DELIVERED BY HAND

August 31, 2004

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

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

Ladies and Gentlemen:

Re: Newfoundland Power's 2005 Capital Budget Application

A. General

Enclosed are 15 copies of Newfoundland Power's 2005 Capital Budget Application and supporting materials in 2 volumes. The Application is filed in compliance with the filing requirements set out in Order No. P.U. 35 (2003) (the "Order").

The following describes the organization of the Application and the contents of the 2 volumes.

B. Organization of the Application

General Approach: Newfoundland Power's organization of the Application continues to reflect the nature of its utility assets and its management of those assets. Project categories are substantially the same as those used in recent capital budget applications. This provides a level of consistency which allows reasonable year over year comparisons.

The Order, and particularly the *Conditions for Future Filings* (Schedule A to the Order), required specific information to be provided with the Application. This information has been provided.

To provide a reasonable measure of organization of the volume of information, the Company has presented the information in 2 volumes. Volume I contains the primary layer of information. The second, more detailed, layer of information is contained in Volume II.

Volume I: Volume I contains the Application and supporting Schedules in the format which has historically been submitted to the Board by Newfoundland Power.

Volume I also contains the following reports which the Board has specifically ordered Newfoundland Power to file with the Application:

> *2004 Capital Expenditure Status Report*: filed in compliance with paragraph 4, page 35 of the Order;
>
> *2005 Capital Budget Plan*: filed in compliance with paragraph 5, page 36 of the Order;
>
> *Report on the Amortization of the Unfunded Pension Liability*: filed in compliance with paragraph 8, page 36 of the Order; and
>
> *Report on Deferred Charges and Rate Base*: filed in compliance with paragraph 5(i), page 120 of Order No. P.U. 19 (2003).

Volume II: Volume II of the Application contains expenditure details, reports and studies. This information is provided to meet the requirements contained in the Order.

The information contained in Volume II is divided into capital budget categories, with appendices for those projects for which additional detailed information is required.

Attachments are used to separate supporting material which is typically in the form of engineering reports and studies.

Accessing information in the Application: The material contained in Volume 1, particularly Schedule B to the Application, provides project descriptions, operating experience, project justifications and future commitments. For many, but not all, projects reference will be made in Schedule B to a specific Budget Category and Appendix contained in Volume II. In that Appendix, further detail on the project can be found.

C. Filing Details and Circulation

The enclosed material has been provided in binders with appropriate tabbing. For convenience, additional materials such as Responses to Requests for Information will be provided on three-hole punched paper.

A PDF file of the Application will be forwarded to the Board in due course.

A copy of the Application has been forwarded directly to Maureen Greene, Q.C. of Newfoundland & Labrador Hydro.

D. Concluding

We trust the foregoing and enclosed are found to be in order.

If you have any questions on the Application, please contact us at your convenience.

Yours very truly,

Peter Alteen
Vice President, Regulatory Affairs
& General Counsel

Enclosures

c. Maureen P. Greene, Q.C.
Newfoundland & Labrador Hydro

Newfoundland Power Inc.
2005 Capital Budget Application
Filing Contents

Volume I
Application

Application

Schedule A ***2005 Capital Budget Summary***
Schedule B ***2005 Capital Projects Explanations***
Schedule C ***Estimate of Future Required Expenditures on 2005 Projects***
Schedule D ***Rate Base***
Schedule E ***Average Invested Capital***
Schedule F ***Calculation of Rate of Return on Rate Base***

2005 Capital Budget Plan

2004 Capital Expenditure Status Report

Report on Deferred Charges and Rate Base

Report on the Amortization of the Unfunded Pension Liability

Volume II
Expenditure Details, Reports and Studies

Energy Supply

Appendix 1 ***Hydro Plants - Facility Rehabilitation***

Appendix 2 ***Wesleyville Gas Turbine Overhaul***

Attachment A ***Rolls-Royce Field Service Report dated December 22, 2003***

Appendix 3 ***Rattling Brook Hydro Plant Refurbishment***

Attachment A ***Engineering Plan – Rattling Brook Refurbishment***

Attachment B ***Project Justification - Rattling Brook Refurbishment Project***

Substations

Appendix 1 ***Rebuild Substations***

Appendix 2 ***Replacement and Standby Substation Equipment***

Transmission

Appendix 1 ***Rebuild Transmission Lines***

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

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

IN THE MATTER OF an application by Newfoundland Power Inc. for an order pursuant to Sections 41, 78 and 80 of the Act:

(a) approving its 2005 Capital Budget of $48,141,000;
(b) (i) fixing and determining its average rate base for 2003 in the amount of $675,730,000; (ii) approving its revised forecast average rate base for 2004 in the amount of $713,072,000; and (iii) approving its forecast average rate base for 2005 in the amount of $740,142,000; and
(c) approving revised values for rate base and invested capital for use in the automatic adjustment formula (the "Automatic Adjustment Formula") for the calculation of return on rate base for 2005 pursuant to Order No. P.U. 19 (2003).

2005 Capital Budget Application

NEWFOUNDLAND POWER
A FORTIS COMPANY

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

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

IN THE MATTER OF an application by Newfoundland Power Inc. for an order pursuant to Sections 41, 78 and 80 of the Act:

(a) approving its 2005 Capital Budget of $48,141,000;
(b) (i) fixing and determining its average rate base for 2003 in the amount of $675,730,000; (ii) approving its revised forecast average rate base for 2004 in the amount of $713,072,000; and (iii) approving its forecast average rate base for 2005 in the amount of $740,142,000; and
(c) approving revised values for rate base and invested capital for use in the automatic adjustment formula (the "Automatic Adjustment Formula") for the calculation of return on rate base for 2005 pursuant to Order No. P.U. 19 (2003).

TO: The Board of Commissioners of Public Utilities (the "Board")

THE APPLICATION OF Newfoundland Power Inc. ("Newfoundland Power") **SAYS THAT:**

1. Newfoundland Power is a corporation duly organized and existing under the laws of the Province of Newfoundland and Labrador, is a public utility within the meaning of the Act, and is subject to the provisions of the *Electrical Power Control Act, 1994*.

2. Schedule A to this Application is a summary of Newfoundland Power's 2005 Capital Budget in the amount of $48,141,000 which includes an estimated amount of $1,500,000 in contributions in aid of construction that the Applicant intends to demand from its customers in 2005. All contributions to be recovered from customers shall be calculated in a manner approved by the Board.

3. Schedule B to this Application is a list of those 2005 capital expenditures, exclusive of general expenses capital, which comprise Newfoundland Power's 2005 Capital Budget.

4. Schedule C to this Application is an estimate of future required expenditures on improvements or additions to the property of Newfoundland Power that are included in the 2005 Capital Budget but will not be completed in 2005.

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

6. Schedule D to this Application shows Newfoundland Power's actual average rate base for 2003 of $675,730,000; revised forecast average rate base for 2004 of $713,072,000, and forecast average rate base for 2005 of $740,142,000.

7. Schedule E to this Application shows Newfoundland Power's revised forecast average invested capital for 2004 of $706,291,000 and forecast average invested capital for 2005 of $736,119,000.

8. Schedule F to this Application shows the calculation of the rate of return on rate base for Newfoundland Power using the values approved by the Board by virtue of Order No. P.U. 19 (2003); and the rate of return on rate base using the forecast average rate base and forecast average invested capital for 2005 as set out in paragraphs 6 and 7 of this Application.

9. The use of current forecasts of average rate base and average invested capital for use in the Automatic Adjustment Formula is appropriate as it reflects capital expenditures approved by the Board.

10. Communication with respect to this Application should be forwarded to the attention of Ian Kelly, Q.C. and Gerard Hayes, Counsel to Newfoundland Power.

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

   (a) pursuant to Section 41 of the Act, approving Newfoundland Power's purchase and construction in 2005 of the improvements and additions to its property in the amount of $48,141,000;

   (b) pursuant to Section 78 of the Act:

      (i) fixing and determining Newfoundland Power's average rate base for 2003 in the amount of $675,730,000;
      (ii) approving Newfoundland Power's revised forecast average rate base for 2004 in the amount of $713,072,000; and
      (iii) approving Newfoundland Power's forecast average rate base for 2005 in the amount of $740,142,000;

   and

   (c) pursuant to Section 80 of the Act approving revised values for rate base and invested capital for use in the Automatic Adjustment Formula for the calculation of Newfoundland Power's return on rate base for 2005.

DATED at St. John's, Newfoundland and Labrador, this 31st day of August, 2004.

NEWFOUNDLAND POWER INC.

Ian Kelly, Q.C. and Gerard Hayes
Counsel to Newfoundland Power Inc.
P.O. Box 8910
55 Kenmount Road
St. John's, NL   A1B 3P6

Telephone:	(709) 737-5609
Telecopier:	(709) 737-2974

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

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

IN THE MATTER OF an application by Newfoundland Power Inc. for an order pursuant to Sections 41, 78 and 80 of the Act:

(a) approving its 2005 Capital Budget of $48,141,000;
(b) (i) fixing and determining its average rate base for 2003 in the amount of $675,730,000; (ii) approving its revised forecast average rate base for 2004 in the amount of $713,072,000; and (iii) approving its forecast average rate base for 2005 in the amount of $740,142,000; and
(c) approving revised values for rate base and invested capital for use in the automatic adjustment formula (the "Automatic Adjustment Formula") for the calculation of return on rate base for 2005 pursuant to Order No. P.U. 19 (2003).

AFFIDAVIT

I, Phonse Delaney, of St. John's in the Province of Newfoundland and Labrador, Professional Engineer, make oath and say as follows:

1. That I am Vice-President, Engineering and Operations, of Newfoundland Power Inc.
2. To the best of my knowledge, information and belief, all matters, facts and things set out in this Application are true.

SWORN to before me at St. John's
in the Province of Newfoundland and
Labrador this 31st day of August, 2004,
before me:

Barrister   Phonse Delaney

Newfoundland Power Inc.
2005 Capital Budget
Budget Summary
(000s)

Energy Supply	$	3,361
Substations		3,037
Transmission		2,597
Distribution		28,635
General Property		1,016
Transportation		2,642
Telecommunications		60
Information Systems		3,243
Unforeseen Items		750
General Expenses Capital		2,800
Total	**$**	**48,141**

Newfoundland Power Inc.
2005 Capital Budget

ENERGY SUPPLY

Project	(000s)	Details on Page
HYDRO PLANTS - FACILITY REHABILITATION	$1,887	10
WESLEYVILLE GAS TURBINE OVERHAUL	1,124	12
RATTLING BROOK - HYDRO PLANT REFURBISHMENT	350	14
TOTAL - ENERGY SUPPLY	**$3,361**	

Newfoundland Power Inc.
2005 Capital Budget

SUBSTATIONS

Project	**(000s)**	**Details on Page**
REBUILD SUBSTATIONS	$351	17
REPLACEMENT AND STANDBY SUBSTATION EQUIPMENT	1,052	19
TRANSFORMER COOLING REFURBISHMENT	174	21
PROTECTION AND MONITORING IMPROVEMENTS	78	23
DISTRIBUTION SYSTEM FEEDER REMOTE CONTROL	1,114	25
FEEDER ADDITIONS DUE TO LOAD GROWTH AND RELIABILITY	268	27
TOTAL - SUBSTATIONS	**$3,037**	

Newfoundland Power Inc.
2005 Capital Budget

TRANSMISSION

Project	**(000s)**	**Details on Page**
REBUILD TRANSMISSION LINES	$2,597	29
TOTAL - TRANSMISSION	**$2,597**	

Newfoundland Power Inc.
2005 Capital Budget

DISTRIBUTION

Project	**(000s)**	**Details on Page**
EXTENSIONS	$6,374	31
METERS	965	33
SERVICES	1,895	35
STREET LIGHTING	1,254	37
TRANSFORMERS	5,189	39
RECONSTRUCTION	2,825	41
ALIANT POLE PURCHASE	4,044	43
TRUNK FEEDERS		
Rebuild Distribution Lines	4,210	44
Relocate/Replace Distribution Lines For Third Parties	734	47
Distribution Reliability Initiative	872	49
Feeder Additions and Upgrades to Accommodate Growth	173	51
INTEREST DURING CONSTRUCTION	100	53
TOTAL - DISTRIBUTION	**$28,635**	

Newfoundland Power Inc.
2005 Capital Budget

GENERAL PROPERTY

Project	**(000s)**	**Details on Page**
TOOLS AND EQUIPMENT	$691	54
ADDITIONS TO REAL PROPERTY	325	56
TOTAL - GENERAL PROPERTY	**$1,016**	

Newfoundland Power Inc.
2005 Capital Budget

TRANSPORTATION

Project	**(000s)**	**Details on Page**
PURCHASE VEHICLES AND AERIAL DEVICES	$2,642	57
TOTAL - TRANSPORTATION	**$2,642**	

Newfoundland Power Inc.
2005 Capital Budget

TELECOMMUNICATIONS

Project	**(000s)**	**Details on Page**
REPLACE/UPGRADE COMMUNICATIONS EQUIPMENT	$60	59
TOTAL - TELECOMMUNCIATIONS	**$60**	

Newfoundland Power Inc.
2005 Capital Budget

INFORMATION SYSTEMS

Project	**(000s)**	**Details on Page**
APPLICATION ENHANCEMENTS	$1,087	61
APPLICATION ENVIRONMENT	710	63
CUSTOMER SYSTEMS REPLACEMENT	144	65
NETWORK INFRASTRUCTURE	276	67
PERSONAL COMPUTER INFRASTRUCTURE	455	69
SHARED SERVER INFRASTRUCTURE	571	71
TOTAL – INFORMATION SYSTEMS	**$3,243**	

Newfoundland Power Inc.
2005 Capital Budget

UNFORESEEN ITEMS

Project	(000s)	Details on Page
ALLOWANCE FOR UNFORESEEN ITEMS	$750	73
TOTAL – UNFORESEEN ITEMS	**$750**	

ENERGY SUPPLY

Project Title: **Hydro Plants - Facility Rehabilitation**

Location: **Various**

Classification: **Energy Supply**

Project Cost: **$1,887,000**

Project Description

This project is necessary for the replacement or rehabilitation of deteriorated hydro plant components that have been identified through routine inspections.

The work includes the replacement or rehabilitation of major components at the following plants: Cape Broyle; Hearts Content; Mobile; Port Union; and, Seal Cove.

The project also includes expenditures necessary to improve the efficiency and reliability of various hydro plants or to maintain environmental compliance. Details on various items are included in Volume II, Energy Supply, Appendix 1.

Project Cost (000s)				
Cost Category	**2005**	**2006**	**2007 - 2009**	**Total**
Material	$1,401	-	-	-
Labour – Internal	220	-	-	-
Labour – Contract	-	-	-	-
Engineering	224	-	-	-
Other	42	-	-	-
Total	**$1,887**	**$1,851**	**$7,628**	**$11,366**

Operating Experience

The following table gives the expenditures for the past five years.

Project Cost (000s)					
Year	**2000**	**2001**	**2002**	**2003**	**2004F**
Total	**$1,670**	**$1,482**	**$2,031**	**$2,510**	**$1,819**

These facilities provide energy to the Island Interconnected electrical system. Maintaining these generating facilities and infrastructure reduces the need for additional, more expensive, generation capacity.

Project Justification

The Company's 23 hydroelectric plants range in age from the 104 year old Petty Harbour Plant to the 6 year old Rose Blanche Plant.

Projects involving replacement and rehabilitation work, which are identified during ongoing inspections and maintenance activities, are necessary to the continued operation of hydroelectric generation facilities in a safe, reliable and environmentally compliant manner. The alternative to maintaining these facilities would be to retire them. These facilities produce a combined average annual production of 426 GWh.

Replacing only the energy produced by these facilities by increasing production at the Holyrood generation facility would require approximately 675,000 barrels of fuel annually. At oil prices of $30 per barrel, this translates into approximately $20 million in annual fuel savings.

Maintaining these generating facilities also contributes to system stability and, in many cases, provides local backup generation.

All material expenditures on individual hydroelectric plants, such as the replacement of penstocks, surge tanks, runners, or forebays, are justified on the basis of maintaining access to hydroelectric generation at a cost that is lower than the cost of replacement options.

The Company will ensure this project is completed at the lowest possible cost consistent with reliable service. All material and contract labour will be obtained through competitive tendering.

Future Commitments

None.

Project Title: **Wesleyville Gas Turbine Overhaul**

Location: **Wesleyville**

Classification: **Energy Supply**

Project Cost: **$1,124,000**

Project Description

This project involves the overhaul of the Wesleyville gas turbine. This involves dismantling and shipping the unit to a qualified gas turbine overhaul facility for bulk disassembly and rebuild or replacement as appropriate.

Project Cost (000s)				
Cost Category	**2005**	**2006**	**2007 - 2009**	**Total**
Material	$953	-	-	-
Labour – Internal	58	-	-	-
Labour – Contract	-	-	-	-
Engineering	73	-	-	-
Other	40	-	-	-
Total	**$1,124**	**$0**	**$0**	**$1,124**

Operating Experience

The Wesleyville gas turbine was installed in the Bonavista North area to provide emergency power in the event of loss of supply from the Island electrical grid. In December 2003, the unit was internally inspected by the original equipment manufacturer, Rolls Royce. The inspection report is included in Volume II, Energy Supply, Appendix 2, Attachment A. The inspection revealed damage to a number of the blades in the high-pressure section of the turbine. Rust and corrosion was also detected on various components of the turbine. Protection coatings are worn off the first three stages of the compressor blades. The compressor section of this unit operates at 4,800 revolutions per minute subjecting the blades to considerable rotational inertia under normal operation. It is the original equipment manufacturer's recommendation that this unit be overhauled.

Project Justification

The gas turbine has reached the stage where a bulk disassembly and rebuild is required. A major criteria used by the original equipment manufacturer in determining age and subsequently timing for a gas turbine overhaul is the number of start or attempted starts and the total turbine operating hours. The existing turbine has surpassed both criteria since its last overhaul in 1987. Any in service failure in the unit is a risk to system reliability and security of supply to the customers in the area serviced by the unit.

Future Commitments

None.

Project Title: **Rattling Brook - Hydro Plant Refurbishment**

Location: **Rattling Brook, Norris Arm South**

Classification: **Energy Supply**

Project Cost: **$350,000**

Project Description

This project involves an assessment and detailed engineering for the refurbishment of the Rattling Brook hydroelectric generating station. The project scope includes replacement of the woodstave penstock, rehabilitation of the existing steel surge tank, replacement and refurbishment of the protection and governor control systems, and of switchgear. Detailed engineering assessment is required to further define the scope of work for this project and to determine specific requirements for electrical and mechanical work associated with plant systems. The total cost of the project is currently estimated to be $11.4 million and is planned to be expended as noted.

Project Cost (000s)				
Cost Category	**2005**	**2006**	**2007 - 2009**	**Total**
Material	$-	-	-	-
Labour – Internal	10	-	-	-
Labour – Contract	-	-	-	-
Engineering	276	-	-	-
Other	64	-	-	-
Total	**$350**	**$5,643**	**$5,409**	**$11,402**

Operating Experience

Rattling Brook plant went into service in 1958. The system has operated continuously since that time providing an average of 69.4 GWh of energy on an annual basis. In 2002, Unit # 2 generator stator failed and was rewound, and in 2004, Unit # 1 generator stator will be rewound. With the exception of these upgrades and the addition of remote control capability from the SCADA system in 1988 there has been no significant capital investment in this facility since the original in service date.

The wood stave penstock is in poor condition, with excessive deterioration, and significant leakage along the springline. The penstock has reached the stage where there are significant leaks that develop regularly, and water leaking from the penstock continues to undermine the supporting structure. The diameter of the penstock is also undersized, and limits the maximum output of the plant when both units are in operation. Engineering studies indicate that increasing the diameter from 2,133mm to 2,895mm diameter and replacing the leaking wooden penstock with a new steel penstock will increase annual output by as much as 7 GWh.

The steel surge tank is in fair to poor condition, and has reached the stage where significant rehabilitation of the structural steel, main tank and internal riser are now required. The external riser has also deteriorated to the point where complete replacement is necessary.

The following table gives the expenditures for the past five years for work at Rattling Brook Hydro Plant:

Project Cost (000s)					
Year	**2000**	**2001**	**2002**	**2003**	**2004F**
Total	**$128**	**$100**	**$932**	**$51**	**$477**

Project Justification

Reports including site assessment are included in Volume II, Energy Supply, Appendix 3, Attachments A and B.

Rattling Brook generating station is the largest energy producer in Newfoundland Power's system of hydroelectric plants.

Some of the equipment within the plant is forty-six years old, is obsolete and presents challenges when components fail and need to be repaired or replaced.

The wood stave penstock has experienced failures in recent years that have allowed large amounts of water to escape in an uncontrolled manner. Inspection of the surge tank has identified deterioration of structural steel components and temporary repairs have been carried out in recent years. There is a potential for damage and risk to employee and public safety if a catastrophic failure of either the penstock or surge tank were to occur.

The age of the protection and control equipment, governor and AC station service equipment justifies their replacement based upon obsolescence. Technical support for the electromechanical protection devices is limited, and as a result, the current situation is a mix of technologies created by temporary repairs completed over the years. The protection afforded by the existing electromechanical protection devices no longer provides the minimum standard of protection leaving the units susceptible to damage.

The alternative to replacing the penstock and refurbishing this plant would be to retire it. An economic analysis of the Rattling Brook hydroelectric system, considering this project and the expected capital and operating expenditures required over the next 25 years, indicates a positive net present value and an incremental levelized cost of energy, including capital and operating expenditures over the next 25 years of 1.7 cents per kWh. Energy from Rattling Brook can be produced at a cost significantly lower than that of replacement energy from Hydro's Holyrood Generating Station.

The Company will ensure this project is completed at the lowest possible cost consistent with reliable service. All material and contract labour will be obtained through competitive tendering.

Future Commitments

2006 - $5,643,000
2007 - $5,409,000

SUBSTATIONS

Project Title: **Rebuild Substations**

Location: **Greenspond, Grand Beach, Topsail and St. John's Main**

Classification: **Substations**

Project Cost: **$351,000**

Project Description

This project is necessary for the replacement of deteriorated and substandard substation infrastructure, such as bus structures, poles and support structures, equipment foundations, switches and fencing.

Replacement work will take place primarily at the St. John's Main substation, with additional minor work at three other substations.

Details are contained in Volume II, Substations, Appendix 1.

Project Cost (000s)				
Cost Category	**2005**	**2006**	**2007 - 2009**	**Total**
Material	$232	-	-	-
Labour – Internal	61	-	-	-
Labour – Contract	-	-	-	-
Engineering	46	-	-	-
Other	12	-	-	-
Total	**$351**	**$429**	**$4,704**	**$5,484**

Operating Experience

The following table gives the expenditures for the past five years for this project.

Project Cost (000s)					
Year	**2000**	**2001**	**2002**	**2003**	**2004F**
Total	**$426**	**$1,191**	**$687**	**$399**	**$531**

Project Justification

The Company has 137 substations varying in age from 3 years to greater than 100 years. The original cost of these substations is in excess of $100 million. Infrastructure to be replaced was identified as a result of monthly inspections and engineering studies. These expenditures will ensure reliable service and address safety concerns.

The Company will ensure this project is completed at the lowest possible cost consistent with reliable service. All material and contract labour will be obtained through competitive tendering.

Future Commitments

None.

Project Title: **Replacement and Standby Substation Equipment**

Location: **Various substations including Rocky Pond, Hardwoods, Twillingate and Garnish**

Classification: **Substations**

Project Cost: **$1,052,000**

Project Description

This project is necessary for the replacement of obsolete and/or unreliable electrical equipment and the maintenance of appropriate levels of spare equipment for use during emergencies.

The locations where the work will be undertaken in 2005 are noted above. Details are contained in Volume II, Substations, Appendix 2.

Project Cost (000s)				
Cost Category	**2005**	**2006**	**2007 - 2009**	**Total**
Material	$642	-	-	-
Labour – Internal	223	-	-	-
Labour – Contract	-	-	-	-
Engineering	174	-	-	-
Other	13	-	-	-
Total	**$1,052**	**$1,201**	**$6,727**	**$8,980**

Operating Experience

The following table gives the expenditures for the past five years for this project.

Project Cost (000s)					
Year	**2000**	**2001**	**2002**	**2003**	**2004F**
Total	**$313**	**$232**	**$2,716**	**$1,159**	**$1,287**

Project Justification

The Company has 137 substations. The major equipment items comprising a substation include power transformers, circuit breakers, reclosers, potential transformers and battery banks. In total the Company has approximately 190 power transformers, 400 circuit breakers, 200 reclosers, 340 voltage regulators, 220 potential transformers and 140 battery banks.

The need to replace equipment is determined on the basis of tests, inspections and the operational history of the equipment. The provision of adequate levels of spare equipment is based on past experience and engineering judgement, as well as a consideration of the impact the loss of a particular apparatus would have on the electrical system.

This project is justified based on the need to replace equipment to restore and maintain service. The budget estimate is based on equipment inspections and historical replacement requirements, as well as on assessments of the current stock of spare equipment.

The Company will ensure this project is completed at the lowest possible cost consistent with reliable service. All material and contract labour will be obtained through competitive tendering.

Future Commitments

None.

Project Title: **Transformer Cooling Refurbishment**

Location: **Humber**

Classification: **Substations**

Project Cost: **$174,000**

Project Description

This project involves the replacement of cooling radiators on two power transformers at Humber Substation that have begun to leak oil as a result of corrosion. This will address environmental concerns of oil spills due to leaking equipment.

Project Cost (000s)				
Cost Category	**2005**	**2006**	**2007 - 2009**	**Total**
Material	$87	-	-	-
Labour – Internal	37	-	-	-
Labour – Contract	-	-	-	-
Engineering	45	-	-	-
Other	5	-	-	-
Total	**$174**	**$300**	**$600**	**$1,074**

Operating Experience

The original radiators supplied with the transformers when they were purchased in 1968 and 1974 respectively, were coated with primer and enamel based paint for protection from the elements. Exposure to our environment causes the radiators to rust and blister. Eventually the radiators begin to leak at the welded seams and through the thinner cooling panel surfaces.

The original radiators are being replaced with galvanized units, which provide enhanced rust resistance. The new radiators have a life expectancy in the range of 40 years.

The following table gives the expenditures for the past five years for this project.

Project Cost (000s)					
Year	**2000**	**2001**	**2002**	**2003**	**2004F**
Total	**$206**	**$0**	**$0**	**$0**	**$293**

Project Justification

The cost of this project is justified based on the need to replace equipment to maintain reliable service. Oil is used in a transformer as part of its electrical insulation system. An uncontrolled loss of oil would compromise that system with the resulting failure of the transformer and the interruption of service to customers.

The amounts budgeted are based on equipment inspections and historical replacement requirements, as well as the current inventory of backup equipment.

The Company will ensure this project is completed at the lowest possible cost consistent with reliable service. All material and contract labour will be obtained through competitive tendering.

Future Commitments

None.

Project Title: **Protection and Monitoring Improvements**

Location: **Bay Roberts, Memorial and Gander**

Classification: **Substations**

Project Cost: **$78,000**

Project Description

This project is necessary for the replacement and/or addition of protective relaying equipment and control devices required to maintain system protection and increase operating reliability.

In 2005, work will take place at Bay Roberts Substation where a tap changer controller will be installed, at Memorial Substation where current transformers will be installed on the bus tie breaker and at Gander Substation where test blocks will be added to the 138 kV bus protection.

Project Cost (000s)				
Cost Category	**2005**	**2006**	**2007 - 2009**	**Total**
Material	$20	-	-	-
Labour – Internal	21	-	-	-
Labour – Contract	-	-	-	-
Engineering	37	-	-	-
Other	-	-	-	-
Total	**$78**	**$625**	**$693**	**$1,396**

Operating Experience

The following table gives the expenditures for the past five years for this project.

Project Cost (000s)					
Year	**2000**	**2001**	**2002**	**2003**	**2004F**
Total	**$92**	**$283**	**$116**	**$448**	**$60**

Project Justification

This project will make improvements to the protection and monitoring systems of the selected substations to allow for the safe and reliable operation of these substations.

The project is justified on the basis of maintaining reliable and safe operation of the electrical system.

The Company will ensure this project is completed at the lowest possible cost consistent with reliable service. All material and contract labour will be obtained through competitive tendering.

Future Commitments

None.

Project Title: **Distribution System Feeder Remote Control**

Location: **Various substations including Broad Cove, Lewisporte and Long Lake**

Classification: **Substations**

Project Cost: **$1,114,000**

Project Description

This is a continuation of a project initiated in 2002. It involves replacing a number of aging, limited function, electromechanical feeder relays and oil-filled reclosers with modern multi-function electronic relays and reclosers that can be remotely controlled from the System Control Centre (SCC).

By the end of 2004, the System Control Centre (SCC) will have remote control over 55 feeders through new electronic feeder relays and over 40 feeders through reclosers.

In 2005, 11 feeder relays will be replaced at various substations. There will also be 9 reclosers replaced in Broad Cove, Lewisporte and Long Lake substations.

Project Cost (000s)				
Cost Category	**2005**	**2006**	**2007 - 2009**	**Total**
Material	$587	-	-	-
Labour – Internal	218	-	-	-
Labour – Contract	-	-	-	-
Engineering	290	-	-	-
Other	19	-	-	-
Total	**$1,114**	**$1,024**	**$3,000**	**$5,138**

Operating Experience

The Company's electromechanical feeder relays and oil-filled reclosers are, on average, 25 years old and are nearing the end of their useful life.

The following table gives the expenditures for the past five years for this project.

Project Cost (000s)					
Year	**2000**	**2001**	**2002**	**2003**	**2004F**
Total	**$0**	**$0**	**$1,092**	**$1,165**	**$1,000**

Project Justification

This project is justified on the basis of improvements in safety, operating efficiencies, power system reliability improvements and a reduction in risk to the environment. The report which supports this project, *"Distribution Feeder Remote Control and Relay/Recloser Replacement Review",* was previously filed in response to Request for Information PUB-9.3 in the Newfoundland Power 2002 Capital Budget Application.

The Company will ensure this project is completed at the lowest possible cost consistent with reliable service. All material and contract labour will be obtained through competitive tendering.

Future Commitments

None.

Project Title: **Feeder Additions Due To Load Growth and Reliability**

Location: **Virginia Waters Substation**

Classification: **Substations**

Project Cost: **$268,000**

Project Description

This project involves the installation of a new 25 kV feeder at the Virginia Waters substation in the east end of St. John's to accommodate growth.

Details are contained in Volume II, Distribution, Appendix 2, Attachment A.

Project Cost (000s)				
Cost Category	**2005**	**2006**	**2007 - 2009**	**Total**
Material	$177	-	-	-
Labour – Internal	35	-	-	-
Labour – Contract	-	-	-	-
Engineering	40	-	-	-
Other	16	-	-	-
Total	**$268**	**$412**	**$380**	**$1,060**

Operating Experience

The following table gives the expenditures for the past five years for this project.

Project Cost (000s)					
Year	**2000**	**2001**	**2002**	**2003**	**2004F**
Total	**$64**	**$282**	**$0**	**$261**	**$200**

Project Justification

The project is justified on the basis of accommodating customer load growth. The proper sizing of equipment is necessary to avoid overloading conductors and equipment and to maintain system reliability.

The Company will ensure this project is completed at the lowest possible cost consistent with reliable service. All material and contract labour will be obtained through competitive tendering.

Future Commitments

None.

TRANSMISSION

Project Title: **Rebuild Transmission Lines**

Location: **Various**

Classification: **Transmission**

Project Cost: **$2,597,000**

Project Description

This project involves the replacement of poles, crossarms, conductors, insulators and miscellaneous hardware due to deficiencies identified during inspections and engineering reviews.

The work includes major upgrades on transmission lines 11L, 43L and 124L. Expenditures estimated at less than $50,000 will take place on approximately 50 other lines.

Project Cost (000s)				
Cost Category	**2005**	**2006**	**2007 - 2009**	**Total**
Material	$1,102	-	-	-
Labour – Internal	665	-	-	-
Labour – Contract	495	-	-	-
Engineering	110	-	-	-
Other	225	-	-	-
Total	**$2,597**	**$5,154**	**$15,506**	**$23,257**

Operating Experience

Many of the Company's transmission lines are experiencing pole, crossarm, conductor, insulator and hardware deterioration. Replacement is required to maintain the strength and integrity of these lines. Thirty per cent of the Company's 110 transmission lines are in excess of forty years of age.

The following table gives the expenditures for the past five years for this project.

Project Cost (000s)					
Year	**2000**	**2001**	**2002**	**2003**	**2004F**
Total	**$727**	**$2,289**	**$2,976**	**$4,026**	**$2,401**

Project Justification

This project is necessary to replace poles, crossarms, conductors, insulators and miscellaneous hardware due to deficiencies identified during annual inspections in order to ensure that such lines provide safe & reliable service to customers.

Detailed information on the projects is outlined in Volume II, Transmission, Appendix 1.

Future Commitments

None.

DISTRIBUTION

Project Title: **Extensions**

Location: **Various**

Classification: **Distribution**

Project Cost: **$6,374,000**

Project Description

This project involves the construction of both primary and secondary distribution lines to connect new customers to the electrical distribution system. The project also includes upgrades to the capacity of existing lines to accommodate customers who increase their electrical load. The project includes labour, materials, and other costs to install poles, wires and related hardware.

Project Cost (000s)				
Cost Category	**2005**	**2006**	**2007 - 2009**	**Total**
Material	$2,089	-	-	-
Labour – Internal	1,959	-	-	-
Labour – Contract	1,516	-	-	-
Engineering	626	-	-	-
Other	184	-	-	-
Total	**$6,374**	**$5,581**	**$16,431**	**$28,386**

Operating Experience

The project cost for the connection of new customers is calculated on the basis of historical data. Historical annual expenditures are adjusted for inflation and divided by the number of new customers in each year to derive an average extension cost per customer. Unusually high and low data is excluded from the average. This historical average is then modified by the GDP Deflator for Canada before being multiplied by the forecast number of new customers to determine the budget estimate. The forecast number of new customers is derived from economic projections provided by independent agencies.

The following table shows the annual expenditure for the past five years.

Project Cost (000s)					
Year	**2000**	**2001**	**2002**	**2003**	**2004F**
Total	**$3,981**	**$5,404**	**$5,717**	**$6,586**	**$6,854**

Project Justification

This project is justified on the basis of customer requirements.

The Company will ensure this project is completed at the lowest possible cost consistent with reliable service. All material and contract labour will be obtained through competitive tendering.

Future Commitments

None.

Project Title: **Meters**

Location: **Various**

Classification: **Distribution**

Project Cost: **$965,000**

Project Description

This project includes the purchase and installation of meters for new customers and replacement meters for existing customers. In 2005 the Company proposes the purchase and installation of meters as noted in the table below.

Meter Type	Number of Meters
Energy Only Domestic Meters	8,000
Other Energy Only and Demand Meters	1,010

Project Cost

Project Cost (000s)				
Cost Category	**2005**	**2006**	**2007 - 2009**	**Total**
Material	$787	-	-	-
Labour – Internal	149	-	-	-
Labour – Contract	28	-	-	-
Engineering	-	-	-	-
Other	1	-	-	-
Total	**$965**	**$819**	**$2,479**	**$4,263**

Operating Experience

The purchase of new meters is necessary to accommodate customer growth and to replace deteriorated meters. The quantity of meters for new customers is based on the Company's forecast of customer growth. The quantity for replacement purposes is determined using historical data for retired meters and sampling results from previous years. Sampling is done in accordance with regulations under the Electricity and Gas Inspection Act.

The following table shows the expenditures for the past five years.

Project Cost (000s)					
Year	**2000**	**2001**	**2002**	**2003**	**2004F**
Total	**$564**	**$569**	**$674**	**$595**	**$1,287**

Project Justification:

The requirement for regular meters is based on customer requirements and Industry Canada regulations.

The Company will ensure this project is completed at the lowest possible cost consistent with reliable service. All material and contract labour will be obtained through competitive tendering.

Future Commitments

None.

Project Title: **Services**

Location: **Various**

Classification: **Distribution**

Project Cost: **$1,895,000**

Project Description

This project involves the installation of service wires to connect new customers to the electrical distribution system. Service wires are low voltage wires that connect the customer's electrical service equipment to the utility's transformers. Also included in this category is the replacement of existing service wires due to deterioration, failure or damage, as well as the installation of larger wires to accommodate customers' additional load.

Project Cost (000s)				
Cost Category	**2005**	**2006**	**2007 - 2009**	**Total**
Material	$567	-	-	-
Labour – Internal	1,024	-	-	-
Labour – Contract	121	-	-	-
Engineering	159	-	-	-
Other	24	-	-	-
Total	**$1,895**	**$1,820**	**$5,473**	**$9,188**

Operating Experience

The project cost for the connection of new customers is calculated on the basis of historical data. For new services, historical annual expenditures are adjusted for inflation and divided by the number of new customers in each year to derive an average new service cost per customer. Unusually high and low data is excluded from the average. This historical average is then modified by the GDP Deflator for Canada before being multiplied by the forecast number of new customers to determine the budget estimate. A similar process is followed for replacement services using historical actual expenditures to replace damaged or deteriorated service wires. Street light customers are excluded for the purpose of this calculation.

The following table shows the expenditures for the past five years.

Project Cost (000s)					
Year	**2000**	**2001**	**2002**	**2003**	**2004F**
Total	**$1,532**	**$1,838**	**$1,843**	**$1,989**	**$1,876**

Project Justification

These projects are justified on the basis of customer requirements.

The Company will ensure this project is completed at the lowest possible cost consistent with reliable service. All material and contract labour will be obtained through competitive tendering.

Future Commitments

None.

Project Title: **Street Lighting**

Location: **Various**

Classification: **Distribution**

Project Cost: **$1,254,000**

Project Description

This project involves the installation of new lighting fixtures, replacement of existing fixtures, and the provision of associated overhead and underground wiring. A street light fixture includes the light head complete with bulb, photocell and starter as well as the pole mounting bracket and other hardware. The project is driven by customer requests and historical levels of lighting fixtures requiring replacement.

Project Cost (000s)				
Cost Category	**2005**	**2006**	**2007 - 2009**	**Total**
Material	$757	-	-	-
Labour – Internal	326	-	-	-
Labour – Contract	133	-	-	-
Engineering	37	-	-	-
Other	1	-	-	-
Total	**$1,254**	**$1,107**	**$3,313**	**$5,674**

Operating Experience

The project cost is calculated on the basis of historical data. For new street lights, historical annual expenditures are adjusted for inflation and divided by the number of new customers in each year to derive an average cost per new customer. This historical average is then modified by the GDP Deflator for Canada before being multiplied by the forecast number of new customers to determine the budget estimate.

For replacement street lights, historical annual expenditures for replacement of damaged, deteriorated or failed street lights are adjusted for inflation and divided by the total number of customers served in each year to derive an average replacement street light cost per customer. This historical average is then modified by the GDP Deflator for Canada before being multiplied by the forecast of the total number of customers served to determine the budget estimate.

The following table shows the expenditures for the past five years.

Project Cost (000s)					
Year	**2000**	**2001**	**2002**	**2003**	**2004F**
Total	**$911**	**$935**	**$1,199**	**$1,287**	**$1,144**

Project Justification

These projects are justified on the basis of customer requirements.

The Company will ensure this project is completed at the lowest possible cost consistent with reliable service. All material and contract labour will be obtained through competitive tendering.

Future Commitments

None.

Project Title: **Transformers**

Location: **Various**

Classification: **Distribution**

Project Cost: **$5,189,000**

Project Description

This project includes the cost of purchasing transformers for customer growth and the replacement or refurbishment of units that have deteriorated or failed.

Project Cost (000s)				
Cost Category	**2005**	**2006**	**2007 - 2009**	**Total**
Material	$5,189	-	-	-
Labour – Internal	-	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	-	-	-	-
Total	**$5,189**	**$4,700**	**$13,798**	**$23,687**

Operating Experience

The project requirements can be divided into three categories as follows:

a) The number of transformers required for new customers is based upon the forecast number of new residential and general service customers.

b) Replacement transformers are based on field surveys of rusty or deteriorated transformers.

c) The "other" category is for transformers required for conversions and upgrades, plus an allowance for contingency (burnouts and storm damage, etc.). This category is estimated on the basis of planned projects and historical data.

The following table shows the expenditures for the past five years.

Project Cost (000s)					
Year	**2000**	**2001**	**2002**	**2003**	**2004F**
Total	**$4,243**	**$4,550**	**$5,194**	**$5,529**	**$5,340**

Project Justification

This project is required to provide and maintain service to customers.

The Company will ensure this project is completed at the lowest possible cost consistent with reliable service. All material and contract labour will be obtained through competitive tendering.

Future Commitments

None.

Project Title: **Reconstruction**

Location: **Various**

Classification: **Distribution**

Project Cost: **$2,825,000**

Project Description

This project involves the replacement of deteriorated or storm damaged distribution structures and electrical equipment. This project is generally comprised of a number of smaller projects that are identified during the year as a result of line inspections, or recognized following operational problems. By their nature, these are high priority projects that normally cannot be deferred to the next budget year. This project differs from the Rebuild Distribution Lines project, which involves rebuilding sections of lines that are identified and planned in advance of budget preparation.

Project Cost (000s)				
Cost Category	**2005**	**2006**	**2007 - 2009**	**Total**
Material	$634	-	-	-
Labour – Internal	1,224	-	-	-
Labour – Contract	719	-	-	-
Engineering	135	-	-	-
Other	113	-	-	-
Total	**$2,825**	**$3,064**	**$9,853**	**$15,742**

Operating Experience

The project cost is estimated on the basis of average historical expenditures related to unplanned repairs to distribution feeders.

The following table shows the expenditures for the past five years.

Project Cost (000s)					
Year	**2000**	**2001**	**2002**	**2003**	**2004F**
Total	**$1,888**	**$2,547**	**$2,878**	**$2,846**	**$2,440**

Project Justification

These projects are justified on the need to replace damaged electrical equipment to maintain a safe and reliable system.

The Company will ensure this project is completed at the lowest possible cost consistent with reliable service. All material and contract labour will be obtained through competitive tendering.

Future Commitments

None.

Project Title: **Aliant Pole Purchase**

Location: **Corporate**

Classification: **Distribution**

Project Cost: **$4,044,000**

Project Description

This project covers the 2005 installment associated with the Support Structures Purchase Agreement entered into with Aliant Telecom Inc. in 2001.

Operating Experience

Not Applicable.

Project Justification

This project is necessary to comply with the terms of the Support Structures Purchase Agreement between Newfoundland Power Inc. and Aliant Telecom Inc. covering the purchase of all joint-use poles within Newfoundland Power's service territory over a five year period.

Future Commitments

In accordance with the terms of the Support Structures Purchase Agreement, the final amount of $4,044,000 required to complete the purchase of all joint-use poles within Newfoundland Power's service territory from Aliant Telecom Inc. will be paid in 2005.

Project Title: **Rebuild Distribution Lines**

Location: **Various**

Classification: **Distribution**

Project Cost: **$4,210,000**

Project Description

This project involves the replacement of deteriorated distribution structures and electrical equipment that have been previously identified through ongoing line inspections, engineering reviews, or day to day operations. The total budget estimate for this category is based on individual estimates.

Distribution rebuild projects can involve either the complete rebuilding of deteriorated distribution lines or the selective replacement of various line components based on inspections and engineering reviews. These typically include the replacement of poles, crossarms, conductor, cutouts, surge/lightning arrestors, insulators and transformers.

The work for 2005 includes feeder improvements on 52 of the Company's 300 feeders, and the replacement of deteriorated padmount transformers and underground services.

Project Cost (000s)				
Cost Category	**2005**	**2006**	**2007 - 2009**	**Total**
Material	$2,018	-	-	-
Labour – Internal	1,608	-	-	-
Labour – Contract	305	-	-	-
Engineering	53	-	-	-
Other	226	-	-	-
Total	**$4,210**	**$5,347**	**$14,850**	**$24,407**

The following table shows the expenditures for the past five years.

Project Cost (000s)					
Year	**2000**	**2001**	**2002**	**2003**	**2004F**
Total	**$755**	**$2,223**	**$3,210**	**$3,351**	**$4,181**

Operating Experience

Distribution feeders are inspected in accordance with Newfoundland Power's distribution inspection standards on a five-year rotation to identify:

a) Deficiencies with plant that are a risk to public safety, employee safety, or are likely to result in imminent failure of a structure or hardware.
b) Transformers containing PCBs that need to be replaced.
c) Transformers that must be replaced due to rust.
d) Locations where lightning arrestors are required as per the 2003 Lightning Arrestor Review. See the 2004 Capital Budget Application, Volume III, Distribution, Appendix 2, Attachment B.
e) Locations where CP8080 and 2-piece insulators still exist. These insulators have a history of failure. See the 2004 Capital Budget Application, Volume III, Distribution, Appendix 2, Attachment C.
f) Locations where current limiting fuses are required in accordance with the internal memo dated January 11, 2000. See the 2004 Capital Budget Application, Volume III, Distribution, Appendix 2, Attachment D.
g) Hardware that has high risk of failure, such as automatic sleeves and porcelain cutouts. See the 2004 Capital Budget Application, Volume III, Distribution, Appendix 2, Attachment E and Attachment F.

In addition to items identified during regularly scheduled inspections noted above, specific engineering reviews and the day to day operations of the Company also identify plant deficiencies that need to be addressed within the capital expenditure program.

Project Justification

The Company has over 8,000 kilometers of distribution lines in service and has an obligation to maintain this plant in good condition to safeguard the public and its employees and to maintain reliable electrical service. The replacement of deteriorated distribution structures and equipment is an important part of meeting this obligation.

The Company will ensure this project is completed at the lowest possible cost consistent with reliable service. All material and contract labour will be obtained through competitive tendering.

Future Commitments

None.

Project Title: **Relocate/Replace Distribution Lines For Third Parties**

Location: **Various**

Classification: **Distribution**

Project Cost: **$734,000**

Project Description

This project is necessary to accommodate third party requests for the relocation or replacement of distribution lines. The relocation or replacement of distribution lines results from (1) work initiated by municipal, provincial and federal governments, (2) work initiated by other utilities such as Aliant Telecom, Persona and Rogers Cable, (3) requests from customers or (4) vehicle accident damage.

Project Cost (000s)				
Cost Category	**2005**	**2006**	**2007 - 2009**	**Total**
Material	$185	-	-	-
Labour – Internal	258	-	-	-
Labour – Contract	247	-	-	-
Engineering	22	-	-	-
Other	22	-	-	-
Total	**$734**	**$435**	**$1,305**	**$2,474**

Operating Experience

The cost estimate is based on historical expenditures and individual project estimates. Generally these expenditures are associated with a number of small projects that are not specifically identified at the time the budget is prepared. Historical costs have varied significantly from year to year based on third party requests. Recent increases are primarily due to other utility and government initiated work.

The following table shows the annual expenditures for the past five years.

Project Cost (000s)					
Year	**2000**	**2001**	**2002**	**2003**	**2004F**
Total	**$769**	**$585**	**$390**	**$330**	**$620**

Project Justification

The Company must respond to requests for relocation and replacement of distribution facilities under the provisions of agreements in place with the requesting parties.

Estimated contributions from customers and requesting parties associated with this project have been included in the $1.5 million contribution in aid of construction amount referred to in the Application.

The Company will ensure this project is completed at the lowest possible cost consistent with reliable service. All material and contract labour will be obtained through competitive tendering.

Future Commitments

None.

Project Title: **Distribution Reliability Initiative**

Location: **Various**

Classification: **Distribution**

Project Cost: **$872,000**

Project Description

The project involves the replacement of deteriorated poles, conductor and hardware to reduce both the frequency and duration of power interruptions to the customers served by the distribution line. The nature of the upgrading work follows from a detailed assessment of past problems, knowledge of local environmental conditions (such as salt contamination and wind and ice loading), and engineering knowledge to apply location specific design and construction standards. Project plans are subsequently developed from an engineering analysis and options are evaluated that improve reliability performance.

Project Cost (000s)				
Cost Category	**2005**	**2006**	**2007 - 2009**	**Total**
Material	$375	-	-	-
Labour – Internal	250	-	-	-
Labour – Contract	116	-	-	-
Engineering	17	-	-	-
Other	114	-	-	-
Total	**$872**	**$1,568**	**$3,000**	**$5,440**

Operating Experience

The following table identifies the feeders selected for upgrading in 2005 and indicates the number of customers affected, and the average unscheduled distribution yearly interruption statistics for the five-year period ending December 31, 2003. The SAIFI and SAIDI statistics exclude planned power interruptions and interruptions due to loss of supply from Hydro. See 2004 Capital Budget Application, Volume III, Distribution, Appendix 3, Attachment A for an analysis of WES-02. An analysis of GBY-02 is contained in Volume II, Distribution, Appendix 1, Attachment A of this Application.

Feeder	Number of Customers	SAIFI[1] Interruptions Per Year	SAIDI[2] Hours Per Year
Lumsden/Cape Freels (WES-02)	766	3.9	8.0
Carmanville/Gander Bay (GBY-02)	886	3.5	8.2
Company Average		**1.6**	**2.3**

Notes:
[1] System Average Interruption Frequency Index (SAIFI) is the average number of interruptions per customer. It is calculated by dividing the number of customers that have experienced an outage by the total number of customers in an area.

[2] System Average Interruption Duration Index (SAIDI) is the average interruption duration per customer. It is calculated by dividing the number of customer-outage-hours (e.g., a two hour outage affecting 50 customers equals 100 customer-outage-hours) by the total number of customers in an area.

The following table shows the expenditures for this project for the past five years.

Project Cost (000s)					
Year	**2000**	**2001**	**2002**	**2003**	**2004F**
Total	**$1,776**	**$3,422**	**$1,092**	**$1,546**	**$889**

Project Justification

These projects are justified on the basis of reliability improvement. Customers currently supplied by these feeders experience power interruptions more often or of longer duration than the Company average. Individual feeder projects have been prioritized based on their historic SAIFI and SAIDI statistics.

Expenditures on the distribution reliability initiative have had a positive impact on the reliability performance of the feeders that have been upgraded.

The total WES-02 project is estimated at $1,099,000, of which $692,000 will be expended in 2004, and approximately $407,000 in 2005.

The total GBY-02 project is estimated at $863,000 of which $465,000 will be expended in 2005 and approximately $398,000 in 2006.

The Company will ensure this project is completed at the lowest possible cost consistent with reliable service. All material and contract labour will be obtained through competitive tendering.

Future Commitments

None.

Project Title: **Feeder Additions and Upgrades to Accommodate Growth**

Location: **Virginia Waters, Broad Cove and Grand Bay**

Classification: **Distribution**

Project Cost: **$173,000**

Project Description

This project consists of the construction of a new feeder, equipment or conductor upgrades on existing feeders, and/or installation of sections of feeders to accommodate energy sales growth.

The work for 2005 includes the construction of a new feeder at Virginia Waters and the installation of voltage regulators on the Broad Cove-04 and Grand Bay-02 feeders.

Project Cost (000s)				
Cost Category	**2005**	**2006**	**2007 - 2009**	**Total**
Material	$122	-	-	-
Labour – Internal	28	-	-	-
Labour – Contract	19	-	-	-
Engineering	4	-	-	-
Other	-	-	-	-
Total	**$173**	**$202**	**$150**	**$525**

Operating Experience

Forecast and actual peak load conditions and customer growth indicate that these projects are warranted in order to maintain the electrical system within recommended guidelines. See Volume II, Distribution, Appendix 2 for more details.

The following table shows the expenditures for the past five years.

Project Cost (000s)					
Year	**2000**	**2001**	**2002**	**2003**	**2004F**
Total	**$262**	**$0**	**$0**	**$454**	**$544**

Project Justification

This project is required to maintain substation transformer loading, voltage regulation and/or conductor loading within recommended guidelines.

The Company will ensure this project is completed at the lowest possible cost consistent with reliable service. All material and contract labour will be obtained through competitive tendering.

Future Commitments

None.

Project Title: **Interest During Construction**

Location: **N/A**

Classification: **Distribution**

Project Cost: **$100,000**

Project Description

This is an estimate of the interest during construction that will be charged on distribution work orders with an estimated expenditure of less than $50,000 and a construction period in excess of three months.

Operating Experience

This calculation is based on an estimated monthly average of total distribution work in progress of $1.0 million. The interest rate which is applied each month is dependent on the source of funds to finance the capital expenditure and is calculated in accordance with Order No. P.U. 37 (1981).

The following table shows the expenditures for the past five years.

Project Cost (000s)					
Year	**2000**	**2001**	**2002**	**2003**	**2004F**
Total	**$83**	**$78**	**$80**	**$74**	**$100**

Project Justification

These costs are justified on the same basis as the distribution work orders to which they are charged.

Future Commitments

None.

GENERAL PROPERTY

Project Title: **Tools and Equipment**

Location: **Company offices, service buildings and vehicles**

Classification: **General Property**

Project Cost: **$691,000**

Project Description

This project is the addition or replacement of tools and equipment utilized by line and support staff in the day-to-day operations of the Company, as well as the replacement or addition of office furniture and equipment. Details of equipment to be acquired in 2005 are contained in Volume II, General Property, Appendix 1.

Project Cost (000s)				
Cost Category	**2005**	**2006**	**2007 - 2009**	**Total**
Material	$691	-	-	-
Labour – Internal	-	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	-	-	-	-
Total	**$691**	**$505**	**$1,245**	**$2,441**

Operating Experience

The following table gives the expenditures for the past five years for this project.

Project Cost (000s)					
Year	**2000**	**2001**	**2002**	**2003**	**2004F**
Total	**$427**	**$537**	**$378**	**$865**	**$574**

Project Justification

This equipment enables staff to perform work in a safe, effective and efficient manner.

The project cost is based on historical costs for the replacement of tools and equipment that become broken or worn out. Additional or replacement tools are purchased to increase employee productivity, quality of work and overall operational efficiency.

Future Commitments

None.

Project Title: **Additions to Real Property**

Location: **Electrical Maintenance Facility, Duffy Place Building, Kenmount Road Building, Corner Brook West Street Building**

Classification: **General Property**

Project Cost: **$325,000**

Project Description

This project is the addition to, or renovation of, Company buildings and property that are not part of the electrical supply to customers. Details of work associated with each location noted above are contained in Volume II, General Property, Appendix 2.

Project Cost (000s)				
Cost Category	**2005**	**2006**	**2007 - 2009**	**Total**
Material	$221	-	-	-
Labour – Internal	4	-	-	-
Labour – Contract	-	-	-	-
Engineering	2	-	-	-
Other	98	-	-	-
Total	**$325**	**$918**	**$1,854**	**$3,097**

Operating Experience

The following table gives the expenditures for the past five years for this project.

Project Cost (000s)					
Year	**2000**	**2001**	**2002**	**2003**	**2004F**
Total	**$503**	**$407**	**$337**	**$237**	**$271**

Project Justification

The project is necessary to maintain buildings and support facilities and to operate them in a safe and efficient manner.

Future Commitments

None.

TRANSPORTATION

Project Title: **Purchase Vehicles and Aerial Devices**

Location: **Various**

Classification: **Transportation**

Project Cost: **$2,642,000**

Project Description

This project involves the necessary replacement of aerial devices (line trucks), and passenger and off-road vehicles. The Company has determined that the units to be replaced have reached the end of their useful lives.

Project Cost (000s)				
Cost Category	**2005**	**2006**	**2007 - 2009**	**Total**
Material	$2,587	-	-	-
Labour – Internal	46	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	9	-	-	-
Total	**$2,642**	**$2,987**	**$7,871**	**$13,500**

The following table lists units to be acquired in 2004.

Category	No. of Units
Heavy fleet vehicles [1]	7
Passenger vehicles [2]	46
Off-road vehicles [3]	8
Total	**61**

Notes:
[1] The Heavy Fleet Vehicles category includes the purchase of replacement line trucks.
[2] The Passenger/Off-Road Vehicles category includes the purchase of cars and light duty trucks.
[3] The off-road category includes snowmobiles, ATVs and trailers.

Operating Experience

Volume II, Transportation, Appendix 1 provides information with respect to age, odometer reading and maintenance cost for each vehicle selected for replacement.

The following table gives the expenditures for the past five years for this project.

Project Cost (000s)					
Year	**2000**	**2001**	**2002**	**2003**	**2004F**
Total	**$2,276**	**$2,061**	**$1,609**	**$3,429**	**$2,887**

Project Justification

The Company has a guideline that initiates the consideration of the replacement of vehicles. For heavy fleet vehicles the guideline is age of 10 years or 250,000 kilometers. For passenger vehicles the guideline is age of 5 years or 150,000 kilometers.

All units to be replaced have been evaluated for factors such as overall condition, maintenance history and immediate repair requirements. Based on this evaluation, it has been determined that each unit has reached the end of its useful life.

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

Future Commitments

None.

TELECOMMUNICATIONS

Project Title: **Replace/Upgrade Communications Equipment**

Location: **Various**

Classification: **Telecommunications**

Project Cost: **$60,000**

Project Description

This project involves the replacement and/or upgrade of equipment identified during inspections and routine operations.

Project Cost (000s)				
Cost Category	**2005**	**2006**	**2007 - 2009**	**Total**
Material	$35	-	-	-
Labour – Internal	-	-	-	-
Labour – Contract	-	-	-	-
Engineering	25	-	-	-
Other	-	-	-	-
Total	**$60**	**$75**	**$361**	**$496**

Operating Experience

Older vintage radio equipment and towers are susceptible to breakdown and other deficiencies. Where practical, equipment is repaired and deficiencies rectified. However, where it is not feasible to repair the equipment or correct the deficiencies, new units are acquired.

The following table gives the expenditures for the past five years for this project.

Project Cost (000s)					
Year	**2000**	**2001**	**2002**	**2003**	**2004F**
Total	**$125**	**$94**	**$105**	**$41**	**$160**

Project Justification

Newfoundland Power engages an engineering consultant to inspect radio towers. Deficiencies identified through these inspections are addressed through this project. The Company has approximately 340 mobile radios in service. Each year approximately 20 units that show a high frequency of breakdown and repair are identified and replaced with more reliable units.
The Company will ensure this project is completed at the lowest possible cost consistent with reliable service.

Future Commitments

None.

INFORMATION SYSTEMS

Project Title: **Application Enhancements**

Location: **All Service Areas**

Classification: **Information Systems**

Project Cost: **$1,087,000**

Project Description

The Company has software applications that are custom developed, such as the Customer Service System ("CSS") and the Outage Management System, and others that are vendor provided such as Microsoft Great Plains. This project is necessary to enhance these software applications to support changing business requirements. For details see Volume II, Information Systems, Appendix 1.

Project Cost (000s)				
Cost Category	**2005**	**2006**	**2007 - 2009**	**Total**
Material	$135	-	-	-
Labour – Internal	684	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	268	-	-	-
Total	**$1,087**	**$1,377**	**$3,225**	**$5,689**

Operating Experience

The project cost is based on an assessment of historical expenditures. For comparison purposes, the following table gives the expenditures for this project for the past five years.

Project Cost (000s)					
Year	**2000**	**2001**	**2002**	**2003**	**2004F**
Total	**$906**	**$619**	**$726**	**$920**	**$1,319**

Project Justification

This project is justified on the basis of improvements in customer service and increased operational efficiencies.

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

Future Commitments

None.

Project Title: **Application Environment**

Location: **All Service Areas**

Classification: **Information Systems**

Project Cost: **$710,000**

Project Description

This project involves the necessary upgrading of technology products and related processes required to support the implementation, upgrading, and enhancement of the Company's computer applications. It includes upgrades to current software tools, processes and applications as well as the acquisition of new software licences. For details see Volume II, Information Systems, Appendix 2.

Project Cost (000s)				
Cost Category	**2005**	**2006**	**2007 - 2009**	**Total**
Material	$280	-	-	-
Labour – Internal	330	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	100	-	-	-
Total	**$710**	**$701**	**$2,832**	**$4,243**

Operating Experience

The project cost is based on an assessment of historical expenditures. For comparison purposes, the following table gives the expenditures for this project for the past five years.

Project Cost (000s)					
Year	**2000**	**2001**	**2002**	**2003**	**2004F**
Total	**$587**	**$560**	**$724**	**$721**	**$811**

Project Justification

This project is justified on the basis of maintaining customer service and operational efficiencies.

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

Future Commitments

None.

Project Title: **Customer Systems Replacement**

Location: **All Service Areas**

Classification: **Information Systems**

Project Cost: **$144,000**

Project Description

This project involves efficiency enhancements to the Customer Service System which also will reduce reliance on the OpenVMS operating system. This includes improvements to the CSS overnight batch processing. For details see Volume II, Information Systems, Appendix 3.

Project Cost (000s)				
Cost Category	**2005**	**2006**	**2007 - 2009**	**Total**
Material	$-	-	-	-
Labour – Internal	103	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	41	-	-	-
Total	**$144**	**$170**	**$526**	**$840**

Operating Experience

The following table gives the expenditures for this project for the past five years.

Project Cost (000s)					
Year	**2000**	**2001**	**2002**	**2003**	**2004F**
Total	**$0**	**$0**	**$0**	**$113**	**$226**

Project Justification

This project is justified on the basis of improved operational efficiencies.

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

Future Commitments

None.

Project Title: **Network Infrastructure**

Location: **All Service Areas**

Classification: **Information Systems**

Project Cost: **$276,000**

Project Description

This project involves the replacement of aging network components that have reached the end of their useful life and upgrades to increase the connectivity and reliability of the data centers located at Kenmount Road, Duffy Place, and Topsail Road. For details see Volume II, Information Systems, Appendix 4.

Project Cost (000s)				
Cost Category	**2005**	**2006**	**2007 - 2009**	**Total**
Material	$196	-	-	-
Labour – Internal	53	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	27	-	-	-
Total	**$276**	**$50**	**$250**	**$576**

Operating Experience

The project cost is based on an assessment of historical expenditures. For comparison purposes, the following table gives the expenditures for this project for the past five years.

Project Cost (000s)					
Year	**2000**	**2001**	**2002**	**2003**	**2004F**
Total	**$205**	**$0**	**$0**	**$532**	**$393**

Project Justification

This project is justified on the basis of maintaining customer service and operational efficiencies.

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

Future Commitments

None.

Project Title: **Personal Computer Infrastructure**

Location: **All Service Areas**

Classification: **Information Systems**

Project Cost: **$455,000**

Project Description

This project is necessary for the replacement or upgrade of personal computers, printers and associated assets that have reached the end of their useful life. The Company currently experiences a four to six year life cycle for personal computers. In 2005, 113 PCs will be replaced (88 desktop computers and 25 laptop computers). This project also covers the purchase of 6 printers to replace existing printers that have reached the end of their useful life and additional peripheral equipment such as monitors. For details see Volume II, Information Systems, Appendix 5.

Project Cost (000s)				
Cost Category	**2005**	**2006**	**2007 - 2009**	**Total**
Material	$262	-	-	-
Labour – Internal	91	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	102	-	-	-
Total	**$455**	**$550**	**$1,655**	**$2,660**

Operating Experience

The project cost is based on an assessment of historical expenditures. For comparison purposes, the following table gives the expenditures for this project for the past five years.

Project Cost (000s)					
Year	**2000**	**2001**	**2002**	**2003**	**2004F**
Total	**$784**	**$405**	**$635**	**$518**	**$459**

Project Justification

This project is justified on the basis of maintaining customer service and operational efficiencies.

All materials and services for this project will be purchased after examining the competitive bids of prospective suppliers.

Future Commitments

None.

Project Title: **Shared Server Infrastructure**

Location: **All Service Areas**

Classification: **Information Systems**

Project Cost: **$571,000**

Project Description

The Shared Server Infrastructure project includes the procurement, implementation, and management of the hardware and software relating to the operation of shared servers. Shared servers are computers that support applications used by multiple employees. Management of these shared servers, and their components, is critical to ensuring that these applications operate effectively at all times.

