmission Line 124L to GLV Substation to a looped configuration. The section of line between GAM Substation and GLV Substation will be renamed 121L, and the section between GLV Substation and CLV Substation will be remain designated as 124L.

[23] *IEEE Standard 980-2013 Guide for Containment and Control of Oil Spills in Substations* recommends spill containment to prevent or mitigate the environmental impacts of an oil release or spill. These impacts can range from the clean-up costs associated with a spill to the contamination of a water supply. Additionally, *IEEE Standard 979-2012 Guide for Substation Fire Protection* recommends spill containment to minimize the surface area of a spill. This provides fire protection benefits.

bus extension will be installed to accommodate the new equipment. The 138 kV structure will also be equipped with a set of bus mounted potential transformers, and 4 side break switches.

The existing high-speed ground switch which provides transformer protection for GLV-T1 will be replaced by a 138 kV circuit breaker and associated protective relaying. In addition, a second 138 kV circuit breaker will be installed to accommodate the new termination for Transmission Line 124L. Replacing the existing high-speed ground switch with a circuit breaker and protective relaying, will reduce the exposure of transformer GLV-T1 and other substation equipment to fault currents.[24]

All low-voltage equipment will have standard varmint protection installed.[25]

Protection Relays

The protection and control of the 138 kV equipment will be provided by new microprocessor-based digital relays to monitor and control these assets. The two 138 kV transmission line breakers, 121L-B and 124L-B, will be monitored and controlled by digital protection relays. The same circuit breakers will also be used to protect GLV-T1 transformer which will be monitored and controlled by a digital transformer protection relay. This will provide automation capabilities and reduce the duration of substation outages.

The new protection relays for GLV Substation will be housed inside the existing substation control building with the existing substation protection relays.

Site Conditions

The GLV Substation site is in good condition, with minor upgrades required at this time.

A grounding study will be completed and the ground grid for the substation will be extended to cover the expanded substation yard and new equipment.[26]

Scope of Work

The 2022 scope of work at GLV Substation involves the following:

(i) Complete a yard extension and 138 kV steel bus extension,
(ii) Install 2 new 138 kV breakers for 121L and 124L,
(iii) Install 138 kV switches and potential transformers,

---

[24] The time for a high speed ground switch to operate and the upstream circuit breaker to trip, is slower than a standard circuit breaker operation. This exposes a transformer and low-voltage bus to fault currents for longer periods of time, which effectively reduces the life of the assets exposed to the fault. Replacing high-speed ground switches with transmission line breakers provides standard protection and the ability to remote control operation of the transmission lines.

[25] 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. 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."

[26] 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.

(iv) Install protection and control equipment for transformer GLV-T1, 121L and 124L,
(v) Install a new concrete spill containment foundation for GLV-T1,
(vi) Extend ground grid to include new equipment, and
(vii) Complete standard varmint protection on all 25 kV equipment.

Completing the refurbishment and modernization project at the same time as the *Transmission Line Rebuild* project in 2022 maximizes project management and engineering efficiencies.

4.0 Ground Grid Upgrades ($446,000)

In accordance with *ANSI/IEEE Standard 80-2013 Guide for Safety in AC Substation Grounding,* the Company's substation ground grids are designed to:

i. Provide a means to carry electric currents into the earth under normal and fault conditions without exceeding any operating and equipment limits or adversely affecting continuity of service.
ii. Reduce the risk of a person in the vicinity of grounded facilities being exposed to the danger of electric shock or electrocution through step and touch potential.

In 2020, Newfoundland Power completed an engineering assessment of its substation ground grids. The assessment determined that 46 substations have deficiencies that need to be addressed. Grounding studies will be completed to ensure upgrades are in compliance with *ANSI/IEEE Standard 80-2013*. This will include field testing and computer modeling to complete a step and touch potential analysis to identify the upgrades required. Modifications will include the addition of equipment bonding, grounding mats, below-grade copper wire, and ground wells as required to improve ground grid impedance. Upgrades will be prioritized based on the condition of the existing ground grid and substation fault levels to determine the substations with the highest step and touch potential hazards.

In 2022, the substation ground grids will be upgraded at the Company's St. John's Main, Goulds, and Oxen Pond Substations. This will improve safety for personnel working inside the substation.

5.0 Substation Monitoring Upgrades ($187,000)

There continues to be an increase in computer-based digital equipment in electrical system control and operations at Newfoundland Power. Periodic upgrades of this equipment are necessary to address errors in manufacturer's source code, hardware defects and cybersecurity vulnerabilities to ensure continued effective electrical system control and operations.

In 2022, hardware and software upgrades are planned to the communications gateways that connect multiple digital devices in substations to the SCADA system.[27] This work will incorporate manufacturers' upgrades to communications gateways and other computer-based equipment located in Company substations. These upgrades are required to effectively manage

[27] Software upgrades typically address cybersecurity and functional issues. Hardware upgrades typically involve replacement of obsolete or recalled equipment.

increased volumes of electrical system data. Upgrades typically increase the functionality of the equipment and software, and remedy known deficiencies.

6.0 Project Cost

Table 2 provides a detailed breakdown of the *2022 Substation Refurbishment and Modernization* cost by cost category for each project.

Table 2
Project Cost
($000)

Cost Category	HUM	TCV	GLV	GND	SMU	Total
Engineering	414	152	322	64	57	1,009
Labour - Contract	0	0	0	0	0	0
Labour - Internal	87	35	55	6	25	208
Material	2,245	1,596	1,322	367	102	5,632
Other	112	30	46	9	3	200
Total	**$2,858**	**$1,813**	**$1,745**	**$446**	**$187**	**$7,049**

7.0 Conclusion

In 2022, Newfoundland Power is proposing to refurbish and modernize HUM Substation. The Company will dismantle the existing 4.16 kV infrastructure and replace it by expanding the 12.5 kV infrastructure. Power transformer HUM-T2 will be retired and HUM-T3 will be replaced with a higher capacity unit.

In 2022, Newfoundland Power is proposing to refurbish and modernize TCV Substation. The 71 year old power transformer has reached the end of its service life and will be replaced. To accommodate the transformer replacement the substation yard will be relocated to allow for proper design clearances. Completing this project in 2022 is necessary to ensure the power transformer does not fail in service, causing the loss of 27.7 GWH of energy supplied from Tors Cove plant.

In 2022, Newfoundland Power is proposing to rebuild Transmission Line 124L with a new termination at GLV Substation. This transmission reconfiguration will convert the existing 3 terminal transmission tap into GLV Substation into a looped transmission system. The GLV Substation refurbishment and modernization work is required in 2022 to coordinate with this transmission reconfiguration. This will allow the replacement of the substation's high-speed ground switch with a transmission line breaker.

In 2022, Newfoundland Power will complete ground grid upgrades at 3 substations to ensure these substation ground grids are compliant with industry standards and to address deficiencies identified through an engineering assessment. This work must proceed in 2022 to address safety for employees working inside the substation in order to ensure the continued supply of safe, reliable electrical service to customers.

In 2022, Newfoundland Power will continue the substation monitoring project by upgrading communication gateways and other computer-based equipment located in Company substations. These upgrades are required to effectively manage an increased volume of electrical system data collected by the Company's SCADA system. Completing this project in 2022 is necessary to address obsolescence issues in equipment being upgraded, thereby ensuring the continued supply of safe, reliable electrical service to customers.

Appendix A

Substation Refurbishment and Modernization Plan
5-Year Forecast
2022 to 2026

Table A-1
Substation Refurbishment and Modernization Plan
5-Year Forecast
2022 to 2026
($000s)

2022		2023		2024		2025		2026	
SUB	**Cost**	**SUB**	**Cost**	**SUB**	**Cost**	**SUB**	**Cost**	**SUB**	**Cost**
TCV	1,813	MOP	540	GBY	5,687	MOL	3,642	HWD	1,438
GLV	1,745	MUN	2,557	LAU	1,756	GAM	3,839	MRP	300
HUM	2,858	WAL	4,276	SLA	1,733	PBD	2,529	GOU	5,929
		BCV	3,059	BOT	948	ISL	825	LLK	2,016
		LOK	699			BLA	1,324	DLK	635
								BLK	895
								GFS	497
		MISC	936	MISC	1,123	MISC	1,348	MISC	1,617
GND	446	GND	535	GND	642	GND	770	GND	925
SMU	187	SMU	191	SMU	195	SMU	200	SMU	205
	$7,049		**$12,793**		**$12,084**		**$14,477**		**$14,457**

Note: SUB: Substation (Refer to the Electrical System Handbook included with the *2006 Capital Budget Application* for 3-letter substation designations.)
GND: Ground Grid Upgrades
SMU: Substation Monitoring Upgrades
MISC: Miscellaneous Substation Equipment Replacements

Appendix B

Humber Substation 4.16 kV Infrastructure Replacement

Humber Substation 4.16 kV Infrastructure Replacement

May 2021

Prepared by:
Robert Cahill, Eng. L.

REGISTERED LIMITED LICENSEE - ENG. L.
PEG Newfoundland and Labrador
ROBERT J. CAHILL
SIGNATURE
2021-05-05
DATE
NEWFOUNDLAND & LABRADOR

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A FORTIS COMPANY

Table of Contents

1.0 Introduction

Newfoundland Power's (the "Company") Humber ("HUM") Substation is located in the downtown core of the City of Corner Brook (the "City") on the west coast of Newfoundland and Labrador. HUM Substation supplies electricity to approximately 1,850 residential and commercial customers in mature areas of the City including the central business district and surrounding residential neighbourhoods. The customers served from HUM Substation are supplied via two 12.5 kV distribution feeders and three 4.16 kV distribution feeders.[1] The location of HUM Substation and areas supplied by its 4.16 kV and 12.5 kV distribution feeders as well as the areas supplied by the adjacent Walbournes ("WAL") and Bayview ("BVS") substations 12.5 kV distribution feeders are illustrated in Figure 1.

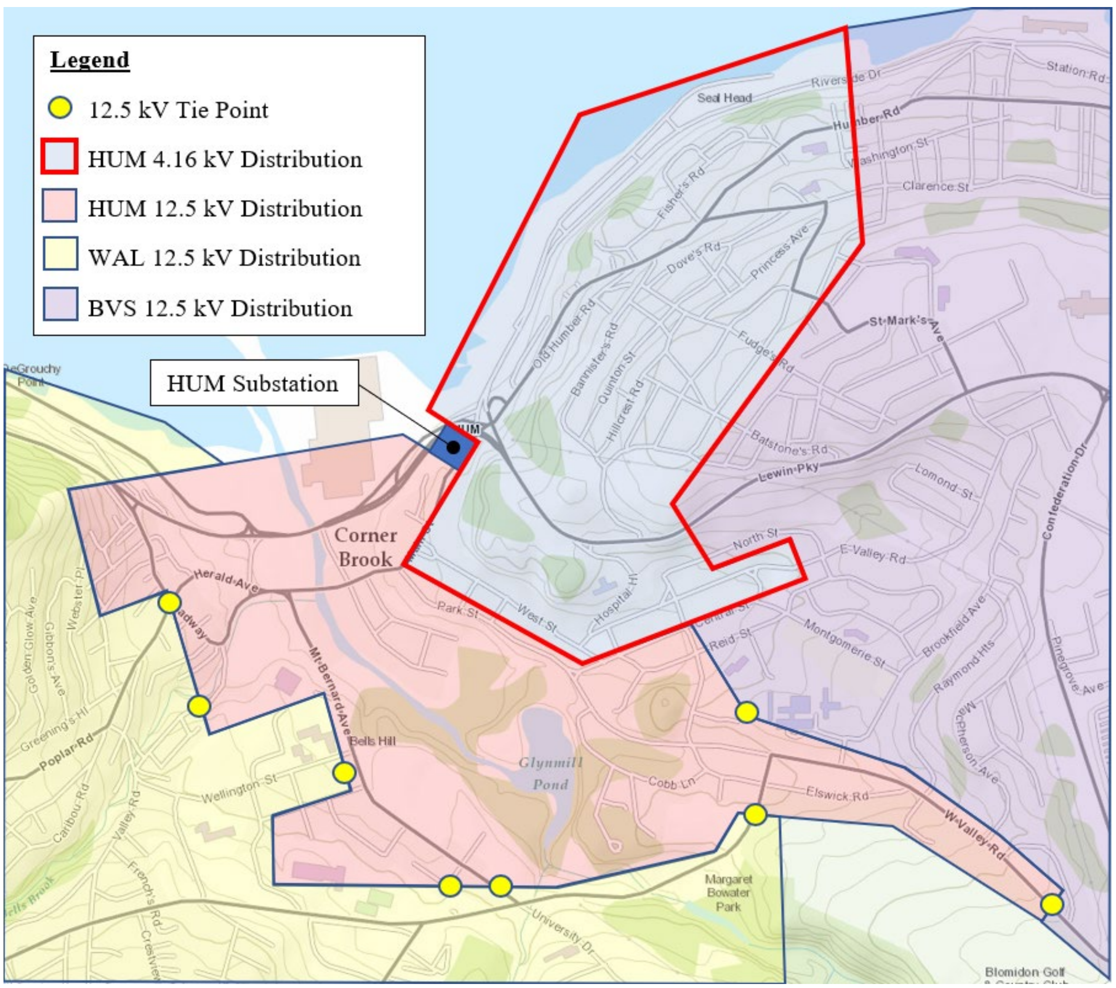

Figure 1: HUM Substation and Distribution Systems

[1] The two 12.5 kV distribution feeders serve approximately 850 customers and three 4.16 kV distribution feeders serve approximately 1,000 customers.

The Company's *2021 Substation Refurbishment and Modernization* plan identified HUM Substation for refurbishment and modernization in 2022.[2] When determining the project's final scope of work, the site limitations, existing equipment condition, and constraints associated with the 4.16 kV distribution system required a broad examination of alternatives.

The existing HUM 4.16 kV distribution system is islanded, meaning there is no ability to transfer load to feeders originating from surrounding substations in the event of planned or unplanned outages.[3] The 4.16 kV components within the HUM Substation are at the end of their service life. In recent years, deteriorated and failed components on the 4.16 kV distribution system have been replaced with components compatible with a future 12.5 kV voltage conversion.[4]

In 2020, Newfoundland Power engaged van Kooy Transformer Consulting Services Inc. (the "Consultant") to perform an independent transformer condition assessment on HUM-T2.[5] Based on the results of this assessment, the Consultant concluded HUM-T2 is at the end of its service life. The Consultant recommended replacing HUM-T2 in 2022 due to its age, physical deterioration, tap-changer operational concerns and the polychlorinated biphenyl ("PCB") contaminants in the transformer bushings.

This report provides an engineering assessment of the 4.16 kV infrastructure at HUM Substation and evaluates 2 technically viable alternatives for continued safe, reliable operation of HUM Substation. Based on the results of an economic analysis of alternatives it is recommended that the least cost option to refurbish and modernize HUM Substation in 2022 involves dismantling the existing 4.16 kV distribution equipment and replacing it with 12.5 kV equipment including the associated distribution infrastructure modifications.

2.0 Background

HUM Substation was built in 1954. The substation is supplied by 2 Newfoundland Power 66 kV transmission lines, 356L from Massey Drive ("MAS") Terminal Station and 359L from BVS Substation.

HUM Substation has a total transformer capacity of 20.76 MVA. The 4.16 kV metal clad distribution switchgear is energized by a single 66 kV to 4.16 kV power transformer, HUM-T2 (7.46 MVA). The 12.5 kV distribution bus structure is energized by a single 66 kV to 12.5 kV power transformer, HUM-T3 (13.3 MVA).[6]

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[2] See Appendix A to 2.1 *2021 Substation Refurbishment and Modernization* report filed with the Company's 2021 Capital Budget Application.

[3] The 4.16 kV distribution system in the City is considered to be *islanded* as there are no other adjacent substations with 4.16 kV distribution systems that would allow customer load to be transferred between substations. All adjacent substations have only 12.5 kV distribution systems.

[4] Compatibility with a future 12.5 kV voltage conversion involves installation of dual-wound pole-mounted transformers and insulators rated for 12.5 kV.

[5] The Consultant has more than 35 years of experience in the transformer services industry. Newfoundland Power has been using the Consultant in various aspects of its power transformer asset management program since 2002. The transformer condition assessment completed by the Consultant is included in Attachment B.

[6] HUM Substation single line diagram is illustrated in Attachment A.

The substation has four 4.16 kV feeder exits that leave the substation via underground cables, crossing congested utility and transportation corridors to connect with the overhead sections of the feeders.[7] Much of the remaining 4.16 kV rated distribution infrastructure was installed in the 1950s and 1960s, and is nearing the end of the equipment's expected service life.[8]

3.0 HUM Substation 4.16 kV Condition Assessment

Given the age, condition, and recent failure history of the 4.16 kV components at HUM Substation, a comprehensive condition assessment of these components are outlined in this section of the report.

4.16 kV Infrastructure

The 4.16 kV distribution feeders are supplied by metal clad switchgear breakers that were installed in HUM Substation in 1968.[9] Based on an engineering assessment, this equipment is at the end of its service life. The switchgear is not built to current standards which mitigate arc flash hazards.[10] Support from the manufacturer has been discontinued and replacement parts are difficult to source.[11]

---

7 Distribution feeder HUM-03 serves no customers but provides a spare breaker and alternate substation exit for HUM-04. Distribution feeder HUM-04 has no tie points to the other 4.16 kV feeders therefore there is no ability to supply customers by paralleling HUM-04 with another feeder.

8 As a result of their age, remaining 4.16 kV components are expected to appear as deficiencies in greater numbers in upcoming feeder inspections.

9 The switchgear also includes a 4.16 kV breaker for HUM-T2 and the station service transformer for the substation.

10 Arc resistant switchgear relieves the pressure buildup from severe arcing and exhausts the rapidly expanding air away from operating personnel. Arc flash protective relays can detect the early stage of an arc's development and initiate instantaneous tripping of the associated breaker(s). These technologies on newer switchgear mitigate the hazards of arc flash events to prevent injury to personnel and mitigate equipment damage.

11 The Company has a limited supply of spare 4.16 kV switchgear parts from equipment that was removed from service over time.

Figures 2 and 3 show images of the 4.16 kV switchgear cubicles. The age, condition, lack of spare parts and arc flash hazard indicate that the switchgear is at the end of its service life and should be replaced.

Figure 2: Front Panel of HUM-4.16 kV Switchgear and Substation Controls

Figure 3: Back of HUM-4.16 kV Switchgear and Substation Controls

The 4.16 kV feeders exit the switchgear underground via paper insulated, lead covered ("PILC") cables installed in 1968 and 1972.[12] The PILC cables are approaching 50 years in service and are at an increased risk of failure. The reliability of the PILC cables has become a concern in recent years. HUM-04 PILC cable faulted on January 1, 2020, resulting in damage to both terminations.[13] The physical condition of the underground cables make it highly likely that there will be further cable faults experienced.

The 4.16 kV distribution feeders exit HUM Substation switchgear via underground cables and cross main arterial roads and a congested transmission right-of-way before connecting with aerial distribution. Future replacement of the PILC cables or alternate feeder exits will be difficult and time consuming to complete due to these constrains, resulting in extended customer outages.

The condition assessment of the HUM Substation 4.16 kV infrastructure has identified that all of the individual components are in need of replacement.

[12] Report *2.1 Substation Strategic Plan* included with the *2007 Capital Budget Application* identified that power cable failures begin to occur when cables are about 35 years old.

[13] All customers served by HUM substation experienced an outage ranging from 8 minutes to 5 hours 50 minutes as a result of the fault. HUM-04 customers were transferred to a redundant 4.16 kV feeder trunk from the HUM Substation, and repairs to the cable terminations were made. Repairs required experienced staff to travel from St. John's to assist. This failure resulted in 84,364 customer minutes of outage.

Power Transformer HUM-T2

HUM-T2 power transformer was manufactured by Canadian General Electric in 1968, and installed at HUM Substation in 1999.[14] HUM-T2 is a 66 kV to 4.16 kV (7.46 MVA) power transformer supplying the 4.16 kV distribution system in the City. The transformer tank is showing signs of physical deterioration, as illustrated in Figure 4. As a consequence of the deterioration, leaks have resulted in the transformer enclosure, as illustrated in Figure 5. The on-load tap changer is a GE LRT-68, which is no longer supported by the manufacturer and replacement parts are no longer available.

Figure 4: Deterioration on HUM-T2

Figure 5: Oil Leak at Previous Repair on HUM-T2

In recent years, a number of outages have occurred as a result of faults on HUM-T2. On November 21, 2019 a failure occurred to a HUM-T2 lightening arrester, as shown in Figure 6.[15] In August 2020, several oil leaks and cracked welds were observed on HUM-T2. A portable transformer was installed to avoid customer outages while making the necessary repairs.

[14] Prior to being installed at HUM Substation transformer HUM-T2 was installed at Port aux Basques Substation.

[15] This 2.5 hour substation outage resulted in 149,702 customer outage minutes.

Figure 7 illustrates the repairs made to HUM-T2.[16]

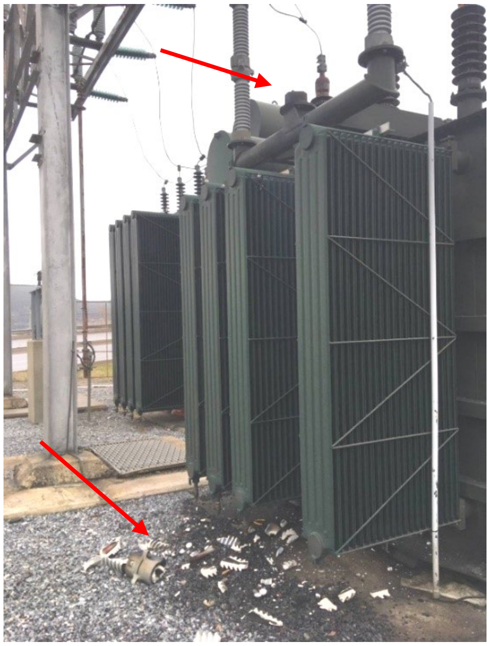

Figure 6: Failed Lightening Arrestor on HUM-T2

Figure 7: Leak Repairs on HUM-T2

Due to the age and physical deterioration of HUM-T2, along with the maintenance concerns around the on-load tap changer and PCB contaminants in the transformer bushings, it is recommended that the transformer be replaced. In 2020, the Consultant concluded HUM-T2 is at the end of its service life and recommended replacing HUM-T2 in 2022.[17]

Protection Relays

The feeder protection for three of the four 4.16 kV feeder exits that supply customers are early vintage microprocessor-based digital relays. A number of these early vintage digital relays have failed in recent years with 8 of these relays in various Company substations requiring replacement within the past 5 years. The protection relays for the spare 4th feeder as well as for HUM-T2 and HUM-T3 are vintage electromechanical type and are 42 years old.[18] The age and general deterioration of these relays indicate that they are at the end of their service life and should be replaced.

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16 HUM-T2 was painted in 2020 to slow corrosion. Plastic steel epoxy was also applied to repair leaks on the main tank of the transformer.

17 Attachment B includes a transformer condition assessment completed by van Kooy Transformer Consulting Services Ltd.

18 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. 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, examined Newfoundland Power's practice of replacing multiple obsolete electromechanical relays with a single modern microprocessor controlled relay and concluded that the Company uses reasonable practices that conform to industry practice.

Building and Site

The current substation building houses protection and control equipment and the 4.16 kV switchgear. The 4.16 kV switchgear takes up much of the available space inside the building. The building was constructed in 1954 with minor improvements made over the years. The structural elements of the building are in good condition. The building envelope has deteriorated components including the windows, doors and roofing which require replacement. There is also asbestos in some of the interior construction materials which would require abatement in order to complete any necessary upgrades or building modifications.

The HUM Substation property is bordered on 3 sides by major thoroughfares and on the 4th side by a transmission right-of way containing five 66 kV transmission circuits.[19] As a result of the site constraints, there is no ability to expand the substation footprint, as shown in Figure 8.

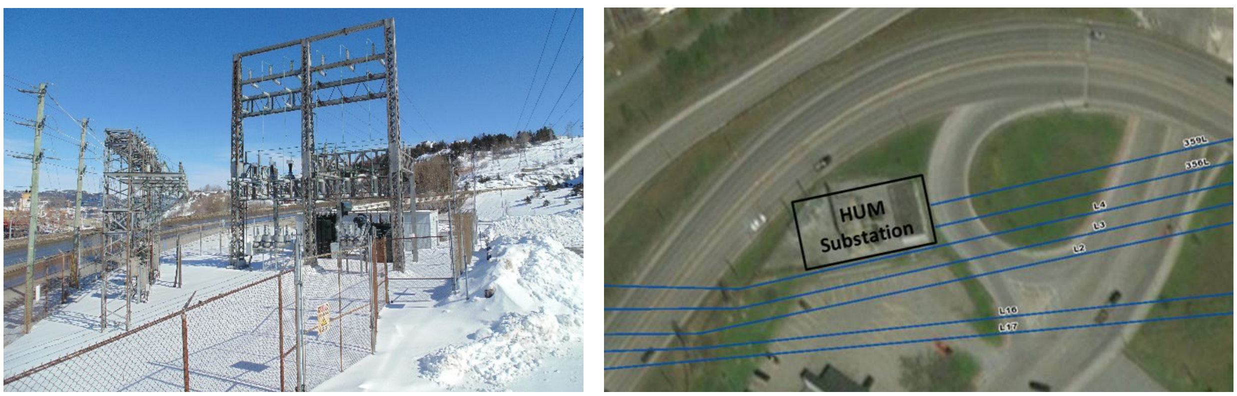

Figure 8: Site Constraints on 4 Sides

Surficial corrosion is present on the fence however it is structurally sound and secure.

4.0 Development of Alternatives

Two technically feasible alternatives were developed and evaluated to address the refurbishment and modernization of HUM Substation, taking into consideration the 4.16 kV components that have reached the end of their service life. The 2 alternatives include (i) continuing to supply customers from both the 4.16 kV and 12.5 kV distribution systems or (ii) retire the 4.16 kV distribution system and complete necessary upgrades to operate exclusively at 12.5 kV.

Newfoundland Power's 2020 Substation Load Forecast for the Corner Brook area was considered in the development of alternatives. Current load growth in the Corner Brook area is being driven by the new Corner Brook Acute Care Hospital which is scheduled to be complete in 2023. The associated load addition of approximately 8.4 MVA to the Corner Brook service area limits the available system capacity of the surrounding 12.5 kV distribution systems to support the potential voltage conversion and load transfer of the existing 4.16 kV distribution system at

19 The five 66 kV transmission circuits feed the nearby paper mill.

HUM to neighbouring substations. The additional 12.5 kV system capacity to support the potential voltage conversion will have to be added to HUM Substation.

The alternatives include estimates for all of the costs involved, including substation and distribution costs as listed below.

4.1 Alternative 1 – Substation Refurbishment and Modernization with 4.16 kV System

Alternative 1 involves completing the refurbishment and modernization of HUM Substation with both the 4.16 kV and 12.5 kV distribution systems continuing to supply customers. This includes refurbishing and modernizing the 66 kV and 12.5 kV infrastructure as well as replacing the existing 4.16 kV infrastructure with new components.[20] The work required as part of this alternative includes:

In 2022,

- (i) Replace the existing 7.46 MVA, 66/4.16 kV HUM-T2 transformer with a new 8.3 MVA, 66/4.16 kV transformer and associated transformer protection;[21]
- (ii) Replace the deteriorated 4.16 kV metal clad switchgear;
- (iii) Replace the substation underground cable and duct banks;
- (iv) Install a firewall separating the 2 HUM Substation power transformers, and install spill containment for the new HUM-T2 and existing HUM-T3 transformers;
- (v) Replace deteriorated 12.5 kV and 66 kV equipment;
- (vi) Replace obsolete 4.16 kV feeder protection and HUM-T3 transformer protection;
- (vii) Replace the deteriorated windows, doors and roof on the existing switchgear building, complete asbestos abatement, and complete upgrades to the building interior to facilitate equipment replacement; and
- (viii) Replace the underground 4.16 kV distribution feeder exit cables and duct banks.

In 2034,

- (ix) Replace the existing 13.3 MVA, 66/12.5 kV HUM-T3 transformer with a new 25 MVA, 66/12.5 kV transformer and associated transformer protection;[22]

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[20] See Section 3.1 of *2.1 2022 Substation Refurbishment and Modernization* report for condition assessment of the 12.5 kV and 66 kV infrastructure.

[21] A 7.46 MVA transformer is no longer a standard unit size; therefore, it is proposed to install the next available standard transformer.

[22] The future cost of replacement of HUM-T3 is necessary for completeness of the economic analysis. A 2013 CIGRE report titled, *Asset Management Decision Making using different Risk Assessment Methodologies for Electricity Transmission Working Group C1.25* identified the typical expected life of power transformers to be 30 to 50 years. Considering that HUM-T3 has been in service for 48 years, it has been estimated that the remaining service life of the transformer is 12 years, at 60 years of age, requiring replacement in 2034.

Table 1 provides the capital cost estimate for Alternative 1.

Table 1
Alternative 1 Capital Costs
($000s)

Item	**Cost**
In 2022, install an 8.3 MVA, 66/4.16 kV transformer and associated transformer protection, replace the 4.16 kV metal clad switchgear, duct banks and underground cable, install transformer firewall and spill containment, replace deteriorated 12.5 kV and 66 kV equipment, replace 4.16 kV feeder protection and HUM-T3 transformer protection, and refurbish the existing switchgear building.	3,506
In 2022, replace the underground PILC 4.16 kV distribution feeder exit cables.	909
In 2034, replace the existing 13.3 MVA, 66/12.5 kV HUM-T3 transformer with a new 25 MVA, 66/12.5 kV transformer and associated transformer protection	1,349
Total	**5,764**

4.2 Alternative 2 – Substation Refurbishment and Modernization without 4.16 kV System

Alternative 2 involves dismantling the 4.16 kV equipment at HUM Substation and expanding the 12.5 kV substation equipment to supply the existing 4.16 kV distribution system at 12.5 kV. This includes refurbishing and modernizing the 66 kV and 12.5 kV infrastructure as well as adding an additional 12.5 kV distribution feeder. The existing 4.16 kV distribution infrastructure will be converted to supply customers at 12.5 kV. This alternative would result in a significant reduction in substation equipment including a power transformer, a 66kV air break switch and the replacement of four 4.16 kV breakers with a single 12.5 kV recloser. The work required for this alterative includes:

In 2022,

(i) Retire the existing 7.46 MVA, 66/4.16 kV HUM-T2 transformer;
(ii) Retire existing 4.16kV switchgear and switchgear building. Install a new control building and cable trench;
(iii) Replace the existing 13.3 MVA, 66/12.5 kV HUM-T3 transformer with a new 25 MVA, 66/12.5 kV transformer and associated protection devices to HUM Substation. This additional capacity is required to supply the newly converted 4.16 kV feeder load from the HUM-12.5 kV system;[23]

[23] A 15/20/25 MVA transformer would be required to support the 2022 forecast load of the combined HUM system, which is 19.5 MVA.

(iv) Install new spill containment for HUM-T3;[24]
(v) Replace deteriorated 12.5 kV and 66 kV equipment;
(vi) Install a new 12.5 kV distribution feeder HUM-10, including a new recloser and associated switches;[25]
(vii) Convert the HUM 4.16 kV distribution feeders, HUM-01, HUM-04 and HUM-07, to 12.5 kV; and
(viii) Build a new 12.5 kV feeder trunk to connect the newly converted 4.16 kV distribution feeders to the HUM Substation.[26] The new HUM-12.5 kV feeder will be supplied by HUM-T3 and will replace the existing three 4.16 kV feeders.

Table 2 provides the capital cost estimate for Alternative 2.

Table 2
Alternative 2 Capital Costs
($000s)

Item	**Cost**
Install a 25 MVA, 66/12.5 kV transformer and associated transformer protection, replace deteriorated 12.5 kV and 66 kV equipment, and install new control building and transformer spill containment.	2,639
Convert the HUM 4.16 kV distribution feeders to 12.5 kV.	1,180
Substation portion of the construction of a new 12.5 kV distribution feeder (HUM-10).	219
Distribution portion of the construction of a new 12.5 kV distribution feeder (HUM-10).	175
Total	**4,213**

5.0 Evaluation of Alternatives

The economic impact of each alternative was evaluated through a Net Present Value ("NPV") analysis of customer revenue requirement. Capital costs from 2022 were converted to the customer revenue requirement. The economic analysis also includes the impact of future operating costs associated with each of the 2 alternatives. The estimated annual operating costs associated with Alternative 1 is $27,287. The estimated annual operating costs associated with

[24] *IEEE Standard 980-2013 Guide for Containment and Control of Oil Spills in Substations* recommends spill containment to prevent or mitigate the environmental impacts of an oil release or spill. These impacts can range from the clean-up costs associated with a spill to the contamination of a water supply. Additionally, *IEEE Standard 979-2012 Guide for Substation Fire Protection* recommends spill containment to minimize the surface area of a spill. This provides fire protection benefits.

[25] A single 12.5 kV recloser will replace the 4.16 kV switchgear with 4 breakers and associated substation exits.

[26] A single 12.5 kV distribution feeder will be capable of supplying the load previously supplied by the three 4.16 kV distribution feeders.

Alternative 2 is $7,859. The lower estimated operating costs for Alternative 2 relates to the reduction in annual maintenance costs associated with the dismantling of the 4.16 kV infrastructure. The resulting customer revenue requirement was reduced to an NPV using the Company's incremental weighted average cost of capital over a 20 year time horizon.

Table 3 provides the NPV of customer revenue requirement for each alternative under the base case load forecast.

Table 3
Net Present Value Analysis
($000s)

Alternative 1	$6,545
Alternative 2	$4,961

Alternative 2 has the lowest NPV of customer revenue requirement.

5.1 Sensitivity Analysis

A sensitivity analysis was completed to evaluate the impact of varying the timing of the future replacement of HUM-T3 in Alternative 1.

Table 4 provides the NPV of customer revenue requirement with (i) the future replacement of HUM-T3 advanced to 2027 and (ii) the future replacement HUM-T3 deferred beyond the 20 year time horizon.

Table 4
Sensitivity Analysis
($000s)

Alternative	Base Case NPV	HUM-T3 Advanced Replacement NPV	HUM-T3 Deferred Replacement NPV
1	$6,545	$6,728	$5,461
2	$4,961	-	-

Alternative 2 remains the least-cost alternative compared to both Alternative 1 sensitivity scenarios for the future replacement of HUM-T3.

6.0 Recommendation

The results of the economic analysis show that Alternative 2 is the least cost alternative to address the 4.16 kV substation deficiencies required to maintain safe, reliable service to customers served by HUM Substation. This alternative has the added benefit of eliminating the islanded 4.16 kV distribution system and add additional interconnection points with the existing 12.5 kV system, thereby improving reliability performance in all circumstances. In addition, the aging HUM-T3 transformer will be replaced with a larger unit eliminating additional capital expenditures required to replace it in the future as well as provide additional capacity for future load growth on the Corner Brook distribution system. Reducing the amount of actual equipment by 1 transformer, 1 distribution bus and multiple distribution feeder exits will reduce maintenance costs associated with this additional equipment. As a result, Alternative 2 has both overall cost and operational advantages over Alternative 1.

7.0 2022 Project Description

Implementing Alternative 2 includes both Substation and Distribution projects in 2022. The Substation component is included in the *2022 Substation Refurbishment and Modernization* substation project. The Distribution component is included in the *Trunk Feeders – Humber 4.16 kV Conversion* distribution project.

7.1 2022 Substation Refurbishment and Modernization Project

The substation portion of the project includes dismantling the 4.16 kV infrastructure at HUM Substation including removal of the switchgear and building, power cables, power transformer HUM-T2, and associated protection devices.

Power transformer HUM-T3 will be replaced with a new 25 MVA unit. A new spill containment foundation will be constructed for the new transformer to protect against environmental damage in the event of an oil spill from the unit. A new recloser, air break switch, side break switch, hook stick operated switches, and associated protection and control will be installed to accommodate the new 12.5 kV distribution feeder.

Table 5 summarizes the 2022 substation project costs.

Table 5
2022 Substation Project Costs
($000s)

Cost Category	Total
Engineering	414
Labour - Contract	-
Labour - Internal	87
Material	2,245
Other	112
Total	**$2,858**

7.2 Trunk Feeders – Humber 4.16 kV Conversion Project

The distribution portion of the project includes conversion of the 4.16 kV distribution feeders to 12.5 kV and construction of a new feeder, HUM-10, to supply the loads associated with the former 4.16 kV system.[27] Components that require upgrading to support voltage conversion include, distribution pole top transformers, insulators and lightening arrestors.

Table 6 summarizes the estimated quantity of each component required to convert the remainder of the HUM 4.16 kV distribution feeders to 12.5 kV.

Table 6
Estimate of Work Required

Work	HUM-01	HUM-04	HUM-07	Total
Replace Transformer	36	28	20	84
Replace Lightening Arrestor	19	11	21	51
Replace Insulators	18	4	12	34

[27] When converted to 12.5 kV the transfer of the former 4.16 kV feeder loads to adjacent substations will become feasible. This will provide operational flexibility during storms or other unplanned outages as sections of former 4.16 kV feeders will be capable of reconfiguration to supply customs from an alternate supply point.

In addition to installing 12.5 kV compatible components, additional upgrades will be required to accommodate the final configuration, as well as minimize the customer impact during the project. Associated work will include:

- Upgrading sections to support reconfigured distribution feeder trunks;
- Establishing appropriate feeder tie points for facilitating conversion; and
- Replacement of protective fusing to accommodate changes in voltage and configuration.

A new feeder, HUM-10, will be constructed to connect the existing 4.16 kV distribution system to the HUM-12.5 kV Substation infrastructure. Approximately 400 metres of new aerial trunk feeder will exit HUM Substation and connect with the existing HUM-01 trunk, near the existing underground cable feeder termination.

Table 7 summarizes the 2022 Distribution project capital costs.

Table 7
2022 Distribution Project Costs
($000s)

Cost Category	**Total**
Material	152
Labour – Internal	514
Labour – Contract	370
Engineering	205
Other	114
Total	**$1,355**

8.0 Conclusion

This report recommends the dismantling of the 4.16 kV equipment at HUM Substation including transformer HUM-T2 and the expansion of the 12.5 kV equipment to supply all customer loads in downtown Corner Brook. It also recommends the conversion of the HUM - 4.16 kV distribution system to operate as a single 12.5 kV distribution feeder. Both projects will be completed in 2022. This includes the retirement of existing HUM-T3, installation of a new 66-12.5 kV power transformer and 12.5 kV feeder termination at HUM Substation to replace the aging 4.16 kV infrastructure. Completing this dismantling and conversion is least cost compared to refurbishing the existing 4.16 kV substation equipment. Proceeding with this project also has overall cost and operational benefits.

In addition to being least cost in 2022, the selected alternative provides additional capacity in the Corner Brook distribution system and removes future capital investment required to replace HUM-T3. After conversion, the HUM distribution system will be comprised of three 12.5 kV feeders, removing the islanded 4.16 kV system, and creating additional interconnection points between the 12.5 kV distribution system in the Corner Brook area. Other benefits include lower distribution system losses resulting from the increase in supply voltage for the existing 4.16 kV feeders, lower power transformer losses for a single new transformer compared with 2 transformers built 50 years ago, less substation equipment to maintain and increased substation capacity for future load growth on the Corner Brook distribution system.

Attachment A

HUM Substation Single Line Diagram

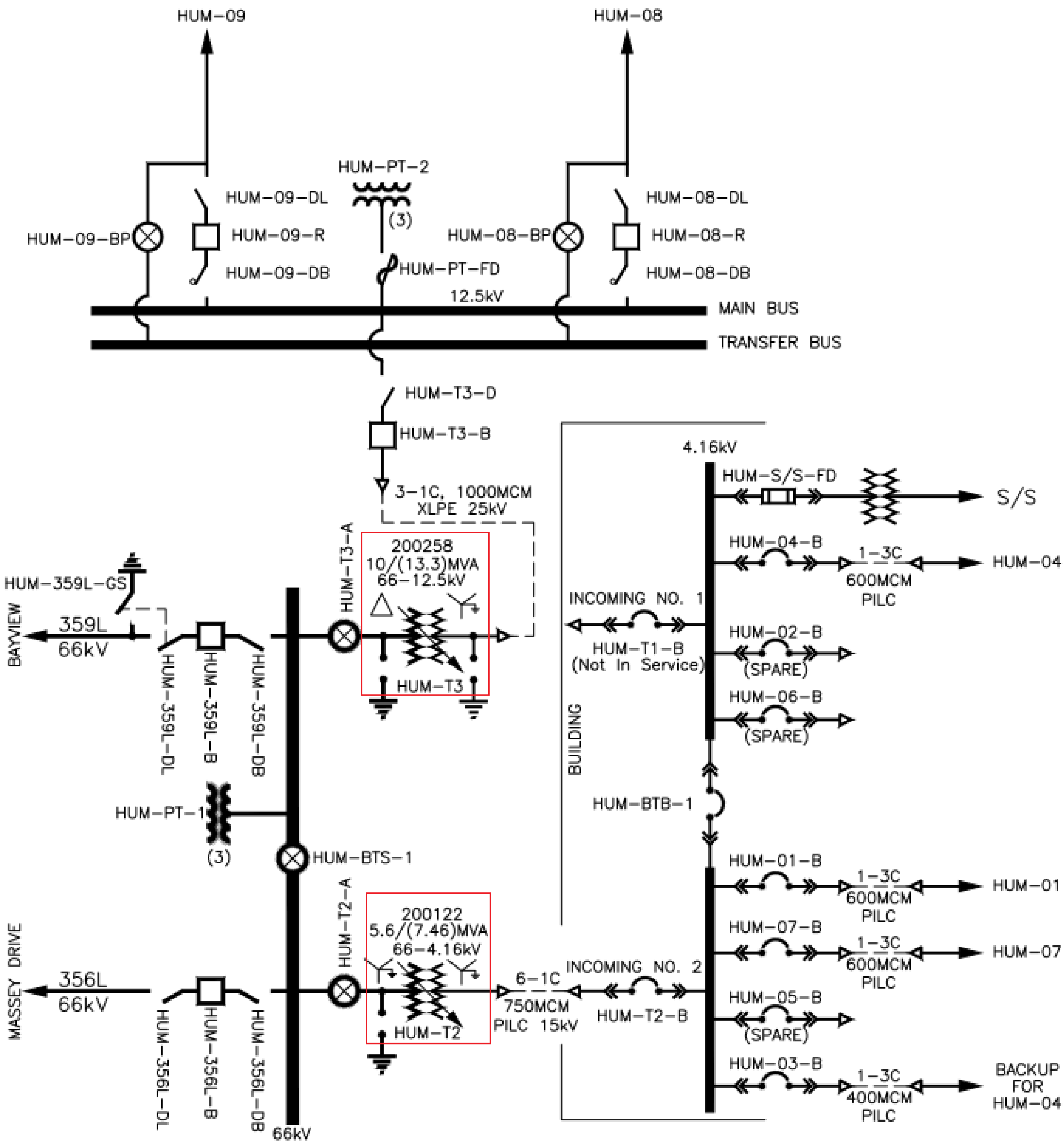


Figure A-1: HUM Substation Single Line Diagram

Attachment B

HUM-T2 Transformer Condition Assessment

van Kooy
Transformer Consulting Services Inc.

