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Newfoundland Power Inc.
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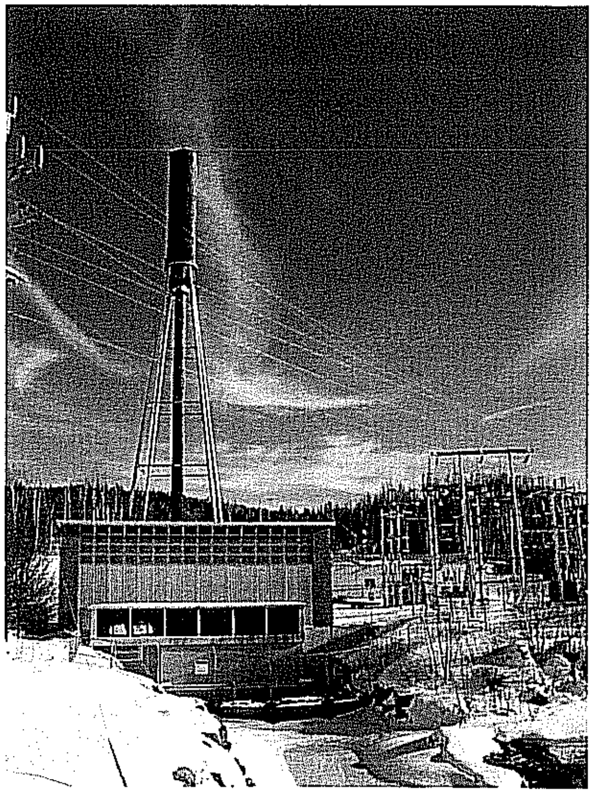
Volume II

Supporting Materials

Rattling Brook Hydro Plant Refurbishment

Rattling Brook Hydro Plant Refurbishment



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March 2006

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NEWFOUNDLAND & LABRADOR

NEWFOUNDLAND POWER
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1.0 Introduction

The Rattling Brook hydroelectric development is the largest generating station operated by Newfoundland Power. It is located approximately 50 kilometres west of Gander in the Notre Dame Bay community of Norris Arm South. The development went into service in December 1958 and has provided 48 years of reliable energy production. The normal annual plant production is approximately 69.8 GWh of energy, or about 16.6% of Newfoundland Power's total hydroelectric generation.

In 2007, Newfoundland Power has confirmed that the woodstave penstock and surge tank require replacement and refurbishment respectively. In addition, Newfoundland Power has identified necessary electrical and mechanical upgrades for 2007.

In 2008, Newfoundland Power has identified replacement and refurbishment work required on the dams and spillways that comprise the water storage system for the Rattling Brook development.

This project is necessary at this time due to the age and physical condition of the plant assets, the details of which are included in the appendices of this report. The woodstave penstock is 48 years old and at the end of its service life. It is in poor condition and must be replaced in 2007. The surge tank has a corroded lower riser pipe and deteriorated surfaces and coating in the main tank. In addition, the exterior cladding system is deteriorated and requires replacement. Undertaking the refurbishment of the surge tank in 2007 will avoid the complete replacement of this 300 foot high structure in the near future. See Appendix A for pictures of the penstock and surge tank.

Due to the condition of the penstock, the only alternative to this project is to decommission the plant, resulting in the loss of 69.8 GWh of energy and 11.2 MW of capacity. However, results of the feasibility analysis conclude that the continued operation of the Rattling Brook hydroelectric development, including the planned replacement and refurbishment project, is economically viable over the long term.

The replacement of the penstock and main valves provides an opportunity to increase the energy production from the plant. By delivering the water to the generator turbines more efficiently, 6.2 GWh in additional energy can be recovered. This quantity of incremental energy is similar to the quantity of energy provided annually from the Morris plant on the Southern Shore and will displace approximately 10,500 barrels of oil per year burned at Newfoundland and Labrador Hydro's Holyrood thermal generating plant.

After refurbishment, the Rattling Brook plant will provide an additional 2.9 MW of energy on peak to the Island Interconnected electrical system. This project will allow Newfoundland Power to continue to operate this facility over the long term, maximizing the benefits of this renewable resource for its customers.

2.0 Background

The Newfoundland and Labrador Board of Commissioners of Public Utilities (the "Board") approved the expenditure of $350,000 in Newfoundland Power's 2005 Capital Budget Application for the preparation of detailed engineering relating to the Rattling Brook plant rehabilitation. As part of this engineering, Newfoundland Power commenced an assessment of the Rattling Brook system early in 2005 to determine the project scope and verify the budget for the work to be completed. Assessment reports are included as Appendices B through F of this summary report. Appendix G includes the project schedule. Appendix H includes a feasibility analysis of the costs and benefits associated with the project. Figure 1 is a map of the lower section of the Rattling Brook hydroelectric development.

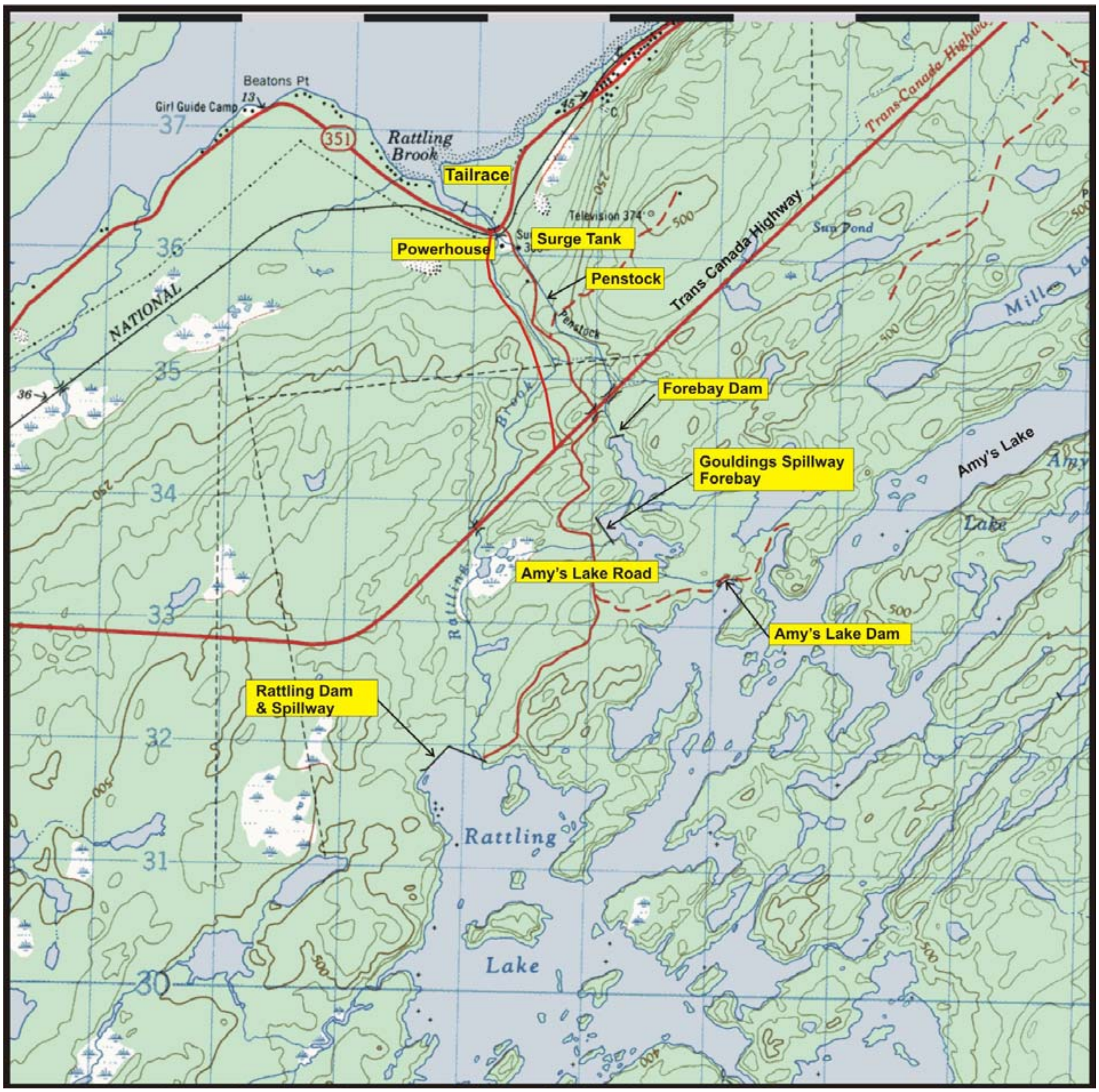

Figure 1

Since 1958, there have been various upgrades to the original plant and equipment. The major upgrades that have occurred in the past 20 years are:

- In 1986 and 1987, the turbine runners were replaced on both units;
- In 1988, Frozen Ocean Lake dam was rebuilt;
- In 2002, a new power transformer was installed in the substation replacing the two original transformers;
- In 2002, the stator on unit #2 generator was rewound due to an in-service failure; and
- In 2004, the stator on unit #1 generator was rewound.

Due to these past upgrades, no work is required on the above plant and equipment at this time.

Engineering assessments were completed on the penstock and surge tank in 2003. Engineering assessments for the remaining systems were completed in 2005 and early 2006. All major components of the Rattling Brook system have been reviewed. Based on these engineering assessments, the project scope and budget have been finalized and are presented in this report.

3.0 Civil Works

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

- Replace woodstave penstock;
- Coat interior of existing steel penstock;
- Refurbish surge tank; and
- Powerhouse extension and other plant modifications.

Justification for replacement of the woodstave penstock and upgrades to the surge tank were submitted to the Board as part of the 2005 Capital Budget Application. The report completed by SGE Acres titled *Surge Tank and Penstock Replacement – Rattling Brook Hydroelectric Development* is located in Appendix B.

3.1 Penstock

The woodstave penstock is 48 years old and is in poor condition with excessive deterioration and significant leakage along the spring line. The penstock bedding is saturated resulting in localized settlement of the pipe, with the penstock resting on the ground in a number of locations. In recent years, a number of major leaks have resulted in undermining of the support structure in several locations. Leakage is expected to worsen causing operational difficulties, increasing maintenance costs and lost energy. It is proposed to replace the woodstave penstock in 2007.

The lower steel section of the penstock is in fair condition but is showing signs of internal corrosion. It is proposed to coat the interior of the existing steel penstock with a coating system to extend the life of this section of the penstock.

3.1.1 Optimum Penstock Diameter

The existing penstock diameter limits the maximum output of the plant when both units are in operation. When the plant was originally designed, it operated on an isolated system in the Grand Fall's area. Only one unit was operated at a time, with the second unit available as a backup for maintenance purposes. When the plant was connected to the provincial grid the operational requirements changed and both units were in-service simultaneously. However, the plant output and capacity were limited when operating the two units due to high head losses in the penstock. Newfoundland Power intends to increase the plant output and capacity by installing a larger diameter penstock when replacing the deteriorated woodstave penstock. The larger diameter penstock will reduce the head losses in the penstock and result in higher plant production and capacity.

Newfoundland Power intends to replace the existing 2.1 and 2.3 metre diameter woodstave penstock with a 2.9 metre diameter penstock to obtain an additional estimated 5.2 GWh of energy and 2.9 MW of capacity. The incremental cost of increasing the penstock diameter to the optimal diameter of 2.9 metres is justified by the increased energy supplied.

A review selecting the optimum replacement diameter for the woodstave penstock was completed by SGE Acres. A copy of this report is contained in Appendix C *Rattling Brook Development Selection of Optimum Penstock Diameter*. It should be noted that no additional water is required to obtain this energy gain from the system. The additional energy is a result of reduced head losses in the larger diameter penstock, resulting in a higher head at the turbines and thus higher energy output. The larger penstock will increase the megawatt output at the plant from 11.2 to 14.1 MW.

3.1.2 Penstock Replacement Options

Two options are being considered for the replacement of the penstock. These include:

- Building a new penstock adjacent to the existing; or
- Building a new penstock in the same location as the existing.

A review of both options was completed to determine the most feasible and lowest cost alternative. The completed assessment identified several reasons construction of a new penstock adjacent to the existing penstock was not feasible. The reasons include:

1. The surge tank requires a six month outage to complete the refurbishment during which the penstock and surge tank must be drained. Therefore, lost production will not be avoided by twinning the penstock route during this period;

2. The section where the existing penstock crosses under the TCH could not accommodate the second parallel penstock;

3. The civil cost associated with building an adjacent penstock and access road is greater than the cost of replacing the penstock in the existing location;

4. Project costs increase with twinning of the penstock as the project would have to be executed over two construction seasons; and

5. Demolition costs increase significantly as the old penstock must be removed with the new penstock in place making demolition and removal costly as access to the old penstock would be obstructed by the new penstock.

For these reasons the most feasible option is to construct the new penstock in the same location as the existing penstock with some slight alignment improvements over one construction season. The existing penstock does not have an access road adjacent to it. Either replacement option will require the construction of an access road along the existing penstock.

In addition to the two options presented above, the following construction material options are being considered for the replacement of the penstock:

- Building a steel penstock; or
- Building a fibreglass reinforced penstock.

The penstock can potentially be constructed from steel or fibreglass. Engineering estimates have shown that currently the steel and fibreglass options are similar in cost. However, both materials have seen volatility in pricing in recent years. While steel is widely used for penstock applications, fibreglass is not commonly used in the larger diameter penstock proposed for Rattling Brook. It is planned to tender both the steel and fibreglass options to ensure competitive bidding and proceed with the least cost option that meets all technical and engineering requirements.

3.2 Surge Tank

The surge tank is in fair to poor condition and requires an extensive refurbishment to extend the life of the structure. Significant rehabilitation of the structural steel, main tank and internal riser are required. The external riser has deteriorated to the point where complete replacement is necessary. An inspection of the surge tank was completed by SGE Acres in 2003 and their report is included in Appendix B. Issues that will be addressed as part of the 2007 refurbishment plan includes:

- Replacement of the external riser due to heavy corrosion;
- Sandblasting and coating of the tank section;
- General structural and coating upgrades;
- Demolition of the deteriorated wood cladding and installation of a new metal cladding system;
- Installation of a new tank winter heating system; and
- Installation of a new fall arrest system to comply with safety code requirements.

Upgrades to the surge tank will extend the life of the structure and avoid costly replacement of the entire structure in the near future.

3.3 Civil Infrastructure (2008)

Assessments were completed of the civil infrastructure at Rattling Brook including dams, dykes, tunnels, control gates and roads. The assessment is included in Appendix D, *Civil Infrastructure Assessment*. In summary, the civil infrastructure is in good condition. However several items require attention in 2008 to ensure the continued safe and reliable operation of this facility.

Based on the findings in the report the following work is planned for the Rattling Brook hydro system in 2008:

- Replacement of Rattling Lake spillway;
- Upgrades to Amy’s dam and Amy’s three freeboard dams;
- Replacement of Amy’s outlet gate;
- Upgrades to Rattling Lake dam; and
- Upgrades to site access roads.

Due to the need to maximize water storage in the reservoir during the 2007 construction period, water levels in the reservoir will be too high to complete the dam and spillway upgrades. The upgrades will be scheduled in 2008 so they can be completed at lower water levels and without any additional spill from the system. The proposed upgrades will be submitted for approval with the 2008 Capital Budget Application.

3.4 Powerhouse Upgrades

The powerhouse will be upgraded to house the communications equipment, office space and washroom facilities, which are currently in the former control centre building. A small extension will be required in the powerhouse to accommodate these additions. The former control centre building will be used during construction for office space by the project team but will be demolished after completion of the project. This will result in operational savings by eliminating any future maintenance and upgrades to the control centre building.

Other upgrades to the powerhouse include replacement of the 25 year old roof, replacement of the overhead door, provision for a battery room, provision of a switchgear room and installation of access ladders and platforms which are required for safe access to equipment. The garage building adjacent to the powerhouse has become dilapidated and will be renovated.

In summary, the powerhouse upgrades will include:

- Powerhouse building extension;
- Replacement of the powerhouse roof;
- Provision of access ladders and platforms;
- Construction of battery and switchgear rooms within existing building;
- Upgrades to the garage building; and
- Demolition of the old control centre building.

4.0 Electrical Works

Except for the new power transformer, the substation is in its original 1958 condition. Consequently, the materials, hardware and clearances do not comply with current standards. Advances in materials and electrical equipment standards provide a safer and more reliable electrical system. In particular, modern day protective relays are able to respond within fractions of a second to disturbances in the power system, thereby isolating expensive power system equipment such as transformers and generators from the energy of the fault. This results in a longer life for power system equipment and lower operating costs overall.

Deficiencies have been identified with the electrical protection of the generator windings, lack of instrumentation for unit protection, and limitations with the operation of the existing Woodward hydraulic governors. The switchgear, current/potential transformer windings and power cables are original to the 1958 installation and due to age and deterioration must be replaced.

In 2002, the windings were replaced on unit no. 2 generator after there was an in-service failure. The windings on unit no. 1 generator were replaced in 2004. The set of electromechanical protective relays on the generators do not meet the current IEEE recommendations, falling short in the area of ground fault protection, over-frequency protection and stator unbalance. The additional protection provided by implementing the complete set of IEEE recommended protection elements will reduce the risk of the windings failing in service.

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. Both the synchronizer and annunciator must be replaced in 2007.

The plant AC and DC systems are no longer supported by the manufacturer and do not meet current CSA standards. The 25 kV distribution line to the forebay and Amy's dam is deteriorated and the communications cable to the upstream gate structures is unreliable and must be replaced.

Appendix E, *Electrical Equipment Site Assessment* has identified electrical work to be completed during the plant refurbishment including extension and upgrades to the substation, replacing the existing switchgear and replacing the transmission line and bus protection.

5.0 Mechanical Works

An internal inspection of the turbine runners was completed in 1998 and a further inspection was completed in February of 2005. Some minor work was identified to be completed in 2007. The turbines are in fair condition and a major overhaul will not be required until 2012 and 2013. At that time, one turbine overhaul can be completed in each year, thus resulting in no lost energy.

As was evident during the inspection in February 2005, the main valves do not seal completely. During the assessment, a number of pressure tests were performed. The results show that the main inlet butterfly valves have pressure losses that are approximately three times more than that of modern butterfly valves. Losses across the valves will be reduced significantly by replacing them with new butterfly valves. The new valves will result in an additional 0.5 GWh of energy per unit. It is recommended that the main valves and associated equipment be replaced.

While the governors are in good shape, they do require a minor mechanical overhaul to prevent issues in the future. In order to avail of better unit control and operation with a PLC based control system, the governors will be upgraded with a new electronic control head.

A redesign of the cooling water system is required to address existing operational issues. Separate cooling water systems and backwash strainers for each turbine will result in a more reliable system.

The generator cooling intake dampers are dilapidated and require replacement. An associated walkway for the damper system will be refurbished to provide safe access for employees.

Appendix F, *Mechanical Site Assessment*, has identified mechanical work to be completed during the plant refurbishment including a minor turbine overhaul, replacement of the main valves and associated systems, and overhauling the governors.

6.0 Project Execution

The refurbishment of the Rattling Brook hydroelectric development is necessary for 2007. The completion of the dam and other civil upgrades will be planned for 2008 due to the high storage levels that will exist during construction in 2007.

Consideration was given to completing the entire refurbishment planned for 2007 over one or two years. An engineering review has determined that completing the majority of the work over one year is the least cost alternative. The plant outage required to complete the surge tank upgrade is estimated to take 24 weeks. It is estimated that it will take 32 weeks to complete the woodstave penstock replacement. As a result these two items will be completed in parallel with only eight weeks additional work related to the penstock project. If the project were to be completed over two years additional costs would be incurred due to staging the project twice, maintaining the upper half of the watered woodstave penstock and increasing the duration of the construction period.

Staging the project over two years introduces risk that is not present in the one year option. The risk is due to the need to maintain the upper half of the penstock while the lower half is being replaced. The upper half of the penstock would have to remain watered to keep the wood staves from drying out to the point that they will no longer seal. The penstock would remain under pressure and a bulkhead would have to be installed to seal the end. The bulkhead structure would take three weeks to construct. During this time the woodstave penstock would remain dewatered and the wood staves would shrink as the penstock dries. This shrinkage would result in new leaks when the penstock is watered and considerable effort would be required to reseal the wood staves after the bulkhead is complete. The addition of the bulkhead would involve considerable construction, engineering and maintenance effort, all of which would increase the cost of the project.

Another factor in the decision to complete the penstock replacement and surge tank refurbishment in one year was the necessity to replace the Rattling Lake spillway in 2008. Penstock replacement and dam upgrades cannot be completed during the same construction season because of their different water storage requirements. During penstock replacement the dams must maximize their storage. During dam upgrades, production must be maximized to lower water elevations to allow work to be completed on the dam.

In consideration of all options, the most feasible engineering and financial solution is to complete the penstock and surge tank work in one construction season. All other scheduled work in 2007 will be completed within the 32 week plant outage required for the penstock replacement. The mechanical and electrical upgrades will be scheduled such that installation and pre-commissioning will be completed while the plant is out of service. When the new penstock is re-watered, commissioning can commence and the plant will be back in service within three weeks of rewatering. It is estimated that the plant will be out of service for 35 weeks from early April until the end of November.

In order for the project to be completed on schedule several major items will have to be procured in 2006. The penstock will have to be tendered in the 3rd Quarter of 2006 and awarded in early October 2006 in order to meet the project schedule for fabrication of the penstock. An access road will have to be constructed along the existing penstock in 2006 to advance construction in 2007. Similarly the surge tank rehabilitation will have to be tendered in 2006 and awarded in late 2006 to allow for fabrication of the riser. Other major equipment to be ordered in late 2006 includes the switchgear, main valves and governor controls.

During the 35 week plant downtime it is estimated that 38.2 GWh of water will be spilled at the plant. This lost production has a value of $1.8 million in increased purchase power costs. This lost production is factored into the feasibility analysis.

A detailed project schedule is found in Appendix G. Table 1 shows the proposed high-level schedule for the project.

Table 1
High-Level Project Schedule

2006	2007	2008
Complete engineering design of penstock and surge tank	Replace Penstock	Replace Rattling spillway
Complete electrical engineering design	Refurbish surge tank	Replace Amy's outlet gate
Complete mechanical engineering design	Replace main valves on units #1 and #2	Upgrade Amy's dam
Prepare tenders necessary for 2006 construction	Complete powerhouse extension and upgrades	Upgrade Rattling Brook dam
Tender and award penstock contract	Complete mechanical system upgrades	Upgrade site access roads
Tender and award surge tank contract	Complete substation upgrades	
Tender and award major equipment supply	Complete electrical upgrades	
Construct access road along existing penstock	Complete protection and control upgrades	
	Upgrade forebay/Amy's communication line	
	Upgrade forebay/Amy's distribution line	
	Prepare and execute tenders necessary for 2008	

7.0 Project Cost

The total project cost is estimated at $20.9 million which includes $18.82 million in 2007 and an additional $2.08 million in 2008. Table 2 below provides the project cost breakdown by electrical, mechanical and civil works and by year and system component.

Table 2
Cost Estimate for Rattling Brook Refurbishment
(000s)

Description	2005	2006	2007	2008
Engineering[1]				
Engineering Assessments 2005	$256			
Engineering Assessments 2006		$94		
Civil				
Penstock			$11,705	
Upgrade Existing Steel Penstock			$193	
Surge Tank Upgrade			$1,470	
Plant Upgrades			$352	
Civil Infrastructure				
Amy's Gate				$208
Rattling Spillway				$1,467
Access Road				$35
Amy's Lake Dam Rehabilitation				$218
Rattling Lake Dam Rehabilitation				$152
Sub-Total			**$13,720**	**$2,080**
Mechanical				
Main Valves			$729	
Governor Upgrades			$26	
Cooling Water System			$144	
Plant HVAC and Balance of Plant			$96	
Bearings and Instrumentation			$97	
Commissioning			$25	
Sub-Total			**$1,117**	
Electrical				
Substation Upgrades[2]			$578	
AC and DC Distribution			$154	
Protection and Remote Control			$483	
Switchgear HV			$670	
Exciter Upgrades/Grounding			$68	
Control, Automation and Governor			$760	
Instrumentation			$126	
Communications Relocations			$53	
Communications/Distribution Line			$129	
Supervision and Commissioning			$297	
Sub-Total			**$3,318**	
Project Management				
IDC			$350	
Project Management and Insurance			$315	
Sub-Total			**$665**	
ANNUAL TOTALS	**$256**	**$94**	**$18,820**	**$2,080**
Lost Production			**$1,833**	

[1] Expenditure approved in Order No. P.U. 43 (2004).
[2] This project is budgeted under the Substations category.

