Q. Describe Newfoundland Power's asset management practices for its generating facilities, including both maintenance and capital refurbishment programs and practices, and how the generator maintenance programs are managed including the use of maintenance management software. In the response provide copies of any documents that describe the policies and practices followed.

A. **1. Generation Asset Management Practices**

Newfoundland Power operates 32 hydro generators in 23 small hydro plants and 5 thermal plants.[1] All preventative maintenance and inspections as well as deficiency identification and corrective maintenance activities for hydro and thermal plants are recorded in the Company's computerized maintenance management system Avantis.

Preventative maintenance activities are completed by plant operators, maintenance staff, engineering staff, and consultants or a combination of same depending on the activity being performed. The responsibility of scheduling preventative maintenance activities lies with the planner. It is the planner's responsibility to ensure the appropriate personnel are assigned to ensure that the work is completed in the specified timelines. If a deficiency is identified and is considered to be an emergency, the Superintendent of Generation Operations is immediately notified.

Corrective maintenance activities are identified through preventative maintenance inspections and through normal day to day plant operations. Priorities are assigned to each deficiency to establish when corrective action is required. The assignment of priorities is based on engineering judgement and is done by experienced staff to ensure consistency in priority assignment.

Attachment A to this response to Request for Information PUB-NP-175 contains a listing of all the preventative maintenance activities, including the frequencies that are completed on the various structures and components of the hydro and thermal generating plants. Attachment B to this response to Request for Information PUB-NP-175 contains a listing of typical corrective maintenance activities including priorities assigned to each activity.

The Superintendent of Generation Operations and the maintenance supervisors are responsible to ensure that all corrective maintenance is completed within the timelines as outlined in the asset management program.

Guidelines for the inspection and maintenance of generating facilities are included in the Plant Operating Guidelines which were provided in Attachment B to the response to Request for Information CA-NP-007.

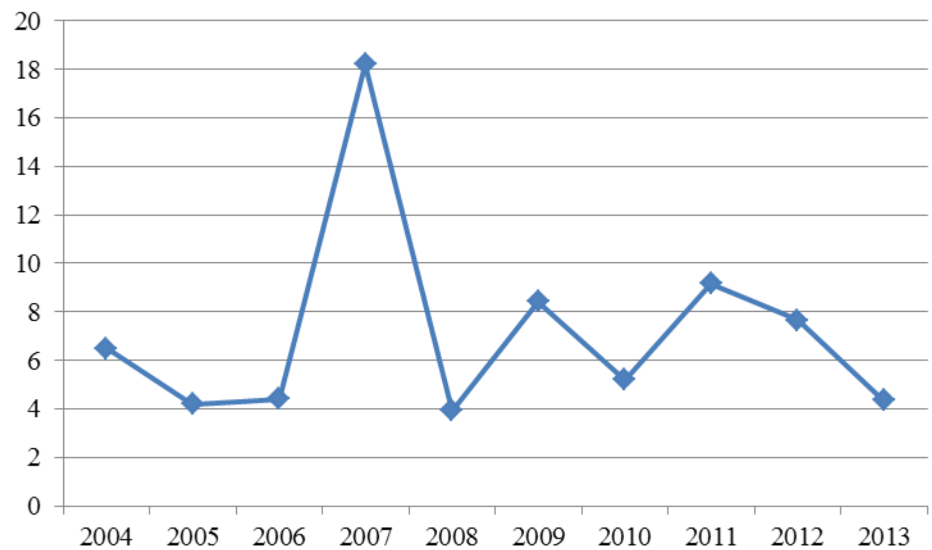
[1] The average age of these 23 small hydro plants is 71 years. The Company's 5 thermal plants including 2 mobile have an average age of 36 years.

2. Generation Capital Refurbishment Programs

The performance of Newfoundland Power's electrical system is largely a function of the condition of electrical system assets. For this reason, the leading justification for annual capital budget expenditures is the refurbishment of existing in-service assets. Approximately 50% of Newfoundland Power's overall annual capital expenditures are directed at plant replacement.[2] Generation capital refurbishment programs involve considerable capital expenditures on an annual basis as in-service assets deteriorate with age and service.

Graph 1 shows Newfoundland Power's generation plant refurbishment expenditures from 2004 to 2013.

Graph 1
Expenditures for Generation Plant Replacement[3]
2004-2013
($ millions)



Newfoundland Power aims to maintain stable annual capital expenditures on plant replacement for all asset classes, including generation. This follows from the Board's

[2] Newfoundland Power's 2014 Capital Plans filed as part of its 2014 Capital Budget Application is included in Attachment A to the response to Request for Information PUB-NP-080. At page 9 of the capital plan it states that over the past 5 years the capital expenditures on plant refurbishment was 49%, while estimated expenditures on plant refurbishment for the next 5 years make up 52% of the total.

[3] In 2007 Newfoundland Power completed a $17.5 million refurbishment of the Rattling Brook hydro plant.

determination that stable and predictable year over year capital budgets for Newfoundland Power are a desirable objective which assists in fostering stable and predictable rates for consumers into the future.[4]

Capital Projects - Hydro Plants
Newfoundland Power's annual capital expenditures on hydro plants are guided by asset condition. Capital expenditures are generally undertaken in 3 separate projects, (i) Facility Rehabilitation, (ii) Hydro Plant Production Increase and (iii) plant specific refurbishment projects. The scope of these projects is included in each year's annual capital budget and submitted for approval by the Board.

The Facility Rehabilitation project involves the replacement or rehabilitation of deteriorated plant assets such as dams, spillways, or intake structures as well as the replacement of plant components due to in-service failures. Replacement and rehabilitation projects are identified during ongoing inspections and maintenance activities. These projects are necessary for the continued operation of generation facilities in a safe, reliable and environmentally compliant manner.

Attachments C through F of this response to Request for Information PUB-NP-175 are the Facility Rehabilitation reports for the 2011 through 2014 Newfoundland Power Capital Budget Applications respectively.

The Hydro Plant Production Increase project identifies projects that will result in energy production increases or reduce losses through the refurbishment of the Company's existing hydro plants.[5] In 2008, Newfoundland Power conducted a study into alternative ways to improve efficiency and energy production.[6] The study reviewed 14 hydro developments identifying 9 viable projects.[7] At the end of 2014, 7 of these viable projects will have been completed.

Since 2002 the Company has untaken hydro plant refurbishment projects on its legacy hydro plants.[8] These refurbishment projects have involved penstock replacements, surge tank refurbishment, main valve replacements, mechanical upgrades of turbines, turbine runner replacements, generator rewinds, replacement of electromechanical protective relaying with multifunction generator protection relays, and the replacement of governors and controls with modern programmable logic controller technology. Refurbishment project scope will vary depending upon the engineering assessment of the level of

[4] See Order No. P.U. 36 (2002-2003), page 25.
[5] For example, replacement of a legacy turbine runner that has cavitation damage with a modern more efficient design will increase plant production.
[6] A copy of the study was filed as Attachment A to the response to Request for Information PUB-NP-09 in the Company's 2010 Capital Budget Application.
[7] Included in the 31 potential projects are 9 projects involving the construction of small hydro plants and another 13 that are not considered viable on either economic terms or because of environmental regulations.
[8] Newfoundland Power's fleet of hydro plants range in age from 16 to 114 years.

deterioration experienced by the particular plant.[9] Prior to all plant refurbishment projects being considered, engineering assessments are completed on all plant systems and any systems that have reached the end of their useful lives will be replaced or refurbished.

Table 1 includes a listing of the hydro plants that have undergone refurbishment since 2002, the capital budget application where the expenditure was approved, and for some selected projects the attachment to this response where the project report can be found.

Table 1
Capital Refurbishment Projects

Plant	Application	Attachment
Hearts Content	2014 CBA	Attachment G
Pittman's Pond	2013 CBA	
Lockston	2012 CBA	Attachment H
Port Union	2011 Supplemental	Attachment I
Sandy Brook	2011 CBA	Attachment J
Lookout Brook	2010 CBA	Attachment K
Horse Chops	2009 CBA	
Rocky Pond	2009 CBA	
Cape Broyle	2008 CBA	
Rattling Brook	2007 CBA	
Petty Harbour	2006 CBA	Attachment L
New Chelsea	2004 CBA	
Topsail	2003 CBA	
Tors Cove	2003 CBA	
Seal Cove	2002 CBA	

Further Information concerning the refurbishment of Newfoundland Power's hydro plant including these reports not prepared with this response can be found in its annual capital budget applications filed with the Board. These applications can be found on the Board's public website at www.pub.nf.ca.

Capital Projects - Thermal Plants

Newfoundland Power currently operates 3 gas turbine generators and 2 diesel plants. The Company's gas turbines range in age from 39 years to 45 years.[10] The Port aux Basques diesel was commissioned in 1969 while the mobile diesel was commissioned in 2004.

9 The average of the plants when they underwent refurbishment was 67 years.
10 The Greenhill gas turbine is 39 years old, the Wesleyville gas turbine is 45 years old and the mobile gas turbine is 40 years old.

These units provide emergency generation, both locally and for the Island Interconnected System, and facilitate scheduled maintenance on the Company's radial transmission and distribution systems. Refurbishment projects are identified during ongoing inspections and maintenance activities.

Newfoundland Power's annual capital expenditures on thermal plants are guided by asset condition. Capital expenditures are generally undertaken in the Facilities Rehabilitation Thermal project. For a major refurbishment a stand-alone capital project would be considered.

The Facilities Rehabilitation Thermal project typically consists of the refurbishment or replacement of thermal plant structures and equipment due to damage, deterioration, corrosion and in-service failures.

Following the winter of 2013/2014 Newfoundland Power engaged the necessary engineering expertise to complete assessments on its thermal generation facilities at Wesleyville and Greenhill. These assessments identified a number of issues that need to be addressed prior to the 2014/2015 winter season. In June 2014 Newfoundland Power filed a Capital Budget Application Supplement to address the issues identified at the Wesleyville and Greenhill gas turbines prior to the 2014/2015 winter season. Attachment M to this response includes Schedule A to the supplemental application titled *Thermal Generation Refurbishment* providing details of ongoing refurbishment work[11].

Refurbishment of the Wesleyville and Greenhill gas turbines is necessary for their continued safe and reliable operation in the immediate term. The 2014 refurbishment work underway will ensure the availability of the Greenhill and Wesleyville gas turbines to provide capacity support to the Island Interconnected System for at least the next 2 to 3 years. However the age of the gas turbines is cause for concern. The Company has determined that a further review is necessary to determine the long-term viability of continued investment in these assets.[12] Newfoundland Power has engaged a consultant with expertise in thermal generation systems to review the engineering assessments completed in 2014 and assess the long-term viability of continued investment in the 2 systems.[13] The review is expected to be completed before the end of 2014. The results and any recommendations will be reflected in the 2016 Capital Plan to be filed with the Company's 2016 Capital Budget Application.

[11] The refurbishment work on both gas turbines is underway and on schedule to be completed prior to the start of the 2014/2015 winter season.
[12] Both the Wesleyville and Greenhill gas turbines underwent life extension projects over 10 years ago.
[13] In May 2014, Newfoundland Power issued a Request for Information to various engineering consulting firms to identify a qualified consultant to assist in the review. The work has been awarded to Hatch and is currently ongoing and expected to be complete by the 3rd quarter.

Newfoundland Power's
Generation - Preventative Maintenance Activities

Generation - Preventative Maintenance Activities

Title	Work Type	Frequency	Comments
Above Ground Fuel Line Inspection	Inspection/Investigation	Ten Years	GRT,WES & (PAB Question).
Annual Air Inlet Filter Cleaning	Preventive Maintenance (M3)	Yearly	GRT
Annual Cleaning/Lubrication of Filter Intake Fan and Drop Down Box	Preventive Maintenance (M3)	Yearly	
Annual Confined Space and Fall Arrest Certification	Preventive Maintenance (M3)	Yearly	Five Retracting Lifelines.
Annual Inspection of SJN Diesel Site	Inspection/Investigation	Yearly	
Annual Lube Oil Sampling(SJN/AV Area, Mech)	Inspection/Investigation	Six Months	KEN,CAR,CLV,GFW,DUF & BUR.
Annual Lube Oil Sampling(Western, Mech)	Inspection/Investigation	Yearly	PAB,MD3,MGT PT,MGT GG & CBK.
Annual Main Inlet Butterfly Valve Maintenance at RBK	Preventive Maintenance (M3)	Yearly	RBK G1 & G2.
Annual Overhead Crane Inspection	Inspection/Investigation	Yearly	All Cranes & Lifts for Breakers.
Annual Valve Maintenance	Inspection/Investigation	Yearly	NCH
Annual Vibration Analysis	Predictive Maintenance	Yearly	All Units Two Tasks Test & Analyzie
Bi-Annual Boroscope Inspection	Predictive Maintenance	Two Years	GRT & WES
Bubbler System Calibration	Predictive Maintenance	As Required	
BUR Weekly Tank Dip and Inspection	Inspection/Investigation	Weekly	
Burin Diesel Annual Inspection	Inspection/Investigation	Yearly	
Burin Diesel Bi - Annual Inspection	Inspection/Investigation	Two Years	
Burin Diesel Quarterly Inspection	Inspection/Investigation	Three Months	
CAB - Dam Safety Operator Inspection, Quarterly	Inspection/Investigation	Three Months	
Calibration of Leak Detection Equipment	Acceptance Testing	Five Years	WES
CAR Diesel Annual Inspection	Inspection/Investigation	Yearly	
CAR Diesel Monthly Inspection	Inspection/Investigation	Monthly	
CAR Weekly Tank Dip and Inspection	Inspection/Investigation	Weekly	
CBK Weekly Tank Dip and Inspection	Inspection/Investigation	Weekly	
Check/Calibrate Overfill Protection	Inspection/Investigation	Five Years	GRT, 1 & 2, WES 1 & 2 & GRT Waste oil.
Clarenville Diesel Annual Inspection	Inspection/Investigation	Yearly	
Clarenville Diesel Monthly Inspection	Inspection/Investigation	Monthly	
Clarenville Diesel Weekly Inspection (Eric Seward)	Inspection/Investigation	Weekly	
Clean and Maintain Cooling Water Solenoids (PPM)	Preventive Maintenance (M3)	Three Years	TOP
CLV Weekly Tank Dip and Inspection	Inspection/Investigation	Weekly	
Control Gate Inspection	Inspection/Investigation	Two Years	All Control Gates except Pun Wells & Halfway
Control Gate Operational Test	Preventive Maintenance (M3)	Yearly	All Control Gates except Pun Wells & Halfway & HCP Spillway
Corner Brook Diesel Annual Inspection	Inspection/Investigation	Yearly	
Corner Brook Diesel Bi - Annual Inspection	Inspection/Investigation	Two Years	
Corner Brook Diesel Monthly Inspection	Inspection/Investigation	Monthly	
Corner Brook Diesel Weekly Inspection (Larry Clark)	Inspection/Investigation	Weekly	
Dam Safety Engineering Inspection	Inspection/Investigation	Two Years	All Waterworks System except PHR,TCV,ROP, PHR & ROP
DUF Weekly Tank Dip and Inspection	Inspection/Investigation	Weekly	
Duffy Diesel Annual Inspection	Inspection/Investigation	Yearly	
Duffy Diesel Monthly Inspection	Inspection/Investigation	Monthly	
Duffy Diesel Weekly Inspection	Inspection/Investigation	Weekly	

Generation - Preventative Maintenance Activities

Title	Work Type	Frequency	Comments
Eyewash Station Maintenance	Safety	90 Days	All Plant & some sheds.
Fire and Security Alarm System Battery Replacement	Preventive Maintenance (M3)	Four Years	All Plant Two Tasks
Fire Responders Orientation (PPM)	Safety	Yearly	All Plants & Fossils Fuels Units
Fish Valve Calibration	Acceptance Testing	Ten Years	RBH,SCV & LOK.
Five Year Confined Space and Fall Arrest Certification	Preventive Maintenance (M3)	Five Years	Four Winches.
Fluke 744 Process Calibrator Re-Calibration	Preventive Maintenance (M3)	Two Years	Procesor
Forebay Dam Site Walkabout	Inspection/Investigation	Monthly	All Forebays except HCP,ROP,MRP & PIT.
FPD - Dam Safety Operator Inspection, Quarterly	Inspection/Investigation	Three Months	
FPD Generating Equipment Operational Inspection (6-months)	Inspection/Investigation	Six Months	
FPD Generating Equipment Visual Inspection(Monthly)	Inspection/Investigation	Monthly	
Fuel Flow Meter Calibration	Inspection/Investigation	Five Years	PAB,KEN,SCC,CAR,MGT & MD3.
Gated Spillway Conditional Assessment	Inspection/Investigation	Six years	SBK & TOP
Gated Spillway Inspection	Inspection/Investigation	Two Years	SBK & TOP
Gated Spillway Operational Test	Preventive Maintenance (M3)	Yearly	SBK & TOP
Generating Equipment Operational Inspection (6-month)	Inspection/Investigation	Six Months	Southern Shore & CAR Plants
Generating Equipment Visual Inspection (Monthly)	Inspection/Investigation	Monthly	Southern Shore & CAR Plants except HCP.
GFW Weekly Tank Dip and Inspection	Inspection/Investigation	Weekly	
Grand Falls Diesel Bi - Annual Inspection	Inspection/Investigation	Two Years	
Grandfalls Diesel Monthly Inspection	Inspection/Investigation	Monthly	
Grandfalls Diesel Weekly Inspection (PPM)	Inspection/Investigation	Weekly	
Green Hill Gas Turbine Black Start	Preventive Maintenance (M3)	Two Monthy	GRT
Green Hill Parallel Operation	Preventive Maintenance (M3)	Two Monthy	GRT
Greenhill Annual Fisher Regulator Filter Cleaning	Preventive Maintenance (M3)	Yearly	
GreenHill Annual Fuel Tank Dip	Inspection/Investigation	Yearly	GRT
Greenhill Annual Lube Oil Sampling	Inspection/Investigation	Yearly	GRT PT & GRT GG Lube.
GreenHill Fuel Flow Meter Calibration	Inspection/Investigation	Five Years	GRT
Greenhill Fuel Recirculation System Annual Maintenance	Preventive Maintenance (M3)	Yearly	
GRT Louvers Operational Check	Preventive Maintenance (M3)	Six Months	
GRT Synchronous Condenser Run	Inspection/Investigation	Yearly	GRT
GRT Tank 1 Weekly Tank Dip and Inspection	Inspection/Investigation	Weekly	
GRT Tank 2 Weekly Tank Dip and Inspection	Inspection/Investigation	Weekly	
HCP - Dam Safety Operator Inspection, Full Semi Annual	Inspection/Investigation	Six Months	
HCP - Dam Safety Operator Inspection, Partial Semi Annual	Inspection/Investigation	Six Months	
HCP G1 Generating Equipment Visual Inspection (Monthly)	Inspection/Investigation	Monthly	
HCT - Dam Safety Operator Inspection, Full Semi Annual	Inspection/Investigation	Six Months	
HCT - Dam Safety Operator Inspection, Partial Semi Annual	Inspection/Investigation	Six Months	
HCT1 Turbine Bearing Monthly Lubrication	Inspection/Investigation	Monthly	
Infrared Thermography	Inspection/Investigation	Yearly	All Plants & Fossils Fuels Units
Inspect RBK Penstock CANS	Inspection/Investigation	Yearly	
Inspect Victoria Penstock Manway Tee Leak	Inspection/Investigation	Two Months	

Generation - Preventative Maintenance Activities

Title	Work Type	Frequency	Comments
Install/Remove Chain-link Fence	Preventive Maintenance (M3)	Yearly	LWN
Intake Engineering Assessment	Preventive Maintenance (M3)	Seven Years	All Intakes except RBK has two this a three Task PM.
Intake Operational Test	Preventive Maintenance (M3)	Yearly	All Plants except FPD & PUN
Interstitial Alarm Testing	Preventive Maintenance (M3)	Five Years	GRT,WES,MGT,MD3,PAB & GRT Waste Oil Storage.
KEN Diesel Annual Inspection	Preventive Maintenance (M3)	Yearly	
KEN Diesel Monthly Inspection	Inspection/Investigation	Monthly	
KEN Weekly Tank Dip and Inspection	Inspection/Investigation	Weekly	
Lawn Dam Monthly Monitoring for Seepage	Inspection/Investigation	Monthly	
LBK - Dam Safety Operator Inspection, Full Semi Annual	Inspection/Investigation	Six Months	
LBK - Dam Safety Operator Inspection, Partial Semi Annual	Inspection/Investigation	Six Months	
LBK G3 Generating Equipment Operational Inspection(6-months)	Inspection/Investigation	Six Months	
LBK G3 Generating Equipment Visual Inspection(monthly)	Inspection/Investigation	Monthly	
LBK G4 Generating Equipment Operational Inspection(6-months)	Inspection/Investigation	Six Months	
LBK G4 Generating Equipment Visual Inspection(monthly)	Inspection/Investigation	Monthly	
LBK Oil Separator Inspection (weekly)	Environmental	Weekly	
LOK - Dam Safety Operator Inspection, Full Semi Annual	Inspection/Investigation	Six Months	
LOK - Dam Safety Operator Inspection, Partial Semi Annual	Inspection/Investigation	Six Months	
LOK G1 Generating Equipment Operational Inspection (6-months)	Inspection/Investigation	Six Months	
LOK G2 Generating Equipment Operational Inspection (6-months)	Inspection/Investigation	Six Months	
LOK Fish Valve Monthly Visual Inspection	Inspection/Investigation	Monthly	LOK
LOK G1 Generating Equipment Visual Inspection	Inspection/Investigation	Monthly	
LOK G2 Generating Equipment Visual Inspection	Inspection/Investigation	Monthly	
LWN - Dam Safety Operator Inspection, Quarterly	Inspection/Investigation	Three Months	
LWN Generating Equipment Operational Inspection (6-months)	Inspection/Investigation	Six Months	
LWN Generating Equipment Visual Inspection (monthly)	Inspection/Investigation	Monthly	
MD3 - Portable Diesel Bi-Annual Maintenance	Preventive Maintenance (M3)	Two Years	
MD3 Portable Diesel Monthly Inspection	Inspection/Investigation	Monthly	
MD3 Weekly Tank Dip and Inspection	Inspection/Investigation	Weekly	
MGT Black Start Test Run	Inspection/Investigation	Two Months	MGT
MGT Parallel Test Run	Inspection/Investigation	Two Monthy	MGT
MGT Weekly Tank Dip and Inspection	Inspection/Investigation	Weekly	
Mobile Big Pond Trash Rack Annual Debris Removal	Preventive Maintenance (M3)	Yearly	
Monthly Crane Inspection Electric Hoist & Trolley, Manual Bridge (PPM)	Preventive Maintenance (M3)	Monthly	HCT,PHR,PBK & ROP
Monthly Crane Inspection Electric Hoist Manual Bridge & Trolley (PPM)	Preventive Maintenance (M3)	Monthly	NCH,LOK,RBK,SBK,MOP & CAB
Monthly Crane Inspection Electric Hoist, Bridge & Trolley (PPM)	Preventive Maintenance (M3)	Monthly	SCV
Monthly Crane Inspection Electric Hoist, Bridge & Trolley (PPM)	Preventive Maintenance (M3)	Monthly	RBH & HCP
Monthly Crane Inspection Manual Hoist & Trolley (PPM)	Preventive Maintenance (M3)	Monthly	MRP
Monthly Crane Inspection Manual Hoist, Trolley & Bridge (PPM)	Preventive Maintenance (M3)	Monthly	PIT,TCV & TOP
Monthly Portable Gas Monitor Recalibration	Acceptance Testing	Monthly	
MOP - Dam Safety Operator Inspection, Full Semi Annual	Inspection/Investigation	Six Months	

Generation - Preventative Maintenance Activities

Title	Work Type	Frequency	Comments
MOP - Dam Safety Operator Inspection, Partial Semi Annual	Inspection/Investigation	Six Months	
MRP - Dam Safety Operator Inspection, Full Semi Annual	Inspection/Investigation	Six Months	
MRP - Dam Safety Operator Inspection, Partial Semi Annual	Inspection/Investigation	Six Months	
MRP Bearing Oil Cooler Maintenance and Inspection	Inspection/Investigation	Six Months	
NCH - Dam Safety Operator Inspection, Quarterly	Inspection/Investigation	Three Months	
Oil Level Differential Pressure Transducer Recalibration	Acceptance Testing	Five Years	Three Separate PM's depending on type of system used.
Oil Sampling & Anaylsis - Bearing System	Preventive Maintenance (M3)	Six Months	All Plants Bearing Systems
Oil Sampling & Anaylsis - Governor	Preventive Maintenance (M3)	6 Months	All Plants with Oil Governor.
P.T. Lube Oil Pump Motor Commutator Brush Inspection (MGT)	Inspection/Investigation	Six Months	MGT
PAB Diesel - Ten Year Maintenance	Preventive Maintenance (M3)	Ten Years	PAB
PAB Diesel Annual Brush Gear Maintenance	Preventive Maintenance (M3)	Yearly	PAB
PAB Diesel Annual Fan Bearing Maintenance	Inspection/Investigation	Yearly	PAB
PAB Diesel Annual Oil Separator Maintenance	Preventive Maintenance (M3)	Yearly	PAB
PAB Diesel Monthly Inspection	Inspection/Investigation	Monthly	PAB
PAB Weekly Tank Dip and Inspection	Inspection/Investigation	Weekly	
Partial Discharge Analysis Testing (Avalon/St. John's)	Inspection/Investigation	Six Months	NCH,PBK,MOP,ROP,HCP,CAB Except HCT which three months.
Partial Discharge Analysis Testing (Gander)	Inspection/Investigation	Six Months	SBK RBK G1 & G2.
Partial Discharge Analyzer Re-Calibration	Acceptance Testing	Yearly	Analyzer
PBK - Dam Safety Operator Inspection, Full Semi Annual	Inspection/Investigation	Six Months	
PBK - Dam Safety Operator Inspection, Partial Semi Annual	Inspection/Investigation	Six Months	
Penstock Consultant Inspection	Inspection/Investigation	Cancelled	All penstocks
Petty Harbour Dam Safety Engineering Inspection	Inspection/Investigation	Yearly	
PHR - Dam Safety Operator Inspection, Full Semi Annual	Inspection/Investigation	Six Months	
PHR - Dam Safety Operator Inspection, Partial Semi Annual	Inspection/Investigation	Six Months	
PIT - Dam Safety Operator Inspection, Full Semi Annual	Inspection/Investigation	Six Months	
PIT - Dam Safety Operator Inspection, Partial Semi Annual	Inspection/Investigation	Six Months	
Polarization Index Testing (Central/Western)	Preventive Maintenance (M3)	Yearly	All Plant & Fossils Fuels Central/Western
Polarization Index Testing (SJN/AV Area)	Predictive Maintenance	Yearly	All Units SJN/Avalon Area.
Power Factor Testing (Central/West)	Inspection/Investigation	Three Years	All Plant & Fossils Fuels Central/Western except RBK & SBK.
Power Factor Testing (SJN/AV Area)	Inspection/Investigation	Three Years	VIC,PIT,PHR G1,2 & 3,MRP, TCV G1,2 & 3,SCV G1 & 2.
Powerhouse Crane Operational Inspection	Preventive Maintenance (M3)	Monthly	LBK
PUN - Dam Safety Operator Inspection, Quarterly	Inspection/Investigation	Three Months	
PUN G1 Generating Equipment Operational Inspection (6-months)	Inspection/Investigation	Six Months	
PUN G1 Generating Equipment Visual Inspection	Inspection/Investigation	Monthly	
PUN G2 Generating Equipment Operational Inspection (6-months)	Inspection/Investigation	Six Months	
PUN G2 Generating Equipment Visual Inspection	Inspection/Investigation	Monthly	
RBH - Dam Safety Operator Inspection, Full Semi Annual	Inspection/Investigation	Six Months	
RBH - Dam Safety Operator Inspection, Partial Semi Annual	Inspection/Investigation	Six Months	
RBH 1&2 Generating Equipment Operational Inspection(6-months)	Inspection/Investigation	Six Months	
RBH 1&2 Generating Equipment Visual Inspection(monthly)	Inspection/Investigation	Monthly	

Generation - Preventative Maintenance Activities

Title	Work Type	Frequency	Comments
RBH Annual Governor and Bearing Filter Change	Preventive Maintenance (M3)	Yearly	
RBH Fisheries Inspection (weekly)	Environmental	Weekly	RBH
RBH Oil Level Limit Switch/Transducer Functional/Calibration Check	Acceptance Testing	Five Years	
RBH Oil Sampling & Analysis - Bearing System	Preventive Maintenance (M3)	Six Months	RBH Gov & Bearing
RBH1 Fish Valve Inspection	Inspection/Investigation	90 Days	
RBK - Dam Safety Operator Inspection, Full Semi Annual	Inspection/Investigation	Six Months	
RBK - Dam Safety Operator Inspection, Partial Semi Annual	Inspection/Investigation	Six Months	
RBK G1 Generating Equipment Operational Inspection (6-months)	Inspection/Investigation	Six Months	
RBK G1 Generating Equipment Visual Inspection (monthly)	Inspection/Investigation	Monthly	
RBK G2 Generating Equipment Operational Inspection (6-months)	Inspection/Investigation	Six Months	
RBK G2 Generating Equipment Visual Inspection (monthly)	Inspection/Investigation	Monthly	
Re-Apply For Permit ALT To Carry Out Maintenance Work At Hydro Facilities	Regulatory	Five Years	PHR
Replace Backup Battery for Internal Memory in Control Logix Processor	08 Installation	Three Years	WES & GRT.
Replace Internal Battery for UPS At Forebay	Preventive Maintenance (M3)	Five Years	TOP,SBK,LOK,RBK,LBK & RBK Amy's Gate
Replace MGT PT Lube Oil Filters.	Preventive Maintenance (M3)	Yearly	
Rocky Pond Dam Safety Engineering Inspection	Inspection/Investigation	Two Years	
ROP - Dam Safety Operator Inspection, Full Semi Annual	Inspection/Investigation	Six Months	
ROP- Dam Safety Operator Inspection, Partial Semi Annual	Inspection/Investigation	Six Months	
Rose Blanche Black Start Operational Test	Preventive Maintenance (M3)	Monthly	
SBK - Dam Safety Operator Inspection, Full Semi Annual	Inspection/Investigation	Six Months	
SBK - Dam Safety Operator Inspection, Partial Semi Annual	Inspection/Investigation	Six Months	
SBK Generating Equipment Operational Inspection (6-months)	Inspection/Investigation	Six Months	
SBK Generating Equipment Visual Inspection (monthly)	Inspection/Investigation	Monthly	
SBK1 Main Inlet Pit Inspection	Inspection/Investigation	90 Days	
SCC Diesel Monthly Inspection	Inspection/Investigation	Monthly	
SCC Weekly Tank Dip and Inspection	Inspection/Investigation	Weekly	
SCV - Dam Safety Operator Inspection, Quarterly	Inspection/Investigation	Three Months	
SCV Fish Valve Monthly Visual Inspection	Inspection/Investigation	Monthly	
Semi-Annual Portable Gas Monitor Recalibration	Acceptance Testing	Six Months	Five Portable Gas Monitors.
Semi-Annual Turbine Pit Maintenance/Cleaning	Preventive Maintenance (M3)	Six Months	PBK,MOP,HCP & CAB.
Sluice Gate Conditional Assessment	Inspection/Investigation	Six years	LBK,FPD,LOK & VIC. Others cancelled HCT, SCV & TOP.
Sluice Gate Inspection	Inspection/Investigation	Two Years	LBK,LOK & VIC all others cancelled
Sluice Gate Operational Test	Preventive Maintenance (M3)	Four Years	LOK All others cancelled
St. Georges Weekly Tank Dip and Inspection	Inspection/Investigation	Weekly	
Stoplog Structure Operational Test	Preventive Maintenance (M3)	Yearly	LBK,PBK,MOP,HCP East Dam,HCP Mount Carmel,CAB & PBK
Storage Dam Site Walkabout	Inspection/Investigation	Monthly	VIC,PHR & RBK
TCV - Dam Safety Operator Inspection, Quarterly	Inspection/Investigation	Three Months	
TCV Annual Generator Pit Maintenance/Cleaning	Preventive Maintenance (M3)	Six Months	TCV G1,2 & 3
Thermoscan Camera Bi-Annual Recalibration	Preventive Maintenance (M3)	Two Years	Camera P40
TOP - Dam Safety Operator Inspection, Full Semi Annual	Inspection/Investigation	Six Months	

Generation - Preventative Maintenance Activities

Title	Work Type	Frequency	Comments
TOP - Dam Safety Operator Inspection, Partial Semi Annual	Inspection/Investigation	Six Months	
Tors Cove Dam Safety Engineering Inspection	Inspection/Investigation	Two Years	
Trepassey Weekly Tank Dip and Inspection	Inspection/Investigation	Weekly	
TRP Weekly Tank Dip and Inspection	Inspection/Investigation	Weekly	
Underground Fuel Line Inspection	Inspection/Investigation	Two Years	GRT & WES
VIC - Dam Safety Operator Inspection, Quarterly	Inspection/Investigation	Six Months	
Water Level Transducer Calibration Check	Inspection/Investigation	Monthly	21 Plants
WBK - Dam Safety Operator Inspection, Full Semi Annual	Inspection/Investigation	Six Months	
WBK - Dam Safety Operator Inspection, Partial Semi Annual	Inspection/Investigation	Six Months	
WBK Generating Equipment Operational Inspection (6-months)	Inspection/Investigation	Six Months	
WBK Generating Equipment Visual Inspection(Monthly)	Inspection/Investigation	Monthly	
WES Quarterly Inspection Fuel Piping	Preventive Maintenance (M3)	Three months	
WES Tank 1 Weekly Tank Dip and Inspection	Inspection/Investigation	Weekly	
WES Tank 2 Weekly Tank Dip and Inspection	Inspection/Investigation	Weekly	
Weslyville Annual Fuel Tank Dip	Inspection/Investigation	Yearly	WES
Weslyville Annual Lube Oil Sampling	Inspection/Investigation	Yearly	WES PT & WES GG Lube.
Weslyville Black Start Test Run	Inspection/Investigation	Two Monthy	WES
Weslyville Fuel Flow Meter Calibration	Inspection/Investigation	Five Years	WES
Weslyville Parallel Test Run	Inspection/Investigation	Two Monthy	WES
WUL Application Due	Standing	3-21 Years	Most Water Supplies.