Ph. 905 308-9888
Email john@vankooy.com
web site www.vankooy.com

November 16, 2020

To: Nicholle Marsh, Adam Wong - Newfoundland Power

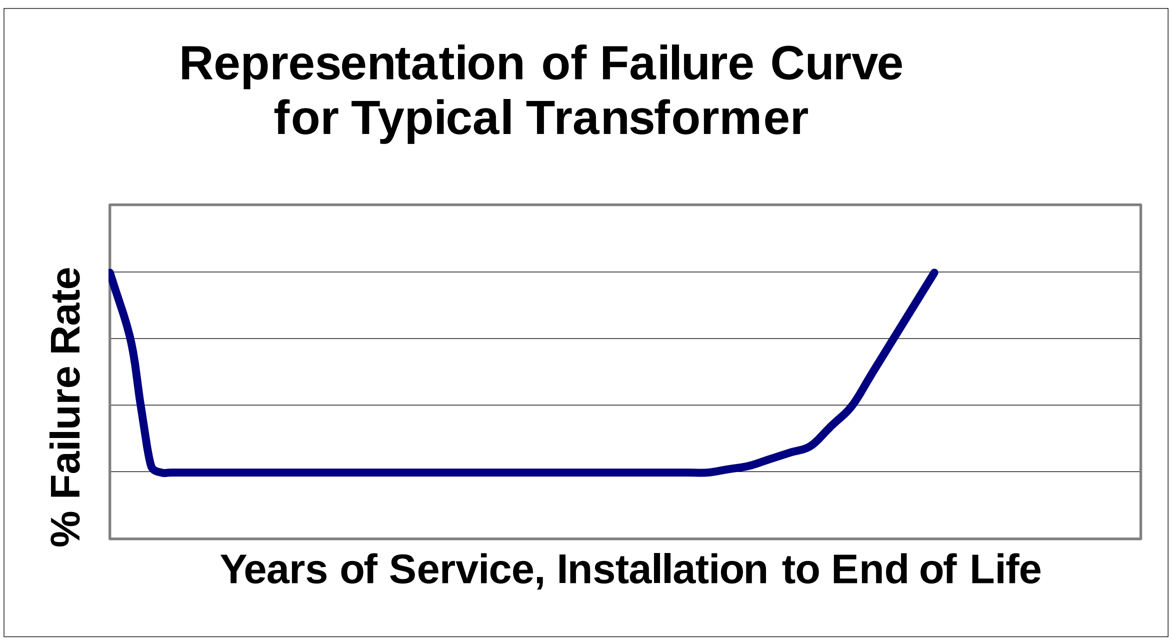
Subject: Humber T2 Transformer Condition Assessment

Executive Summary

Humber T2, P-122, GE S# 286712 is approaching end of life and should be a candidate for decommissioning within 2 years.

Basis of Evaluation

There are a number of factors that impact longevity in power transformers. Like much long-lived equipment, the life span of power transformers typically follow a ‘bathtub’ curve as shown in the figure below. After a short period of potentially a higher failure rate, there is a long period of a low probability of failure (< 1%) and then as the equipment approaches end of life, the failure rate spikes up. The tipping point will vary with transformer application (transmission, generation, distribution, industrial, specialty industrial) as well as with other factors.



The **Age** of the transformer is certainly a key factor. The weak point in all power transformers is the cellulous (paper) insulation that is integral to the windings and interconnecting leads and is vital for electrical isolation and mechanical support. As this cellulous insulation ages, it becomes more brittle and prone to failure as the result of the normal stresses of short circuits, over voltages and overloads. The characteristic of this insulation, flexibility when new and brittleness when aged, is called Degree of Polymerization (DP). It is not possible to effectively monitor DP while the transformer is in use and can only be determined by a biopsy of samples of insulation in key areas which cannot practically be done unless a 'post mortem' is performed.

The insulation aging is affected by operating temperature which of course is related to loading. Short periods of overloading do not generally lead to failure but have a cumulative affect over time. The effects of overloading can be somewhat monitored through Dissolved Gas in Oil testing. Excessive moisture will also accelerate insulation degradation and can be monitored through General Oil Quality testing.

The other main elements inside the transformer, copper and steel, do not effectively age so the key to long life is keeping the insulation in the best shape as possible with the understanding that like the human experience, there is no cure for old age.

Dissolved Gas in Oil Analysis (DGA) is the best ongoing way to monitor the condition of a fluid filled transformer. Issues of overloading, overvoltage, lightning strikes, and decaying internal components can be detected with the interpretation of the results.

Standard Oil Quality (SOQ) is another fluid sampled test that monitors the key parameters around the cleanliness and effectiveness of the oil as an insulation medium.

Field Test Results offer the ability to take snapshots of key parameters of the transformer over time and to confirm viability in the case of suspected failure. This testing is limited in that the testing is done at a relatively low voltage and cannot simulate operating voltages. Testing such as Turns Ratio and Winding Resistance will verify internal connections and other tests such as Insulation Resistance (Megger) and Power Factor/Dissipation Factor and Capacitance can monitor general insulation condition over time.

The **Condition of Key Components** is critical to the operation of the transformer since the failure of any of these components will render the transformer inoperable. Key components include, Bushings, On Load Tap Changers (OLTC) and De-Energized Tap Changers (DETC).

There are **Other Risks** to be considered including mechanical compromise of the main tank or radiators leading to oil leaks, Lightning Strikes, Over Voltage events, Overloading events and the presence of PCB's in the transformer.

Detailed Analysis

Humber T2, P-122, GE S# 286712, 5000 kVA, 66 kV w OLTC to 4.16 kV, built in 1968

This transformer is 52 years old. The latest Dissolved gas in oil analysis does not show any elements of concern and indicates that the present loading is well within this transformer capability. For a transformer of this vintage, caution must be applied when only looking at a few years of data. The General Oil Quality is showing some signs of degradation. At this point oil sampling is being performed on a 6-month cycle which is prudent for this age of equipment.

An area of significant concern is the Automatic On Load Tap Changer (OLTC) which is a GE LRT-68. Not only has GE Canada not existed for many years, this OLTC is no longer supported, and finding replacement parts is problematic. The oil test data from the OLTC is presently not showing signs of concern.

The HV bushings are PCB contaminated with levels ranging from 100 to 490 ppm. The OLTC oil has 56 ppm PCB and a recent sample of the main tank has tested 3 ppm. There is evidence of cracked welds on this tank that are leaking oil. These areas have been patched as can be seen in the pictures below. Patches never last very long as the seeping oil deteriorates the epoxy/glue bond to the steel.

Hole in Transformer Tank Base – Patch Applied

Hole in Transformer Tank Cover near Bushing – Prior to Patch Application

Hole in Transformer Tank Cover near Bushing – After Patch Application

van Kooy Transformer Consulting Services Inc.

Assessing this transformer based on the criteria listed and the data provided results in a ranking of 3.2, where 1.0 would be suitable for continued service with no concerns and 4.0 would be remove from service ASAP.

Recommendations

Although the outward signs from this transformer are not presently too negative, the age, mechanical degradation along with the maintenance concerns around the OLTC and HV bushing PCB concerns make this transformer a candidate for replacement. I suggest planning to replace within 2 years. Better to remove from service in a planned, controlled manner ahead of a failure and un-planned outage.

Regards,

van Kooy Transformer Consulting Services Inc.

per: Sjoerd (John) van Kooy

Appendix C

Tors Cove Substation Power Transformer Replacement

Tors Cove Substation
Power Transformer Replacement

May 2021

Prepared by:
Michael Power, P. Eng.

REGISTERED PROFESSIONAL ENGINEER
PEG Newfoundland and Labrador
MICHAEL J.T. POWER
SIGNATURE
May 5, 2021
DATE
NEWFOUNDLAND & LABRADOR

Table of Contents

1.0 Introduction

Newfoundland Power's Tors Cove ("TCV") Hydro Plant (the "Plant") is a 6.5 MW hydroelectric generating plant located in Tors Cove on the Southern Shore of the Avalon Peninsula.[1] The Plant was placed into service in 1941. The Plant produces 27.7 GWh of energy annually, representing 6.3% of Newfoundland Power's total hydroelectric production. The Tors Cove Substation connects the Plant to the Island Interconnected System by Transmission Line 11L, which runs 5 kilometres from the Plant to the Company's Mobile Substation.

This report recommends the replacement of TCV-T1 with a new transformer in 2022, and relocation of the Plant substation to accommodate the new transformer. In 2020, an assessment performed by van Kooy Transformer Consulting Services Inc. (the "Consultant") resulted in the recommendation to remove this transformer from service within 1 to 2 years.[2]

2.0 Background

TCV-T1 is a 71 year old, 66/33-6.9 kV, 7.5 MVA power transformer manufactured by Canadian General Electric in 1950. The transformer increases the voltage of energy produced at the Plant from 6.9 kV to 66 kV for transmission to Mobile substation. This transformer is 1 of the 2 oldest units in Newfoundland Power's transformer fleet with 1 other transformer also manufactured in 1950. Attachment A contains a single line diagram of the TCV Substation.

The TCV-T1 tank is severely deteriorated as can be seen from the pictures in Attachment B.[3] There is heavy rusting on the bushing mounting flanges and on the transformer base members. The radiators are also severely rusted and require immediate replacement. The oil filled bushings were recently replaced as they were chipped and leaking. However, due to the age of this transformer, new replacement bushings could not be obtained so an older style bushing that was in inventory was reused as a replacement.

3.0 Transformer Assessment

Newfoundland Power engaged the Consultant to perform a transformer condition assessment of TCV-T1.[4] The Consultant's review and assessment of TCV-T1 included the dissolved gas in oil analysis reports, maintenance reports, and photographs to aid in the assessment.[5]

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[1] Located immediately off the coast from the Plant is the Witless Bay Ecological Reserve. In summer it is home to hundreds of thousands of seabirds that come to the islands to nest and raise their young.

[2] The transformer assessment is located in Attachment C to this report.

[3] These pictures were taken prior to the transformer being painted in 2019. However, the underlying severe rust condition remains.

[4] The Consultant has more than 35 years of experience in the transformer services industry. Newfoundland Power has been using the Consultant in various aspects of its power transformer asset management program since 2002.

[5] Dissolved gas analysis is useful in evaluating transformer health, as the breakdown of electrical insulating materials inside a transformer generates gases within the transformer. Any sharp increase over time in key gas concentration is indicative of a potential problem within the transformer. The analysis of oil samples is part of the Company's transformer condition monitoring program.

On November 26, 2020, Newfoundland Power received the Consultant's transformer condition assessment for TCV-T1. The assessment concluded that, based on the age and condition of the transformer, removal from service in a planned, controlled manner should be completed within 1 to 2 years.

The transformer condition assessment completed by the Consultant is included in Attachment C.

4.0 Assessment of Alternatives

In general, the potential alternatives for addressing an end of life power transformer involve the following:

(i) The refurbishment of the existing power transformer, typically including removing the unit from site, shipping out of province, extensive internal component disassembly and replacement.
(ii) The replacement of the power transformer with a new unit.

This 71 year old transformer is severely deteriorated and has reached the end of its service life. It would not be cost-effective to refurbish this transformer due to the extensive work that would be required. Even if this transformer was removed from service to replace radiators and bushings, the transformer's core and windings would still be 71 years old. Therefore this would not necessarily extend the life of the transformer.

A replacement transformer would be manufactured to current standards and would be more energy efficient than the existing unit.

The TCV-T1 transformer has been in service for 71 years, and has operated under full load for most of that time.[6] Based on the: (i) age (ii) deterioration and (iii) the opinion of an expert consultant, the preferred alternative is to replace TCV-T1 with a new unit in 2022.[7]

5.0 Concluding

TCV-T1 is a critical piece of equipment at the TCV Plant substation. Continued operation of this transformer could result in an in-service failure. An in-service failure could result in the Plant being out of service for an extended period with associated cost of lost production. Due to the location of the Plant being in close proximity of the ocean, there is also the potential for environmental damage if there is a loss of transformer oil.

Inspection and assessment results indicate that this 71 year old transformer has reached the end of its service life. It is necessary that TCV-T1 be replaced with a new unit, and that the modifications to TCV Substation be completed as recommended in this report.

---

[6] Plant transformers are load matched with the generators and typically operate at or near full rated load.
[7] The capital project to replace TCV-T1 will require additional capital expenditures to relocate the existing substation to accommodate the new transformer.

Attachment A

TCV Substation Single Line Diagram

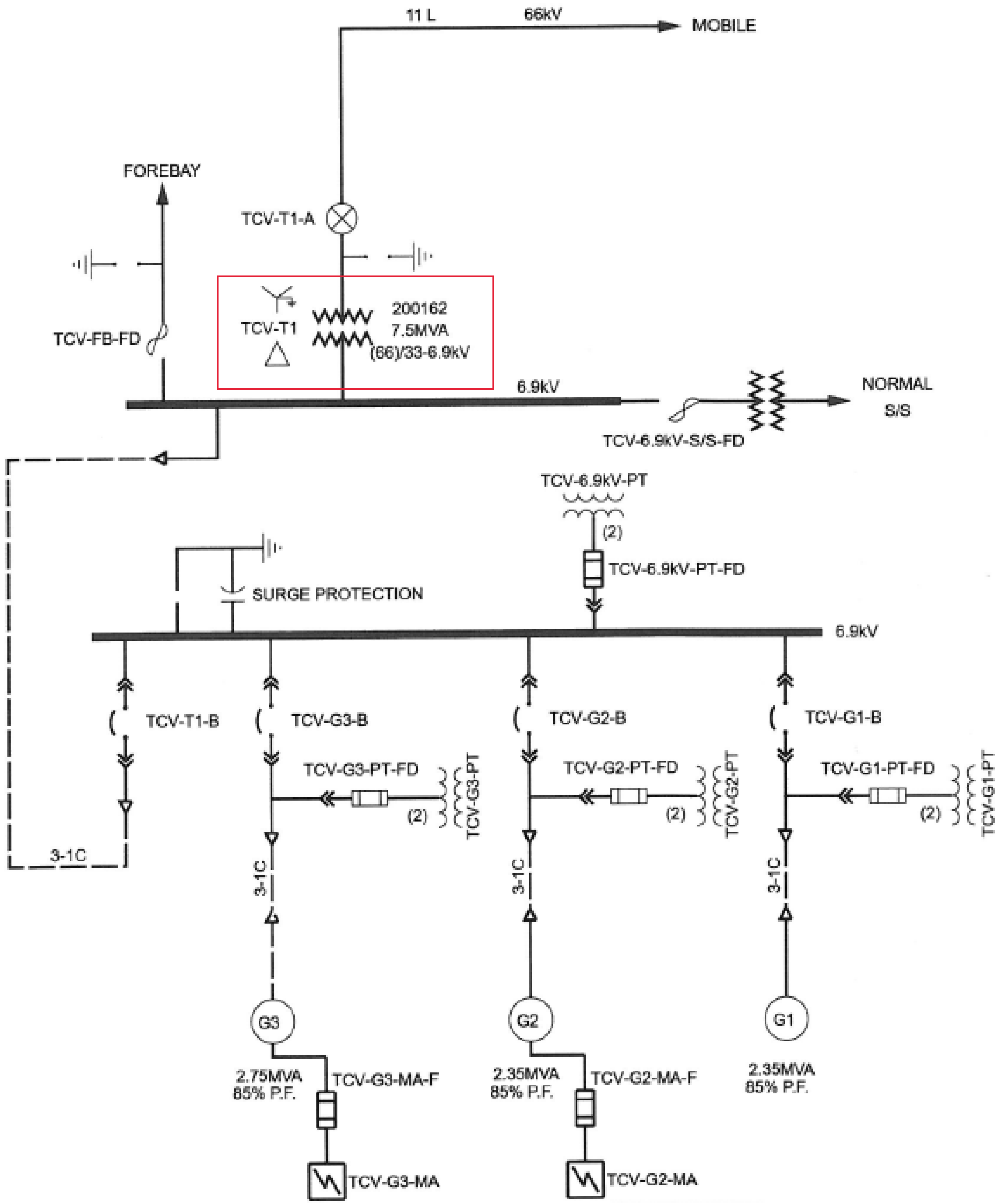


Figure B-2: TCV Substation Single Line Diagram

Attachment B

Photographs

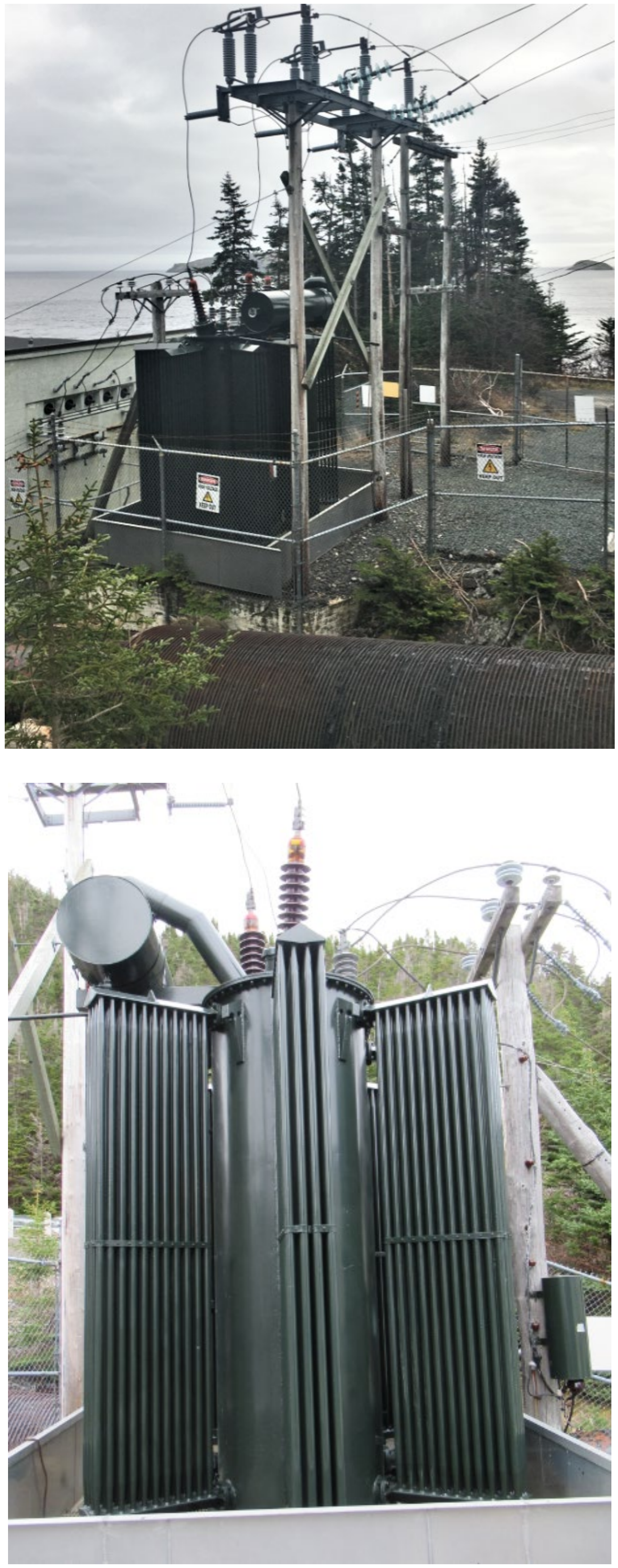


Figure B-3: Tors Cover Substation TCV-T1 Power Transformer

Figure B-4: Tors Cover Substation TCV-T1 Power Transformer – Severe Rusting

Attachment C

TCV-T1 Transformer Condition Assessment

van Kooy
Transformer Consulting Services Inc.

Ph. 905 308-9888
Email john@vankooy.com
web site www.vankooy.com

November 26, 2020

To: Nicholle Marsh, Adam Wong - Newfoundland Power

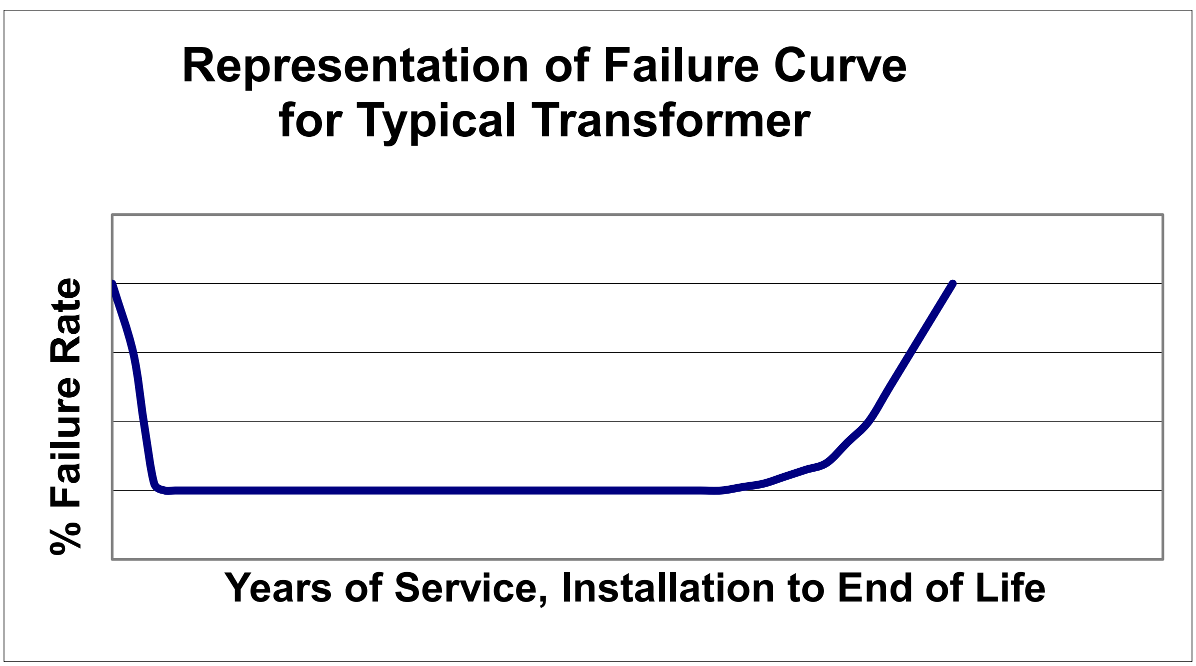
Subject: Tors Cove T1 Transformer Condition Assessment

Executive Summary

Tors Cove T1, P-162, Canadian General Electric, S# 256858 is near end of life and should be a candidate for replacement in the next 1 to 2 years.

Basis of Evaluation

That are a number of factors that impact longevity in power transformers. Like much long-lived equipment, the life span of power transformers typically follow a ‘bathtub’ curve. After a short period of potentially a higher failure rate, there is a long period of a low probability of failure (< 1%) and then as the equipment approaches end of life, the failure rate spikes up. The tipping point will vary with transformer application (transmission, generation, distribution, industrial, specialty industrial) as well as with other factors.



The **Age** of the transformer is certainly a key factor. The weak point in all power transformers is the cellulous (paper) insulation that is integral to the windings and interconnecting leads and is vital for electrical isolation and mechanical support. As this cellulous insulation ages, it becomes more brittle and prone to failure as the result of the normal stresses of short circuits, over voltages and overloads. The characteristic of this insulation, flexibility when new and brittleness when aged, is called Degree of Polymerization (DP). It is not possible to effectively monitor DP while the transformer is in use and can only be determined by a biopsy of samples of insulation in key areas which cannot practically be done unless a 'post mortem' is performed.

The insulation aging is affected by operating temperature which is related to loading and ambient temperature. Short periods of overloading do not generally lead to failure but have a cumulative affect over time. The effects of overloading can be somewhat monitored through Dissolved Gas in Oil testing. Excessive moisture will also accelerate insulation degradation and can be monitored through General Oil Quality testing.

The other main elements inside the transformer, copper and steel, do not effectively age so the key to long life is keeping the insulation in the best shape as possible with the understanding that like the human experience, there is no cure for old age.

Dissolved Gas in Oil Analysis (DGA) is the best ongoing way to monitor the condition of a fluid filled transformer. Issues of overloading, overvoltage, lightning strikes, and decaying internal components can be detected with the interpretation of the results.

Standard Oil Quality (SOQ) is another fluid sampled test that monitors the key parameters around the cleanliness and effectiveness of the oil as an insulation medium.

Field Test Results offer the ability to take snapshots of key parameters of the transformer over time and to confirm viability in the case of suspected failure. This testing is limited in that the testing is done at a relatively low voltage and cannot simulate operating voltages. Testing such as Turns Ratio and Winding Resistance will verify internal connections and other tests such as Insulation Resistance (Megger) and Power Factor/Dissipation Factor and Capacitance can monitor general insulation condition over time.

The **Condition of Key Components** is critical to the operation of the transformer since the failure of any of these components will render the transformer inoperable. Key components include, Bushings, On Load Tap Changers (OLTC) and De-Energized Tap Changers (DETC).

There are **Other Risks** to be considered including mechanical compromise of the main tank or radiators leading to oil leaks, Lightning Strikes, Over Voltage events, Overloading events and the presence of PCB's in the transformer.

van Kooy Transformer Consulting Services Inc.

Detailed Analysis

Tors Cove T1, P-298, Canadian General Electric S# 256858, 7.5 MVA, 6.9 kV to 33//66 kV, GSU, built in 1950

This transformer is 70 years old. The latest (2008 to 2020) Dissolved gas in oil analysis does not show any elements of concern and indicates that the present loading is within this transformer capability The General Oil Quality is not showing signs of degradation. I expect the oil has been replaced at some earlier point in this transformer's life. At this point, oil sampling is being performed on a 6-month cycle which is prudent for this age of equipment.

Recent field maintenance reports (2019) indicate that the old, chipped leaking HV bushings have replaced with old GE bushings. These bushing tested well after installation. The PCB content of these bushings has not been indicated but experience shows that GE bushing PCB in oil testing has yielded results between 5 and 110 ppm, well above the < 2 ppm requirement for new equipment.

The tank has been repainted but there is still concern over the leaking radiators and the radiator isolation valves cannot be closed. The PCB content of the main tank oil is in question but General Electric transformers of this vintage have shown > 2 ppm.

Assessing this transformer based on the criteria listed and the data provided, results in a ranking of **3.3**, where 1.0 would be suitable for continued service with no concerns and 4.0 would be remove from service ASAP.

Recommendations

There are sufficient negative indicators to position this transformer near end of life. It is better to remove a transformer from service in a planned and controlled way as opposed to dealing with the outfall of an unplanned failure.

I suggest planning to replace in the next 1 to 2 years.

Regards,

van Kooy Transformer Consulting Services Inc.

per: Sjoerd (John) van Kooy

2022 Transmission Line Rebuild

May 2021

Prepared by:
Sheldon Baikie, P. Eng.

LICENSED PROFESSIONAL ENGINEER
10231
SHELDON BAIKIE
SIGNATURE
May 5th 2021
DATE
NEWFOUNDLAND & LABRADOR

Table of Contents

1.0 Introduction

Newfoundland Power Inc.'s ("Newfoundland Power" or the "Company") transmission lines are the backbone of the electricity system providing service to customers. The Company operates approximately 2,060 kilometres of transmission lines at 66 kV and 138 kV. Most of these transmission lines are located across country, away from road right of ways.

Transmission line failures typically result in outages to a significant number of customers at once. Maintaining transmission lines is therefore critical to the delivery of reliable service to customers.

Newfoundland Power plans to continue implementation of the *Transmission Line Rebuild Strategy* in 2022.

The transmission line sections to be rebuilt in 2022 are included in Table 1.

Table 1
2022 Transmission Line Projects[1]

Transmission Line	Distance to be Constructed	Year Constructed
124L	29.0 kilometres	1964
94L	21.5 kilometres	1969

2.0 Background

Newfoundland Power filed a *Transmission Line Rebuild Strategy* as part of its *2006 Capital Budget Application.* The strategy outlines a long-term plan to rebuild aging transmission lines with the prioritization of projects based on: (i) physical condition; (ii) risk of failure; and (iii) potential customer impact in the event of a failure.

This strategy is regularly updated to ensure it reflects the latest condition assessments, inspection information, and reliability data. A total of 26 transmission lines have been rebuilt under the strategy since 2006. By the end of 2021, 76% of the rebuild strategy will have been executed.[2]

[1] The 50.5 kilometres of Transmission Line being rebuilt in 2022 represents 2.5% of the Company's in-service transmission line assets.

[2] Three transmission lines have been removed from the strategy since 2006: 101L and 102L, which have been addressed as part of the *Central Newfoundland System Planning Study*, and 53L, which is no longer in service. This brings the total number of transmission lines encompassed by the strategy to 34. One transmission line included in the strategy is being partially rebuilt in 2021 (124L), keeping the total rebuilt by year end to 26 (26 / 34 = 0.76, or 76%). Six of the 8 remaining transmission lines rebuilds are included in the schedule provided in Appendix A. The final 2 transmission line rebuilds, 105L and 35L, are currently scheduled for 2027.

3.0 Transmission Line 124L ($6,020,527)

Transmission Line 124L is a 138 kV H-Frame line running between Clarenville ("CLV") Substation and Gambo ("GAM") Substation. This line is part of the 138 kV looped transmission system between Sunnyside ("SUN") Terminal Station and Stony Brook ("STY") Terminal Station near Grand Falls-Windsor. The line was originally constructed in 1964 and is 86.1 kilometres in length.[3] The line consists primarily of H-Frame structures with 397.5 Aluminum Conductor Steel Reinforced ("ACSR") transmission line conductor.

Since 2001, a total of 22.3 kilometres of Transmission Line 124L was rebuilt between CLV Substation and Thorburn Lake.[4] These upgrades were necessary to correct ground clearance issues and address line failures in the area caused by severe ice and wind loading. Transmission Line 124L was originally designed to withstand conductor ice loading of 12.7 mm (½") of radial ice. Actual accumulation of 38 mm (1½") has been measured on this line. Ice loading has been severe enough that the conductor in this section of the line has been permanently stretched, thus increasing the sag of the conductor and decreasing the ground clearance.

During 2021, the Company is rebuilding 30.0 kilometres of Transmission Line 124L between Port Blandford ("PBD") Substation and Terra Nova ("TNS") Substation.[5]

In 2022, Newfoundland Power will address the remaining 26.7 kilometres of the 1964 vintage section of Transmission Line 124L from TNS Substation to GAM Substation.[6] The project will include the rebuild of 23.6 kilometres of transmission line infrastructure, the dismantling of 3.1 kilometres of transmission line infrastructure, and the construction of a new 5.4 kilometre section of transmission line infrastructure into Glovertown ("GLV") Substation. The net result will be 29.0 kilometres of transmission line construction. The reconfigured Transmission Line 124L will loop the transmission system in this area.[7] The reconfiguration of Transmission Line 124L will also remove the two 138 kV switch structures at Alexander Bay ("ALX") Switchyard serving GLV Substation that are due for refurbishment.

Condition Assessment
Deterioration on this section of Transmission Line 124L primarily relates to deteriorated poles and ball link eye bolts.

---

3 The line consists of approximately 79 kilometres of original construction built in 1964 and 7.2 kilometres built in 1986.

4 From 2001 to 2005, a total of 17.3 kilometres of the line was rebuilt and in 2012 a 5.0 kilometre rebuild was completed.

5 See Board Order No. P.U. 37 (2020).

6 The section of Transmission Line 124L to be addressed in 2022 is the sole supply for 3,700 customers in the Glovertown and Eastport Peninsula areas. Approximately 20.0 kilometres of this section of line is located in the back country west of Terra Nova National Park.

7 Looping the transmission system at GLV Substation creates operational flexibility that will provide reliability benefits to the customers served by GLV Substation.

Table 2 provides an overview of the deterioration identified during the 2020 inspection of the section of Transmission Line 124L that is proposed to be rebuilt.

Table 2
Transmission Line 124L Deterioration

Line Component	Total Number of Line Components	Number of Deteriorated Line Components	Percentage Deteriorated
Poles	203	197	97%
Eye Bolts	321	303	94%
Cross Braces	110	37	34%
Cross Arms	110	17	15%

Approximately 97% of poles on this section of line are deteriorated. Noted deterioration includes decay, shell separation and checks in the poles.[8]

Approximately 94% of the ball link eye bolts on this section of line are deteriorated. These bolts connect insulators to crossarms on H-Frame structures. Due to the design and movement over time, the friction that results from these eye bolts rubbing together causes the pieces to wear through as seen in the picture below. When the insulator separates from the eyebolt, both the insulator and attached conductor falls free of the crossarm. This can cause a phase to ground fault that results in a protection trip which de-energizes the transmission line or a serious safety hazard where an energized line could be suspended close to the ground.

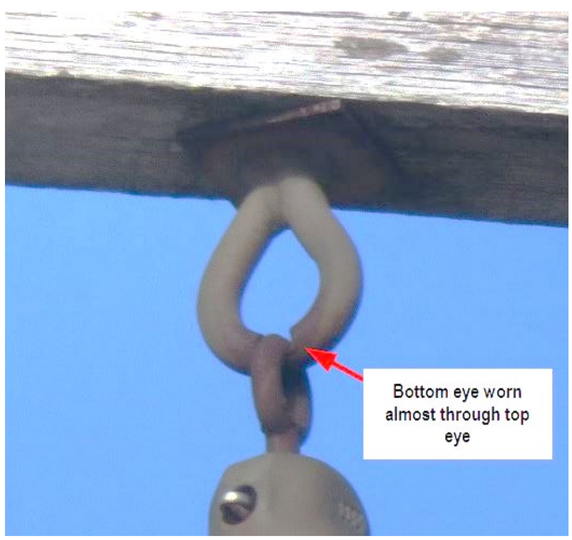


Figure 1: Worn Ball Link Eye Bolt

[8] See Figures C-1 through C-4 of Appendix C.

In addition to deteriorated components, this line was originally constructed with equipment that does not meet current standards. This includes sub-standard insulators, guying and framing. For example, approximately 65% of structures on this section of line have porcelain insulators manufactured by Canadian Ohio Brass ("COB") or Canadian Pacific.[9] These insulators are prone to failure and are no longer considered industry standard.[10]

Transmission Line 124L Reconfiguration

Transmission Line 124L serves approximately 3,700 customers through GLV, PBD and TNS substations via 3 radial transmission taps.[11] With the current design, a fault at either substation or anywhere along the line results in outages to all customers in these 3 substations. An analysis of historical outage data suggests that 124L has been prone to outages primarily due to wind and lightning.

The work proposed as part of this rebuild, in conjunction with the *Substation Refurbishment and Modernization* project for GLV Substation, will result in the termination of Transmission Line 124L at GLV Substation, thereby reducing outages to customers supplied from GLV, PBD and TNS substations.[12]

Transmission Line 124L supplies GLV Substation via Transmission Line 121L, a radial transmission tap extending approximately 5.3 kilometres from ALX Switchyard to GLV Substation.

---

9 The Company has changed its standard from porcelain to toughened glass for suspension insulators. Figures C-5 and C-6 in Appendix C show structures with sub-standard porcelain insulators.

10 The most common mode of failure for these insulators is cement growth, which is the expansion of the material that holds in place the pin supporting the connection of the insulator to the pole and conductor. Cement growth causes hairline cracks in the porcelain, weakening the insulator leading to electrical and mechanical failure.

11 GLV Substation serves approximately 2,700 customers. TNS Substation serves approximately 300 customers. PBD substation serves approximately 700 customers. In total, approximately 3,700 customers are served directly by Transmission Line 124L.

12 The effect of sectionalizing 124L via breakers in GLV, PBD or TNS substations on historical outage minutes was assessed and it was determined that sectionalizing the line at GLV Substation would have resulted in a potential net reduction of transmission-related outage minutes to all 124L customers by 80% since 2002. In comparison, sectionalizing the line at PBD or TNS substations would have resulted in a potential net reduction to transmission-related outage minutes by 18% and 29%, respectively.

Figure 2 includes a map illustrating the existing configuration of the transmission system at ALX Switchyard and GLV Substation.

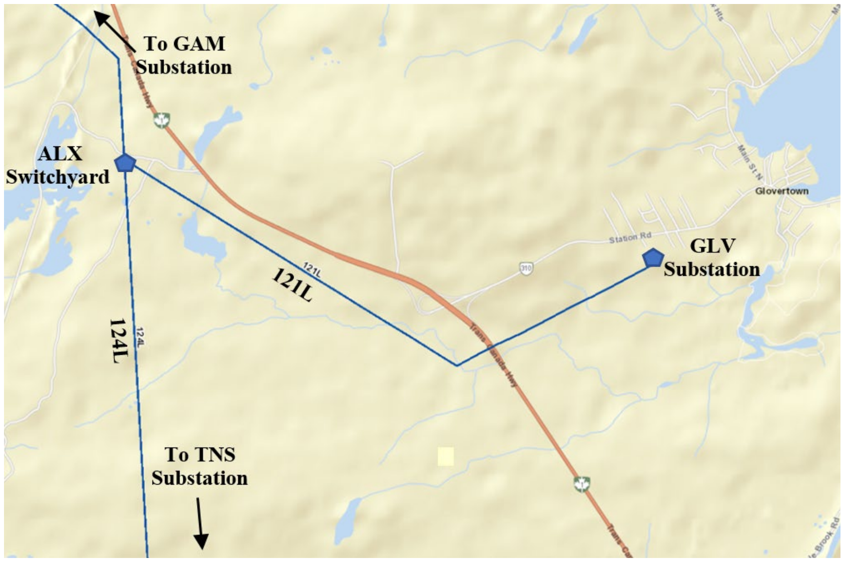


Figure 2: Existing Configuration of 121L/124L at ALX Switchyard and GLV Substation

ALX Switchyard consists of 2 separately fenced 138 kV air break transmission switches. One switch, ALX-124L-A2, was built in 1983 and the other switch, ALX-124L-A3, was built in 1994. The 2 switchyards are shown in Figure 3.

Figure 3: ALX-124L-A2 (Left) and ALX-124L-A3 (Right)

ALX-124L-A2 has been in service for 38 years and ALX-124L-A3 has been in service for 27 years.

Both switches and associated infrastructure are in poor condition and due for refurbishment.[13] Mechanical deterioration in recent years has resulted in the unreliable operation of these switches during manual fault isolation activities when responding to outages on 124L. This has resulted in extended outage times to customers supplied by Transmission Line 124L.

As part of the 2022 rebuild of 124L, the ALX Switchyard will be retired and 124L will connect directly into GLV Substation. This will result in 2 separate transmission lines entering GLV Substation and will result in a looped configuration with 121L. The section of line between GAM Substation and GLV Substation will be renamed 121L, and the section between GLV Substation and CLV Substation will be remain designated as 124L. Figure 4 includes a map illustrating the proposed configuration following the 2022 rebuild of 124L.

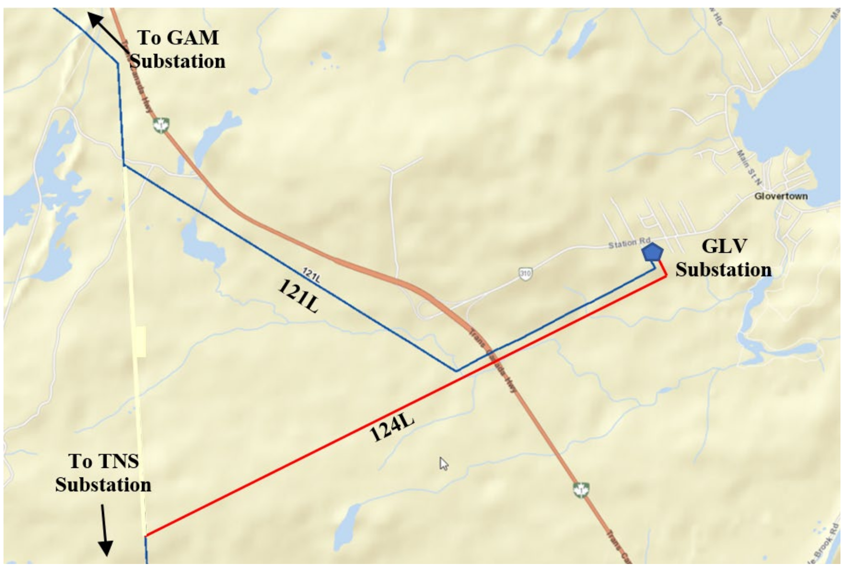


Figure 4: Proposed Configuration of 121L/124L Terminating at GLV Substation

Project Scope

The 29.0 kilometre section of 124L from TNS Substation to GAM Substation is approaching 58 years in service and has reached the point where continued maintenance on individual structures is no longer feasible due to widespread deficiencies throughout the line. This section of line must be rebuilt to ensure the line can operate reliably and meet the design criteria for transmission lines operating in the geographic area. The rebuild of this section of 124L will include a reconfiguration of the transmission line with a termination at GLV Substation. This will involve an additional 2.3 kilometres of transmission line construction, and results in the retirement of ALX Switchyard. The reconfigured Transmission Line 124L will provide

13 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 a switch, its operation contributes to 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, which causes heating, arcing and eventually switch failure.

operational flexibility and associated benefits to the 3,700 customers directly served by Transmission Line 124L.