8.0 Feasibility Analysis

Appendix H provides a 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 facility is economical over the long term. Investing in the life extension of the Rattling Brook hydroelectric development ensures the continued availability of 69.8 GWh of energy plus the addition of 6.2 GWh of new low cost energy to the Island Interconnected electrical system.

The estimated levelized cost of energy from Rattling Brook over the next 50 years, including the proposed capital expenditures, is 2.9 cents per kWh. This energy is lower in cost than replacement energy from sources such as new hydroelectric developments or additional Holyrood thermal generation. Incremental energy from the Holyrood thermal generating station is estimated to cost 7.1 cents per kWh in the short term (assuming $45.00[3] per barrel), with an associated levelized cost of 8.8[4] cents per kWh.

9.0 Conclusion

Engineering assessments have been completed on the civil, electrical and mechanical systems of the Rattling Brook hydroelectric development as approved in the 2005 Capital Budget Application. The engineering assessments have identified necessary work associated with the refurbishment and life extension of the Rattling Brook hydroelectric development. In particular, the woodstave penstock must be replaced as it is at the end of its service life and continues to deteriorate.

Increasing the diameter of the penstock and replacing the main valves will provide 6.2 GWh of new energy and 2.9 MW of capacity. This amount of energy and capacity would be similar to what would be expected from a new small hydroelectric development. This new energy will be provided from a more efficient use of the existing water resource. No additional water will be required to provide the new energy.

The feasibility analysis included in Appendix H verifies the financial viability of completing this project. The 76 GWh of energy that will be available from Rattling Brook each year will play a significant role in providing affordable energy to the customers of Newfoundland Power for years to come. The planned schedule for project execution ensures the minimum amount of lost production due to spill. Based upon these considerations, and others outlined in this report and attached assessments, the project is recommended to proceed in the 4th Quarter of 2006 with execution of construction in 2007.

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3 Newfoundland and Labrador Hydro's forecast fuel price submitted in response to request for information PUB 13 NLH for their application for 1 percent sulphur fuel recovery costs through the RSP.

4 50-year levelized using escalation factors based on the Conference Board of Canada GDP deflator, December 13, 2005.

Appendix A

Pictures of Rattling Brook Penstock and Surge Tank

Figure 1: Water Leakage from Penstock

Figure 2: Water Leakage from Penstock

Figure 3: Water Leakage from Penstock

Figure 4: Water Leakage from Penstock

Figure 5: Water Leakage from Penstock

Figure 6: View of Surge Tank

Figure 7: Lower Section of Woodstave Penstock

Figure 8: Ice Build-up on Penstock due to Water Leakage

Figure 9: Ice Build-up on Penstock due to Water Leakage

Figure 10: Ice Forming on Penstock during Winter

Figure 11: Settlement of Penstock Supports

Figure 12: Crushing of Woodstaves

Figure 13: Undermining of Penstock Bedding


Figure 14: Settlement of Penstock into Bedding


Figure 15: Repairing Leakage

Figure 16: Leakage at Lower Section of Penstock

Figure 17: Leaking Woodstaves

Figure 18: Leakage at Expansion Joint

Figure 19: Leakage at Expansion Joint

Appendix B

SGE Acres: Surge Tank and Penstock Replacement – Rattling Brook Hydroelectric Development

Prepared for

Newfoundland Power

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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
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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.

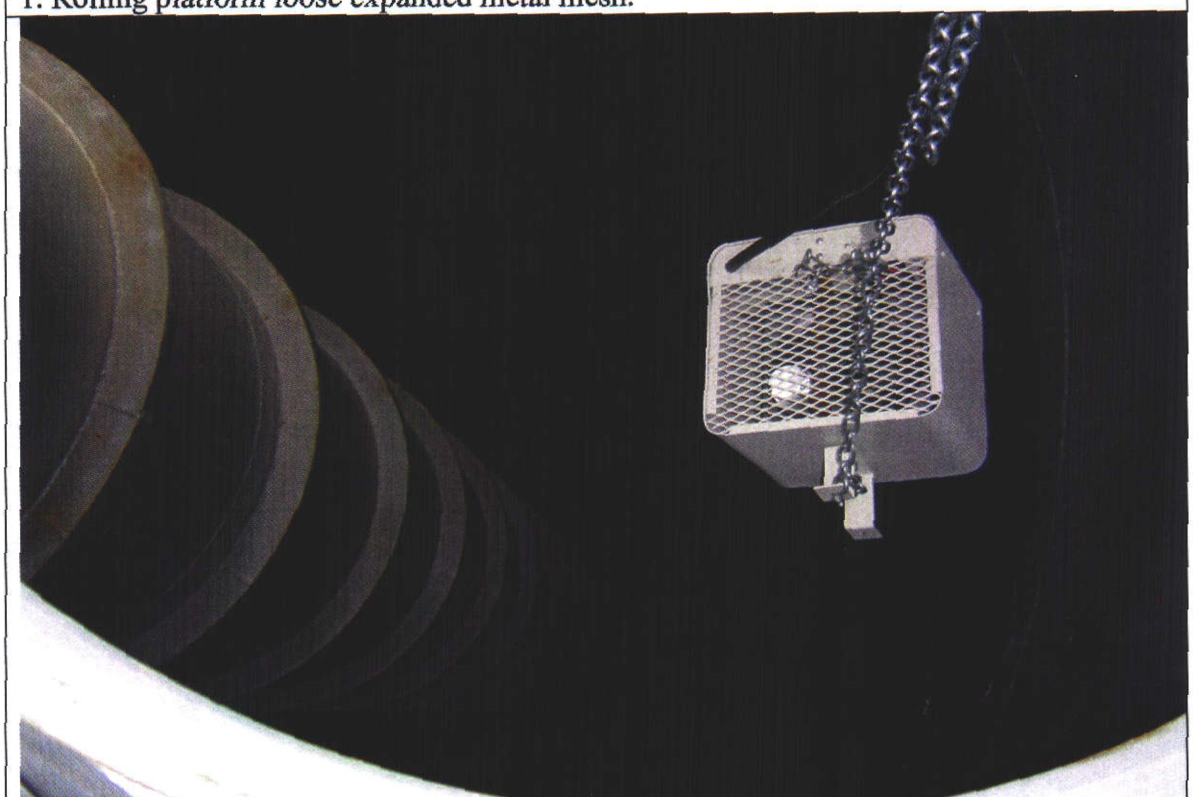
10. Concrete repairs identified in the 1998 Varcon report for the crack at the top of the surge tank anchor block and the tops of the concrete foundations under the surge tank legs should be completed in 2004. The cost to repair these areas is small. Delaying these repairs by many years will allow continued 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.

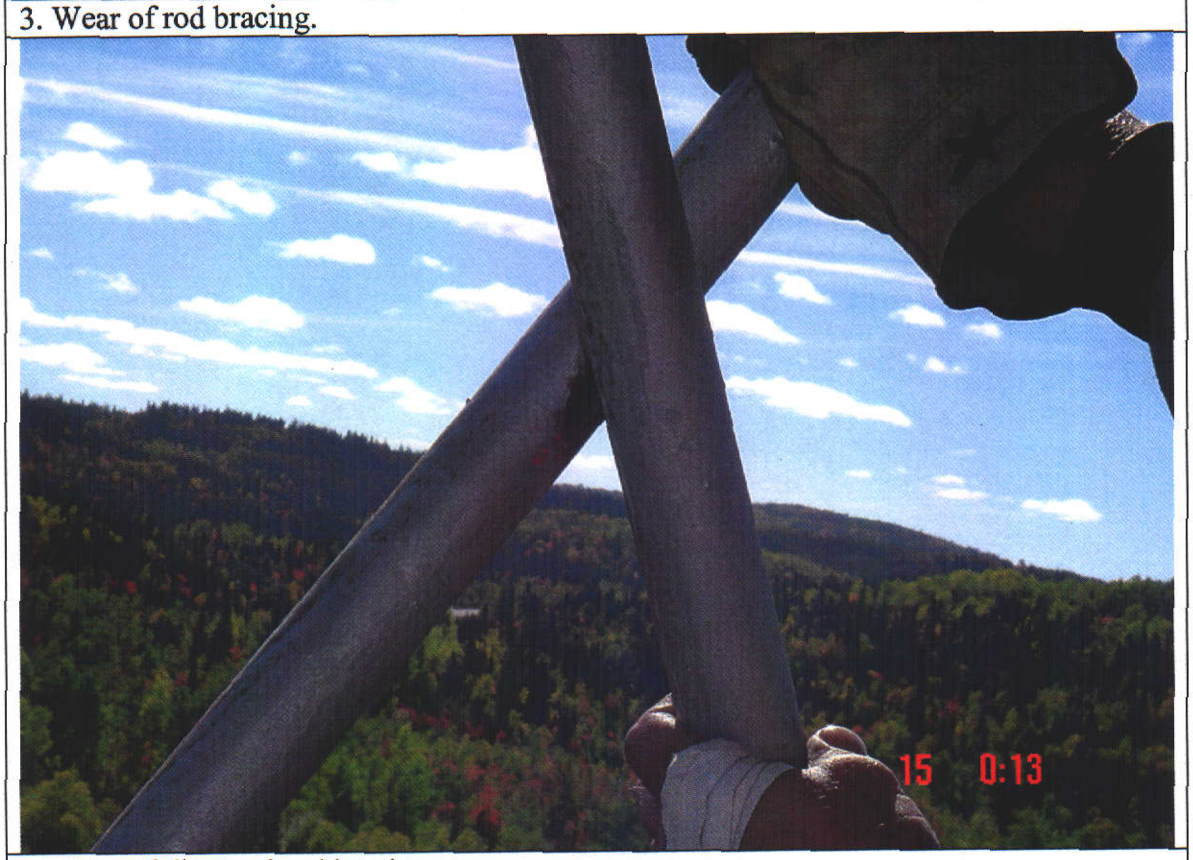
Appendix A – Photographs

1. Rolling platform loose expanded metal mesh.

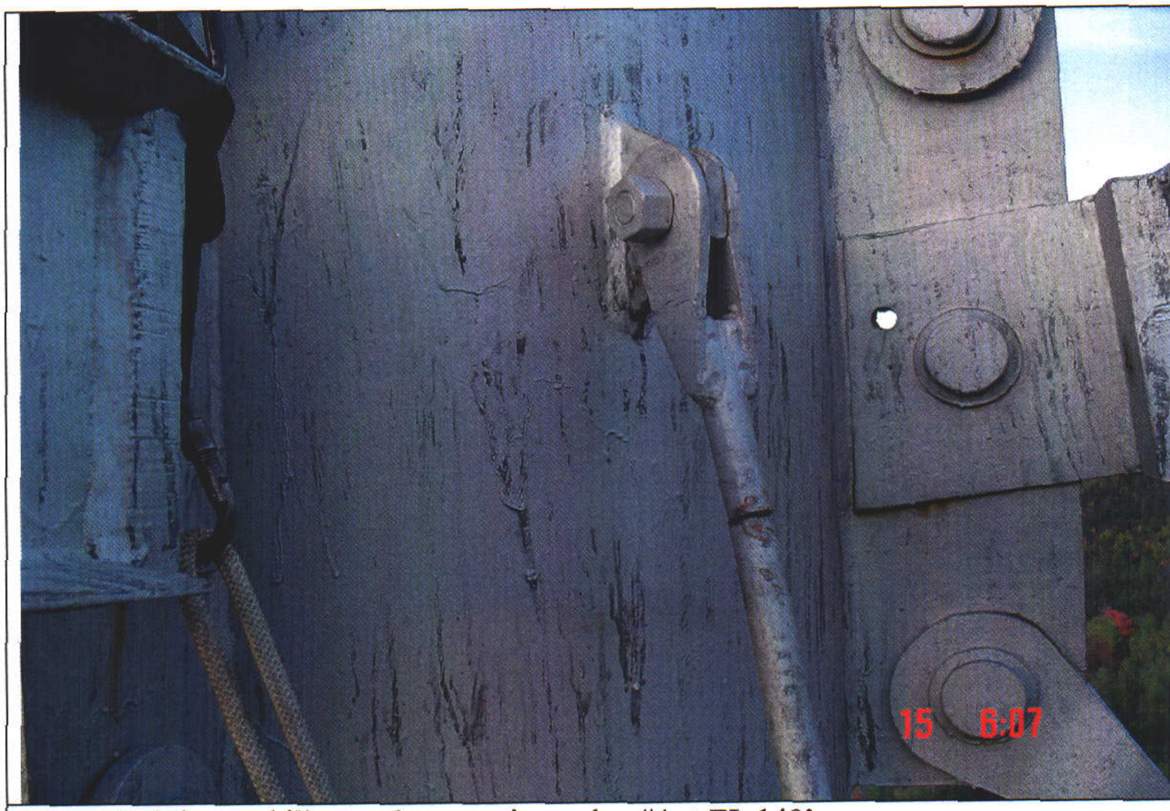


2. View of internal riser and surge tank from roof hatch.

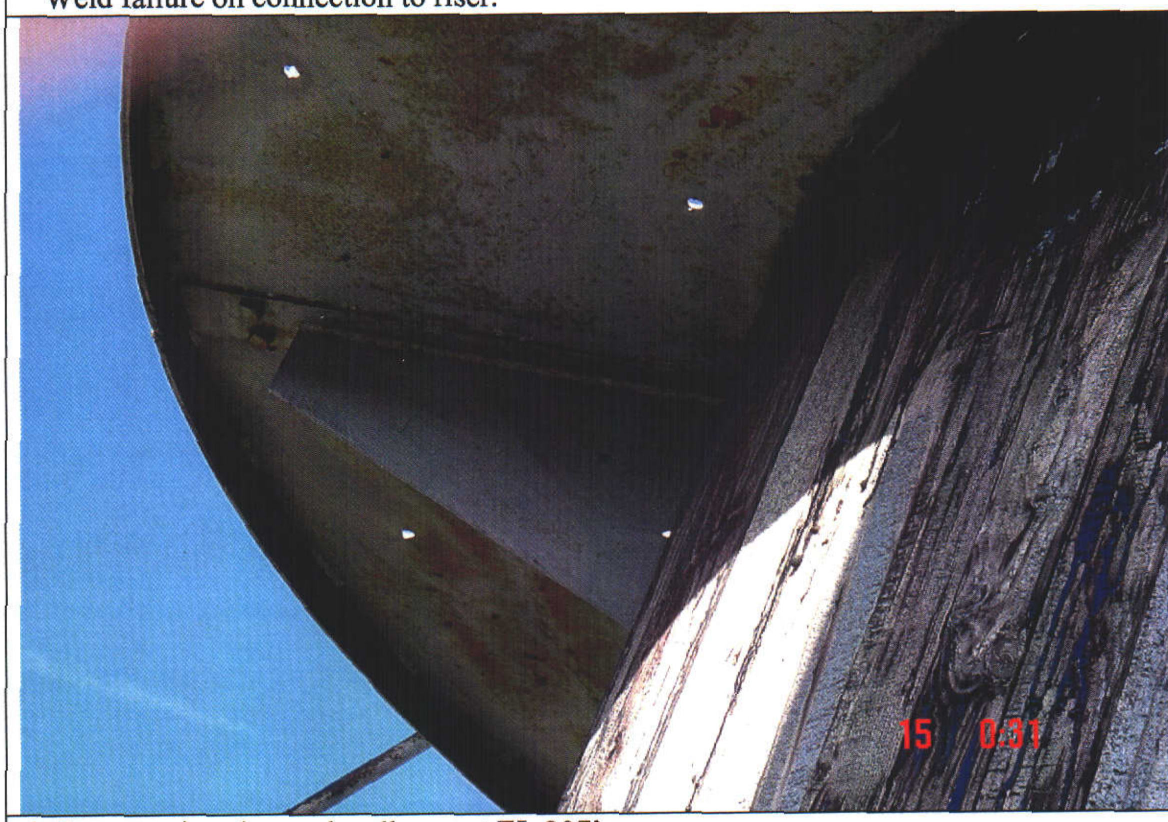
3. Wear of rod bracing.



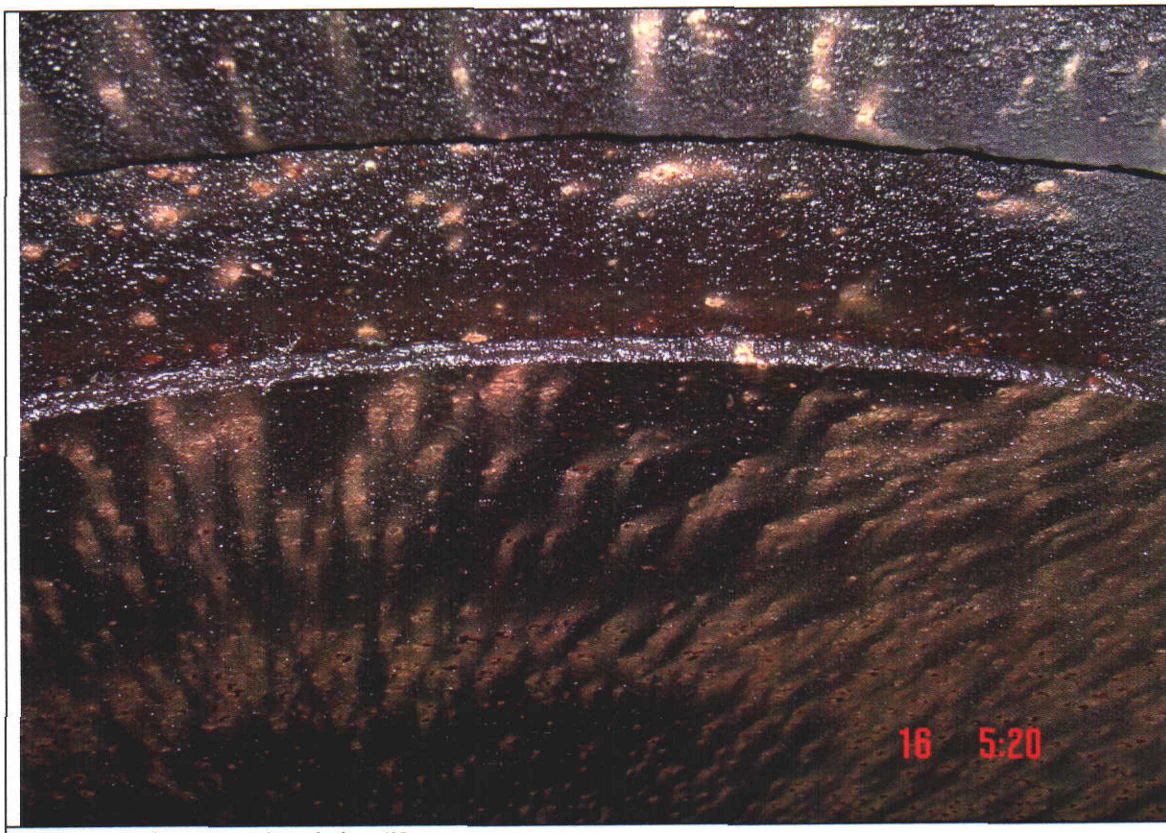
4. Wear of diagonal rod bracing.



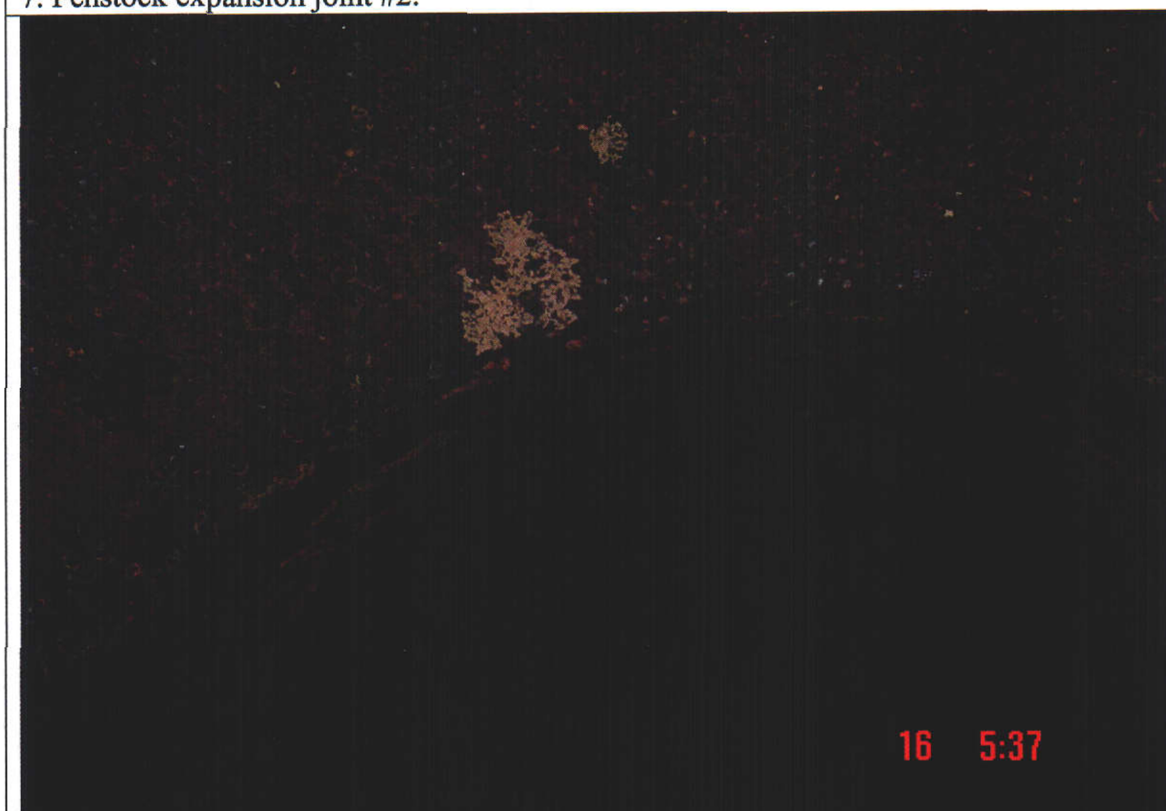
5. External riser stabilizer rod connection to leg #4 at EL.140'.
Weld failure on connection to riser.