This project is necessary to maintain current performance on the Company's shared servers and to provide the additional infrastructure needed to accommodate new and existing applications. This involves the replacement and upgrade of disks, processors, and memory, as well as security and monitoring software. For details see Volume II, Information Systems, Appendix 6.

Project Cost (000s)				
Cost Category	**2005**	**2006**	**2007 - 2009**	**Total**
Material	$320	-	-	-
Labour – Internal	163	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	88	-	-	-
Total	**$571**	**$750**	**$2,201**	**$3,522**

Operating Experience

The project cost is based on an assessment of historical expenditures. For comparison purposes, the following table gives the expenditures for this project for the past five years.

Project Cost (000s)					
Year	**2000**	**2001**	**2002**	**2003**	**2004F**
Total	**$286**	**$625**	**$705**	**$1,608**	**$686**

Project Justification

This project is justified on the basis of maintaining customer service and operational efficiencies.

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

Future Commitments

None.

UNFORESEEN ITEMS

Project Title: **Allowance for Unforeseen Items**

Location: **Various**

Classification: **Unforeseen Items**

Project Cost: **$750,000**

Project Description

This allowance is necessary to cover any unforeseen capital expenditures which have not been budgeted elsewhere. The purpose of the account is to permit the Company to act expeditiously to deal with events affecting the electrical system in advance of seeking specific approval of the Board. Examples of such expenditures are the replacement of facilities and equipment due to major storm damages or equipment failure.

Operating Experience

This project provides funds for timely service restoration.

Project Justification

Projects for which these funds are intended and justified on the basis of reliability, or on the need to immediately replace deteriorated or damaged equipment.

The Company will ensure this project is completed at the lowest possible cost consistent with reliable service. All material and contract labour will be obtained through competitive tendering.

Future Commitment

None.

Newfoundland Power Inc.
2005 Capital Budget
Estimate of Future Required Expenditures on
2005 Projects
(000s)

Budget Class and Project	2005	2006	2007
Energy Supply			
Rattling Brook - Hydro Plant Refurbishment	$350	$5,643	$5,409

Newfoundland Power Inc.
2005 Capital Budget
Rate Base
(000s)

	Historical Data 2002	Historical Data 2003	Forecast 2004	Forecast 2005
Plant Investment	$ 1,005,674	$ 1,069,420	$ 1,109,713	$ 1,146,952
Deduct:				
Accumulated Depreciation	420,736	448,245	464,072	482,406
Contributions in Aid of Construction	19,788	20,300	20,915	21,242
Deferred Income Taxes	-	988	1,425	1,208
Weather Normalization Reserve	(10,919)	(10,435)	(11,368)	(10,242)
	429,605	459,098	475,044	494,614
	576,069	610,322	634,669	652,338
Add - Contributions Country Homes	570	653	550	550
Balance - Current Year	576,639	610,975	635,219	652,888
Balance - Previous Year	553,586	576,639	610,975	635,219
Average	565,113	593,807	623,097	644,054
Cash Working Capital Allowance	4,712	4,977	5,248	5,495
Materials and Supplies	3,512	4,009	4,575	4,085
Average Deferred Charges[1]	-	72,937	80,152	86,508
Average Rate Base at Year End	$ 573,337	$ 675,730	$ 713,072	$ 740,142

[1] As per Order No. P.U. 19 (2003), the Board approved a change in Average Rate Base to include Average Deferred Charges beginning in 2003.

Newfoundland Power Inc.
2005 Capital Budget
Average Invested Capital

	Forecast 2004		Forecast 2005	
	(000s)	%	(000s)	%
Common Equity	$ 316,947	44.87%	$ 329,524	44.77%
Debt	379,915	53.79%	397,166	53.95%
Preferred Equity	9,429	1.34%	9,429	1.28%
Total	$ 706,291	100.00%	$ 736,119	100.00%

Newfoundland Power Inc.
2005 Capital Budget
Calculation of Rate of Return on Rate Base

Return on Rate Base Formula Approved by Order No. P.U. 36 (1998-99):

$$\textbf{Rate of Return on Rate Base} = \left[\frac{\text{Invested Capital}}{\text{Rate Base}} \times \text{Weighted Average Cost of Capital} \right] + \frac{\text{Z}}{\text{Rate Base}}$$

Where Z represents amounts which are recognized in the calculation of either weighted average cost of capital or rate of return on rate base, but not both. These amounts include:

(a) Amortization of Capital Stock Issue Expenses (Recognized in the rate of return on rate base calculation but not the weighted average cost of capital calculation.);
(b) Interest on Customer Deposits (Recognized in the weighted average cost of capital calculation but not the rate of return on rate base calculation.); and,
(c) Interest Charged to Construction (Recognized in the rate of return on rate base calculation but not the weighted average cost of capital calculation.).

2004 (approved by Order No. P.U. 19 (2003)):

$$\mathbf{8.91\%} = \left[\frac{\$\ 700{,}244}{\$\ 703{,}102} \times 8.97\% \right] + \frac{\$\ 66 + \$\ 30 - \$\ 246}{\$703{,}102}$$

Forecast 2005 rate base and invested capital values as per 2005 capital budget application, and an allowed return on equity of 9.75%:

$$\mathbf{8.90\%} = \left[\frac{\mathbf{\$\ 736{,}119}}{\mathbf{\$\ 740{,}142}} \times 8.97\% \right] + \frac{\$\ 66 + \$\ 30 - \$\ 246}{\mathbf{\$740{,}142}}$$

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

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

IN THE MATTER OF an application by Newfoundland Power Inc. for an order pursuant to Sections 41, 78 and 80 of the Act:

(a) approving its 2005 Capital Budget of $48,141,000;
(b) (i) fixing and determining its average rate base for 2003 in the amount of $675,730,000; (ii) approving its revised forecast average rate base for 2004 in the amount of $713,072,000; and (iii) approving its forecast average rate base for 2005 in the amount of $740,142,000; and
(c) approving revised values for rate base and invested capital for use in the automatic adjustment formula (the "Automatic Adjustment Formula") for the calculation of return on rate base for 2005 pursuant to Order No. P.U. 19 (2003).

2005 Capital Budget Plan

August 31, 2004

NEWFOUNDLAND POWER
A FORTIS COMPANY

CONTENTS

I. Overview

In Order No. P.U. 36 (2002-2003) (the "Order"), the Board of Commissioners of Public Utilities for Newfoundland and Labrador (the "Board") expressed its view that stable and predictable year over year capital budgets was a desirable objective for Newfoundland Power (the "Company"). In the Order, the Board also recognized that uncertainties and exigencies faced by the Company would challenge year over year capital expenditure stability. The Order directed the Company to file a Capital Budget Plan as part of its 2004 Capital Budget Application.

In Order No. P.U. 35 (2003) the Board reiterated its position.

> ***"Unless otherwise directed by the Board, NP shall file a 'Capital Budget Plan' as part of its 2005 and future Capital Budget Applications and should include:***
> ***(a) An updated five (5) year plan for maintaining the stability of the capital budget and capital works program, including an amount of maximum budget growth and a contingency for unexpected or unusual events during the period; and***
> ***(b) Identification of any changes or anticipated change in expenditure patterns and full explanation of reasons therefore."***

The 2005 Capital Budget Plan (the "Plan") is filed by Newfoundland Power as part of its 2005 Capital Budget Application in compliance with the Board's directives.

The Plan includes:

- An overview of expenditure patterns by budget category and origin;
- A summary of the five-year plan for maintaining the stability of the capital budget and the capital works program; and,
- An assessment of risks to the plan including the maximum budget growth and a contingency for unexpected or unusual events during the period.

II. Capital Budget Plan

This report outlines a five-year capital budget plan for maintaining the stability of the capital budget, including an assessment of risks to the Plan which could cause budget growth to exceed that planned. In addition, this section assesses maximum budget growth and contingencies for unusual events during this period.

A. Plan Overview

The Company plans to invest approximately $256 million in plant and equipment during the 2005 through 2009 period. On an annual basis capital expenditures are expected to average approximately $51 million and range from a low of $48 million in 2005 to a high of $55 million in 2006. As shown in Chart 1, excluding expenditures related to the purchase of joint-use poles from Aliant, planned capital expenditures are forecast to remain relatively stable and consistent with the average for the past five years.

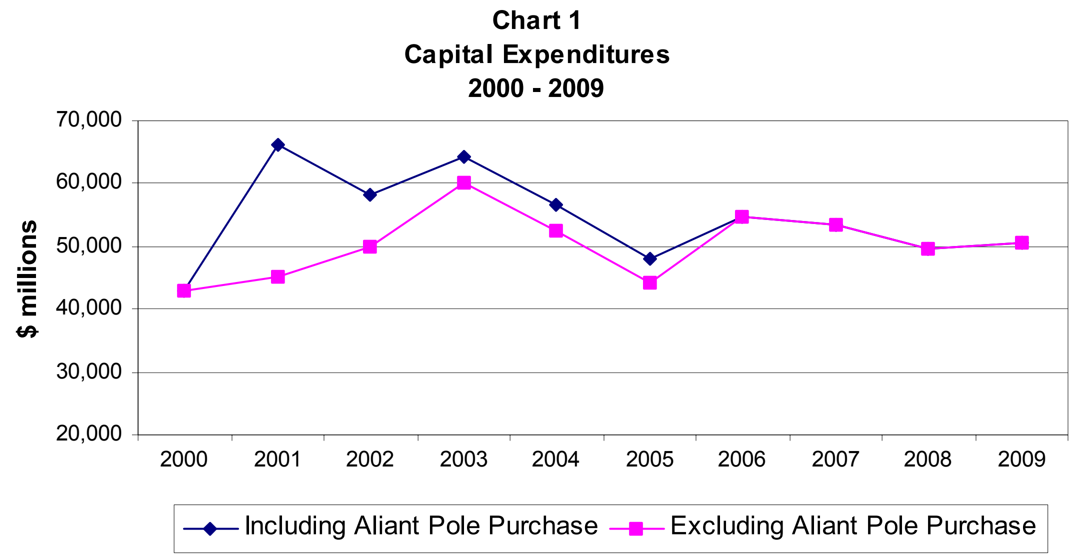
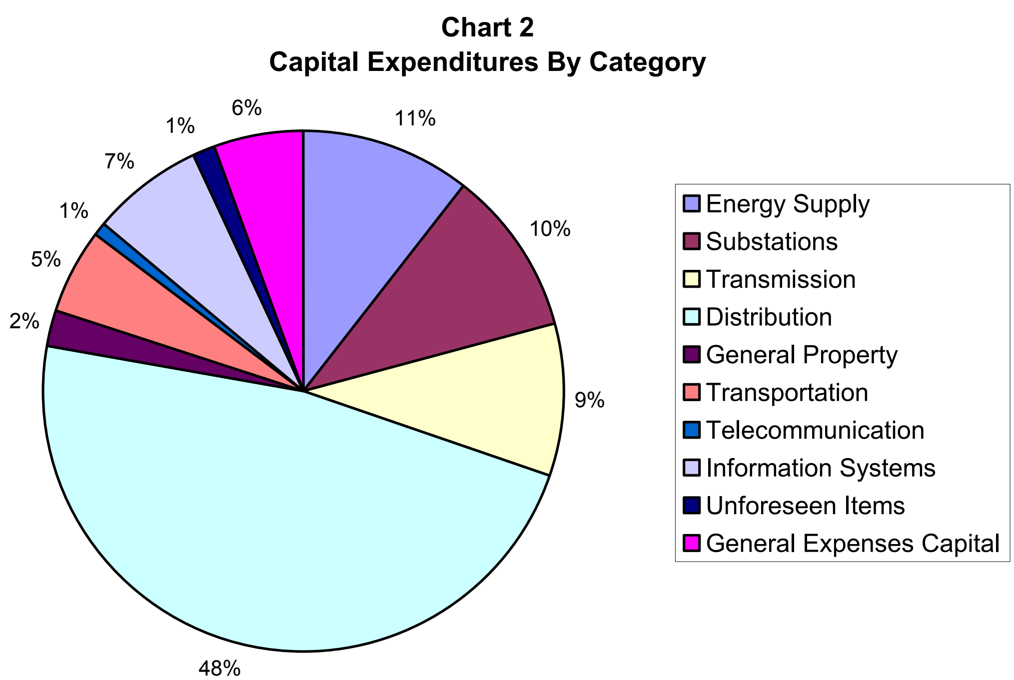
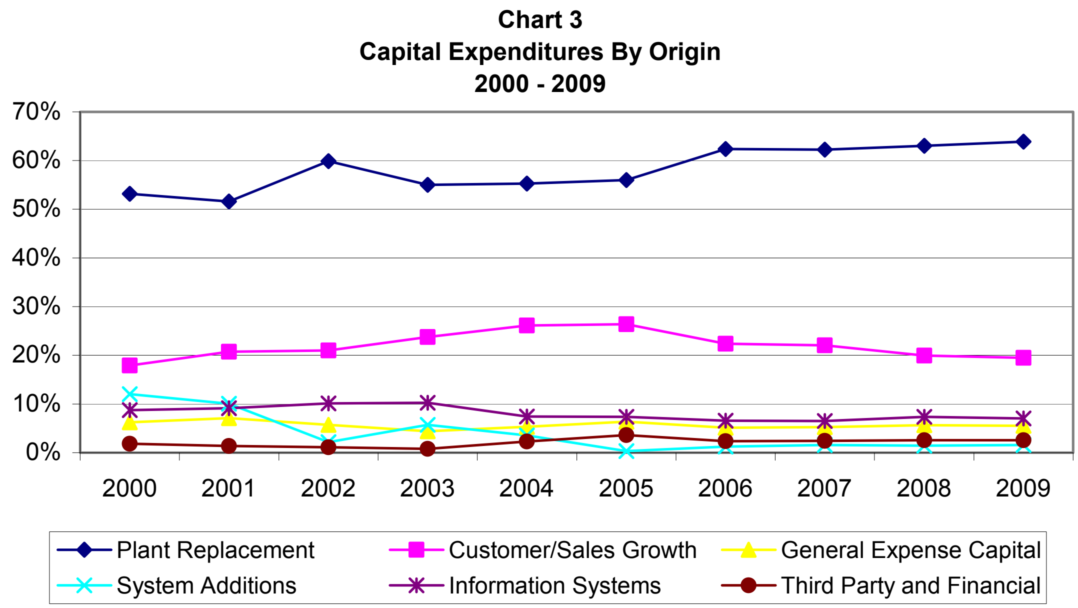


Chart 2 indicates the Distribution category accounts for 48% of all planned expenditures over the next five years, followed by Energy Supply (11%), Substations (10%) and Transmission (9%). The remaining six categories account for 22% of total capital expenditures for the 2005 through 2009 period. The pattern of planned capital expenditures by category is consistent with that of the 2000 through 2004 period.



Expenditures by origin during the 2005 through 2009 period are also similar to the 2000 through 2004 period. As shown in Chart 3, the Company does not anticipate any significant changes in the pattern of expenditures by origin.



Like most North American utilities, Newfoundland Power must address the issue of aging infrastructure. As the infrastructure ages, the power system becomes less safe, less reliable, and more expensive to operate and maintain. The Company therefore continues to focus on the replacement of deteriorated, defective or obsolete electrical equipment, which accounts for approximately 60% of total capital expenditures (excluding the purchase of joint-use poles from Aliant).

In recent years, the Company has focused attention on rural distribution lines where reliability has been appreciably worse than the Company average. Over the next 5 years, the Company will continue its efforts to refurbish distribution lines that have performed poorly with respect to reliability. These distribution lines tend to be either very old, or are exposed to abnormally adverse weather conditions.

The Plan also provides for the refurbishment of a number of the Company's aged and deteriorated transmission lines. Many of these lines have been in service for in excess of 40 years, and inspections have revealed deterioration resulting from their long exposure to harsh weather and salt contamination. In other locations, it has been determined that the original line design does not provide adequate vertical clearance.

Many of the Company's hydro generating plants are in excess of 50 years old. The Plan will address the replacement of major components at many of these facilities in order to remove deteriorated or obsolete plant from service. The Plan addresses replacing penstocks at the Rattling Brook, Heart's Content and Rocky Pond hydroelectric plants. These expenditures are required to maintain energy production levels and to maintain safe and reliable service to customers.

Capital expenditures related to customer and sales growth are expected to decline from 26% of total expenditures in 2005 to 20% in 2009. This pattern of expenditures mirrors the forecast economic performance for the province.

The Company will continue to invest in information technology to maintain existing systems, as well as invest in projects that introduce further improvements in customer service, operational efficiency and public and employee safety.

B. Plan Summary

A summary of planned capital expenditures for the 2005 - 2009 period by category along with a breakdown by project is contained in Appendix A. Overall, planned expenditures are expected to remain stable in all categories with the exception of Energy Supply, Transmission and Distribution. The following briefly summarizes each category.

1. Energy Supply

The Energy Supply category includes capital expenditures related to the replacement of deteriorated plant and equipment at the Company's hydro plants and thermal generating stations. While these facilities are relatively small when viewed as stand-alone production centers, collectively they displace approximately 675,000 barrels of oil (at an estimated annual cost of approximately $20 million) burned at Newfoundland and Labrador Hydro's Holyrood Thermal station, contribute to system reliability and, in many cases, provide a source for local backup.

While Energy Supply capital expenditures are expected to average $5.4 million per year over the 2005 to 2009 period, annual expenditures range from a low of $3.4 million in 2005 to a high of $7.5 million in 2006. The increased level of expenditures in 2006 and 2007 are related to the refurbishment of the Rattling Brook Plant, the Company's largest hydroelectric plant. This project, which includes the replacement of the penstock and other key components of the plant, will be completed in 2007 at a total cost of approximately $11.4 million. In addition, $3.0 million has been included in 2009 for the replacement of the penstocks at Heart's Content and Rocky Pond.

2. Substations

The Substations category includes capital expenditures related to rebuilding substations, replacement and spare substation equipment, feeder remote control, and the addition of transformer capacity. The replacement and spare substation equipment capital expenditures involve the replacement of items such as circuit breakers, reclosers, potential transformers, batteries and other equipment that either fail in service or have reached the end of their useful lives. The Plan also includes the addition of a transformer at the

Glendale substation in 2006 and the construction of a new substation in the Humber Valley in 2007. The projects in this category focus on improved system reliability and operational efficiency, safety, reduced environmental risk associated with oil-filled reclosers, and meeting customer growth.

Substation capital expenditures are expected to average $5.2 million annually over the 2005 through 2009 period.

3. Transmission

The Transmission category includes capital expenditures related to rebuilding transmission lines. The projects include: replacement of poles, crossarms, and conductor; replacement of pin type and suspension insulators; and improvement of conductor sag and clearances. The projects in this category are primarily focused on reliability and safety.

As a result of the need to refurbish the Company's oldest transmission lines, transmission expenditures will increase from $2.6 million in 2005 to an average of $5.2 million annually over the 2006 through 2009 period.

4. Distribution

The Distribution category includes capital expenditures for extensions, services, street lighting and transformers that are influenced by growth in the number of customers served by the Company. These capital expenditures are determined with reference to the Company's forecast of new customers using historical capital expenditures as a guide. This category also includes reconstruction projects that are primarily focused on maintaining reliability and safety.

The Distribution category also includes capital expenditures related to the relocation of plant at the request of third parties. A significant portion of these costs is recovered from the parties making the requests.

Distribution capital expenditures are expected to decline from $28.6 million in 2005 to $23.7 million in 2009. The decline in capital expenditures is related to forecast reduced growth in the number of customers served and the completion of the purchase of the joint-use poles from Aliant in 2005. During this period, capital expenditures related to the replacement of deteriorated, defective or obsolete plant and equipment are expected to remain stable and similar to the capital expenditures recorded in 2004.

5. General Property

The General Property category includes capital expenditures for the addition or replacement of tools and equipment utilized by line and support staff in the day-to-day operation of the Company, as well as the replacement or addition of office furniture and equipment. The category includes additions to real property necessary to maintain buildings and facilities and to operate them in an efficient manner.

General Property capital expenditures are expected to average $1.1 million annually over the 2005 through 2009 period.

6. Transportation

The Transportation category includes the replacement of existing heavy fleet, passenger and off-road vehicles. The replacement of these vehicles can be influenced by a number of factors including kilometres traveled, vehicle condition, operating experience and operating expenditures.

Transportation capital expenditures are expected to average $2.7 million annually over the 2005 through 2009 period.

7. Telecommunications

The Telecommunications category includes the replacement or upgrading of various communications systems. These systems contribute to customer service, safety, and maintenance of power system reliability by supporting communications between the Company's fleet of mobile vehicles and the various plants and offices.

Telecommunications capital expenditures are expected to average $0.3 million annually over the 2005 through 2009 period.

8. Information Systems

The Information Systems category includes: the replacement of personal computers, printers and associated assets; upgrades to current software tools, processes, and applications as well as the acquisition of new software licenses; and, the development of new applications or enhancements to existing applications to support changing business requirements and take advantage of new developments and product improvements.

Information Systems capital expenditures are expected to average $3.5 million annually over the 2005 through 2009 period.

9. Unforeseen Items

The Unforeseen Items category covers any unforeseen capital expenditures that have not been budgeted elsewhere. The purpose of the account is to permit the Company to act expeditiously to deal with events affecting the electrical system in advance of seeking the approval of the Board.

Unforeseen Items capital expenditures are budgeted at $750,000 annually over the 2005 through 2009 period.

10. General Expenses Capital

The General Expenses Capital category covers the allocation of a portion of administrative costs to capital. In accordance with Order No. P.U. 3 (1995-96), the Company uses the incremental cost method of accounting for the purpose of capitalization of general expenses.

General Expenses Capital expenditures are budgeted at $2.8 million annually over the 2005 through 2009 period.

C. Plan Risks

While the Company accepts the Board's view of the desirable effects of year to year capital expenditure stability, the nature of the utility obligation to serve will not, in some circumstances, necessarily facilitate such stability. The Plan has identified some risks to such stability in the period 2005 through 2009.

Newfoundland Power has an obligation to serve customers located in its service territory. Therefore, should customer and energy growth vary from forecast, so will the capital expenditures that are sensitive to growth. For instance, the Company is aware of a potential mine that, if developed, would require additional capital expenditures in the order of $5 million. Due to the uncertainty of the project's proceeding at this time, it has not been included in the Plan.

The Company's Customer Service System ("CSS") is 12 years old. As the replacement cost of a CSS system could be as high as $15 million, the Company is taking steps to extend the life of CSS through 2009. Accordingly, while the Company has no plans to replace CSS during the 2005 through 2009 period, changing technology and vendor support could conceivably dictate otherwise. Eventual replacement of the CSS will likely be staged over more than 1 year.

Capital expenditures can be impacted by natural disasters. In 1984 and 1994, the Company was impacted by sleet storms that resulted in widespread damage and service interruption to customers. In 2003, Hurricane Juan hit Nova Scotia, resulting in severe damage to that province's transmission and distribution systems and the loss of power to over 260,000 customers. The occurrence and costs of natural disasters are not predictable.

Overall, planned capital expenditures are forecast to be relatively stable during the 2005 through 2009 period. However, circumstances can change and, as a result, so can priorities and the level of capital expenditures.

Assessment of maximum budget growth in this period necessarily involves a significant degree of conjecture. Given that a single customer addition (i.e., such as the mine mentioned above) could conceivably add capital expenditures of $5 million, a maximum annual capital budget could approximate $60 million. In such a case, it is expected that certain otherwise justifiable projects might be deferred in a way that minimizes the negative impact of deferral on the quality of service.

In each year of the Plan, the Company's forecast budget includes $750,000 for unforeseen items. This amount is in the nature of a contingency for unexpected or unusual events. While the amount is not in the nature of an *approved* expenditure, it provides an allowance for unexpected events of almost 1.5% of the average budget.

The allowance of a larger contingency of, say, 5% of the average budget, or approximately $2.5 million, would allow the Company greater flexibility to respond expeditiously to unforeseen circumstances. However, the number of supplementary approvals required in recent years has not been unduly large or burdensome. The current allowance therefore appears to be sufficient for present circumstances.

III. Summary

Over the next five years, the Company plans to invest approximately $256 million in plant and equipment. Planned expenditures are expected to remain relatively stable in all categories, and consistent with expenditures incurred during the 2000 through 2004 period.

Approximately 60% of planned expenditures focus on the replacement of deteriorated, defective or obsolete distribution, transmission, generation and substation electrical equipment. Capital expenditures related to customer and sales growth is forecast to decline as a result of reduced growth in the number of customers served and the completion of the purchase of the joint-use poles from Aliant in 2005. The Company does not anticipate any significant changes in the pattern of planned expenditures by origin.

While planned capital expenditures are forecast to be relatively stable during the 2005 through 2009 period, circumstances can change and, as a result the maximum capital budget could approximate $60 million. The Company accepts the Board's view of the desirable effects of stable year to year capital expenditures, and projects will be prioritized accordingly.

Newfoundland Power Inc.
2005 Capital Budget Plan
(000s)

Category	**2005**	**2006**	**2007**	**2008**	**2009**
Energy Supply	$3,361	$7,494	$6,625	$3,771	$5,651
Substations	3,037	5,433	6,799	5,316	5,402
Transmission	2,597	5,154	5,189	5,263	5,054
Distribution	28,635	24,743	23,431	23,818	23,703
General Property	1,016	1,423	1,334	900	865
Transportation	2,642	2,987	2,650	2,810	2,411
Telecommunications	60	422	268	456	423
Information Systems	3,243	3,598	3,483	3,648	3,558
Unforeseen Items	750	750	750	750	750
General Expenses Capital	2,800	2,800	2,800	2,800	2,800
Total	**$48,141**	**$54,804**	**$53,329**	**$49,532**	**$50,617**

Newfoundland Power Inc.
2005 Capital Budget Plan
(000s)

ENERGY SUPPLY

Project	2005	2006	2007	2008	2009
Hydro Plants – Facility Rehabilitation	$1,887	$1,851	$1,216	$3,771	$2,641
Wesleyville Gas Turbine Overhaul	1,124	-	-	-	-
Rattling Brook - Hydro Plant Refurbishment	350	5,643	5,409	-	-
Hydro Plant – Penstock Replacement	-	-	-	-	3,010
Total - Energy Supply	**$3,361**	**$7,494**	**$6,625**	**$3,771**	**$5,651**

Newfoundland Power Inc.
2005 Capital Budget Plan
(000s)

SUBSTATIONS

Project	2005	2006	2007	2008	2009
Rebuild Substations	$351	$429	$1,093	$1,642	$1,969
Replacement and Standby Substation Equipment	1,052	1,201	2,433	2,194	2,100
Transformer Cooling Refurbishment	174	300	200	200	200
Protection and Monitoring Improvements	78	625	280	280	133
Distribution System Feeder Remote Control	1,114	1,024	1,000	1,000	1,000
Feeder Additions Due To Load Growth and Reliability	268	412	380	-	-
Additional Transformer – Glendale	-	1,442	-	-	-
New Substation – Humber Valley	-	-	1,413	-	-
Total – Substations	**$3,037**	**$5,433**	**$6,799**	**$5,316**	**$5,402**

Newfoundland Power Inc.
2005 Capital Budget Plan
(000s)

TRANSMISSION

Project	2005	2006	2007	2008	2009
Rebuild Transmission Lines	$2,597	$5,154	$5,189	$5,263	$5,054
Total – Transmission	**$2,597**	**$5,154**	**$5,189**	**$5,263**	**$5,054**

Newfoundland Power Inc.
2005 Capital Budget Plan
(000s)

DISTRIBUTION

Project	2005	2006	2007	2008	2009
Extensions	$6,374	$5,581	$5,497	$5,426	$5,508
Meters	965	819	802	936	741
Services	1,895	1,820	1,802	1,816	1,855
Street Lighting	1,254	1,107	1,095	1,100	1,118
Transformers	5,189	4,700	4,648	4,601	4,549
Reconstruction	2,825	3,064	2,927	3,429	3,497
Aliant Pole Purchase	4,044	-	-	-	-
Trunk Feeders					
Rebuild Distribution Lines	4,210	5,347	5,050	4,900	4,900
Relocate/Replace Distribution Lines For Third Parties	734	435	435	435	435
Distribution Reliability Initiative	872	1,568	1,000	1,000	1,000
Feeder Additions and Upgrades to Accommodate Growth	173	202	75	75	-
Interest During Construction	100	100	100	100	100
Total – Distribution	**$28,635**	**$24,743**	**$23,431**	**$23,818**	**$23,703**

Newfoundland Power Inc.
2005 Capital Budget Plan
(000s)

GENERAL PROPERTY

Project	2005	2006	2007	2008	2009
Tools and Equipment	$691	$505	$415	$415	$415
Additions to Real Property	325	918	919	485	450
Total – General Property	**$1,016**	**$1,423**	**$1,334**	**$900**	**$865**

Newfoundland Power Inc.
2005 Capital Budget Plan
(000s)

TRANSPORTATION

Project	2005	2006	2007	2008	2009
Purchase Vehicles and Aerial Devices	$2,642	$2,987	$2,650	$2,810	$2,411
Total – Transportation	**$2,642**	**$2,987**	**$2,650**	**$2,810**	**$2,411**

Newfoundland Power Inc.
2005 Capital Budget Plan
(000s)

TELECOMMUNICATIONS

Project	2005	2006	2007	2008	2009
Replace/Upgrade Communications Equipment	$60	$75	$81	$195	$85
SCADA Infrastructure	-	74	-	-	-
Fibre Optic Networking	-	273	187	261	338
Total – Telecommunications	**$60**	**$422**	**$268**	**$456**	**$423**

Newfoundland Power Inc.
2005 Capital Budget Plan
(000s)

INFORMATION SYSTEMS

Project	2005	2006	2007	2008	2009
Application Enhancements	$1,087	$1,377	$1,097	$958	$1,170
Application Environment	710	701	861	1,060	911
Customer Systems Replacement	144	170	175	175	176
Network Infrastructure	276	50	50	150	50
Personal Computer Infrastructure	455	550	550	555	550
Shared Server Infrastructure	571	750	750	750	701
Total – Information Systems	**$3,243**	**$3,598**	**$3,483**	**$3,648**	**$3,558**

Newfoundland Power Inc.
2005 Capital Budget Plan
(000s)

UNFORESEEN ITEMS

Project	2005	2006	2007	2008	2009
Allowance for Unforeseen Items	$750	$750	$750	$750	$750
Total – Unforeseen Items	**$750**	**$750**	**$750**	**$750**	**$750**

Newfoundland Power Inc.
2005 Capital Budget Plan
(000s)

GENERAL EXPENSES CAPITAL

Project	2005	2006	2007	2008	2009
Allowance for General Expenses Capital	$2,800	$2,800	$2,800	$2,800	$2,800
Total – General Expenses Capital	**$2,800**	**$2,800**	**$2,800**	**$2,800**	**$2,800**

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

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

IN THE MATTER OF an application by Newfoundland Power Inc. for an order pursuant to Sections 41, 78 and 80 of the Act:

(a) approving its 2005 Capital Budget of $48,141,000;
(b) (i) fixing and determining its average rate base for 2003 in the amount of $675,730,000; (ii) approving its revised forecast average rate base for 2004 in the amount of $713,072,000; and (iii) approving its forecast average rate base for 2005 in the amount of $740,142,000; and
(c) approving revised values for rate base and invested capital for use in the automatic adjustment formula (the "Automatic Adjustment Formula") for the calculation of return on rate base for 2005 pursuant to Order No. P.U. 19 (2003).

2004 Capital Expenditure Status Report

August 31, 2004

NEWFOUNDLAND POWER
A FORTIS COMPANY

NEWFOUNDLAND POWER INC.

2005 CAPITAL BUDGET APPLICATION

2004 Capital Expenditure Status Report

Explanatory Note

This report is presented in compliance with the directive of the Board of Commissioners of Public Utilities (the "Board") contained in paragraph 4 of Order No. P.U. 35 (2003).

Page 1 of the 2004 Capital Expenditure Status Report outlines the forecast variances from budget of the capital expenditures approved by the Board in Order No. P.U. 35 (2003). The detailed tables on pages 2 to 12 provide additional detail on capital expenditures in 2004, and also include information on those capital projects approved for 2002 and 2003 that were not completed prior to 2004.

Variances of more than 10% of approved expenditure or $50,000 or greater are explained in the Notes contained in Appendix A, which immediately follows the blue page at the conclusion of the 2004 Capital Expenditure Status Report.

Capital expenditures that have been deferred to 2005 are shown in Column K on the attached report.

Newfoundland Power Inc.
2005 Capital Budget

2004 Capital Budget Variances
(000s)

	Approved by Order No. P.U. 35 (2003)	Forecast[1]	Variance
Energy Supply	$5,245	$5,928	$683
Substations	5,199	4,938	(261)
Transmission	2,315	2,503	188
Distribution	27,636	30,102	2,466
General Property	709	845	136
Transportation	3,487	3,487	-
Telecommunications	120	114	(6)
Information Systems	3,948	3,894	(54)
Unforeseen Items	750	750	-
General Expenses Capital	2,800	2,800	-
Total	$52,209	$55,361	$3,152
Projects carried forward from 2002 & 2003	-	3,790	

1. Includes deferral to 2005.

2004 Capital Expenditure Status Report
(000s)

	Capital Budget				Actual Expenditures				Forecast				
	2002	**2003**	**2004**	**Total**	**2002**	**2003**	**YTD 2004**	**Total To Date**	**Remainder of 2004**	**Total 2004**	**Deferrals**	**Overall Total**	**Variance**
	A	B	C	D	E	F	G	H	I	J	K	L	M
2004 Projects	$ -	$ -	$ 52,209	$ 52,209	$ -	$ -	$ 27,286	$ 27,286	$ 25,907	$ 53,193	$ 2,168	$ 55,361	$ 3,152
2003 Projects	-	15,425	-	15,425	50	13,104	1,867	15,021	590	2,457	500	16,111	686
2002 Projects	3,674	-	-	3,674	1,404	2,769	601	4,774	232	833	-	5,006	1,332
Grand Total	**$ 3,674**	**$ 15,425**	**$ 52,209**	**$ 71,308**	**$ 1,454**	**$ 15,873**	**$ 29,754**	**$ 47,081**	**$ 26,729**	**$ 56,483**	**$ 2,668**	**$ 76,478**	**$ 5,170**

Column A	Approved Capital Budget for 2002
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2004 Capital Expenditure Status Report
(000s)

Category: Energy Supply

Project	Capital Budget				Actual Expenditures				Forecast					
	2002	2003	2004	Total	2002	2003	YTD 2004	Total To Date	Remainder of 2004	Total 2004	Deferrals	Overall Total	Variance	Notes*
	A	B	C	D	E	F	G	H	I	J	K	L	M	
2004 Projects														
Hydro Plants - Facility Rehabilitation	$ -	$ -	$ 1,122	$ 1,122	$ -	$ -	$ 263	$ 263	$ 1,071	$ 1,334	$ 40	$ 1,374	$ 252	1
New Chelsea - Hydro Plant Refurbishment	-	-	3,973	3,973	-	-	1,311	1,311	2,678	3,989	375	4,364	391	2
Major Electrical Equipment Repairs	-	-	150	150	-	-	133	133	57	190	-	190	40	3
	-	-	5,245	5,245	-	-	1,707	1,707	3,806	5,513	415	5,928	683	
2003 Projects														
Hydro Plants - Facility Rehabilitation	-	2,345	-	2,345	-	2,028	161	2,189	324	485	-	2,513	168	4
Purchase Portable Diesel Generation	-	1,500	-	1,500	-	589	1,151	1,740	78	1,229	-	1,818	318	5
	-	3,845	-	3,845	-	2,617	1,312	3,929	402	1,714	-	4,331	486	
2002 Projects														
Wesleyville Gas Turbine Relocation	1,674	-	-	1,674	1,356	1,416	458	3,230	3	461	-	3,233	1,559	6
Total - Energy Supply	**$ 1,674**	**$ 3,845**	**$ 5,245**	**$ 10,764**	**$ 1,356**	**$ 4,033**	**$ 3,477**	**$ 8,866**	**$ 4,211**	**$ 7,688**	**$ 415**	**$ 13,492**	**$ 2,728**	

* See Appendix A for notes containing variance explanations.

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2004 Capital Expenditure Status Report
(000s)

Category: Substations

	Capital Budget				Actual Expenditures				Forecast					
Project	**2002**	**2003**	**2004**	**Total**	**2002**	**2003**	**YTD 2004**	**Total To Date**	**Remainder 2004**	**Total 2004**	**Deferrals**	**Overall Total**	**Variance**	**Notes***
	A	B	C	D	E	F	G	H	I	J	K	L	M	
2004 Projects														
Rebuild Substations	$ -	$ -	$ 1,023	$ 1,023	$ -	$ -	$ 204	$ 204	$ 327	$ 531	$ 387	$ 918	$ (105)	7
Replacement and Standby Substation Equipment	-	-	1,314	1,314	-	-	810	810	404	1,214	69	1,283	(31)	
Transformer Cooling Refurbishment	-	-	398	398	-	-	17	17	276	293	-	293	(105)	8
Protection and Monitoring Improvements	-	-	80	80	-	-	21	21	39	60	-	60	(20)	9
Distribution System Feeder Remote Control	-	-	1,000	1,000	-	-	877	877	123	1,000	-	1,000	-	
Feeder Additions Due to Load Growth and Reliability	-	-	200	200	-	-	80	80	120	200	-	200	-	
Increase Corner Brook Transformer Capacity	-	-	1,184	1,184	-	-	206	206	978	1,184	-	1,184	-	
	-	-	5,199	5,199	-	-	2,215	2,215	2,267	4,482	456	4,938	(261)	
2003 Projects														
Replacement and Spare Substation Equipment	-	1,107	-	1,107	-	1,016	21	1,037	52	73	-	1,089	(18)	
Reliability and Power Quality Improvements	-	198	-	198	-	76	2	78	12	14	101	191	(7)	
Chamberlains - Add 66/25kV Transformer	-	1,250	-	1,250	-	1,076	50	1,126	-	50	-	1,126	(124)	10
Virginia Waters - Add 66/12.5 kV Transformer	-	1,150	-	1,150	-	901	156	1,057	-	156	-	1,057	(93)	11
	-	3,705	-	3,705	-	3,069	229	3,298	64	293	101	3,463	(242)	
2002 Projects														
Purchase Power Transformer	2,000	-	-	2,000	48	1,353	143	1,544	229	372	-	1,773	(227)	12
Total - Substations	**$ 2,000**	**$ 3,705**	**$ 5,199**	**$ 10,904**	**$ 48**	**$ 4,422**	**$ 2,587**	**$ 7,057**	**$ 2,560**	**$ 5,147**	**$ 557**	**$ 10,174**	**$ (730)**	

* See Appendix A for notes containing variance explanations.

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2004 Capital Expenditure Status Report
(000s)

Category: Transmission

	Capital Budget				Actual Expenditures				Forecast					
Project	**2002**	**2003**	**2004**	**Total**	**2002**	**2003**	**YTD 2004**	**Total To Date**	**Remainder 2004**	**Total 2004**	**Deferrals**	**Overall Total**	**Variance**	**Notes***
	A	B	C	D	E	F	G	H	I	J	K	L	M	
2004 Projects														
Rebuild Transmission Lines	$ -	$ -	$ 2,315	$ 2,315	$ -	$ -	$ 569	$ 569	$ 1,737	$ 2,306	$ 197	$ 2,503	$ 188	13
2003 Projects														
Rebuild Transmission Lines	-	4,129	-	4,129	50	4,026	62	4,138	33	95	-	4,171	42	
Total - Transmission	**$ -**	**$ 4,129**	**$ 2,315**	**$ 6,444**	**$ 50**	**$ 4,026**	**$ 631**	**$ 4,707**	**$ 1,770**	**$ 2,401**	**$ 197**	**$ 6,674**	**$ 230**	

* See Appendix A for notes containing variance explanations.

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2004 Capital Expenditure Status Report
(000s)

Category: Distribution

Project	Capital Budget				Actual Expenditures				Forecast					
	2002	2003	2004	Total	2002	2003	YTD 2004	Total To Date	Remainder 2004	Total 2004	Deferrals	Overall Total	Variance	Notes*
	A	B	C	D	E	F	G	H	I	J	K	L	M	
2004 Projects														
Extensions	$ -	$ -	$ 4,956	$ 4,956	$ -	$ -	$ 3,354	$ 3,354	$ 3,500	$ 6,854	$ -	$ 6,854	$ 1,898	14
Meters	-	-	1,174	1,174	-	-	874	874	413	1,287	-	1,287	113	15
Services	-	-	1,946	1,946	-	-	789	789	1,087	1,876	-	1,876	(70)	16
Street Lighting	-	-	1,242	1,242	-	-	647	647	497	1,144	100	1,244	2	
Transformers	-	-	4,965	4,965	-	-	3,848	3,848	1,492	5,340	-	5,340	375	17
Reconstruction	-	-	2,461	2,461	-	-	1,372	1,372	1,068	2,440	-	2,440	(21)	
Aliant Pole Purchase	-	-	4,044	4,044	-	-	4,044	4,044	-	4,044	-	4,044	-	
Trunk Feeders														
Rebuild Distribution Lines	-	-	4,137	4,137	-	-	2,282	2,282	1,634	3,916	200	4,116	(21)	
Relocate/Replace Distribution Lines For Third Parties	-	-	235	235	-	-	251	251	369	620	-	620	385	18
Distribution Reliability Initiative	-	-	949	949	-	-	631	631	258	889	120	1,009	60	19
Feeder Additions and Upgrades to Accommodate Growth	-	-	677	677	-	-	100	100	444	544	80	624	(53)	20
Switch Replacement and Upgrade Underground Distribution - Water Street, St. John's	-	-	750	750	-	-	77	77	471	548	-	548	(202)	21
Interest During Construction	-	-	100	100	-	-	26	26	74	100	-	100	-	
	-	-	27,636	27,636	-	-	18,295	18,295	11,307	29,602	500	30,102	2,466	
2003 Projects														
Rebuild Distribution Lines	-	3,504	-	3,504	-	3,351	174	3,525	91	265	399	4,015	511	22
Total - Distribution	**$ -**	**$ 3,504**	**$ 27,636**	**$ 31,140**	**$ -**	**$ 3,351**	**$ 18,469**	**$ 21,820**	**$ 11,398**	**$ 29,867**	**$ 899**	**$ 34,117**	**$ 2,977**	

* See Appendix A for notes containing variance explanations.

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2004 Capital Expenditure Status Report
(000s)

Category: General Property

	Capital Budget				Actual Expenditures				Forecast					
Project	2002	2003	2004	Total	2002	2003	YTD 2004	Total To Date	Remainder 2004	Total 2004	Deferrals	Overall Total	Variance	Notes*
	A	B	C	D	E	F	G	H	I	J	K	L	M	
2004 Projects														
Tools and Equipment	$ -	$ -	$ 535	$ 535	$ -	$ -	$ 334	$ 334	$ 240	$ 574	$ -	$ 574	$ 39	
Additions to Real Property	-	-	174	174	-	-	113	113	158	271	-	271	97	23
Total - General Property	**$ -**	**$ -**	**$ 709**	**$ 709**	**$ -**	**$ -**	**$ 447**	**$ 447**	**$ 398**	**$ 845**	**$ -**	**$ 845**	**$ 136**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2002
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2004 Capital Expenditure Status Report
(000s)

Category: Transportation

Project	Capital Budget 2002	Capital Budget 2003	Capital Budget 2004	Capital Budget Total	Actual Expenditures 2002	Actual Expenditures 2003	Actual Expenditures YTD 2004	Actual Expenditures Total To Date	Forecast Remainder 2004	Forecast Total 2004	Forecast Deferrals	Forecast Overall Total	Variance	Notes*
	A	B	C	D	E	F	G	H	I	J	K	L	M	
2004 Projects														
Purchase Vehicles and Aerial Devices	$ -	$ -	$ 3,487	$ 3,487	$ -	$ -	$ 556	$ 556	$ 2,331	$ 2,887	$ 600	$ 3,487	$ -	
Total - Transportation	**$ -**	**$ -**	**$ 3,487**	**$ 3,487**	**$ -**	**$ -**	**$ 556**	**$ 556**	**$ 2,331**	**$ 2,887**	**$ 600**	**$ 3,487**	**$ -**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2002
Column B	Approved Capital Budget for 2003
Column C	Approved Capital Budget for 2004
Column D	Total of Columns A, B and C
Column E	Actual Capital Expenditures for 2002
Column F	Actual Capital Expenditures for 2003
Column G	YTD Actual Capital Expenditures for 2004
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Column I	Forecast Capital Expenditures for Remainder of 2004
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Column M	Column L less Column D

2004 Capital Expenditure Status Report
(000s)

Category: Telecommunications

	Capital Budget				Actual Expenditures				Forecast					
Project	**2002**	**2003**	**2004**	**Total**	**2002**	**2003**	**YTD 2004**	**Total To Date**	**Remainder 2004**	**Total 2004**	**Deferrals**	**Overall Total**	**Variance**	**Notes***
	A	B	C	D	E	F	G	H	I	J	K	L	M	
2004 Projects														
Replace/Upgrade Communications Equipment	$ -	$ -	$ 70	$ 70	$ -	$ -	$ -	$ -	$ 70	$ 70	$ -	$ 70	$ -	
Substation Telephone Circuit Protection	-	-	50	50	-	-	17	17	27	44	-	44	(6)	24
	-	-	120	120	-	-	17	17	97	114	-	114	(6)	
2003 Projects														
Replace/Upgrade Communications Equipment	-	242	-	242	-	41	90	131	-	90	-	131	(111)	25
Total - Telecommunications	**$ -**	**$ 242**	**$ 120**	**$ 362**	**$ -**	**$ 41**	**$ 107**	**$ 148**	**$ 97**	**$ 204**	**$ -**	**$ 245**	**$ (117)**	

* See Appendix A for notes containing variance explanations.

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2004 Capital Expenditure Status Report
(000s)

Category: Information Systems

	Capital Budget				Actual Expenditures				Forecast					
Project	**2002**	**2003**	**2004**	**Total**	**2002**	**2003**	**YTD 2004**	**Total To Date**	**Remainder 2004**	**Total 2004**	**Deferrals**	**Overall Total**	**Variance**	**Notes***
	A	B	C	D	E	F	G	H	I	J	K	L	M	
2004 Projects														
Application Enhancements	$ -	$ -	$ 1,355	$ 1,355	$ -	$ -	$ 578	$ 578	$ 741	$ 1,319	$ -	$ 1,319	$ (36)	
Application Environment	-	-	791	791	-	-	412	412	399	811	-	811	20	
Customer Systems Replacement	-	-	226	226	-	-	118	118	108	226	-	226	-	
Network Infrastructure	-	-	393	393	-	-	144	144	249	393	-	393	-	
Personal Computer Infastructure	-	-	539	539	-	-	322	322	137	459	-	459	(80)	26
Shared Server Infastructure	-	-	644	644	-	-	339	339	347	686	-	686	42	
Total - Information Systems	**$ -**	**$ -**	**$ 3,948**	**$ 3,948**	**$ -**	**$ -**	**$ 1,913**	**$ 1,913**	**$ 1,981**	**$ 3,894**	**$ -**	**$ 3,894**	**$ (54)**	

* See Appendix A for notes containing variance explanations.

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2004 Capital Expenditure Status Report
(000s)

Category: Unforeseen Items

	Capital Budget				Actual Expenditures				Forecast					
Project	**2002**	**2003**	**2004**	**Total**	**2002**	**2003**	**YTD 2004**	**Total To Date**	**Remainder 2004**	**Total 2004**	**Deferrals**	**Overall Total**	**Variance**	**Notes***
	A	B	C	D	E	F	G	H	I	J	K	L	M	
2004 Projects														
Allowance for Unforeseen Items	$ -	$ -	$ 750	$ 750	$ -	$ -	$ -	$ -	$ 750	$ 750	$ -	$ 750	$ -	
Total - Unforeseen Items	**$ -**	**$ -**	**$ 750**	**$ 750**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 750**	**$ 750**	**$ -**	**$ 750**	**$ -**	

* See Appendix A for notes containing variance explanations.

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2004 Capital Expenditure Status Report
(000s)

Category: General Expenses Capital

	Capital Budget				Actual Expenditures				Forecast					
Project	**2002**	**2003**	**2004**	**Total**	**2002**	**2003**	**YTD 2004**	**Total To Date**	**Remainder 2004**	**Total 2004**	**Deferrals**	**Overall Total**	**Variance**	**Notes***
	A	B	C	D	E	F	G	H	I	J	K	L	M	
2004 Projects														
Allowance for General Expenses Capital	$ -	$ -	$ 2,800	$ 2,800	$ -	$ -	$ 1,567	$ 1,567	$ 1,233	$ 2,800	$ -	$ 2,800	$ -	
Total - General Expenses Capital	**$ -**	**$ -**	**$ 2,800**	**$ 2,800**	**$ -**	**$ -**	**$ 1,567**	**$ 1,567**	**$ 1,233**	**$ 2,800**	**$ -**	**$ 2,800**	**$ -**	

* See Appendix A for notes containing variance explanations.

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2004 Capital Expenditure Status Report
Notes

Energy Supply

1. *Hydro Plants - Facility Rehabilitation:*
Budget: $1,122,000 Forecast: $1,374,000 Variance: $252,000

The variance is primarily the result of implementing demand metering in plants for the Hydro demand-energy rate, installing fire and intruder alarms in our hydro plant buildings and an increase in the Rattling Brook generator rewind. Demand metering in the plants is required to implement a demand-energy rate for Hydro's billing of Newfoundland Power. The alarms project was not originally included in the budget for 2004 as the requirement for the alarms was only recently identified after completion of independent risk inspections of the various plants. The increase in the Rattling Brook generator rewind project is a result of higher than anticipated bids from contractors.

2. *New Chelsea - Hydro Plant Refurbishment:*
Budget: $3,973,000 Forecast: $4,364,000 Variance: $391,000

There will be an increased expenditure on this project as a result of increased steel prices for penstock pipe of $180,000, increased engineering labour and material costs of $130,000 associated with required temporary substation equipment protection, and increased contract costs of $80,000 associated with the electrical and mechanical equipment installation. The requirement for temporary protection was identified during the detailed engineering assessment.

Scheduling and contracting constraints made it difficult to cost effectively perform the generator rewind in 2004. Consequently, an expenditure of $375,000 related to this aspect of the project has been deferred to 2005.

3. *Major Electrical Equipment Repairs:*
Budget: $150,000 Forecast: $190,000 Variance: $40,000

The variance is the result of higher than anticipated costs to repair the mobile gas turbine unit located at Grand Bay Substation.

4. *Hydro Plants - Facility Rehabilitation (2003 Project):*
Budget: $2,345,000 Forecast: $2,513,000 Variance: $168,000

The variance is the result of higher than anticipated costs to replace the governor at the Tors Cove hydroelectric plant and commissioning the unit for service.

2004 Capital Expenditure Status Report
Notes

Energy Supply

5. *Purchase Portable Diesel Generation (2003 Project):*
Budget: $1,500,000 Forecast: $1,818,000 Variance: $318,000

The variance is due to a higher than expected contract price for the purchase of the diesel generator.

6. *Wesleyville Gas Turbine Relocation (2002 Project):*
Budget: $1,674,000 Forecast: $3,233,000 Variance: $1,559,000

The variance is the result of several factors relating to delays in completing the project and additional necessary work identified prior to installation of the equipment at Wesleyville. The budget was based on a contract labour cost of $350,000 consistent with bids received in early 2002. Following the decision to postpone relocation and re-tendering in 2003 the contract cost to relocate the gas turbine increased by $420,000 to $770,000. The postponement of the project also resulted in additional IDC charges of $96,000. Assessment of equipment during dismantling identified several items requiring replacement or refurbishment as recommended by the contractor and original equipment manufacturer resulting in additional scope of work costing $580,000. This included replacement of the alternator air cooling system, exhaust volute, speed switches, fuel pumping system, installation of a fuel leak detection system and refurbishment of the power turbine inlet cone, exhaust stack structure, lube oil cooling system and other items as well as resolving problems with the gear box. This additional scope of work along with delays in completing the project resulted in additional engineering and project management and supervision costs totaling $460,000.

The gas turbine was relocated and commissioned for operation at the end of the 4th quarter, 2003. The work associated with upgrading the lube oil cooling system, fuel system, and providing remote control was completed in the 2nd quarter of 2004. With this, the Wesleyville Gas Turbine Relocation Project is completed.

2004 Capital Expenditure Status Report
Notes

Substations

7. *Rebuild Substations:*
Budget: $1,023,000 Forecast: $918,000 Variance: ($105,000)

This variance is the result of cancelling site work at the Trepassey Substation that would have been required to accommodate the installation of the proposed new portable diesel generator. With the removal of the diesel generator from the budget, the proposed site work was no longer necessary.

8. *Transformer Cooling Refurbishment:*
Budget: $398,000 Forecast: $293,000 Variance: ($105,000)

This variance stems from the Company's decision to reduce the number of transformer radiators to be refurbished in 2004. The reduction reflects a review of the Company's overall capital expenditure plan for 2004 and a re-prioritization of some projects.

9. *Protection and Monitoring Improvements:*
Budget: $80,000 Forecast: $60,000 Variance: ($20,000)

This variance stems from the Company's decision to reduce the number of tap changer control installations scheduled for 2004. The reduction reflects a review of the Company's overall capital expenditure plan for 2004 and a re-prioritization of some projects.

10. *Chamberlains - Add 66/25kV Transformer (2003 Project):*
Budget: $1,250,000 Forecast: $1,126,000 Variance: ($124,000)

The variance is the result of lower than anticipated pricing for the power transformer following a competitive bidding process.

11. *Virginia Waters - Add 66/12.5kV Transformer (2003 Project):*
Budget: $1,150,000 Forecast: $1,057,000 Variance: ($93,000)

The variance is the result of lower than anticipated pricing for the power transformer following a competitive bidding process.

2004 Capital Expenditure Status Report
Notes

Substations

12. *Purchase Power Transformer (2002 Project):*
Budget: $2,000,000 Forecast: $1,773,000 Variance: ($227,000)

The variance is the result of lower than anticipated pricing for the power transformer following a competitive bidding process.

2004 Capital Expenditure Status Report
Notes

Transmission

13. *Rebuild Transmission Lines:*
Budget: $2,315,000 Forecast: $2,503,000 Variance: $188,000

The variance is the result of a higher than expected number of third party requests to relocate transmission lines.

2004 Capital Expenditure Status Report
Notes

Distribution

14. *Extensions:*
Budget: $4,956,000 Forecast: $6,854,000 Variance: $1,898,000

The increase in the Extensions category is primarily related to customer driven projects, both commercial and residential. Examples of significant projects include the Humber Valley Resort development in the Corner Brook area, the INCO (Voisey's Bay) demonstration plant site at Argentia, and a line extension for various services previously served by the distribution system operated by the Argentia Management Authority.

15. *Meters:*
Budget: $1,174,000 Forecast: $1,287,000 Variance: $113,000

Completion of the sample testing of meters specified by Measurement Canada resulted in a higher than anticipated number of residential meters having to be removed from service. Consequently, a further $100,000 was required for the purchase of additional meters.

16. *Services:*
Budget: $1,946,000 Forecast: $1,876,000 Variance: ($70,000)

The variance is primarily a result of a lower than expected requirement for both new and replacement services in the Avalon operating area.

17. *Transformers:*
Budget: $4,965,000 Forecast: $5,340,000 Variance: $375,000

The increase in the Transformers category reflects additional requirements for padmount transformers, primarily due to customer related growth.

2004 Capital Expenditure Status Report
Notes

Distribution

18. *Relocate/Replace Distribution Lines For Third Parties:*
Budget: $235,000 Forecast: $620,000 Variance: $385,000

The variance is the result of a higher than expected number of third party requests to relocate distribution lines. The relocations relate to road realignment work being completed by the Department of Transportation and Works, as well as replacements required by the cable television companies.

19. *Distribution Reliability Initiative:*
Budget: $949,000 Forecast: $1,009,000 Variance: $60,000

The variance relates to higher than expected costs associated with the construction of a new feeder from Pulpit Rock Substation.

20. *Feeder Additions and Upgrades to Accommodate Growth:*
Budget: $677,000 Forecast: $624,000 Variance: ($53,000)

The reduction in forecast for this category is primarily the result of the postponement of a project to install voltage regulators on Springfield-01 feeder due to load growth being less than expected.

21. *Switch Replacement and Upgrade Underground Distribution - Water Street, St. Johns:*
Budget: $750,000 Forecast: $548,000 Variance: ($202,000)

This project is now complete. The variance is a result of the Company's determination that a smaller than anticipated number of distribution vaults required upgrading.

2004 Capital Expenditure Status Report
Notes

Distribution

22. Rebuild Distribution Lines (2003 Project):
Budget: $3,504,000 Forecast: $4,015,000 Variance: $511,000

At the end of 2003, this 2003 capital project showed a variance below budget of approximately $153,000, which was the net effect of the deferral of two individual projects and increased costs on several rebuild projects completed in 2003.

The current forecast variance over budget principally reflects the planned completion of the two deferred projects, to be completed in 2004 and 2005. These projects are the rebuild of St. John's feeder KBR-08 and an extension of feeder GLV-02 to Charlottetown. The forecast total expenditure for these two projects has increased from approximately $440,000 to approximately $625,000. The KBR-08 project is to be completed in 2004. The forecasted increase is largely due to the cost of addressing environmental issues on the portion of GLV-02 that runs through Terra Nova National Park, which will be completed in 2005.

2004 Capital Expenditure Status Report
Notes

General Property

23. *Additions to Real Property:*
Budget: $174,000 Forecast: $271,000 Variance: $97,000

The variance is the result of several expenditure requirements that were not identified at the time the budget was developed. These consisted of building upgrades at Duffy Place, an upgrade of the fire suppression system at the Kenmount Road building, and upgrading of the elevators at both the Duffy Place and Kenmount Road buildings to address safety concerns.

2004 Capital Expenditure Status Report
Notes

Telecommunications

24. *Substation Telephone Circuit Protection:*
Budget: $50,000 Forecast: $44,000 Variance: ($6,000)

This variance is the result of lower than expected costs to complete the installation of telephone circuit protection equipment.

25. *Replace/Upgrade Communications Equipment (2003 Project):*
Budget: $242,000 Forecast: $131,000 Variance: ($111,000)

The variance is due in part to the replacement of the UHF radio system in central Newfoundland with a lower cost fibre optic cable solution from Aliant Communications. In addition, the cost incurred while addressing deficiencies on the substation protection equipment were less than anticipated due to positive results during equipment inspections.

2004 Capital Expenditure Status Report
Notes

Information Systems

26. *Personal Computer Infrastructure:*
Budget: $539,000 Forecast: $459,000 Variance: ($80,000)

The reduction in this project reflects lower than anticipated costs for the purchase and installation of personal computers. The reduction in purchase costs reflects a somewhat general downward trend in the industry for PC pricing. The reduced installation costs result from changes in the technology used to complete PC installations that allows for faster installation.

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

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

IN THE MATTER OF an application by Newfoundland Power Inc. for an order pursuant to Sections 41, 78 and 80 of the Act:

(a) approving its 2005 Capital Budget of $48,141,000;
(b) (i) fixing and determining its average rate base for 2003 in the amount of $675,730,000; (ii) approving its revised forecast average rate base for 2004 in the amount of $713,072,000; and (iii) approving its forecast average rate base for 2005 in the amount of $740,142,000; and
(c) approving revised values for rate base and invested capital for use in the automatic adjustment formula (the "Automatic Adjustment Formula") for the calculation of return on rate base for 2005 pursuant to Order No. P.U. 19 (2003).

Report on Deferred Charges and Rate Base

NEWFOUNDLAND POWER
A FORTIS COMPANY

INTRODUCTION

In Order No. P.U. 19 (2003), the Board ordered Newfoundland Power (the "Company") to incorporate deferred charges in rate base commencing in 2003. In addition, the Board ordered that evidence relating to changes in deferred charges, in particular deferred pension costs, be filed annually at the Company's capital budget hearing. The Board also ordered that Newfoundland Power provide a reconciliation of average rate base to average invested capital annually during the capital budget approval process.

This report provides evidence with respect to changes in deferred charges and the reconciliation of average rate base to average invested capital as ordered by the Board in Order No. P.U. 19 (2003).

DEFERRED CHARGES

General

Table 1 sets out the actual deferred charges to be included in rate base for 2003 and forecast deferred charges for 2004 and 2005.

Table 1
Deferred Charges: 2003-2005F
($000s)

	Actual 2003	Forecast 2004	Forecast 2005
Weather Normalization Account	10,435	11,368	10,242
Deferred Regulatory Costs	693	347	0
Unamortized Debt Discount & Expense	3,370	3,171	3,721
Unamortized Capital Stock Issue Expense	392	325	261
Deferred Pension Costs	72,787	79,218	85,973
Total Deferred Charges	**87,677**	**94,429**	**100,197**

The 2004 forecast for deferred charges is approximately $1.4 million higher than the 2004 forecast filed in the Company's 2003 General Rate Application due to the normal operation of the weather normalization account ($1.9 million) offset by a reduction in deferred pension costs ($0.5 million).

Unamortized Debt Discount and Expense is expected to increase in 2005 relating to a $75 million issue of 30-year first mortgage bonds forecast for late 2005.

There is a slight change in Deferred Regulatory Costs for 2004 in comparison to the forecast included in the 2003 General Rate Application. The change reflects the finalization of the regulatory costs deferred. There are no changes in the forecast for Unamortized Capital Stock Issue Expense from that presented in the Company's 2003 General Rate Application.

Weather Normalization Account

The Weather Normalization Account has been historically included as a component of rate base, and the treatment of the Weather Normalization Account is unchanged by the inclusion of certain deferred charges in rate base as ordered by the Board in Order No. P.U. 19 (2003).

The balance in the Weather Normalization Account is comprised of two reserve accounts as shown in Table 2.

Table 2
Weather Normalization Account: 2003-2005F
($000s)

	2003	**2004F**	**Change 2004F vs. 2003**	**2005F**	**Change 2005F vs. 2004F**
Hydro Production Equalization Reserve	9,166	8,740	(426)	7,614	(1,126)
Degree Day Normalization Reserve	1,269	2,628	1,359	2,628	0
Total	10,435	11,368	933	10,242	(1,126)

In Order No. P.U. 19 (2003), the Board accepted Newfoundland Power's proposal to amortize the recovery of the $5.6 million non-reversing balance in the Hydro Production Equalization Reserve over a period of five years. A reduction in the Hydro Production Equalization Reserve of $1,126,000 in 2003 and the 2004 and 2005 forecasts are reflective of that amortization. The remaining change in the Hydro Production Equalization Reserve in 2004 relates to the actual operation of the reserve.

Both the Hydro Production Equalization Reserve and the Degree Day Normalization Reserve are affected by actual weather patterns compared to normal weather patterns. The difference between normal weather and weather actually experienced to the end of July 2004 has been reflected in the 2004 forecast. The 2004 and 2005 forecasts assume normal weather conditions from August 2004 through December 2005.

The functioning of these reserves is governed by orders of the Board; Order No. P.U. 32 (1968) in the case of the Hydro Production Equalization Reserve, and Order No. P.U. 1 (1974) in the case of the Degree Day Normalization Reserve. The combined balances in the Weather

Normalization Account are provided annually to the Board in Return 14 for review and approval. Order No. P.U. 33 (2004) approved the balance in the Weather Normalization Account as of December 31, 2003.

Deferred Regulatory Costs & Other

The reduction in deferred regulatory costs in 2004 and 2005 reflects the incurrence of approximately $1 million of hearing costs, and their subsequent amortization over three years beginning in 2003 in accordance with Order No. P.U. 19 (2003). The details of the changes are set out in Table 3.