Based on its age, deteriorated condition and criticality, this 29.0 kilometre section of the transmission line will be rebuilt in 2022 at an estimated cost of $6,020,527.

4.0 Transmission Line 94L ($4,473,000 in 2022, $4,346,000 in 2023, $4,276,000 in 2024)

Transmission Line 94L is a 66 kV H-Frame radial line running between Blaketown ("BLK") Substation on the Trans-Canada Highway near Whitbourne, and Riverhead ("RVH") Substation located in Riverhead, St. Mary's Bay. The line was originally constructed in 1969 by Newfoundland and Labrador Hydro.[14] The line includes approximately 58 kilometres of original construction consisting of 290 two-pole H-Frame structures and 32 single pole structures, with sub-standard 266.8 ACSR transmission line conductor.[15] This line provides the only source of supply for St. Catherine's and Riverhead substations along with Trepassey Substation via Transmission Line 95L. In total, the 3 substations serve approximately 2,500 customers.

Deterioration of the entire line primarily relates to deteriorated poles, cribs, cross braces and predominance of deteriorated FleXall clamps.

FleXall clamps attach the conductor to the underside of the suspension insulator. These clamps were installed on some transmission lines in the late 1960's. Recent inspections have found that after over 50 years in service the clevis pins are wearing through the clamp due to line vibration. In some cases, the pin has worn through the underside of the suspension clamp damaging the conductor.[16] Figure 5 shows images of a worn clamp and the damage it caused to the conductor.

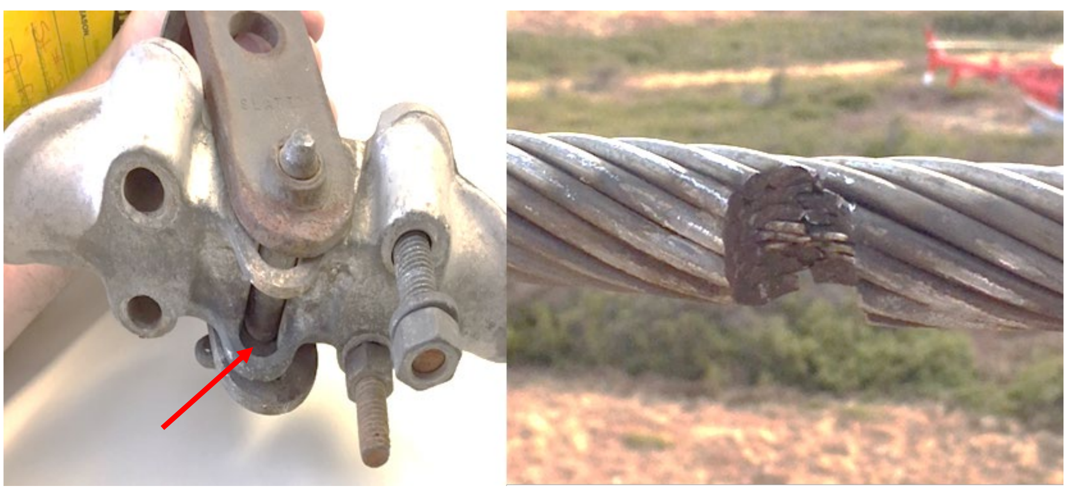


Figure 5: Worn FleXall Clamp and Associated Damaged Conductor

[14] Transmission Line 94L was purchased by Newfoundland Power in 1972.

[15] ACSR is a bare overhead conductor constructed with aluminum outer strands and a steel core to support the weight of the cable. 266.8 ACSR has been noted to have poor operating characteristics in a salt spray environment. 266.8 ACSR is no longer a standard conductor for the Company's transmission lines.

[16] The Company has been recording the locations and monitoring these clamps since the issue was first discovered in 2018.

Table 3 provides an overview of the deterioration identified during the 2020 inspection of the section of Transmission Line 94L that is proposed to be rebuilt.

Table 3
Transmission Line 94L Deterioration

Line Component	Total Number of Line Components	Number of Deteriorated Line Components	Percentage Deteriorated
Poles	612	378	62%
Cross Braces	97	66	68%
Cross Arms	581	120	21%
Cribs	53	44	83%
FleXall Clamps	714	383	54%

Approximately 62% of poles on this line are deteriorated. Noted deterioration includes decay, shell separation and splits in the poles.[17] Approximately 68% of structures that include cross braces are deteriorated. Noted deterioration includes decay and cracks. Approximately 54% of the FleXall clamps show visible wear.

In addition to deteriorated components, this line also does not meet current design standards. This includes conductor, guying and framing. For example, approximately 51% of structures on this line were framed without cross braces.[18]

Transmission Line 94L has reached the point where continued maintenance is no longer practical. As this is a radial line with no alternate source of supply, its deteriorated condition exposes customers to potentially more frequent and extended unplanned outages. For planned outages to address deficiencies, there are significant costs to transport, install and operate mobile generation to supply customers for the duration of planned outages.

Transmission Line 94L must be rebuilt to continue the provision of safe and reliable service to customers in the area. Based on its age, deteriorated condition and criticality, the line will be rebuilt over 3 years starting in 2022. In 2022, a 21.5 kilometre section of the transmission line 94L will be rebuilt at an estimated cost of $4,473,000. Where feasible, sections of the line will be moved to the roadside right-of-way to improve access, thereby decreasing construction costs and making ongoing maintenance easier and less expensive.[19]

17 See Figures C-7 through C-9 of Appendix C.
18 Figure C-16 in Appendix C shows an example of a 2-pole H-Frame structure without cross bracing. An H-Frame structure without cross-bracing is susceptible to failure due to unbalanced structural loading on the structure.
19 Approximately 20 kilometres of the entire line will be moved roadside.

In 2023 a further 20 kilometre section will be rebuilt at an estimate cost of $4,346,000. In 2024 the final 19.5 kilometre section will be rebuilt at an estimated cost of $4,276,000.[20]

5.0 Conclusion

In 2022, Newfoundland Power is proposing to rebuild the final 29.0 kilometre section of Transmission Line 124L and a 21.5 kilometre section of 94L. Recent inspections have identified significant deterioration and deficiencies on both lines. Continued maintenance is no longer feasible and these 2 sections of transmission line must be rebuilt to continue providing safe and reliable electrical service to customers.

Table 4 provides a detailed breakdown of the 2022 project cost by transmission line.

Table 4
2022 Project Cost
($000s)

Description	124L	94L	Total
Engineering	88	65	153
Labour - Contract	2,773	2,050	4,823
Labour - Internal	121	90	211
Material	2,106	1,579	3,685
Other	933	689	1,622
Total	**$6,021**	**$4,473**	**$10,494**

[20] Figures B-3 to B-6 of Appendix B shows the route taken by 94L and identifies the sections to be rebuilt in 2022, 2023 and 2024.

Appendix A

**Transmission Line Rebuild Strategy Schedule:
2022-2027**

Table A-1
Transmission Line Rebuilds
2022-2027
($000s)

Line	**Year Built**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
124L CLV-GAM	1964	6,021					
94L BLK-RVH	1969	4,473	4,346	4,276			
108L GAN-GBY[1]	1965		2,887	3,931			
146L GAN-GAM	1964		2,812	2,880	3,105		
95L RVH-TRP	1969				4,854	4,971	
55L BLK-CLK	1971				3,530	2,405	2,341
100L SUN-CLV	1964					5,033	
105L GFS-SBK	1963						2,422
35L OXP-KEN	1965						391
TOTAL		**10,494**	**10,044**	**11,087**	**11,489**	**12,409**	**5,154**

[1] Transmission Line 108L was not in the *2006 Transmission Line Rebuild Strategy*. Recent inspections indicate that Transmission Line 108L is deteriorating and in need of replacement. A system planning study will be filed in a future capital budget application.

Appendix B

**Maps of Transmission Lines
124L and 94L**

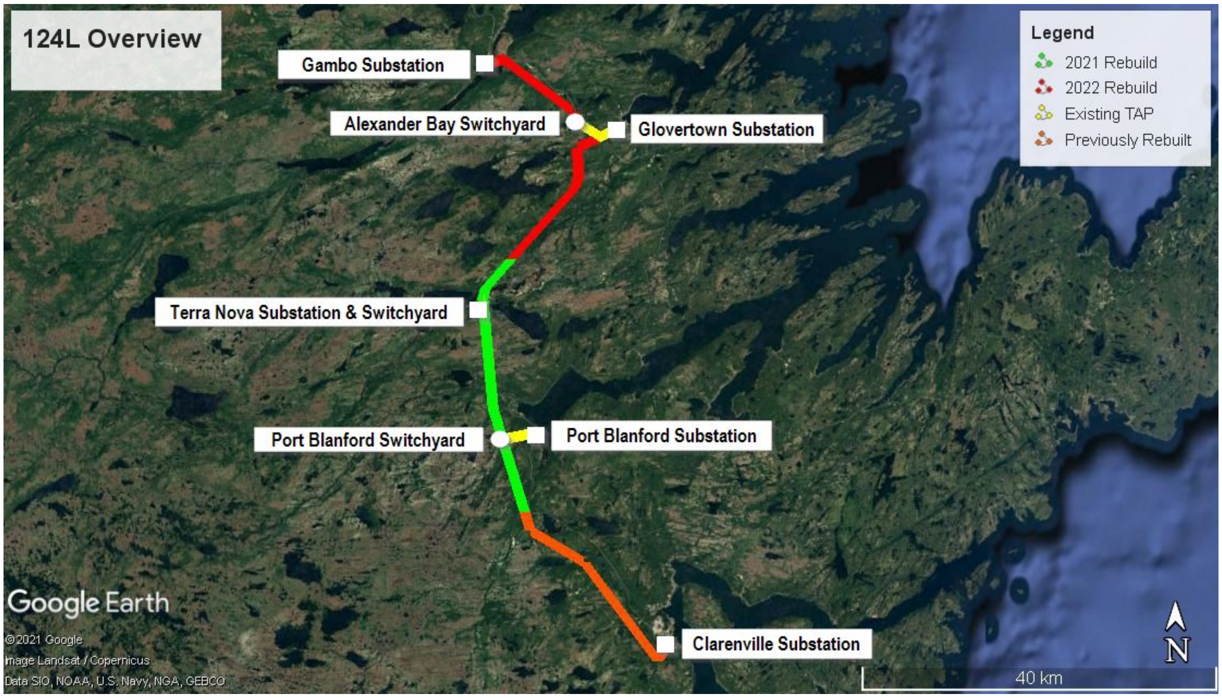


Figure B-1: Map of Transmission Line 124L

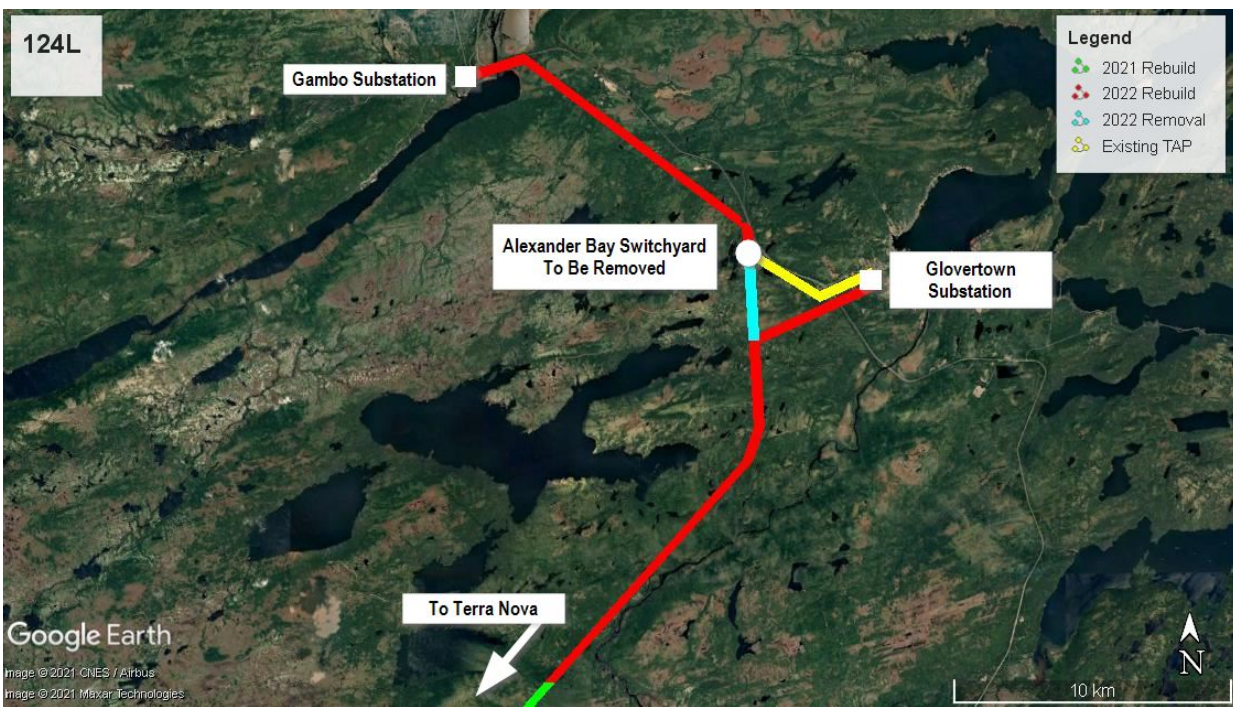


Figure B-2: Map of Transmission Line 124L (2022 Rebuild)

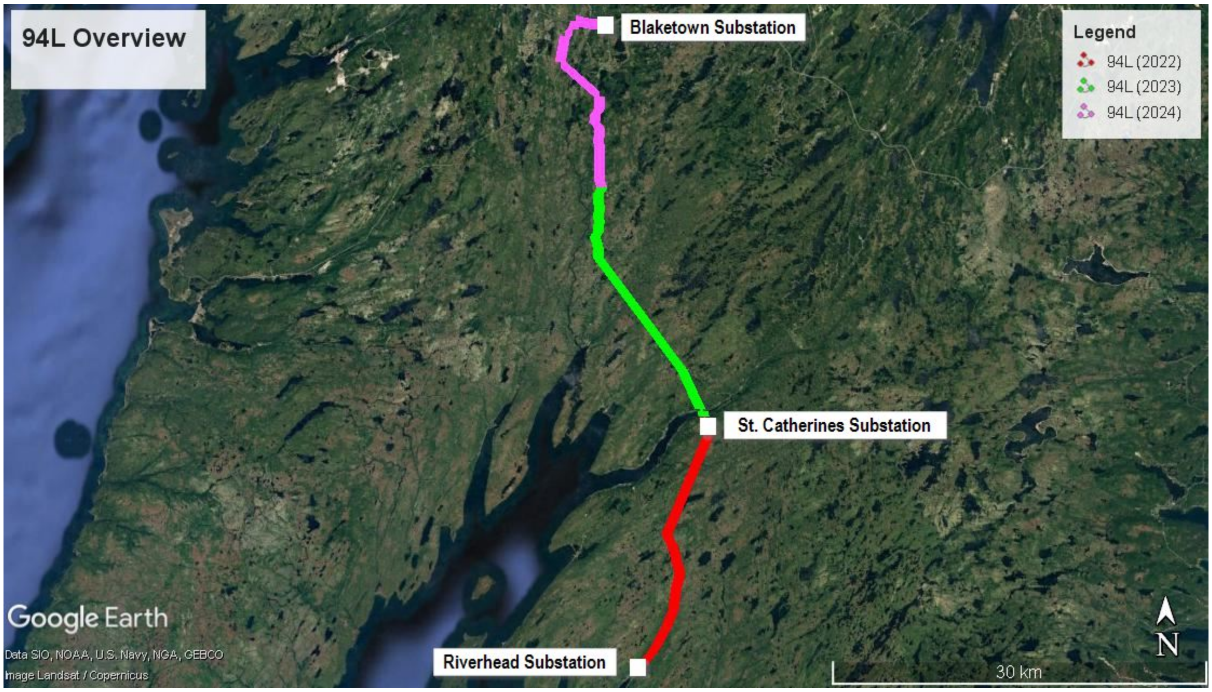


Figure B-3: Map of Transmission Line 94L

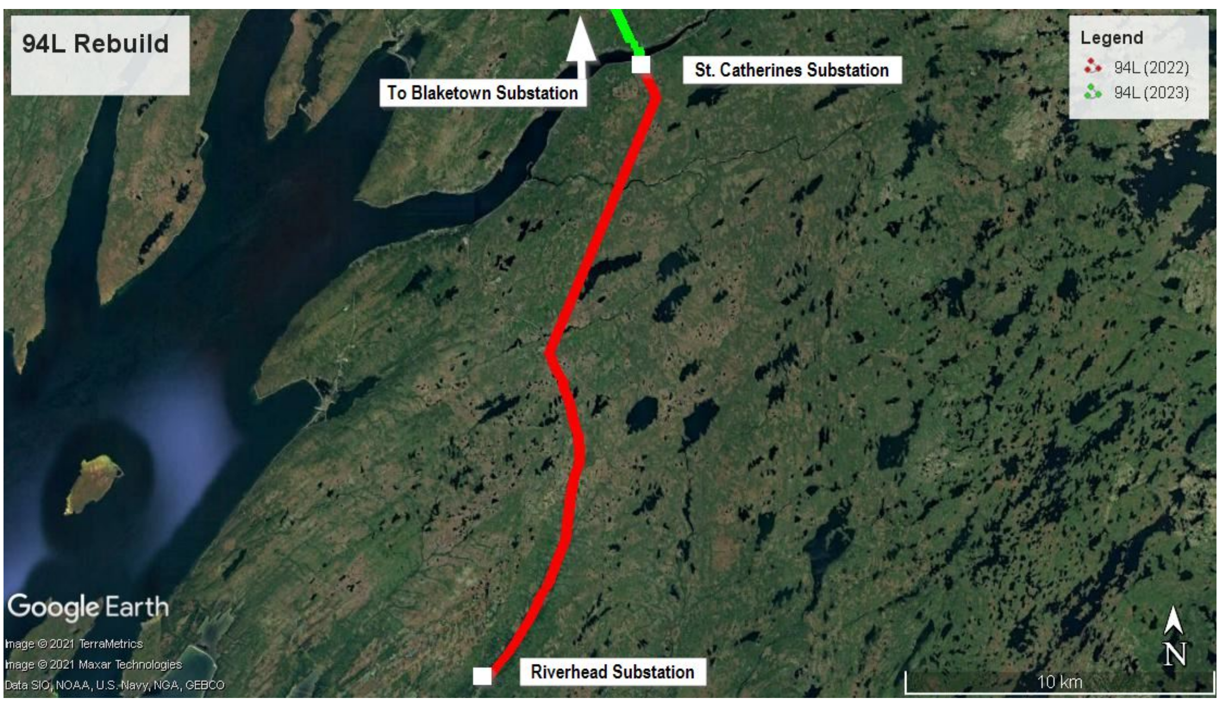


Figure B-4: Map of 94L Route (2022)

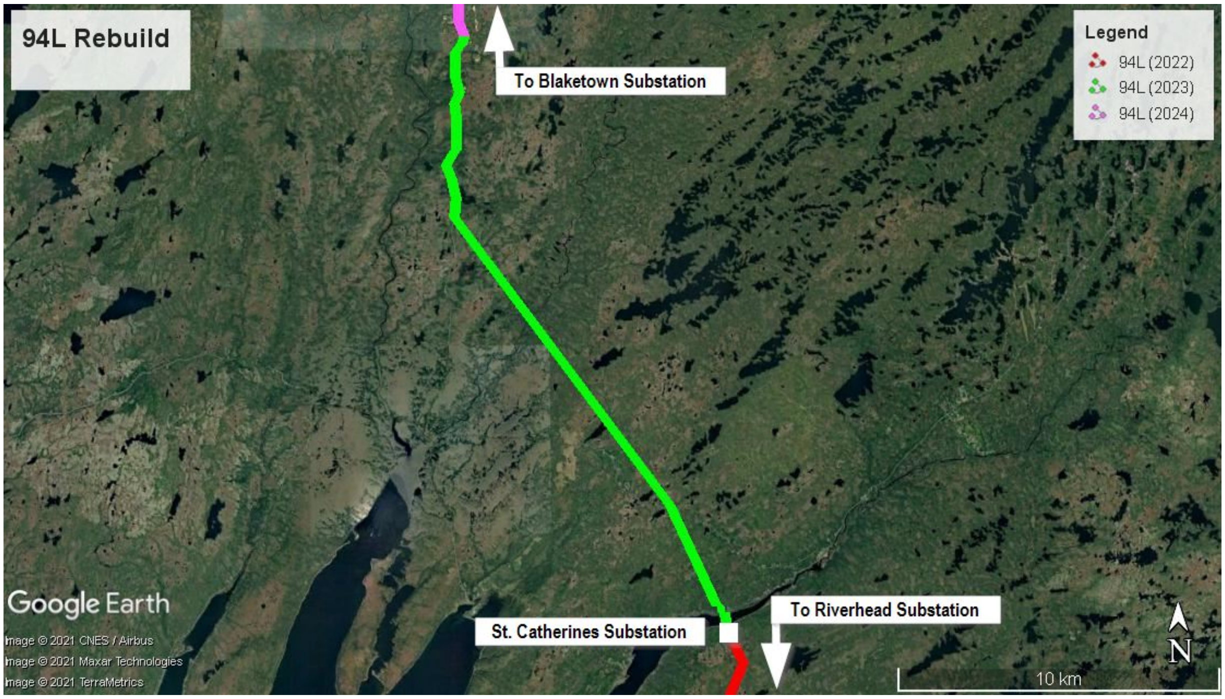


Figure B-5: Map of 94L Route (2023)

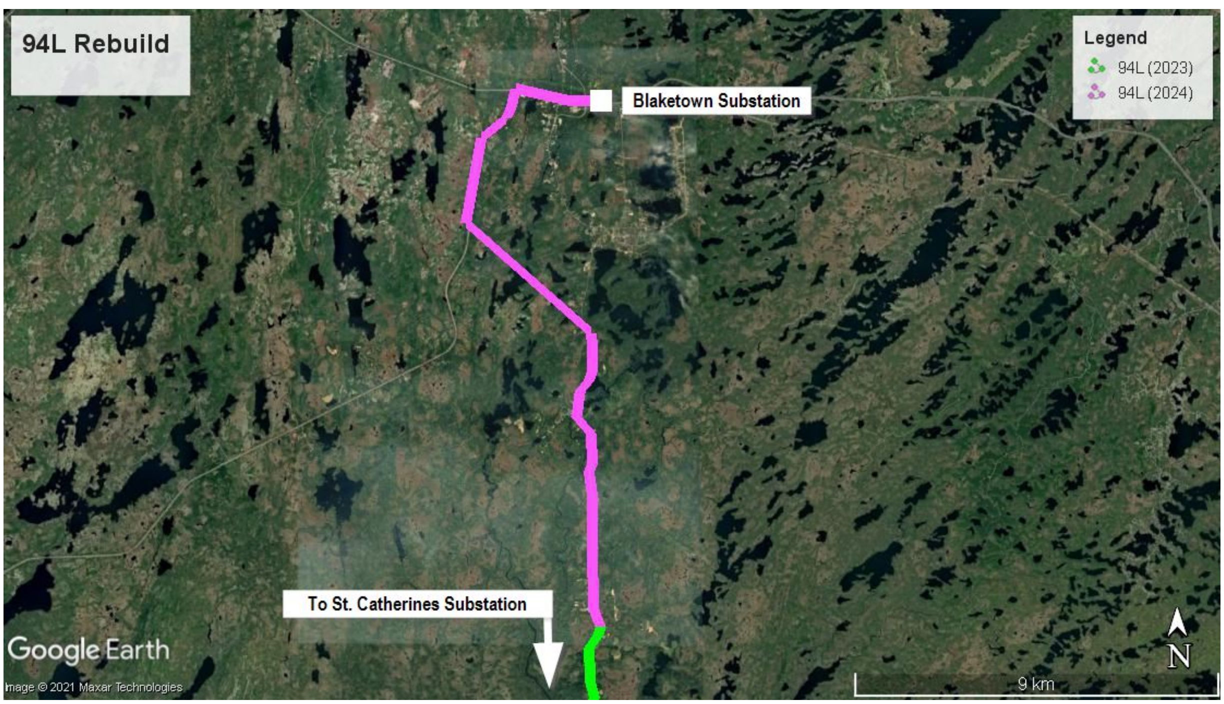


Figure B-6: Map of 94L Route (2024)