6. Compression ring and walkway at EL.207'.

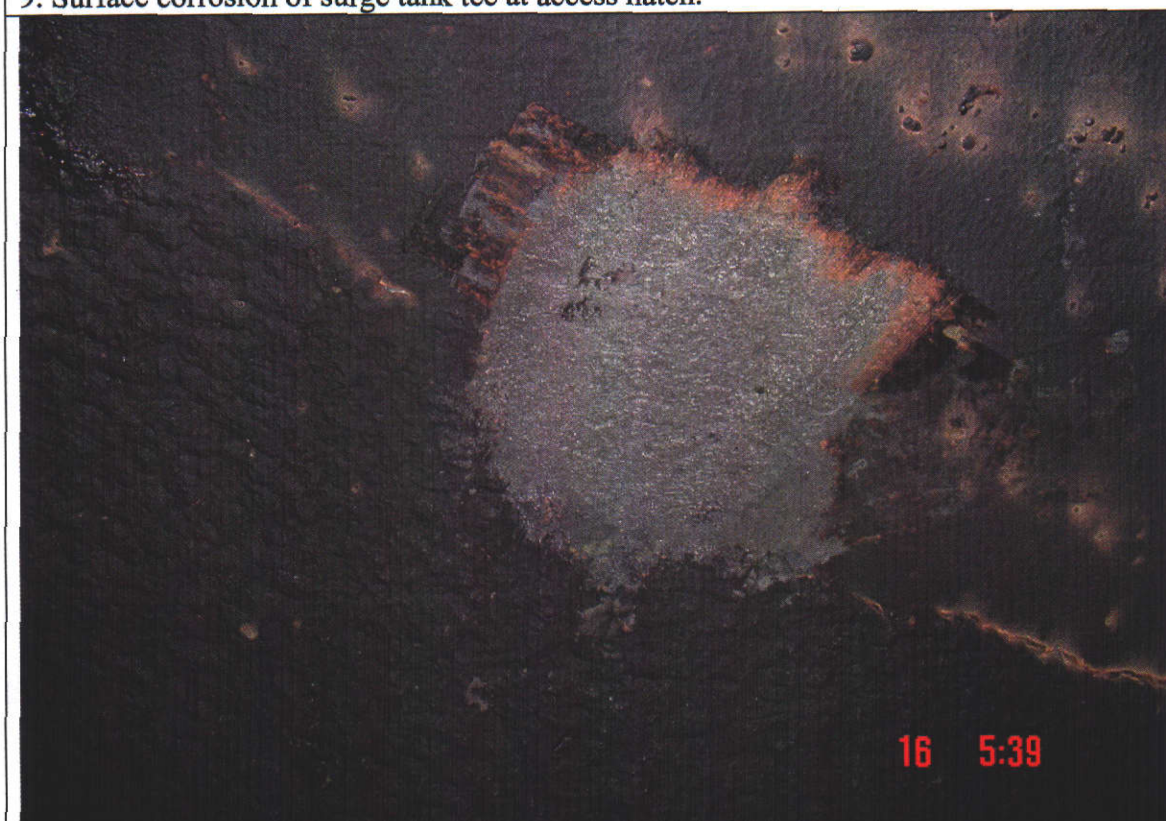


7. Penstock expansion joint #2.



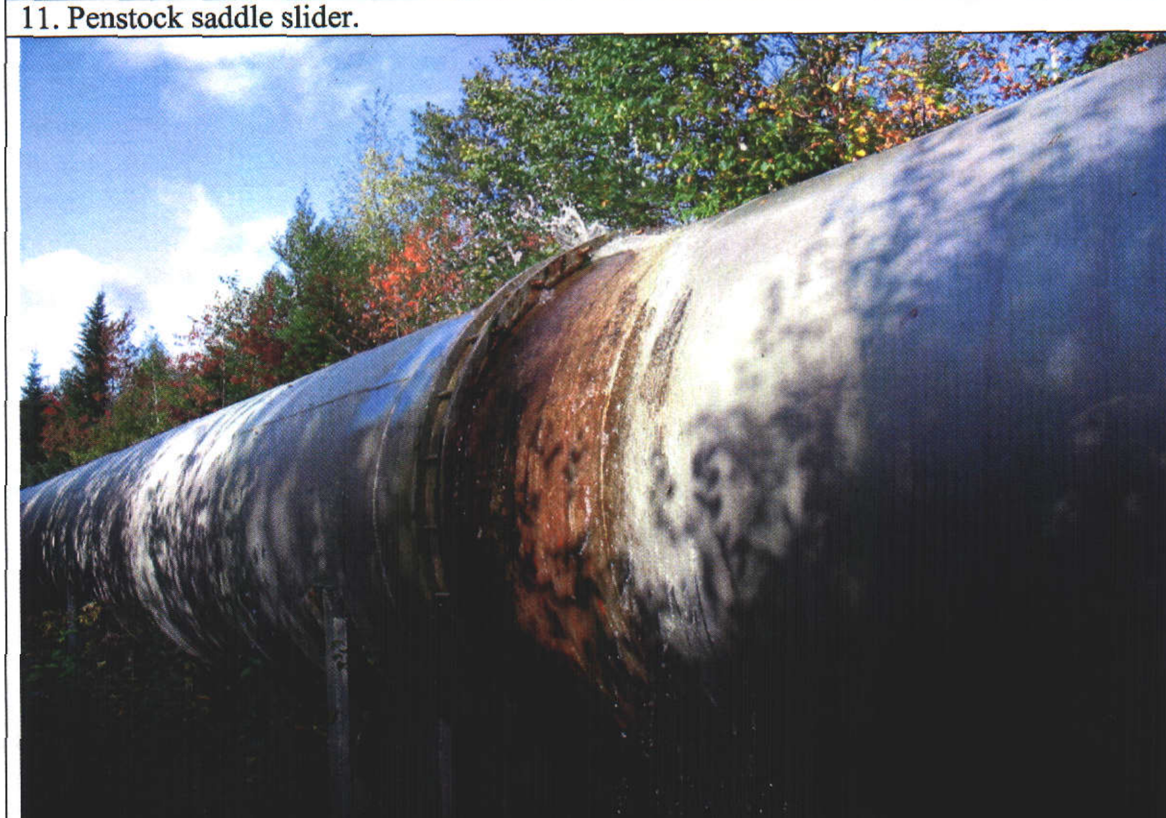
8. Carbuncles on surge tank tee looking up stream.

9. Surface corrosion of surge tank tee at access hatch.

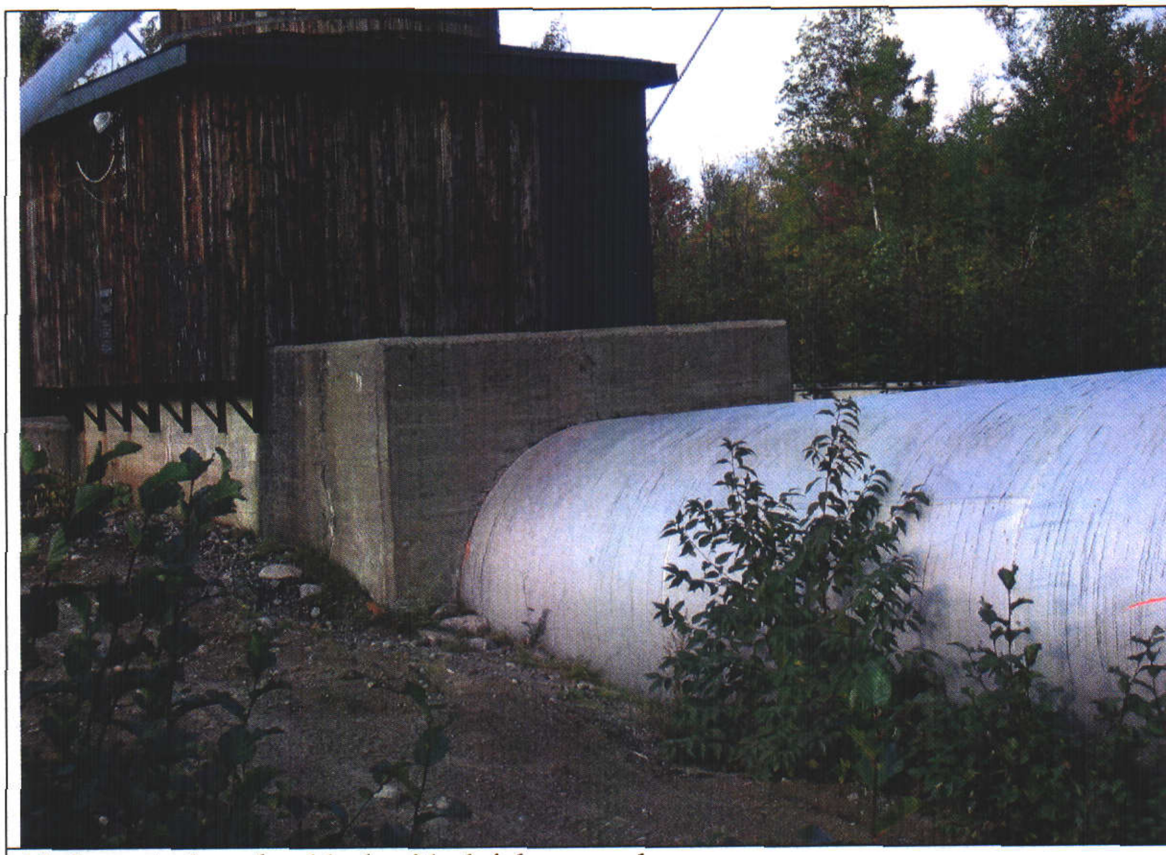


10. Caked build up on floor of surge tank tee.

11. Penstock saddle slider.



12. Expansion joint #2 leaking at top.

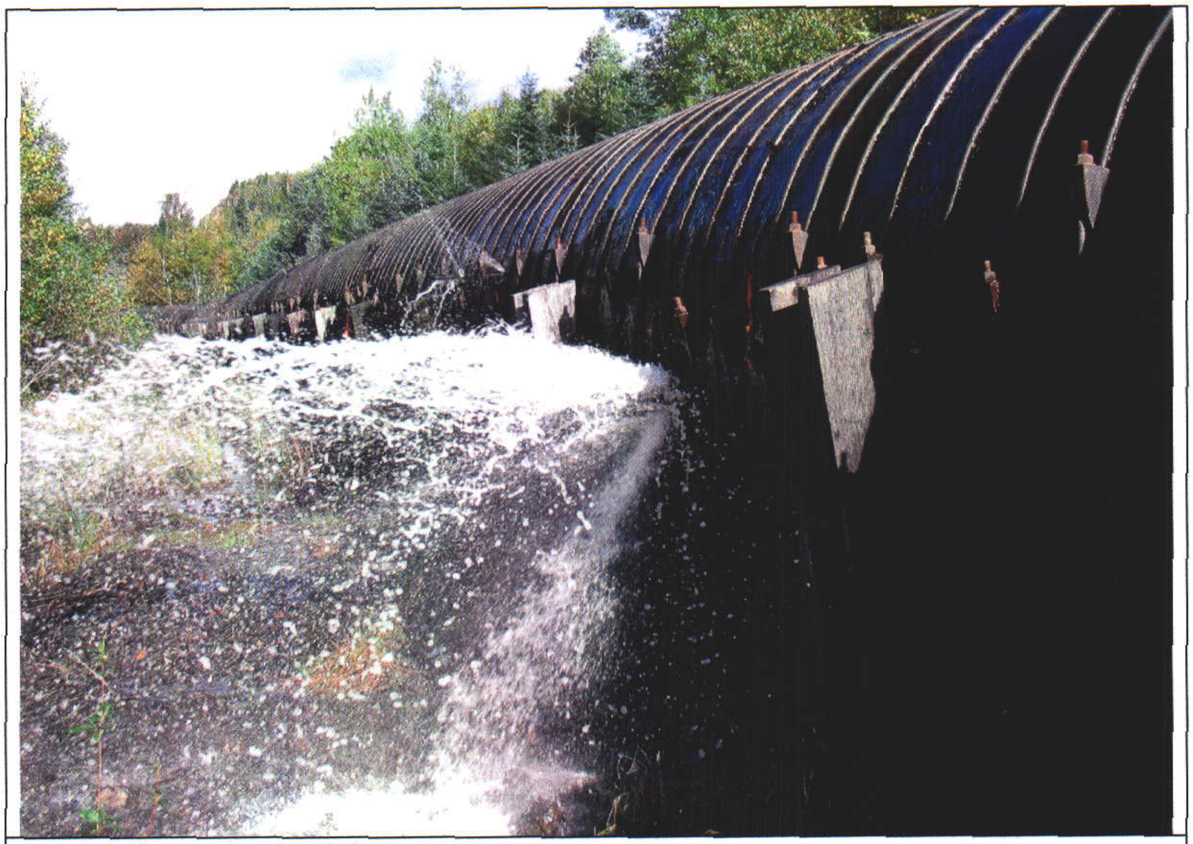


13. Surge tank anchor block with shrinkage crack.

14. Wood stave penstock steel plate patch.

15. Wood stave penstock typical patch plate location marking.

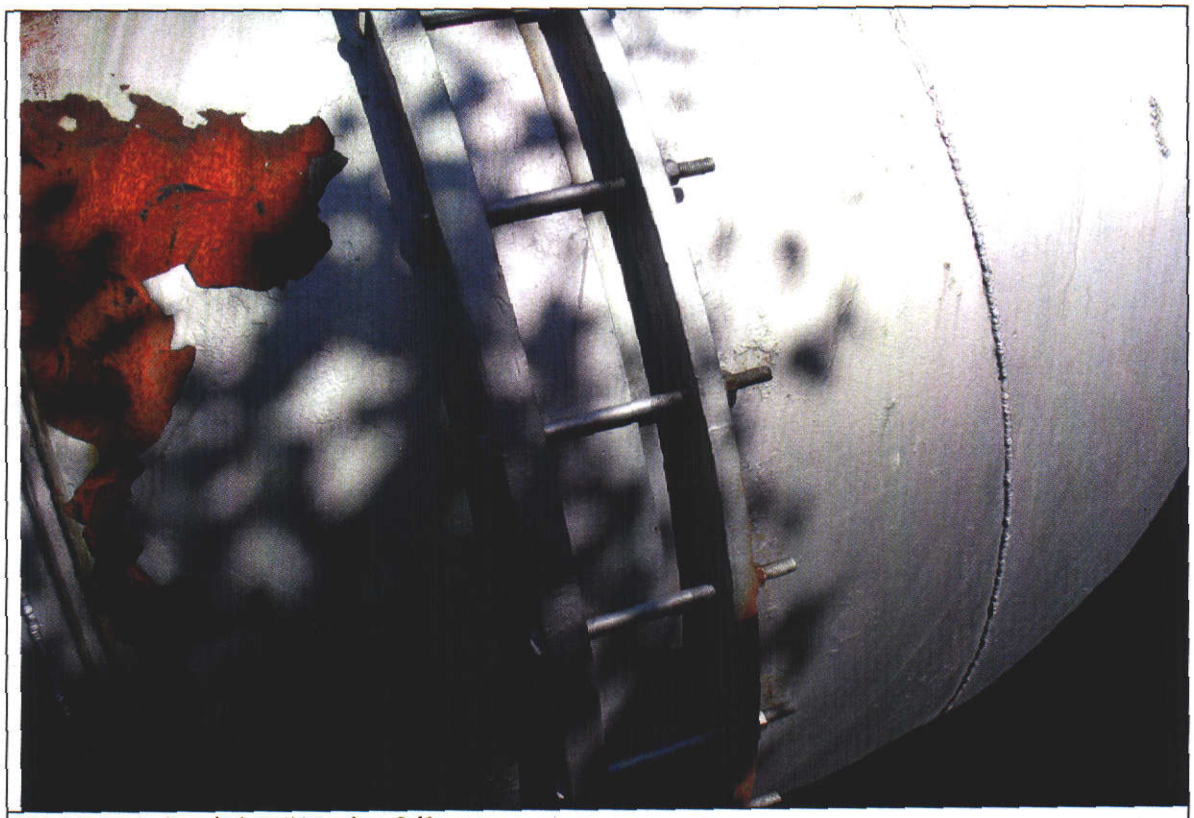
16. Wood stave penstock surface condition.


17. Wood stave penstock leakage.

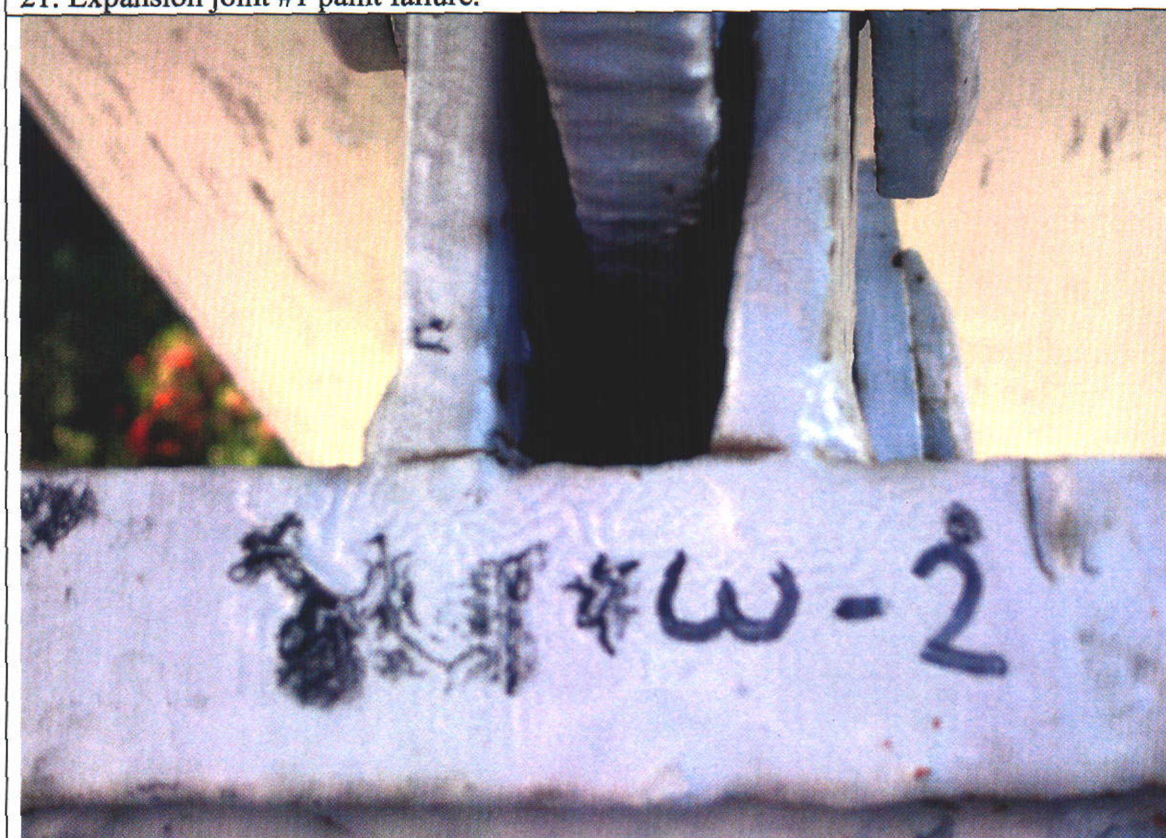

18. Wood stave penstock leakage.

19. Wood stave penstock leakage.

20. Wood stave penstock saddle deterioration.

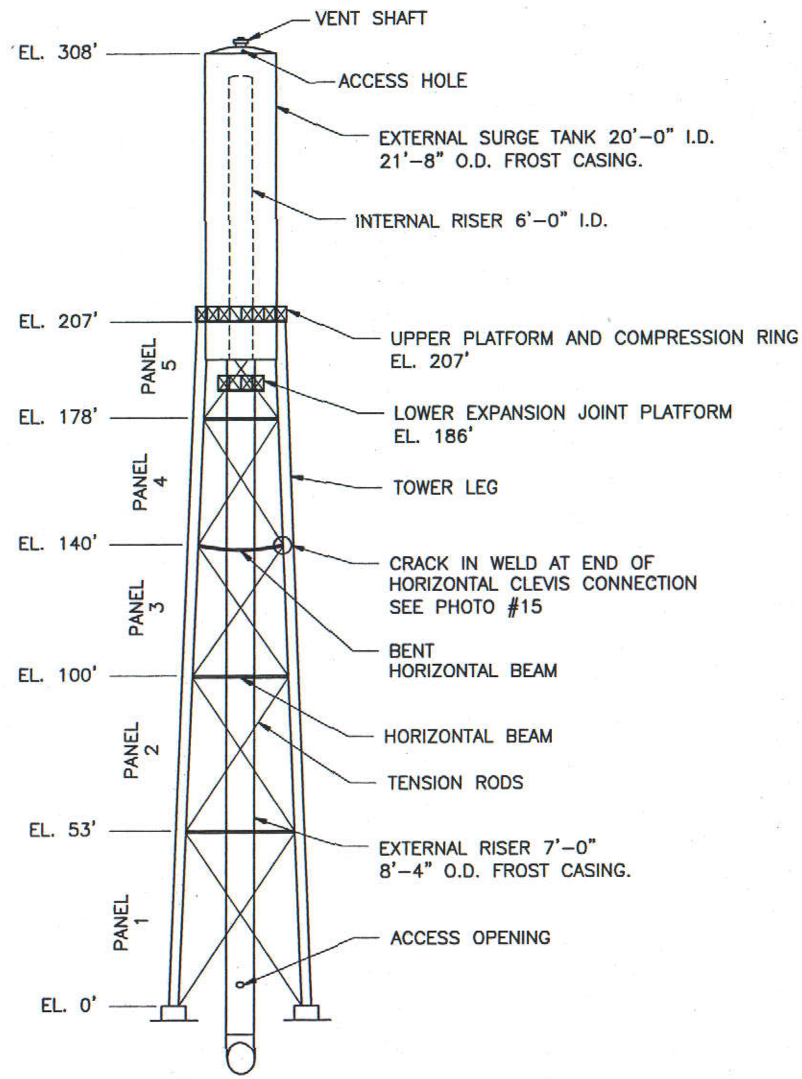


21. Expansion joint #1 paint failure.

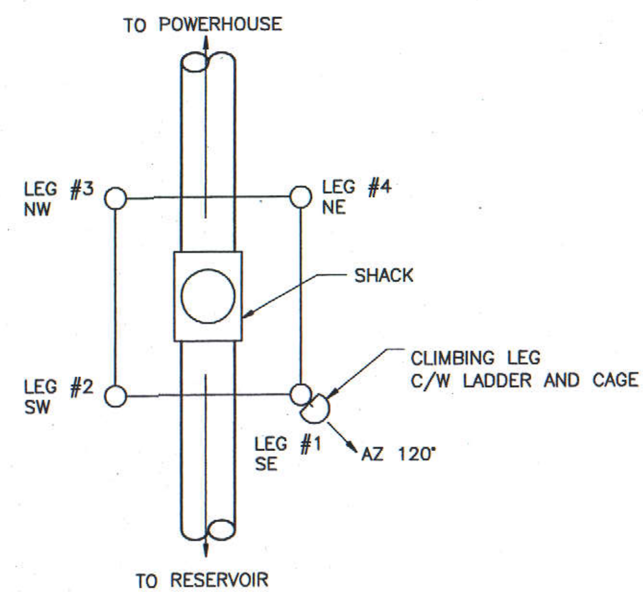


22. Horizontal brace north face at leg #3. Cracks in welds.

Appendix B – Sketches

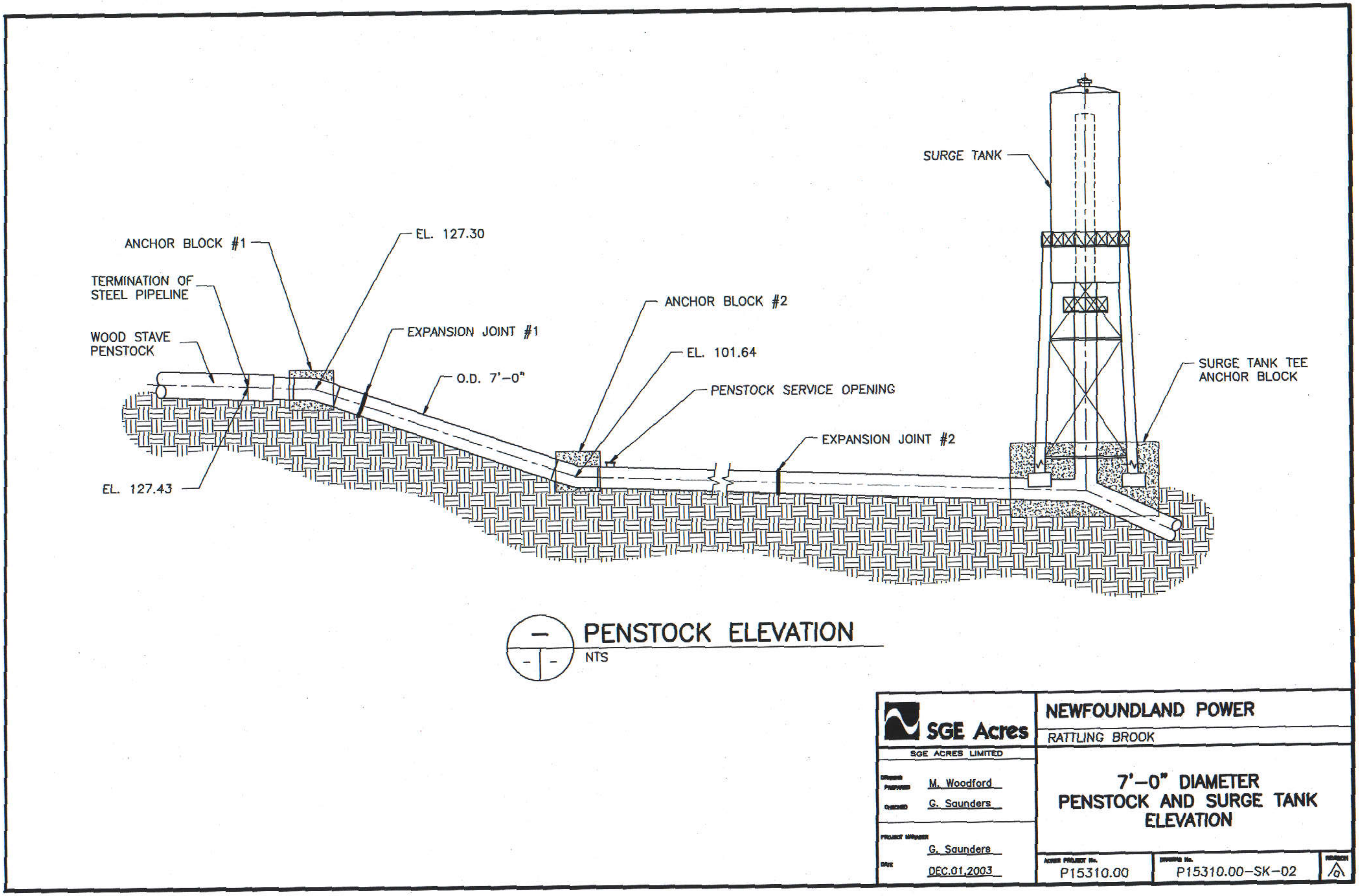


NORTH ELEVATION
NTS



SITE LAYOUT
NTS

SGE Acres — SGE ACRES LIMITED	NEWFOUNDLAND POWER
	RATTLING BROOK
DRAWN/PREPARED: M. Woodford	308' DIFFERENTIAL SURGE TANK ELEVATION AND LAYOUT
CHECKED: G. Saunders	
PROJECT MANAGER: G. Saunders	
DATE: DEC.01.2003	ACRES PROJECT No. P15310.00 — DRAWING No. P15310.00-SK-01 — REVISION 0


SURGE TANK
ANCHOR BLOCK #1
EL. 127.30
TERMINATION OF STEEL PIPELINE
ANCHOR BLOCK #2
WOOD STAVE PENSTOCK
EXPANSION JOINT #1
EL. 101.64
O.D. 7'-0"
PENSTOCK SERVICE OPENING
SURGE TANK TEE ANCHOR BLOCK
EXPANSION JOINT #2
EL. 127.43
PENSTOCK ELEVATION
NTS
SGE Acres
SGE ACRES LIMITED
M. Woodford
G. Saunders
G. Saunders
DEC.01.2003
NEWFOUNDLAND POWER
RATTLING BROOK
7'-0" DIAMETER
PENSTOCK AND SURGE TANK
ELEVATION
P15310.00
P15310.00-SK-02

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.