Table 3
Deferred Regulatory Costs: 2003-2005F
($000s)

	2003	**2004F**	**Change 2004F vs. 2003**	**2005F**	**Change 2005F vs. 2004F**
Deferred Regulatory Costs	693	347	(346)	0	(347)

Unamortized Debt Discount and Capital Stock Issue Expenses

Changes in unamortized debt discount and capital stock issue expenses are set out in Table 4.

Table 4
Capital Issue Expenses: 2003-2005F
($000s)

	2003	**2004F**	**Change 2004F vs. 2003**	**2005F**	**Change 2005F vs. 2004F**
Unamortized Debt Discount & Expense	3,370	3,171	(199)	3,721	550
Unamortized Capital Stock Issue Expense	392	325	(67)	261	(64)

The decline in the Unamortized Debt Discount & Expense in 2004 reflects the normal amortization of these costs over the life of each debt issue. The increase in amortization for 2005 is related to an expected $75 million issue of 30-year first mortgage bonds forecast for late 2005, offset by the normal amortization of existing debt issue costs. Issue expenses for the new bond financing are forecast to be 1% of face value, or $750,000.

The decline in the Unamortized Capital Stock Issue Expense each year reflects the normal amortization of these costs over a 20-year period.

Deferred Pension Costs

The difference between pension plan *funding* and pension plan *expense* is captured as a deferred pension cost on the balance sheet in accordance with Order No. P.U. 17 (1987).

Deferred pension costs for 2003 are unchanged from those forecast in the Company's 2003 General Rate Application. Forecast changes in deferred pension costs for 2004 and 2005 are set out in Table 5.

Table 5
Forecast Deferred Pension Costs: 2004-2005
($000s)

	2004F	**2005F**
Deferred pension costs, January 1st	72,787	79,218
Pension plan funding		
- Current service funding	3,367	3,594
- Special funding	6,384	6,384
Total pension plan funding	9,751	9,978
Pension plan expense	(3,320)	(3,223)
Increase in deferred pension costs	6,431	6,755
Deferred pension costs, December 31st	79,218	85,973

Pension plan funding is comprised of two components: current service funding which is determined by an independent actuary and is related to service rendered by active employees in the current year; and special funding, which refers to additional pension funding requirements to address increases in the unfunded liability in the pension plan since its inception. The status of the unfunded liability is determined each time an actuarial study is completed. Under pension legislation, this has to occur at least once every three years.

The Company calculates annual pension expense in accordance with recommendations of the Canadian Institute of Chartered Accountants ("CICA") and relevant Board orders, the most recent of which is Order No. P.U. 19 (2003).

The forecasting of pension plan expense is subject to changes based upon the following factors:

1. The final pension plan expense for 2005 can only be determined early in 2005, once actual pension plan asset balances are known. This determination is made based on the December 31, 2004 market value of pension plan assets in accordance with CICA Handbook recommendations and Order No. P.U. 19 (2003).

2. The discount rate required to be used under the CICA Handbook rules to calculate 2005 pension expense is the actual market rate of interest as at December 31, 2004.

While pension plan expense for 2004 and 2005 is subject to change from the forecast provided above, both will be determined based on standards that have been consistently applied year over year, and which are in compliance with CICA recommendations, actuarial principles, and Board orders.

Pension plan funding is considered in a report entitled *Report on the Amortization of the Unfunded Pension Liability* filed in this proceeding.

RATE BASE

Reconciliation of Average Rate Base to Average Invested Capital

The reconciliation of average rate base to average invested capital for 2003 and for forecast 2004 and 2005 is set out in Table 6.

Table 6
Reconciliation of Average Invested Capital
To Average Rate Base

2004-2005 Forecasts
($000's)

	2003 Actual	2004 Forecast	2005 Forecast
Average Invested Capital	669,779	706,291	736,119
Average Rate Base (as per Schedule D)	675,730	713,072	740,142
Difference[1]	(5,951)	(6,781)	(4,023)
Reconciliation:			
Deferred Income Taxes	494	1,206	1,316
Plant (primarily construction in progress)	1,678	1,186	1,657
Corporate Income Tax Deposit	6,949	6,949	6,949
Materials and Supplies (actual vs. allowance)	879	800	1,165
Working Capital (actual vs. allowance)	(24,044)	(25,992)	(25,215)
Common Equity (book vs. regulated)	8,093	9,070	10,105
	(5,951)	(6,781)	(4,023)

[1] As per Order No. P.U. 19 (2003), the remaining reconciling items that constitute the difference between Rate Base and Invested Capital will be reviewed by the Company at its next general rate application.

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

IN THE MATTER OF an application by Newfoundland Power Inc. for an order pursuant to Sections 41, 78 and 80 of the Act:

(a) approving its 2005 Capital Budget of $48,141,000;
(b) (i) fixing and determining its average rate base for 2003 in the amount of $675,730,000; (ii) approving its revised forecast average rate base for 2004 in the amount of $713,072,000; and (iii) approving its forecast average rate base for 2005 in the amount of $740,142,000; and
(c) approving revised values for rate base and invested capital for use in the automatic adjustment formula (the "Automatic Adjustment Formula") for the calculation of return on rate base for 2005 pursuant to Order No. P.U. 19 (2003).

Report on the Amortization of the Unfunded Pension Liability

NEWFOUNDLAND POWER
A FORTIS COMPANY

Introduction

In Order No. P.U. 35 (2003), the Board ordered Newfoundland Power (the "Company") to file a report addressing the amortization period in respect of the unfunded pension liability.

This report summarizes the components of the Company's pension funding for the 2004 and 2005 forecast periods based on the most recent actuarial valuation of the Plan by Mercer Human Resource Consulting ("Mercer"). The report also addresses Newfoundland Power's current approach to the amortization of pension funding.

Overview

In Order No. P.U. 19 (2003), the Board ordered Newfoundland Power (the "Company") to incorporate deferred charges in rate base commencing in 2003. Deferred pension costs are the cumulative differences between pension funding and pension expense over the life of the pension plan, and account for approximately 85% of Newfoundland Power's deferred charges.

Newfoundland Power funds its defined benefit pension plan (the "Plan") in accordance with Board approvals and actuarial determinations.

There are two components of pension funding. The first is current service cost. This is the actuary's determination of the present value of benefits to be paid related to service rendered by active employees during the current year.

The second component is past service pension funding, or special funding. This is funding to meet additional costs that are not related to the current service rendered by employees during the current year. These additional pension funding requirements can arise on plan initiation or amendments, early retirement programs, changes in assumptions or market returns on assets in the fund being greater or less than those expected. The actuary determines the payments that are necessary to eliminate this additional liability over a given period.

Pension legislation requires that pension funding be based on actuarial recommendations. Actuarial valuations must be conducted, at a minimum, once every three years. Newfoundland Power's special pension funding payments are in accordance with Board Orders and within the requirements of the *Pension Benefits Act, 1997*. Section 12 (3) of the *Pension Benefits Act Regulations* requires, in relation to a pension plan containing defined benefit provisions, that:

"…every employer shall pay to a pension fund

(c) special payments required to liquidate by equal payments made at least quarterly, with interest at the going concern valuation rate, any other going concern unfunded liability within 15 years of the review date of the actuarial valuation in which the liability is identified…"

Existing Rates

Newfoundland Power's current electricity rates were set following the Company's 2003 General Rate Application (GRA). The test year forecasts of pension funding presented to the Board during the 2003 GRA were based on Mercer's findings as presented in their actuarial valuation of the Plan as at December 31, 2000. An executive summary of that valuation was filed in the 2003 GRA as Undertaking U-12.

The December 31, 2000 valuation indicated that the unfunded liability in the Plan was $27.9 million, and that special funding would be necessary, beginning in 2001, to liquidate the liability.

Incorporating Board-authorized funding, the Company provided for total special funding of $7.6 million in 2003 and $6.4 million in 2004, as shown in Table 1. The Company's test year revenue requirement, upon which current electricity rates are based, is premised on pension funding at the forecast levels.

Table 1
Total Special Pension Funding

($000s)

	2003 Test Year	2004 Test Year
Special funding as authorized by Board	7,175	5,970
Special funding as determined by the actuary in accordance with actuarial guidelines	414	414
Total Special Funding	**7,589**	**6,384**

Current Forecasts

Newfoundland Power is required to file its next valuation report with pension regulators by September 30, 2004. On August 18, 2004, at the request of Newfoundland Power, Mercer completed an actuarial valuation of the Plan as at December 31, 2003. Appendix A is a copy of Mercer's letter, dated August 18, 2004, summarizing the most recent actuarial valuation.

The results of the valuation indicate that there remained an unfunded liability, as at December 31, 2003, of $24.1 million (as compared to $27.9 million as at December 31, 2000).

To reflect the reduction in the present value of the unfunded liability as at December 31, 2003, the actuary derived a revised schedule of special funding payments that maintained the current

Board-approved schedule of funding in the immediate term and adjusted those payments that were in the most distant future. The present value of the revised schedule of special payments is equal to the going concern unfunded liability of $24.1 million identified in the most recent valuation.

The current 2004 and 2005 forecasts of special funding are unchanged from the 2004 test year forecast. Table 2 sets out the total forecast of special pension funding for 2004 and 2005 based on the revised schedule of special payments.

Table 2
Total Special Pension Funding

($000s)

	2004F	**2005F**
Special funding as authorized by Board	5,970	5,970
Special funding as determined by the actuary in accordance with actuarial guidelines	414	414
Total Special Funding	**6,384**	**6,384**

Amortization Period

Adequate funding of the Plan provides long term stability in the cost of pension liabilities to the Company's current and former employees. Adequate funding also allows the Plan and the Company as its sponsor to better weather variations in actual plan performance from that assumed when the funding levels are determined.

The Board has authorized the Company's current funding stream. The Company's approach has been to follow the approved funding stream until such time as the Plan is fully funded. Present estimates as set out in Appendix A indicate that this will be achieved in 2008, which is marginally faster than the amortization periods envisaged at the time the funding streams were authorized by the Board. Actual achievement of full funding can vary depending on such things as pension asset performance over time.

Current electricity rates were established with reference to special pension funding totalling $6,384,000 in the 2004 test year. Because income tax rules allow the deduction of pension funding (and not pension expense) in the determination of taxable income, the Company's income taxes are reduced by approximately $2.2 million in the test year ($6,384,000 × 35% income tax rate). This tax effect reduced the Company's 2004 revenue requirement and current consumer rates by approximately $3.4 million. Any reduction in funding levels would therefore have the effect of increasing revenue requirement and, consequently, electricity rates.

The unfunded liability of $24.1 million at December 31, 2003 is required under pension legislation to be funded over a maximum period of 15 years. While earlier funding is acceptable from a pension regulatory perspective, the present value of any pension funding stream chosen to liquidate the unfunded liability must equal the $24.1 million liability on an actuarial basis.

The Company has examined the overall impact of liquidating the unfunded pension plan liability over a longer period of time than that currently authorized by the Board. This would have the effect of increasing the Company's current revenue requirements and at least marginally jeopardizing the benefits in pension fund stability which full funding provides to the Company, its employees, and its customers.

Conclusion

Newfoundland Power's current schedule of pension funding incorporates the most recent actuarial determinations and is in compliance with pension legislation and Board orders. The tax effect of the current pension funding lowers the Company's revenue requirement, and the 2004 test year effect is a reduction of approximately $3.4 million in the revenue required from rates.

The overall impact of liquidating the unfunded liability in the Plan over a longer period than the currently authorized funding pattern is an increase in the Company's current revenue requirements.

While pension plan funding for 2004 and 2005 is subject to change from the forecast provided above, it will be determined based on standards that have been consistently applied, and which are in compliance with actuarial principles and Board orders.

Appendix A

Letter from Mercer Human Resource Consulting
Dated August 18, 2004

MERCER
Human Resource Consulting

BCE Place
161 Bay Street, P.O. Box 501
Toronto, Ontario M5J 2S5
416 868 2000 Fax 416 868 7671
www.mercerHR.com

18 August 2004

Ms. Lisa Hutchens
Newfoundland Power Inc.
P.O. Box 8910
55 Kenmount Road
St. John's, Newfoundland
A1B 3P6

Private & Confidential

Subject:
Final Valuation Results as at December 31, 2003

Dear Lisa:

As requested, we have completed final valuation results, as at December 31, 2003, for the Newfoundland Power Inc. Retirement Income Plan (the "Plan"). These results reflect the current Plan provisions.

Going Concern Basis

The results of the valuation as at December 31, 2003 in comparison with those of the previous valuation as at December 31, 2000 are summarized as follows:

	12.31.2003	12.31.2000
Actuarial value of assets	$176,473,000	$158,105,000
Actuarial liability		
Present value of accrued benefits for:		
▪ active and disabled members	$101,001,000	$84,447,000
▪ pensioners and survivors	99,158,000	100,683,000
▪ deferred pensioners	433,000	894,000
Total liability	$200,592,000	$186,024,000
Funding excess/(unfunded liability)	$(24,119,000)	$(27,919,000)

MERCER
Human Resource Consulting

18 August 2004
Ms. Lisa Hutchens

The valuation results as at December 31, 2003 are based on the same going concern assumptions are were used for the actuarial valuation of the Plan as at December 31, 2000 except for the following:

	12.31.2003	12.31.2000
Increases in Pensionable Earnings	4.0%	4.5%
Increases in the YMPE	4.0%	4.5%
Increases in the Maximum Pension Permitted under the Income Tax Act	4.0% starting in 2006	4.0% starting in 2005

Solvency Basis

The Plan's solvency position as at December 31, 2003, in comparison with that of the previous valuation as at December 31, 2000, is determined as follows:

	12.31.2003	12.31.2000
Market value of assets	$178,960,000	$162,491,000
Termination expenses	(200,000)	(100,000)
Net market value of assets	$178,760,000	$162,391,000
Actuarial liability		
Present value of accrued benefits for:		
▪ active and disabled members	$59,578,000	$38,952,000
▪ pensioners and survivors	101,533,000	95,322,000
▪ deferred pensioners	458,000	789,000
Total liability	$161,569,000	$135,063,000
Solvency excess	$17,191,000	$27,328,000

The assumptions used in the solvency valuation as at December 31, 2003 are as follows:

Mortality rates:	GAM 1983
Interest rates for benefits to be settled through lump sum transfer:	6.00% per year
Interest rates for benefits to be settled through annuity purchase:	5.25% per year
Family composition:	Same as for going concern valuation
Termination expenses:	$200,000

Funding Requirements

Current Service Cost

The estimated value of the benefits that will accrue on behalf of the active members during 2004, in comparison with the corresponding value determined in the previous valuation as at December 31, 2000, is summarized below:

	2004	2001
Total current service cost	$4,642,000	$4,186,000
Estimated member required contributions	(1,275,000)	(1,167,000)
Estimated company current service cost	$3,367,000	$3,019,000
Company current service cost expressed as a percentage of members' pensionable earnings	9.96%	9.65%

Special Payments

We understand that the current schedule of special payments, approved by the Board of Commissioners of Public Utilities, to amortize the going concern unfunded liability is as follows:

Effective Date	Annual Special Payment	End of Amortization Period	Present Value of Remaining Payments as at December 31, 2003
April 1, 1984	$4,188,000	March 31, 2009	$18,896,000
January 1, 1991	140,000	December 31, 2005	264,000
January 1, 1992	256,000	December 31, 2006	703,000
January 1, 1993	158,000	December 31, 2007	562,000
July 1, 1997	775,000	June 30, 2007	2,448,000
January 1, 1998	258,000	December 31, 2007	918,000
July 1, 1998	88,000	June 30, 2008	347,000
December 31, 1999	521,000	January 31, 2010	2,662,000
	$6,384,000		$26,800,000

The present value of these special payments ($26,800,000) now exceeds the going concern unfunded liability of $24,119,000 as at December 31, 2003. Therefore, we have adjusted the schedule of payments, reducing those payments in the most distant future, such that the present value of the revised schedule of special payments equals the going concern unfunded liability. The resulting schedule of special payments is as follows:

Effective Date	Annual Special Payment	End of Amortization Period	Present Value of Remaining Payments as at December 31, 2003
April 1, 1984	$4,188,000	July 31, 2008	$16,788,000
January 1, 1991	140,000	December 31, 2005	264,000
January 1, 1992	256,000	December 31, 2006	703,000
January 1, 1993	158,000	December 31, 2007	562,000
July 1, 1997	775,000	June 30, 2007	2,448,000
January 1, 1998	258,000	December 31, 2007	918,000
July 1, 1998	88,000	June 30, 2008	347,000
December 31, 1999	521,000	July 31, 2008	2,089,000
	$6,384,000		$24,119,000

MERCER
Human Resource Consulting

This series of special payments meets the requirements of the Pension Benefits Act of Newfoundland and Labrador.

We trust that this provides you with the information you require. Should you have any questions or need anything further, please call.

Sincerely,

Scott Cushing

Scott Cushing
Tel: 416 868 2504
Fax: 416 868 0322
scott.cushing@mercer.com

Copy:
Tony White, Newfoundland Power Inc.
Lisa Hutchens, Newfoundland Power Inc.
Anil Narale, Mercer Human Resource Consulting

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Newfoundland Power Inc.
2005 Capital Budget Application
Filing Contents

Volume I
Application

Volume II
Expenditure Details, Reports and Studies

Project Title: **Hydro Plants - Facility Rehabilitation**

Location: **Various**

Classification: **Energy Supply**

Project Cost: **$1,887,000**

This project consists of a number of items as noted.

(a) Cape Broyle – Replace Inlet, Drain and Bypass Valves

Cost: $249,000

Description: Replace existing turbine inlet valve, drain valve and bypass valves.

Operating Experience: The 78 inch turbine inlet valve and associated drain and bypass valves were installed in 1952. Erosion of the valve disc and seats have rendered this equipment ineffective in providing positive water shut off required to perform maintenance on the equipment. On occasion the water leakage through the valve has caused the turbine unit to continue to turn during machine shutdown.

The following table gives the expenditures for the past five years for the Cape Broyle Plant.

Expenditures					
Year	**2000**	**2001**	**2002**	**2003**	**2004F**
($000s)	$38	$1,086	$5	$91	-

The following table gives the projected expenditures for this plant for the next five years.

Projected Expenditures					
Year	**2005**	**2006**	**2007**	**2008**	**2009**
($000s)	$289	-	-	$1,098	-

Justification: The inlet valve and associated equipment is a critical link in the continued safe and effective operation and maintenance of the Cape Broyle Hydro Generation Plant. Normal production at this facility is 34.2 GWh per year.

A cost benefit analysis to determine the long term economic viability of the plant based on forecasted capital expenditures and operating costs indicates an incremental cost of 0.67 cents per kilowatt hour for Cape Broyle plant energy when levelized over 25 years on a NPV basis.

(b) Seal Cove – Fenelons Pond Dam Refurbishment

Cost: $390,000

Description: Refurbish Fenelons Pond dam, including earth fill embankment, spillway and flow control structure.

Operating Experience: Regularly scheduled engineering dam safety inspections have identified that the dam, spillway and flow control structure have all reached a state of advanced deterioration. Of particular concern is the erosion of embankment materials evident throughout the crest, upstream face and at the spillway abutments.

The following table gives the expenditures for the past five years for the Seal Cove Plant.

Expenditures					
Year	**2000**	**2001**	**2002**	**2003**	**2004F**
($000s)	-	-	$4,013	$532	$11

The following table gives the projected expenditures for this plant for the next five years.

Projected Expenditures					
Year	**2005**	**2006**	**2007**	**2008**	**2009**
($000s)	$390	$131	$25	$470	-

Justification: The Fenelons Pond dam and associated structures are critical to the safe and effective operation of the Seal Cove Hydro Generation Plant. The refurbishment of these structures will minimize risk of failure and associated risk to public safety and environmental damage. Normal production at this plant is 8.8 GWh per year.

A cost benefit analysis to determine the long term economic viability of the plant based on forecasted capital expenditures and operating costs indicates an incremental cost of 2.74 cents per kilowatt hour for Seal Cove energy when levelized over 25 years on a NPV basis.

(c) Heart's Content – Forebay Canal Refurbishment, Long Pond Dam Refurbishment and Rocky Pond Dam Refurbishment

Cost: $337,000

Description: Refurbish existing forebay canal, gate house foundation, Long Pond dam, Rocky Pond dam and spillway located within the Hearts Content Hydro Generation Plant watershed.

Operating Experience: Hydrology studies and recently completed inspections at the Heart's Content watershed areas assessed the spill/discharge capacities of the reservoir and general conditions of the existing structures. The studies and inspections identified that:

- the crest of the forebay canal embankment and adjacent structures should be raised to ensure flood conditions are adequately routed through the Rocky Pond spillway.
- the gabion abutments at the Long Pond dam have deteriorated. In particular, the gabion walls located at the spillway and outlet structure are leaning away from the embankment, thus compromising the integrity of the dam embankment.
- there was insufficient freeboard allowance at the Long Pond dam, posing a risk of dam crest overtopping during flood events.
- there was insufficient freeboard allowance at the Rocky Pond dam, posing a risk of dam crest overtopping during flood events.

The following table gives the expenditures for the past five years for the Heart's Content Plant.

Expenditures					
Year	**2000**	**2001**	**2002**	**2003**	**2004F**
($000s)	$17	$78	$55	$17	-

The following table gives the projected expenditures for this plant for the next five years.

Projected Expenditures					
Year	**2005**	**2006**	**2007**	**2008**	**2009**
($000s)	$337	-	$150	-	$1,631

Justification: The canal, dams and associated structures are critical components for the continued safe and effective operation of the Heart's Content Hydro Generation Plant. The refurbishment of these structures will minimize the risk of flooding and associated risk to public safety and environmental damage. Normal production at this plant is 8.2 GWh per year.

A cost benefit analysis to determine the long term economic viability of the plant based on forecasted capital expenditures and operating costs indicates an incremental cost of 3.43 cents per kilowatt hour for Heart's Content Plant energy when levelized over 25 years on a NPV basis.

(d) Mobile – Replace Inlet, Drain and Bypass Valves

Cost: $240,000

Description: Replace existing turbine inlet valve, drain valve and bypass valves.

Operating Experience: The 60-inch turbine inlet valve and associated drain and bypass valves were installed in the early 1950's. Erosion of the valve disc and seals has rendered this equipment ineffective in providing positive water shut off required to perform maintenance on the equipment. On occasion, the water leakage through the valve, has caused the turbine unit to continue to turn during machine shutdown. Several attempts during the past 10 years to fix the inlet valve by repairing internal valve seals have not been successful.

The following table gives the expenditures for the past five years for the Mobile Plant.

Expenditures					
Year	**2000**	**2001**	**2002**	**2003**	**2004F**
($000s)	$56	$46	$9	$1	$5

The following table gives the projected expenditures for this plant for the next five years.

Projected Expenditures					
Year	**2005**	**2006**	**2007**	**2008**	**2009**
($000s)	$240	-	-	-	-

Justification: The inlet valve and associated equipment is a critical link in the continued safe and effective operation and maintenance of the Mobile Hydro Generation Plant. Normal production at this facility is 41.8 GWh per year.

A cost benefit analysis to determine the long term economic viability of the plant based on forecasted capital expenditures and operating costs indicates an incremental cost of 0.58 cents per kilowatt hour for Mobile Plant energy when levelized over 25 years on a NPV basis.

(e) Port Union – Refurbish Whirl Pond Dam

Cost: $76,000

Description: Refurbish existing Whirl Pond dam at the Port Union Hydro Plant.

Operating Experience: Regularly scheduled inspections by an independent engineering consultant and Newfoundland Power engineering and operations staff have identified that the timber crib dam at Whirl Pond has become deteriorated. In particular, excessive rotting of timber and movement/settlement of rock fill is evident throughout.

Justification: The Whirl Pond dam is a critical component for the continued safe and effective operation of the Port Union Hydro Generating plant. The refurbishment of the dam will minimize risk of failure and associated risk to public safety and environmental damage. Normal production at this plant is 2.3 GWh per year.

(f) Various Plants – Upgrade Protection and Controls

Cost: $302,000

Description: Replace protection and control systems in Newfoundland Power's hydro plants to provide for the reliable and safe operation of the plants and to support a predictive maintenance program. This will be achieved by addressing issues pertaining to equipment requiring maintenance but no longer supported by the manufacturer thus making replacement parts expensive or unavailable. As well, this project will improve the control and protection of the equipment by using more versatile electronic devices. Additional monitoring, control and protective devices will be installed to meet present day standards. These upgrades will also facilitate increased automation and remote control capabilities. In 2005 upgrades are planned for the following Hydro Plants: Lookout Brook, Lockston, Lawn and Tors Cove.

Operating Experience: The power plants owned by Newfoundland Power range in age from 6 to 104 years. Much of the original protection and control equipment is still in service, in particular the hydraulic gateshaft governors, switchgear and protective relays. The switchgear in some plants is over fifty years old and the majority of plants have protection schemes utilizing electromechanical relays that do not provide the present IEEE minimum protection requirements.

Justification: The continued reliable, safe and environmentally responsible operation of Newfoundland Power's generating stations requires the replacement of equipment which is beyond its serviceable life as well as the application of new technology to better monitor and control the units to minimize the possibility of costly, major failures.

(g) Refurbish/Replace Hydro Generating Plant Infrastructure & Equipment

Cost: $150,000

Description: Refurbish/replace deteriorated or damaged structures and equipment identified through the normal inspection process.

Operating Experience: Newfoundland Power maintains a variety of dams and control structures forming part of the watershed areas for its various hydro generating facilities.

These dams and control structures are subjected to repetitive natural forces which exert pressures that could lead to failure. Ice action is an annual event causing movement of rock fill on the upstream slopes of the embankment dams. Excessive ice loading conditions leads to failures of timber stop log structures used to control the flow of water past a control structure or overflow spillway.

Wave action during windstorms results in the erosion of earth fill dam materials that undermines the integrity of the structure.

During the spring runoff, with reservoir water levels high, spillway structures are susceptible to damage from flood events during that period of the year.

Since the integrity of these facilities is critical to the efficient operation of the generating facilities, environmental protection and public safety, the facilities are inspected on a regular basis. Deficiencies identified during inspections normally require immediate attention.

Justification: The dams and control structures are critical components in the safe and efficient operation of its hydro generating plants. The expeditious refurbishment of damaged structures will minimize the risk of failure and associated risk to public safety and environmental damage.

(h) Projects < $50,000

Cost: $143,000

Description: Listed are projects estimated at less than $50,000.

1. Cape Broyle – Dam refurbishment
2. Lookout Brook – Bridge refurbishment
3. Rose Blanche – Building and drainage refurbishment
4. Sandy Brook – Spillway and outlet structure refurbishment

Project Title: **Wesleyville Gas Turbine Overhaul**

Location: **Wesleyville**

Classification: **Energy Supply**

Project Cost: **$1,124,000**

See Attachment A, *Rolls-Royce Field Service Report* dated December 22, 2003, outlining the recommendations for this project.

Rolls-Royce

Field Service Report

Operator: Newfoundland Power

Site: Wesleyville

Reason for Visit: Engine and Installation Inspection

Operator Contact:
John Budgell
Kent Nicholson

Contact phone number:

Visit Dates From:
Dec 07th, 2003

to:
Dec 12th, 2003

Equipment: Avon Mk1533-76L

Gas Generator serial no:
37127

Hours since new:
2745

Power Turbine/package serial no:
N/A

Hours since *new/overhaul:
N/A

Field Service Rep:
Gary Glancy

Date of report:
Dec 22nd, 2003

Report Reference:
SWOF: 03-2111
SV-IMD-A762

1.0 INTRODUCTION

1.1 This unit was moved from Salt Pond Newfoundland to Wesleyville. During the move the power turbine was overhauled and a complete new intake assembly was installed. A new Allen Bradley fuel control was also installed.

1.2 Newfoundland Power asked for a Rolls-Royce Representative to inspect the gas generator and installation prior to starting the unit.

2.0 CONCLUSIONS

2.1 The gas generator was inspected prior to the move and the recommendation at that time was to have the unit sent to an approved overhaul facility for repair prior to running the unit. This visit was not different in that the customer was informed that the gas generator is in poor condition and should be overhauled as soon as possible to prevent the possibility of a catastrophic failure.

3.0 RECOMMENDATIONS TO CUSTOMER

3.1 This engine should be removed and sent to an approved overhaul facility as soon as possible.

3.2 The fuel drain from the fuel cooled oil cooler should be tubed in to the common drain tank.

3.3 The fuel drain from the low fuel pressure switch should be tubed in to the common drain tank.

3.4 A thermocouple should be installed in the cooling air pipe work and a trip setting of 360DegC should be set into the fuel control.

3.5 The gearbox breather was open to inside the enclosure, this should be fed into the exhaust ducting or to outside of the building.

3.6 The bleed valve ductwork was adjusted during installation; a further check should be carried out when the engine is warm to make sure that the ductwork does not come in contact with the engine off takes.

3.7 Customer should seriously consider installing a variable inlet guide vane feedback. At this time it is impossible to check variable inlet guide vane position. Although there is no guide vane position indication; the bleed valve opening set-points should be checked during initial running.

3.8 Flex couplings should be added to the cooling and sealing air pipe work to prevent any stress at the engine interface.

3.9 Entry should be made in engine log book to record work performed and any modifications embodied in the engine listed below.

4.0 WORK PERFORMED, OBSERVATIONS AND TEST RESULTS

4.1 After arriving at site the engine installation was inspected. The front mounts were found installed correctly, the rear mounts were also found installed correctly. The rear exhaust section was already installed and had been inspected by site personnel; the complete alignment checks were therefore not completed.

4.2 A further inspection of the engine externals was carried out which led to the recommendation as reported above.

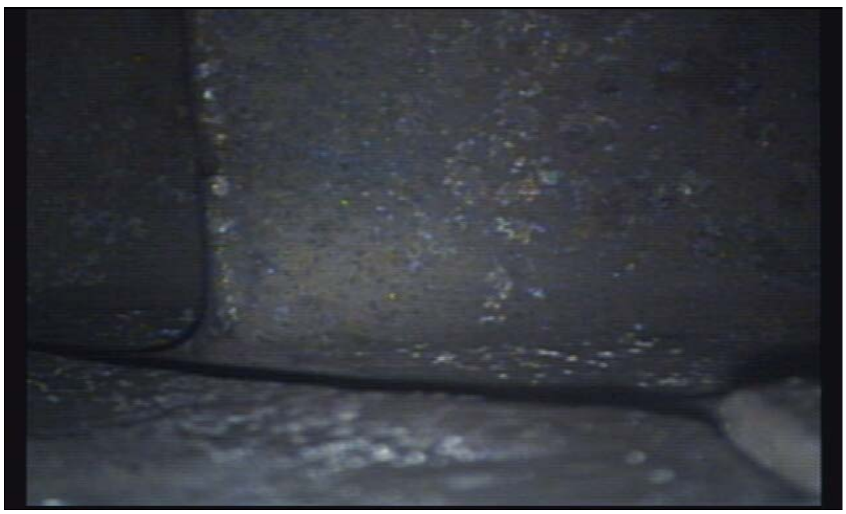
4.3 The top and bottom intake assemblies were inspected prior to motoring the engine. This was then signed off along with NFP personnel.

4.4 A boroscope inspection was carried out and the following pictures will show the poor condition of the gas generator. The first few pictures show the intake casing and guide vanes. Both the casing and vanes are extremely salt corroded, eroded and pitted:

4.5 The next two pictures show the last stage of compressor blade with FOD impact damage:

4.6 The fuel burners had recently been removed and cleaned and were found in good condition. The combustors were also in reasonable condition with exception to heavy carbon build-up.

4.7 The HP NGV's and HP Turbine were found in poor condition as the following pictures will show. These blades are also corroded, eroded and pitted, FOD damage and splatter also apparent.



4.8 All inspections and/or processes described in this report have been carried out in accordance with the following list of reference documents and their amendments.
Ind Avon Installation Manual.
Ind Avon Maintenance Manual

5.0 ROLLS-ROYCE ACTIONS

5.1 None.

Gary Glancy
Customer Service Business

Project Title: **Rattling Brook Hydro Plant Refurbishment**

Location: **Rattling Brook – Norris Arm South**

Classification: **Energy Supply**

Project Cost: **$350,000**

See Attachment A, *Engineering Plan – Rattling Brook Refurbishment*, which describes the engineering work proposed for 2005 and Attachment B, *Project Justification -Rattling Brook Refurbishment Project*, which outlines the rationale and justification for this project.

Engineering Plan
Rattling Brook Refurbishment

July 16, 2004

Prepared By:

Jack Casey P. Eng.
Gary Humby P. Eng.

NEWFOUNDLAND POWER
A FORTIS COMPANY

Table of Contents

1.0 General

The Rattling Brook hydro development was placed into service in 1958. Since 1958, some refurbishment work has been completed within the plant. In 1986 and 1987, the turbine runners were replaced on each unit. In 1994, the Rattling Brook generating station was placed under remote control from the system control centre in St. John's. In 2002, the stator on unit # 2 generator was rewound after it failed in service. The rewind of generating unit #1 is included in the 2004 Capital Budget. Also in 2002, a new power transformer was installed replacing the two original units. With the exception of these major projects, the plant remains in original condition.

During the 2006 and 2007 construction seasons, Newfoundland Power intends to undertake a refurbishment of the civil, electrical and mechanical systems at Rattling Brook. The level of preliminary engineering completed to date varies across the different engineering disciplines. Preliminary engineering studies have been completed on the in-plant electrical and mechanical systems. More detailed engineering studies have been completed on the replacement of the woodstave penstock and the refurbishment of the surge tank and the turbine runners.

Construction will be completed in two phases during the 2006 and 2007 construction seasons. The penstock will be replaced in two stages, with the lower half being replaced in 2006, and the upper half in 2007. The mechanical work associated with the runner, wicket gates and valves will also be undertaken in 2006. The surge tank refurbishment and the plant electrical, governors, protection and control work will be completed in 2007.

In 2005 detailed engineering design, specification and tender preparation work will be completed for the replacement of the woodstave penstock and for the mechanical work planned for 2006. Also preliminary engineering work is planned for 2005 for the refurbishment of the surge tank and the electrical work planned for 2007. This preliminary engineering work is necessary to provide detailed estimates for the 2006 and 2007 capital budgets.

2.0 Deliverables

To ensure the project is completed on budget and on schedule, with a minimal impact on the production available from the Rattling Brook development, the major pieces of engineering work should be completed in advance of the 2006 construction season. It is proposed that most of the engineering design work be completed during 2005. The following list of engineering deliverables, organized by engineering discipline, will be completed in 2005.

2.1 Civil Engineering

2.1.1 Environmental
Complete the necessary environmental work required for the replacement of the woodstave penstock. Conduct environmental investigation and soil testing to determine the extent of contamination from the creosote treated penstock, and to determine an environmentally acceptable method for disposal of soil and penstock materials.

2.1.2 Penstock Engineering Design
Complete detailed engineering design to optimize penstock diameter, and to explore alternatives for penstock material (steel or fibreglass). Complete design of penstock sections, penstock supports, anchor blocks, steel bulkhead, and transition to existing steel penstock.

Conduct testing on the lower section of steel penstock to determine the location and causes of excess head losses upstream and downstream of the bifurcation.

Research design information and past load rejection history, and conduct load rejection testing to confirm the capacity of the components that are to remain.

2.1.3 Penstock Installation Specification
Complete field survey and geotechnical investigation, and prepare engineering specifications.

2.1.4 Penstock Supply Tender Preparation
Complete the necessary tender documents including the tender form, agreement, schedule of prices, schedule of equipment and all other necessary schedules.

2.1.5 Penstock Installation Tender Preparation
Complete the necessary tender documents including the tender form, agreement, schedule of prices, schedule of equipment and all other necessary schedules.

2.1.6 Surge Tank Engineering Design Specification
Complete field surveys and prepare engineering specifications. Engage consultant with expertise in the design of surge tanks.

2.2 Electrical Engineering

2.2.1 Prepare Final Design Document
Review documented maintenance history for the plant and review current maintenance issues with local operators. Inspect electrical equipment, including control system, synchronizer, voltage regulator, and governor electrical interfaces. Identify issues with wear, corrosion, and other forms of degradation. Prepare a final design document based upon the conceptual design for review by technical experts. Review budget estimates in light of final design and revise as necessary.

2.2.2 Protection Review
Review existing protection system, including relay settings and single line diagrams. Apply current protection standards and identify areas where existing protection fails to meet current standard. Prepare a detailed protection plan for inclusion in protection and control specifications.

2.2.3 Electrical Installation Design Specifications
Complete engineering specifications for replacement equipment, and other electrical work to be completed by an electrical contractor. Specification document will include all electrical work to be completed during the 2006 construction season. Specifications will include electrical work associated with all civil and mechanical work planned for 2006.

2.2.4 Electrical Installation Tender Preparation
Complete the necessary tender documents including the tender form, agreement, schedule of prices, schedule of equipment and all other necessary schedules.

2.2.5 Governor Design Specifications
The mechanical inspection will verify if the power components of the existing Woodward hydraulic governor remain serviceable. If, as expected, this proves to be the case, develop engineering specifications for replacing the governor control head with an electronic controller. However, if the power components of the existing Woodward hydraulic governor prove not to be serviceable, then prepare engineering specifications for a replacement all-electric governor.

2.2.6 Governor Tender Preparation
Complete the necessary tender documents including the tender form, agreement, schedule of prices, schedule of equipment and all other necessary schedules.

2.2.7 Protection and Control System Design Specifications
The protection review will provide the protection plan required for these generators. Apply the generator protection standards to the protection plan developing the necessary design drawings and specifications. Incorporate the generator protection design with the specific control system requirements of the generator, to prepare specifications for the construction of a PLC-based unit control panel.

2.2.8 Inspection of Switchgear
Complete an internal inspection of the switchgear and associated potential and current transformers. Inspect the bus work, exciter cables, power cables and power cable terminations. Make recommendations on the remaining service life of the switchgear.

2.3 Mechanical Engineering

2.3.1 Internal Inspection of Mechanical Components
Remove the plant from service and dewater the penstock. Inspect the internal components associated with the main valve and the wicket gates. Identify which components need to be replaced or refurbished.

Disassemble the Woodward hydraulic governors and inspect the power components for wear and oil leaks. If possible, include a manufacturer's representative with the inspection team. Determine the condition of all spare parts and source additional spare parts as necessary. Make an assessment of the remaining life of these components.

2.3.2 Main Valve Engineering Design Specifications
The internal inspection will confirm if a valve refurbishment is technically possible, or if the main valves will need to be replaced. Prepare engineering specifications on alternative chosen. Review budget estimates in light of final design and revise as necessary.

2.3.3 Main Valve Tender Preparation
Complete the necessary tender documents including the tender form, agreement, schedule of prices, schedule of equipment and all other necessary schedules.

2.3.4 Turbine Runner Engineering Design Specifications
The mechanical internal inspection will identify the work necessary on the turbine runner. Prepare engineering specifications for the work identified. Review budget estimates in light of final design and revise as necessary.

2.3.5 Turbine Runner Tender Preparation
Complete the necessary tender documents including the tender form, agreement, schedule of prices, schedule of equipment and all other necessary schedules.

2.3.6 Mechanical Installation Design Specifications
Complete engineering specifications for replacement equipment, and other mechanical work to be completed by a mechanical contractor. Include the realignment of unit #2 and the replacement of the generator cooling air intake dampers with these specifications. Specification document will include all mechanical work to be completed during the 2006 construction season.

2.3.7 Mechanical Installation Tender Preparation
Complete the necessary tender documents including the tender form, agreement, schedule of prices, schedule of equipment and all other necessary schedules.

2.4 Resource Assignment

It is anticipated that internal Newfoundland Power resources will be used to complete most engineering work, including equipment inspections. Engineering consultants will be engaged for specialized expertise such as the inspection of the surge tank and the required environmental assessments.

3.0 Cost Estimate

The table below identifies the effort and associated cost for preparing the various engineering deliverables:

Deliverable	Internal Cost	Consultant Cost	Total
Civil Engineering			
Testing and Inspections	$14,000.00	$10,000.00	$24,000.00
Engineering Design	$40,000.00	$20,000.00	$60,000.00
Tenders and Procurement	$29,000.00		$29,000.00
Electrical Engineering			
Testing and Inspections	$16,000.00		$16,000.00
Engineering Design	$98,500.00		$98,500.00
Tenders and Procurement	$28,000.00		$28,000.00
Mechanical Engineering			
Testing and Inspections	$22,500.00		$22,500.00
Engineering Design	$50,500.00		$50,500.00
Tenders and Procurement	$21,500.00		$21,500.00
		TOTAL	**$350,000.00**

Energy Supply
Appendix 3
Attachment B
NP 2005 CBA

Project Justification
Rattling Brook Refurbishment Project

July 9, 2004

Prepared By:
John W. Pardy, P.Eng.
Jack W. Casey, P. Eng.

NEWFOUNDLAND POWER
A FORTIS COMPANY

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1.0 Introduction

The Rattling Brook hydro development is located approximately 50 kilometres west of Gander in the Notre Dame Bay area. The development was placed into service on December 16, 1958 utilizing two 8500 horsepower vertical shaft Francis type turbines connected to separate generators, each with an individual rating of 7500 kVA. The original construction cost of this project was approximately $6 million.

Since that time, refurbishment work has been completed on some systems within the plant. In 1986 and 1987 the turbine runners were replaced on each unit. In 1994, the Rattling Brook generating station was placed under remote control from the system control centre in St. John's. The stator on unit # 2 generator was rewound after it failed in service in 2002. The stator on unit #1 generator is being rewound in the summer of 2004 as part of the 2004 Capital Budget. Also in 2002 the installation of a new power transformer in the substation was completed replacing the two original units. With the exception of these major projects, the plant remains in original condition.

During the 2006 and 2007 construction seasons, Newfoundland Power proposes to undertake a refurbishment of the civil, electrical and mechanical systems at Rattling Brook. Engineering assessments of the systems are included in Appendices A, B and C. Appendix D includes a detailed feasibility analysis of the costs and benefits associated with this project.

The extent of preliminary engineering completed to date varies across the different engineering disciplines. Detailed engineering studies have been completed on the replacement of the woodstave penstock and the refurbishment of the surge tank and the turbine runners. Preliminary engineering studies have been completed on the in-plant electrical and mechanical systems. Construction will be completed in two phases during the 2006 and 2007 construction seasons. In 2005 detailed engineering design, specification and tender preparation work will be completed for the replacement of the woodstave penstock. Also more detailed engineering work is planned for 2005 dealing with the refurbishment of the surge tank and the electrical and mechanical work. This more detailed engineering work will provide final estimates for the 2006 and 2007 capital budgets.

This multiphase approach to the engineering design will ensure the lowest cost solutions, proposing replacement of systems only when refurbishment is not practical. Budget costs presented in the second and third year of the project will be the result of detailed engineering assessments completed during planned outages in the previous year.

2.0 Civil Works

The engineering assessment has identified the following pieces of civil work to be completed during the plant refurbishment:

- Replace wood stave penstock
- Refurbish surge tank
- Rehabilitation of Amy's Lake control structure

In the fall of 2003, the SGE Acres consulting firm were engaged to complete inspections of the penstock and surge tank at Rattling Brook. Their report, included in Appendix A, recommends the replacement of the woodstave penstock and refurbishment of the surge tank. The penstock is described as being in poor condition with leakage along the springline. The surge tank has serious cracking of welds, wear of metal components due to friction, wood rot and corrosion damage. Undertaking the refurbishment of the surge tank in the near term can avoid the complete replacement of the structure at some future date.

In 1982, Newfoundland Power undertook a study into the potential for increasing the Rattling Brook plant capacity through a redesign of the flow area of the penstock. At that time it was determined that the cost of replacing the penstock was not justified by the benefits associated with an estimated 6.7 GWH in additional energy. In the twenty-two years since the original study, the condition of the penstock has deteriorated to the point where its replacement is required for public safety reasons and to ensure the reliable operation of the generating plant. The incremental cost of increasing the penstock diameter from its original diameter of 2.1 and 2.3 metres to the optimal diameter of 2.9 metres is justified by the increased energy supplied.

3.0 Electrical Works

An engineering assessment in Appendix B has identified the following pieces of electrical work to be completed during the plant refurbishment:

- Upgrade electrical and mechanical protection system for Rattling Brook plant
- Replace voltage regulator, synchronizer and alarm annunciation
- Replace power cables and exciter cables
- Replace existing relay control system with PLC based control system
- Refurbish or replace existing governor systems
- Replace or upgrade the existing switchgear, pending further internal inspections
- Replace AC and DC electrical distribution systems

The assessment identified concerns with the electrical protection of the new generator windings, the lack of vibration monitoring, power cable condition and future support of the existing Woodward hydraulic governors.

In 2002, the windings were replaced on the unit #2 generator after there was an in-service failure. The replacement of the windings on the unit #1 generator is planned for the summer of 2004. The set of electromechanical protective relays on the generator do not meet the current IEEE recommendations, falling short in the area of ground fault protection, over-frequency protection and stator unbalance.

The synchronizer is vacuum tube technology dating back to the 1958 installation. Replacement vacuum tubes are no longer manufactured. Similarly, the alarm annunciator is constructed using antiquated technology and fails regularly.

The switchgear and power cables are original to the 1958 installation. Deterioration of the oil filled power cables and the current/potential transformer windings due to age are a concern. An engineering review of the condition of the power cables, breakers, bus work and current/potential transformers will be undertaken with the entire system de-energized in 2005.

4.0 Mechanical Works

The engineering assessment has identified the following pieces of mechanical work to be completed during the plant refurbishment:

- Refurbish runners
- Refurbish the main valves
- Replace the five way control valves
- Replace wicket gates
- Replace the governors' hydraulic control head
- Upgrade the cooling water system and replace strainers
- Alignment of unit #2
- Replace the air intake louvers

The internal inspection of the turbine runners was completed in 1998 with the balance of plant inspection completed in May 2004. The inspection has identified both replacement and refurbishment work to be undertaken during the plant outages in 2006 and 2007.

Damage to the runners has been identified in the mechanical assessment included in Appendix C. This damage can be repaired at relatively low cost if undertaken in the next few years. The main valves are leaking, but it is felt that if the work is undertaken at this time the valves can be refurbished and not replaced. Repairs completed on the wicket gates in the 1980s have failed and the wicket gates need to be replaced.

When unit #2 generator was rewound in 2002 and issued with the unit alignment was identified that requires attention during the next plant outage of significant duration. The work on the runners during this project presents an excellent opportunity to realign unit #2.

The governors are responsible for regulating the speed of the generator, which translates into the frequency component of power quality to the customer. This is particularly important when the generators are operating isolated from the grid and do not benefit from the dampening effect of the larger power system. The existing governors are original to the plant and require more frequent maintenance as the various linkages and springs wear with age. The original equipment manufacturer can no longer provide replacement parts for the various linkages and springs that are used to regulate generator speed. However the original equipment manufacturers, and other suppliers, do manufacture an electronic upgrade for the original hydraulic control head. As the oil reservoir and power piston appear to be in good condition, these governors are candidates for this form of upgrade, as opposed to the replacement of the complete hydraulic package with newer technology.

A redesign of the cooling water system is required to address existing operational maintenance issues. Separate cooling water systems and duplex strainer systems will allow maintenance to be completed on one unit while the second unit remains in service. The generator cooling intake dampers are in need of repair and contain an amount of non-friable asbestos that will be disposed of. An associated walkway presents a safety hazard to employees that must be addressed with the replacement of the dampers.

5.0 Feasibility Analysis

Appendix D provides a detailed feasibility analysis for the continued operation of the Rattling Brook hydroelectric development assuming that the planned capital refurbishment is undertaken. The results of the feasibility analysis show that the continued operation of the facilities is economical over the long term. Investing in the life extension of the Rattling Brook hydroelectric development ensures the continued availability of 69.4 GWH of low cost energy to the provincial electrical system.

The estimated levelized cost of energy from the facility over the next 25 years based upon the proposed capital expenditures is 1.7 cents per kWh. This energy is lower in cost than replacement energy from sources such as new hydroelectric developments and additional Holyrood thermal generation.

6.0 Project Execution

The refurbishment of the Rattling Brook hydroelectric development will be a large project executed over two construction seasons. The primary reason for completing the work in two phases is to reduce the spill associated with the construction downtime. The preferred construction window for Rattling Brook is approximately twelve to sixteen weeks each summer to minimize spill. If the plant is unavailable for a period outside of this window then the potential for spilling water is increased. Therefore, it is prudent to undertake this refurbishment over two construction seasons.

To complete the entire project in a single construction season would require a continuous twenty-five week period of downtime for the plant. It is estimated that 15 GWH of energy would be lost by extending the construction period nine weeks into either the spring or early winter.

To ensure that the work is ready to proceed when the construction window opens it is essential that all engineering design, specification documents and tenders are prepared in advance of the construction season. Advanced preparation of the detailed engineering specifications will also enhance the accuracy of cost estimates. Therefore, it is proposed to undertake the necessary engineering design work in the year prior to commencement of construction.

The following is the proposed high-level schedule for the work:

2005

Complete engineering design of penstock and surge tank
Complete electrical engineering final design
Complete mechanical engineering final design
Prepare and execute tenders necessary for 2006 construction

2006

Install first section of penstock
Refurbish main valves on units #1 and #2
Refurbish runners on units #1 and #2
Replace wicket gates on units #1 and #2
Complete engineering design for Amy's control structure
Complete engineering design for unit control panels
Complete engineering design for governor upgrading
Prepare and execute tenders necessary for 2007 construction

2007

Install second section of penstock
Refurbish surge tank
Replace unit control panel
Replace forebay water level control
Refurbish Amy's control structure

7.0 Conclusion

To date preliminary engineering assessments have been completed on the civil, electrical and mechanical systems of the Rattling Brook hydroelectric development. The civil engineering studies have been completed with the assistance of outside experts and have identified the penstock replacement and surge tank refurbishment as being required to be completed within the next two years. This requires that the detailed engineering design and procurement process be completed in 2005.

Preliminary engineering assessments have also identified electrical and mechanical systems that should be addressed in the near future. It is proposed that the engineering work associated with these systems be completed in 2005 to ensure that the necessary work proceeds in either 2006 or 2007. This will allow Newfoundland Power to take advantage of the extended outages associated with the penstock replacement to complete all necessary electrical and mechanical work, and will avoid extended outages being required in future years.

The engineering assessments have identified work associated with the refurbishment and life extension of the Rattling Brook hydroelectric development. The feasibility analysis included in Appendix D verifies the financial viability of completing this project. The 69.4 GWh of energy produced at Rattling Brook each year plays a significant role in providing affordable energy to the customers of Newfoundland Power. Safety issues with the penstock and surge tank must be addressed in the near future. The planned schedule for project execution ensures the minimum amount of lost energy due to spill. Based upon these considerations, and others outlined in this report and attached assessments, the project is recommended to proceed in 2005.

Appendix A

Civil Engineering Reports

Prepared for

Newfoundland Power
55 Kenmount Road, St. John's, NL A1B 3P6

Consulting Services for

Surge Tank and Penstock Inspection – Rattling Brook Hydroelectric Development

Final Report

PROVINCE OF NEWFOUNDLAND
PERMIT HOLDER
CLASS "A"
This Permit Allows
SGE ACRES LIMITED

To practice Professional Engineering in Newfoundland and Labrador
Permit No. as issued by APEGN T0060
which is valid for the year 2003

REGISTERED PROFESSIONAL ENGINEER
E. M. SAUNDERS
SIGNATURE
Dec 8/03
DATE
NEWFOUNDLAND & LABRADOR

Prepared by
SGE Acres Limited

November 2003
P15310.00

SGE Acres

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1 Introduction

1.1 General

Following the submission of a proposal on September 18, 2003, SGE Acres was contracted by Newfoundland Power (NP) to carry out an inspection of the penstock and surge tank at the company's Rattling Brook hydroelectric station in central Newfoundland. This report is the result of that inspection.

Prior to the site visit, as a requirement of the contract, SGE Acres submitted a project specific Health and Safety Plan to NP for review. SGE Acres also subcontracted inspection support relating to rigging and structure access to Remote Access Technology (Newfoundland) Limited of St. John's. This company also carried out ultrasonic thickness measurements as required by the contract.

The site inspections, which were carried out from October 14-17, 2003, comprised:

- a visual inspection of the exterior of the woodstave portion of the penstock
- a visual inspection of the interior of the surge tank and surge tank internal and external risers
- a visual inspection of the surge tank support structure
- a visual inspection of the interior and exterior of the steel portion of the penstock
- ultrasonic measurements of the wall thickness of the surge tank and steel penstock.

Mr. G. Saunders, P.Eng., of SGE Acres St. John's office carried out the inspections with the support of the subcontractor. Mr. G. Murray, P.Eng., was NP's representative during the inspections.

1.2 Description of the Facility

The Rattling Brook Hydroelectric Development, which is located near Norris Arm in central Newfoundland, has a capacity of 15 MW from two identical units fed from a bifurcation. The facility was commissioned in 1958. The water conveyance system consists of a combination woodstave and steel penstock and steel surge tank. The tank has four main components:

- Four support legs with a base diameter of 9.6 m (31'- 6") and height of 63.1m (207' ft)
- Steel tank which is 32.9 m (107'-9") high with a 6.1 m (20'- 0") ID steel shell and 6.6 m (21'- 8" ft) OD frost casing
- Internal riser with a diameter of 1.8 m(6'- 0") and height of 32 m (105ft)
- External riser with a diameter of 2.1 m (7'- 0"), 2.5 m (8'-4") diameter frost casing and height of 62 m (203'-9").

The tank and lower riser are protected with an external creosoted timber jacket.

The woodstave/steel penstock is approximately 1980 m (6500 ft) long. The first 1677 m (5550 ft) is woodstave with the first 634 m (2080 ft) having an internal diameter of 2.3 m (7.5 ft) and the remainder having a diameter of 2.1m (7 ft). The steel portion is 290 m (950 ft) long and about 192 m of this is upstream of the surge tank and is supported on steel saddles on concrete bases. The remaining 97.5 m (320 ft) downstream of the surge tank is buried.

2 Results of the Inspection

2.1 Woodstave Portion of Penstock

A visual inspection of the woodstave penstock from the intake thimble to the aboveground steel portion of the penstock was undertaken on October 14, 2003. This inspection was carried out while the penstock was pressurized so that an assessment of the water leakage and condition could be made under normal operating conditions. To visually inspect as much as possible Mr. Saunders and Mr. Murray walked opposite sides of the penstock.

The wood staves were found to be in poor condition. (See photo number 16) Many areas along the spring line were leaking. Most of the leaks were in end joints; however, there were leaks in longitudinal joints and displaced knots. As would be expected, the leakage intensified as the pressure in the penstock increased. (See photos number 17, 18 and 19)

The steel bands and rod ends were in good condition with little corrosion evident. The stud bolts holding the saddles together showed signs of corrosion.

Along the penstock, there was evidence of previous repairs which included steel plates and wooden wedges.

Two different styles of wooden saddles were used to support the penstock. In general both support types were in satisfactory condition. In some areas, the cradle blocks were cracked around the tie rods. These cracks in the wood were not serious enough to weaken the saddle load carrying capacity. A few of the saddles were in areas of high water flow, caused by leakage, where washout of the supporting gravel base was a concern. (See photo number 20)

Following the inspection, repairs were made to previously identified areas. Approximately 100 steel plates 1.6 mm thick ranging in size from 300 mm x 300 mm to 300 mm x 1200 mm were placed between the exterior of the penstock and the steel bands. Rubber gasket material was placed underneath the plates to make a seal. After the penstock was depressurized, 30 bundles of cedar roofing shingles were used to seal some of the remaining leaking areas. (See photos number 14 and 15)

2.2 Steel Portion of the Penstock

2.2.1 External

An external visual and ultrasonic thickness inspection of the steel penstock was performed. The initial inspection was made when the penstock was pressurized so that any areas of leakage could be identified.

The penstock changes from woodstave to a welded steel section as it nears the surge tank. There are two concrete anchor blocks and two slip type expansion joints in the aboveground section of the penstock. The penstock was shop fabricated in sections of approximately 30 to 40 feet and field welded together. The aboveground sections are supported on steel saddles and concrete base pads. The supports have a fabric bearing pad placed between the curved saddle plate and the penstock; there are no wear plates welded to the penstock at the saddle locations. The notes on the drawing indicate the bearing fabric is a bonded material containing asbestos. This original material was supplied in two pieces which were cemented to the saddle and penstock metal surfaces. During the initial inspection it was noted that in some areas the bearing fabric was pulled out from between the penstock and the saddle. These areas were revisited after the penstock was dewatered. It would appear that the longitudinal motion due to expansion and contraction has caused slippage of the fabric. (See photo number 11)

The above ground portion of the steel penstock runs from the first concrete anchor block, where the woodstave is connected, to the surge tank anchor block. The portion of the penstock downstream of the surge tank is underground and can be accessed through hatches in each leg of the bifurcation located inside the powerhouse, through the hatch at the bottom on the surge tank external riser or through the main penstock access hatch located downstream of the second anchor block.

The penstock is coated with a silver coloured painting system which is in good condition. There is one area near the first expansion joint where the paint is missing causing the steel plate to oxidize. (See photo number 21)

The welded joints are sound; however, there is evidence of out of roundness and peaking at many of the joints. None of these defects are detrimental to the performance of the penstock.

The penstock supports were in good condition with no signs of damage or corrosion. The concrete base pads and the anchor bolts were inspected and found to be in good condition.

The concrete anchor blocks were in good condition considering their age. One area requiring repair was found on the upstream end of the first anchor block. There was concrete damage and a small amount of water leakage at the 6 o'clock position.

The expansion joints were inspected and found to be tightened incorrectly. The packing ring was not pulled in evenly around the circumference indicating the tensioning bolts were not tightened evenly. The expansion joint located between the two anchor blocks was not leaking; however, the second expansion joint, located between the second anchor block and the surge tank, had a large leak at the top which appeared to have been leaking for some time. (See photo number 12)

The inspection hatch, which is located in the top of the penstock just downstream of the second anchor block, was found to be in good condition with no evidence of leakage.

After the penstock was dewatered, a second external inspection was completed. This included a further inspection of the saddles, ultrasonic thickness measurements of the penstock shell plate and the interior of the access hatch. The recorded thickness readings can be found in Appendix C.

2.2.2 Internal

After the penstock was dewatered, the inspection hatches in the powerhouse, surge tank and aboveground steel penstock were opened and the penstock allowed too ventilate naturally. The penstock was then checked for oxygen level before entering.

The inspection was performed in two phases. The first phase of the inspection was carried out by a two person team which included Mr. Saunders and an assistant from RAT. This phase involved the inspection of the interior of the penstock from the access hatch to the surge tank tee where the slope was shallow and rope access unnecessary.

The 23 m (75 ft) section of the penstock upstream of the access hatch has a steep slope and could not be accessed for inspection.

A thick cake-like deposit was found on the bottom of the penstock, at the base of the elbow located at anchor block number 2. This deposit was easily chipped away from the penstock exposing a layer of oxidized metal. (See photo number 10)

Moderate corrosion pitting of the interior surface was evident over the entire length. The surface was generally rough with no signs of erosion damage on any surfaces. There did not appear to be any increased corrosion activity at the welded joints.

The expansion joint appeared to be in good condition with no significant corrosion of the leading edge of the slip joint. There was no build up of sediment in the joint and it appeared free to move. (See photo number 7)

The surge tank tee had the most corrosion. The low pressure area just above the upstream entrance to the tee was covered in large scale deposits and carbuncles. (See photos number 8 and 9) Also areas around the bottom of the tee had thick cake deposits similar to those found at the base of the upstream elbow. Samples of this caked material were taken for future analysis.

Removal of the deposits and carbuncles revealed large deep pitting of the metal surface. The surface was very rough, making it impossible to accurately measure the depth of the corrosion.

The lower section of the penstock from the surge tank tee to the powerhouse required rope access and was completed by RAT during the second phase of the inspection. The interior of the underground portion of the penstock was found to be in a similar condition to the aboveground portion.

2.3 Surge Tank

The surge tank inspection was performed in several phases all of which required rope access and were completed by RAT personnel under the supervision of Mr. Saunders.

2.3.1 Exterior Structure

The surge tank is supported on four pipe legs with a system of diagonal rod braces and horizontal box sections used to transfer the wind loads to the foundations. There are two platform levels, one at the external riser expansion joint and the other at the base of the surge tank. The platform at the base of the tank also serves as the compression ring at the top of the support legs. Both platforms were found to be in good condition. (See photo number 6)

The caged ladder is attached to the leg on the southeast corner. The ladder has an anti-fall device, which has been condemned. Rope access was used to provide a safe means of ascending and descending the ladder.

An inspection of the surge tank tower was completed in 1998 by Varcon Inc. The results of this inspection were made available to the inspection team, and it was found that the issues which were found in 1998 were still evident during this inspection. In addition NP advised that a leak in the surge tank access opening located in the side of the hemispherical dish had caused a large buildup of ice during the 2002 -2003 winter. Mild temperatures caused a large piece of ice to fall and strike one of the tie rods connecting the external riser to the support leg and a horizontal support member. The tie rod was found hanging from its pin connection at the leg because the connection plate to the external riser had sheared at the weld. To remove the potential hazard, the tie rod was cut using a hand grinder and lowered to the ground. (See photo number 5)

The horizontal member located on the north face, second horizontal from the top has been bent and has two cracks in the welds which connect the clevis plates to the end plate of the box section. The two cracks, which are short in length, are located on the top of the joints and are consistent with an impact load acting on the top of the horizontal member. This joint is normally under compression and the welds under shear due to the horizontal compression from the diagonal bracing and vertical dead load. It is not anticipated that the cracks will grow under normal live and dead loads. (See photo number 21)

As stated in the Varcon report the diagonal braces are sagging and have kinks and bends. At the point where they cross, there is noticeable metal loss due to the constant rubbing. (See photos number 3 and 4)

The frost casing is made of wood. There is noticeable deterioration of the wooden surface due to weathering. (See photo number 6)

The 2-inch pipe nipple connection to the external riser, located inside the small building at the base of the surge tank, was removed and replaced with a 2 inch 3000# capacity coupling and steel plug.

The cover of the external riser access hatch was heavily corroded.

2.3.2 Surge Tank Interior

Rope access was used to inspect the interior surface of the surge tank. The tank, roof structure and vent are in good condition for the upper 17 m with the painting system intact. The lower section is in fair condition with surface corrosion and pitting.

Thickness measurements were taken on the shell plate using an ultrasonic thickness meter. The measurements are listed in Appendix C.

2.3.3 Internal Riser

Rope access was used to inspect both surfaces of the riser. The upper tie rods and upper 17 m of the riser and external stiffener rings are all in good condition with the painting system intact. The lower section is in fair to poor condition with surface corrosion and pitting. (See photo number 2)

The connection to the hemispherical dished head is in fair condition with surface corrosion and pitting.

Thickness measurements were taken on the shell plate using an ultrasonic thickness meter. The measurements are listed in Appendix C.

2.3.4 External Riser

Rope access was used to inspect the interior surface of the external riser. The surface is rough and corroded over the entire length. The surface roughness was such that no thickness or reliable pitting measurements could be taken on the interior. Some ultrasonic thickness measurements were taken from the exterior near the access opening at the base of the riser and are listed in Appendix C.

3 Conclusions and Recommendations

3.1 Woodstave Penstock

3.1.1 General

Based on a visual inspection, the penstock is in poor condition. Leakage of the penstock at the springline is substantial. The surface quality of the wood is poor and the saddles, although substantially intact, are showing their age. Woodstave penstocks generally have a life of 50 years and this penstock is currently 45 years old. We recommend the penstock be replaced in the near future as we expect the leakage problem to worsen causing operational difficulties and increasing maintenance costs.