Appendix C

Photographs of Transmission Lines 124L and 94L

Transmission Line 124L

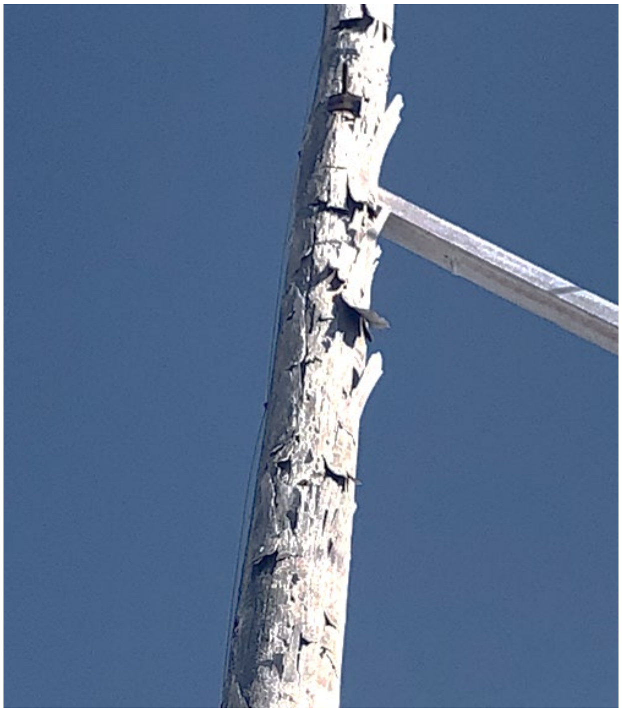


Figure C-1: Severe Pole Shell Separation

Figure C-2: Sizable Woodpecker Holes

Figure C-3: Pole Deterioration

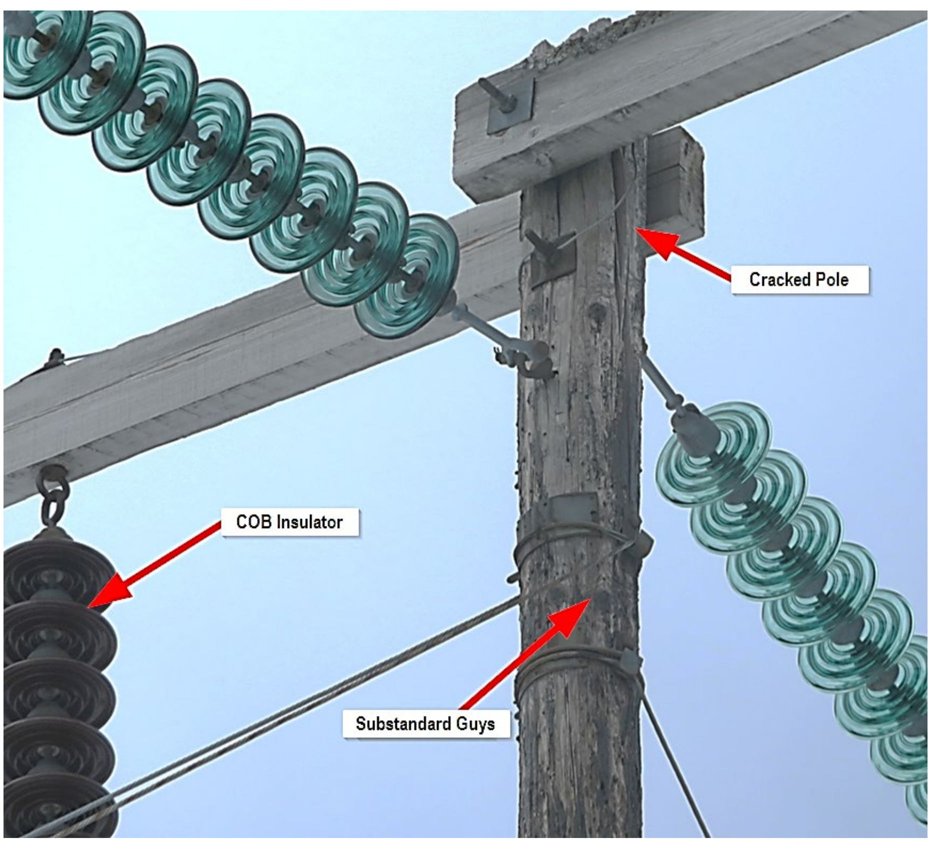


Figure C-4: Deteriorated Pole, Sub-standard Construction and COB Insulator

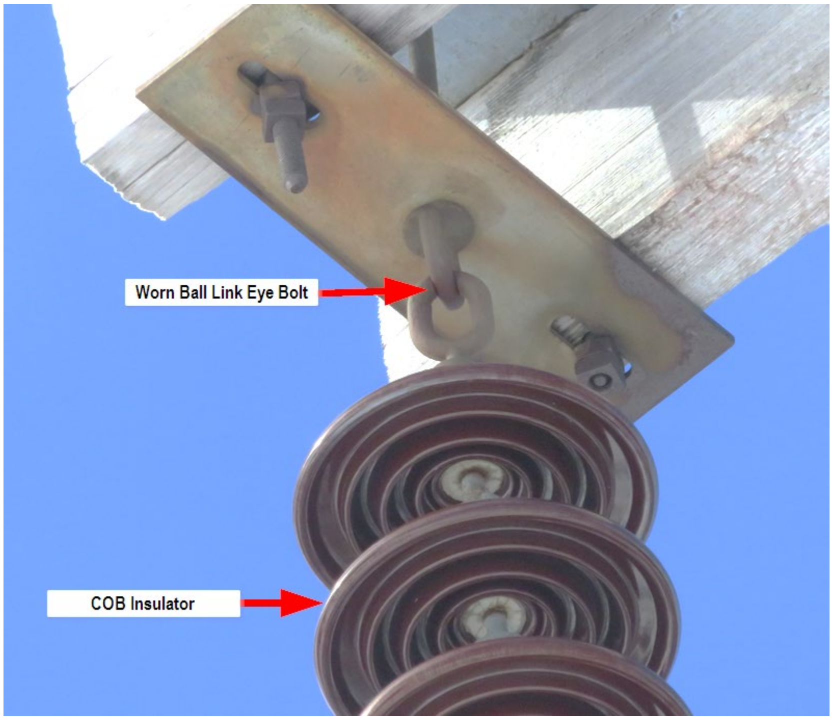


Figure C-5: Ball Link Eye Bolt Wear and COB Insulator

Figure C-6: Broken COB Insulator

Transmission Line 94L

Figure C-7: Deteriorated Pole Top

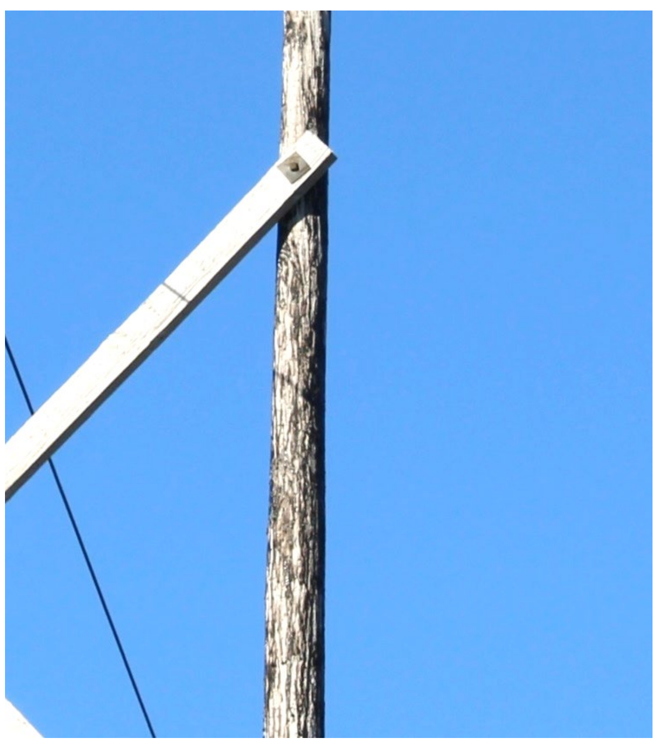


Figure C-8: Deteriorated Pole – Shell Separation

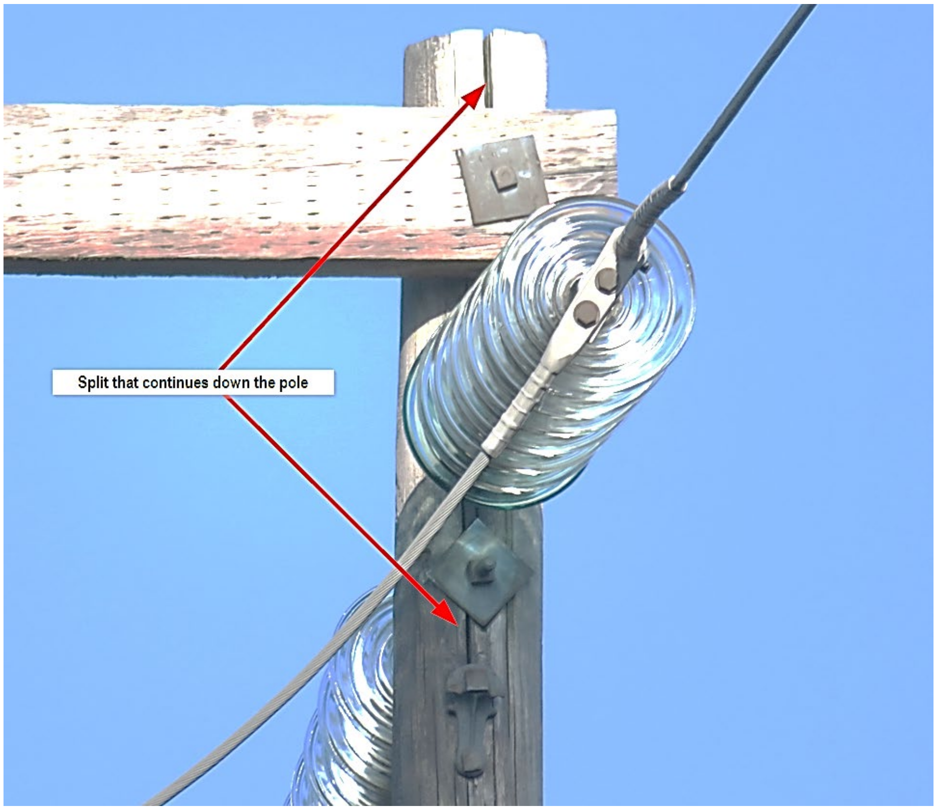


Figure C-9: Split Pole

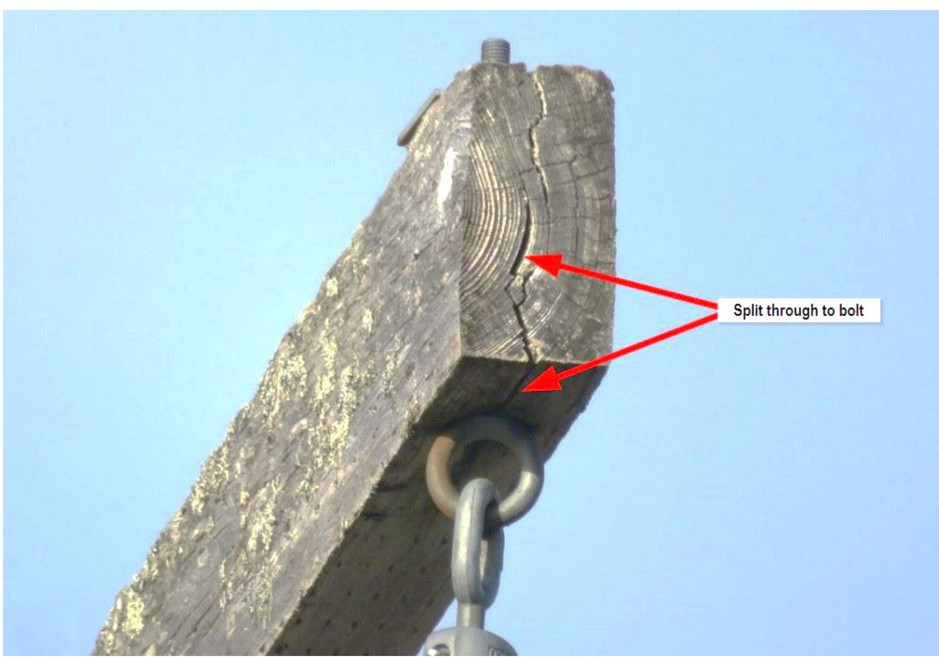


Figure C-10: Split Cross Arm

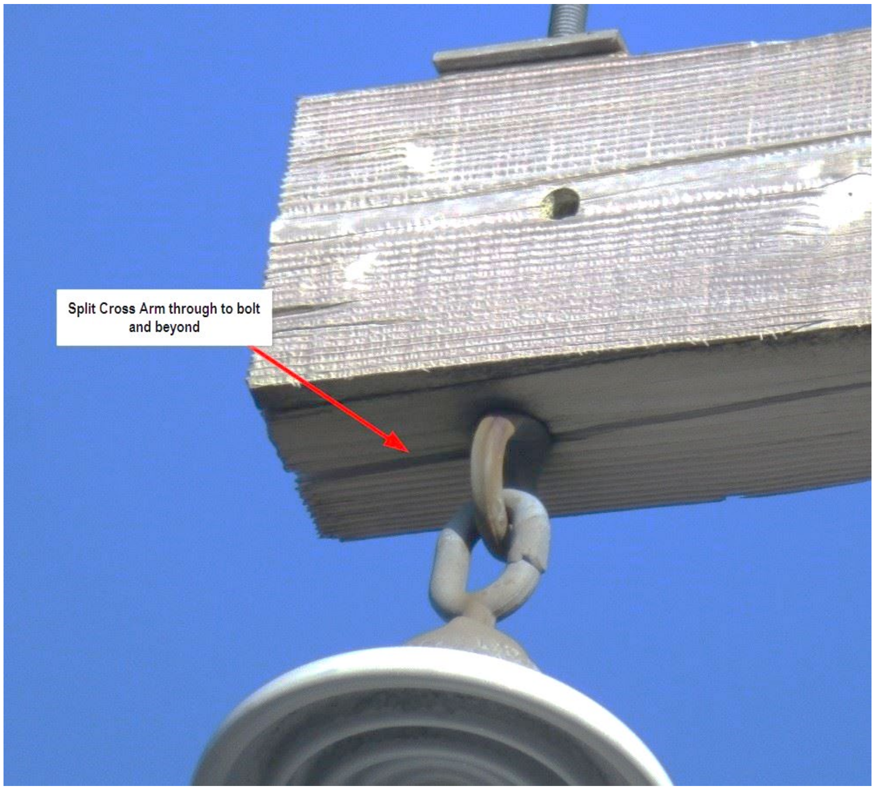


Figure C-11: Split Cross Arm

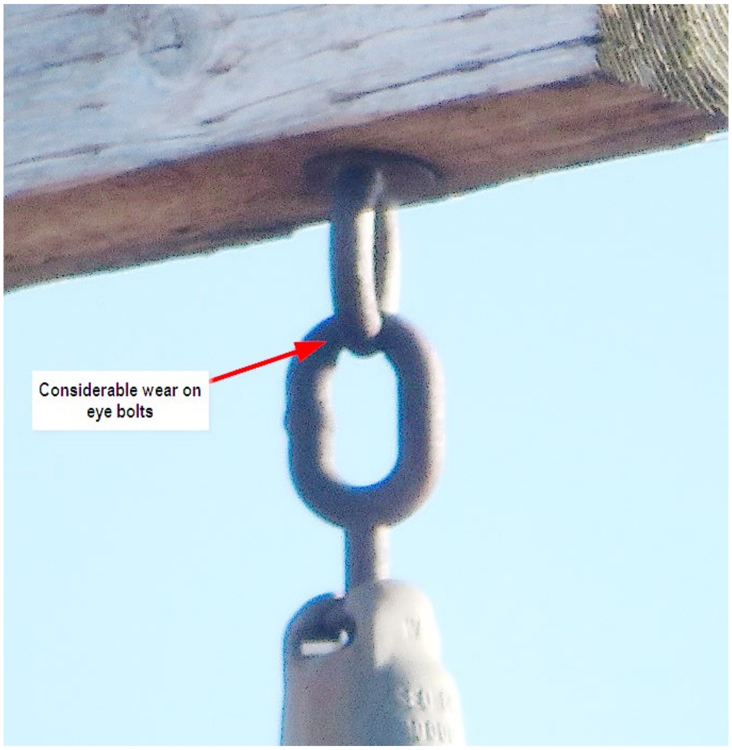


Figure C-12: Worn Ball Link Eye Bolt

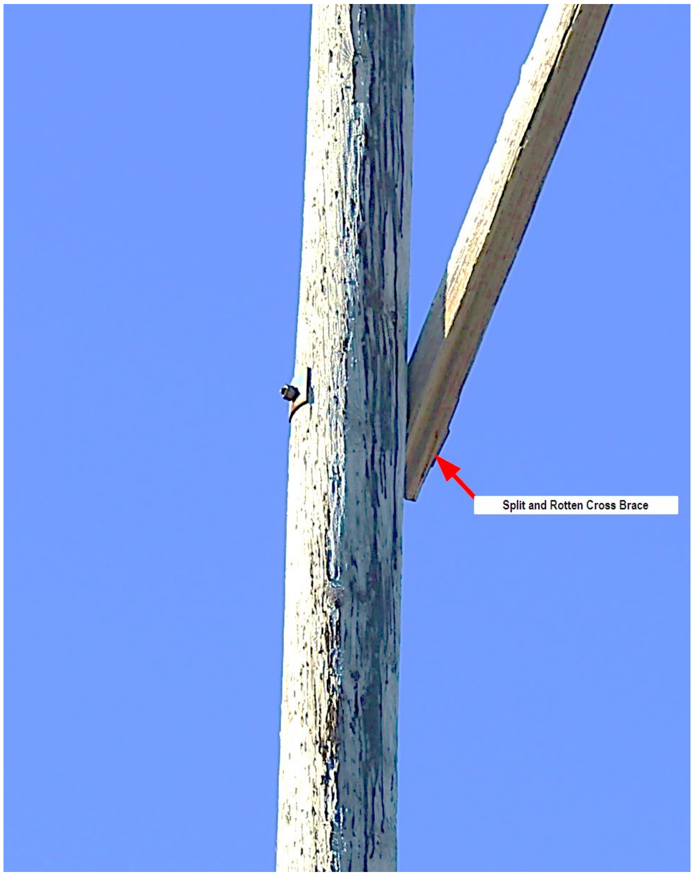


Figure C-13: Deteriorated Cross Brace

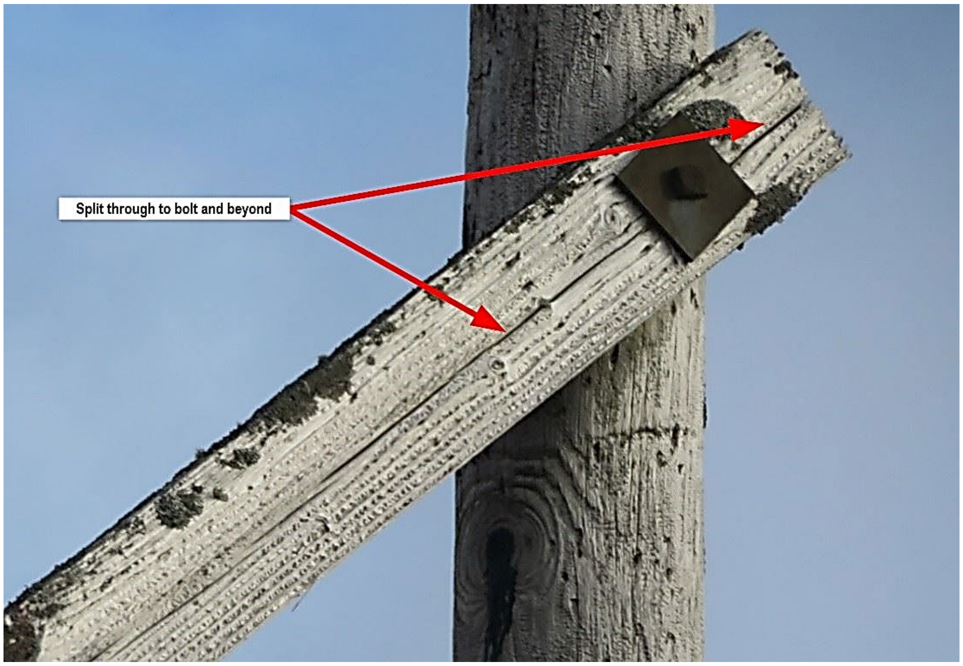
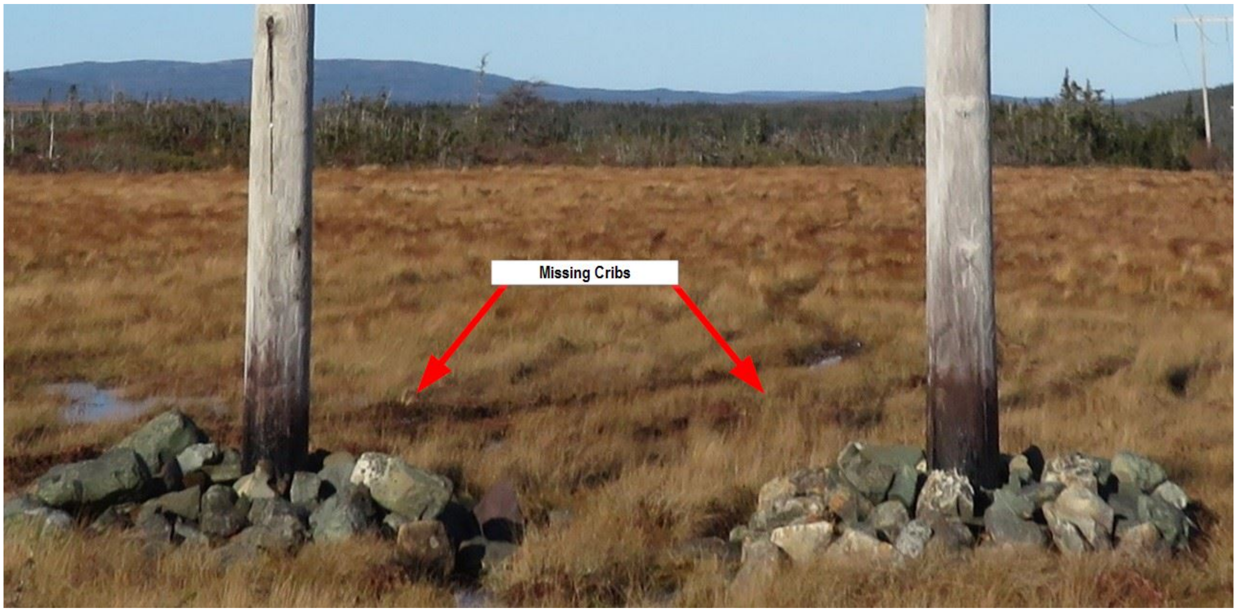


Figure C14: Cracked, Rotten Cross Brace



C-15: Missing Cribs

C-16: Leaning Structure – Substandard Construction

Distribution Reliability Initiative

May 2021

Prepared by:
Ralph Mugford, P. Eng.

REGISTERED PROFESSIONAL ENGINEER
RALPH W. MUGFORD
R. Mugford
SIGNATURE
May 15, 2021
DATE
NEWFOUNDLAND & LABRADOR

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1.0 Introduction

Newfoundland Power Inc. ("Newfoundland Power" or the "Company") manages electrical system reliability through capital upgrades, maintenance practices and operational deployment. On an ongoing basis, the Company examines its actual distribution reliability performance to assess where targeted upgrades are warranted to improve service reliability to customers in specific areas.

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. Targeted upgrades on these feeders is consistent with maintaining an acceptable level of reliability for all customers.

The process used by Newfoundland Power to identify which distribution feeders will benefit from targeted upgrades involves: (i) calculating reliability performance indices for all feeders; (ii) analyzing 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.

In September of 2019, Newfoundland Power implemented a new Outage Management System. The new system, called Responder, is capable of providing outage data with much greater granularity. This allows Newfoundland Power to not only identify worst performing feeders but to isolate specific sections of feeders, or even specific communities or neighbourhoods, that are experiencing poor reliability performance. The Outage Management System allows Newfoundland Power's technical staff to identify specific areas where reliability is a concern.

The decision to make upgrades to improve the reliability performance of the worst performing feeders or specific sections of feeders is based on engineering assessments completed as part of the process.

2.0 Background

Historically, Newfoundland Power identified its worst performing feeders exclusively on the basis of the 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.

[1] SAIDI is calculated by dividing the number of customer-outage-hours by the total number of customers in an area (e.g. a 2-hour outage affecting 50 customers equals 100 customer-outage-hours). Distribution SAIDI represents the average hours of outage related to distribution system failure. 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 represents the average number of outages related to distribution system failure.

SAIDI and SAIFI are used to rank the reliability performance of distribution feeders based on the impact outages have on customers. However, it is recognized that relying solely on these indices to identify worst performing feeders can lead to overlooking shorter feeders with chronic issues.[2]

In 2012, the Canadian Electricity Association began reporting on 2 additional indices: Customer Hours of Interruption per Kilometre ("CHIKM") and Customers Interrupted per Kilometre ("CIKM").[3] CHIKM and CIKM are used to rank the reliability performance of distribution feeders based on the length of line exposed to outages. These indices tend to be more reflective of 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, engineering assessments to determine whether targeted upgrades are warranted to improve service reliability.

Newfoundland Power has incorporated CHIKM and CIKM into its reliability analysis in this report.[4]

Appendix A provides distribution reliability data for the Company's worst performing feeders. Appendix B contains a summary of the assessment carried out on each of the feeders listed in Appendix A.

3.0 Project Description

3.1 Reliability Performance

The 2022 *Distribution Reliability Initiative* project involves a project on a specific section of Broad Cove ("BCV") Substation distribution feeder BCV-04. The feeder extends from BCV Substation located on Belbin's Road in the community of Portugal Cove – St. Phillip's and heads northeast along Beachy Cove Road. It then extends to Portugal Cove Road and northeast along Bauline Line Extension.

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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 CHIKM is calculated by dividing the number of customer-outage-hours by the kms of line. CIKM is calculated by dividing the number of customers that have experienced an outage by the kilometres of line.

4 Newfoundland Power started using the CHIKM and CIKM in its analysis of worst performing feeders in 2015. By using indices that consider customer interruptions and circuit length, the worst performing feeders have generally been found in urban settings where the Company has older poles and associated infrastructure.

Table 1 summarizes the feeder level reliability data for the BCV-04 feeder and provides a comparison to the Company average.

Table 1
Distribution Interruption Statistics
5-Year Average to December 31, 2020

Feeder	Customers	SAIFI	SAIDI	CHIKM	CIKM
BCV-04	1,037	1.85	4.23	130	22
Company Average	**835**	**1.33**	**1.82**	**50**	**39**

At the feeder level BCV-04 is experiencing below average reliability performance for 3 out of 4 indicators. Data taken from Responder shows that most of the outages experienced on the feeder are along a 2 km section of the main trunk from Beachy Cove Road to Portugal Cove Road along the coast of Conception Bay. The primary cause of these outages was wind, and salt contamination caused by high winds. The average SAIDI for customers along this section of feeder is 16.47 or 9 times the corporate average for SAIDI, and the average SAIFI is 5.44, or 4 times the corporate average for SAIFI.

3.2 Engineering Assessment

Distribution feeder BCV-04 currently serves approximately 1,037 customers. Responder data and an engineering assessment completed in 2021 determined the reliability experienced by customers on the specific 2 km section of the feeder from Beachy Cove Road to Portugal Cove Road is being driven by salt contamination and related equipment failures including insulators and cutouts. Electrical current tracking from the conductor, over the salt contaminated insulators, cause damage to the wooden crossarms and poles adjacent to the insulator. Deteriorated hardware and crossarms have also contributed to the reliability issues being experienced.

A detailed engineering assessment of distribution feeder BCV-04 is included in Appendix C.

4.0 Project Cost

The estimate to complete the work associated with the 2022 *Distribution Reliability Initiative* project is $350,000.

Table 2 provides a detailed breakdown of the 2022 project cost.

Table 2
2022 Project Cost

Description	**BCV-04**
Engineering	$23,000
Labour - Contract	90,000
Labour - Internal	126,000
Material	96,000
Other	15,000
Total	**$350,000**

5.0 Conclusion

The *Distribution Reliability Initiative* outlines targeted upgrades to improve the reliability of service experienced by customers in areas where it is significantly below the Company average. While reliability is considered satisfactory on a Company-wide basis, customers on certain distribution feeders and sections of feeders experience reliability performance that is not satisfactory. Targeting upgrades in these areas is consistent with maintaining an acceptable level of service reliability for all customers.

In 2022, a 2 km section of distribution feeder BCV-04 has been identified for improvements at a cost of $350,000.

Appendix A

Distribution Reliability Data:
Worst Performing Feeders

Table A-1
Unscheduled Distribution-Related Outages
5-Year Average
(2016-2020)
Sorted By Customer Minutes of Interruption

Feeder	Annual Customer Interruptions	Annual Customer Minutes of Interruption	Annual Distribution SAIFI	Annual Distribution SAIDI
SUM-01	6,840	843,596	3.80	7.80
DUN-01	5,846	574,459	5.58	9.14
SCR-01	2,998	551,880	3.14	9.62
DOY-01	6,935	545,015	3.99	5.22
DLK-03	3,091	526,151	2.20	6.23
BVS-04	6,077	523,148	3.84	5.50
GLV-02	5,289	469,095	3.49	5.16
BHD-01	3,369	439,725	3.57	7.76
BOT-01	2,820	439,162	1.64	4.27
BLK-02	4,181	408,256	2.01	3.28
LEW-02	4,956	400,847	3.32	4.48
WAV-01	3,309	397,537	2.54	5.09
GFS-06	5,042	366,428	2.64	3.20
CHA-03	3,906	335,904	1.78	2.55
CAB-01	2,004	325,096	1.65	4.47
Company Average	**1,111**	**91,736**	**1.33**	**1.82**

Table A-2
Unscheduled Distribution-Related Outages
5-Year Average
(2016-2020)
Sorted By Distribution SAIFI

Feeder	Annual Customer Interruptions	Annual Customer Minutes of Interruption	Annual Distribution SAIFI	Annual Distribution SAIDI
DUN-01	5,846	574,459	5.58	9.14
SUM-02	2,604	306,994	4.38	8.60
LEW-03	4,789	163,051	4.22	2.39
TWG-03	1,263	84,251	4.06	4.52
DOY-01	6,935	545,015	3.99	5.22
BVS-04	6,077	523,148	3.84	5.50
GBS-01	3,304	181,295	3.80	3.48
SUM-01	6,840	843,596	3.80	7.80
BUC-02	599	89,909	3.74	9.37
OPL-01	1,637	131,209	3.67	4.90
BHD-01	3,369	439,725	3.57	7.76
GLV-02	5,289	469,095	3.49	5.16
TWG-02	2,345	169,132	3.39	4.07
LEW-02	4,956	400,847	3.32	4.48
LGL-02	2,033	117,642	3.30	3.18
Company Average	**1,111**	**91,736**	**1.33**	**1.82**

Table A-3
Unscheduled Distribution-Related Outages
5-Year Average
(2016-2020)
Sorted By Distribution SAIDI

Feeder	Annual Customer Interruptions	Annual Customer Minutes of Interruption	Annual Distribution SAIFI	Annual Distribution SAIDI
SCR-01	2,998	551,880	3.14	9.62
BUC-02	599	89,909	3.74	9.37
DUN-01	5,846	574,459	5.58	9.14
SUM-02	2,604	306,994	4.38	8.60
SBK-01	3	1,474	0.85	8.19
SUM-01	6,840	843,596	3.80	7.80
BHD-01	3,369	439,725	3.57	7.76
SCT-02	540	115,393	2.17	7.72
DLK-03	3,091	526,151	2.20	6.23
GBY-03	2,458	273,863	3.22	5.98
RVH-02	261	54,404	1.63	5.67
TRP-01	1,651	200,663	2.78	5.63
BVS-04	6,077	523,148	3.84	5.50
ABC-02	2,672	321,910	2.68	5.38
SCT-01	2,135	232,116	2.95	5.34
Company Average	**1,111**	**91,736**	**1.33**	**1.82**

Table A-4
Unscheduled Distribution-Related Outages
5-Year Average
(2016-2020)
Sorted By Distribution CHIKM

Feeder	Annual Distribution CHIKM
KBR-10	251
GDL-04	249
SLA-10	249
GFS-02	242
KBR-12	229
SJM-06	211
PEP-01	209
WAV-03	208
MOL-04	175
MOL-08	162
TWG-02	153
PAB-05	149
KEN-03	146
WAL-02	143
RRD-10	137
Company Average	**50**

Table A-5
Unscheduled Distribution-Related Outages
5-Year Average
(2016-2020)
Sorted By Distribution CIKM

Feeder	**Annual Distribution CIKM**
GFS-02	305
SLA-10	276
KBR-10	266
KBR-12	232
PAB-03	193
PEP-01	192
HWD-07	190
WAV-03	183
GDL-04	177
KEN-03	161
MSY-01	153
KEN-01	141
GBS-01	138
KBR-13	127
GFS-05	126
Company Average	**39**

Appendix B

Worst Performing Feeders: Summary of Data Analysis

Worst Performing Feeders Summary of Data Analysis	
Feeder	**Comments**
ABC-02	Reliability historically has been good. There was a significant outage in 2016 due to broken conductor and 2 large outages due to broken poles. There were 2 incidents of insulator failure and 2 of conductor failure in 2020. No work is required at this time.
BCV-04	Reliability during normal operation is above average in terms of SAIDI, SAIFI and CHIKM. Problems are significantly compounded during storms. Work is required on sections of line to address wind and salt spray issues during wind events.
BHD-01	Reliability historically has been good. Poor 2016 reliability statistics were driven by wind-related incidents. In 2017, there were 2 outages caused by broken poles. There were numerous insulator and conductor issues in 2020. No work is proposed at this time but the feeder will continue to be monitored.
BLK-02	Reliability statistics were driven by a sleet storm in 2018. No work is required at this time.
BUC-02	Reliability is worsening principally due to conductor issues. No work is proposed at this time but the feeder will be monitored.
BVS-04	Reliability is worsening principally due to conductor and insulator issues. No work is proposed at this time but the feeder will be monitored.
BOT-01	In 2018, poor statistics were due to a vehicle hitting a pole. In 2019, poor reliability was due to a recloser issue. No work is required at this time.
CAB-01	Reliability statistics were driven by trees and 2 outages related to vehicle accidents damaging poles. No work is required at this time.
CHA-03	Poor reliability over the past 5 years on CHA-03 was driven by a broken pole and a single downed conductor event in 2017. No work is required at this time.
DLK-03	A broken pole in 2018 caused a major outage and was the primary cause of poor reliability over the past 5 years. No work is required at this time.
DOY-01	Overall reliability statistics on this feeder have been impacted by feeder unbalance caused by a number of long, single-phase taps. The poor reliability statistics are also driven by weather-related events in 2016 and 2019. No work is required at this time.

Worst Performing Feeders Summary of Data Analysis	
Feeder	**Comments**
DUN-01	Reliability statistics for this feeder continue to worsen. Poor reliability statistics in 2016 and 2017 were caused by numerous issues. Work was carried out in 2019 and planned to continue in 2020 and 2021 as part of the *Distribution Reliability Initiative* project.
GBS-01	The poor reliability experienced on GBS-01 is principally due to weather related issues. No work is required at this time.
GBY–03	Poor reliability statistics over the past 5 years were driven by equipment failure. Broken insulators caused outages in 2016. Conductor and insulator failure caused several large outages again in 2017. Work has been carried out in 2019 and 2020 as part of the *Distribution Reliability Initiative* project.
GDL-04	Poor reliability statistics over the past 5 years were driven largely by equipment failure. Work was completed in 2020 as part of the *Distribution Reliability Initiative* project to address identified issues.
GFS-02	This feeder was upgraded as part of the *2016 Distribution Reliability Initiative* project and has performed well since then. Reliability has improved, no work is required at this time.
GFS-05	Poor reliability statistics over the past 5 years were driven largely by a failed cable termination in 2016.
GFS-06	Poor reliability was principally due to tree and conductor issues. Work was carried out in 2020 as part of the *Trunk Feeder* project to address identified issues.
GLV-02	Poor reliability statistics were driven by a wind-related event in 2017 and a broken pole in 2018. No work is required at this time.
HWD-07	Significant upgrades were carried out as part of the *2016 Distribution Reliability Initiative* project. No work is required at this time.
KBR-10	Historically this feeder had poor reliability statistics due to the condition of the aerial cable along Kings Bridge Road. There were several outages in 2020 due to adverse weather and trees. No work is required at this time.
KBR-12	Reliability has generally been good. There were several outages in 2020 due to adverse weather and trees. No work is required at this time.
KBR-13	Reliability has generally been good. Tree issues in 2017 and 2020 contributed to reduced reliability in those years. No work is required at this time.

Worst Performing Feeders Summary of Data Analysis	
Feeder	**Comments**
KEN-01	Poor reliability statistics were driven by a broken conductor in 2018. No work is required at this time.
KEN-03	Poor reliability statistics were driven by a broken insulator in each of 2016, 2018 and 2020. 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.
LEW-03	Reliability was poor in 2019 and 2020. In 2020, outages were due to conductor issues and a vehicle accident. In 2019 issues were mainly due to wind and lightning. No work is required at this time.
LGL-02	Poor reliability statistics were driven by wind and trees in 2029 and a broken insulator in 2020. No work is required at this time.
MOL-04	Poor reliability statistics were driven by a wind event in 2017 and a damaged riser in 2019. No work is required at this time.
MOL-08	Poor reliability statistics were due to several underground cable faults in 2018. No work is required at this time.
MSY-01	Poor reliability statistics were due to a vehicle accident in 2019. No work is required at this time.
OPL-01	Poor reliability statistics were due to a fire at a fish plant and lightning in 2016. No work is required at this time.
PAB-03	Poor reliability statistics were due to wind issues in 2016 and 2020. No work is required at this time.
PAB-05	Poor reliability statistics were due to an insulator failure and a broken conductor in 2020. No work is required at this time.
PEP-01	Poor reliability statistics were caused by a single wind-related event in 2017 and an insulator failure in 2020. No work is required at this time.
RRD-10	Poor reliability statistics were caused by a wind-related event in 2017 and insulator and conductor issues in 2020. No work is required at this time.
RVH-02	Poor reliability statistics were due to a wind-related event in 2017. Work was carried out on this feeder in the *2017 Distribution Reliability Initiative* project. No work is required at this time.
SBK-01	Poor reliability was caused by damage by a rodent in 2016 and birds in 2018. No work is required at this time.

Worst Performing Feeders Summary of Data Analysis	
Feeder	**Comments**
SCR-01	The feeder had significant reliability issues in 2016 and 2017, caused by broken insulators, birds, trees and vandalism. No work is proposed at this time.
SCT-01	Poor reliability statistics were driven by wind and tree-related events in 2017 and several broken insulators in 2018. No work is proposed at this time.
SCT-02	Poor reliability statistics were driven by wind and vegetation-related events in 2016 and 2017.
SJM-06	Poor reliability statistics were driven by copper conductor corrosion and equipment failures in recent years. This feeder was included in the *2019 Distribution Reliability* project. No work is required at this time.
SLA-10	Poor reliability statistics were caused by a vehicle accident in 2016. No work is required at this time.
SUM-01	Poor reliability statistics were caused by multiple events in 2016, one involving salt spray and the others involving broken conductor. Wind caused several outages in 2018, 2019 and 2020. No work is proposed at this time but the feeder will continue to be monitored.
SUM-02	Work was carried out in 2017 and 2018 as part of the *Distribution Reliability Initiative* project. No additional work is required at this time.
TRP-01	Work was carried out on this feeder in 2017 and 2018 as part of the *Distribution Reliability Initiative* project. No additional work is required at this time.
TWG-02	Poor reliability statistics were caused by a failed insulator in 2016 and several conductor issues in 2020. No work is required at this time.
TWG-03	Poor reliability statistics were caused by several insulator failures in 2017 and a broken conductor in 2020. No work is required at this time.
WAL-02	Poor reliability statistics were driven by wind and tree-related events in 2020. No work is proposed at this time.
WAV-01	Poor reliability statistics were caused by wind-related issues in 2017. In addition there was an outage caused by freezing rain in 2020. No work is required at this time.
WAV-03	Poor reliability statistics were caused by wind-related issues in 2017 and 2019. No work is required at this time.

Appendix C

Broad Cove BCV-04 Feeder Study

Broad Cove BCV-04 Feeder Study

May 2021

Prepared by:
Bernard Price

Approved by:
Robert Cahill, Eng. L.

REGISTERED LIMITED LICENSEE - ENG. L.
PEG Newfoundland and Labrador
ROBERT J. CAHILL
SIGNATURE
2021-05-05
DATE
NEWFOUNDLAND & LABRADOR

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1.0 Introduction

The *Distribution Reliability Initiative* is a project that involves the replacement of deteriorated poles, conductor and hardware to reduce both 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. Once identified, a detailed engineering assessment of the feeder is carried out to determine if any upgrade work is required. The assessment looks at the physical condition of plant, the risk of failure and the potential impact to customers in the event of a failure.

The *Distribution Reliability Initiative* analysis has identified a 2 km section of Broad Cove ("BCV") Substation distribution feeder BCV-04 as the main contributor to the poor reliability performance of the BCV-04 feeder. An engineering evaluation of the feeder was carried out in early 2021. This report summarizes the findings of that evaluation and presents a plan to improve the reliability to customers on the specific 2 km section of the feeder.

2.0 BCV-04 Feeder

Distribution feeder BCV-04 is 1 of 4 distribution feeders originating from BCV Substation. It is a 12.5 kV distribution feeder that was originally constructed in the early 1980's and currently serves approximately 1,037 customers. The feeder extends from BCV Substation located on Belbin's Road in the community of Portugal Cove – St. Phillip's and heads northeast along Beachy Cove Road. It then extends to Portugal Cove Road and northeast along Bauline Line Extension.[1]

The main 3 phase trunk section of BCV-04 is approximately 7.2 kms in length and travels from BCV Substation to Bauline Line Extension. The majority of pole line infrastructure on the main trunk is comprised of 4/0 Aluminum Alloy Stranded Conductor ("AASC").

A 2 km section of the main trunk of BCV-04 routes along the coastline of Conception Bay from Beachy Cove Road to Portugal Cove Road. This section of feeder is exposed to high levels of salt contamination due to exposure along the coast.[2]

3.0 Engineering Assessment

Newfoundland Power's Outage Management System, Responder, is able to pinpoint specific sections of feeders where high frequencies of outages occur. Data for BCV-04 indicates that the feeder has an average of 45 outages per year, of which approximately 50% are due to wind and salt contamination on the specific 2 km section of feeder. Data from 2020 indicated BCV-04 experienced 78 outages, the majority of which were due to wind and salt contamination on the specific 2 km section of feeder.

---

1 Attachment A contains a map showing the areas supplied by BCV-04.

2 When strong winds blow over the ocean, the wind can pick up salt from the sea, commonly referred to as salt contaminated moisture or salt spray.

Inspections have identified the major contributing factors to outage duration and frequency to be wind and salt spray resulting in poor reliability on the 2 km section of feeder from Beachy Cove Road to Portugal Cove Road.

This section of feeder is exposed to high levels of salt contamination due to exposure along the coast. When salt builds up on insulators, the insulating capability is compromised. Once compromised, the insulator breaks down, causing small amounts of electricity to track over the surface of the insulator. This salt contamination results in insulator flashover and equipment failures, which lead to customer outages.[3] Insulators on this section of BCV-04 have been determined to have insufficient creepage distance for the salt spray conditions experienced.[4] Replacement of insulators with higher insulation levels and creepage distances to account for salt contamination is required.[5] Additionally, some cross-arms on this section of feeder have severe signs of deterioration and are more susceptible to damage when exposed to severe wind, ice and snow loading. The conductor in this section is 4/0 AASC and is in good condition.

4.0 Recommendations

Regular maintenance will not remediate all the reliability issues identified and hence an upgrade of the 2 km section is required to ensure safe reliable operation.

Based on the reliability data and engineering assessment of BCV-04 feeder, the following upgrades are proposed:

(i) Upgrade 2.0 kms of distribution line with new insulators, hardware, switches and cut-outs that have higher insulation value enabling the feeder to withstand severe salt contamination.
(ii) Replace all deteriorated fittings and crossarms.

The estimated cost to complete the work in 2022 is $350,000.

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[3] Insulator flashover is a result of salt contamination creating a path for electricity to travel across the insulator to ground.
[4] The distance measured along the surface of the solid insulating material from high voltage to ground is called the creepage distance.
[5] Existing insulators are rated for 12.5 kV. Replacement insulators will be rated for 35 kV to provide the increased creepage distance required to prevent insulator flashover due the salt spray conditions experienced in this location.

Attachment A

BCV-04 Feeder Schematic Diagram

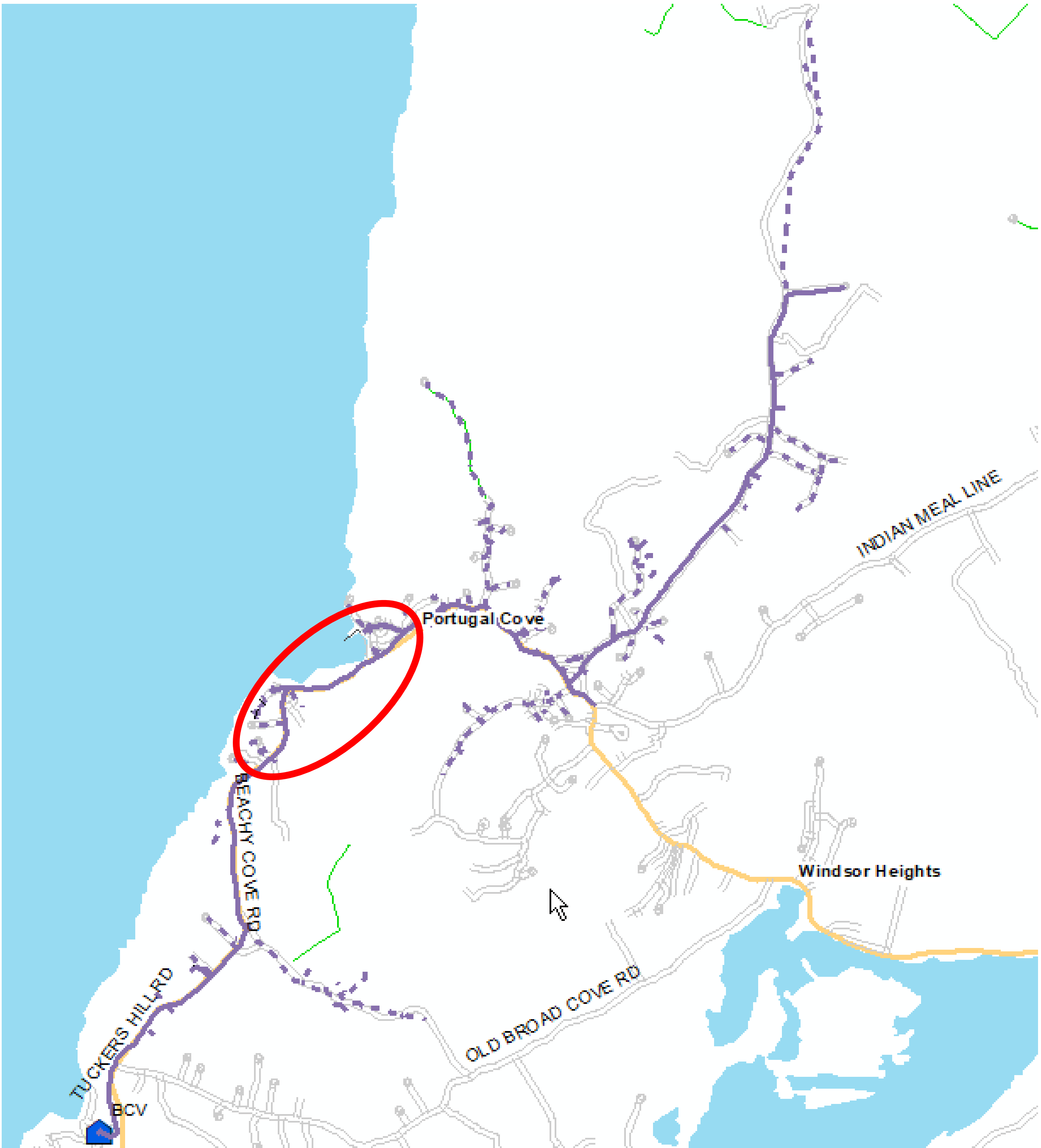

Figure A-1: BCV-04 Map with 2 km Section Identified

Attachment B

BCV-04 Distribution System Photographs

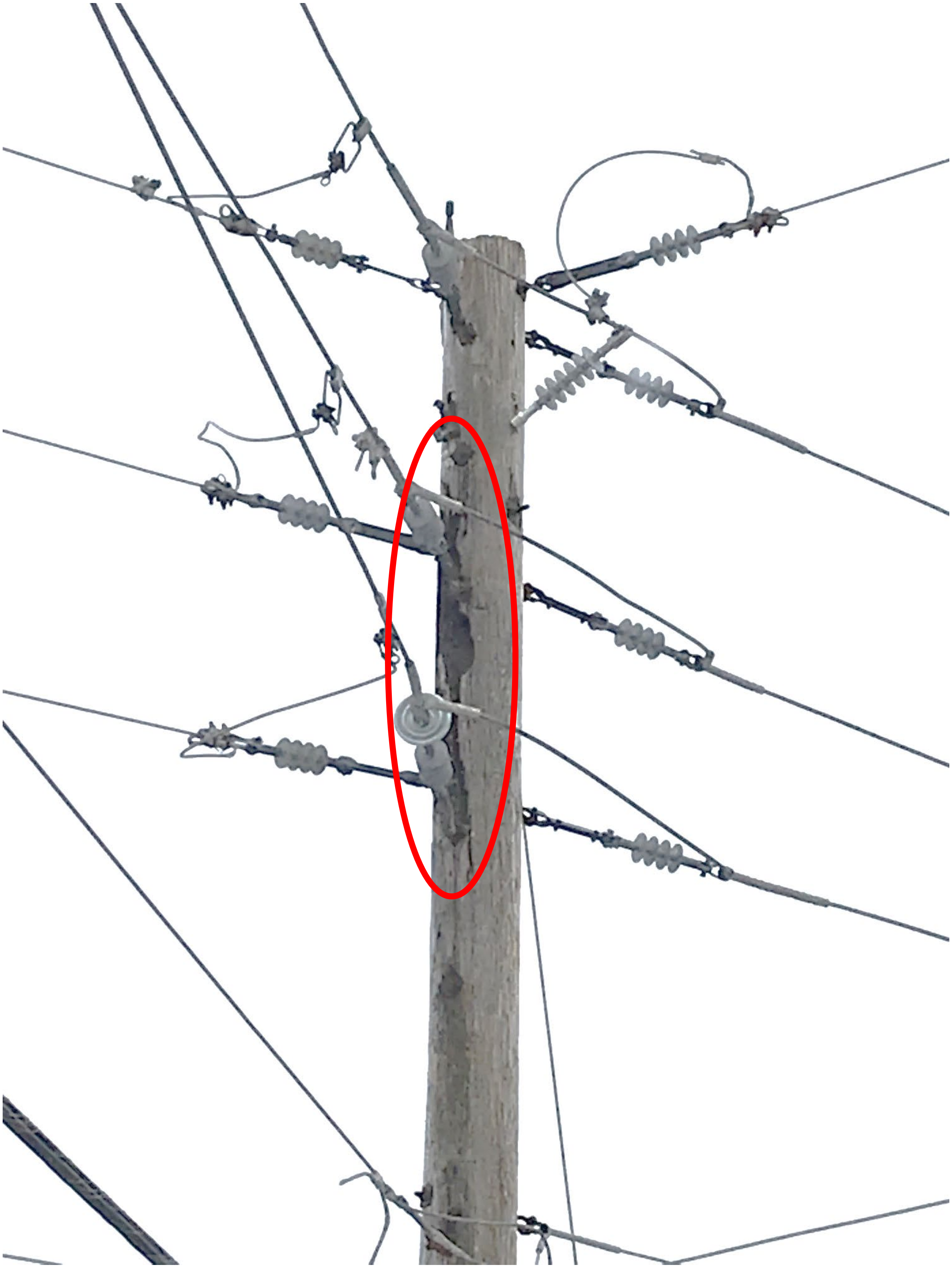

Figure B-1: Pole Damaged Due To Insulator Flashover

Figure B-2: Insulator Replacement Due to Insulator Flashover

Figure B-3: Damage to Crossarm from Insulator Flashover Due to Insufficient Creepage Distance

Figure B-4: Damaged Pole due to Insulator Flashover

Figure B-5: Insulator Flashover Damage

Figure B-6: Evidence of Insulator Flashover on Crossarm

Feeder Additions for Load Growth

May 2021

Prepared by:
Kourtney Edwards, E.I.T.

Approved by:
Robert Cahill, Eng. L.

REGISTERED LIMITED LICENSEE - ENG. L.
PEG Newfoundland and Labrador
ROBERT J. CAHILL
SIGNATURE
2021-05-05
DATE
NEWFOUNDLAND & LABRADOR

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1.0 Introduction

As load increases on an electrical system, the components of the system can become overloaded. These overload conditions can occur at the substation level, on equipment such as transformers, breakers and reclosers, or on specific sections of 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. Eliminating overload conditions prevents in-service equipment failures, which can result in significant repair costs and extended customer outages.

This report identifies 4 overload conditions to be addressed in 2022. All of the conditions will be addressed by upgrading existing distribution lines.

The overload conditions described in this report can each be attributed to commercial and residential customer growth in Newfoundland Power Inc.'s ("Newfoundland Power" or the "Company") service territory.

2.0 Overloaded Conductors

2.1 General

An overloaded section of conductor on a distribution line is at risk of failure. Failures are caused by overheating of the conductor as the load exceeds the conductor's capacity ratings. As a result, the conductor will have excessive sag, which may result in the conductor coming into contact with other conductors or, ultimately, the conductor breaking, causing a fault and subsequent customer outage. Overloaded conductor can also have a negative impact on restoration efforts following customer outages due to increased conductor loading associated with cold load pick-up.

Newfoundland Power 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]

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1 Feeder balancing involves transferring load from one phase to another on a 3-phase distribution feeder in order to balance the amount of load on each phase. Load transfers involve transferring load from one feeder to another adjacent feeder.

2 Where necessary, load measurements are taken to verify the results of the computer modeling. The analysis uses conductor capacity ratings based on Newfoundland Power's *Distribution Planning Guidelines*. These ratings are shown in Appendix A.

2.2 Alternatives for Overloaded Conductor

There are several alternatives for addressing conductor overload conditions. Each alternative may not be applicable to every overload condition. They are dependent on factors such as available tie points to surrounding feeders, the amount of conductor overload, physical limitations of line construction, or the effect on offloading strategies for surrounding feeders.

Alternative #1 – Feeder Balancing
In some cases, 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 1 of the more lightly loaded phases. In some situations, overload conditions on individual phases can be alleviated by extending the 3-phase trunk of the feeder. This is only applicable in situations where all 3 phases are not overloaded.

Alternative #2 – Load Transfer
On a looped system, if a tie point exists downstream of the overload condition, it may be possible to transfer a portion of load to an adjacent feeder. However, consideration must be given to the loading on the adjacent feeder to ensure a new overload condition is not created.

Alternative #3 – Upgrade Conductor
The overload condition can be eliminated by increasing the conductor size on the overloaded section. This will improve load transfer capabilities for the feeder and will not add to the total load or cause an overload condition on an adjacent feeder.

Alternative #4 – New Feeder
In cases where the feeder conductor leaving a substation is overloaded, and none of the above alternatives can be used to resolve the overload condition, then the addition of a new feeder from the substation is required to transfer a portion of load from the overloaded conductor.

2.3 Overloaded Feeders

PUL-03 Feeder Upgrade ($560,000)
Pulpit Rock (“PUL”) Substation is located along Whiteway’s Pond Road in Torbay. PUL-03 distribution feeder leaves PUL Substation and extends east along Whiteway’s Pond Road and Patrick’s Path, serving approximately 1,100 residential and commercial customers in the Torbay area. The single line diagram for PUL-03 is outlined in Figure 1.

A 2.5 kilometre section of PUL-03 feeder, which extends west along Bauline Line, is overloaded. Load growth on this 2-phase section of distribution line can be mainly attributed to customer connection growth, as well as large home renovations and electrical service upgrades in the areas of Bauline Line, Middle Three Island Pond Cabin Area, Bauline Line Extension and Pondside Subdivision. The number of customers supplied by this line has increased by 24% over the last 10 years.[3]

[3] In 2011, there were 404 customers supplied by this line. Currently, there are 502 customers supplied by this line (502 / 404 – 1 = 0.243 or 24%).

The 2-phase section of distribution line that serves this area is constructed using non-standard #2 aluminium conductor. The planning rating of #2 aluminum conductor is 168 amps.[4] An analysis of PUL-03 feeder was completed using a distribution feeder modelling application and verified using actual load measurements. This analysis showed that the load on the 2-phase section of the feeder is approximately 198 amps per phase.