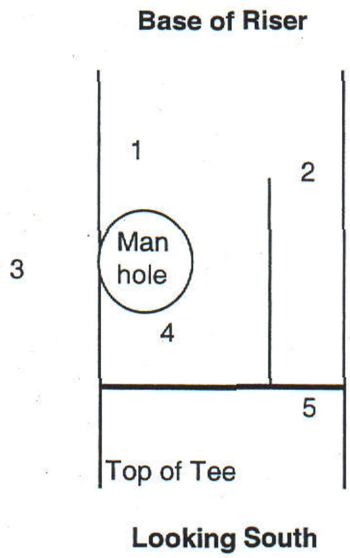
Newfoundland Power
Rattling Brook Penstock Inspection

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



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

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

Item	Yes	No	N/A
Personal Protective Equipment	✓		
First Aid Equipment	✓		
Fire Protection		✓	
Emergency Communication and Response	✓		
Fall Protection	✓		
Minimum Approach Distances Maintained			✓
Tail Board / Tool Box Meetings	✓		
Warning /Danger Signs	✓		
Public Safety	✓		

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 of Contractor's Supervisor:

White: Originator, Yellow: Contractor

Form No. 399 Revised 03/28/01

Remote Access Technology (Newfoundland) Inc.

Confined Space Entry Checklist ✓

Yes	No	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: 4:48pm

Standby Person: Steve Deathe (name) ______ (sign)

747-2515

REMOTE ACCESS TECHNOLOGY	Safety Policy and Procedures Manual **ANNEX A – Code of Practice**		Reviewed by: MDS Approved by: ADB
	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	[signature]
3	Pat Heath Pat Heath	11	
4	Hayward Miller	12	Hayward Miller
5	G. Murray	13	[signature]
6	G. Saunders	14	[signature]
7		15	[signature]
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 IRATA guidelines for access methods
8.

Comments

This safety meeting conducted by: [signature]

COPIES TO: OFFICE (ORIGINAL) Safety Coordinator

FORM 9-4-13

JOB HAZARD ANALYSIS

Date: Oct 15/03 Time: 8:30 Location: Ratting Brook P.S./NFLD

Supervisor:

Job Description: Inspection of serge 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 Delrizzo 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: 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 o²	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	[signature]		
Steve Westhe	[signature]		

Appendix C

SGE Acres: Rattling Brook Development
Selection of Optimum Penstock Diameter

March 17, 2006
H-322125

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

Attention: Mr. Gary Murray, 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. NP requested an incremental analysis, with the energy benefits incremental to existing, and costs incremental to replacement.

The findings of this study are that a penstock with a diameter of 9 ½ ft is optimal. The capacity at full output will increase by about 2.9 MW, the incremental expected average energy output is estimated to be at least 5.1 GWh over existing, and, and the incremental cost over replacement is about $2.1 million.

This letter report documents the analysis and results of the study.

1 System Description

The Rattling Brook hydroelectric 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 ½ 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 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 is 4ft. 9 in. inside diameter. A butterfly valve is located just upstream of each of the units.

2 Methodology

2.1 Capacity and Energy Benefits

Based on previous reports and practical considerations, diameters in the range of 7 ½ ft. to 10 ft were considered. An energy simulation model of the Rattling Brook system previously developed for NP for a Water Management Study was used to estimate the available energy.[1] A 15 year inflow sequence was used in the simulation, as in the Water Management Study.

The head losses in the existing and proposed system, required for the energy calculations, were estimated using data from index testing in the 1980's by NP, from efficiency testing carried out by SGE Acres for NP in 2000 and standard references. Additional tests in 2005 confirmed the assumed values for the woodstave portion. The reduction in head losses with increasing penstock diameter leads to increasing energy. A reduction in head loss due to the larger penstock also increases the available capacity.

The actual energy generated at the station is higher than simulated, 69.8 GWh compared to the 63.5 GWh simulated. This difference is likely due to more runoff, as discussed in the Water Management Study. Given this possibility, the energy was also calculated using a mean annual runoff 10 per cent higher than previously assumed, to determine the effect of higher runoff on incremental energy. Detailed site data to allow calculation of inflows would be required to confirm the runoff.

2.2 Costs

NP prepared detailed cost estimates for replacing the woodstave section with a steel penstock of 7 ½ ft. diameter, as well as with a 9 ½ ft. diameter steel penstock. NP advised that the costs for other sizes in approximately this range could be estimated by linear interpolation.

2.3 Economic Analysis

The annual value of the incremental benefits of each diameter under consideration was calculated assuming values of \$0.071/kWh and \$0.093/kWh. These values were provided by NP. The lower value is the cost of short run energy at Holyrood, and the higher value is a blended rate, including both the cost of short run energy plus capacity benefits. A discount rate of 7.15 per cent and a period of 50 years were assumed, also provided by NP. The sensitivity of the results to a period of 25 years was also checked.

The net present worth value (benefits minus costs) and the incremental (stepwise) net benefit were then calculated. The optimal diameter is the diameter which maximizes the net present worth, and for which the incremental investment is still positive.

[1] Acres International, *Water Management Study*, Report prepared for Newfoundland Power, December 2000.

3 Results

The results of the power and energy analysis are shown in Figure 1, which plots energy and capacity as a function of penstock diameter. This figure shows that the capacity and energy continue to increase as the diameter increases, but the curves flatten out at the larger diameters. The annual incremental energy benefits over the existing simulated energy range from from 2.6 GWh for the 8 ft. penstock to 5.5 GWh for the 10 ft. penstock. For the case of the 10 per cent increase in runoff, the simulated existing average annual energy increments range from 2.9 GWh for the 8 ft penstock to 6.4 GWh for the 10 ft diameter.

The capacity increases from the existing 11.2 MW to 12.5 MW with the 8 ft. penstock and 14.3 MW with the 10 ft. penstock. (Losses in the existing steel section limit the plant to an output below the full nameplate production of 15.1 MW even with a larger diameter penstock as replacement for the woodstave section.)

Figure 2 shows the present value of the benefits for the two different assumptions of value of energy, and Figure 3 shows the linear cost curve. The cost estimate for supply and installation of the 7 ½ ft diameter penstock is $9,541,000, and $11,706,000 for the 9 ½ ft. penstock. The incremental cost is thus approximately $541,000 for each ½ ft. increment.

The information in these plots is combined in Figures 4 and 5 to show the results of the optimization. Figure 4 shows the net present value of the project, assuming each of the penstock diameters, in ½ ft increments. Figure 4a shows the results for the given discount rate and two values of energy case (no increase in runoff, period of 50 years). The net present value is optimized at the 9 ½ ft. diameter. Figure 4b shows the results for the sensitivity to period (25 years) and to higher runoff. The range of optimal diameters is from 9 ft. to 10 ft. in all cases.

Figures 5a and 5b show the results as incremental net benefits. From an economic perspective, it is beneficial to invest each incremental amount (in this case, $541,000) until the incremental net present value is negative. The diameter at which the return is still positive is the optimum, in this case 9 ½ ft. The range for all sensitivities is 9 ft. to 10 ft.

The results are also summarized in Table 1.

4 Conclusions and Recommendations

The conclusions of this study are that a 9 ½ ft. diameter penstock is optimal, for the costs and economic parameters evaluated. It is a robust choice, since the optimum diameter ranges from 9 ft. to 10 ft. for the sensitivities considered.

The estimated cost for supply and installation of the 9 ½ ft. diameter penstock is $11,706,000, an increment of $2,165,000 over the cost of replacement with a 7½ ft. diameter penstock. The average annual energy is expected to increase by at least 5.1 GWh. Given the present production of 69.8 GWh, the expected average annual energy would be about 75 GWh. The capacity benefit is 2.9 MW, from the existing 11.2 MW to an estimated 14.1 MW.

Yours very truly,

SHR:sjc

Susan Richter, P.Eng.
Project Manager

Attachments

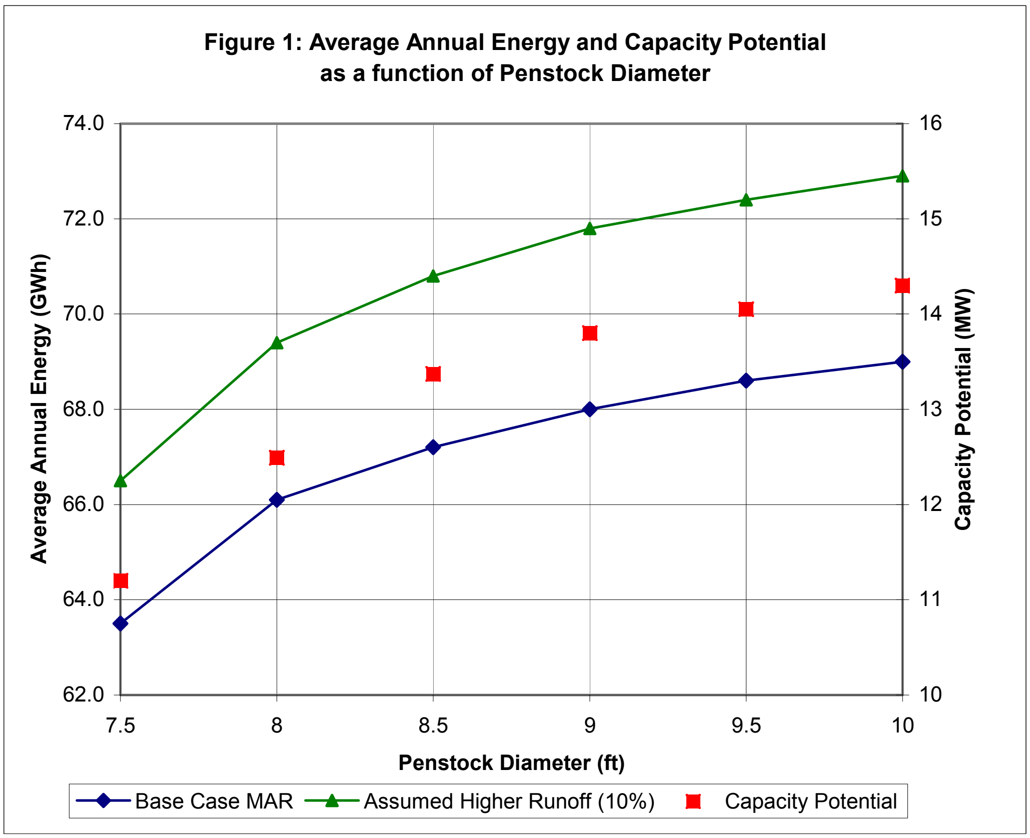


Figure 1: Average Annual Energy and Capacity Potential
as a function of Penstock Diameter
74.0
72.0
70.0
68.0
66.0
64.0
62.0
Average Annual Energy (GWh)
16
15
14
13
12
11
10
Capacity Potential (MW)
7.5
8
8.5
9
9.5
10
Penstock Diameter (ft)
Base Case MAR
Assumed Higher Runoff (10%)
Capacity Potential

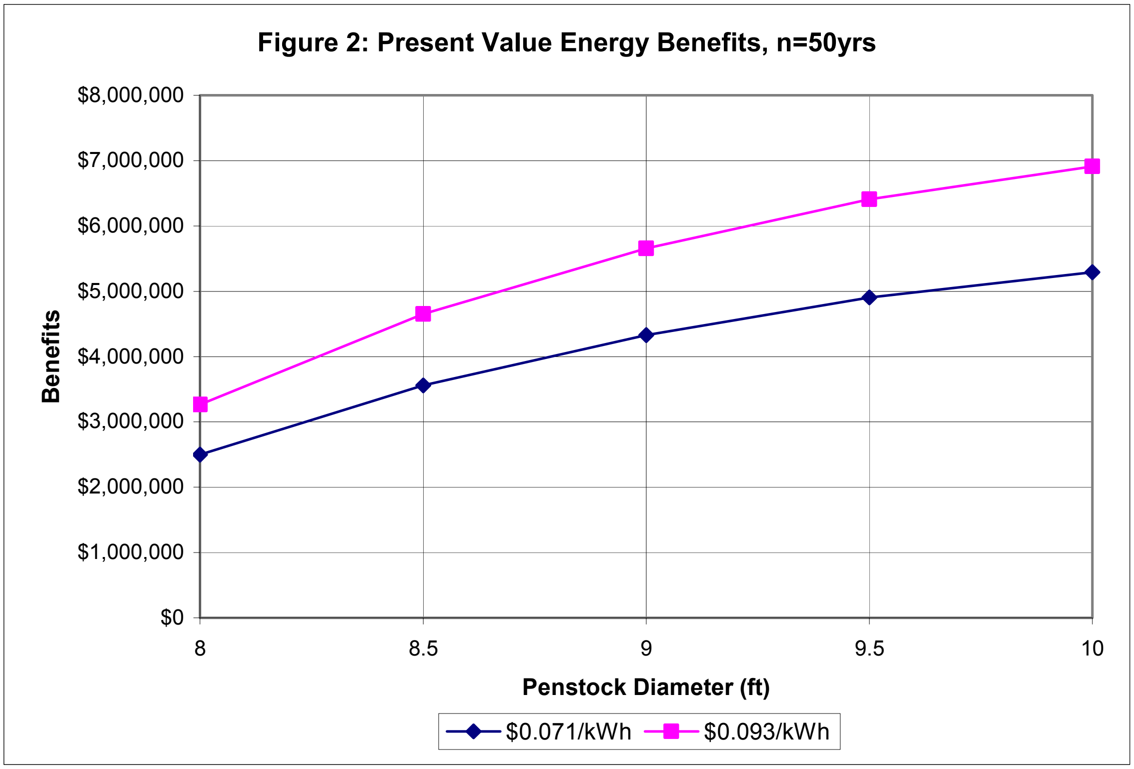


Figure 2: Present Value Energy Benefits, n=50yrs
Benefits
$8,000,000
$7,000,000
$6,000,000
$5,000,000
$4,000,000
$3,000,000
$2,000,000
$1,000,000
$0
8
8.5
9
9.5
10
Penstock Diameter (ft)
$0.071/kWh
$0.093/kWh

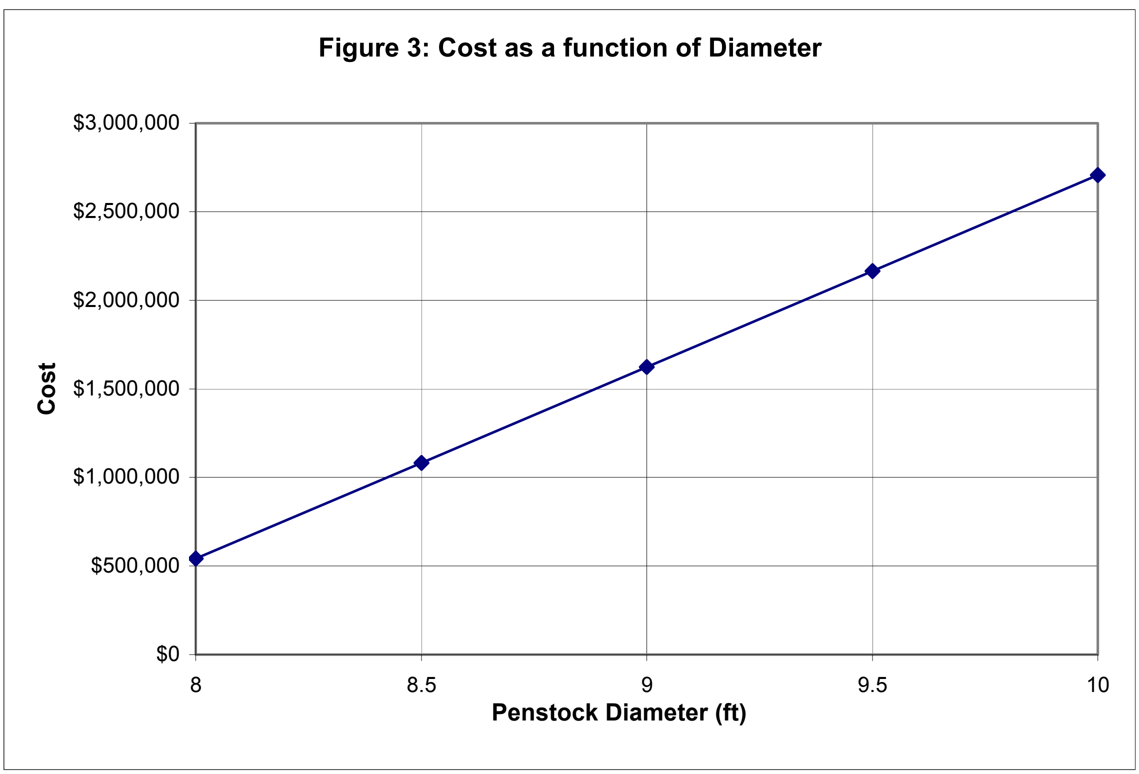


Figure 3: Cost as a function of Diameter
Cost
$3,000,000
$2,500,000
$2,000,000
$1,500,000
$1,000,000
$500,000
$0
8
8.5
9
9.5
10
Penstock Diameter (ft)

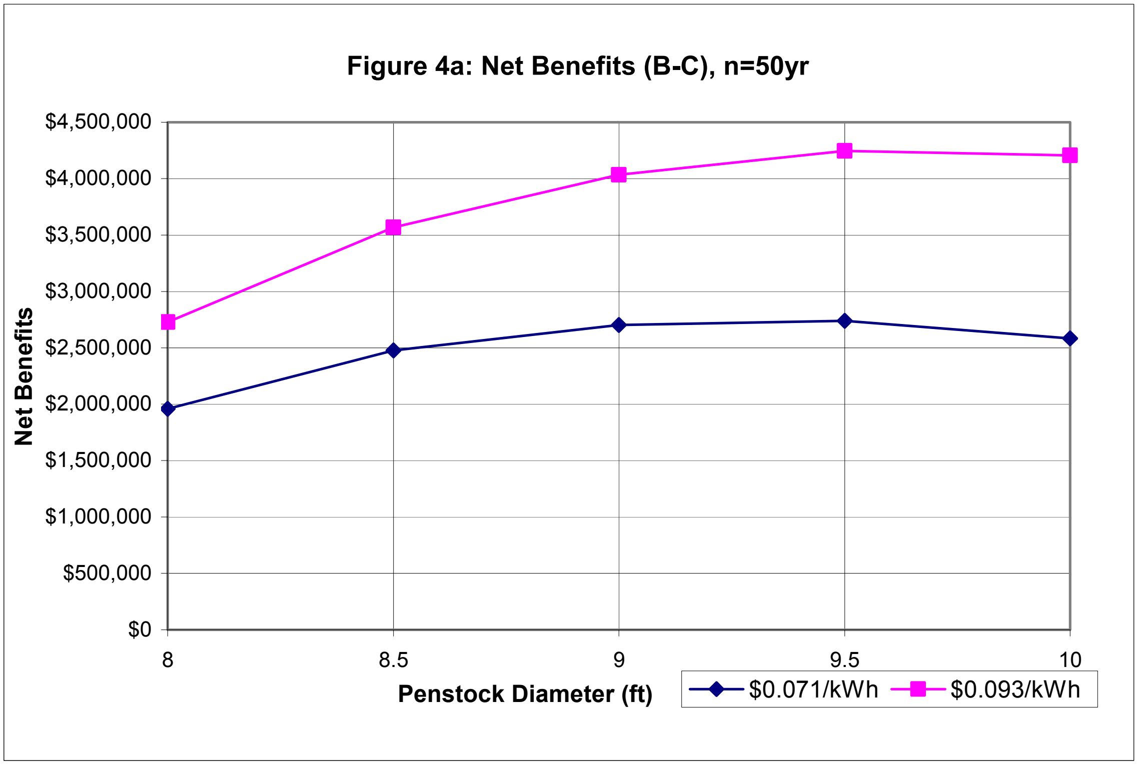


Figure 4a: Net Benefits (B-C), n=50yr
Net Benefits
$4,500,000
$4,000,000
$3,500,000
$3,000,000
$2,500,000
$2,000,000
$1,500,000
$1,000,000
$500,000
$0
8
8.5
9
9.5
10
Penstock Diameter (ft)
$0.071/kWh
$0.093/kWh

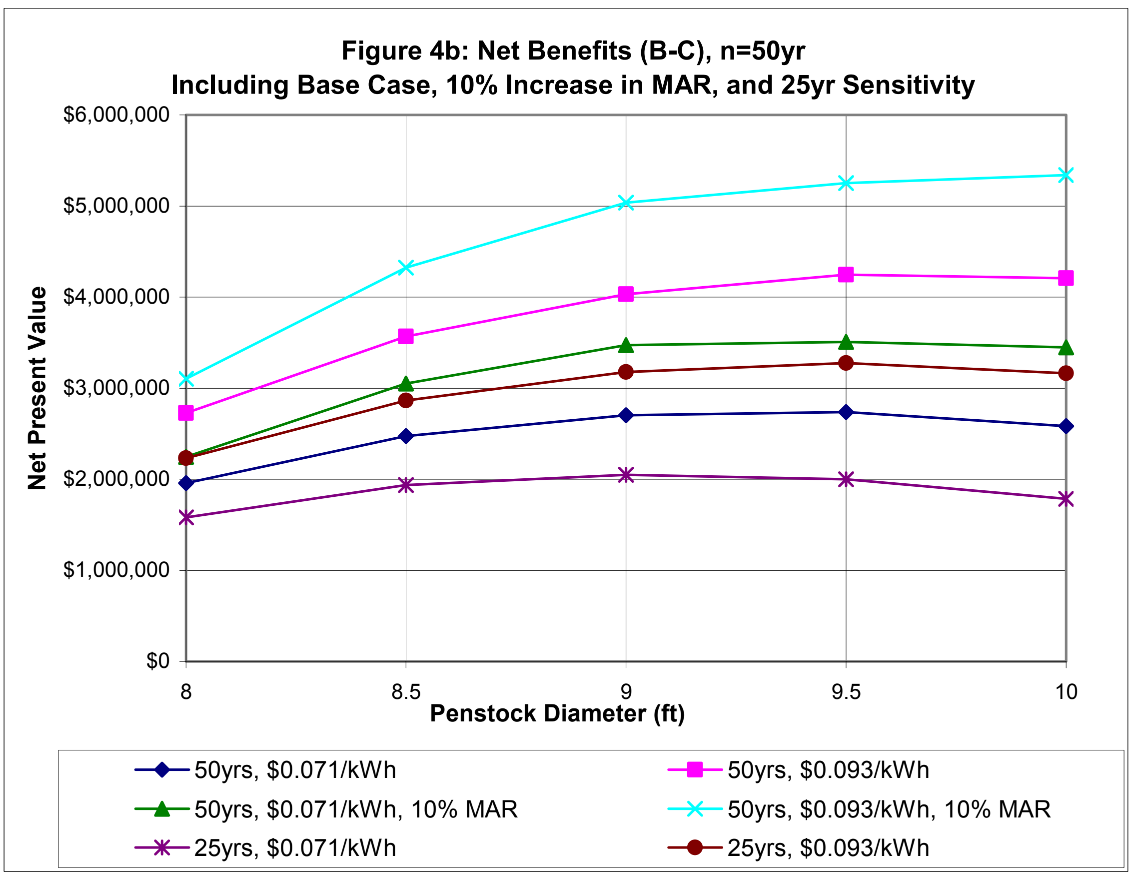


Figure 4b: Net Benefits (B-C), n=50yr
Including Base Case, 10% Increase in MAR, and 25yr Sensitivity
Net Present Value
$6,000,000
$5,000,000
$4,000,000
$3,000,000
$2,000,000
$1,000,000
$0
8
8.5
9
9.5
10
Penstock Diameter (ft)
50yrs, $0.071/kWh
50yrs, $0.093/kWh
50yrs, $0.071/kWh, 10% MAR
50yrs, $0.093/kWh, 10% MAR
25yrs, $0.071/kWh
25yrs, $0.093/kWh