3.2 Steel Portion of the Penstock

3.2.1 General

The penstock is in fair condition, but there is evidence of deep isolated pitting of the internal surface. There are many areas of thick surface deposits such as carbuncles and thick cake.

There is no immediate danger to the structural integrity of the penstock shell but continued surface corrosion will reduce its service life. Failure due to pitting corrosion will not be catastrophic but will come in the form of pinhole leaks. The penstock life could be extended indefinitely provided the corrosion deposits are removed and the metal surface blast cleaned and coated with a high build epoxy coating system.

3.2.2 Aboveground Penstock

1. The saddle bearing fabric should be readjusted where it has moved out of position. Appropriate care in handling should be taken as the material contains asbestos and is considered hazardous.
2. Where paint is missing, it should be repaired.
3. The expansion joints should be checked periodically for leakage. During the inspection, the second expansion joint was disassembled, due to a large leak at the top, and repacked with new flax rope. Care was taken to tighten the packing evenly around the circumference.

4. Concrete repairs are needed on the upstream side of the first anchor block. There is leakage and deteriorated concrete at the 6 o'clock position.

3.2.3 Underground Penstock

See general recommendations Section 3.2.1.

3.3 Surge Tank Structure, Surge Tank and Internal Riser

1. The horizontal support which was damaged during the winter of 2002/03 should be replaced. One of the clevis ends is cracked at the welds. See location marked on Drawing No. P15310.00SK-01.
2. Due to the type of loading to which this member is subjected, we do not anticipate the cracks will grow and cause a failure of the connection. We recommend the structural member be replaced as early as practical.
3. The diagonal bracing is sagging and needs to the tightened. In some of the braced bays the bracing appears to be bent or permanently deformed. A replacement assessment should be made after tightening is attempted.
4. Due to the sagging of the diagonal rod bracing, there is metal loss where the rods cross. The material loss should be stopped by attaching a wear plate between the two rods. We recommend using 10mm thick HDPE plastic pads which can be attached to the rods with galvanized U-bolts.
5. There is a loose piece of expanded metal mesh on the revolving dolly located on the roof. A temporary repair was made during the inspection, but a permanent repair should be made as soon as practical.
6. The removed external riser tie rod should be replaced.
7. The wooden frost casing is dried out and should be replaced within the next 5 years.
8. The surge tank and internal riser are deteriorating and need to be blast cleaned and coated with a high build epoxy paint system. Some of the plate may require patching but an assessment is not possible without blast cleaning the surface. If necessary, the lower can sections could be replaced when the external riser is replaced.
9. General painting touch-up should be carried out where rusted areas appear. The coatings, both internal and external, should be inspected every five years. Maintenance of the coatings will prevent further corrosion of the steel and

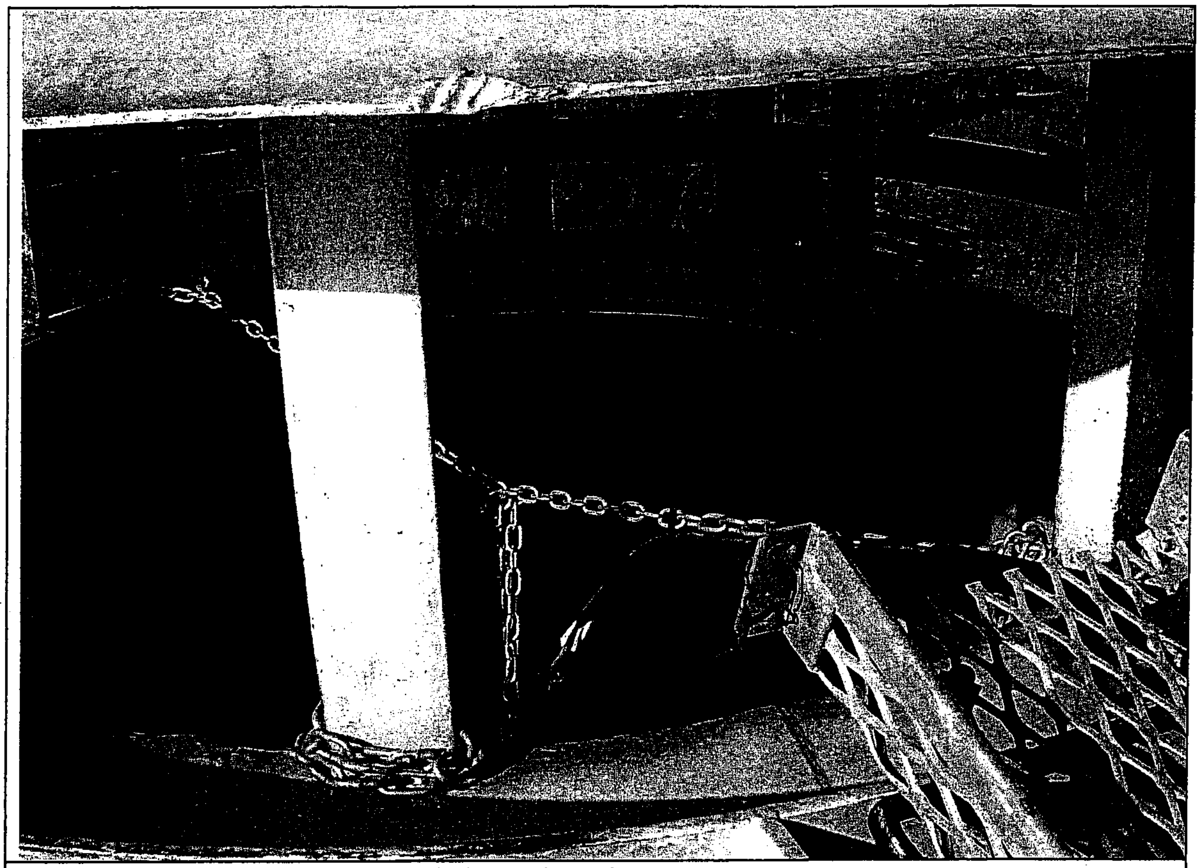
avoid costly replacement of the surge tank, surge tank risers and its structural frame.

10. Concrete repairs identified in the 1998 Varcon report for the crack at the top of the surge tank anchor block and the tops of the concrete foundations under the surge tank legs should be completed in 2004. The cost to repair these areas is small. Delaying these repairs by many years will allow continued deterioration of the anchor block and its steel reinforcing and deterioration of the support grout under the surge tank legs. (See photos 3 and 4 in the 1998 Varcon report)

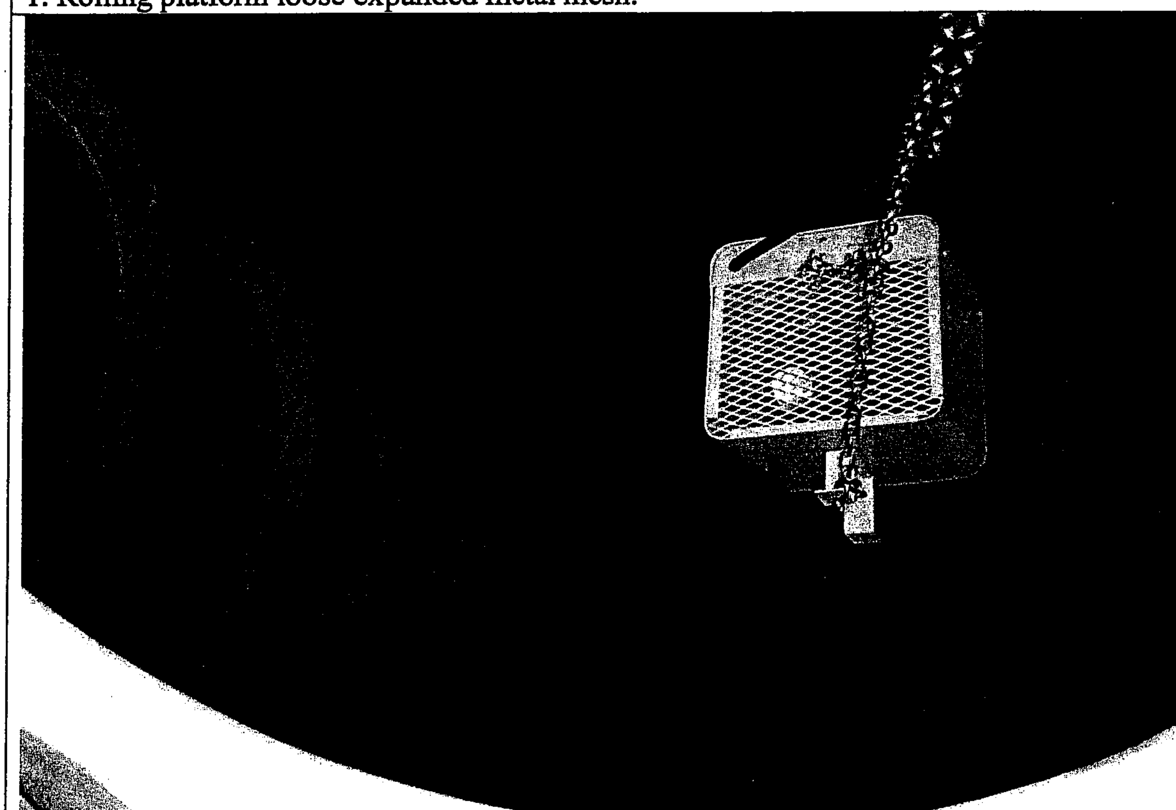
3.4 External Riser

The external riser is heavily corroded and is in the worst condition of all the fabricated steel components. In our opinion, it has deteriorated to the point that it cannot be repaired and should be replaced within the next 5 years.

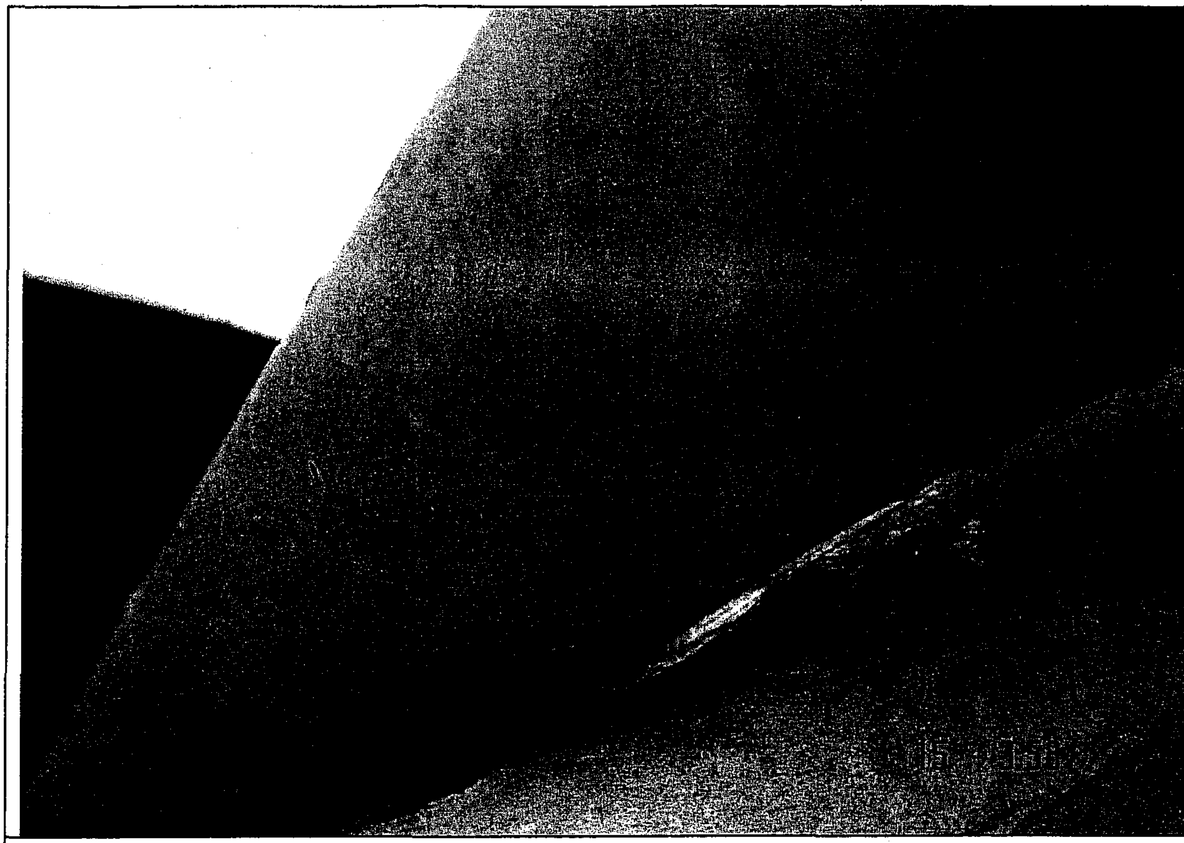
Appendix A – Photographs



1. Rolling platform loose expanded metal mesh.

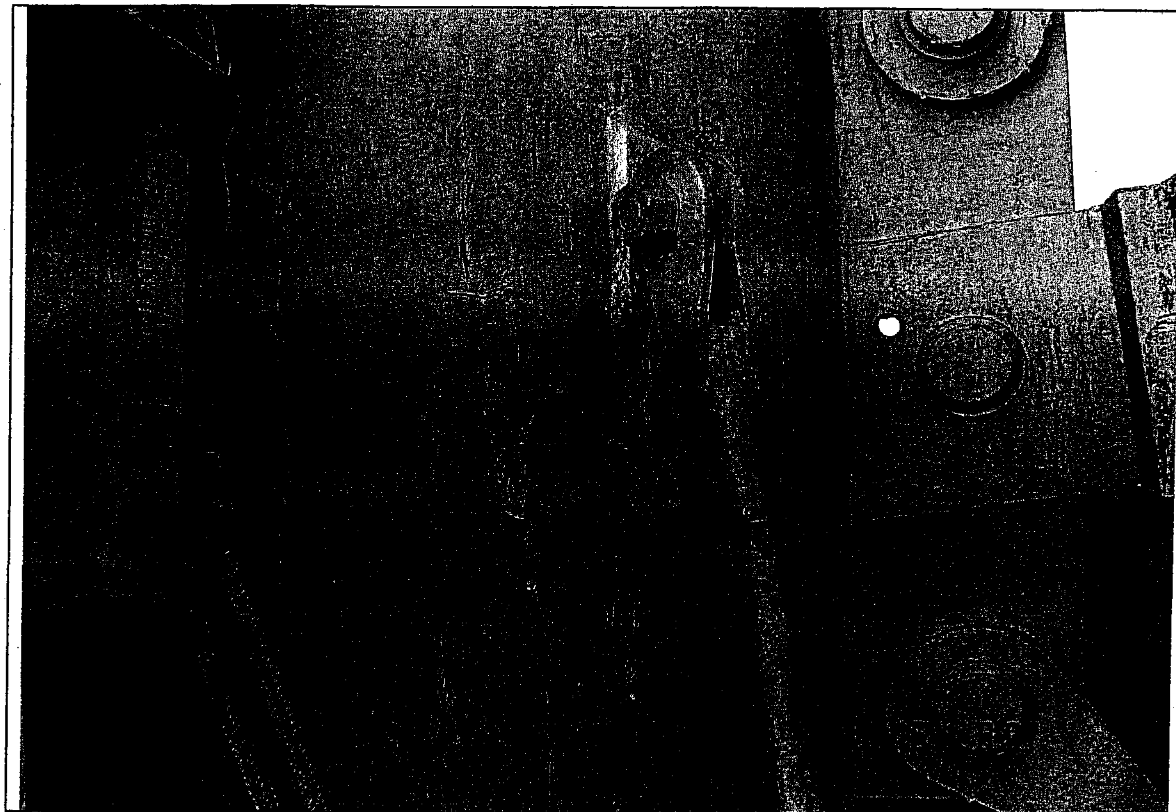


2. View of internal riser and surge tank from roof hatch.

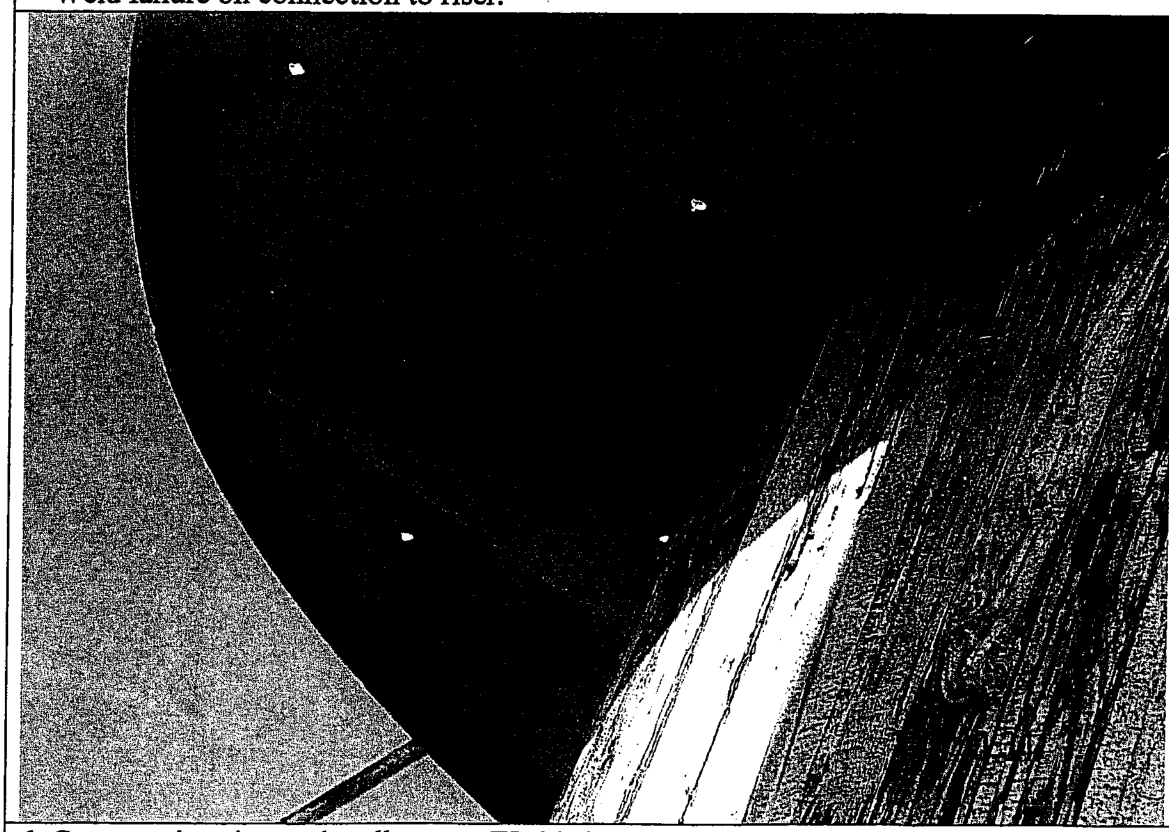


3. Wear of rod bracing.

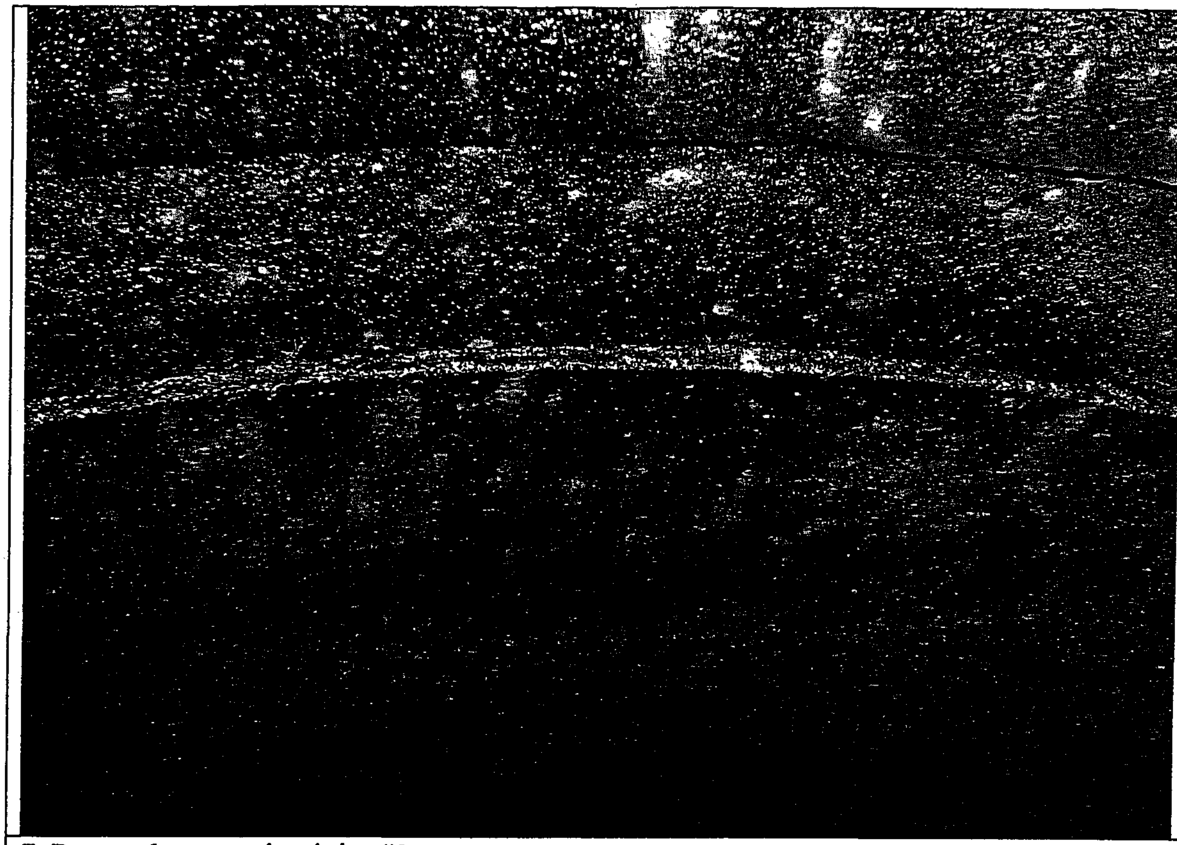
4. Wear of diagonal rod bracing.



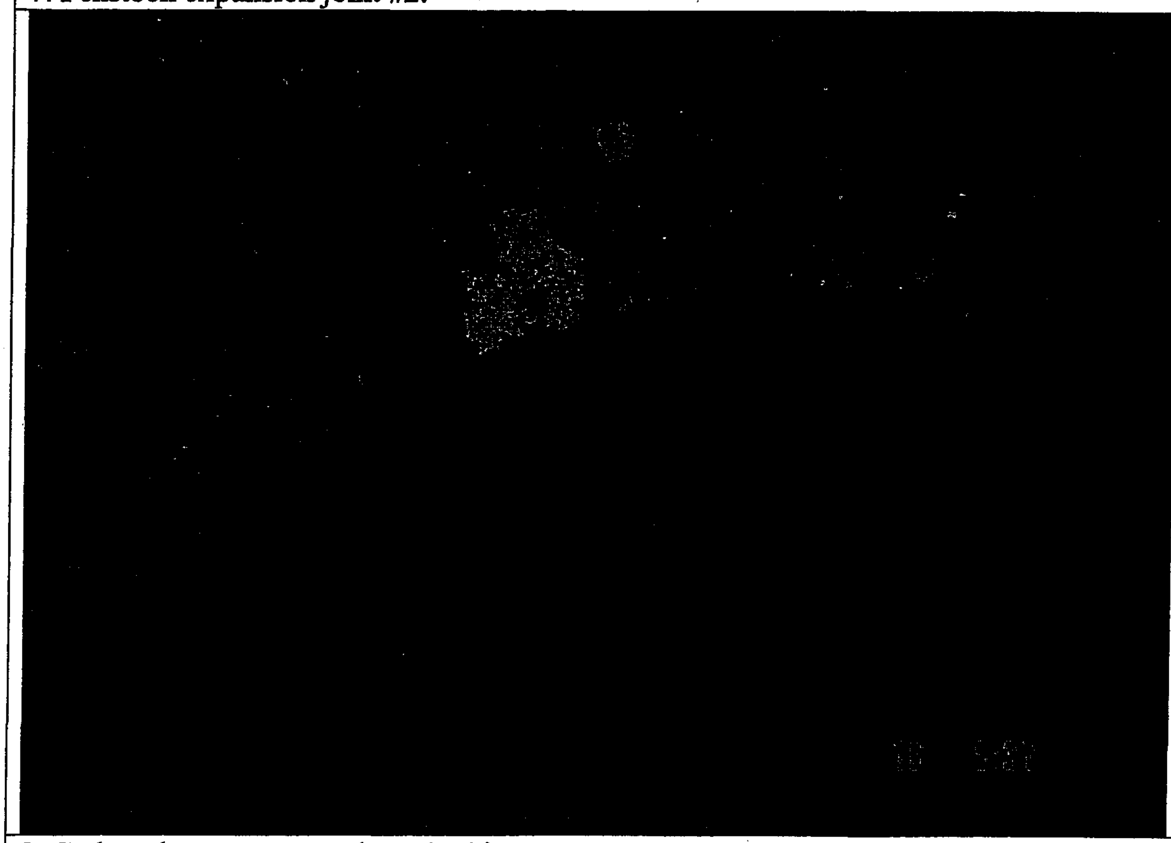
5. External riser stabilizer rod connection to leg #4 at EL.140'.
Weld failure on connection to riser.



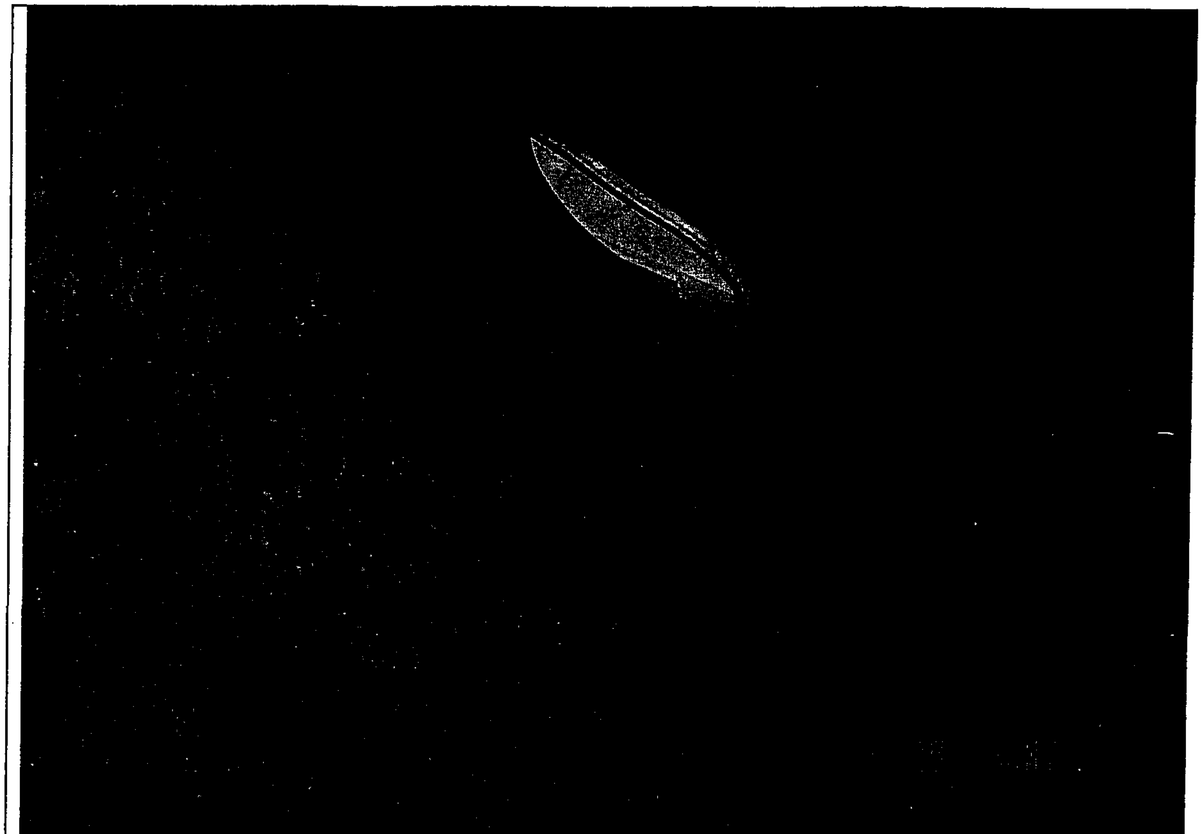
6. Compression ring and walkway at EL.207'.



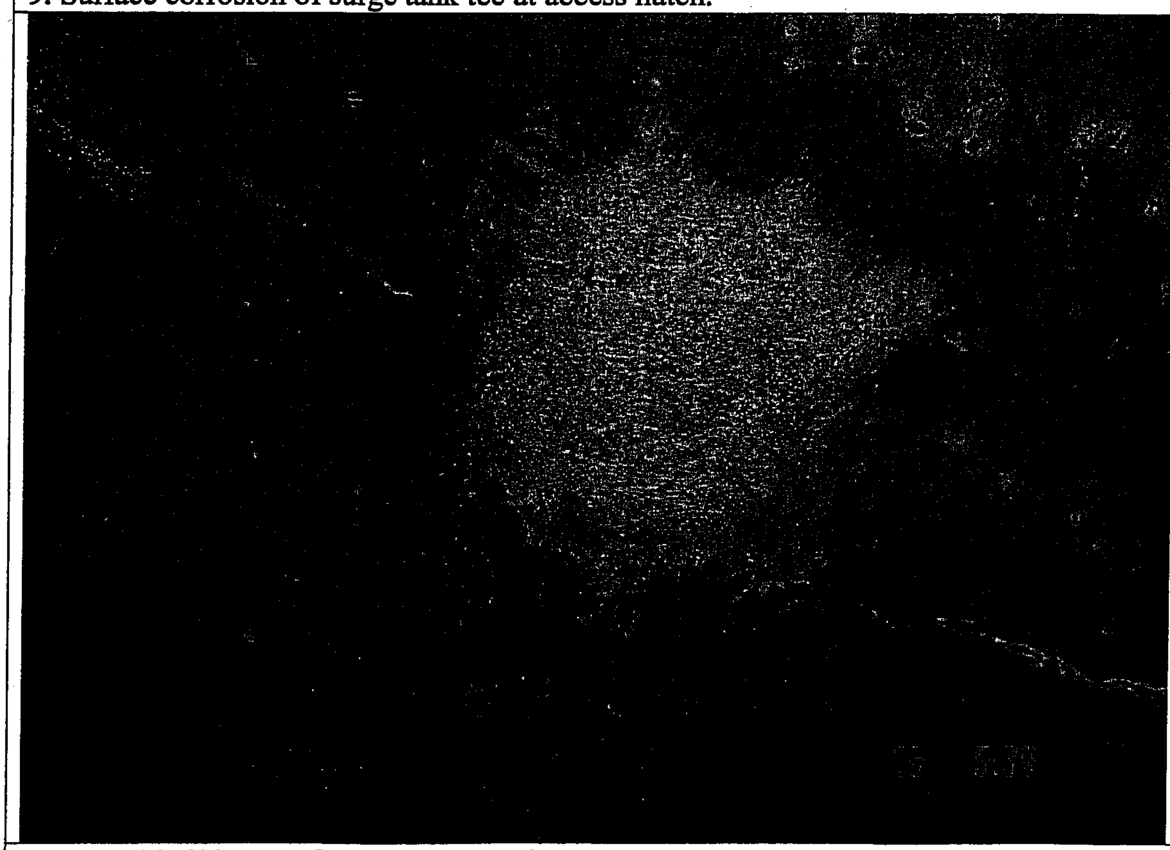
7. Penstock expansion joint #2.



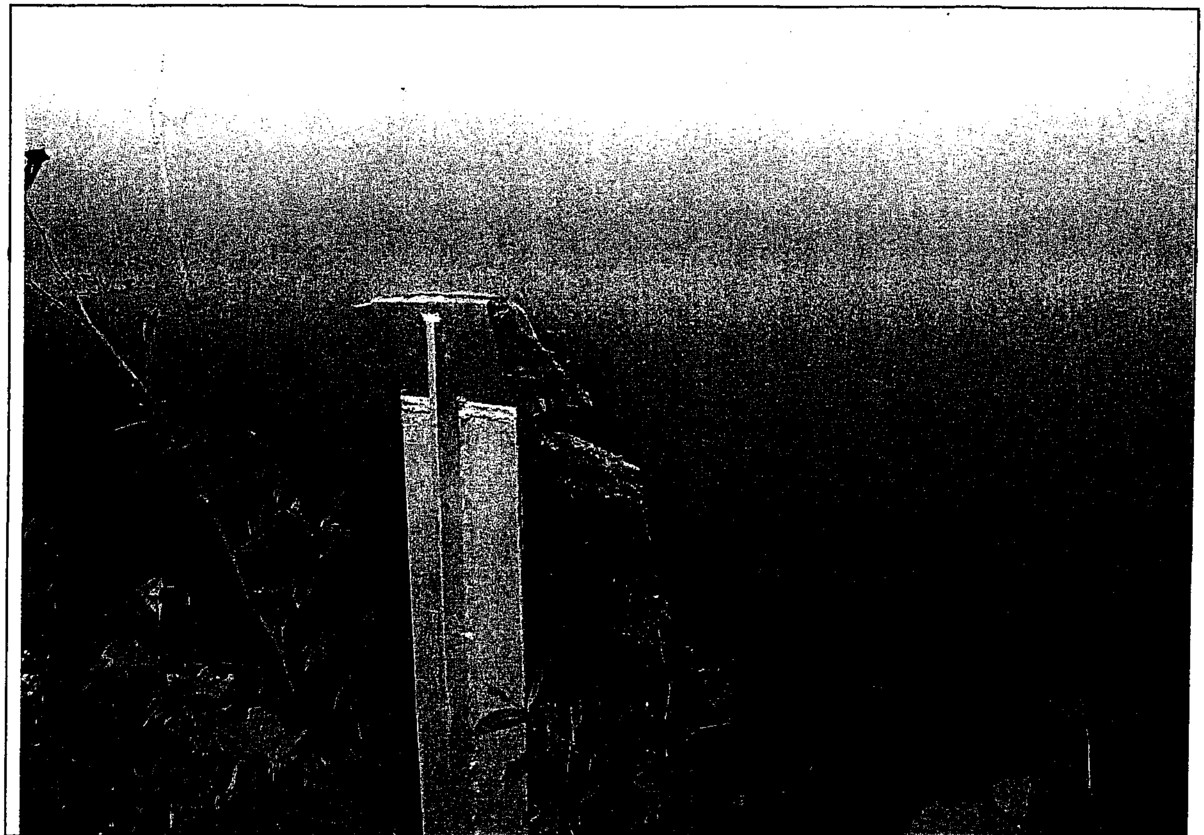
8. Carbuncles on surge tank tee looking up stream.



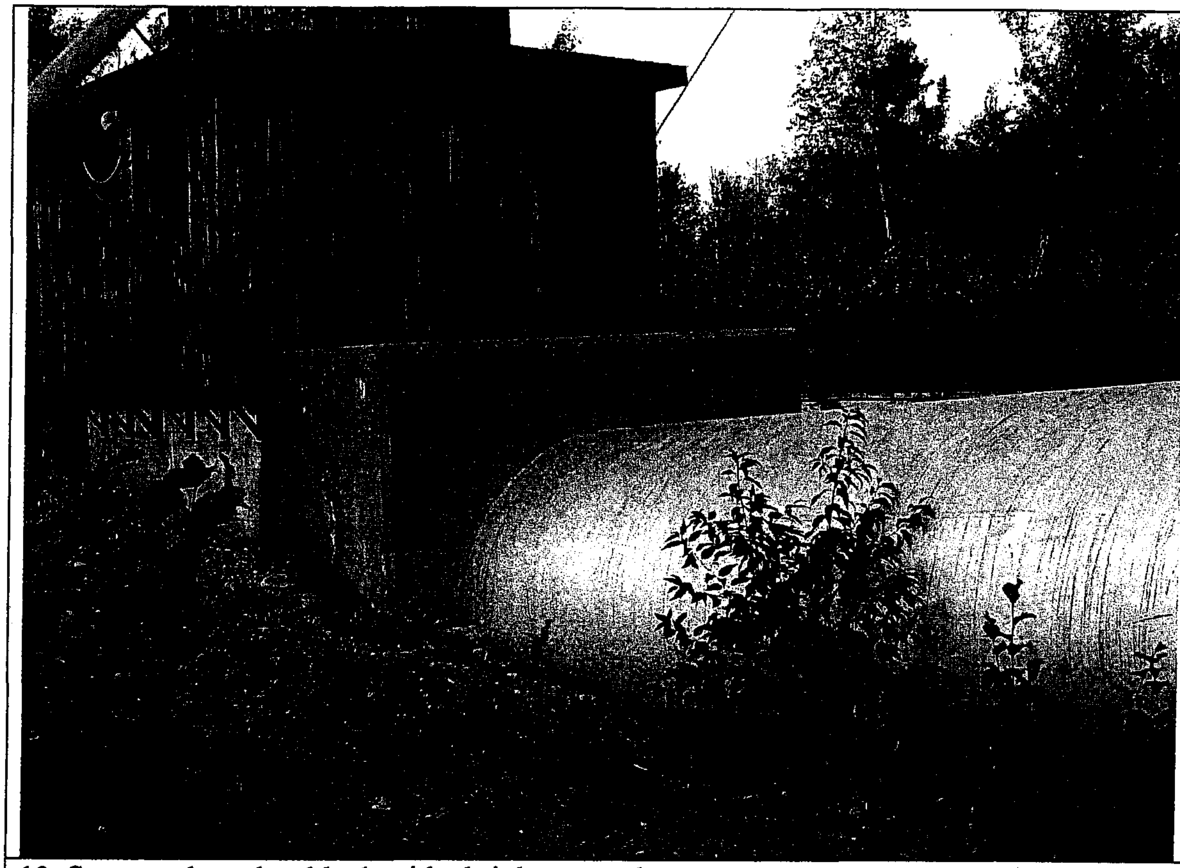
9. Surface corrosion of surge tank tee at access hatch.



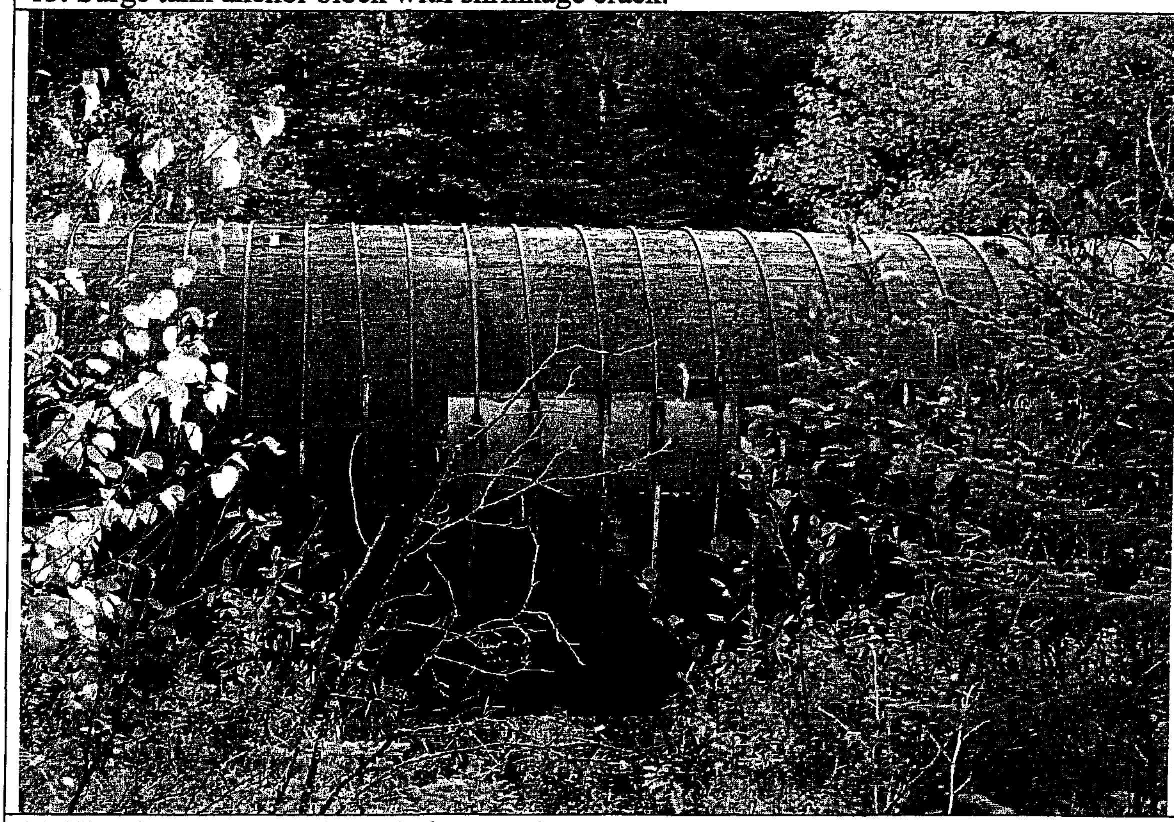
10. Caked build up on floor of surge tank tee.


11. Penstock saddle slider.

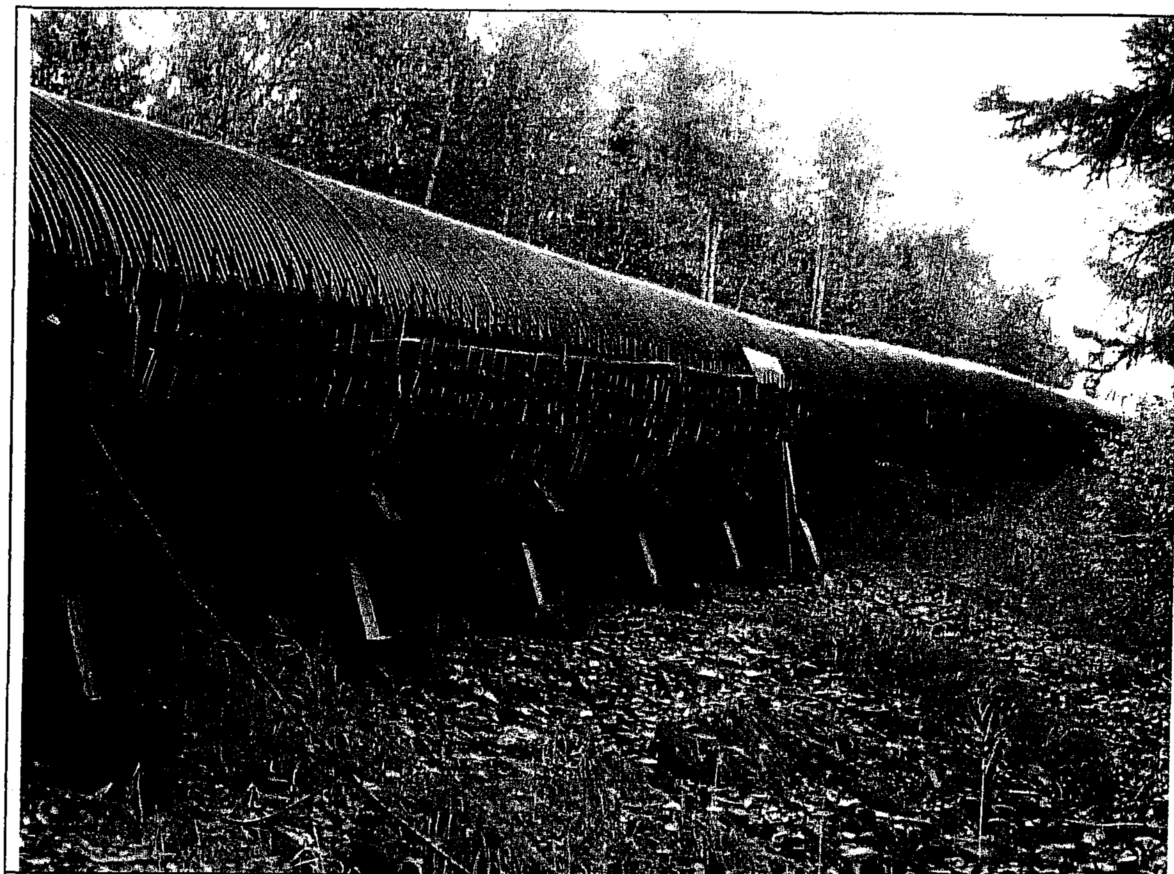

12. Expansion joint #2 leaking at top.



13. Surge tank anchor block with shrinkage crack.

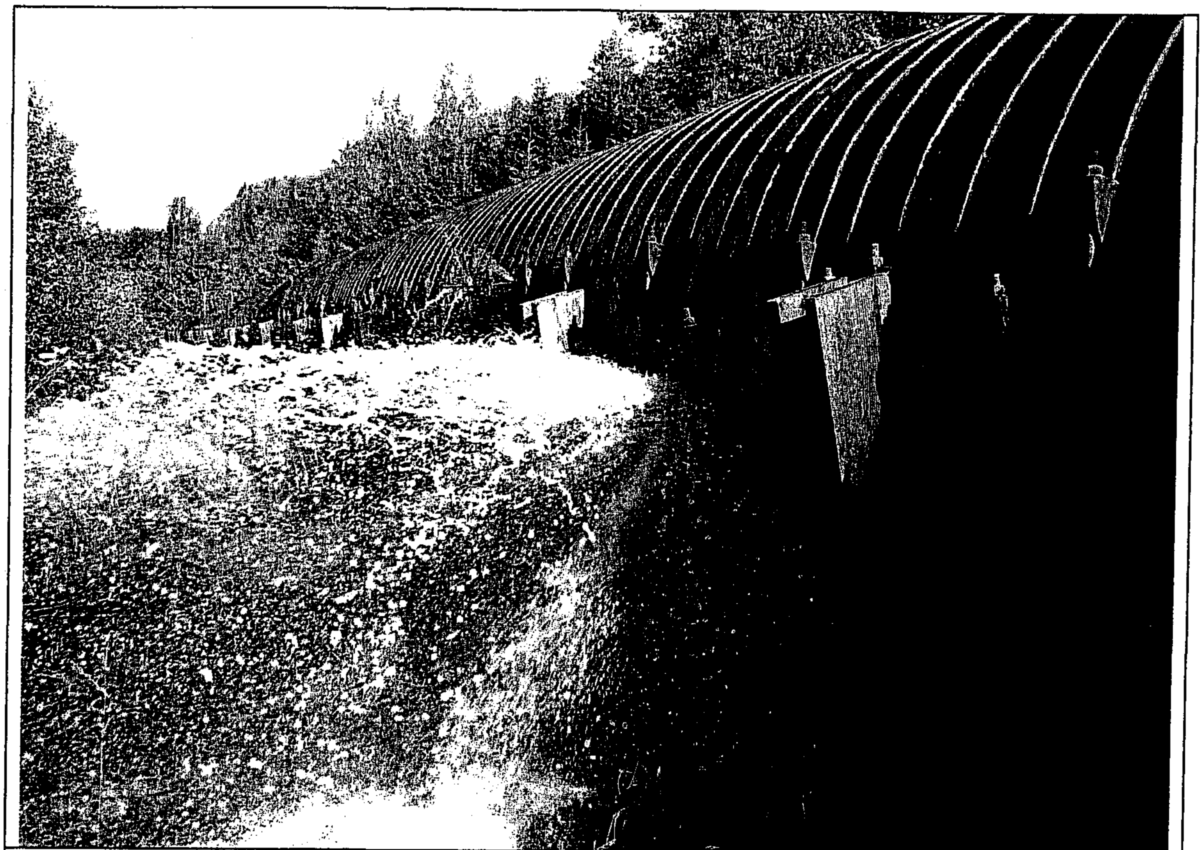


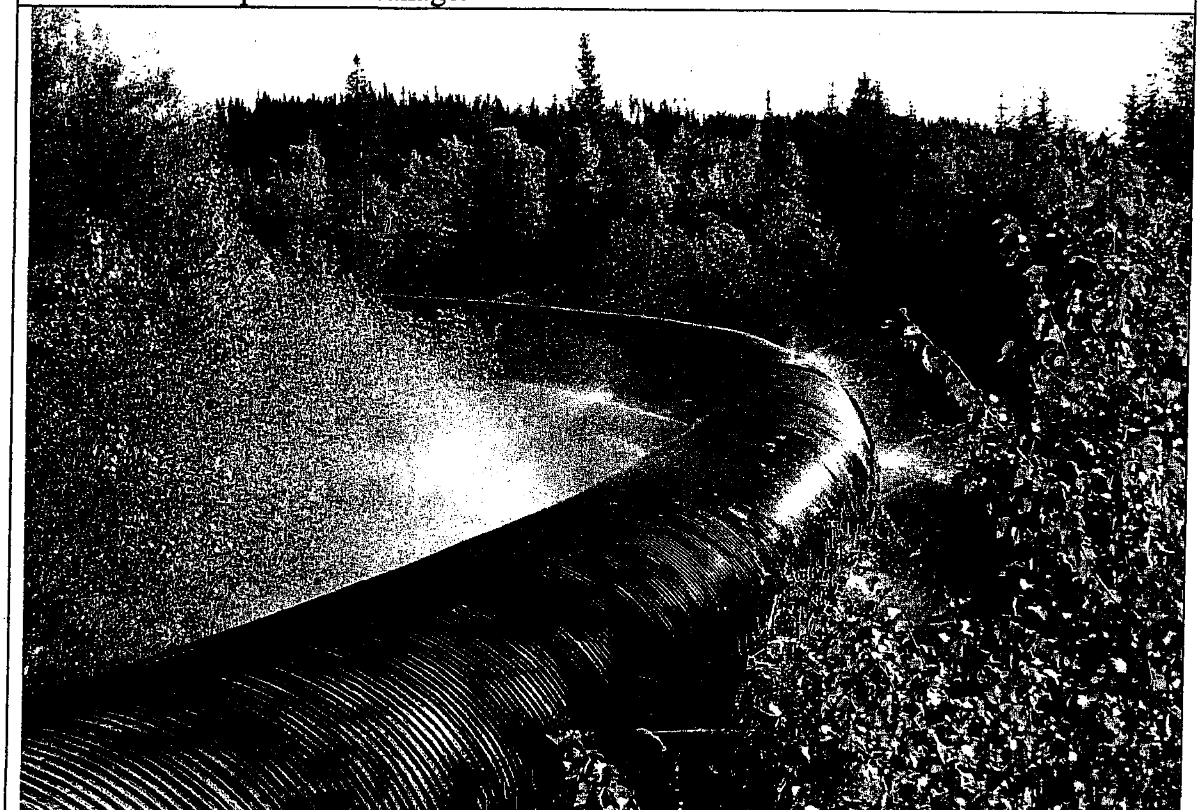
14. Wood stave penstock steel plate patch.



15. Wood stave penstock typical patch plate location marking.

16. Wood stave penstock surface condition.


17. Wood stave penstock leakage.


18. Wood stave penstock leakage.

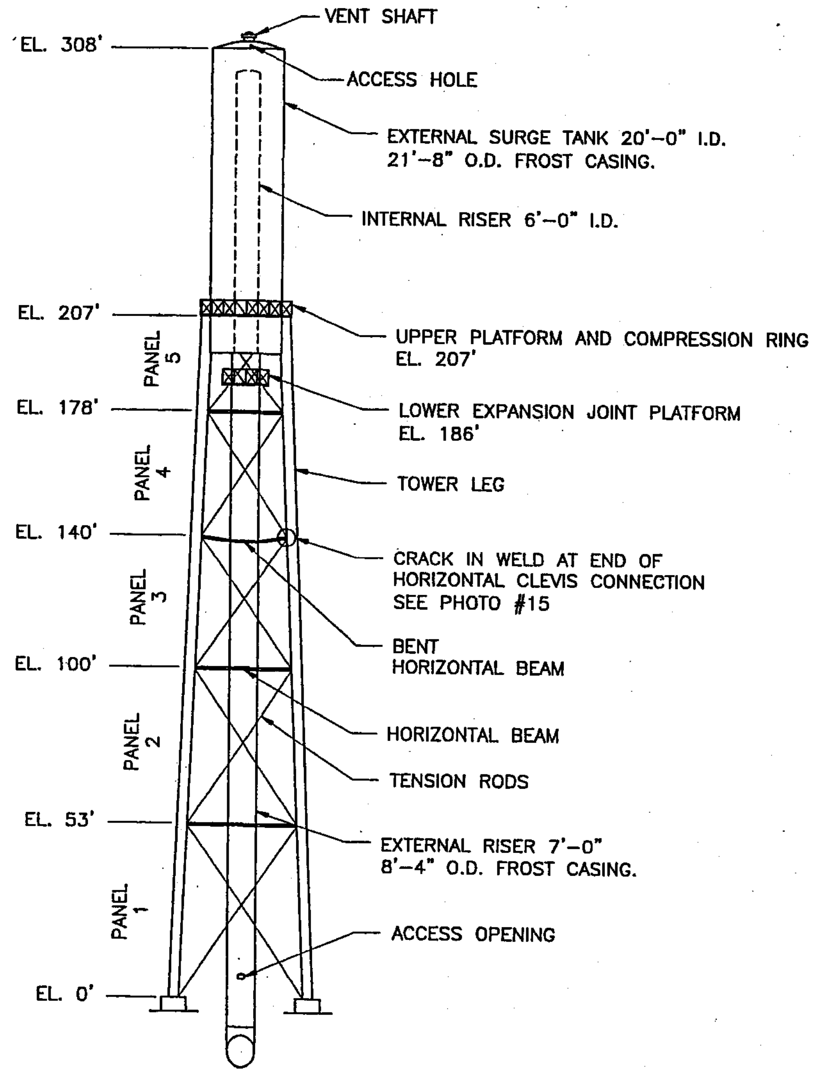
19. Wood stave penstock leakage.

20. Wood stave penstock saddle deterioration.

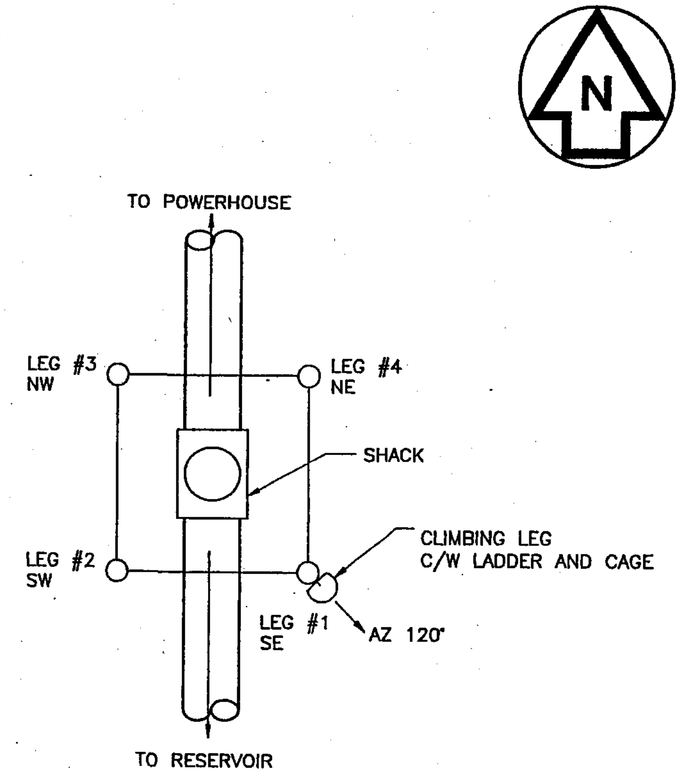
21. Expansion joint #1 paint failure.

22. Horizontal brace north face at leg #3. Cracks in welds.

Appendix B – Sketches

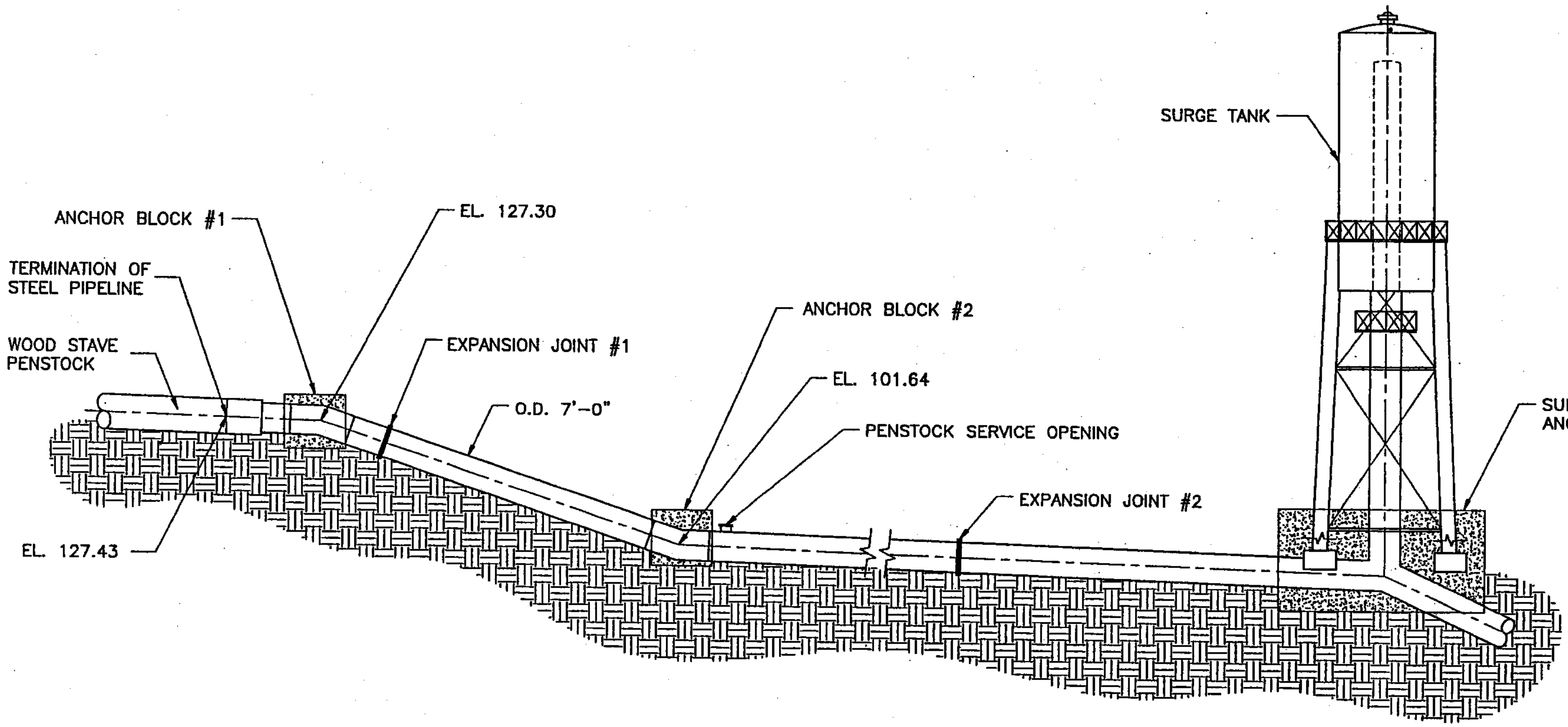


NORTH ELEVATION
NTS



SITE LAYOUT
NTS

SGE Acres — SGE ACRES LIMITED	NEWFOUNDLAND POWER
	RATTLING BROOK
M. Woodford	308' DIFFERENTIAL SURGE TANK ELEVATION AND LAYOUT
G. Saunders	
G. Saunders	
DEC.01,2003	P15310.00 — P15310.00-SK-01 — 0



PENSTOCK ELEVATION
NTS

SGE Acres / SGE ACRES LIMITED	NEWFOUNDLAND POWER
	RATTLING BROOK
M. Woodford / G. Saunders	7'-0" DIAMETER PENSTOCK AND SURGE TANK ELEVATION
G. Saunders / DEC.01.2003	P15310.00 / P15310.00-SK-02 / 0

Appendix C – Thickness Measurements

Newfoundland Power
Rattling Brook Penstock Inspection

Penstock Ultrasonic Thickness Readings (Starting From Surge Tank Going Upstream)

Can Number	Thickness inches	Pit Indication Lowest Thickness inches	Original Thickness	Percentage Loss	Location
#1	0.446		0.4375	0.00	First Can Upstream of Surge Tank Anchor Block
#2	0.460	0.134	0.4375	0.00	
#3	0.417	0.233	0.4375	4.69	
#4	0.409	0.31	0.4375	6.51	
#5	0.447	0.29	0.4375	0.00	
#6	0.480	0.123	0.4375	0.00	
#7	0.462	0.383	0.4375	0.00	
#8	0.489		0.4375	0.00	
#9	0.466	0.342	0.4375	0.00	
#10	0.466		0.4375	0.00	
#11	0.435	0.163	0.4375	0.57	
#12	0.447		0.4375	0.00	
#13	0.445		0.4375	0.00	
#14	0.461		0.4375	0.00	
#15	0.435		0.4375	0.57	
#16	0.443		0.4375	0.00	
#17	0.450		0.4375	0.00	
#18	0.448		0.4375	0.00	
#19	0.437		0.4375	0.11	
#20	0.464	0.108	0.4375	0.00	
#21	0.443		0.4375	0.00	
#22	0.456		0.4375	0.00	
#23	0.373	0.28	0.375	0.53	
#24	0.360		0.375	4.00	
#25	0.361		0.375	3.73	
#26	0.338	0.173	0.375	9.87	
#27	0.360	0.115	0.375	4.00	
#28	0.354		0.375	5.60	

Newfoundland Power
Rattling Brook Penstock Inspection

Penstock Ultrasonic Thickness Readings (Starting From Surge Tank Going Upstream)

Can Number	Thickness inches	Pit Indication Lowest Thickness inches	Original Thickness	Percentage Loss	Location
#29	0.353		0.375	5.87	
#30	0.371	0.187	0.375	1.07	
#31	0.338		0.375	9.87	
#32	0.361		0.375	3.73	
#33	0.359		0.375	4.27	
#34	0.376		0.375	0.00	
#35	0.364		0.375	2.93	
#36	0.377		0.375	0.00	
#37	0.364		0.375	2.93	
#38	0.355		0.375	5.33	
#39	0.357		0.375	4.80	
#40	0.359	0.21	0.375	4.27	
#41	0.364	0.248	0.375	2.93	
#42	0.356	0.171	0.375	5.07	
#43	0.372		0.375	0.80	
#44	0.354		0.375	5.60	
#45	0.359		0.375	4.27	
#46	0.359		0.375	4.27	
#47	0.362		0.375	3.47	
#48	0.369	0.053	0.375	1.60	
#49	0.361		0.375	3.73	
#50	0.371		0.375	1.07	
#51	0.356		0.375	5.07	
#52	0.355		0.375	5.33	
#53	0.369		0.375	1.60	
#54	0.305		0.375	**18.67**	
#55	0.367		0.375	2.13	
#56	0.371	0.109	0.375	1.07	

Newfoundland Power

Rattling Brook Penstock Inspection

Penstock Ultrasonic Thickness Readings (Starting From Surge Tank Going Upstream)

Can Number	Thickness inches	Pit Indication Lowest Thickness inches	Original Thickness	Percentage Loss	Location
#57	0.388		0.375	0.00	
#58	0.378		0.375	0.00	
#59	0.369		0.375	1.60	
#60	0.361		0.375	3.73	
#61	0.370		0.375	1.33	
#62	0.371		0.375	1.07	
#63	0.367		0.375	2.13	
#64	0.376	0.248	0.375	0.00	
#65	0.370		0.375	1.33	
#66	0.364		0.375	2.93	
#67	0.363		0.375	3.20	
#68	0.362		0.375	3.47	
#69	0.381		0.375	0.00	
#70	0.368	0.152	0.375	1.87	
#71	0.359		0.375	4.27	
#72	0.370		0.375	1.33	
#73	0.360		0.375	4.00	
#74	0.361		0.375	3.73	
#75	0.371		0.375	1.07	
#76	0.370		0.375	1.33	
#77	0.395		0.4375	9.71	Thimble Attached to Woodstave Penstock

Note - negative numbers represent thickness which exceed the thickness stated on the original drawings.