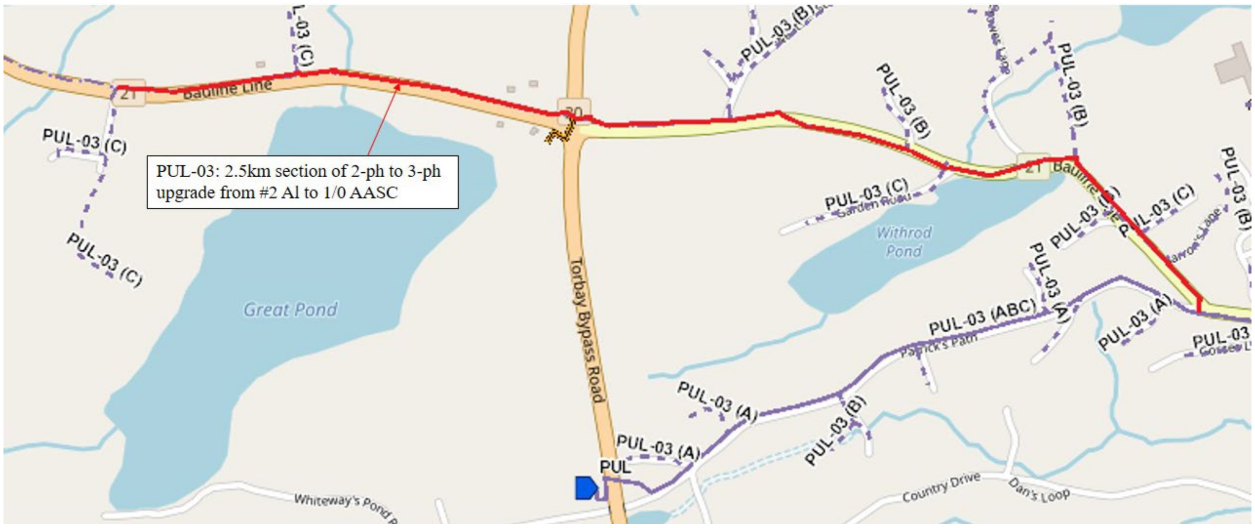

Figure 1: PUL-03 Distribution Feeder Upgrade

An adjacent distribution feeder is within the vicinity of PUL-03. However, a load transfer of the overloaded section of PUL-03 would require a feeder extension and upgrades that is not least cost compared to upgrading the 2-phase section of PUL-03.[5]

Compared to extending an adjacent distribution line, or constructing a new feeder, the least-cost alternative to address this overload condition is to upgrade and re-conductor 2.5 kilometres of existing distribution line along Bauline Line. Upgrading the 2-phase section of distribution line to 3-phase and re-conductoring the existing #2 aluminum conductor to 1/0 AASC conductor will resolve the overload conditions.

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4 #2 Aluminum is no longer standard conductor size for Newfoundland Power.

5 This alternative would require the rebuilding of approximately 1 kilometre of existing distribution feeder from PUL Substation to Bauline Line as a double circuit to create an interconnection point to facilitate a load transfer. In addition, an upgrade of approximately 1 kilometre of existing distribution line along the Bauline Line would also be required to resolve the overload condition. Due to the off-road route of the double circuit distribution line, the estimated cost of this alternative at $607,000 is higher than the proposed alternative at $560,000.

SPF-01 Feeder Upgrade ($600,000)

Springfield ("SPF") Substation is located on Springfield Road in the community of South River, Conception Bay. SPF-01 feeder, which is a 12.5 kV feeder, leaves SPF Substation and extends northward along Clarke's Beach Road and the Conception Bay Highway (Route 70). SPF-01 serves approximately 1,200 primarily residential customers in the community of Clarke's Beach and North River. The single line diagram for SPF-01 is outlined in Figure 2.

A 3.8 kilometre section of the feeder is deteriorated and overloaded. This section of SPF-01 has experienced growth attributed to residential development in the community of North River, Halls Town and the cabin area along North River Road. The number of customers supplied by this line has increased by 30% over the last 10 years.[6]

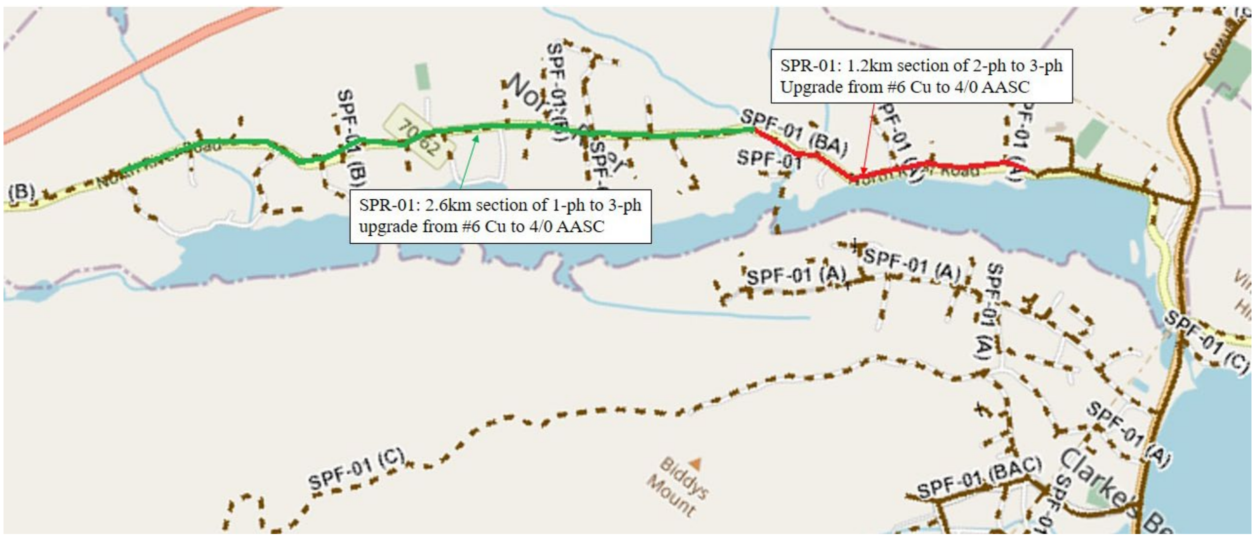

Figure 2: SPF-01 Distribution Feeder Upgrade

The majority of this section of feeder was originally built in the 1980s and includes sections of 2-phase and single-phase construction with non-standard #6 copper conductor.[7] The winter planning rating of new #6 copper conductor is 132 amps.[8] An analysis of SPF-01 feeder was completed using a distribution feeder modelling application and verified using actual load measurements. This analysis showed that the load on the 2-phase section of the feeder is heavily unbalanced due to a downstream single-phase tap on this section of line. The analysis also showed that the load on the single-phase section of approximately 145 amps which exceeds the Company's planning criteria for maximum current on a single-phase distribution line.

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[6] In 2011, there were 262 customers supplied by this line. Currently, there are 340 customers supplied by this line (340 / 262 – 1 = 0.298 or 30%).

[7] #6 copper conductor is known to stretch over time, thinning the conductor and resulting in risk of breakage during peak loads, wind storms and when being worked on by Power Line Technicians.

[8] See Appendix A. Due to wear and stretching of the conductor over its life, the rating of #6 copper conductor is reduced over time.

In addition, SPF-01 feeder exceeds the Company's planning criteria for maximum neutral current on an unbalanced 3-phase distribution line.[9]

An adjacent distribution line, SPF-02, is within the vicinity of the SPF-01 feeder. However, a load transfer between SPF-01 and SPF-02 would require a significant feeder extension and is not a viable alternative.[10]

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 and re-conductor 1.2 kilometres of 2-phase distribution line to 3-phase along North River Road; and (ii) upgrade and re-conductor 2.6 kilometres of single-phase distribution line to 3-phase along North River Road.

Upgrading the 2-phase and single-phase section of distribution line to 3-phase will reduce the unbalanced load and replacing the #6 copper conductor on the 3.8 kilometre section with 4/0 AASC will address both conductor deterioration and resolve the overload.

HAR-02 Feeder Upgrade ($180,000)

Harmon ("HAR") Substation is located on Connecticut Drive in Stephenville. HAR-02 leaves the substation and extends southward along Connecticut Drive. HAR-02 serves approximately 530 residential and commercial customers in the Stephenville area. The single line diagram for HAR-02 is outlined in Figure 3.

Due to the Northern Harvest Smolt Salmon Hatchery development in the area, a 1.1 kilometre section of this feeder will be overloaded. This facility currently has a peak load of 1.6 MVA, with an additional 3.25 MVA to be added by the end of 2022.

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[9] Newfoundland Power's planning criteria for maximum current on a single-phase distribution line is 85 amps. Newfoundland Power's planning criteria for maximum neutral current on an unbalanced 3-phase distribution feeder is 50 amps. 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. This results in unnecessary outages to customers and extended time for restoring service. The unbalanced load condition can occur during peak load, cold load pick-up or when a protection fuse operates on the single-phase tap.

[10] This alternative would require a 5.8 kilometre distribution feeder extension with an approximate cost of $870,000, which is higher than the proposed alterantive at $600,000.

Figure 3: HAR-02 Distribution Feeder Upgrade

The majority of this section of feeder includes 3-phase construction with 1/0 aluminum conductor. The planning rating of new 1/0 aluminum conductor is 228 amps.[11] An analysis of HAR-02 feeder was completed using a distribution feeder modelling application. This analysis showed that the load on the 3-phase section of the feeder with the Northern Harvest Smolt Salmon Hatchery development in service is approximately 253 amps per phase, which exceeds the Company's planning criteria for maximum current on 1/0 AASC conductor.

An adjacent distribution line from the Stephenville Crossing ("STX") Substation, STX-01, is within the vicinity of the HAR-02 feeder. However, a load transfer between HAR-02 and STX-01 would require significant feeder extension and is not a least cost alternative.[12]

Compared to extending an adjacent distribution line, or constructing a new feeder, the least-cost alternative to address this overload condition is to re-conductor 1.1 kilometres of 3-phase 1/0 AASC conductor to 4/0 AASC conductor. Upgrading the 3-phase section of distribution line from 1/0 AASC conductor to 4/0 AASC conductor will resolve the overload conditions.

2.4 Overloaded Single-Phase Lines

A heavily loaded single-phase tap can result in unbalanced loads on the 3 phases of a feeder and subsequent operation of the feeder protection at the substation occurs. This results in outages to customers and extended time for restoring service. The unbalanced load condition can occur

[11] See Appendix A.
[12] This alternative would require an approximate 2 km distribution feeder extension, with an estimated cost of $240,000, which is higher than the proposed alternative at $180,000.

during peak load, cold load pick-up or when a protection fuse operates on the single-phase tap. Eliminating unbalanced conditions caused by growth on single-phase feeder taps will result in a more reliable distribution system.

Analysis of the Company's distribution feeders was completed using a distribution feeder computer modelling application to identify single-phase lines that may be overloaded.[13] Where necessary, load measurements were taken to verify the results of the computer simulation.

The analysis identified one location where a single-phase to 3-phase upgrade is required.

VIR-01 Feeder Upgrade ($350,000)
Virginia Waters ("VIR") Substation is located on the corner of Snow's Lane and Stavanger Drive in St. John's. VIR-01 distribution feeder leaves VIR Substation and extends east along the Outer Ring Road, serving approximately 880 residential and commercial customers in the Logy Bay-Middle Cove-Outer Cove area. The single line diagram for VIR-01 is outlined in Figure 4.

A 1.8 kilometre section of distribution feeder, which extends north on Marine Drive in the Town of Logy Bay-Middle Cove-Outer Cove, is overloaded. Load growth on this single-phase line can be mainly attributed to customer connection growth as well as large home renovations and electrical service upgrades in the area of Marine Drive and Doran's Lane. The number of customers supplied by this line has increased by 27% over the last 10 years.[14]

The single-phase section of distribution line that serves this area is constructed using non-standard #4 copper conductor.[15] An analysis of VIR-01 feeder was completed using a distribution feeder modelling application and verified using actual load measurements. This analysis showed that the load on the single-phase section of the feeder is approximately 113 amps which exceeds the Company's planning criteria for maximum current on a single-phase distribution line.[16]

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13 Overloaded single-phase taps typically start out as only a few spans in length, but over time can grow into much larger feeder extensions. The growth most often occurs in new subdivisions where a large number of customers requiring single-phase service are added over time.

14 In 2011, there were 73 customers supplied by this line. Currently, there are 93 customers supplied by this line (93 / 73 – 1 = 0.274 or 27%).

15 #4 Copper is no longer standard conductor size for Newfoundland Power.

16 Newfoundland Power's planning criteria for maximum current on a single-phase distribution line is 85 amps.

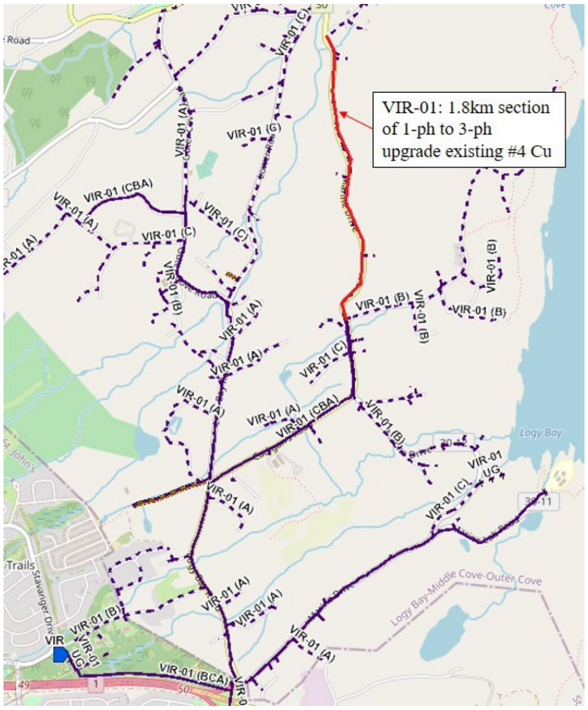

Figure 4: VIR-01 Distribution Feeder Upgrade

An adjacent distribution line is within the vicinity of the overloaded section of VIR-01, however, a load transfer would require a feeder extension that is not least cost compared to upgrading the single-phase section of VIR-01.[17]

Compared to extending an adjacent distribution line, or constructing a new feeder, the least-cost alternative to address this overload condition is to upgrade and re-conductor 1.8 kilometres of single-phase distribution line to 3-phase along Marine Drive. Upgrading the single-phase section of distribution line to 3-phase and replacing the #4 copper conductor on the 1.8 kilometre section with #1/0 AASC conductor will resolve the overload.

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[17] This alternative would require a 2.1 kilometre section of single-phase to 3-phase upgrade, with an estimated cost of $498,000, which is higher than the proposed alternative at $350,000.

3.0 Project Cost

Table 1 provides the estimated 2022 *Feeder Additions for Load Growth* project cost.

Table 1
2022 Project Cost
($000s)

Description	Cost Estimate
PUL-03 Feeder Upgrade	560
SPF-01 Feeder Upgrade	600
HAR-02 Feeder Upgrade	180
VIR-01 Feeder Upgrade	350
Total	**$1,690**

4.0 Conclusion

The *Feeder Additions for Load Growth* project for 2022 includes:

- Upgrading a 2.5 kilometre section of PUL-03 feeder from 2-phase to 3-phase and re-conductoring this section of the feeder from #2 Aluminum to 1/0 AASC;
- Upgrading a 1.2 kilometre section of SPF-01 feeder from 2-phase to 3-phase, upgrading 2.6 kilometre from single-phase to 3-phase, re-conductoring 3.8 kilometre from #6 Copper to 4/0 AASC;
- Re-conductoring a 1.1 kilometre section of HAR-02 feeder from 1/0 AASC to 4/0 AASC;
- Upgrading a 1.8 kilometre section of VIR-01 feeder from single-phase to 3-phase.

The estimated cost to complete this work in 2022 is $1,690,000.

Appendix A

Distribution Planning Guidelines
Conductor Ampacity Ratings

Table A-1
Aerial Conductor Ampacity 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
#6 Copper	175	125	132	0.95	2.9	5.7
#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 2 ft/s wind speed.

[2] The summer rating is based on ambient conditions of 25ºC and 2 ft/s wind speed.

[3] The planning rating is theoretically 75% of the winter conductor ampacity. In practice, the actual percentage will be something less due to: (i) the age and physical condition of the conductor; (ii) the number of customers on the feeder; (iii) the ability to transfer load to adjacent feeders; and (iv) operational considerations including the geographic layout and the distribution of customers on the feeder.

[4] Cold load pick-up ("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] A 2-stage sectionalizing factor is used during CLPU conditions to increase the Planning Rating of aerial conductors. Restoring power to 1 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.

Clarenville Area Office Building Refurbishment

May 2021

Prepared by:
Amy Lester, P. Eng.

LICENSED PROFESSIONAL ENGINEER
08797
AMY C. LESTER
Amy Lester
SIGNATURE
May 5, 21
DATE
NEWFOUNDLAND & LABRADOR

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1.0 Introduction

Newfoundland Power Inc. ("Newfoundland Power" or the "Company") maintains several office buildings throughout its service territory to support the operation and maintenance of the electricity system (Figure 1).

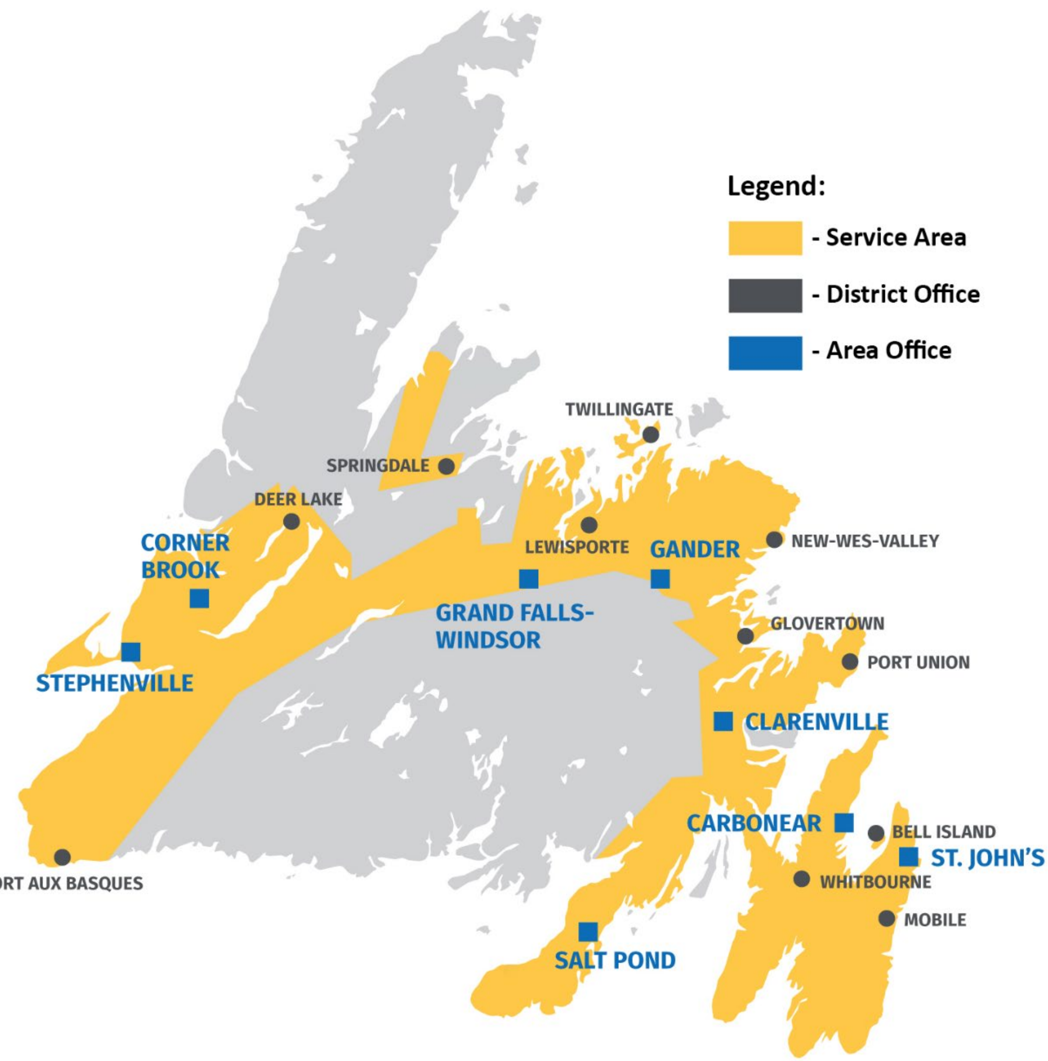

Figure 1: Service Territory

Area Office buildings provide local management, engineering, operational support, warehouse facilities and customer service throughout each geographic region. Within the St. John's, Eastern and Western regions there are District Operation buildings that provide operational support and storage of materials in areas remote from the Area Offices.[1]

[1] To decrease the duration of customer outages, more remote areas are provided with powerline technician crew(s) and commonly required materials (distribution transformers, cross-arms, conductor, street lights and hardware). The Company targets to respond to 85% of customer outages within 2 hours.

The Company periodically reviews its general property assets to identify infrastructure that requires upgrade, refurbishment, additions or decommissioning. For 2022, the Company has identified refurbishments required at the Clarenville Area Office Building (the "Facility").

The Facility is Newfoundland Power's centre of operations for the Clarenville Area (the "Area"). The Area's service territory extends from Southern Harbour in the east to Port Blandford in the west and includes the Bonavista Peninsula. Staff based out of the Facility also assist with Company operations on the Burin Peninsula. In total, the Facility serves approximately 30,000 customers, representing 11% of all customers served by the Company.[2]

The Facility provides support for 22 employees and equipment necessary for operations in the Area. This includes area customer service staff, line crews, maintenance and planning staff, a materials handler, and associated management staff. The Facility also supports corporate functions, such as emergency material storage needed for regional storm response.

The Facility was originally constructed in 1990. No major work has been completed since the original construction except for the following:

(i) Building security system (1999),
(ii) Emergency diesel generator (2006), and
(iii) Motorized vehicular security gate (2017).

Minor maintenance work has been completed to address deterioration and failures as they occur.

Some building components have deteriorated such that capital improvements are necessary at this time to ensure the Company can continue to provide safe and reliable service to its customers in the Area.

2.0 Condition Assessment

Condition assessments were completed for the roof and the heating, ventilation and air conditioning ("HVAC") systems in 2020. The HVAC system was inspected by Crosbie Engineering Ltd. in 2020.[3] A summary of the condition assessments is provided below.

Throughout the report, the Facility is divided into two (2) zones for clarity: the office area and the warehouse/maintenance area.

[2] Approximately 1,500 customer visits occur annually at the Facility.
[3] HVAC condition assessment report can be found in Appendix A.

2.1 Roofing System

The office area roofing system is approximately 950 m^2 in area and is a built-up roof assembly.[4] The warehouse/maintenance area has a standing seam metal roof approximately 1,000 m^2 in area.[5] Both roofing systems will be 32 years old in 2022.

The office area roof has several penetrations including 4 skylights, drains, exhaust vents, a rooftop heat pump unit and an access hatch. Water ponding is regularly observed in areas away from the roof drains and the ballast gravel has been displaced in several areas (Figure 2). Moss and vegetation growth has also been noted throughout the roof area with a high concentration of vegetation along the wall adjoining the warehouse/maintenance area roof (Figure 3).

Figure 2: Water Ponding and Displaced Gravel

Figure 3: Moss and Vegetation Growth

4 Built-up roofing system consists of insulation, waterproof membranes, and gravel ballast.
5 Standing seam metal roofing consist of corrugated metal sheets and sealants.

In 2014, roof repairs were required as a result of water ingress into the building. The repairs included work on the 4 skylights that are located above the conference room. Repairs to additional areas were necessary in 2017. While these repairs were initially successful, there is an ongoing issue with water leaks that result in water migration into the building (Figures 4 and 5).

Figure 4: Interior Damage due to Roof Leak

Figure 5: Interior Damage due to Roof Leak

Additionally, moss growth on the roof is indicative of moisture which will accelerate roof deterioration. Continued water infiltration into the building envelope will also support mould growth and, if left uncorrected, the growth of mould may require additional significant remediation to make the Facility safe for human occupancy. Leaks above critical areas, such as utility rooms containing sensitive electrical and data communications equipment, will pose an immediate risk to business continuity. In the event that the electrical or data systems are compromised, service to customers in the Area will be impacted. The office area roof is in poor condition and is at the end of its service life.

The roof access hatch (Figure 6) is located 1.8 metres from the roof edge. Since the hatch was installed in 1990, the Newfoundland and Labrador Occupational Health and Safety Regulationshave been amended to require fall protection for work done within two (2) meters of the edge of a roof.[6] In addition, the existing roof access hatch has no extension pole to aid individuals' egress from the interior ladder to the rooftop. Refurbishing the roof would ensure compliance with the current Occupational Health and Safety Regulations.

[6] See section 29 of the *Occupational Health and Safety Regulations, 2009 (Newfoundland and Labrador Regulation 70/09).*

Figure 6: Existing Roof Hatch

The warehouse/maintenance area roof also has several penetrations for fans and vents (Figure 7). Sealant around the penetrations and along the seams is deteriorated due to aging and is missing altogether in some areas (Figure 8). With the exception of the deteriorated and missing sealant, the standing seam metal roof is in good condition and no leaks have been experienced in the warehouse/maintenance area.

Figure 7: Warehouse/Maintenance Area Metal Roof

Figure 8: Deteriorated Sealants

2.2 HVAC System

A rooftop heat pump unit provides heating, cooling and ventilation to the office area of the building (Figure 9). This unit is original to the 1990 building construction and has recently experienced numerous breakdowns with approximately $28,000 in repair costs over the past 4 years. Additionally, the HVAC system uses Freon R-22 as a refrigerant which is not environmentally friendly and is due to be totally phased out of use in commercial air conditioning equipment by 2030.[7] Due to the deteriorated condition of the rooftop HVAC unit, it has experienced Freon R-22 refrigerant leaks as a result of worn internal piping.

Figure 9: Rooftop HVAC Unit

The control system for the rooftop heat pump is a variable volume and temperature zone distribution control system and is proprietary to the original heat pump manufacturer. As a result of its proprietary nature, generic replacement parts are not available. The controls are not functioning as designed and replacement parts from the manufacturer are unavailable because the unit is obsolete. Newer, modern control systems would be more effective for the layout of the Facility, which includes both offices and open cubicles.

Exhaust fans provide air extraction for other specific rooms in the office area of the building, such as the men's washroom. The Facility's exhaust fans are not all functional. The system therefore does not provide sufficient exhaust and there are areas without any exhaust, including the women's washroom and computer server room.

The warehouse/maintenance area is ventilated by a combination of exhaust fans that are in poor condition and which are also not functioning properly. The truck bay is equipped with a gas detection system designed to activate roof-mounted fans if carbon monoxide or nitrous dioxide is

[7] Hydrochlorofluorocarbons ("HCFC"), including R-22 are ozone-depleting refrigerants, and under the terms of the Montreal Protocol, will be 99.5% phased out by 2020 and completely eliminated by 2030. After 2020, R-22 refrigerant will no longer be imported or manufactured in Canada.

detected in the truck bay. The gas detection system is original to the Facility. The sensors upon which this system relies are antiquated. Additionally, new, larger fans would more effectively ventilate the truck bay in accordance with current standards.[8]

3.0 Recommendations

3.1 Roofing System

The expected life of a built-up roofing system is generally 20 to 25 years depending upon the initial quality, climate and traffic.[9] The office area roofing system will be 32 years old in 2022. The Company has replaced several similar building roofing systems with the average age of 26 years.[10] The Clarenville roof is the same age and design as the Duffy Place Facility roof which was replaced in 2018 as a result of continuing water infiltration.

The roof over the office area has reached the end of its service life and based on the age, condition and risk associated with failure replacement is recommended.

The roof over the warehouse/maintenance area should undergo replacement of sealants at seams and penetrations to ensure that this component reaches or exceeds its expected service life.

3.2 HVAC System

The roof-mounted heat pump unit has experienced numerous breakdowns and no longer operates reliably. Repair efforts over the last four years have not been able to return the system to normal operation. Without adequate ventilation, the building does not meet the Newfoundland and Labrador Occupational Health and Safety Regulations.[11] Improvements are also required to the various ventilation and exhaust systems in the warehouse and maintenance areas. Also, the gas detection and ventilation system in the truck bay requires upgrade. The replacement of the HVAC systems is necessary and cannot be deferred.

4.0 Project Description

The project scope involves the replacement of the built-up roofing system and installation of a new HVAC system. Both items will be co-ordinated to maximize efficiencies in work execution, project management and supervision. Replacement of the rooftop heat pump will create considerable traffic on the roof. This additional traffic will increase the risk of damage to the existing roofing system. With the existing roofing system at end-of-life, replacement of the

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8 Section 45(2) of the *Occupational Health and Safety Regulations, 2009 (Newfoundland and Labrador Regulation 70/09)* requires that ventilation systems be employed to protect workers against the inhalation of impurities in the workplace.

9 The built-up roofing system at the Company's Duffy Place Facility in St. John's was replaced in 2018. At that time, consultants Morrison Hershfield noted the typical life expectancy of a built-up roofing system to be 20-25 years. See *2018 Supplemental Capital Budget Application – Duffy Place Roof Replacement*.

10 Location and ages of built-up roofing systems replacements at Company buildings include: Carbonear - 21 years; Gander - 29 years; Corner Brook - 24 years; Duffy Place - 29 years; and Kenmount Road - 30 years.

11 Section 45 of the *Occupational Health and Safety Regulations, 2009 (Newfoundland and Labrador Regulation 70/09)* details ventilation requirements for a workspace.

roofing system at the same time as the HVAC system will ensure integrity of the roofing system and prevent damage due to leaks in the roof membrane.

4.1 Roofing System ($512,000)

To mitigate the risk of compromising the building envelope and the possibility of water infiltration into the building structure, the following work is required to be completed in 2022:

(i) Demolition of the existing 32-year-old built-up office area roofing system,
(ii) Installation of a new office area roofing system including insulation, waterproof membranes and flashing details,
(iii) Installation of a new roof access hatch complete with extension pole and guardrail, and
(iv) Replacement of the warehouse/maintenance area roofing sealants.

Installation of a new roofing system will eliminate the risk of damage to the existing deteriorated roof due to traffic required for the HVAC system replacement.

4.2 HVAC System ($342,000)

The existing HVAC systems require replacement. In 2022, the following work is required:

(i) Replacement of rooftop heat pump unit and associated controls,
(ii) Improvements to exhaust air systems,
(iii) Installation of a new independent HVAC system for the warehouse/maintenance area, and
(iv) Replacement of gas detection system with integrated controls and dedicated exhaust fans.

5.0 2022 Project Costs

Table 1 provides a breakdown of the proposed expenditure for 2022 by item.

Table 1
2022 Planned Capital Expenditures
By Item
($000s)

Description	**Amount**
Roofing	512
HVAC Systems	342
Total	**$854**

Table 2 provides a breakdown of the proposed expenditures for 2022 by cost category.

Table 2
2022 Planned Capital Expenditures
By Cost Category
($000s)

Cost Category	**Amount**
Material	680
Labour - Internal	4
Labour - Contract	-
Engineering	122
Other	48
Total	**$854**

6.0 Conclusion

In 2022, capital improvements are necessary to replace the HVAC system and deteriorated roofing system at the Clarenville Area Office Building. This project is justified by the requirement to replace deteriorated infrastructure, ensure compliance with occupational health and safety regulations, and to ensure adequate facilities for the Company to provide safe, least-cost, and reliable electrical service to customers in the Area.

Appendix A

HVAC Assessment
Crosbie Engineering Ltd.

Heating, Ventilation and Air Conditioning Assessment
Newfoundland Power
Clarenville, NL

Prepared for:
Newfoundland Power
50 Duffy Place
St. John's, NL A1B 3P6

PROVINCE OF NEWFOUNDLAND
PERMIT HOLDER
Class "A"
This Permit Allows
CROSBIE ENGINEERING LIMITED
To practice Professional Engineering in Newfoundland and Labrador Permit No. as issued by PEG–NL D0123 which is valid for the year 2021.

Prepared By:

CROSBIE ENGINEERING LTD.

Neil Cleary, P.Eng., Principal
1243 Kenmount Road, Suite 102
P.O. Box 13295, STN "A"
St. John's, NL   A1B 4A5
Ph.: 709.754.1911
e-Mail: ncleary@crosbieeng.com

REGISTERED PROFESSIONAL ENGINEER
K. NEIL CLEARY
SIGNATURE
PROVINCE OF NEWFOUNDLAND

CEL Project No.: 20-2816

Date: April 27, 2021

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1.0 INTRODUCTION

Neil Cleary, P.Eng. of Crosbie Engineering Limited visited the Newfoundland Power Building on Manitoba Drive in Clarenville, NL on Friday, September 11, 2020 to complete a heating, ventilation, and air conditioning (HVAC) assessment of the building. The building was constructed in 1991.

This report describes our assessment and notes deficiencies within the existing HVAC systems in the building as observed during the site visit and gathered from discussions with building personnel.

We have not carried out any investigations relating to the presence of hazardous substances, contaminants, or pollutants. We do note that there is R22 Refrigerant in the existing rooftop heat pump unit. This is a refrigerant that has been phased out.

Codes Referenced for general assessment purposes:

- ASHRAE 62.1 Standard for Acceptable Indoor Air Quality
- ASHRAE 90.1 Energy Standard for Buildings
- National Building Code of Canada 2010

2.0 HVAC - HEATING/VENTILATION/AIR-CONDITIONING

2.1 HEATING

The building can generally be divided into two area types, the Office Side (Commercial Services, Regional Operations etc.) and the Warehouse/Maintenance Side (Electrical Maintenance, Distribution Maintenance, Stores, Loading Dock etc.).

Heating in the Office Side is first delivered via the roof top heat pump unit. The roof top heat pump is a Carrier unit, and it is controlled by antiquated Carrier variable volume, and temperature (VVT) controls. The roof top unit is outdated, failing and must be replaced. The control system is outdated, troublesome, and also must be replaced. The office side heat pump is supplemented by baseboard heat throughout various spaces.

The Warehouse/Maintenance Side of the building is heated through electrical resistance heating, a combination of baseboards and unit heaters.

We recommend the Warehouse/Maintenance Side of the building be heated in the future by a heat pump that has ducted airflow throughout that side of the building. It is an environmentally friendly and cost effective technology.

2.2 VENTILATION

The building, again, is generally divided into two area types, the Office Side (Commercial Services, Regional Operations etc.) and the Warehouse/Maintenance Side (Electrical Maintenance, Distribution Maintenance, Stores, Loading Dock etc.).

Ventilation within the Office Side is provided by an existing roof top heat pump unit. Ventilation air is mixed with the conditioned air and delivered to occupants via the distribution ductwork. As the heat pump unit, further described below, needs to be replaced, the ventilation for this portion of the building will be addressed with a new roof top unit. This office side of the building also does not have sufficient exhaust airflow. Some washroom and utility areas do not have any exhaust, the female washroom for example. The lack of proper exhaust makes the air very stale.

Ventilation within the Warehouse/Maintenance Side is from a combination of exhaust fans. Many of these fans are no longer in good operating condition and they are not set to operate on a schedule that is linked to building occupancy. This side of the building requires a new dedicated ventilation unit or heat recovery ventilator (HRV) to provide the proper amount of ventilation air. Also, as mentioned above, a new heat pump unit could be coupled with the ventilation unit to provide energy and cost effective heating and ventilation.

The Warehouse/Maintenance side of the building also has antiquated gas detection sensors and alarms that protect occupants from hazardous combustion gasses that may be present when vehicles operate inside the truck bay. These systems detect carbon monoxide and nitrous dioxide. Typical installations also automatically turn on exhaust fans and intakes when these gasses are detected. The fans in this building are undersized should be replaced with new and larger fans. The sensors themselves are also quite dated and should be replaced as part of any planned HVAC upgrades.

2.3 AIR CONDITIONING

The Office Side of the building receives air conditioning (cooling) from the heat pump unit. This functionality will continue with the replacement of the unit.

The Warehouse/Maintenance Side of the building has no air conditioning. An advantage to converting the Warehouse/Maintenance Side of the building to heat pump heating will be the availability of cooling in the warmer months.

3.0 HVAC CONTROLS

The heat pump unit that serves the Office Side of the building has an antiquated, poorly functioning, and proprietary "Carrier VVT" zone distribution control system that is not well suited for a combination of open office space and perimeter enclosed offices. The existing VVT controls system is causing operational issues and has to be reset on a continual basis. This system is obsolete.

The controls system needs to be updated to a newer modern system for efficiency, maintenance and comfort reasons.

The building has manual starters for most of the exhaust fans. These fans are in poor condition, do not operate when needed, and are no longer effective in serving the spaces where they are installed. Almost all fans and starters would be replaced as part planned upgrades.

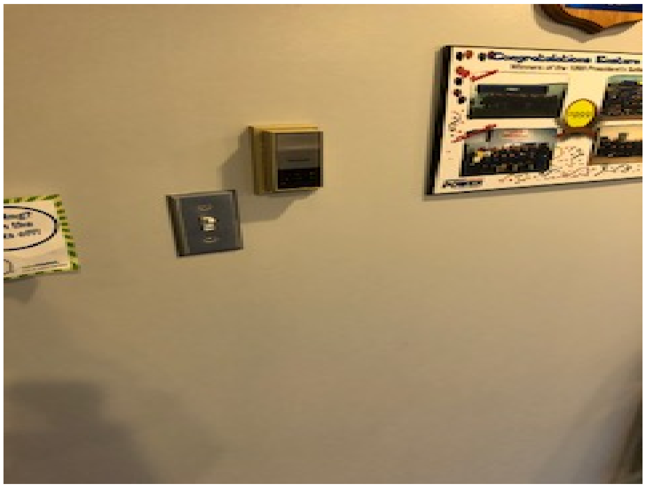
4.0 RECOMMENDATIONS

The majority of HVAC systems, as referenced herein, should be replaced and/or upgraded.