Newfoundland Power's
Generation - Completed Corrective Maintenance
Work Order Tasks (Typical)

Generation - Completed Corrective Maintenance Work Order Tasks (Typical)			
Work Order Title	**Priority**	**Task Name**	**Entity Name**
TOP Turbine Repairs	1 - Very High (1 Month)	TOP Turbine Repairs (ELECT)	TOP: Topsail Plant Unit 1
Investigate meg-alert trip	1 - Very High (1 Month)	Investigate meg-alert trip	NCH: Unit 1 Meg-Alert System
Temporary repairs to valve pit sump pump discharge line.	1 - Very High (1 Month)	Temporary repairs to valve pit sump pump discharge line.	MRP: Powerhouse Plumbing/Hot Water Heater
Install repaired HMI and verify control functions	1 - Very High (1 Month)	Install repaired HMI and verify control functions	MGT: Controls Trailer
HMI will not power up.	1 - Very High (1 Month)	HMI will not power up.	RBH: Instrumentation System
Replace Oil	1 - Very High (1 Month)	Replace Oil	HCP: Turbine Guide Bearing
Investigate and Repair Pit Flood Trip not Working	2 - High (3 Months)	Investigate and Repair Pit Flood Trip not Working	ROP: Hydroelectric Turbine
Install DC Overload	2 - High (3 Months)	Install DC Overload	MGT: DC Lube Oil Pump
GRT Flow Meter Leak In Pumping Shed	2 - High (3 Months)	GRT Flow Meter Leak In Pumping Shed	GRT: Fuel Flow Meters
Oil Change Required	2 - High (3 Months)	Oil Change Required	HCP: Turbine Guide Bearing
Investigate and Repair Interstitial Alarm and Tank Integrity	2 - High (3 Months)	Investigate and Repair Interstitial Alarm and Tank Integrity	WES: Interstitial Vacuum Guage 2
Check Exhaust Fan	2 - High (3 Months)	Check Exhaust Fan	TOP: Powerhouse Ventilation System
Repair Gate Hoist	2 - High (3 Months)	Repair Gate Hoist	TOP:Intake Gate Hoist
Clean Septic Tank	2 - High (3 Months)	Clean Septic Tank	MOB: Depot Plumbing
Clean Debris Out Of Water	2 - High (3 Months)	Clean Debris Out Of Water	SCV: Intake Trashracks
Repair/Replace Coolant Sensor	2 - High (3 Months)	Repair/Replace Coolant Sensor	GFW Diesel Engine
Investigate wicket gate problem	2 - High (3 Months)	Switching Order Preparation And Approval	TOP: Topsail Plant Unit 1
Clean Brearing And Change Oil	2 - High (3 Months)	Clean Brearing And Change Oil	PUN: Unit 2 Thrust Bearing
Investigate and Repair Bypass Valve	3 - Medium (6 mth)	Investigate and Repair Bypass Valve	SCV: Unit1 Bearing Cooling Water System
Investigate and Repair Water Level Transducer	3 - Medium (6 mth)	Investigate and Repair Water Level Transducer (Tech)	PHR: Unit 3 Controls System
Investigate and Repair Turbine Flow Meter Operation	3 - Medium (6 mth)	Investigate and Repair Turbine Flow Meter Operation	SCV: Unit 1 Flow Metering Equipment
Replace Trash Rack Probe and Install New Pressure Switch at Plant	3 - Medium (6 mth)	Replace Trash Rack Probe and Install New Pressure Switch a	SBK: Intake Trashracks
Investigate and Repair Pit Flood Pump Float	3 - Medium (6 mth)	Investigate and Repair Pit Flood Pump Float Operation	MOP: Main Inlet Pivot Valve
Investigate and Repair Wear on Slip Rings	3 - Medium (6 mth)	Investigate and Repair Wear on Slip Rings	PHR: Petty Harbour Plant Unit 1
Install New Junction Box	3 - Medium (6 mth)	Install New Junction Box	ROP: DC Exciter
Relpace Turbine Packing	3 - Medium (6 mth)	Relpace Turbine Packing	PHR: Unit 1 Turbine Head Cover
Investigate and Repair Water Level System	3 - Medium (6 mth)	Investigate and Repair Water Level System	PBK: Intake Gatehouse
DC lighting at Wesleyville gas turbine building not working	3 - Medium (6 mth)	DC lighting at Wesleyville gas turbine building not working	WES: Electrical System
Relocate Slip Ring Brush Sensors	4 - Low (1 Year)	Relocate Slip Ring Brush Sensors	SCV: Unit 1 Brush Gear
Follow Up From Ground Fault	4 - Low (1 Year)	Switching Order Preparation & Approval	NCH: Switchgear
Replace BX To Flow Meter	4 - Low (1 Year)	Replace BX To Flow Meters	NCH: Bearing System
Speed Switch Calbration & Wiring Upgrade	4 - Low (1 Year)	Speed Switch Calibration & Upgrade Wiring	PIT: Pittman's Pond Plant Unit 1
Install Memory Card In PLC	4 - Low (1 Year)	Install Memory Card In PLC	RBK: Unit 2 Controls System
Investigate Where Water is Entering Enclosures and Repair Rust on Floor	4 - Low (1 Year)	Investigate Where Water is Entering Enclosures and Repair	DUF - Diesel Fuel Tank
Investigate and Repair Garage Door	4 - Low (1 Year)	Investigate and Repair Garage Door	RBH: Electric Overhead Door Hoist
Check Potheads For Leaks	4 - Low (1 Year)	Check Potheads For Leaks	MRP: Switchgear
Modify HMI Screens	4 - Low (1 Year)	Modify HMI Screens	TCV: Unit 2 Controls System
Complete As Built AC Schematic Drawings	4 - Low (1 Year)	Complete As Built AC Schematic Drawings	SBK: Metering Equipment
Gate House Repairs Required	5 - Project	Gate House Repairs Required	PBK:West Country Pond Gate Structure
Complete Overhaul of Main Inlet By-Pass Valve	5 - Project	Isolate Unit and De-Water Penstock	WBK: Hydroelectric Turbine
Install Braking System	5 - Project	Install Piping & Braking System	PHR: AC Synchronous Generator 3
Install New Block Heater	6 - Deficiency (>3 mths)	Install New Block Heater	MD3: Engine Electric Block Heater
Fuel Tank Painting Required	6 - Deficiency (>3 mths)	Fuel Tank Painting Required	SCC - Diesel Genset
Brush Gear Maintenance Required	6 - Deficiency (>3 mths)	Switching Order Preparation and Approval	PHR: Unit 2 Brush Gear

2011 Facility Rehabilitation
June 2010

2011 Facility Rehabilitation

June 2010

Prepared by:

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1.0 Introduction

The 2011 Facility Rehabilitation project is necessary for the replacement or rehabilitation of deteriorated plant components that have been identified through routine inspections, operating experience and engineering studies. The project includes expenditures necessary to improve the efficiency and reliability of various hydro plants or to replace plant due to in-service failures.

Newfoundland Power ("the Company") has 23 hydroelectric plants that provide energy to the Island Interconnected System. Maintaining these generating facilities reduces the need for additional, more expensive, generation.

Items involving replacement and rehabilitation work, which are identified during inspections and maintenance activities, are necessary for the continued operation of these generation facilities in a safe, reliable and environmentally compliant manner. The Company's hydro generation facilities produce a combined normal annual production of 428.8 GWh[1]. The alternative to maintaining these facilities is to retire them.

The 2011 Facility Rehabilitation project totalling $1,610,000 is comprised of Hydro Dam Rehabilitation; Generation Equipment Replacements Due to In-Service Failures, Main Valve Replacement at West Brook and Engineering for Lockston Plant Refurbishment.

2.0 Hydro Dam Rehabilitation

Cost: $780,000

The Company has over 150 dam structures throughout its 23 hydroelectric facilities. Based on the average age of structures in the Newfoundland Power system, deterioration of embankment and concrete dams is to be expected. Refurbishment is required to ensure integrity of the structures is maintained to an appropriate level of dam safety as per the guidelines established by the Canadian Dam Association. The cost of the projects is justified based on the need to restore the structures to an appropriate safety level based on the site design conditions and to allow for future operation of the hydro system in a safe and reliable manner.

This item involves the refurbishment of deteriorated components at various dam structures.

Specific work to be completed in 2011 includes:

1. *Heart's Content Seal Cove Pond Dam Improvements. ($350,000)*
   This project involves construction of an earth dam with metal cut-off wall. Dam safety inspections indicate the existing rock filled timber crib dam has deteriorated with water infiltrating through the structure. Remedial work was completed during 2006 as a temporary measure to stabilize the structure. Timbers have since

[1] Normal annual production was established as 419.6 GWh in the Water Management Study – Hydrology Update prepared by SGE Acres dated August 1, 2005. Normal production was increased as a result of capacity increases at Rattling Brook and Rose Blanche to make the revised base normal hydroelectric production to 428.8 GWh.

deteriorated to the point that additional rehabilitation is now required to maintain the integrity of the structure.

2. *Petty Harbour Gatehouse Rehabilitation ($100,000)*
   This project involves replacement of the wooden gatehouse, which houses control equipment for the intake gate and water level monitoring equipment. Inspections have determined that the roof and building exterior has deteriorated. The handrail, perimeter platform and security fence at the forebay dam and along the penstock are also a public safety concern and require improvements to meet safety standards.

3. *Rocky Pond: Cluney's Dam and Spillway Rehabilitation ($125,000)*
   This project involves replacement of the existing rock filled timber crib spillway and rip rap improvements on the existing dam. Inspections have determined that the timbers are in poor condition, sections of the spillway crest are rotted and broken, and rip rap on the dam face is sparse and undersized.

4. *Tors Cove: Frank's Pond Spillway Improvements ($75,000)*
   This project involves replacement of the wooden spillway crest, the addition of rip rap and drainage improvements. Inspections indicate rip rap is sparse on abutments, wooden sill rotted with significant leakage, and ponded water at the downstream toe of the spillway.

5. *Sandy Brook: Forebay Spillway Rehabilitation ($130,000)*
   This project involves rehabilitation of the concrete abutments and piers, and refurbishment of the lift mechanism and monorail hoist on the spillway structure. Inspections have indicated concrete deterioration on the abutments, and structural concerns with the gate lift mechanism under certain loading conditions.

The physical condition and observed deterioration of these structures has been assessed within the scope of regularly scheduled dam safety inspections. These inspections are the primary means of identifying deficiencies and establishing capital improvement plans on a priority basis.

3.0 Generation Equipment Replacements Due to In-Service Failures

Cost: $535,000

Equipment and infrastructure at generating facilities, such as turbines and generators, routinely requires upgrading or replacement to extend the life of the asset.

This item involves the refurbishment or replacement of structures and equipment due to damage, deterioration, corrosion, technical obsolescence and in-service failure. This equipment is critical to the safe and reliable operation of generating facilities and must be replaced in a timely manner. Equipment replaced under this item includes civil infrastructure, instrumentation, mechanical, electrical, and protection and controls equipment.

Replacements under this item are typically due to one of two reasons:

1. Emergency replacements – where components fail and require immediate replacement to return a unit to service; or

2. Observed deficiencies – where components are identified for replacement due to imminent failure or for safety or environmental reasons.

Table 1 shows the expenditures for replacements due to in-service failures since 2006.

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

Year	**2006**	**2007**	**2008**	**2009**	**2010F**
Total	$591[1]	$409	$679	$475	$520

[1] Excludes Rocky Pond rebuild.

Based upon this recent historical information and engineering judgement, $535,000 is estimated to be required in 2011 for replacement of equipment due to in-service failures or equipment at risk of imminent failure.

Generation equipment, buildings, intakes, dams and control structures are critical components in the safe and reliable operation of generating facilities. This item is required to enable the timely refurbishment or replacement of equipment to facilitate the continued operation of generating facilities in a safe and reliable manner.

4.0 Main Valve Replacement - West Brook Plant

Cost: $275,000

West Brook Plant is located on the southern part of the Burin Peninsula near the community of St Lawrence. It was commissioned in 1942 and has an installed capacity of 680 KW. The unit consists of one Francis turbine manufactured by Leffel, and a Westinghouse generator. The original 1942 main valve at West Brook was replaced in 1967 by a 24 inch butterfly valve.[2]

The 43 year old valve experiences leaks and control problems. This type of butterfly valve has an expected service life of approximately 40 years. Erosion of the valve disc and seat has rendered the valve ineffective in providing the positive water shut off required to perform maintenance on the turbine, runner and wicket gates. It is impossible to seal off the turbine for maintenance because of the leakage. As a result the penstock has to be drained each time

[2] The main valve is water actuated with a water actuated bypass valve. The valve does not have a dismantling joint making its removal for servicing difficult.

maintenance is required on the turbine. This situation limits the Company's ability to maintain and service other equipment in the plant. Typically the main valve assembly includes a bypass valve and drain valve.[3] The existing main valve does not include either a drain valve or bypass valve. The lack of a bypass valve appears to be a contributing factor in the excessive leakage around the valve disc when in the closed position.

Figure 1 - West Brook Main Valve

In its current condition the valve is prone to sticking in the open position. In 2009 the valve actuator failed in the open position. This presents a risk of equipment damage if the wicket gates fail to close on unit shut down.

The closure of both the main valve and wicket gates is typically necessary to stop the flow of water from entering the turbine. If the wicket gates failed to stop the flow of water in this situation, a catastrophic failure of the turbine and generator would be very likely.

The battery bank and charger were installed in 1991 and having met their useful life expectancy will be replaced during the plant outage to install the new main valve.

The thrust bearing is oil cooled. In recent years the oil cooling system has not been able to sufficiently cool the bearing during the summer months when the ambient air temperature is higher. As a result there have been a number of incidents where the generator has tripped off line due to high bearing temperature. The oil cooling system will be redesigned with a larger heat exchanger and greater capacity for oil flow to address the inability of the current system to cool the bearing.

Due to age and condition, the main valve, the battery bank, battery charger, and cooling water system will be replaced as part of this project.

The continued operation of West Brook Plant is economical over the long term. Investing in the life extension of the plant ensures the continued availability of 2.9 GWh of energy to the Island Interconnected electrical system. The estimated levelized cost of energy from the plant over the next 50 years, including the capital expenditure of $275,000 in 2011, is 5.38 cents per kWh. This energy is lower in cost than replacement energy from sources such as new hydroelectric developments or additional Holyrood thermal generation[4].

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3 The drain valve is a manually operated valve that is used to drain the penstock for maintenance. The bypass valve is used to direct water past the main valve prior to opening, thereby equalizing the pressure on both sides of the main valve to reduce the strain on the valve disc when opening.

4 The cost of electricity from the Holyrood thermal generating plant is estimated at 11.63 ¢/kWh. This is based upon a 630 kWh/barrel conversion efficiency and oil price forecast from Hydro of $73.30/barrel for 2010 as per Newfoundland Hydro 2010 Capital Budget Application, Generating Planning Issues 2009 Mid Year Report dated July 2009.

5.0 Engineering for Lockston Plant Refurbishment

Cost: $20,000

Newfoundland Power's Lockston hydroelectric generating plant is located on the Bonavista Peninsula near the community of Port Rexton. The plant was commissioned in 1956 and has an installed capacity of 3,375 KW. The normal annual production at Lockston plant is approximately 8.4 GWh or 2.0% of the total hydroelectric production of Newfoundland Power.

The plant has 2 units each consisting of a horizontal Francis turbine manufactured by Gilkes and a generator manufactured by General Electric. Selected pieces of plant equipment are 54 years old and the Company intends to undertake a refurbishment of the civil, electrical, and mechanical systems at Lockston plant starting in 2012.

Figures 2 and 3 are photographs of the turbine runner on Generator No. 2 taken during a 2007 inspection. This runner was refurbished in 2001, with extensive repairs to the runner blades. Holes in the buckets were welded with aluminum bronze rods. The entire runner was coated with a Belzona Super Glide ceramic coating. Two new 660 bronze rotating seals were installed and machined to give proper clearance. The stationary seal was repaired and reinstalled in the turbine. Subsequent inspections have revealed additional cavitation and 50% of the Belzona coating has since eroded.

Figure 2-Low pressure side showing loss of belzona coating

Figure 3-Cavitation

As part of the overall plant refurbishment the Company currently plans to bring forward a capital budget project proposal for the replacement of the turbine runners at Lockston Plant in the 2012 Capital Budget Application. This capital budget project proposal will require detailed engineering design work be completed. Completing the detailed engineering design work in advance will allow Newfoundland Power to prepare engineering specifications and tender documents in 2011 to ensure the project can be completed during the 2012 construction season.[5]

[5] Turbine runners typically have long delivery periods after the engineering design has been approved.

6.0 Concluding

This project, for which there is no feasible alternative, is required in order to ensure the continued provision of safe, reliable plant operations. A 2011 budget of $1,610,000 for Facility Rehabilitation is recommended as follows:

- $780,000 for Hydro Dam Rehabilitation;
- $535,000 for Generation Equipment Replacements Due to In-Service Failures;
- $275,000 for West Brook Plant Main Valve Replacement
- $20,000 for Engineering for Lockston Plant Refurbishment

2012 Facility Rehabilitation
June 2011

2012 Facility Rehabilitation

June 2011

Prepared by:

Gary K. Humby, P.Eng.

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1.0 Introduction

The 2012 Facility Rehabilitation project is necessary for the replacement or rehabilitation of deteriorated plant components that have been identified through routine inspections, operating experience and engineering studies. The project includes expenditures necessary to improve the efficiency and reliability of various hydro plants or to replace plant due to in-service failures.

Newfoundland Power ("the Company") has 23 hydroelectric plants that provide energy to the Island Interconnected System. Maintaining these generating facilities reduces the need for additional, more expensive, generation.

Items involving replacement and rehabilitation work, which are identified during inspections and maintenance activities, are necessary for the continued operation of these generation facilities in a safe, reliable and environmentally compliant manner. The Company's hydro generation facilities produce a combined normal annual production of 430.5 GWh[1]. The alternative to maintaining these facilities is to retire them.

The 2012 Facility Rehabilitation project totalling $1,362,000 is comprised of Hydro Dam Rehabilitation and Generation Equipment Replacements Due to In-Service Failures.

2.0 Hydro Dam Rehabilitation

Cost: $784,000

The Company has over 150 dam structures throughout its 23 hydroelectric facilities. Based on the age of structures in the Newfoundland Power system, deterioration of embankment, timber crib, and concrete dams and appurtenant structures is to be expected. Refurbishment is required to ensure integrity of the structures is maintained to an appropriate level of dam safety as per the guidelines established by the Canadian Dam Association. The cost of the projects is justified based on the need to restore the structures to an appropriate safety level based on the site design conditions and to allow for future operation of the hydro system in a safe and reliable manner.

This item involves the refurbishment of deteriorated components at various dam structures.

Specific work to be completed in 2012 includes:

1. *Port Union Long Pond Spillway. ($212,000)*
   This project involves the replacement of the existing rock filled timber crib dam and outlet structure with a new concrete/rock filled dam and concrete outlet structure. Dam safety inspections indicate the existing dam and outlet has deteriorated with water infiltrating through the structure. Remedial work was completed during October 2008 and January 2010 as temporary measures to stabilize the surface of the structure. In September 2010, heavy rains from Hurricane Igor, as shown in Figure 1, caused severe erosion in the right abutment. Earth fill and riprap, in the eroded area,

1 Normal annual production was established as 430.5 GWh in the Normal Production Review, Newfoundland Power Inc. December 2010.

were replaced in November 2010. The internal timbers and structural members, however, were not replaced during the 2008 and 2010 remediation work. As illustrated in Figures 2 and 3, these have now deteriorated to the point that replacement of the dam and outlet is required to maintain the integrity of the structure.

Figure 1 - Long Pond Dam (Hurricane Igor)

Figure 2 - Long Pond Dam (Deteriorated Decking)

Figure 3 - Long Pond Dam (Deteriorated Outlet and Cribbing)

2. *Tors Cove Forebay Spillway Rehabilitation ($191,000)*
   This project involves replacement of the existing stoplog spillway, shown in Figures 4 and 5, with a new concrete structure. Stability analysis indicates that the spillway does not meet requirements for overturning and the structure lacks available freeboard with the stoplogs in place. Accessing the structure to remove stoplogs during flood conditions is difficult, and presents a safety hazard for power plant operators. Replacing the stoplog spillway will address dam safety deficiencies and remove a significant safety hazard.

Figure 4 - Tors Cove Spillway (Upstream)

Figure 5 - Tors Cove Spillway (Downstream)

3. *Paddy's Pond Dam and Spillway ($381,000)*
   This project involves the replacement of the existing timber crib dam and spillway with a new embankment dam and rock filled overflow metal cut-off wall structure. The existing structure has deteriorated, timbers are rotted, the upstream face is misaligned and the spillway decking is in very poor condition as illustrated in Figures 6 and 7. Recent visual inspection also shows signs of seepage and water overtopping the dam, as shown in Figure 8. Recent dam safety review indicates that this structure has insufficient freeboard. Replacement of the structure is required to address all these issues.

Figure 6 - Misaligned Timber Facing with Ice Damage

Figure 7 - Delaminating Spillway Decking

Figure 8 - Deteriorated Timbers with Erosion of Rockfill from Overtopping

3.0 Generation Equipment Replacements Due to In-Service Failures

Cost: $578,000

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

This item involves the refurbishment or replacement of structures and equipment due to damage, deterioration, corrosion, technical obsolescence and in-service failure. This equipment is critical to the safe and reliable operation of generating facilities and must be replaced in a timely manner. Equipment replaced under this item includes civil infrastructure, instrumentation, mechanical, electrical, and protection and controls equipment.

Replacements under this item are typically due to one of two reasons:

1. Emergency replacements – where components fail and require immediate replacement to return a unit to service; or

2. Observed deficiencies – where components are identified for replacement due to imminent failure or for safety or environmental reasons.

Table 1 shows the expenditures for replacements due to in-service failures since 2007.

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

Year	2007	2008	2009	2010	2011F
Total	$409	$679	$475	$569[2]	$535

Based upon this recent historical information and engineering judgement, $578,000 is estimated to be required in 2012 for replacement of equipment due to in-service failures or equipment at risk of imminent failure.

Generation equipment, buildings, intakes, dams and control structures are critical components in the safe and reliable operation of generating facilities. This item is required to enable the timely refurbishment or replacement of equipment to facilitate the continued operation of generating facilities in a safe and reliable manner.

[2] Excludes Hurricane Igor related costs from 2010.

4.0 Concluding

This project, for which there is no feasible alternative, is required in order to ensure the continued provision of safe, reliable generating plant operations. A 2012 budget of $1,362,000 for Facility Rehabilitation is recommended as follows:

- $784,000 for Hydro Dam Rehabilitation;
- $578,000 for Generation Equipment Replacements Due to In-Service Failures;

2013 Facility Rehabilitation
June 2012

2013 Facility Rehabilitation

June 2012

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1.0 Introduction

The 2013 Facility Rehabilitation project is necessary for the replacement or rehabilitation of deteriorated plant components that have been identified through routine inspections, operating experience and engineering studies. The project includes expenditures necessary to improve the efficiency and reliability of various hydro plants or to replace plant due to in-service failures.

Newfoundland Power ("the Company") has 23 hydroelectric plants that provide energy to the Island Interconnected System. Maintaining these generating facilities reduces the need for additional, more expensive, generation.

Items involving replacement and rehabilitation work, which are identified during inspections and maintenance activities, are necessary for the continued operation of these generation facilities in a safe, reliable and environmentally compliant manner. The Company's hydro generation facilities produce a combined normal annual production of 430.5 GWh.[1] The alternative to maintaining these facilities is to retire them.

The 2013 Facility Rehabilitation project totalling $1,400,000 is comprised of Hydro Dam Rehabilitation and Generation Equipment Replacements Due to In-Service Failures.

2.0 Hydro Dam Rehabilitation

Cost: $825,000

The Company has over 150 dam structures throughout its 23 hydroelectric facilities. Based on the age of structures in the Newfoundland Power system, deterioration of embankment, timber crib and concrete dams is to be expected. Refurbishment is required to ensure integrity of the structures is maintained to an appropriate level of dam safety as per the guidelines established by the Canadian Dam Association. The cost of the projects is justified based on the need to restore the structures to an appropriate safety level based on the site design conditions and to allow for future operation of the hydro system in a safe and reliable manner.

This item involves the refurbishment of deteriorated components at various dam structures.

Specific work to be completed in 2013 includes:

1. *Lookout Brook Forbay Dam/Spillway. ($225,000)*
   This project involves the rehabilitation of deteriorated concrete on the sluice and upstream face of the structure. Dam safety inspections have noted that the concrete on the wing/breast walls of the sluice is in the late stages of deterioration with cracking/fracturing and the development of efflorescence paste in most joints. The concrete at the toe of the spillway has eroded along the bedrock interface. It is recommended that all the deteriorated concrete surfaces be refinished to ensure design performance of the structure is maintained. The railings on this spillway do

[1] Normal annual production was established as 430.5 GWh in the Normal Production Review, Newfoundland Power Inc. December 2010.

not meet current National Building Code of Canada requirements and the spillway abutment was constructed without railing. These deficiencies have been noted through inspections and will be corrected as part of this project.

Figure 1 – Concrete Erosion at Spillway Toe

Figure 2 – Deteriorated Concrete on Sluice

Figure 3 – Missing and Substandard Railing

Figure 4 – Deteriorated Concrete on Upstream Face

2. *Three Island Pond Spillway ($305,000)*
   This project involves replacement of the existing timber crib spillway and outlet. Inspections have determined the foundation near the existing gate has settled and the gate is misaligned as a result. Timbers along the structure are deteriorated from exposure to ice and water. Due to the deterioration and settlement of the foundation the structure will be completely replaced.

Figure 5 – Results of Settling Foundation

Figure 6 – Misalignment Due to Settling

Figure 7 – Deteriorated Wood and Misaligned Gate

Figure 8 – Deteriorated Wood Structure

3. *Cochrane Pond Outlet ($70,000)*
   This project involves the replacement of the existing timber crib outlet and spillway. This structure previously housed an operational gate that has since been decommissioned as it was no longer required. This outlet remains important to the regulation of flow from Cochrane Pond. The structure in its current deteriorated condition is prone to vandalism including timber removal and camp fires. The outlet will be replaced with a modified steel or concrete design to reduce vandalism and public safety risks.

Figure 9 – Evidence of Fires and Crossing Using Structure Timbers

Figure 10 – Removed Timbers

Figure 11 – Timber Deterioration

4. *Soldiers Pond Outlet ($225,000)*
This project involves replacing the existing timber outlet structure and gabion wing walls. The lower sections of the gabion wing walls have corroded and are losing ballast. The risk of collapse of the gabian rock ballast has increased as the corrosion becomes more prevalent on the gabian baskets. The existing structure is used as a pedestrian bridge by the public. The wing walls currently do not have safety railings as they cannot be accommodated with the existing design. A more robust wingwall design that incorporates appropriate safety measures is required.

