Q. Please describe how distribution substation equipment repairs are prioritized and state the repair-by time limits for each prioritization.

A. **1. Distribution Substation Maintenance in Context**

The reliability performance of Newfoundland Power's electrical system is largely a function of the condition of electrical system assets.[1] For this reason, the principal factor in the prioritization of capital and operating maintenance for all Newfoundland Power electricity network assets is the establishment of reasonable levels of overall system reliability.[2] This reliability based perspective was identified in the 1998 report to the Board on *Newfoundland Light & Power Co. Limited Quality of Service and Reliability of Supply* where it was indicated that:

"The reliability of supply to Company customers is considered to be acceptable, although lower than the average for Canadian utilities. It is important that the utility maintain and in fact seek to improve its performance in this regard."[3]

The reliability of Newfoundland Power's electrical system is examined by the Board in every Newfoundland Power general rate application.[4]

In Newfoundland Power's 2013/2014 General Rate Application, the evidence before the Board was that the reliability of the Company's service was improved from that in 1998. Newfoundland Power's SAIDI, or system average interruption duration index (excluding major events), was better than composite measures provided by the Canadian Electricity Association ("CEA") in 8 of the 10 years ended in 2011. Newfoundland Power's SAIFI, or system average interruption frequency index (excluding major events), was better than composite measure provided by the CEA in 4 of the 10 years ended in 2011.[5]

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[1] This is a widely accepted engineering principle. It was recognized in, amongst other places, the 1991 *Report on the Technical Performance of Newfoundland Light & Power Co. Limited*, prepared by George Baker, P. Eng., for the Board.

[2] Newfoundland Power's electricity network assets include its transmission, substation and distribution system assets.

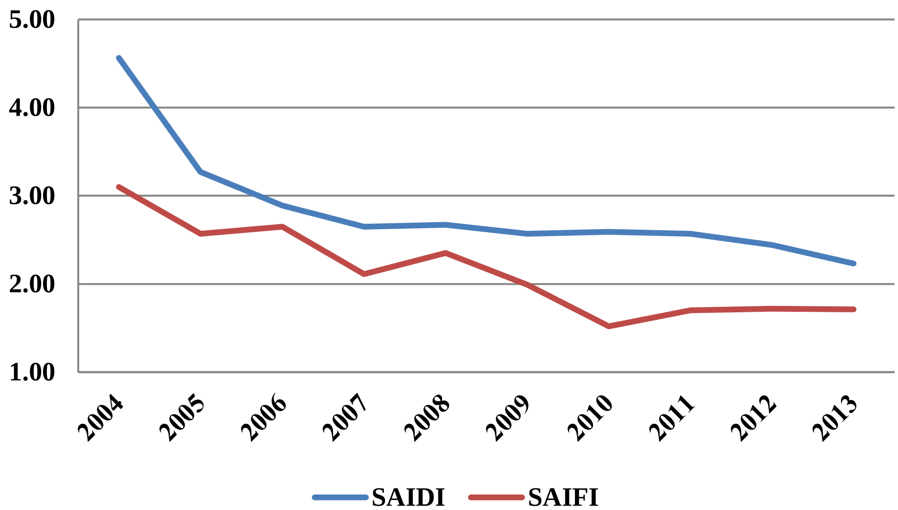
[3] See *Newfoundland Light & Power Co. Limited Quality of Service and Reliability of Supply*, prepared by D.G. Brown, P.Eng., page v.

[4] See, for example, Newfoundland Power's *2008 General Rate Application*, Company Evidence, Section 2: Customer Operations, Page 22, line 11 *et seq.* where reliability management was described, in effect, as a combination of (i) capital investment, (ii) maintenance practices and (iii) operational deployment. See also Newfoundland Power's *2010 General Rate Application*, Company Evidence, Section 2: Customer Operations, Page 2-7, line 6 *et seq.* where Newfoundland Power's evidence was that plant replacement was expected to continue to be the primary focus of capital expenditure for the Company. Finally, see Newfoundland Power's *2013/2014 General Rate Application*, Company Evidence, Section 2: Customer Operations, Page 2-3, line 8 *et seq.* where Newfoundland Power's evidence outlined the maintenance costs associated with its aging electricity system assets.

[5] Newfoundland Power's SAIDI, including all events, was better than the CEA composite in 6 of the 10 years ended in 2011; the Company's SAIFI, including all events, was better than the CEA composite in only 1 of the 10 years. See the response the Request for Information CA-NP-143 filed in Newfoundland Power's *2013/2014 General Rate Application.*

Graph 1 shows SAIDI and SAIFI for Newfoundland Power's electrical system from 2004 to 2013.[6]

Graph 1
SAIDI and SAIFI
2004 - 2013



Graph 1 indicates that the overall reliability of Newfoundland Power's electrical system, excluding extraordinary events, has steadily improved in the decade since 2004. This improvement reflects Newfoundland Power's overall management of the condition of its electricity network assets through the period. The condition of those network assets, including the distribution substation assets, is largely a function of the combination of the Company's ongoing capital investment and operating maintenance practices.[7]

2. Distribution Substation Plant Replacement

Approximately ½ of Newfoundland Power's overall annual capital expenditures are directed at plant replacement.[8]

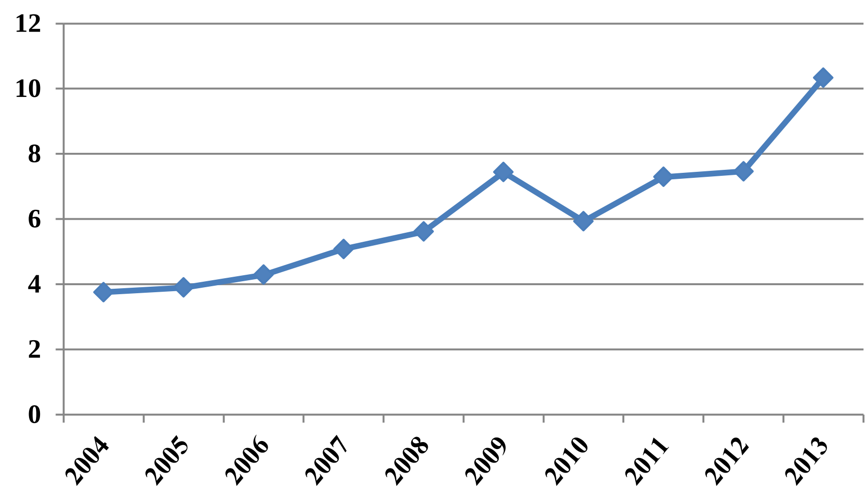
[6] SAIDI measures the average number of customer *hours* of electrical supply outage in a year. SAIFI measures the average *number* of customer outages in a year. The SAIDI and SAIFI from 2004 to 2013 shown in Graph 1 have been adjusted to remove the effects of severe weather events and major electrical system disruptions such as those experienced during the January 2-8, 2014 period.

[7] System reliability is also a reflection of Newfoundland Power's operational deployment and, in particular, its ability to respond to trouble on the electrical system in an organized and efficient manner. Since the Company's 2005 early retirement program, field operations staff and equipment deployment throughout the Company's service territory has not changed materially.

[8] See the *2014 Capital Plan* filed with Newfoundland Power's *2014 Capital Budget Application* where it is indicated that for the period 2014-2018, plant replacement is forecast to account for 52% of all capital expenditures. For the period 2009-2013, plant replacement accounted for 49% of annual capital expenditure.

Graph 2 shows Newfoundland Power's distribution substation plant replacement expenditures from 2004 to 2013.

Graph 2
Distribution Substation Plant Replacement
2004 – 2013
($ millions)



Newfoundland Power aims to maintain stable annual capital expenditures on plant replacement for all asset classes, including distribution substations. This follows from the Board's determination that stable and predictable year over year capital budgets for Newfoundland Power are a desirable objective which assists in fostering stable and predictable rates for consumers into the future.[9]

Newfoundland Power's annual capital expenditures on distribution substation plant are guided by its *Substation Strategic Plan*.[10] This plan is essentially proactive in approach and recognizes that failures of equipment are the leading causes of substation outages. The plan provides for coordination of capital and operating maintenance to minimize customer outages and take maximum advantage in the deployment of the Company's portable substations.

The predominant portion of Newfoundland Power's annual distribution substation plant replacement expenditure is undertaken in 3 separate projects. The *Substation*

[9] See Order No. P.U. 36 (2002-2003), page 25.
[10] Newfoundland Power filed its *Substation Strategic Plan*, March 2006 with the Board as part of its 2007 Capital Budget Application. Each year, the Company provides an update to this plan under the *Substation Refurbishment and Modernization* project as part of its annual Capital Budget Application. See, for example, *2014 Substation Refurbishment and Modernization*, June 2013, filed with Newfoundland Power's 2014 Capital Budget Application.

Refurbishment and Modernization project provides for comprehensive targeted refurbishment and modernization of distribution substations on a planned basis. The *Replacements Due to In-Service Failures* project provides for the replacement of substation equipment due to damage, technical obsolescence or testing failure in cases where replacement is required within the budget year. The *PCB Bushing Phase-Out* project provides for the identification and replacement of substation equipment as required by Federal regulation.[11] Over the period from 2011-2013, approximately $6 million in expenditures were incurred related to the *PCB Bushing Phase-Out* project.

The following attachments to this response to Request for Information PUB-NP-065 provide additional information related to Newfoundland Power's annual capital expenditures on distribution substations which are aimed at maintaining or improving system reliability:

Attachment A: *Substation Strategic Plan,* March 2006
Attachment B: *2014 Substation Refurbishment and Modernization,* June 2013
Attachment C: *2013 Substation Refurbishment and Modernization,* June 2012
Attachment D: *2012 Substation Refurbishment and Modernization,* June 2011
Attachment E: *2011 Substation Refurbishment and Modernization,* June 2010
Attachment F: *2010 Substation Refurbishment and Modernization,* June 2009
Attachment G: *2011 PCB Removal Strategy,* June 2010

Further Information concerning Newfoundland Power's utility plant can be found in its annual capital budget applications filed with the Board. These applications can be found on the Board's public website at www.pub.nf.ca.

Stable annual capital expenditures on Newfoundland Power's distribution substations play a significant role in ensuring that the Company's distribution substations are maintained in appropriate physical condition on an ongoing basis. This, in turn, contributes to the ongoing performance of the Company's overall electricity network. Together, it is the stable annual replacement of deteriorated and damaged equipment *and* the Company's operating maintenance regime that ensures the Company is in a position to deliver reliable electrical service to its customers.

3. Distribution Substation Maintenance

Substation equipment repairs are prioritized as follows:

- Emergency[12] – address immediately.
- Urgent[13] – address immediately or within one week;

[11] Annual expenditures under the *PCB Bushing Phase-Out* project are guided by the Company's *2011 PCB Removal Strategy,* June 2010 filed with Newfoundland Power's *2011 Capital Budget Application.*

[12] Equipment that has already failed or is at risk of imminent failure which will or can impact safety, environment or loss of supply will be dealt with on an emergency basis. An example is the failure of a power transformer.

[13] For example, a hot spot on the riser to a piece of equipment.

- P1[14] – address within a week to a month;
- P2[15] – address within one month to three months;
- Minor deficiency[16] - normally addressed when other work is planned to take place in the substation.

The assignment of priorities is based on engineering judgement and is done by experienced maintenance electricians under the supervision of maintenance supervisors to ensure consistency of priority assignment.

Please refer to the response to Request for Information PUB-NP-064 for detailed information on priorities and time limits concerning Newfoundland Power's distribution substation equipment and relay inspection, testing, and maintenance programs and practices.

Please refer to the response to Request for Information PUB-NP-066 for information concerning distribution substation equipment and relay inspection, maintenance testing and repair jobs for 2011, 2012 and 2013.

4. Conclusion

Newfoundland Power conducts distribution substation equipment repairs so that, when taken in combination with annual capital investment in the system and current deployment of employees and equipment, reliability to customers is maintained at an acceptable level.

In the 10 years ending 2013, the overall reliability of the service provided by Newfoundland Power to its customers has materially improved.

[14] For example, the failure of a recloser that can be by-passed for a short period.
[15] For example, failure of the tank heater in a breaker during summer months.
[16] For example, a control cabinet in need of repainting.

Substation Strategic Plan
March 2006

Substation Strategic Plan

March 2006

Prepared by:
Sean LaCour P. Eng.

REGISTERED PROFESSIONAL ENGINEER
SEAN LaCOUR
SIGNATURE
PROVINCE OF NEWFOUNDLAND

NEWFOUNDLAND POWER
A FORTIS COMPANY

Table of Contents

1.0 Introduction

This report outlines a change in the way Newfoundland Power's ("the Company") substation capital projects are planned and executed. This change will help the Company realize productivity and reliability gains by organizing refurbishment and modernization projects on an individual substation basis. In addition, capital work will be coordinated as much as possible with major operating maintenance work, thereby minimizing service interruptions to customers.

In recent years, the Company's substation capital program has consisted of five projects: Rebuild Substations, Replacement and Standby Equipment, Protection and Monitoring Improvements, Additions Due to Load Growth and Feeder Remote Control. In 2007 and beyond, Newfoundland Power's substation capital budget will be organized into three projects as follows:

1. Substation Refurbishment and Modernization;
2. Replacements Due to In-Service Failures; and
3. Additions Due to Load Growth.

The revised approach is supported by a detailed review of the Company's substation assets that was recently undertaken. The review has identified Substation Refurbishment and Modernization capital projects in 80% of the Company's substations. These capital projects will be planned in conjunction with operating maintenance involving major equipment over a ten-year cycle. The Substation Refurbishment and Modernization capital projects are expected to require an average annual capital expenditure of approximately $4 million.

2.0 Background

2.1 Newfoundland Power's Substations

Newfoundland Power has 130 substations located throughout its operating territory. A small number of those substations connect generating plants to the electrical system. The remainder, which constitute the vast majority of the Company's substations, interconnect transmission lines and distribute electricity to customers via distribution feeders. The equipment in the substation controls the flow of that electrical energy to other parts of the electrical system, safely and at appropriate voltage levels. Appendix A is a description of a typical substation.

Figure 1 on the following page shows the location of the Company's transmission lines, substations and generating plants, as well as those of Newfoundland and Labrador Hydro on the island of Newfoundland. Substations are listed in the map legend as "Terminal Stations", and each substation is depicted on the map as a small black square labelled with the substation's three-letter designation.

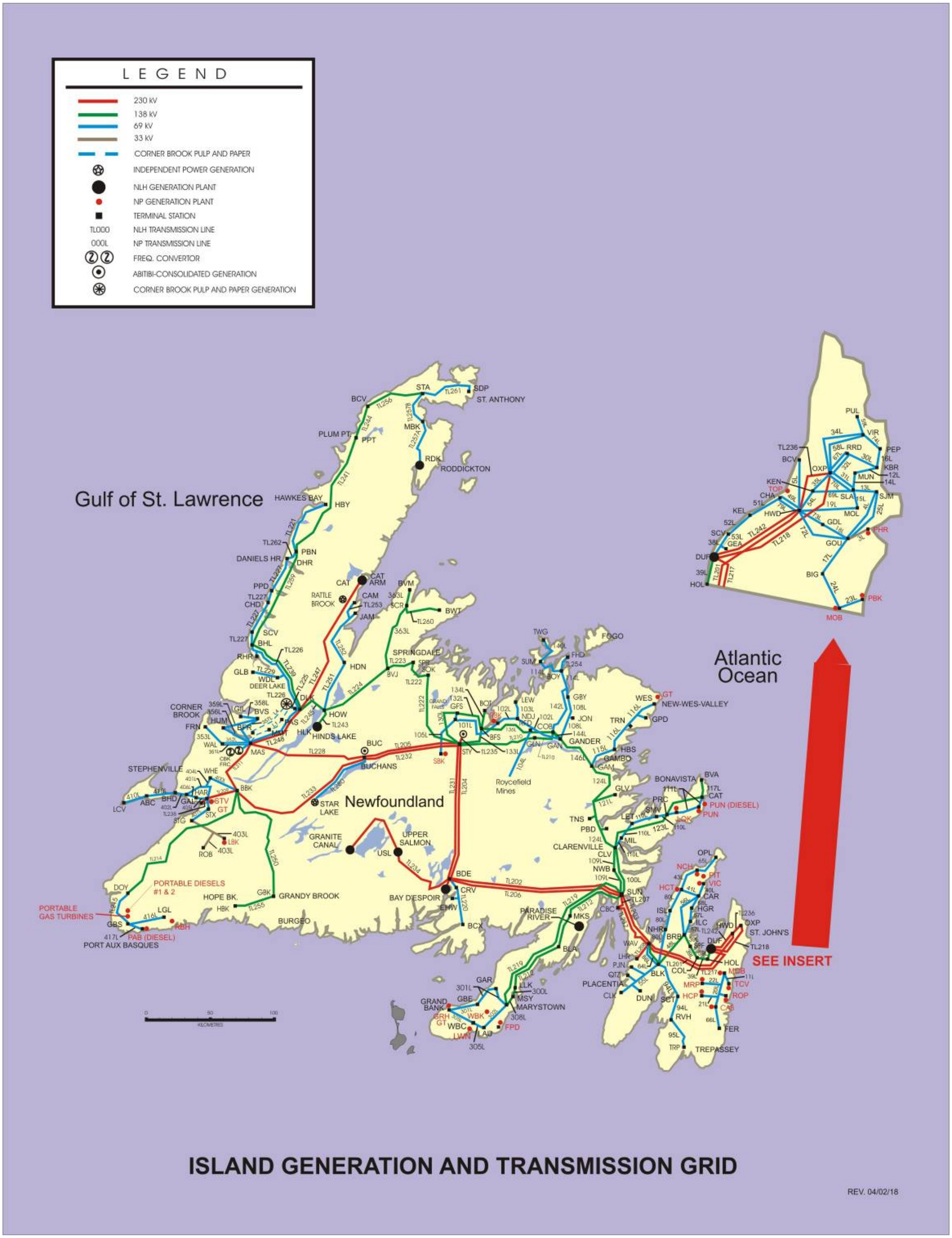
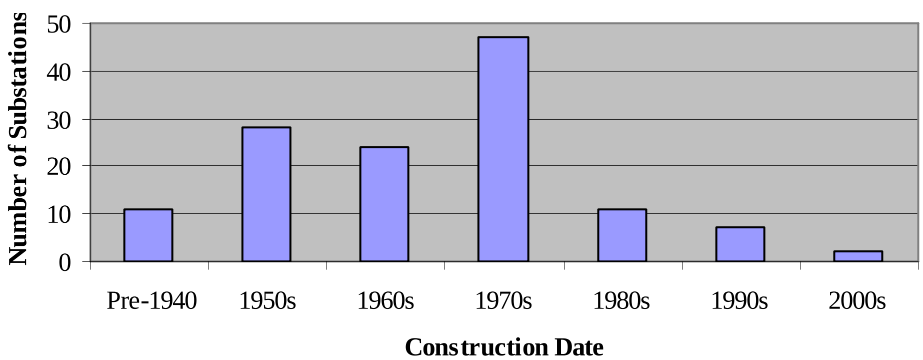

LEGEND
230 kV
138 kV
69 kV
33 kV
CORNER BROOK PULP AND PAPER
INDEPENDENT POWER GENERATION
NLH GENERATION PLANT
NP GENERATION PLANT
TERMINAL STATION
TL000 NLH TRANSMISSION LINE
000L NP TRANSMISSION LINE
FREQ. CONVERTOR
ABITIBI-CONSOLIDATED GENERATION
CORNER BROOK PULP AND PAPER GENERATION
Gulf of St. Lawrence
Atlantic Ocean
Newfoundland
ST. ANTHONY
RODDICKTON
HAWKES BAY
PLUM PT.
DANIELS HR.
CAT ARM
SPRINGDALE
DEER LAKE
CORNER BROOK
HINDS LAKE
BUCHANS
STAR LAKE
STEPHENVILLE
GRANITE CANAL
UPPER SALMON
BAY D'ESPOIR
GRANDY BROOK
HOPE BK.
BURGEO
PORTABLE DIESELS #1 & 2
PORTABLE GAS TURBINES
PAB (DIESEL)
PORT AUX BASQUES
FOGO
NEW-WES-VALLEY
GANDER
GAMBO
Roycefield Mines
BONAVISTA
PUN (DIESEL)
CLARENVILLE
PARADISE RIVER
MARYSTOWN
GRAND BANK
PLACENTIA
ST. JOHN'S
TREPASSEY
SEE INSERT
ISLAND GENERATION AND TRANSMISSION GRID
REV. 04/02/18

Figure 1

2.2 Aging Substation Infrastructure

Nearly half of Newfoundland Power's substations are over 40 years old, with approximately one-third exceeding 50 years of age. The core infrastructure and major equipment in the Company's substations includes foundations, structures, grounding systems, fencing, power transformers, oil filled breakers, cables, potential transformers, control buildings, switchgear and protective relaying. With few exceptions, the core infrastructure and major equipment in the Company's substations has been in service since the substations were built. Chart 1 shows the age grouping of the Company's 130 substations.

Chart 1
Age of Substations



Typically, the requirement for refurbishment or replacement of substation equipment is minimal during the first 40 years in service. During this period, components will be replaced or refurbished if their condition warrants it. Consequently, the Company's substation capital refurbishment and replacement programs have tended to focus on specific equipment with a recent history of failure. Examples of this program-based approach include the insulator replacement programs of the 1990s and the lightning arrestor program which is currently being implemented. These programs have been successful in reducing the risk associated with specific substation equipment.

Beyond 40 years of age, the number of substation components requiring refurbishment or replacement tends to increase significantly. Civil infrastructure, including foundations and bus structures, reach the end of their useful lives and must be replaced. On the other hand, other major substation equipment, such as power transformers, can remain in service if the external components of the equipment such as gas relays are refurbished or replaced in a timely way.

2.3 Substation Maintenance Program

Because of the critical role they play in the power system, substations must be designed and maintained to provide a high degree of reliability. Unplanned outages to Newfoundland Power customers caused by substation problems have accounted for only 6% of total unplanned customer minutes of outage over the past 5 years. The three leading causes of substation outages have been failures of breakers and reclosers, failures of lightning arrestors and failures caused by birds and animals. These account for about 25%, 20% and 15%, respectively, of unplanned substation related customer minutes of outage.

While substation-based outages are infrequent, they affect a large number of customers (typically several thousands) when they do occur. It is therefore essential that substation outages be avoided where possible.

Newfoundland Power has an effective substation asset management and equipment maintenance program that follows industry best practices. The scheduling of maintenance on major substation equipment such as transformers and breakers is condition-based, relying on results from oil testing and other predictive techniques. Maintenance of substation yards, structures and auxiliary equipment usually follows inspection results. All remaining substation equipment is generally maintained on a time-based schedule.

The Company's predictive and preventive equipment maintenance programs are designed to minimize unexpected mechanical and electrical equipment failures. One of the major challenges presented by Newfoundland's harsh, salt-contaminated environment, however, is the prevention of premature failure of equipment due to corrosion. In the Company's experience, time-based maintenance is most effective when it comes to dealing with corrosion. The Company has found that a 10-year substation maintenance cycle is appropriate.

Many types of substation maintenance work can only be carried out when the substation is de-energized. When the nature or extent of the work could result in a lengthy outage, one of the Company's portable substations is deployed to carry the substation load. In some cases, particularly in urban areas where switching options are greater, the load can alternatively be transferred to other substations.

Whenever possible, the Company will coordinate all future maintenance work on individual substations so that it is carried out on a single occasion. This approach will be further coordinated with substation capital work as described in this report. The coordinated approach will minimize service interruptions to customers and will also take maximum advantage of the deployment of portable substations or the switching of loads to other substations, as the case may be.

2.4 A Modified Approach to Capital Work

In light of the large number of substations that are now in excess of 40 years of age, Newfoundland Power is modifying its approach to substation capital improvement. Following a detailed individual assessment of all of its substations, the Company has determined that an approach that focuses on the overall condition of individual substations will be more effective and efficient than the existing program-based approach.

Each substation has been assessed, with particular consideration given to the physical condition of core infrastructure and equipment. Based on these individual substation assessments, the Company has established priorities and developed a plan for the overall refurbishment and modernization of its substations that will coordinate with ongoing major equipment maintenance and replacement activities.

The substation plan will follow a 10-year cycle, coinciding with the maintenance cycle for major substation equipment. The objective is to complete the capital work at each substation at the same time as major operating maintenance work. This will improve the overall condition of individual substations, and will be more productive and less disruptive to the operation of the substation than having multiple jobs scheduled for individual substations over a period of time.

In between the planned capital and major operating maintenance work, regular substation inspections and equipment preventive maintenance will continue as usual. Additions and modifications due to load growth, as well as replacements due to in-service failures, will also continue on an as-required basis.

2.5 Benefits of the New Approach

For the most part, the Company's existing capital program has focused on programs that addressed issues identified with specific equipment and infrastructure. This has allowed the Company to address high priority reliability and safety issues affecting most of the Company's substations. Programs such as wholesale insulator replacements (because of high failure rates due to cement growth) and, more recently, the replacement of silicon carbide lightning arrestors (due to high failure rates from aging) are examples of focused programs that had immediate positive impacts on substation reliability.

The new approach will focus on coordinating substation major operating maintenance and substation capital work on a substation by substation basis to improve reliability and productivity. With this approach, 80% of the Company's substations will be refurbished and modernized on a priority basis over the 10-year planning period.

Capital projects will be planned in conjunction with major operating maintenance to realize improved productivity, with project planning and execution encompassing both capital and operating work. This is similar to the "blitz" approach to line work adopted by the Company in recent years where all deficiencies on a distribution line are addressed at the same time. This approach will be particularly beneficial when installation of a portable substation or offloading of the substation is required, as it will reduce the number of outages required to perform work on the substation.