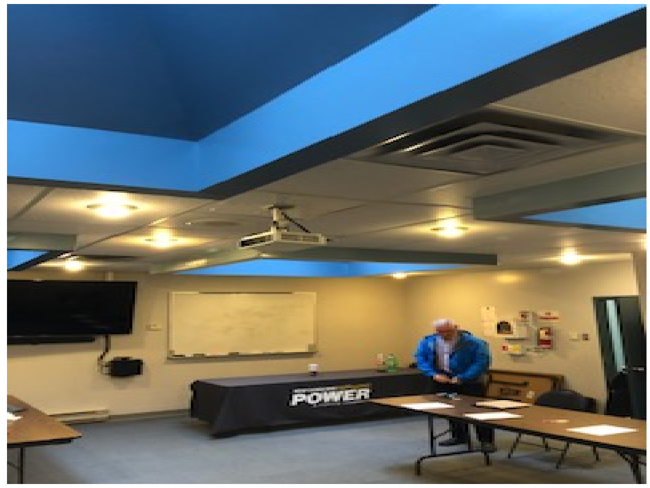
The following is a list of upgrades that are required:

- Office Side Roof Top Heat Pump Unit
- Office Side Building Control System
- Warehouse/Maintenance Side Heat Pump System
- Warehouse/Maintenance Side Ventilation Unit
- Miscellaneous Fans and Controls New and Upgrade
- Gas Detection Control System and Automatic Fans

APPENDIX “A”
SITE PHOTOS



Thermostatic Control



Meeting Room

HVAC Controls

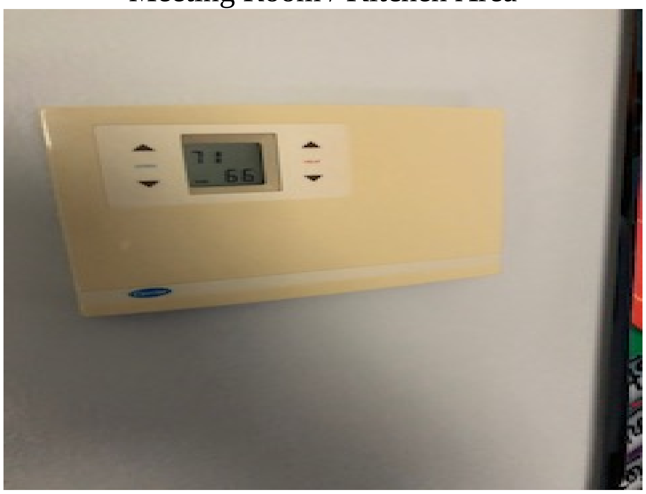
Warehouse/Maintenance Fan Unit

Truck Bay

Tailpipe Hose Reel

Meeting Room / Kitchen Area

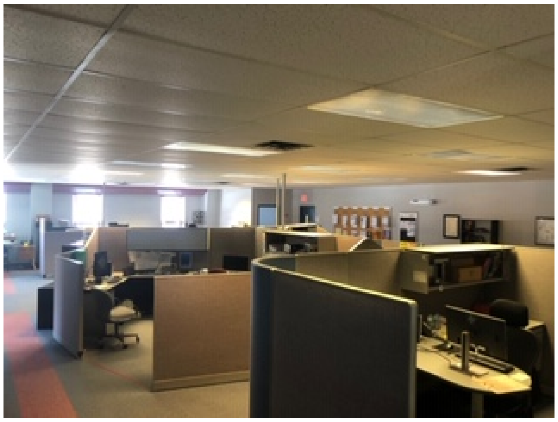
HVAC Control



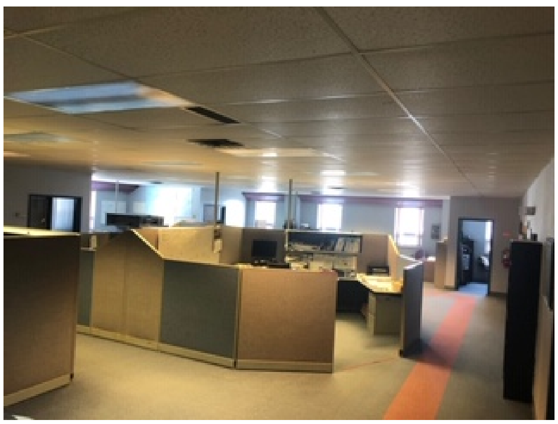
HVAC Control

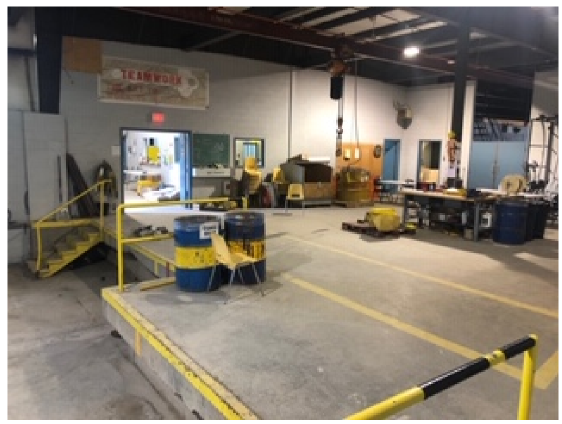
Gas Detection Sensor

Office Area


Office Area


Customer Service Area

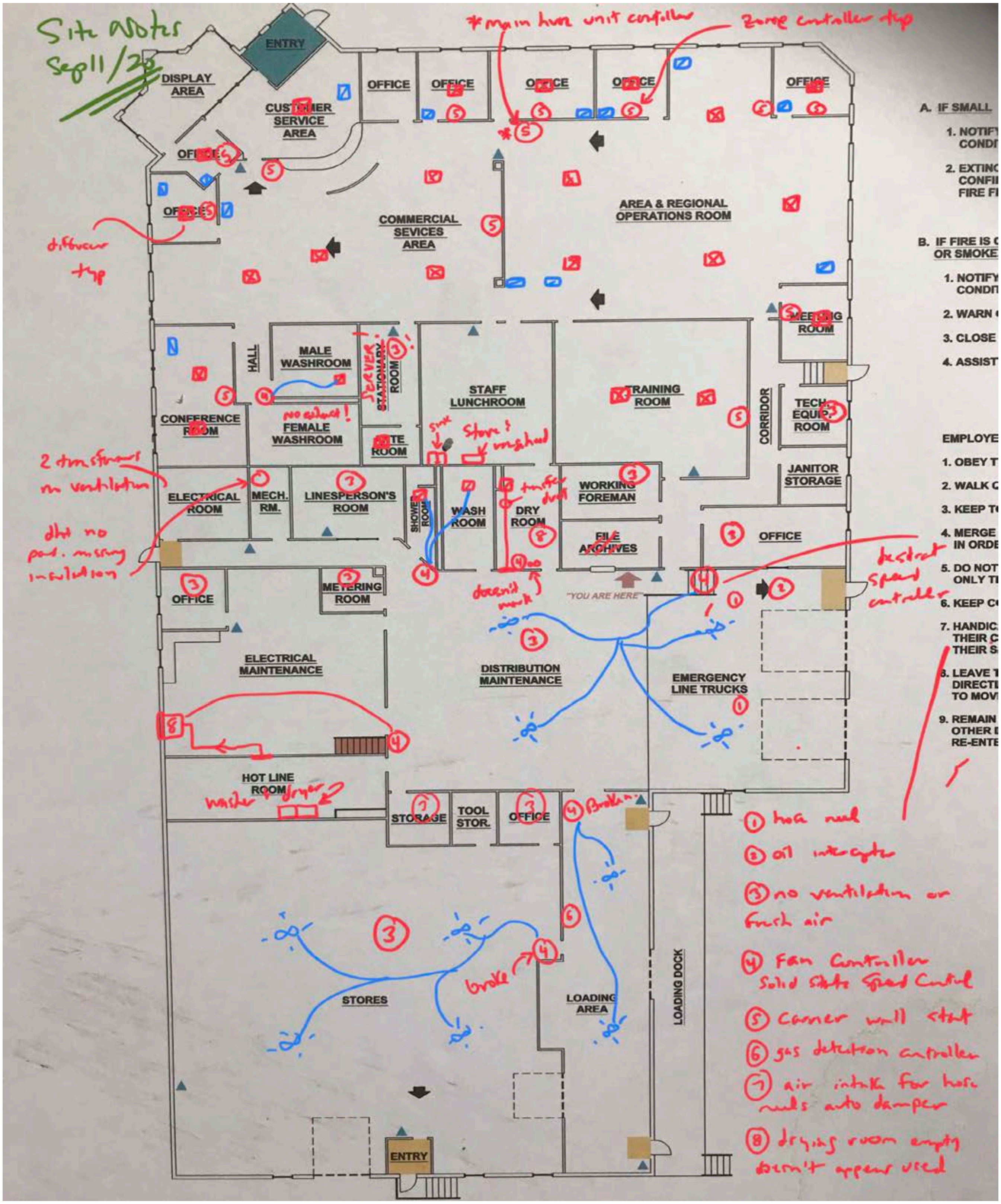

Office Area


Loading Dock


Warehouse/Maintenance Area


Warehouse/Maintenance Area

APPENDIX "B"
SITE NOTES


Site Notes Sep11/20
ENTRY
DISPLAY AREA
CUSTOMER SERVICE AREA
OFFICE
COMMERCIAL SEVICES AREA
AREA & REGIONAL OPERATIONS ROOM
MEETING ROOM
HALL
MALE WASHROOM
FEMALE WASHROOM
SERVER STATIONARY ROOM
STAFF LUNCHROOM
TRAINING ROOM
CORRIDOR
TECH. EQUIP. ROOM
CONFERENCE ROOM
JANITOR STORAGE
ELECTRICAL ROOM
MECH. RM.
LINESPERSON'S ROOM
SHOWER ROOM
WASH ROOM
DRY ROOM
WORKING FOREMAN
FILE ARCHIVES
METERING ROOM
"YOU ARE HERE"
ELECTRICAL MAINTENANCE
DISTRIBUTION MAINTENANCE
EMERGENCY LINE TRUCKS
HOT LINE ROOM
STORAGE
TOOL STOR.
LOADING DOCK
STORES
LOADING AREA
*main hvac unit controller
Zone controller typ
diffuser typ
2 transformers no ventilation
dirt no pad. missing insulation
no exhaust!
sink
stove & washer
transfer duct
doesn't work
washer & dryer
destrat speed controller
broken
broke
A. IF SMALL
1. NOTIFY CONDI
2. EXTING CONFI FIRE FI
B. IF FIRE IS OR SMOKE
1. NOTIFY CONDI
2. WARN
3. CLOSE
4. ASSIST
EMPLOYE
1. OBEY T
2. WALK C
3. KEEP T
4. MERGE IN ORDE
5. DO NOT ONLY TI
6. KEEP C
7. HANDIC THEIR C THEIR S
8. LEAVE T DIRECTI TO MOV
9. REMAIN OTHER RE-ENTE
1 hose reel
2 oil interceptor
3 no ventilation or fresh air
4 Fan Controller Solid State Speed Control
5 Carrier wall stat
6 gas detection controller
7 air intake for hose reels auto damper
8 drying room empty doesn't appear used

St. John's Teleprotection System Replacement

May 2021

Prepared by:
Jack Casey, P. Eng.

REGISTERED PROFESSIONAL ENGINEER
J. W. CASEY
SIGNATURE
May 5, 2021
PROVINCE OF NEWFOUNDLAND

WHENEVER. WHEREVER.
We'll be there.

NEWFOUNDLAND POWER
A FORTIS COMPANY

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1.0 Introduction

Newfoundland Power Inc. ("Newfoundland Power" or the "Company") operates a teleprotection system in the St. John's area protecting 22 transmission lines which interconnect 14 substations.[1] The teleprotection equipment communicates using fibre optic cable in order to meet the critical clearing time requirements for differential line protection.[2] The St. John's teleprotection system is critical to the safe and reliable operation of both the Holyrood Thermal Generating Station ("HTGS") and the Labrador Island Link ("LIL").

Since 2002, the Company has used an IMUX 2000 equipment platform for transmission line teleprotection within the St. John's area.[3] The existing IMUX 2000 equipment platform has become increasingly unreliable and has reached the end of its service life. The critical nature and continued need for the teleprotection functionality requires that the Company replace the existing teleprotection system.

In order to complete the transition to a new teleprotection system and strengthen the St. John's fibre network, additional fibre optic cables are required. Currently the 2 fibre optic cables at Pepperrell Substation are leased from a 3rd party telecommunications provider with no spare fibre capacity available. In 2023, the Company will replace the leased fibre optic cables by constructing its own fibre optic cables from Pepperrell Substation to Virginia Waters Substation and from Pepperrell Substation to Kings Bridge Substation. Additional fibre capacity on these cable routes is critical to providing adequate communications for transmission line protection in the east end of the City of St. John's.

The Company plans to upgrade the St. John's teleprotection system as a multi-year project starting in 2022. The multi-year project will be completed over 2 years at an estimated cost of approximately $1.6 million.[4]

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1 The teleprotection system consists of transmission line relays, IMUX 2000 multiplexers and the fibre optic cables that interconnect the relays and multiplexers.

2 The differential line protection principle is based on the comparison of the currents at the beginning and at the end of the line, resulting in a quick, sensitive and simple protection concept that ensures that a faulted transmission line is quickly disconnected from the network.

3 Appendix A provides a detailed description of the existing teleprotection system.

4 The economic analysis provided in Appendix E shows it is least cost for the Company to discontinue the lease arrangement and build its own fibre optic cables between these 3 substations.

2.0 St. John's Teleprotection System Description

2.1 St. John's Transmission Network

The St. John's 66 kV transmission network consists of 22 transmission lines operating between 14 substations. Using the IMUX 2000 equipment platform and fibre optic communications, differential relays at both ends of each transmission line communicate with each other to detect and clear any electrical faults that develop on the transmission line. The IMUX 2000 equipment platform uses multiplexing technology to combine multiple low speed communication circuits from individual transmission line relays onto a single high speed circuit, providing communications between all relays in the transmission network.[5]

The differential transmission line protection relays at each end of the transmission line rely on the teleprotection system to communicate with each other to detect and clear any electrical faults that develop on that line. If a transmission line fault occurs when the differential protection is in service, the transmission line breakers at both ends will open and the power flow in the transmission network will automatically adjust, with no customer outages resulting. If a transmission line fault occurs when the differential protection is not in service, then the transmission network relies on backup protection to clear the fault.

As a backup to differential protection, each of the transmission lines in the St. John's area uses distance/impedance protection and overcurrent protection.[6] Each of these backup protection schemes will take longer than differential protection to clear the same fault. If the fault is not cleared within the required critical clearing time, it could cause cascading outages on other transmission lines, or cause loss of generation to the Avalon Peninsula.[7]

2.2 St. John's Teleprotection System

In 1991, Newfoundland Power and Newfoundland and Labrador Hydro ("Hydro") jointly completed a critical clearing time study.[8] This study addressed clearing times for transmission line faults on the Avalon Peninsula. The study determined that faults with excessive clearing times on the St. John's 66 kV transmission network could cause severe voltage depressions on the HTGS service equipment. The occurrence of these voltage depressions posed a risk to the successful operation of the HTGS.[9] To reduce the severity of the voltage depressions, high speed clearing was required on the St. John's 66 kV transmission network. Following the critical

---

[5] Without a multiplexing technology like the IMUX 2000, 2 pairs of dedicated fibre optic strands would be required per transmission line. In the case of the St. John's transmission network with 22 transmission lines, 88 fibre optic strands (22 transmission lines × 2 relays per transmission line × 2 directions) would be required.

[6] In the event of a communications failure, the relays disable the primary differential protection and automatically switches to the backup protection.

[7] In the event of a cascading failure due to the differential protection not being available, multiple substations could be disconnected from the electrical system resulting in a large number of customers experiencing an outage.

[8] *Eastern System Critical Clearing Time Study– Island Interconnected Transmission System*, dated August 22, 1991, jointly prepared by Hydro and Newfoundland Power.

[9] In the years prior to the study, 2 separate incidents involving faults of extended duration on the St. John's 66 kV transmission network resulted in the loss of generation at the HTGS.

clearing time study, Newfoundland Power upgraded the protection on the St. John's 66 kV transmission network to include differential protection as the primary protection scheme.[10]

In March 2021, TransGrid Solutions Inc., at the direction of Hydro, issued its report of a study of critical clearing times on Newfoundland Power's 138 kV and 66 kV transmission systems following the interconnection of the LIL. Study results, which were presented in Technical Note TN1205.81.06, confirmed the need to maintain critical clearing times when the HTGS is no longer operational and the LIL begins supplying the Island Interconnected System.[11]

In 2002, Newfoundland Power installed the IMUX 2000 equipment platform to provide communications for teleprotection, Supervisory Control and Data Acquisition ("SCADA") data, business communications and telephone services. Over time, other cost effective solutions became available for SCADA data, business communications and telephone services. Only the teleprotection circuits remain on the IMUX 2000 equipment platform.

The legacy technology of Newfoundland Power's 2002 vintage IMUX 2000 equipment platform is approaching obsolescence. Most of the vintage modules have since been upgraded or replaced by the manufacturer, and vendor support is becoming an issue.

Failures of the IMUX equipment platform affecting the teleprotection system have become more frequent.[12] When the IMUX system fails, the transmission line differential protection is disabled. Of particular concern is the failure of the IMUX system to wrap when failures do occur, resulting in the complete loss of differential protection on all transmission lines associated with the fibre ring that has failed to wrap.[13] Loss of differential protection on transmission lines in the St. John's area can affect the time it takes to trip both ends of the transmission line in the event of a fault.

With an increasing number of IMUX module card failures, the Company's supply of spare parts is becoming depleted.[14] The St. John's transmission network requires a reliable teleprotection system to be operational at all times. As well, any additions to the St. John's area transmission system will require expansion of the teleprotection system to provide adequate line protection.[15]

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[10] Initially the differential protection was provided using dedicated fibre optic cable strands. As more transmission lines were upgraded to differential protection the Company moved away from using dedicated fibre optic cable strands and installed the IMUX equipment platform in a ring topology for high reliability.

[11] Hydro filed the study report with the Board on March 31, 2021.

[12] See Section 2.4 for information on past IMUX equipment failures.

[13] Teleprotection system failures will only result in customer outages if a transmission line fault occurs during the time when the teleprotection system is out of service. "Wrapping" refers to a fail-safe mechanism inherent in the system design. Wrapping is explained in detail in Section 3.0 in Appendix A.

[14] The original design included a terminal at the Duffy Place building. As services other than teleprotection were moved to other technologies, this terminal was no longer required. The modules and cards comprising the Duffy Place terminal were placed into the stock of spare parts, increasing the inventory. These additional spare parts have extended the service lives of the remaining in-service terminals.

[15] For example, in 2021, the Company is adding a new substation adjacent to the St. John's International Airport. Adding the transmission lines supplying this substation to the St. John's teleprotection network will require the addition of a new teleprotection node assembled from spare parts. Diverting the existing limited supply of spare parts to assemble a new teleprotection node to expand the existing system will further deplete the spare parts inventory and make recovery from an equipment failure more difficult.

The existing IMUX 2000 equipment platform cannot be expanded to incorporate any future transmission line additions. The age of the existing IMUX 2000 equipment platform, the limited supply of spare parts, the inability to expand, and the critical nature of the teleprotection function requires that it be replaced commencing in 2022.

2.3 Fibre Optic Cable Plant

Newfoundland Power utilizes 78 fibre optic circuits across its service territory, 73 of which are owned by the Company. The remaining 5 circuits are leased from a 3rd party telecommunications service provider. These fibre circuits are used for teleprotection, business data, substation communications, voice communications, SCADA data and data communications between Newfoundland Power's and Hydro's control centres.

In St. John's, Newfoundland Power operates a fibre optic cable network that connects 17 substations and 6 office buildings.[16] In addition to SCADA data, business voice and data traffic, the fibre optic cable network carries the teleprotection system data.[17]

The fibre optic cable network in St. John's is comprised of 22 fibre optic cables owned by the Company and the 5 cables leased from a 3rd party telecommunications provider. In 2 of these leased fibre optic cables, there is no spare fibre capacity. These 2 cables extend from Pepperrell Substation to Virginia Waters Substation and from Pepperrell Substation to Kings Bridge Substation. Additional fibre optic cable strands are required between these 3 substations to successfully transition from the existing IMUX system to the new teleprotection system.[18]

2.4 St. John's Teleprotection System Performance

The IMUX system's performance is degrading, with the large number of equipment failures compromising the protection of the St. John's transmission network. The large number of equipment failures are exhausting the supply of spare parts.[19] Some equipment modules have been discontinued by the vendor, and the Company's stock of spare parts cannot be replenished.[20]

---

[16] The 6 office buildings include the System Control Centre, Duffy Place operations centre, Duffy Place service centre, Electrical Maintenance centre, Kenmount Road head office and Hydro Place. Hydro Place is included in the fibre optic network as the Inter Control Centre Protocol ("ICCP") link continuously exchanges real-time power system data between both companies' SCADA systems.

[17] There are 14 substations and the System Control Centre on the IMUX system for teleprotection.

[18] Appendix D includes topographic maps that show the routes for these 2 fibre optic cables.

[19] Appendix B includes a list of spare parts.

[20] Hydro also uses IMUX 2000 systems typically in point-to-point configuration and using some different equipment modules. The discontinued spare parts in Newfoundland Power's IMUX 2000 system are only used in a small number of Hydro's IMUX 2000 systems. Hydro is agreeable to provide a spare part in an emergency; but they would need the part returned, as they have a limited number of spare modules as well.

Table 1 shows the number of IMUX 2000 equipment failures since 2016.

Table 1
IMUX 2000 Equipment Failures

Years	Number of Failures
2016	9
2017	6
2018	14
2019	5
2020	4
Total	**38**

Failures with the IMUX equipment platform typically relate to IMUX module failures and issues with fibre terminations. During these failure events, the lack of real-time system monitoring, as well as unreliable failover to the redundant paths, has prolonged system restoration for customers. Failures related to failover to the redundant paths require visits to adjacent, or possibly all other sites to troubleshoot the failure.[21]

With the large number of IMUX module failures, the probability that the loss of the St. John's teleprotection system will occur due to a failure of the IMUX equipment platform is high. Further, due to the customer impact associated with a resulting loss of either the HTGS or the LIL, the consequence is also high. Due to the high probability and high consequence of a failure of the St. John's teleprotection system, its current poor performance indicates a significant risk to system operations.

3.0 Project Justification

3.1 IMUX System Replacement Alternatives

Three potential alternatives exist to deal with the IMUX 2000 system failures. These include: (i) do nothing and continue to maintain the existing IMUX 2000 equipment platform, (ii) replace the existing IMUX 2000 equipment platform with modern technology through a request for proposals from multiple vendors, and (iii) upgrade the existing IMUX 2000 equipment platform with the most recent version of modules currently available from the existing vendor.

The "do nothing" alternative is not acceptable. Continuing to maintain the existing equipment has become impossible due to the unavailability of spare modules and a lack of expertise in this

[21] The absence of real-time monitoring with the IMUX system extends system restoration time as technicians must use a guess and check method to locate and repair the system. Real-time system monitoring would consolidate troubleshooting efforts and reduce the time to diagnose and repair failures.

legacy technology.[22] Operating the St. John's transmission network without teleprotection will result in an unstable power system, and widespread outages may result.[23]

The alternative of replacing the existing IMUX equipment platform with modern technology through a Request for Proposals from multiple vendors will deal directly with the IMUX 2000 system failures. The benefits of a modern technology solution include an extended service life, availability of spare parts, remote monitoring capability and integration with the existing information technology network infrastructure.

The alternative of upgrading the existing IMUX equipment platform with current technology from the existing vendor is technically possible. However, the upgraded IMUX equipment platform will not provide remote monitoring and will not integrate with the Company's existing information technology network infrastructure. Therefore, it will be necessary to maintain dedicated expertise in this outmoded technology. The cost of this alternative is estimated to be similar to the replacement alternative.[24] However, since the IMUX product has been in the marketplace for over 20 years, the expected service life of an upgraded IMUX equipment platform would be shorter than that of more current technology.

Replacement of the existing IMUX equipment platform with modern technology is the preferred alternative over the long term for this critical system. Legacy technology, increased rate of failures, lack of spare IMUX module cards, and unreliable ring wrapping necessitates that the existing IMUX 2000 equipment platform be replaced in 2023.

3.2 Fibre Optic Cable Builds

The leased fibre cables that extend from Pepperrell Substation to Virginia Waters Substation and from Pepperrell Substation to Kings Bridge Substation have no spare capacity. Consequently, if a fibre strand failure occurs in these 2 cables, the transmission line teleprotection on these fibre circuits will be out of service for an extended period.[25] On each of the other fibre cables in St. John's, there are at least 4 spare fibre strands.[26] This is the minimum number of spare fibre strands per link required for the St. John's fibre network. Spare fibre capacity is also necessary to accommodate the commissioning of the new teleprotection system and cut-over from the existing IMUX system. To ensure minimal impact on the St. John's transmission line protection

22 Modern technology based on Internet Protocol ("IP") communications standards will enhance system support as existing internal resources and tools could also maintain and support a new IP based solution. With the legacy IMUX equipment, the Company is required to maintain specialized expertise which currently exists with senior employees who are nearing retirement. Recent technology graduates are not being trained to maintain these legacy technologies.

23 Both the HTGS and the LIL contribute significant generation to the Island Interconnected System.

24 The equipment cost with this alternative would be less, however the labour cost associated with training, testing, installation and commissioning will be the same whether it is a significant upgrading of the existing equipment or a wholesale equipment replacement.

25 If practical, during times when teleprotection is not available, the Company will remove the associated transmission line from service. Depending upon which fibre strands are not available, if ring wrapping functions as designed, the differential protection will remain in service unless there is another fibre break which results in loss of all differential protection.

26 The existence of spare fibre strands allows the operation channels to be transferred to the spare fibre strands returning the system to service while the repairs are undertaken.

system during commissioning and cut-over, at least 4 spare fibre strands in each cable are required. This will allow the 2 systems to be operated in parallel while testing and commissioning of the new teleprotection system is carried out.

In 2023, the Company will replace the 2 leased fibre cables with 2 new Company owned fibre optic cables.[27] These 2 cables will be constructed in advance of the new teleprotection system installation, which is scheduled for 2023. The additional fibre strands will strengthen the resiliency of the St. John's fibre optic network by ensuring an appropriate number of spare fibre strands are available.

The Net Present Value Analysis, provided in Appendix E, compares the alternative of constructing Company-owned fibre optic cables to the alternative of leasing additional fibre strands from a 3rd party telecommunications provider. The analysis is completed over a 25 year period, with the alternative of Company owned fibre cable costing approximately $33,000 less than the alternative to continue to lease fibre capacity. The result shows that building Company-owned fibre optic circuits from Pepperrell Substation to Kings Bridge Substation and Pepperrell Substation to Virginia Waters Substation is the least-cost alternative.[28]

4.0 Project Description

The multi-year project to upgrade the St. John's teleprotection system involves the following:

(i) In 2022 and 2023, replacement of the existing IMUX 2000 equipment platform with a system of similar capability based on current technology;
(ii) In 2023, install fibre optic cables from Pepperrell Substation to Kings Bridge Substation and Pepperrell Substation to Virginia Waters Substation; and
(iii) In 2023, configuration, testing and commissioning of the new teleprotection system, and related training.

This project is necessary to ensure the continued provision of reliable teleprotection for the Company's St. John's transmission network.

5.0 Project Schedule

The Company plans to replace the St. John's teleprotection system as a multi-year project commencing in 2022 following the scope of work described in Section 4.0.

27 The new fibre cables will include additional fibre strands to provide for expansion and necessary spares.
28 Upon completion of fibre builds in 2023, Newfoundland Power will be leasing 2 less fibre optic cables.

Figure 1 shows the schedule for this work.

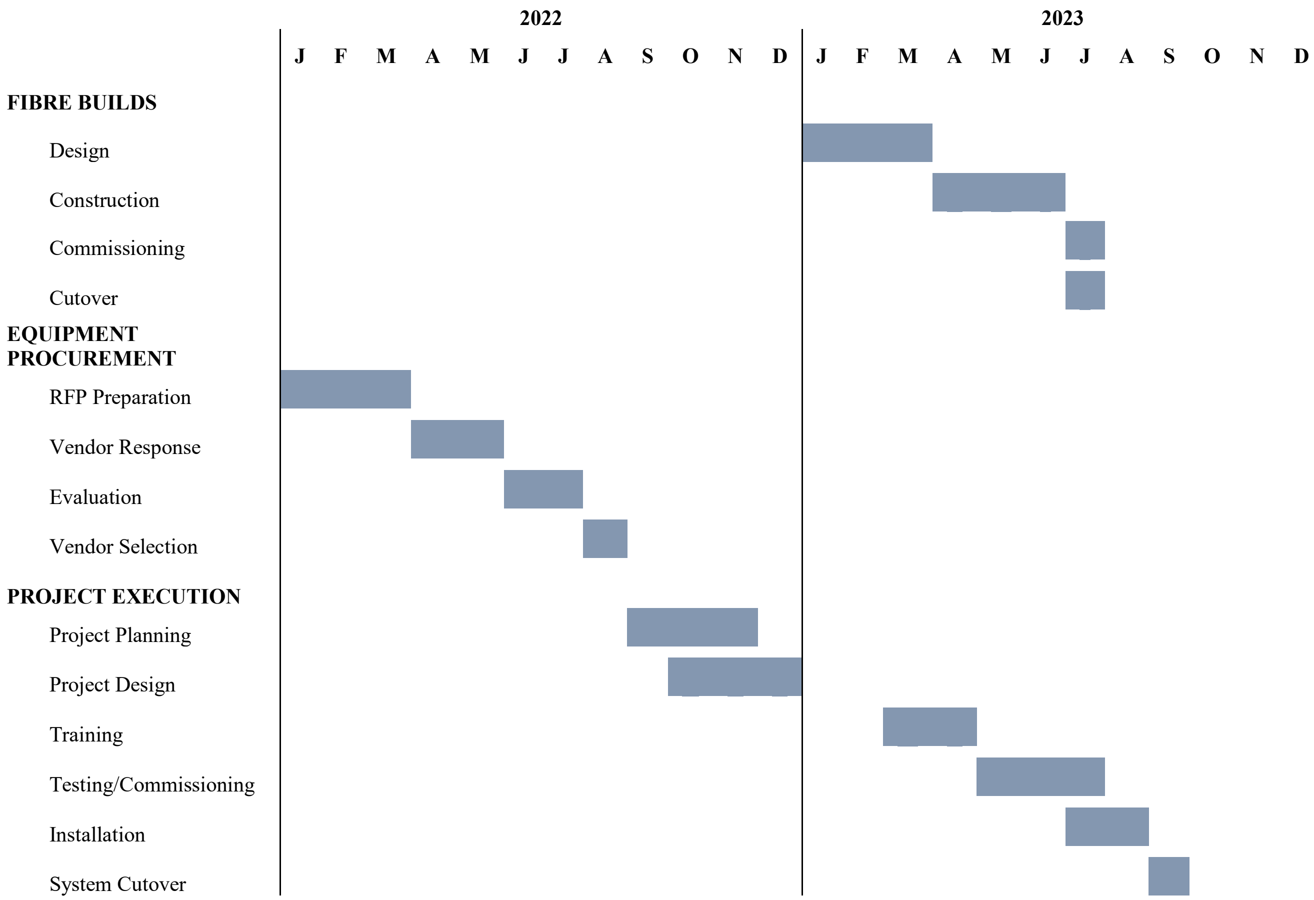

Figure 1: Project Schedule

In 2022, Newfoundland Power will solicit Requests for Proposals ("RFP") from qualified teleprotection system vendors for the replacement of the entire IMUX 2000 system. It is estimated that it will take approximately 8 months to prepare the technical specification, complete the RFP, and select the vendor for the St. John's teleprotection system replacement. It is estimated that the manufacture of the system components, training, testing, system installation and final system cutover will take another 12 months to complete. The work associated with the fibre optic cable builds will commence in January 2023 to ensure completion in advance of the IMUX 2000 replacement. Starting the project in the 1st quarter of 2022 will ensure that the new teleprotection system is operational in the 3rd quarter of 2023, in advance of the winter season.

6.0 Project Cost Estimate

The estimate to complete all work associated with the *St. John's Teleprotection System Replacement* is $1,600,000. Table 2 provides a breakdown of the multi-year project cost by year.

Table 2
Project Cost

Description	**2022**	**2023**
IMUX Replacement	$450,000	$900,000
Fibre Optic Cable Builds	-	250,000
Total	**$450,000**	**$1,150,000**

7.0 Conclusion

The continued requirement for the Company's St. John's teleprotection system following the commissioning of the LIL and subsequent to the decommissioning of the HTGS has been confirmed by Hydro's consultant, TransGrid Solutions Inc.

The Company's existing IMUX 2000 equipment platform has been in service for 20 years, and has reached the end of its service life. Support from the vendor in relation to replacement parts is becoming exhausted and the Company stock of spare parts has diminished. The critical nature of the teleprotection network, and the potential of a teleprotection failure causing outages to the HTGS, the LIL and other transmission lines on the Avalon Peninsula, makes the replacement of the existing IMUX 2000 system necessary at this time.

The project should proceed in 2022 because of the risk associated with extending the maintaining technology due to the lack of spare parts and vendor support. Continuing with the existing IMUX 2000 system is not an acceptable alternative due to the high risk associated with its frequent failures. Replacing the existing IMUX 2000 equipment platform is required to ensure continued teleprotection for the St. John's transmission network.

Appendix A

St. John's Teleprotection System Description

St. John's Teleprotection System Description

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1.0 Introduction

Teleprotection systems are used by transmission utilities to protect high voltage transmission networks. The teleprotection equipment is the interface between microprocessor-controlled digital protective relays and the telecommunications channels that transmit signals between relays located in remote substations.[1] Newfoundland Power Inc.'s (the "Company") St. John's teleprotection system is based on the IMUX 2000 equipment platform, which was installed in 2002. The St. John's teleprotection system comprises the teleprotection equipment and the high-speed telecommunications channels carried on fibre optic cables.

2.0 Transmission Line Protection

2.1 Transmission Line Protection Background

Transmission lines are a vital part of the high voltage electrical system, typically providing the path to transfer power from sources of generation to customer load centres. When faults occur on transmission lines, their associated protection systems are designed to quickly identify the location of these faults and isolate only the faulted section.[2]

Key engineering considerations influencing transmission line protection include the (i) criticality of the line in terms of both load transfer and system stability, (ii) fault clearing time requirements for system stability, (iii) line length, (iv) configuration of the line, (v) line loading, (vi) communications alternatives available, and (vii) failure modes of various protection equipment.

The function of protective relaying is to promptly remove from service any element of a power system that experiences a short circuit, or when it starts to operate in any abnormal manner that might cause damage or otherwise interfere with the effective operation of the rest of the system. Typically, protection designs include both primary protection and backup protection elements. The protective relaying equipment is aided in this task by circuit breakers that are capable of disconnecting the faulted element when identified by the protective relaying equipment. Radial transmission line protection is straightforward, as electricity flows in only one direction and protective relay operation relies principally on the magnitude of the current being supplied. Protection of radial transmission lines is typically achieved by distance/impedance and overcurrent protective relaying equipment opening the breaker at the source end of the transmission line.

Looped and networked transmission line protection is more complex because of the multiple paths that can supply current to the faulted element. As electricity can flow from both ends of looped transmission lines, when a fault is detected, breakers at both ends of the faulted

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1 Technically, the digital protective relays may be considered part of the teleprotection system. For the purposes of this system description the digital protective relays are not considered to be part of the St. John's teleprotection system.

2 Highly reliable transmission line protection systems are critical to system reliability. Protection schemes are used to minimize damage to equipment and minimize interruptions to customer service when there is a disturbance on the electrical system.

transmission line must operate to stop the supply of current to the fault. Protection of looped and networked transmission lines is best achieved by differential protection elements.

Newfoundland Power has been replacing obsolete electromechanical relays with microprocessor controlled digital relays that improve accuracy, flexibility, and monitoring capability, while reducing maintenance requirements. One programmable relay can replace multiple electromechanical ones, as they typically incorporate more than one protection element. Self-diagnostic capability and programmable monitoring capacity combine to improve the reliability of protection, and increase efficiency in the use of field personnel. Digital relays are ideally suited for teleprotection systems.

2.2 St. John's Area Transmission Network

The St. John's area transmission network is a looped system that consists of 22 transmission lines operating between 14 substations.[3] Each of these transmission lines has both primary and backup protection schemes in place. Electricity flows over this network through multiple paths, and the network can be switched such that the flow of electricity can be altered so that individual substations can be supplied from different locations.

For the St. John's transmission network, differential protection is the primary protection scheme. Using fibre optic communications, 2 differential transmission line relays communicate with each other to detect and clear any electrical faults that develop on that specific transmission line. For the 66 kV transmission network in St. John's, differential protection is used to meet the critical clearing times required.[4]

Critical clearing times are defined as the prescribed time for a fault or short circuit to be removed from a power system to ensure that the system remains stable and to prevent major outages. The power system can be expected to remain stable if the fault can be cleared within this critical clearing time. For the St. John's transmission network, the critical clearing times range from 10 cycles (167 milliseconds) for a multi-phase fault and 25 cycles (416 milliseconds) for a line-to-ground fault. Transmission line protective relays use differential protection as per the IEEE C37.94 standard to meet the necessary critical clearing times.[5]

As backup to differential protection, each of the transmission lines in the St. John's area use distance/impedance protection and overcurrent protection.[6] Each of these backup protection schemes will have much slower clearing times in the case of a fault. If the fault is not cleared

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3 The St. John's area transmission network has multiple looped transmission lines supplying all substations in and around the City of St. John's.

4 *Eastern System Critical Clearing Time Study– Island Interconnected Transmission System*, dated August 8, 1991, jointly prepared by Newfoundland & Labrador Hydro and Newfoundland Power, determined critical clearing times for the St. John's 66 kV transmission network.

5 The IEEE C37.94 standard establishes the data structure and encoding over fibre optic communications for differential protection.

6 In the event of a communications failure, the relays disable the primary differential protection and automatically switches to the backup protection.

within the required critical clearing time, it could cause cascading outages to other transmission lines and generation on the Avalon Peninsula.[7]

3.0 St. John's Teleprotection System Design

To adequately protect the St. John's transmission network from faults and to ensure power system stability, Newfoundland Power uses a transmission line teleprotection system based on the IMUX 2000 equipment platform. The IMUX 2000 equipment platform combines multiple communication circuits over fibre optic cables to allow communication between multiple transmission line relays.[8]

Newfoundland Power installed the IMUX 2000 equipment platform in 2002 to provide the required differential protection schemes. The IMUX system is configured in a dual ring topology with the rings joining together at the System Control Centre ("SCC"). The ring design of the St. John's fibre network provides each transmission relay with a redundant optical path around the fibre ring via the IMUX system.

Figure A-1 shows a block diagram of the dual ring topology design of the St. John's IMUX system.

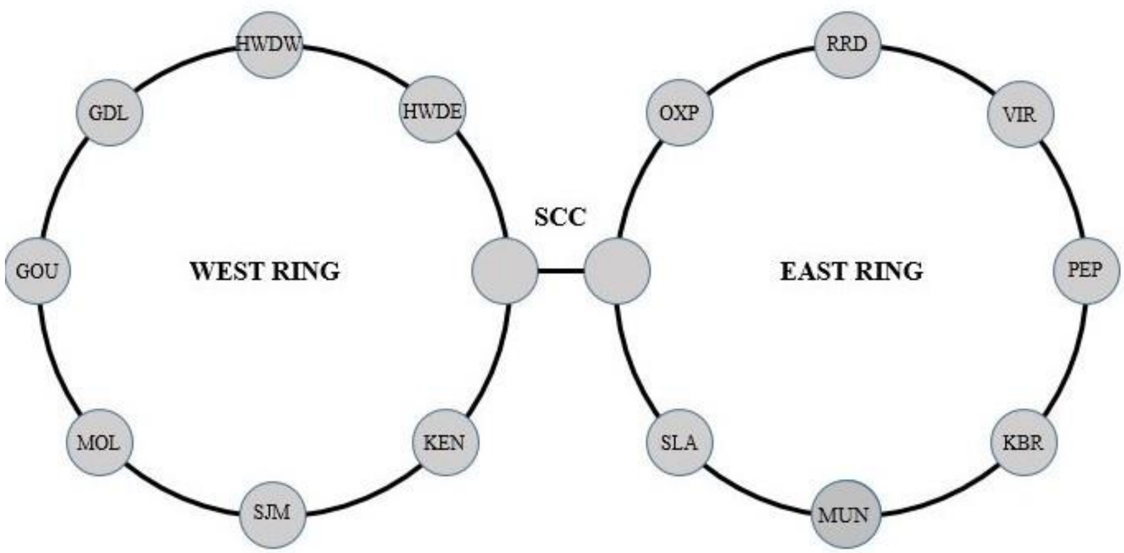

Figure A-1: Block Diagram of IMUX 2000 System – Dual Ring Topology

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7 If a transmission line fault occurs when the differential protection is active, the transmission line breakers will open at both ends and the power flow will automatically adjust with no customer outages resulting. If the differential protection is not active and the time to clear the fault is beyond the critical clearing time, other transmission lines may trip as part of a cascading failure, and the associated voltage drop at the Holyrood generating station may cause the generators to trip offline in response. In the event that differential protection is not operational a significant number of customer outages will result.

8 Without a multiplexing technology like the IMUX 2000, 2 pairs of dedicated fibre optic strands would be required per transmission line. In the case of the St. John's transmission network with 22 transmission lines, 88 strands (22 × 2 × 2) of fibre optics would be required.

In addition to the dual ring topology, the St. John's IMUX 2000 equipment platforms are configured in a dual counter rotating ring arrangement. With this configuration, one pair of fibre strands are used to form the primary bidirectional ring while the second pair of fibre optic strands are used to form the secondary bidirectional path. If there is a break in the primary ring, all traffic will automatically transfer to the secondary ring. This ensures the reliability of the differential relay communications and maintains the interconnection of the relays to meet the critical clearing time requirement.

The dual counter rotating ring arrangement is demonstrated in Figure A-2.

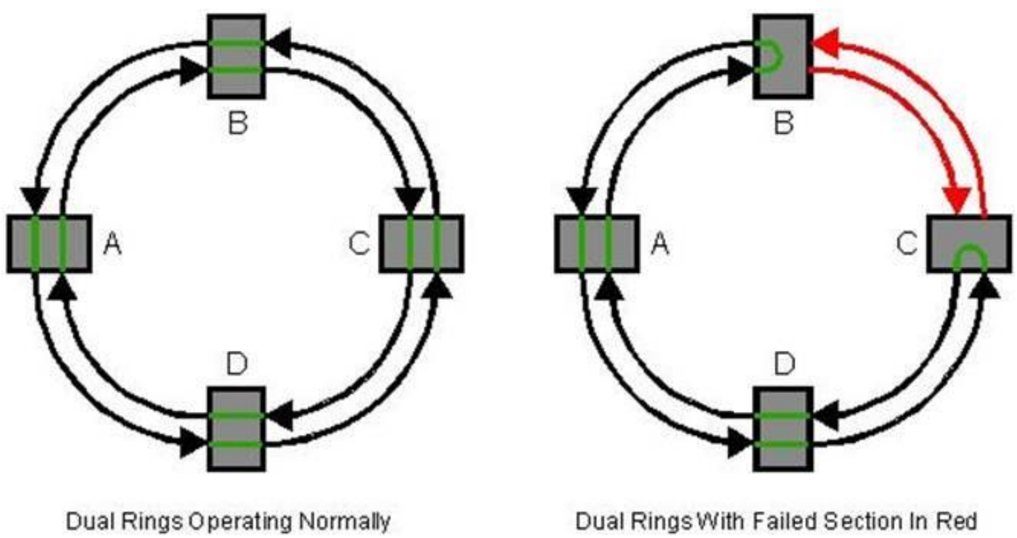

Figure A-2: Dual Counter Rotating Rings

In Figure A-2, under normal operation, data flows freely between all 4 nodes. Each node has 4 fibre ports typically referred to as inbound east, outbound east, inbound west and outbound west. If a fibre break occurs as shown by the red arrows, the inbound and outbound ports on the adjacent nodes B and C "wrap", thereby ensuring that all 4 nodes continue to receive data.

The IMUX 2000 equipment platform uses time division multiplexing technology.[9] This has become a legacy technology with the advent of Internet Protocol ("IP") based telecommunication networks.

[9] Conceptually, time division multiplexing is very much similar to a train with a fixed number of freight cars. Each freight car, or time slot, has a specific origin and destination it serves. In this way multiple services can share the same circuit.

Figure A-3 shows a conceptual diagram for time division multiplexing.

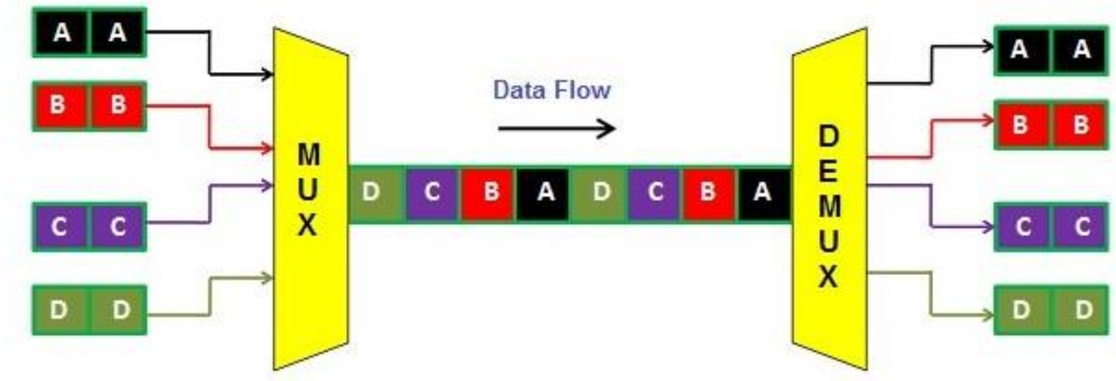

Figure A-3: TDM Conceptual Diagram

Using coloring, Figure A-3 shows how 4 individual data channels are multiplexed onto a single high speed channel, and then de-multiplexed at the remote end into 4 discrete data channels. Data flow on the aggregate channel must be orders of magnitude faster than the individual data channels (A, B, C and D in the diagram).