Figure 12 – Gate Structure

Figure 13 – Corroded Gabions - Upstream

Figure 14 – Corroded Gabions - Downstream

Figure 15 – Corroded Gabions - Downstream

3.0 Generation Equipment Replacements Due to In-Service Failures

Cost: $575,000

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

This item involves the refurbishment or replacement of structures and equipment due to damage, deterioration, corrosion, technical obsolescence and in-service failure. This equipment is critical to the safe and reliable operation of generating facilities and must be replaced in a timely manner. Equipment replaced under this item includes civil infrastructure, instrumentation, mechanical, electrical, and protection and controls equipment.

Replacements under this item are typically due to one of two reasons:

1. Emergency replacements – where components fail and require immediate replacement to return a unit to service; or

2. Observed deficiencies – where components are identified for replacement due to imminent failure or for safety or environmental reasons.

Table 1 shows the expenditures for replacements due to in-service failures since 2008.

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

Year	2008	2009	2010	2011	2012F
Total	$679	$475	$569[2]	$464	$578

Based upon this recent historical information and engineering judgement, $575,000 is estimated to be required in 2013 for replacement of equipment due to in-service failures or equipment at risk of imminent failure.

Generation equipment, buildings, intakes, dams and control structures are critical components in the safe and reliable operation of generating facilities. This item is required to enable the timely refurbishment or replacement of equipment to facilitate the continued operation of generating facilities in a safe and reliable manner.

[2] Excludes Hurricane Igor related costs from 2010.

4.0 Concluding

This project, for which there is no feasible alternative, is required in order to ensure the continued provision of safe, reliable generating plant operations. A 2013 budget of $1,400,000 for Facility Rehabilitation is recommended as follows:

- $825,000 for Hydro Dam Rehabilitation;
- $575,000 for Generation Equipment Replacements Due to In-Service Failures.

2014 Facility Rehabilitation
June 2013

2014 Facility Rehabilitation

June 2013

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1.0 Introduction

The 2014 Facility Rehabilitation project is necessary for the replacement or rehabilitation of deteriorated plant components that have been identified through routine inspections, operating experience and engineering studies. The project includes expenditures necessary to improve the efficiency and reliability of various hydro plants or to replace plant due to in-service failures.

Newfoundland Power ("the Company") has 23 hydroelectric plants that provide energy to the Island Interconnected System. Maintaining these generating facilities reduces the need for additional, more expensive, generation.

Items involving replacement and rehabilitation work, which are identified during inspections and maintenance activities, are necessary for the continued operation of these generation facilities in a safe, reliable and environmentally compliant manner. The Company's hydro generation facilities produce a combined normal annual production of 430.5 GWh.[1] The alternative to maintaining these facilities is to retire them.

The 2014 Facility Rehabilitation project totalling $1,610,000 is comprised of Hydro Dam and Intake Structure Rehabilitation and Generation Equipment Replacements Due to In-Service Failures.

2.0 Hydro Dam Rehabilitation

Cost: $1,025,000

The Company has over 150 dam structures throughout its 23 hydroelectric facilities. Based on the age of structures in the Newfoundland Power system, deterioration of embankment, timber crib and concrete dams is to be expected. Refurbishment is required to ensure integrity of the structures is maintained to an appropriate level of dam safety as per the guidelines established by the Canadian Dam Association.[2] The cost of the projects is justified based on the need to restore the structures to an appropriate safety level based on the site design conditions and to allow for future operation of the hydro system in a safe and reliable manner.

This item involves the refurbishment of deteriorated components at various dam structures.

Specific work to be completed in 2014 includes:

1. *Topsail Forebay Refurbishment ($115,000)*
   This project involves the rehabilitation of several deteriorated components of the gate house as well as improvements to reduce flooding. The trashrack and adjacent timber

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1 Normal annual production was established as 430.5 GWh in the Normal Production Review, Newfoundland Power Inc. December 2010.

2 The guidelines established by the Canadian Dam Association ("CDA") applicable to the Hydro Dam Rehabilitation projects are *CDA Dam Safety Guidelines 2007*, *Dam Safety Guidelines 2007 Technical Bulletins* and *Guidelines for Public Safety Around Dams 2011*. Copies of these guidelines can be ordered online from www.cda.ca.

floor were replaced in 1991. Recent observations and inspections have indicated that both the trashrack and adjacent timber joists have deteriorated significantly. A new trashrack is required, as failure could cause extensive damage to the turbine. Replacement of the gatehouse deck joists is required to ensure employee safety.

During period of high inflows, such as significant rainfall events or snow melts, the water rises to, or exceeds the height of the gatehouse timber frame. The water flows through the gatehouse and floods the adjacent parking area. As a result of the timber being frequently close to or in the water, it has deteriorated significantly. During extreme flood events, high water limits access to the gatehouse. Improvements to the structure and parking lot grade are required to divert the flood waters toward the spill channel to ensure the continued safety and integrity of the structure.

Figure 1 – Deteriorated Trash Rack

Figure 2 – Deteriorated Timber Deck

Figure 3 – High Water (Above Floor Elevation)

2. *Cape Broyle Spillway ($495,000)*
   The Cape Broyle Spillway was constructed in the mid 1950's as part of the original hydro development. This project involves replacement of the existing stoplog spillway with a new concrete structure. Stability analysis indicates that the spillway does not meet requirements for overturning and the structure lacks available freeboard with the stoplogs in place. The concrete base has deteriorated in places and the right abutment is prone to washout during periods of high flow.

   Accessing the structure to remove stoplogs is critical to dam safety. Access during extreme flood conditions is difficult, and operation of this type of spillway is a safety hazard for power plant operators. In addition to dam safety deficiencies, the spillway does not meet public safety requirements. Replacing the stoplog spillway with a concrete overflow spillway without an access walkway will address dam safety deficiencies and remove a significant public and employee safety hazard.

   The deteriorated stoplogs leak considerably and this condition is expected to worsen over time. Based on field measurements, it is estimated that approximately 1.35 GWh of energy is lost annually as a direct result of the leakage. Addressing the leakage as part of the construction of a new concrete structure will save approximately $227,000 in annual purchase power cost.[3]

Figure 4 – Cape Broyle Spillway

Figure 5 – Access Walkway

[3] Reducing the leakage through the stoplogs has not been previously considered as a hydro production increase project. At the time of the *"Hydroelectric Systems Strategic Planning Study* "completed by Hatch in 2001, the leakage at the spillway would have been significantly less and therefore not investigated as a potential project.

Figure 6 – Deteriorated Concrete and Abutment Prone to Washout

Figure 7 – Significant Leakage

Figure 8 – Concrete Deterioration

3. *West Lake Dam and Spillway ($215,000)*
   The West Lake dam and spillway are a part of the Sandy Brook plant watershed. West Lake Dam was reconstructed in 1984. This project involves replacing the existing concrete outlet structure, refurbishing the spillway and completing safety improvements. Refurbishment of the concrete outlet structure is required as it has significant vertical cracking and the wingwall concrete has eroded due to turbulence. The steel spillway cutoff has heaved vertically and as a result the spillway is no longer level. Refurbishment is required as the vertical rise has decreased spillway capacity and poses a tripping hazard to both employees and cabin owners in the area. The walkway also does not meet current public safety requirements. Improvements to walkway safety will be incorporated into the new outlet design.

Figure 9 – West Lake Dam and Spillway

Figure 10 – Deteriorated Wingwall Concrete

Figure 11 – Heaved Cutoff Wall

Figure 12 – Walkway and Gate Structure

4. *Lawn Plant: Intake Structure Rehabilitation ($200,000)*
The Lawn intake structure was constructed in the mid 1930's as part of the original hydro development. The concrete intake conduit and support structure for the intake gate at Lawn Plant requires rehabilitation. This portion of the structure has deteriorated to the point where pieces of concrete are breaking free of the intake structure and traveling through the penstock to the generator turbine. In addition, excessive flows currently migrate through the concrete that is installed on the top and sides of the gate when the gate is in the closed position. The flows have increased such that the penstock can no longer be dewatered for maintenance purposes.

This project involves rehabilitation of the existing concrete intake conduit and support structure for the intake gate at Lawn Plant.


Figure 13 – Lawn Forebay Dam


Figure 14 – Concrete Removed from Turbine


Figure 15 – Gate Guide (Note: Deteriorated Concrete behind gate guide)

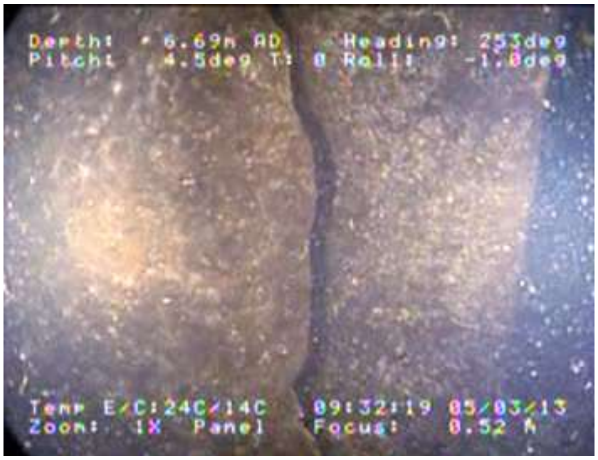


Figure 16 – Crack in intake conduit roof

3.0 Generation Equipment Replacements Due to In-Service Failures

Cost: $585,000

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

This item involves the refurbishment or replacement of structures and equipment due to damage, deterioration, corrosion, technical obsolescence and in-service failure. This equipment is critical to the safe and reliable operation of generating facilities and must be replaced in a timely manner. Equipment replaced under this item includes civil infrastructure, instrumentation, mechanical, electrical, and protection and controls equipment.

Replacements under this item are typically due to one of two reasons:

1. Emergency replacements – where components fail and require immediate replacement to return a unit to service; or

2. Observed deficiencies – where components are identified for replacement due to imminent failure or for safety or environmental reasons.

Table 1 shows the expenditures for replacements due to in-service failures since 2008.

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

Year	**2009**	**2010**	**2011**	**2012**	**2013F**
Total	$475	$569[4]	$464	$523	$575

Based upon this recent historical information and engineering judgement, $585,000 is estimated to be required in 2014 for replacement of equipment due to in-service failures or equipment at risk of imminent failure.

Generation equipment, buildings, intakes, dams and control structures are critical components in the safe and reliable operation of generating facilities. This item is required to enable the timely refurbishment or replacement of equipment to facilitate the continued operation of generating facilities in a safe and reliable manner.

[4] Excludes Hurricane Igor related costs from 2010.

4.0 Concluding

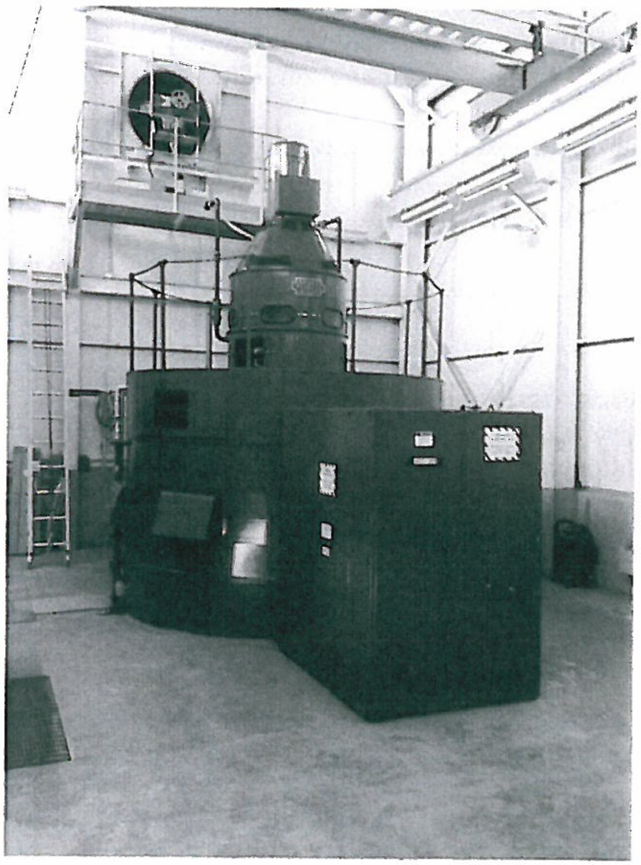
This project, for which there is no feasible alternative, is required in order to ensure the continued provision of safe, reliable generating plant operations. A 2014 budget of $1,610,000 for Facility Rehabilitation is recommended as follows:

- $1,025,000 for Hydro Dam Rehabilitation;
- $585,000 for Generation Equipment Replacements Due to In-Service Failures.

Heart's Content Hydro Plant Refurbishment
June 2013

Heart's Content Hydro Plant Refurbishment

June 2013



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1.0 Background

1.1 General

Newfoundland Power's Heart's Content hydroelectric development (the "Plant") is located on the Avalon Peninsula, near the community of Heart's Content, approximately 125 km west of the City of St. John's.

The Plant was placed into service in 1960 and contains one generating unit with a nameplate capacity of 2.4 MW and a rated net head of 46.9 m.[1] The Plant contains a single vertical 3,400 hp Francis turbine manufactured by Inglis (English Electric) and a 3,000 kVA Bruce Peebles & Co. Ltd. generator.[2] The Plant's normal annual production is approximately 8.3 GWh or 1.9 % of the total hydroelectric production of Newfoundland Power. The Plant has provided 54 years of reliable energy production.

The refurbishment and life extension of the Plant includes necessary work on the generator, protection and control equipment and switchgear.[3] The estimated levelized cost of energy from the Plant over the next 50 years, including the capital expenditure of $6.4 million over the next 25 years, is 6.27¢ per kWh.[4]

This report provides a summary of the engineering assessment of the Plant and the refurbishment proposed for 2014.

1.2 Previous Upgrades

There have been a number of upgrades to the original plant and equipment since commissioning in 1960.

The following is a list of the upgrades that have been completed in the past 25 years:

1989 – Controls upgraded on main inlet and bypass valves
1996 – Forebay line relocated
1997 – Main inlet valve replaced
1997 – Anti-condensation heaters added
1997 – Generator stator re-wedged
1998 – PDA system and multifunction generator protection relay added
1999 – PLC and bearing temperature monitoring added
2000 – Cooling coils and cooling water solenoids replaced
2001 – Generator circuit breaker replaced
2002 – PLC upgrades
2003 – Roof replacement

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[1] The original generating station at the Hearts Content site dates back to 1918.
[2] The generator is rated at 3,000 kVA at 80% power factor, which equates to a 2,400 kW load rating.
[3] Associated with this project is the replacement of the penstock which was approved as a multiyear project in Order No. P.U. 31 (2012). A copy of the report describing the penstock replacement project can be found with the 2013 Capital Budget Application at ***1.2*** *Heart's Content Plant Penstock Replacement*.
[4] Details of the feasibility analysis can be found in Appendix B.

2004 – Intruder and fire alarm systems added
2005 – Fisheries compensation valve added
2007 – Forebay water level system upgraded
2008 – Cooling water system upgraded and duplex filters added
2008 – Runner replaced
2008 – Garage door replaced
2008 – Two exhaust fans with dampers and hood installed
2009 – AC distribution upgraded and station service transformer replaced
2009 – Controls upgraded
2009 – 15-ton crane and trolley installed
2009 – ION 7550 revenue meter installed

2.0 Engineering Assessment

2.1 General Condition Assessment

A detailed engineering assessment has been completed and has determined that the Plant is in generally good condition.[5] Most civil and mechanical systems have been upgraded over the past 25 years and are in good condition, requiring only minor work. The engineering assessment has determined that the Plant requires the refurbishment of three major electrical systems at this time.

The overall building structure is in good condition, including the roof, entrance systems and overhead crane. The turbine runner, wicket gates and the main valve have been recently replaced. The bypass valve and mechanical sections of the governor are original to the Plant. The bypass valve does not require any work at this time and the mechanical section of the governor requires only a minor overhaul. The AC and DC electrical distribution panels are in good condition and have sufficient capacity to accommodate the necessary refurbishment. Most instrumentation, including the MegAlert system and the control of the heating and ventilating equipment, is in good condition.

The primary systems requiring refurbishment for the life extension of a plant include the generator, protection and control equipment, switchgear and some miscellaneous ancillary equipment.

2.2 Generator ($790,000)

The Plant generator was manufactured in 1959 by Bruce Peebles & Co. Ltd. and the stator and rotor windings are original to the 55 year old unit. In 1997, the stator winding was re-wedged as a result of the stator coils becoming loose.[6] Winding coils in the stator are subjected to thermal and mechanical stresses during normal operation. Electrical insulation of the rotor is subjected to similar thermal stresses as the stator due to normal operation of the generator. Mechanical stresses experienced by rotor poles are substantially higher than the stator due to centrifugal

[5] Appendix A includes a detailed engineering assessment of the Plant.
[6] Loose coils results in rapid deterioration of the insulating material encasing the coils due to increased movement caused by the mechanical forces exerted on them.

forces present during normal operation. The condition and age of the stator winding and the rotor insulation necessitates their replacement in 2014.

The pilot exciter and main exciter are the original units supplied with the generator in 1959. The pilot exciter will no longer be required when the new digital voltage regulator is installed. The exciter commutator and the slip rings are scored and require resurfacing. The condition and age of the exciter dictates that it should be rewound in conjunction with the generator rewind.

The rewinding of the stator and exciter, and the re-insulation of the rotor constitutes a major overhaul of the generator. During the course of this work other ancillary systems will be replaced and refurbished as required. Replacement of the surge protection, neutral grounding transformer and resistor are required. The generator potential transformers and current transformers, field breaker and field discharge resistor will also be replaced. All of this equipment will be located in either the generator termination cubicle or the switchgear.

The power cables between the exciter and the rotor are original to the 1959 installation. The condition and age of the cables require that they be replaced.

2.3 Protection and Control ($840,000)

The existing mechanical section of the governor including the hydraulic power piston assembly, the relay valve, hand wheel, and gate operating linkages are in good operating condition and will be retained.[7] The governor controls are antiquated and will be modernized. The control head, which initiates the movement of the power piston, will be replaced with a programmable logic controller ("PLC") based digital control system.[8] The new governor control system will facilitate the implementation of a water management system. The water management system will optimize efficiency of the plant by controlling the load on the unit based upon the amount of water available. A fibre optic cable will replace the existing figure 8 copper communications cable to transfer water level information from the forebay to the Plant.

Similar to the governor control, the balance of plant control will be transferred to an upgraded PLC system. An Allan-Bradley CompactLogix® programmable logic controller will be installed to replace the existing plant control system. The upgraded PLC will improve the local and remote monitoring and control functionality and will provide additional information about the performance of key plant components. The new unit control panel containing the upgraded PLC, and a computer based operator interface will be located in the upstairs control room. The unit control panel will also house all associated monitoring and control equipment, control switches and meters necessary to locally operate the Plant. The generator protection, voltage regulation and metering equipment is antiquated and will be replaced with digital equipment located in the unit control panel that readily interfaces to the upgraded PLC system.

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7 Reconditioning of all seals, bushings and other components that have deteriorated through the previous 54 years of service will be required to eliminate leakage and extend the life of the power piston and relay valve assemblies.

8 The fly ball governor head, pilot valve assembly, mechanical restoring linkages and permanent magnet generator used for speed sensing will be removed.

Most of the existing instrumentation in the Plant will be interfaced with the upgraded PLC system. The exceptions include speed sensing, vibration monitoring and governor condition sensing. Instrumentation for these measurements will be upgraded to interface with the PLC system.

The upgraded PLC will also integrate with the existing SCADA data concentrator to communicate with the System Control Centre for remote monitoring and control of the Plant.

2.4 Switchgear ($465,000)

The existing switchgear will be replaced with an arc flash rated assembly, equipped with an arc-flash protection system and containing a new vacuum breaker with closed-door racking capability. Higher accuracy instrument transformers for improved protection and metering will be supplied with the switchgear. The existing 3-phase station service transformer will be incorporated into the new switchgear.

The existing power cables between the switchgear and the generator will be reused. New power cables will be installed between the switchgear and the power transformer in the substation yard replacing the existing original cable and terminations. The power cables will be terminated on a new structure in the substation yard on which a disconnect switch and current transformers for the arc-flash relay system will be mounted.

2.5 Miscellaneous ($145,000)

The remainder of the work associated with the 2014 refurbishment project involves miscellaneous ancillary systems required for the safe and reliable operation of the Plant.

Both the battery bank and charger are beyond their life expectancy and will be replaced with a gel-cell battery bank and temperature compensated battery charger. The intake louvers in the west end of the building are deteriorated and will be replaced while the existing actuator will be reused. The existing generator and turbine floor heaters will be replaced with blower-type heaters.

Compressed air is used to operate the generator brakes. The existing compressor and pressure tank are 1959 vintage and lack necessary features such as an air-water separator, pressure regulator or pressure switch for low air alarm. The condition and age of the compressed air system dictates that it should be replaced.

3.0 Project Proposal

3.1 Cost Breakdown

The total project cost for the refurbishment of the Plant, excluding cost associated with the penstock replacement, is estimated at $2,240,000. Table 1 below summarizes the cost breakdown.

Table 1
Project Cost
($000s)

Cost Category	**Cost**
Material	1,689
Labour - Internal	246
Labour - Contract	-
Engineering	146
Other	159
Total	**2,240**

Associated with this project is the replacement of the penstock at a 2014 estimated cost of $3,495,000 which was approved as a multiyear project in Order No. P.U. 31 (2012).

3.2 Feasibility Analysis

Appendix B provides an economic feasibility analysis for the continued operation of the Plant. The results of the analysis show that the continued operation of the Plant is economical over the long term. Investing in the life extension of the Plant ensures the availability of 8.3 GWh of energy to the Island Interconnected electrical system.

The estimated levelized cost of energy from the Plant over the next 50 years, including the capital expenditure of $6.4 million over the next 25 years, is 6.27¢ per kWh. This energy is lower in cost than replacement energy from sources such as new hydroelectric developments or additional Holyrood thermal generation.[9]

[9] The avoided cost of fuel at the Holyrood Thermal Generating Station is estimated at 16.8¢ per kWh. This is based upon a 630 kWh/barrel conversion efficiency and oil price forecast from Hydro of $105.80 per barrel for 2013 as per Newfoundland and Labrador Hydro letter regarding Rate Stabilization Plan – Fuel Price Projection dated April 12, 2013.

4.0 Conclusion

A detailed engineering assessment has been completed on the Heart's Content Hydro Plant and has determined that the Plant is in generally good condition. The primary systems requiring refurbishment at this time for the life extension of the Plant include the generator, protection and control equipment, switchgear and some miscellaneous ancillary equipment.

The generator and exciter winding will be replaced during the extended outage associated with the penstock replacement. Installation of a PLC based governor control system, improved PLC based plant control system, upgraded protection and replacement of equipment that has surpassed its reliable service life are required to ensure reliable, efficient operation of the Plant and the provision of energy to the Island Interconnected system.

The feasibility analysis included in Appendix B verifies the financial viability of completing this project. The 8.3 GWh of energy that will be available from Heart's Content each year will provide affordable energy to the customers of Newfoundland Power for the foreseeable future. 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 analysis, the project is recommended to proceed in 2014.

Appendix A
Heart's Content Hydro Plant
Engineering Assessment

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1.0 General

The following summarizes the results of the detailed engineering assessment performed on Newfoundland Power's Heart's Content Hydro Plant ("the Plant"). This assessment included an evaluation of the condition of the various components contained in the facility together with comprehensive recommendations for required refurbishment to permit life extension.

2.0 Civil

Structurally, the Plant is in good condition, the roof was replaced in 2003 and a galvanized rolling door was installed in 2008. The only civil work required during this upgrade is the installation of channel iron in the concrete floor, to which the new switchgear will be attached, and the interior of the Plant will be painted upon completion of the refurbishment.

3.0 Governor

The Woodward Type LR gateshaft governor is the original unit. It has been reliable and, except for minor oil leakage, has no outstanding maintenance issues. The original equipment manufacturer discontinued manufacturing replacement parts for these units as of July 1, 2008. A number of third party companies provide maintenance support, including parts, but these companies and the utility industry is moving towards replacing the hydraulic control portion of these governors with digital systems that provide enhanced control and feedback capabilities.[1]

Figure 1 - Woodward Governor

The governor speed control and gate limit are motorized and can be operated remotely utilizing electromechanical relay logic to control the load on the unit. There are no gate position or gate limit setpoint transducers and therefore no feedback of these quantities for unit control or remote indication. More advanced control of the governor setpoints is required to implement a water management system in the unit control PLC to optimize the energy produced from the available water.

[1] The Company has 16 Woodward gateshaft governors in service in its hydro plants. In previous capital budget applications that included hydro plant refurbishment projects, 12 of the 16 Woodward governors have been refurbished in a manner similar to what is recommended at Heart's Content.

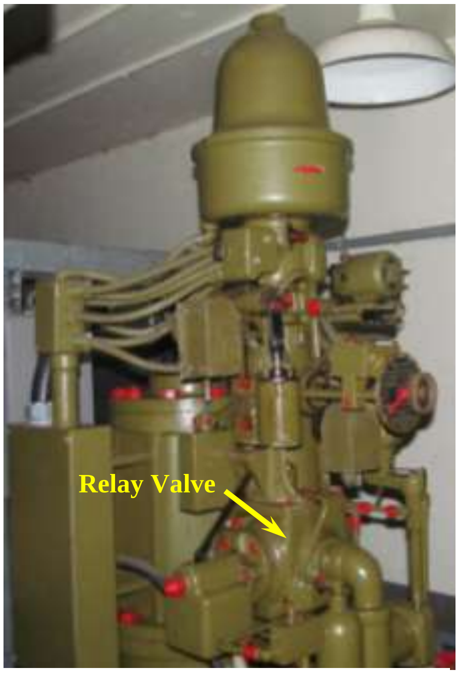


Figure 2 - Governor Control Head

The governor consists of two sections, the power piston that provides the force necessary to operate the wicket gates under load and the control head that adjusts the position of the power piston to maintain the system frequency through varying load conditions. The control head, which initiates the movement of the power piston, will be replaced down to the relay valve with a PLC based digital control system. The fly ball governor head, pilot valve assembly, mechanical restoring linkages and permanent magnet generator used for speed sensing will be removed. The new governor control system will facilitate the implementation of a water management system. The existing hydraulic power piston assembly will be retained, along with the relay valve, handwheel, and gate operating linkages. Reconditioning of all seals, bushings and other components that have deteriorated through the previous 54 years of service will be required to eliminate leakage and extend the life of the power piston and relay valve assemblies.

4.0 Generator

The generator at the Plant was manufactured by Bruce Peebles & Co. Ltd. in 1959 and the stator and rotor windings are original to the 55 year old unit. Generator winding insulation has a design life of 40 years, with the actual life dependent upon several factors including quality control during manufacture, quality control during installation and operating conditions such as loading of the generator, ambient temperature, humidity and exposure to system electrical faults.

Winding coils in the stator are subjected to thermal and mechanical stresses during normal operation. These stresses result in movement of the coils in the stator slots. This movement as well as the normal electrical stress placed on the insulation when the unit is operating, leads to degradation of the insulating material on the coils. Failure of the insulating material will result in an in service failure of the generator similar to the one experienced in 2002 on one unit at the Rattling Brook hydro plant.[2]

Insulation for the rotor is subjected to similar thermal stresses as the stator due to normal operation of the generator. Mechanical stresses experienced by rotor poles are substantially higher than the stator due to centrifugal forces present during normal operation. During an emergency shutdown the speed of the rotor accelerates dramatically thereby increasing the magnitude of the centrifugal force exerted on the rotor poles.

2 The in service failure at Rattling Brook hydro plant occurred when the generator had been in service 43 years.

The Plant generator stator windings, which operate at 2,400 volts, are among the oldest windings remaining in service in the Company's fleet of generating plants.[3] In 1997, the stator was re-wedged as a result of the stator coils becoming loose. Loose coils results in rapid deterioration of the insulating material encasing the coils due to increased movement caused by the mechanical forces exerted on them.

The replacement of the Heart's Content intake and penstock are scheduled to be completed in 2014. It is estimated that the plant will be out of service for 20 weeks from June to October to complete this work. Completing the generator rewind at the same time would add efficiencies by eliminating the need for additional down time and lost production. It is recommended that the generator rewind be completed in conjunction with this project.

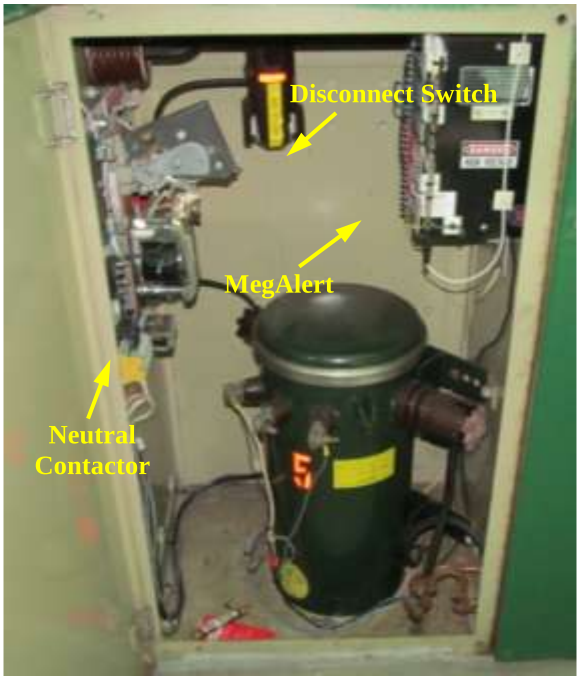


Figure 3 – Neutral Grounding Transformer

The generator neutral is high-impedance grounded through a grounding transformer, resistor, disconnect switch and neutral contactor located in the generator termination cubicle. To minimize the magnitude of fault currents, high impedance grounding is the preferred method of generator neutral to ground connection. The grounding transformer is a 1960's vintage 5 kVA oil-filled distribution unit. The resistor connected across the secondary of the grounding transformer is original. The size of the resistor required will be recalculated with the new power cables and surge capacitors. A properly sized resistor minimizes the transient overvoltage in the event of an arcing ground fault. A new dry-type neutral grounding transformer with secondary resistor will be installed in the generator termination cubicle. The neutral disconnect switch will be removed and the neutral contactor will be incorporated into the new grounding system.