Advanced planning and coordination of both capital and operating maintenance work will achieve the following benefits:

- Greater utilization of (and thus fewer overall) portable transformer set ups and substation offloading will reduce costs.
- Greater use of the "blitz" approach to execute work will increase worker productivity and efficiency, and will create savings by reducing overall travel time and accommodation expenses.
- A reduction in the number of smaller projects will reduce the total number of projects and associated project overheads such as job plans, safety and environmental management plans, protection plans, switching orders and work orders.
- There will be more effective use of project supervisors, who will manage more work in a shorter period of time.
- Fewer overall projects, portable installs and switching orders will result in fewer outages to customers.

3.0 Substation Refurbishment and Modernization Plan

The new 10-year substation refurbishment and modernization plan was developed following a detailed review of the assets in each of the Company's substations. Each substation was assessed based on a number of factors including physical condition, history of equipment maintenance and performance, equipment life expectancy, impact of failures on service to customers and requirements for modernizing substation protection and control.

The following is a high level overview, with reference to specific substation components, of the refurbishment and modernization work identified from the substation assessments.

3.1 Power Transformers

It has been the industry experience that power transformers often remain in service well beyond the manufacturer's estimate of life expectancy. It is not unusual to find units in service for well in excess of fifty years. Incidents of heavy loading and damage caused by external forces, such as lightning, resulting in premature failure are rare in Newfoundland Power's system. Good maintenance practices should therefore ensure that Newfoundland Power's units remain in service for a very long time.

The Company will continue with oil sampling and analysis to gauge the internal health of transformers and plan transformer replacements based upon this predictive style of maintenance. However, if a transformer fails unexpectedly, the Company will bypass it with the use of a portable transformer until a replacement unit can be installed.

Although power transformers are expected to remain in service for a long time, the associated monitoring and protection equipment, which is exposed to the climate, often requires earlier replacement. For example, to function effectively, transformer radiators are made of thinner metals. Although newer radiators are made of galvanized steel to prevent premature rust perforations and oil leaks, some older units will require replacement due to corrosion.

To ensure reliable operation, the auxiliary equipment used to monitor and protect power transformers must be replaced after 25 to 30 years in service. The condition of such auxiliary devices as gas relays, temperature and oil level gauges, pressure relief switches and associated piping, conduits, cabinets and wiring is determined from inspection and testing. All auxiliary equipment will be replaced at the same time during a scheduled maintenance overhaul of power transformers.

Sixty-eight of the Company's 190 transformers have tap changer mechanisms that adjust the transformer's output voltage. The older tap changer controllers contain discrete electronic components that age and deteriorate with time, causing the tap changer to fail to operate. Based on the Company's experience with failures of tap changer controllers they will be replaced when they approach 25 years of age. The newer technology tap changer mechanisms can be integrated with the Company's SCADA system, enabling remote control of those units replaced in substations that have remote control infrastructure in place.

3.2 Lightning Arrestors

The primary function of lightning arrestors is to protect power transformers. Until the early 1980s, silicon carbide lightning arrestors were standard. They are known to fail as they age due to water leaking into the arrestor through failed seals. The Company has experienced increasing failures of this type of lightning arrestor. There is no reliable way to test or monitor an arrestor to predict its failure. All remaining silicon carbide lightning arrestors will be replaced on a prioritized basis over the next 5 years. The majority of these replacements will require the use of a portable transformer, and will be coordinated with other capital work and transformer maintenance.

3.3 Bus Structures and Foundations

Bus structures are galvanized steel or wood pole structures that support the switches, insulators and conductors in a substation. Newfoundland Power has 118 wooden and 138 steel bus structures in service. Galvanized steel structures last longer than wood structures, and are essentially maintenance-free. They are also more physically stable than wood structures, making them more suited to ensuring isolating switches stay properly aligned, reducing maintenance. Steel structures do not require guying. This decreases the overall dimensions of the substation compared to designs employing guyed wooden structures. In future, Newfoundland Power will install only galvanized steel structures.

Existing steel structures are in generally good condition. The existing wooden bus structures range in age from five to over 60 years of age. Wooden structures over 50 years of age are showing signs of deterioration such as rotting, cracking and splitting. Some have deteriorated to the point where replacement of some or all of the structure is necessary.

Concrete foundations weather over time and begin to deteriorate. If left unchecked, the deterioration of foundations and footings can jeopardize the structural stability of substation equipment. The Company will repair or replace these as required in conjunction with planned substation work.

3.4 Buses and Insulators

The main problem with buses is the failure of supporting insulators. One of the most common modes of failure of porcelain insulators is cement growth. In the 1990s, the Company undertook a major program to replace substation insulators vulnerable to this mode of failure. Newer insulators are not failing due to cement growth. Overall, the insulators and buses in Newfoundland Power substations are in very good condition, and no major upgrading work is required.

3.5 Power Cables

Power cables in substations are used to transfer the output of the power transformer to the low-voltage bus. The majority of these cables are the original equipment installed when the substation was built. Experience has shown that power cable failures begin to occur when cables are about 35 years old. There is currently no accurate test to predict cable failure. Failure normally occurs in the termination at the end of the cable. Replacing cable terminations is difficult due to the cable's fabrication, location and made-to-measure installation. To ensure reliable operation of substation power cables, the Company will replace those that are more than 35 years old.

3.6 Protective Relaying

Protective relaying protects transmission lines, substation equipment and distribution feeder circuits. Most of the Company's substations were constructed with electro-mechanical relays. Electro-mechanical relays contain moving parts and are prone to failure as they age, wear and accumulate dirt and dust. In recent years, there has been ongoing replacement of distribution feeder protective relaying as part of the Company's Feeder Remote Control program. In addition, relaying associated with the St. John's transmission system has been replaced to improve fault-clearing times. However, much of the protective relaying equipment in Newfoundland Power's substations is the original electro-mechanical equipment.

The Company has also experienced failure in electronic components in older transmission line relays. The failures are due to the aging of components causing the relays to drift out of calibration. As recently as March 2006, the relay at Carbonear Substation for transmission line 56L failed to operate to clear a fault, resulting in customer outages. The Company's experience has been that as these older type relays approach 40 years of age they may fail to clear faults.

Failure of protective relaying can result in widespread outages and significant equipment damage and can jeopardize the safe operation of the electrical system. Older relays will be scheduled for replacement with modern protective relaying as part of substation refurbishment and modernization upgrading plans.

3.7 Switches

Substation switches provide isolation for equipment such as power transformers, breakers and reclosers. Switches that are operated infrequently have a tendency to seize due to deterioration of bushings, corrosion in operating mechanisms or misalignment of blades. Substation switches such as transformer isolating and bus tie switches are operated infrequently. Consequently, they are susceptible to failure.

The work required to address seized bushings and switch alignment problems cannot practically be undertaken while a switch is energized. As well, refurbishment of the switch is best undertaken in a maintenance shop environment. 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. Switches removed from the field will be refurbished at the electrical maintenance shop, or scrapped if deemed uneconomical to repair.

3.8 Buildings and Batteries

Many of the Company's substation buildings are of steel pre-engineered fabrication and are generally in good condition. However, the roofs of some buildings are more than 25 years old and are badly corroded. If left unchecked, corrosion can result in water entering a substation building and damaging protective equipment and controls. The Company will carry out substation building upgrading work such as roof replacement when other major work is planned for the substation.

Battery banks provide continuous power to substation protection and control equipment and have a normal life expectancy of 15 to 20 years. Testing will determine when the entire battery bank needs to be replaced.

3.9 Protection from Animals and Birds

Small animals and birds have caused significant substation outages. Most commonly, they cause short circuits in equipment such as reclosers, metering tanks and station service transformers, often severely damaging the equipment. The problem has been more prevalent in rural substations.

Insulated coverings, guards and leads can be effective in preventing damage and outages caused by small animals and birds. In future, Newfoundland Power will install the necessary protective covers and insulated leads in rural substations.

4.0 Substation Capital Budget Presentation

4.1 Modified Presentation

The revised approach to substation capital budget planning has prompted the Company to modify its presentation of the capital budget for substation work. In recent years, the Company's substation capital program has consisted of the following five major projects:

Rebuild Substations
The Rebuild Substations project provided for replacement of deteriorated substation infrastructure such as buses, structures, foundations, fencing, switches, lightning arrestors and other equipment, including replacement of PCB contaminated equipment.

Replacement and Standby Equipment
The Replacement and Standby Equipment project provided for the replacement of deteriorated or unreliable equipment on a planned basis and the replacement of equipment that actually failed in service also provided for the appropriate inventory levels of spare equipment for use during emergencies.

Protection and Monitoring Improvements
The Protection and Monitoring Improvements project provided for the upgrading of protective relaying equipment and control devices required to improve or maintain the protection and control of the electrical system to ensure a reliable supply of electricity.

Feeder Remote Control
Feeder Remote Control was a specific program to replace old protective relays and oil filled reclosers on distribution lines and to expand the remote control of the electrical system to realize productivity and reliability gains.

Additions Due to Load Growth
Additions Due to Load Growth provided for the upgrading of system and equipment capacity, as well as the installation of additional system capacity or new equipment to accommodate load growth and the connection of new customers on the system.

Commencing with the 2007 Capital Budget Application, the Rebuild Substations, Protection and Monitoring Improvements and Feeder Remote Control projects have been consolidated into a single project known as Substation Refurbishment and Modernization. All planned replacements of substation equipment under the new 10-year plan described in this report will be included in this project.

The Replacement and Standby Substation Equipment project is renamed the Replacements Due to In-Service Failures project. This project is ultimately driven by the need to replace failed equipment and equipment identified as being in imminent danger of failing.

The Additions Due to Load Growth project is unchanged.

4.2 2007 Substation Capital Program

Newfoundland Power's 2007 substation capital program is presented as three projects:

1. Substation Refurbishment and Modernization;
2. Replacements Due to In-Service Failures; and
3. Additions Due to Load Growth.

The Substation Refurbishment and Modernization project will address all planned work that has been identified based upon inspections and testing. The capital work will be coordinated with the ten-year cycle of major operating substation maintenance work and scheduled to maximize productivity.

In the first ten-year period, Substation Refurbishment and Modernization work will take place in 80% of the Company's substations and will require an average annual expenditure of approximately $4 million.

The Replacements Due to In-Service Failures and Additions Due to Load Growth projects permit the Company to respond to equipment failures and customer load growth, respectively. Replacements Due to In-Service Failures will be budgeted based primarily on historical budget data. Additions Due to Load Growth will be based on load forecasts and equipment ratings.

Appendix B shows the proposed ten-year substation plan and expenditures for Substation Refurbishment and Modernization. The plan will be revisited yearly as part of the preparation of the annual capital budget, and may change due to changing priorities as indicated by the most recent inspections, assessments and operating experience.

Appendix C contains a detailed review of the Substation Refurbishment and Modernization work required in 2007.

Appendix A

A Typical Substation

A Typical Substation

A typical distribution substation “steps down” electricity from the transmission network to the distribution network. Stepping down involves converting high voltage power, necessary to transport electricity over great distances at lower losses, to lower voltage power, capable of being used by residential and commercial customers.

Electricity enters a distribution substation via transmission lines. The electricity passes through a high voltage bus, disconnect switches and circuit breakers on the way to the step down power transformer. Circuit breakers monitor the electrical current and will break the circuit if they detect a problem thus protecting the electrical equipment from damage caused by an overload or a short circuit.

Switches allow the entire substation or separate distribution lines to be disconnected from the network when necessary. Switching can be planned, for example to perform maintenance, or unplanned, for example to isolate problems on the grid.

By far, the largest, most critical, and most expensive piece of equipment in a substation is the power transformer. The transformer converts high voltage power to low voltage power. Once the voltage has been lowered it passes through the voltage regulator and on to the distribution low voltage bus.

The voltage regulator ensures the power is maintained at a constant voltage level making the necessary adjustments as the customer loads vary throughout the day. The distribution low voltage bus, which is comprised of conductors and insulators, splits the power off into multiple directions for delivery to particular service areas by using distribution breakers or reclosers.

All the major components and high voltage buses are located outdoors. Equipment such as buses and switches are mounted on wooden or steel structures. Equipment such as transformers and voltage regulators are mounted on concrete foundations. Where outdoor space is restricted, some equipment, such as low voltage buses and some circuit breakers, is located inside substation buildings.

Substations also include many systems and devices such as grounding systems and telecommunications devices, to provide protection for equipment as well as remote control and monitoring of substations from a central location.

A key aspect of substation design is employee and public safety. Substations are surrounded by security fences with secured access for employees only. All equipment is grounded to ensure safe operation and can be isolated from the network for safety and maintenance reasons.

Figure 1 is a photograph of a typical substation. The red arrows depict the direction and flow of electricity through the substation. The major substation components have been numbered according to the legend.

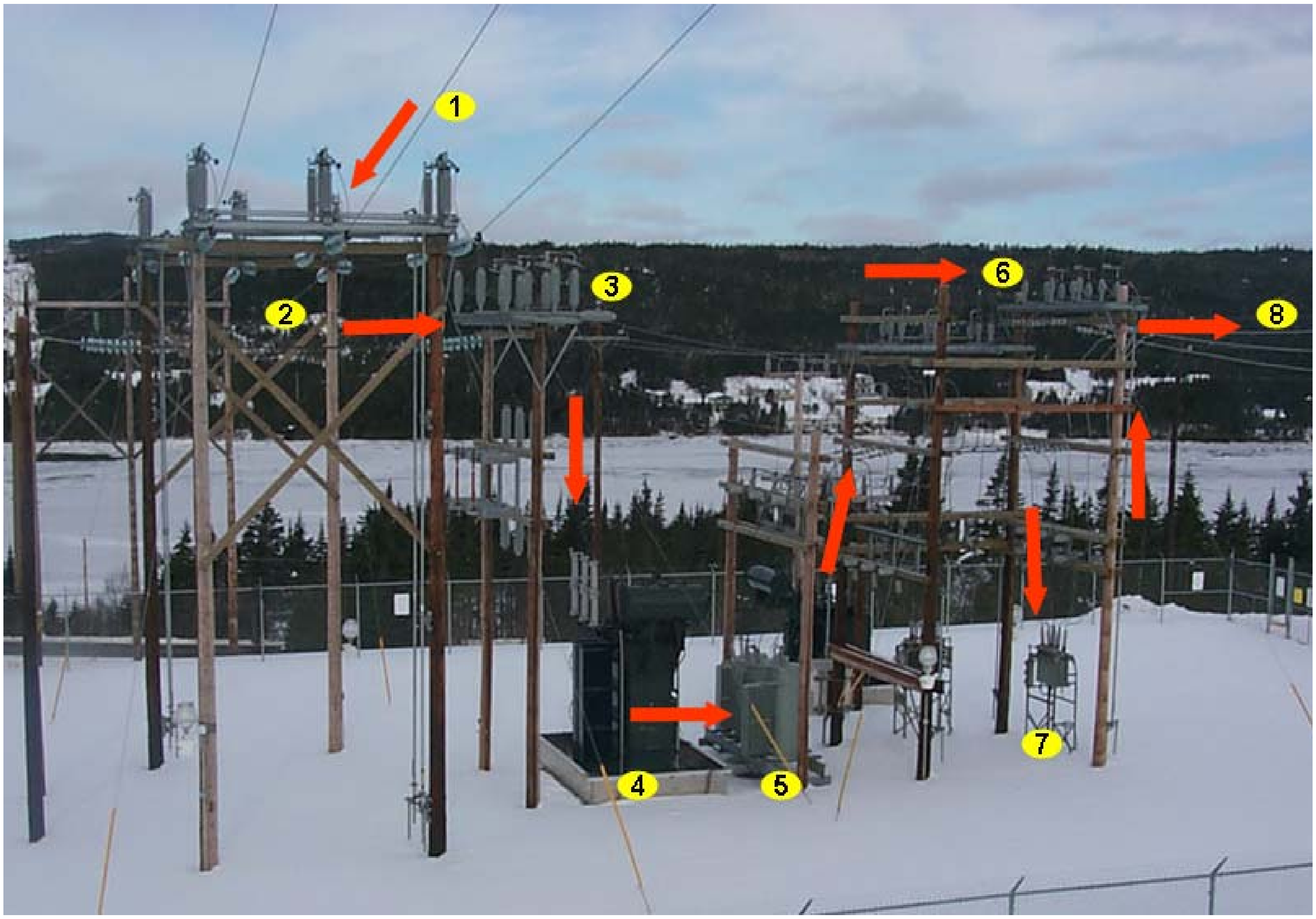


Figure 1

Legend

1	Transmission Line	5	Voltage Regulator
2	High Voltage Bus	6	Low Voltage Bus
3	Switch	7	Recloser
4	Power Transformer	8	Distribution Feeder

Appendix B

Ten-Year Substation Refurbishment and Modernization Plan

Ten-Year Substation Refurbishment and Modernization Capital Plan
($000s)

2007		2008		2009		2010		2011		2012		2013		2014		2015		2016	
SUB	**Cost**	**SUB**	**Cost**	**SUB**	**Cost**	**SUB**	**Cost**	**SUB**	**Cost**	**SUB**	**Cost**	**SUB**	**Cost**	**SUB**	**Cost**	**SUB**	**Cost**	**SUB**	**Cost**
BLK	231	CLV	476	ABC	99	CAR	464	BRB	770	GBE	71	LLK	596	CAT	574	SLA	306	BCV	411
CAR	26	BOT	538	BHD	228	GAL	396	BON	620	BLA	161	GBY	162	HUM	803	CAB	834	COL	277
CLV	26	FER	57	BOY	26	FRN	436	GIL	145	BVS	567	GPD	195	LEW	498	CHA	238	HOL	822
CLK	215	GAN	738	GFS	749	GLN	183	MAS	367	BIG	295	HWD	290	MIL	451	COB	1,058	ICV	507
GAL	46	BVJ	68	HCT	187	HGR	1,276	MKS	428	GAM	697	MOL	322	PBD	335	FPD	108	LAU	399
GAR	374	KEL	218	LET	105	HAR	159	NHR	423	HBS	165	NWB	633	PUL	304	HCP	77	PJN	15
GLV	209	KBR	654	NCH	428	JON	13	QTZ	24	ISL	114	PEP	389	SCV	546	MMT	389	RVH	472
GOU	174	LOK	178	P335	237	SPR	222	SCR	516	P135	377	SPF	553	SMV	937	PAS	536	SUM	1,135
GRB	11	LBK	12	P435	237	STX	123	TWG	165	ROB	170	SJM	185			PBK	77	WES	129
LLK	26	MOB	277	STV	239	VIR	223	WAL	345	SCT	81	TCV	247						
PUN	16	OXP	117	SUN	318	WAV	154	ROB	16	TBS	712								
RRD	312	ROP	388	FPD	7	BLA	17	SPF	57	TRP	880								
SBK	15	LEW	48	PJN	7	ISL	53	DLK	57	TRN	154								
SLA	509	MIL	48	PAB	182	P135	10	PAS	17	WBC	235								
		BRC	48	SLP	221	TRN	53	PBK	8	BFS	603								
				WES	7	PEP	49	ICV	55										
						SCV	7	LAU	17										
						SUM	16	WES	8										
						MMT	53	MRP	11										
						VIC	446	MGT	8										
								GBS	629										
Total	**2,190**		**3,865**		**3,277**		**4,353**		**4,686**		**5,282**		**3,572**		**4,448**		**3,623**		**4,167**

Notes: SUB: Substation - Refer to the Electrical System handbook for three letter substation designations.
P135, P335 and P435 are the designations for the portable substations.

Appendix C

2007 Substation Refurbishment and Modernization Projects

2007 Projects

Table 1 is a summary of the Substation Refurbishment and Modernization projects planned for 2007. A further $578,000 is budgeted for the Rattling Brook Substation Rebuild, which is clustered with the Rattling Brook Plant Refurbishment project in accordance with the Provisional Capital Budget Application Guidelines.

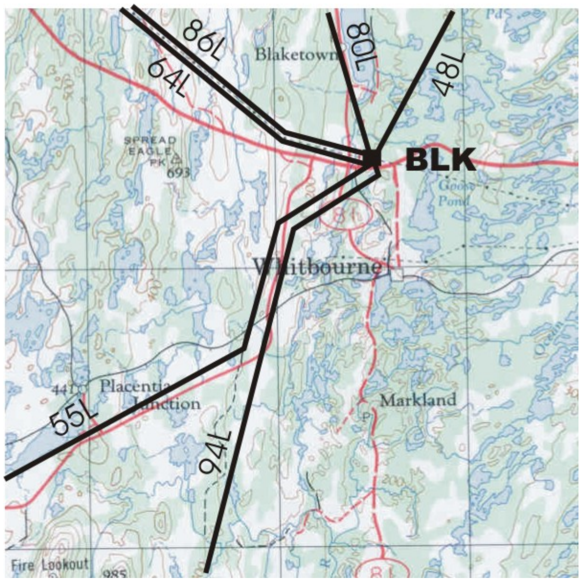
Table 1
2007 Substation Projects
(000s)

Substation	Budget
Blaketown (BLK)	$ 231
Carbonear (CAR)	26
Clarenville (CLV)	26
Clarkes Pond (CLK)	215
Gallant Street (GAL)	46
Garnish (GAR)	374
Glovertown (GLV)	209
Goulds (GOU)	174
Grand Beach (GRB)	11
Linton Lake (LLK)	26
Port Union (PUN)	16
Ridge Road (RRD)	312
Sandy Brook (SBK)	15
Stamps Lane (SLA)	509
Total	**$ 2,190**

The following pages outline the above projects as well as the ongoing lightning arrestor and tap changer projects.

1. Blaketown Substation ($231,000)

Blaketown substation was built in 1977 as a combined transmission and distribution substation. It contains a 138 kV to 66 kV, 42 MVA transformer (T3) and a 138 kV to 25 kV, 20 MVA transformer (T2). The 138 kV bus is energized via two 138 kV transmission lines, 64L from Western Avalon substation and 48L transmission line from Bay Roberts substation. The 66 kV bus has four transmission lines terminated on it. Line 55L is a radial transmission line to Clarkes Pond substation. Line 94L is a radial line to St. Catherines substation. Line 80L services New Harbour substation and line 86L is an in-feed from Western Avalon substation. The distribution part of the substation services approximately 2,600 customers in the Whitbourne and Blaketown areas through two 25 kV feeders.



Blaketown Substation Location

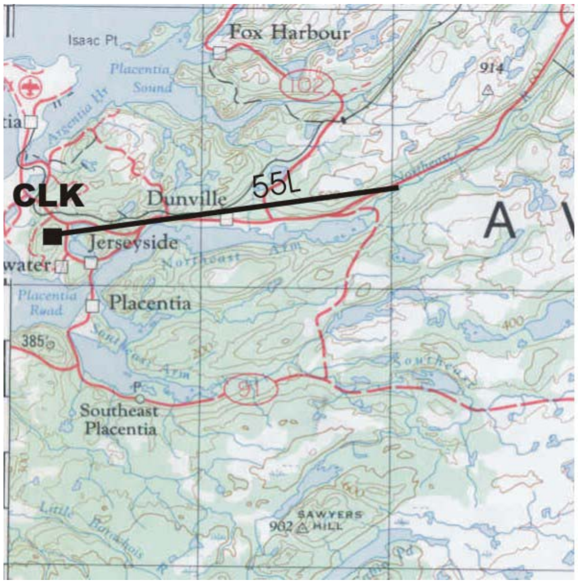
After reviewing maintenance records and conducting on-site engineering assessments it was determined that the 138 kV, 66 kV and 25 kV steel structures and concrete foundations are in good condition with no sign of deterioration. The 138 kV, 66 kV and 25 kV bus and insulators are also in good condition with no signs of deterioration.

T3 transformer is in good condition. T2 transformer has cooling radiator fin edges that are perforated due to rusting. The perforated fin edges have been patched as a temporary measure to prevent leaking but require replacement. The lightning arrestors on T2 and T3 transformers are silicon carbide and require replacement with metal oxide arrestors. The air break switch on T2 transformer is 30 years old and requires replacement. Protection against small animals should be installed on the 25 kV equipment and bus. A maintenance overhaul is required for the T2 and T3 power transformers in 2007 which will be completed at the same time as the required capital work.

Deteriorated radiator fin edges – Blaketown Substation

2. Clarkes Pond Substation ($215,000)

Clarkes Pond substation was built in 1976 as a distribution substation. It contains two 66 kV to 12.5 kV power transformers (T1 & T2). Each power transformer is rated for 7.5 MVA for a total station capacity of 15 MVA. The 66 kV bus is energized via a radial 66 kV transmission line 55L from Blaketown substation. The substation services approximately 2,500 customers in the Placentia/Argentia areas through three 12.5 kV feeders.



Clarkes Pond Substation Location

After reviewing maintenance records and conducting on-site engineering assessments, it was determined the 66 kV and 12.5 kV steel structures are in good condition with no sign of deterioration. Inspections of the concrete foundations show that there are two recloser and three bus structure concrete foundations that are crumbling and require replacement.

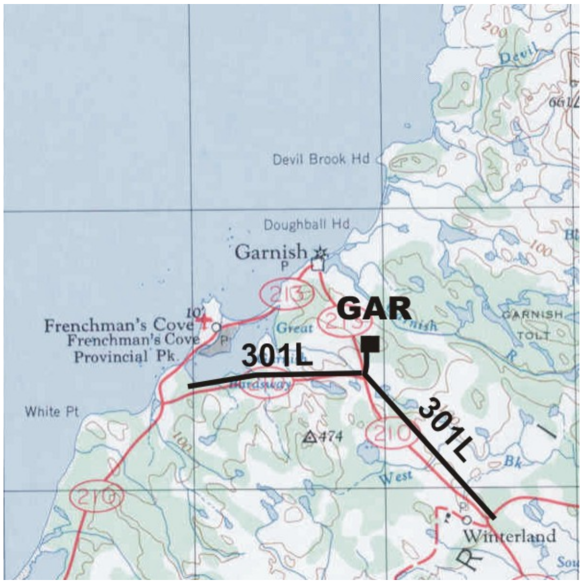
The two power transformers are in good condition with no obvious signs of deterioration. The tap changer controllers on T1 and T2 are twenty-nine and thirty years old respectively and require replacement. Small animal protection should be installed on the 12.5 kV equipment and bus. The Nulec reclosers were installed in 2002 and are capable of being remote controlled. The three feeders will be automated to allow remote control from the System Control Centre. A maintenance overhaul is required to be completed for both power transformers T1 and T2 in 2007 which will be completed at the same time as the required capital work.