Newfoundland Power
Rattling Brook Penstock Inspection

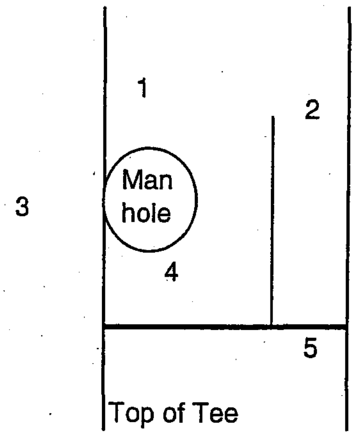
Surge Tank Shell Ultrasonic Thickness Readings

Can Number	Thickness inches	Pit Indication Lowest Thickness inches	Original Thickness inches	Percentage Loss	Location
1	0.323		0.313	0.00	Top of Surge Tank
2	0.317		0.313	0.00	
3	0.326		0.313	0.00	
4	0.310		0.313	0.96	
5	0.331		0.313	0.00	
6	0.297		0.313	**5.11**	
7	0.303		0.313	3.19	
8	0.332		0.344	3.49	
9	0.391	0.297	0.375	0.00	
10	0.419	0.328	0.406	0.00	
11	0.471		0.438	0.00	
12	0.467		0.468	0.21	
13	0.682		0.688	0.87	Hemispherical Head

Newfoundland Power
Rattling Brook Penstock Inspection

External Riser Ultrasonic Thickness Readings

Base of Riser



Looking South

Location Number	Thickness inches	Pit Indication Lowest Thickness inches	Original Thickness	Percentage Loss
1	0.476		0.531	10.36
2	0.473		0.531	**10.92**
3	0.488	0.34	0.531	8.10
4	0.531	0.343	0.531	0.00
5	0.615	0.264	Unknown	

Newfoundland Power
Rattling Brook Penstock Inspection

Internal Riser Ultrasonic Thickness Readings

Can Number	Thickness inches	Pit Indication Lowest Thickness inches	Original Thickness	Percentage Loss	Location
1	0.347		0.313	0.00	Top of Riser
2	0.323		0.313	0.00	
3	0.332		0.313	0.00	
4	0.319		0.313	0.00	
5	0.321		0.313	0.00	
6	0.302		0.344	12.21	
7	0.316		0.344	8.14	
8	0.311		0.375	17.07	
9	0.291		0.375	**22.40**	
10	0.344	0.313	0.375	8.27	
11	0.373		0.375	0.53	
12	0.397		0.375	0.00	
13	0.405		0.375	0.00	

Appendix D – Safety Reports

REMOTE ACCESS TECHNOLOGY
50 Pippy Place, St. John's, Newfoundland, Canada A1B 4H7
Ph: 709 738 6353 Fax: 709 738 6355 e-mail: info@ropeaccess.ca

SGE ACRES LIMITED
RECEIVED
OCT 22 2003
St. John's, NL

October 22, 2003

Greg,

Here is all the information gathered during the inspection. It was a pleasure working with you, not to mention, the chuckle I got when I saw you in your $0.50 rain gear made the trip worthwhile. I look forward to working with you again in the future.

Cheers,

JB DelRizzo
General Manager
Remote Access Technology (Newfoundland) Inc.

Prejob Site Meeting
Contractor Safety Checklist

NEWFOUNDLAND POWER
A FORTIS COMPANY

Contractor's Name: SGE-Acres and Remote Access Technology

Location: Rattling Brook

Date: Oct 14/03

Personal Protective Equipment	✓ Yes ___ No ___ N/A
First Aid Equipment	✓ Yes ___ No ___ N/A
Fire Protection	___ Yes ✓ No ___ N/A
Emergency Communication and Response	✓ Yes ___ No ___ N/A
Fall Protection	✓ Yes ___ No ___ N/A
Minimum Approach Distances Maintained	___ Yes ___ No ✓ N/A
Tail Board / Tool Box Meetings	✓ Yes ___ No ___ N/A
Warning /Danger Signs	✓ Yes ___ No ___ N/A
Public Safety	✓ Yes ___ No ___ N/A

Comments:

Remote Access Conducted their own Tool box meeting. Completed prejob / hazard checklist.

Lock-out Provided by NF Power to enter tank and penstock.

Action taken to address any issues:

Signature of Owner's Representative: [signature]

Signature of Contractor's Supervisor: [signature]

White: Originator, Yellow: Contractor

Form No. 399 Revised 03/28/01

Remote Access Technology (Newfoundland) Inc.

Confined Space Entry Checklist ✓

	Yes	No	
	✓		Personnel entering confined space have been trained in the hazards of confined space entry.
	✓		Approved Permit to Work has been obtained.
	✓		Designated trained standby person assigned to standby the confined space entrance at all times.
	✓		Oxygen/Gas detector is present and calibrated.
N/A		✓	Minimum of two explosion-proof portable lights in use.
N/A		✓	Explosion-proof personal radios in use.
N/A		✓	Appropriate warning signs/barricades in use.
	✓		Portable tripod with a combined fall arrestor-retrieving winch or similar system in use.
	✓		One Company approved full body harness in use per person.
	✓		Internal pressure checked and vented before removing fastening devices on confined space.
	✓		Designated standby person will monitor air quality upon entry and each re-entry.
	✓		Oxygen levels is between 19.5% to 22% **DO NOT ENTER IF ABOVE OR BELOW AFOREMENTIONED RANGE!**
	✓		Air Quality is tested for H2S / Explosive gases – None Present.
		✓	Confined space will be sounded for fluid before entered. Flotation device will be worn if a drowning hazard exists.
	✓		Standby person will maintain constant radio contact with persons in confined space and control room.
	✓		Standby person knows how to raise the alarm if person inside or confined space require emergency assistance and knows not to enter confined space until assistance arrives.
	✓		Adequate rescue equipment is readily available and standby person is familiar with its use.
	✓		Standby person will keep a tally of number / names of persons inside confined persons.
	✓		Standby person will notify Person in Charge for a relief watchman to be assigned as relief and wait until being properly relieved before leaving the post.
	✓		Adequate handover and safety briefing will be conducted with any person who relieves the standby person or crew members working in the confined space.
	✓		Explosion proof ventilation will be used for a continuous supply of fresh air unless sufficient airflow is obtained through a free flow process.
N/A		✓	No source of ignition will be introduced into a confined space where flammable vapors or gasses may be present.
	✓		All pipelines discharging into that space will be closed with blind flanges, plugs or valves and energy isolation signs and tags posted.
N/A		✓	If torch cutting or welding is carried out on pipelines passing through confined spaces, they will be isolated, purged if necessary, energy isolations signs and tags posted prior to the hot work starting.
N/A		✓	Oxygen/ Acetylene hoses will be removed from confined space where during the extended breaks and air retested for gas before reentry.
	✓		The time of opening or closing a confined space entry or exit of personnel will be recorded at the manned control point (Control Room, Radio Room, etc.)

Person in charge: J.B. DelRizzo (name) [signature] (sign)
Date: Oct 16/03 Time: 4:48 pm
Standby Person: Steve Deathe (name) ____________ (sign)

447-2515

	Safety Policy and Procedures Manual **ANNEX A – Code of Practice**		Reviewed by: MDS Approved by: ADB
REMOTE ACCESS TECHNOLOGY	Doc: 13354.1	Date: 2003-04-08	

TAILGATE SAFETY MEETING REPORT

Date of Meeting: Oct 15/03

Time of Meeting: 8:30 am/pm

Location of Meeting: Rattling brook P.S./NFLD

Employees Present:

1	Steve Deathe	9	
2	JB Delrizzo	10	[illegible]
3	Pat Heath Pat Heath	11	
4	Hayward Miller	12	Hayward Miller
5	G. Murray	13	[illegible]
6	G. Saunders	14	[illegible]
7		15	[illegible]
8		16	

Items Discussed

1. Review unsafe situations mentioned at previous meeting
2. Review any safety suggestions from the crew
3. Review of hazards expected in upcoming work
4. Proper P.P.E, radio communication, First Aid kit in the truck
5. lanyards on all tools, all rigging assessed by Level 3 climber
6. install fall arrest system for climbing ladders
7. FOLLOW ALL TIATA GUIDELINES FOR ACCESS METHODS
8.

Comments

This safety meeting conducted by: [illegible]

COPIES TO: OFFICE (ORIGINAL) Safety Coordinator

FORM 9-4-13

Remote Access Technology Inc.

JOB HAZARD ANALYSIS

Date: Oct 15/03 Time: 8:30 Location: Rattling Brook P.S./NFLD

Supervisor:

Job Description: Inspection of surge tank & penstock (visual & U.T.)

Work Crew (List names & have employees initial on same line) Completed By: Steve Deathe

Name Steve Deathe Name: Pat Heath Name: G. McCoy
Name JB Delrizza Name: Hayward Miller Name: G. Sanders

Permits Required	yes	no	n/a	Other Checks	yes	no	n/a
General Work	☑	☐	☐	Safety Operator Required	☐	☑	☐
Hot Work	☐	☑	☐	Hazardous Material Present	☐	☑	☐
Entry	☑	☐	☐	Evac./Assembly Are Confirmed	☑	☐	☐
RPP Scba	☑	☐	☐	Job Objective Discussed with Crew	☑	☐	☐
Other ( )	☐	☑	☐	Is Crew Aware of MSDS Location	☐	☐	☑

yes	no	n/a		Comments / Notes / Actions
☑	☐	☐	Proper permits obtained/signed?	
☑	☐	☐	RPP equipment required?	Scba's on standby for internal work
☑	☐	☐	Confined space entry permit req'd?	
☐	☑	☐	Staging required / OK Tag?	
☑	☐	☐	Personal fall protection req'd?	
☐	☐	☑	Staging(s) inspected & confirmed adequate by	
☑	☐	☐	Evacuation/assembly area known?	
☐	☐	☑	Eyewash/safety shower location known?	
☐	☐	☑	Hot work requirements?	
☑	☐	☐	Protective equipment required?	
☐	☐	☑	Location of fire equipment known?	
☑	☐	☐	Equipment blinded or not?	
☑	☐	☐	Proper lighting for work?	outside natural/internal headlamps Flashlights
☐	☑	☐	Conflicting jobs in area?	
			Safety behaviors discussed	**Hazard recognized/corrective action**
☑	☐	☐	Proper PPE Used (eye/hearing/gloves/nomex/etc.)	
☑	☐	☐	Housekeeping (tripping hazards/hoses/leads)	

Rope Hazard Identification & control

Hazard	Rank	Corrective Actions
Pinch points	A	proper rigging/assessed by Level 3
Sharp edges	A	proper rope protection

Considerations / Comments:

Corrective actions carried out? Yes / No If no, state reason below:

Rank: A = could easily result in a fatality B = could result in serious injury C = could result in minor injury

Form 12-6-19

SAFETY MEETING FORM

Document #: R-QA1002

Page 1 of 1 Date: Oct 16/03 Job #:

Project: ~~R~~ Inspection of surge tank & penstock

Location: Rattling Brook G.S. NFLD

Supervisor: JB Delrizzo

Topics Discussed:

Constant air monitoring
Scba's for rescue personal
Radio communication (10-15 min checkins)
fall arrest harness for rescue purposes
all equipment locked & taged out
be aware of slippery conditions

20.2 o° | 0 | 0 | 0

Personnel to print and sign below to say that you have read and understood the specific rescue procedure.

Print Name	Signature	Print Name	Signature
JB Delrizzo	[signature]		
GREG SAUNDERS	[signature]		
HAYWARD Miller	H miller		
Steve Westha	[signature]		

February 18, 2004
P15602.00

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

Attention: Mr. G. Humby, P. Eng.

Dear Sir:

Rattling Brook Development
Selection of optimum penstock diameter

Newfoundland Power (NP) proposes to replace the existing woodstave penstock at the Rattling Brook Development with a new steel penstock. NP requested SGE Acres to carry out a study to determine the optimum diameter for the replacement penstock, and to comment on the feasibility of replacing the buried steel section. For the woodstave portion, the analysis requested by NP is incremental; energy benefits are taken to be incremental to existing, and costs are incremental to replacement costs. As a separate item, NP requested a cost to replace the external riser of the surge tank.

This letter report documents the findings of the study.

1 System Description

The Rattling Brook station is located near Norris Arm, on the northeast coast of the Island of Newfoundland. It was built in 1958, with a nominal installed capacity of 12.75 MW provided by two units. The nameplate capacity is 15.1 MW; the nameplate unit capacities are 7.5 MW and 7.6 MW. The gross head is 99 m.

The woodstave penstock is 1693 m long, 1054 m of 7 ft diameter, and 639 m of 7 1/2 ft diameter. (Penstock diameters are given here in imperial units for consistency with design drawings and previous reports.) A 7 ft steel section 50 m long joins provides the connection from the intake to the woodstave section. The penstock winds along a river valley, with numerous changes to the alignment.

The last 309 m of penstock is a steel section, of which the last 115 m from the surge tank to the units is buried. The penstock bifurcates about 16 m upstream of the units into two sections leading to the two units, each section 4 ft 9 in. inside diameter. A butterfly valve is located just upstream of each of the units.

The steel section as well as the surge tank were inspected by SGE Acres in the fall of 2003, and a separate report documents the findings and recommendations arising from those inspections.

2 Methodology

2.1 Energy Benefits

Based on previous reports and practical considerations of the maximum size of penstock that could be installed at the Rattling Brook location, diameters in the range of 7 1/2 ft to 11 ft were considered. An energy simulation model of the Rattling Brook system previously developed for NP for a Water Management Study was updated and used to estimate the available energy[1].

The head losses in the existing and proposed system required for the modeling were estimated using data from index testing in the 1980's by NP,[2] from efficiency testing carried out by SGE Acres for NP in 2000, and from standard references. Only the woodstave section was assumed to be replaced. Curves of energy benefit as a function of penstock diameter were developed from the results. The sensitivity to higher or lower friction factors was checked.

The effect on available capacity of head loss reduction was taken into account in the modeling. The capacity increases from 11.3 MW in the existing case to 12.4 MW with a penstock with a diameter of 8 ft. With a 10 ft diameter penstock, the capacity is 14.2 MW. With two units of about 7.5 MW each, the maximum capacity would be about 15 MW. (These calculations assume there are no other limiting factors on installed capacity.)

In addition, the Water Management Study carried out for NP had indicated that the mean annual runoff might be higher than the estimated value of 900 mm/yr. Given this possibility, the sensitivity of the results to a mean annual runoff 10 percent higher than previously estimated was checked.

The energy benefit of replacing the intake and the 50 m steel section of the existing penstock connecting the intake to the woodstave penstock was not calculated, since it is clear that the cost of replacing the intake and/or that short section of steel would far exceed the benefits. At present there is no requirement to replace these components, and therefore the value of the incremental benefits would have to exceed the total cost of replacement, not just the incremental cost above replacing the existing intake and short length of steel penstock.

2.2 Costs

A preliminary design considering plate thickness for hoop stress and material handling requirements was prepared for each of the optional diameters. Following discussions with NP, a plate thickness of 9.5 mm (3/8 in) was assumed for all diameters. The required weight of steel was then calculated. Costs were developed from experienced fabricators and from estimates prepared by NP. Cost per unit weight of steel was the most comparable measure between the projects referenced by fabricators.

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[1] Acres International, *Water Management Study*, Report prepared for Newfoundland Power, Dec. 2000.

[2] Newfoundland Power, *Rattling Brook Report to Increase Plant Capacity by Increasing Flow area*, Feb. 1984

The future cost of steel plate is uncertain, but the consensus among suppliers is that it will certainly rise. The costs were thus re-estimated assuming increases in steel supply costs of 20% and 50%. These lead to total penstock cost increases of 10% and 25%. The 10 percent increase was used as the base case, and a 25 percent increase as a sensitivity check. An installation cost per unit weight of steel derived from NP estimates compared well with the information provided by the fabricators. The analysis used a base supply cost of $2600/tonne and an install cost of $3000/tonne. Our estimated costs are summarized in Table 1.

The budget price for replacing the external riser and expansion joint and installing new insulation and cladding is $430,000 (no HST). This estimate is provided for information, as requested, and is not used elsewhere in this report.

2.3 Economic Analysis

The annual value of the energy benefits was calculated assuming two marginal values of energy, $0.0553/kWh and $0.0771/kWh. A discount rate of 8.52 percent and periods of 25 and 50 years were considered to determine the present worth value of the benefits. Sensitivity checks were done with discount rates of 7.5 and 9.5 percent and periods of 50 years.

The net present worth value for each penstock replacement diameter, as well as the incremental (stepwise) net benefit, were then tabulated, and the results plotted. The optimal diameter was taken as the diameter at which the net present worth is highest, and the incremental benefit of the increase in diameter exceeds the incremental cost.

3 Results

The curve of energy benefits as a function of penstock diameter is shown in Figure 1. This shows that the benefits continue to increase as the diameter increases, but the curve flattens out at the larger diameters. The shape is similar for the sensitivity to mean annual runoff. The curves start at 8.0 ft since the 7.5 ft diameter is the diameter assumed to replace the existing penstock.

The incremental energy benefits over the existing simulated energy of 63.5 GWh range from 1.9 to 5.7 GWh. As Figure 2 shows, the lowest energy is 65.4 GWh, for the 8 ft diameter case, for the highest friction factor, and the maximum is 69.7 GWh for the 11 ft diameter case with the lowest friction factor. The results for 11 ft are included in the plot but were not used further in the analysis since it became clear that the incremental benefits would only outweigh the incremental costs for the most attractive economic conditions. The cost assumptions are also not likely to apply at such a large diameter.

For the case with an increase of mean annual runoff of 10 percent, the average annual energy for the existing case is also higher, at 66.5 GWh. This value increases to 72.9 GWh with a 10 ft diameter penstock, a difference of 6.4 GWh annually. These results assume a Manning's n friction factor of 0.013.

The curve of costs as a function of penstock diameter is shown in Figure 2. The cost estimates are most accurate for diameters in the middle of the study range (8.5-9.0 ft). The penstock weights are calculated based on preliminary design of the penstock; the curves are linear because a plate thickness of 9.5 mm is used for all diameters. Plate thinner than 9.5 mm may be acceptable for smaller diameters; thicker shell plate may be required for larger diameters to permit suitably long spans between ring girder supports.

Figure 3 shows the net benefits (energy benefits minus cost) for the periods and values of energy provided by NP. These curves are all for the specified discount rate of 8.52 percent. As long as the slope of the curve remains positive, the investment is attractive, that is, the incremental energy benefits of an increase in diameter of 1/2 ft are less than the incremental costs. The diameter at which the net present value reaches its maximum is the optimal diameter.

For the cases presented in Figure 3, the optimal diameter is 9.5 ft, except for the case with the lower value of energy and shorter payback period. The net present value of the benefits ranges from about $1.5 million to over $3 million, depending on the economic factors. Figure 4 is a similar figure including results for higher and lower discount rates.

The results for the base case and all the sensitivities are summarized in Table 1. Figures 5 shows the range of net benefits for all the cases in Table 1, and Figure 6 shows the incremental net benefits. The optimum diameter is the one at which the incremental net benefit is positive.

For the combinations considered, these figures show that the minimum optimal diameter is 9 ft, and the maximum is 10 ft. The absolute range of net benefits is wide, from less than $1 million to nearly $4 million. The lowest net benefit is for an 8 ft diameter penstock, assuming a higher friction factor, the lower value of energy and shorter period (all other parameters at base case values). The highest net benefit is for a 10 ft diameter penstock, assuming increased runoff, higher energy values, lower discount rate, and longer period.

Although the absolute range is wide, the difference in net present value in the 9 ft to 10 ft range for any individual case is small, generally less than 5 percent of the cost. It therefore would not take much change in cost or economic assumptions to shift the optimal diameter within this range.

3.1 Energy benefit of replacement of steel section

During the course of this study it was determined that up to half the head loss in the system is occurring in the buried section downstream of the surge tank. It is not clear whether these occur in the buried penstock, at the bifurcation, in the short 4 1/2 ft diameter sections below the bifurcations, or in the butterfly valves. There is some indication that the excess loss may be occurring between the bifurcation and the unit, but this requires confirmation.

Organic/mineral deposits were found in parts of the steel section, and these are likely to be contributing to the losses.

Even if the total head losses in the system can be reduced by around 3 percent by replacing the steel section, bifurcation and valves, the net present value of the energy benefits would be in the range of $1 to $2 million. This amount is far below the capital cost that would be required to replace this section.

4 Conclusions and Recommendations

4.1 Conclusions

The conclusions of this study are as follows.

- The net benefits of replacing the existing penstock with one of a larger diameter for all cases are positive, ranging from less than $1 million to nearly $4 million. The net benefits continue to increase for all cases for pipe diameters up to at least 9 ft.
- The net present value of the benefits is within the accuracy of the estimates in the range of 9 ft to 10 ft. For the combinations considered, a 9 1/2 ft diameter penstock is a reasonable choice. A more detailed design and cost analysis is required to confirm this.
- Factors that favour a 10 ft diameter penstock are a higher value of energy, a higher frictional resistance (for example, if deposits form) and a lower discount rate.
- If the above factors tend in the opposite direction, a smaller diameter penstock will be favoured. Also, if a plate thickness of 9.5 mm is not acceptable for a larger pipe without a large number of ring girders, then a smaller penstock will be favoured.

4.2 Recommendations

The recommendations arising from this study are as follows.

- A detailed cost estimate should be prepared for the 9 1/2 ft diameter penstock to confirm the values used in this study.
- Head loss tests should be conducted on the lower section of the penstock, similar to those conducted in the 1980's. These tests should measure losses upstream and downstream of the bifurcation and of the butterfly valves separately, to isolate the losses. If the location and causes of the excess losses can be determined, then NP can take remedial action. Also, if losses are greater than previously measured, then accumulations in or deterioration of the steel penstock are likely causes and NP can consider remediation (e.g., pressure washing, coating).
- NP should research design information, past load rejection histories and/or conduct load rejection tests to confirm the capacity of the components that are to remain. The preliminary penstock design for this study was based on load rejection surge pressure information provided in drawing 6-601-22-5. It is unclear if the surge pressure line on this drawing

refers to one or two-unit load rejection and hence if the existing steel penstock and surge tank are suitable for a two-unit load rejection. Determining existing surge capacity was beyond the scope of this study but will have a significant impact on the replacement penstock. The energy benefits of the larger diameter penstocks are calculated assuming that 15 MW capacity is available. If total plant output must be limited so that the existing steel penstock and surge tank will not be over pressurized, then larger diameter penstocks will not be economically feasible.

Yours very truly,

S.H. Richter, P.Eng.
Project Manager

SHR:sjc

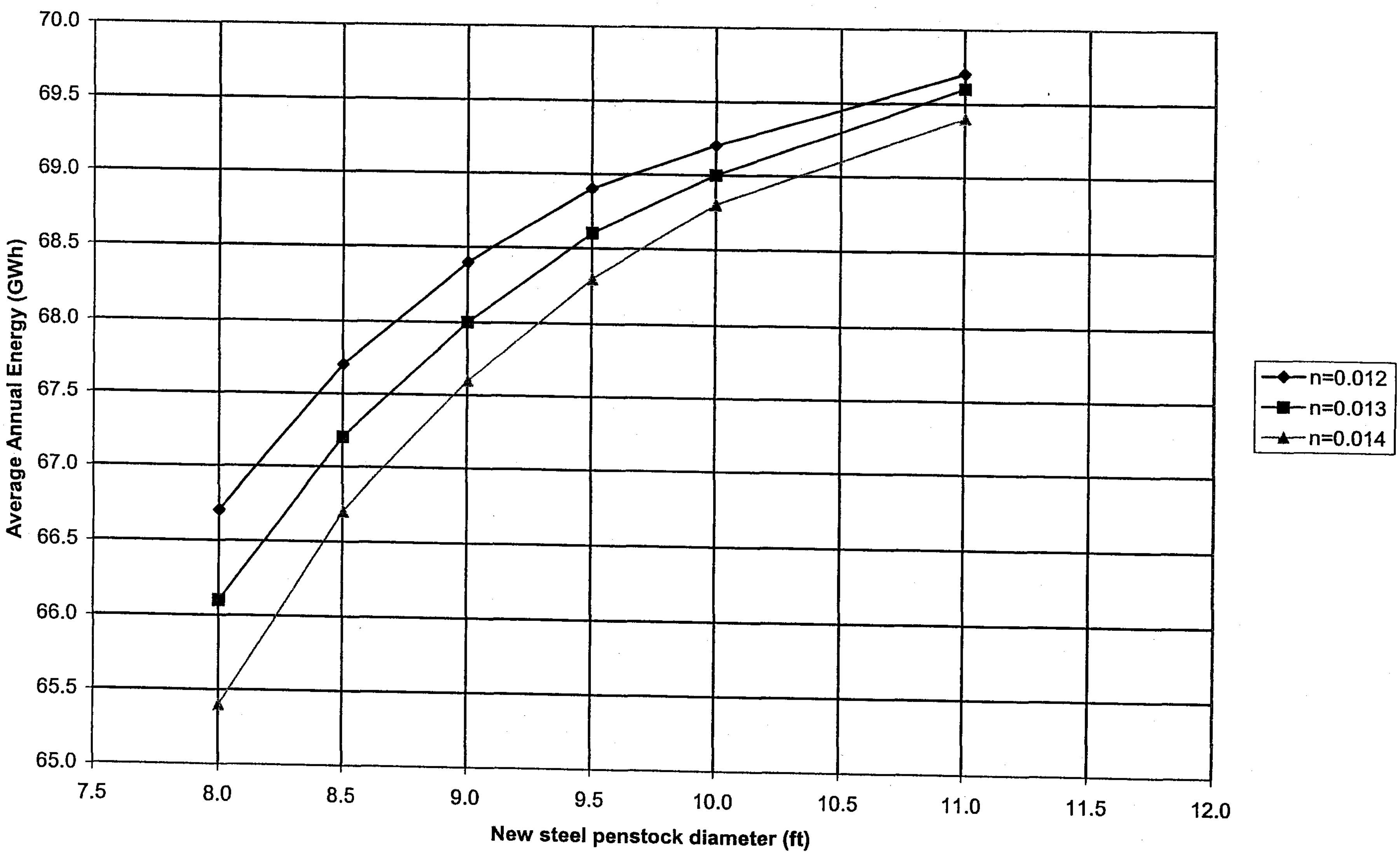
Attachments

Table 1
Cost Estimates

Penstock Diameter (ft)	**7.5**	**8.0**	**8.5**	**9.0**	**9.5**	**10.0**
Weight of Steel Shell (lbs)	2,016,647	2,150,381	2,284,115	2,417,848	2,551,582	2,685,316
Starting Shell Thickness (in)	3/8	3/8	3/8	3/8	3/8	3/8
Ending Shell Thickness (in)	3/8	3/8	3/8	3/8	3/8	3/8
Weight [tonnes]	914.7	975.4	1036.1	1096.7	1157.4	1218.0
Supply Cost, Jan. 2004 [$2600/t]	$ 2,378,000	$ 2,536,000	$ 2,694,000	$ 2,851,000	$ 3,009,000	$ 3,167,000
Install Cost [$3000/t]	$ 2,744,000	$ 2,926,000	$ 3,108,000	$ 3,290,000	$ 3,472,000	$ 3,654,000
Total Cost, Jan 2004	**$ 5,122,000**	**$ 5,462,000**	**$ 5,802,000**	**$ 6,141,000**	**$ 6,481,000**	**$ 6,821,000**
Incremental Cost	$ -	$ 340,000	$ 680,000	$ 1,019,000	$ 1,359,000	$ 1,699,000
Supply Cost +10% [$2860/t]	$ 2,616,000	$ 2,790,000	$ 2,963,000	$ 3,137,000	$ 3,310,000	$ 3,484,000
Install Cost [$3000/t]	$ 2,744,000	$ 2,926,000	$ 3,108,000	$ 3,290,000	$ 3,472,000	$ 3,654,000
Total Cost (+ 10% on supply)	**$ 5,360,000**	**$ 5,716,000**	**$ 6,071,000**	**$ 6,427,000**	**$ 6,782,000**	**$ 7,138,000**
Incremental Cost per 1/2 ft	$ -	$ 356,000	$ 355,000	$ 356,000	$ 355,000	$ 356,000
Supply Cost + 25% [$3250/t]	$ 2,973,000	$ 3,170,000	$ 3,367,000	$ 3,564,000	$ 3,761,000	$ 3,959,000
Install Cost [$3000/t]	$ 2,744,000	$ 2,926,000	$ 3,108,000	$ 3,290,000	$ 3,472,000	$ 3,654,000
Total Cost (+25% on supply)	**$ 5,717,000**	**$ 6,096,000**	**$ 6,475,000**	**$ 6,854,000**	**$ 7,233,000**	**$ 7,613,000**
Incremental Cost	$ -	$ 379,000	$ 758,000	$ 1,137,000	$ 1,516,000	$ 1,896,000

Note: These estimates assume that 3/8 in plate is used for all penstock diameters.

Figure 1: Average Annual Energy



SGE Acres
15602

F:\SGEAcres\Projects\2004\P15602.00 Rattling Brook Penstock\Hydrotech\srichter\Base case and sens\Base Case, Figs 1-4.xlsFig 1

Figure 2: Cost as a function of diameter

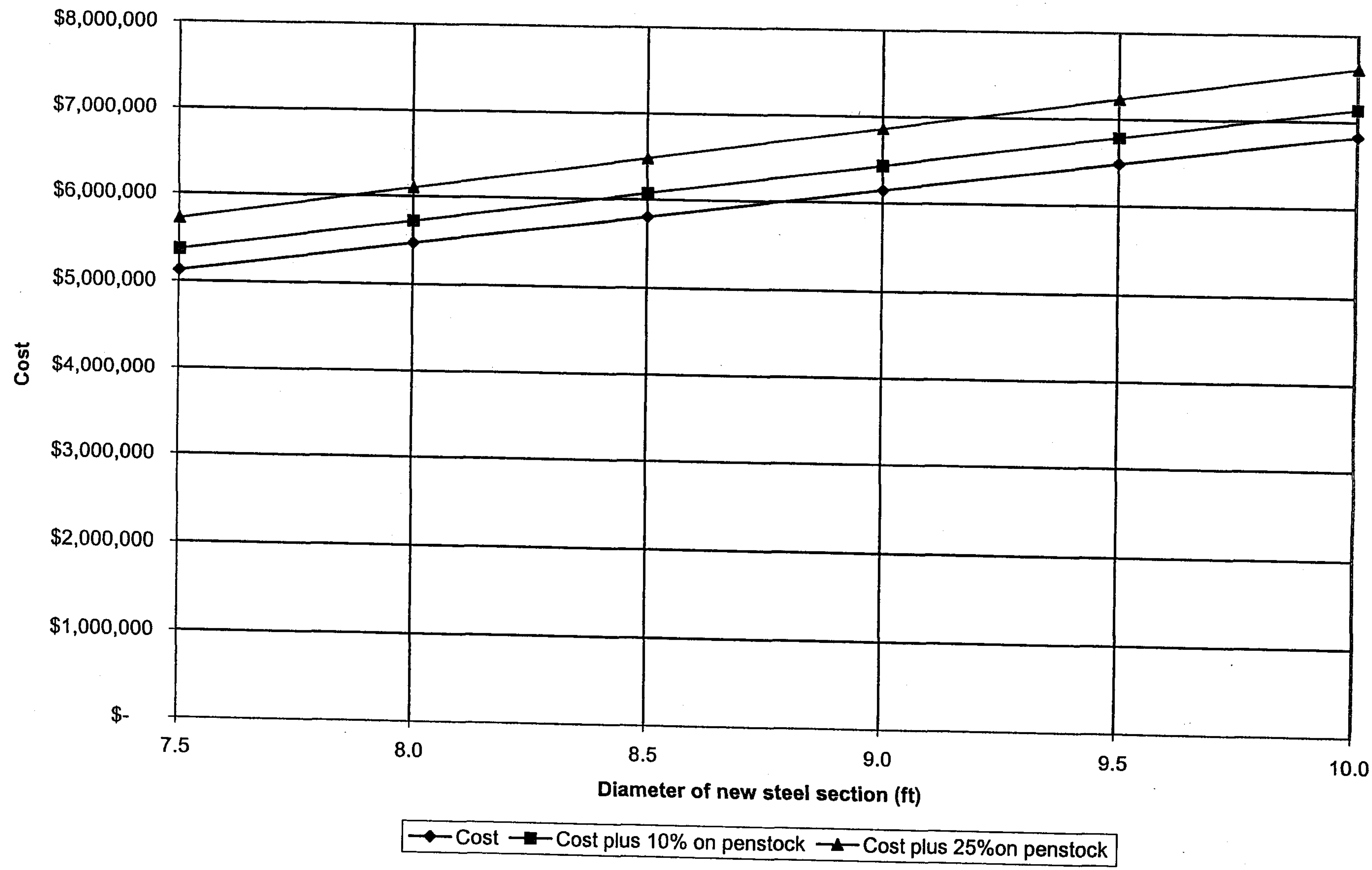


Figure 3: Net Benefits, Varying $/kWh and period (energy incremented to existing)

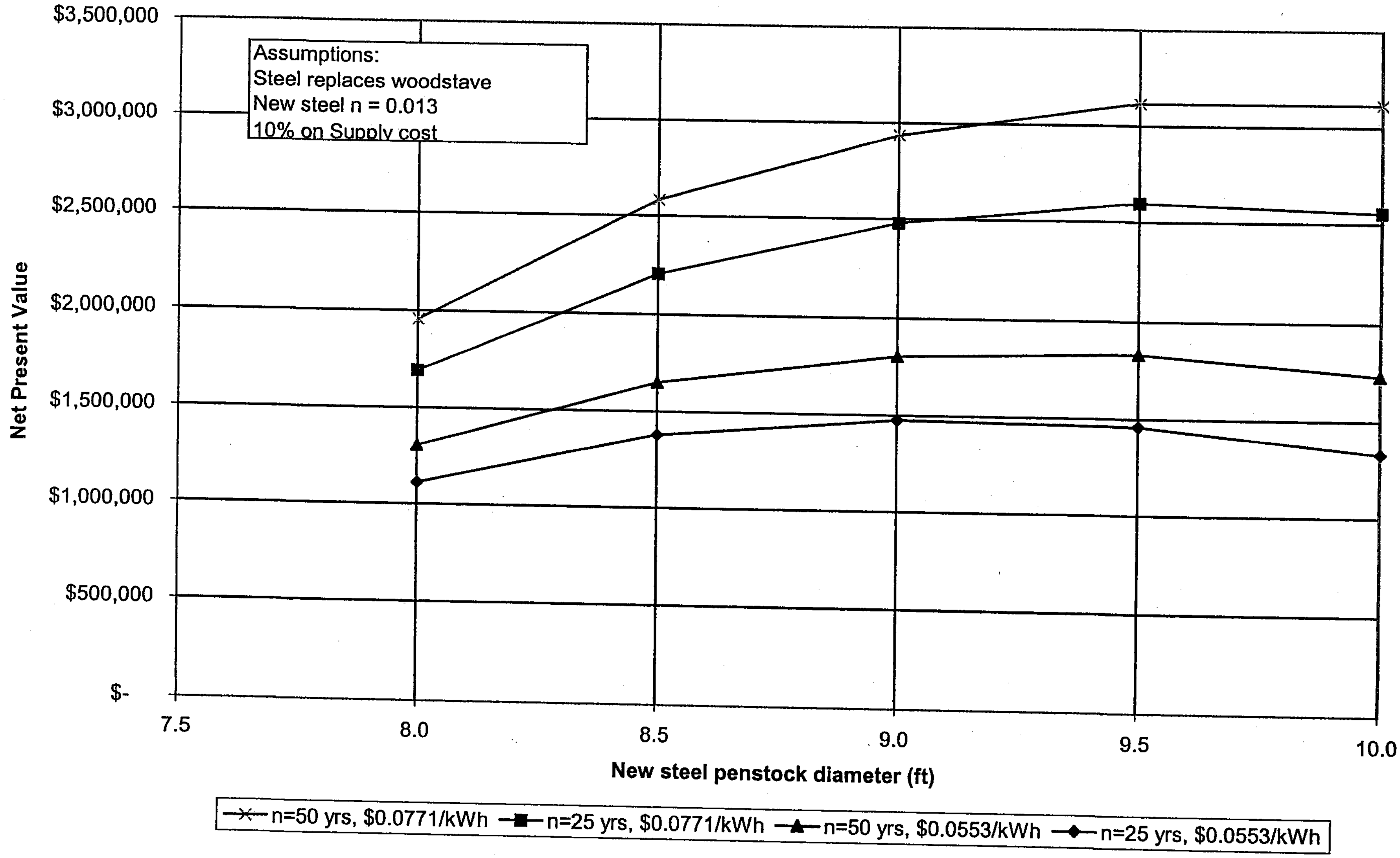
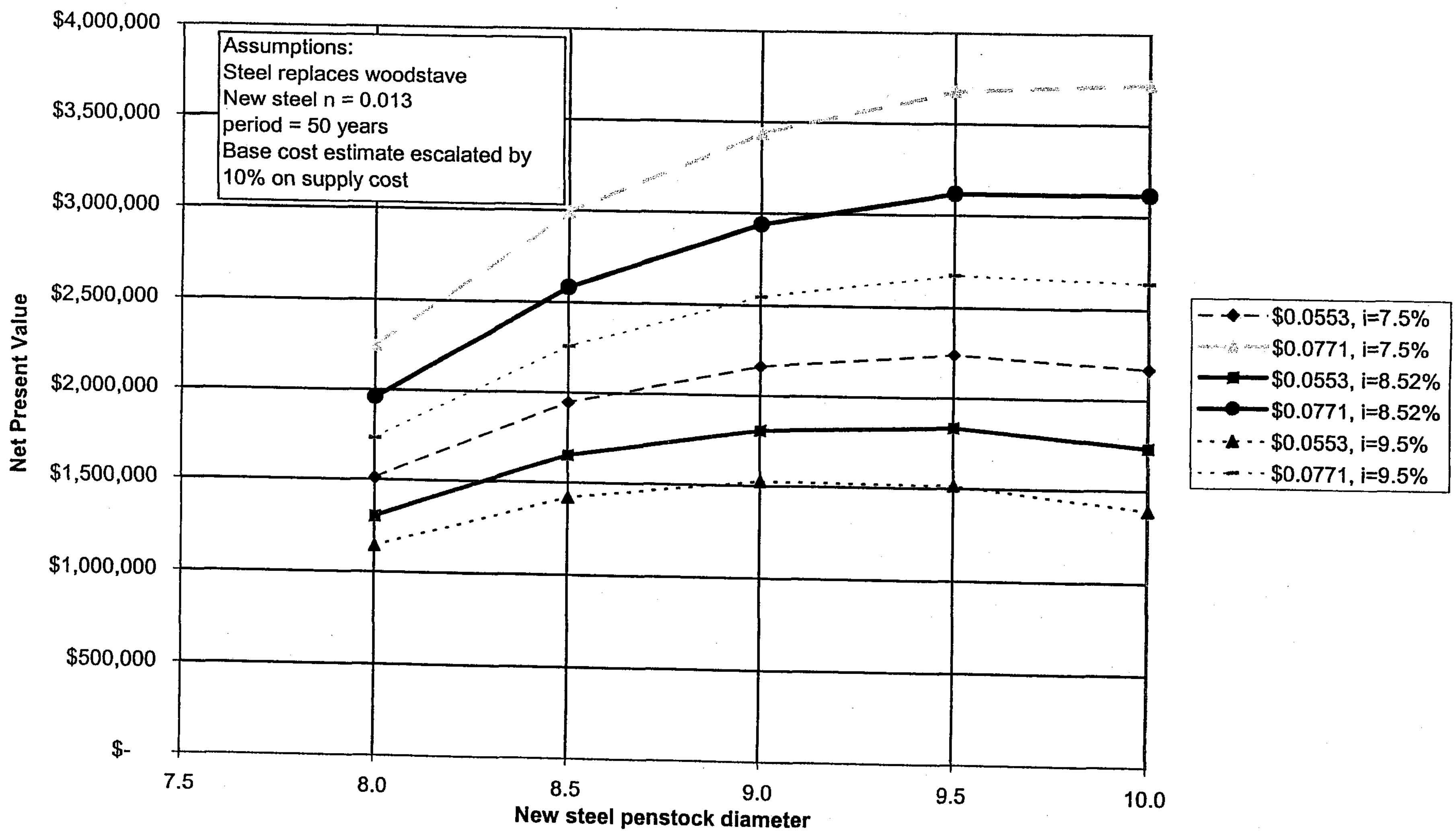


Figure 4: Net Benefits, Varying Discount Rate and $/kWh
(energy incremented to existing)



le 2

Case and Sensitivities

		Diam. new steel penstock (ft)	Net Benefits 25 Years Energy value ($/kWh) 0.0553	0.0771	Incremental - Stepwise 25 Years Energy value ($/kWh) 0.0553	0.0771	Net Benefits 50 Years Energy value ($/kWh) 0.0553	0.0771	Incremental - Stepwise 50 Years Energy value ($/kWh) 0.0553	0.0771
Base Case										
Cost	10%	8	*$1,113,000*	*$1,692,000*	$1,113,000	$1,692,000	*$1,303,000*	*$1,957,000*	$1,303,000	$1,957,000
Discount Rate	8.52%	8.5	*$1,380,000*	*$2,204,000*	$267,000	$512,000	*$1,650,000*	*$2,581,000*	$347,000	$624,000
Friction factor	0.013	9	*$1,476,000*	*$2,478,000*	$96,000	$274,000	*$1,805,000*	*$2,937,000*	$155,000	$356,000
Runoff	900 mm/yr	9.5	*$1,460,000*	*$2,595,000*	($16,000)	$118,000	*$1,833,000*	*$3,116,000*	$28,000	$179,000
		10	*$1,330,000*	*$2,555,000*	($130,000)	($41,000)	*$1,732,000*	*$3,116,000*	($101,000)	($98)
Sensitivity to increased cost										
Cost	**25%**	8	*$1,090,000*	*$1,669,000*	$1,090,000	$1,669,000	*$1,280,000*	*$1,934,000*	$1,280,000	$1,934,000
Discount Rate	8.52%	8.5	*$1,333,000*	*$2,157,000*	$243,000	$488,000	*$1,603,000*	*$2,534,000*	$323,000	$600,000
Friction factor	0.013	9	*$1,406,000*	*$2,408,000*	$73,000	$251,000	*$1,735,000*	*$2,867,000*	$132,000	$333,000
Runoff	900 mm/yr	9.5	*$1,366,000*	*$2,501,000*	($40,000)	$94,000	*$1,739,000*	*$3,022,000*	$4,000	$155,000
		10	*$1,212,000*	*$2,437,000*	($154,000)	($65,000)	*$1,614,000*	*$2,998,000*	($125,000)	($24,000)
Senstivity to friction factor										
Cost	10%	8	*$1,452,000*	*$2,165,000*	$1,452,000	$2,165,000	*$1,686,000*	*$2,491,000*	$1,686,000	$2,491,000
Discount Rate	8.52%	8.5	*$1,662,000*	*$2,598,000*	$210,000	$433,000	*$1,969,000*	*$3,026,000*	$283,000	$535,000
Friction factor	**0.012**	9	*$1,702,000*	*$2,793,000*	$40,000	$195,000	*$2,060,000*	*$3,293,000*	$91,000	$267,000
Runoff	900 mm/yr	9.5	*$1,629,000*	*$2,832,000*	($72,000)	$39,000	*$2,024,000*	*$3,383,000*	($36,000)	$90,000
		10	*$1,443,000*	*$2,712,000*	($186,000)	($120,000)	*$1,860,000*	*$3,294,000*	($165,000)	($89,000)
Senstivity to friction factor										
Cost	10%	8	*$718,000*	*$1,141,000*	$718,000	$1,141,000	*$857,000*	*$1,335,000*	$857,000	$1,335,000
Discount Rate	8.52%	8.5	*$1,097,000*	*$1,810,000*	$380,000	$669,000	*$1,331,000*	*$2,136,000*	$475,000	$802,000
Friction factor	**0.014**	9	*$1,250,000*	*$2,163,000*	$153,000	$353,000	*$1,550,000*	*$2,581,000*	$218,000	$445,000
Runoff	900 mm/yr	9.5	*$1,290,000*	*$2,359,000*	$41,000	$196,000	*$1,641,000*	*$2,849,000*	$92,000	$268,000
		10	*$1,217,000*	*$2,397,000*	($73,000)	$38,000	*$1,604,000*	*$2,938,000*	($37,000)	$89,000
Sensitivity to average runoff										
Cost	10%	8	*$1,283,000*	*$1,928,000*	$1,283,000	$1,928,000	*$1,495,000*	*$2,224,000*	$1,495,000	$2,224,000
Discount Rate	8.52%	8.5	*$1,719,000*	*$2,676,000*	$436,000	$748,000	*$2,033,000*	*$3,115,000*	$538,000	$891,000
Friction factor	0.013	9	*$1,928,000*	*$3,108,000*	$209,000	$432,000	*$2,315,000*	*$3,649,000*	$282,000	$534,000
Runoff	**990 mm/yr**	9.5	*$1,912,000*	*$3,226,000*	($16,000)	$118,000	*$2,343,000*	*$3,828,000*	$28,000	$179,000
		10	*$1,838,000*	*$3,264,000*	($73,000)	$38,000	*$2,306,000*	*$3,916,000*	($37,000)	$89,000
Sensitivity to discount rate										
Cost	10%	8					*$1,510,000*	*$2,245,000*	$1,510,000	$2,245,000
Discount Rate	**7.50%**	8.5					*$1,944,000*	*$2,990,000*	$434,000	$745,000
Friction factor	0.013	9					*$2,162,000*	*$3,435,000*	$218,000	$444,000
Runoff	900 mm/yr	9.5					*$2,237,000*	*$3,680,000*	$76,000	$245,000
		10					*$2,168,000*	*$3,724,000*	($69,000)	$44,000
Sensitivity to discount rate										
Cost	10%	8					*$1,141,000*	*$1,732,000*	$1,141,000	$1,732,000
Discount Rate	**9.50%**	8.5					*$1,420,000*	*$2,260,000*	$278,000	$528,000
Friction factor	0.013	9					*$1,524,000*	*$2,546,000*	$105,000	$286,000
Runoff	900 mm/yr	9.5					*$1,515,000*	*$2,673,000*	($9,000)	$127,000
		10					*$1,389,000*	*$2,638,000*	($126,000)	($35,000)

Figure 5: Net Benefits

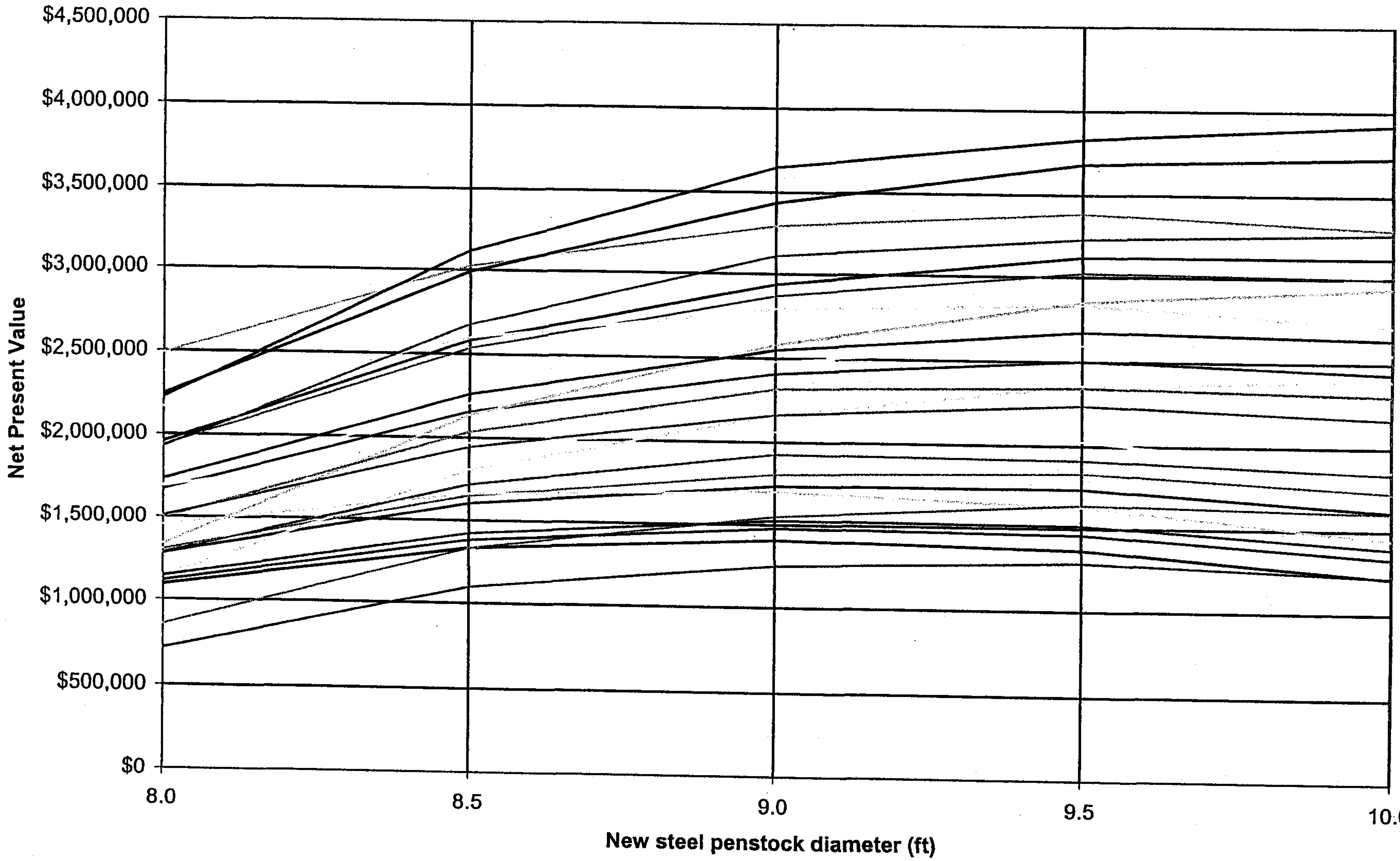
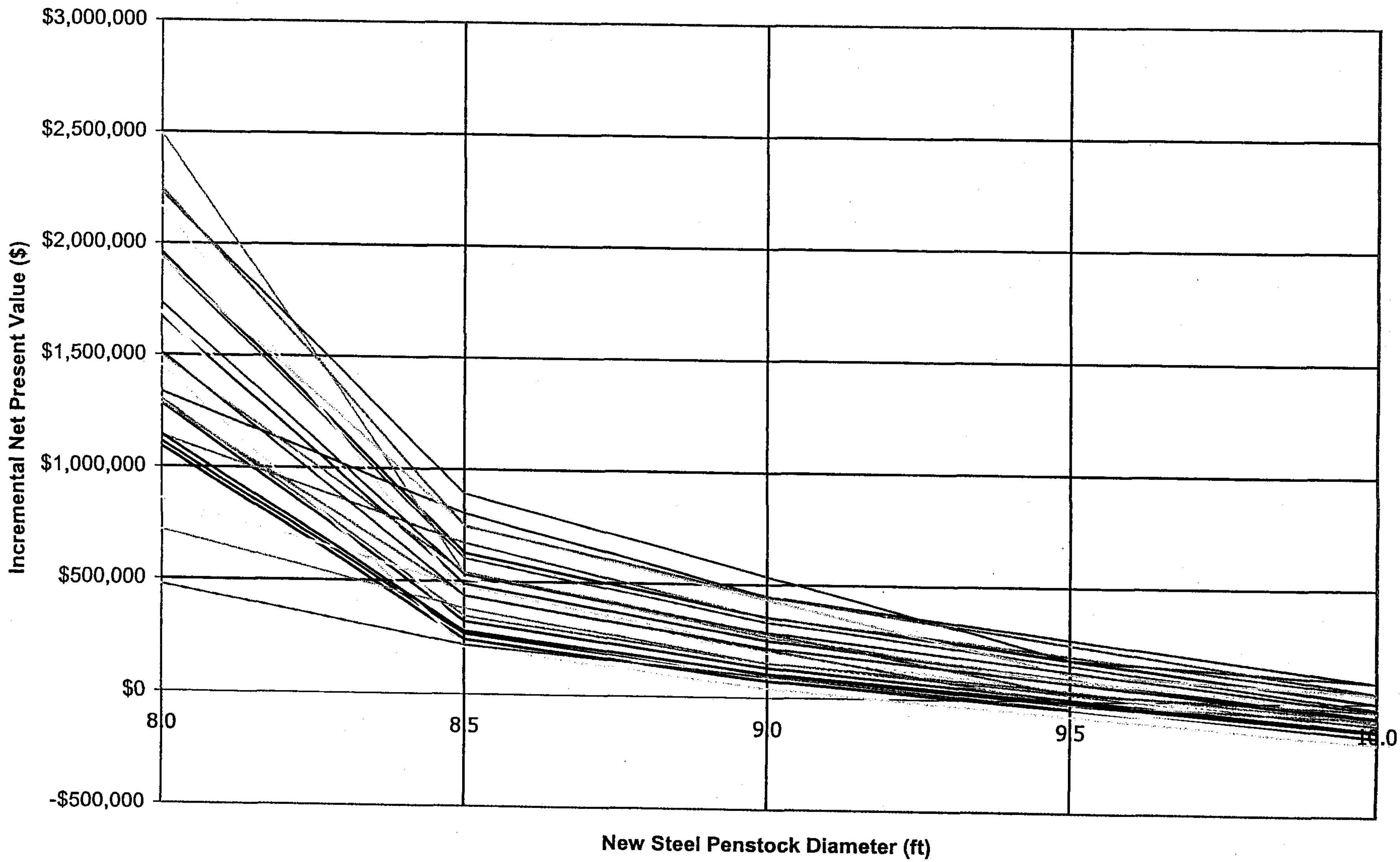


Figure 6: Incremental net benefits



<u>RATTLING BROOK</u>

<u>REPORT</u>

<u>TO</u>

<u>INCREASE PLANT CAPACITY</u>

<u>BY</u>

<u>INCREASING FLOW AREA</u>

A. Greeley

1982 10 08

Revised 1984 02 29

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I

INTRODUCTION

Rattling Brook Development is located on the east coast of Central Newoundland. The plant, commissioned in 1958, consists of two 8,500 h.p. turbines with generators rated at 6,375 kW each.

The actual plant capacity is given by Newfoundland Light & Power Co. Limited as 7,200 kW with one machine and 10,800 kW with both machines generating.

The purpose of this study is to ascertain reasons for the load restrictions with both machines operating and to analyze the feasibility of increasing production by increasing the flow area.

II

PRESENT PLANT CAPACITY

Two 8,500 h.p. turbines were installed at Rattling Brook in 1958. At present, the output in the plant is 7,200 kW with one machine in operation and 10,800 kW with both machines operating. Theoretically, the plant should have a capacity of approximately 14,000 kW.

Original design at Rattling consisted of two generating stations, each with a single machine. It was later decided, however, to erect one plant with two machines. Since the area was operated as an isolated system, the station was designed to carry all the area load on one machine with the second machine essentially a spare.

After 1966, when Rattling was tied to the provincial grid, it became feasible to operate both machines at full load if water was available. However, with both machines at full gate, excessive head losses in the pipe prevented full load on both machines.

At present, the production given for Rattling Brook during an average year is 70,000,000 kWh. With full load at 10,800 kW, this represents a load factor of 74%.

This production is achieved with a 6,850 ft. pipeline and penstock, consisting of 5,850 ft. woodstave and 1,000 ft. steel, operating with a discharge of approximately 620 cfs.

III

EXPECTED PLANT CAPACITY

It was initially thought that higher production could be accomplished by a combination of the following:

(1) Higher output for same discharge by doubling flow area through looping a second penstock with that existing or replacing the existing pipe with a 9.25 ft. diameter pipe.

(2) Greater efficiencies.

(3) Picking-up some of the frequent spills.

To help evaluate item no. 1 above, site measurements were conducted for various plant conditions. With machines operating independently and together, readings were taken at various loads for the following: penstock pressure at the plant; water drop in the surge tank; forebay level; tailwater level; and flow in the tailrace. The results of the measurements are shown in the Appendix.

Two alternatives were considered, to loop another penstock from the intake to the surge tank or build a new 9.25 ft. diameter penstock, in both cases leaving the section from the surge tank to the plant unaltered.

Either alternative would increase the net head on the plant, thereby increasing the output proportionately. To calculate the average annual output due to the increased head, a load duration curve was produced for the year 1973 (see appendix "B"). 1973 was chosen because that year the production at Rattling Brook was within one percent of the average production.

The load duration graph was then divided into five sections and the increase in net head for the larger flow area calculated for each load increment. Knowing the increase in net head and discharge associated with each load increment, the increase in production was calculated using the following equation:

$$kWH = \frac{(Q)\ (Hn\ increase)\ (e)\ (\%\ load\ duration)\ (8760)}{11.814}$$

kWH = output due to increase in head for each load increment

Q = discharge for each load increment

e = efficiency - assumed 75%

Hn = increase in net head

% load duration = % load increment of annual load duration

8760 = hours in one year

11.814 = constant incorporating water density and conversion of horsepower to kilowatts

The results of the calculation are shown in appendix "E". The increase in production for an average year will be in the area of 6,231,500 kWH.

An analysis of the spill records for Rattling was conducted to determine how much production could be attained from the spill. The daily spills since

1966 were reviewed and by comparing plant load on a specific day with the available production with a new pipeline, it was determined that approximately 500,000 kWh could be picked up each year by capturing the spill.

The efficiency of the plant could be increased by replacing the runner in each machine. It is anticipated the runner replacement could increase the efficiency by 4-5 percent. Another report will be completed to analyze the runner characteristics and ascertain the increase in production associated with runner replacement.

Note that increase in production due to runner replacement cannot be used to justify replacement of the penstock. Therefore, the remainder of this report will be concerned with the economics of increasing the flow area only.

IV

ECONOMIC ANALYSIS

Appendix "E" shows the additional production available from Rattling Brook Plant for an average year by looping another 7 ft. pipe with the existing pipe or erecting a new 9.25 ft. diameter pipe. In either case, the additional production for an average year is 6,231,573 kWh, plus 500,000 kWh by reducing spill. The total additional production is approximately 6,700,000 kWh.

The value of the 6,700,000 kWh of additional production was estimated from information obtained from Newfoundland and Labrador Hydro Corporation for the period 1983-2040. Accordingly, the benefit available from 6,700,000 kWh over the remaining life of the plant (56 years) is approximately $3,640,000 ($1984).

For a 7 ft. diameter pipeline, the cost is estimated to be $4,196,750. The cost of operating this pipeline is estimated to be $1,000 per year beginning in 1985.

For a 9.25 ft. diameter pipeline, the cost is estimated to be $4,835,000. The cost of operating this pipeline should not be higher than that of the existing pipe and no operating cost will be included in the analysis.

If the project is eligible for a federal government incentive program to aid small hydro, CCA class 34 can be used in the corporate income tax calculation. Class 34 allows 25%, 50%, and 25% of the capital value of the asset to be applied against income in the first, second, and third years respectively. If the project is not eligible for the program, Class 2 will apply and allows the capital value of the asset to be applied against income at a 6% declining rate.

Economic calculations for looping another 7 ft. pipeline indicated the present worth of the annual charges under class 34 to be $3,467,000, ($1984). If class 34 is not applicable, the present worth of the annual charges is $5,266,000 ($1984).

The benefit cost ratio under class 34 is 1.05:1. The benefit cost ratio under class 2 is 0.70:1.

Economic calculations for replacing the existing pipeline with a 9.25 ft. pipeline indicated the present worth of the annual charges under class 34 to be $3,995,000 ($1984). If CCA class 34 is not applicable, the present worth of the annual charges is $6,073,000 ($1984).

The benefit cost ratio under class 34 is 0.91:1. The benefit cost ratio under class 2 is 0.60:1.

A summary of economic calculation is:

Alternative	CCA Class	Benefit/Cost Ratio
7 ft. pipeline	34	1.05:1
7 ft. pipeline	2	0.70:1
9.25 ft. pipeline	34	0.91:1
9.25 ft. pipeline	2	0.60:1

V

CONCLUSIONS

In conclusion, it is not economically feasible, at this time, to increase the plant output at Rattling Brook by increasing the penstock flow area. The increased output of 6,700,000 kWh cannot justify the expenditure of $4,500,000.

The project is barely economical if the work is done under Class 34, and only if the Class 34 program is continued into 1985. It is not possible to design, receive material, and erect a new 7'0" pipeline at Rattling Brook in 1984.