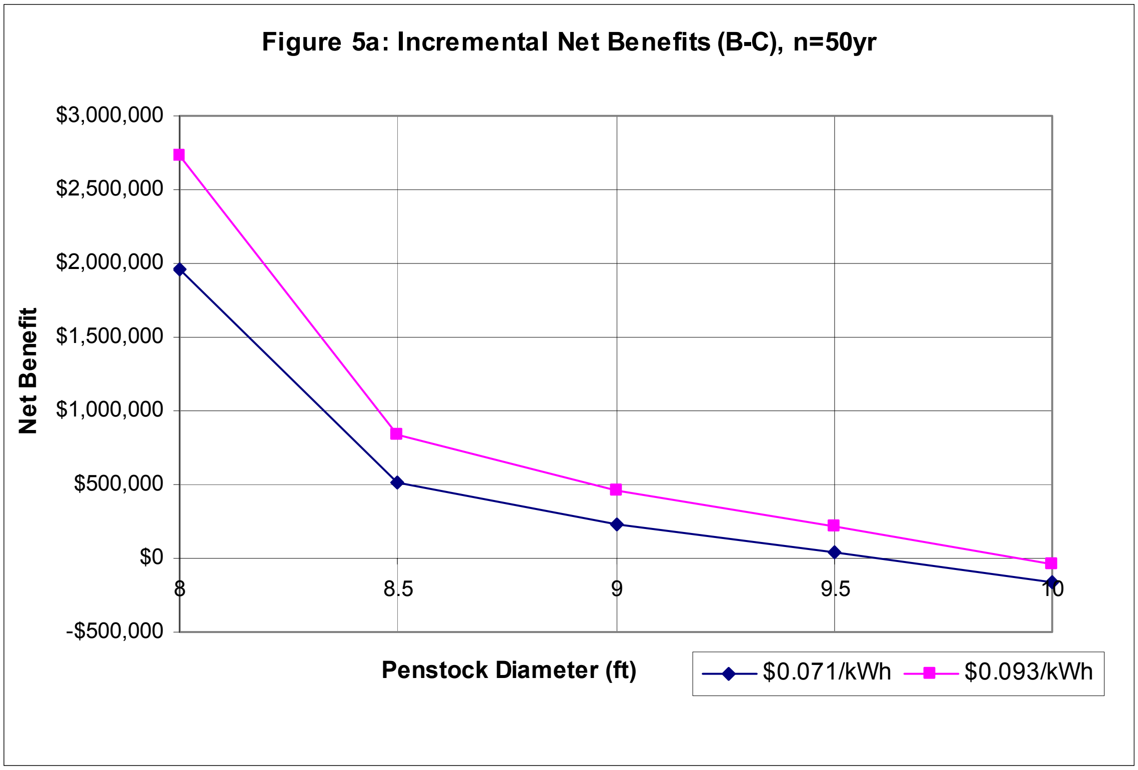


Figure 5a: Incremental Net Benefits (B-C), n=50yr
Net Benefit
$3,000,000
$2,500,000
$2,000,000
$1,500,000
$1,000,000
$500,000
$0
-$500,000
8
8.5
9
9.5
10
Penstock Diameter (ft)
$0.071/kWh
$0.093/kWh

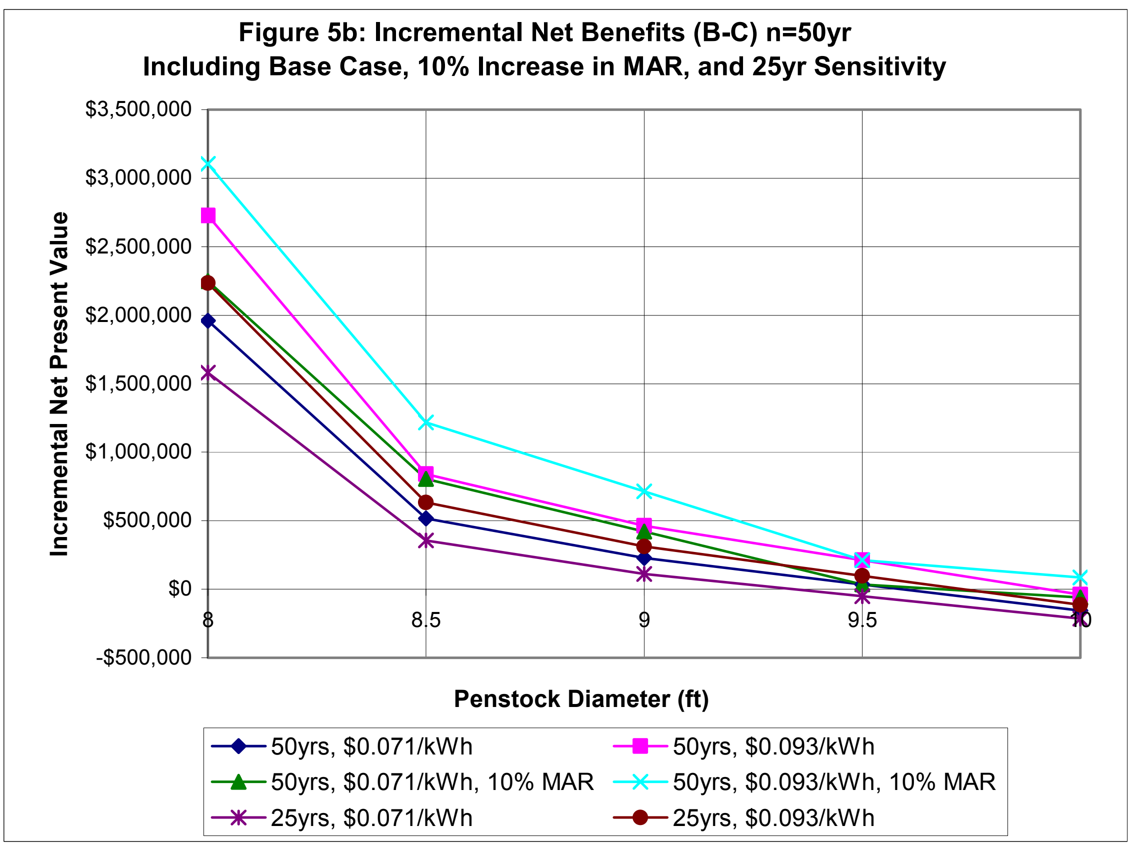


Figure 5b: Incremental Net Benefits (B-C) n=50yr
Including Base Case, 10% Increase in MAR, and 25yr Sensitivity
Incremental Net Present Value
$3,500,000
$3,000,000
$2,500,000
$2,000,000
$1,500,000
$1,000,000
$500,000
$0
-$500,000
8
8.5
9
9.5
10
Penstock Diameter (ft)
50yrs, $0.071/kWh
50yrs, $0.093/kWh
50yrs, $0.071/kWh, 10% MAR
50yrs, $0.093/kWh, 10% MAR
25yrs, $0.071/kWh
25yrs, $0.093/kWh

Table 1

Results of Economic Analysis

Value of Energy	$0.071	/kWh				
Diameter (ft)	**7.5**	**8**	**8.5**	**9**	**9.5**	**10**
Average Energy (GWh)	63.5	66.1	67.2	68.0	68.6	69.0
Energy Benefits (above existing)		$2,500,000	$3,558,000	$4,327,000	$4,904,000	$5,289,000
Costs incremental above 7.5ft		$541,154	$1,082,000	$1,623,000	$2,165,000	$2,706,000
Net Benefits (Benefits - Costs)		$1,959,000	$2,476,000	$2,704,000	**$2,739,000**	$2,583,000
Incremental Energy (GWh)		2.6	1.1	0.8	0.6	0.4
Annual Incremental Benefits		$184,600	$78,100	$56,800	$42,600	$28,400
Present worth Incremental Benefits		$2,500,000	$1,058,000	$769,300	$576,900	$384,600
Costs incremental above 7.5ft		$541,154	$541,154	$541,154	$541,154	$541,154
Incremental Net Benefits		$1,959,000	$516,800	$228,100	**$35,750**	-$157,000

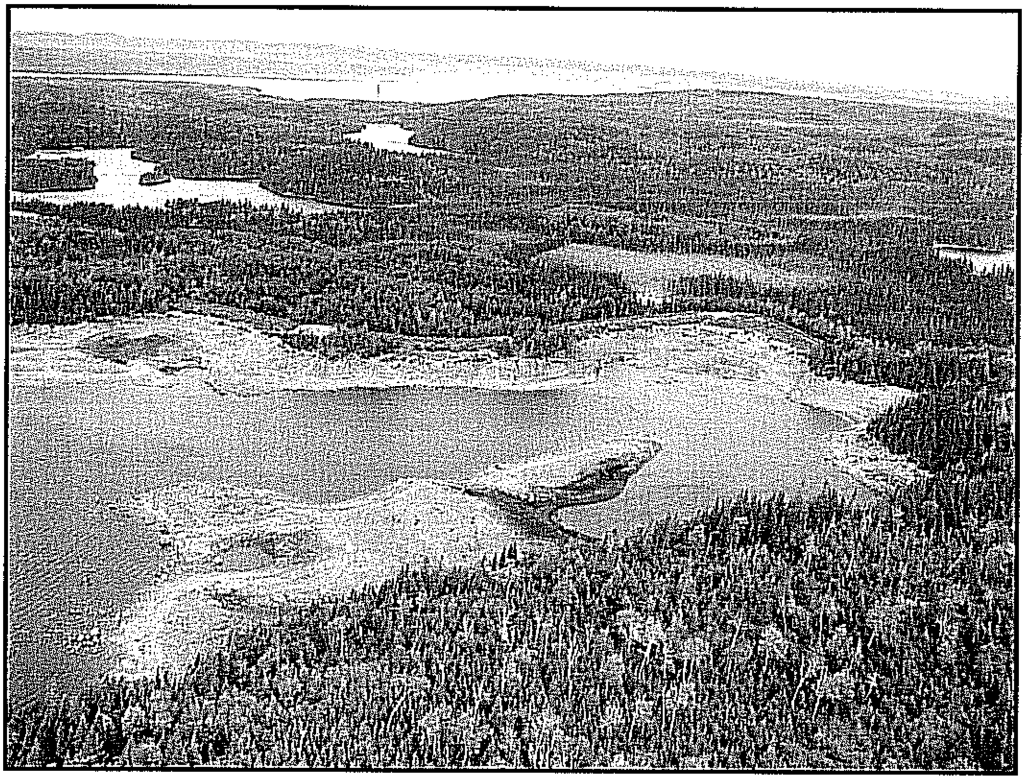
Value of Energy	$0.093	/kWh				
Diameter (ft)	**7.5**	**8**	**8.5**	**9**	**9.5**	**10**
Average Energy (GWh)	63.5	66.1	67.2	68.0	68.6	69.0
Energy Benefits (above existing)		$3,268,000	$4,651,000	$5,656,000	$6,410,000	$6,913,000
Costs incremental above 7.5ft		$541,154	$1,082,000	$1,623,000	$2,165,000	$2,706,000
Net Benefits (Benefits - Costs)		$2,727,000	$3,569,000	$4,033,000	**$4,245,000**	$4,207,000
Incremental Energy (GWh)		2.6	1.1	0.8	0.6	0.4
Annual Incremental Benefits		$241,300	$102,100	$74,240	$55,680	$37,120
Present worth Incremental Benefits		$3,268,000	$1,383,000	$1,005,000	$754,100	$502,700
Costs incremental above 7.5ft		$541,154	$541,154	$541,154	$541,154	$541,154
Incremental Net Benefits		$2,727,000	$841,800	$463,800	**$212,900**	-$38,500

Note: Discount rate is 7.15% and time is 50 years

Appendix D

Civil Infrastructure Assessment

Rattling Brook Hydro Plant
Civil Infrastructure Assessment



Prepared by:
Tony Chislett, P.Eng

February, 2006

REGISTERED PROFESSIONAL ENGINEERS
GARY L. MURRAY
SIGNATURE
Apr 27/06
DATE
NEWFOUNDLAND & LABRADOR

NEWFOUNDLAND POWER
A FORTIS COMPANY

Table of Contents

1.0 General

A complete inspection of the civil infrastructure of the Rattling Brook system was completed in 2005. The purpose of this assessment is to document the condition of existing infrastructure of the system and make recommendations for required improvements.

The total storage volume of all reservoirs in the Rattling Brook system is about 76 million cubic metres, with a drainage basin of 383 km^2. There are a number of dam and flow control structures in the storage reservoirs that comprise the Rattling Brook system. The furthest upstream reservoir, Frozen Ocean Lake, contains an embankment dam, a timber outlet structure and a rockfill overflow spillway. Rattling Lake contains an embankment dam and an adjacent concrete/wooden stoplog spillway. Amy's Lake contains an embankment dam, a concrete outlet structure, and three freeboard dams. The furthest downstream reservoir, the Forebay, contains an embankment dam, a concrete power intake structure, and a rockfill overflow spillway.

2.0 Civil Infrastructure Condition Assessment

2.1 Frozen Ocean Lake

Frozen Ocean Lake is the furthest upstream reservoir within the Rattling Brook system and is comprised of an embankment dam, a rockfill overflow spillway and a timber outlet structure.

2.1.1 Frozen Ocean Lake Dam

Frozen Ocean Lake dam was completely rebuilt in 1988. Major upgrades since that time include riprap improvements in 2001.

Overall the embankment dam is in good condition. The riprap on the upstream face of the dam is well graded with no signs of apparent movement. The downstream face, abutments and crest are all in good condition. At the time of inspection there was no observed evidence of slope instability or overtopping of the dam. Furthermore there was no evidence of seepage through the dam.

The embankment dam is in good condition and no recommendations for improvement are suggested at this time.

2.1.2 Timber Outlet Structure

A complete new outlet structure was installed in 1988. Since that time the concrete sill floor and mechanical equipment for the gate structure was upgraded in 2004.

Overall the timber outlet structure is in good condition. The approach and discharge channels were clear at the time of inspection and there were no apparent deficiencies with regards to the timber structure and abutments.

No recommendations for improvement are suggested at this time.

2.1.3 Frozen Ocean Lake Spillway

The original spillway installed in 1958 was completely rebuilt in 1988. No major upgrades have been carried out since that time.

Overall the spillway is in good condition. The upstream face and crest of the spillway is in good condition. The riprap on the downstream face is well graded with no apparent signs of movement. The abutments are stable with good rockfill protection at the spillway and dam interface. At the time of inspection the approach and outlet channels were clear with no obstructions. Furthermore there was no evidence of seepage through the spillway.

No suggested improvements are recommended at this time.

2.2 Rattling Lake

Rattling Lake site consists of an embankment dam and a concrete and stoplog spillway.

2.2.1 Rattling Lake Dam

Since the commissioning of the site in 1958 major upgrades to Rattling Lake Dam include the replacement of the riprap on the upstream face in 2000.

The upstream face of the dam is in good condition. The riprap is well graded with no indication of movement of the material. No unusual conditions were observed at the abutments. There was a good transition from the embankment sections to the abutments. The crest of the dam is in good condition. At the time of inspection there was no evidence of overtopping or damage observed due to vehicular traffic.

To minimize the amount of vegetation growth on the downstream face of the dam it is recommended the downstream face be re-graded and rockfill be placed over the entire length of the dam.

2.2.2 Rattling Lake Spillway

Rattling Lake Spillway is the main spillway in the Rattling Brook system. Since it’s commissioning in 1958, with the exception of replacement of deteriorated stoplogs and other minor upgrades, the spillway is for the most part in its original state. A detailed assessment revealed that it was necessary to replace the spillway as part of the capital works improvements. This detailed assessment is included as Attachment B of this report.

2.3 Amy’s Lake

Amy’s Lake consists of an embankment dam, a concrete outlet structure and three freeboard dykes.

2.3.1 Amy’s Lake Dam

Amy’s Lake dam for the most part is in its original state. Other than the replacement of the trash racks in 2000, no major upgrades have been carried out on this structure.

The riprap on the upstream face of the dam is sparse throughout most sections. Some sliding of rockfill into the approach channel was observed. No unusual conditions were observed at the abutments and the crest of the dam appears to be in good condition. No seepage was observed, potentially due to low reservoir levels.

Riprap refurbishment is required on the upstream face of the dam. To prevent sliding of rockfill into the approach channel, it is recommended that the intake be raised by either extending the concrete wing wall or placing large boulders along the channels edge. Furthermore, to minimize vegetation growth, it is recommended that the downstream slope be re-graded and rockfill be placed along the entire length of the dam.

2.3.2 Amy's Control Gate

The control gate at Amy's Lake is the original gate that was installed in 1958. Newfoundland Power intends to implement a water management system at the Rattling Brook facility as part of the capital works improvement. This type of system requires frequent raising and lowering of gates to control the water level to the forebay channel. The current gate installed at Amy's Lake is not suitable for this type of operation. Therefore, it is recommended that the gate at Amy's Lake be replaced with a hydraulic operating gate, suitable to water management operations.

2.3.3 Amy's Concrete Outlet Tunnel

A visual inspection of the exterior and interior of the tunnel was completed. During the internal inspection leakage around the sides and top of the gate was observed as well as normal signs of aging concrete (i.e. exposed aggregate). At the exterior of the discharge channel the concrete retaining wall is showing signs of deterioration (i.e. erosion/weathering). In addition accumulation of rockfill in the discharge channel was observed.

Amy's canal is a man made canal that was constructed in 1958. It is evident that the sides of the canal downstream of the tunnel have failed overtime resulting in an accumulation of rockfill. To eliminate backwater effects at the tailrace it is recommended that the discharge channel be dredged. In addition, to prevent further deterioration of the concrete retaining wall at the exterior of the discharge channel, it is recommended a concrete overlay be implemented.

2.3.4 Amy's Lake Freeboard Dykes

Freeboard Dyke No. 1

No unusual conditions were observed at the abutments and the crest is in good condition with no evidence of overtopping. In addition, at the time of inspection no seepage was observed, potentially due to low reservoir levels.

Freeboard Dyke No.2 and No.3

The riprap on Freeboard Dyke No.3 requires some re-grading.

As part of the Rattling Brook refurbishment project it is recommended that the Freeboard Dyke be upgraded.

2.4 Forebay Dam

The Rattling Brook forebay dam consists of an embankment dam, an intake structure and a rockfill overflow spillway.

2.4.1 Forebay Dam

Since original installation in 1958, major upgrades included riprap improvements completed in 2001.

The riprap on the upstream face of the dam is well graded and shows no signs of movement. The abutments and crest of the dam are in good condition with no evidence of overtopping observed. There was a minimum amount of seepage at the downstream toe running in the penstock right of way.

No recommendations for improvements are suggested at this time.

2.4.2 Forebay Spillway

Major upgrades to the spillway since 1958 include riprap improvements that were completed at the same time as the upgrades to the Forebay dam in 2001.

Both the upstream and downstream face of the spillway is in good condition. Riprap is stable with very few signs of movement. Good riprap protection is evident along the abutment embankments. At the time of inspection the approach and outlet channels were clear with no obstructions.

No recommendations for improvements are suggested at this time.

2.5 Powerhouse Tailrace Tunnel

Since the Rattling Brook facility was placed into service, no upgrades have been completed to the powerhouse tailrace tunnel. An internal inspection of the tunnel was carried out in September 2005. The tunnel is in good condition with minor weathering and spalling of the concrete.

No recommendations for improvements are suggested at this time.

2.6 Access Roads

The access road to Amy’s Lake and Rattling Lake dam is currently in fair to good condition. However before construction begins it is recommended that the road be widened to allow the larger equipment to easily access the various sites.

3.0 Conclusion

Assessments were completed of the civil infrastructure at Rattling Brook including dams, dykes, tunnels, control gates and roads. In summary, the civil infrastructure is in good condition. However, several items require attention to ensure the continued safe and reliable operation.

Based on the findings in this report, the following work is recommended for the Rattling Brook hydro plant system in 2008:

- Replacement of Rattling Lake spillway;
- Upgrades to Amy’s Lake dam and Amy’s Lake freeboard dam;
- Replacement of Amy’s Lake outlet gate;
- Upgrades to Rattling Lake dam; and
- Upgrades to site access roads.

Attachment A

Pictures of Rattling Brook Civil Infrastructure

Figure 1: Aerial Shot of Frozen Ocean Lake Infrastructure

Figure 2: Frozen Ocean Lake Dam

Figure 3: Aerial Shot of Rattling Lake Dam and Spillway

Figure 4: Rattling Lake Dam (Note excessive vegetation on downstream face)

Figure 5: Rattling Lake Dam (Upstream Face)

Figure 6: Aerial Shot of Rattling Lake Spillway

Figure 7: Aerial Shot of Amy's Lake Dam and Outlet

Figure 8: Amy's Lake Dam (Upstream Face)

Figure 9: Amy's Freeboard Dyke No. 1

Figure 10: Amy's Freeboard Dyke No. 3

Figure 11: Aerial Shot of the Forebay Dam

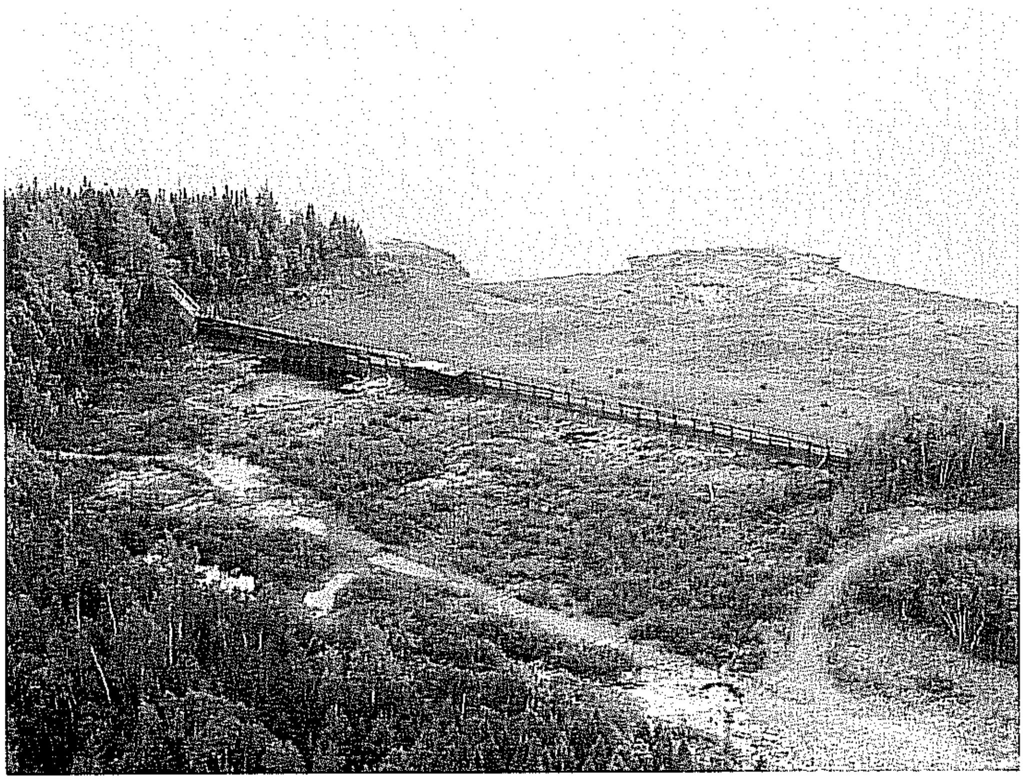
Figure 12: Forebay Dam (Upstream Face)

Figure 13: Forebay Spillway

Attachment B

Rattling Lake Spillway Assessment

Rattling Brook Hydro Plant
Rattling Lake Spillway Assessment



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1.0 General

Rattling Lake Spillway is the main spillway in the Rattling Brook Development and is a High Consequence structure, according to the Canadian Dam Association (CDA) classification system. Since it's commissioning in 1958, with the exception of the replacement of deteriorated stoplogs and other minor upgrades, the spillway is in its original condition.