In the TDM application, a common chassis includes multiple slots to house modules for individual services. In the case of the St. John's teleprotection system the chassis includes individual modules for each differential relay channel. Figure A-4 shows a typical IMUX 2000 chassis.

Figure A-4: Typical IMUX Chassis

Appendix B

Spare Parts Inventory

IMUX SPARE PARTS INVENTORY

Part	Purpose	Vendor Comments	Total	Spare
ILS Chassis		Discontinued with limited repair only	16	1
Alarm Config		Discontinued with limited repair only	16	2
ILS/DACS	Processor module	Discontinued with limited repair only	16	3
ILS	ILS module	Discontinued with limited repair only	14	3
Mini-DACS	Processor module	Discontinued with limited repair only	2	2
MA-220	Module adapter in ILS chassis for connection to T1 chassis	Discontinued with limited repair only	16	3
MA-225	Module adapter in ILS chassis for connection to T1 chassis	Discontinued with limited repair only	16	3
PS Main	48/125VDC Power supply - 9547-920	Discontinued	16	3
T1 Chassis		Available	19	6
MA-210	Module adapter for connection to ILS chassis and CM3R logic card	Available	17	3
MA-215	Module adapter for connection to ILS chassis and CM3R logic card	Available	17	5
PS Main	48/125VDC Power supply - 9547-920	Discontinued	19	3
CM3R	Logic Card	Discontinued	34	10
DS-562I	Card for differential protection	Discontinued	12	21
DS-562NC	Card for differential protection	Available	32	8
MA-620	Module adapter for DS-562I or DS-562NC card (fibre)	Available	28	7
MA-409IA/B	Module adapter for DS-562I or DS-562NC card (copper)	Available	16	26
DS-64NC	Card for differential protection	Discontinued	2	7
MA-427	Module adapter for DS-64NC	Discontinued	2	7
BRM	Buss Repeater Module	Available	2	3
MA-501	Module adapter for buss repeater module	Available	2	1

Appendix C

List of Substations and Transmission Lines on the IMUX System

Table C-1
List of Substations and Transmission Lines on the IMUX System

Transmission Line	From	To
19L	Hardwoods West Substation	Molloys Lane Substation
54L	Hardwoods West Substation	Kenmount Road Substation
72L	Hardwoods West Substation	Goulds Substation
73L	Hardwoods East Substation	Glendale Substation
35L	Kenmount Road Substation	Oxen Pond Road Substation
69L	Kenmount Road Substation	Stamps Lane Substation
31L	Oxen Pond Road Substation	Stamps Lane Substation
32L	Oxen Pond Road Substation	Ridge Road Substation
34L	Oxen Pond Road Substation	Virginia Waters Substation
58L	Oxen Pond Road Substation	Virginia Waters Substation
67L	Oxen Pond Road Substation	Ridge Road Substation
70L	Oxen Pond Road Substation	Stamps Lane Substation
4L	Goulds Substation	St. John's Main Substation
18L	Goulds Substation	Glendale Substation
25L	Goulds Substation	St. John's Main Substation
12L	Kings Bridge Substation	Memorial Substation
16L	Kings Bridge Substation	Pepperrell Substation
30L	Kings Bridge Substation	Ridge Road Substation
13L	Stamps Lane Substation	St. John's Main Substation
14L	Stamps Lane Substation	Memorial Substation
15L	Stamps Lane Substation	Molloys Lane Substation
74L	Pepperrell Substation	Virginia Waters Substation

Appendix D

Map of PEP-KBR and PEP-VIR Fibre Optic Cable Builds

Figure D-1: PEP-KBR Fibre Optic Cable Build

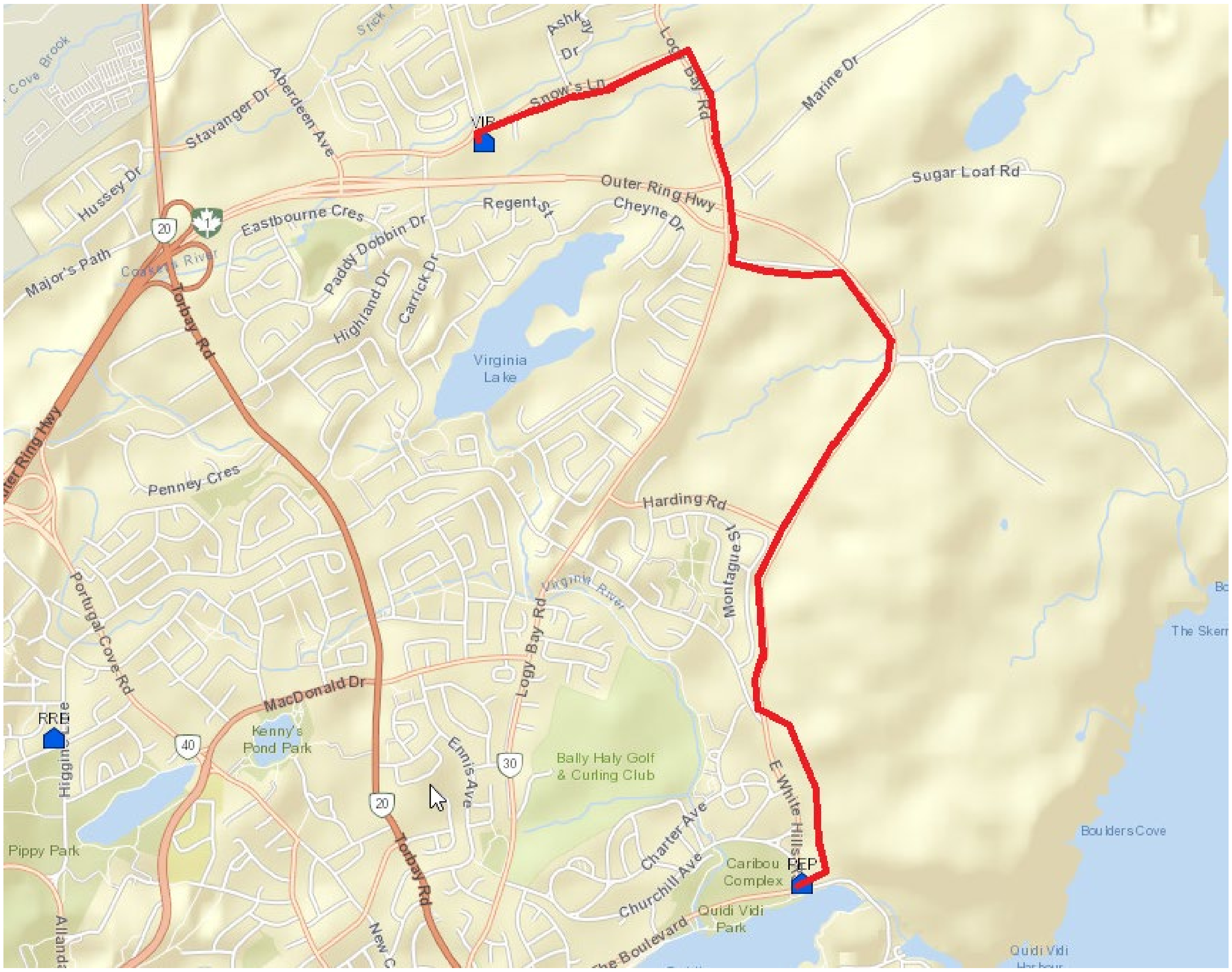

Figure D-2: PEP-VIR Fibre Optic Cable Build

Appendix E

Fibre Optic Cable Build Net Present Value Analysis

Table E-1
Net Present Value Analysis
Construct Company-Owned Fibre Optic Circuits

Year	Capital Expenditure	Capital Revenue Requirement	Operating Costs	Net Benefit	Present Worth Benefit	Cumulative Present Value	Present Worth of Sunk Costs	Total Present Worth
2022	0	0	17,732	-17,732	-17,732	-17,732	-269,778	-287,510
2023	250,000	23,621	9,014	-32,635	-30,843	-48,575	-247,454	-296,029
2024	0	27,751	1,033	-28,784	-25,709	-74,284	-222,667	-296,952
2025	0	26,669	1,049	-27,718	-23,398	-97,682	-200,155	-297,837
2026	0	25,650	1,068	-26,717	-21,315	-118,997	-179,692	-298,689
2027	0	24,686	1,087	-25,773	-19,432	-138,430	-161,079	-299,508
2028	0	23,771	1,106	-24,877	-17,727	-156,157	-144,140	-300,296
2029	0	22,900	1,125	-24,025	-16,180	-172,337	-128,718	-301,054
2030	0	22,066	1,145	-23,210	-14,773	-187,110	-114,673	-301,783
2031	0	21,265	1,165	-22,430	-13,492	-200,602	-101,882	-302,484
2032	0	20,494	1,185	-21,679	-12,324	-212,926	-90,231	-303,157
2033	0	19,748	1,205	-20,953	-11,258	-224,184	-79,621	-303,805
2034	0	19,025	1,226	-20,251	-10,283	-234,467	-69,960	-304,428
2035	0	18,322	1,247	-19,569	-9,391	-243,859	-61,167	-305,026
2036	0	17,637	1,269	-18,905	-8,575	-252,433	-53,168	-305,602
2037	0	16,967	1,290	-18,257	-7,826	-260,259	-45,896	-306,155
2038	0	16,310	1,313	-17,623	-7,139	-267,398	-39,288	-306,687
2039	0	15,666	1,335	-17,001	-6,509	-273,907	-33,290	-307,198
2040	0	15,032	1,358	-16,390	-5,930	-279,838	-27,851	-307,689
2041	0	14,407	1,381	-15,788	-5,399	-285,237	-22,924	-308,161
2042	0	13,791	1,405	-15,196	-4,911	-290,148	-18,467	-308,615
2043	0	13,182	1,429	-14,610	-4,463	-294,611	-14,441	-309,052
2044	0	12,579	1,453	-14,032	-4,051	-298,661	-10,810	-309,471
2045	0	11,981	1,478	-13,459	-3,672	-302,333	-7,541	-309,874
2046	0	11,389	1,503	-12,892	-3,324	-305,658	-4,605	-310,262
2047	0	18,895	1,529	-20,424	-4,977	-310,635	0	-310,635

Table E-2
Net Present Value Analysis
Request Additional Fibre from 3rd Party Communications Provider

Year	Capital Expenditure	Capital Revenue Requirement	Operating Costs	Net Benefit	Present Worth Benefit	Cumulative Present Value	Present Worth of Sunk Costs	Total Present Worth
2022	0	0	17,732	-17,732	-17,732	-17,732	-49,639	-67,371
2023	46,000	4,346	18,027	-22,374	-21,145	-38,877	-45,532	-84,409
2024	0	5,106	18,316	-23,423	-20,921	-59,798	-40,971	-100,769
2025	0	4,907	18,602	-23,509	-19,845	-79,643	-36,828	-116,472
2026	0	4,720	18,936	-23,655	-18,872	-98,515	-33,063	-131,578
2027	0	4,542	19,269	-23,812	-17,954	-116,469	-29,638	-146,107
2028	0	4,374	19,609	-23,983	-17,090	-133,559	-26,522	-160,080
2029	0	4,214	19,953	-24,167	-16,276	-149,834	-23,684	-173,518
2030	0	4,060	20,300	-24,360	-15,505	-165,339	-21,100	-186,439
2031	0	3,913	20,655	-24,567	-14,778	-180,117	-18,746	-198,863
2032	0	3,771	21,013	-24,784	-14,090	-194,207	-16,603	-210,809
2033	0	3,634	21,376	-25,010	-13,437	-207,644	-14,650	-222,294
2034	0	3,501	21,744	-25,244	-12,819	-220,463	-12,873	-233,335
2035	0	3,371	22,117	-25,488	-12,232	-232,695	-11,255	-243,949
2036	0	3,245	22,499	-25,744	-11,676	-244,371	-9,783	-254,154
2037	0	3,122	22,882	-26,004	-11,147	-255,517	-8,445	-263,962
2038	0	3,001	23,275	-26,276	-10,645	-266,162	-7,229	-273,391
2039	0	2,883	23,671	-26,553	-10,166	-276,328	-6,125	-282,454
2040	0	2,766	24,077	-26,843	-9,713	-286,041	-5,125	-291,166
2041	0	2,651	24,489	-27,140	-9,281	-295,322	-4,218	-299,540
2042	0	2,538	24,908	-27,446	-8,870	-304,193	-3,398	-307,591
2043	0	2,425	25,335	-27,760	-8,479	-312,672	-2,657	-315,329
2044	0	2,314	25,769	-28,083	-8,107	-320,779	-1,989	-322,768
2045	0	2,205	26,210	-28,415	-7,752	-328,532	-1,388	-329,919
2046	0	2,096	26,659	-28,755	-7,414	-335,946	-847	-336,793
2047	0	3,477	27,116	-30,592	-7,455	-343,401	0	-343,401

2022 Application Enhancements

May 2021

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Page

1.0 Introduction

Newfoundland Power Inc. ("Newfoundland Power" or the "Company") operates and supports approximately 180 software applications. This includes third-party software products, such as the Microsoft Dynamics Great Plains financial system and the Responder Outage Management System. It also includes internally developed software, such as the Technical Work Request System for creating and tracking work orders for customer-driven requests. These applications help employees work more effectively and efficiently in the day-to-day provision of service to customers.

Newfoundland Power's *2022 Application Enhancements* include business support system enhancements and internet enhancements. In addition, the Company budgets for various minor enhancements to respond to unforeseen requirements encountered during the course of each year.

Enhancing these applications in 2022, either through vendor-supplied products or internal software development, will better enable Newfoundland Power to meet customers' service expectations and to serve its customers at least cost.

The following report describes the application enhancements planned for 2022.

2.0 Business Support System Enhancements

This category includes enhancements necessary to support Newfoundland Power's business support systems. Business support systems include the various applications used to manage the safety, human resource and financial functions of the Company. For 2022, enhancements are proposed to the Digital Forms System, Technology Services System and Financial Management System.

Table 1 summarizes the estimated cost associated with these enhancements.

Table 1
Business Support System Enhancements
2022 Project Expenditures
($000s)

Cost Category	**Amount**
Material	120
Labour – Internal	265
Labour – Contract	-
Engineering	-
Other	160
Total	**$545**

2.1 Digital Forms System Enhancements ($185,000)

Description

This item involves enhancing the Digital Forms System to include forms related to work observations, contractor inspections and job risk assessments ("tailboards").[1] These processes are necessary to comply with provincial legislation and support the safety of Newfoundland Power's employees and the general public.

Operating Experience

The Company's Work Observation Program requires documenting the observation of working employees, including an assessment of safety performance and on-site discussions with crew members.[2] Documented work observations are essential for monitoring employee safety performance and providing support and coaching to employees.[3] Currently, these work observations are documented manually using paper forms that are later keyed into the Safety Management System ("Intelex") at Company offices.[4] A total of 444 work observations were completed and manually keyed into Intelex in 2020.

Newfoundland Power's Contractor Safety Program requires the health and safety performance of contractors to be monitored and documented through contractor inspections.[5] Documented inspections are essential for monitoring contractor performance and compliance with Company procedures and codes. Currently, contractor inspections are documented manually by employees in the field using paper forms.[6] These forms are later manually keyed into Intelex at Company offices. A total of 274 contractor inspections were completed and manually keyed into Intelex in 2020.

Provincial Occupational Health and Safety Regulations require safety tailboards to be completed.[7] Newfoundland Power completes approximately 32,000 tailboards each year.[8]

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[1] The Company's *Digital Forms System Enhancements* project, which was included the *2021 Capital Budget Application*, was approved by the Board in Order No. P.U. 37 (2020). The project involves the digitization of daily truck inspection and Record of Duty forms.

[2] The Company's Work Observation Program is part of Newfoundland Power's Safety Management System (currently Occupational Health and Safety Assessment Series 18001).

[3] For example, non-conformances documented during work observations are tracked for follow up.

[4] Work observations are typically conducted by Line Supervisors.

[5] Per Newfoundland Power's Safety Management System, contractors are an extension of the Company's workforce and must follow Company procedures and codes.

[6] Contractor inspections are typically completed by the employee that is assigned to oversee a particular contract, such as a Line Supervisor.

[7] See section 22.1 of the *Occupational Health and Safety Regulations, 2012* (NLR 5/12) under the *Occupational Health and Safety Act*, RSNL 1990, c. O-3. Newfoundland Power's Risk Management and Job Safety Planning Code requires tailboards to be documented when work groups are completing activities designated as medium or high-risk. Medium-risk hazards could result in temporary disability (i.e. lost time injury). High-risk hazards could result in fatality or serious injury (i.e. permanent disability).

[8] The estimate includes approximately 26,000 annual tailboards completed electronically by field staff (66 line crews x 195 average on-road days yearly x 2 tailboards/day average = 25,740) and approximately 6,000 annual tailboards currently completed manually by maintenance operations employees.

Tailboards ensure key safety procedures are followed and that job steps, associated hazards and barriers are considered before starting each job. Tailboards were originally implemented as a paper form in 1997. A digital tailboard form was implemented in 2015 as part of the Workforce Management System, Click. Click will be obsolete in 2023.[9] As a result, the digital tailboard form will no longer be available.[10]

Enhancing the existing Digital Forms System to include work observations, contractor inspections and tailboard workflows will reduce the number of manual processes required. The digital solution will provide efficiencies in completing forms in the field. For example, the forms will automatically capture employee location and other information. It will also provide efficiencies through a reporting dashboard and include third-party vendor support to resolve any software issues.

Justification

This enhancement is justified on the basis of improved operating efficiencies. An analysis shows that implementing this solution will provide a positive net present value for customers over the next 7 years.[11]

2.2 Technology Service Management Solution ($200,000)

Description

This item involves replacing Newfoundland Power's current systems and manual processes used to manage technology service requests with a modern technology management solution.

Implementing a modern technology management solution will create operating efficiencies for Technology department staff responsible for completing technology inquiries and requests (the "Helpdesk").[12]

Operating Experience

Newfoundland Power operates and supports approximately 180 software applications that are used by over 600 employees to deliver service to customers. The Helpdesk receives approximately 8,000 technology requests per year.[13] Maintaining Company technology is essential to the delivery of reliable service to customers at least cost.

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9 See the *2022 Capital Budget Application, Report 7.3 Workforce Management System*.

10 As tailboards can be accessed through Newfoundland Power's existing Digital Forms System, the proposed replacement Workforce Management System project will not require additional costs to include a digital forms module.

11 See Appendix A.

12 Technology enquires and requests range from trouble shooting questions to requests for access to Company applications, servers and buildings.

13 In 2020, technology questions and requests increased to approximately 11,000 primarily as a result of changes in business processes related to the COVID-19 pandemic.

Currently, a combination of internally developed systems, commercial systems and manual processes are used to manage technology service requests.[14] Employees' requests are received by the Helpdesk through internally developed electronic forms, phone or email. The Helpdesk then rekeys the requests into a commercial system that is used to track and store each request. The Helpdesk also manually routes requests to appropriate personnel for approval and completion.[15] Weekly reports required for corporate governance and cybersecurity management purposes must also be created manually by retrieving information from various systems.

Implementing a modern technology management solution will provide a centralized environment where all requests can be received and stored.[16] Workforce management tools will streamline approval, completion and reporting processes.[17] Similar to the customer website, modern solutions also provide self-service options, thereby reducing the number of requests received by the Helpdesk.[18]

These capabilities will create efficiencies in managing technology requests by eliminating manual processes and reducing the number of requests received by the Helpdesk.

Justification

This enhancement is justified on the basis of improved operating efficiencies. An analysis shows that implementing this solution will provide a positive net present value for customers over the next 7 years.[19]

2.3 Dynamics GP Automation ($160,000)

Description

This item involves enhancing Newfoundland Power's Financial Management System, Microsoft Dynamics Great Plains ("Dynamics GP") to automate processes for recording financial transactions. These are: (i) the creation of projects to track expenses incurred annually; and (ii)

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14 The Company currently uses 2 internally developed systems to receive employee technology requests. Newfoundland Power also uses 2 commercial software solutions to record, track and store all employee requests.

15 For example, an employee may submit a request using the internally developed electronic form to access the Company's Responder Outage Management System ("Responder"). The Helpdesk must: (i) rekey the request into a commercial system to maintain a record of the request; (ii) route the request to the appropriate personnel responsible for managing access to Responder; (iii) follow up, as necessary, to ensure the request is completed; and (iv) close the request in both the internally developed access system and the commercial tracking system.

16 One benefit of a modern, centralized system is its ability to identify common issues underlying multiple calls to the Helpdesk, which can reduce request volumes.

17 For example, an employee request for access to Responder would be automatically routed to the appropriate personnel.

18 Modern technology management solutions contain knowledge management repositories that allow employees to see documented solutions for issues they are experiencing. Industry guidance indicates that self-service options can reduce direct contacts by approximately 10%.

19 See Appendix B.

the creation of General Journal Vouchers ("GJVs") to ensure financial transactions are attributed to the appropriate time period.

Operating Experience

Newfoundland Power manages approximately 3,000 projects per year in Dynamics GP. The creation of projects in Dynamics GP allows the Company to track costs incurred throughout the year in providing service to customers. This includes both labour and non-labour costs for capital and operating work.

Projects are manually created in Dynamics GP prior to the start of each year. This requires manually inputting key details into a project template, such as the department, project name, cost categories, and other information. Each year, 6 to 8 Company employees are involved in creating projects in Dynamics GP to ensure expenses are accurately tracked.

Of the 3,000 projects required annually, approximately ¾ are recurring projects that are substantially the same from year to year.[20]

This item involves enhancing Dynamics GP to automatically carry forward recurring projects. This enhancement will eliminate the manual process currently required to create recurring projects.

Newfoundland Power processes approximately 960 GJVs each year. GJVs are created to ensure financial transactions are attributed to the appropriate time period. For example, GJVs are created to ensure certain costs are amortized over time periods approved by the Board.[21] GJVs are also created for the monthly purchased power bill received from Newfoundland and Labrador Hydro. The creation of GJVs ensures Newfoundland Power's financial transactions are recorded in a manner consistent with Board orders and United States generally accepted accounting principles ("US GAAP").[22]

GJVs are currently created, tracked and approved using an Excel spreadsheet. Once approved, information on each GJV is manually entered into Dynamics GP.

This item involves enhancing Dynamics GP to create a digital workflow for GJV approval that will automatically import GJV information into Dynamics GP. This automation will streamline the approval process and eliminate the manual entry of GJV information into Dynamics GP.

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[20] Approximately 2,200 Dynamics GP projects are substantially the same from year to year (2,200 / 3,000 = 0.73).

[21] For example, in Order No. P.U. 2 (2019), the Board approved the amortization over 34 months an estimated $1 million in Board and Consumer Advocate costs related to the Company's *2019/2020 General Rate Application*. In these cases, the Board typically issues 1 invoice to the Company for its costs. A monthly GJV is then created to recognize this expense over the amortization period approved by the Board.

[22] Under US GAAP, Newfoundland Power follows accrual-based accounting, which matches an expense to the period in which the work was completed or goods received.

Justification

This enhancement is justified on the basis of improved operating efficiencies. An analysis showed implementing this solution will provide a positive net present value for customers over the next 7 years.[23]

3.0 Internet Enhancements

This category includes enhancements to Newfoundland Power's web-based applications, which provide customers with convenient, self-service options 24 hours a day. Applications in this category include the Company's customer website and the takeCHARGE website.[24]

For 2022, enhancements to the takeCHARGE website are proposed to ensure customers continue to have access to up-to-date information on energy conservation and electrification initiatives.

Table 2 summarizes the estimated cost associated with this item.

Table 2
Internet Enhancements
2022 Project Expenditures
($000s)

Cost Category	**Amount**
Material	-
Labour – Internal	42
Labour – Contract	-
Engineering	-
Other	20
Total	**$62**

3.1 takeCHARGE Website Enhancements ($62,000)

Description

This item involves enhancing the website that supports customer energy conservation and electrification initiatives under the takeCHARGE partnership.

In 2022, takeCHARGE website enhancements are required to support changes to customer energy conservation and electrification initiatives arising from implementation of the *Electrification, Conservation and Demand Management Plan: 2021-2025* (the "2021 Plan").

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23 See Appendix C.
24 The takeCHARGE website supports joint Newfoundland and Labrador Hydro and Newfoundland Power customer energy conservation and electrification initiatives.

Specific enhancements include: (i) modifying the website to include updated information on customer programs; and (ii) expanding educational content for residential and commercial customers related to energy conservation and electrification.

Operating Experience

The takeCHARGE website has been an integral part of the Company's customer energy conservation programs since 2009. The website serves as the primary communication channel to provide customers with information on available programs and rebates, as well as energy conservation and electrification education and awareness resources.

There were over 390,000 visits to the takeCHARGE website in 2020. This is consistent with promotion of the takeCHARGE website as the primary resource for customer information and customers' increasing preference for digital communication.

Justification

Enhancements to the takeCHARGE website are justified on the basis of improvements in customer service delivery and the continued promotion of energy conservation and electrification initiatives to customers. Updates to the takeCHARGE website will ensure customers continue to have access to accurate, up-to-date information on energy conservation and electrification.

4.0 Various Minor Enhancements ($400,000)

Description

The purpose of this item is to enhance 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 and operational efficiency.

Based on a 3-year historical average cost, $400,000 is estimated to be required in 2022 for Various Minor Enhancements.

Table 3 summarizes the cost breakdown of this item.

Table 3
Various Minor Enhancements
Project Expenditures
($000s)

Cost Category	Amount
Material	-
Labour – Internal	280
Labour – Contract	-
Engineering	-
Other	120
Total	**$400**

Operating Experience

Examples of work that would be completed under this budget item include modifications to customer service, 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.

Justification

Work completed as part of Various Minor Enhancements is justified on the basis of improved customer service, operating efficiencies, or compliance with regulatory and legislative requirements.

Appendix A

Net Present Value Analysis
Digital Forms System Enhancements

NET PRESENT VALUE ANALYSIS

Digital Forms System Enhancements

		Capital Impacts						Operating Cost Impacts						
		Capital Additions		CCA Tax Deductions				Cost Increases		Cost Benefits				
	YEAR	New Software A	New System Software B	Software	System Hardware C	Residual CCA	Total	Labour D	Non-Lab	Labour E	Non-Lab	Net Operating Savings F	Income Tax G	After-Tax Cash Flow H
0	2022	($185,000)	$0	$185,000	$0		$185,000	$0	$0	$30,000	$0	$30,000	$46,500	($108,500)
1	2023	$0	$0	$0	$0		$0	$0	($38,101)	$65,920	$0	$27,819	($8,346)	$19,473
2	2024	$0	$0	$0	$0		$0	$0	($38,695)	$67,898	$0	$29,203	($8,761)	$20,442
3	2025	$0	$0	$0	$0		$0	$0	($39,389)	$69,935	$0	$30,546	($9,164)	$21,382
4	2026	$0	$0	$0	$0		$0	$0	($40,083)	$72,033	$0	$31,950	($9,585)	$22,365
5	2027	$0	$0	$0	$0		$0	$0	($40,790)	$74,194	$0	$33,404	($10,021)	$23,383
6	2028	$0	$0	$0	$0		$0	$0	($41,506)	$76,419	$0	$34,913	($10,474)	$24,439
7	2029	$0	$0	$0	$0	$0	$0	$0	($42,227)	$78,712	$0	$36,485	($10,946)	$25,539
7Yr	Present Value (See Note I)	@		5.21%										$19,127

NOTES:

- A is the sum of the software additions by year.
- B is the sum of the computer network hardware additions by year.
- C is the Capital Cost Allowance deduction. It was calculated using declining balance depreciation and the 50% rule for capitalizing additions.
- D is any software maintenance fees and internal support costs associated with the project. The non-labour costs are escalated to current year using the GDP Deflator Index. The labour cost estimates are escalated to current year using Newfoundland Power's Labour Escalation Rates.
- E is the reduced operating costs. The non-labour cost estimates are escalated to current year using the GDP Deflator Index. The labour costs are escalated to current year using Newfoundland Power's Labour Escalation Rates.
- F is the sum of columns D and E.
- G is the impact on taxes from the CCA and operating cost deductions. It is equal to column C (total) less column F times the tax rate.
- H is the after tax cash flow which is the sum of the capital expenditure (columns A + B) plus operating expenditures (column F) plus income tax (column G).
- I is the present value of column H. Column H is discounted using the weighted after-tax cost of capital.

Appendix B

Net Present Value Analysis
Technology Service Management Solution

NET PRESENT VALUE ANALYSIS

Technology Service Management Solution

		Capital Impacts						Operating Cost Impacts						
		Capital Additions		CCA Tax Deductions				Cost Increases		Cost Benefits				
	YEAR	New Software A	New System Software B	Software	System Hardware C	Residual CCA	Total	Labour	Non-Lab D	Labour E	Non-Lab	Net Operating Savings F	Income Tax G	After-Tax Cash Flow H
0	2022	($200,000)	$0	$200,000	$0		$200,000	$0	($20,000)	$33,344	$0	$13,344	$55,997	($130,659)
1	2023	$0	$0	$0	$0		$0	$0	($20,321)	$51,516	$0	$31,195	($9,359)	$21,836
2	2024	$0	$0	$0	$0		$0	$0	($20,637)	$53,062	$0	$32,425	($9,727)	$22,698
3	2025	$0	$0	$0	$0		$0	$0	($21,007)	$54,654	$0	$33,647	($10,094)	$23,553
4	2026	$0	$0	$0	$0		$0	$0	($21,378)	$56,293	$0	$34,915	($10,475)	$24,440
5	2027	$0	$0	$0	$0		$0	$0	$0	$57,982	$0	$57,982	($17,395)	$40,587
6	2028	$0	$0	$0	$0		$0	$0	$0	$59,722	$0	$59,722	($17,917)	$41,805
7	2029	$0	$0	$0	$0	$0	$0	$0	$0	$61,513	$0	$61,513	($18,454)	$43,059
7Yr	Present Value (See Note I)		@	5.21%										$43,230

NOTES:

- A is the sum of the software additions by year.
- B is the sum of the computer network hardware additions by year.
- C is the Capital Cost Allowance deduction. It was calculated using declining balance depreciation and the 50% rule for capitalizing additions.
- D is any software maintenance fees and internal support costs associated with the project. The non-labour costs are escalated to current year using the GDP Deflator Index. The labour cost estimates are escalated to current year using Newfoundland Power's Labour Escalation Rates.
- E is the reduced operating costs. The non-labour cost estimates are escalated to current year using the GDP Deflator Index. The labour costs are escalated to current year using Newfoundland Power's Labour Escalation Rates.
- F is the sum of columns D and E.
- G is the impact on taxes from the CCA and operating cost deductions. It is equal to column C (total) less column F times the tax rate.
- H is the after tax cash flow which is the sum of the capital expenditure (columns A + B) plus operating expenditures (column F) plus income tax (column G).
- I is the present value of column H. Column H is discounted using the weighted after-tax cost of capital.

Appendix C

Net Present Value Analysis
Dynamics GP Automation

NET PRESENT VALUE ANALYSIS

Dynamics GP Automation

		Capital Impacts						Operating Cost Impacts						
		Capital Additions		CCA Tax Deductions				Cost Increases		Cost Benefits				
	YEAR	New Software A	New System Software B	Software	System Hardware C	Residual CCA	Total	Labour D	Non-Lab	Labour E	Non-Lab	Net Operating Savings F	Income Tax G	After-Tax Cash Flow H
0	2022	($160,000)	$0	$160,000	$0		$160,000	$0	$0	$14,000	$0	$14,000	$43,800	($102,200)
1	2023	$0	$0	$0	$0		$0	$0	$0	$30,600	$0	$30,600	($9,180)	$21,420
2	2024	$0	$0	$0	$0		$0	$0	$0	$31,518	$0	$31,518	($9,455)	$22,063
3	2025	$0	$0	$0	$0		$0	$0	$0	$32,464	$0	$32,464	($9,739)	$22,725
4	2026	$0	$0	$0	$0		$0	$0	$0	$33,438	$0	$33,438	($10,031)	$23,407
5	2027	$0	$0	$0	$0		$0	$0	$0	$34,441	$0	$34,441	($10,332)	$24,109
6	2028	$0	$0	$0	$0		$0	$0	$0	$35,474	$0	$35,474	($10,642)	$24,832
7	2029	$0	$0	$0	$0	$0	$0	$0	$0	$36,538	$0	$36,538	($10,961)	$25,577
7Yr	Present Value (See Note I)		@	5.21%										$31,623

NOTES:

A is the sum of the software additions by year.
B is the sum of the computer network hardware additions by year.
C is the Capital Cost Allowance deduction. It was calculated using declining balance depreciation and the 50% rule for capitalizing additions.
D is any software maintenance fees and internal support costs associated with the project. The non-labour costs are escalated to current year using the GDP Deflator Index. The labour cost estimates are escalated to current year using Newfoundland Power's Labour Escalation Rates.
E is the reduced operating costs. The non-labour cost estimates are escalated to current year using the GDP Deflator Index. The labour costs are escalated to current year using Newfoundland Power's Labour Escalation Rates.
F is the sum of columns D and E.
G is the impact on taxes from the CCA and operating cost deductions. It is equal to column C (total) less column F times the tax rate.
H is the after tax cash flow which is the sum of the capital expenditure (columns A + B) plus operating expenditures (column F) plus income tax (column G).
I is the present value of column H. Column H is discounted using the weighted after-tax cost of capital.

2022 System Upgrades

May 2021

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1.0 Introduction

Newfoundland Power Inc. ("Newfoundland Power" or the "Company") depends on the effective implementation and ongoing operation of its information systems to provide reliable service to its customers at least cost.

System upgrades, including the timing of required upgrades, are largely determined by the third-party vendors for each system. As vendors release new versions of systems to improve performance and address known issues, such as functionality issues or cybersecurity weaknesses, older versions may no longer be supported. In these cases, system upgrades are required to ensure continued vendor support. Vendor support helps minimize risks of system failure and cybersecurity threats.

Systems upgrades are also occasionally required to improve compatibility with other software or hardware upgrades, or to take advantage of newly developed functionality and security improvements.[1]

2.0 2022 Project Cost

System upgrades involve third-party software products that support Newfoundland Power's information systems. For 2022, upgrades are proposed for the Company's Supervisory Control and Data Acquisition system ("SCADA"), System Control Reporting System ("PI"), Database Management Systems and various other minor systems. Project expenditures also include renewal of the Microsoft Enterprise Agreement.

Table 1 summarizes the cost associated with these items.

Table 1
System Upgrades
2022 Project Expenditures
($000s)

Cost Category	**Amount**
Material	250
Labour – Internal	367
Labour – Contract	-
Engineering	-
Other	185
Total	**$802**

[1] Cybersecurity threats are increasing in the utility industry. For example, in January 2021, the Company observed over 41,000 cybersecurity threats on its network traffic.

3.0 2022 System Upgrades ($557,000)

3.1 Description

Newfoundland Power's information systems are reviewed annually to determine whether upgrades are required. 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.

For 2022, upgrades include:

SCADA System Upgrade ($91,000)

This item involves upgrading the Company's SCADA System to ensure system operations benefit from the latest system and security updates available from the vendor.

Newfoundland Power's SCADA System was implemented in 2016. The SCADA System is used by the Company's System Control Centre to monitor and control the electrical system on a real-time basis. Frequent functionality and security upgrades of SCADA systems have become industry best practice. Newfoundland Power completes annual upgrades of its SCADA System in accordance with industry best practice.

For 2022, the proposed upgrade of the Company's SCADA System will ensure consistent and effective system operation and apply the latest security updates and features available. The upgrade will ensure the SCADA System continues to provide real-time monitoring and control of the electrical system. The upgrade will also ensure information continues to be exchanged automatically between the SCADA System and other Company information systems used in providing reliable service to customers, such as the Outage Management System and the Geographic Information System.

PI Reporting Upgrade ($106,000)

This item involves upgrading the Company's SCADA Reporting System ("PI System") to ensure system operations benefit from the latest functionality and security updates available from the vendor.

Newfoundland Power's PI System was implemented in 2016. The PI System extracts electrical system data from the SCADA System and creates a version of the SCADA database on the Company's business network. This approach to application design ensures that the security of the SCADA System is not compromised while making the necessary information available to other Newfoundland Power employees for system analysis and planning.

The current PI System will no longer be supported by the vendor as of December 31, 2021. Upgrading the software in the first quarter of 2022 is required to ensure full vendor support moving forward.

Database Management Software Upgrade ($135,000)

This item involves upgrading Newfoundland Power's database management software ("DBMS") to the latest versions supported by the vendor. The Company operates multiple versions of DBMS from Microsoft and Oracle to support over 80 database applications.

The version of DBMS selected for a particular application is typically the latest version available from the vendor at the time of implementation. Versions of SQL Server 2008 R2 DBMS currently in use by Newfoundland Power will no longer be supported by the vendor, Microsoft, as of July 2022. No updates and security patches will be available from Microsoft for this product after that date. As a result, applications associated with this product will be at a higher risk of experiencing performance issues and security breaches.

Upgrades are required to ensure continued vendor support for over 80 database applications the Company has in service.

Various Minor Upgrades ($225,000)

This item involves upgrading other minor software applications that have either reached the end of vendor support, require bug fixes, security patches, or changes to comply with regulatory and legislative requirements.

Newfoundland Power currently maintains a software portfolio consisting of approximately 180 applications used by employees in carrying out their daily work. Upgrades are required to ensure continued vendor support, improve compatibility with different devices and applications, minimize software vulnerabilities, remove outdated features, and improve software stability. New software versions also typically include cybersecurity improvements. Newfoundland Power assesses these security improvements to ensure the Company maintains a secure computing environment.

The process of estimating the budget for Various Minor Upgrades is based on the historical average cost of this project.

3.2 Operating Experience

System upgrades help ensure the reliability and effectiveness of Newfoundland Power'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 under consideration. New versions of third-party software products are generally designed to address identified deficiencies, thereby improving performance and allowing the Company to take advantage of new functionality and technical enhancements, and mitigate cybersecurity threats.

3.3 Justification

Unstable and unsupported software products can negatively impact operating efficiencies and customer service delivery. Investments in the SCADA systems and DBMS will ensure continued vendor support, add new and improved features, and improve compatibility with other systems. Keeping current with the latest versions of software also helps protect customer and Company information against cybersecurity risks.

4.0 The Microsoft Enterprise Agreement ($245,000)

4.1 Description

The Microsoft Enterprise 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 annual agreement is a fixed price based on the number of eligible employees that use Microsoft software products on Company-assigned personal computers.[2] An agreement to renew the Microsoft Enterprise Agreement commenced in 2021 and will continue in 2022. Under this agreement, the Company distributes its purchasing costs for these licenses over 3 years, as outlined in Schedule C.

4.2 Operating Experience

The Company has had the Microsoft Enterprise Agreement in place providing access to the latest versions of software products for over 16 years.[3] The terms of the agreements are typically 3 years in duration, with requirements reviewed and adjusted annually.

4.3 Justification

The Microsoft Enterprise Agreement is the least-cost option to ensure access to current Microsoft software products.

[2] Personal computers include desktops, laptops, tablets and other mobile computing devices.

[3] The agreement covers software products such as Microsoft Windows, Microsoft Office, Microsoft Teams, SharePoint, SQL Server, and other products used by employees in the completion of their normal duties.

Workforce Management System Replacement

May 2021

Prepared by:
Sandra Flynn

Approved by:
M. R. Murphy, P. Eng.

REGISTERED PROFESSIONAL ENGINEER
PEG Newfoundland and Labrador
PROFESSIONAL ENGINEERS AND GEOSCIENTISTS
M. R. MURPHY
SIGNATURE
5 MAY 2021
DATE
NEWFOUNDLAND & LABRADOR

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1.0 Introduction

Newfoundland Power Inc. ("Newfoundland Power" or the "Company") is seeking approval of a multi-year project commencing in 2022 to replace its workforce management system, Click.

Click was deployed in 2011. The system supports the effective and efficient management of Newfoundland Power's field response, including the scheduling, dispatching and monitoring of field work.

Click has been discontinued by its vendor and will no longer be supported at year-end 2023. Newfoundland Power has determined that replacing Click with a commercially available system is the least-cost alternative to provide continuity in its field response capabilities. Details on the assessment and evaluation of alternatives are included in Appendix A.

2.0 Background

Responding to customers' requests for field work is a cornerstone of Newfoundland Power's operations. The Company responds to approximately 34,000 customer requests for field work annually, including trouble calls, new service connections and street light repairs.[1]

Click is used to support virtually all customer requests for field work. The system is used to: (i) schedule work for Newfoundland Power's 66 field crews; (ii) dispatch field crews to respond to issues that arise during day-to-day operations; and (iii) monitor the completion of field work.[2] The system also provides timely information directly from field staff to customer communication channels, including the customer website.