The generator is shut down when there is inadequate water available for production. This usually occurs during the summer and early fall when humidity is high. As a result, moisture accumulation on the stator windings compromises the winding insulation. Energizing the generator with moisture present could result in an electrical flashover and permanent winding damage. A MegAlert® stator insulation test system provides a warning that allows prompt corrective action to be taken when the insulation value is reduced.[4] To enable the testing to be completed, the insulation testing system includes a neutral contactor to automatically disconnect

[3] Newfoundland Power currently has 16 generators operating at 2,400 volts with an average winding age of 30 years. Nine of the 16 generators have been rewound. The average age of the windings when rewound was 63 years. The Heart's Content stator windings will be 55 years old when replaced.

[4] The Company has installed MegAlert® insulation testing systems on 16 generators. The MegAlert® system continuously monitors the integrity of the insulation while the unit is shut down, ensuring it can be re-energized when required. It will also prevent re-energizing the generator should the insulation measurement fall below a safe value.

the stator windings from ground when the generator shuts down. A MegAlert® system has been previously installed at Heart's Content and will be incorporated into the new control system as part of this project.

The existing generator surge protection capacitor and lightning arresters are connected to the 2,400 volt bus in the switchgear. The three phase capacitor was installed in 1986 and the lightning arresters are the original installation. Three new two bushing capacitors and MOV type lightning arresters will be installed in the generator termination cubicle and connected to the generator leads to provide improved surge protection. The two bushing capacitors will facilitate the use of the MegAlert® stator insulation test system. The three phase capacitor will be returned to inventory.

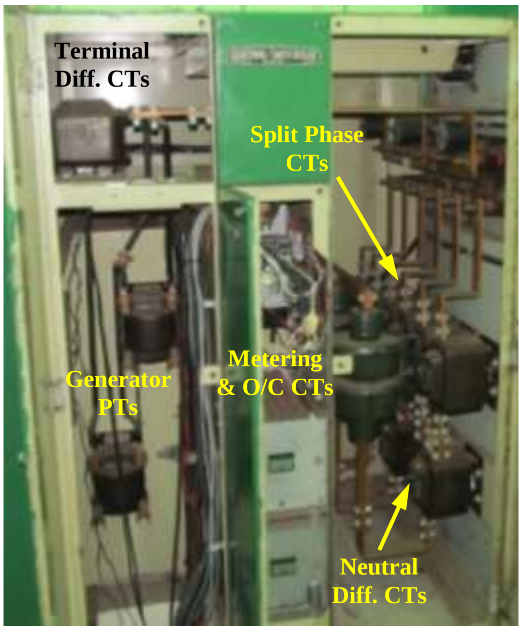


Figure 4 – Generator CTs and PTs

The generator protection and metering potential transformers (PTs) and current transformers (CTs), located in the generator termination cubicle, are original to the 1959 installation. The PTs and CTs are critical to the electrical protection of the generator and will be replaced.[5] The six 400:5 CTs used for generator split phase protection will be replaced with three 100:5 split phase CTs with a rated ampacity of 800 amps. The three neutral-side differential protection CTs and three dual-secondary overcurrent protection and metering CTs will be replaced with three protection CTs, located in the generator termination cubicle, and three revenue class metering CTs, located in the new switchgear lineup. The three terminal side differential CTs and generator PTs will be replaced with new units located in the new switchgear. The single crosscurrent compensation CT will be removed since it will not be required for the new digital voltage regulator. The CT reconfiguration will necessitate modifications to the buswork in the generator termination cubicle. The reconfiguration will also free up enough space to enable the generator surge protection to be installed in the generator termination cubicle.

[5] PTs and CTs are all critical to electrical protection of the generators, and an in-service failure of these components could result in serious damage to the generator windings.

5.0 Excitation System

The pilot exciter and main exciter are the original units supplied with the Bruce Peebles & Co. Ltd. generator in 1959. The pilot exciter will no longer be required when the new digital voltage regulator is installed. The exciter commutator and the slip rings are scored and require resurfacing. The age of the exciter dictates that it should be rewound in conjunction with the generator rewind. Infrared brush temperature sensors will be added to the commutator and slip rings.

Figure 5 – Exciter Commutator

The voltage regulator is the original Brown Boveri Model AV4/1 with mechanical operating mechanisms. These units have been discontinued for many years. The voltage regulator cannot be integrated into the upgraded control system to provide the required automated control. It will be replaced with a digital voltage regulator incorporated into the Combination Generator Control Module (CGCM) located in the unit control panel. The CGCM is designed to be easily integrated into the control system and provide improved voltage regulation under varying system conditions.

The field breaker, which is located in the generator termination cubicle, is the original ITE Model AKF-1 breaker which is no longer supported by the original manufacturer and is beyond its expected service life. A new field breaker will be installed, located either in the generator termination cubicle or in a cabinet mounted on top of the generator termination cubicle, if there is insufficient space. The power cables between the exciter and the rotor will also be replaced.

6.0 Switchgear

The switchgear is original to the 1959 English Electric installation. Several upgrades have been completed over the years. The surge protection was replaced in 1986, the generator circuit breaker was replaced with a Cutler Hammer Type VPC vacuum unit in 2001 and the power cables from the generator to the switchgear were also replaced at that time. The non-standard 27-inch switchgear cubicles greatly limited the options for replacement breakers. A three-phase, 75 kVA, 120/208V station service transformer was installed in the switchgear in 2009. The remaining equipment, including the bus potential transformers and current transformers, are original.

Figure 6 – Switchgear with Doors Open

As a result of the high energy fault levels at this location, there is a very high arc flash hazard associated with this switchgear requiring an arc flash boundary of 3 metres when all cubicle doors are fully secured and 14 meters when racking the breaker, necessitating the use of Level 3 arc flash personal protective equipment.[6]

The protective relays, meters and voltage regulator are incorporated into the switchgear doors, which greatly increase arc flash hazards for operating personnel. The high voltage compartments in the front of the switchgear are vented through the bottom of the doors. In the event of an internal fault, the electric arc and hot gases would exit the switchgear directly towards personnel.

The existing switchgear will be replaced with an arc flash rated assembly, equipped with an arc-flash protection system and containing a new vacuum breaker with closed-door racking capability. Higher accuracy instrument transformers for improved protection and metering will be supplied with the switchgear. The existing station service transformer will be incorporated into the new switchgear. The generator breaker and 3-phase capacitor will be removed from the existing switchgear and returned to inventory.[7] The protective relays, meters and voltage regulator will be located in a new unit control panel to be located in the control room upstairs, providing additional employee safety.

The existing power cables between the switchgear and the generator will be reused. New power cables will be installed between the switchgear and the power transformer in the substation yard to replace the existing original cable and terminations, which are beyond their life expectancy. The power cables will be terminated on a new structure in the yard, on which a T1-D switch and current transformers for the arc-flash relay system will also be installed.

7.0 AC Distribution System

A 75kVA, 120/208 V three phase station service transformer was installed in the switchgear in 2009. It will be relocated to the new switchgear.

A 120/208V, 250A, 84-circuit AC panel, meter and distribution system were installed in 2009. Additional circuits associated with this refurbishment will be connected to this panel. An emergency station service is included in the project design to supply plant heating and lighting in the event of a power interruption to the switchgear.

[6] An arc flash study for the Heart's Content switchgear is included as Appendix C.
[7] The generator breaker can be used to replace an existing breaker at 6 other Company plants. The 3-phase capacitor is a direct replacement for the unit in service at Pitman's Pond plant and could also be used at 6 other Company plants.

The generator and turbine floor lighting, heating and generator and cable tray grounding will be upgraded.

8.0 DC System

The existing GNB Exide lead-acid battery bank was installed in 1995 and the Staticon battery charger was purchased in 1977. Three cells of the battery bank were found to be defective during maintenance performed in 2011. Both the battery bank and charger are beyond their life expectancy and will be replaced. A gel-cell battery bank and temperature compensated battery charger will be installed.

The 42-circuit, 250A Siemens DC distribution panel, installed in 1996, has ten spare breakers and does not require replacement. Additional circuits associated with this refurbishment will be connected to this panel.

9.0 Protective Relaying

The generator electrical protection is provided by a Beckwith M-3420 multifunction generator protection relay, installed in 2002, and original Westinghouse electromechanical relays. The following protective elements are in service:

27	Undervoltage
32	Reverse Power
51V	Voltage Controlled Overcurrent
59	Overvoltage
59GN	Residual Neutral Overvoltage
81	Under and Over Frequency
87	Differential
87SP	Split Phase

The existing protective relaying lacks three elements of the minimum protection set.[8] Newfoundland Power has only two Beckwith M-3420 relays in service and has no spare available.[9] This relay will be removed from service, placed in inventory and replaced with a Schweitzer digital multifunction generator protection relay, rotor ground module and split phase overcurrent relay, located in the unit control panel. Improved protection reduces stresses due to electrical faults and in turn extends the life of the generator.

10.0 Plant Control

The plant is remotely monitored from the System Control Centre. Presently there is no automation with respect to water management and the setting of machine loads to optimize the use of the water resources. An Allen-Bradley Model SLC 5/04 programmable logic controller

8 The existing generator protection does not include Rotor Ground Fault (64F), Loss of Field Fault (40), Stator Unbalance Current / Negative Sequence Fault (46) protective elements, which are recommended by the IEEE for these generators.

9 The other unit is at Rose Blanche Hydro Plant.

was installed in 1999 to monitor bearing temperature and vibration. PLC upgrades were completed in 2002 and 2009 but the standardized Newfoundland Power remote control and water management systems were not implemented because of the type of governor control in place.

An Allan-Bradley CompactLogix® programmable logic controller will be installed to replace the existing system, which will be returned to inventory.[10] The upgraded processor will provide processing power that will greatly improve the local and remote monitoring and control functionality and will provide additional information about the performance of key plant components. It will facilitate the implementation of a variety of control modes to ensure efficient operation of the plant and utilization of available water. Standard control, protection and automation functionality will be implemented.

The existing annunciation is provided by a 15" LCD rack-mounted monitor using a Windows-XP desk-top computer and keyboard as the human-machine interface ("HMI"). This will be replaced by an Allan-Bradley PanelView Plus®. This HMI will provide enhanced alarm and event indication, plant monitoring and trending, set point management and control functionality.

A new data concentrator and network communications switch were installed in 2012 in conjunction with the upgrade of the Heart's Content substation. A high speed data link will be established in 2013 and no additional upgrading will be required as part of this project. The new control system will be integrated with this system and the communications infrastructure will permit remote administration of the PLC and digital relays by head office engineering staff that would normally require a site visit.

The new unit control panel, which will be located in the upstairs control room, will contain the processor, associated monitoring and control equipment, control switches and generator protection relays.

The following equipment will be located in the panel:

a) Allan Bradley CompactLogix® PLC
b) Allan-Bradley PanelView Plus® HMI
c) MegAlert® remote LED display and switch board meter
d) Emergency stop pushbutton (latching)
e) Start pushbutton
f) Stop pushbutton
g) Alarm reset pushbutton
h) Generator breaker control switch (ANSI device No. 52CS)
i) Field breaker control switch (ANSI device No. 41CS)
j) Speed raise/lower control switch (ANSI device No. 15CS)
k) Gate limit control switch (ANSI device No. 65CS)
l) Voltage raise/lower control switch (ANSI device No. 70CS)
m) Generator lock out relay (ANSI Device No. 86G) and blocking switches

[10] The Allan-Bradley CompactLogix® programmable logic controller will provide functionality similar to the ControLogix® programmable logic controller used in the upgrade of larger plants, but with scaled down processing power and capabilities better suited to smaller hydro plants.

n) Three position manual/local/remote control switch (ANSI Device No. 43CS)
o) Schweitzer SEL-700G1 relay with SEL-2664 rotor ground module
p) Schweitzer SEL-551 relay for split phase protection
q) Ethernet Switch
r) Combination Generator Control Module (CGCM)
s) Synchroscope
t) Automatic/manual synchronizing control switch (ANSI device No. 25CS)
u) Schneider PowerLogic® ION 7550 for revenue metering

11.0 Instrumentation

The instrumentation has been upgraded over the past number of years with stator temperature RTD's added as part of the stator rewedging in 1997, bearing temperature and vibration monitoring installed in 1999, the cooling water flow meters and a speed switch installed in 2000 and bearing oil level sensors installed in 2008.

The existing instrumentation, with the exception of the speed switch and vibration monitor, will be reused and integrated into the new control system. The speed switch will be removed and dual magnetic speed sensors installed on the existing PMG toothgear to provide analogue speed signals to the governor and unit control PLCs. The unit control PLC will perform the speed processing functions previously performed by the speed switch. The vibration sensors will be reused but the monitor will be replaced with a Rockwell Automation Entek® system, designed to be seamlessly integrated into the Allan-Bradley PLC. Brush temperature instrumentation will be added and the analog gauges on the governor oil, scroll case and braking air will be replaced with new digital gauges which will provide analog signals to the PLC.

The Schneider PowerLogic® ION 7550 revenue meter, which was installed in the switchgear in 2009, will be relocated to the new unit control panel.

12.0 Heating and Ventilation

Generator anti-condensation heaters were installed in 1997. The heat and ventilation control cabinet, installed in 2009, will be integrated with the PLC. The existing Omega HX303C thermostat/humidistat on the generator floor and a new thermostat to be installed on the turbine floor will be used by the PLC to control all heat and ventilation equipment. Intake louvers on the fan in the west end of the building are deteriorated and will be replaced. The existing actuator will be reused. The existing generator and turbine floor heaters will be replaced with blower-type heaters.

13.0 Water Level Monitoring and Control

The forebay water level system is critical to the implementation of the Water Management System in the PLC. The water level and trash rack signals are transmitted to the plant utilizing pulse width modulated signals over a copper cable. The copper cable is no longer reliable as it has experienced damage due to lightning and ground potential rise and will be replaced with a fibre optic cable. The existing communications system will be upgraded to technology compatible with the new plant control system. In addition, the forebay building will be replaced as part of the penstock upgrade which will result in the replacement of the water level probe.

The PLC will use the water level signal to control the Water Management System. High level (spill) and low level alarms will be initiated when specified water levels are reached. The Water Management System will optimize efficiency of the plant by controlling the load on the unit based upon the following water level, inflow, wicket gate position and control mode set points:

Peak Water Level	Peak Gate Position
Low Inflow Peak Water Level	Efficient Gate Position
Efficient Water Level	Partial Gate Position
Low Inflow Efficient Water Level	Gate Position Deadband
Partial Water Level	Rate of Rise (Bump)
Low Inflow Partial Water Level	Elevation Mode Water Level
Shutdown Water Level	Elevation Mode Gate Shutdown Level
Low Inflow Shutdown Water Level	Load Control Mode Voltage Level
Level Deadband	Load Control Mode Kilowatt Level
Start-up Water Level	Load Control Mode Kilowatt Deadband

14.0 Cooling Water

The cooling water system was partially upgraded in 1997 in conjunction with the main inlet valve replacement and in 2000, the bearing cooling coils and cooling water solenoids were replaced. In 2008, further upgrades including the addition of a duplex filter were completed. No upgrading will be completed as part of this project. The controls will be integrated into the new CompactLogix® PLC.

15.0 Turbine

The runner, nose cone and wicket gates were replaced in 2008 and no additional work is required at this time.

16.0 Main Inlet and Bypass Valves

The main inlet valve, installed in 1997, is a 48-inch Pratt butterfly valve with Rotork actuator. It is in good condition with no leakage observed during the most recent inspection. There has been minor leakage around the actuator gearbox but no work is required at this time. The bypass valve is the original 1960 vintage 5-inch type SMA unit with a limit torque actuator. The valve has been recently refurbished and there is no leakage across the valve seat and only minor leakage around the gate stem. The bypass valve will not be replaced or overhauled as part of this project. The controls, which were upgraded in 1989, will be integrated into the new CompactLogix® PLC.

17.0 Compressor

Figure 8 – Compressor

Compressed air is used to operate the generator braking system. The compressor motor was replaced in 2004 but the compressor and pressure tank are 1959 vintage. The unit does not have an air-water separator, pressure regulator or pressure switch for low air alarm. The age of the 80-gallon J.B Bairid pressure vessel dictates that the compressor should be replaced.

18.0 Overhead Crane

A new 15-ton crane and trolley were installed in 2009 and no additional work is required.

Appendix B
Heart's Content Hydro Plant
Feasibility Analysis

Table of Contents

1.0 Introduction

This feasibility analysis examines the future viability of generation at Newfoundland Power's Heart's Content hydroelectric plant (the "Plant"). The continued long-term operation of the Plant is reliant on the completion of capital improvements in 2014.

With investment required in 2014 to permit the continued reliable operation of the 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 Plant over the next 25 years have been identified. The capital expenditures required to maintain the safe and reliable operation of the facilities are summarized in Table 1.

Table 1
Heart's Content Hydroelectric Plant
Capital Expenditures

Year	**($000s)**
2014	$5,736
2029	20
2033	275
2038	180
2039	200
Total	**$6,411**

The estimated capital expenditure for the Plant over the next 25 years is $6.41 million. A more comprehensive breakdown of capital costs is provided in Attachment A.

3.0 Operating Costs

Operating costs for the Plant are estimated to be approximately $57,750[1] per year. This estimate is based primarily upon recent historical operating experience. The operating cost represents both direct charges for operations and maintenance at the Plant as well as indirect costs such as those related to managing the environment, safety, dam safety inspections and staff training. 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 based on yearly hydro plant generation/output. This charge is reflected in the historical annual operating costs for the Heart's Content plant.

[1] 2013 dollars.

Penstock maintenance and issues surrounding ice have accounted for a large portion of the operating costs of this plant in recent years. Future operating costs have been estimated at $47,750 to include a reduction of $10,000 per year to reflect the penstock and intake replacement project.

4.0 Benefits

The maximum output from the Plant is 2,400 kW. The Plant normally operates at an efficient load of 2,100 kW to maximize the energy from the water.

The estimated long-term normal production of the Plant under present operating conditions is 8.3 GWh per year.

5.0 Financial Analysis

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

The estimated levelized cost of energy from the Plant over the next 50 years is 6.27¢ per kWh. This figure includes all projected capital and operating costs necessary to operate and maintain the facility. Energy from Heart's Content 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.[2]

The future capacity benefits of the continued availability of the 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.

6.0 Conclusion

The results indicate that continued operation of the Plant is economically viable. Investing in the current upgrades of the facilities at Heart's Content guarantees the availability of low cost energy to the Province. Otherwise, the projected annual production of 8.3 GWh would be replaced by more expensive energy sources such as new generation or additional production from the Holyrood thermal generating station. The project will benefit the Company and its customers by providing least cost, reliable energy for years to come.

[2] The avoided cost of fuel at the Holyrood Thermal Generating Station is estimated at 16.8¢ per kWh. This is based upon a 630 kWh/barrel conversion efficiency and oil price forecast from Hydro of $105.80 per barrel for 2013 as per Newfoundland and Labrador Hydro letter regarding Rate Stabilization Plan – Fuel Price Projection dated April 12, 2013.

Attachment A
Summary of Capital Costs

Heart's Content Feasibility Analysis Summary of Capital Costs ($000s)					
Description	**2014**	**2029**	**2033**	**2038**	**2039**
Civil					
Dam, Spillways and Gates			50		
Penstock & Intake	3,495				200
Powerhouse				180	
Mechanical					
Governor Overhaul	12		15		
Air Compressor	7				
Heat and Ventilation	8				
Electrical					
Generator Rewind	786				
P&C and Governor Controls	840		200		
Switchgear	468				
AC & DC Systems	90				
Battery Bank/Charger	30	20	10		
Annual Totals ($2013)	**5,736**	**20**	**275**	**180**	**200**

Attachment B
Summary of Operating Costs

Heart's Content Feasibility Analysis
Summary of Operating Costs

Actual Annual Operating Costs
($2013)

Year	Amount
2008	$36,848
2009	$45,907
2010	$48,713
2011	$91,431
2012	$65,850
Average	**$57,750**

5 -Year Average Operating Cost	$57,750[1]
Reduced Future Penstock Maintenance	-$10,000
Total Forecast Annual Operating Cost	$47,750

[1] 2013 dollars.

Attachment C
Calculation of Levelized Cost of Energy

Present Worth Analysis

Weighted Average Incremental Cost of Capital	7.50%
PW Year	2013

YEAR	Generation Hydro 64.4yrs 8% CCA	Generation Hydro 64.4yrs 50% CCA	Capital Revenue Requiremen	Operating Costs	Operating Benefits	Net benefit	Present Worth Benefit +ve	Cumulative Present Value Benefit +ve	Present Worth of Sunk Costs	Total Present Worth Benefit +ve	Rev Rqmt (¢/kWhr)	Levelized Rev Rqmt (¢/kWhr) 50 years
2014	2,240,800	3,495,000	566,877	47,750	0	-614,627	-571,268	-571,268	-5,362,750	-5,934,018	7.405	6.2656
2015	0	0	582,424	48,849	0	-631,273	-545,348	-1,116,615	-4,859,602	-5,976,218	7.606	6.2656
2016	0	0	544,784	49,872	0	-594,657	-477,475	-1,594,090	-4,422,172	-6,016,262	7.165	6.2656
2017	0	0	520,619	50,807	0	-571,426	-426,455	-2,020,545	-4,033,635	-6,054,180	6.885	6.2656
2018	0	0	503,339	51,743	0	-555,082	-385,033	-2,405,578	-3,684,494	-6,090,072	6.688	6.2656
2019	0	0	489,638	52,704	0	-542,342	-349,657	-2,755,234	-3,368,816	-6,124,051	6.534	6.2656
2020	0	0	477,852	53,647	0	-531,499	-318,493	-3,073,727	-3,082,471	-6,156,198	6.404	6.2656
2021	0	0	467,139	54,620	0	-521,759	-290,599	-3,364,327	-2,822,292	-6,186,619	6.286	6.2656
2022	0	0	457,069	55,614	0	-512,683	-265,400	-3,629,727	-2,585,682	-6,215,409	6.177	6.2656
2023	0	0	447,417	56,656	0	-504,074	-242,535	-3,872,262	-2,370,407	-6,242,669	6.073	6.2656
2024	0	0	438,065	57,762	0	-495,827	-221,737	-4,094,000	-2,174,501	-6,268,500	5.974	6.2656
2025	0	0	428,945	58,824	0	-487,769	-202,746	-4,296,745	-1,996,206	-6,292,951	5.877	6.2656
2026	0	0	420,018	59,965	0	-479,983	-185,435	-4,482,180	-1,833,937	-6,316,118	5.783	6.2656
2027	0	0	411,256	61,121	0	-472,377	-169,622	-4,651,802	-1,686,263	-6,338,065	5.691	6.2656
2028	0	0	402,642	62,271	0	-464,914	-155,165	-4,806,967	-1,551,881	-6,358,848	5.601	6.2656
2029	26,590	0	396,835	63,483	0	-460,318	-142,793	-4,949,760	-1,428,780	-6,378,541	5.546	6.2656
2030	0	0	388,657	64,692	0	-453,348	-130,710	-5,080,471	-1,316,722	-6,397,193	5.462	6.2656
2031	0	0	380,322	65,913	0	-446,235	-119,583	-5,200,054	-1,214,803	-6,414,856	5.376	6.2656
2032	0	0	372,094	67,161	0	-439,255	-109,408	-5,309,462	-1,122,123	-6,431,585	5.292	6.2656
2033	394,002	0	403,575	68,413	0	-471,988	-109,268	-5,418,730	-1,028,693	-6,447,423	5.687	6.2656
2034	0	0	398,229	69,688	0	-467,917	-100,684	-5,519,413	-943,004	-6,462,418	5.638	6.2656
2035	0	0	389,013	71,014	0	-460,027	-92,003	-5,611,416	-865,204	-6,476,620	5.542	6.2656
2036	0	0	379,935	72,350	0	-452,285	-84,073	-5,695,489	-794,579	-6,490,069	5.449	6.2656
2037	0	0	370,983	73,712	0	-444,695	-76,831	-5,772,320	-730,484	-6,502,804	5.358	6.2656
2038	283,099	0	390,609	75,099	0	-465,709	-74,785	-5,847,106	-667,758	-6,514,864	5.611	6.2656
2039	320,475	0	416,039	76,513	0	-492,552	-73,516	-5,920,622	-605,662	-6,526,284	5.934	6.2656
2040	0	0	408,700	77,953	0	-486,653	-67,512	-5,988,133	-548,965	-6,537,098	5.863	6.2656
2041	0	0	398,281	79,420	0	-477,702	-61,595	-6,049,728	-497,610	-6,547,338	5.755	6.2656
2042	0	0	388,038	80,915	0	-468,953	-56,201	-6,105,929	-451,107	-6,557,036	5.650	6.2656
2043	172,647	0	395,313	82,438	0	-477,751	-53,216	-6,159,145	-407,073	-6,566,218	5.756	6.2656
2044	0	0	386,560	83,990	0	-470,550	-48,717	-6,207,862	-367,052	-6,574,914	5.669	6.2656
2045	0	0	376,211	85,571	0	-461,782	-44,436	-6,252,298	-330,850	-6,583,148	5.564	6.2656
2046	0	0	366,015	87,182	0	-453,196	-40,533	-6,292,831	-298,114	-6,590,946	5.460	6.2656
2047	0	0	355,959	88,823	0	-444,781	-36,974	-6,329,806	-268,524	-6,598,329	5.359	6.2656
2048	0	0	346,032	90,494	0	-436,526	-33,728	-6,363,534	-241,787	-6,605,322	5.259	6.2656
2049	0	0	336,223	92,198	0	-428,421	-30,767	-6,394,301	-217,642	-6,611,943	5.162	6.2656
2050	0	0	326,524	93,933	0	-420,457	-28,065	-6,422,366	-195,847	-6,618,213	5.066	6.2656
2051	0	0	316,925	95,701	0	-412,626	-25,599	-6,447,965	-176,185	-6,624,150	4.971	6.2656
2052	0	0	307,419	97,503	0	-404,921	-23,349	-6,471,314	-158,458	-6,629,772	4.879	6.2656
2053	208,038	0	318,913	99,338	0	-418,251	-22,416	-6,493,730	-141,366	-6,635,096	5.039	6.2656
2054	0	0	310,994	101,208	0	-412,202	-20,533	-6,514,263	-125,874	-6,640,138	4.966	6.2656
2055	0	0	301,060	103,113	0	-404,173	-18,713	-6,532,976	-111,935	-6,644,912	4.870	6.2656
2056	0	0	291,225	105,053	0	-396,278	-17,053	-6,550,030	-99,403	-6,649,433	4.774	6.2656
2057	0	0	281,481	107,031	0	-388,512	-15,540	-6,565,569	-88,144	-6,653,714	4.681	6.2656
2058	0	0	271,821	109,045	0	-380,866	-14,159	-6,579,728	-78,039	-6,657,767	4.589	6.2656
2059	0	0	262,238	111,098	0	-373,335	-12,900	-6,592,628	-68,978	-6,661,606	4.498	6.2656
2060	0	0	252,725	113,189	0	-365,914	-11,752	-6,604,380	-60,861	-6,665,241	4.409	6.2656
2061	0	0	243,278	115,320	0	-358,598	-10,704	-6,615,084	-53,599	-6,668,684	4.320	6.2656
2062	0	0	233,891	117,490	0	-351,381	-9,749	-6,624,833	-47,110	-6,671,943	4.234	6.2656
2063	0	0	224,559	119,702	0	-344,261	-8,878	-6,633,711	-41,319	-6,675,030	4.148	6.2656
2064	0	0	215,278	121,955	0	-337,233	-8,083	-6,641,794	-36,160	-6,677,953	4.063	6.2656

Feasibility Analysis

Major Inputs and Assumptions

Specific assumptions include:

Income Tax: Income tax expense reflects a statutory income tax rate of 29%.

Operating Costs: Operating costs were assumed to be in 2013 dollars escalated yearly using the GDP Deflator for Canada.

Average Incremental Cost of Capital:

	Capital Structure	Return	Weighted Cost
Debt	55.00%	6.606%	3.63%
Common Equity	45.00%	8.800%	3.96%
Total	**100.00%**		**7.59%**

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.

Escalation Factors: Conference Board of Canada GDP deflator, November 16, 2012.

Appendix C
Heart's Content Hydro Plant
Switchgear Arc Flash Study

ELECTRICAL ENGINEERING

ARC FLASH HAZARD STUDY

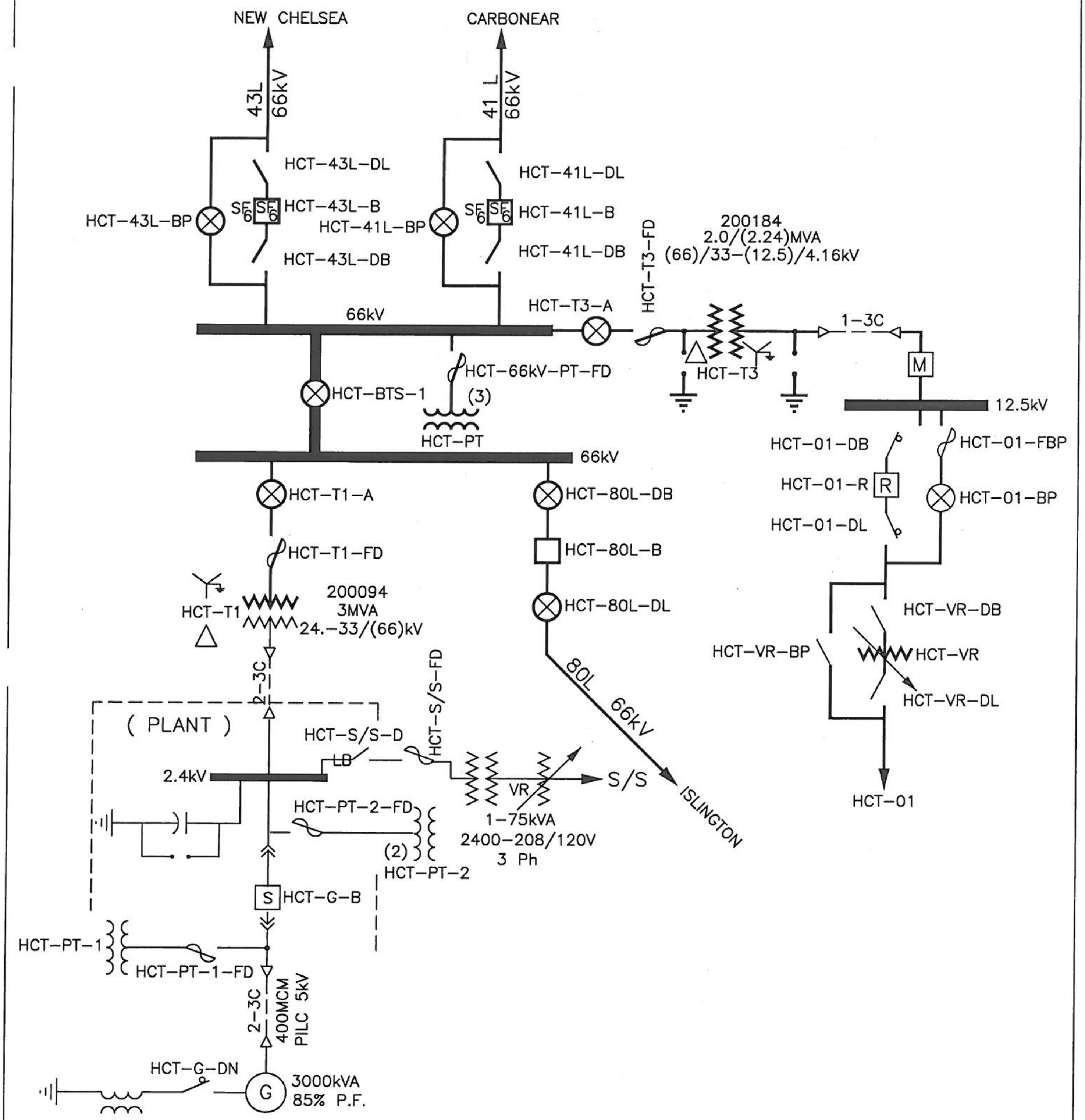
Company Area:	Avalon		
Switchgear Included:	HCT 2.4 kV		
Prepared by:	D Jones	**Date:**	3/7/2006

REASON FOR ARC FLASH HAZARD STUDY

Arc Flash Hazard calculations to be done for all Metal Clad Switrchgear.