The purpose of this report is to provide a brief description of the existing Rattling Lake Spillway, document the existing condition of the spillway and assess the existing capacity with respect to spill and stability.

2.0 Rattling Lake Spillway

2.1 Description of Structure

The existing spillway structure was commissioned in 1958. The base of the spillway is a concrete weir that varies in height based on the natural topography of the supporting bedrock. The concrete is anchored to the rock with 20-M dowels. The top of the concrete spillway crest is at elevation 112.78 m.

The spillway elevation is increased to a maximum storage elevation of 115.12 m with 15 wooden stoplogs. The spillway has a total of 42 stoplog bays; 35 bays have a net length of 2.44 m each and 7 bays have a net length of 1.83 m each. The total net length of the spillway openings is 98.15 m. The overall length of the spillway structure between abutments is 107.35 m.

The Full Supply Level (FSL) for the reservoir, based on current operating practice, is 114.91 m, with a storage capacity of 69.2 million cubic metres at FSL. Any reservoir impoundment above the stoplog operating level spills into Rattling Brook downstream. The freeboard, or difference in elevation between the dam crest and maximum storage elevation, is 1.01 m (116.13 m – 115.12 m).

2.2 Existing Operation

During the winter months, the elevation of Rattling and Amy's lakes must be kept at approximately 112.2 m to keep ice from rafting up on the flashboards. This lowered elevation, approximately 2.71 m below FSL, provides sufficient storage to enable Rattling Brook hydroelectric plant to operate efficiently during the winter months, and provides capacity for the high inflows during spring run-off.

During periods when excessive spill events are anticipated, the stoplogs that form the existing structure are manually removed by plant operations staff.

Due to the inefficient operation of this type of structure some energy is spilled that could otherwise be utilized for energy production. The value of the energy is difficult to quantify but is considered to be significant.

2.3 Assessment of the Structure

As part of Newfoundland Power's Dam Safety Program, an inspection of the Rattling Lake Spillway was conducted in 2005 to assess and document the current condition of the structure. Additional input to the structure's assessment was compiled through a review of available documentation.

2.3.1 Dam Safety Inspection Reports

Regularly scheduled dam safety inspections have identified that the spillway and its structural components are showing signs of deterioration. Observations that were made concerning the spillway during the regular scheduled inspections are as follows:

- Concrete crest continues to show signs of deterioration due to weathering and aging. Exposed aggregate and spalling was observed throughout.
- Walkway timbers are showing continuing signs of deterioration and should be replaced in some locations.
- On the downstream end of the spillway there is a significant amount of fractures in the bedrock foundation along the downstream toe. Undercutting is evident throughout the concrete and bedrock interface.

2.3.2 Dam Safety Review

In 2001, AMEC conducted a Dam Safety Review of the Rattling Brook Development. Based on their assessment, Rattling Lake dam was categorized as a High Consequence structure, according to the Canadian Dam Association (CDA) classification system. Within the scope of the dam safety study, a review of the Rattling Lake spillway flood discharge capacity was investigated. Simulations showed that the lifting of stoplogs during flood flows would have to be maintained possibly up to 50 hours, in order to achieve the required discharge capacity of the spillway. In the event that an operator could not remove the stoplogs during times of extreme flow, there is an increased possibility of downstream flooding or dam failure at Rattling Brook.

Due to the configuration and design of the existing spillway, removal of the stoplogs is a labour intensive and potentially hazardous activity for the plant operations staff.

2.3.3 Flood and Dam Break Study

In 2002, AMEC conducted a Flood and Dam Break Study for the Rattling Brook system. In the event that the plant staff is unable to remove the stoplogs during an extreme flood event, and as a result dam failure at Rattling Lake was to occur, the locations judged to be vulnerable are:

- Trans Canada Highway Bridge crossing Rattling Brook
- Route 351 Bridge crossing Rattling Brook
- Rattling Brook powerhouse. Damage to the powerhouse will likely cease power production.
- Rattling Brook substation located near the powerhouse. Damage to the substation will mean loss of power to the town of Norris Arm.

The report indicates that the failure of these structures could damage the bridges and buildings in the vicinity of the Rattling Brook development.

In accordance with the Canadian Dam Association (CDA) guidelines, Rattling Lake dam is classified as having high consequences in the event of a failure. The normal practice for a high consequence structure is to use an Inflow Design Flood (IDF) somewhere between a 1,000 year return flood to the Probable Maximum Flood (PMF). However, based on the risks posed at the bridges, AMEC recommends upgrading the IDF return period for the Rattling Lake spillway from a 1,000 year flood to a 10,000 year flood.

2.3.4 Analysis of Existing Structure

Due to the importance of the spillway in the Rattling Brook development, the condition and age of the structure, a preliminary stability evaluation was performed by Newfoundland Power to assess the structural integrity of the spillway.

All loading cases were considered with anchors extending into the rock foundation, each instance being examined for overturning about the toe of the concrete weir and sliding of the concrete over the underlying rock. In addition, the location of the resultant force was checked to ensure that no tension is induced at the structure and foundation interface.

Because minimal upgrades were completed on the structure since its original installation in 1958, assumptions were made regarding the capacity of the structural components of the spillway system. To perform all applicable checks it was assumed that the strength of both the bracing system and rock anchor dowels was reduced to 75% and 50% of their original capacity.

Based on the preliminary analysis, and the stated assumptions, the spillway structural acceptance criteria for sliding stability is marginal at 75% of the brace and rock anchor's original capacity and it does not meet acceptance criteria when the capacity of the brace and rock anchor system is reduced to 50% of its original capacity.

3.0 Conclusions and Recommendations

3.1 Conclusions

Stability

Based on the stability analysis performed, for the stated assumptions, Rattling Lake spillway does not satisfy industry standard performance criteria. Both sliding and overturning stability were considered. Stability of the structure is dependent on bracing and anchoring systems, which provide some measure of resistance, but should not be relied upon for ongoing stability under long-term service conditions.

Flood Discharge Capacity

The spillway design flood cannot be safely passed with stoplogs in place. Provision for adequate discharge capacity and freeboard requirements at Rattling Lake is largely dependent on stoplog removal operations. This requires a labour intensive effort from plant operations staff for a prolonged period.

Operation of Stoplogs
Under the current arrangement, stoplogs are typically removed during periods of high inflows in order to provide adequate spillway discharge capacity. The manual stoplog removal process is a hazardous operation, and requires diligent job planning to ensure worker safety is not compromised. External factors, including extreme flood conditions and the inability to access the site may prevent the execution of stoplog removal operations, thus jeopardizing dam safety.

3.2 Recommendations

It is recommended that Newfoundland Power replace the existing stoplog spillway structure at Rattling Brook in 2008. The new structure will be designed to provide adequate discharge capacity under extreme flood conditions, while satisfying freeboard requirements. When evaluating various rehabilitation alternatives, primary consideration must be given to operating features under extreme flood conditions. Preliminary assessments of viable alternatives are in the order of $1.5 million dollars. Alternatives will be evaluated and a recommendation on the appropriate structure design will be undertaken prior to the 2008 Capital Budget Application.

Attachment A

Rattling Lake Spillway Photos


Figure 1: Rattling Lake Spillway (Aerial View)


Figure 2: Undercutting of Concrete/Bedrock Interface

Figure 3: Fractured Brace Foundation

Figure 4: Deteriorated Walkway Timbers & Operation Staff's "Removal" System

Figure 5: Rattling Lake Spillway (Winter Conditions)

Figure 6: Rattling Lake Spillway (Spill Conditions)

Figure 7: Rattling Lake Spillway (Spill Conditions)

Appendix E

Electrical Equipment Site Assessment

Rattling Brook Hydroelectric Plant
Electrical Equipment Site Assessment

Revised March 2005

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1.0 General

The Rattling Brook hydroelectric development went into service in December 1958. The generating station contains two vertical shaft Francis turbines connected to separate generators each with an original rating of 7500 kVA.

Generating unit no. 2 experienced an in-service failure of the windings and underwent a stator rewind in 2002. A planned rewind of generating unit no. 1 was completed in November 2004.

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 electrical projects, the electrical plant remains in original condition.

In February 2005, a site assessment was completed to determine which electrical and mechanical components of the development require refurbishment or replacement.

2.0 AC Distribution

The existing 120/240V 3-phase AC service panel (figure 1) 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 away from the switchgear line-up to provide ease of access for wiring future circuits.

Figure 1 - AC Distribution

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 three 25 kVA 240 volt secondary transformers, with one transformer low voltage winding tapped to provide 120 volt 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. A redundant station service, consisting of a normal supply and an emergency supply, will be installed to ensure the availability of this critical black start plant. This will require modification to the outside distribution substation.

4.0 DC Distribution

The DC distribution panel (figure 2) is original to the plant and has no spare breaker positions for additional circuits. Additional breaker positions will be required to accommodate the various electronic components to be included in the governor and unit control panels. Additional DC circuits are also required for the motor actuators associated with the new valves to be installed as part of the plant mechanical upgrade. Due to its age, and lack of spare capacity it is recommended that the DC distribution panel be replaced.

Figure 2 - DC Distribution

5.0 Battery Plant and Charger

The battery bank (figure 3) was installed in 1996 and is in good condition. The battery charger is 21 years old and the supply of spare parts has been exhausted. During the inspection its condition was assessed and the charger requires replacement. The battery bank and the charger are located in the same room as the switchgear instead of in a separate battery room. The plant refurbishment will include the construction of a separate battery room to house the battery bank.

Figure 3 - Battery Bank

6.0 Generators

Generator No. 2 and Generator No. 1 were rewound in 2002 and 2004 respectively. No additional work is required on the generator windings. The temperature signals from the resistance temperature devices installed in the stator windings during the rewinds will be monitored by the new control system. The existing terminal blocks in the generation terminal cabinet will be replaced with resistance temperature device terminal blocks.

Figure 4 – Termination Cabinet

7.0 Excitation Systems

The exciters on both generators are original equipment installed in 1958.

Generator No. 1 exciter stator, rotor and brush gear were cleaned and painted by General Electric during the stator rewind completed in 2004. The winding impedance is good so no additional work is required on the Generator No. 1 exciter as part of this project with the exception of the installation of brush gear temperature sensors. Similarly, the Generator No. 2 exciter was cleaned and painted during the 2002 generator stator rewind. The winding impedance is poor and it is recommended the exciter be overhauled and rewound as part of this project.

Both units have Brown Boveri voltage regulators (figure 5) with mechanical operating mechanisms and have been manufacturer discontinued. These units will be replaced with digital voltage regulators.

The Field Breakers (figure 6) on both units are original to the 1958 installation, are obsolete and lack a sufficient number of auxiliary contacts required by the PLC control system being installed. New field breakers will be installed in the new switchgear lineup. The power cables from the exciters to the generators via the field breaker are also original to the plant and will be replaced as they are at the end of their service life.

Figure 5 - Voltage Regulator

Figure 6 - Field Breaker

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 are original equipment installed in 1958. The PT and CT winding insulation appear brittle due to age. They must be replaced due to the critical role this equipment plays in the electrical protection of the generators.

The existing switchgear design was based upon two incoming breakers fed from two separate power transformers. In 2002, the two 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 dual 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 proposed design incorporates 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 will not be possible to relocate these cables to new switchgear cubicles without severely damaging the insulation. Therefore the power cables and terminations will need to be replaced as a result of the planned switchgear replacement.

Figure 7 - Unit No. 1 Switchgear Cable Terminations

Figure 8 - Unit No. 1 Generator Cable Terminations

10.0 Generator Grounding

Both generators currently have their stator windings star point solidly connected to ground, which in the event of a phase to ground fault will subject the windings to the electrical stresses of the total available fault current. Industry best practices involve the installation of a small transformer between the winding star point and ground creating a high impedance path for fault current. This will significantly reduce the available fault current resulting in reduced electrical and mechanical stresses on the generators under fault conditions. It is recommended that the high impedance ground design be implemented, and related ground fault protection improvements be completed.

The termination cabinets attached to the generators do not have space for the grounding transformers. Modifications will have to be made to accommodate mounting the grounding transformers on top of the existing termination cabinets.

11.0 Protective Relays

Protective relaying systems provide protection to equipment and personnel during abnormal loading or fault conditions. Thus protective relaying functions are a critical component and must be sufficient to protect generating units and other electrical equipment against all harmful conditions that may develop. The evaluation of the protective relays considers the age of the relay, its reliability, and its ability to address changes in protection standards since the plant was placed in service.

The existing generator protection for both generating unit no. 1 and no. 2 is provided through obsolete electromechanical relays consisting of the following:

- 40 Loss of field protection
- 49 Stator thermal protection
- 51N Neutral overcurrent
- 87G 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:

- 59N Over voltage relay for ground faults
- 64F Voltage relay for rotor ground faults
- 46 Stator unbalanced current protection
- 81U/81O Under/over-frequency protection
- 27/59 Under/overvoltage
- 24 Volts/Hz protection
- 32 Reverse power protection
- 50/27 Dead machine protection
- 27N 100% stator earth fault protection
- 78 Pole slip protection
- 51 Overcurrent protection

It is recommended that the existing generator protective relays be replaced with modern digital generator protective relays to provide all of the above functions, as well as additional functions. These relays will provide the ground fault protection improvements in conjunction with the recommended grounding transformers in Section 10.0. Improved generation protection reduces stresses due to electrical faults and in turn extends the life of the generator.

The existing plant power transformer protection will be upgraded for consistency with the standard protection and control scheme for generating plant applications.

The existing 66 kV high voltage bus at Rattling Brook substation does not have it own primary high speed protection. It is presently protected by time delayed overcurrent protection on the incoming transmission lines. A high voltage bus differential protection relay will be installed to bring the 66 kV bus protection up to standard. This bus differential scheme will require the addition of current transformers on the high voltage side of the distribution power transformer. The new relay will provide bus current differential protection and backup phase overcurrent protection for all equipment feeding into the bus.

Rattling Brook substation is presently serviced by two 66 kV transmission lines. The existing protection on these lines is a combination of overcurrent and impedance relaying. These relays are of the same vintage as other units operated by Newfoundland Power that have failed to operate correctly under fault conditions. It is recommended that these obsolete electromechanical relays be replaced with modern digital distance line protection relays. The new relays will provide improved line protection with both impedance protection and overcurrent protection, which will also improve coordination with other protection devices. The transmission line protection standard application will be applied to these lines.

12.0 Alarm Annunciation

Industrial computer human-machine interfaces will be installed in the unit control panels to provide improved alarm indication and functionality. The annunciator panel currently located in the switchgear line up is antiquated and will be removed from service.

13.0 Governor Interface

The original Woodward Type HR hydraulic governors still in service on both generating units have been reliable and have no outstanding maintenance issues. However, the original equipment manufacturer advises they will no longer manufacture replacement parts for these units after July 1, 2008. Initially this raised concerns regarding the future maintenance of these units. Newfoundland Power has since determined that parts, service and training for Woodward governors are provided by a number of third-party companies.

More advanced control of the governor load and droop setpoints is required to implement a PLC controlled water management system and remote black starting of the units. With the present configuration of the governors the speed reference setpoint feedback cannot be obtained and the starting gate limit and droop settings cannot be controlled. The Woodward governors consist of two sections, the power piston that provides the force necessary to operate the wicket gates under load, and the control head that provides regulation to the power piston. A number of suppliers can provide an electronic control head that replaces the existing mechanical control column down to the relay valve that initiates the action of the power piston. The fly ball governor head, pilot valve assembly, and mechanical restoring linkages are all removed. The existing hydraulic power piston assembly is retained, along with the relay valve, servomotor, handwheel, and gate operating linkages. The life extension of the power piston assembly will require reconditioning of all seals, bushings and other components that have deteriorated through the previous 48 years of service.

14.0 Plant Control

Although this plant is remotely controlled and monitored, remote control functions are limited. Intervention by a local or SCADA operator is required to start and stop both units at this plant. Adjusting the load for efficient operation requires manual input from an operator and frequent adjustments. At present, there is no automation with respect to water management and the automatic setting of loads. The addition of programmable logic controllers ("PLC") will provide improved local and remote monitoring and control functionality and facilitate the implementation of a variety of control modes to ensure the efficient operation of the plant and utilization of available water. To provide the required processing power and reliability, PLCs will be utilized to control each generator, common plant functions such as heating and ventilation, forebay water level monitoring, Amy's gate monitoring and control and synchronizing.

The synchronizer (figure 9) is original to the plant and is based on vacuum tube technology making parts difficult to obtain. It will be replaced with modern digital synchronizers as part of the upgraded unit control panel.

Figure 9 - Existing Synchronizer

15.0 Instrumentation

The companion mechanical assessment report that was completed at the same time as this electrical assessment report has identified condition monitoring devices that are antiquated and need to be replaced. These devices are original to the 1958 plant construction. The devices have alarm contacts that operate when a predetermined alarm level has been exceeded and the typical response to the contact closure is to trip the unit off line.

Upgrading the plant control to PLC technology provides the capability to continuously monitor the state of the various mechanical subsystems. The operating condition of these bearings, cooling water, windings and other mechanical equipment can be recorded and trends identified before any damage occurs. To provide this capability the antiquated condition monitoring devices must be replaced with modern devices that provide a scaled analog quantity in addition to the trip contact.

The following condition monitoring devices will be replaced as part of the electrical and mechanical refurbishment. The justification for this work is found in Appendix F, *Mechanical Site Assessment* report.

- Speed Switch
- Vibration Sensors
- Bearing Temperatures Sensors
- Pit Flood Sensors

- Stator Temperature Sensors
- Brush Gear Temperature Sensors
- Scroll Case Pressure Gauge
- Wicket Gate Position Transducer
- Bearing Oil Level Sensors

16.0 Bearing Cooling Water Control

The bearing cooling water system is comprised of a water filter, pressure-reducing valve, manual control valve, inlet control solenoid, flow meter, cooling coil and discharge solenoid. Inlet and drain valves with partial automated control are currently in place for both units. Flow monitoring and valve controlled solenoids have been installed to provide protection and control. This system will be integrated into the new PLC control system. Proper control of the system will reduce cooling coil wear, extending the life of the system and reducing the potential for release of petroleum products into the environment.

A detailed assessment of the bearing cooling water system including the condition of the piping and valves is included in Appendix F, *Mechanical Site Assessment* report.

17.0 Heating and Ventilation

There are anti-condensation heaters installed on each generating unit. The building ventilation louvers are original equipment and are pneumatically operated. Additional generator pit heating is required to adequately control condensation. Presently only the generator gallery temperature is monitored.

Heating and ventilation control equipment will be upgraded to interface with the unit control PLCs. Temperatures will be monitored in the generator gallery, turbine pit and valve pit and humidity monitored in the generator gallery. The PLC will use building ambient temperature and humidity inputs to control the operation of the exhaust fans, louvers, generator winding heater, infrared turbine heaters, infrared valve pit heaters and anti-condensation heaters. A manual override of the heating and ventilation control system will be provided to permit operator intervention. A high building temperature alarm will be initiated when a specified ambient temperature is exceeded.

A detailed assessment of the dampers, louvers, actuators and fans is included in Appendix F, *Mechanical Site Assessment* report.

18.0 Forebay Water Level Monitoring and Control

The forebay and Amy's Gate water level probes and transducers are older technology installed in 1987. This equipment will be replaced with new 4 to 20 mA water level transducers and new control cabinets will be installed at the forebay, Amy's gate and in the plant with a small PLC at the forebay. Both sites will communicate with the PLC at the plant via a new fibre optic cable.

One of the unit PLCs will use the water level signals to control the water management system including the control of Amy's gate. The water management system will optimize the efficiency of the plant by controlling the load on both units based upon the water level, inflow, wicket gate position and control mode setpoints. In addition high level (spill) and low level alarms will be initiated when specified water levels are exceeded.

19.0 Forebay Line

The 12.5 kV forebay distribution line was built in 1958. The line was rebuilt in 1980 with penta treated poles and untreated cross arms. Inspection of the line indicates that while the treated poles are in reasonably good condition and may have an extended life of 20 to 25 years, the cross arms and insulators are deteriorated and require replacement. The cross arms are untreated and at 25 years have exposed wood rot. As well many of the cross arms are badly cracked which greatly reduces the structural strength of the entire line. The insulators are older and many are the two piece porcelain type which are prone to failure and have been replaced throughout the system.

This forebay line is used to operate gates which control water levels for operation of the plant. It is also used as the carrier for the communications cable for monitoring these levels. Thus the line is an integral part of the infrastructure required to maintain the plant operations. The forebay line will be upgraded to correct the noted deficiencies.

20.0 Substation

Rattling Brook substation was built in 1958 as a 66 kV transmission switching substation and as a 12.5 kV distribution substation. The distribution substation contains one power transformer (T4) with a capacity of 2.2 MVA at 12.5 kV. The substation directly services approximately 674 customers in the Norris Arm area. In the transmission substation there are two 66 kV transmission lines terminated in the high voltage bus. These are transmission lines 101L to Grand Falls substation and 102L to Gander substation.

The substation has a 4.16 kV bus connected to the 66kV bus through a single transformer (T1) rated at 20 MVA. The 4.16 kV bus connects the power output from the generating station to the transmission and distribution substations.

The existing substation is wood pole construction. The current 12.5 kV distribution bus has non-standard clearances, materials and hardware. The existing substation bus does not have adequate space to accommodate the addition of a new station services transformer required for the new plant switchgear (reference section 3.0). Also, an emergency station service taken from the 12.5 kV distribution bus is required for the plant. Section 11.0 identifies protective relaying deficiencies and recommends protection improvements for the transmission lines, transformer and high voltage bus. The substation site is too small to facilitate the installation of a Portable Substation for transformer maintenance or emergency situations and needs to be enlarged. For these reasons the existing substation needs to be upgraded to current standards, enlarged and modified to provide both normal and emergency station services.

21.0 Communications

Communications systems at Rattling Brook collect information on site at the facility and sends data back to the System Control Centre in St. John's. The communications systems will be upgraded to improve the reliability of the plant and to meet other project objectives such as retirement of the old Control Centre building.

Present System

Two 25 pair figure eight copper communications cables are used to provide water level indication, gate control and gate position from both the forebay and Amy's Lake intake structures back to the plant. The water level indications are used to manage the day to day operation of the plant and to manage the water storage levels. The condition assessment of the plant communications cables indicated that the various cable pairs range from good to poor condition, with some cable pairs no longer intact. Table 1 shows the percentages of pairs in-service, spare and failed.

Table 1
Rattling Brook Communications Cable Assessment
(%)

Cable Section	In-Service	Spare	Failed
Plant to Forebay	40	32	28
Forebay to Amy's	55	27	18

Metallic communication cables are prone to failure caused by voltage gradients on the cable pairs induced by ground potential rises ("GPR"). The GPR effect is common in the utility environment where cables connect the substation ground grid where a fault current may be present to a remote location where the effects of the ground fault are not present. Hence a potential difference exists and a current will flow through the cable. Faulty cable pairs can cause controls to operate incorrectly and errors in reporting of forebay levels.

Proposed Cable System

Reliable operation of the forebay communications, monitoring and control systems contributes greatly to plant production efficiencies. A fibre optic based communications system is proposed to replace the copper communications. The fiber optic cable is not impacted by GPR effects and associated voltage gradients causing analog signal loss. New electronic fibre interface equipment will be installed to transfer signals from the forebay equipment to the plant PLC system.