Foundation damage at Clarkes Pond Substation

3. Garnish Substation ($374,000)

The 38 year old Garnish substation services approximately 430 customers. The substation is deteriorated and will be replaced with a new substation. All the insulators are old and prone to cement growth failure. The fence is deteriorated. Cross-arms are split and wood rot is present. Some cross-arms have been temporarily reinforced to prevent failure. Most of the concrete foundations are crumbling. The metering tank and other equipment are severely rusted. The transformer fans have to be replaced as their motor bearings are seized.

The new substation will be built adjacent to Highway 210, reducing overall cost and improving access for operational staff. The current substation required a high voltage bus structure. However, when transmission line 301L was rebuilt in 2003, it was constructed so that a high voltage bus structure would not be required for the new substation thereby reducing the capital and operating costs associated with this substation. Establishing this new site will also avoid rebuilding the transmission tap to the existing substation.



Garnish Substation Location

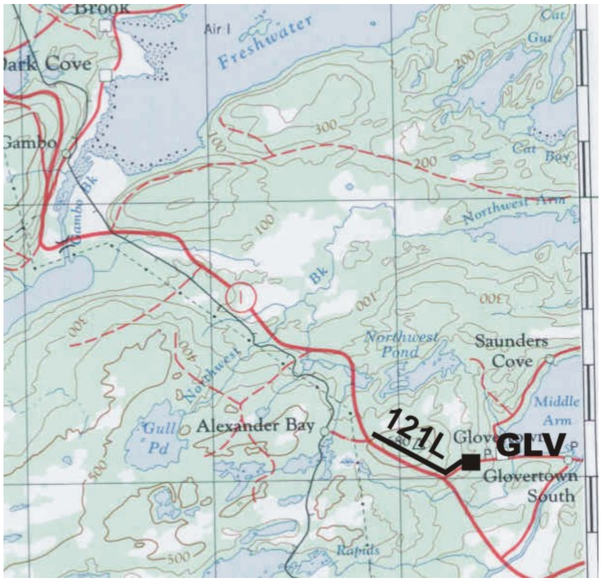

Cracked crossarm Garnish Substation

Corrosion damage Garnish Substation

Foundation damage Garnish Substation

4. Glovertown Substation ($209,000)

Glovertown substation was built in 1976 as a distribution substation. The power transformer (T1) is a 138 kV to 25 kV, 20 MVA unit. The 138 kV bus is energized via a tap from 124L transmission line which runs between Clarenville and Gambo substations. The substation services approximately 2,300 customers in the Glovertown area through two 25 kV feeders.



Glovertown Substation Location

After reviewing maintenance records and conducting on-site engineering assessments it was determined that the 138 kV and 25 kV wood pole structures and concrete foundations are in good condition with no sign of deterioration. The power transformer is in good condition with no signs of deterioration.

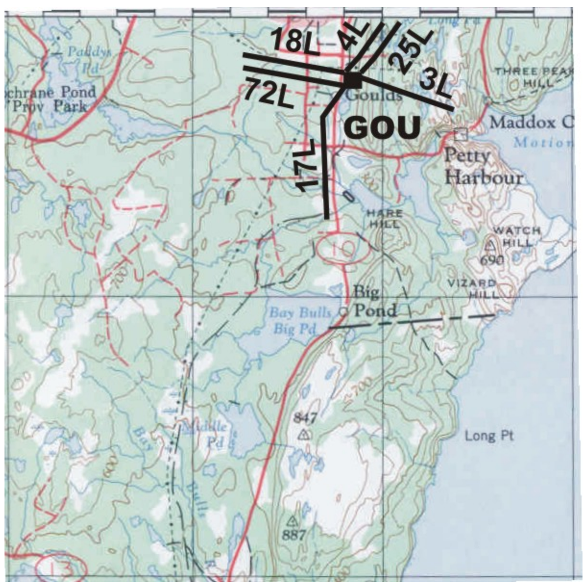
The lightning arrestors on T1 are silicon carbide and require replacement with metal oxide arrestors. The tap changer controller is thirty years old and should be replaced. Small animal protection will be installed on the 25 kV equipment and bus.

The Nulec reclosers in this substation were installed in 2002 and are capable of being remote controlled. The two feeders and the transformer tapchanger require automation to allow remote control from the System Control Centre. A maintenance overhaul is required to be completed on power transformer T1 in 2007 which will be completed at the same time as the required capital work.

5. Goulds Substation ($174,000)

Goulds substation was built in 1954 as a major 66 kV transmission switching substation and also as a 12.5 kV distribution substation. The substation contains two distribution power transformers (T2 & T3) with a combined capacity of 33 MVA. The substation directly services approximately 3,400 customers in the Goulds and Kilbride areas through three 12.5 kV feeders.

As a transmission substation there are five 66 kV transmission lines terminated in the substation. These are transmission lines 4L to St. John's Main substation, 17L to Big Pond substation, 18L to Glendale substation, 25L to St. John's Main substation and 72L to Hardwoods substation. As well there is a 66kV to 33 kV power transformer (T1) servicing 3L transmission line to Petty Harbour substation.



Goulds Substation Location

After reviewing maintenance records and conducting on-site engineering assessments it was determined that the 66 kV and 12.5 kV wood pole structures are in good condition and no issues are expected over the next ten years. The concrete foundations are in good condition with no signs of deterioration with the exception of T1 concrete foundation which must be replaced.

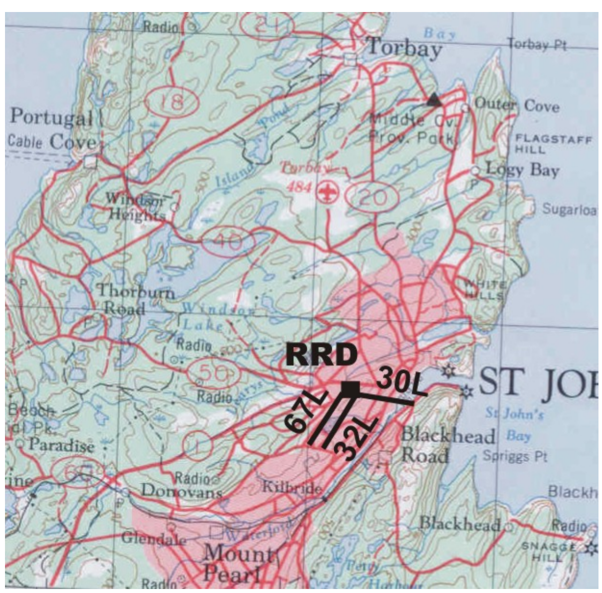
The power transformers are in good condition with no obvious signs of deterioration. The switches in the substation are in good condition with the exception of one 66 kV bus tie switch which is inoperable and currently bypassed. This switch must be replaced.

The radial line 17L to Big Pond substation requires a bypass switch to facilitate maintenance on the breaker. The 66 kV potential transformers are over 40 years old and showing signs of deterioration. These potential transformers are essential for providing protection for the transmission lines and equipment at Goulds substation and must be replaced to maintain reliability. A maintenance overhaul is required to be completed on the three power transformers in 2007 which will be completed at the same time as the required capital work.

Bus Tie Switch Bypassed Goulds Substation

6. Ridge Road Substation ($312,000)

Ridge Road substation was built in 1963 as a 66 kV transmission switching substation and as a 12.5 kV distribution substation. The substation contains three power transformers (T1, T2 & T3) with a combined capacity of 40 MVA at 12.5 kV and 2.2 MVA at 4.16 kV. The existing 4.16 kV section of the substation is being converted to 12.5 kV and the 4.16 kV power transformer (T1) will be retired in 2006. The substation directly services approximately 4,200 customers in the Higgins Line area of St. John's through eight 12.5 kV metal clad switchgear feeders. In the substation there are three 66 kV transmission lines terminated in the high voltage bus. These are transmission lines 30L to King's Bridge substation and 32L and 67L to Oxen Pond substation.



Ridge Road Substation Location

After reviewing maintenance records and conducting on-site engineering assessments it was determined the 66 kV steel structures and 12.5 kV metal clad switchgear are in good condition with no signs of deterioration.

The concrete foundations are in good condition with no signs of deterioration, with the exception of one 66 kV structure concrete foundation which must be refurbished.

The power transformers are in good condition with no obvious signs of deterioration. As a continuation of the feeder remote control program the eight 12.5 kV feeders will have relaying replaced and be automated to allow remote control from the System Control Centre. A maintenance overhaul is required to be completed on the two power transformers in 2007 which will be completed at the same time as the required capital work.

7. Stamps Lane Substation ($509,000)

Stamp's Lane substation was built in 1963 as a 66 kV transmission switching substation and as a 4.16 kV and a 12.5 kV distribution substation. The distribution substation contains four power transformers (T1, T2, T3 & T4) with a combined capacity of 50 MVA at 12.5 kV and 21 MVA at 4.16 kV. The substation directly services approximately 9,300 customers in the central area of St. John's through five 4.16 kV metal clad switchgear feeders and six 12.5 kV outdoor feeders. There are six 66 kV transmission lines terminated in the substation. These are transmission lines 13L to St. John's Main substation, 14L to Memorial substation, 15L to Molloy's Lane substation, 69L to Kenmount substation and 31L and 70L to Oxen Pond substation.

Ridge Road Substation Location

After reviewing maintenance records and conducting on-site engineering assessments it was determined that the 66 kV and 12.5 kV steel structures and 4.16 kV metal clad switchgear are in good condition with no signs of deterioration. Four 66 kV concrete structure foundations are in poor condition and require refurbishment. The remaining concrete foundations are in good condition with no signs of deterioration.

The power transformers are in good condition with no signs of deterioration. The 1971 power cables connecting transformer T2 show signs of compound leaking and require replacement. Eleven feeders will have relaying replaced and be automated to allow remote control from the System Control Centre. A maintenance overhaul is required to be completed on the power transformers in 2007 which will be completed at the same time as the required capital work.

8. Tap Changer Controllers ($124,000)

As discussed in the strategic plan, tap changer controllers have a service life of approximately 25 years. The older tap changer controllers contain discrete electronic components that age and deteriorate with time causing the tap changer to fail to operate. Regulation of the transformer tap is critical in maintaining the distribution feeder voltage within acceptable values.

Tap changer controllers will be replaced with SCADA operated tap changer controllers at the following substations:

- Carbonear Substation
- Clarenville Substation
- Gallants Substation
- Linton Lake Substation

9. Lightning Arrestors ($42,000)

As discussed in the strategic plan, lightning arrestors protect power transformers and other substation equipment. Silicon carbide lightning arrestors were installed on power transformers until the early 1980s. It has been Newfoundland Power’s experience that these arrestors fail as they age due to water leaking into the arrestor through failed seals. All remaining silicon carbide arrestors will be replaced on a prioritized basis within the next 5 years.

Silicon carbide lightning arrestors will be replaced in the following substations:

- Sandy Brook Substation
- Grand Beach Substation
- Port Union Substation

2014 Substation Refurbishment and Modernization
June 2013

2014 Substation Refurbishment and Modernization

June 2013

Prepared by:

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NEWFOUNDLAND POWER
A FORTIS COMPANY

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1.0 Substation Refurbishment and Modernization Strategy

Newfoundland Power (the "Company") has 130 substations located throughout its operating territory. Distribution substations connect the low voltage distribution system to the high voltage transmission system. Transmission substations connect transmission lines of different voltages. Generation substations connect generating plants to the electrical system. Substations are critical to reliability; an unplanned substation outage can affect thousands of customers. The Company's substation maintenance program and the Substation Refurbishment and Modernization project ensure the delivery of reliable least cost electricity to customers in a safe and environmentally responsible manner.

The Substation Refurbishment and Modernization project provides a structured approach for the overall refurbishment and modernization of substations and coordinates major equipment maintenance and replacement activities.[1] Where practical the substation plan is coordinated with the maintenance cycle for major substation equipment. Such coordination minimizes customer service interruptions and ensures optimum use of resources. This approach is consistent with the least cost delivery of reliable service.

Substation refurbishment and modernization is reviewed annually. When updating the substation refurbishment and modernization plan, assessments are made based upon (i) the condition of the infrastructure and equipment, (ii) the need to upgrade and modernize protection and control systems, and (iii) other relevant work. For example, in 2014 the Company has included the Bay Roberts substation in the Substation Refurbishment and Modernization project. This work was scheduled for 2015 but has been advanced to 2014 principally to permit coordination with the installation of a second power transformer required in 2014. The efficiencies gained in this coordination contribute to the approximately 17% cost reduction associated with the rescheduling of this work.

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

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

2.0 Substation Refurbishment and Modernization 2014 Projects

The 2014 Substation Refurbishment and Modernization Project includes planned refurbishment and modernization of five substations. This substation work is estimated to cost a total of $5,868,000 which comprises approximately 97% of the total 2014 project cost. The remaining project cost of $155,000 is associated with Substation Monitoring and Operations upgrades to substation communication systems to accommodate increased data requirements.

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

Table 1 identifies the 2014 Substation Refurbishment and Modernization Project expenditures for 2014.

Table 1
2014 Substation Refurbishment and Modernization Projects
(000s)

Project	Budget
Springdale (SPR)	$963
Massey Drive (MAS)	$747
Holyrood (HOL)	$622
Bay Roberts (BRB)	$1,485
Carbonear (CAR)	$2,051
Substation Monitoring and Operations	$155
Total	**$6,023**

2.1 2014 Substation Projects ($5,868,000)

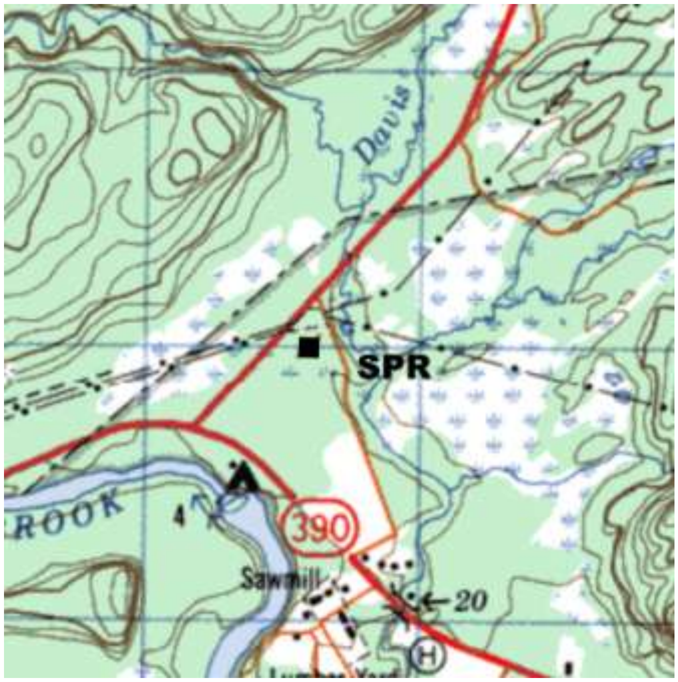
Springdale Substation ($963,000)

Springdale Substation (SPR) was built in 1965 as a distribution substation and is a shared substation with Newfoundland and Labrador Hydro (Hydro).[2] The substation contains one 138 kV to 25 kV distribution power transformer (SPR-T1) with a capacity of 16.7 MVA. The substation directly serves approximately 1,552 customers in the Springdale area through four 25 kV feeders.

In 2014 the Company will replace the bushings on transformer T1 as part of the PCB phase out program. The Company will also undertake other substation refurbishment and modernization work at Springdale substation to take advantage of the installation of the portable substation to minimize the number and duration of customer outages.[3]

[2] The substation is connected to Hydro's 138 kV transmission lines TL222 to South Brook substation and TL223 to Indian River substation. The 138 kV bus and breakers are owned and maintained by Hydro.

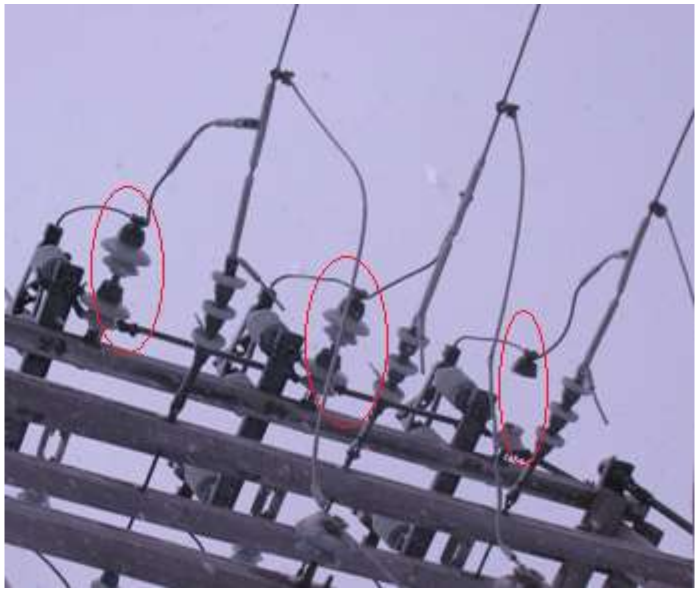
[3] Wherever possible the Company coordinates maintenance work on individual substations with capital substation refurbishment projects to minimize interruption to customers.



Springdale Substation Location

Maintenance records and on-site engineering assessments determine that the 25 kV structures and bus are in good condition, with the exception of deteriorated cap-and-pin insulators and some switch-supporting cross arms that are deteriorated due to decay. These insulators and cross arms will be replaced as a part of this project.

Low Voltage Bus Structure (Wood Poles and Cross Arms)



Low Voltage Structure Insulator Missing

A portable substation will be installed to bypass the substation to replace PCB bushings, refurbish the power transformer and upgrade the transformer's auxiliary protection. The existing auxiliary devices that are used for transformer protection and monitoring, which include a temperature gauge, oil level gauge, and gas detection relay, will be replaced. These devices are showing signs of deterioration, largely due to their exposure to the elements.[4] This can lead to false trips, and as such, these devices can no longer operate reliably. New transformer tap changer controls will be installed to provide the ability to adjust the transformer's output voltage. This upgrade will enhance operational versatility and account for seasonal variations in transformer loading. The new tap changer controller will be integrated with the SCADA system, enabling remote control from the System Control Centre.

The transformer 138 kV air break switch (SPR-T1-A), transformer low voltage disconnect switch, and four 25kV feeder bypass switches are 36 years old and will be replaced due to their mechanical condition and associated age. These switches are operated infrequently and due to deterioration of Teflon bushings, corrosion of the operating mechanisms, and misalignment of blades, they frequently seize during operation.[5] Over the course of the last number of years, failures in switches of this vintage have required the use of line personnel to close them by use of excessive force (i.e., a hot line hookstick).[6]

[4] Transformer auxiliary protection devices are contained inside NEMA rated enclosures mounted to the side of the transformer. Over time, the presence of moisture and humidity corrodes these devices, causing them to fail, leading to false trips and unplanned outages. In 2013, at each of Berry Head and Doyles substations, a transformer gas detect relay of the same vintage failed, resulting in unplanned service interruptions.

[5] 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.

[6] The use of hot line hooksticks to forcibly close airbreak switches under load is not considered by the Company to be an operational best practice or an efficient use of line personnel.

The existing transformer protection relays are electromechanical types that are original to the 1965 substation construction.[7] The 48 year old transformer protection will be replaced with new microprocessor based digital relays. In addition, a complete communications package including a gateway will be installed, to facilitate remote monitoring and control of the various protection elements within the substation. The monitored protection elements will include the T1 transformer protection and 4 intelligent reclosers.

Transformer Protection Panel (Electromechanical Relays)

The 4 feeder reclosers for feeders SPR-01, SPR-02, SPR-03, and SPR-04 are all hydraulic-type reclosers ranging in age from 29 years to 37 years old. These reclosers are not equipped with protection and control capabilities that would facilitate automation, enhanced fault isolation, and remote settings changes to minimize unnecessary trips in the event of cold load pickup. The 4 reclosers will be replaced with new intelligent reclosers that have no maintenance requirements, are oil-free, and will be automated for monitoring and control from the System Control Center. The automation equipment, transformer protection and recloser controls will be installed in the existing control building. With feeder automation, the Springdale feeders will be added to the provincial under-frequency load shedding scheme.[8]

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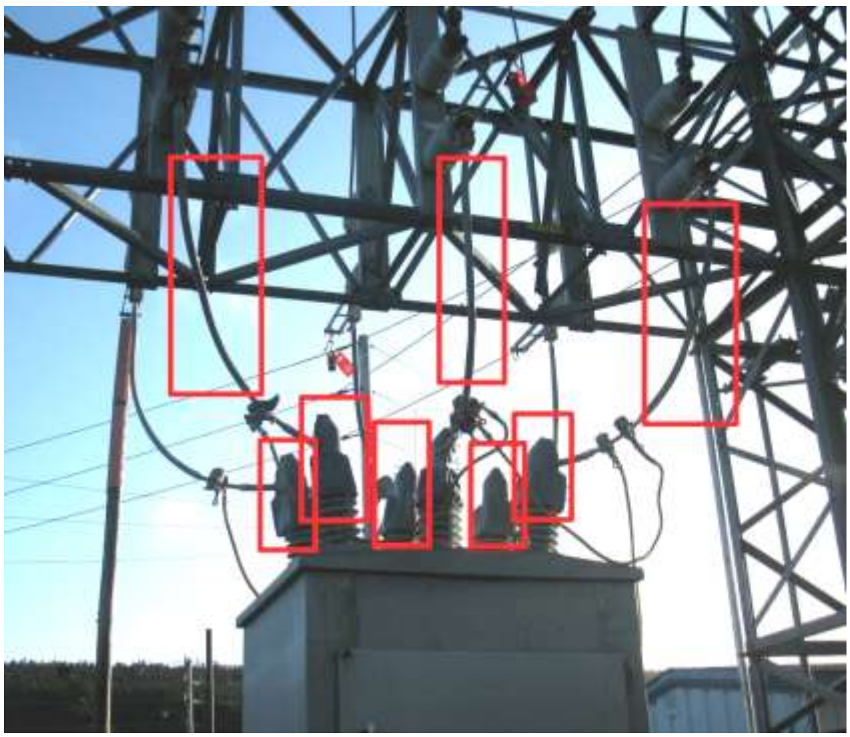
[7] Report ***2.1*** *Substation Strategic Plan* included with the 2007 Capital Budget Application identified that electro-mechanical relays contain moving parts and are prone to failure as they age, wear and accumulate dirt and dust.

[8] The automation of distribution feeders through digital relays or intelligent reclosers allows for remote monitoring and control through SCADA. In addition these feeders can be remotely tagged for employee safety, included in under-frequency load shedding and have their protection setting adjusted remotely to allow for cold load pickup after extended outages.

A grounding study will be completed and the ground grid for the Newfoundland Power portion of the substation will be extended to improve safety for personnel inside the substation.[9] The grounding study and ground grid upgrade will be coordinated with Newfoundland and Labrador Hydro.

Standard varmint protection practices, in the form of insulated coverings, guards, and leads, will be installed on all low voltage switches and recloser bushings.[10]



Varmint Protection Example Including Insulated Busing Covers and Leads

Massey Drive Substation ($747,000)

The Massey Drive substation was built in 1967 as a transmission substation, and is located on a shared site containing assets for Newfoundland Power, Newfoundland and Labrador Hydro, and Deer Lake Power. The Newfoundland Power transmission portion of the substation contains high voltage switches and 4 breakers associated with the 66kV transmission lines.[11] The substation indirectly serves approximately 21,500 customers in the greater Corner Brook area through this transmission network.

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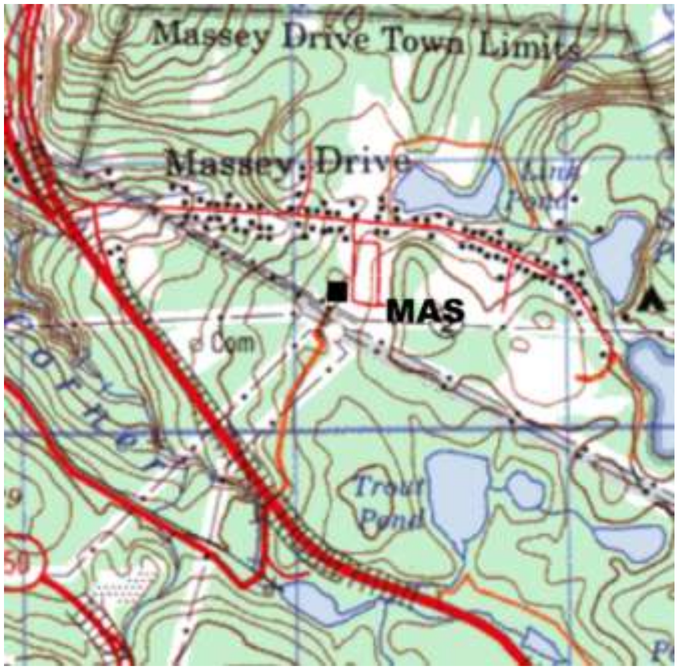
[9] Newfoundland Power designs substation ground grids using the *ANSI/IEEE Standard 80-2000 Guide for Safety in AC Substation Grounding*. This standard is considered industry best practise for designing substation ground grids.

[10] These barriers have proven effective in preventing damage to equipment and customer outages caused by small animals and birds.