Alternative	CCA Class	Benefit/Cost Ratio
7 ft. pipeline	34	1.05:1
7 ft. pipeline	2	0.70:1
9.25 ft. pipeline	34	0.91:1
9.25 ft. pipeline	2	0.60:1

APPENDIX "A"

RATTLING BROOK PLANT

SUMMARY MEASUREMENTS

November 3, 1983

Unit #1

LOAD	% GATE #1	% GATE #2	PRESSURE AT MACHINE #1	PRESSURE AT MACHINE #2	HEAD AT MACHINE #1	HEAD AT MACHINE #2	TOTAL LOSSES	LOSSES TO SURGE TANK	LOSSES TANK TO PLANT	DISCHARGE
(KW)			(psi)	(psi)	(ft.)	(ft.)	(ft.)	(ft.)	(ft.)	(cfs)
5000	50		135		314.0		20.7	8.9	11.8	290
5500	54		134		311.6		23.0	9.8	13.2	336
6000	61		132		307.0		27.6	11.4	16.2	345
6500	70		128		297.7		37.0	13.8	23.2	348
7000	93		127		295.3		39.4	18.8	20.6	420

Unit #1 & #2

RATTLING OOK PLANT

SUMMARY MEASUREMENTS

November 3, 1983

LOAD	% GATE #1	% GATE #2	PRESSURE AT MACHINE #1	PRESSURE AT MACHINE #2	HEAD AT MACHINE #1	HEAD AT MACHINE #2	TOTAL LOSSES	LOSSES TO SURGE TANK	LOSSES TANK TO PLANT	DISCHARGE
(KW)			(psi)	(psi)	(ft.)	(ft.)	(ft.)	(ft.)	(ft.)	(cfs)
5000	29	29	140	137	325.6	318.6	16.0	10.6	5.4	333
6000	33	35	137	135	318.6	314.0	20.6	17.2	3.4	382
7000	38	40	133	132	309.3	306.9	27.8	19.9	7.9	405
8000	43	46	130	130	302.3	302.3	32.4	24.1	8.3	434
9000	48	52	127	125	295.3	290.7	44.0	31.8	12.2	507
10000	58	61	121	122	281.4	283.7	51.0	37.3	13.7	550
10500	67	68	118	117	274.4	272.1	62.6	43.5	19.1	580
10600	72	73	116	115	269.7	267.4	67.3	47.9	19.4	586
10800	86	87	112	112	260.5	260.5	74.2	54.9	19.3*	565*

RATTLING [illegible] OK PLANT

SUMMARY MEASUREMENTS

September 16, 1982

Unit #1

LOAD	MACHINE PRESSURE #1	MACHINE PRESSURE #2	HEAD AT MACHINE #1	HEAD AT MACHINE #2	TOTAL LOSSES	LOSSES TO SURGE TANK	LOSSES TANK TO PLANT	DISCHARGE	LOAD
(KW)	(psi)	(psi)	(ft.)	(ft.)	(ft.)	(ft.)	(ft.)	(cfs)	(KW)
0	144		334.9		--	--			
5000	136		316.0		18.9	9.0	9.9	247.0	5000
5500	135		314.0		20.9	10.9	10.0	293.5	5500
6000	133		309.0		25.9	13.2	12.7	316.0	6000
6500	130		302.0		32.9	15.7	17.2	343.0	6500
7000	126		293.0		41.9	21.9	20.0	445.0	7000

RATTLING ЬOOK PLANT

SUMMARY MEASUREMENTS

November 3, 1983

Unit #2

LOAD	% GATE #1	% GATE #2	PRESSURE AT MACHINE #1	PRESSURE AT MACHINE #2	HEAD AT MACHINE #1	HEAD AT MACHINE #2	TOTAL LOSSES	LOSSES TO SURGE TANK	LOSSES TANK TO PLANT	DISCHARGE
(KW)			(psi)	(psi)	(ft.)	(ft.)	(ft.)	(ft.)	(ft.)	(cfs)
5000		50		135		314.0	21.0	--	--	284
5500		55		135		314.0	21.0	--	--	319
6000		62		132		307.0	28.0	--	--	348
6500		75		128		297.7	37.3	--	--	391
7000		93		126		295.3	39.7	--	--	420

RATTLING BROOK PLANT

SUMMARY MEASUREMENTS

September 16, 1982

Unit #1 & 2

LOAD	MACHINE PRESSURE #1	MACHINE PRESSURE #2	HEAD AT MACHINE #1	HEAD AT MACHINE #2	TOTAL LOSSES	LOSSES TO SURGE TANK	LOSSES TANK TO PLANT	DISCHARGE	LOAD
(KW)	(psi)	(psi)	(ft.)	(ft.)	(ft.)	(ft.)	(ft.)	(cfs)	(KW)
9000	126	125	293.0	290.7	44.2	33.2	11.0	549	9000
9500	125	123	290.7	286.0	48.9	36.4	12.5	516	9500
10000	122	120	283.7	279.0	55.9	40.7	15.2	537	10000
10400	120	118	279.0	274.4	60.5	46.4	14.1	524	10400
10500	119	117	276.7	272.0	62.9	47.8	15.1	541	10500
10600	118	116	274.4	269.7	65.2	48.7	16.5	545	10600
10700	116	115	269.7	267.4	67.5	53.1	14.4	550	10700
10800	115	113	267.4	262.8	72.1	54.7	17.4	619	10800

RATTLING OOK PLANT

SUMMARY MEASUREMENTS

September 16, 1982

Unit #2

LOAD	MACHINE PRESSURE #1	MACHINE PRESSURE #2	HEAD AT MACHINE #1	HEAD AT MACHINE #2	TOTAL LOSSES	LOSSES TO SURGE TANK	LOSSES TANK TO PLANT	DISCHARGE	LOAD
(KW)	(psi)	(psi)	(ft.)	(ft.)	(ft.)	(ft.)	(ft.)	(cfs)	(KW)
0		144		334.8					
5000		136		316.0	18.8			235	5000
5500		134		312.0	22.8			254	5500
6000		132		307.0	27.8			279	6000
6500		130		302.0	32.8			302	6500
7000		126		293.0	41.8			355	7000

Unit 1

RATTLING BROOK PLANT

SUMMARY MEASUREMENTS

June 14, 1983

LOAD	PRESSURE AT MACHINE #1	PRESSURE AT MACHINE #2	HEAD AT MACHINE #1	HEAD AT MACHINE #2	LOSSES	% GATE	DISCHARGE	LOAD	UNIT
(KW)	(psi)	(psi)	(ft.)	(ft.)	(ft.)		(cfs)	(KW)	
All Down	145	145	337.0	337.0			9.66	All Down	All Down
0	145		337.0				37.40	0	
5000	137		318.6		18.4		212.20	5000	
5500	136		316.0				255.10	5500	
6000	134		311.6		25.4		294.70	6000	
6500	132		307.0		30.0	68%	313.40	6500	
7000	127		295.0		42.0		333.90	7000	
7100	126		293.0		44.0	100%	406.00	7100	

RATTLING BROOK .LANT

SUMMARY MEASUREMENTS

June 14, 1983

Units 1 & 2

LOAD	PRESSURE AT MACHINE #1	PRESSURE AT MACHINE #2	HEAD AT MACHINE #1	HEAD AT MACHINE #2	LOSSES	% GATE	DISCHARGE	LOAD
(KW)	(psi)	(psi)	(ft.)	(ft.)	(ft.)		(cfs)	(KW)
9000	128	126	297.7	293.0	44.0		508.2	9000
9500	125	123	290.7	286.0	51.0		520.3	9500
10000	123	121	286.0	281.4	56.0		554.5	10000
10400	121	119	281.4	276.7	60.5		601.8	10400
10500	117	115	272.0	267.4	69.8		622.3	10500
10600	117	115	272.0	267.4	69.8		627.1	10600
10700	117	115	272.0	267.4	69.8		627.1	10700
10800	115	114	267.4	265.0	72.0	No. 1 75%	599.0	10800
						No. 2 80%		

APPENDIX "B"

LOAD DURATION GRAPH

RATTLII BROOK PLANT

SUMMARY MEASUREMENTS

June 14, 1983

No. 2 Machine

LOAD	PRESSURE AT MACHINE #1	PRESSURE AT MACHINE #2	HEAD AT MACHINE #1	HEAD AT MACHINE #2	LOSSES	% GATE	DISCHARGE	LOAD	UNIT
(KW)	(psi)	(psi)	(ft.)	(ft.)	(ft.)		(cfs)	(KW)	
0		145		337			38.5	0	
5000		136		316	21		223.4	5000	
5500		133		309	28		263.1	5500	
6000		132		307	30		284.6	6000	
6500		130		302	35	72%	316.4	6500	
7000		125		291	46		402.4	7000	
7100		125		291	46	100%	406.0	7100	

APPENDIX "C"

ESTIMATES

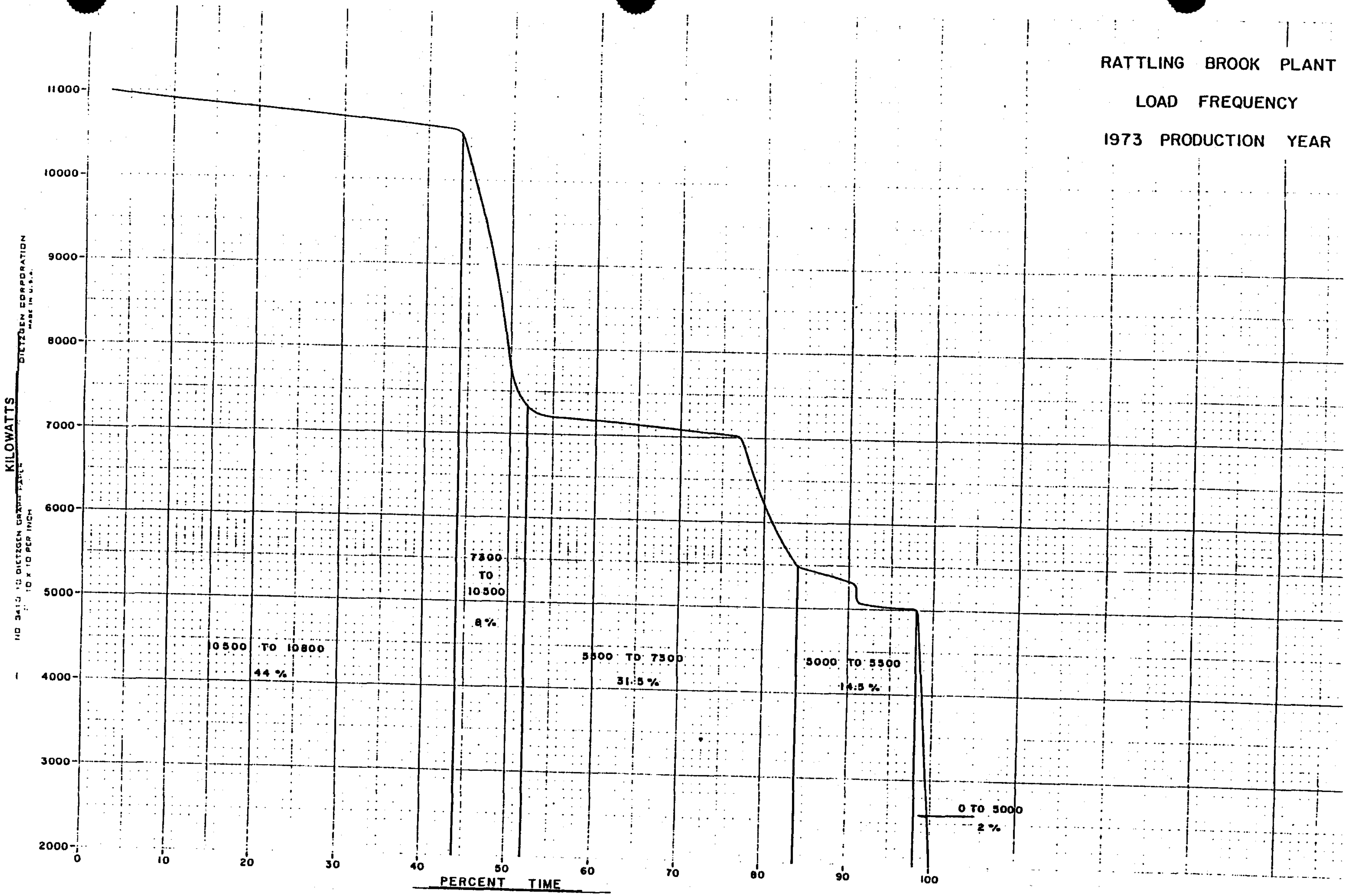
7'0" PIPE AND 9'3" PIPE

$1984

RATTLING BROOK PLANT

LOAD FREQUENCY

1973 PRODUCTION YEAR



APPENDIX "C"

ESTIMATE

NEW 9'3" DIAMETER WOODSTAVE PIPELINE

Item	Description	Quantity	Unit Price	Amount
1.	Woodstave Material	6,000 ft.	$ 567	$3,400,000
2.	Woodstave Erection	6,000 ft.	100	600,000
3.	Demolish Existing Pipe	L.S.		150,000
4.	Steel Thimbles			75,000
5.	Bed Alterations			50,000
6.	Engineering and Supervision			50,000
7.	Surveying			10,000
	Sub-Total			$4,335,000
	I.D.C. over 12 Months			250,000
	Contingency			250,000
	Total			$4,835,000

APPENDIX "C"

ESTIMATE

NEW 7'0" DIAMETER WOODSTAVE PIPELINE

Item	Description	Quantity	Unit Price	Amount
1.	Woodstave Material	6,210 ft.	$ 418	$2,600,000
2.	Woodstave Erection	6,210 ft.	75	465,750
3.	Bed Preparation	6,210 ft.	64	400,000
4.	Stream Crossings	2	10,000	20,000
5.	Steel Thimbles	2	38,000	76,000
6.	Rebuild Under Highway	L.S.		75,000
7.	Engineering and Supervision			50,000
8.	Surveying			10,000
	Sub-Total			$3,696,750
	I.D.C. over 12 Months			250,000
	Contingency			250,000
	Total			$4,196,750

NOTE: To extend the two penstocks from the surge tank to the plant will cost an additional $450,000.

APPENDIX "D"

CALCULATION FOR

INCREASE IN NET HEAD

FOR INCREASED FLOW AREA

kW	Q (cfs)	LOSSES TO TANK (ft)	V 7'0" PIPE (ft/sec)	1.5 V2/2g 7'0" PIPE (ft)	FRICTION LOSS TO TANK 7'0" PIPE (3-5)	FRICTION LOSS TO TANK 9.3" PIPE (ft)	INCREASE NET HEAD (ft)
5,000	290	8.9	7.5	1.31	7.59	2.8	4.8
5,500	336	9.8	8.7	1.76	8.04	2.96	5.1
6,000	345	11.4	8.9	1.84	9.56	3.54	6.0
6,500	348	13.8	9.0	1.88	11.92	4.41	7.5
7,000	420	18.8	10.9	2.76	16.04	5.85	10.2
8,000	434	24.1	11.3	2.97	21.13	7.70	13.4
9,000	507	31.8	13.2	4.06	27.74	10.27	17.6
10,000	550	37.3	14.3	4.76	32.54	11.91	20.6
10,500	580	43.5	15.1	5.31	38.19	13.98	24.2
10,600	605	47.9	15.7	5.74	42.16	15.60	26.8
10,800	620	54.9	16.1	6.03	48.87	17.86	31.0

APPENDIX "E"

INCREASE IN PRODUCTION

1973

ESTIMATED INCREASE IN PRODUCTION

1973

FLOW AREA DOUBLED

LOAD GROUP (kW)	LOAD DURATION (% OF ANNUAL LOAD)	INCREASE NET HEAD (ft)	DISCHARGE (cfs)	INCREASE IN PRODUCTION (kWH)
0- 5,000	2	4.8	290	15,482
5,000- 5,500	14.5	5.1	336	138,180
5,500- 7,300	.31.5	10.2	420	750,462
7,300-10,500	8	24.2	580	624,455
10,500-10,800	44	31.0	620	4,702,994
			TOTAL	6,231,573

Appendix B

Electrical Equipment Site Assessment

Electrical Equipment
Site Assessment

May 28, 2004

Prepared By:
John W. Pardy, P.Eng.
Jack Casey, P. Eng

NEWFOUNDLAND POWER
A FORTIS COMPANY

Table of Contents

1.0 General

The Rattling Brook hydro development went into service in December 1958. The generating station comprises two 8500 horsepower vertical shaft Francis turbines connected to separate generators each with an original rating of 7500 kVA.

Generating unit # 2 experienced an in-service failure of the windings and underwent a stator rewind in 2002. The planned rewind of generating unit #1 is scheduled to occur in September 2004.

In 1987 the turbine runners were replaced in each unit. In 1994, the Rattling Brook generating station was placed under remote control from the system control centre in St. John's. With the exception of these major projects, the plant remains in original condition.

2.0 AC Distribution

The existing 120/240V 3-phase AC service panel is located in a cell in the existing switchgear line up. This equipment is original to the plant and replacement breakers are no longer available. With additional loading from the proposed plant upgrading and the addition of new heating and ventilating equipment, this panel will no longer have sufficient capacity. It is preferred to locate the AC panel remote from the switchgear line up to provide ease of access for wiring future circuits.

3.0 Station Service

There are currently two station services connected to the 6900 volt generator bus. The original plant station service located in the switchgear cabinet consists of (3) 25 KVA 240 volt secondary transformers, with one transformer low voltage winding tapped to provide 120v secondary voltage. The second station service transformer was installed to supply the former control centre building located on this site. This service consists of a 150 kVA three-phase transformer with a 120/208 volt secondary. With the installation of new electrical equipment, it will be necessary to change the voltage of the existing plant station service transformer to satisfy the voltage requirements of the new equipment and increase transformer capacity to accommodate the additional load. Consideration will be given to providing redundant station services, a normal supply and an emergency supply to ensure the availability of this critical black start plant.

4.0 DC Distribution

The DC distribution panel is original to the plant. Additional circuit breakers will be required to protect the DC control circuits for the various electronic components to be included in the governor and unit control panels. Due to its age, additional circuit breakers for this panel are no longer available. Insufficient spare locations exist in the panel to accommodate the additional circuits requiring the installation of an additional panel. It is recommended that the DC distribution panel be replaced with one adequate for the additional DC powered equipment.

5.0 Battery Plant and Charger

The battery bank was installed in 1996 and is in good condition. The battery charger was installed in 1984. Its condition will be assessed and replacement considered. The concern to be addressed with the battery system is that the battery bank and the charger are located in the same room as the switchgear. This situation contravenes the Canadian Electrical Code and needs to be addressed. The plant refurbishment must include the construction of a separate battery room meeting CSA standards to house the battery bank.

6.0 Generators

Generator unit #2 was rewound in 2002 after failing in service. Generator unit #1 will be rewound in 2004. The existing termination cabinets attached to the generators as presently configured do not have space for a grounding transformer to enhance unit protection. The termination cabinets will be redesigned to accommodate a grounding transformer.

7.0 Excitation Systems

The exciters on generating units #1 and #2 are the original to the generating station but are in good condition. During the plant refurbishment, these exciters will be refurbished to ensure continued reliable service. Both units have Brown Bovari voltage regulators that are mechanical in nature and have been discontinued for many years. These voltage regulators will be replaced with digital voltage regulators. The excitation cables are original to plant and will be replaced as they are near the end of their service life

8.0 Switchgear

The generator and incoming breakers are original units installed in 1958. The potential transformers (PT) and current transformers (CT) are integral to the switchgear and there is no indication that they have been replaced since their original installation. Concerns exist with the condition of the PT and CT windings due to their age. The critical role this equipment plays in the electrical protection of the generators dictates that they be replaced.

The existing switchgear design was based upon two incoming breakers fed from two separate power transformers. In 2002, the original transformers were replaced with a single power transformer. The two original incoming breakers and associated power cables are connected in parallel feeding the new power transformer. A replacement switchgear design will connect the 6900-volt bus to the power transformer with a single incoming breaker and single set of power cables capable of carrying the total maximum current of both generators.

Another issue to be addressed with the switchgear is the combining of the breaker protection and control with the generator sequencing, monitoring and control functions in a single panel. Replacement of generator control is best done in concert with the switchgear replacement since the existing design has incorporated both functions into a single panel.

9.0 Power Cables

The power cables from the generator termination cabinets to the switchgear are the original 1000 MCM paper insulated lead covered (PILC) cables with pitch filled pothead terminations. PILC cables typically have a long life expectancy. However, these cables are susceptible to stress fractures if the insulation is subjected to movement following years of resting in a fixed position. It is expected that the movement these cables will be subjected to during the reconstruction will cause stresses in the cables leading to premature failure. Therefore the power cables and terminations will need to be replaced when the switchgear is replaced.

Unit #1 Switchgear
Cable Terminations

Unit #1 Generator
Cable Terminations

10.0 Grounding

Both generators currently have their windings solidly connected to earth, which in the event of a fault will subject the windings to the electrical stresses of the total available fault current. Installation of grounding transformers will introduce a high impedance ground path. This will significantly reduce the available fault current thereby reducing the electrical and mechanical stresses on the generators under fault conditions thereby reducing the risk of catastrophic failure. It is recommended that the high impedance ground design be implemented, and related ground fault protection improvements be completed.

11.0 Protective Relays

The existing generator protection for both generating unit #1 and #2 is provided through electromechanical relays consisting of the following:

- 40 loss of field protection
- 49 stator thermal protection
- 51N neutral overcurrent
- 87G unit differential protection
- 87S split phase protection
- 51V Voltage restrained overcurrent

Over the past 50 years improvements in generator protection have been developed and the following additional protection is recommended:

- 59G over voltage relay for ground faults
- 87GN Sensitive ground fault protection
- 64F voltage relay for rotor ground faults
- 46 Stator unbalanced current protection
- 81 Over-frequency protection

The existing transformer protection is provided through a Alstom P632 digital relay and as a result can be maintained without modification.

12.0 Alarm Annunciation

The annunciator panel located in the switchgear line-up is original to the plant. It is a mechanical unit where metal targets drop down to annunciate an alarm. There are numerous targets no longer operational. With the installation of unit control panels equipped with human machine interfaces (HMI's), this device will be redundant and can be removed.

13.0 Synchronizer

The vacuum tube synchronizer design is original to the 1958 plant construction. The fact that the synchronized is constructed from vacum tube technology means that parts are no longer available. Within Newfoundland Power, no expertise exists in the maintenance of this device. It will be replaced with a modern synchronizer as part of the upgraded unit control panel.

14.0 Governor Interface

The original Woodward Type HR hydraulic governors are still in service on both units. It is becoming increasingly difficult to obtain replacement parts for these units. The original equipment manufacturer has declared the product as obsolete and will no longer manufacture replacement parts. Within the Company, there is also a decreasing knowledge base of expertise in the operation and maintenance of these governors, making it increasingly difficult to reliably maintain this equipment.

Electronic upgrades are available to replace the mechanical speed governing components from a number of different suppliers. These upgrades may be feasible if the power piston and oil reservoir are in good condition. An inspection of these components by the original equipment manufacturer would determine if this solution is viable.

15.0 Plant Control

Although this plant is remotely controlled and monitored, remote control functions are limited. Intervention by a local or remote operator is required to start and stop both units at this plant. Adjusting the load to efficient operation requires manual input from an operator and frequent adjustments. At present, there is no automation with respect to water management and automatic setting of loads.

Improving the plant control using a programmable logic controller would enable a variety of control modes best suited for the efficient operation of the plant.

16.0 Mechanical Protection

Unit #1 has been upgraded with a programmable logic controller (PLC) that provides a measure of mechanical protection through the monitoring of some equipment temperatures. Problems encountered in interfacing a PLC with the existing control systems have delayed the provision of mechanical protection on Unit #2. Neither unit has vibration monitoring which is critical in early detection of many mechanical failures.

17.0 Instrumentation

Thermocouples and resistance temperature devices (RTD) exist for most bearings surfaces, oil reservoirs, and cooling water systems. However it is difficult to assess their accuracy without first disassembling the generator. The integration of these temperature measuring devices into the existing control system is the cause of many false trips on the units. Integrating the thermocouples into a PLC based unit control panel will allow for finer control and pre-alarming functionality that can avoid potential false trips on the units.

18.0 Bearing Cooling Water Control

There are valves and piping in place for both units, and there is some automated control of these valves at present. Flow monitoring and controlled valves are installed to provide protection and control. This system will need to be integrated into any new control system for automating the plant.

19.0 Heating and Ventilation

There are anti-condensation heaters and infrared heaters installed for each unit controlled by a hand operated humidistat and thermostat respectively. All of the controls of heating and ventilation equipment should be upgraded so that desired building temperature and humidity can be monitored and controlled by the unit control PLC. Integrating the heating and ventilating control with the generator control PLC will ensure that a generator covered in condensation will not be energized and subsequently damaged.

20.0 Forebay Water Level Monitoring and Control

The existing water level probe and transducer are older vintage equipment. This equipment should be replaced with a new 4 to 20-milliamp water level transmitter at the forebay. The forebay cable is in good condition, but the cable terminations are in poor condition. The cable will be re-terminated.

21.0 Conclusion

The following is a list of the major recommendations that should be addressed during the refurbishment of the generating station:

- Upgrade electrical and mechanical protection system for Rattling Brook plant
- Replace voltage regulator, synchronizer and alarm annunciation
- Replace the power cables
- Replace existing relay control system with PLC based control system
- Refurbish or replace existing governor systems
- Replace or upgrade the existing switchgear, pending further internal inspections
- Replace AC and DC electrical distribution systems

Appendix C

Mechanical Site Assessment

Mechanical Site Assessment

June 18, 2004

Prepared By:
Kent Nicholson, P. Eng

NEWFOUNDLAND POWER
A FORTIS COMPANY

Table of Contents

1.0 General

The Rattling Brook hydro development went into service in December 1958. The generating station comprises two 8500 horsepower vertical shaft Francis turbines connected to separate generators each with an original rating of 7500 kVA.

Both units were overhauled in the 1986/1987 timeframe including the replacement of the runner and general mechanical overhaul of the machine. The wicket gates and bushings were not replaced and it has not been determined whether or not the stationary seals were replaced at that time.

An inspection of both turbine runners at Rattling Brook Plant was performed during the summer of 1998 and the balance of plant inspection was carried out in May 2004. The scope of the inspections in 1998 included: the high & low pressure sides of the runner; the wicket gates and seals; gate closure and water passage opening; general condition of the scroll case and the main valve disk; disk seat; and stationary seat.

2.0 Unit #1 Turbine Runner

Both runners on Unit #1 and Unit #2 are stainless steel cast construction. The inspection found several areas where erosion and cavitation have exposed faults in the stainless steel casting, possibly porosity during the casting process. This was concentrated near the root of the blades and the top band. The rest of the runner was in good condition with little evidence of erosion or cavitation.

Some of the wicket gates were repaired in the late 1980's using a Belzona plastic-metal product. For the most part this Belzona product has eroded away and separated from the gate leaving large crevasses exposed.

The general condition of the scroll case is good. During the inspection of this unit in 1998 a three foot long section of 2"x1/4" angle iron was found wedged in the scroll case. There was no damage to the wicket gates or turbine runner as the piece did not protrude out past the stay vanes. The surge tank and penstock inspections did not give any hard evidence as to the origin of the angle iron. No other pieces were found in the tank, pipeline or, the intake.

3.0 Unit #2 Turbine Runner

The runner has several areas where erosion and cavitation has exposed faults in the stainless steel casting. This erosion is concentrated near the root of the blading. There is evidence of hair line fractures tracking between the faulted areas. The wicket gates were repaired in the late 1980s with Belzona. This material has since eroded leaving large crevasses in the wicket gate body. The general condition of the scroll case is good. The draft tube door on Unit #2 is not sealing properly and will require some work.

Photo 1 – Shows localized cavitation and erosion of the turbine runner blades.

4.0 Unit #1 Main Inlet Valve

The valve body is in good condition. The disk seat has a small chip removed from the brass in the lap joint approximately 1/8” long, but otherwise the seal is in good shape. The stationary seat also looks to be in good condition.

Existing flexible pipe is to be replaced with new so that all piping will have generally the same life span.

5.0 Unit #2 Main Inlet Valve

The main valve disk seat is in fair condition with one area approximately 3/4” long x 1/2” wide where pitting is evident. The visual inspection showed that the disk and the stationary seat are in good condition.

Both valves do however leak around the disc edge on the butterfly valve. During our last internal inspection of the scroll casing the employees had to install a tarp downstream of the main inlet valve to cut down on the amount of water spray coming from around the circumference of the valve disc. It is recommended that the existing adjustable seats on the valves be adjusted to try and eliminate the leakage around the valve disc; if this is not successful the valves may require new valve seats on the disc and the stationary components.

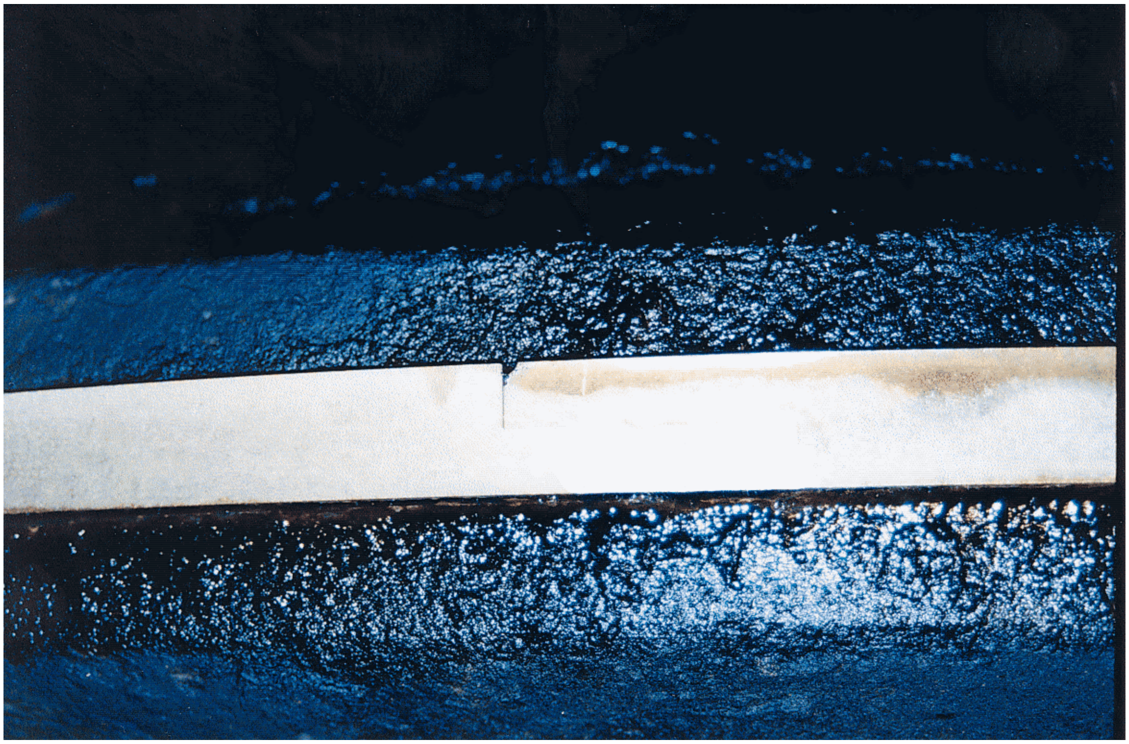


Photo 2 – Shows a chipped and cracked area on the main inlet valve disc seat.

The 5-way valves that control the opening and closing of the main inlet valves have been experiencing operational problems. These 5-way valves should be replaced. The existing flexible pipe is to be replaced with new so that all piping will have generally the same life span.

6.0 Unit #2 Alignment

In December 2002 Voith Siemens Hydro Power Generation rewound Rattling Brook Unit #2 stator and performed a realignment of the turbine-generator unit. Voith Siemens found that a proper alignment of the machine would require a lateral move of the stator which Newfoundland Power was not prepared to undertake at that time. It is thought that this out-of-alignment problem in the stator may be due to some subsidence in the concrete foundations of either the machine or the building. During this project, the stator will be moved so that proper alignment can be accomplished.

7.0 Unit #1 & #2 Gate Shaft Governor & Pumping Units

The governors and control linkages were inspected for worn bushings and lost motion. In general these two gate shaft governors were found to be in reasonable condition. There is some movement in the operating ring, tower and guide blocks on both units. There is also some movement in the governor operating arm as well as in the cross head on Unit #2.

The pumping units are in relatively good condition, with no major oil leaks. However, the packings leak and should be replaced. The units still maintain proper operating pressure and accumulator air volume.

These governors are a key component in regulating the speed of the generators and the quality of the power delivered by the plant. Due to the fact that they are 46 years old and difficult to maintain due to availability of spare parts and due to the fact that there is unnecessary movement in regular operating components as noted above, it is recommended that the hydraulic control head on each unit be replaced with an electro-hydraulic control head.

Unit #1 Governor Control
And Wicket Gate Actuator

Unit #1 Oil Accumulator
And Governor Oil Pump

8.0 Unit #1 & #2 Bearing Cooling Water Systems

The units at Rattling Brook have been suffering from higher than normal bearing temperatures which are attributed to the use of the Hydrosafe oil that is breaking down and is leaving 'gluey' deposits on the bearing cooling coils. The bearing cooling water system piping is suffering from frequent plugging of the piping. These piping systems should be replaced along with appropriate shutdown solenoids and flow meters. The 1958 vintage twinned strainer for both units is leaking around the operating shaft stems and is in need of repair. The existing strainer was initially designed to supply water to the two units' obsolete fire suppression system that is no longer in use. Currently the system is only required to supply cooling water to the bearings and the eductor pump, thus a large twinned strainer is no longer required. The current arrangement has caused problems in that both units have to be shut down in the event that the strainer needs maintenance. This system should be changed to a more conventional duplex filter element system installed on each unit with its own take off supply.

9.0 Plant Heating & Ventilation

The generator cooling air intake dampers located overhead on the tailrace wall are in a state of disrepair and need to be replaced. The seals in the positioners for the operable dampers also need to be replaced. There is also a large amount of non-friable asbestos panelling located adjacent to these operable dampers, which should be removed during this project. Finally, some new grating and framing is required in this area to improve the safety of employees on the walkway, which runs along these operable dampers.

10.0 Unit Instrumentation

The instrumentation on Unit #2 was upgraded in 2002 during the rewinding of the generator stator by Voith Siemens. The instrumentation on Unit #1, however, was not upgraded and thus needs to be done. Unit #1 needs the following instrumentation upgrades:

1. New bearing oil level sensors
2. New bearing cooling water flow meters and switches
3. New bearing cooling water shut-off solenoid valves
4. Speed pickup for creep control and unit speed telemetry

11.0 Balance of Plant Auxiliaries

The existing plant air compressor is 46 years old and in fair condition and should be replaced as part of the plant overhaul.

The eductor pump in the sump pit has been failing and causing pit flooding. The building's pit eductor, piping and level switch in the sump pit should be replaced.

The building's intake louver cylinder and operator both need a new seal kit to be installed.

12.0 Conclusion

The following is a list of the major recommendations that should be addressed during the refurbishment of the generating station:

1. The runners should be removed for a detailed inspection. Weld repair cast runners based on results of inspection. This weld repair procedure will have to be performed by a contractor with experience in weld repairing cast stainless steel turbine runners.

2. It is recommended that the existing adjustable seats on the main inlet valves be adjusted to try and eliminate the leakage around the valve disc. If this is not successful the valves may require new valve seats on the disc and the stationary components.

3. The 5-way valves that control the opening and closing of the main inlet valves have been experiencing operational problems. These 5-way valves should be replaced.

4. Perform detailed inspection on the wicket gates. If the inspection indicates that a repair is not feasible; the wicket gates, wicket gate bushings and stationary seals on both units should be replaced.

5. It is recommended that Unit #2 stator be moved so that proper alignment can be accomplished.

6. It is recommended that the hydraulic control head on each of the Woodward gate shaft governor units replaced with a newer electro-hydraulic control head.

7. The bearing cooling water system piping is suffering from frequent plugging of the piping and all of these piping systems should be replaced. The use of one large twinned strainer unit for both units has caused problems in that both units have to be shutdown in the event that the strainer needs maintenance. This system should be changed to a more conventional duplex filter element system installed on each unit.

8. All cooling water piping and cooling coils to be inspected tested and replaced if necessary during the overhaul.

9. The operable intake dampers need to be replaced and new motor operators installed. The control for the plant heating and ventilation should be incorporated into the PLC logic control for the plant. There is some replacement required to the catwalk system along the operable dampers and some non-friable asbestos to be removed.

10. Unit #1 needs the following instrumentation upgrades:
    - New bearing oil level sensors/switches, one per bearing oil pot
    - New bearing cooling water flow meters and switches
    - New bearing cooling water shut-off solenoid valves
    - Speed pickup for creep control and unit speed telemetry
    - Bearing thermocouples or resistance temperature devices (two per bearing)
    - Vibration monitoring one per bearing
    - The existing stator resistance temperature devices should be fed into the new PLC based control system along with the bearing instrumentation for mechanical protection.

11. The eductor pump, piping and level switch in the sump pit should be replaced.

Appendix D

Feasibility Analysis

Feasibility Analysis

June 22, 2004

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1.0 Introduction

The Rattling Brook hydroelectric development is located in the community of Norris Arm, in central Newfoundland. The generating plant at Rattling Brook was commissioned in 1958 and consists of two vertical Francis units, each with a maximum capacity of about 7500 KVA.

Newfoundland Power's continued long-term operation of the Rattling Brook hydroelectric development is dependent on the completion of capital improvement initiatives for major components within the system. As a result, various refurbishment projects are planned for the 2006 and 2007 construction seasons.

Several major components of the development are in need of replacement or refurbishment, including the woodstave penstock, surge tank, governors, generator controls/protection, and main valves. With substantial investment required in the near-term to permit the continued reliable operation of this plant, an economic analysis of this development over a 25-year horizon is warranted. A summary of the costs, benefits, and associated financial analysis is summarized in this report.

2.0 Capital Costs

All significant capital expenditures foreseen for the hydroelectric development over the next 25 years have been identified. The majority of these expenditures ($11,402,000) are currently planned for 2005, 2006 and 2007, and the remaining ($200,000) expenditures are planned for 2015. The capital expenditures required to maintain the safe and reliable operation of the facilities are summarized below.

Hydroelectric Development Capital Expenditures	
Year	**Cost**
2005	350,000
2006	5,643,000
2007	5,409,000
2015	200,000
Total	11,602,000

The total capital expenditure of all of the projects listed above is $11,602,000 (in 2005 dollar values). A more comprehensive breakdown of capital costs is provided in Schedule "A".

3.0 Operating Costs

Operating cost for this hydroelectric system is estimated to be in the order of $236,000 per year. This estimate is based primarily upon recent years' operating experience. The operating cost represents both direct charges for operations and maintenance at this plant as well as indirect costs related to activities associated with managing the environment, safety, dam safety inspections, staff training, etc.

The annual operating cost also includes a water power rental rate of $0.80 per MWh. This fee is paid annually to the Provincial Department of Environment and Conservation (Water Resources Management Division) based on yearly hydro plant generation/output. Such a charge is not reflected in the historical annual operating costs for the Rattling Brook development. Therefore, an adjustment is applied to account for the associated increased operating expenses on a go-forward basis.

Penstock and surge tank maintenance has accounted for a portion of the operating costs of this plant in recent years. Future operating cost has been estimated to include an assumed reduction of $10,000 per year to reflect the penstock and surge tank rehabilitation initiatives.

4.0 Benefits

The estimated long-term normal production at this plant under present operating conditions is 69.4 GWh/yr. This estimate is based on the results of the Water Management Study completed by Acres International Limited December 2000 adjusted for actual average production and practical operations.

Some of the capital improvement projects will result in decreased energy losses, and subsequent increases in capacity and generation. In particular, it is anticipated that a newly constructed 9.5 ft diameter steel penstock will significantly reduce headloss, eliminate penstock leakage and reduce water spillage. The annual energy generation is expected to increase by about 10% (7 GWh) per year at Rattling Brook.

The downtime associated with the 2006 and 2007 capital works at this plant will result in a higher amount of spill at the forebay compared to a normal operating year. It is anticipated that the potential lost generation may be in the order of 15 GWh/yr. Therefore, the analysis assumed production at Rattling Brook of 54 GWh in 2006 and 2007, and 76 GWh/yr thereafter.

5.0 Financial Analysis

An overall financial analysis of combined costs and benefits has been completed using the levelized cost of energy approach. The levelized cost of energy is representative of the revenue requirement required to support the combined capital and operating costs associated with the development.

The estimated levelized cost of energy from the Rattling Brook plant over the next 25 years is 1.7 cents per kWh. This figure includes all projected capital and operating costs necessary to operate and maintain the facility. Energy from Rattling Brook can be produced at a significantly lower price than the cost of replacement energy, assumed to come from Newfoundland Hydro's Holyrood Generating Station. Based on information provided in Newfoundland Hydro's 2003 GRA, incremental energy is estimated to cost 4.6 cents per kWh in the short term (assuming $28.95 per barrel, and 630 kWh/barrel), with an associated levelized cost of 5.8 cents per kWh assuming a 2% long-term escalation rate.

The future capacity benefits of the continued availability of Rattling Brook hydro plant have not been considered in this analysis. If factored into future feasibility analysis, the financial benefit associated with system capacity would further support the viability of continued plant operations.

6.0 Recommendation

Newfoundland Power should proceed with this project in 2005 as planned. The project is will benefit the Company and its customers through improvement from the current situation in safety, environmental stewardship and reliability.

The results of this feasibility analysis show that that the continued operation of the Rattling Brook hydroelectric development is economically viable over the long term. Investing in the life extension of facilities at Rattling Brook guarantees the availability of low cost energy to the Province. Otherwise the annual production of nearly 69.4 GWh would be replaced by more expensive energy sources such as new generation or additional production from the Holyrood thermal generating station.

Schedule A
Summary of Capital Costs

Rattling Brook Feasibility Analysis Summary of Capital Costs	
Description	**Cost (2005)**
Civil	
Civil Engineering (2005)	$ 150,000
Penstock Replacement – Phase 1 (2006)	3,940,000
Penstock Replacement – Phase 2 (2007)	3,840,000
Refurbish Surge Tank (2007)	892,000
Amy's Control Structure Rehab (2007)	30,000
Amy's Dam Slope Improvements (2015)	100,000
Rattling Spillway Rehabilitation (2015)	100,000
Subtotal Civil	**$9,052,000**
Mech/Elec	
Refurbish Plant Engineering (2005)	$ 200,000
Unit 1 Refurbishment (2006)	851,000
Unit 1 Refurbishment (2007)	230,000
Unit 2 Refurbishment (2006)	852,000
Unit 2 Refurbishment (2007)	375,000
Forebay Water Level Control (2007)	42,000
Subtotal Mech/Elec	**2,550,000**
Total	**$11,602,000**

Schedule B
Summary of Operating Costs

Rattling Brook Feasibility Analysis
Summary of Operating Costs

Annual Operating Costs (actuals)

Year	Amount
1999	$158,963
2000	$149,301
2001	$237,556
2002	$172,364
2003	$232,081
Average	$190,053

5-year Average Operating Cost =	**$190,053**	
Water Use Charges = **($0.80/MWh * 70,000 MWh/yr)**	**$56,000**	
Reduced Future Penstock Maintenance =	**$10,000**	(-ve)
Total Annual Operating Cost = **(forecasted)**	**$236,053**	

Project Title: **Rebuild Substations**

Location: **Greenspond, Grand Beach, Topsail and St. John's Main**

Classification: **Substations**

Project Cost: **$351,000**

This project consists of a number of items as noted.

(a) Enclose Switchgear Buildings at St. John's Main Substation

Cost: $251,000

Description: At St. John's Main substation there are three sections of 15kV metalclad switchgear housing a total of 17 air circuit breakers. This project involves the construction of two buildings around the switchgear to enclose and protect them from the weather.

Operating Experience: The existing weather enclosures for the three sections of switchgear are in advanced stages of deterioration. Deterioration is such that the roofs of the existing buildings are leaking and there is rusting of the metalclad weather enclosures and switchgear support frame to the extent that the buildings are no longer weatherproof. Corrective action needs to be taken to stop further deterioration (see attached pictures).

St. John's Main Substation
Deteriorated Metal Clad Switchgear
Picture #1

St. John's Main Substation
Deteriorated Metal Clad Switchgear
Picture #2

St. John's Main Substation
Deteriorated Metal Clad Switchgear
Picture #3

Justification: The overall project is justified based on employee safety and maintaining the reliability of the electrical system.

(b) Projects < $50,000

Cost: $100,000

The following is a list of projects estimated at less than $50,000.

1. Greenspond – replace feeder by-pass switch
2. Grand Beach – replace substation fence
3. Topsail – replace transformer foundation
4. Stephenville – install personnel gates

Project Title: **Replacement & Standby Substation Equipment**

Location: **Various Substations including Rocky Pond, Hardwoods, Twillingate, and Garnish**

Classification: **Substations**

Project Cost: **$1,052,000**

This project consists of a number of items as noted.

(a) Deteriorated Breaker/Recloser Replacement

Cost: $81,000

Description: This project is part of an ongoing program to replace circuit breakers and reclosers that are deteriorated beyond economical repair.

In 2005 the 6.9 kV breaker at Rocky Pond will be replaced.

Operating Experience: The Rocky Pond unit is 27 years old. The arc extinguishing mechanisms has deteriorated and the manufacturer has informed us that parts are no longer available. Failure of these parts will limit the ability of the breaker to extinguish the arc produced during a fault. This can ultimately lead to catastrophic failure.

Justification: This project is justified based on the need to replace equipment to maintain reliable and safe operation of the electrical system.

(b) Underrated Interrupting Capacity Breaker Replacement

Cost: $79,000

Description: This project replaces circuit breakers that have a fault current interrupting less than the fault current levels present at a substation.

In 2005, the 25 kV breaker serving Hardwoods – 04 distribution feeder will be replaced.

Operating Experience: At Hardwoods Substation the substation fault level is approximately 16 KA, which exceeds the maximum fault interrupting capacity of HWD-04 feeder breaker which has a fault interruption capacity of 12.5 KA.

Justification: This project is justified based on the fact that equipment ratings have been exceeded. This could result in failure of the equipment and compromise safety, reliability and the environment.

(c) Corporate Spares & Replacements

Cost: $850,000

Description: Purchase equipment to be used for corporate spares.

For 2005, the budgeted figure includes:

1 – 15/25 kV Circuit Breaker
1 – 25 kV Electronic Recloser
3 – 138 kV Potential Transformers
3 – 66 kV Potential Transformers
6 – 15/25 kV 100 amp Voltage Regulators
9 – 15/25 kV 200 amp Voltage Regulators
10 – Universal Regulator Controls and Enclosures
1 – 15/25 kV 300 amp Voltage Regulator
2 – 48 Volt Battery Banks
3 – 120 Volt Battery Bank
2 – 48 Volt Battery Chargers
3 – 120 Volt Battery Chargers
6 – Transformer – on Load Tap Changers

This equipment is required to either replace equipment that fails in the field or to return corporate spares to appropriate levels.

Operating Experience: Every year the Company retires equipment due to vandalism, storm damage, lightning strikes, electrical or mechanical failure, corrosion damage, technical obsolescence, failure during maintenance testing, etc. This equipment is essential to the integrity and reliability of the electrical supply to our customers and as such, the Company has to be able to replace equipment that has failed, in a timely manner. Based on past operating experience, the above list is representative of what will need to be replaced in a typical year.

Justification: This project is justified on the basis that this equipment is necessary to maintain service in a reliable, safe, environmentally sound manner. The following provides details on the major components to be acquired in 2005.

Circuit Breakers:

Newfoundland Power has approximately 400 circuit breakers in service. Breakers are used to switch transmission lines, transformers, feeders, generators and other equipment on and off the electrical system. In conjunction with protective relaying, they are used to isolate electrical faults. The majority of breakers are either transmission breakers (138 or 66 kV) or distribution breakers (typically 15 or 25 kV). The remainder are required in generation stations. The older breakers are often oil-filled and represent an environmental risk. By the nature of their operation, breakers will deteriorate and even though they are maintained, unexpected failures can occur.

Based on past experience, the Company maintains a pool of spare breakers to respond to these failures. This pool normally contains one 138 kV, two 66 kV and two 25 kV breakers. The 25 kV units can be installed in either 15 or 25 kV installations, thereby reducing the number of spares required. The budget is based upon past experience and existing quantities in the pool.

Electronic Reclosers:

The Company has approximately 200 reclosers in service. Reclosers allow switching of rural feeders, which carry lighter loads and have smaller electrical fault levels than urban feeders. They have built-in control units that sense electrical faults and operate the recloser to de-energize the feeder in the event of a fault.

The Company's older reclosers can be divided into four basic types – hydraulic, relay, resistor, and electronic, depending upon controller. The ability to isolate an electrical fault and functionality increases in the order they are listed above. Therefore, as the electrical system has evolved, the units with lower functionality have fewer places where they can be installed.

Reclosers are replaced due to failure; deterioration; and, obsolescence. In order to respond to these situations, the Company maintains a pool of spare reclosers. The budget is based upon past experience and existing quantities in the pool. The purchased unit will be an oil free, low maintenance and digitally controlled so that it is capable of replacing any other recloser.

Potential Transformers (PTs):

The Company has approximately 220 PTs in-service. They measure voltage levels for input to protective relays, the SCADA system and metering circuitry. Failure of this equipment compromises the reliable operation of the electrical system. A failure can endanger staff and require clean up of oil. Each year unexpected PT replacements are required due to in-service failures. Based upon past experience and existing quantities in the pool, the budget includes purchases to allow for response to operational situations. Normally new units will be a *dry-type* design, eliminating the environmental risk associated with the older oil-filled units.

Voltage Regulators:

The Company has approximately 340 voltage regulators in service. These regulators are used to control voltages on rural feeders.

The regulators are replaced due to failure or deterioration. The budget is based upon past experience and existing quantities in the pool. The replacements will maintain the pool of spare voltage regulators at a level sufficient to respond to operational situations and maintenance programs. The new units can operate at 15 or 25 kV, allowing a reduction in the size of the pool. They also have stainless steel cases to reduce future corrosion related failures.

Direct Current Electrical Supply Systems (Batteries and Battery Chargers):

The substation direct current (DC) power supplies provide electricity for protective relays, circuit breakers, reclosers and emergency substation lighting.

The use of advanced battery testing methods has allowed the Company to adopt an approach whereby battery banks are replaced only when problems to a majority of batteries in the bank occur. Based upon past experience, the budget includes an allocation to replace battery banks as required.

Battery chargers are low maintenance, long life devices. The Company maintains a pool of units to allow prompt replacement of failed units to ensure the security of its DC electrical supplies. The units in the budget will allow for unexpected failures of battery chargers.

(d) Recording Voltmeter Replacement

Cost: $42,000

Description: This project involves the replacement of broken recording voltmeters at Twillingate and Garnish.

Operating Experience: The existing recording voltmeter has deteriorated beyond repair.

Justification: The recording voltmeters are required to properly manage the power system and to address voltage quality concerns.

Project Title: **Rebuild Transmission Lines**

Location: **Various**

Classification: **Transmission**

Project Cost: **$2,597,000**

This project consists of a number of items as noted.

(a) Rebuild 11L (Tors Cove – Mobile)

Cost: $343,000

Description: This project consists of the replacement of deteriorated poles, hardware and conductor on 5.0 km of 11L.

Operating Experience: 11L is a 66 kV line that was built in 1942. It provides a tie between the Tors Cove hydro plant and the main electrical grid. In 2000, $9,000 was spent and in 2002 $15,000 was spent correcting deficiencies identified during regular inspections.

Justification: Inspections have determined that there is significant deterioration of the poles, crossarms and other hardware on the 5.0 km line. Upgrading of this line is necessary to ensure continuity of service to customers in the area as well as provide the Tors Cove hydro plant with a safe and secure connection to the main grid.

(b) Rebuild 43L (Hearts Content – New Chelsea)

Cost: $707,000

Description: This project consists of the replacement of deteriorated poles, hardware and conductor on an 8.0 km section of 43L.

Operating Experience: 43L is a 66 kV line that was built in 1956. It is a 25.1 km radial line servicing in excess of 2,500 customers in the New Chelsea – Old Perlican area of the Bay de Verde peninsula. It also provides a tie between the New Chelsea hydro plant and the main electrical grid. In 2001, 2002 and 2003, $85,000, $6,000 and $7,000 respectively was spent correcting deficiencies identified during normal inspection.

Justification: Inspections have determined that there is significant deterioration of the poles, crossarms and other hardware on 43L. Upgrading of this section of line is necessary to ensure continuity of service to customers in the New Chelsea – Old Perlican area as well as to provide the New Chelsea hydro plant with a secure connection to the main grid. It is anticipated that the remaining 17 km of line will be rebuilt during 2006 and 2007.

(c) Rebuild 124L (Clarenville – Gambo)

Cost: $500,000

Description: This project consists of rebuilding a 5.0 km section of 124L to establish and maintain adequate ground clearance.

Operating Experience: 124L is a 138 kV line that was built in 1964. The line which runs from Clarenville to Gambo has a total length of 90 km. It is a loop line; however, it directly serves in excess of 2,700 customers in the Port Blandford, Glovertown and Eastport areas. It was constructed using a wind/ice loading criteria that is lower than today's standard. Inspections and surveys during the past few years have identified sections where the conductor has stretched and sagged to unacceptable levels due to past severe ice loading in the area.

In 2001 and 2003, a 5.2 km section and a 5.5 km section were rebuilt at a cost of $323,000 and $424,000 respectively.

During the winter of 2003, an older section of line experienced crossarm failure during a period of ice accumulation. This resulted in conductors falling to the ground, causing a lengthy outage.

Justification: Inspections have identified a number of locations where adequate ground clearance cannot be maintained during ice/wind conditions. Rebuilding a 5.0 km section will address a number of these locations.

It is anticipated that the remaining locations will be addressed through rebuilding a 6.4 km section in 2006.

(d) Projects < $50,000

Cost: $1,047,000

Description: There are approximately 50 other lines that require replacement of deteriorated items.

Operating Experience: Annual inspections have identified deteriorated items that need to be replaced.

Justification: This project is necessary to replace poles, crossarms, conductors, insulators and miscellaneous hardware due to deficiencies identified during annual inspections in order to ensure that such lines provide safe and reliable service to customers.

Project Title: **Distribution Reliability Initiative**

Location: **Lumsden/Cape Freels (WES-02), Carmanville/Gander Bay (GBY-02)**

Classification: **Distribution**

Project Cost: **$872,000**

This project consists of a number of items as noted.

(a) Lumsden/Cape Freels (WES-02)

Cost: $407,000

Description: This project involves the replacement of poles, conductor and hardware on various sections of WES-02. This is a 2-year project at a total cost of $1,099,000 of which $692,000 was spent in 2004.

Operating Experience: The reliability of this feeder is below the company average. See 2004 Capital Budget Application, *"A Review of Reliability Wesleyville-02 Feeder",* Volume III, Distribution, Appendix 3, Attachment A.

Justification: This project is justified on the basis of reliability improvements.

(b) Carmanville/Gander Bay (GBY-02)

Cost: $465,000

Description: This project involves the replacement of poles, conductor and hardware on various sections of GBY-02. This is a 2-year project at a total cost of $863,000, consequently $398,000 will be required in 2006.

Operating Experience: The reliability of this feeder is below the Company average. See *"A Review of Reliability – Gander Bay-02Feeder*", Distribution, Appendix 1, Attachment A.

Justification: This project is justified on the basis of reliability improvements.

A Review of Reliability
Gander Bay-02 Feeder

June 18, 2004

Written by: Mick Ellsworth
Approved by: Peter Feehan, P. Eng

NEWFOUNDLAND POWER
A FORTIS COMPANY

Table of Contents

1.0 Executive Summary

The purpose of this report is to recommend measures to improve reliability on the Gander Bay-02 feeder ("GBY-02"), which has exhibited poor reliability performance. The feeder was examined in sections with a detailed look at the causes of outages and the components that failed. This was combined with field knowledge of the feeders to produce recommended actions to improve reliability.

GBY-02 originates at Gander Bay Substation in Gander Bay. It has been prone to failure, mainly due to the condition of its primary conductor (#2 ACSR) and the failure of insulators. Outages have been extended due to the inaccessibility of some sections of the line. Along this section of the north east coast, the feeder is exposed to high winds, salt spray, ice loading, and lightning strikes. Upgrading the feeder is recommended, at a cost of approximately $863,000.

This project will have a positive effect on the reliability performance of this feeder, resulting in fewer outages to customers and lower operating costs. Due to the cost and resources required for the project, it is recommended that the work be completed over two years.

2.0 Introduction

This report recommends a plan to improve the reliability of GBY-02. This report contains information on the reliability performance and on how this feeder compares with other Newfoundland Power feeders. Also included is information about the outage history and the major causes and trouble areas. Recommendations are based on costs and the suitability of the options considered.

3.0 Distribution Reliability

A Newfoundland Power report titled "2004 Corporate Distribution Reliability Review" identified feeders that have exhibited consistently poor reliability. The report examined such items as the average annual total number of customer minutes of interruption, System Average Interruption Frequency Index (SAIFI), and the System Average Interruption Duration Index (SAIDI). The report concluded that GBY-02 was amongst the poorest reliability performers and should have work completed to improve its performance.

For the period 1999 to 2003, SAIFI was 3.45 and SAIDI was 8.18 hours. The Company average for the same period for SAIFI was 1.56 and for SAIDI was 2.30 hours.

4.0 GBY-02 Feeder

Located in the Gander operating area of the Western Region, GBY-02 feeder is a 25 kV line that originates at the Gander Bay Substation located in the community of Gander Bay and serves approximately 886 customers. The three-phase portion of this line extends from Gander Bay to

Carmanville, passing through the communities of Harris Point, Main Point and Davidsville. Taps from Carmanville also service the communities of Noggin Cove and Frederickton.

This line was originally constructed in 1965. The majority of this feeder is conductored with #2 ACSR (Aluminium Conductor Steel Reinforced). However, 3.5 kilometres has been reconductored with 4/0 AASC (Aluminium Alloy Stranded Conductor). Many of the original spans were quite long. However, approximately 18 out of 20 kilometres have been mid-spanned to reduce span lengths. Highway upgrading and rerouting have caused several sections of this feeder to become remote from the main road and, consequently, difficult to maintain.

The entire feeder is in an exposed area and is subject to salt contamination, very high winds, ice loading and lightning strikes.

A feeder inspection was completed in early 2004. The inspection revealed a number of items that need to be addressed. These include:

- Two Piece Insulators
- CP 8080 Deadend Insulators
- Porcelain Cutouts
- Lightning Arrestors
- Grounding and guying issues that could impact on employee and public safety
- Deteriorated Crossarms. These involve cracks developing in crossarms, rotting arms, woodpecker holes, etc.
- Conductor conditions such as broken strands, burn marks, etc.

5.0 Outage History for Feeder

The feeder is located 50 kilometres from Newfoundland Power's Gander Service Centre. Sections of the highway in this area are subject to heavy drifting, sometimes making the roads impassable for long periods of time. This can sometimes impact outage durations.

Sections of the main trunk of the feeder are located up to 1 kilometre off the new road right-of-way, making damage difficult to find and repair during winter storms. Another 3-kilometre section now crosses from Davidsville along the old highway, which is no longer maintained. These sections must be accessed by ATVs in the summer months. All sections located along the old road must be accessed by snowmobile during the winter months.

The bulk of the main trunk of the feeder is conductored with the original #2 ACSR. This conductor has poor operating characteristics in a salt spray environment. Over time, the outer aluminium strands break, leaving the steel core to carry the load. As the load increases, the steel core melts, breaking the conductor. Broken conductor has accounted for 38% of all distribution caused outages to the feeder. An inspection of the feeder conducted in 2004 noted several locations where the conductor is frayed.

As most of the main trunk of the feeder has been mid-spanned, the insulators on the newer structures are in good shape and have not caused outages. The remaining insulators on the original poles have been prone to failure. Outages due to insulator failure account for 21.5% of all distribution caused outages to the feeder.

5.1 GBY-02 Feeder by Component that Failed

Table 1 below shows a summary of the 115 problem calls received from 1999 to 2003, indicating which failed component caused the problem. In some occurrences, such as in sleet and windstorms, there are no components that failed. (Fuses and substation equipment that operate under these conditions are operating properly.)

Table 1

Problem Call Summary by Component
1999 – 2003

Component that Failed	Number of Outages	Customer Minutes
Conductor	10	821,472
Conductor Hardware	1	440
Fuses [1]	41	116,337
Insulators	7	461,446
Other	2	44,202
Control Equipment at Sub [2]	9	682,675
Pole Hardware	3	1,030
Transformers	5	5,386
Service Wires	27	3,485
Cutout / Switch	10	33,837
Total	**115**	**2,170,310**

[1] Fuses operated as a result of sleet, wind, and lightning.
[2] Includes operations for wind, trees in line etc. Equipment operated as it should.

5.2 GBY-02 Feeder by Cause

Table 2 below summarizes the 115 problem calls received for the time frame from 1999 to 2003. Problems are sorted using the "Cause" as its base.

Table 2

Problem Call Summary by Cause
1999 – 2003

Cause	Number of Outages	Customer Minutes
Salt Spray [1]	7	10,768
Wind	18	966,736
Lightning	7	2,962
Broken/Defective Equipment [2]	64	923,281
Damage Outside Party	4	208,180
Unexplained	6	33,733
Other	1	18,837
Overloaded Equipment	2	1,831
Animals	5	3,972
Fire	1	10
Total	115	2,170,310

[1] Although only seven outages were reported as salt spray, most of the outages reported as wind involved salt contamination also.
[2] Broken/Defective Equipment includes items such as insulators, conductor and hardware. In a windstorm, outages can occur due to trees on line, damage to conductor, etc.

6.0 Alternatives

Two alternatives are considered to improve reliability of the GBY-02 feeder. These alternatives are:

1. Install a New Substation at Carmanville.
2. Rebuild / Relocate GBY-02 Trunk Feeder

These alternatives are discussed in the following sections.

6.1 Install a New Substation at Carmanville

Since the mid-1970's, several studies have examined the viability of building Carmanville Substation. Transmission line 129L, which extends from Gander Bay to Carmanville, was built in 1979, and utilized as a feeder with the expectation that the increased load in the area would warrant the building of the substation shortly thereafter. When the expected load growth did not materialize, plans to build Carmanville Substation were shelved.

Studies since then have supported the continued deferral of Carmanville Substation, which was accomplished by various means. 129L has been utilized as a distribution feeder (GBY-03) relieving the load requirements on GBY-02. Gander Bay Substation has changed from the original two power transformer set up to a single transformer with an on-line tap changer. This added transformer capacity to the area while also improving voltage regulation.

Load forecasts for the next 20 years do not indicate an overload condition on the power transformer (Appendix A provides the 20-year load forecast for this area). Feeder model computer simulation using the 20-year forecast does not indicate any overload or under voltage condition on GBY-02. However, the installation of the new substation would eliminate the need to rebuild/relocate the 3.3 km section of line along the abandoned highway near Davidsville. This section would be retired and not replaced. The capital cost of a new substation installation and feeder work directly related to the substation installation is estimated at $1,834,900.

Although an already-constructed transmission line makes the Carmanville substation an option that ought to be looked at, building the new substation without upgrading the feeder will not address most of the reliability issues already identified. The alternative requires most of the same work on the feeder as the alternative described in Section 6.2, with the exception of the work on the 3.3 km section near Davidsville. Excluding the Davidsville section, the capital cost of correcting the identified feeder reliability issues is $585,844. The total cost of this alternative is therefore $2,420,744. Due to the considerable capital cost, this alternative is not recommended.

6.2 Rebuild / Relocate GBY-02 Trunk Feeder

The main trunk of this feeder was inspected to determine the cost of addressing deficiencies. This included access to the line, conductor replacement, insulator and pole replacements.

Relocating the main trunk of the feeder to the main road will shorten the time needed to patrol the line during feeder inspections and unscheduled outages. Currently, a feeder problem along the side of the abandoned road requires crews to return to Gander to obtain additional equipment. This increases the outage duration to customers.

Relocating the main trunk of the feeder to the road effectively places the distribution lines in the communities on side taps from the main feeder. Problems on these taps should not cause outages to other customers along the main trunk of the feeder. For example, under the existing situation, a problem on the primary in Harris Point results in a power interruption to 766 customers. If this occurred on a tap off the main trunk, the same problem would be isolated by a fused cutout and would only cause an outage to the customers in the community of Harris Point.

This alternative would also correct a majority of the deficiencies noted in the feeder inspection. The total cost for this alternative is estimated at $862,695.

Rebuilding / relocating the feeder using new 4/0 AASC primary conductor directly addresses the known problems and will have an immediate positive effect on the reliability of supply to our customers.

Details on each problem area follow in Section 7.

7.0 Detailed Review of Selected Alternative

The GBY-02 feeder was reviewed for location characteristics (i.e. subject to extreme salt spray conditions, ice loading etc.). Each section of the feeder was then analyzed to see if specific causes could be determined and appropriate solutions recommended.

7.1 All Sections of GBY-02 Feeder

1. Replace all 8080 and 2-piece insulators.

2. Correct all deficiencies identified in the inspection of the feeder conducted in 2004.

7.2 Gander Bay Substation to Harris Point (0.6 km)

This section of the main trunk of the feeder is conductored using #2 ACSR. It is located along Route 330 through Georges Point. This section will be reconductored using 4/0 AASC primary and a 1/0 AASC neutral. Deficiencies identified in the feeder inspection conducted in 2004 would be corrected.

Appendix B is a map of the area. Total estimated cost for this work is $15,251.

7.3 Harris Point (1.8 km)

This section of the main feeder trunk is located away from Route 330 through the community of Harris Point. Relocating the main trunk to the highway would improve the overall condition of the main trunk while making patrol of the line easier. As noted above, placing Harris Point on a tap off the feeder will lessen the possibility of a problem in the community causing an outage on the remainder of the feeder. All new construction will use 4/0 AASC for the primary and 1/0 AASC for the neutral. The cost of the new construction is $75,195. The cost associated with correcting deficiencies identified in the feeder inspection conducted in 2004 for this section of line is estimated at $12,100.