22.0 Recommendations

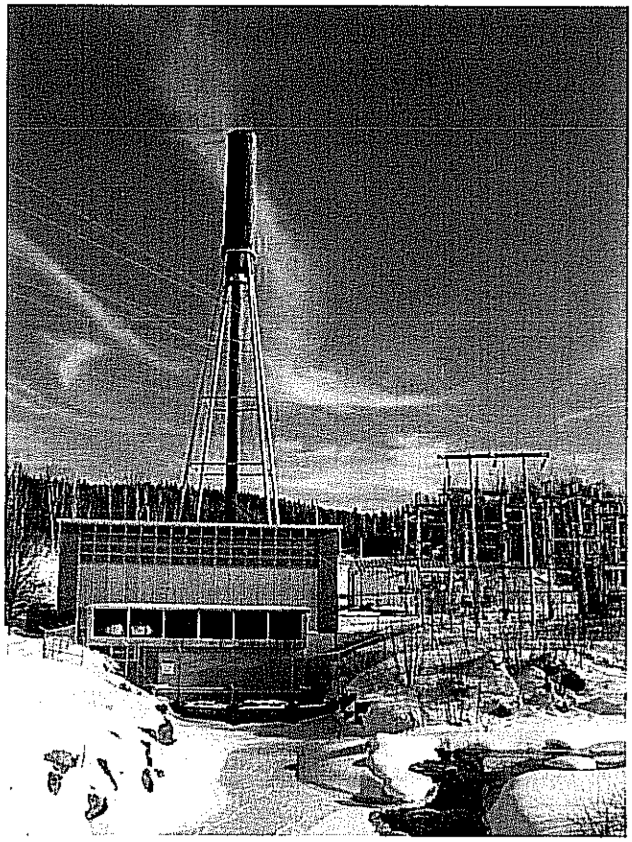
The following upgrades are recommended to be completed in 2007:

1. Replace AC distribution panel and provide new normal and emergency station service
2. Replace DC distribution panel and build battery room
3. Rewind the exciter on unit no. 2
4. Replace the switchgear and generator power cables
5. Replace the Field Breakers and voltage regulators on both units
6. Upgrade protective relay technology for both generators
7. Install generator ground protection on both units
8. Expand the existing substation, improving clearances and modify structures to accommodate station services
9. Install new protection panels for the transformer, two transmission lines and 66 kV bus
10. Refurbish governors and equip with electronic control units
11. Install new unit control panels (PLC) and interface with instrumentation for both units
12. Upgrade to plant and equipment heating and ventilation systems
13. Upgrade the existing forebay 12.5 kV distribution line
14. Replace forebay communication cable and water level monitoring equipment

Appendix F

Mechanical Site Assessment

Rattling Brook Hydro Plant
Mechanical Site Assessment



Prepared by:
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April 20, 2005

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NEWFOUNDLAND POWER
A FORTIS COMPANY

Table of Contents

1.0 General

The purpose of this report is to document the existing condition of the mechanical equipment at the Rattling Brook hydro plant and to make recommendations for required improvements to extend the life and improve the reliability and efficiency of the plant.

For the most part, the existing mechanical equipment was originally installed when the plant was constructed in 1958. The only notable mechanical upgrade was the replacement of the two turbine runners in 1986-87.

2.0 Equipment Condition Assessment

Site visits were conducted in February 2005 to inspect and assess the condition of the various components and systems including the main and bypass valves, turbines, generators, bearings and related instrumentation, bearing cooling water systems, governors, compressed air system, and powerhouse heating and ventilation.

Additional input to the equipment assessment was compiled through a review of available documentation including: historical inspection and assessment reports; recent maintenance history; outage reports; drawings; and manufacturer's information including maintenance manuals. Discussions were also held with Rattling Brook plant operations personnel regarding maintenance history, issues and recommendations.

2.1 Main Inlet (Butterfly) Valves and Associated Equipment

2.1.1 Main Inlet Valves

The main inlet valve for each unit is a 57 inch butterfly valve manufactured by Vancouver Iron Works (Baldwin-Lima-Hamilton) in 1958. The two identical valves are water actuated and each has a Dresser Coupling dismantling joint, located upstream.

The existing main inlet valves have experienced leaks and related problems. Attempts were made to mitigate these issues however none resulted in long term success. The valves currently leak and make it unsafe to access the scroll case without having to dewater the penstock.

Figure 1- Main Valve

During the site visit, a series of pressure and load rejection tests were carried out. These tests were conducted to determine the pressure differential across the butterfly valves. The maximum pressure loss across each valve was measured to be approximately 3 psi. This pressure loss is approximately three times that which would be typical of a modern butterfly valve. Assuming an annual plant production of 76 GWh after plant refurbishment and a cost of energy of $0.07/kwh, the replacement costs were justifiable.

Both butterfly valves will be replaced. Due to the high cost and long delivery of non-standard 57 inch butterfly valves and dismantling joints, it will be more cost effective to replace the existing with new standard sized 60 inch equipment and make any necessary modifications to accommodate the slight increase in diameter. The new electric valve actuators will operate on standard 125 VDC.

2.1.2 Drain and Bypass Valves

Each system has a 6 inch manual drain valve (figure 2) and a 6 inch manual bypass gate valve (figure 3). All valves are original equipment with the exception of the water actuated bypass valve on unit no. 2 which was replaced in 2001 and is in good condition.

Since both actuated bypass valves are water operated via the same system as the butterfly valves, their replacement will occur at the same time and the new actuators will also be the standard 125 VDC electric actuators.

Based on age and anticipated service life, the manually operated bypass and drain valves will be replaced.

Figure 2 - Drain Valve

Figure 3 - Bypass Valve

2.1.3 Valve Actuators

The existing butterfly and bypass valves for each unit are water actuated via a 2 inch 5-way control valve as shown in figure 4. Both 5-way control valves were refurbished in 2004 however, the original piping remains. Manual operation of the valves was at one time possible by means of a hand pump circuit and auxiliary water supply, but this system is no longer functional.

This system will be decommissioned and the valve actuators replaced with 125 VDC electric actuators.

Figure 4 - Valve Actuator

2.1.4 Valve Control Panel

The control panel for the valves has been modified since its initial installation however the controls for both units are obsolete. The controls for unit no. 2 have only the "main valve closed" indicator light currently operational. The controls for unit no. 1 are original equipment and no indicator lights are working. This control panel will be replaced.

Figure 5 - Valve Control Panel (exterior)

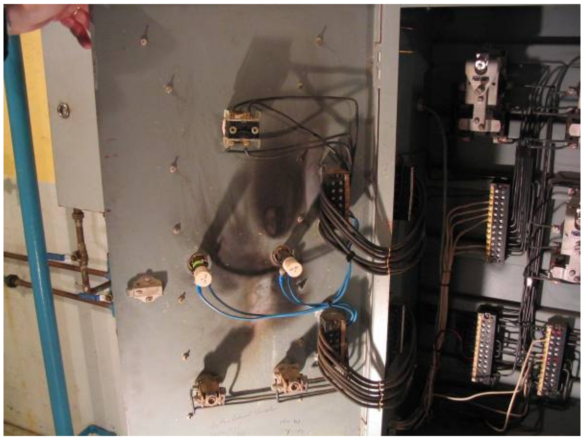


Figure 6 – Valve Control Panel (interior)

2.2 Turbine

During the site visit, it was difficult to conduct an internal inspection of the turbines because of the excessive leakage past the two main inlet butterfly valves. On both units, when the scroll case access hatch was opened (figure 7), the field of view was clouded by the significant spray of water originating around the butterfly valve disc. To mitigate this problem the drain valve was opened and a plywood barricade was placed downstream of the butterfly and drain valves. Even with this barricade in place, there was still a considerable amount of water interfering with the inspection.

Figure 7 – Scroll Case Access Hatch

Prior to this inspection, the most recent documented internal inspection of the turbines was conducted in 1998. The scope of that inspection included the runner, wicket gates and seals, scroll case, and the main inlet butterfly valves of both units.

There is no mention of wicket gate or wicket gate pin and bushing replacements in any of the historical records for either unit. Nor is there mention of the replacement of any of the pins and bushings on any of the other linkages between the governor and the turbine. While it is assumed that this is all original equipment, there currently appears to be little or no lost motion in any of the linkages. As well, since the gate clearances appear uniform and since there seems to be little leakage past the wicket gates, there will be no need to replace this equipment in the immediate future.

It is recommended that a thorough inspection of each turbine be completed during the 2007 plant outage. This inspection should confirm the current schedule for complete turbine overhauls in five to seven years on both units, with one unit undergoing a turbine overhaul in 2012 and the second unit in 2013. Previous overhauls were completed in 1986-87.

2.2.1 Unit No. 1

In 1987, the unit no. 1 turbine runner was replaced with a new Allis-Chalmers runner. During that overhaul, shaft pitting was identified and repairs were made at a local machine shop. As well, the stainless steel gland sleeve was found to be badly worn and was repaired. Severe cavitation was noted in the area of the scroll case head cover and discharge ring seal. This cavitation was also identified as a problem in 1968 and at that time was repaired with Devcon. By 1987, much of that material had washed away and the area was sandblasted and built up, this time using Mazel molecular metal.

Currently, the runner (figure 8) is in good condition. There is some evidence of minor cavitation in essentially the same location on each of the blades.

Figure 8 – Turbine Blades Unit No. 1

All but two wicket gates are in good condition. These two gates are located near the 2nd and 3rd stay vanes, counting from the area near the scroll case access hatch. These gates will be repaired as a temporary measure until the unit is overhauled in about 2012.

Heal-to-toe clearance between the gates is currently less than 0.002”, on the five gates that were measured. There is less than 0.0015” between the top surfaces of the gates and the upper facing plate and approximately 0.015” to 0.018” between the bottom surfaces of the gates and the lower facing plate. Overall, clearances are approximately equal on all gates and there is minimal leakage through the gates into the draft tube area. There has been no change in the wicket gate clearances since the 1998 inspection report.

The upper and lower facing plates appear to be uniform across their surfaces and are in reasonably good condition.

The shaft gland packing on the unit was completely replaced in 2004 and the scroll case air vent valve was replaced in 1999.

2.2.2 Unit No. 2

In 1986, the unit no. 2 turbine runner was replaced with a new Allis-Chalmers runner. The runner is currently in good condition (figure 9). There is some evidence of minor cavitation in essentially the same location on each of the blades. There is no cause for concern at this time.

Figure 9 – Turbine Blades Unit 2

All wicket gates, but one, are in good condition. Like on unit no. 1, this gate is located near the 2nd and 3rd stay vanes, counting from the area near the scroll case access hatch. These gates will be repaired as a temporary measure until the unit is overhauled in 2013.

Heal-to-toe clearance between the gates is less than 0.002" on the five gates that were measured. There is less than 0.0015" between the top surfaces of the gates and the upper facing plate and approximately 0.015" to 0.020" between the bottom surfaces of the gates and the lower facing plate. Overall, clearances are approximately equal on all gates and there is very little leakage through the gates into the draft tube area. There has been no change in the wicket gate clearances since the 1998 report.

The upper and lower facing plates appear to be uniform across their surfaces and in reasonably good condition.

The scroll case air vent valve on this unit is original equipment (figure 10). Given the age and condition of this equipment, and the fact that identical equipment on unit no. 1 of the same vintage has already required replacement, this valve will be replaced.

Figure 10 – Scroll Case Air Vent

2.3 Generator

2.3.1 Unit No. 1

The generator stator on unit no. 1 was rewound in 2004 and the exciter received a minor overhaul that included cleaning and painting. In addition new leads, brackets, and insulators were installed on the exciter. Electrically the exciters tests results were good.

Figure 11 – Generator Gallery

During the rewind project, the braking system was overhauled and air lines were replaced with all new flexible high pressure lines, the brake cylinders were overhauled, and all new brake pads were installed.

2.3.2 Unit No. 2

The generator stator on unit no. 2 was rewound in 2002 and the exciter received a minor overhaul that included cleaning and painting. In addition new leads, brackets, and insulators were installed on the exciter. Electrically the exciters tests results were poor and it is recommended that the exciter be overhauled and rewound as part of this project.

The braking system on this unit has not had any recent upgrades or maintenance other than replacement of the brake pads. Based on the present service life and condition of the system, an overhaul will be completed on the brake cylinders and the existing air lines will be replaced with new flexible high pressure lines.

2.4 Bearings & Bearing Instrumentation

The current assessment of the bearings includes a high-level evaluation of the condition of the bearings on each unit with a more detailed review of the bearing instrumentation and other related equipment.

2.4.1 Bearings

The most recent oil analysis reports for each bearing were reviewed and do not indicate any significant issues requiring immediate action. However, previous inspections have identified some issues on unit no. 1 that require repair. The thrust bearing insulation has been breached and has the potential to cause deterioration of the bearing and must be repaired. The thrust pad springs are no longer within the specified tolerance and require replacement. On the turbine bearing, delamination of the babbit surface from the shell has been noted and has resulted in minor surface damage on the bearing itself. This bearing will be re-babbitted as part of the turbine overhaul in 2012.

Figure 12 – Bearing Oil Level Switch

2.4.2 Bearing Oil Level Instrumentation
The existing oil level switches on the bearings (figure 12) provide alarm contacts only. These will be replaced with new sensors that are also capable of transmitting an analog signal to the unit PLC.

2.4.3 Bearing Temperature Instrumentation
Currently, only the bearing shell temperatures are being measured on both units, not the temperatures of the bearing surface. Measurement of bearing surface temperature wherever possible is superior to measurement of bearing shell temperature as it more precisely measures the temperature of the contact surface. Bearing surface temperature measurement is critical to improve bearing condition monitoring and to improve the response time when problems occur. Therefore, all bearing temperature instrumentation will be relocated and/or replaced as described below.

Unit No. 1

The temperature of each bearing shell is measured with a capillary tube temperature thermal bulb (figure 13). These will be replaced since they are contact only and there is no analog signal which can be transmitted to the PLC.

Unit No. 2

Much of the instrumentation on unit no. 2 has been upgraded in recent years and is tied to the existing unit PLC.

There are currently eight temperature thermocouples (two per: turbine, lower guide, upper guide, and thrust bearing) tied to the plant PLC. However, these thermocouples currently measure bearing shell temperature only and all eight will be relocated to measure bearing surface temperatures.

Figure 13 – Bearing Temperature Switch

2.4.4 Vibration Monitoring
Vibration monitoring is a critical piece of information that identifies growing problems with a dynamic mechanical system. As large machines rotate at high speed their motion should be constant and very stable. As problems develop the equilibrium that exists within the rotating machine is disturbed and vibrations develop. Continuous condition monitoring with vibration sensors identify when these problems begin and allow the engineer an opportunity to correct the problem before it leads to an equipment failure.

There is no vibration monitoring equipment installed on unit no. 1. It is recommended that vibration monitoring be installed on this unit.

The vibration monitoring equipment on unit no. 2 is the type of technology used by the Company for installations that do not use PLC control systems. The system does not provide the operator with real-time data to aid in identifying potential problems with the generator. The existing vibration equipment on unit no. 2 will be replaced with PLC compatible equipment. The existing equipment is still functional, and will be retained as spares for in-service equipment remaining in older installations.

2.5 Bearing Cooling Water Systems

The assessment of the bearing cooling water systems includes a high-level evaluation of the condition of the bearing cooling coils on each unit with a more detailed review of the cooling water piping, and other related equipment.

2.5.1 Bearing Cooling Coils

Table 1 shows the most recent cooling coil replacements.

Table 1
Cooling Coil Replacements

Cooling Coil	Unit No. 1 Year Replaced	Unit No. 2 Year Replaced
Upper guide thrust bearing	2000	2000
Lower guide bearing	2000	2000
Turbine Bearing	1999	1998

In the latest revision of Newfoundland Power's Environmental Management System (EMS) Plant Operating Guidelines, it is recommended that such cooling coils be replaced every 15 years. This recommendation is based on historical operating experience and will be followed to minimize the risk to the environment due to an oil spill. Using these guidelines, no replacement is required at this time.

2.5.2 Cooling Water Piping

The bearing cooling water system was originally part of a much larger system designed to supply water not only for bearing cooling, but also for an exterior fire hydrant, a sump pit eductor pump, a hot water tank (for plant domestic water), an office building (former control centre) domestic water, and a tap located on a plant exterior wall. As a result there is a complex, interconnected network of water piping and fittings in the turbine area.

Problems related to system deterioration have been well documented, particularly in recent years, as the cause of many unscheduled plant outages. The entire cooling water system will be redesigned and replaced to better suit the application.

Figure 14 – Twin Strainer

The existing twin strainer (figure 14) is original 1958 vintage equipment and has caused problems in recent years. It supplies both bearing cooling water systems as well as other water systems that are no longer in use.

To clean the existing strainer, as is periodically required, both hydro units must be shut down. This strainer will be replaced.

There are solenoid valves (figure 15) and flow meters on the cooling water lines for each bearing and oil level switches on each bearing oil reservoir. This system is designed to control the flow of cooling water when the generator is operating. In addition it monitors the oil level in the bearing oil reservoir. By closely monitoring water flow and oil levels, the system can detect if water is leaking into the bearing reservoir and can stop the flow of water, preventing the release of oil into the environment.

Figure 15 – Solenoid Valve

The solenoid valves were installed on unit no. 1 in 2000 and at that time some of the original bearing cooling water piping was replaced with new copper piping. Similar work was carried out on unit no. 2 at the same time. Experience has shown that the service life of this particular make and model of solenoid valve is limited and therefore all the cooling water solenoid valves will be replaced with more robust equipment.

The flow meters were installed, and associated copper piping replaced, on both units in 2001. However, the flow meters on Unit no. 2 have since been replaced with a newer type. All flow meters are contact only and all appear to be operational. However, experience has shown that the type of flow meters on Unit no. 1 frequently provide erroneous readings and therefore will be replaced.

There currently is no measurement of inlet cooling water temperature. Monitoring equipment will be installed for the purpose of trending bearing temperatures relative to bearing cooling water temperatures.

Cooling water is also directed to the shaft gland seal. Because of the condition and age of this cooling water piping on both units (original 1958 vintage) it will be replaced. The flow meters on this system will be replaced for the same reasons stated above for the flow meters on Unit no. 1.

2.5.3 Other Related Equipment

During normal operation, the 5-way valves drain water into their respective sumps whenever the butterfly valves are opened or closed. This water then drains through concrete embedded pipes to the main plant sump. Water is also piped to the main sump from the discharge of the turbine gland seal cooling water systems on each unit.

The sump is also utilized whenever the draft tube is drained for maintenance and to collect water should there be a leak from the main valves, turbine head cover, draft tube door, or any of the other water piping in the turbine area.

The sump is continuously dewatered by a water operated eductor pump. This pump is original equipment and has frequently required repairs in recent years. Since it has reached the end of its useful life, it will be replaced.

The sump also has an electric pump, which is currently started and stopped by float switches whenever the eductor pump does not have the capacity to handle inflows or has failed. While this electric pump is original equipment, it has not been used extensively because it was manually operated only until recently when the float switches were installed to permit automatic operation. This pump will be removed from service and thoroughly inspected and overhauled if necessary to ensure continued reliable operation.

In addition to the float switches, there is a high water level switch located in the sump which is used to trigger an alarm. These float switches and the high level switch will be connected to the plant PLC to facilitate annunciation of alarms, to initiate unit shut-down sequences, and to facilitate the protection of electrical equipment in the turbine and valve pit areas.

The vast majority of the piping system associated with this sump is original equipment and will be replaced due to its corroded condition.

2.6 Governor

Mechanically, both Woodward governors (figure 16) at Rattling Brook are in good condition and have operated reliably. Despite the fact that Woodward no longer supports its product to any great extent, parts, service, and training are now available from non-OEM providers.

The governors at Rattling Brook will be mechanically overhauled as part of the upgrades recommended in the Electrical Equipment Assessment Report. The functionality of the governors in terms of unit control capabilities is also found in this report.

Figure 16 – Woodward Governor

2.7 Compressed Air System

The central air compressor supplies the braking system on each unit as well as the actuators for the air intake and recirculation operable dampers. This compressor (figure 17) is original 1958 vintage equipment and will be replaced.

Upgrades will also be completed on the entire compressed air system, which is also original equipment. This includes replacement of the piping, valves, regulator, filters, separators, gauges, and related equipment.

Figure 17 – Air Compressor

2.8 Powerhouse Heating and Ventilation

The Rattling Brook powerhouse has a system of air inlet and recirculation dampers for building heating and cooling. Three exhaust fans are also located inside the powerhouse to facilitate cooling.

2.8.1 Air Inlet and Recirculation Operable Dampers and Fixed Louvers

Horizontally, there is approximately 30 inches between the recirculation (interior) dampers and the air inlet (exterior) dampers. Vertically, the top of the recirculation damper is located at approximately the same elevation as the bottom of the air inlet damper.

The recirculation and air inlet dampers are all actuated by the same pneumatic actuators and interconnected linkages.

<u>Recirculation (Interior) Operable Dampers</u>
The recirculation dampers are located on the interior plant wall just above the generator floor level. They are original equipment and will be replaced. The exterior frame openings are approximately 84 inches long by 64 inches high for three of the dampers and 51 inches long by 64 inches high for one of the dampers. The four dampers each have 9 inches horizontal, parallel blades in a 6 inch deep frame. These dampers are deteriorated and will be replaced.

<u>Air Inlet (Exterior) Operable Dampers</u>
The six air inlet dampers (figure 18) each have 9 inch horizontal, parallel blades in a 6 inch deep frame. The inside of each frame opening measures approximately 80½ inches long by 66 inches high. These dampers are badly corroded and require replacement.

Figure 18– Air Inlet Dampers

<u>Exterior Fixed Louvers</u>
The six fixed louvers (figure 19) are located immediately outside air inlet dampers within the same building openings. As such, the overall dimensions of each louver match that of the air inlet dampers. Each louver has 9 inch horizontal, parallel blades in a 6 inch deep frame. The louvers also have an exterior bird screen with ¼ inch openings. This equipment is badly corroded and requires replacement.

Figure 19 – Exterior Louvers

<u>Access</u>
Access to the air inlet dampers is via a small access hatch on the generator floor level behind the air compressor. Inside the hatch is a small wooden ladder leading to wooden planks that run along the length of the six operable dampers. These planks are located at a considerable height since the opening extends downward beyond the recirculation dampers to openings at the turbine floor level. To improve employee safety, improved access ladders and platforms will be installed.

Actuation and Controls

Some upgrades have taken place on the actuation and controls system for the intake and recirculation dampers. While the actuators were upgraded, they still leak considerably (resulting in greater than normal cut in cycles of the air compressor) and will be replaced with new electric actuators. The single thermostat that controls the operation of the dampers was replaced during the upgrade. However, the system will now be tied into the plant PLC system to consolidate control and the thermostat will be replaced with a combined thermostat / humidistat to meet current standards and to provide the required control functionality. The new design will maximize the energy efficiency of the plant, limiting the amount of cooling outside air to times when the plant is operating at full capacity.

2.8.2 Building Exhaust Fans

Two of the 1.5 hp building exhaust fans, located at each end of the plant building are original equipment. These fans are in good condition with operable back draft dampers and bird screens. The additional 15 hp exhaust fan, which was installed in 1993, is in good working condition and is equipped with a functional back draft damper and a bird screen. The nameplate information on all three fans indicates that all are suitable for operation at 208 Volts.

Figure 20 – Building Exhaust Fans

At present each fan is controlled by a dedicated thermostat, each with a slightly different temperature set point. These thermostats will be replaced and the fan control system will now be tied into the plant PLC system to improve energy efficiency.

The walkway around the exhaust fans is in good condition however, it would be safer for plant operations personnel if there were access ladders leading up to the walkways. Such ladders will be installed.

2.8.3 Heating Equipment

There are a number of wall mounted heaters located throughout the powerhouse. As well, there are anti-condensation heaters mounted directly beneath the generator windings.

There are no heaters on the turbine floor or in the valve pits. Presently portable heaters are used in these locations when required. Permanent heaters will be installed at these locations.

3.0 Recommendations

Based on the existing condition of the mechanical equipment at the Rattling Brook hydro plant, a number of improvements are required. These recommendations have been grouped by the timeframe in which they should be completed.

3.1 Year 2007

- Replace butterfly valves and water actuated bypass valves on both units with new 125VDC actuated valves and controls.
- Replace drain valves on both units.
- Replace valve control panels.
- Complete repairs on the deteriorated wicket gates.
- Replace unit no. 2 scroll case air vent valve.
- Overhaul unit no. 2 exciter.
- Overhaul unit no. 2 generator brake system.
- Complete bearing instrumentation upgrades (oil level, temperature, etc.) on both units.
- Install vibration monitoring equipment on both units.
- Upgrade bearing cooling water system including piping, strainers, solenoid valves and flow meters.
- Upgrade sump dewatering system including pumps, piping and controls.
- Mechanically overhaul the power pistons on both governors.
- Replace compressed air system.
- Upgrade powerhouse ventilation.
- Upgrade heating systems.
- Replace air intake louvers.