POINTS TO NOTE

1. PPE level class 4 at 16 inches (working inside switchgear).
2. PPE level class 3 at 36 inches (racking out breaker).



REGISTERED PROFESSIONAL ENGINEER G. Richard Spurrell SIGNATURE 2006-01-30 DATE PROVINCE OF NEWFOUNDLAND	SINGLE LINE DIAGRAM	NEWFOUNDLAND POWER
PROVINCE OF NEWFOUNDLAND PERMIT HOLDER This Permit Allows NEWFOUNDLAND POWER INC. To practice Professional Engineering in Newfoundland and Labrador. Permit No. as issued by APEGN G0057 which is valid for the year 2006.	HEART'S CONTENT (HCT)	
	Date: 2006-01-30	Page 1 Of 1
	App: / Drawn: FWA	SLD No. 2-913

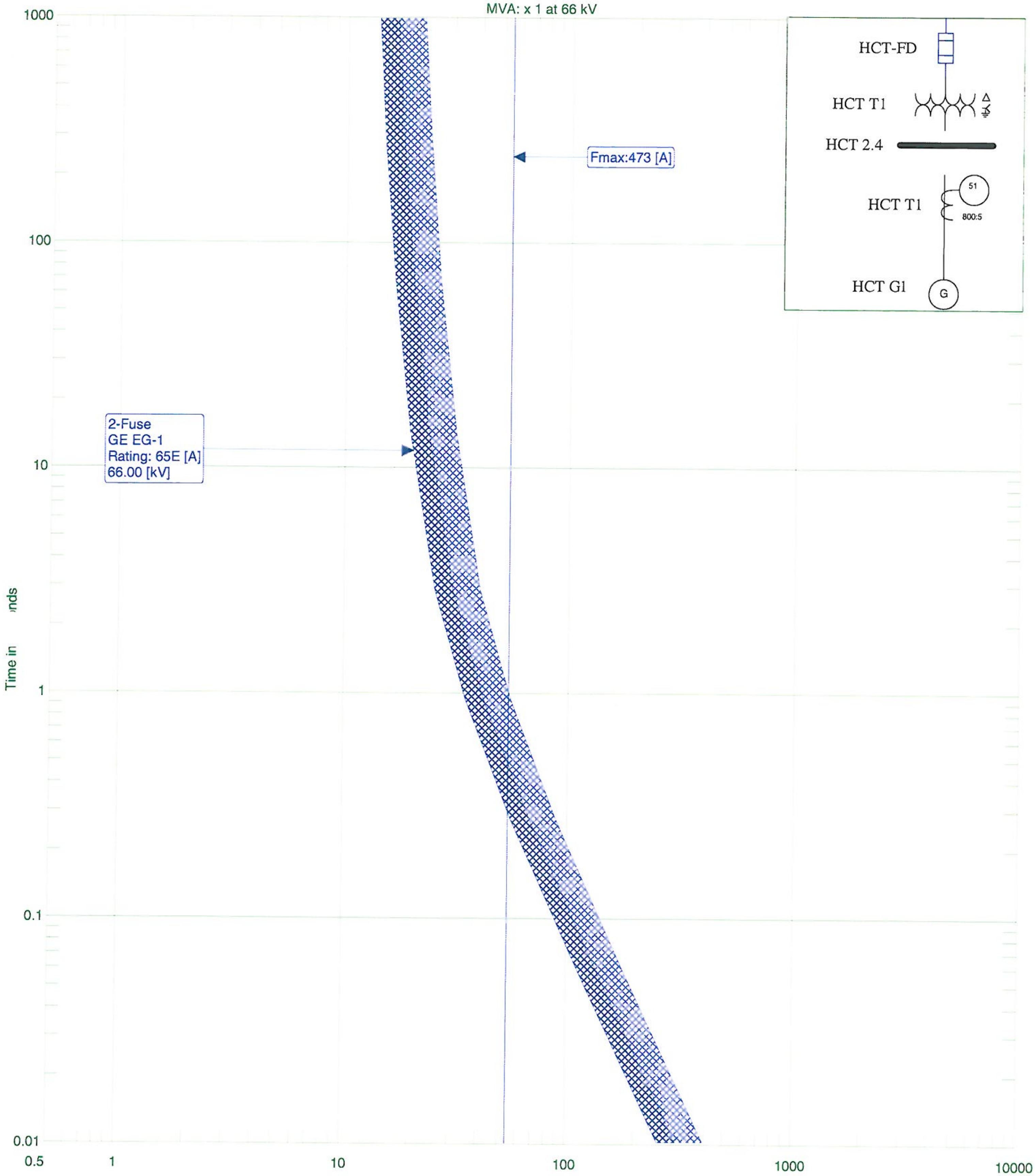
Maximum Generation Faullt HCT 2.4 kV.

ID	Type	Prefault kV	Angle	Fault type	Fault S [MVA]	Ia [A]	Ia [deg]	Ib [A]	Ib [deg]	Ic [A]	Ic [deg]	In [A]	In [deg]
Faulted Bus ->													
HCT 02		2.4	0	LLL	54	13013.7875	-84.2433	13013.7874	155.7567	13013.7874	35.7567	0	0
First Ring Contributions													
HCT G1	Generator	2.4	0	LLL	14	3281.2738	-90	3281.2738	150	3281.2738	30	0	0
HCT T1	Fixed-Tap Xmer	2.4	0	LLL	41	9754.0187	-82.3095	9754.0187	157.6905	9754.0187	37.6905	0	0

Current Multiplier for CYMTCC HCT FD

= 54 MVA / 41 MVA

Current Multiplier = 1.32



For LLL HCT 2.4 kV fault at Maximum Generation. HCT-FD maximum melting time 1.0158 seconds. with existing General Electric GE EG-1 65E fuse.

Dave Jones

March 07, 2006

Study: C:\Arc Flash\Plants\HCT\HCT T1 Fuse Max Gen LLL.tcc

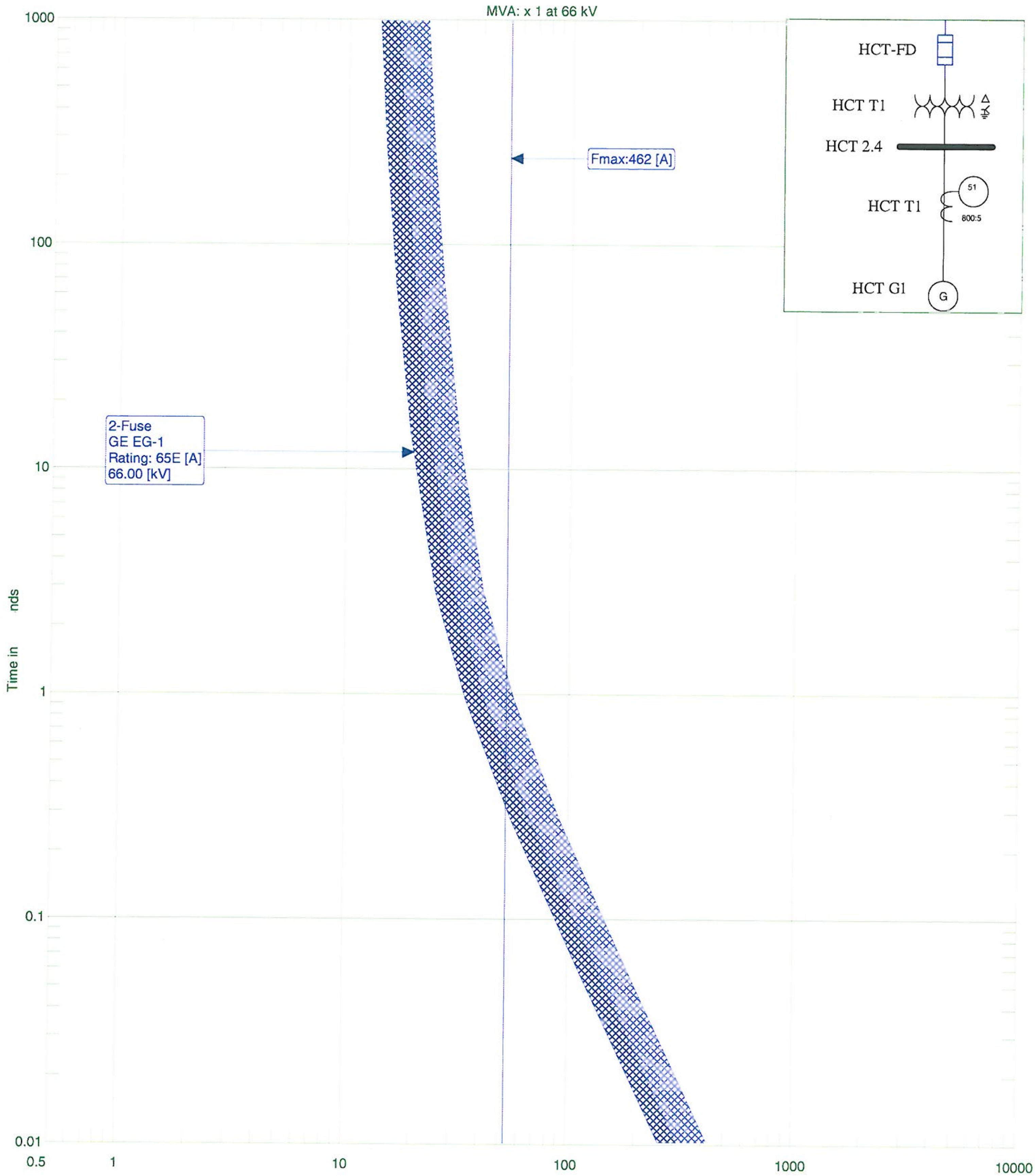
Minimum Generation Faullt HCT 2.4 kV. HCt plant on.

ID	Type	Prefault kV	Angle	Fault type	Fault S [MVA]	Ia [A]	Ia [deg]	Ib [A]	Ib [deg]	Ic [A]	Ic [deg]	In [A]	In [deg]
Faulted Bus ->													
HCT 02		2.4	0	LLL	53	12698.2652	-84.2038	12698.2652	155.7962	12698.2652	35.7962	0	0
First Ring Contributions													
HCT T1	Fixed-Tap Xmer	2.4	0	LLL	39	9438.9161	-82.1912	9438.9161	157.8088	9438.9161	37.8088	0	0
HCT G1	Generator	2.4	0	LLL	14	3281.2738	-90	3281.2738	150	3281.2738	30	0	0

Current Multiplier for CYMTCC HCT FD

= 53 MVA / 39 MVA

Current Multiplier = 1.36



For LLL HCT 2.4 kV fault at Minimum Generation. HCT-FD maximum melting time 1.2264 seconds. with existing General Electric GE EG-1 65E fuse.

Dave Jones

March 07, 2006

Study: C:\Arc Flash\Plants\HCT\HCT T1 Fuse Min Gen LLL.tcc

Arc Flash Hazard HCT 2.4 kV.
IEEE standard

Faulted Bus	Generation	Fault	Fault Current	CT	CT Plus Fuse	Working Distance	Flash Hazard Boundry	cal / cm2	PPE Level	L.A.B.	R.A.B.	P.A.B.
HCT 2.4	Max	LLL	13014	1.0158	1.0158	16"	466"	32.7	4	60"	26"	7"
HCT 2.4	Min	LLL	12698	1.2264	1.2264	16"	551"	38.4	4	60"	26"	7"

Faulted Bus	Generation	Fault	Fault Current	CT	CT Plus Breaker	Working Distance	Flash Hazard Boundry	cal / cm2	PPE Level	L.A.B.	R.A.B.	P.A.B.
HCT 2.4	Max	LLL	13014	1.0158	1.0158	36"	466"	14.8	3	60"	26"	7"
HCT 2.4	Min	LLL	12698	1.2264	1.2264	36"	551"	17.5	3	60"	26"	7"

***Arc Flash Calculated for Switchgear and fixed conductor.**
PSAF Software won't supply Arc Flash results for clearing times over one second.
Arc Flash calculations for clearing times over one second obtained from IEEE calculator on the internet.

L.A.B. Limited Approach Boundry
R.A.B. Restricted Approach Boundry
P.A.B. Prohibited Approach Boundry

IEEE 1584 Based Arc Flash Calculator

Equipment Class: Switchgear

Gap between Conductors: 104 mm.

Grounding Type: Grounded

Working Distance: 406.4 mm.

Available 3 Phase Bolted Current: 13.014 kA

System Voltage: 2400 Volt

☑ I agree to be bound with Terms & Conditions of this website.

Calculate Boundaries

Equipment Type: Switchgear

Typical Gap bw. Electrodes: 104mm.

Grounding: Grounded

Work Distance: 406.4 mm.

Arc Duration @ Predicted Arcing Current: 1.0158 sec.

Arc Duration @ 15% Reduced Arc Current : 1.0158 sec.

Available 3Ø Bolted Current: 13.014 kA

Predicted 3Ø Arcing Current: 12570 A

System Voltage L-L: 2400 Volt

Calculation Mode	Incident Energy Exposure (cal/cm ^{2})	Flash Protection Boundary (feet)	Level of PPE
@ 100% Arcing Current	32.66	38.85	4
@ 85% Arcing Current	27.40	32.43	4

IEEE 1584 Based Arc Flash Calculator

Equipment Class	Switchgear	
Gap between Conductors	104	mm.
Grounding Type	Grounded	
Working Distance	406.4	mm.
Available 3 Phase Bolted Current	12.698	kA
System Voltage	2400	Volt

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Calculate Boundaries

Equipment Type:	Switchgear
Typical Gap bw. Electrodes:	104mm.
Grounding:	Grounded
Work Distance:	406.4 mm.
Arc Duration @ Predicted Arcing Current:	1.2264 sec.
Arc Duration @ 15% Reduced Arc Current :	1.2264 sec.
Available 3Ø Bolted Current:	12.698 kA
Predicted 3Ø Arcing Current:	12270 A
System Voltage L-L:	2400 Volt

Calculation Mode	Incident Energy Exposure (cal/cm^2)	Flash Protection Boundary (feet)	Level of PPE
@ 100% Arcing Current	38.41	45.90	4
@ 85% Arcing Current	32.22	38.32	4

IEEE 1584 Based Arc Flash Calculator

Equipment Class: Switchgear

Gap between Conductors: 104 mm.

Grounding Type: Grounded

Working Distance: 914.4 mm.

Available 3 Phase Bolted Current: 13.014 kA

System Voltage: 2400 Volt

☑ I agree to be bound with Terms & Conditions of this website.

Calculate Boundaries

Equipment Type: Switchgear

Typical Gap bw. Electrodes: 104mm.

Grounding: Grounded

Work Distance: 914.4 mm.

Arc Duration @ Predicted Arcing Current: 1.0158 sec.

Arc Duration @ 15% Reduced Arc Current : 1.0158 sec.

Available 3Ø Bolted Current: 13.014 kA

Predicted 3Ø Arcing Current: 12570 A

System Voltage L-L: 2400 Volt

Calculation Mode	Incident Energy Exposure (cal/cm ^{2})	Flash Protection Boundary (feet)	Level of PPE
@ 100% Arcing Current	14.84	38.85	3
@ 85% Arcing Current	12.45	32.43	3

IEEE 1584 Based Arc Flash Calculator

Equipment Class	Switchgear	
Gap between Conductors	104	mm.
Grounding Type	Grounded	
Working Distance	914.4	mm.
Available 3 Phase Bolted Current	12.698	kA
System Voltage	2400	Volt

☑ I agree to be bound with Terms & Conditions of this website.

Calculate Boundaries

Equipment Type:	Switchgear
Typical Gap bw. Electrodes:	104mm.
Grounding:	Grounded
Work Distance:	914.4 mm.
Arc Duration @ Predicted Arcing Current:	1.2264 sec.
Arc Duration @ 15% Reduced Arc Current :	1.2264 sec.
Available 3Ø Bolted Current:	12.698 kA
Predicted 3Ø Arcing Current:	12270 A
System Voltage L-L:	2400 Volt

Calculation Mode	Incident Energy Exposure (cal/cm^2)	Flash Protection Boundary (feet)	Level of PPE
@ 100% Arcing Current	17.45	45.90	3
@ 85% Arcing Current	14.64	38.32	3

Lockston Hydro Plant Refurbishment
June 2011

Lockston Hydro Plant

Refurbishment

June 2011

Prepared by:

Jeremy Decker, P.Eng.
Shaun Marshall, P.Eng.

REGISTERED PROFESSIONAL ENGINEER
Jeremy B. Decker
SIGNATURE
2011 06 23
DATE
NEWFOUNDLAND & LABRADOR

NEWFOUNDLAND POWER
A FORTIS COMPANY

Table of Contents

1.0 Background

The Lockston hydroelectric generating plant ("the Plant"), located on the Bonavista Peninsula of eastern Newfoundland near the town of Port Rexton, was commissioned in 1956 with a capacity of 1.5 MW under a net head of approximately 80 m. The plant originally contained a single horizontal 2,000 hp Francis turbine manufactured by Gilkes and a Canadian General Electric generator. The plant capacity was increased to 3.0 MW in 1962 with the addition of a second identical unit.

The original unit was labelled as G2 even though it was the first unit installed in 1956. The second unit installed in 1962 was labelled as G1.

The Plant is connected to the Island interconnected electrical system at Lockston substation. There have been a number of upgrades to the original plant and equipment. The following is a list of the upgrades that have been completed in the past 25 years:

2009 – Battery bank, battery charger and revenue meter replaced
2007 – Vibration monitoring added
2003 – Penstock replaced
2003 – G1 Runner, governor and wicket gates refurbished
2003 – Fisheries compensation valve added
2001 – G2 runner refurbished and main valve repaired
1999 – Bypass valves replaced
1992 – Water level indication upgraded
1991 – Louver and exhaust fan replaced
1989 – G2 Overhauled
1988 – G1 Overhauled
1986 – Capacitors Replaced

This report provides a summary of the engineering assessment of the Lockston hydroelectric plant and the refurbishment proposed for 2012.[1]

2.0 General

The Plant has a capacity of 3.0 MW and an annual production of 8.1 GWhr of energy. This amount of energy production could be provided by only one of the two generators. As a result Newfoundland Power ("the Company") has determined that only unit G1 will be fully automated with a new digital governor and water management system.[2] Unit G2 will be refurbished to the extent necessary to provide reliable peaking capacity and to operate at base load during periods of high inflows and when operating isolated from the grid.

[1] This assessment is based upon a mechanical site inspection completed by Shaun Marshall P. Eng. on February 18, 2011; an electrical site inspection completed by Jeremy Decker P. Eng. and John Pardy P. Eng. on March 3, 2011 and detailed plant equipment assessment reports completed by John Budgell on October 31, 2007.

[2] Newfoundland Power has two other hydro plants where the extent of automation is different between generators. Both Petty Harbour and Tors Cove plants have 2 generators fully automated with programmable logic controller based water management systems and 1 generator operated manually.

3.0 Governors

The governors consist of two sections, the power piston and the control head. The power piston provides the force necessary to operate the wicket gates under load. The control head adjusts the position of the power piston to maintain system frequency through varying load conditions.

The governor bases, power pistons and Giljet operating mechanisms are the original Gilkes units. The control heads and hydraulic pressure units were replaced with Woodward hydraulic retrofits in 1980.

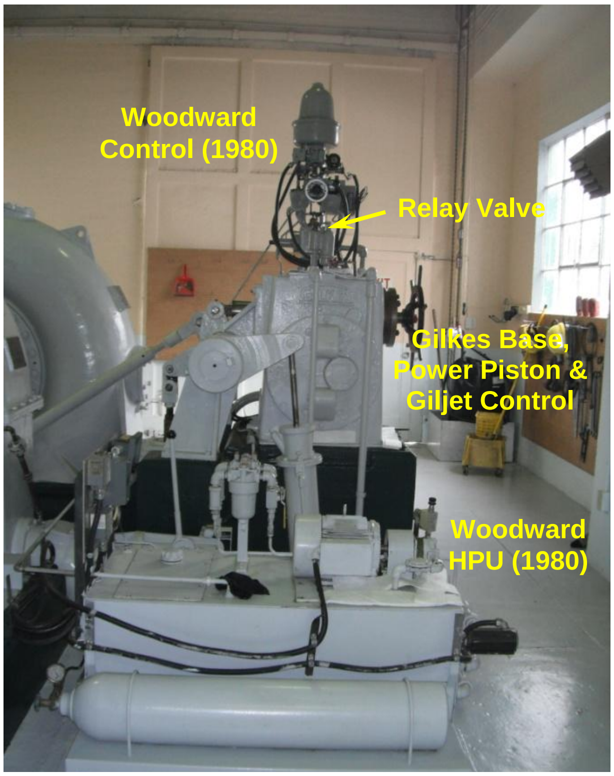


Figure 1 - Gilkes/Woodward Governor

The G1 governor was refurbished in 2003. The original equipment manufacturer discontinued supplying replacement parts for these units as of July 1, 2008. Due to its robust design with no parts exposed to excessive wear, the hydraulic power portion of the governor will remain serviceable for many years.[3]

The governor speed control and gate limit are motorized and can be operated remotely using electromechanical relay logic to control the load on the unit. There is no feedback of gate position or limit for unit control or remote indication.

More advanced control of the governor setpoints is required to implement a water management system in the unit control programmable logic controller (PLC). This will optimize energy production from the available water, increasing the energy output of the plant.

The control head, above the relay valve, will be replaced with a PLC based digital control system. The relay valve, which initiates the movement of the power piston, will be inspected and overhauled as required. The fly ball governor head, pilot valve assembly and mechanical restoring linkages will be removed. The new governor control system will interface with the unit control PLC and will facilitate the implementation of a water management system.

The existing hydraulic power piston assembly, hand wheel and gate operating linkages will be retained. All seals, bushings and other components will be inspected and upgraded as required. This will eliminate leakage and extend the life of the power piston assemblies.

The existing G2 governor will not be upgraded. This unit will operate manually at base load only at times of high water inflows and during periods of time when peak capacity is required.

[3] Recent plant refurbishment projects have replaced the hydraulic control portion of these governors with digital systems that provide enhanced control and feedback capabilities.

As these situations arise infrequently it would be more cost effective to manually operate this generator than to incur the expense of fully automating this unit.

4.0 Generators

The generator G1stator and rotor windings are original to the 1962 installation and have reached the average age at which Newfoundland Power has had to complete rewinds of 6,900 volt generator stators. The rotor was cleaned and painted in 2003. Megger readings taken at the time showed low resistance to ground. The poles were isolated and it was determined that one pole contained a short to ground. Attempts to remove the pole were unsuccessful so the unit was returned to service with the grounded pole. If a second ground were to develop on the rotor, a potentially damaging short circuit would occur. It is recommended to rewind the stator and reinsulate the rotor during the refurbishment project. Temperature signals from the resistance temperature detectors ("RTDs") that will be installed in the new stator windings will be monitored by the new control system.

The generator neutral is low impedance connected to ground. This method of grounding does not provide adequate protection of the generator windings as it permits high ground fault currents to flow. To minimize the magnitude of fault currents, high impedance grounding is the preferred method of generator neutral connection. A neutral grounding transformer with secondary resistor will be installed to provide this protection.

Generators are shut down when there is inadequate water available for production. This usually occurs during the summer and early fall when humidity is high. As a result, moisture accumulation on the stator windings compromises the winding insulation. Energizing the generator with moisture present could result in an electrical flashover and permanent winding damage. A MegAlert® stator insulation testing system will be installed to provide a warning and prompt corrective action when the insulation value is reduced. It will also prevent re-energizing the generator should the insulation value fall below a safe value. It will continuously monitor the integrity of the insulation while the unit is shut down, ensuring it can be re-energized when required. To enable the testing to be completed, the insulation testing system must include a neutral contactor to automatically disconnect the stator windings from ground when the generator shuts down.

The surge protection, which consists of surge capacitors only, is located in the pit under the generator. The surge capacitors, which were installed in 1986, will be replaced with two-bushing units to facilitate the operation of the MegAlert® insulation tester. To ensure the surge protection system can adequately protect the generator windings from electric system surges, intermediate class MOV type surge arrestors will be added.

The three generator protection neutral current transformers and ground current transformer, located in the generator pit, are the original units. The ground CT will be eliminated since this sensing will be provided by the neutral grounding transformer. The neutral CTs, which provide the critical sensing for all the generator protection elements, will be replaced.

The generator G2 stator and rotor windings are original to the 1956 installation but are in good condition and testing has not indicated any significant deterioration of the insulation. Although the age of the windings would make them candidates for rewinding, since the unit will be operated infrequently and an in service failure would not result in any loss of energy production, they will not be rewound during this project. Due to the minimal exposure to fault conditions the existing grounding system, surge protection, neutral CT and ground CTs will not be replaced and a MegAlert® insulation tester will not be installed.

5.0 Excitation Systems

The G1 exciter is the original unit supplied with the General Electric generator in 1962. Although it is in relatively good condition, its age dictates that it should be rewound in conjunction with the generator stator rewind. Infrared brush temperature sensors will be added to the commutator and slip rings.

The G2 exciter is also the original unit supplied with the General Electric generator in 1956. It is in relatively good condition and for the same reasons outlined above for the generator windings, it will not be rewound as part of this project.

The voltage regulators are the original Brown Boveri Model AB2/1 with mechanical operating mechanisms. They have been discontinued for many years. They cannot be integrated into the upgraded control system to accomplish the required automated control. The voltage regulators will be replaced with digital voltage regulators incorporated into the Combination Generator Control Modules (CGCM) located in the unit control panel. The CGCM is designed to be easily integrated into the control system and provide improved voltage regulation under varying system conditions.

The field breakers for both units, which are located in the switchgear, are the original General Electric Model AKF-1 and are beyond their expected service life. They are no longer supported by the original manufacturer, making it very expensive to overhaul and maintain. New field breakers will be installed for both generators, located in cabinets on the upstream wall of the powerhouse. The power cables between the exciter and the rotor will also be replaced.

6.0 Switchgear

The generator breakers, station service breaker, forebay line breaker, potential transformers (PTs) and current transformers (CTs) are integral to the switchgear and are original to the 1956 and 1962 installations. Concerns of failure exist because of the age and deteriorated condition of this equipment. The existing General Electric Type PL-7.5-100 oil blast breakers do not operate dependably, are at the end of their service life and must be replaced. The PTs and CTs must also be replaced.[4]

The protective relays and control switches are incorporated into the switchgear doors, which greatly increase arc flash hazards for personnel operating these switches. The high voltage compartments in the front of the switchgear are vented through the bottom of the doors. In the event of an internal fault, the electric arc and hot gases would exit the switchgear directly towards personnel who may be standing in front of the door operating the control switches. Figure 2 shows the control switches for the station service and transformer T1 breakers

4 Circuit breakers, PTs and CTs are all critical to electrical protection of the generators, and an in-service failure of these components could result in serious damage to the generator windings.

switchgear cubicles, and the proximity of these cubicles to other equipment operated by employees.

Figure 2 - Switchgear and Control Panels

The existing five-breaker switchgear line-up will be replaced with an arc flash rated assembly with three vacuum breakers, which requires minimum maintenance. As outlined below the normal station service will be relocated to the substation and the station service breaker will not be required. The forebay power line will be connected to the overhead section of the 6.9 kV line from the substation to the switchgear and the forebay line breaker will not be required. Higher accuracy instrument transformers for improved protection and metering will be supplied with the switchgear. The control switches and associated wiring will be relocated to a new unit control panel remote from the switchgear and outside the arc flash zone of influence, providing increased employee safety. A 120/208 V three phase emergency station service transformer will be incorporated into the new switchgear to enable the plant to be black started and carry isolated load in the event of a system power interruption.

As a result of the fault energy levels at this location there is a high arc flash hazard associated with this switchgear requiring an arc flash boundary of 3 metres.[5] To provide protection from this hazard, walls will be constructed to separate the switchgear from the control room and the generator gallery.

The installation of the new switchgear in an extension to the building will necessitate reconfiguration of the power cables to the generators and to the power transformer. The cables and terminations are beyond their life expectancy and will be replaced. A new underground termination pole will be installed just outside the building extension and a conduit installed from the termination pole to the switchgear. The overhead line from the termination pole to the unit transformers in the substation will be relocated and upgraded.

7.0 AC Distribution System

The station service transformer bank is mounted on a pole on LOK-01 feeder but supplied from the switchgear in the powerhouse. There is a power cable from the switchgear to the insulated connectors embedded in the powerhouse wall and a span of open wire from there to the transformer pole. A service drop is then run from the transformer bank back to the powerhouse.

[5] An arc flash study for the Lockston switchgear is included as Appendix B.

Figure 3 – Station Service Transformers

Figure 4 – AC Panels & Meter

The transformer bank consists of two single phase 120/240 V transformers connected in a nonstandard open delta configuration. It will be replaced with a new transformer bank located in the substation. The existing single phase substation station service transformer connected to the 12.5 kV bus will be replaced with a three phase 120/208 V wye connect transformer bank. The service drop will be run overhead from the substation to the powerhouse.