Appendix C for a map of the area involved. The total estimated cost for completing all work required on this section is $87,295.

7.4 Harris Point to Old Road Intersection (1 km)

This portion of the feeder consists of 500 metres of new construction that is located away from the road and another 500 metres of reconstruction along Route 330. Plans include relocating all portions of the feeder to the road right-of-way and upgrading the conductor to current standards using 4/0 AASC primary and a 1/0 AASC neutral. Moving the feeder to the right-of-way of Route 330 aids in the patrolling and inspection of the line, and also moves the line to a less wooded area. Deficiencies identified in the feeder inspection conducted in 2004 would be corrected.

Appendix D is a map of the area. The total estimated cost of this work is $30,843.

7.5 Old Road Section (3.1 km)

This portion of the feeder consists of 3.3 kilometres of existing construction that is located along the old road. One half of the poles and insulators would have to be replaced in this section if the feeder was rebuilt in the existing location. All existing conductor here is #2 ACSR. This section must be accessed by ATVs in the summer months and snowmobiles during the winter months.

Relocating this section to the right-of-way of the new Route 330 would require 3.1 kilometres of new construction. Deficiencies identified in the feeder inspection conducted in 2004 would be eliminated by the retirement of the old line.

Appendix E is a map of the area. The total cost to rebuild this section is estimated at $128,606.

7.6 Davidsville Section (4.1 km)

This portion of the existing feeder consists of 3.5 kilometres of line through the communities of Main Point and Davidsville and an additional 3.3 kilometres of line along the abandoned old highway. The existing conductor is #2 ACSR and 50% of the existing structures are original. This section must be accessed by ATVs in the summer months and snowmobiles during the winter months.

The new construction would see 4.1 kilometres of new line built along Route 330, making Main Point and Davidsville a tap off the main trunk of the feeder. The 3.3 kilometres along the abandoned highway would be removed. All new conductors would be 4/0 AASC primary and 1/0 AASC neutral. The cost estimate for this relocation / reconfiguration is $276,851.

Relocating this section to the right-of-way of the new Route 330 will eliminate the need to correct deficiencies identified in the feeder inspection conducted in 2004 on the section of feeder along the abandoned road. The cost of correcting deficiencies on the 3.5 kilometres of line through the communities of Davidsville and Main Point is estimated at $42,270.

In changing the configuration of the feeder, other customers on the feeder would be isolated from the impact of problems originating in the communities of Main Point and Davidsville. The two communities would now be on a tap that would be protected by a fuse. In the event of a problem on the tap, the fuse would operate, isolating the problem from the remainder of the feeder.

Appendix F is a map of the area. The total cost to relocate this section of line and correct deficiencies identified in the feeder inspection conducted in 2004 is estimated at $319,121.

7.7 Structures along Route 330 (2.7 km)

This portion of the planned work consists of 2.7 kilometres of reconstruction along Route 330. Plans include replacing all existing #2 ACSR, re-insulating older structures, and correcting deficiencies identified in the feeder inspection conducted in 2004.

Appendix G is a map of the area. The total cost estimate for rebuilding this section of feeder is $31,703.

7.8 Carmanville (2.6 km)

Plans for this section include the rerouting of the main line out of the Town of Carmanville to the right-of-way of Route 330. The Town of Carmanville will be supplied from a tap off the main feeder and outages in the town will be isolated and will not affect other customers on the feeder. In addition, Carmanville would now be energized from two directions. This will further add flexibility in isolating faults and minimizing customer outages.

The cost to rebuild this section of feeder is estimated at $87,161. The cost of correcting deficiencies identified in the feeder inspection conducted in 2004 in the communities of Carmanville, Noggin Cove and Frederickton is $145,157.

Appendix H is a map of the area. The total cost to rebuild this section in the new location and correct the identified deficiencies is estimated at $232,318.

7.9 Carmanville to End of Feeder (1.2 km)

This portion of the planned work consists of 1.2 kilometres of reconstruction along Route 330. Plans include replacing all existing #2 ACSR, re-insulating older structures, and correcting deficiencies identified in the feeder inspection conducted in 2004.

Appendix I is a map of the area. The total cost estimate for rebuilding this section of feeder is $17,558.

7.10 Construction Cost

Gander Bay-02 Feeder Construction Cost	
Section	**Cost**
7.2: Gander Bay Substation to Harris Point (0.6 km)	$15,251
7.3: Harris Point (1.8 km)	87,295
7.4: Harris Point to Old Road Intersection (1 km)	30,843
7.5: Old Road Section (3.1 km)	128,606
7.6: Davidsville Section (4.1 km)	319,121
7.7: Structures along route 330 (2.7 km)	31,703
7.8: Carmanville (2.6 km)	232,318
7.9: Carmanville to end of feeder (1.2 km)	17,558
Total	**$862,695**

8.0 Conclusion

Outage data does not indicate that GBY-02 should be built using heavy loading construction. Seventy-seven per cent of all outages were directly related to conductor, conductor and pole hardware, trees in line, cutout failure and insulators. Rebuilding of the feeder will correct these problems. Relocating the feeder will shorten patrol times in responding to problem calls as well as help in the isolation of the problem area from the rest of the feeder.

Deficiencies identified in the feeder inspection conducted in 2004 should be corrected. These are known problems that could result in unscheduled outages or unsafe conditions to our customers and employees if not corrected.

There were two different options for improving the reliability of this feeder considered.
- Installing a new substation at Carmanville
- Rebuild / Relocate GBY-02 Trunk Feeder

The Rebuild / Relocate GBY-02 Trunk Feeder offered the best solution to the current problems on this feeder. The Rebuild / Relocate GBY-02 Feeder Project for the trunk feeder will result in a reduction in the number and duration of outages to customers along this feeder. By supplying communities along the feeder through taps from the main trunk, we will be minimizing the impact of a problem on one section of the feeder causing outages to all customers on the feeder.

Overall, the $862,695 investment to improve areas of the feeder with known problems will result in improved reliability for the customers. Due to the size and nature of the project, it is proposed to complete all the work over a two-year period. The work identified in Sections 7.5, 7.7, 7.8 and 7.9, along with the deficiencies identified in the feeder inspection conducted in 2004 noted in Sections 7.3 and 7.6, should be completed in 2005. The total cost of this work is estimated at \$464,555. The remaining work, estimated at \$398,140, should be completed in 2006.

Appendix A

Load Growth per Year
Forecasted Undiversified Peak

Appendix A

Load Growth per Year
Forecasted Undiversified Peak

Year	Growth	Load (Mva)
2003		7.30
2004	13.12%[1]	8.26
2005	0.76%	8.32
2006	0.56%	8.37
2007	1.97%	8.53
2008	1.82%	8.69
2009	0.73%	8.75
2010	0.75%	8.82
2011	0.77%	8.88
2012	0.79%	8.95
2013	0.81%	9.03
2014	0.82%	9.10
2015	0.84%	9.18
2016	0.86%	9.26
2017	0.88%	9.34
2018	0.90%	9.42
2019	0.91%	9.51
2020	0.93%	9.60
2021	0.95%	9.69
2022	0.97%	9.78
2023	0.99%	9.88
2024	1.00%	9.98

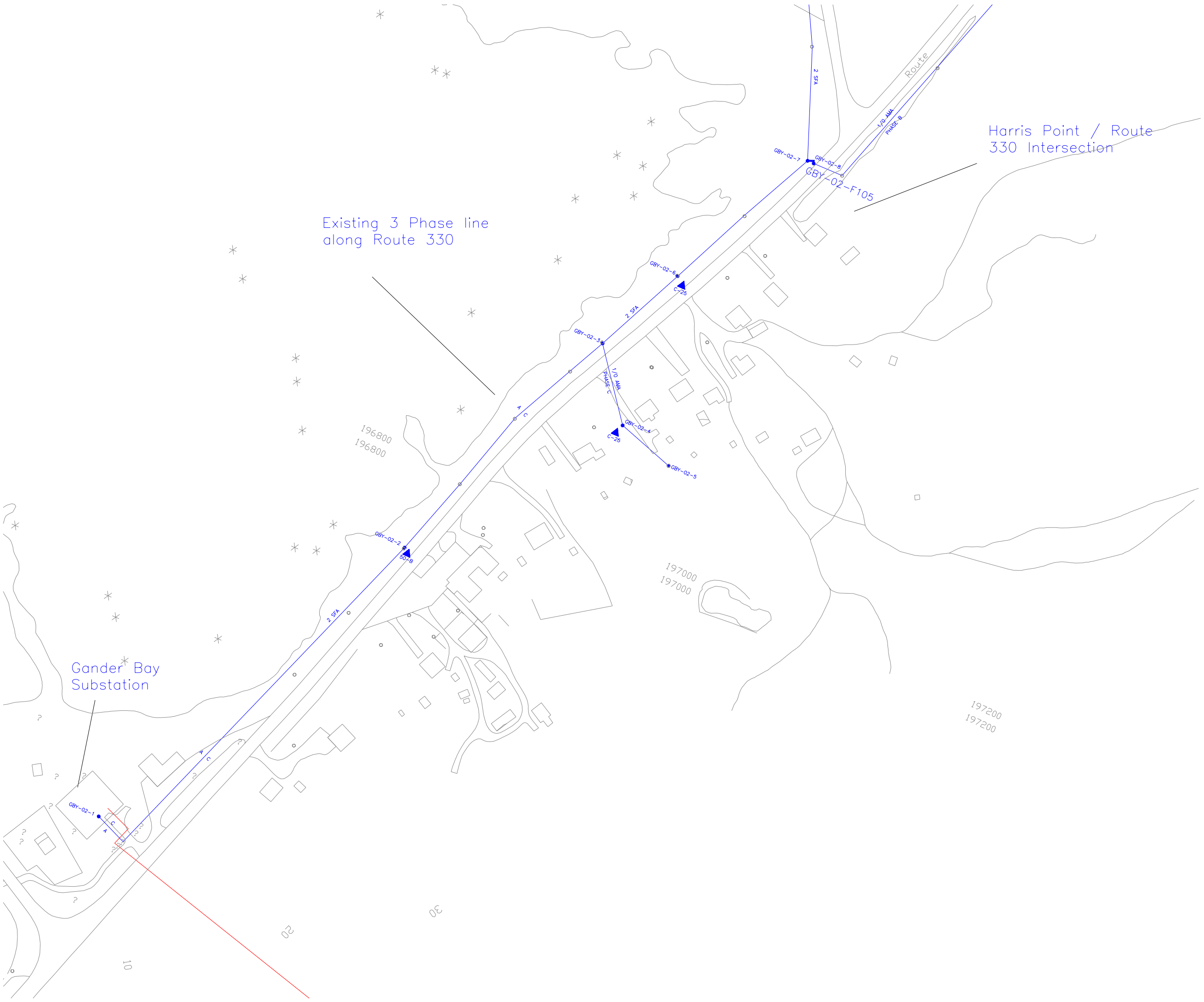
[1] The 13.12% growth in 2004 reflects both the normal load growth, similar in size to the subsequent years, and an allowance for a colder than normal peak. This allowance is based on one in ten year's worse case peak.

Source:
2003 – Actual
2004 to 2009 - 2004 5 year Substation Load Forecast
2010 to 2024 - Load growth in 2024 to be 1%. All other years prorated to this

Appendix B

Map Showing Gander Bay Substation to Harris Point (0.6 km)

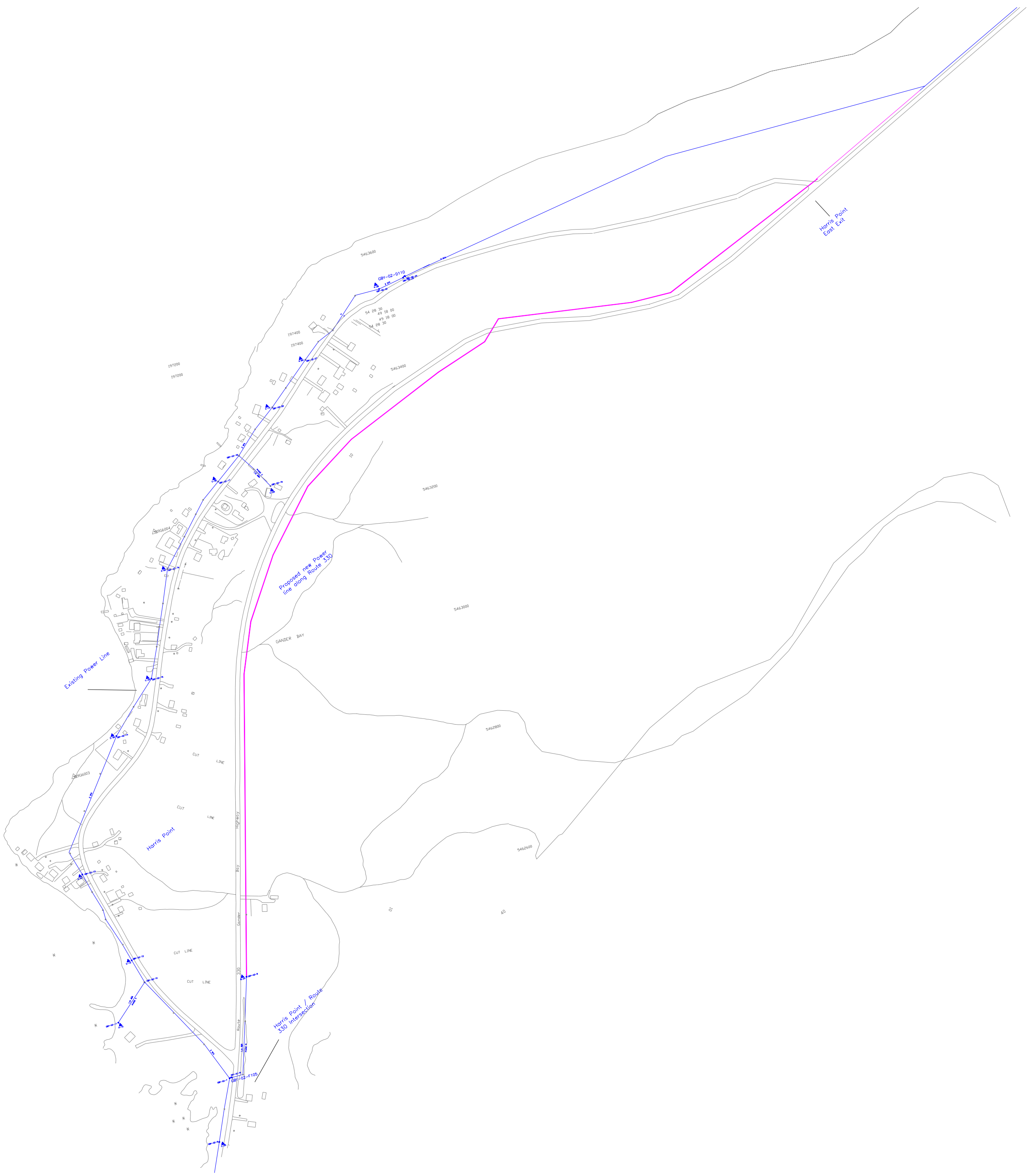
Appendix B


Existing 3 Phase line
along Route 330
Harris Point / Route
330 Intersection
GBY-02-F105
Gander Bay
Substation
Route
196800
197000
197200

Appendix C

Map Showing Harris Point (1.8 km)

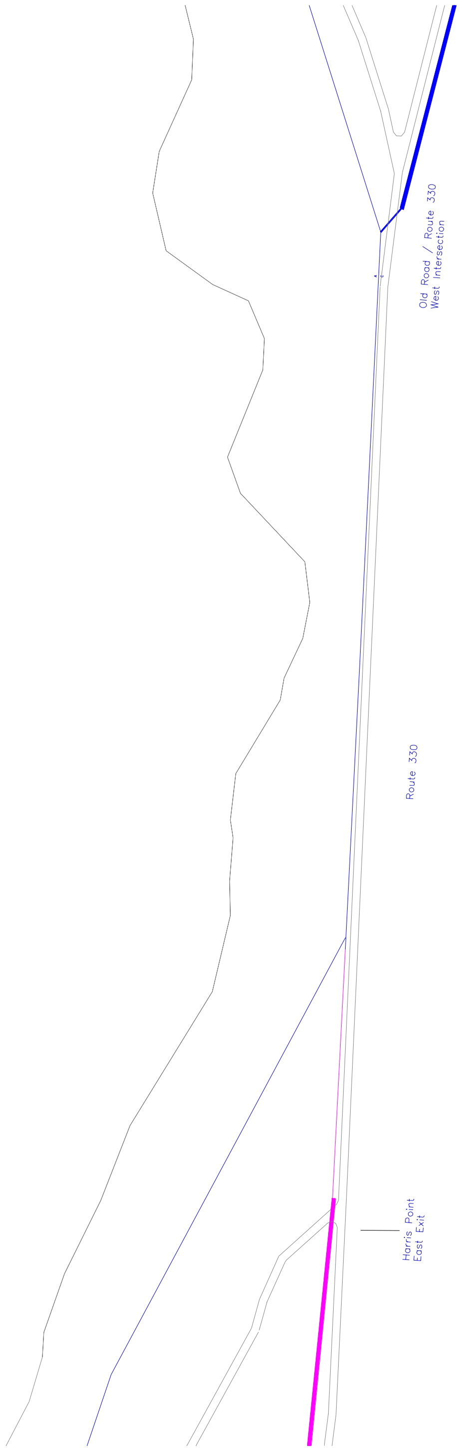
Appendix C


Harris Point
East Exit
Proposed new Power
line along Route 330
Existing Power Line
Harris Point
Harris Point / Route
330 Intersection

Appendix D

Map Showing Harris Point to Old Road Intersection (1 km)

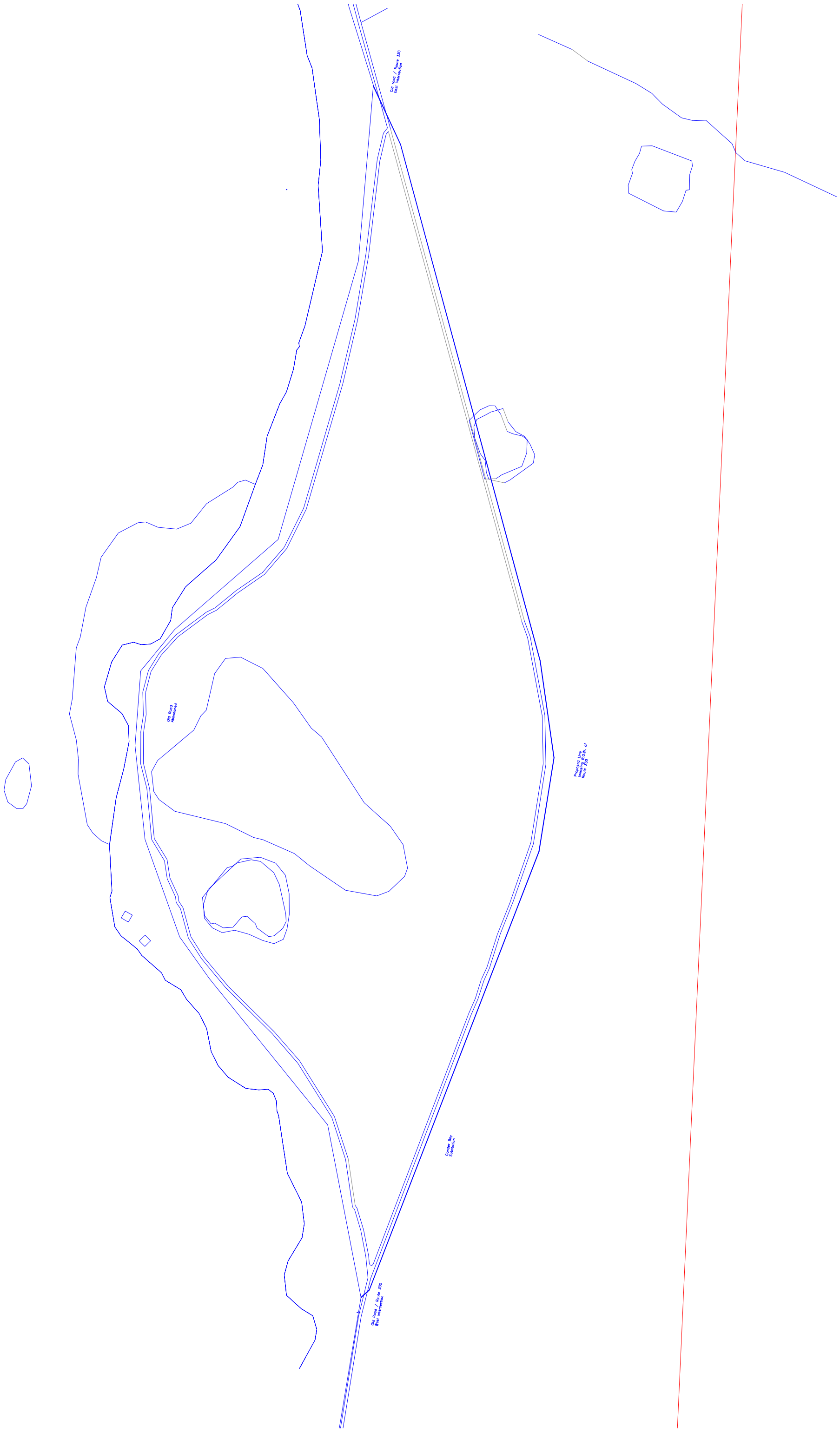
Appendix D


Old Road / Route 330
West Intersection
Route 330
Harris Point
East Exit

Appendix E

Map Showing Old Road Section (3.1 km)

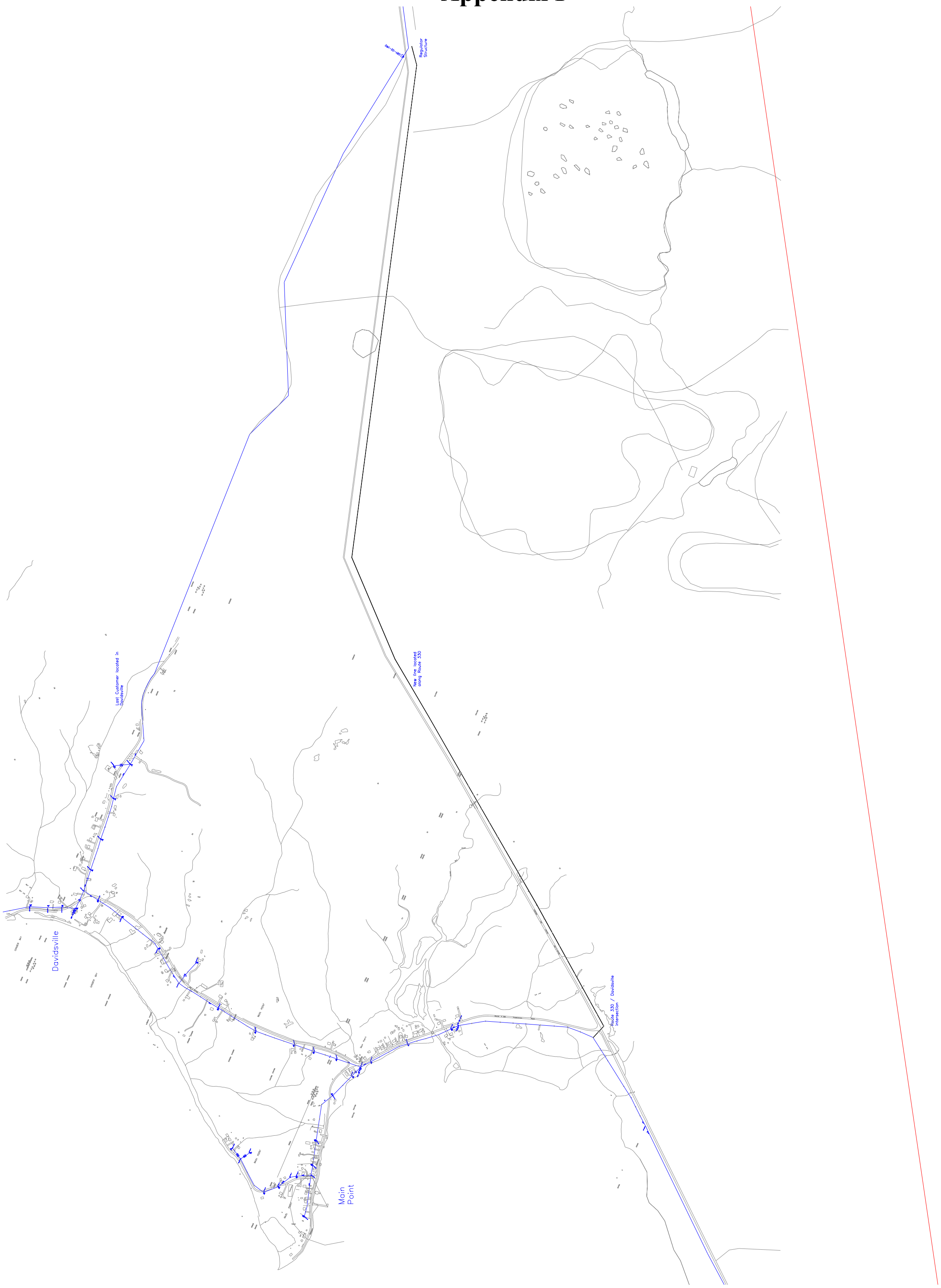
Appendix E



Appendix F

Map Showing Davidsville Section (4.1 km)

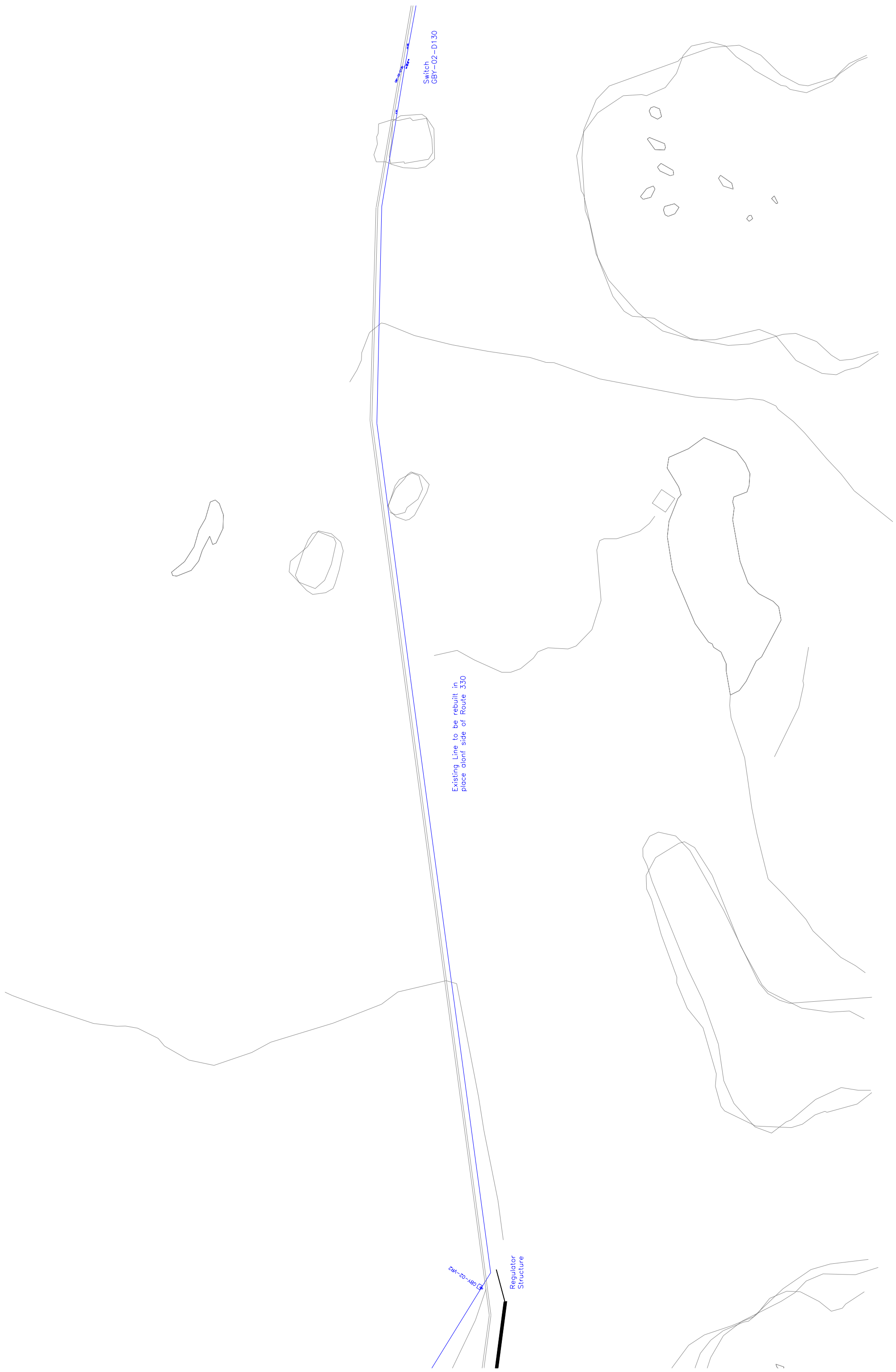
Appendix F


GBY-02-VR2
Regulator Structure
Last Customer located in Davidsville
New line located along Route 330
Davidsville
Route 330 / Davidsville intersection
Main Point

Appendix G

Map Showing Regulator Structure along Route 330 (2.7 km)

Appendix G


Switch
GBY-02-D130
Existing Line to be rebuilt in
place alonf side of Route 330
GBY-02-VR2
Regulator
Structure

Appendix H

Map Showing Carmanville (2.6 km)

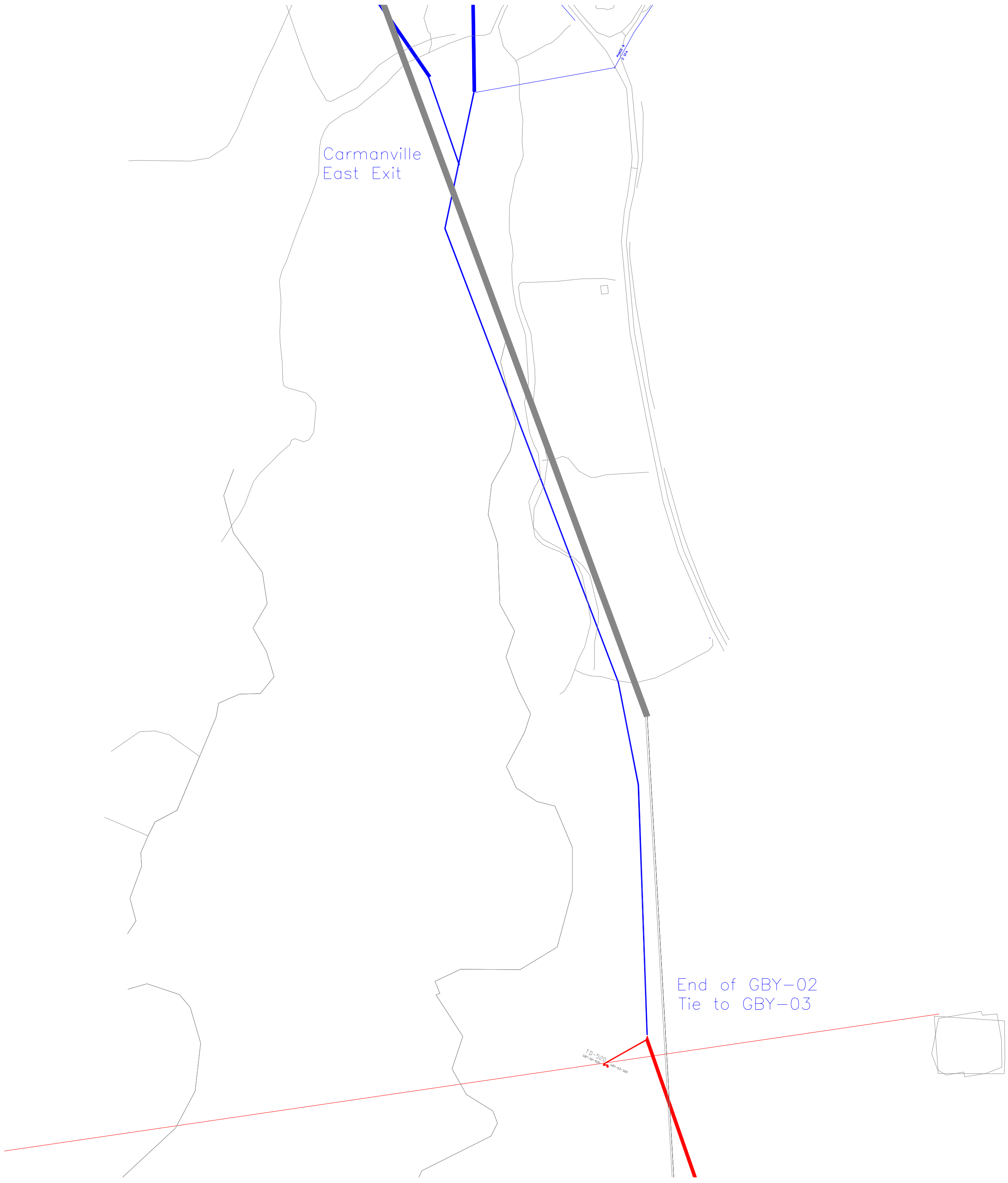
Appendix H


Carmanville
New Construction
along Route 330
Carmanville
West Exit
Carmanville
East Exit

Appendix I

Map Showing Carmanville to End of Feeder (1.2 km)

Appendix I

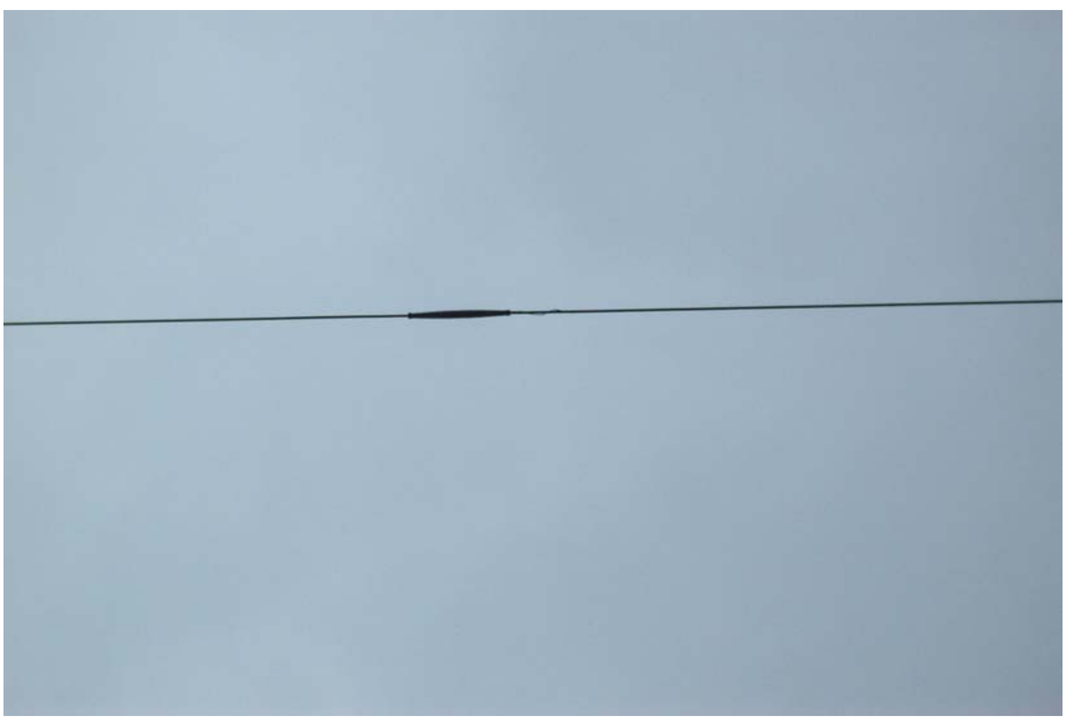


Appendix J

Pictures

Appendix J

Center Phase has "Bird caging" along old splice.
Note previous repair on outside phase.
Picture #1



Another location with "Bird Caging" with a splice in the conductor.
Picture #2

Another Span with 3 splices in the #2 ACSR.
Picture #3

This is typical of the sections of the feeder that follow the abandoned road.
This location is along Davidsville to the Regulator Structure.
Picture #4

Project Title: **Feeder Additions and Upgrades to Accommodate Growth**

Location: **Virginia Waters, Broad Cove and Grand Bay**

Classification: **Distribution**

Project Cost: **$441,000**

This project consists of a number of items as noted.

(a) Install New Feeder – VIR-08

Cost: $319,000 – Distribution, $51,000 – Substations, $268,000

Description: This project involves the construction of a distribution feeder from Virginia Waters substation on Snows Lane.

Operating Experience: Load and customer growth in the east end of St. John's is causing certain electrical system parameters to exceed recommended guidelines.

Justification: An engineering study, *"St. John's East End Planning Study"* indicates that this proposal is the low cost alternative to maintain electrical system parameters within recommended guidelines. See Distribution, Appendix 2, Attachment A.

(b) Install Voltage Regulators – GBS-02 and BCV-04

Cost: $122,000

Description: Install a bank of voltage regulators on GBS-02 and BCV-04.

Operating Experience: Voltage measurements taken during peak load conditions show that customers in the areas served by GBS-02 and BCV-04 experience voltage levels lower than the CSA recommended minimum.

Justification: This project is required to add voltage regulation to the system in order to alleviate voltage problems for customers in the area.

St. John's East End Planning Study: Virginia Waters, Ridge Road, Broad Cove and Pulpit Rock Substations

July 21, 2004

Prepared By:
Jennifer Meaney-Williams, P. Eng.

Table of Contents

Page

1.0 Introduction

The purpose of this study is to determine the distribution system alternative that best meets the electrical demands of the east end of St. John's, in the Winsor Lake, Virginia Waters and Newfoundland Drive areas. The installation in 2003 of an additional 25 MVA transformer at Virginia Waters (VIR) substation addressed an existing transformer overloading issue. However, two issues remain. The first issue is continued growth in the commercial and residential sectors near the VIR substation including addition of a water filtration plant in 2005 at Winsor Lake. The second issue is the forecasted loading on particular distribution feeders at the VIR, Ridge Road (RRD), Pulpit Rock (PUL) and Broad Cove (BCV) substations.

This study projects the electrical demands for the St. John's east end to the year 2023, develops technical alternatives to meet these demands, and determines the most cost effective alternative.

2.0 Description of Existing System

The St. John's east end is electrically supplied from the island grid through the Oxen Pond 230/66 kV substation. 66 kV transmission lines connect the Oxen Pond supply point to a number of 66/12.5 kV substations in the east end. These 66/12.5 kV substations supply feeders that distribute electricity to the various customers within the east end of the city.

The VIR substation is located on Snow's Lane in St. John's. It currently has seven distribution feeders serving 5,800 customers. This substation has experienced a high load growth over the past 7 years associated with the Stavanger Drive commercial area, and residential subdivisions such as Clovelly, King William Estates, Caroline Estates, Pine Ridge Creek and the Woodlands development. To address this increasing load, a distribution feeder was added in 2000 and a transformer was added in 2003.

The Ridge Road (RRD) substation is located at the intersection of Ridge Road and Higgin's Line in St. John's. It has 8 distribution feeders serving a total of 4,200 Customers. This area has also experienced growth primarily associated with residential construction along Airport Heights Drive. Future residential growth in this area will be somewhat restricted by the St. John's watershed, Pippy Park golf course and the airport. Planned commercial activity in the area includes the addition of a water filtration plant at Winsor Lake.

The Broad Cove (BCV) substation is located in St. Philip's on Belbins Road and has four distribution feeders, all operating at 12.5 kV. The total number of customers supplied from this substation is 4,100. The BCV substation is experiencing moderate growth. Most of the growth is composed of small subdivision (5-15 lots) and infill housing. In order to defer the addition of a second transformer at Broad Cove, during the past few years, portions of a Broad Cove feeder (BCV-03) have been converted to 25 kV and transferred to Hardwoods substation.

The Pulpit Rock (PUL) substation is located in Torbay on Whiteway's Pond Road and currently has two feeders, PUL-01 and PUL-02, both operating at 12.5 kV. The total number of customers fed from this substation is 3,500. A third feeder, PUL-03, is being added in 2004. These feeders are also experiencing moderate growth, with small subdivisions and infill housing being constructed throughout the service area.

3.0 Technical Criteria

The following technical criteria were utilized to develop various alternatives that meet the forecasted load growth:

- The steady state substation power transformer loading should not exceed the transformer nameplate rating.
- The conductor loading should not exceed the ampacity rating established in the Company's Distribution Planning Guidelines.
- The distribution feeder normal peak loading should be restricted to permit load pickup during outage conditions. These restrictions are based on three factors: substation equipment capacity, underground cable capacity and trunk feeder conductor capacity.

4.0 Load Forecast and Capacity Limitations

Base case values for the load forecast for each individual feeder utilized historical data for the period 1996 to 2003.

Growth projections were developed through the analysis of existing loads and in consultation with personnel familiar with the growth in the areas in question. It was determined that the future growth will be mostly residential, as most of the Stavanger Drive commercial area is complete. The growth will occur mainly in: the area bound by Clovelly Golf Course, Pine Line and Logy Bay Road; the area bound by King William Estates and Logy Bay Road; continued growth in the Pine Ridge Creek area; and some additional residential growth in the Airport Heights vicinity. Based on these assumptions, various growth rates were allocated to each feeder. This information was then used to create a 20-year load forecast for capacity planning purposes. The 20 year substation and feeder base load forecast and associated substation capacities are set out in Appendix A. As well, feeder ampacity ratings are noted in Appendix B. The feeder limitation is the winter planning rating of the feeder (MVA). Cold load pickup (CLPU) factors were assigned to various substations as follows:

1. VIR and RRD are assigned a CLPU factor of 2.0 due to high penetration of electric heat.
2. BCV and PUL are assigned a CLPU factor of 1.6 due to the nature of rural feeders. The exception is BCV-02, which has two down line reclosers that are sectionalized when picking up load; therefore, the CLPU factor is 1.33.

The load forecast (see Appendix A) indicates that the peak load on feeders VIR-06 and RRD-09 exceeds feeder capacity in the short term. The 2003 transformer capacity addition at VIR has resulted in significant transformer capacity being available at VIR. However, there are loading issues associated with transformer capacity at RRD, BCV and PUL. If no action is taken, the transformer loads at RRD, BCV and PUL will exceed capacity in 2011, 2016 and 2017 respectively. The transformer capacity deficit can be met through either adding transformer capacity at the substation or transferring load from RRD, BCV and PUL substations to neighbouring substations. If no action is taken, at the end of the 20-year substation forecast period, RRD will be at 140% of transformer capacity, BCV will be at 110%, VIR will be at 97%, and PUL will be at 113% of capacity.

The results of the base case load forecast contain the following technical criteria violations for the existing system:

1. VIR-06 peak load exceeds feeder capacity in 2004.
2. RRD-09 peak load exceeds feeder capacity in 2006 (includes filtration plant load).
3. RRD transformer peak load exceeds capacity in 2011.
4. PUL-02 peak load exceeds feeder capacity in 2012.
5. VIR-02 peak load exceeds feeder capacity in 2013.
6. VIR-03 peak load exceeds feeder capacity in 2013.
7. BCV transformer peak load exceeds capacity in 2016.
8. PUL transformer peak load exceeds capacity in 2017.

Consideration has also been given to load forecast sensitivity. Even with forecasts 2% higher or lower than the base case forecast, both VIR-06 and RRD-09 peak loads exceed recommended peak loads in 2004 and 2006, respectively.

5.0 Alternatives

5.1 Development of Alternatives

Alternatives are developed to meet the forecasted electrical demands and are limited to those that meet the technical criteria. These alternatives are evaluated using economic criteria. Based on this analysis, a preferred alternative is selected.

As an aid in interpreting each alternative, a substation feeder drawing is contained in Appendix C.

A description of each alternative follows.

5.1.1 Alternative #1

The first alternative is to construct a new 12.5 kV feeder (VIR-08) from the VIR substation in 2005. As well, when additional load is requested for the filtration plant at Winsor Lake, VIR-02 will be extended to the location at Winsor Lake. Load will be transferred to VIR-08 and VIR-05 from VIR-06 and VIR-02. In later years, an additional feeder is required at VIR, at PUL and at BCV. Additional load transfers within the substations accompany the new feeder construction to optimize feeder usage. The load forecast shows transformer capacity is required at RRD in 2013, at PUL in 2014, at BCV in 2018. The new feeders and associated transfers alleviate loading issues at RRD and VIR.

The following table notes timing, cost in today's dollars, and cost in escalated dollars for each component of Alternative 1. Capital costs are escalated by 2% per year.

Alternative # 1 ($000s)			
Description	**Year**	**Capital Cost $2005 x 1,000**	**Escalated Cost 2%/ yr x $1,000**
Construction of VIR-08 feeder	2005	318	318
Transfer 5 MVA from VIR-06 to VIR-08 and from 750 kVA VIR-02 to VIR-05	2005	1	1
Construction of VIR-09	2013	350	410
Construction of PUL-04	2013	300	351
Construction of BCV-05	2013	300	351
Load transfers within VIR, PUL, BCV	2013	30	35
Add additional 66-12.5, 25 MVA transformer at RRD substation	2013	1,200	1,407
Add additional 66-12.5, 25 MVA transformer at PUL substation	2014	1,200	1,434
Add additional 66-12.5, 25 MVA transformer at BCV substation	2018	1,200	1,552
Total Cost		**4,899**	**5,859**

See Appendix D for the load forecast by feeder and substation resulting from this alternative.

5.1.2 Alternative #2

The second alternative is to construct a new feeder from the RRD substation (RRD-11) in 2005. This alleviates the loading issue on RRD-09. There is a spare cubicle at RRD substation but the work to construct a new feeder is complex. Transformer capacity will still be an issue at RRD and so a 25 MVA transformer is added in 2006. In addition to dealing with RRD, the VIR-06 overloading should be addressed. To address this, VIR-06 will be offloaded onto PUL-01 and VIR-02, which will then be offloaded onto RRD-09. Future feeders are required at PUL in 2012, at VIR in 2013, and at BCV in 2018. Associated with all new feeder construction will be load transfers within the substation to optimize feeder usage. Transformer capacity is required at RRD in 2006, at PUL in 2013, and at BCV in 2016.

The following table notes timing, cost in today's dollars, and cost in escalated dollars for each component of Alternative 2.

Alternative # 2 ($000s)			
Description	**Year**	**Capital Cost $2005 x 1,000**	**Escalated Cost 2%/ yr x $1,000**
Construction of RRD-11 feeder	2005	450	450
Transfer 4.5 MVA from RRD-09 to RRD-11	2005	1	1
Transfer 3.0 MVA from VIR-02 to RRD-09	2005	1	1
Transfer 3.0 MVA from VIR-06 to VIR-02	2005	1	1
Transfer 1.0 MVA from PUL-01 to PUL-03	2005	1	1
Transfer 2 MVA from VIR-06 to PUL-01.	2005	1	1
Add additional 66-12.5, 25 MVA transformer at RRD Substation	2006	1,200	1,224
Add additional 66-12.5, 25 MVA transformer at PUL Substation	2012	1,200	1,378
Construction of PUL-04	2012	300	345
Load transfers within PUL	2012	10	12
Construction of VIR-08	2013	350	410
Load transfers within VIR	2013	10	12
Add additional 66-12.5, 25 MVA transformer at BCV Substation	2015	1,200	1,463
Construction of BCV-05	2018	300	388
Load transfers within BCV	2018	10	13
Total Cost		**5,035**	**5,700**

See Appendix E for the load forecast by feeder and substation resulting from this alternative.

5.1.3 Alternative #3

This alternative is to construct a new PUL feeder to split the load on PUL-01 and VIR-06. As well, new feeders at VIR in 2012 and 2023, one new feeder at BCV in 2015 and one at RRD in 2018 is required. Associated with all new feeder construction will be load transfers within the substation to optimize feeder usage. The load forecast shows transformer capacity is required at PUL in 2007, at BCV in 2013 and at RRD in 2014. To address the VIR-06 overload, load will be transferred to PUL-01. Further load reconfiguration will occur within the PUL feeders to spread the load over all PUL feeders.

The following table notes timing, cost in today's dollars, and cost in escalated dollars for each component of Alternative 3.

Alternative # 3 ($000s)			
Description	**Year**	**Capital Cost $2005 x 1,000**	**Escalated Cost 2%/ yr x $1,000**
Construction of PUL-04 Feeder	2005	450	450
Transfer 4.5 MVA from VIR-06 to PUL-01 & 04	2005	1	1
Transfer 1.0 MVA from RRD-09 to VIR-02	2005	1	1
Transfer .75 MVA from RRD-09 to BCV-01	2005	1	1
Transfer 1.5 MVA from VIR-02 to VIR-05	2005	1	1
Transfer 1.5 MVA from PUL-01 to PUL-04	2005	1	1
Transfer 1.5 MVA from PUL-02 to PUL-04	2005	1	1
Transfer 1.0 MVA from PUL-03 to PUL-04	2005	1	1
Add additional 66-25/12.5, 25 MVA transformer at PUL Substation	2007	1,200	1,248
Construction of VIR-08	2012	350	402
Load transfers within VIR	2012	10	12
Add additional 66-25/12.5, 25 MVA transformer at BCV Substation	2013	1,200	1,406
Add additional 66-25/12.5, 25 MVA transformer at RRD Substation	2014	1,200	1,434
Construction of BCV-05	2015	300	366
Load transfers within BCV	2015	10	12
Construction of RRD-11	2018	450	582
Load transfers within RRD.	2018	10	13
Construction of VIR-08	2023	350	500
Total Cost		**5,537**	**6,432**

See Appendix F for the load forecast by feeder and substation resulting from this alternative.

5.2 Economic Analysis

A NPV (net present values) analysis was performed for the capital costs associated with each alternative. Within each alternative, capital cost were present worthed by first escalating the capital cost by 2% per year for price escalation and then present worthing each capital cost by the WAIC (weighted average incremental cost of capital at 8.52%).

The capital cost and NPV for each alternative is shown in the Net Present Value Analysis Table. The Table indicates that while the capital costs for the alternatives vary by 13% the NPV totals vary by 27%. Alternative #2 has the lowest escalated cost by 3%, and alternative #1 has the lowest NPV cost by 24%. This is primarily due to the much smaller costs in the very early years of the analysis period for alternative #1.

Net Present Value Analysis
($1,000)

Alternative	Escalated Cost	NPV
#1	5,859 (103%)	2,870 (100%)
#2	5,700 (100%)	3,566 (124%)
#3	6,432 (113%)	3,655 (127%)

6.0 Recommendations

A 20-year load forecast by feeder has projected the electrical demands for the east end of St. John's in the Stavanger Drive area and vicinity. The development and analysis of alternatives has established a preferred expansion plan to meet these needs.

The lowest NPV alternative that meets all of the technical criteria is alternative #1. It includes the 2005 construction of the VIR-08 feeder, as well as the offloading of VIR-06. It also includes future feeder construction and additional transformer capacity in the east end.

Appendix A

Substation and Feeder Load Forecast

APPENDIX A - Estimated Load Forecast (BASE) - CLPU factor = 1.6 for BCV and PUL (Rural) except 1.33 for BCV-02 and CLPU = 2.0 for VIR and RRD

Feeders	CLPU Emerg	CLPU kVA	Planning	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
VIR-01	785	16976	8488	5462	6157	6442	6711	6995	7217	7404	7596	7791	7992	8196	8405	8619	8837	9060	9288	9521	9759	10003	10251
VIR-02	785	16976	8488	5854	6549	6834	7103	7387	7608	7796	7988	8183	8383	8588	8797	9011	9229	9452	9680	9913	10151	10395	10643
VIR-03	785	16976	8488	5948	6643	6928	7197	7481	7703	7890	8082	8277	8478	8682	8891	9105	9323	9546	9774	10007	10245	10489	10737
VIR-04	785	16976	8488	5199	5668	5860	6041	6233	6383	6509	6638	6770	6905	7043	7184	7328	7475	7626	7780	7937	8097	8262	8429
VIR-05	785	16976	8488	5450	5919	6111	6292	6484	6633	6760	6889	7021	7156	7294	7435	7579	7726	7877	8030	8188	8348	8512	8680
VIR-06	785	16976	8488	9154	10302	10772	11216	11686	12051	12361	12677	13001	13331	13669	14014	14366	14727	15095	15472	15857	16250	16652	17062
VIR-07	785	16976	8488	5734	5960	6053	6140	6233	6305	6366	6429	6492	6557	6624	6692	6762	6833	6905	6980	7055	7133	7212	7293
Sub Total				**42800**	**47200**	**49000**	**50700**	**52500**	**53900**	**55086**	**56298**	**57536**	**58802**	**60096**	**61418**	**62769**	**64150**	**65561**	**67004**	**68478**	**69984**	**71524**	**73097**
VIR T1, T2, T3																							
Avaliable				75000	75000	75000	75000	75000	75000	75000	75000	75000	75000	75000	75000	75000	75000	75000	75000	75000	75000	75000	75000
TFMR Requirements				42800	47200	49000	50700	52500	53900	55086	56298	57536	58802	60096	61418	62769	64150	65561	67004	68478	69984	71524	73097
Capacity				32200	27800	26000	24300	22500	21100	19914	18702	17464	16198	14904	13582	12231	10850	9439	7996	6522	5016	3476	1903
RRD-02	658	14229	7115	4538	4469	4485	4506	4524	4540	4568	4596	4625	4655	4685	4717	4749	4782	4816	4851	4887	4924	4962	5001
RRD-03	462	9991	4995	3174	3105	3121	3142	3161	3176	3204	3232	3261	3291	3322	3353	3385	3418	3452	3487	3523	3560	3598	3637
RRD-04	658	14229	7115	5570	4886	5044	5254	5439	5596	5871	6154	6444	6742	7048	7362	7684	8016	8356	8706	9064	9433	9812	10200
RRD-05	708	15311	7655	4197	4128	4144	4165	4183	4199	4227	4255	4284	4314	4344	4376	4408	4441	4475	4510	4546	4583	4621	4660
RRD-07	658	14229	7115	4277	3935	4014	4119	4211	4290	4427	4569	4714	4862	5015	5173	5334	5500	5670	5844	6024	6208	6397	6592
RRD-08	708	15311	7655	4413	4071	4150	4255	4347	4426	4564	4705	4850	4999	5152	5309	5470	5636	5806	5981	6160	6345	6534	6728
RRD-09	708	15311	7655	6423	6938	8396	8607	8791	8949	9224	9506	9796	10094	10400	10714	11037	11368	11708	12058	12417	12785	13164	13553
RRD-10	708	15311	7655	3510	3167	3246	3352	3444	3523	3660	3801	3946	4095	4248	4405	4567	4732	4903	5077	5257	5441	5630	5825
Sub Total				**36100**	**34700**	**36600**	**37400**	**38100**	**38700**	**39745**	**40818**	**41920**	**43052**	**44214**	**45408**	**46634**	**47893**	**49186**	**50514**	**51878**	**53279**	**54718**	**56195**
RRD T1, T2																							
Avaliable				40000	40000	40000	40000	40000	40000	40000	40000	40000	40000	40000	40000	40000	40000	40000	40000	40000	40000	40000	40000
TFMR Requirements				36100	34700	36600	37400	38100	38700	39745	40818	41920	43052	44214	45408	46634	47893	49186	50514	51878	53279	54718	56195
Capacity				3900	5300	3400	2600	1900	1300	255	-818	-1920	-3052	-4214	-5408	-6634	-7893	-9186	-10514	-11878	-13279	-14718	-16195
BCV-01	474	10250	6406	5691	5441	5541	5416	5566	5641	5716	5791	5868	5946	6024	6104	6185	6267	6350	6434	6519	6605	6692	6780
BCV-02	474	10250	7707	6654	6654	6654	6654	6654	6654	6654	6654	6654	6654	6654	6654	6654	6654	6654	6654	6654	6654	6654	6654
BCV-03	474	10250	6406	5691	5441	5541	5416	5566	5641	5716	5791	5868	5946	6024	6104	6185	6267	6350	6434	6519	6605	6692	6780
BCV-04	474	10250	6406	5165	4665	4865	4615	4915	5065	5214	5366	5519	5674	5832	5991	6153	6316	6482	6650	6820	6993	7167	7344
Sub Total				**23200**	**22200**	**22600**	**22100**	**22700**	**23000**	**23299**	**23602**	**23909**	**24220**	**24534**	**24853**	**25176**	**25504**	**25835**	**26171**	**26511**	**26856**	**27205**	**27559**
BCV T1																							
Avaliable				25000	25000	25000	25000	25000	25000	25000	25000	25000	25000	25000	25000	25000	25000	25000	25000	25000	25000	25000	25000
TFMR Requirements				23200	22200	22600	22100	22700	23000	23299	23602	23909	24220	24534	24853	25176	25504	25835	26171	26511	26856	27205	27559
Capacity				1800	2800	2400	2900	2300	2000	1701	1398	1091	780	466	147	-176	-504	-835	-1171	-1511	-1856	-2205	-2559
PUL-01	630	13624	8515	5718	5796	5912	6068	6262	6418	6578	6742	6908	7078	7251	7427	7606	7789	7976	8166	8359	8556	8757	8962
PUL-02	474	10250	6406	5741	5785	5852	5941	6052	6141	6232	6326	6421	6518	6617	6717	6820	6924	7031	7139	7250	7363	7477	7595
PUL-03	785	16976	10610	8441	8519	8636	8791	8986	9141	9302	9465	9632	9801	9974	10150	10330	10513	10699	10889	11083	11280	11481	11686
Sub Total				**19900**	**20100**	**20400**	**20800**	**21300**	**21700**	**22112**	**22532**	**22961**	**23397**	**23841**	**24294**	**24756**	**25226**	**25706**	**26194**	**26692**	**27199**	**27716**	**28242**
PUL T1																							
Avaliable				25000	25000	25000	25000	25000	25000	25000	25000	25000	25000	25000	25000	25000	25000	25000	25000	25000	25000	25000	25000
TFMR Requirements				19900	20100	20400	20800	21300	21700	22112	22532	22961	23397	23841	24294	24756	25226	25706	26194	26692	27199	27716	28242
Capacity				5100	4900	4600	4200	3700	3300	2888	2468	2039	1603	1159	706	244	-226	-706	-1194	-1692	-2199	-2716	-3242

VIR Substation Growth 2.20% RRD Substation Growth 1.70% BCV Substation Growth 1.30% PUL Substation Growth 1.9%

Appendix B

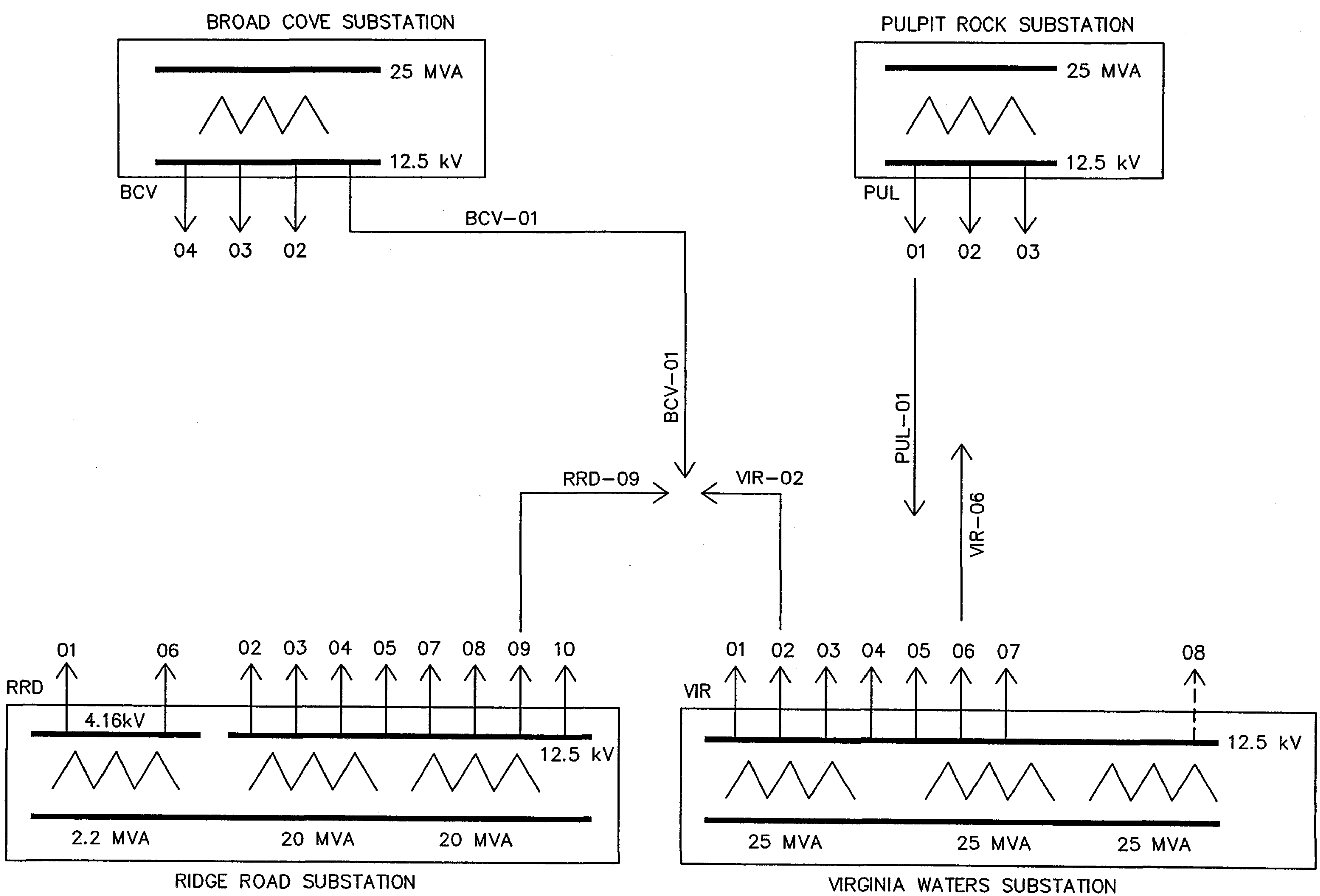
Feeder Capacity Ratings

Feeder		Appendix B - Feeder Capacity Ratings			
	Cold Load Pick Up Factor	Cold Load Rating of Feeder (A)	Cold Load Rating of Feeder (MVA)	Winter Planning Rating of Feeder (A)	Winter Planning Rating of Feeder (MVA)
VIR-01	2.0	785	16,956	393	8,489
VIR-02	2.0	785	16,956	393	8,489
VIR-03	2.0	785	16,956	393	8,489
VIR-04	2.0	785	16,956	393	8,489
VIR-05	2.0	785	16,956	393	8,489
VIR-06	2.0	785	16,956	393	8,489
VIR-07	2.0	785	16,956	393	8,489
RRD-02	2.0	658	14,213	329	7,106
RRD-03	2.0	462	9,979	231	4,990
RRD-04	2.0	658	14,213	329	7,106
RRD-05	2.0	708	15,293	354	7,646
RRD-07	2.0	658	14,213	329	7,106
RRD-08	2.0	708	15,293	354	7,646
RRD-09	2.0	708	15,293	354	7,646
RRD-10	2.0	708	15,293	354	7,646
BCV-01	1.6	474	10,238	237	5,119
BCV-02	1.33	474	10,238	237	5,119
BCV-03	1.6	474	10,238	237	5,119
BCV-04	1.6	474	10,238	237	5,119
PUL-01	1.6	630	13,608	393	8,489
PUL-02	1.6	474	10,238	237	5,119