The implementation of Click allowed Newfoundland Power to centralize the management of its field response in 2014. A Central Dispatch team located in St. John's is now responsible for scheduling, dispatching and monitoring the completion of all field work throughout the Company's service territory. Prior to implementing Click, these functions were completed separately for each of Newfoundland Power's 8 area offices.[3]

The technology-based, centralized dispatching process has supported the efficient and effective management of Newfoundland Power's field response. Since centralizing this function, the Company has reduced the labour requirements for dispatching by nearly 40%, or 3 full-time equivalents.[4] At the same time, the Company has maintained an average restoration time for customer outages that is approximately 40% better than the Canadian average.[5]

Newfoundland Power has assessed all viable alternatives to provide continuity in its field response capabilities following the obsolescence of Click. A Net Present Value ("NPV") analysis determined that implementing a replacement workforce management system is the least-

[1] See Appendix A, Section 2.1 Field Response Performance, page 2, line 9 to page 3, line 4.
[2] See Appendix A, Section 2.2. Field Response Technology, page 5, lines 6-28.
[3] See Appendix A, Section 2.2 Field Response Technology, page 4, lines 13-16.
[4] See Appendix A, Section 2.2 Field Response Technology, page 6, lines 1-6.
[5] See Appendix A, Section 2.1 Field Response Performance, page 3, line 9 to page 4, line 2.

cost alternative.[6] Implementing a replacement system is also consistent with sound public utility practice.[7]

3.0 Project Description

3.1 Project Scope

Newfoundland Power plans to commence replacement of Click with a commercially available workforce management system in 2022. The replacement system will be deployed in 2023 prior to the obsolescence of Click.

The replacement system will provide functionality equivalent to that of Newfoundland Power's existing system. This will allow the Company to maintain its service efficiency, service responsiveness and customer communications.[8] These customer benefits are consistent with customers' service expectations and the delivery of reliable service at the lowest possible cost.

Newfoundland Power's plan for implementing a replacement workforce management system is provided as Appendix A to this report.

3.2 Project Cost

Newfoundland Power is seeking approval of $808,000 in 2022 and $1,201,000 in 2023 to implement a replacement workforce management system.

Table 1 provides the estimated capital expenditures for this project.

Table 1
2022-2023 Project Cost
($000s)

Cost Category	**2022**	**2023**	**Total**
Material	150	250	400
Labour – Internal	418	266	684
Labour – Contract	-	-	-
Engineering	-	-	-
Other	240	685	925
Total	**$808**	**$1,201**	**$2,009**

6 See Appendix A, Attachment A Net Present Value Analysis.
7 See Appendix A, Section 2.3 Current Utility Practice, page 6, lines 9-20.
8 See Appendix A, Section 4.0 Customer Benefits, page 10, lines 2-29.

3.3 Project Schedule

Table 2 provides the project schedule.

Table 2
Project Schedule

Milestone	**Completion Date**
Vendor Selection	June 2022
Project Design	October 2022
System Configuration	February 2023
System Testing	May 2023
Employee Training	August 2023
System Deployment	September 2023

4.0 Concluding

Effective workforce management processes are broadly accepted to be a critical component of overall utility management. Implementing a replacement workforce management system will address the upcoming obsolescence of Click and provide continuity in Newfoundland Power's field response capabilities. This is consistent with the least-cost delivery of reliable service to customers.

Appendix A

Workforce Management System Replacement Plan

Workforce Management System Replacement Plan

May 2021

NEWFOUNDLAND POWER
A FORTIS COMPANY

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1.0 Executive Summary

Newfoundland Power Inc. ("Newfoundland Power" or the "Company") responds to approximately 34,000 customer requests for field work each year, including customer outages.

The Company responds to customers' field requests using a technology-based, centralized dispatching process. Since implementing a centralized process, labour requirements for dispatching crews have been reduced by nearly 40%. At the same time, the Company has maintained an average restoration time for customer outages that is 40% better than the Canadian average.

The primary technology underpinning Newfoundland Power's field response is its workforce management system, Click. Click supports all essential functions for managing the Company's 66 field crews, including scheduling, dispatching and monitoring field work.

Click has been discontinued and will no longer be supported by the vendor at year-end 2023.

Newfoundland Power assessed all viable alternatives to provide continuity in its field response capabilities. The assessment determined that implementing a replacement workforce management system is the least-cost solution to continue managing the Company's field response.

A survey of Canadian utility practice confirmed that implementing a commercially available workforce management system is sound public utility practice.

Newfoundland Power plans to implement a replacement workforce management system over 2 years commencing in 2022. The estimated cost of this project is approximately $2.0 million.

Implementing a replacement workforce management system will enable the Company to continue providing reliable service to its customers at the lowest possible cost.

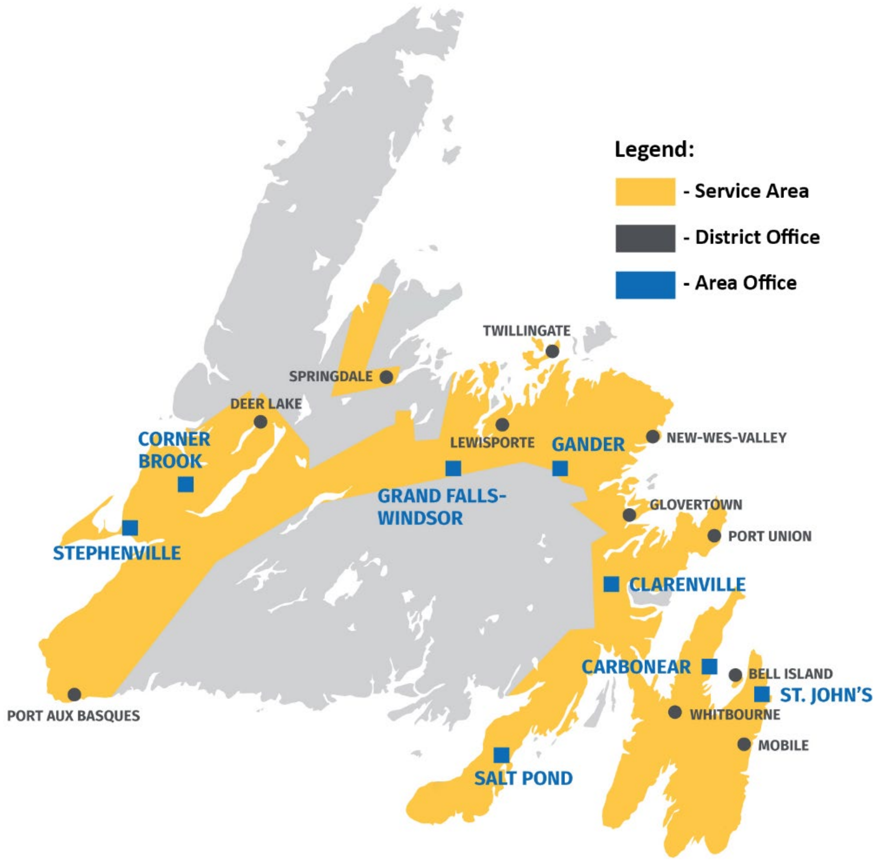
2.0 Background

2.1 Field Response Performance

Newfoundland Power is the primary distributor of electricity in Newfoundland and Labrador. The Company serves approximately 271,000 customers, or 87% of all customers in the province. Providing an efficient and effective response to customers' requests for field work is essential to the delivery of reliable service to customers at least cost.

Figure 1 shows Newfoundland Power's service territory, including the location of Company offices.

Figure 1:
Newfoundland Power's Service Territory



Newfoundland Power currently maintains 66 field crews to respond to customer outages and customer-driven work requests. These crews are located at area offices throughout the Company's service territory.

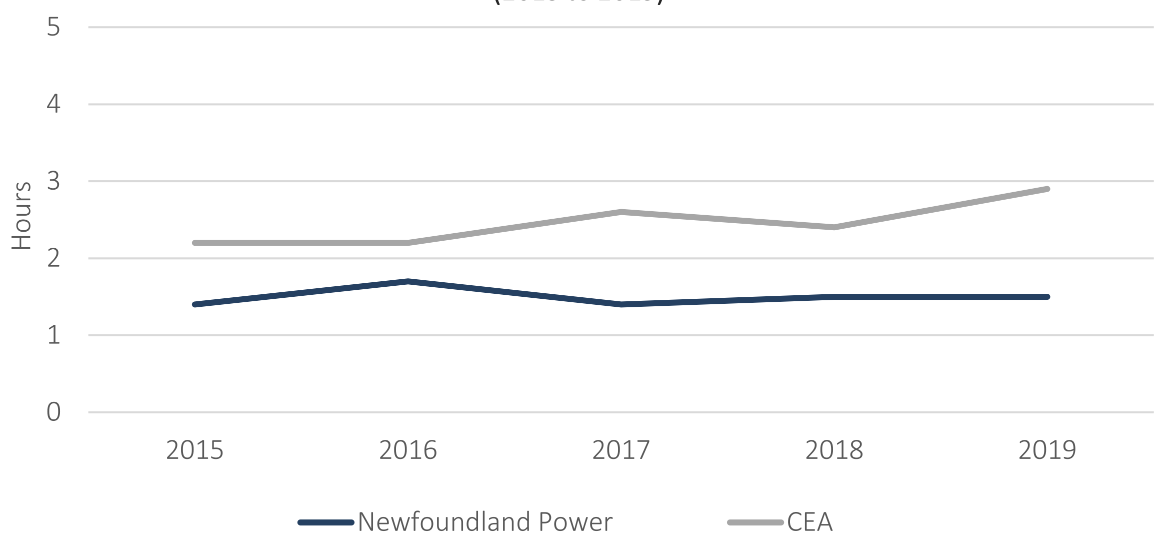
Newfoundland Power's field crews are dispatched approximately 45,000 times each year. This includes approximately 34,000 requests for field work from customers, including outage calls, new service connections and street light repairs. It also includes approximately 11,000 tasks per year to inspect, maintain and undertake other work on the distribution system.

Newfoundland Power aims to provide a timely response to customer outages and customer-driven work requests.

The Company compares its field response to other utilities using the Customer Average Interruption Duration Index ("CAIDI"). CAIDI measures the average time it takes to restore service to customers following an unscheduled outage.[1]

Figure 2 compares Newfoundland Power's average restoration time for unscheduled outages to the Canadian average over the period 2015 to 2019.

Figure 2:
CAIDI
Newfoundland Power vs. Canadian Average
(2015 to 2019)



[1] CAIDI is the restoration time measure used by the Canadian Electricity Association ("CEA"). In arithmetic terms, CAIDI is expressed as System Average Interruption Duration Index / System Average Interruption Frequency Index.

Newfoundland Power's average restoration time for unscheduled outages has been approximately 40% better than the Canadian average since 2015.[2]

The Company aims to complete at least 85% of new service connections within 10 business days. This target has been met or exceeded in each of the last 5 years. The average response time for completing new service connections was approximately 7.7 days over the period 2016 to 2020.

Customers have indicated a reasonable level of satisfaction with Newfoundland Power's field response. Over the last 5 years, customers who requested service in the field indicated an average satisfaction level of 92%.

2.2 Field Response Technology

Newfoundland Power centralized its dispatching process in 2014. A Central Dispatch team in St. John's is responsible for managing all requests for field work throughout the Company's service territory. Prior to centralizing this function, dispatching was completed separately for each of Newfoundland Power's 8 operating areas using paper-based processes.[3]

The Central Dispatch team relies on a combination of operational technologies to effectively and efficiently respond to customers' requests for field work. The primary system used to manage customers' requests for field work is the workforce management system, Click.[4]

Click is used to manage virtually all customer requests for field work, including outage reports, new service connections, and street light repairs. Click also supports the execution of

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[2] From 2015 to 2019, Newfoundland Power's average restoration time was 1.5 hours compared to a CEA average of 2.5 hours ((1.5 - 2.5) / 2.5 = -0.40, or -40%).

[3] Prior to implementing Click, a supervisor in each of the Company's 8 operating areas would review the inventory of field requests to be completed in their area. The supervisor would then assign and schedule the necessary work to crews in their area using paper job packages. Crews would provide the completed packages to the Area Office at the end of the day for manual entry into Company systems.

[4] Click is the Service Optimization system provided by ClickSoftware. This system was implemented as part of the Work Dispatch Improvements project approved in the Company's *2011 Capital Budget Application*. See *Report 6.1 2020 Application Enhancements* and Order No. P.U. 28 (2010).

Newfoundland Power's annual inspection and maintenance program, and the completion of capital work on the electrical system.

The principal functions of Click are:

(i) ***Work Scheduling.*** Click is used to create daily work schedules for each of the Company's 66 field crews. The Central Dispatch team uses Click to review the inventory of field requests required to be completed. Click provides information on the specific job requirements, including estimated resource requirements, job duration, and materials. Schedules are created using Click for each field crew based on the job type, location and crew capacity. Job requirements are then loaded onto mobile devices for each field crew prior to being dispatched into the field.

(ii) ***Work Dispatching.*** Click is used to dispatch field requests received from customers during day-to-day operations. For example, over 10,000 trouble calls are received from customers each year.[5] When a call is received from a customer, the Central Dispatch team uses the Geographic Information System ("GIS") and Automatic Vehicle Location ("AVL") system to identify crews in close proximity to the customer's service issue. Click is then used to send the relevant documentation to the nearest available crew to resolve the issue.

(iii) ***Work Monitoring.*** Click is used to monitor progress towards completing field work. Crews use their mobile devices to provide updates on each job being completed. Details on work progress are automatically provided to the Central Dispatch team and Customer Service Representatives. This allows the Company to provide customers with up-to-date information on the status of their requests and customer outages. It also provides information to the Central Dispatch team on which crews are available to respond to issues that arise during day-to-day operations.

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[5] Trouble calls include calls for no service, partial service and safety-related or other emergency issues.

The implementation of Click provided operational efficiencies by permitting the consolidation of work tasks associated with managing Newfoundland Power's field crews. Upon implementing Click, Newfoundland Power reduced the number of employees responsible for dispatching by 3 full-time equivalents ("FTEs"), or nearly 40%.[6] The use of electronic forms via mobile devices also eliminated manual processes associated with monitoring the completion of field work, as the completion of thousands of paper forms are no longer required.[7]

2.3 Current Utility Practice

The implementation of a commercially available workforce management system is sound public utility practice.

A survey conducted in 2020 determined that, of 8 Canadian utilities, 6 use a commercially available workforce management system. One additional utility plans to implement a workforce management system in the near future.[8]

The functionality provided by utilities' workforce management systems is comparable to the functionality provided by Newfoundland Power's current system. As examples, the utilities surveyed in 2020 use their systems for outage response, asset management, and customer-driven work requests. Newfoundland Power's system supports its field response in each of these areas.

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[6] By centralizing the dispatch function, Newfoundland Power reduced the number FTEs required to complete dispatching from 8 to 5 ((5 - 8) / 8 = -0.38, or 38%).

[7] Prior to implementing Click, field crews would record their progress in completing field work on paper forms. These forms were then manually input into Company systems. Examples of previous paper-based forms include: (i) over 1,000 maintenance work orders annually; (ii) over 12,000 street light outage tickets annually; (iii) over 2,000 new service forms annually; and (iv) over 10,000 trouble call tickets annually. Details recorded on these forms were manually input into various company systems, including systems for outage response, asset management and customer service. Using Click, these forms are now completed electronically and the data is automatically provided to other Company systems.

[8] The survey was conducted by the CEA. Survey respondents were anonymous.

3.0 Assessment of Alternatives

3.1 General

Click is a critical business application for Newfoundland Power.[9] The Company maintains vendor support for all critical business applications, including Click. Vendor support ensures that critical applications operate reliably and securely during the day-to-day provision of service to customers. Unsupported applications are more prone to failure and cybersecurity threats.

Failure of Click would require considerable manual effort to manage customers' requests for field work. The level of manual effort required to manage customers' requests would be beyond the Company's day-to-day resource levels. Failure of Click would therefore practically result in additional costs and time to respond to customers' requests.

The software vendor has indicated that Click has been discontinued and will no longer be supported at year-end 2023.[10] Given the criticality of Click in serving customers, continuing to operate Click without vendor support is not a viable option.

3.2 Description of Alternatives

Newfoundland Power completed an assessment of alternatives to identify the least-cost solution to provide continuity in its field response. The Company identified 2 viable alternatives:

(i) ***System Retirement.*** Prior to implementing Click in 2011, Newfoundland Power followed a regional approach to dispatching field work throughout its service territory. Each of the Company's 8 operating areas maintained staff to schedule, dispatch and monitor their field crews. The retirement of Click would involve

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9 Examples of other critical business applications include Newfoundland Power's Customer Service System, Supervisory Control and Data Acquisition ("SCADA") system, Outage Management System and Geographic Information System ("GIS").

10 ClickSoftware, the developer of Click, was purchased by Salesforce.com Inc ("Salesforce") in 2019. In August 2020, Salesforce notified customers that the development of Click has ended and support for Click will expire on Dec 31, 2023. Salesforce software will be among the products evaluated during the competitive procurement process.

reverting back to a regional approach to managing field work. Three additional Operations Coordinators would be required to schedule, dispatch and monitor field work. This is consistent with the number of dispatchers required prior to the implementation of Click.[11] The dispatching of crews would be completed using paper-based job packages. The monitoring of field work would require manually recording data at the end of each day.

(ii) ***System Replacement.*** The replacement of Click with a commercially available solution would enable the existing centralized dispatching process to continue. A capital project would be required in 2022/2023 to implement a replacement system that provides equivalent functionality. Annual licensing and support costs would be required for a replacement system. Consistent with past practice, a system upgrade would be expected following 3 years of system operation. No additional staffing would be required upon implementing a replacement system.

Newfoundland Power evaluated both alternatives through a net present value ("NPV") analysis to determine the least-cost solution to provide continuity in its field response.

3.3 Evaluation of Alternatives

The NPV analysis assesses whether the operating efficiencies associated with maintaining a centralized dispatching process would exceed the cost of implementing a replacement workforce management system. The analysis considers capital and operating costs over a 7-year period.

11 Under the alternative of system retirement, the total complement of Operations Coordinators would be 8 FTEs. This includes the 5 existing Operations Coordinators and 3 additional Operations Coordinators.

Table 1 summarizes the results of the NPV analysis for each alternative.

Table 1: NPV Result ($000s)					
	Capital Costs[12]	Labour Costs[13]	Other Costs[14]	Total Costs	NPV
Alternative 1: System Retirement	0	9,144	60	9,204	7,778
Alternative 2: System Replacement	2,509	5,080	708	8,297	7,279
Difference	**(2,509)**	**4,064**	**(648)**	**907**	**499**

The NPV analysis determined that replacement of Click with a commercially available solution is the least-cost alternative to provide continuity in Newfoundland Power's field response.

The operating efficiencies maintained through implementing a centralized dispatching process would provide a benefit to customers of approximately $499,000 over 7 years on an NPV basis. This is principally due to the lower staffing requirements and reduced manual processes associated with a technology-based, centralized process.[15]

Attachment A provides the inputs, assumptions and detailed results of the NPV analysis.

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[12] Capital costs include approximately $2.0 million in 2022/2023 to replace Click, as well as a system upgrade in 2026 estimated at $500,000. See Attachment A for additional information.

[13] Labour costs include costs associated with scheduling field work and recording information on job completion. See Attachment A for additional information.

[14] Other costs include licensing and support costs associated with a replacement system, as well as material costs associated with implementing paper-based processes. See Attachment A for additional information.

[15] In comparison to system retirement, the replacement of Click would provide lower labour costs of approximately $4.1 million. Of this amount, approximately $2.4 million is associated with the 3 additional employees that would be required in each operating area to manage the Company's field requests. The remainder is associated with the elimination of manual data entry processes.

4.0 Customer Benefits

Implementing a replacement workforce management system that provides equivalent functionality would provide 3 principal customer benefits:

(i) ***Maintain Service Efficiency.*** Click has provided operational efficiencies by enabling a centralized dispatching process that consolidates work tasks and eliminates manual processes. Implementing a replacement workforce management system would allow Newfoundland Power to maintain the operating efficiencies previously achieved in serving customers. The operating efficiencies associated with implementing a replacement system were confirmed through an NPV analysis.

(ii) ***Maintain Service Responsiveness.*** Newfoundland Power has maintained a reasonable level of responsiveness to customers' field requests since implementing Click in 2011. Over the last 5 years, the Company's restoration time for unscheduled outages has been 40% better than the Canadian average, target response times for new service connections have been consistently met, and customers have indicated a satisfaction level of 92% with Newfoundland Power's field service.

(iii) ***Maintain Customer Communications.*** Newfoundland Power responds to approximately 2.7 million customer enquiries annually, including enquiries regarding customer outages and customer-driven work requests. Click allows field crews to provide real-time updates on the status of their work, including estimated restoration times for customer outages. This information is automatically provided to the customer website, High-Volume Call Answering system and Customer Service Representatives. The implementation of a replacement workforce management system will ensure customers continue to have access to timely and accurate information on the status of field work.

These benefits are consistent with customers' service expectations and the least-cost delivery of reliable service to customers.

5.0 Project Scope and Cost

Newfoundland Power plans to implement a replacement workforce management system over 2 years commencing in 2022. This timeframe will ensure a replacement system is implemented prior to the expiration of vendor support for Click at year-end 2023.

The replacement workforce management system will deliver functionality equivalent to that of the existing system, including the scheduling, dispatching and monitoring of field work.

A competitive Request for Proposals process will be completed in 2022 to select the least-cost software that meets Newfoundland Power's requirements. Hardware and software configuration will commence in 2022 and be finalized in 2023. System training, testing and deployment will occur in 2023.

Table 2 provides a breakdown of the cost of implementing a replacement workforce management system.

Table 2:
Project Cost
($000s)

Cost Category	2022	2023	Total
Material	$150	$250	$400
Labour – Internal	418	266	684
Other	240	685	925
Total	**$808**	**$1,201**	**$2,009**

The estimated cost of implementing a replacement workforce management system is approximately $2.0 million. Material costs include the cost of procuring the necessary software and hardware. Internal labour costs include the cost of configuring and testing the replacement system, as well as employee training. Other costs include third-party vendor costs to configure the replacement system.

Attachment A

Net Present Value Analysis

1.0 Inputs and Assumptions

The NPV analysis considers differences in capital costs and operating costs associated with: (i) Alternative 1 – System Retirement; and (ii) Alternative 2 – System Replacement.

Capital Costs

The NPV analysis considers the difference in capital costs associated with the 2 alternatives.

Alternative 1 assumes there will be no capital costs incurred.

Alternative 2 assumes there will be a 2-year capital project estimated at $808,000 in 2022 and $1,201,000 in 2023, as well as a system upgrade in 2026 estimated at $500,000.

Scheduling Labour Costs

The NPV analysis accounts for the difference in labour costs associated with scheduling and dispatching across the 2 alternatives.[16]

Alternative 1 assumes that scheduling and dispatching will be completed using manual processes to replace the automation provided by Click. This would involve regional employees retrieving and prioritizing work tasks from various Company systems, and compiling and printing documentation. These employees would distribute the tasks according to resource capacity and provide paper documentation to the field crews. Based on pre-2014 staffing levels, it is assumed that these manual scheduling and dispatching processes would require 8 FTEs to complete.[17]

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[16] Scheduling and dispatching are estimated to be split 54% capital and 46% operating for the analysis period.
[17] It is expected that 2 employees would be required in St. John's Region, and 3 employees each in Eastern Region and Western Region. The cost of 1 FTE is assumed to be $100,000 (2022$ loaded), consistent with the Operations Coordinator rate in the IBEW Clerical Collective Agreement.

Alternative 2 assumes that scheduling and dispatching will be completed using the existing complement of 5 FTEs in Central Dispatch.[18]

Work Order Completion Labour Costs

The NPV analysis accounts for differences in labour costs associated with completing field work using paper-based processes. The alternatives assume that approximately 45,101 work tasks will be completed annually.[19]

Alternative 1 assumes there will be an average of 5 minutes of labour per work task associated with completing paperwork and manually rekeying information into Company systems. This results in additional labour costs of approximately $200,000 annually.[20]

Alternative 2 assumes there will be no additional labour costs as the manual rekeying of information is eliminated by the use of a workforce management system.

Non-Labour Costs

The NPV analysis accounts for differences in non-labour costs associated with using paper-based processes for monitoring field work, as well as third-party licensing and support costs associated with deploying a replacement workforce management system.

Alternative 1 assumes that the Company will incur costs of approximately $7,860 annually related to the printing of paperwork.[21] The average work order is estimated to contain 1.83 pages, and the cost of a printed page is estimated to be $0.0952. Alternative 1 does not include any third-party software licensing and support costs.

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[18] In addition to 5 Operations Coordinators responsible for dispatching field crews, 1 additional Operations Coordinator is responsible for incident management associated with the operation of the Outage Management System. This position is common to both alternatives and is therefore not included in the analysis.

[19] Based on the most recent 3-year average.

[20] 45,101 work orders x 0.083 hrs per work order x $53/hr (Avg of loaded PLT rate & clerk rate) = $198,399.

[21] 45,101 work orders x 1.83 average pages per work order x $0.0952 per printed page = $7,860.

Alternative 2 assumes third-party licensing and support costs associated with a replacement workforce management system of approximately $93,000 annually. This is consistent with current licensing and support costs for Click.

2.0 Detailed Results

The detailed results of the NPV analysis of Alternative 1 and Alternative 2 are provided in Table A-1 and Table A-2, respectively.

Table A-1:
NPV Analysis
Alterative 1: Retire System

	Capital				Operating								
	Work Order Labour	Scheduling Labour	Software	Capital Revenue Requirement	Non-Labour	Scheduling Labour	Work Order Labour	Total Operating Costs	Total Cost	Present Worth	Cumulative Present Value	Present Worth of Sunk Costs	Total Present Worth
	50 years 8% CCA	50 years 8% CCA	10 years 100% CCA										
2022	0	270,000	0	23,175	0	230,000	0	230,000	253,175	253,175	253,175	4,436,882	4,690,058
2023	0	278,100	0	49,712	0	236,900	0	236,900	286,612	270,874	524,050	4,389,900	4,913,950
2024	114,577	458,309	0	100,857	8,119	390,411	97,603	496,133	596,990	533,229	1,057,279	4,299,814	5,357,093
2025	118,015	472,058	0	155,623	8,246	402,124	100,531	510,900	666,523	562,646	1,619,925	4,168,445	5,788,370
2026	121,555	486,220	0	210,499	8,393	414,187	103,547	526,128	736,627	587,680	2,207,605	4,000,509	6,208,114
2027	125,202	500,806	0	265,550	8,541	426,613	106,653	541,808	807,357	608,741	2,816,345	3,800,287	6,616,632
2028	128,958	515,831	0	320,838	8,692	439,411	109,853	557,956	878,794	626,220	3,442,565	3,571,661	7,014,226
2029	132,826	531,306	0	376,424	8,845	452,594	113,148	574,587	951,010	640,469	4,083,034	3,318,154	7,401,188
2030	136,811	547,245	0	432,364	8,998	466,171	116,543	591,712	1,024,077	651,807	4,734,841	3,042,962	7,777,802

Table A-2:
NPV Analysis
Alterative 2: Replace System

	Capital				Operating								
	Work Order Labour	Scheduling Labour	Software	Capital Revenue Requirement	Non-Labour	Scheduling Labour	Work Order Labour	Total Operating Costs	Total Cost	Present Worth	Cumulative Present Value	Present Worth of Sunk Costs	Total Present Worth
	50 years 8% CCA	50 years 8% CCA	10 years 100% CCA										
2022	0	270,000	0	23,175	0	230,000	0	230,000	253,175	253,175	253,175	4,857,942	5,111,118
2023	0	278,100	2,009,000	274,755	0	236,900	0	236,900	511,655	483,560	736,736	4,598,274	5,335,010
2024	0	286,443	0	371,457	96,065	244,007	0	340,072	711,529	635,535	1,372,271	4,266,490	5,638,761
2025	0	295,036	0	387,594	97,562	251,327	0	348,889	736,484	621,703	1,993,974	3,939,302	5,933,276
2026	0	303,887	500,000	459,826	99,312	258,867	0	358,179	818,006	652,604	2,646,577	3,572,453	6,219,031
2027	0	313,004	0	493,624	101,063	266,633	0	367,696	861,320	649,428	3,296,005	3,200,265	6,496,270
2028	0	322,394	0	507,503	102,844	274,632	0	377,476	884,979	630,627	3,926,633	2,838,624	6,765,256
2029	0	332,066	0	521,555	104,651	282,871	0	387,522	909,077	612,229	4,538,861	2,487,376	7,026,237
2030	0	342,028	0	535,808	106,467	291,357	0	397,824	933,632	594,240	5,133,101	2,146,344	7,279,445

Rate Base:
Additions, Deductions & Allowances

May 2021

WHENEVER. WHEREVER.
We'll be there.

NEWFOUNDLAND POWER
A FORTIS COMPANY

Table of Contents

1.0 Introduction

1.1 General

In the *2022 Capital Budget Application* (the "Application"), Newfoundland Power Inc. ("Newfoundland Power" or the "Company") seeks final approval of its 2020 average rate base. This is consistent with current regulatory practice before the Board.

Newfoundland Power's 2020 average rate base of $1,181,897,000 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 2 historical years, the current year and the subsequent year. The 2021 and 2022 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 2019 and 2020, and the forecast additions for 2021 and 2022.

Table 1
Additions to Rate Base
2019-2022F
($000s)

	2019	**2020**	**2021F**	**2022F**
Deferred Pension Costs	91,824	89,900	88,900	94,151
Deferred Credit Facility Issue Costs	61	46	31	16
Cost Recovery Deferral – Hearing Costs	494	247	-	-
Cost Recovery Deferral – Conservation	17,371	17,049	17,497	18,185
Cost Recovery Deferral - Electrification	-	-	935	935
Customer Finance Programs	2,494	2,098	2,147	2,184
Demand Management Incentive Account	1,881	1,002	1,268	1,268
Total Additions	**114,125**	**110,342**	**110,778**	**116,739**

Additions to rate base were approximately $110.3 million in 2020. This is approximately $3.8 million lower than 2019. The lower additions to rate base in 2020 primarily reflect decreases in the Deferred Pension Cost Account. The account decreased primarily due to an increase in pension expense, which was the result of a reduction in the pension discount rate and higher amortizations related to actuarial losses.

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 provides details of changes in Newfoundland Power's deferred pension costs from 2019 through 2022F.

Table 2
Deferred Pension Costs
2019-2022F
($000s)

	2019	**2020**	**2021F**	**2022F**
Deferred Pension Costs, January 1st	89,678	91,824	89,900	88,900
Pension Plan Funding	2,770	2,838	2,765	2,730
Pension Plan Expense	(624)	(4,762)	(3,765)	2,521
Deferred Pension Costs, December 31st	91,824	89,900	88,900	94,151

2.3 Deferred Credit Facility Issue 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 *2019/2020 General Rate Application*, the amortization of credit facility costs associated with the balance as of December 31, 2018 of $120,000 was included as a component of the Company's cost of capital for 2019 and 2020 for revenue requirement purposes. As these costs are reflected in customer rates, they are not included in rate base for those years.

In August 2018, the committed credit facility was renegotiated to extend its maturity date to August 2023. Costs related to this amendment totaled $40,000 and are being amortized over the 5-year life of the agreement, beginning in 2018.

In August 2019, the committed credit facility was renegotiated to extend its maturity date to August 2024. Costs related to this amendment totaled $35,000 and are being amortized over the 5-year life of the agreement, beginning in 2019.

There were no amendments to the credit facility in 2020.

[1] Deferred pension costs were approved for inclusion in average rate base in Order No. P.U. 19 (2003).

The unamortized credit facility issue costs associated with the 2018 and 2019 credit facility amendments are included in rate base as these costs have not yet been reflected in the Company's revenue requirements.

Table 3 provides details of Newfoundland Power's amortization of deferred credit facility issue costs for 2019 through 2022F.

Table 3
Deferred Credit Facility Issue Costs
2019-2022F
($000s)

	2019	2020	2021F	2022F
Balance, January 1st	120	61	46	31
Cost – Reduction	(64)	-	-	-
Cost – Addition	35	-	-	-
Amortization	(30)	(15)	(15)	(15)
Balance, December 31st	61	46	31	16

2.4 Cost Recovery Deferral – Hearing Costs

In Order No. P.U. 2 (2019), the Board approved hearing costs of up to $1.0 million related to the Company's *2019/2020 General Rate Application* to be recovered in customer rates over the period March 1, 2019 to December 31, 2021.

Table 4 provides details of the changes in Newfoundland Power's deferred hearing costs from 2019 through 2022F.

Table 4
Deferred Hearing Costs
2019-2022F
($000s)

	2019	2020	2021F[2]	2022F[2]
Balance, January 1st	-	494	247	-
Cost	700	-	-	-
Amortization	(206)	(247)	(247)	-
Balance, December 31st	494	247	-	-

2 Deferred hearing cost balances are included in rate base on an after-tax basis consistent with the treatment of other regulatory assets and liabilities.

2.5 Cost Recovery Deferral – Conservation

Table 5 provides details of the forecast amortizations of the deferred cost recovery related to conservation for 2019 through 2022F.

Table 5
Cost Recovery Deferral – Conservation
2019-2022F
($000s)

	2019[3]	**2020**	**2021F**	**2022F**
Balance, January 1st	15,784	17,371	17,049	17,497
Cost	4,805	3,583	4,571	5,019
Amortization	(3,218)	(3,905)	(4,123)	(4,331)
Balance, December 31st	17,371	17,049	17,497	18,185

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 Rate Stabilization Account ("RSA").

2.6 Cost Recovery Deferral – Electrification

Table 6 provides details of the forecast amortizations of the deferred cost recovery related to electrification for 2019 through 2022F.

Table 6
Cost Recovery Deferral – Electrification
2019-2022F
($000s)

	2019	**2020**	**2021F**	**2022F**
Balance, January 1st	-	-	-	935
Cost	-	-	935	-
Amortization	-	-	-	-
Balance, December 31st	-	-	935	935

Electrification costs are based on Newfoundland Power's 2021 Electrification, Conservation and Demand Management Application which was filed with the Board on December 16, 2020.

[3] The opening balance for 2019 has been adjusted to reflect a 30% corporate income tax rate. This is consistent with the deferred tax treatment required for financial reporting purposes in 2019 and 2020.

Approval and recovery of electrification costs and amortizations are subject to a future Order of the Board.

2.7 Customer Finance Programs

Customer finance programs are loans provided to customers for the purchase and installation of products and services related to conservation programs and contributions in aid of construction ("CIAC").

Table 7 provides details of changes to balances related to customer finance programs for 2019 through 2022F.

Table 7
Customer Finance Programs
2019-2022F
($000s)

	2019	2020	2021F	2022F
Balance, January 1st	2,460	2,494	2,098	2,147
Change	34	(396)	49	37
Balance, December 31st	2,494	2,098	2,147	2,184

2.8 Demand Management Incentive Account

In Order No. P.U. 32 (2007), the Board approved the Demand Management Incentive Account (the "DMI Account") to replace the Purchase Power Unit Cost Variance Reserve.

Table 8 provides details of the DMI Account from 2019 through 2022F.

Table 8
DMI Account
2019-2022F
($000s)

	2019	2020	2021F	2022F
Balance, January 1st	-	1,881	1,002	1,268
Transfers to the RSA	-	(1,881)	(1,002)	(1,268)
Operation of DMI	1,881	1,002	1,268	1,268
Balance, December 31st	1,881	1,002	1,268	1,268

The disposition of the December 31, 2020 balance in the DMI Account to the RSA as of March 31, 2021 was approved in Order No. P.U. 14 (2021).

3.0 Deductions from Rate Base

3.1 Summary

Table 9 summarizes Newfoundland Power's deductions from rate base for 2019 and 2020, and the Company's forecasts for 2021 and 2022.

Table 9
Deductions from Rate Base
2019-2022F
($000s)

	2019	**2020**	**2021F**	**2022F**
Other Post Employment Benefits ("OPEBs")	61,791	66,739	72,113	77,787
Customer Security Deposits	1,420	1,212	1,212	1,212
Accrued Pension Obligation	5,104	5,258	5,363	5,496
Accumulated Deferred Income Taxes	10,088	12,683	14,664	17,330
Weather Normalization Reserve	(5,654)	3,734	3,915	-
2019 Revenue Surplus	1,226	613	-	-
Total Deductions	**73,975**	**90,239**	**97,267**	**101,825**

Deductions from rate base were approximately $90.2 million in 2020. Newfoundland Power's total deductions from rate base in 2020 were approximately $16.3 million higher than 2019 primarily due to the increase in the OPEBs liability, an increase in Accumulated Deferred Income Taxes and an increase in the Weather Normalization Reserve Account. The increase in the OPEBs liability reflects the amortization of the OPEBs regulatory asset.[4] The increase in Accumulated Deferred Income Taxes reflects continued investment in the electricity system and the impact of actuarial results on the Company's employee future benefits. The increase in the Weather Normalization Reserve Account reflects warmer than normal weather patterns in 2020.

This section outlines the deductions from rate base in further detail.

[4] In Order No. P.U. 31 (2010), the Board approved, beginning in 2011, the adoption of the accrual method of accounting for OPEBs and related income tax. In addition, the Board approved a 15-year straight line amortization of a transitional balance starting in 2011.

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.

Table 10 provides details of the changes related to the net OPEBs liability from 2019 through 2022F.

Table 10
Other Post Employment Benefits
2019-2022F
($000s)

	2019	2020	2021F	2022F
Regulatory Asset	30,235	27,718	14,016	10,512
OPEBs Liability	92,026	94,457	86,129	88,299
Net OPEBs Liability	61,791	66,739	72,113	77,787

3.3 Customer Security Deposits

Customer security deposits are provided by customers in accordance with the *Schedule of Rates, Rules and Regulations*.

Table 11 provides details on the changes in customer security deposits from 2019 through 2022F.

Table 11
Customer Security Deposits
2019-2022F
($000s)

	2019	2020	2021F	2022F
Balance, January 1st	1,071	1,420	1,212	1,212
Change	349	(208)	-	-
Balance, December 31st	1,420	1,212	1,212	1,212

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 provides details of changes related to accrued pension obligation for 2019 through 2022F.

Table 12
Accrued Pension Obligation
2019-2022F
($000s)

	2019	**2020**	**2021F**	**2022F**
Balance, January 1st	5,016	5,104	5,258	5,363
Change	88	154	105	133
Balance, December 31st	5,104	5,258	5,363	5,496

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, for regulatory purposes, with respect to timing differences related to plant investment, pension costs and other employee future benefit costs.[5,6,7]

5 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.

6 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.

7 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).

Table 13 provides details of changes in the accumulated deferred income taxes from 2019 through 2022F.

Table 13
Accumulated Deferred Income Taxes
2019-2022F
($000s)

	2019	2020	2021F	2022F
Balance, January 1st	4,887	10,088	12,683	14,664
Change	5,201	2,595	1,981	2,666
Balance, December 31st	10,088	12,683	14,664	17,330

3.6 Weather Normalization Reserve

In Order No. P.U. 1 (1974), the Board approved that rate base be adjusted for the balance in the Weather Normalization Reserve.

Table 14 provides details of changes in the balance of the Weather Normalization Reserve from 2019 through 2022F.

Table 14
Weather Normalization Reserve
2019-2022F
($000s)

	2019	2020	2021F	2022F
Balance, January 1st	(1,517)	(5,654)	3,734	3,915
Operation of the reserve	(5,654)	3,734	3,915	-
Transfers to the RSA	1,517	5,654	(3,734)	(3,915)
Balance, December 31st	(5,654)	3,734	3,915	-

The disposition of the December 31, 2020 balance in the Weather Normalization Reserve account to the RSA as of March 31, 2021 was approved by the Board in Order No. P.U. 13 (2021).

3.7 2019 Revenue Surplus

The Board's determination on Newfoundland Power's *2019/2020 General Rate Application* in Order No. P.U. 2 (2019) resulted in a $2.5 million ($1.7 million after-tax) surplus in the recovery of the revenue requirements for 2019 (the "2019 Revenue Surplus"). The Order provided for credit of the 2019 Revenue Surplus through a regulatory amortization beginning on March 1, 2019 and ending December 31, 2021.

Table 15 provides details on the 2019 revenue surplus amortization for 2019 through 2022F.

Table 15
Cost Over Recovery – 2019 Revenue Surplus
2019-2022F
($000s)

	2019	**2020**	**2021F**	**2022F**
Balance, January 1st	-	1,226	613	-
Credit	1,737	-	-	-
Amortization	(511)	(613)	(613)	-
Balance, December 31st	1,226	613	-	-

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.

Table 16 provides details on changes in the cash working capital allowance from 2019 through 2022F.

Table 16
Rate Base Allowances
Cash Working Capital Allowance[8]
2019-2022F
($000s)

	2019	**2020**	**2021F**	**2022F**
Gross Operating Costs	527,263	541,367	540,660	541,499
Income Taxes	6,142	17,004	10,691	7,439
Municipal Taxes Paid	17,041	18,092	16,780	17,111
Non-Regulated Expenses	(2,504)	(2,892)	(2,411)	(2,349)
Total Operating Expenses	547,942	573,571	565,720	563,700
Cash Working Capital Factor	1.754%	1.789%	1.789%	1.789%
	9,611	10,261	10,120	10,084
HST Adjustment	296	242	242	242
Cash Working Capital Allowance	9,907	10,503	10,362	10,326

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.[9]

[8] The cash working capital allowance for 2019 through 2022F is calculated based on the method used to calculate the 2019/2020 Test Year average rate base approved by the Board in Order No. P.U. 2 (2019).

[9] 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 17 provides details on changes in the materials and supplies allowance from 2019 through 2022F.

Table 17
Rate Base Allowances
Materials and Supplies Allowance
2019-2022F
($000s)

	2019	2020	2021F	2022F
Average Materials and Supplies	8,525	9,572	10,822	10,820
Expansion Factor[10]	24.05%	24.05%	24.05%	24.05%
Expansion	2,050	2,302	2,603	2,602
Materials and Supplies Allowance	6,475	7,270	8,219	8,218

10 The expansion factor is based on a review of actual inventories used for expansion projects. The calculation of the 2019 rate base, including a materials and supplies allowance based upon an expansion factor of 24.05%, was approved by the Board in Order No. P.U. 2 (2019).