The two existing AC panels have been loaded to capacity. All the circuits in the 42-circuit, 225 A AC panel have been used and a 24-circuit, 125 A panel, which is connected to a 40A breaker in the 225 A panel, has been added. There is only one spare single pole circuit in this panel.

The service entrance will be replaced and a new 600A switchboard installed that will be supplied from the new transformer bank in the substation. A standard 60-circuit 120/208V Non-Essential Services panel will be connected to the switchboard. A 60-circuit 120/208V Essential Services panel will also be installed. It will connect to an automatic transfer switch that will normally supply the panel from the switchboard but will transfer to the emergency station service transformer, located in the switchgear, during a black start.

8.0 DC System

The existing GNB Exide gel-cell battery bank and the temperature compensated C-Can battery charger were installed in 2009 and will be relocated to accommodate the new switchgear. The 22-circuit DC distribution panel was installed in 1980 and breakers are no longer readily available. A new 60-circuit panel will be installed to ensure the availability of replacement circuit breakers.

9.0 Protective Relaying

The generator electrical protection is provided by CGE, GE and Westinghouse electromechanical relays. The following protective elements are in service:

40	Loss of Field
49	Thermal Protection
51GN	Ground Overcurrent
51V	Backup Protection – Voltage Controlled Overcurrent
87	Differential

The existing protective relaying at Lockston plant lacks five elements[6] of the minimum protection set. It will be replaced with digital relays to provide the minimum protection set. Improved generator protection reduces stresses due to electrical faults and in turn extends the life of the generator. Digital relays will also be installed for G2 since it is more cost effective than relocating the existing electromechanical relays from switchgear.

10.0 Plant Control

There is no programmable logic controller (PLC) at Lockston and the existing plant control utilizes relay-based logic. An Allan-Bradley CompactLogix® programmable logic controller will be installed to provide plant control, protection and automation.[7] It will provide local and remote control of the generator and plant functions. All Newfoundland Power standard control, protection and automation functionality will be implemented for generator G1 while only a minimal amount will be implemented for G2.

The plant is remotely monitored from the System Control Centre. The unit has remote control functions that are limited to start, stop and loading capability. At present, there is no automation with respect to water management and the setting of machine loads to optimize the use of the water resources. The installation of a PLC will provide processing power that will greatly improve the local and remote monitoring and control functionality. It will facilitate the implementation of a variety of control modes to ensure the efficient operation of the plant and utilization of available water.

The new unit control panel will contain the processor, associated monitoring and control equipment and control switches. The following equipment will be located there:

- AB CompactLogix® PLC
- Industrial Computer HMI with keyboard
- Ethernet Switch
- Combination Generator Control Module (CGCM)
- MegAlert® remote LED display and switch board meter
- Synchroscope
- Emergency stop pushbutton (latching)
- Start pushbutton
- Stop pushbutton

---

[6] The existing generator protection does not include Stator Unbalance 46, Overvoltage 59, Rotor Ground 64F, Frequency 81 and Sensitive Ground Fault 87GN protection elements, which are recommended by the IEEE for these generators.

[7] The Allan-Bradley CompactLogix® programmable logic controller will provide functionality similar to that provided by the ControLogix® programmable logic controller used in the upgrade of larger plants since 2004 but with scaled down processing power and capabilities better suited to smaller hydro plants..

- Alarm reset pushbutton
- Generator breaker control switch (ANSI device No. 52CS)
- Field breaker control switch (ANSI device No. 41CS)
- Speed raise/lower control switch (ANSI device No. 15CS)
- Gate limit control switch (ANSI device No. 65CS)
- Voltage raise/lower control switch (ANSI device No. 70CS)
- Automatic/manual synchronizing control switch (ANSI device No. 25CS)
- Generator lock out relay (ANSI Device No. 86G)
- Three position local/remote control switch (ANSI Device No. 43CS)

A new Gateway data concentrator will be installed to replace the existing RTU, improving communications to the SCADA system. This communications system in conjunction with the upgraded processor will enhance plant operations. It will provide additional information about the performance of key plant components. Improved communications infrastructure will also permit remote administration of the PLC and digital relays by head office engineering staff that would normally require a time consuming and costly site visit.

The Brown Boveri Synchrotact 2 auto-synchronizer, installed in 1980, is an electronic device that has been out of production since 1983. ABB still offers spare parts and repair service. This unit will not be reused, however, since the Combination Generator Control Module (CGCM), located in the unit control panel, provides synchronizing functionality that is integrated with the PLC. Both automatic and manual synchronizing will be supervised by the synchrocheck function provided in the generator multifunction protection relay. This will ensure unit speed and voltage are within acceptable limits before the generator breaker closure is permitted.

11.0 Instrumentation

The instrumentation has been upgraded over the past number of years with speed, bearing oil temperature and cooling water flow added in 1980 and vibration monitoring in 2007. Except for the speed switch on generator G1,all existing instrumentation will be maintained. The G1 speed switch will be removed and dual speed sensors installed on the existing toothgear to provide analog speed signals to the governor and unit control PLCs. The unit control PLC will perform the speed processing functions previously performed by the speed switch.

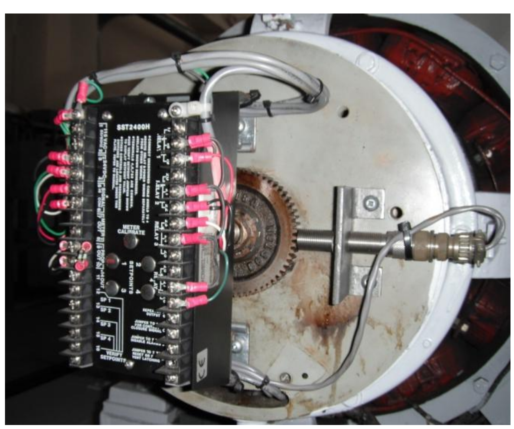


Figure 5 – Speed Switch, Sensor & Toothgear

The bearing oil temperature, cooling water monitoring and control and vibration sensors for both units will be integrated into the PLC.

Bearing temperature and bearing oil level will be added on G1and integrated into the PLC. Scroll case pressure sensors will be added to both units and integrated into the PLC.

The revenue meters on each unit were replaced with Schneider PowerLogic ION 7550 meters in 2009. One meter will be reused and the other will be returned to inventory.

12.0 Heating and Ventilation

The anti-condensation blower type heater in the generator G1 pit will be controlled by a humidistat located in the generator room. The existing G2 pit heater and control will not be replaced. The two exhaust fans located in the building that are in good condition. The louvers in the downstream side of the building do not close properly and will be upgraded.

The heat and ventilation controls will be consolidated into one plant control panel and integrated with the plant control PLC. Temperature and humidity sensors will be installed in the generator room. Addition blower heaters will be installed in the generator gallery.

13.0 Water Level Monitoring and Control

The forebay water level system is critical to the implementation of the Water Management System in the PLC. The water level probe was installed in 1992. The water level and trash rack signals are transmitted to the plant utilizing pulse modulated and hard wired signals over an 18 year old 6-pair copper communications cable which is susceptible to lightning damage. To eliminate legacy equipment with its inherent maintenance problems and to facilitate the use of more reliable technology, the water level probe will be replaced and the copper cable will be replaced with a fibre optic cable. The existing communications system will be upgraded to technology compatible with the new control system.

Figure 6 – Trinity Pond Gate

The plant PLC will use the water level signal to control the Water Management System. High level (spill) and low level alarms will also be initiated when specified levels are reached. The water level signal is presently obtained from the forebay, which is the level of the relatively small Rattling Pond storage reservoir. Water flows into Rattling Pond from the Trinity Pond, the primary storage reservoir, via a manually controlled gate. Automatic control of this gate is required to ensure the Water Management System can maximize energy production from the available water. This will require construction of a single phase power line from the tap to Lockston hilltop communications site, installation of a fibre optic cable from the forebay to the Trinity Pond Gate including poles from the forebay to the Lockston Hilltop tap, construction of a gatehouse, installation of a new gate with motor operator and de-icing system and installation of water level indication at Trinity Pond.

The Water Management System will optimize the efficiency of the plant by controlling the load on the unit based upon the following water level, inflow, wicket gate position and control mode setpoints:

Peak Water Level	Peak Gate Position
Low Inflow Peak Water Level	Efficient Gate Position
Efficient Water Level	Partial Gate Position
Low Inflow Efficient Water Level	Gate Position Deadband
Partial Water Level	Rate of Rise (Bump)
Low Inflow Partial Water Level	Elevation Mode Water Level
Shutdown Water Level	Elevation Mode Gate Shutdown Level
Low Inflow Shutdown Water Level	Load Control Mode Voltage Level
Water Level Deadband	Load Control Mode Kilowatt Level
Start-up Water Level	Load Control Mode Kilowatt Deadband

14.0 Cooling Water

Cooling water solenoids were added to both units in 2001. Some additional upgrading of the generator G1cooling water system and controls will be completed to permit integration into the new CompactLogix PLC. The generator G2 cooling water system will not be upgraded.

15.0 Turbines

In 1989, the G1 turbine runner was replaced with the spare unit, constructed of mild steel. After only fourteen years in service with G2 sharing operating time, refurbishment was necessary in 2003 due to excessive cavitation. During this refurbishment two new rotating seals were installed and machined. Major blade damage was repaired using bronze filler rods and minor blemishes were filled with Belzonia Super Glide ceramic coating. The draft tube elbow was not removed during the 2007 inspection so access to the runner was limited to the inspection ports on the low pressure side which revealed that most of the Belzona was eroded away, with blemishes exposed and cavitation evident (see Figure 7). The high pressure side and seal faces have not been inspected since 2003.

Figure 7 – 2007 Inspection of Low Pressure Side of G1 Runner showing Belzona Erosion and Cavitation

Index testing, performed by ACRES in 2003, determined the peak efficiency of unit G1 was 84.4%. This is considered low as compared to that expected of a modern runner design. To improve efficiency and minimize the operating cost associated with maintaining the existing mild steel runner, it will be replaced with a higher efficiency stainless steel unit. A replacement runner is expected to result in a peak unit efficiency of 87% with a resulting increase in energy production of 0.3 GWH annually. The stationary seals and downstream spool pieces that form part of the seal around the runner are eroding and will need to be replaced to ensure proper operation of the new runner.

The G1 turbine wicket gates, constructed of bronze, have also experienced erosion. Stainless steel wicket gates will be installed to minimize erosion to ensure continued reliability. The existing wicket gate bushings require manual lubrication. Self-lubricating bushings, which require no maintenance and are more environmentally friendly, will be installed with the new wicket gates.

The G1 Giljet is showing considerable leakage across the seats and will be refurbished.

The G2 turbine runner was refurbished in 2001 with extensive repairs to the runner blades filling the holes in the buckets with aluminum bronze rods and the minor blemishes with Belzona. The entire runner was then coated with a Belzona Super Glide ceramic coating. Two new 660 bronze rotating seals were installed and machined to give proper clearance. A spare stationary seal along with one original seal were repaired and installed in the turbine. An inspection in 2007 revealed that fifty percent of the Belzonia coating had been eroded away leaving minor blemishes exposed. The runner however is in relatively good condition with only minor cavitation on the low pressure side. The 2007 inspection determined that the G2 wicket gates were in good condition, clearances were set in 2001, and there was no evidence of corrosion or operational issues to indicate any problems with binding or gate leakage. The G2 giljet has considerable leakage around the seat with only minimal pressure on the spear. The entrance grating into the G2 giljet has also deteriorated. With the minimal running time of generator G2 after completion of this project, it is expected that the existing turbine runner, wicket gates and G2 giljet will be serviceable for many years and will not be upgraded.

16.0 Main Inlet Valves

The G1 main inlet valve is a 27-inch gate valve and is original equipment that is 49 years old. The valve was installed for manual operation and was motorized in 1980. An internal assessment of the valve was not completed during the 2007 inspection, however, it is evident from the constant flow of water when the valve is closed, that it is not sealing properly. When the unit is shut down, this leakage around the valve builds up in the scroll case. Safe access to the scroll case without dewatering the penstock cannot be achieved. This situation limits the ability to safely maintain and service other plant equipment.

Both the valve seats and discs have been overhauled in the past which requires dewatering the penstock and installing a bulkhead. These components are prone to wear due to the brass construction. Current practice is to install a butterfly valve instead of a gate valve, reducing head losses and increasing reliability.

Based upon the age and condition, the G1 main valve and actuator will be replaced. In addition, a bypass valve and dismantling joint will be incorporated into the redesigned arrangement.

The G2 main inlet valve is also a 27-inch gate valve and is original equipment that is 55 years old. It was repaired in 1999 replacing the stationary seats and the gate stem guide and nut. Similar to G1 main valve, there is a minor leak in the disk seat but the valve otherwise is in relatively good condition. The bypass valve was replaced in 2001 and is in good condition. With the minimal running time of generator G2 after completion of this project, it is expected that the existing valves will be serviceable for many years and will not be upgraded.

17.0 Project Cost

The total project cost is estimated at $3,451,000. Table 1 below provides the cost breakdown by cost category.

Table 1
Projected Expenditures

Cost Category	Estimated Cost
Material	$2,784,000
Labour - Internal	$280,000
Labour - Contract	
Engineering	$190,000
Other	$197,000
Total	**$3,451,000**

18.0 Summary of Work

The following is a summary of the work proposed to be completed during the 2012 refurbishment project.

Common Equipment

- Construct a switchgear room
- Replace the switchgear with an arc flash rated assembly complete with breaker, potential transformers, current transformers and emergency station service transformer
- Replace power cables from switchgear to generators
- Install underground termination pole near the extension to the plant, relocate and upgrade overhead line from termination pole to substation and install new power cable from termination pole to switchgear
- Remove the existing station service transformer bank and install a new bank in the substation
- Replace the two AC panels with a non-essential distribution panel, an essential services distribution panel and an automatic transfer switch
- Replace the DC distribution panel
- Replace the 110L, transformer protection and bus differential protective relays
- Install a programmable logic controller system that will monitor and control plant functions and the unit G1 with minimal monitoring and control of G2
- Install a Gateway data concentrator to communicate with SCADA and provide remote administration of the new equipment
- Modify the plant heating and ventilation system and upgraded controls
- Replace forebay communications cable and communications equipment
- Replace forebay water level probe
- Replace Trinity Pond gate and install automatic control

Unit G1

- Replace the G1 auto-synchronizers
- Replace the G1 voltage regulators
- Replace the G1 field breaker and power cables
- Install programmable logic controller based digital control systems to replace the hydraulic control portion of the governor
- Replace G1 generator protective relaying
- Complete mechanical modifications to G1 governor
- Rewind the G1 generator stator and reinsulate the rotor windings
- Replace G1 surge capacitors and add surge arresters
- Replace the G1 generator neutral current transformers
- Rewind the G1exciter
- Install infrared brush temperature sensors on G1
- Install neutral grounding transformer and resistor on G1
- Install automatic stator insulation testing system on G1
- Upgrade the G1speed sensing
- Add bearing temperature and bearing oil level sensors to G1
- Upgrade G1 cooling water system

- Implement a water management system in the plant programmable logic controller including upgraded communications to the forebay
- Replace G1 turbine runner and wicket gates
- Replace G1turbine wear ring and downstream spool piece
- Replace G1main inlet valve and actuator
- Upgrade the G1 bearing vibration system
- Add scroll case pressure sensors to G1

Unit G2

- Replace the G2 auto-synchronizers
- Replace G2 voltage regulators
- Replace the G2 field breaker and power cables
- Replace G2 generator protective relaying
- Upgrade the G2 bearing vibration system
- Add scroll case pressure sensors to G2

19.0 Economic Feasibility

Appendix A provides an economic feasibility analysis for the continued operation of the Plant. The results of the analysis show that the continued operation of the Plant is economical over the long term. Investing in the life extension of the Plant, including a high efficiency turbine runner, ensures the availability of 8.1 GWh of energy to the Island Interconnected electrical system.

The estimated levelized cost of energy from the Plant over the next 50 years, including the capital expenditure of $4,421,000 over the next 25 years, is 5.924 cents per kWh. This energy is lower in cost than replacement energy from sources such as new hydroelectric developments or additional Holyrood thermal generation[8].

[8] The cost of electricity from the Holyrood thermal generating plant is estimated at 16.37 ¢/kWh. This is based upon a 630 kWh/barrel conversion efficiency and oil price forecast from Hydro of $103.10/barrel for 2011 as per Newfoundland Hydro letter regarding Rate Stabilization plan – Fuel Price Projection dated April 14, 2011.

Appendix A
Feasibility Analysis

Table of Contents

Page

1.0 Introduction

This feasibility analysis examines the future viability of generation at Newfoundland Power's Lockston hydroelectric plant (the "Plant"). The continued long-term operation of the Plant is reliant on the completion of capital improvements in 2012.

With investment required in 2012 to permit the continued reliable operation of the 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 Plant over the next 25 years have been identified. The capital expenditures required to maintain the safe and reliable operation of the facilities are summarized in Table 1.

Table 1
Lockston Hydroelectric Plant
Capital Expenditures

Year	**($000s)**
2012	3,451
2017	235
2020	200
2024	20
2029	8
2032	565
2037	142
Total	**4,621**

The estimated capital expenditure for the Plant over the next 25 years is $4,621,000. A more comprehensive breakdown of capital costs is provided in Attachment A.

3.0 Operating Costs

Operating costs for the Plant are estimated to be approximately $92,699[1] per year. This estimate is based primarily upon recent historical operating experience. The operating cost represents both direct charges for operations and maintenance at the Plant as well as indirect costs such as those related to managing the environment, safety, dam safety inspections and staff training. A summary of operating costs is provided in Attachment B.

[1] 2011 dollars

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 based on yearly hydro plant generation/output.

4.0 Benefits

The maximum output from the Plant with only generator G1 is 1.7 MW. The Plant normally operates at an efficient load of 1.5 MW to maximize the energy from the water.

The estimated long-term normal production of the Plant with generator G1 under present operating conditions is 8.1 GWh per year. The estimated long-term normal production at the Plant with generator G1 equipped with a high efficiency turbine runner is 8.4 GWh per year.

5.0 Financial Analysis

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

The estimated levelized cost of energy from the Plant over the next 50 years is 5.924 cents per kWh. This figure includes all projected capital and operating costs necessary to operate and maintain the facility. Energy from Lockston 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.[2]

The future capacity benefits of the continued availability of the 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.

6.0 Concluding

The results indicate that continued operation of the Plant is economically viable. Investing in the current upgrades of the facilities at Lockston guarantees the availability of low cost energy to the Province. Otherwise, the annual production of 8.4 GWh would be replaced by more expensive energy sources such as new generation or additional production from the Holyrood thermal generating station. The project will benefit the Company and its customers by providing least cost, reliable energy for years to come.

[2] The cost of electricity from the Holyrood thermal generating plant is estimated at 16.37 ¢/kWh. This is based upon a 630 kWh/barrel conversion efficiency and oil price forecast from Hydro of $103.10/barrel for 2011 as per Newfoundland Hydro letter regarding Rate Stabilization plan – Fuel Price Projection dated April 14, 2011.

Attachment A
Summary of Capital Costs

Lockston Feasibility Analysis
Summary of Capital Costs
($000s)

Description	2012	2017	2020	2024	2029	2032	2037
Civil							
Dam, Spillways and Control Structures			200				
Penstock		235				235	
Powerhouse							
Mechanical							
Turbine Upgrades	525						
Governor Upgrades						30	
Main Inlet and Bypass Valves	363						
Bearings							
Cooling Water							80
Heat and Ventilation							50
Compressed Air							12
Giljet							
Electrical							
P&C and Governor Controls	1,264					300	
Generator Rewind	350						
Remote Control Trinity Pond Gate	250						
Exciter							
Switchgear	699						
AC & DC Systems				20	8		
Annual Totals ($2012)	**3,451**	**235**	**200**	**20**	**8**	**565**	**142**

Attachment B
Summary of Operating Costs

Lockston Feasibility Analysis
Summary of Operating Costs

Actual Annual Operating Costs
($2011)

Year	Amount
2006	$ 87,742
2007	$ 78,052
2008	$ 98,632
2009	$ 85,245
2010	$ 80,226
Average	**$ 85,979**

5 -Year Average Operating Cost	$ 85,979[1]
Water Use Rental Fee	$ 6,720[2]
Total Forecast Annual Operating Cost	$ 92,699

[1] 2011 dollars
[2] Provincial Department of Environment and Conservation annual fee based on $ 0.80 per MWhr

Attachment C
Calculation of Levelized Cost of Energy

Present Worth Analysis

Weighted Average Incremental Cost of Capital 7.40%
PW Year 2011

YEAR	Generation Hydro 64.4yrs 8% CCA	Generation Hydro 64.4yrs 50% CCA	Capital Revenue Requirement	Operating Costs	Operating Benefits	Net Benefit	Present Worth Benefit +ve	Cumulative Present Worth Benefit +ve	Present Worth of Sunk Cost	Total Present Worth Benefit +ve	Rev Rqmt (¢/kWhr)	Levelized Rev Rqmt (¢/kWhr) 50 years
2012	3,451,000	0	337,811	94,849	0	-432,660	-402,849	-402,849	-4,602,940	-5,005,789.11	5.151	5.924
2013	0	0	361,678	96,930	0	-458,608	-397,588	-800,437	-4,289,385	-5,089,821.90	5.460	5.924
2014	0	0	351,002	99,060	0	-450,062	-363,295	-1,163,731	-4,006,053	-5,169,784.11	5.358	5.924
2015	0	0	340,853	101,211	0	-442,064	-332,253	-1,495,984	-3,749,870	-5,245,853.84	5.263	5.924
2016	0	0	331,190	103,298	0	-434,488	-304,058	-1,800,042	-3,518,101	-5,318,142.67	5.172	5.924
2017	260,734	0	347,496	105,235	0	-452,731	-294,995	-2,095,037	-3,291,676	-5,386,713.03	5.390	5.924
2018	0	0	340,493	107,226	0	-447,719	-271,629	-2,366,665	-3,085,101	-5,451,766.63	5.330	5.924
2019	0	0	331,258	109,235	0	-440,493	-248,831	-2,615,497	-2,897,976	-5,513,472.37	5.244	5.924
2020	234,671	0	345,383	111,292	0	-456,675	-240,197	-2,855,694	-2,716,314	-5,572,008.44	5.437	5.924
2021	0	0	338,516	113,381	0	-451,896	-221,307	-3,077,001	-2,550,533	-5,627,534.36	5.380	5.924
2022	0	0	329,628	115,558	0	-445,185	-202,999	-3,280,000	-2,400,227	-5,680,227.21	5.300	5.924
2023	0	0	321,077	117,791	0	-438,868	-186,330	-3,466,330	-2,263,907	-5,730,237.73	5.225	5.924
2024	25,323	0	315,316	120,091	0	-435,407	-172,123	-3,638,454	-2,139,258	-5,777,711.77	5.183	5.924
2025	0	0	307,537	122,413	0	-429,951	-158,255	-3,796,709	-2,026,060	-5,822,769.46	5.118	5.924
2026	0	0	299,768	124,793	0	-424,561	-145,504	-3,942,213	-1,923,325	-5,865,538.17	5.054	5.924
2027	0	0	292,244	127,188	0	-419,433	-133,842	-4,076,056	-1,830,069	-5,906,124.44	4.993	5.924
2028	0	0	284,947	129,660	0	-414,607	-123,187	-4,199,242	-1,745,406	-5,944,648.54	4.936	5.924
2029	11,148	0	278,949	132,174	0	-411,123	-113,735	-4,312,978	-1,668,236	-5,981,213.88	4.894	5.924
2030	0	0	272,128	134,729	0	-406,857	-104,800	-4,417,777	-1,598,140	-6,015,917.84	4.844	5.924
2031	0	0	265,372	137,333	0	-402,704	-96,583	-4,514,360	-1,534,495	-6,048,855.17	4.794	5.924
2032	833,880	0	340,406	139,987	0	-480,393	-107,277	-4,621,637	-1,458,478	-6,080,115.80	5.719	5.924
2033	0	0	339,731	142,693	0	-482,424	-100,308	-4,721,945	-1,387,840	-6,109,785.10	5.743	5.924
2034	0	0	330,848	145,450	0	-476,298	-92,211	-4,814,156	-1,323,788	-6,137,944.05	5.670	5.924
2035	0	0	322,220	148,262	0	-470,481	-84,809	-4,898,964	-1,265,705	-6,164,669.56	5.601	5.924
2036	0	0	313,826	151,127	0	-464,953	-78,037	-4,977,001	-1,213,033	-6,190,034.59	5.535	5.924
2037	230,628	0	328,224	154,048	0	-482,272	-75,367	-5,052,368	-1,161,740	-6,214,108.39	5.741	5.924
2038	0	0	321,839	157,025	0	-478,865	-69,678	-5,122,046	-1,114,910	-6,236,956.70	5.701	5.924
2039	2,291,663	0	537,655	160,060	0	-697,715	-94,528	-5,216,574	-1,042,068	-6,258,641.90	8.306	5.924
2040	0	0	545,197	163,154	0	-708,351	-89,356	-5,305,930	-973,293	-6,279,223.21	8.433	5.924
2041	0	0	529,988	166,307	0	-696,295	-81,783	-5,387,714	-911,043	-6,298,756.80	8.289	5.924
2042	0	0	515,301	169,521	0	-684,822	-74,894	-5,462,607	-854,689	-6,317,296.03	8.153	5.924
2043	0	0	501,095	172,798	0	-673,892	-68,620	-5,531,228	-803,664	-6,334,891.51	8.023	5.924
2044	0	0	487,330	176,137	0	-663,468	-62,904	-5,594,132	-757,460	-6,351,591.28	7.898	5.924
2045	0	0	473,973	179,542	0	-653,515	-57,691	-5,651,823	-715,618	-6,367,440.93	7.780	5.924
2046	0	0	460,990	183,012	0	-644,002	-52,934	-5,704,757	-677,727	-6,382,483.75	7.667	5.924
2047	0	0	448,351	186,549	0	-634,900	-48,590	-5,753,348	-643,413	-6,396,760.80	7.558	5.924
2048	0	0	436,029	190,154	0	-626,184	-44,621	-5,797,969	-612,342	-6,410,311.07	7.455	5.924
2049	0	0	423,999	193,830	0	-617,828	-40,993	-5,838,962	-584,210	-6,423,171.56	7.355	5.924
2050	0	0	412,236	197,576	0	-609,812	-37,673	-5,876,635	-558,743	-6,435,377.37	7.260	5.924
2051	0	0	400,721	201,394	0	-602,115	-34,634	-5,911,269	-535,693	-6,446,961.84	7.168	5.924
2052	4,140,413	0	794,728	205,287	0	-1,000,015	-53,559	-5,964,828	-493,129	-6,457,956.59	11.905	5.924
2053	0	0	812,283	209,254	0	-1,021,538	-50,942	-6,015,770	-452,622	-6,468,391.65	12.161	5.924
2054	0	0	788,586	213,299	0	-1,001,885	-46,519	-6,062,289	-416,006	-6,478,295.50	11.927	5.924
2055	0	0	765,699	217,421	0	-983,120	-42,503	-6,104,792	-382,903	-6,487,695.20	11.704	5.924
2056	0	0	743,557	221,623	0	-965,180	-38,852	-6,143,644	-352,972	-6,496,616.39	11.490	5.924
2057	0	0	722,100	225,907	0	-948,007	-35,532	-6,179,176	-325,908	-6,505,083.45	11.286	5.924
2058	0	0	701,274	230,273	0	-931,547	-32,509	-6,211,685	-301,435	-6,513,119.48	11.090	5.924
2059	0	0	681,027	234,724	0	-915,751	-29,756	-6,241,441	-279,306	-6,520,746.44	10.902	5.924
2060	0	0	661,315	239,260	0	-900,575	-27,246	-6,268,687	-259,298	-6,527,985.14	10.721	5.924
2061	2,679,288	0	904,363	243,884	0	-1,148,247	-32,346	-6,301,033	-233,822	-6,534,855.35	13.670	5.924

Feasibility Analysis
Major Inputs and Assumptions

Specific assumptions include:

Income Tax: Income tax expense reflects a statutory income tax rate of 32%.

Operating Costs: Operating costs were assumed to be in 2011 dollars escalated yearly using the GDP Deflator for Canada.

Average Incremental Cost of Capital:

	Capital Structure	Return	Weighted Cost
Debt	55.00%	6.606%	3.63%
Common Equity	45.00%	8.380%	3.77%
Total	**100.00%**		**7.40%**

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.

Escalation Factors: Conference Board of Canada GDP deflator, February 4, 2011.