[11] The four 66 kV transmission lines are 356L to Humber substation, 351L and 352L to Walbournes substation, and 357L to Bayview substation.



Massey Drive Substation Location

Maintenance records and on-site engineering assessments determine that the substation steel structures, foundations, bus work, and insulators are all in good condition. There are 2 side-break disconnect switches and 2 line to ground switches that have been in service since 1967 and will be replaced with new 66 kV switches due to their mechanical condition and associated age. Substation switches are operated infrequently, and as they age will seize when operated due to deterioration of bushings, corrosion in operating mechanisms and/or misalignment of blades.[12]

The relays for the transmission lines and bus protection are vintage electro-mechanical type and are original to the 1967 substation construction. Electro-mechanical relays work by using torque-producing coils, energized by current and voltage inputs, which open or close contacts based upon mechanically calibrated thresholds. The mechanical parts contained within electro-mechanical relays are prone to failure as they age, wear, and accumulate dirt and dust. The age of these relays dictate they are to be replaced with new microprocessor based digital relays.[13]

At present, there are 15 electromechanical relays installed in 2 individual protection panels inside the substation control building. These relays, used for the protection of 4 transmission lines, are

[12] The Company's strategy for switches is to operate and maintain switches whenever opportunities and substation work permit, and to replace switches when they are more than 30 years old.

[13] More than 20 failures of this type of relay have contributed to system events and unplanned outages since 2006. During Hurricane Leslie in September 2012, electro-mechanical relay failures resulted in the slow clearing of faults which contributed to prolonged system outages. The investigation identified the failure of electro-mechanical relays used to protect transmission lines 48L and 64L at Blaketown substation as having contributed to the system event. These relays are being replaced in 2013. Report ***2.1** Substation Strategic Plan* included with the 2007 Capital Budget Application identified that electro-mechanical relays contain moving parts and are prone to failure as they age, wear and accumulate dirt and dust.

vintage electromechanical type with more than 35 years in service. Replacing the electro-mechanical relays with digital relays reduces the total protection relay device count from 15 to 4.

The protection upgrade will also involve replacing both of the existing protection panels. This approach minimizes the number of active devices used to provide protection to substation assets, consolidates the control and automation architecture, and reduces ongoing maintenance. In addition, the communications package will be upgraded to enhance SCADA system remote-control and monitoring of the power system from the newly installed protection equipment.[14] The gateway will integrate the digital protection relays for the 4 transmission lines and the 66 kV bus structure into the SCADA system.

Transmission Line Electromechanical Relay Panels and RTU

A grounding study will be completed and the ground grid for the Newfoundland Power portion of the substation will be upgraded as required to enhance safety for personnel inside the substation.[15] The grounding study and ground grid upgrade will be coordinated with Newfoundland and Labrador Hydro and Deer Lake Power Company.

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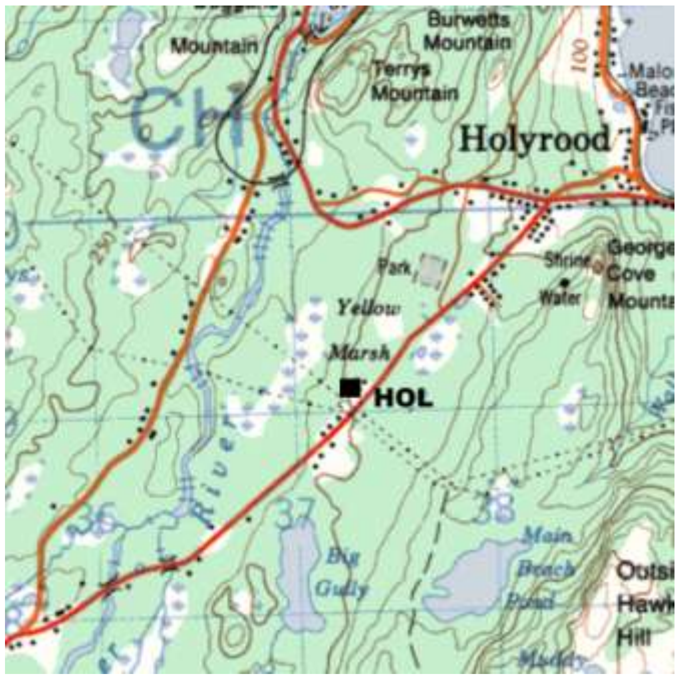
14 Remote monitoring and control of protection equipment provides efficiency improvements by remote tagging and setting changes on distribution feeders and transmission lines without personnel needing to actually visit the substation.

15 Newfoundland Power designs substation ground grids using the *ANSI/IEEE Standard 80-2000 Guide for Safety in AC Substation Grounding*. This standard is considered industry best practise for designing substation ground grids.

Holyrood Substation ($622,000)

Holyrood substation was built in 1976 as both a transmission and distribution substation. The transmission portion of the substation contains two 138 kV transmission lines.[16] There is a single 20 MVA, 138kV to 12.5kV power transformer (HOL-T1) feeding the 12.5kV bus infrastructure. There are two feeders (HOL-01 and HOL-02), which serve approximately 2,700 customers in the community of Holyrood and surrounding area.[17]



Holyrood Substation Location

Maintenance records and on-site engineering assessments determine that the 138kV and 12.5 kV steel structures, foundations, buses, switches and insulators are all in good condition.

Feeder HOL-01 is a distribution feeder that splits outside the substation to serve 2 different areas. One section of feeder serving approximately 800 customers south of the substation travels 24.5 km along the Salmonier Line to its termination south of the TransCanada Highway. The second section of feeder serves approximately 1,300 customers north of the substation and travels 13.5 km along the Conception Bay Highway through the communities of Harbour Main, Chapel Cove and Avondale. HOL-01 feeder will be broken into 2 separate feeders with one feeder serving the customers on the Salmonier Line section and a second feeder serving the customers along the

[16] The 138 kV transmission lines are 39L to the Holyrood Thermal Generating Station and 39L to Colliers Substation.

[17] HOL-01 serves approximately 2,150 customers and HOL-02 serves approximately 550 customers.

Conception Bay Highway.[18] This work will involve adding a new recloser and associated switches in an existing bay in the 12.5 kV substation bus structure. No distribution work is required for this project as the feeder splits just outside the substation.

Low Voltage Distribution Bus Structure (Feeder Infrastructure)

The substation has 2 existing reclosers, a hydraulic recloser (HOL-01) and an intelligent Nulec recloser (HOL-02). The hydraulic recloser on HOL-01 is 30 years old and not capable of automation through the SCADA system.[19] The hydraulic recloser on HOL-01 will be replaced with a new intelligent recloser. The new feeder will also be equipped with an intelligent recloser thereby providing all 3 feeders with automation for monitoring and control from the System Control Center. This will provide a means of automated restoration of service which will improve service reliability for customers. With feeder automation, the Holyrood feeders will be added to the provincial under-frequency load shedding scheme.

Control of the existing motor operated switch will be integrated into the overall system protection and control scheme including remote monitoring and control from the System Control Center. In the event of a fault at the transformer, this new motor operator will provide enhanced protection for the transformer.

Transformer HOL-T1 has been in service for 37 years. The power transformer will be refurbished and upgrades made to both the transformer's primary and auxiliary protection.

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18 Breaking feeder HOL-01 into 2 separate feeders will improve reliability for customers by (1) reducing the exposure of each customer group to outages on the section of feeder serving the other customer group and (2) reducing the time required to locate a faulted section of line during an outage.

19 The automation of distribution feeders through digital relays or intelligent reclosers allows for remote monitoring and control through SCADA. In addition these feeders can be remotely tagged for employee safety, included in under-frequency load shedding and have their protection setting adjusted remotely to allow for cold load pickup after extended outages.

Upgrades to the primary protection involve a new digital protection relay to monitor the substation transformer. The existing auxiliary protection devices, including a temperature gauge and gas detection relay, will be replaced. After 37 years in service, these devices are showing signs of deterioration. This has led to false trips, and as such, these devices no longer operate reliably. These auxiliary devices are used to monitor and protect the power transformer, and due to their exposure to the elements, require replacement to ensure continued protection and safe operation of the power transformer.[20]

New transformer tap changer controls will be installed on HOL-T1 to provide the ability to adjust the transformer's output voltage. This upgrade will enhance operational versatility and account for seasonal variations in transformer loading. The new tap changer controller will be integrated with the SCADA system, enabling remote control from the System Control Centre.

A small control building will be erected to provide a climate controlled environment for the new microprocessor based digital relays that will be installed for transformer and feeder protection and control upgrades.

Standard varmint protection practices, in the form of insulated coverings, guards, and leads, will be installed on all low voltage switches and recloser bushings.[21]

A grounding study will be completed and the ground grid for the substation will be extended to improve safety for personnel inside the substation.[22]

Bay Roberts ($1,485,000)

The refurbishment and modernization of Bay Roberts substation will be undertaken in 2014 in concert with the installation of an additional power transformer.[23]

Bay Roberts substation was built in 1967 as a distribution substation and expanded to include both transmission and distribution in 1978. The transmission portion of the substation contains two 138 kV transmission lines and two 66 kV transmission lines.[24] There are two 42 MVA, 138 kV to 66 kV power transformers (BRB-T2 and BRB-T3) feeding the 66 kV bus structure. There is a single 20 MVA, 138 kV to 12.5 kV power transformer (BRB-T1) feeding the 12.5 kV bus infrastructure.[25] There are five feeders (BRB-01 to BRB-05), which serve approximately 3,600 customers in the Town of Bay Roberts and surrounding area.

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[20] The Company's strategy for these protection devices is to replace them once they approach 25 to 30 years of service life. See page 4, footnote 4 for further details.

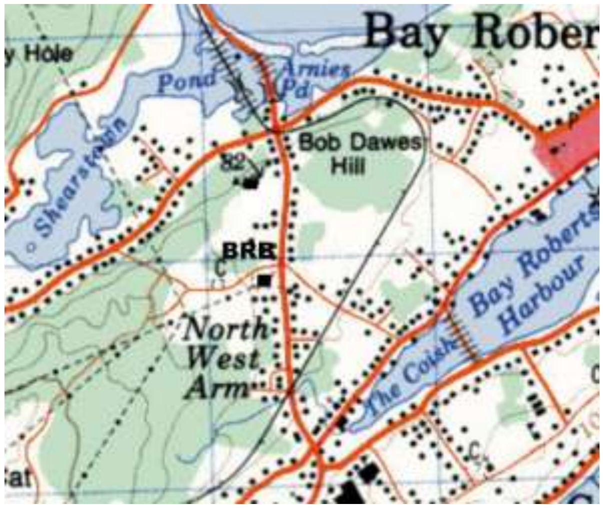
[21] These barriers have proven effective in preventing damage to equipment and customer outages caused by small animals and birds.

[22] Newfoundland Power designs substation ground grids using the *ANSI/IEEE Standard 80-2000 Guide for Safety in AC Substation Grounding*. This standard is considered industry best practise for designing substation ground grids.

[23] The Substations project *2014 Additions Due to Load Growth* includes a new 25 MVA substation transformer required for Bay Roberts substation.

[24] The two 138 kV transmission lines are 39L to Springfield substation and 48L to Blaketown substation. The two 66 kV transmission lines are 56L to Carbonear substation and 57L to Upper Island Cove substation.

[25] The Substations *2014 Additions Due to Load Growth* project includes an item to install a new 25 MVA 66/12.5 kV substation transformer to operate in parallel with BRB-T1.



Bay Roberts Substation Location

Maintenance records and on-site engineering assessments determine that the 138 kV, 66 kV and 12.5 kV steel structures, foundations, buses, and insulators are all in good condition.

At present, there are 42 electromechanical relays installed in 9 individual protection panels inside the substation control building. These relays, used for the protection of 4 transmission lines, 3 transformers and 2 bus structures are vintage electromechanical type, ranging in age from 35 to 45 years old. Electro-mechanical relays contain moving parts and are prone to failure as they age, wear, and accumulate dirt and dust. The age of these relays dictate they are to be replaced.

Electromechanical Relay Panels

The protection and control of the substation will be modernized by replacing these obsolete devices with microprocessor based digital relays, reducing the total protection relay device count from 42 to 8.[26] The protection upgrade will also involve replacing all of the existing protection panels. This approach minimizes the number of active devices used to provide protection to substation assets, consolidates the control and automation architecture, and reduces ongoing maintenance.

In addition, the communications package will be upgraded to enhance SCADA system remote-control and monitoring of the power system from the newly installed protection equipment.

A portable substation will be installed to bypass transformer BRB-T1 to refurbish the power transformer and replace the air break switch.

The 3 power transformers installed between 1976 and 1984 will be refurbished and upgrades made to the transformers' auxiliary protection. The existing auxiliary protection devices, including a temperature gauge and gas detection relay, will be replaced. Having been in service for 30 years or more, these devices are showing signs of deterioration. This can lead to false trips, and as such, these devices no longer operate reliably. These auxiliary devices are used to monitor and protect the power transformer, and due to their exposure to the elements, require replacement to ensure continued protection and safe operation of the 3 power transformers.[27]

The transformer 138 kV air break switch (BRB-T1-A) is 35 years old and will be replaced due to its mechanical condition and associated age. The switch is operated infrequently and due to deterioration of bushings, corrosion in its operating mechanism and misalignment of blades it frequently seizes during operation.[28]

Standard varmint protection practices, in the form of insulated coverings, guards, and leads, will be installed on all low voltage switches and recloser bushings.[29]

A grounding study will be completed and the ground grid for the substation will be extended to improve safety for personnel inside the substation.[30]

[26] Report ***2.1*** *Substation Strategic Plan* included with the 2007 Capital Budget Application identified that electro-mechanical relays contain moving parts and are prone to failure as they age, wear and accumulate dirt and dust.

[27] The Company's strategy for these protection devices is to replace them once they approach 25 to 30 years of service life.

[28] 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.

[29] These barriers have proven effective in preventing damage to equipment and customer outages caused by small animals and birds.

[30] Newfoundland Power designs substation ground grids using the *ANSI/IEEE Standard 80-2000 Guide for Safety in AC Substation Grounding*. This standard is considered industry best practise for designing substation ground grids.

Carbonear Substation ($2,051,000)

Carbonear substation was built in 1974 as both a transmission and distribution substation. The transmission portion of the substation contains four 66 kV transmission lines.[31] There is a single 25 MVA, 66 kV to 12.5 kV power transformer (CAR-T1) which provides distribution voltage to the 12.5 kV bus infrastructure. There are four feeders (CAR-01, CAR-02, CAR-03, and CAR-04), which serve approximately 2,700 customers in the community of Carbonear and surrounding areas.

In 2014, the Company has transformer maintenance activities scheduled for transformer T1 at Carbonear substation. The Company will also undertake other substation refurbishment and modernization work at Carbonear substation to take advantage of the installation of the portable substation, which is being installed to minimize the number and duration of customer outages.[32]

Carbonear Substation Location

Maintenance records and on-site engineering assessments determine that the 66kV and 12.5 kV steel structures are in good condition. The foundation for transmission line breaker 56L-B is in poor condition, and will be replaced. In addition, column foundations for two 66kV steel structures are in poor condition and will be refurbished.

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31 The 4 transmission lines include 56L to Bay Roberts Substation, 68L to Harbour Grace Substation, 41L to Heart's Content Substation, and 40L to Victoria Substation.

32 Wherever possible the Company coordinates maintenance work on individual substations with capital substation refurbishment projects to minimize interruption to customers.

Deteriorated 15kV Pothead Structure Column Foundation

A large section of cable trench and 26 trench covers will be replaced with rust-resistant trench covers.[33] A large section of substation fencing is in need of replacement due to frost heaving. The root cause of the frost heaving issue is poor drainage in that area of the substation, and to correct this issue, a continuous ditch will be created around the perimeter of the substation.

Deteriorated Cable Trench Covers

[33] In addition to being corroded the cable tray covers are bent as they were not designed to permit heavy vehicle traffic. As a result the existing cable trench presents a tripping hazard for employees working in the substation.

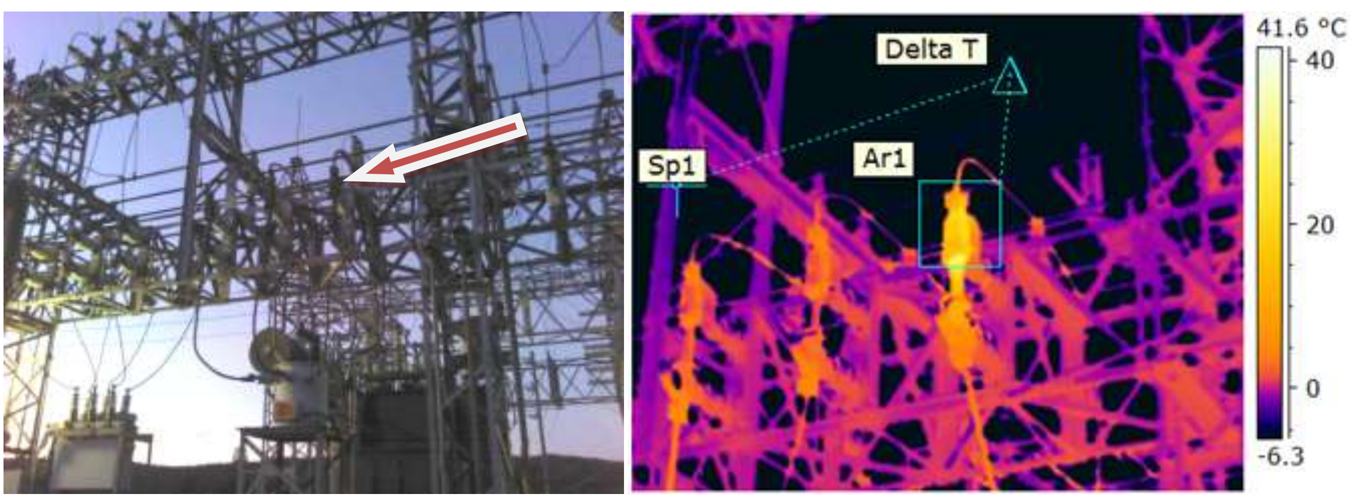
Upgrades to the substation control building are required, including work on the roof, siding and access door in order to maintain a weather-proof operating environment for the various protection devices operating inside the building. A contained battery room will be installed inside the building in order to bring the control building up to current design standards for employee safety.

A portable substation will be installed to bypass the substation and facilitate the refurbishment of power transformer CAR-T1 and associated protection and control devices. The existing 40 year old 66kV potential transformers will be replaced with dry-type units. In addition, the 15 kV oil-filled metering tank has been in service for 25 years and will be replaced with an oil free unit for transformer metering.

The existing switch (CAR-T1-A) used to isolate transformer T1 will be replaced with a new motorized air break switch to allow for the integration of switch operation into the overall protection and control scheme for the station.

The existing auxiliary protection devices, including a temperature gauge and gas detection relay, will be replaced. After more than 25 years in service, these devices are showing signs of deterioration. This can lead to false trips, and as such, these devices can no longer operate reliably. These auxiliary devices are used to monitor and protect the power transformer, and due to their exposure to the elements, require replacement to ensure continued protection and safe operation of the 3 power transformers.[34]

In addition, all 1974 vintage high voltage and low voltage switches will be replaced due to their age and the presence of multiple hot spots in the current carrying path. [35]



CAR-T1-D Switch Replacement (Hot spots visible with infrared camera)

[34] The Company's strategy for these protection devices is to replace them once they approach 25 to 30 years of service life.

[35] The need to replace additional switches arose as a result of inspection and is a primary contributor to the increase in forecast cost of refurbishment and modernization of Carbonear substation from approximately $1.3 million in the 2013 Capital Budget Application to $2.1 million in this Application. See page 4 and footnotes 5 and 6 for more detail on the reliability of switches of this vintage.

The protection and controls for transmission lines 56L, 68L, 41L and 40L currently incorporate 40 year old electro mechanical protection relays and these will be replaced utilizing micro processor based digital relays.[36] The age and condition of these relays dictate they are to be replaced.

Three of the 4 distribution feeders are protected and controlled using hydraulic reclosers ranging in age from 31 to 44 years old.[37] The hydraulic reclosers are not capable of automation through the SCADA system.[38] New intelligent reclosers will be installed to replace the hydraulic reclosers providing automation for monitoring and control from the System Control Center. This will provide a means of automated restoration of service which will improve customer service as a result of this enhanced restoration capability. With feeder automation, the 4 Carbonear distribution feeders will be added to the provincial under-frequency load shedding scheme.

The feeder automation equipment, transformer protection and recloser controls will be installed in the existing control building. This will provide a means of automated restoration of power delivered to the station and in-turn, will improve customer service as a result of this enhanced power restoration capability.

A complete communications package including a gateway will be installed to facilitate SCADA system remote-control and monitoring of the power system protection equipment. The gateway will integrate the digital devices monitoring and controlling the transmission lines, distribution feeders and substation transformers into the SCADA system.

Standard varmint protection practices, in the form of insulated coverings, guards, and leads, will be installed on all low voltage switches and recloser bushings.[39]

A grounding study will be completed and the ground grid for the substation will be extended to improve safety for personnel inside the substation.[40]

2.2 Substation Monitoring and Operations ($155,000)

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

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[36] Report ***2.1*** *Substation Strategic Plan* included with the 2007 Capital Budget Application identified that electro-mechanical relays contain moving parts and are prone to failure as they age, wear and accumulate dirt and dust.

[37] The 3 hydraulic reclosers are associated with distribution feeders CAR-01, CAR-02 and CAR-03. Distribution feeder CAR-04 has an intelligent Nulec recloser.

[38] The automation of distribution feeders through digital relays or intelligent reclosers allows for remote monitoring and control through SCADA. In addition these feeders can be remotely tagged for employee safety, included in under-frequency load shedding and have their protection setting adjusted remotely to allow for cold load pickup after extended outages.

[39] These barriers have proven effective in preventing damage to equipment and customer outages caused by small animals and birds.

[40] Newfoundland Power designs substation ground grids using the *ANSI/IEEE Standard 80-2000 Guide for Safety in AC Substation Grounding*. This standard is considered industry best practise for designing substation ground grids.

In 2014, upgrades to the communications hubs that connect multiple devices in substations to the SCADA system are planned. Effective management of increased volumes of electrical system data requires the upgrading of the hubs. This requires both hardware and software upgrades.

In 2014, the required work will incorporate manufacturers' upgrades to communications and other computer-based equipment located in Company substations. These upgrades typically increase functionality of the equipment and software and remedy known deficiencies.

Appendix A

Substation Refurbishment and Modernization Plan
Five-Year Forecast 2014 to 2018

Substation Refurbishment and Modernization Plan Five-Year Forecast 2014 to 2018 (000s)									
2014		**2015**		**2016**		**2017**		**2018**	
SUB	**Cost**	**SUB**	**Cost**	**SUB**	**Cost**	**SUB**	**Cost**	**SUB**	**Cost**
SPR	$ 963	STX	$ 552	SPO	$1,631	CAT	$2,474	HCP	$ 503
MAS	$ 747	RRD	$1,047	P135	$ 740	BVA	$ 946	NCH	$1,605
HOL	$ 622	BVS	$1,400	HUM	$2,506	GAN	$3,385	TCV	$ 619
CAR	$2,051	VIC	$1,685	SMU	$ 165	SMU	$ 170	BLA	$ 743
BRB	$1,485	SMU	$ 160					MOL	$1,914
SMU	$ 155							GBS	$1,472
								SMU	$ 176
	$6,023		**$4,844**		**$5,042**		**$6,975**		**$7,032**

Note: SUB: Substation - Refer to the Electrical System handbook included with the 2006 Capital Budget Application for three letter substation designations. P1, P3 and P4 are the designations for the portable substations.

2013 Substation Refurbishment and Modernization
June 2012

2013 Substation Refurbishment and Modernization

June 2012

Prepared by:

John Pardy, P.Eng.

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PROVINCE OF NEWFOUNDLAND

NEWFOUNDLAND POWER
A FORTIS COMPANY

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1.0 Substation Refurbishment and Modernization Strategy

Newfoundland Power (the "Company") has 130 substations located throughout its operating territory. Distribution substations connect the low voltage distribution system to the high voltage transmission system. Transmission substations connect transmission lines of different voltages. Generation substations connect generating plants to the electrical system. Substations are critical to reliability; an unplanned substation outage will affect thousands of customers. The Company's substation maintenance program and the Substation Refurbishment and Modernization project ensure the delivery of reliable least cost electricity to customers in a safe and environmentally responsible manner.

The Substation Refurbishment and Modernization project provides a structured approach for the overall refurbishment and modernization of substations and coordinates with major equipment maintenance and replacement activities.[1] Where practical the substation plan is coordinated with the maintenance cycle for major substation equipment. This coordination minimizes customer service interruptions and ensures optimum use of resources.

When updating the substation strategic refurbishment and modernization plan substations are assessed with particular consideration given to the condition of the infrastructure and equipment, and the need to upgrade and modernize protection and control systems. This assessment is used to determine substation work.

Much of this work requires the power transformer to be removed from service; and, therefore, the timing of the work is restricted to the availability of the portable substation and the capacity of the portable substation to meet the load requirement. In many circumstances, this requires the work to be completed in the late spring and summer when the substation load is reduced.

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

2.0 Substation Refurbishment and Modernization 2013 Projects

The 2013 Substation Refurbishment and Modernization Project includes planned refurbishment and modernization projects of 5 substations and one portable substation. This work is estimated to cost a total of $4,020,000 which comprises approximately 90% of the total 2013 project costs. The remaining project cost of $432,000 is associated with Substation Monitoring and Operations upgrades to substation communication systems to accommodate increased data requirements and the addition of new metering at infeed points on the Island Interconnected System.[2]

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

2 These infeed points are some of the locations where Newfoundland Power takes delivery of electricity from Newfoundland Hydro.

Table 1 identifies the 2013 Substation Refurbishment and Modernization Project expenditures for 2013.