Appendix C

Substation and Feeder Drawing

Feeders & Substations
Impacting St. John's East End Planning Study



Appendix D

Alternative #1
Substation and Feeder Load Forecast

APPENDIX D - Estimated Load Forecast (BASE) - Alternative #1

Feeders	CLPU Emerg	CLPU kVA	Planning	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
VIR-01	785	16976	8488	5462	6124	6394	6650	6920	7131	7312	7498	7688	6373	6562	6755	6952	7154	7360	7570	7785	8005	8230	8460
VIR-02	785	16976	8488	5854	4216	5786	6042	6312	6523	6704	6890	7080	6265	6454	6647	6844	7046	7252	7462	7677	7897	8122	8352
VIR-03	785	16976	8488	5948	6610	6880	7136	7406	7617	7798	7984	8174	6359	6548	6741	6938	7140	7346	7556	7771	7991	8216	8446
VIR-04	785	16976	8488	5199	5645	5828	6000	6183	6325	6447	6572	6700	6825	6952	7082	7215	7351	7490	7632	7777	7926	8077	8232
VIR-05	785	16976	8488	5450	5896	6079	6251	6434	6576	6698	6823	6951	7076	7203	7333	7466	7602	7741	7883	8028	8177	8328	8483
VIR-06	785	16976	8488	9154	4746	5193	5615	6062	6410	6709	7016	7329	5134	5346	5665	5990	6323	6664	7011	7367	7730	8101	8480
VIR-07	785	16976	8488	5734	5949	6037	6121	6209	6277	6336	6397	6459	7519	7581	7644	7708	7773	7840	7909	7979	8051	8124	8199
VIR-08	785	16976	8488		7715	7803	7887	7975	8043	8102	8136	8225	7285	7347	7410	7474	7539	7606	7675	7745	7817	7890	7965
VIR-09	785	16976	8488										7060	7222	7285	7349	7414	7481	7550	7620	7692	7765	7840
Sub Total				**42801**	**46901**	**50000**	**51702**	**53501**	**54902**	**56106**	**57316**	**58606**	**59895**	**61213**	**62560**	**63936**	**65343**	**66780**	**68249**	**69751**	**71285**	**72854**	**74456**
VIR T1, T2, T3																							
Avaliable				75000	75000	75000	75000	75000	75000	75000	75000	75000	75000	75000	75000	75000	75000	75000	75000	75000	75000	75000	75000
TFMR Requirements				42801	46901	50000	51702	53501	54902	56106	57316	58606	59895	61213	62560	63936	65343	66780	68249	69751	71285	72854	74456
Capacity				32199	28099	25000	23298	21499	20098	18894	17684	16394	15105	13787	12440	11064	9657	8220	6751	5249	3715	2146	544
RRD-02	658	14229	7115	4538	4469	4485	4506	4524	4540	4557	4574	4592	4609	4627	4646	4664	4683	4703	4722	4742	4763	4783	4804
RRD-03	462	9991	4995	3174	3105	3121	3142	3161	3176	3193	3210	3228	4246	4264	4282	4301	4320	4339	4359	4379	4399	4419	4440
RRD-04	658	14229	7115	5070	4386	4544	4754	4939	5096	5265	5437	5611	4789	4969	5152	5339	5529	5722	5918	6118	6321	6527	6737
RRD-05	708	15311	7655	4697	4628	4644	4665	4683	4699	4716	4733	4751	4768	4786	4805	4823	4842	4862	4881	4901	4922	4942	4963
RRD-07	658	14229	7115	4277	5435	5514	5619	5711	5790	5874	5960	6047	6136	6226	6318	6411	6506	6603	6701	6800	6902	7005	7110
RRD-08	708	15311	7655	4413	4071	4150	4255	4347	4426	4511	4596	4684	4772	4862	4954	5048	5142	5239	5337	5437	5538	5642	5747
RRD-09	708	15311	7655	6423	5738	5896	6107	6291	6449	6617	6789	6963	7141	7321	7505	6191	6381	6574	6770	6970	7173	7380	7590
RRD-10	708	15311	7655	3510	3167	3246	3352	3444	3523	3607	3693	3780	3369	3459	3551	5144	5239	5335	5434	5533	5635	5738	5843
Sub Total				**36100**	**35000**	**35600**	**36400**	**37100**	**37700**	**38341**	**38993**	**39656**	**39830**	**40515**	**41213**	**41922**	**42643**	**43376**	**44122**	**44881**	**45652**	**46437**	**47235**
RRD T1, T2 (& T3)																							
Avaliable				40000	40000	40000	40000	40000	40000	40000	40000	40000	65000	65000	65000	65000	65000	65000	65000	65000	65000	65000	65000
TFMR Requirements				36100	35000	35600	36400	37100	37700	38341	38993	39656	39830	40515	41213	41922	42643	43376	44122	44881	45652	46437	47235
Capacity				3900	5000	4400	3600	2900	2300	1659	1007	344	25170	24485	23787	23078	22357	21624	20878	20119	19348	18563	17765
BCV-01	474	10250	6406	5691	5441	5541	5416	5566	5641	5716	5791	5868	4420	4455	4490	4526	4562	4599	4636	4674	4712	4750	4790
BCV-02	474	10250	7707	6654	6654	6654	6654	6654	6654	6654	6654	6654	6654	6654	6654	6654	6654	6654	6654	6654	6654	6654	6654
BCV-03	474	10250	6406	5691	5441	5541	5416	5566	5641	5716	5791	5868	4420	4455	4490	4526	4562	4599	4636	4674	4712	4750	4790
BCV-04	474	10250	6406	5165	4665	4865	4615	4915	5065	5214	5366	5519	4623	4692	4763	4834	4907	4980	5055	5130	5206	5284	5362
BCV-05	474	10250	6406										4000	4070	4140	4212	4284	4358	4432	4507	4584	4661	4739
Sub Total				**23201**	**22201**	**22601**	**22101**	**22701**	**23001**	**23300**	**23602**	**23909**	**24116**	**24325**	**24537**	**24752**	**24969**	**25190**	**25413**	**25639**	**25868**	**26099**	**26334**
BCV T1 (& T2)																							
Avaliable				25000	25000	25000	25000	25000	25000	25000	25000	25000	25000	25000	25000	25000	25000	50000	50000	50000	50000	50000	50000
TFMR Requirements				23201	22201	22601	22101	22701	23001	23300	23602	23909	24116	24325	24537	24752	24969	25190	25413	25639	25868	26099	26334
Capacity				1799	2799	2399	2899	2299	1999	1700	1398	1091	884	675	463	248	31	24810	24587	24361	24132	23901	23666
PUL-01	630	13624	8515	5718	6296	6412	6568	6762	6918	7089	7264	8442	6573	6705	6841	6979	7119	7263	7409	7557	7709	7864	8021
PUL-02	474	10250	6406	5741	6285	6352	6441	6552	6641	6739	6838	5940	5015	5091	5168	5247	5327	5409	5492	5577	5664	5752	5842
PUL-03	785	16976	10610	8441	9019	9136	9291	9486	9641	9813	9987	10165	7796	7928	8064	8202	8342	8486	8632	8780	8932	9087	9244
PUL-04	785	16976	10610										5631	5763	5899	6037	6177	6321	6467	6615	6767	6922	7079
Sub Total				**19900**	**21600**	**21900**	**22300**	**22800**	**23200**	**23641**	**24089**	**24547**	**25013**	**25488**	**25972**	**26464**	**26966**	**27478**	**28000**	**28531**	**29072**	**29624**	**30186**
PUL T1																							
Avaliable				25000	25000	25000	25000	25000	25000	25000	25000	25000	25000	50000	50000	50000	50000	50000	50000	50000	50000	50000	50000
TFMR Requirements				19900	21600	21900	22300	22800	23200	23641	24089	24547	25013	25488	25972	26464	26966	27478	28000	28531	29072	29624	30186
Capacity				5100	3400	3100	2700	2200	1800	1359	911	453	-13	24512	24028	23536	23034	22522	22000	21469	20928	20376	19814

VIR Substation Growth 2.20% RRD Substation Growth 1.70% BCV Substation Growth 1.30% PUL Substation Growth 1.9%

Appendix E

Alternative #2
Substation and Feeder Load Forecast

APPENDIX E - Estimated Load Forecast (Medium) - Alternative #2

Feeders	CLPU Emerg	CLPU kVA	Planning	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
VIR-01	785	16976	8488	5462	6157	6442	6711	6995	7217	7387	7560	7738	6782	6929	7079	7233	7390	7551	7715	7882	8054	8229	8408
VIR-02	785	16976	8488	5854	6549	6834	7103	7387	7608	7779	7952	8130	6774	6921	7071	7225	7382	7543	7707	7874	8046	8221	8400
VIR-03	785	16976	8488	5948	6643	6928	7197	7481	7703	7873	8046	8224	6768	6915	7065	7219	7376	7537	7701	7868	8040	8215	8394
VIR-04	785	16976	8488	5199	5668	5860	6041	6233	6383	6497	6614	6734	7031	7130	7232	7335	7441	7550	7660	7773	7889	8007	8128
VIR-05	785	16976	8488	5450	5919	6111	6292	6484	6633	6748	6865	6985	7282	7381	7483	7586	7692	7801	7911	8024	8140	8258	8379
VIR-06	785	16976	8488	9154	5302	5772	6216	6686	7051	7332	7619	7912	5750	5993	6241	6495	6754	7019	7290	7567	7850	8139	8434
VIR-07	785	16976	8488	5734	5960	6053	6140	6233	6305	6361	6417	6475	7222	7270	7319	7369	7420	7472	7526	7580	7636	7693	7751
VIR-08	785	16976	8488										5738	5981	6229	6483	6742	7007	7278	7555	7838	8127	8422
VIR-09	785	16976	8488										0	0	0	0	0	0	0	0	0	0	0
Sub Total				**42801**	**42198**	**44000**	**45700**	**47499**	**48900**	**49977**	**51073**	**52198**	**53346**	**54520**	**55719**	**56945**	**58198**	**59478**	**60787**	**62124**	**63491**	**64888**	**66315**
VIR T1, T2, T3																							
Avaliable				75000	75000	75000	75000	75000	75000	75000	75000	75000	75000	75000	75000	75000	75000	75000	75000	75000	75000	75000	75000
TFMR Requirements				42801	42198	44000	45700	47499	48900	49977	51073	52198	53346	54520	55719	56945	58198	59478	60787	62124	63491	64888	66315
Capacity				32199	32802	31000	29300	27501	26100	25023	23927	22802	21654	20480	19281	18055	16802	15522	14213	12876	11509	10112	8685
RRD-02	658	14229	7115	4538	4484	4496	4513	4528	4540	4555	4570	4586	4601	4617	4634	4650	4667	4684	4702	4719	4737	4756	4774
RRD-03	462	9991	4995	3174	4120	4132	4149	4164	4176	4191	4206	4222	4237	4253	4270	4286	4303	4320	4338	4355	4373	4392	4410
RRD-04	658	14229	7115	5570	4028	4153	4320	4466	4591	4740	4893	5047	5205	5365	5528	5693	5861	6033	6207	6384	6564	6747	6933
RRD-05	708	15311	7655	4197	4143	4155	4172	4187	4199	4214	4229	4245	4260	4276	4293	4309	4326	4343	4361	4378	4396	4415	4433
RRD-07	658	14229	7115	4277	4006	4069	4152	4225	4287	4362	4438	4516	4594	4674	4756	4839	4923	5008	5095	5184	5274	5366	5459
RRD-08	708	15311	7655	4413	4142	4205	4288	4361	4423	4498	4574	4652	4730	4810	4892	4975	5059	5144	5231	5320	5410	5502	5595
RRD-09	708	15311	7655	6423	4331	5756	5923	6069	5194	5343	5496	5650	5808	5968	6131	6296	6464	6636	6810	6987	7167	7350	7536
RRD-10	708	15311	7655	3510	4489	4552	4635	4708	5770	5845	5921	5999	6077	6157	6239	6322	6406	6491	6578	6667	6757	6849	6942
RRD-11	708	15311	7655	0	4500	4625	4792	4938	5063	5212	5364	5519	5676	5836	5999	6165	6333	6504	6678	6856	7036	7219	7405
Sub Total				**36102**	**38244**	**40144**	**40944**	**41644**	**42244**	**42962**	**43692**	**44435**	**45190**	**45959**	**46740**	**47534**	**48343**	**49164**	**50000**	**50850**	**51715**	**52594**	**53488**
RRD T1, T2 (&T3)																							
Avaliable				40000	40000	65000	65000	65000	65000	65000	65000	65000	65000	65000	65000	65000	65000	65000	65000	65000	65000	65000	65000
TFMR Requirements				36102	38244	40144	40944	41644	42244	42962	43692	44435	45190	45959	46740	47534	48343	49164	50000	50850	51715	52594	53488
Capacity				3898	1756	24856	24056	23356	22756	22038	21308	20565	19810	19041	18260	17466	16657	15836	15000	14150	13285	12406	11512
BCV-01	474	10250	6406	5691	5441	5541	5416	5566	5641	5716	5791	5868	5946	6024	6104	6185	6267	4822	4880	4939	4999	5059	5121
BCV-02	474	10250	7707	6654	6654	6654	6654	6654	6654	6654	6654	6654	6654	6654	6654	6654	6654	6654	6654	6654	6654	6654	6654
BCV-03	474	10250	6406	5691	5441	5541	5416	5566	5641	5716	5791	5868	5946	6024	6104	6185	6267	4822	4880	4939	4999	5059	5121
BCV-04	474	10250	6406	5165	4665	4865	4615	4915	5065	5214	5366	5519	5674	5832	6991	6153	6316	5427	5543	5661	5780	5901	6023
BCV-05	474	10250	6406															5111	5227	5345	5464	5585	5707
Sub Total				**23201**	**22201**	**22601**	**22101**	**22701**	**23001**	**23300**	**23602**	**23909**	**24220**	**24534**	**25853**	**25177**	**25504**	**26836**	**27184**	**27538**	**27896**	**28258**	**28626**
BCV T1																							
Avaliable				25000	25000	25000	25000	25000	25000	25000	25000	25000	25000	25000	50000	50000	50000	50000	50000	50000	50000	50000	50000
TFMR Requirements				23201	22201	22601	22101	22701	23001	23300	23602	23909	24220	24534	25853	25177	25504	26836	27184	27538	27896	28258	28626
Capacity				1799	2799	2399	2899	2299	1999	1700	1398	1091	780	466	24147	24823	24496	23164	22816	22462	22104	21742	21374
PUL-01	630	13624	8515	5718	6796	6912	7068	7262	7418	7593	7771	5902	6035	6171	6310	6451	6595	6741	6891	7043	7198	7356	7517
PUL-02	474	10250	6406	5741	5785	5852	5941	6052	6141	6241	6343	4918	4994	5072	5151	5232	5314	5397	5483	5570	5658	5749	5841
PUL-03	785	16976	10610	8441	9519	9636	9791	9986	10141	10371	10495	8126	8259	8395	8534	8675	8819	8965	9115	9267	9422	9580	9741
PUL-04	785	16976	10610									6131	6264	6400	6539	6680	6824	6970	7120	7272	7427	7585	7746
Sub Total				**19900**	**22100**	**22400**	**22800**	**23300**	**23700**	**24205**	**24609**	**25077**	**25553**	**26039**	**26533**	**27037**	**27551**	**28075**	**28608**	**29152**	**29705**	**30270**	**30845**
PUL T1																							
Avaliable				25000	25000	25000	25000	25000	25000	25000	25000	50000	50000	50000	50000	50000	50000	50000	50000	50000	50000	50000	50000
TFMR Requirements				19900	22100	22400	22800	23300	23700	24205	24609	25077	25553	26039	26533	27037	27551	28075	28608	29152	29705	30270	30845
Capacity				5100	2900	2600	2200	1700	1300	795	391	24923	24447	23961	23467	22963	22449	21925	21392	20848	20295	19730	19155

VIR Substation Growtl 2.20% RRD Substation Growth 1.70% BCV Substation Growth 1.30% PUL Substation Growth = 1.9%

Appendix F

Alternative #3
Substation and Feeder Load Forecast

APPENDIX F - Estimated Load Forecast (BASE) - Alternative #3

Feeders	CLPU Emerg	CLPU kVA	Planning	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
VIR-01	785	16976	8488	6462	6157	6442	6711	6995	7217	7392	7571	6295	6473	6655	6841	7030	7224	7423	7625	7832	8044	8260	7471
VIR-02	785	16976	8488	5854	6049	6334	6603	6887	7108	7284	7463	6312	6490	6672	6858	7047	7241	7440	7642	7849	8061	8277	7488
VIR-03	785	16976	8488	5948	6643	6928	7197	7481	7703	7878	8057	6731	6909	7091	7277	7466	7660	7859	8016	8268	8480	8696	7907
VIR-04	785	16976	8488	5199	5668	5860	6041	6233	6383	6501	6622	6989	7109	7232	7357	7485	7616	7750	7886	8026	8169	8315	7457
VIR-05	785	16976	8488	5450	7419	7611	7792	7984	8133	8252	8372	7014	7134	7257	7382	7510	7641	7775	7911	8051	8194	8340	7482
VIR-06	785	16976	8488	9154	5802	6272	6716	7186	7551	7841	8137	4875	5168	5469	5775	6089	6409	6736	7071	7412	7762	8119	7967
VIR-07	785	16976	8488	5734	5960	6053	6140	6233	6305	6362	6421	7778	7836	7895	7955	8017	8080	8145	8211	8278	8347	8417	7986
VIR-08	785	16976	8488									7807	7865	7866	7926	7988	8051	8116	8182	8249	8318	8388	7957
VIR-09	785	16976	8488																				6569
Sub Total				**43801**	**43698**	**45500**	**47200**	**48999**	**50400**	**51510**	**52643**	**53801**	**54984**	**56137**	**57371**	**58632**	**59922**	**61244**	**62544**	**63965**	**65375**	**66812**	**68282**
VIR T1, T2, T3																							
Avaliable				75000	75000	75000	75000	75000	75000	75000	75000	75000	75000	75000	75000	75000	75000	75000	75000	75000	75000	75000	75000
TFMR Requirements				43801	43698	45500	47200	48999	50400	51510	52643	53801	54984	56137	57371	58632	59922	61244	62544	63965	65375	66812	68282
Capacity				31199	31302	29500	27800	26001	24600	23490	22357	21199	20016	18863	17629	16368	15078	13756	12456	11035	9625	8188	6718
RRD-02	658	14229	7115	4538	4469	4485	4506	4524	4540	4557	4574	4591	4608	4626	4644	4662	4681	4698	4715	4732	4750	4767	4786
RRD-03	462	9991	4995	3174	6105	3121	3142	3161	3179	3193	3210	3227	3244	3262	3280	3298	3317	3334	3351	3368	3386	3403	3422
RRD-04	658	14229	7115	5570	4886	5044	5254	5439	5596	5762	5930	6101	6275	6452	6632	6815	7001	5168	5338	5511	5687	5866	6048
RRD-05	708	15311	7655	4197	4128	4144	4165	4183	4199	4216	4233	4250	4267	4285	4303	4321	4340	4357	4374	4391	4409	4426	4445
RRD-07	658	14229	7115	4277	3935	4014	4119	4211	4290	4373	4457	4543	4629	4718	4808	4899	4992	5076	5161	5247	5335	5424	5515
RRD-08	708	15311	7655	4413	4071	4150	4255	4347	4426	4509	4593	4679	4765	4854	4844	5035	5128	5212	5297	5383	5471	5560	5651
RRD-09	708	15311	7655	6423	5188	6646	6857	7041	7199	7364	7532	6703	6877	7054	7234	7417	7603	5270	5440	5613	5789	5968	6150
RRD-10	708	15311	7655	3510	3167	3246	3352	3444	3523	3605	3689	4775	4861	4950	5040	5131	5224	5308	5393	5479	5567	5656	5747
RRD-11	708	15311	7655															4584	4669	4755	4843	4932	5023
Sub Total				**36102**	**35949**	**34850**	**35650**	**36350**	**36952**	**37579**	**38218**	**38869**	**39526**	**40201**	**40785**	**41578**	**42286**	**43005**	**43736**	**44479**	**45236**	**46005**	**46787**
RRD T1, T2 (&T3)																							
Avaliable				40000	40000	40000	40000	40000	40000	40000	40000	40000	40000	65000	65000	65000	65000	65000	65000	65000	65000	65000	65000
TFMR Requirements				36102	35949	34850	35650	36350	36952	37579	38218	38869	39526	40201	40785	41578	42286	43005	43736	44479	45236	46005	46787
Capacity				3898	4051	5150	4350	3650	3048	2421	1782	1131	474	24799	24215	23422	22714	21995	21264	20521	19764	18995	18213
BCV-01	474	10250	6406	5691	5691	5791	5666	5816	5891	5968	6046	6125	6206	6287	4842	4898	4954	5011	5069	5127	5187	5247	5308
BCV-02	474	10250	7707	6654	6654	6654	6654	6654	6654	6654	6654	6654	6654	6654	6654	6654	6654	6654	6654	6654	6654	6654	6654
BCV-03	474	10250	6406	5691	5441	5541	5416	5566	5641	5718	5796	5875	5956	6037	5092	5148	5204	5261	5319	5377	5437	5497	5558
BCV-04	474	10250	6406	5165	5165	5365	5115	5415	5565	5719	5875	6034	6194	6357	4967	5078	5191	5305	5421	5538	5656	5776	5898
BCV-05	474	10250	6406												4110	4221	4334	4448	4564	4681	4799	4919	5041
Sub Total				**23201**	**22951**	**23351**	**22851**	**23451**	**23751**	**24059**	**24371**	**24688**	**25010**	**25335**	**25665**	**25998**	**26336**	**26679**	**27026**	**27377**	**27733**	**28093**	**28459**
BCV T1																							
Avaliable				25000	25000	25000	25000	25000	25000	25000	25000	25000	50000	50000	50000	50000	50000	50000	50000	50000	50000	50000	50000
TFMR Requirements				23201	22951	23351	22851	23451	23751	24059	24371	24688	25010	25335	25665	25998	26336	26679	27026	27377	27733	28093	28459
Capacity				1799	2049	1649	2149	1549	1249	941	629	312	24990	24665	24335	24002	23664	23321	22974	22623	22267	21907	21541
PUL-01	630	13624	8515	5718	5274	5358	5470	5610	5722	5861	6003	6147	6294	6444	6597	6753	6912	7073	7238	7406	7577	7751	7929
PUL-02	474	10250	6406	5741	4273	4321	4385	4465	4529	4608	4689	4772	4856	4942	5029	5118	5209	5301	5395	5491	5589	5689	5790
PUL-03	785	16976	10610	8441	7497	7581	7693	7833	7945	8084	8226	8370	8517	8667	8820	8976	9135	9296	9461	9629	9800	9974	10152
PUL-04	786	16997	10623		7500	7584	7696	7836	7948	8087	8229	8373	8520	8670	8823	8979	9138	9299	9464	9632	9803	9977	10155
Sub Total				**19900**	**24544**	**24844**	**25244**	**25744**	**26144**	**26641**	**27147**	**27663**	**28188**	**28724**	**29270**	**29826**	**30392**	**30970**	**31558**	**32158**	**32769**	**33392**	**34026**
PUL T1																							
Avaliable				25000	25000	25000	50000	50000	50000	50000	50000	50000	50000	50000	50000	50000	50000	50000	50000	50000	50000	50000	50000
TFMR Requirements				19900	24544	24844	25244	25744	26144	26641	27147	27663	28188	28724	29270	29826	30392	30970	31558	32158	32769	33392	34026
Capacity				5100	456	156	24756	24256	23856	23359	22853	22337	21812	21276	20730	20174	19608	19030	18442	17842	17231	16608	15974

VIR Substation Growth 2.20% RRD Substation Growth 1.70% BCV Substation Growth 1.30% PUL Substation Growth = 1.9%

Project Title: **Tools and Equipment**

Location: **Company Offices, Service Buildings and Vehicles**

Classification: **General Property**

Project Cost: **$691,000**

This project consists of a number of items as noted.

(a) Regional Tools and Equipment

Cost: $290,000

Description: Replacement of tools and equipment utilized by line and support staff in the day-to-day operations of the Company.

Operating Experience: Line tools and equipment include those used by line staff, electrical maintenance staff, and engineering and field technical staff. These tools are maintained on a regular basis, however, over time they degrade and wear out, especially hot line equipment which must meet rigorous safety requirements. Concerns have also been expressed by linepersons related to the difficulty of using certain types of cutting & compression hand tools. Where feasible, such tools will be replaced with battery and hydraulic alternatives to improve productivity and working conditions.

Justification: Proper tools and equipment are required for the efficient and effective management of the electrical system as well as the safety of line workers and the public.

(b) Head Office Tools and Equipment

Cost: $341,000

Description: This project includes engineering test equipment, tools used by electrical and mechanical maintenance personnel and tools used for the handling and shipping of printed material including customer bills.

Engineering test equipment includes items to perform systems calibration, commissioning and testing of protection equipment and data communications testing and analysis. The 2005 equipment requirements involve the purchase of one Relay Test Set.

Equipment for the electrical maintenance personnel is required for staff involved in the maintenance of substation equipment and generation. The following are the items required for 2005:

1 – Transformer Turns Ratio Tester
1 – 10 A Ductor (c/w long leads)
2 – 5 kV Megger
2 – Oil Test Set
2 – Thermocal
1 – Transformer Winding Resistance Meter
2 – Air Quality Gas Monitor
1 – Battery Ground Fault Locator

Equipment for mechanical maintenance personnel is required for staff involved in generation maintenance. The following are items required for 2005:

1 – Process Calibrator
1 – Boroscope
1 – Laser Shaft Alignment Equipment
1 – Generator grounding studs and cables
1 – Vibration Detector Calibration Equipment
1 – Process Meter
1 – Filter Press

Equipment for printed material handling and shipping for 2005 include the following:

1 – Punch and Binding Machine
1 – Numbering, Perforating and Scoring Unit
1 – Shrink Wrap Machine

Operating Experience: Engineering test equipment is used to verify the operation of the protection and remote control systems. The relay test equipment is used to verify a protection system's operation prior to its going into service and to diagnose problems once the protection equipment is in operation.

The electrical maintenance group is responsible for the integrity and reliability of the equipment located in 137 substations across the Company's service territory. The electrical maintenance equipment includes power transformers, breakers, reclosers, voltage regulators, metering tanks, three phase pad mount transformers and step down transformers. Diagnostic testing and repair of the various types of equipment requires specialized tools and test equipment such as circuit breaker motion analyzers, insulation resistance testers (meggers), oil dielectric testers, recloser testers, transformer ratio testers, low resistance ohmmeters (ductors), SF6 gas reclaimers, vacuum pumps, oil filters, hand held gas monitors, potential indicators, fault locators, battery testers, etc. Innovations in tools and test equipment often lead to better diagnostic tools that result in less equipment failures. As well, normal deterioration and the inability to maintain obsolete test equipment require that some of these items be replaced every year.

The mechanical maintenance group is responsible for the integrity and reliability of a variety of mechanical equipment located in numerous generation facilities located throughout the Company's operating area. Diagnostic testing, calibration and repair of these various types of equipment require numerous types of specialized tools and test equipment. Innovations in tools and test equipment often lead to better diagnostic tools that result in less equipment failures. As well, normal deterioration and an inability to maintain obsolete technology require that some of this equipment be replaced at regular intervals.

Justification: The test equipment noted above are the base tools required to design, verify and maintain reliable operation of the electric power system and associated equipment.

The relay test set is required to design, verify and maintain a reliable protection system that properly isolates power system faults and maintains safety.

The electrical and mechanical maintenance test equipment is required to ensure the integrity and reliability of the equipment located in the Company's substations and generation plants across its service territory.

(c) Furniture

Cost: $60,000

Description: Replacement of chairs and furniture that have deteriorated.

Operating Experience: The Company has approximately 660 full time employee equivalents. The office furniture utilized by these employees deteriorates through normal use and needs to be replaced.

Justification: Proper furniture is necessary for a safe and productive work environment.

Project Title: **Additions to Real Property**

Location: **Electrical Maintenance Facility, Duffy Place Building, Kenmount Road Building and Corner Brook West Street Building**

Classification: **General Property**

Project Cost: **$325,000**

This project consists of 2 items greater than $50,000 and several items estimated at less than $50,000 each.

(a) Duffy Place – Renovate Maintenance Center

Cost: $100,000

Description: Renovate maintenance center to accommodate generation/mechanical maintenance personnel.

Operating Experience: Prior to the retirement of the steam plant facility on the south side of St. John's, the mechanical maintenance staff worked from that location. Subsequent to that they worked from leased space on Topsail Road. A review of the Duffy Place facilities identified that space previously used as a vehicle garage could be renovated and made available to this group.

Justification: This project will provide office space with appropriate climate control and adjustable workstations for this group similar to facilities provided other company personnel engaged in similar activities. It will also provide for organized storage of spare parts and equipment that are critical to the Company's asset management strategy.

(b) Duffy Place – Upgrade UPS (Uninterruptible Power Supply)

Cost: $80,000

Description: This project involves the addition of a Maintenance Bypass Module (MBM) to the UPS at the Duffy Place Building. The UPS ensures that power to critical operations and equipment is not interrupted in the event of a failure on the regular utility power supply.

Operating Experience: The UPS at the St. John's Regional Office (Duffy Place Building) was originally installed in 1999. It was recently determined that the UPS has no maintenance bypass switch. Without a bypass switch, the UPS cannot be electrically isolated from the building without interrupting the electrical supply to its circuits. This means that, if the unit should fail, all services powered by the UPS, which include the Customer Contact Center, St. John's Area Operations, Disaster Recovery IS Computer Room, SCADA Disaster Recovery Site, and Outage Management would be shut down for an extended period of time.

Justification: This project is justified based on the need to reduce the risk of losing critical services, such as SCADA, the Customer Call Center and St. John's Area Operations, for extended periods of time as a result of failure or malfunction of UPS equipment at the St. John's Regional Office.

(c) Projects < $50,000.

Cost: $145,000

Description: Listed are projects estimated at less than $50,000.

1. Duffy Place – Upgrade Telecommunication & Meter Shops
2. Electrical Maintenance Facility – Storage Ramp Upgrade
3. Corner Brook – Renovate West Street Building
4. Kenmount Road Building – Replace Steps and Doors at Front Entrance
5. Kenmount Road Building – Upgrade Security Systems and Deteriorated Fixtures

Project Title: **Purchase Vehicles and Aerial Devices**

Location: **Various**

Classification: **Transportation**

Project Cost: **$2,642,000**

Operating Experience: See Transportation, Appendix 1, Attachment A for details on the vehicles being replaced in 2005.

Appendix 1
Attachment A

Details – 2005 Capital Vehicle Budget

SUMMARY 5YR CAPITAL VEHICLE BUDGET (2005 - 2009)

Year	Proposed Yrs to be Replaced Heavy Fleet	# Units/Yr Heavy Fleet	Budget $$ Heavy Fleet	Proposed Yrs to be Replaced Passenger Fleet	# Units/Yr Passenger	Budget $$ Passenger	# Units Off Road	Budget $$ Off Road	Overall Totals
2005	1992	1	$1,004,489	1996	1	$1,339,402	8	$299,434	$2,643,325
	1993	2		1997	1				
	1994	3		1998	1				
	1995	1		1999	43				
2006	1995	10	$1,959,323	2000	27	$800,991	9	$227,433	$2,987,747
	1996	1							
2007	1996	2	$897,556	2001	30	$1,448,433	8	$303,577	$2,649,566
	1997	5		2002	18				
2008	1997	1	$1,042,870	2002	18	$1,534,743	9	$231,685	$2,809,299
	1998	4		2003	32				
2009	1998	1	$1,924,721	2004	14	$437,125	6	$48,823	$2,410,669
	1999	1							
	2000	6							

DETAILS 2005 CAPITAL VEHICLE BUDGET

Heavy Fleet

Unit #	Dept Name	Year	Make/Model	Vehicle Type	Aerial Info	Odom Reading Date	Last Odom Reading	Maint Hist May 03-Apr 04
033C	WESTERN GANDER	1992	INTERNATIONAL C&C	Medium Duty Aerial	Altec AM438H Material Handler	30-Apr-04	310000	**$8,638.76**
218B	WESTERN GRAND FALLS	1993	FREIGHTLINER	Medium Duty Aerial	Altec Am438H Material Handler	30-Apr-04	247000	**$12,703.17**
091B	WESTERN GANDER	1993	INTERNATIONAL C&C	Medium Duty Aerial	Altec AM550H DBL Bucket Material Handler	30-Apr-04	220000	**$38,145.88**
124C	OPERATIONS	1994	FORD F450 4X2 DRW CHASSIS CAB	Other Heavy Equip	Cube Van Body (No Aerial)	30-Apr-04	221000	**$3,465.83**
327C	WESTERN CLARENVILLE	1994	FORD F450 4X2 DRW CHASSIS CAB	Other Heavy Equip	Stake Body (No Aerial)	30-Apr-04	134918	**$5,712.49**
711A	OPERATIONS	1994	GMC	Other Heavy Equip	Cube Van (No Aerial)	30-Apr-04	63000	**$5,911.35**
031D	WESTERN GRAND FALLS	1995	FORD F450 4X2 DRW CHASSIS CAB	Light Duty Aerial	Altec AT2506 Light Duty Aerial Device	30-Apr-04	210000	**$6,039.68**
Totals	7							

Passenger

Unit #	Dept Name	Year	Make	Model	Vehicle Type	Odom Reading Date	Last Odom Reading	Maint Hist May 03-Apr 04
117D	EASTERN ST. JOHN'S	1996	FORD TRUCK	RANGER P/UP	LIGHT DUTY TRUCK	6/3/2004	174091	**$911.56**
714A	MATERIALS MANAGEMENT	1997	PONTIAC	TRANSPORT	VAN	4/2/2004	131225	**$3,099.71**
028D	WESTERN CORNER BROOK	1998	TOYOTA	RAV4	FOUR WHEEL DRIVE	3/29/2004	133230	**$4,055.58**
185D	EASTERN BURIN	1999	DODGE TRUCK	RAM 1500	LIGHT DUTY TRUCK	4/13/2004	207287	**$4,031.92**
366D	WESTERN STEPHENVILLE	1999	FORD TRUCK	F150 P/UP	LIGHT DUTY TRUCK	5/3/2004	177530	**$2,843.24**
705B	EASTERN CARBONEAR	1999	FORD TRUCK	RANGER P/	LIGHT DUTY TRUCK	3/19/2004	214530	**$3,681.19**
367C	WESTERN CLARENVILLE	1999	DODGE TRUCK	RAM 1500	LIGHT DUTY TRUCK	3/19/2004	227638	**$4,686.42**
391C	ENGINEERING & ENERGY SUPPL\	1999	SUZUKI	VITARA 4X	FOUR WHEEL DRIVE	4/16/2004	59011	**$1,551.38**
223C	OPERATIONS	1999	CHEVROLET	CHEV VAN	VAN	5/19/2004	64548	**$1,274.75**
287D	OPERATIONS	1999	CHEVROLET	CHEV S10	LIGHT DUTY TRUCK	2/16/2004	72155	**$3,454.61**
358D	CUSTOMER SERVICE/MR	1999	SUZUKI	VITARA 4X	FOUR WHEEL DRIVE	3/18/2004	76590	**$2,834.52**
332D	CUSTOMER SERVICE/MR	1999	SUZUKI	VITARA 4X	FOUR WHEEL DRIVE	4/5/2004	85631	**$6,317.51**
069D	CUSTOMER SERVICE/MR	1999	TOYOTA	RAV4	FOUR WHEEL DRIVE	6/3/2004	98716	**$1,733.05**
035D	ENGINEERING & ENERGY SUPPL\	1999	DODGE TRUCK	DODGE P/U	PICKUP	6/3/2004	94520	**$3,340.16**
209E	WESTERN GRAND FALLS	1999	SUZUKI	VITARA 4X	FOUR WHEEL DRIVE	3/30/2004	108621	**$721.52**
194D	CUSTOMER SERVICE/MR	1999	SUZUKI	VITARA 4X	FOUR WHEEL DRIVE	3/30/2004	121203	**$3,823.88**
039C	CUSTOMER SERVICE/MR	1999	SUZUKI	VITARA 4X	FOUR WHEEL DRIVE	4/2/2004	123234	**$2,214.05**
079D	ENGINEERING & ENERGY SUPPL\	1999	JEEP	CHEROKEE	FOUR WHEEL DRIVE	4/30/2004	140845	**$3,066.34**
198E	WESTERN STEPHENVILLE	1999	SUZUKI	VITARA 4X	FOUR WHEEL DRIVE	5/25/2004	127236	**$1,140.51**
041E	WESTERN GRAND FALLS	1999	FORD TRUC	F150 P/UP	LIGHT DUTY TRUCK	4/15/2004	126652	**$5,982.02**
341D	WESTERN CLARENVILLE	1999	DODGE TRU	RAM 2500	LIGHT DUTY TRUCK	3/10/2004	135697	**$4,249.85**
093D	EASTERN ST. JOHN'S	1999	JEEP	CHEROKEE	FOUR WHEEL DRIVE	6/3/2004	122205	**$791.85**
286D	MATERIALS MANAGEMENT	1999	FORD TRUC	WINDSTAR	VAN	4/16/2004	137853	**$1,296.23**
276D	WESTERN GRAND FALLS	1999	DODGE TRU	DODGE P/U	PICKUP	6/3/2004	129741	**$1,688.91**
067E	WESTERN GRAND FALLS	1999	SUZUKI	VITARA 4X	FOUR WHEEL DRIVE	4/16/2004	138122	**$4,004.14**
376C	OPERATIONS	1999	DODGE TRUCK	DODGE B35	VAN	3/16/2004	130042	**$3,194.71**
141E	WESTERN STEPHENVILLE	1999	DODGE	STRATUS	CAR	4/26/2004	141361	**$1,586.32**
042E	WESTERN CORNER BROOK	1999	CHEVROLET	ASTRO C/V	VAN	5/28/2004	139863	**$3,529.70**
221C	CUSTOMER SERVICE/SAFETY	1999	CHEVROLET	ASTRO C/V	VAN	5/12/2004	130708	**$1,445.43**
164D	WESTERN GANDER	1999	FORD TRUC	RANGER P/U	LIGHT DUTY TRUCK	4/5/2004	147653	**$2,010.44**
313D	WESTERN STEPHENVILLE	1999	DODGE TRU	DODGE P/U	PICKUP	3/10/2004	161248	**$1,413.02**
011D	ENGINEERING & ENERGY SUPPL\	1999	CHEVROLET	CHEV S10	LIGHT DUTY TRUCK	5/13/2004	155171	**$3,606.86**
165C	EASTERN BURIN	1999	DODGE TRU	RAM P/UP	LIGHT DUTY TRUCK	4/13/2004	150840	**$4,940.44**
244E	CUSTOMER SERVICE/MR	1999	TOYOTA	RAV4	FOUR WHEEL DRIVE	4/30/2004	168144	**$1,036.60**
148C	ENGINEERING & ENERGY SUPPL\	1999	CHEVROLET	ASTRO C/V	VAN	4/27/2004	167871	**$5,830.70**
349D	EASTERN CARBONEAR	1999	FORD TRUC	RANGER P/	LIGHT DUTY TRUCK	6/3/2004	156811	**$2,386.14**
015D	TRANSPORTATION & LANDS	1999	CHEVROLET	ASTRO C/V	VAN	4/6/2004	155011	**$6,211.19**
281D	ENGINEERING & ENERGY SUPPL\	1999	DODGE TRUCK	DODGE B35	VAN	4/8/2004	159227	**$4,483.77**
182D	EASTERN BURIN	1999	DODGE TRU	DODGE P/U	LIGHT DUTY TRUCK	4/15/2004	162585	**$4,196.73**
399C	WESTERN GRAND FALLS	1999	TOYOTA	RAV4	FOUR WHEEL DRIVE	6/1/2004	164921	**$770.11**
181D	WESTERN GANDER	1999	SUZUKI	VITARA 4X	FOUR WHEEL DRIVE	4/30/2004	170909	**$10,566.54**
335D	WESTERN CLARENVILLE	1999	FORD TRUC	F150 P/UP	LIGHT DUTY TRUCK	5/11/2004	171799	**$5,566.43**
183E	WESTERN CLARENVILLE	1999	SUZUKI	VITARA 4X	FOUR WHEEL DRIVE	4/7/2004	174775	**$2,750.45**
363E	WESTERN GANDER	1999	CHEVROLET	CHEV S10	LIGHT DUTY TRUCK	4/12/2004	172699	**$6,385.30**
096C	WESTERN CLARENVILLE	1999	DODGE TRU	RAM P/UP	LIGHT DUTY TRUCK	5/25/2004	175877	**$2,479.58**
333D	CUSTOMER SERVICE/MR	1999	TOYOTA	RAV4	FOUR WHEEL DRIVE	5/4/2004	184716	**$3,345.94**
Totals	46							

DETAILS 2005 CAPITAL VEHICLE BUDGET

Off Road Unit #	Dept Code	Dept Name	Year	Unit Type	Comments
		EASTERN/WESTERN		ATV	
				ATV	
				Snowmobile	
				Snowmobile	
				Reel Trailer	
				Snowmobile	
				Tension Stringer	
				Tension Stringer	
Totals	**8**				

Project Title: **Application Enhancements**

Location: **All Service Areas**

Classification: **Information Systems**

Project Cost: **$1,087,000**

This project consists of a number of items as noted.

(a) Business Support Systems

Cost: $115,000

Description: The purpose of this project is to enhance the processes related to the Company's financial, materials management and human resources applications. For 2005, the proposed enhancements include:

1. **Fixed Assets - $34,000**
   Plant information is used to determine the Company's depreciation expenses, provide information for the financial reports and to determine the net book value of assets.

   Approximately 40,000 plant records are stored in a Microsoft Access database to which access is limited to a small number of employees in the Finance department. This project will enhance processes related to the capturing, tracking and reporting of the Company's plant records by providing employees outside of the Finance department (such as engineering technicians) with access to plant information. This is regularly needed to determine the original cost of plant, installation dates, and age of plant assets.

2. **Bank Reconciliation - $44,000**
   Today each area office keys bank deposits into a Microsoft Access database. Every month this information is compiled and re-keyed into the Company's financial system, Great Plains. Benefits of this project include:

- The elimination of re-keying as area offices will key bank deposits directly into Great Plains on a daily basis.

- The automatic matching of deposits and cheques by date and amount, reducing the time Finance employees have to spend reconciling these items (including the reliance on specific individuals).

- The creation of standard reports including cheque book list, cheque book register report, and bank distribution history within Great Plains.

3. **Contract Management System – $37,000**
   This project involves enhancing the current contract management system. Benefits of this project include:

- The ability to view current and previous performance issues with a contractor which may affect the decision to award a contract to them.

- The ability to foresee potential contractor capacity challenges by knowing the number of other contracts already awarded to the same contractor.

- The ability to view the status of insurances and Workplace Health and Safety forms to ensure the appropriate documentation is in place.

- The automatic generation of a Contractor Standing Agreement with a contract number assigned would eliminate the need for the Purchasing group to re-key data into the system.

- The ability of staff outside the Purchasing group to view Contractor Standing Agreements.

(b) Intranet/Internet Enhancements

Cost: $101,000

Description: The purpose of this item is to enhance the Company's internal web site (Intranet) used by employees, as well as the Company's Internet website used by the Company's customers and other interested parties. For 2005, the proposed enhancements include:

1. **Changes to the Intranet - $50,000**
   Make improvements to the Company's Intranet to increase the availability of information by providing quicker access to data, applications and reports that employees need to respond to customer inquiries and perform other work responsibilities. Benefits include:

- Improved access to information making it easier to retrieve, enabling faster response to customer queries.

- Improved access and management of documentation to reduce the need to prepare, consolidate, and distribute information to various stakeholders. The information is available from a single location when needed. For example, Company targets can be posted on the Intranet for viewing by all employees instead of emailing the information to each employee. This ensures employees are always using the most current information.

- Improved communication and collaboration through the sharing of information.

- A financial analysis of the costs and benefits associated with this project results in a positive net present value over the next 5 years.

2. **Changes to the Company's Internet site - $51,000**
   Make enhancements to customer self-service options on the Company's Internet site. Benefits include:

- Providing customers with the ability to view their electric bill for the previous 12 months.

- More efficient responses to customer requests by ensuring the most appropriate staff respond to the internet query based on the category selected by the customer.

(c) Operations and Engineering Enhancements

Cost: $368,000

Description: The purpose of this item is to implement improvements in the Company's operations and engineering applications in the areas of asset management, work order management and SCADA. The following are the individual initiatives within this item:

1. **Line Inspections - $83,000**
   This project involves improvements to the current line inspection systems. Currently, inspection findings are recorded on paper forms in the field and the deficiencies are later entered into the system. With the current system there is no efficient method to track, schedule or follow-up on these deficiencies. An improved system will provide the following benefits:

- Make the planning, scheduling, completion, and follow-up of both inspections and deficiencies more efficient and manageable.

- Capture more information on the history of inspections and maintenance of all lines.

- Improve the planning processes to ensure that the required tools and equipment are available to perform maintenance work.

- A financial analysis of the costs and benefits associated with this project results in a positive net present value over the next 5 years.

2. **<u>MRO Inventory</u> – $108,000**
This project involves improvements to the MRO inventory processes. MRO inventory is the inventory necessary for the maintenance, repair and overhaul work performed in substations and plants. Currently there is limited inventory tracked or reserved for maintenance work. The integration between the Asset Management System and the Great Plains Inventory System will be enhanced in order to ensure inventory is available when the maintenance job is scheduled. Benefits include:

- Placing the procurement of inventory for MRO with the Purchasing group will allow for materials to be purchased using established procurement processes such as purchasing in bulk rather than "just in time" purchasing.

- Reducing the amount of time spent by planners, supervisors, engineers, and trades people on the ad-hoc purchase of materials.

- A financial analysis of the costs and benefits associated with this project results in a positive net present value over the next 5 years.

3. **<u>SCADA Enhancements</u> - $177,000**
This project consists of the following improvements to the Company's System Control and Data Acquisition (SCADA) system. The SCADA system provides the capability and capacity for the Company to remotely monitor and control sections of the electrical distribution system. The proposed enhancements include improving the Company's information exchange with Newfoundland and Labrador Hydro ("Hydro") and adding electronic tagging capabilities to the SCADA system for the System Control Centre (SCC).

(i) With the implementation of Hydro's new Energy Management System, the sharing of SCADA-related data between the two companies can be improved. This project involves upgrading the Company's communications protocol to the same protocol to be used by Hydro. Benefits include:

- Sharing of a greater range of data between Newfoundland Power and Hydro related to the respective electrical systems.

- Improvements in the accuracy of SCADA-related information transferred between the two utilities.

(ii) The SCADA system will be enhanced to include the ability for the SCC to confirm and tag normally open devices on distribution feeders and tag mechanical components of the Company's hydro generating plants. Tagging indicates a component's status, such as whether a cutout is open or closed. Benefits include:

- Eliminating the time it takes for crews to travel to, and physically tag, normally open devices before beginning any work. This will help to improve the responsiveness of crews to customer trouble calls.

- Improved compliance with safety rules and standards. The Standard Protection Code states *Normally Open cutouts permanently identified with yellow signs must be confirmed open by the Control Authority or tagged***.** Currently, the Control Authority (i.e. the SCC) has no ability to confirm normally open cutouts for line crews. Therefore, the crews must physically locate and tag them before beginning their work.

- Improved communications between the SCC and field personnel when conducting work on the electrical system related to switching orders and safety procedures.

(d) Customer Service System Enhancements

Cost: $353,000

Description: The purpose of this item is to implement improvements in the customer service area. The following are the individual initiatives within this item:

1. **<u>Service Order Improvements</u> - $54,000**
When field work, such as the installation of a streetlight, is required, a service order request is generated through the Customer Service System and a paper copy of the request is printed and forwarded manually to area office personnel for scheduling and completion. Because this process is paper based, Customer Contact Centre agents have limited access to information about the current status of service orders. Further, misplaced or misdirected paper can delay service order completion. Benefits include:

- Enabling the Customer Contact Centre to respond to customer inquiries regarding their service orders more accurately and efficiently by monitoring the status of each service order electronically.

- Completion of service orders in a timelier manner.

- Improving the tracking and scheduling of service orders and reducing the risk of lost or misplaced service orders.

- Better control over service orders will reduce the number of accounts that are billed incorrectly due to delays caused by the manual process.

2. **<u>Interactive Voice Response</u> - $156,000**
The improved self-service application will offer customers the ability to make mailing address changes, requests for brochures, and submit self-read meter readings without having to talk to an agent. Benefits include:

    - Allowing the company to provide better response to customers during peak usage times by having the IVR handle calls for routine items such as name changes or final read requests through system prompted messages. The agents can then complete these requests during times when call volumes are reduced.

    - An additional 15,000 to 20,000 calls per year would be completed through the self-service functions.

    - A financial analysis of the costs and benefits associated with this project results in a positive net present value over the next 5 years.

3. **<u>Customer Service Reporting</u> - $143,000**
This project involves collecting information regarding customer contacts and recording this information in a database to support more efficient routing of customer calls to Contact Centre agents and to allow reporting which will support new and revised customer service programs.

    Examples of the information demographics which will be recorded and tracked include frequency of repeat calls by customers and the nature of calls. Benefits include:

    - An integrated contact tracking and reporting environment will allow incoming calls to be routed to agents with the appropriate experience and skill level based on information gathered about the call and the customer. This will improve customer service and introduce efficiencies by reducing both the length of calls and the incidence of multiple contacts for the same issue.

    - A better understanding of the nature of contacts will help identify where service improvements are required, support agent training and coaching activities, and identify where existing programs might be improved to provide better service to customers.

    - A financial analysis of the costs and benefits associated with this project results in a positive net present value over the next 5 years.

(e) Various Minor Enhancements:

Cost: $150,000

Description: The purpose of this item is to complete enhancements to the Company's computer applications in response to unforeseen requirements such as legislative and compliance changes, vendor driven changes and employee driven enhancements designed to improve customer service or staff productivity. Examples of previous changes include adding criteria to the Customer Service System to flag accounts that are outside of a normal consumption range for manual review before billing, and government driven changes to income tax calculations in the payroll applications.

Project Title: **Application Environment**

Location: **All Service Areas**

Classification: **Information Systems**

Project Cost: **$710,000**

Description: This project consists of upgrades to software components and processes related to the operation of the Company's business applications. For 2005, the proposed upgrades include:

1. **<u>The Microsoft Enterprise Agreement</u> – $210,000**
   This Agreement covers the purchase of Microsoft software and provides access to the latest versions of each software product purchased under this agreement.

   Through the Microsoft Enterprise Agreement, Newfoundland Power achieves an overall cost savings. This is a fixed, annual price agreement based on the number of eligible desktops. Under this agreement, the Company distributes its purchasing costs for these licenses over three years.

   In June 2004, the Company investigated the three options for the purchase of the following Microsoft licenses: Windows Professional, Office Professional and Client Access Licenses for Exchange Server, SQL Server, Windows Server, and System Management Server. The three options identified by the Company were:

   - Do nothing now, and pay for new licenses to upgrade in the future. The expected cost per personal computer is $1,117 over three years.

   - Renew the existing Microsoft Enterprise Agreement at the proposed discount. This provides the Company with ownership of the latest releases of the identified software. These licenses are paid for annually following a count of the personal computers within the Company. Costs are spread out over the three-year period. The annual cost per personal computer is $263, or $789 over three years.

   - Purchase a Microsoft Select Agreement for each installation of the software. This provides the Company with ownership of the latest releases of the identified software. These licenses have to be purchased individually as they are needed. The annual cost per personal computer is $311, or $933 over three years.

   The Enterprise Agreement is the least expensive and least administratively burdensome option for Newfoundland Power at this time.

2. **<u>Database and Development software</u> – $270,000**
   This item involves upgrades to the underlying software components used by the Company's application systems. These components include database management software and software used to develop, modify and operate business applications. These upgrades will ensure the Company's business applications continue to function in a stable and reliable manner and ensure an appropriate level of vendor support is sustained. For 2005, proposed upgrades include:

   - Oracle Database Upgrade - $48,000
     Customer self service data, used by customers who access their account information over the Internet, uses Oracle database software. The version currently in use is no longer supported by Oracle. An upgrade is required to ensure an appropriate level of support from Oracle.

   - Internet Website Environment Upgrade - $53,000
     The Company's Internet website environment resides on a server running Microsoft Windows NT version 4.0 operating system. This operating system will not be supported by Microsoft beyond 2004. The Company's Internet website receives in excess of 17,000 visits per month. Customers who use the eBills option access the website to view an electronic copy of their electric bill. Upgrading the Internet website environment will ensure the availability, integrity, and security of the website for customers.

   - Cognos Powerhouse and Axiant Upgrade - $169,000
     Powerhouse and Axiant software, which are used by Contact Centre Agents to access the Customer Service System to respond to customer requests for service, will not be supported by Cognos beyond February 2005. This upgrade will ensure continued vendor support for this critical software component.

3. **<u>Environment Management software</u> – $230,000**
   Environment Management, from an Information Technology perspective, refers to the technology and processes used to develop, configure, test, implement, and maintain applications and infrastructure throughout the Company. For 2005 this includes:

   - Help Desk Software Upgrade - $62,000
     This project involves upgrades to the Company's Information Services Help Desk software to support asset configuration and change management business processes. Asset configuration is used to track PCs and shared servers and the installed software. Change management is used to track changes made to applications and technology infrastructure.

   - Password Management Software - $55,000
     This project involves the purchase and deployment of password management software. Password management software will allow Company employees to efficiently change and control their passwords on the Company's computing systems,

eliminating calls to the Information Services Help Desk for assistance when passwords are forgotten.

- Automated Software Test Tools - $66,000
  This project involves the purchase and deployment of automated software test tools used in maintaining and enhancing the Company's corporate applications such as the Customer Service System and the Outage Management System. By utilizing automated testing tools the Company will reduce overall testing time, increase the speed to implement enhancements, and decrease the possibility of human error.

- Development and Test Systems Improvements - $47,000
  This project involves improvements to the Company's development and test systems that will allow employees to develop and test multiple versions and configurations of its applications simultaneously. An improved testing environment will reduce start-up and preparation time and allow employees to effectively analyze the full impact of changes prior to implementing them in the production environment.

Justification: Investment in the Application Environment is necessary to upgrade outdated technology that is no longer supported by vendors and to take advantage of newly developed capabilities. The Application Environment is essential to ensuring that changes made to software applications are sufficiently tested and stable before deployment into the production environment, thereby reducing the risk of downtime. Unstable and unsupported software applications can negatively impact operating efficiencies and customer service.

Project Title: **Customer Systems Replacement**

Location: **All Service Areas**

Classification: **Information Systems**

Project Cost: **$ 144,000**

Description: This project consists of enhancing the nightly Customer Service System (CSS) batch processing (e.g. posting meter readings, posting cash payments, billing, etc.) to reduce the amount of time it takes to execute the programs, reduce the amount of manual intervention currently required, and to reduce the Company's dependence on the OpenVMS operating system. This will be achieved by enhancing the existing batch processing programs to run more efficiently and by the automatic scheduling of batch processing programs to run during the night.

Operating Experience: The CSS batch processing typically occurs from 6:00pm to 3:00am each weeknight. Computer Operators are required to submit new batch programs as other batch programs complete in a pre-defined sequence. The process of monitoring the completion of batch programs and subsequently running the next program in sequence is very manual, requiring the Computer Operator to be present throughout the night.

Justification: A financial analysis of the costs and benefits associated with this project results in a positive net present value over the next 5 years.

Benefits include:

- Reducing the amount of Computer Operator intervention will allow them to focus on more meaningful tasks;

- Reduced reliance on the OpenVMS system, in keeping with the findings of the *Customer Service System Replacement Analysis* report filed with the Public Utilities Board as part of the Company's 2004 Capital Budget Application (Volume IV, Information Systems, Appendix 3, Attachment A);

- Increased effectiveness of the Computer Operators by reducing the risk of human error associated with manual intervention.

Project Title: **Network Infrastructure**

Location: **All Service Areas**

Classification: **Information Systems**

Project Cost: **$276,000**

Description: This project involves the upgrade and replacement of hardware components of the Company's network infrastructure to enhance the connectivity and reliability at the data centers located at Kenmount Road, Duffy Place, and Topsail Road.

Operating Experience: The network infrastructure is comprised of technical components such as routers and switches that interconnect computers and applications across the Company. These components all work together to enable the transport and sharing of SCADA data, VHF radio signals, and corporate data between the Company's computers across the province. For example, serving customers in Corner Brook requires Customer Service System information to be transmitted from St. John's over the network infrastructure to a cashier's personal computer in Corner Brook. Monitoring the current operating status of the electrical system on the west coast by employees at the System Control Centre ("SCC") in St. John's is also done via the network infrastructure.

Justification: The reliability and availability of the network infrastructure is critical to enabling the Company to continue to provide least cost reliable electric service to customers. The corporate network is the foundation for such critical applications as the Customer Service System, the SCADA System, and the Outage Management System. The replacement or upgrade of the network components will ensure the continued stability of the corporate network, thereby avoiding disruptions to customer service and the interruption of critical communications.

The components of the network infrastructure to be purchased in 2005 include:

- Fibre optic cables and software to interconnect the existing data storage systems located in the Kenmount Road computer room to a backup data storage system located in the computer room at Duffy Place. In the event of a major system failure at Kenmount Road, data stored in the Customer Service System can be recovered within 3 hours rather than twenty-four hours, which is the current recovery time. The budget for this item is $147,000.

- A high availability network switch for the network at the SCC on Topsail Road. The network switch allows the SCC to access outage information stored in the Outage Management System, as well as information about the electrical system stored in the

SCADA system. The network at the System Control Centre is required twenty four hours per day every day in order to ensure that customer service and employee and public safety are not jeopardized. The high availability switch will have built-in redundancy to ensure network availability at all times. The budget for this item is $129,000.

Project Title: **Personal Computer Infrastructure**

Location: **All Service Areas**

Classification: **Information Systems**

Project Cost: **$455,000**

Description: This project involves the addition, upgrade, and replacement of computer hardware and related technology associated with the Company's personal computing infrastructure to ensure that the Company continues to provide effective customer service and to operate efficiently.

Operating Experience: The Personal Computer Infrastructure project includes the procurement, implementation and management of the hardware relating to the operation of personal computing facilities. Management of these computers and their components (i.e. PDAs, printers, scanners, etc) is vital to ensuring that computer applications are available and operating effectively at all times.

Minimum specifications for replacement personal computers ("PCs") are reviewed annually to ensure the personal computing infrastructure continues to remain effective. Industry best practices, technology trends, and the Company's experience are considered when establishing minimum specifications.

The Company's research and experience indicates that an average of four to six years of useful life is attainable before PCs require replacement. This is achieved through the Company's practice of cascading PCs to employees who do not require the computing power of newer PCs, thereby maximizing the asset life of the PC.

The following table outlines the plan for PC additions and retirements:

	2003			**2004 Plan**			**2005 Plan**		
	Add	**Retire**	**Total**	**Add**	**Retire**	**Total**	**Add**	**Retire**	**Total**
Desktop	94	104	490	73	73	490	88	88	490
Laptop	30	26	122	35	35	122	25	25	122
Total	**124**	**130**	**612**	**108**	**108**	**612**	**113**	**113**	**612**

Justification: Personal Computers and associated peripheral equipment are used by employees throughout the Company to access applications to respond to customer requests for service, and to allow employees to be more efficient in their work activities.

The on-going replacement of the personal computer infrastructure ensures that the gains already attained in customer service and operating efficiencies are maintained.

Project Title: **Shared Server Infrastructure**

Location: **All Service Areas**

Classification: **Information Systems**

Project Cost: **$571,000**

Description: This project involves the addition, upgrade and replacement of computer hardware components and related technology associated with the Company's shared server infrastructure to ensure that the Company continues to provide effective customer service and to operate efficiently. For 2005, this project includes:

a) Purchase and implementation of five replacement servers. The budget for this item is $197,000 and includes:
   - Two servers to improve the Company's capabilities to recover its applications and associated infrastructure in the event of a failure at its primary computing facility.
   - Two servers to upgrade the Company's Internet Website. Currently, the website resides on server infrastructure that will be replaced as part of the Application Environment project. This upgrade will also enhance the overall security of the website.
   - One server to improve the Company's access to the Internet. The proxy software that acts as the Company's gateway to the Internet and maintains security controls on data transferred to and from the corporate network is no longer supported by the vendor and security patches are no longer available. Replacement of the software, and the aged server on which it runs, will ensure that the integrity of Internet access is maintained and supported by the vendor.

b) Purchase and implementation of additional disk storage, memory, and CPU upgrades for servers which are currently used to run corporate applications. Upgrades of shared servers are required in order to maintain adequate performance and availability of corporate applications that are used to provide service to customers and enable operating efficiencies. The budget for this item is $49,000.

c) Enhancements to security infrastructure and monitoring capabilities in order to provide adequate protection of customer data, improve operating efficiencies, and improve protection of the Company's information technology investment. Enhancements will be made to the SCADA Infrastructure, Internet Firewalls, Internet Intrusion Detection System, and software used to deploy upgrades to PCs. The budget for this item is $290,000.

d) Purchase of additional Citrix software licenses to provide secure remote access to the Company's applications. This will allow additional employees to access applications and data files stored on the Company's shared server infrastructure from a remote location such as a hotel room or from home. The budget for this item is $35,000.

Operating Experience: The Shared Server Infrastructure project includes the procurement, implementation and management of the hardware and software relating to the operation of shared servers. Shared servers are computers that support applications used by multiple employees. Management of these shared servers, and their components, is critical to ensuring that these applications operate effectively at all times.

Technology components such as servers and disks require on-going investment to ensure that they continue to operate effectively. To maintain this effectiveness, investment in additions, upgrades, monitoring and security is essential.

An upgrade is a modification that extends the useful life of a technology component by fixing known problems, improving usability, and providing additional features and functionality. Hardware upgrades are also necessary to accommodate software enhancements, and include such things as adding extra disk storage or tape backup units.

In order to ensure high availability of applications and minimize the vulnerability of its computer systems to external interference, the Company invests in availability monitoring and proactive security monitoring tools. These tools allow the Company to monitor and respond to problems that could impede the normal operation of applications or damage or destroy information.

Eventually the individual components of technology (servers, disk drives, tape drives, processors and memory chips, etc) will require complete replacement as they become obsolete; the challenge is to make appropriate judgments as to when it is more cost effective to add or replace technology components rather than invest in further upgrades.

Factors considered in determining when to upgrade, replace or add server components include the current performance of the components, the level of support provided by the vendor, the criticality of the applications running on the shared server components, the ability of the components to meet future growth, the cost of maintaining and operating the components using internal staff and the business or customer impact if the component fails. Gartner states that computer servers have a useful life of approximately 5 years.[1] By making appropriate investments in its shared server infrastructure, Newfoundland Power's experience is that the useful life of its corporate servers has exceeded Gartner's findings.

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[1] Gartner Group is a research and advisory firm that helps more than 10,000 businesses understand information technology. Founded in 1979, Gartner is headquartered in Stamford, Connecticut and consists of 4,600 associates, including 1,400 research analysts and consultants, in more than 83 locations worldwide.

Justification: The Shared Server Infrastructure is vital to the provision of low cost, efficient and reliable service to customers. The need to replace and modernize information technology infrastructure is fundamentally the same as the need to replace and modernize the components of the Company's electrical system infrastructure as it deteriorates or becomes obsolete. Instability within the Shared Server Infrastructure has the potential to impact high numbers of employees and customers and therefore is critical to the Company's overall operations and to the provision of overall customer service.