Appendix B
Lockston Switchgear Arc Flash Study

ELECTRICAL ENGINEERING

ARC FLASH HAZARD STUDY

Company Area:	BVA		
Switchgear Included:	LOK 6.9kV		
Prepared by:	D Jones	**Date:**	3/9/2006

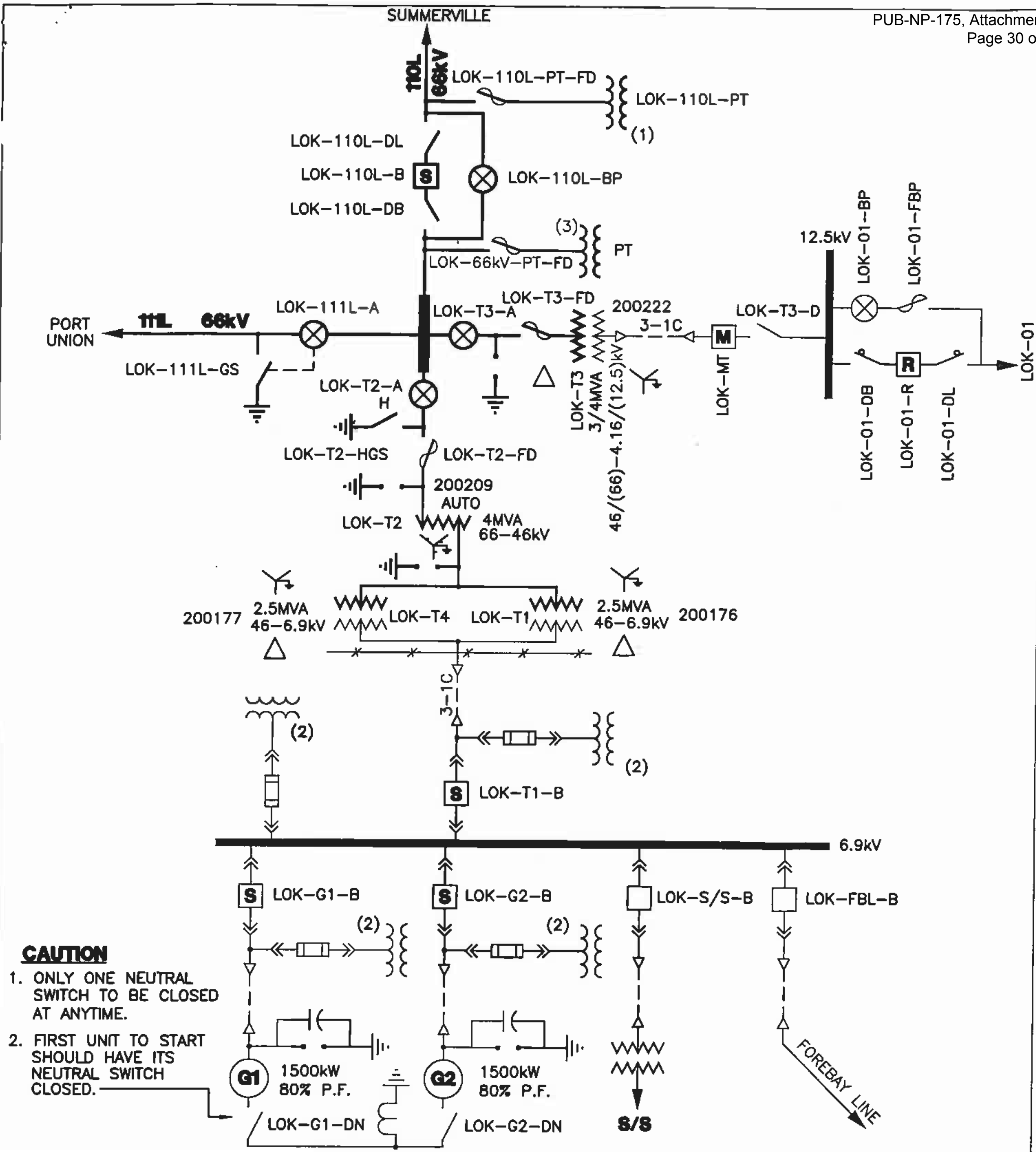
REGISTERED PROFESSIONAL ENGINEER
C. G. B. STACEY
SIGNATURE
11-06-10
DATE
PROVINCE OF NEWFOUNDLAND

REASON FOR ARC FLASH HAZARD STUDY

Arc Flash Hazard calculations to be done for all Metal Clad Switrchgear.

POINTS TO NOTE

1. PPE level class 3 at 16 inches (working inside switchgear).
2. PPE level class 1 at 36 inches (racking out breaker).



REGISTERED PROFESSIONAL ENGINEER
G. Richard Spurrell
SIGNATURE
2002-06-21
DATE
PROVINCE OF NEWFOUNDLAND

SINGLE LINE DIAGRAM

NEWFOUNDLAND POWER
A FORTIS COMPANY

PROVINCE OF NEWFOUNDLAND
PERMIT HOLDER
This Permit Allows
NEWFOUNDLAND POWER INC.
To practice Professional Engineering in Newfoundland and Labrador.
Permit No. as issued by APEGN R0140 which is valid for the year 2002.

LOCKSTON (LOK)

Date: 2002-06-21	Page 1 Of 1
App:	SLD No. 4-907

NEWFOUNDLAND POWER

1996 09 03

Memorandum From: **E.A. Noftall**

To: **L.W. Thompson**

Subject: **Lockston Substation**

File: **PSD-0645.01.03, PSD-415-LOK**

It has been identified that the lockout relay at Lockston Substation will not trip the supply coming from 111L into the 66kV bus at LOK. It was previously indicated that it was not economically feasible to install a breaker on LOK-111L to restore the differential scheme. As proposed, a High Speed Ground Switch will solve this problem by tripping the protection at CAT-T1.

Primary protection of LOK-T1, LOK-T2, LOK-T4 and the LOK 6.9kV power cables can be provided by a set of fuses below LOK-T2-A on the 66kV structure (LOK-T2-FD). The recommended fuse for LOK-T2-FD is a 40E S&C SMD-1A Standard Speed 69kV fuse.

A supervisory relay is recommended for 110L at LOK to prevent the relay LOK-110L-21 from tripping LOK-110L-B when the power is lost to the 66kV system at LOK.

CGS

c.c. E.A. Noftall

Lockston

NOTES: 960829

It was identified that the lockout relay at Lockston Substation was not able to trip the supply coming from 111L into the 66kV bus at LOK. It was proposed that a breaker be reinstalled on 111L at LOK. As a cheaper alternative, a High Speed Ground Switch (HSGS) will be installed at LOK, which will trip the protection at CAT on T1.

The benefits of a breaker (for example the differential protection at LOK could be reinstated with a breaker on 111L) do not out weigh the extra cost of a breaker.

The HSGS will be proposed for the 1997 budget along with a supervisory relay (50) for LOK-110L-21. The supervisory relay will keep LOK-110L-21 from tripping LOK-110L-B everytime the power is lost to the 66kV system at LOK.

A supervisory relay is also needed for CAT-111L-21 which will also be proposed for the 1997 budget.

The HSGS installation is viable as long as the fuses proposed for LOK-T2 are put in place. The fuses for LOK-T2 will provide primary protection for LOK-T1, T2, T4 & the 6.9kV power cables.

NF POWER- RELAY REPORT 1

Thursday, March 09, 2006

50NLV	IAC53B	12.	MVA=	P/U=	TD=	Pri amps=	TCC=	9/14/87		240	PHASE INST BLKD	4-16
51	IAC51B	138	MVA= 33.1	P/U= 12	TD= 3.0	Pri amps= 139	TCC=	9/14/87		20 D	PHASE C 0/C	4-16
51NLV	IAC53B	12.	MVA= 5.2	P/U= 1.0	TD= 3.0	Pri amps= 240	TCC=	9/14/87		240	INST NOT INSTALLED	0.5-2.0

Eqpt code: -GRH-G1 -

Setting group:		kV						Date	PT	CT	Remarks	Range	Power Supply
87T	HUE	66		HV Tap=4	LV KV=1	CTLV=300	LV Tap=4			100	INCLUDES XFMR 1	2.9-8.7	
87T	HUE	66		HV Tap=4	LV KV=1	CTLV=300	LV Tap=4			100	INCLUDES XFMR 1	2.9-8.7	

Eqpt code: -GRH-T1 -

Setting group:		kV						Date	PT	CT	Remarks	Range	Power Supply
87	HU	66		HV Tap=4	LV KV=1	CTLV=300	LV Tap=4			100	INCLUDES GEN 1	2.9-8.7	
87	HU	66		HV Tap=4	LV KV=1	CTLV=300	LV Tap=4			100	INCLUDES GEN 1	2.9-8.7	

Eqpt code: -LOK-110L-

Setting group:		kV						Date	PT	CT	Remarks	Range	Power Supply
67N/50	JBCG53	66	MVA= 14.9	P/U= 6.5	TD=	Pri amps= 130	TCC=	9/8/97		20	DIR GND INST	4-16	
51N	SPAJ14	66	MVA= 2.3	P/U= 1.0	TD=	Pri amps=	TCC=	10/24/97		20	BLOCKED	2.5-25	
51	SPAJ14	66	MVA= 18.3	P/U= 8	TD=	Pri amps= 160	TCC=	10/23/97		20	SUPV LOK-110L-21-1	2.5-25	
50N	SPAJ14	66	MVA= 14.9	P/U= 6.5	TD=	Pri amps=	TCC=	10/24/97		20	BLOCKED	0.5-40	
50	SPAJ14	66	MVA=	P/U=	TD=	Pri amps=	TCC=	10/24/97		20	BLOCKED	0.5-40	
67N	JBCG53	66	MVA= 2.3	P/U= 1.0	TD= 1.5	Pri amps= 20	TCC=	9/8/97		20	Dir blocked closed-RNS req p	0.5-2.0	
21-1	KD-4	66	Zpri= 51.9	T= 2.03	S= 1	L= 0.0	R= 0.03		600	20	L/R	0.75-21	
	SPAJ14	66									START OF THE 51 USED FO		

Eqpt code: -LOK-66B -

Setting group:		kV						Date	PT	CT	Remarks	Range	Power Supply
87	IAC53A	66	MVA= 2.6	P/U= 1.0	TD= 3.0	Pri amps= 23.1	TCC=	9/15/87		40 D	NOT IN SERVICE	0.5-2	

Eqpt code: -LOK-FBL -

Setting group:		kV						Date	PT	CT	Remarks	Range	Power Supply
50	IAC77B	6.9	MVA=	P/U=	TD=	Pri amps=	TCC=	9/15/87		60	PHASE INST BLKD	20-80	
50N	IAC77B	6.9	MVA= 21.5	P/U= 30	TD=	Pri amps= 1800	TCC=	9/15/87		60	GND INST	10-40	
51	IAC77B	6.9	MVA= 4.3	P/U= 6	TD= 1.0	Pri amps= 380	TCC=	9/15/87		60	PHASE O/C	4-16	
51N	IAC77B	6.9	MVA= 1.2	P/U= 1.6	TD= 1.0	Pri amps= 96	TCC=	9/15/87		60	GND O/C	0.5-2.0	

Eqpt code: -LOK-G1 -

Setting group:		kV						Date	PT	CT	Remarks	Range	Power Supply
13	SV	6.9	MVA=	P/U=	TD=	Pri amps=	TCC=	9/15/87				70-160	
87	IJD52A	6.9	MVA=	P/U=	TD=	Pri amps=	TCC=	9/15/87		40	GEN DIFF	0.02-25%	
51V	IJCV51	6.9	MVA= 2.4	P/U= 5.0	TD= 3.0	Pri amps= 200	TCC=	3/16/94		40	VOLT REST O/C	4-16	
51N	IAC58A	6.9	MVA= 0.48	P/U= 2.0	TD= 2.0	Pri amps= 40	TCC=	9/15/87		20	GND O/C	1.5-6	
49I	BL-1	6.9	MVA= 5.7	P/U= 12.0	TD=	Pri amps= 480	TCC=	9/15/87		40	WINDING TEMP. O/C	6.0-50	
27	PJV11B	6.9	MVA=	P/U=	TD=	Pri amps=	TCC=	9/15/87			INST U/V COMMON G1&G2	50-110	
40	KLF			TA=15.8	SA=2	MA=0.000	LA=.06 u				FIELD LOSS VOLT BKD		
49	BL-1	6.9	MVA= 2.0	P/U= 4.25	TD=	Pri amps= 170	TCC=	9/15/87		40	WINDING TEMP. O/C	2.5-5.0	

Eqpt code: -LOK-G2 -

Setting group:		kV						Date	PT	CT	Remarks	Range	Power Supply
51GN	IAC57A	6.9	MVA= 0.48	P/U= 2.0	TD= 2.0	Pri amps= 40	TCC=	9/15/87		20	GND O/C	1.5-6	
13	SV	6.9	MVA=	P/U=	TD=	Pri amps=	TCC=	9/15/87				70-160	

NF POWER- RELAY REPORT 1

Thursday, March 09, 2006

87	IJD52A	6.9	MVA=	P/U=	TD=	Pri amps=	TCC=	9/15/87		40	GEN DIFF	0.02-25%	
51V	IJCV51	6.9	MVA= 2.4	P/U= 5.0	TD= 3.0	Pri amps= 200	TCC=	3/16/94		40	VOLT REST O/C	4-16	
49	BL-1	6.9	MVA= 2.0	P/U= 4.25	TD=	Pri amps= 170	TCC=	9/15/87		40	WINDING TEMP O/C	2.5-5.0	
40	KLF			TA=15.8	SA=2	MA=0.153	LA=.06 u		60	40	VOLT UNIT BKD		
49I	BL-1	6.9	MVA= 5.7	P/U= 12.0	TD=	Pri amps= 480	TCC=	9/15/87		40	WINDING TEMP. O/C	8.0-50	

Eqpt code: -LOK-S/S -

Setting group:		kV						Date	PT	CT	Remarks	Range	Power Supply
50	IAC51B	6.9	MVA=	P/U= 40	TD=	Pri amps=	TCC=	9/15/87			PHASE C INST	20-80	
50	IAC53B	6.9	MVA=	P/U= 20	TD=	Pri amps=	TCC=	9/15/87			PHASE A INST	20-80	
50N	IAC51B	6.9	MVA=	P/U= 16	TD=	Pri amps=	TCC=	9/15/87			GND INST	4-16	
51	IAC53B	6.9	MVA=	P/U= 4.0	TD= 0.5	Pri amps=	TCC=	9/15/87			PHASE A O/C	4-16	
51	IAC51B	6.9	MVA=	P/U= 4.0	TD= 0.5	Pri amps=	TCC=	9/15/87			PHASE C O/C	4-16	
51N	IAC51B	6.9	MVA=	P/U= 0.6	TD= 0.5	Pri amps=	TCC=	9/15/87			GND O/C	0.5-2	

Eqpt code: -LOK-T1 -

Setting group:		kV						Date	PT	CT	Remarks	Range	Power Supply
51N	IAC77B	6.9	MVA= 0.36	P/U= 0.5	TD= 1.0	Pri amps= 30	TCC=	9/15/87		60	GND O/C	0.5-2	
81	KF	6.9	MVA=	P/U=	TD=	Pri amps=	TCC=	9/15/87			U/F COMMON BOTH GEN	55-59.5	
50	IAC77B	6.9	MVA= 28.7	P/U= 40	TD=	Pri amps= 2400	TCC=	9/15/87		60	PHASE INST	20-80	
50N	IAC77B	6.9	MVA= 7.2	P/U= 10	TD=	Pri amps= 600	TCC=	9/15/87		60	GND INST	10-40	
51	IAC77B	6.9	MVA= 4.3	P/U= 6.0	TD= 8.5	Pri amps= 360	TCC=	9/15/87		60	PHASE O/C	4-16	

Eqpt code: -NWB-T1 -

Setting group:		kV						Date	PT	CT	Remarks	Range	Power Supply
51	MCGG2	138	MVA= 14.34	P/U= 1.0	TD= 0.6	Pri amps= 60	TCC=	6/13/95		60	EI CURVE	0.25-12	
51NLV	MCGG2	25	MVA= 4.55	P/U= 1.75	TD= 0.97	Pri amps= 105	TCC=	10/26/92		60	VI CURVE	0.25-12	
50NLV	MCGG2	25	MVA=	P/U=	TD=	Pri amps=	TCC=	10/26/92		60	BLOCKED	0.25-372	
50/2	RXKF1	138	MVA=	P/U=	TD=	Pri amps=	TCC= 2.0	6/13/95				0.2-3.0	
50	MCGG2	138	MVA= 71.71	P/U= 5	TD=	Pri amps= 300	TCC=	10/26/92		60		0.25-372	
REMAR											HSGS AND MOTORIZED AIR		
89/2	RXKF1	138	MVA=	P/U=	TD=	Pri amps=	TCC= 5.0	10/26/92			T1-A TIMER	2-30	

Eqpt code: -PBD-T1 -

Setting group:		kV						Date	PT	CT	Remarks	Range	Power Supply
89/2	RXKF-1	138	MVA=	P/U=	TD=	Pri amps=	TCC= 5.0	11/8/90			T1-A Timer	1.0-10.0	
51NLV	MCGG2	25	MVA= 7.79	P/U= 4.5	TD= 0.65	Pri amps= 180	TCC=	11/8/90		40	VI CURVE	0.5-12.0	
51	MCGG2	138	MVA= 21.51	P/U= 2.25	TD= 0.25	Pri amps= 90	TCC=	11/8/90		40	VI CURVE	0.5-12.0	
50NLV	MCGG2	25	MVA=	P/U=	TD=	Pri amps=	TCC=	11/8/90		40	BLOCKED	0.5-372	
50/2	RXKF-1	138	MVA=	P/U=	TD=	Pri amps=	TCC= 1.5	11/8/90				0.3-3	
50	MCGG2	138	MVA= 86.05	P/U= 9.0	TD=	Pri amps= 360	TCC=	11/8/90		40		0.5-372	

Eqpt code: -PUN-2.4B-

Setting group:		kV						Date	PT	CT	Remarks	Range	Power Supply
46/50	RIRA	2.4									OPERATES FROM 46 OUTP		
27	IAV54	2.4	MVA=	P/U=	TD=	Pri amps=	TCC=	12/30/97	20			55-140	
46/50T	AGAST	2.4	MVA=	P/U=	TD=	Pri amps=	TCC= 0.5	11/16/87			TIMER FOR 46/50	0.5-5	
81	KF	2.4	MVA=	P/U=	TD=	Pri amps=	TCC=	11/9/87	20		TRIPS G1,G2,G3	55-59.5	

Maximum Generation Fault LOK 6.9 kV.

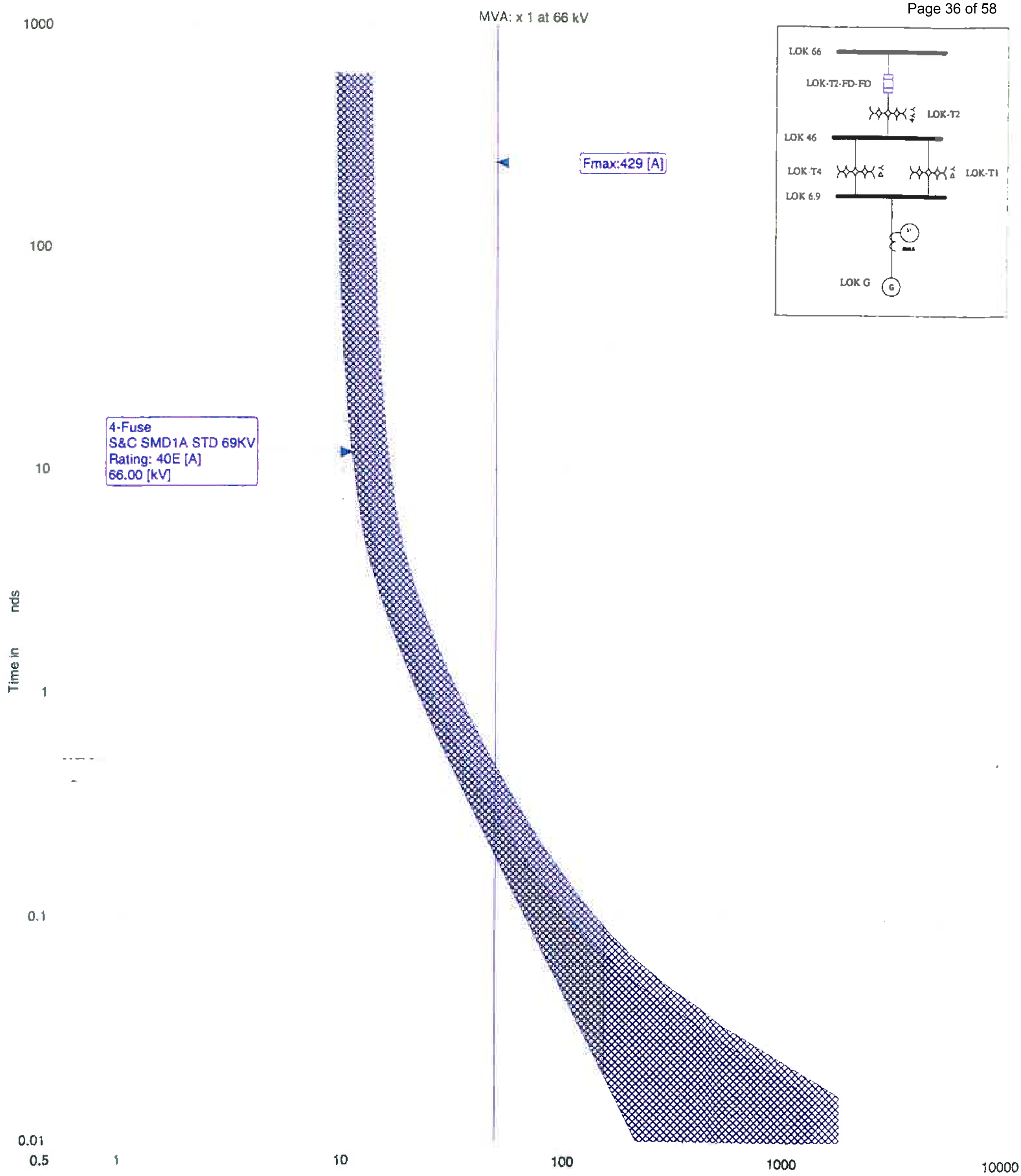
ID	Type	Prefault kV	Angle	Fault type	Fault S [MVA]	Ia [A]	Ia [deg]	Ib [A]	Ib [deg]	Ic [A]	Ic [deg]	In [A]	In [deg]
Faulted Bus ->													
LOK 07		6.9	0	LLL	49	4106.6676	-81.2169	4106.6675	158.7831	4106.6675	38.7831	0	0
First Ring Contributions													
LOK G1	Generator	6.9	0	LLL	12	1033.3733	-90	1033.3733	150	1033.3733	30	0	0
LOK T4	Fixed-Tap Xmer	6.9	0	LLL	18	1534.5262	-78.4658	1534.5262	161.5342	1534.5262	41.5342	0	0
LOK T1	Fixed-Tap Xmer	6.9	0	LLL	19	1555.3501	-78.1188	1555.3501	161.8812	1555.3501	41.8812	0	0

Faulted Bus	Branch Id	Type	Fault type	Branch Sid	Ia [A]	Ia [deg]	Ib [A]	Ib [deg]	Ic [A]	Ic [deg]	In [A]	In [deg]
LOK 07	LOK T2	Fixed-Tap Xme	LLL	LOK 66	323	131.7089	323	11.7089	323	-108.2911	0	0
LOK 07	LOK T2	Fixed-Tap Xme	LLL	LOK 46	463.5	-48.2911	463.5	-168.2911	463.5	71.7089	0	0

Current Multiplier for CYMTCC LOK-T2-FD

= 49 MVA / (323*66*SQRT3/1000)

Current Multiplier = 1.33



For LLL LOK 6.9 kV fault at Maximum Generation. LOK-T2-FD maximum melting time 0.4715 seconds with existing 40E S&C SMD-1A Standard Speed 69kV fuses.

Dave Jones

March 09, 2006

Study: C:\Arc Flash\Plants\LOK\LOK T1 Fuse Max Gen LLL.lcc

Minimum Generation Fault LOK 6.9 kV. LOK plant on.

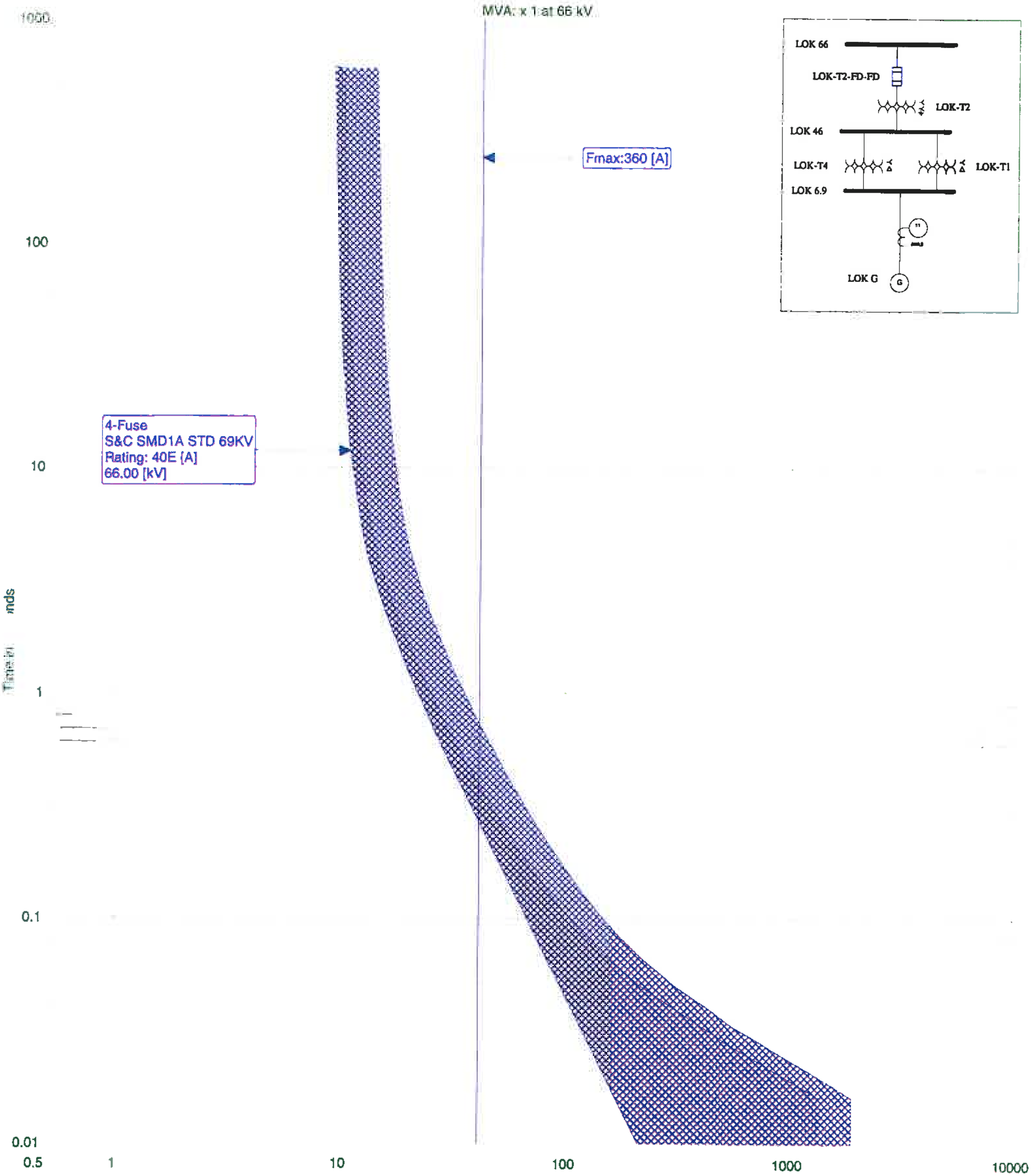
ID	Type	Prefault kV	Angle	Fault type	Fault S [MVA]	Ia [A]	Ia [deg]	Ib [A]	Ib [deg]	Ic [A]	Ic [deg]	In [A]	In [deg]
Faulted Bus ->													
LOK 07		6.9	0	LLL	41	3441.4846	-81.198	3441.4846	158.802	3441.4846	38.802	0	0
First Ring Contributions													
LOK T4	Fixed-Tap Xmer	6.9	0	LLL	14	1204.7335	-77.6356	1204.7335	162.3644	1204.7335	42.3644	0	0
LOK T1	Fixed-Tap Xmer	6.9	0	LLL	15	1221.1073	-77.2894	1221.1073	162.7106	1221.1073	42.7106	0	0
LOK G1	Generator	6.9	0	LLL	12	1033.3733	-90	1033.3733	150	1033.3733	30	0	0

Faulted Bus	Branch id	Type	ault typ	Branch Sid	Ia [A]	Ia [deg]	Ib [A]	Ib [deg]	Ic [A]	Ic [deg]	In [A]	In [deg]
LOK 07	LOK T2	Fixed-Tap Xme	LLL	LOK 66	253.6	132.5382	253.6	12.5382	253.6	-107.4618	0	0
LOK 07	LOK T2	Fixed-Tap Xme	LLL	LOK 46	363.9	-47.4618	363.9	-167.4618	363.9	72.5382	0	0

Current Multiplier for CYMTCC LOK-T2-FD

= 41 MVA / (253.6*66*SQRT3/1000)

Current Multiplier = 1.41



For LLL LOK 6.9 kV fault at Minimum Generation. LOK-T2-FD maximum melting time 0.7292 seconds with existing 40E S&C SMD-1A Standard Speed 69kV fuses.

Dave Jones

March 09, 2006

Study: C:\Arc Flash\Plants\LOK\LOK T1 Fuse Min Gen LLL.tcc

Arc Flash Hazard LOK 6.9 kV
IEEE standard

Faulted Bus	Generation	Fault	Fault Current	CT	CT Plus Fuses	Working Distance	Flash Hazard Boundry	cal / cm2	PPE Level	L.A.B.	R.A.B.	P.A.B.
LOK 6.9	Max	LLL	4107	0.4715	0.4715	16"	91"	6.5	2	60"	26"	7"
LOK 6.9	Min	LLL	3441	0.7292	0.7292	16"	117"	8.3	3	60"	26"	7"

Faulted Bus	Generation	Fault	Fault Current	CT	CT Plus Fuses	Working Distance	Flash Hazard Boundry	cal / cm2	PPE Level	L.A.B.	R.A.B.	P.A.B.
LOK 6.9	Max	LLL	4107	0.4715	0.4715	36"	91"	3.0	1	60"	26"	7"
LOK 6.9	Min	LLL	3441	0.7292	0.7292	36"	117"	3.8	1	60"	26"	7"

***Arc Flash Calculated for Switchgear and fixed conductor.**
Software won't supply Arc Flash results for clearing times over one second.