Table 1
2013 Substation Refurbishment and Modernization Projects
(000s)

Project	Budget
St. Catherine's Substation (SCT)	$561
Portable Substation 4 (P4)	$790
Stephenville Gas Turbine Substation (STV)	$732
Glenwood Substation (GLN)	$967
Twillingate Substation (TWG)	$770
Kenmount Substation (KEN)	$200
Substation Monitoring and Operations (SMU)	$432
Total	**$4,452**

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

2.1 2013 Substation Projects ($4,020,000)

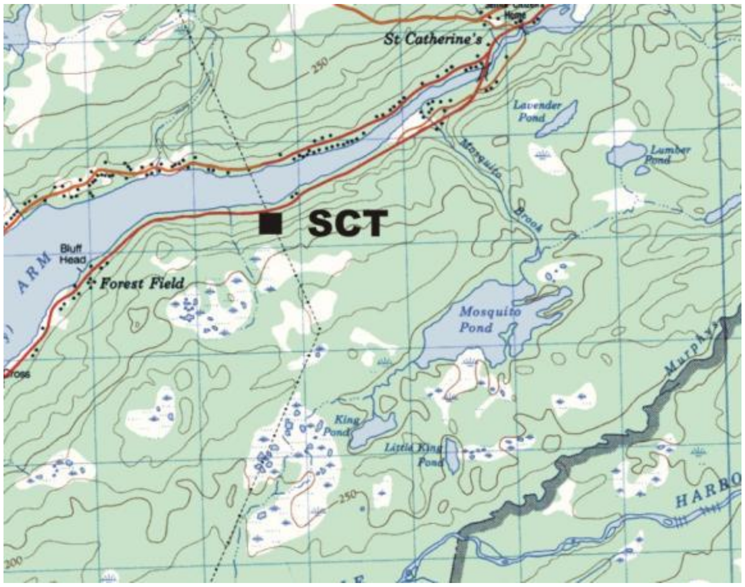
St. Catherine's Substation ($561,000)

St. Catherine's Substation (SCT) was built in 2000 as a distribution substation. The substation contains one 66 kV to 25 kV distribution power transformer (T1) with a capacity of 5 MVA, and one 25kV to 12.5 kV step down power transformer (T2) with a capacity of 4 MVA.

The substation directly serves approximately 924 customers in the St Catherine's area through one 25 kV feeder and one 12.5 kV feeder. In the substation there are two 66 kV transmission lines terminated in the high voltage bus, these being transmission lines 94L to Blaketown substation and 94L to Riverhead substation.

In 2013, the Company has transformer maintenance activities scheduled for both transformer T1 and T2 at St. Catherine's substation. The Company will also undertake other substation refurbishment and modernization work at St. Catherine's substation to take advantage of the installation of the portable substation, which is being installed to minimize the number and duration of customer outages.[3]

[3] Wherever possible, the Company coordinates maintenance work on individual substations with capital substation refurbishment and modernization projects to minimize service interruptions to customers.



St. Catherine's Substation Location

Maintenance records and on-site engineering assessments show that the 66 kV wood pole structures and bus and 25 kV wood pole structures and bus are in good condition.

66 kV & 15 kV Wood Pole Structures and Bus

A portable substation will be installed to bypass St. Catherine's substation to refurbish the transformers and upgrade the transformer's auxiliary protection.[4] Maintenance is scheduled on both transformers. The oil in transformer T2 has PCB concentration tested at over 50 ppm so

[4] Substation transformers are maintained on 10 year cycles. This will be the first transformer refurbishment since the substation was built in 2000.

while the transformer is de-energized the oil will be replaced to comply with current PCB regulations. Upgrades will be completed on both transformers including replacement of temperature gauges and gas detection relays. The silicon carbide lightning arrestors will be replaced with metal oxide arrestors.[5]

Potential transformers and current transformers will be installed for metering of the transformer load and to provide current and voltage signals for protective relays. Engineering staff use transformer load metering data for system modeling and planning.

The two existing feeder reclosers are hydraulic type, and have 40 and 43 years in service. They will be replaced with new Nulec type reclosers and will be automated for control from the System Control Center.[6] Varmint proofing will be installed on the 15 kV bus equipment.

The ground grid for the substation will be extended to improve safety for personnel inside the substation.

Portable Substation P4 ($790,000)

Portable substation P4 was purchased in 1992. It is used to respond to power transformer failures and for planned transformer maintenance and substation refurbishment and modernization work. P4 can provide backup for 70% of the 192 power transformers in service on Newfoundland Power's system.

Portable Substation P4

[5] Report ***2.1*** *Substation Strategic Plan* included with the 2007 Capital Budget Application identified that until the early 1980's silicon carbide lightning arrestors were standard. The Company has experienced many failures of silicon carbide lightning arrestors as they age due to water leaking into the arrestor through failed seals.

[6] Monitoring and control of Nuclec reclosers from the System Control Center will result in real time detection of trouble on the distribution feeder and provide for remote restoration of service. Also, the System Control Center will be able to remotely de-energize feeders in emergency situations thus enhancing employee and public safety.

Engineering for the refurbishment will be completed in 2012 with the actual refurbishment taking place in 2013.[7] This is the first comprehensive refurbishment of this portable substation since its purchase in 1992. Refurbishment of portable substation P4 will ensure its continued availability for the next decade.

The trailer will undergo an overhaul addressing rust damage and applying a rust inhibiting coating to the chassis. A fall arrest system and work platforms will be installed in areas where employees have to work aloft. External lighting will be provided at locations around the trailer.

Deterioration on Chassis above Axle

Deterioration on Axle

7 The engineering work in 2012 on Portable Substation P4 was included in the ***2.1** Substation Refurbishment and Modernization* project approved in Order No. P.U. 26 (2011).

The alarm annunciation panel has had several failures and will be replaced. The original protection relays will be replaced with microprocessor based protection relays.[8] A digital metering system for power, voltage and current will be provided.

The wiring associated with the protection and control of the portable substation is original wiring showing signs of deterioration. Deteriorated wiring, termination and junction boxes will be replaced.

Online monitoring of transformer gas and oil analysis will be provided to protect the transformer. High voltage linkages connecting the power transformer to the switches are deteriorated and will be replaced. The batteries and charging system are at the end of life and will be replaced.

A SCADA remote terminal unit will be installed on the portable substation to provide remote monitoring and control capability of the unit.

Stephenville Gas Turbine Substation ($732,000)

The Stephenville Gas Turbine substation was built in 1976 as a transmission substation, and is located on a site containing assets for both Newfoundland Power and Newfoundland and Labrador Hydro ("Hydro"). The transmission portion of the substation contains a 66 kV bus and associated isolating devices for three transmission lines, 401L to Gallants, 405L to Harmon, and 407L to Stephenville Crossing. A fourth transmission line, 404L to Wheelers, is tapped off of 401L approximately 4.6 km away from the substation fence. The Stephenville Gas Turbine substation indirectly serves 5,569 customers in the greater Stephenville and Port aux Port Peninsula area through this transmission network.

Stephenville Gas Turbine Substation Location

8 Report ***2.1*** *Substation Strategic Plan* included with the 2007 Capital Budget Application identified that electro-mechanical relays contain moving parts and are prone to failure as they age, wear and accumulate dirt and dust. In the past 5 years the Company has experienced increasing numbers of electro-mechanical relay failures.

Maintenance records and on-site engineering assessments show that the substation steel structures, foundations, bus work, and insulators are all in good condition.

66kV Steel Structures & Bus

The switches on the structures are all in good condition, with the exception that the 401L-DB switch is deteriorated and as a result is difficult to operate. The switch is 1976 vintage and will be replaced due to its age and recent operating history.

The steel cable trench covers are corroded and will be replaced. In addition, all substation light fixtures will be replaced.

Currently, the Company uses a set of Hydro's 66 kV potential transformers terminated on their bus to provide the voltage signal for protection of the 3 Newfoundland Power transmission lines that terminate in the station. During switching activity the 66 kV bus can be split into 2 isolated buses resulting in the loss of protection for the 3 transmission lines. To address this shortcoming a new set of 66 kV potential transformers will be installed on the Newfoundland Power side of the 66 kV bus, along with a single fuse-protected potential transformer on transmission line 407L for synchronization monitoring. With this upgrade, service to customers normally supplied via 407L can be maintained, from local generation, while completing transmission line maintenance and reconnected to the grid without an interruption in service.[9]

The relays for the transmission lines and bus protection are 1976 vintage electromechanical type and will be replaced with new microprocessor based relays.[10] In addition, a complete

9 Transmission line 407L connects the Lookout Brook hydro plant to the Island Interconnected System at Stephenville Gas Turbine substation via St. George's substation.

10 Report ***2.1*** *Substation Strategic Plan* included with the 2007 Capital Budget Application identified that electro-mechanical relays contain moving parts and are prone to failure as they age, wear and accumulate dirt and dust. In the past five years Newfoundland Power has experienced increasing numbers of electro-mechanical relay failures.

communications package will be installed, to facilitate both automated and remote control of the various protection elements within the substation. This will provide the capability of remote management of the relays to monitor power system operation and analyze disturbances without travelling to the site.

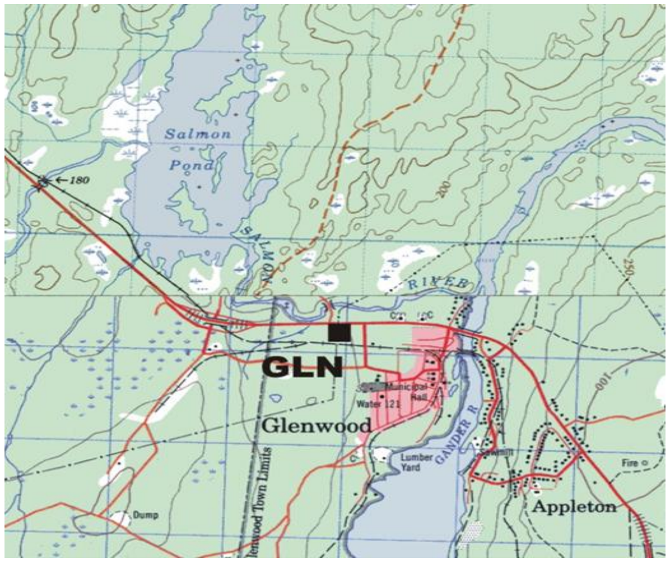
Transmission Line Electromechanical Relays

The ground grid for the substation will be extended to improve safety for personnel inside the substation.

Glenwood Substation ($967,000)

Glenwood substation was built in 1968. Today it is both a transmission and distribution substation. The transmission portion of the substation contains two 138 kV transmission line links; Hydro's TL210 to Cobbs Pond and Stoney Brook. There is a single 8.3 MVA, 138 kV to 25 kV power transformer GLN-T1 terminated at a voltage regulation bank leading to a 25 kV bus infrastructure. The substation services 707 customers in the area of Glenwood through a single feeder GLN-01.

In 2013, the Company has transformer maintenance activities scheduled for T1 at Glenwood substation. The Company will also undertake other substation refurbishment and modernization work at Glenwood substation to take advantage of the installation of the portable substation, which is being installed to minimize the number and duration of customer outages.



Glenwood Substation Location

Maintenance records and on-site engineering assessments show that the 138kV and 25 kV wooden structures, foundations, buses and insulators are all in good condition. Standard varmint protection and vegetation management practices will be implemented.

138kV & 25 kV Wooden Structures & Bus

The portable substation will be installed and the power transformer GLN-T1 will be refurbished.[11] The lightning arrestors on this transformer are silicon carbide and will be replaced with metal oxide arrestors.[12]

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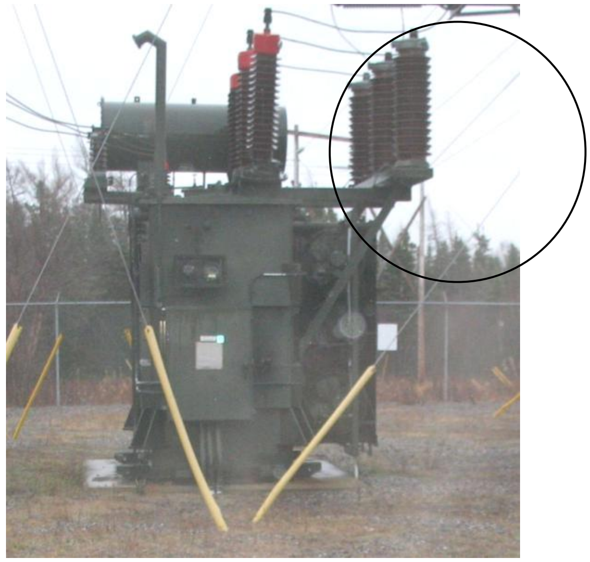
11 Substation transformers are maintained on 10 year cycles. The last transformer maintenance on GLN-T1 was in 1999.

12 Report ***2.1*** *Substation Strategic Plan* included with the 2007 Capital Budget Application identified that until the early 1980's silicon carbide lightning arrestors were standard. The Company has experienced many failures of silicon carbide lightning arrestors as they age due to water leaking into the arrestor through failed seals.



Power Transformer with Silicon Carbide Arrestors

The 27 year old 138 kV motorized air break switch and high speed ground switch for power transformer GLN-T1 will be replaced, to permit integration of the motor operator and the high speed ground switch with the transformer protection relay. The transformer protection relays will be replaced with microprocessor based relays and the transformer protection panel will be installed in a new small control building.[13] Upgraded transformer protection will isolate the transformer from system disturbances more quickly than existing protection.[14]

New 25 kV potential transformers will be installed on the 25 kV bus to facilitate metering and protection upgrades. In addition, the voltage regulator structure will be relocated to a location just outside the substation fence. The existing regulator location does not permit maintenance to be safely performed on the units without a service interruption due to space limitation on the substation low voltage structure. Relocation of the voltage regulators to a standard voltage regulator structure outside the substation will permit safe, unrestricted access.

A grounding study will be completed and the ground grid for the substation will be extended to improve safety for personnel inside the substation. An access gate on the main substation driveway will be installed and crushed stone added to the yard.

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13 Report ***2.1*** *Substation Strategic Plan* included with the 2007 Capital Budget Application identified that electro-mechanical relays contain moving parts and are prone to failure as they age, wear and accumulate dirt and dust. In the past five years Newfoundland Power has experienced increasing numbers of electro-mechanical relay failures.

14 The potential for transformer damage is decreased with improved protection.

Twillingate Substation ($770,000)

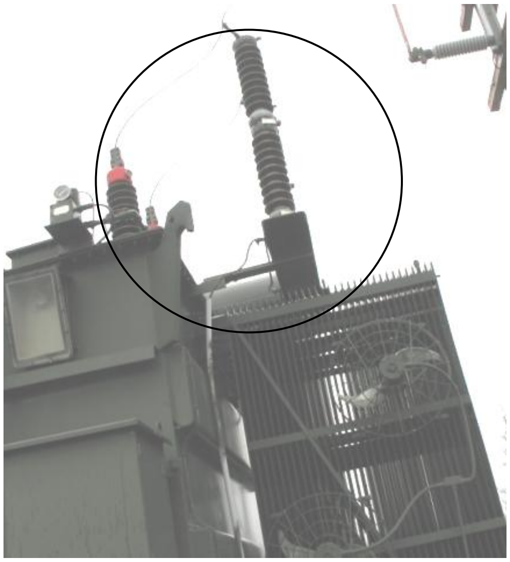
Twillingate ("TWG") substation was built in 1976 as a distribution substation. Transmission line 140L from Summerford terminates at switch T1-A. Transformer TWG-T1 is a 13.3 MVA, 66 kV to 12.5 kV power transformer terminated at a 12.5 kV bus structure. The substation services 1,650 customers in the area of Twillingate through 3 feeders.

Twillingate Substation Location

Maintenance records and on-site engineering assessments show that the 66kV and 12.5 kV wooden structures, foundations, buses and insulators are all in good condition. Standard varmint protection and vegetation management practices will be implemented.


12.5 kV Wooden Structures & Bus

The power transformer TWG-T1 is in good condition. However, the lightning arrestors on this transformer are silicon carbide and will be replaced with metal oxide arrestors.[15]



Power Transformer with Silicon Carbide Arrestors

The 66 kV air-break switch used to isolate power transformer TWG-T1 is deteriorated and will be replaced with a motorized air-break switch to improve the transformer protection.

The 3 hydraulic reclosers will be replaced with Nulec reclosers and will be automated for monitoring and control from the System Control Center.[16] The automation equipment, transformer protection and recloser controls will be installed in a new small control building. A 125 VDC battery bank and charger will be added. With feeder automation, the Twillingate feeders will be added to the provincial under-frequency load shedding scheme.

[15] Report ***2.1*** *Substation Strategic Plan* included with the 2007 Capital Budget Application identified that until the early 1980's silicon carbide lightning arrestors were standard. The Company has experienced increasing failures of this type of arrestor as they age due to water leaking into the arrestor through failed seals.

[16] Monitoring and control of Nuclec reclosers from the System Control Center will result in real time detection of trouble on the distribution feeder and provide for remote restoration of service. Also, the System Control Center will be able to remotely de-energize feeders in emergency situations thus enhancing employee and public safety.

Hydraulic Recloser on TWG-03 Feeder

The 12.5 kV oil-filled metering tank is deteriorated and will be replaced with an oil free unit.

The ground grid for the substation will be extended to improve safety for personnel inside the substation.

Kenmount Substation ($200,000)

Kenmount Substation (KEN) was built in 1975 as a transmission and distribution substation. The substation contains two 66 kV to 25 kV distribution power transformers each with a capacity of 25 MVA. The substation serves approximately 7,184 customers in the Kenmount Road area and west end of the City of St. John’s through four 25 kV feeders. In the substation there are three 66 kV transmission lines terminated in the high voltage bus, these being transmission lines 54L to Hardwoods substation, 69L to Stamps Lane substation and 35L to Oxen Pond substation.

During significant rain events the access road to the substation has flooded.[17] Access to the substation was disrupted during each flooding event. The photo below shows the substation access road during Hurricane Igor on September 21, 2010. Water also entered the substation and flooded the cable trenches and the control building.[18] Access to the substation was disrupted for two days during Hurricane Igor.[19]

17 Recent flood events include hurricane Gabrielle in 2001, a heavy rain storm in November 2009 and the most recent during Hurricane Igor in 2010.

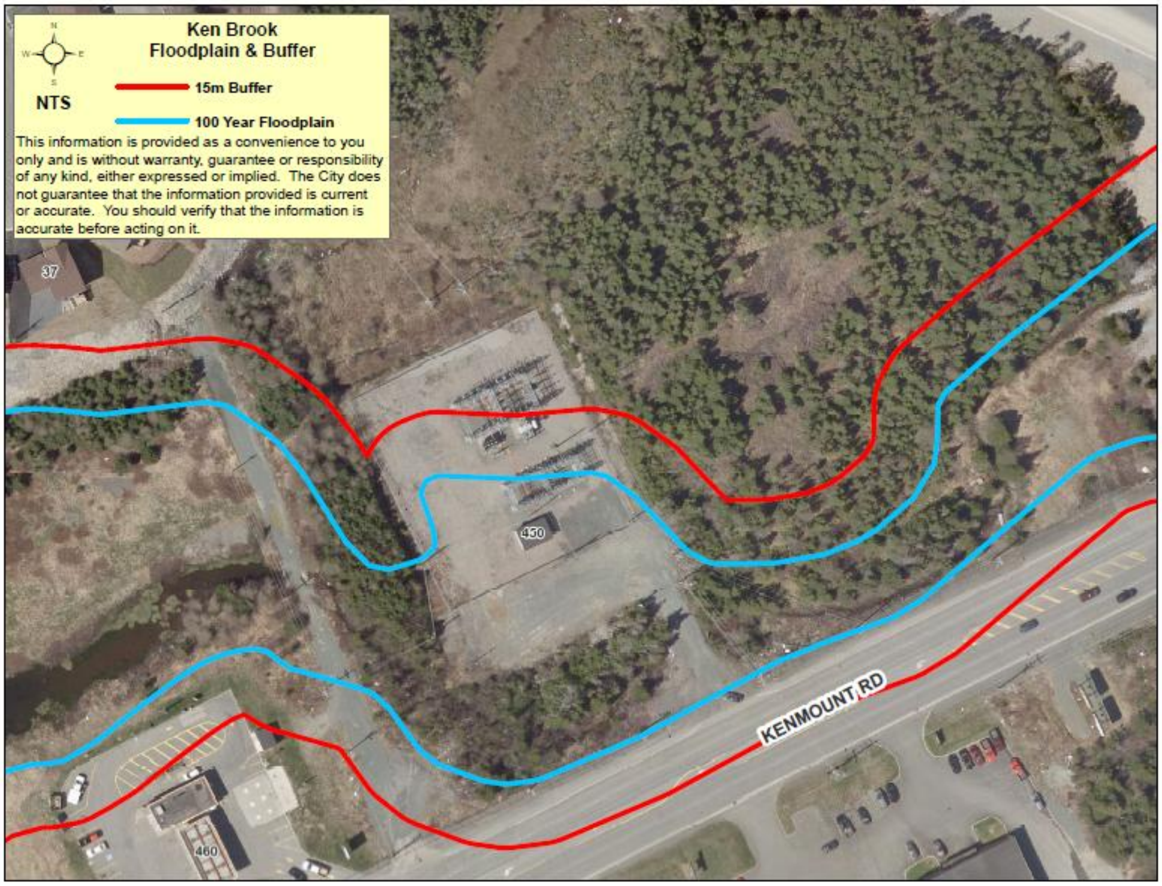
18 Standing flood water in a substation poses a significant safety hazard to workers.

19 Completing work in Kenmount substation during flood conditions will reduce response time and result in longer customer outages if line trucks or other equipment are unable to access the substation.

Flooded Access Road to Kenmount Substation During Hurricane Igor

Flood mapping provided by the City of St. John's shows that the Kenmount Substation is located within a flood plain. With the amount of housing and commercial development ongoing in the area it is anticipated that flood events will be more severe in the future as runoff from these developments is adding to the stream flow on the south side of the substation.[20] Due to the development in the area the design capacity of the access road culvert is no longer adequate for the change in flow during peak rain events. The existing access road to the substation has a 1,525 mm culvert with a cross sectional area of 1.82 m^2 to pass water. In comparison about 150 metres downstream on Ladysmith Drive the City of St. John's has recently installed a 6100 mm × 2290 mm box culvert with a cross sectional area of 14 m^2. The box culvert installed by the City of St. John's has a cross sectional area 7.7 times larger to pass flow from the same stream.

[20] Runoff from a drainage area is a function of the ground surface. Undeveloped areas have a low runoff as the lack of development allows much of the water to infiltrate the soil. Fully developed areas have a higher runoff as these areas tend to have harder asphalt and concrete surfaces which allow less water to infiltrate the soil.



Kenmount Road Substation
1 in 100 Year Flood Plain[21]

To address the flooding problems a new access road will be constructed on the west end of the substation with a larger culvert system to handle the design flood. In addition, a berm will be constructed along the west side of the substation and connected to the access road to provide improved flood protection to the substation.

2.2 Substation Monitoring and Operations ($432,000)

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

In 2013, upgrades to the communications hubs that connect multiple devices in substations to the SCADA system are planned. Effective management of increased volumes of electrical system data requires the upgrading of the hubs. This requires both hardware and software upgrades.

[21] The blue contour line identifies the 100 year floodplain, while the red contour line identifies a 15 metre buffer around the floodplain. Photograph provided by the City of St. John's Planning Department.

In 2013, the required work will incorporate manufacturers' upgrades to communications and other computer-based equipment located in Company substations. These upgrades typically increase functionality of the equipment and software and remedy known deficiencies.

Newfoundland Power receives electricity supply from multiple Hydro infeed locations at various substations throughout its service territory. Many of these infeed locations are monitored through meters connected to the Company's SCADA system. This item involves installing meters and communications equipment at 13 Hydro infeed locations to collect these data points on the Company's SCADA system. These additional data points will provide Newfoundland Power with a more accurate measurement of the total instantaneous system load.

Appendix A
Substation Refurbishment and Modernization Plan
Five-Year Forecast 2013 to 2017

Substation Refurbishment and Modernization Plan
Five-Year Forecast
2013 to 2017
(000s)

2013		2014		2015		2016		2017	
SUB	**Cost**	**SUB**	**Cost**	**SUB**	**Cost**	**SUB**	**Cost**	**SUB**	**Cost**
STV	732	CAR	1,269	BRB	1,796	CAT	2,267	BVA	804
P4	790	ILC	227	BVS	1,090	HUM	2,221	CLV	2,497
SCT	561	MAS	676	RRD	1,084	P1	736	HCP	502
GLN	967	SPR	589	SPO	1,417	SMU	165	TBS	313
TWG	770	STX	372	VIC	1,539			WAL	1,630
KEN	200	SMU	155	SMU	160			NCH	1,510
SMU	432							SMU	170
	$4,452		**$3,288**		**$7,086**		**$5,389**		**$7,426**

Note: SUB: Substation - Refer to the Electrical System handbook included with the 2006 Capital Budget Application for three letter substation designations. P1, P3 and P4 are the designations for the portable substations.

2012 Substation Refurbishment and Modernization
June 2011

2012 Substation Refurbishment and Modernization

June 2011

Prepared by:

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NEWFOUNDLAND POWER
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1.0 Substation Refurbishment and Modernization Strategy

Newfoundland Power (the "Company") has 130 substations located throughout its operating territory. Distribution substations connect the low voltage distribution system to the high voltage transmission system. Transmission substations connect transmission lines of different voltages. Generation substations connect generating plants to the electrical system. Substations are critical to reliability; an unplanned substation outage will affect thousands of customers. The Company's substation maintenance program and the Substation Refurbishment and Modernization project ensure the delivery of reliable least cost electricity to customers in a safe and environmentally responsible manner.