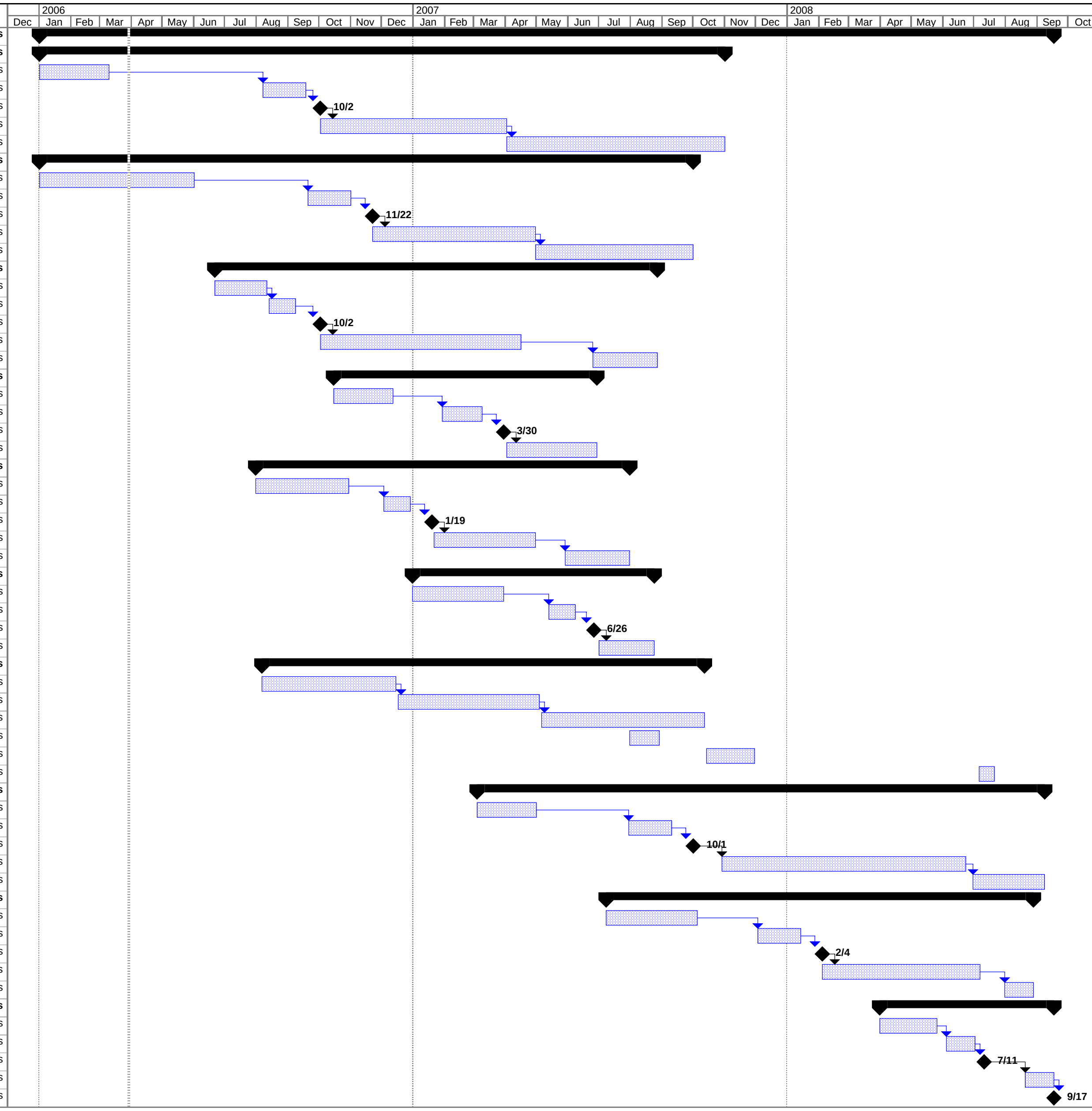
3.2 Years 2012 – 2013

- Overhaul both turbines and replace wicket gates if necessary.

Appendix G

Project Schedule

ID	Task Name	Start	Finish	Duration
1	**Project Management**	**Mon 1/2/06**	**Wed 9/17/08**	**708 days**
2	**Penstock Replacement**	**Mon 1/2/06**	**Thu 11/1/07**	**479 days**
3	Design	Mon 1/2/06	Fri 3/10/06	50 days
4	Tender	Tue 8/8/06	Mon 9/18/06	30 days
5	Award	Mon 10/2/06	Mon 10/2/06	0 days
6	Fabrication	Tue 10/3/06	Mon 4/2/07	130 days
7	Installation	Tue 4/3/07	Thu 11/1/07	153 days
8	**Surge Tank Rehabilitation**	**Mon 1/2/06**	**Mon 10/1/07**	**456 days**
9	Design	Mon 1/2/06	Thu 6/1/06	109 days
10	Tender	Thu 9/21/06	Wed 11/1/06	30 days
11	Award	Wed 11/22/06	Wed 11/22/06	0 days
12	Fabrication of External Riser	Thu 11/23/06	Mon 4/30/07	113 days
13	Construction	Tue 5/1/07	Mon 10/1/07	110 days
14	**Main Valve Replacement**	**Thu 6/22/06**	**Mon 8/27/07**	**308 days**
15	Design	Thu 6/22/06	Fri 8/11/06	37 days
16	Tender	Mon 8/14/06	Fri 9/8/06	20 days
17	Award	Mon 10/2/06	Mon 10/2/06	0 days
18	Fabrication/Delivery of Valve	Tue 10/3/06	Mon 4/16/07	140 days
19	Installation	Tue 6/26/07	Mon 8/27/07	45 days
20	**Powerhouse Extension**	**Mon 10/16/06**	**Fri 6/29/07**	**185 days**
21	Design	Mon 10/16/06	Tue 12/12/06	42 days
22	Tender	Tue 1/30/07	Fri 3/9/07	29 days
23	Award	Fri 3/30/07	Fri 3/30/07	0 days
24	Construction	Tue 4/3/07	Fri 6/29/07	64 days
25	**Mechanical System Upgrades**	**Tue 8/1/06**	**Tue 7/31/07**	**261 days**
26	Design	Tue 8/1/06	Mon 10/30/06	65 days
27	Tender	Mon 12/4/06	Fri 12/29/06	20 days
28	Award	Fri 1/19/07	Fri 1/19/07	0 days
29	Fabrication/Procurement	Mon 1/22/07	Mon 4/30/07	71 days
30	Installation	Wed 5/30/07	Tue 7/31/07	45 days
31	**Substation Upgrades**	**Mon 1/1/07**	**Fri 8/24/07**	**170 days**
32	Design	Mon 1/1/07	Fri 3/30/07	65 days
33	Tender	Mon 5/14/07	Fri 6/8/07	20 days
34	Award	Tue 6/26/07	Tue 6/26/07	0 days
35	Construction	Mon 7/2/07	Fri 8/24/07	40 days
36	**Electrical, Protection & Controls Upgrades**	**Mon 8/7/06**	**Fri 10/12/07**	**310 days**
37	Design	Mon 8/7/06	Fri 12/15/06	95 days
38	Fabrication/Procurement	Mon 12/18/06	Fri 5/4/07	100 days
39	Installation	Mon 5/7/07	Fri 10/12/07	115 days
40	Forebay, Distribution & Communication Line	Wed 8/1/07	Wed 8/29/07	21 days
41	Commissioning	Mon 10/15/07	Fri 11/30/07	35 days
42	Access Road Upgrade	Mon 7/7/08	Mon 7/21/08	11 days
43	**Rattling Lake Spillway Replacement**	**Mon 3/5/07**	**Mon 9/8/08**	**396 days**
44	Design	Mon 3/5/07	Tue 5/1/07	42 days
45	Tender	Tue 7/31/07	Mon 9/10/07	30 days
46	Award	Mon 10/1/07	Mon 10/1/07	0 days
47	Fabrication of Spillway	Tue 10/30/07	Mon 6/23/08	170 days
48	Installation	Tue 7/1/08	Mon 9/8/08	50 days
49	**Amy's Outlet Gate Replacement**	**Mon 7/9/07**	**Thu 8/28/08**	**299 days**
50	Design	Mon 7/9/07	Fri 10/5/07	65 days
51	Tender	Tue 12/4/07	Mon 1/14/08	30 days
52	Award	Mon 2/4/08	Mon 2/4/08	0 days
53	Fabrication/Procurement	Tue 2/5/08	Mon 7/7/08	110 days
54	Installation	Fri 8/1/08	Thu 8/28/08	20 days
55	**Rattling Brook/Amy's Dam Upgrade**	**Tue 4/1/08**	**Wed 9/17/08**	**122 days**
56	Design	Tue 4/1/08	Mon 5/26/08	40 days
57	Tender	Thu 6/5/08	Wed 7/2/08	20 days
58	Award	Fri 7/11/08	Fri 7/11/08	0 days
59	Construction	Thu 8/21/08	Wed 9/17/08	20 days
60	Project Completion	Wed 9/17/08	Wed 9/17/08	0 days



Project: Project1.mpp Date: Wed 3/29/06	Task		Progress		Summary		External Tasks		Deadline
	Split		Milestone		Project Summary		External Milestone	

Appendix H

Feasibility Analysis

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Page

1.0 Introduction

This feasibility analysis examines the future viability of generation at Newfoundland Power's Rattling Brook hydroelectric development. The continued long-term operation of the Rattling Brook hydroelectric development is reliant on the completion of capital improvement in 2007 and 2008. Planned improvements include replacement of the woodstave penstock, switchgear, main valves, spillway, plant controls and protection, and refurbishment of the surge tank, substation and governors.

With substantial investment required in the near-term to permit the continued reliable operation of this plant, an economic analysis of this development was completed. The analysis includes all costs and benefits for the next 50 years to determine the levelized cost of energy from the plant.

2.0 Capital Costs

All significant capital expenditures for the hydroelectric development over the next 50 years have been identified. The majority of these expenditures are planned for 2007 and 2008 with the remaining expenditures planned for future years. The capital expenditures required to maintain the safe and reliable operation of the facilities are summarized in Table 1.

Table 1
Hydroelectric Development
Capital Expenditures

Year	**(000s)**
2007	$18,820
2008	2,080
2012	350
2013	350
2025	2,000
2030	2,000
2032	1,500
Total	**$27,100**

The total capital expenditure of all of the projects listed above is $27,100,000. A more comprehensive breakdown of capital costs is provided in Attachment A.

3.0 Operating Costs

Operating costs for this hydroelectric system are estimated to be in the order of $282,000 per year. This estimate is based primarily upon recent historical operating experience. The operating cost represents both direct charges for operations and maintenance at this plant as well as indirect costs such as those related to managing the environment, safety, dam safety inspections, and staff training. A summary of operating costs is provided in Attachment B.

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 production. 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 costs have been estimated to include a 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 69.8 GWh per year. This estimate is based on the results of the Water Management Study completed by SGE Acres in 2005 and 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 2.9 metre diameter steel penstock will significantly reduce head loss. The replacement of the main valves will also reduce head loss and increase production. The annual energy generation is expected to increase from 69.8 GWh to 76.0 GWh per year and the plant capacity will increase from 11.2 MW to 14.1 MW.

5.0 Lost Production

The downtime associated with the 2007 capital works at this plant will result in a higher amount of spill from the system compared to a normal operating year. It is anticipated that the potential spill may be in the order of 38.2 GWh which is approximately $1.8 million[1] in increased purchased power costs. Therefore, the analysis assumed production at Rattling Brook of 30.2 GWh in 2007 and 76.0 GWh per year thereafter.

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1 Based on the current rate of 4.7 cents/kWh. However, the financial impact on purchased power expense may increase if the wholesale rate from Newfoundland and Labrador Hydro increases.

There are accounting options for dealing with the lost production such as expensing, deferring and amortizing the cost. The Company plans to present its proposal on accounting for lost production in its next general rate application.

6.0 Financial Analysis

An overall financial analysis of combined costs and benefits has been completed using the levelized cost of energy approach. The levelized cost of energy is representative of the revenue requirement to support the combined capital and operating costs associated with the development.

The estimated levelized cost of energy from the Rattling Brook plant over the next 50 years is 2.9 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 and Labrador Hydro's Holyrood thermal generating station. Incremental energy from the Holyrood thermal generating station is estimated to cost 7.1 cents per kWh in the short term (assuming $45.00[2] per barrel), with an associated levelized cost of 8.8[3] cents per kWh.

The future capacity benefits of the continued availability of Rattling Brook hydro plant have not been considered in this analysis. If factored into the feasibility analysis, the financial benefit associated with system capacity would further support the viability of continued plant operations.

7.0 Recommendation

The results of this feasibility analysis show that the continued operation of the Rattling Brook hydroelectric development is economically viable. 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 69.8 GWh would be replaced by more expensive energy sources such as new generation or additional production from the Holyrood thermal generating station. Newfoundland Power should proceed with this project in 2007. The project will benefit the Company and its customers by providing least cost, reliable energy for years to come.

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[2] Newfoundland and Labrador Hydro's forecast fuel price submitted in response to request for information PUB 13 NLH for their application for 1 percent sulphur fuel recovery costs through the RSP.

[3] 50-year levelized using escalation factors based on the Conference Board of Canada GDP deflator, December 13, 2005.

Attachment A
Summary of Capital Costs

Rattling Brook Feasibility Analysis
Summary of Capital Costs
(000s)

Description	2007	2008	2012	2013	2025	2030	2032
Civil							
Plant Civil Refurbishment	$13,720						
Dams, spillways and gates		$2,080					
Amy's Tunnel Upgrade						$1,500	$500
Amy's Intake					$1,500		
Mechanical							
Plant Mechanical Refurbishment	1,117						
Unit No. 1 Turbine Overhaul			$350				
Unit No. 2 Turbine Overhaul				$350			
Unit No. 1 Replacement Runner					500		
Unit No. 2 Replacement Runner						500	
Governor Upgrades							500
Electrical							
Plant Electrical Refurbishment	2,740						
Substation Upgrade	578						
Controls Upgrade							500
Project Management							
IDC	350						
Project Management and Insurance	315						
Annual Totals ($2007)	**$18,820**	**$2,080**	**$350**	**$350**	**$2,000**	**$2,000**	**$1,500**
Total Life Capital Cost ($2007)	**$27,100**						
Lost Production	**$1,833**						

Attachment B
Summary of Operating Costs

Rattling Brook Feasibility Analysis
Summary of Operating Costs

Actual Annual Operating Costs

Year	Amount
2001	$254,000
2002	210,216
2003	270,429
2004	207,114
2005	213,495
Average	**$231,051**

5-Year Average Operating Cost	$231,051
Water Power Rental Rate[1]	60,800
Reduced Future Penstock Maintenance	- 10,000
Total Forecast Annual Operating Cost	$281,851

[1] ($0.80/MWh * 76,000 MWh/yr)

Attachment C
Calculation of Levelized Cost of Energy

Weighted Average Incremental Cost of Capital **7.15%**

Present Worth Year **2007**

YEAR	Generation Hydro 49.26 yrs 8% CCA	Generation Hydro 49.26 yrs 30% CCA	Capital Revenue Requirement	Operating Costs	Operating Benefits	Net Benefit	Present Worth Benefit	Cumulative Present Worth Benefit	Rev Rqmt (¢/kWhr)	Levelized Rev Rqmt (¢/kWhr)
2007	6,385,000	12,434,000	1,105,439	2,114,851	0	-3,220,290	-3,005,403	-3,005,403	4.288	2.899
2008	2,080,000	0	409,697	286,079	0	-695,776	-606,018	-3,611,421	0.926	2.899
2009	0	0	890,543	290,942	0	-1,181,485	-960,399	-4,571,820	1.573	2.899
2010	0	0	1,258,769	295,888	0	-1,554,657	-1,179,413	-5,751,233	2.070	2.899
2011	0	0	1,511,836	300,918	0	-1,812,754	-1,283,447	-7,034,680	2.414	2.899
2012	379,283	0	1,721,673	305,432	0	-2,027,105	-1,339,440	-8,374,120	2.699	2.899
2013	384,972	0	1,866,319	310,013	0	-2,176,333	-1,342,085	-9,716,206	2.898	2.899
2014	0	0	1,932,607	314,664	0	-2,247,271	-1,293,356	-11,009,561	2.992	2.899
2015	0	0	1,979,436	319,384	0	-2,298,819	-1,234,739	-12,244,301	3.061	2.899
2016	0	0	2,005,620	324,174	0	-2,329,795	-1,167,874	-13,412,174	3.102	2.899
2017	0	0	2,016,988	329,037	0	-2,346,025	-1,097,536	-14,509,710	3.124	2.899
2018	0	0	2,017,649	333,973	0	-2,351,622	-1,026,742	-15,536,452	3.131	2.899
2019	0	0	2,010,505	338,982	0	-2,349,487	-957,359	-16,493,811	3.128	2.899
2020	0	0	1,997,614	344,067	0	-2,341,680	-890,507	-17,384,318	3.118	2.899
2021	0	0	1,980,437	349,228	0	-2,329,665	-826,820	-18,211,138	3.102	2.899
2022	0	0	1,960,020	354,466	0	-2,314,486	-766,619	-18,977,757	3.082	2.899
2023	0	0	1,937,112	359,783	0	-2,296,896	-710,026	-19,687,783	3.058	2.899
2024	0	0	1,912,258	365,180	0	-2,277,438	-657,033	-20,344,816	3.033	2.899
2025	2,630,168	0	2,148,439	370,658	0	-2,519,097	-678,256	-21,023,072	3.354	2.899
2026	667,405	0	2,128,161	376,218	0	-2,504,379	-629,298	-21,652,370	3.335	2.899
2027	0	0	2,089,046	381,861	0	-2,470,907	-579,456	-22,231,827	3.290	2.899
2028	0	0	2,064,532	387,589	0	-2,452,121	-536,678	-22,768,505	3.265	2.899
2029	0	0	2,038,415	393,403	0	-2,431,817	-496,719	-23,265,224	3.238	2.899
2030	2,833,438	0	2,293,740	399,304	0	-2,693,044	-513,371	-23,778,595	3.586	2.899
2031	0	0	2,201,071	405,293	0	-2,606,364	-463,693	-24,242,288	3.471	2.899
2032	2,189,309	0	2,394,605	411,373	0	-2,805,978	-465,895	-24,708,183	3.736	2.899
2033	0	0	2,318,404	417,543	0	-2,735,948	-423,954	-25,132,137	3.643	2.899
2034	0	0	2,293,673	423,806	0	-2,717,480	-392,994	-25,525,131	3.618	2.899
2035	0	0	2,266,784	430,163	0	-2,696,948	-363,998	-25,889,129	3.591	2.899
2036	0	0	2,237,915	436,616	0	-2,674,531	-336,886	-26,226,015	3.561	2.899
2037	0	0	2,207,228	443,165	0	-2,650,393	-311,568	-26,537,583	3.529	2.899
2038	0	0	2,174,870	449,813	0	-2,624,683	-287,957	-26,825,539	3.495	2.899
2039	0	0	2,140,977	456,560	0	-2,597,537	-265,962	-27,091,502	3.459	2.899
2040	0	0	2,105,672	463,408	0	-2,569,080	-245,496	-27,336,997	3.421	2.899
2041	0	0	2,069,070	470,359	0	-2,539,429	-226,470	-27,563,467	3.381	2.899
2042	0	0	2,031,274	477,415	0	-2,508,689	-208,799	-27,772,266	3.340	2.899
2043	0	0	1,992,381	484,576	0	-2,476,957	-192,401	-27,964,667	3.298	2.899
2044	0	0	1,952,479	491,845	0	-2,444,323	-177,197	-28,141,864	3.255	2.899
2045	0	0	1,911,648	499,222	0	-2,410,870	-163,109	-28,304,973	3.210	2.899
2046	0	0	1,869,963	506,711	0	-2,376,674	-150,066	-28,455,039	3.165	2.899
2047	0	0	1,827,493	514,311	0	-2,341,804	-137,998	-28,593,037	3.118	2.899
2048	0	0	1,784,299	522,026	0	-2,306,325	-126,838	-28,719,875	3.071	2.899
2049	0	0	1,740,441	529,856	0	-2,270,298	-116,525	-28,836,400	3.023	2.899
2050	0	0	1,695,972	537,804	0	-2,233,776	-107,000	-28,943,400	2.974	2.899
2051	0	0	1,650,940	545,871	0	-2,196,811	-98,208	-29,041,607	2.925	2.899
2052	0	0	1,605,390	554,059	0	-2,159,449	-90,095	-29,131,703	2.875	2.899
2053	0	0	1,559,364	562,370	0	-2,121,734	-82,615	-29,214,318	2.825	2.899
2054	0	0	1,512,900	570,806	0	-2,083,705	-75,720	-29,290,038	2.775	2.899
2055	0	0	1,466,033	579,368	0	-2,045,400	-69,368	-29,359,407	2.724	2.899
2056	0	0	1,418,795	588,058	0	-2,006,853	-63,519	-29,422,926	2.672	2.899
2057	0	0	1,371,215	596,879	0	-1,968,095	-58,136	-29,481,062	2.621	2.899
2058	0	0	1,323,322	605,832	0	-1,929,155	-53,183	-29,534,245	2.569	2.899
2059	0	0	1,275,141	614,920	0	-1,890,061	-48,628	-29,582,874	2.517	2.899
2060	0	0	1,226,693	624,144	0	-1,850,837	-44,442	-29,627,315	2.464	2.899
2061	0	0	1,178,002	633,506	0	-1,811,508	-40,595	-29,667,910	2.412	2.899
2062	0	0	1,129,085	643,008	0	-1,772,094	-37,062	-29,704,972	2.360	2.899
2063	0	0	1,079,962	652,654	0	-1,732,615	-33,818	-29,738,790	2.307	2.899
2064	0	0	1,030,648	662,443	0	-1,693,092	-30,841	-29,769,631	2.254	2.899
2065	0	0	981,160	672,380	0	-1,653,539	-28,111	-29,797,742	2.202	2.899
2066	0	0	931,510	682,466	0	-1,613,975	-25,607	-29,823,350	2.149	2.899
2067	0	0	881,712	692,703	0	-1,574,414	-23,313	-29,846,663	2.096	2.899
2068	0	0	831,777	703,093	0	-1,534,871	-21,211	-29,867,873	2.044	2.899
2069	0	0	781,718	713,640	0	-1,495,357	-19,286	-29,887,159	1.991	2.899
2070	0	0	-605,313	724,344	0	-119,031	-1,433	-29,888,592	0.158	2.899
2071	0	0	331,965	735,209	0	-1,067,174	-11,988	-29,900,580	1.421	2.899
2072	0	0	403,321	746,237	0	-1,149,558	-12,052	-29,912,631	1.531	2.899
2073	0	0	388,605	757,431	0	-1,146,036	-11,213	-29,923,844	1.526	2.899
2074	0	0	373,818	768,793	0	-1,142,611	-10,434	-29,934,278	1.521	2.899
2075	0	0	337,978	780,324	0	-1,118,303	-9,530	-29,943,808	1.489	2.899
2076	0	0	318,088	792,029	0	-1,110,117	-8,829	-29,952,637	1.478	2.899
2077	0	0	320,335	803,910	0	-1,124,244	-8,345	-29,960,982	1.497	2.899
2078	0	0	306,615	815,968	0	-1,122,584	-7,776	-29,968,758	1.495	2.899
2079	0	0	292,850	828,208	0	-1,121,058	-7,248	-29,976,006	1.493	2.899
2080	0	0	279,043	840,631	0	-1,119,674	-6,756	-29,982,762	1.491	2.899
2081	0	0	265,197	853,240	0	-1,118,438	-6,298	-29,989,060	1.489	2.899
2082	0	0	251,316	866,039	0	-1,117,355	-5,872	-29,994,932	1.488	2.899
2083	0	0	237,401	879,030	0	-1,116,431	-5,476	-30,000,407	1.487	2.899
2084	0	0	223,457	892,215	0	-1,115,672	-5,107	-30,005,514	1.486	2.899
2085	0	0	209,485	905,598	0	-1,115,083	-4,763	-30,010,278	1.485	2.899
2086	0	0	195,487	919,182	0	-1,114,669	-4,444	-30,014,722	1.484	2.899
2087	0	0	181,465	932,970	0	-1,114,435	-4,147	-30,018,868		

Feasibility Analysis
Major Inputs and Assumptions

Specific assumptions include:

Income Tax : Income tax expense reflects a statutory income tax rate of 36.12% including surtax of 1.12%.

Operating Costs: Operating costs were assumed to be $281,851 escalated yearly using the GDP Deflator for Canada
Labor is based on union agreements.

Average Incremental Cost of Capital:

	Capital Structure	Return	Weighted Cost
Debt	55.00%	5.44%	2.99%
Common Equity	45.00%	9.24%	4.16%
Total	**100.00%**		**7.15%**

CCA Rates:

Class	Rate	Details
1	4.00%	All generating, transmission, substation and distribution equipment not otherwise noted.
17	8.00%	Expenditures related to the betterment of electrical generating facilities.
43.1	30.00%	Equipment designed to produce energy in a more efficient way.

Escalation Factors: Conference Board of Canada GDP deflator, December 13, 2005