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

When updating the substation strategic refurbishment and modernization plan substations are assessed with particular consideration given to the condition of the infrastructure and equipment, and the need to upgrade and modernize protection and control systems. This assessment is used to establish the priority for substation work.

Much of this work requires the power transformer to be removed from service; and, therefore, the timing of the work is restricted to the availability of the portable substation and the capacity of the portable substation to meet the load requirement. In many circumstances, this requires the work to be completed in the late spring and summer when the substation load is reduced.

In the *Substation Strategic Plan* filed with the Company's 2007 Capital Budget Application, it was indicated that expenditures under the Substation Refurbishment and Modernization project were expected to average approximately $4 million per year. In 2012, the budget estimate is materially below this level due to a requirement to address government regulations concerning polychlorinated biphenyls ("PCB")[1] and the requirement to address additions due to load growth.[2] Also, the 2012 projects at Hearts Content and New Grand Falls substations were originally included in the 2011 Substation Refurbishment and Modernization project. Due to the significant impact of the two storms experienced in 2010, the 2011 plan was revised and these projects delayed until 2012.[3] Such developments highlight the practical requirement for flexibility in execution of the Substation Refurbishment and Modernization project over time.

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1 A description of the work required to meet the new PCB regulations established by Environment Canada can be found in ***2.3*** *2012 PCB Removal Strategy*.

2 The Company has reduced Substation Refurbishment and Modernization project expenditures in 2012 in order to moderate the overall increase in the substation capital budget. A degree of flexibility is necessarily required for ongoing planning of capital expenditures if a reasonable degree of stability in the Company's annual capital budgets is to be achieved. In Order No. P.U. 36 (2002-2003) the Board stated that it believes more stable and predictable year over year capital budgets for Newfoundland Power is a desirable objective.

3 Storm related work associated with the March 2010 ice storm and Hurricane Igor in September 2010 caused planned work in 2010 to be delayed or deferred.

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

2.0 Substation Refurbishment and Modernization 2012 Projects

2012 Substation Projects include planned refurbishment and modernization projects of two substations and one portable substation. Items Under $50,000 include the installation of petro plug devices in eight substations to permit continuous draining of water from spill containment pans. Substation Monitoring and Operations includes upgrades to substation communication systems to accommodate increased data requirements.

Table 1
2012 Substation Refurbishment and Modernization Projects
(000s)

Project	Budget
2012 Substation Projects	
Hearts Content Substation (HCT)	*$1,243*
Portable Substation 4 (P4)	*$100*
New Grand Falls Substation (NGF)	*$899*
Items Under $50,000	$90
Substation Monitoring and Operations	$150
Total	**$2,482**

2.1 2012 Substation Projects ($2,482,000)

Hearts Content Substation ($1,243,000)

Hearts Content substation (HCT) was built in 1956 as a generation substation and over the years has developed also into a distribution substation. The substation contains one 66 kV to 12.5 kV distribution power transformer T3 with a capacity of 2.3 MVA and one 66kV to 2.4 kV generation power transformer T1 with a capacity of 3 MVA.

The substation directly serves approximately 450 customers in the Hearts Content area through one 12.5 kV feeder. In the substation there are three 66 kV transmission lines terminated in the high voltage bus. These are transmission lines 41L to Carbonear substation, 43L to New Chelsea substation and 80L to Islington substation.

Hearts Content Substation Location

Maintenance records and on-site engineering assessments show that the 66 kV steel structures and bus are in good condition. Some of the structure foundations are in poor condition as anchor bolts have rusted off. These foundations will be replaced.

The 66 kV potential transformers will be replaced as their enclosures have deteriorated significantly over their 39 years of service. The 66 kV power fuse holders for T1 have experienced arcing and require replacement.

The power cables for T1 and T3 are 1966 and 1971 vintage, are deteriorated and will be replaced.[4] The lightning arrestors on the 66 kV side of T1 are gap type and will be replaced with new metal oxide arrestors.[5]

The protection relays for the transmission lines and 66 kV bus protection are 1972 vintage electromechanical type and will be replaced with new microprocessor based relays[6].

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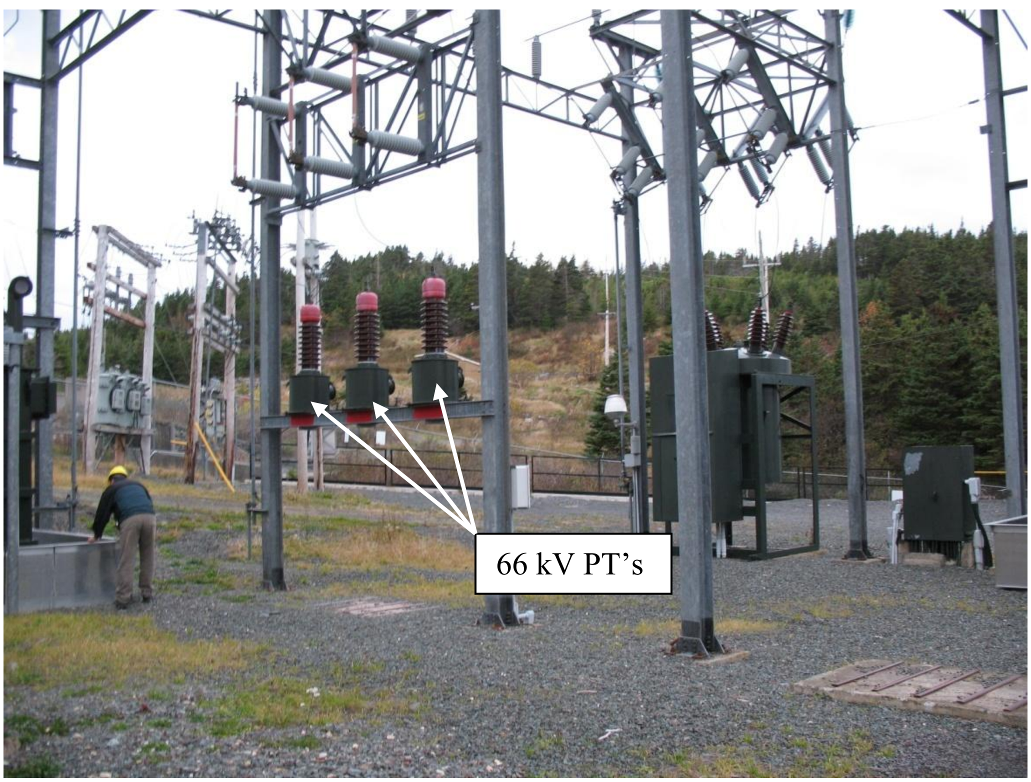
4 Report ***2.1*** *Substation Strategic Plan* included with the 2007 Capital Budget Application identified that power cable failures begin to occur when cables are about 35 years old. The Heart's Content power cables are 39 and 44 years of age and will be replaced during the 2012 refurbishment and modernization of the substation.

5 Report ***2.1*** *Substation Strategic Plan* included with the 2007 Capital Budget Application identified that until the early 1980's silicon carbide lightning arrestors were standard. The Company has experienced increasing failures of this type of arrestor as they age due to water leaking into the arrestor through failed seals.

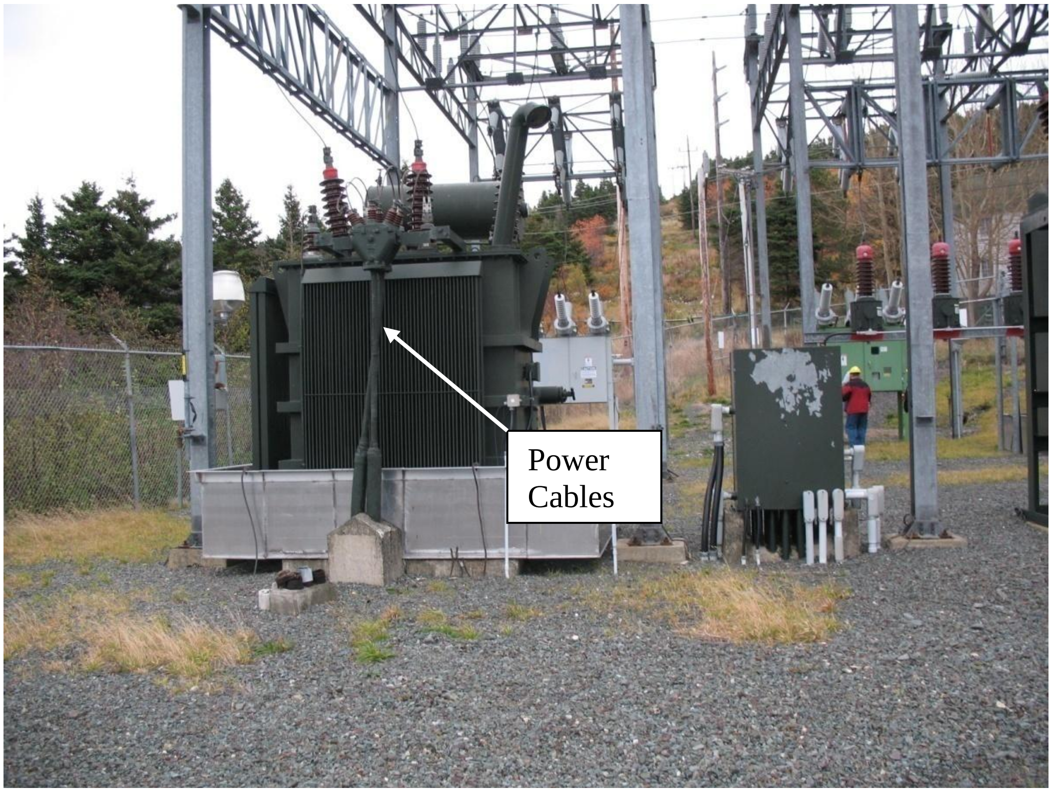
6 Report ***2.1*** *Substation Strategic Plan* included with the 2007 Capital Budget Application identified that electro-mechanical relays contain moving parts and are prone to failure as they age, wear and accumulate dirt and dust. In the past five years Newfoundland Power has experienced increasing numbers of electro-mechanical relay failures.

The fence is showing significant deterioration and sections will be refurbished or replaced. There have been issues with flooding in the station and drainage improvements will be made to prevent re-occurrence. The ground grid for the substation will be extended to improve safety for personnel inside the substation

Severe Rusting On Anchor Bolt



39 Year Old Potential Transformers



1966 Vintage Power Cables

Damage Due To Flooding

Portable Substation P4 ($100,000)

Portable substation P4 was purchased in 1992. It is used to respond to power transformer failures and for planned transformer maintenance and substation refurbishment and modernization work.[7] P4 can provide backup for 70% of the 192 power transformers in service on Newfoundland Power's system.

Portable Substation P4

In 2012 engineering for the refurbishment will be completed with the actual refurbishment taking place in 2013. This is the first comprehensive refurbishment of this portable substation since its purchase. Refurbishment of portable substation P4 will ensure its continued availability for the next decade.

Based upon preliminary inspections, the following work will be required to be undertaken in 2013. The engineering work undertaken in 2012 will finalize scope of work for 2013, and Newfoundland Power will submit the scope of work and cost estimate for Board approval in the 2013 capital budget application.

[7] Portable Substation P4 will be used extensively during the PCB Phase Out program to minimize customer outage minutes to the extent possible.

The trailer will undergo an overhaul addressing rust damage and applying a rust inhibiting coating to the chassis. A fall arrest system and work platforms will be installed in areas where employees have to work aloft. External lighting will be provided at locations around the trailer.

The alarm annunciation panel has had several failures and will be replaced. The protection relays will be replaced with microprocessor based protection relays.[8] A digital metering system for power, voltage and current will be provided.

The control wiring associated with the protection and control of the portable substation is original wiring showing signs of deterioration and will be replaced. Deteriorated termination and junction boxes will be replaced.

Online monitoring of transformer gas and oil analysis will be provided to protect the transformer. High voltage linkages connecting the power transformer to the switches are deteriorated and will be replaced. The batteries and charging system are at the end of life and will be replaced.

A SCADA remote terminal unit will be installed on the portable substation to provide remote monitoring and control capability of the unit.

New Grand Falls Substation ($899,000)

New Grand Falls substation was built in 1976 as both a transmission and distribution substation. The transmission portion of the substation contains one 138 kV to 66 kV, 30 MVA power transformer T1. There are two 138 kV transmission lines terminated in the substation, 130L to Newfoundland & Labrador Hydro's substation at Stoney Brook and 132L to Bishop Falls substation. There are two 66 kV transmission lines terminated in the substation, 101L to Rattling Brook substation and a 66 kV tie to Grand Falls substation. There are two 138 kV to 25 kV distribution power transformers T2 and T3. Each distribution power transformer has a capacity of 20 MVA at 25 kV. The substation directly serves approximately 6,000 customers in the Grand Falls area through five 25 kV feeders.

8 Report ***2.1*** *Substation Strategic Plan* included with the 2007 Capital Budget Application identified that electro-mechanical relays contain moving parts and are prone to failure as they age, wear and accumulate dirt and dust. In the past five years Newfoundland Power has experienced increasing numbers of electro-mechanical relay failures.

New Grand Falls Substation Location

Maintenance records and on-site engineering assessments show that the 138 kV, 66 kV and 25 kV steel structures, foundations, buses and insulators are in good condition.

138kV & 25 kV Steel Structures & Bus

The three power transformers T1, T2 and T3 are in good condition. The lightning arrestors on the transformers are silicon carbide and will be replaced with metal oxide arrestors.[9]

The power cable and terminations for T2 are 35 years old, are approaching the end of their anticipated useful life, and will be replaced.[10] The 138 kV air-break switch for transformer T2 no longer operates reliably and will be replaced.

The 25 kV potential transformers and 66 kV potential transformers on 101L show significant deterioration and will be replaced. A new set of 25 kV potential transformers will be installed on the 25 kV bus of transformer T3 for protection and monitoring when T2 & T3 transformers are not operating in parallel.

66 kV potential Transformers

The relays for the transmission lines and bus protection are 1976 vintage electromechanical type and will be replaced with new microprocessor based relays[11].

9 Report ***2.1*** *Substation Strategic Plan* included with the 2007 Capital Budget Application identified that until the early 1980's silicon carbide lightning arrestors were standard. The Company has experienced increasing failures of this type of arrestor as they age due to water leaking into the arrestor through failed seals.

10 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. The Grand Fall's power cables are 35 years of age and will be replaced during the 2011 refurbishment and modernization of the substation.

11 Report ***2.1*** *Substation Strategic Plan* included with the 2007 Capital Budget Application identified that electro-mechanical relays contain moving parts and are prone to failure as they age, wear and accumulate dirt and dust. In the past five years Newfoundland Power has experienced increasing numbers of electro-mechanical relay failures.

Transmission Line Electromechanical Relays

The ground grid for the substation will be extended to improve safety for personnel inside the substation.

2.2 Items Under $50,000 ($90,000)

The 2012 Substation Refurbishment and Modernization project includes a number of smaller items that must be addressed in the near future, and cannot wait for a more comprehensive refurbishment of the substation. Petro plug devices are to be installed in eight locations to allow continuous draining of water from spill containment pans without endangering the environment.

2.3 Substation Monitoring and Operations ($150,000)

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

In 2012, upgrades to the communications hubs that connect multiple devices in substations to the SCADA system are planned. Effective management of increased volumes of electrical system data requires the upgrading of the hubs. This requires both hardware and software upgrades.

In 2012, the required work will incorporate manufacturers' upgrades to communications and other computer-based equipment located in Company substations. These upgrades typically increase functionality of the equipment and software and remedy known deficiencies.

Appendix A

Substation Refurbishment and Modernization Plan
Five-Year Forecast 2012 to 2016

Substation Refurbishment and Modernization Plan
Five-Year Forecast
2012 to 2016
(000s)

2012		2013		2014		2015		2016	
SUB	**Cost**	**SUB**	**Cost**	**SUB**	**Cost**	**SUB**	**Cost**	**SUB**	**Cost**
HCT	1,243	STV	554	CAR	791	BRB	1,327	BVA	670
P4	100	P4	684	GLN	411	BVS	969	HUM	1,300
NGF	899	SCT	222	ILC	104	CAT	2,008	P1	716
Misc	90	KEN	102	MAS	603	GBE	128	WAL	1,087
SMU	150	SMU	150	RRD	808	NCH	1,214	SMU	150
				SPO	1,166	TWG	274		
				SPR	445	SMU	150		
				STX	238				
				VIC	1,210				
				SMU	150				
	$2,482		**$1,712**		**$5,926**		**$6,070**		**$3,923**

Note: SUB: Substation - Refer to the Electrical System handbook included with the 2006 Capital Budget Application for three letter substation designations. P1, P3 and P4 are the designations for the portable substations.

2011 Substation Refurbishment and Modernization
June 2010

2011 Substation Refurbishment and Modernization

June 2010

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1.0 Substation Refurbishment and Modernization Strategy

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

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

In preparation of annual capital budgets, substations are assessed with particular consideration given to the condition of the infrastructure and equipment and the need to upgrade and modernize protection and control systems. This assessment is used to establish the priority for substation work.

Much of this work requires the power transformer to be removed from service; and, therefore, the timing of the work is restricted to the availability of the portable substation and the capacity of the portable substation to meet the load requirement. In many circumstances, this requires the work to be completed in the late spring and summer when the substation load is light.

In the *Substation Strategic Plan* filed with the Company's 2007 Capital Budget Application, it was indicated that expenditures under the Substation Refurbishment and Modernization project were expected to average approximately $4 million per year. Expenditure is currently expected to reach this level in 2010. In 2011, the budget estimate is materially below this level due to a requirement to address government regulations concerning polychlorinated biphenyls ("PCB").[1] Such developments highlight the practical requirement for flexibility in execution of the Substation Refurbishment and Modernization project over time.

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

2.0 Substation Refurbishment and Modernization 2011 Projects

The 2011 Substation Refurbishment and Modernization Project includes planned refurbishment and modernization work on 4 substations and one of the Company's portable substations. This work is estimated to cost a total of $2,753,000, which comprises approximately 90% of total 2011 project costs. Silicon carbide lightning arrestors are planned to be replaced in an additional 2 substations on a priority basis. Petro plug devices are planned to be installed in 8 substations to permit continuous draining of water from spill containment pans. Protection improvements are planned for 2 substations. These improvements are estimated to cost a total of $171,000, which comprises approximately 6% of total 2011 project costs. Finally, system monitoring and

[1] A description of the work required to meet the new PCB regulations established by Environment Canada can be found in ***2.3*** *2011 PCB Removal Strategy*.

operations technology upgrades are planned at $150,000. This comprises approximately 5% of total 2011 project costs.

The refurbishment of Portable Substation P3, with the exception of the engineering work which is being completed in 2010, is included with the 2011 Refurbishment and Modernization project. The reason for not completing the refurbishment of P3 in 2010 is that the scheduled use of the portable substation in 2010 did not allow sufficient time to complete the refurbishment. A similar project to upgrade Portable Substation P4 was scheduled for 2011 and has been re-scheduled to 2012. Delaying the refurbishment of P4 to 2012 is required since it is not possible to upgrade both portable substations in 2011 and still complete the planned substation capital and maintenance programs.

Table 1
2011 Substation Projects
(000s)

Substation	**Budget**
Heart's Content (HCT)	$1,007
Portable Substation 3 (P3)	440
Port aux Basques (PAB)	440
New Grand Falls (NGF)	707
Stamps Lane (SLA)	159
Items Under $50,000	171
Substation Monitoring	150
Total	**$3,074**

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

2.1 Heart's Content Substation ($1,007,000)

Heart's Content substation was built in 1956 as a generation substation and over the years has developed into a distribution substation. The substation contains one 66 kV to 12.5 kV distribution power transformer T3 with a capacity of 2.3 MVA and one 66kV to 2.4 kV generation power transformer T1 with a capacity of 3 MVA.

The substation directly serves approximately 450 customers in the Heart's Content area through one 12.5 kV feeder. In the substation there are three 66 kV transmission lines terminated on the high voltage bus, transmission lines 41L to Carbonear substation, 43L to New Chelsea substation and 80L to Islington substation.

Heart's Content Substation Location

Maintenance records and on-site engineering assessments show that the 66 kV steel structures and bus are in good condition. Some of the structure foundations are in poor condition as anchor bolts have rusted off. These foundations will be replaced.

The 66 kV potential transformers will be replaced as their enclosures have deteriorated significantly over their 39 years of service. The 66 kV power fuse holders for T1 have experienced arcing and require replacement.

The power cables for both T1 and T3 are 1966 and 1971 vintage, are deteriorated and will be replaced.[2] The lightning arrestors on the 66 kV side of T1 are gap type and will be replaced with new metal oxide arrestors.[3]

The protection relays for the transmission lines and 66 kV bus protection are 1972 vintage electro mechanical type and will be replaced with new micro processor based relays[4].

The fence is showing significant deterioration and sections will be refurbished or replaced. There have been issues with flooding in the station and drainage improvements will be made to prevent re-occurrence. The ground grid for the substation will be extended to improve safety for personnel inside the substation

2 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. The Heart's Content power cables are 39 and 44 years of age and will be replaced during the 2011 refurbishment and modernization of the substation.

3 Report ***2.1*** *Substation Strategic Plan* included with the 2007 Capital Budget Application identified that until the early 1980's silicon carbide lightning arrestors were standard. The Company has experienced increasing failures of this type of arrestor as they age due to water leaking into the arrestor through failed seals.

4 Report ***2.1*** *Substation Strategic Plan* included with the 2007 Capital Budget Application identified that electro-mechanical relays contain moving parts and are prone to failure as they age, wear and accumulate dirt and dust. In the past five years Newfoundland Power has experienced increasing numbers of electro-mechanical relay failures.

Severe Rusting On Anchor Bolt

39 Year Old Potential Transformers

1966 Vintage Power Cables

Damage Due To Flooding

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2.2 Portable Substation P3 ($440,000)

Portable substation P3 was purchased in 1977. It is used to respond to power transformer failures and for carrying out planned transformer and substation maintenance. Of the approximate 190 power transformers in service on Newfoundland Power's system, P3 can provide backup for 68% of them.

Portable Substation P3

This is the first comprehensive refurbishment of this portable substation since its purchase over thirty years ago. Purchase of a comparable new portable substation would cost approximately $5 million. Refurbishment of portable substation P3 will ensure its continued availability for the next decade.

The trailer will undergo an overhaul addressing rust damage and applying a rust inhibiting coating to the chassis. The manual hydraulic jacks on the unit have deteriorated and they will be replaced with a motorized system. A fall arrest system and work platforms will be installed in areas when employees have to work aloft. External lighting will be provided at locations around the trailer.

The alarm annunciation panel has had several failures and will be replaced. The protection relays are 32 year old electro mechanical type and will be replaced with new electronic digital protection relays.[5] A digital metering system for power, voltage and current will be provided.

The control wiring associated with the protection and control of the portable substation is original wiring showing signs of deterioration and will be replaced. Deteriorated termination and junction boxes will be replaced.

5 Report ***2.1*** *Substation Strategic Plan* included with the 2007 Capital Budget Application identified that electro-mechanical relays contain moving parts and are prone to failure as they age, wear and accumulate dirt and dust. In the past five years Newfoundland Power has experienced increasing numbers of electro-mechanical relay failures.

Online monitoring of transformer gas and oil analysis will be provided to protect the transformer. High voltage linkages connecting the power transformer to the switches are deteriorated and will be replaced. The batteries and charging system are at the end of life and will be replaced.

A SCADA remote terminal unit will be installed on the portable substation to provide remote monitoring and control capability of the unit.

2.3 Port aux Basques Substation ($440,000)

Port aux Basques substation was built in 1946. Today it is a distribution substation and a generation substation. The distribution substation contains one power transformer T5 with a capacity of 13.3 MVA at 12.5 kV. The station also contains one 4.16 kV to 12.5 kV generation transformer T3 with a capacity of 3 MVA connecting a 2.5 MW diesel generator to the electricity system. The substation directly services approximately 1,400 customers in the Port aux Basques area through four 12.5 kV outdoor feeders. There is one 66 kV radial transmission line 417L terminated in the substation.

Port aux Basques Substation Location

The power transformers T3 and T5 are in good condition. The lightning arrestors on the transformers are silicon carbide and require replacement with metal oxide arrestors[6].

Maintenance records and on-site engineering assessments show the 66 kV wood pole structure and 12.5 kV steel structures are in good condition. The concrete foundations, buses and insulators are in good condition. However, the retaining wall for the substation is deteriorated and will be replaced.

[6] Report ***2.1*** *Substation Strategic Plan* included with the 2007 Capital Budget Application identified that until the early 1980's silicon carbide lightning arrestors were standard. The Company has experienced increasing failures of this type of arrestor as they age due to water leaking into the arrestor through failed seals.

Deteriorated Retaining Wall

The new retaining wall will enclose a larger area than is currently enclosed and new fencing will be installed along the top of the retaining wall to replace the existing deteriorated fencing.

Fencing Along Retaining Wall Side

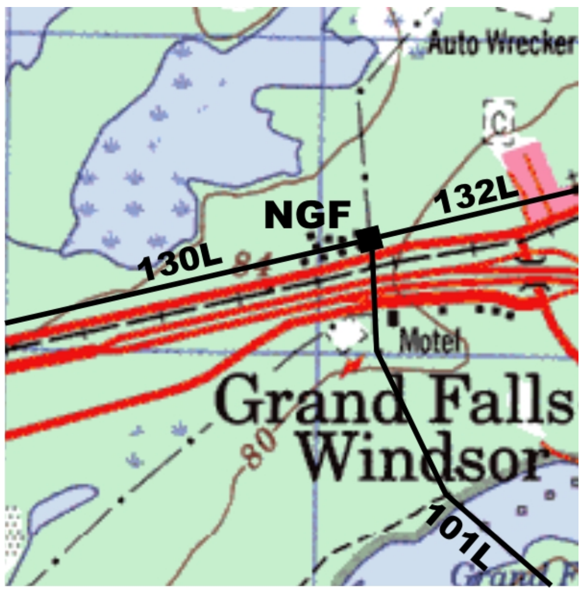
The 12.5 kV metering tank will be replaced with a dry type unit. The feeders have Nulec reclosers installed and these will be automated for control from the System Control Centre[7].

[7] Monitoring and control of the Nulec reclosers from the System Control Centre will result in real time detection of trouble on the distribution feeders and provide for remote restoration of service. Also, the System Control Centre will be able to remotely de-energize feeders in emergency situations thus enhancing employee and public safety.

The ground grid for the substation will be extended to improve safety for personnel inside the substation.

2.4 New Grand Falls Substation ($707,000)

New Grand Falls substation was built in 1976 as both a transmission and distribution substation. The transmission portion of the substation contains one 138 kV to 66 kV, 30 MVA power transformer T1. There are two 138 kV transmission lines terminated in the substation, 130L to Newfoundland & Labrador Hydro's substation at Stoney Brook and 136L to Bishop Falls substation. There are two 66 kV transmission lines terminated in the substation, 101L to Rattling Brook substation and a 66 kV tie to Grand Falls substation. There are two distribution power transformers T2 and T3. Each distribution transformer has a capacity of 20 MVA at 25 kV. The substation directly serves approximately 5,800 customers in the Grand Falls area through five 25 kV feeders.



New Grand Falls Substation Location

Maintenance records and on-site engineering assessments show that the 138 kV, 66 kV and 25 kV steel structures, foundations, buses and insulators are in good condition.

138kV & 25 kV Steel Structures & Bus

The three power transformers T1, T2 and T3 are in good condition. The lightning arrestors on the transformers are silicon carbide and will be replaced with metal oxide arrestors.[8]

The power cable and terminations for T2 are thirty four years old, are approaching the end of their anticipated useful life and will be replaced.[9] The 138 kV air-break switch for transformer T2 no longer operates reliably and will be replaced.

The 25 kV potential transformers and 66 kV potential transformers on 101L show significant deterioration and will be replaced. A new set of 25 kV potential transformers will be installed on the 25 kV bus of transformer T3 for protection and monitoring when T2 & T3 transformers are not operating in parallel.

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8 Report ***2.1*** *Substation Strategic Plan* included with the 2007 Capital Budget Application identified that until the early 1980's silicon carbide lightning arrestors were standard. The Company has experienced increasing failures of this type of arrestor as they age due to water leaking into the arrestor through failed seals.

9 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. The Grand Fall's power cables are 34 years of age and will be replaced during the 2011 refurbishment and modernization of the substation.

66 kV potential Transformers

The relays for the transmission lines are 1976 vintage electro mechanical type and will be replaced with new micro processor based relays[10].

Transmission Line Electro Mechanical Relays

10 Report ***2.1*** *Substation Strategic Plan* included with the 2007 Capital Budget Application identified that electro-mechanical relays contain moving parts and are prone to failure as they age, wear and accumulate dirt and dust. In the past five years Newfoundland Power has experienced increasing numbers of electro-mechanical relay failures.

The ground grid for the substation will be extended to improve safety for personnel inside the substation.

2.5 Stamps Lane Substation ($159,000)

Stamp's Lane substation was built in 1963 as a 66 kV transmission switching substation and as a 4.16 kV and a 12.5 kV distribution substation. The distribution substation contains four power transformers (T1, T2, T3 & T4) with a combined capacity of 50 MVA at 12.5 kV and 21 MVA at 4.16 kV. The substation directly services approximately 9,400 customers in the central area of St. John's through five 4.16 kV metal clad switchgear feeders and six 12.5 kV outdoor feeders. There are six 66 kV transmission lines terminated in the substation. These are transmission lines 13L to St. John's Main substation, 14L to Memorial substation, 15L to Molloy's Lane substation, 69L to Kenmount substation and 31L and 70L to Oxen Pond substation.

Stamps Lane Substation Location

In 2007 Stamp's Lane substation underwent a refurbishment and modernization project that addressed deterioration of concrete foundations and power cables, along with protective relay upgrades on 11 distribution feeders. Recent engineering assessments have determined that the 66 kV and 12.5 kV steel structures and 4.16 kV metal clad switchgear remain in good condition. Concrete foundations remain in good condition.

The five transmission line relays are an older vintage micro processor based relay and the manufacturer has identified a deficiency with these relays. New relays will replace the defective relaying on the five transmission lines.[11]

[11] Report ***2.1*** *Substation Strategic Plan* included with the 2007 Capital Budget Application identified that electro-mechanical relays contain moving parts and are prone to failure as they age, wear and accumulate dirt and dust. In the past five years Newfoundland Power has experienced increasing numbers of electro-mechanical relay failures.

The radiators on transformer T2 are corroded in several locations. Temporary repairs were completed in 2007 to prevent oil leaks. Due to the advanced level of corrosion the radiators on transformer T2 will be replaced in 2011.

Patched Radiator on SLA-T2

2.6 Items Under $50,000 ($171,000)

The 2011 Substation Refurbishment and Modernization project includes a number of smaller items that must be addressed in the near future, and cannot wait for a more comprehensive refurbishment of the substation. The replacement of lightning arrestors in two locations receives priority because of the risk of customer outages related to existing lightning arrestor failure. Petro plug devices are to be installed in eight locations to allow continuous draining of water from spill containment pans without endangering the environment. Protection upgrades are planned in two substations.

2.7 Substation Monitoring and Operations ($150,000)

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

In 2011, upgrades to the communications hubs that connect multiple devices in substations to the SCADA system are planned. Effective management of increased volumes of electrical system data requires the upgrading of the hubs. This requires both hardware and software upgrades.

In 2011, the required work will incorporate manufacturers' upgrades to communications and other computer-based equipment located in Company substations. These upgrades typically increase functionality of the equipment and software and remedy known deficiencies.

Appendix A

Substation Refurbishment and Modernization Plan
Five-Year Forecast 2011 to 2015

Substation Refurbishment and Modernization Plan
Five-Year Forecast
2011 to 2015
(000s)

2011		**2012**		**2013**		**2014**		**2015**	
SUB	**Cost**	**SUB**	**Cost**	**SUB**	**Cost**	**SUB**	**Cost**	**SUB**	**Cost**
HCT	1,007	SPO	823	NCH	1,016	CAT	1,672	BRB	1,205
PAB	440	P4	610	CAR	698	VIC	1,058	FRN	1,016
P3	440	SCT	197	MAS	506	GLN	394	GBE	107
NGF	707	STV	495	SMU	150	TWG	248	GBS	1.074
SLA	159	Misc	90			SPR	397	STX	230
Misc	171	SMU	150			ILC	90	WAL	945
SMU	150					SMU	50	Misc	210
								SMU	50
	$3,074		**$2,365**		**$2,370**		**$3,909**		**$4,837**

Note: SUB: Substation - Refer to the Electrical System handbook included with the 2006 Capital Budget Application for three letter substation designations. P1, P3 and P4 are the designations for the portable substations.

2010 Substation Refurbishment and Modernization
June 2009

2010 Substation Refurbishment and Modernization

June 2009

Prepared by:

G. Richard Spurrell, P.Eng.

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PROVINCE OF NEWFOUNDLAND

NEWFOUNDLAND POWER
A FORTIS COMPANY

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1.0 Substation Refurbishment and Modernization Strategy

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

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

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

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

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

2.0 2010 Substation Refurbishment and Modernization Project

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

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

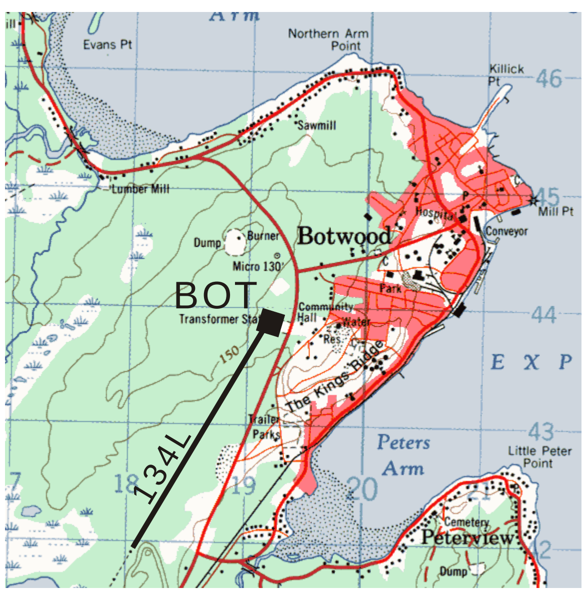
Table 1
2010 Substation Refurbishment and Modernization
(000s)

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

The following provides a description for this work.

2.1 Botwood Substation ($837,000)

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



Botwood Substation Location

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

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

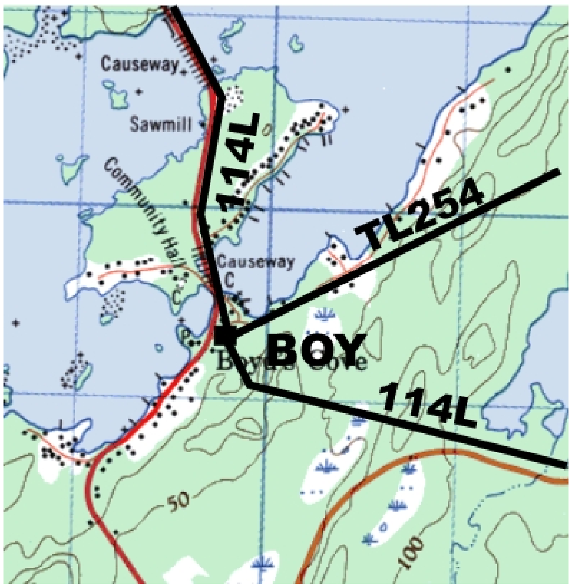
Replacement of existing hydraulic reclosers with computer-controlled reclosers and communication equipment is planned. This will permit remote monitoring of the substation and enable feeder automation, including under frequency load-shedding capability.

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

25 kV Structure Foundation

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

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



Boyd's Cove Substation Location

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

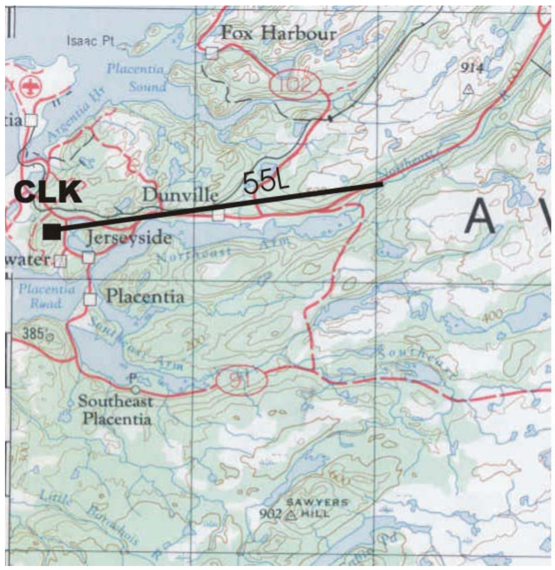
Lightning arrestors are planned to be installed for protection of the 66 kV station service transformer at this substation. Lightning arrestors will reduce the potential for future long duration outages which would result from a lightning strike at the transformer. In turn, this will improve security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

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

Station Service Transformer Structure

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

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



Clarkes Pond Substation Location

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

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

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

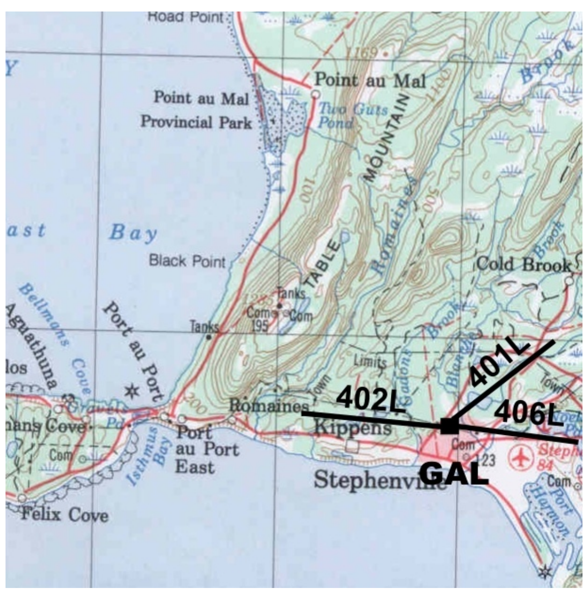
Concrete foundation repairs and protection from small animal risks also comprise part of the required work on this substation.

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

Foundation damage at Clarkes Pond Substation

2.4 Gallant Street Substation ($703,000)

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



Gallant Street Substation Location

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

Transmission Line Protection Relays

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

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

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

2.5 Gillams Substation ($138,000)

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

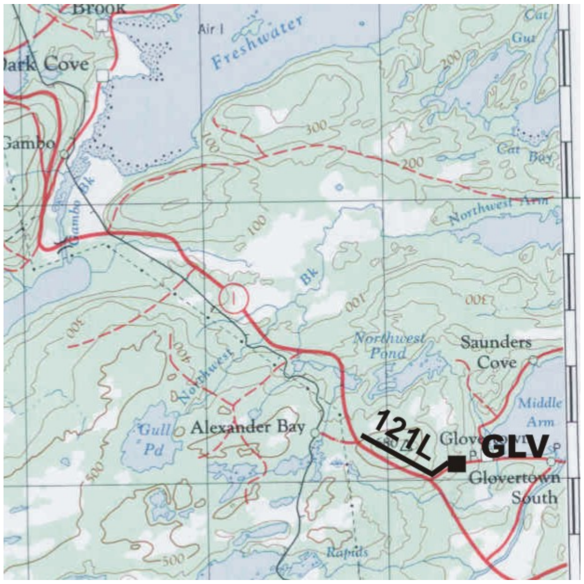
Gillams Substation Location

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

Gillams Transformer Radiator Deterioration

2.6 Glovertown Substation ($199,000)

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



Glovertown Substation Location

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

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

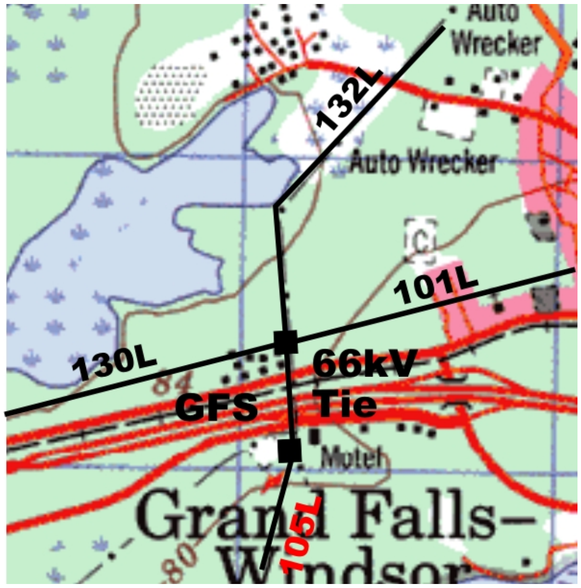
Communication equipment installation is planned to permit remote monitoring of the substation and enable feeder automation, including under frequency load-shedding capability

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

2.7 Grand Falls Substation ($797,000)

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

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



Grand Falls Substation Location

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

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

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

The fifty year old 66 kV wood pole structures in this substation are in poor condition. The structures are leaning considerably and switches will not stay in alignment. These wood pole structures will be replaced with a steel box structure in 2010.

Grand Falls Substation 66 kV Wood Pole Structures (Leaning)

The switchgear building currently houses the 4 kV equipment for the four 4 kV feeders, the transmission line protection panel and the 125 V DC battery bank in one room. A battery room will be constructed within the switchgear building for the 125 V DC battery bank and a wall constructed to separate the protection panels from the switchgear. This will provide the required thresholds of arc flash safety for personnel working in the building.

Grand Falls - Single Room Switchgear & Control Building

2.8 Springfield Substation ($138,000)

Springfield substation was built in 1976 as a 138 kV to 12 kV distribution substation. The distribution substation contains one power transformer with a capacity of 20 MVA at 12 kV. The substation directly serves approximately 2,900 customers in the Springfield area through three 12 kV feeders. There are two 138 kV transmission lines terminated in the substation. These are transmission lines 39L to Colliers substation and 39L to Bay Roberts substation.

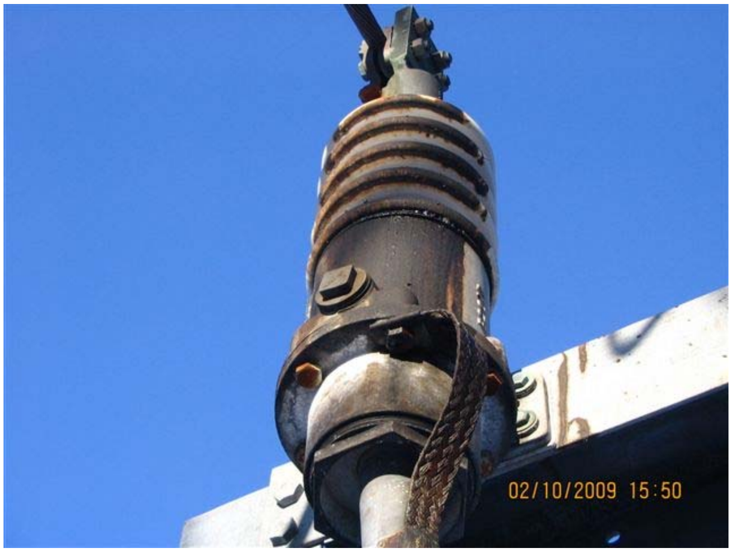
Springfield Substation Location

Inspection of the power transformer identified deteriorated radiators which were leaking insulating oil. One radiator has since been shut off and drained. New radiators will be installed in 2010.

Leaking Radiator

Deteriorated Radiator

The 12 kV power cables supplying the transformer are thirty five years old and are leaking insulating compound. These will be replaced with overhead conductor.



Leaking 12.5 kV Potheads

2.9 Wesleyville Substation ($53,000)

Wesleyville substation was built in 1974 as a 12 kV distribution substation. The distribution substation contains two power transformers. One power transformer is a 66 kV to 12 kV unit with a capacity of 13 MVA. It serves approximately 1700 customers in the New-Wes-Valley area through three 12 kV feeders. A gas turbine was relocated to the substation in 2005. The substation's second power transformer, which is a 66 kV to 13 kV unit with a capacity of 20 MVA, connects the gas turbine to the Island interconnected grid. There is one 66 kV transmission line, 116L from Trinity substation terminated in the substation.

Wesleyville Substation Location

The substation is in generally good condition and the power transformers show no signs of deterioration.

Metal oxide lightning arrestors will be installed on the 13 MVA power transformer. A 66 kV potential transformer at the termination of transmission line 116L will be relocated to permit safe work access.

WES-T1 Low Voltage Lightning Arrestors

2.10 Portable Substation P3 ($540,000)

Portable substation P3 was purchased in 1977. It is used to respond to power transformer failures and for carrying out planned transformer and substation maintenance. Of the approximate 190 power transformers in service on Newfoundland Power's system, P3 can provide backup for 68% of them.

This is the first comprehensive refurbishment of this portable substation since its purchase over thirty years ago. Purchase of a comparable new portable substation would cost approximately $4 million. Refurbishment of portable substation P3 should ensure its continued availability for the next decade.

Portable Substation P3

The manual hydraulic jacks on the unit have deteriorated and they will be replaced with a motorized system. The alarm panel has had several failures and will be replaced. The protection relays are thirty two year old electro mechanical type and will be replaced with new electronic digital protection relays.

The control wiring associated with the protection and control of the portable substation is original wiring showing signs of deterioration and will also be replaced.

A SCADA remote terminal unit will be installed on the portable substation to provide remote monitoring and control capability of the unit.

2.11 Items Under $50,000 ($193,000)

The 2010 Substation Refurbishment and Modernization project includes a number of smaller items that must be addressed in the near future, and cannot wait for a more comprehensive refurbishment of the substation. The replacement of lightning arrestors in six locations receives priority because of the risk of customer outages related to existing lightning arrestor failure. Site improvements are required at one location to ensure employee and public safety.

Lightning Arrestors
The primary function of lightning arrestors in a substation is to protect power transformers. Until the early 1980s, silicon carbide lightning arrestors were standard in the utility industry, and as a result many transformers in the Newfoundland Power fleet are protected using silicon carbide lightning arrestors.

Silicon carbide lightning arrestors are now known to fail as they age due to moisture seeping into the arrestor through failed seals. The Company has experienced high levels of failure on this type of lightning arrestor. There is no reliable way to test or monitor an arrestor to predict its failure. All remaining silicon carbide lightning arrestors in Newfoundland Power substations are being replaced on a priority basis and, where possible, coordinated with other capital work and transformer maintenance.

Table 2 shows the substations and costs associated with 2010 lighting arrestor replacement.

Table 2
2010 Lighting Arrestor Replacement
(000s)

Substation	**Cost**
Islington (ISL)	$34
Jonathan's Pond (JON)	$17
Pepperell (PEP)	$38
Placentia Junction (PJN)	$38
Seal Cove Substation (SCV)	$14
Summerville (SMV)	$24
Total	**$165**

Site Improvements
The fence at West Brook Hydro Plant has deteriorated to the point where it needs to be replaced in 2010 at an estimated cost of $28,000.

2.12 Substation Monitoring and Operations ($150,000)

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

In 2010, upgrades to the communications hubs that connect multiple devices in substations to the SCADA system are planned. Effective management of increased volumes of electrical system data requires the upgrading of the hubs. This requires both hardware and software upgrades.

In 2010, the required work will incorporate manufacturers' upgrades to communications and other computer-based equipment located in Company substations. These upgrades typically increase functionality of the equipment and software and remedy known deficiencies.

Appendix A

Substation Refurbishment and Modernization Plan
Five-Year Forecast 2010 to 2014

Substation Refurbishment and Modernization Plan
Five-Year Forecast
2010 to 2014
(000s)

2010		2011		2012		2013		2014	
SUB	**Cost**	**SUB**	**Cost**	**SUB**	**Cost**	**SUB**	**Cost**	**SUB**	**Cost**
BOT	837	HCT	906	BHD	218	GBS	874	ABC	632
BOY	67	NCH	866	CAR	583	HBS	213	BIG	408
CLK	228	NGF	686	FRN	755	MKS	600	BVA	911
GAL	703	PAS	20	GLN	330	NHR	591	GBY	250
GFS	797	P4	527	GBE	93	SPO	650	GPD	256
GIL	138	SCT	155	ILC	69	SCR	737	HAR	226
GLV	199	VIC	903	MAS	473	SUN	626	HUM	1099
P3	540			P1	486	VIR	393	ISL	156
SPF	138			STX	191	WAV	298	MOL	438
WES	53			STV	440			SPR	346
MISC	193			TBS	157			TCV	386
SCADA	150			TWG	210				
				WAL	612				
	$4,043		**$4,063**		**$4,617**		**$4,982**		**$5,108**

Note: SUB: Substation - Refer to the Electrical System handbook included with the 2006 Capital Budget Application for three letter substation designations. P1, P3 and P4 are the designations for the portable substations.

2011 PCB Removal Strategy
June 2010

2011 PCB Removal Strategy

June 2010

Prepared by:

Peter Feehan, P.Eng.

REGISTERED PROFESSIONAL ENGINEER
PETER J. FEEHAN
SIGNATURE
June 29, 10
DATE
NEWFOUNDLAND & LABRADOR

NEWFOUNDLAND POWER
A FORTIS COMPANY

Table of Contents

1.0 Introduction

In September, 2008 the Canadian Environment Protection Act was amended by the Government of Canada with the *PCB Regulations* coming into effect and the repealing of *The Chlorobiphenyls Regulations* and the *Storage of PCB Material Regulations*. The PCB Regulations ("the Regulations") came into effect for the purpose of minimizing risks posed by polychlorinated biphenyls ("PCBs") and accelerating the elimination of PCBs from electrical equipment in Canada.[1]

Section 16 (1) of the Regulations establishes end-of–use dates for PCB contaminated equipment based on: PCB concentration, equipment type and location. Certain equipment such as power transformers, circuit breakers, reclosers, pad-mounted transformers, current transformers, potential transformers, and bushings with a PCB concentration of 500 mg/kg or more must be removed from service by December 31, 2009. The Regulations permit an extension to the deadline until December 31, 2014, based on approval from the Minister of Environment.[2]

The Company sought and was granted an end-of-use extension to December 31, 2014 for all bushings and instrument transformers where the PCB concentrations are unknown or at 500 mg/kg or more as allowed under Section 17(2) of the Regulations.[3]

Prior to the enactment of the new regulations, Canadian electric utilities were working towards removing from service equipment having a PCB concentration level of 500 mg/kg or more prior to December 31, 2025. This schedule was the result of the 2006 publication by Environment Canada in the Canada Gazette, Part 1, Section 18(c) which stated "A person may continue to use, until December 31, 2025……current transformers, potential transformers, circuit breakers, reclosers and bushings that are located at an electrical generation, transmission or distribution facility". Thus Newfoundland Power and other Canadian utilities planned to phase-out these types of PCB contaminated equipment by the 2025 deadline.

The schedule for testing and replacement of bushings and instrument transformers presented in this report was developed to meet the December 31, 2014 deadline. The Company considers this schedule to be very aggressive. In many instances testing and remedial work will require substation outages which will interrupt electricity service to customers, and will create resource challenges with respect to the Company's other capital work. In light of these issues Newfoundland Power and other utilities have expressed their concern over the 2014 deadline to Environment Canada and is working with the Canadian Electricity Association ("CEA") to reinstate the original 2025 date.

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[1] In the Canada Gazette, Part 1 published in November 2006, Environment Canada states that the purpose of the proposed regulations was to improve the protection of Canada's environment and the health of Canadians and as well, to implement Canada's national and international commitments on the use, storage and elimination of PCBs.

[2] The deadline and extension requirement also apply to the equipment listed above with a PCB concentration of 50 mg/kg or more that is located in sensitive locations. In addition, the above listed equipment with PCB concentrations of 50 mg/kg or more (including pole-top electrical transformers) must be removed from service by December 31, 2025.

[3] This is the only equipment for which Newfoundland Power requires the end-of-use date extension. All other equipment such as pole mounted transformers, power transformers and breakers have been confirmed to be less than 500 mg/kg or less than 50 mg/kg in sensitive locations. The end-of-use date extension is included in Appendix A.

2.0 PCB Equipment Remediation Strategy

Newfoundland Power's end-of-use date extension application ("the Extension Application"), as approved by Environment Canada, identified a total of 429 pieces of equipment which require PCB testing and possible remediation. This included 161 power transformers, 186 circuit breakers, 56 potential transformers, 12 current transformers, 6 metering tanks and 8 station service transformers. A total of 2,330 bushings are associated with this equipment. The PCB concentration of these items is unknown.[4]

Newfoundland Power will conduct PCB testing and, if required, replace any bushings and instrument transformers with a PCB concentration at 500 mg/kg or more to meet the December 31, 2014 deadline.

The strategy is comprised of two parts:

- Part 1 - Test all of the equipment identified to determine actual PCB concentration or to identify which pieces of equipment cannot be tested (for example hermetically sealed oil filled bushings).
- Part 2 - Replace all equipment that either cannot be tested or has a PCB concentration of 500 mg/kg or more. Equipment that cannot be tested will have to be replaced as the level of PCB contamination cannot be determined.

The remediation strategy for each equipment category is discussed in the sections to follow.

2.1 Power Transformers

The average age of the 161 power transformers identified in the Extension Application is approximately 40 years. Over 1,200 transformer bushings were listed in the Extension Application that was approved by Environment Canada.[5]

The remediation strategy for power transformers will require the replacement of the transformer bushings for units that test at 500 mg/kg or more. Replacement of the oil contained within the bushings is not an option as the majority of the PCB contaminated oil in a bushing is contained in the bushing's paper, which cannot be replaced on site. Due to the high replacement cost of power transformers and their relatively long life, the remediation strategy for power transformer bushings will be to test individual bushings and order replacements for units that test at 500 mg/kg or more.[6]

4 Equipment that was built since January 1st, 1986 was deemed to be free of PCB contamination based on a review of Newfoundland Power's records. Consequently all of the equipment in question is twenty-five years old or older.

5 This list has been reduced to approximately 1,100 units by identifying specific types of bushings that are not oil filled and therefore are not subject to PCB contamination.

6 There is a six month lead time required to procure new power transformer bushings.

Figure 1 shows the location of the bushings at the top of the power transformer tank.

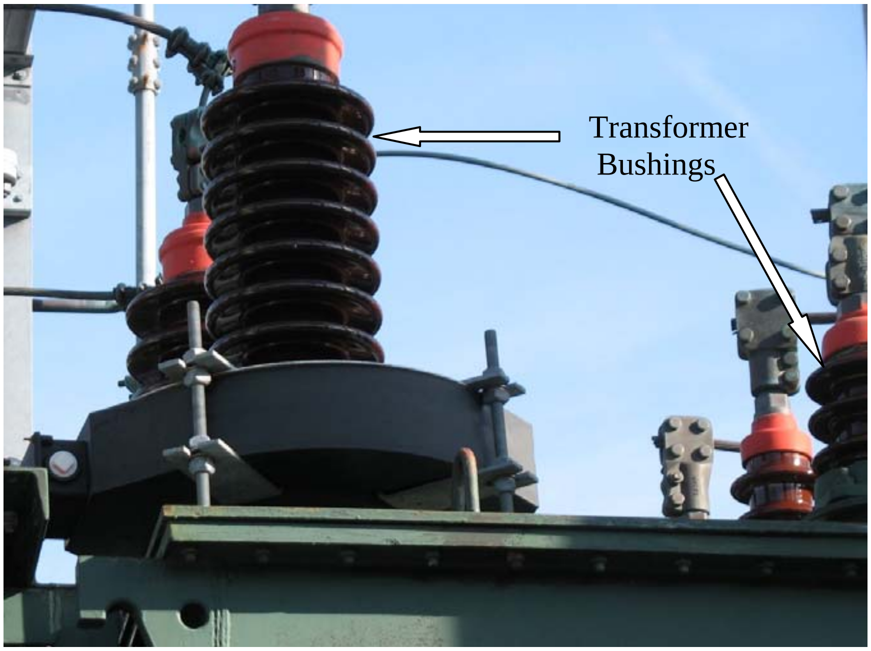

Figure 1 – Power Transformer Bushings

In situations with one or more of a transformer's bushings test at 500 mg/kg or more, all bushings that test above 50 mg/kg will also be replaced. While bushings that test between 50 mg/kg and 500 mg/kg can remain in service until 2025, it is cost effective to replace all bushings during the one power transformer outage, especially in situations where installing a portable substation is required.

Approximately half of the transformer bushings can be tested and remediated without incurring customer outages.[7] The other half will require customer outages to allow testing to be completed. It is estimated that there are 63 transformer locations where the portable substations will not be available to maintain electricity service to customers while testing of the transformer bushings is completed. Each of these 63 transformers will require a four hour customer outage to complete the testing.

Where practical, the Company will schedule bushing testing and remediation to the transformer's normal maintenance schedule. However, because of the requirement to complete all testing and remediation before the 2014 deadline, only one third of the transformer bushings will be tested during the normal maintenance cycle. All testing and remediation work required to meet the 2014 deadline that is completed outside of the normal maintenance schedule will be part of the PCB removal capital project.

To date, the Company has very few actual PCB test results for power transformer bushings. Until the Company accumulates a reasonable sample of its own test data a failure rate will have

[7] In some locations customer load can be transferred to adjacent substations, or there are multiple transformers in the same substation servicing customers. In these situations the testing can be completed without incurring a customer outage.

to be assumed. The Company has assumed a 1% failure rate for transformer bushings.[8] If the actual failure rate turns out to be significantly different than the assumed failure rate then the scheduling of testing and remediation work will be adjusted accordingly. In addition, approximately 25% of Newfoundland Power's transformers have bushings that cannot be tested. These bushings will have to be replaced as their PCB concentration cannot be determined.

Table 1 provides the Company's schedule for testing and replacement of power transformer bushings.

Table 1
Power Transformer Bushing Testing & Replacement Schedule

Year	**Number of Transformers To Test**	**Estimated Number of Transformers Requiring Bushing Replacement[9]**	**Transformer Bushing Replacement Year**
2010	16	5	2 in 2010 3 in 2013
2011	45	13	5 in 2011 8 in 2013
2012	45	13	5 in 2012 8 in 2014
2013	45	13	5 in 2013 8 in 2014
2014	10	4	4 in 2014
Total	**161**	**48**	

2.2 *Bulk Oil Circuit Breakers*

Newfoundland Power has not purchased bulk oil circuit breakers since 1982[10]. The average age of the bulk oil circuit breakers in service is approximately 40 years. The life expectancy of an oil

8 Newfoundland Power has tested bushings on thirteen different transformers to date. Two of the transformers have bushings that tested greater than 50 mg/kg while none have tested above 500 mg/kg. The CEA PCB Equipment Inventory from November 2009 indicates that 1% of tested oil filled bushings have PCB concentrations in excess of 500 mg/kg. Based upon the CEA results, although all transformer bushings must be tested, it is likely only 1% will prove to be greater than 500 mg/kg.

9 Estimate based on a 1% failure rate (above 500 mg/kg) and on the fact that approximately 25% of Newfoundland Power's transformers have some bushings that cannot be tested.

10 The Company has purchased mostly SF6 breakers since 1982. However some minimum oil (not PCB) and some vacuum breakers have also been purchased. Today the Company only purchases SF6 or vacuum breakers.

circuit breaker varies; however, based on experience an average life span of 38 years is reasonable.

Whenever one breaker bushing tests at 500 mg/kg or more then it is likely all 6 bushings on that breaker will have similar PCB content. Replacing all 6 bushings on these breakers would approach the cost of purchasing a new breaker. Therefore, due to their age and the cost of bushing replacement, the complete breaker will be replaced when 1 bushing tests greater than 500 mg/kg.[11]

Figure 2 shows the location of the bushings at the top of the bulk oil circuit breaker tank.

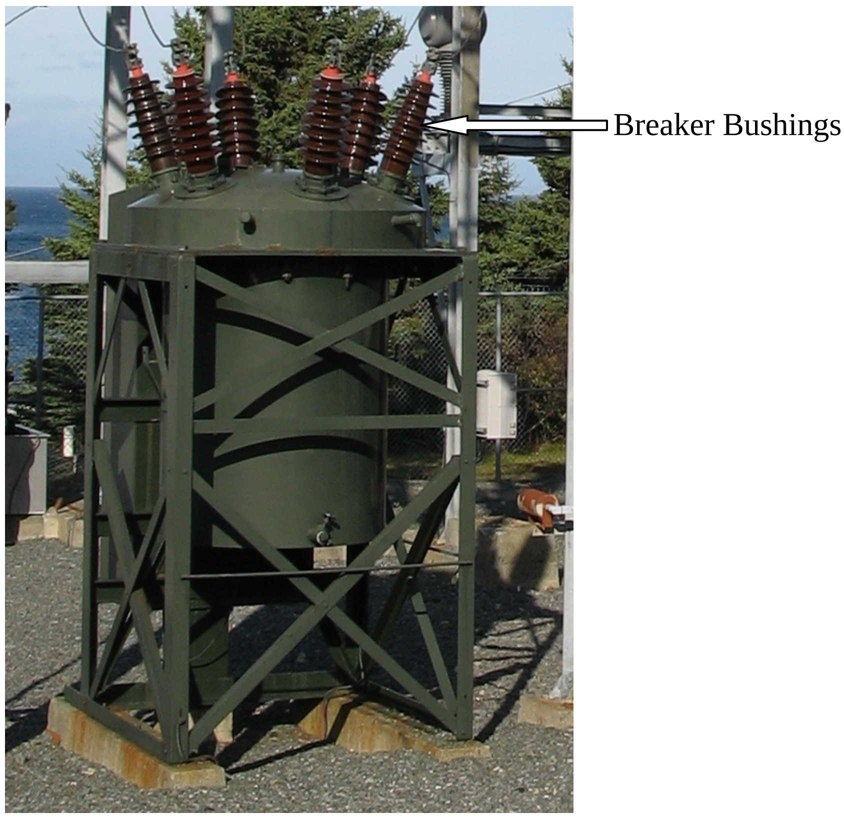

Figure 2 - 66 kV Bulk Oil Breaker

Where practical, the Company will schedule bushing testing and remediation to the breaker's normal maintenance schedule. However, because of the requirement to complete testing and remediation before the 2014 deadline, only one third of the breaker bushings will be tested during the normal maintenance cycle. All testing and remediation work required to meet the 2014 deadline that is completed outside of the normal maintenance schedule will be part of the PCB removal capital project.

[11] The Company anticipates that the majority of breaker bushings can be tested. However, any breakers with bushings that cannot be tested will also be replaced as the PCB concentration cannot be determined.

Table 2 provides the Company's schedule for testing and replacement of circuit breaker bushings.

Table 2
Circuit Breaker Bushing Testing & Replacement Schedule

Testing Year	Number of Breakers To Test	Estimated Number of Breakers Requiring Replacement [12]	Breaker Bushing Replacement Year
2010	12	1	2012
2011	85	8	2012
2012	85	8	2013
2013	4	1	2014
2014	0	0	-
Total	186	18	

Approximately 95% of the breakers can be tested and remediated without incurring customer outages. The remaining 5% will require customer outages to allow testing to be completed. [13] To minimize the total number of customer outages required, remediation of the latter group of breakers will be completed at the same time as the testing for the transformer bushings is completed.

2.3 Potential and Current Transformers

Potential and current transformers are typically hermetically sealed therefore they cannot be tested for PCB concentrations. The units with sampling ports will be tested, and those that test at 500 mg/kg or more will be replaced. All units that cannot be tested will be replaced with new units.

Approximately 60% of the Company's potential transformers ("PTs") and 50% of the current transformers ("CTs") can be tested and remediated without a customer outage. The remainder of the units will require customer outages to test. Replacement of these units will also require outages or the installation of a portable substation if available in order to complete the replacements.

[12] Newfoundland Power has completed testing for the bushings on only 11 breakers. As a result there is little empirical data on which to base an estimated failure rate. For the purpose of preparing a budgetary estimate it is assumed that a minimum of 1 breaker will require replacement during a year when testing is undertaken. A maximum failure rate of 10% is assumed for any year in which testing is completed.

[13] Approximately 6 locations.

The plan is to test one third of these units in each of the three years starting in 2011. All required replacements will be done in 2013 and 2014.

Figure 3 shows the location of a set of three 66 kV PTs on a substation structure.

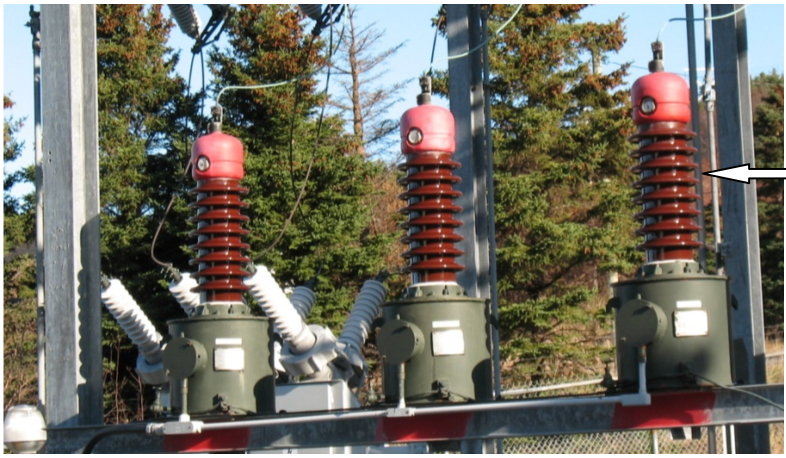

Figure 3 - 66 kV Potential Transformers

2.4 Metering Tanks

The 6 metering tanks identified in the Extension Application will be tested before the end of 2013. All required replacements will be completed prior to the end of 2014.

2.5 Station Service Transformers

These 8 units are low cost and are relatively easy to replace. They will be tested before the end of 2013 and replaced with new units as required before the end of 2014.

3.0 Project Cost

Table 3 identifies capital budget estimates for completing the above testing and expected remediation work prior to the 2014 deadline established by the Government of Canada.

Table 3
Project Cost 2011 to 2014

Year	Expenditure
2011	$1,500,000
2012	$3,000,000
2013	$5,000,000
2014	$5,000,000
2015	$2,000,000

The estimated expenditures include the work outlined in Tables 1 and 2 of section 2.0, including testing and replacement costs. Based on the limited data available from the manufacturers or testing programs completed by other utilities, several assumptions were made in developing the cost estimates for this strategy. As a result the actual expenditure in future years will vary depending upon the accuracy of the assumptions used to create the cost estimates. As more data is collected in 2010, 2011 and 2012 the full implications and cost of meeting the requirements of the Regulations will become better defined.

4.0 Concluding

Replacing equipment with a PCB concentration that is either unknown or at 500mg/kg or more, by the 2014 deadline will be extremely difficult for Newfoundland Power and other Canadian electric utilities. On May 11, 2010 the Canadian Electricity Association ("CEA") wrote to Environment Canada requesting that Canadian utilities be afforded the appropriate time to ensure proper management of PCB contaminated equipment in an economically feasible manner. The CEA has requested that the Regulations be amended to ascribe bushings and instrument transformers an end-of-use date of 2025.

If the CEA amendment is accepted, and the deadline for dealing with the equipment is extended until 2025, the PCB phase-out can be completed over a 15 year period (2011-2025) compared to a 4 year period (2011-2014). This longer timeframe would put the Company in a better position to meet Environment Canada's regulatory requirements without dramatically impacting the Company's annual capital budget expenditures.

The current legislation also requires other equipment such as pole-top transformers with a PCB concentration of 50 mg/kg or more be removed from the system by the end of 2025. The implication is that expenditures on PCB remediation will likely continue until 2025. The work completed over the next couple of years will allow clearer identification of the future remediation that will be required to meet the PCB Regulation.

This project as presented is required to allow Newfoundland Power to meet its obligations as stated in the Extension Application and subsequent approval by Environment Canada.

Appendix A

Extension of End-of-Use Date for Equipment and Liquids Containing PCBs

Environment Canada Environnement Canada

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

05 February 2010 / 05 février 2010

EXTENSION OF DECEMBER 31, 2009 END-OF-USE DATE FOR EQUIPMENT AND LIQUIDS CONTAINING PCBs Granted Under Subsection 17(2) of the *PCB Regulations*

PROLONGATION DE LA DATE DE FIN D'UTILISATION DU 31 DÉCEMBRE 2009 POUR DES PIÈCES D'ÉQUIPEMENT ET DES LIQUIDES QUI CONTIENNENT DES BPC Accordée en vertu du paragraphe 17(2) du *Règlement sur les BPC*

File Number / No. de dossier : 09/109/EXT

The Department of the Environment grants Newfoundland Power, St. John's, the extension requested in its application. The end-of-use date of the equipment and liquids used for their servicing described below is extended from December 31, 2009 to the dates indicated in the table below.

This extension is granted in accordance with subsection 17(2) of the *PCB Regulations*. The condition specified in subparagraph 17(2)(*a*)(i) of the Regulations and referred to in the application is met.

Le ministère de l'Environnement accorde à Newfoundland Power, St. John's, la prolongation exigée dans sa demande. La date de fin d'utilisation des pièces d'équipement et des liquides nécessaires à leur entretien décrits ci-dessous est reportée du 31 décembre 2009 aux dates indiquées au tableau ci-dessous.

Cette prolongation est accordée en vertu du paragraphe 17(2) du *Règlement sur les BPC*. La condition énoncée au sous-alinéa 17(2)*a*)(i) du Règlement et invoquée dans la demande est remplie.

Number of bushings / Nombre de traversées isolées	Number of pieces of equipment/ Nombre de pièces d'équipement	Extension date/ Date de prolongation
6	1	30 October 2010
2,330	429	31 December 2014
Total : 2,336	Total : 430	

Canada

Condition referred to in the application for an extension / Condition invoquée dans la demande de prolongation

The equipment is being replaced with equipment that is engineered to order, and it is not technically feasible to replace the equipment on or before December 31, 2009.

La pièce d'équipement doit être remplacée par une pièce d'équipement conçue et fabriquée sur mesure et il est techniquement impossible de le faire le 31 décembre 2009 ou avant cette date.

Applicant and person authorized to act on applicant's behalf Demandeur et personne autorisée à agir en son nom

Applicant/ Demandeur, 17(3)(a)
Newfoundland Power
55 Kenmount Road, P.O. Box 8910,
St. John's, Newfoundland Canada A1B 3P6

Person authorized to act on applicant's behalf/ Personne autorisée à agir au nom du demandeur, 17(3)(a)
Mr. Paul O'Leary
Director, Environment
Newfoundland Power
P.O. Box 8910
55 Kenmount Road
St. John's, Newfoundland A1B 3P6
Telephone: (709) 737-2868
Fax: (709) 737-2960
Email: poleary@newfoundlandpower.com

Owner of equipment containing PCBs/ Propriétaire des pièces d'équipement contenant des BPC, 17(1)
Same as applicant above.

Description and location of equipment and liquids needed for their servicing / Description et emplacement des pièces d'équipement et des liquides nécessaires à leur entretien

See attached list of equipment for details, this list is part of the authorization / Voir la liste des pièces d'équipements annexée pour le détail, cette liste fait partie intégrante de l'autorisation

Type and function of the equipment/ Type et fonction de l'équipement, 17(3)(b)(i): See Tables 1 and 2 below for details. Equipment covered by the application include:

- breaker,
- oil filled bushing,
- current transformer,
- metering tank,
- potential transformer,
- regulator,
- station service transformer,
- step up transformer,
- step down transformer,
- transformer, and
- load tap changer.

Quantity of liquid (litres) containing PCBs in the equipment/ Quantité de liquide (litres) contenant des BPC dans la pièce d'équipement, 17(3)(b)(ii): Estimated total of 15,250 L of liquid containing PCBs for all known and unknown equipment.

See Tables 1 and 2 below for details. Quantity per equipment is 4L for known PCB containing equipment and varies from 1L to 240 L for equipment with unknown PCB concentration.

Total Table 1- Equipment with known PCB concentration – 1 piece of equipment containing 6 bushings = 24 L.
Total Table 2- Equipment potentially containing PCBs in a concentration of 500 mg/kg or more – 429 pieces of equipment containing 2,330 bushings = 15,226 L

Quantity of liquid (litres) containing PCBs needed for its servicing/ Quantité de liquide (litres) contenant des BPC nécessaire à son entretien, 17(3)(b)(ii): No additional liquids are kept for the purpose of servicing the working equipment.

Concentration of PCBs (mg/kg) in the liquid/ Concentration de BPC (mg/kg) dans le liquide, 17(3)(b)(iii): Known concentrations in Table 1 vary from 570 mg/kg to 700 mg/kg. An average PCB concentration of 638 mg/kg is used as an estimate for all pieces of equipment with "unknown" concentrations in Table 2. See Tables 1 and 2 below for details.

Quantity of PCBs (kg) in the liquid/ Quantité de BPC (kg) dans le liquide/, 17(3)(b)(iv): Estimated total of 8.57 kg of PCBs in the liquid for all known and unknown equipment.

See Tables 1 and 2 below for details. Quantity of PCBs for known equipment varies from 0.0020 to 0.0025 kg and for unknown equipment from 0.0006 kg to 0.0450 kg.
Total for known equipment in Table 1 = 0.0134 kg
Total for unknown equipment in Table 2 = 8.56 kg
Total quantity of PCBs (kg) in all liquids = Table 1 + Table 2 = 0.0134 kg + 8.56 kg = 8.57 kg.

Name-plate description, manufacturer's serial number/ Plaque d'identification et numéro de série , 17(3)(b)(v) : See Tables 1 and 2 below for details. Manufacturer nameplate information and serial numbers are not readily available for the unknown equipment.

Unique identification number on the label required under section 29/ Numéro d'identification unique sur l'étiquette conformément à l'article 29, 17(3)(c): See Tables 1 and 2 below for details. All equipment noted in Table 1 has been labeled in accordance with Section 29 of the PCB Regulations. Each label contains a unique identification number. For the unknown equipment, the equipment will be labeled in accordance with Section 29 of the PCB Regulations once testing has confirmed that the PCB level of concentration is 500 mg/kg or more. Each label will contain a unique identification number (i.e. manufacturer's serial number).

Place where the equipment is located/ Endroit où se trouve la pièce d'équipement, 17(3)(d):

Equipment Known to contain PCBs in a concentration of 500 mg/kg or more: The six electrical bushings on the breaker are located at the Kelligrews Substation. The Kelligrews Substation, with designation KEL, is an entirely fenced facility located on Middle Bight Road in the Town of Conception Bay South, Newfoundland and Labrador. The substation steps down voltage from 66KV to 12.5KV. All equipment is enclosed in a locked fenced area outdoors at all locations.

Equipment with Unknown PCB concentration: See Table 2 below for details on each of the unknown bushings. All equipment is enclosed in a locked fenced area outdoors at all locations, potential of 116 Substations.

Information demonstrating that it is not technically feasible to replace the equipment with equipment that is engineered to order on or before December 31, 2009/ Renseignements qui établissent qu'il est techniquement impossible de remplacer la pièce d'équipement conçue et fabriquée sur mesure le 31 décembre 2009 ou avant cette date, 17(3)(e): The information provided in the application for an extension in accordance with this section indicate that the applicant is meeting the condition specified in subparagraph 17(2)*a*)(i).

Necessary measures taken to minimize or eliminate any harmful effect of the PCBs that are contained in the equipment on the environment and human health/ Mesures nécessaires prises pour éliminer ou atténuer tout effet nocif des BPC contenus dans la pièce d'équipement sur l'environnement et la santé humaine, 17(3)(f): The measures are indicated in the application for an extension.

Plan for ending the use of equipment by the end of the extension along with timelines/ Plan et échéancier mis en oeuvre afin que l'utilisation de la pièce d'équipement cesse à la fin de la prolongation, 17(3)(g): Provided in the application for an extension. The known piece of equipment with 6 bushings containing PCBs as components will be removed from use by October 30, 2010 and the 429 pieces of equipment with 2,330 bushings as components and potentially containing PCBs will be removed from use by December 31, 2014 in accordance with the application.

Plan for inspecting equipment/ Plan d'inspection de la pièce d'équipement, 17(3)(h): Monthly inspections will be conducted for the period of the extension for damage that could lead to the release of PCBs.

Please take note that it is your responsibility as the owner or the person who controls or possesses the equipment and liquids containing PCBs to ensure that the requirements set out in the *PCB Regulations* made pursuant to CEPA 1999 are complied with at all time.

Veuillez noter qu'en tant que propriétaire ou personne qui contrôle ou possède les pièces d'équipement et des liquides contenant des BPC il vous incombe de veiller à ce que les exigences établies dans le *Règlement sur les BPC* et dans la LCPE (1999) soient remplies en tout temps.

Signed for and on behalf of the Minister of the Environment /
Signé au nom du ministre de l'Environnement

CBlain

Carolyne Blain
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Waste Reduction & Management / Réduction et gestion des déchets
Public and Resources Sectors / Secteurs publics et des ressources
Environment Canada / Environnement Canada