L.A.B. Limited Approach Boundry
R.A.B. Restricted Approach Boundry
P.A.B. Prohibited Approach Boundry

WARNING

Arc Flash and Shock Hazard Appropriate PPE Required

91 inches	Flash Hazard Boundary
6.5	cal / cm2 Flash Hazard at 16 inches
class 2	PPE Level, Cotton underwear - conventional short sleeve and brief/sh plus FR shirt and FR pants (1 or 2 layers). Hard hat, arc rated face shield, ear, hand and foot protecti
6900 VAC	Shock Hazard
60 inches	Limited Approach
26 inches	Restricted Approach
7 inches	Prohibited Approach

Equipment Name:LOK 07

WARNING

Arc Flash and Shock Hazard Appropriate PPE Required

91 inches	Flash Hazard Boundary
6.5	cal / cm2 Flash Hazard at 16 inches
class 2	PPE Level, Cotton underwear - conventional short sleeve and brief/sh plus FR shirt and FR pants (1 or 2 layers). Hard hat, arc rated face shield, ear, hand and foot protecti
6900 VAC	Shock Hazard
60 inches	Limited Approach
26 inches	Restricted Approach
7 inches	Prohibited Approach

Equipment Name:LOK 07

WARNING

Arc Flash and Shock Hazard Appropriate PPE Required

91 inches	Flash Hazard Boundary
6.5	cal / cm2 Flash Hazard at 16 inches
class 2	PPE Level, Cotton underwear - conventional short sleeve and brief/sh plus FR shirt and FR pants (1 or 2 layers). Hard hat, arc rated face shield, ear, hand and foot protecti
6900 VAC	Shock Hazard
60 inches	Limited Approach
26 inches	Restricted Approach
7 inches	Prohibited Approach

Equipment Name:LOK 07

WARNING

Arc Flash and Shock Hazard Appropriate PPE Required

91 inches	Flash Hazard Boundary
6.5	cal / cm2 Flash Hazard at 16 inches
class 2	PPE Level, Cotton underwear - conventional short sleeve and brief/sh plus FR shirt and FR pants (1 or 2 layers). Hard hat, arc rated face shield, ear, hand and foot protecti
6900 VAC	Shock Hazard
60 inches	Limited Approach
26 inches	Restricted Approach
7 inches	Prohibited Approach

Equipment Name:LOK 07

WARNING

Arc Flash and Shock Hazard
Appropriate PPE Required

117 inches	Flash Hazard Boundary
8.3	cal / cm2 Flash Hazard at 16 inches
class 3	PPE Level, Cotton underwear plus FR shirt and FR pants plus FR coverall, or cotton underwear plus two FR coveralls (2 or 3 layers). FR hard hat, safety glasses or goggles, flash suit hood, ear, hand and foot protection.
6900 VAC	Shock Hazard
60 inches	Limited Approach
26 inches	Restricted Approach
7 inches	Prohibited Approach

Equipment Name:LOK 07

WARNING

Arc Flash and Shock Hazard
Appropriate PPE Required

117 inches	Flash Hazard Boundary
8.3	cal / cm2 Flash Hazard at 16 inches
class 3	PPE Level, Cotton underwear plus FR shirt and FR pants plus FR coverall, or cotton underwear plus two FR coveralls (2 or 3 layers). FR hard hat, safety glasses or goggles, flash suit hood, ear, hand and foot protection.
6900 VAC	Shock Hazard
60 inches	Limited Approach
26 inches	Restricted Approach
7 inches	Prohibited Approach

Equipment Name:LOK 07

WARNING

Arc Flash and Shock Hazard
Appropriate PPE Required

117 inches	Flash Hazard Boundary
8.3	cal / cm2 Flash Hazard at 16 inches
class 3	PPE Level, Cotton underwear plus FR shirt and FR pants plus FR coverall, or cotton underwear plus two FR coveralls (2 or 3 layers). FR hard hat, safety glasses or goggles, flash suit hood, ear, hand and foot protection.
6900 VAC	Shock Hazard
60 inches	Limited Approach
26 inches	Restricted Approach
7 inches	Prohibited Approach

Equipment Name:LOK 07

WARNING

Arc Flash and Shock Hazard
Appropriate PPE Required

117 inches	Flash Hazard Boundary
8.3	cal / cm2 Flash Hazard at 16 inches
class 3	PPE Level, Cotton underwear plus FR shirt and FR pants plus FR coverall, or cotton underwear plus two FR coveralls (2 or 3 layers). FR hard hat, safety glasses or goggles, flash suit hood, ear, hand and foot protection.
6900 VAC	Shock Hazard
60 inches	Limited Approach
26 inches	Restricted Approach
7 inches	Prohibited Approach

Equipment Name:LOK 07

WARNING

Arc Flash and Shock Hazard
Appropriate PPE Required

91 inches	Flash Hazard Boundary
3.0	cal / cm2 Flash Hazard at 36 inches
class 1	PPE Level, FR shirt and FR pants or FR coverall (1 layer). Hard hat and safety glasses.
6900 VAC	Shock Hazard
60 inches	Limited Approach
26 inches	Restricted Approach
7 inches	Prohibited Approach

Equipment Name:LOK 07

WARNING

Arc Flash and Shock Hazard
Appropriate PPE Required

91 inches	Flash Hazard Boundary
3.0	cal / cm2 Flash Hazard at 36 inches
class 1	PPE Level, FR shirt and FR pants or FR coverall (1 layer). Hard hat and safety glasses.
6900 VAC	Shock Hazard
60 inches	Limited Approach
26 inches	Restricted Approach
7 inches	Prohibited Approach

Equipment Name:LOK 07

WARNING

Arc Flash and Shock Hazard
Appropriate PPE Required

91 inches	Flash Hazard Boundary
3.0	cal / cm2 Flash Hazard at 36 inches
class 1	PPE Level, FR shirt and FR pants or FR coverall (1 layer). Hard hat and safety glasses.
6900 VAC	Shock Hazard
60 inches	Limited Approach
26 inches	Restricted Approach
7 inches	Prohibited Approach

Equipment Name:LOK 07

WARNING

Arc Flash and Shock Hazard
Appropriate PPE Required

91 inches	Flash Hazard Boundary
3.0	cal / cm2 Flash Hazard at 36 inches
class 1	PPE Level, FR shirt and FR pants or FR coverall (1 layer). Hard hat and safety glasses.
6900 VAC	Shock Hazard
60 inches	Limited Approach
26 inches	Restricted Approach
7 inches	Prohibited Approach

Equipment Name:LOK 07

WARNING

**Arc Flash and Shock Hazard
Appropriate PPE Required**

117 inches Flash Hazard Boundary
3.8 cal / cm2 Flash Hazard at 36 inches
class 1 PPE Level, FR shirt and FR pants or FR coverall (1 layer). Hard hat and safety glasses.
6900 VAC Shock Hazard
60 inches Limited Approach
26 inches Restricted Approach
7 inches Prohibited Approach

Equipment Name:LOK 07

WARNING

**Arc Flash and Shock Hazard
Appropriate PPE Required**

117 inches Flash Hazard Boundary
3.8 cal / cm2 Flash Hazard at 36 inches
class 1 PPE Level, FR shirt and FR pants or FR coverall (1 layer). Hard hat and safety glasses.
6900 VAC Shock Hazard
60 inches Limited Approach
26 inches Restricted Approach
7 inches Prohibited Approach

Equipment Name:LOK 07

WARNING

**Arc Flash and Shock Hazard
Appropriate PPE Required**

117 inches Flash Hazard Boundary
3.8 cal / cm2 Flash Hazard at 36 inches
class 1 PPE Level, FR shirt and FR pants or FR coverall (1 layer). Hard hat and safety glasses.
6900 VAC Shock Hazard
60 inches Limited Approach
26 inches Restricted Approach
7 inches Prohibited Approach

Equipment Name:LOK 07

WARNING

**Arc Flash and Shock Hazard
Appropriate PPE Required**

117 inches Flash Hazard Boundary
3.8 cal / cm2 Flash Hazard at 36 inches
class 1 PPE Level, FR shirt and FR pants or FR coverall (1 layer). Hard hat and safety glasses.
6900 VAC Shock Hazard
60 inches Limited Approach
26 inches Restricted Approach
7 inches Prohibited Approach

Equipment Name:LOK 07

ELECTRICAL ENGINEERING

ARC FLASH HAZARD STUDY

Company Area:	BVA		
Switchgear Included:	LOK 6.9kV		
Prepared by:	D Jones	**Date:**	3/9/2006

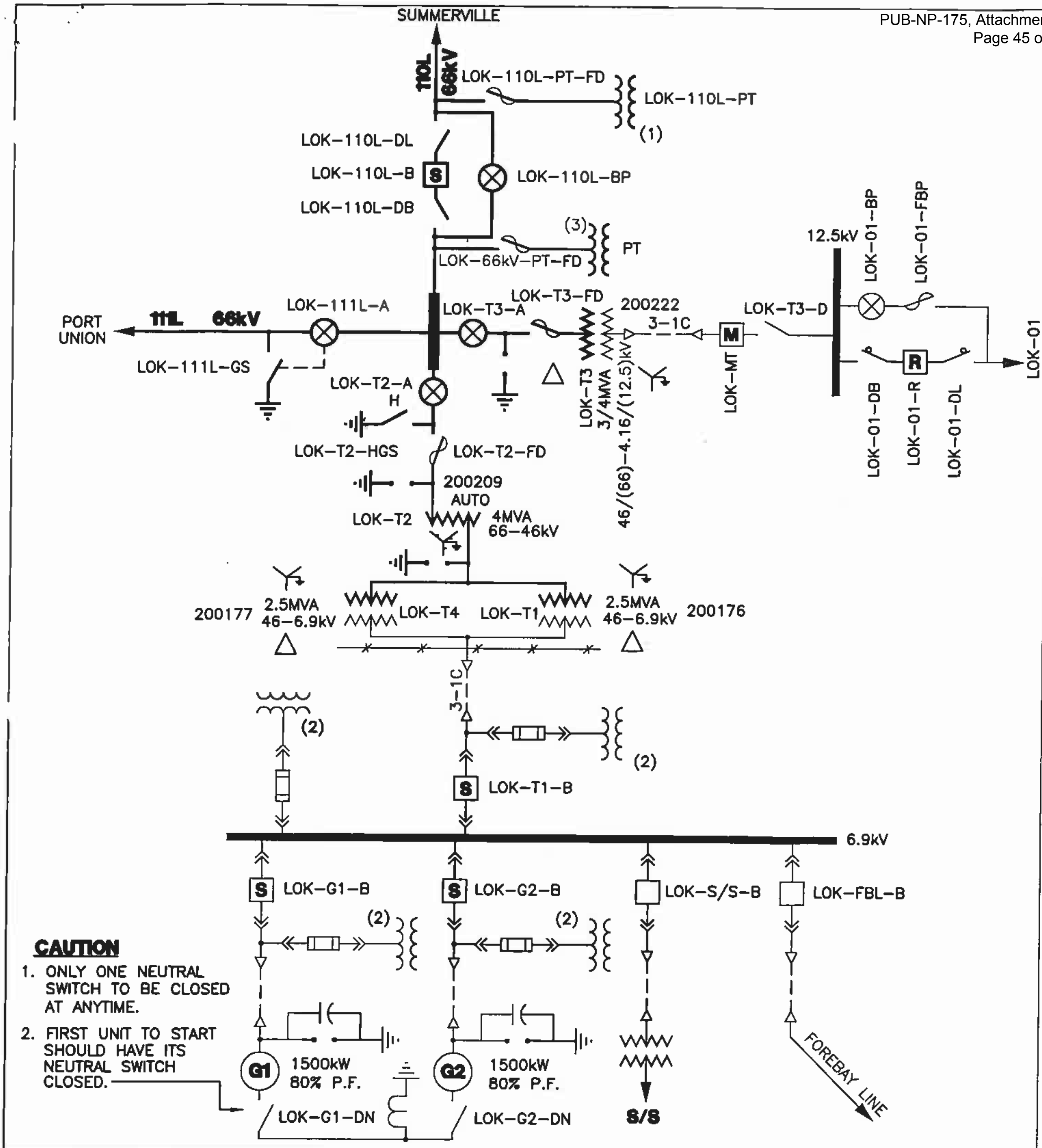
REGISTERED PROFESSIONAL ENGINEER
C. G. B. STACEY
SIGNATURE
11-06-10
DATE
PROVINCE OF NEWFOUNDLAND

REASON FOR ARC FLASH HAZARD STUDY

Arc Flash Hazard calculations to be done for all Metal Clad Switrchgear.

POINTS TO NOTE

1. PPE level class 3 at 16 inches (working inside switchgear).
2. PPE level class 1 at 36 inches (racking out breaker).



REGISTERED PROFESSIONAL ENGINEER
PROVINCE OF NEWFOUNDLAND
G. Richard Spurrell
SIGNATURE
2002-06-21
DATE

SINGLE LINE DIAGRAM

NEWFOUNDLAND POWER
A FORTIS COMPANY

PROVINCE OF NEWFOUNDLAND
PERMIT HOLDER
This Permit Allows
NEWFOUNDLAND POWER INC.
To practice Professional Engineering in Newfoundland and Labrador.
Permit No. as issued by APEGN R0140 which is valid for the year 2002.

LOCKSTON (LOK)

Date: 2002-06-21	Page 1 Of 1
App:	SLD No. 4-907

NEWFOUNDLAND POWER

1996 09 03

Memorandum From: **E.A. Noftall**

To: **L.W. Thompson**

Subject: **Lockston Substation**

File: **PSD-0645.01.03, PSD-415-LOK**

It has been identified that the lockout relay at Lockston Substation will not trip the supply coming from 111L into the 66kV bus at LOK. It was previously indicated that it was not economically feasible to install a breaker on LOK-111L to restore the differential scheme. As proposed, a High Speed Ground Switch will solve this problem by tripping the protection at CAT-T1.

Primary protection of LOK-T1, LOK-T2, LOK-T4 and the LOK 6.9kV power cables can be provided by a set of fuses below LOK-T2-A on the 66kV structure (LOK-T2-FD). The recommended fuse for LOK-T2-FD is a 40E S&C SMD-1A Standard Speed 69kV fuse.

A supervisory relay is recommended for 110L at LOK to prevent the relay LOK-110L-21 from tripping LOK-110L-B when the power is lost to the 66kV system at LOK.

CGS

c.c. E.A. Noftall

Lockston

NOTES: 960829

It was identified that the lockout relay at Lockston Substation was not able to trip the supply coming from 111L into the 66kV bus at LOK. It was proposed that a breaker be reinstalled on 111L at LOK. As a cheaper alternative, a High Speed Ground Switch (HSGS) will be installed at LOK, which will trip the protection at CAT on T1.

The benefits of a breaker (for example the differential protection at LOK could be reinstated with a breaker on 111L) do not out weigh the extra cost of a breaker.

The HSGS will be proposed for the 1997 budget along with a supervisory relay (50) for LOK-110L-21. The supervisory relay will keep LOK-110L-21 from tripping LOK-110L-B everytime the power is lost to the 66kV system at LOK.

A supervisory relay is also needed for CAT-111L-21 which will also be proposed for the 1997 budget.

The HSGS installation is viable as long as the fuses proposed for LOK-T2 are put in place. The fuses for LOK-T2 will provide primary protection for LOK-T1, T2, T4 & the 6.9kV power cables.

NF POWER- RELAY REPORT 1

Thursday, March 09, 2006

50NLV	IAC53B	12.	MVA=	P/U=	TD=	Pri amps=	TCC=	9/14/87		240	PHASE INST BLKD	4-16	
51	IAC51B	138	MVA= 33.1	P/U= 12	TD= 3.0	Pri amps= 139	TCC=	9/14/87		20 D	PHASE C 0/C	4-16	
51NLV	IAC53B	12.	MVA= 5.2	P/U= 1.0	TD= 3.0	Pri amps= 240	TCC=	9/14/87		240	INST NOT INSTALLED	0.5-2.0	
Eqpt code:		-GRH-G1 -											
Setting group:		kV						Date	PT	CT	Remarks	Range	Power Supply
87T	HUE	66		HV Tap=4	LV KV=1	CTLV=300	LV Tap=4			100	INCLUDES XFMR 1	2.9-8.7	
87T	HUE	66		HV Tap=4	LV KV=1	CTLV=300	LV Tap=4			100	INCLUDES XFMR 1	2.9-8.7	
Eqpt code:		-GRH-T1 -											
Setting group:		kV						Date	PT	CT	Remarks	Range	Power Supply
87	HU	66		HV Tap=4	LV KV=1	CTLV=300	LV Tap=4			100	INCLUDES GEN 1	2.9-8.7	
87	HU	66		HV Tap=4	LV KV=1	CTLV=300	LV Tap=4			100	INCLUDES GEN 1	2.9-8.7	
Eqpt code:		-LOK-110L-											
Setting group:		kV						Date	PT	CT	Remarks	Range	Power Supply
67N/50	JBCG53	66	MVA= 14.9	P/U= 6.5	TD=	Pri amps= 130	TCC=	9/8/97		20	DIR GND INST	4-16	
51N	SPAJ14	66	MVA= 2.3	P/U= 1.0	TD=	Pri amps=	TCC=	10/24/97		20	BLOCKED	2.5-25	
51	SPAJ14	66	MVA= 18.3	P/U= 8	TD=	Pri amps= 160	TCC=	10/23/97		20	SUPV LOK-110L-21-1	2.5-25	
50N	SPAJ14	66	MVA= 14.9	P/U= 6.5	TD=	Pri amps=	TCC=	10/24/97		20	BLOCKED	0.5-40	
50	SPAJ14	66	MVA=	P/U=	TD=	Pri amps=	TCC=	10/24/97		20	BLOCKED	0.5-40	
67N	JBCG53	66	MVA= 2.3	P/U= 1.0	TD= 1.5	Pri amps= 20	TCC=	9/8/97		20	Dir blocked closed-RNS req p	0.5-2.0	
21-1	KD-4	66	Zpri= 51.9	T= 2.03	S= 1	L= 0.0	R= 0.03		600	20	L/R	0.75-21	
	SPAJ14	66									START OF THE 51 USED FO		
Eqpt code:		-LOK-66B -											
Setting group:		kV						Date	PT	CT	Remarks	Range	Power Supply
87	IAC53A	66	MVA= 2.6	P/U= 1.0	TD= 3.0	Pri amps= 23.1	TCC=	9/15/87		40 D	NOT IN SERVICE	0.5-2	
Eqpt code:		-LOK-FBL -											
Setting group:		kV						Date	PT	CT	Remarks	Range	Power Supply
50	IAC77B	6.9	MVA=	P/U=	TD=	Pri amps=	TCC=	9/15/87		60	PHASE INST BLKD	20-80	
50N	IAC77B	6.9	MVA= 21.5	P/U= 30	TD=	Pri amps= 1800	TCC=	9/15/87		60	GND INST	10-40	
51	IAC77B	6.9	MVA= 4.3	P/U= 6	TD= 1.0	Pri amps= 360	TCC=	9/15/87		60	PHASE O/C	4-16	
51N	IAC77B	6.9	MVA= 1.2	P/U= 1.6	TD= 1.0	Pri amps= 96	TCC=	9/15/87		60	GND O/C	0.5-2.0	
Eqpt code:		-LOK-G1 -											
Setting group:		kV						Date	PT	CT	Remarks	Range	Power Supply
13	SV	6.9	MVA=	P/U=	TD=	Pri amps=	TCC=	9/15/87				70-160	
87	IJD52A	6.9	MVA=	P/U=	TD=	Pri amps=	TCC=	9/15/87		40	GEN DIFF	0.02-25%	
51V	IJCV51	6.9	MVA= 2.4	P/U= 5.0	TD= 3.0	Pri amps= 200	TCC=	3/16/94		40	VOLT REST O/C	4-16	
51N	IAC58A	6.9	MVA= 0.48	P/U= 2.0	TD= 2.0	Pri amps= 40	TCC=	9/15/87		20	GND O/C	1.5-6	
49I	BL-1	6.9	MVA= 5.7	P/U= 12.0	TD=	Pri amps= 480	TCC=	9/15/87		40	WINDING TEMP. O/C	6.0-50	
27	PJV11B	6.9	MVA=	P/U=	TD=	Pri amps=	TCC=	9/15/87			INST U/V COMMON G1&G2	50-110	
40	KLF			TA=15.8	SA=2	MA=0.000	LA=.06 u				FIELD LOSS VOLT BKD		
49	BL-1	6.9	MVA= 2.0	P/U= 4.25	TD=	Pri amps= 170	TCC=	9/15/87		40	WINDING TEMP. O/C	2.5-5.0	
Eqpt code:		-LOK-G2 -											
Setting group:		kV						Date	PT	CT	Remarks	Range	Power Supply
51GN	IAC57A	6.9	MVA= 0.48	P/U= 2.0	TD= 2.0	Pri amps= 40	TCC=	9/15/87		20	GND O/C	1.5-6	
13	SV	6.9	MVA=	P/U=	TD=	Pri amps=	TCC=	9/15/87				70-160	

NF POWER- RELAY REPORT 1

Thursday, March 09, 2006

87	IJD52A	6.9	MVA=	P/U=	TD=	Pri amps=	TCC=	9/15/87		40	GEN DIFF	0.02-25%
51V	IJCV51	6.9	MVA= 2.4	P/U= 5.0	TD= 3.0	Pri amps= 200	TCC=	3/16/94		40	VOLT REST O/C	4-16
49	BL-1	6.9	MVA= 2.0	P/U= 4.25	TD=	Pri amps= 170	TCC=	9/15/87		40	WINDING TEMP O/C	2.5-5.0
40	KLF			TA=15.8	SA=2	MA=0.153	LA=.06 u		60	40	VOLT UNIT BKD	
49I	BL-1	6.9	MVA= 5.7	P/U= 12.0	TD=	Pri amps= 480	TCC=	9/15/87		40	WINDING TEMP. O/C	8.0-50

Eqpt code: -LOK-S/S -

Setting group:		kV						Date	PT	CT	Remarks	Range	Power Supply
50	IAC51B	6.9	MVA=	P/U= 40	TD=	Pri amps=	TCC=	9/15/87			PHASE C INST	20-80	
50	IAC53B	6.9	MVA=	P/U= 20	TD=	Pri amps=	TCC=	9/15/87			PHASE A INST	20-80	
50N	IAC51B	6.9	MVA=	P/U= 16	TD=	Pri amps=	TCC=	9/15/87			GND INST	4-16	
51	IAC53B	6.9	MVA=	P/U= 4.0	TD= 0.5	Pri amps=	TCC=	9/15/87			PHASE A O/C	4-16	
51	IAC51B	6.9	MVA=	P/U= 4.0	TD= 0.5	Pri amps=	TCC=	9/15/87			PHASE C O/C	4-16	
51N	IAC51B	6.9	MVA=	P/U= 0.6	TD= 0.5	Pri amps=	TCC=	9/15/87			GND O/C	0.5-2	

Eqpt code: -LOK-T1 -

Setting group:		kV						Date	PT	CT	Remarks	Range	Power Supply
51N	IAC77B	6.9	MVA= 0.36	P/U= 0.5	TD= 1.0	Pri amps= 30	TCC=	9/15/87		60	GND O/C	0.5-2	
81	KF	6.9	MVA=	P/U=	TD=	Pri amps=	TCC=	9/15/87			U/F COMMON BOTH GEN	55-59.5	
50	IAC77B	6.9	MVA= 28.7	P/U= 40	TD=	Pri amps= 2400	TCC=	9/15/87		60	PHASE INST	20-80	
50N	IAC77B	6.9	MVA= 7.2	P/U= 10	TD=	Pri amps= 600	TCC=	9/15/87		60	GND INST	10-40	
51	IAC77B	6.9	MVA= 4.3	P/U= 6.0	TD= 8.5	Pri amps= 360	TCC=	9/15/87		60	PHASE O/C	4-16	

Eqpt code: -NWB-T1 -

Setting group:		kV						Date	PT	CT	Remarks	Range	Power Supply
51	MCGG2	138	MVA= 14.34	P/U= 1.0	TD= 0.6	Pri amps= 60	TCC=	6/13/95		60	EI CURVE	0.25-12	
51NLV	MCGG2	25	MVA= 4.55	P/U= 1.75	TD= 0.97	Pri amps= 105	TCC=	10/26/92		60	VI CURVE	0.25-12	
50NLV	MCGG2	25	MVA=	P/U=	TD=	Pri amps=	TCC=	10/26/92		60	BLOCKED	0.25-372	
50/2	RXKF1	138	MVA=	P/U=	TD=	Pri amps=	TCC= 2.0	6/13/95				0.2-3.0	
50	MCGG2	138	MVA= 71.71	P/U= 5	TD=	Pri amps= 300	TCC=	10/26/92		60		0.25-372	
REMAR											HSGS AND MOTORIZED AIR		
89/2	RXKF1	138	MVA=	P/U=	TD=	Pri amps=	TCC= 5.0	10/26/92			T1-A TIMER	2-30	

Eqpt code: -PBD-T1 -

Setting group:		kV						Date	PT	CT	Remarks	Range	Power Supply
89/2	RXKF-1	138	MVA=	P/U=	TD=	Pri amps=	TCC= 5.0	11/8/90			T1-A Timer	1.0-10.0	
51NLV	MCGG2	25	MVA= 7.79	P/U= 4.5	TD= 0.65	Pri amps= 180	TCC=	11/8/90		40	VI CURVE	0.5-12.0	
51	MCGG2	138	MVA= 21.51	P/U= 2.25	TD= 0.25	Pri amps= 90	TCC=	11/8/90		40	VI CURVE	0.5-12.0	
50NLV	MCGG2	25	MVA=	P/U=	TD=	Pri amps=	TCC=	11/8/90		40	BLOCKED	0.5-372	
50/2	RXKF-1	138	MVA=	P/U=	TD=	Pri amps=	TCC= 1.5	11/8/90				0.3-3	
50	MCGG2	138	MVA= 86.05	P/U= 9.0	TD=	Pri amps= 360	TCC=	11/8/90		40		0.5-372	

Eqpt code: -PUN-2.4B-

Setting group:		kV						Date	PT	CT	Remarks	Range	Power Supply
46/50	RIRA	2.4									OPERATES FROM 46 OUTP		
27	IAV54	2.4	MVA=	P/U=	TD=	Pri amps=	TCC=	12/30/97	20			55-140	
46/50T	AGAST	2.4	MVA=	P/U=	TD=	Pri amps=	TCC= 0.5	11/16/87			TIMER FOR 46/50	0.5-5	
81	KF	2.4	MVA=	P/U=	TD=	Pri amps=	TCC=	11/9/87	20		TRIPS G1,G2,G3	55-59.5	

Maximum Generation Fault LOK 6.9 kV.

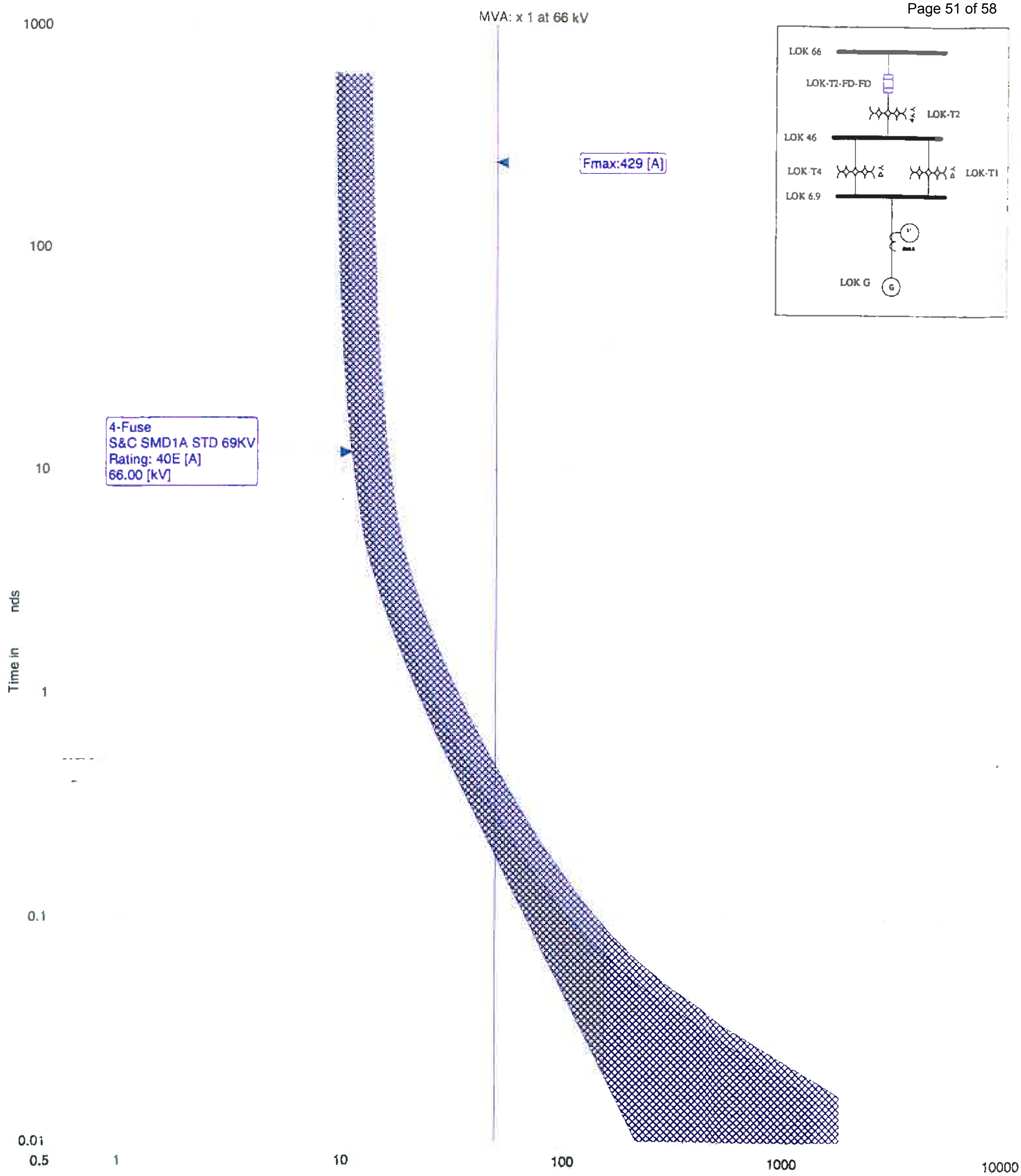
ID	Type	Prefault kV	Angle	Fault type	Fault S [MVA]	Ia [A]	Ia [deg]	Ib [A]	Ib [deg]	Ic [A]	Ic [deg]	In [A]	In [deg]
Faulted Bus ->													
LOK 07		6.9	0	LLL	49	4106.6676	-81.2169	4106.6675	158.7831	4106.6675	38.7831	0	0
First Ring Contributions													
LOK G1	Generator	6.9	0	LLL	12	1033.3733	-90	1033.3733	150	1033.3733	30	0	0
LOK T4	Fixed-Tap Xmer	6.9	0	LLL	18	1534.5262	-78.4658	1534.5262	161.5342	1534.5262	41.5342	0	0
LOK T1	Fixed-Tap Xmer	6.9	0	LLL	19	1555.3501	-78.1188	1555.3501	161.8812	1555.3501	41.8812	0	0

Faulted Bus	Branch Id	Type	Fault type	Branch Sid	Ia [A]	Ia [deg]	Ib [A]	Ib [deg]	Ic [A]	Ic [deg]	In [A]	In [deg]
LOK 07	LOK T2	Fixed-Tap Xme	LLL	LOK 66	323	131.7089	323	11.7089	323	-108.2911	0	0
LOK 07	LOK T2	Fixed-Tap Xme	LLL	LOK 46	463.5	-48.2911	463.5	-168.2911	463.5	71.7089	0	0

Current Multiplier for CYMTCC LOK-T2-FD

= 49 MVA / (323*66*SQRT3/1000)

Current Multiplier = 1.33



For LLL LOK 6.9 kV fault at Maximum Generation. LOK-T2-FD maximum melting time 0.4715 seconds with existing 40E S&C SMD-1A Standard Speed 69kV fuses.

Dave Jones

March 09, 2006

Study: C:\Arc Flash\Plants\LOK\LOK T1 Fuse Max Gen LLL.lcc

Minimum Generation Fault LOK 6.9 kV. LOK plant on.

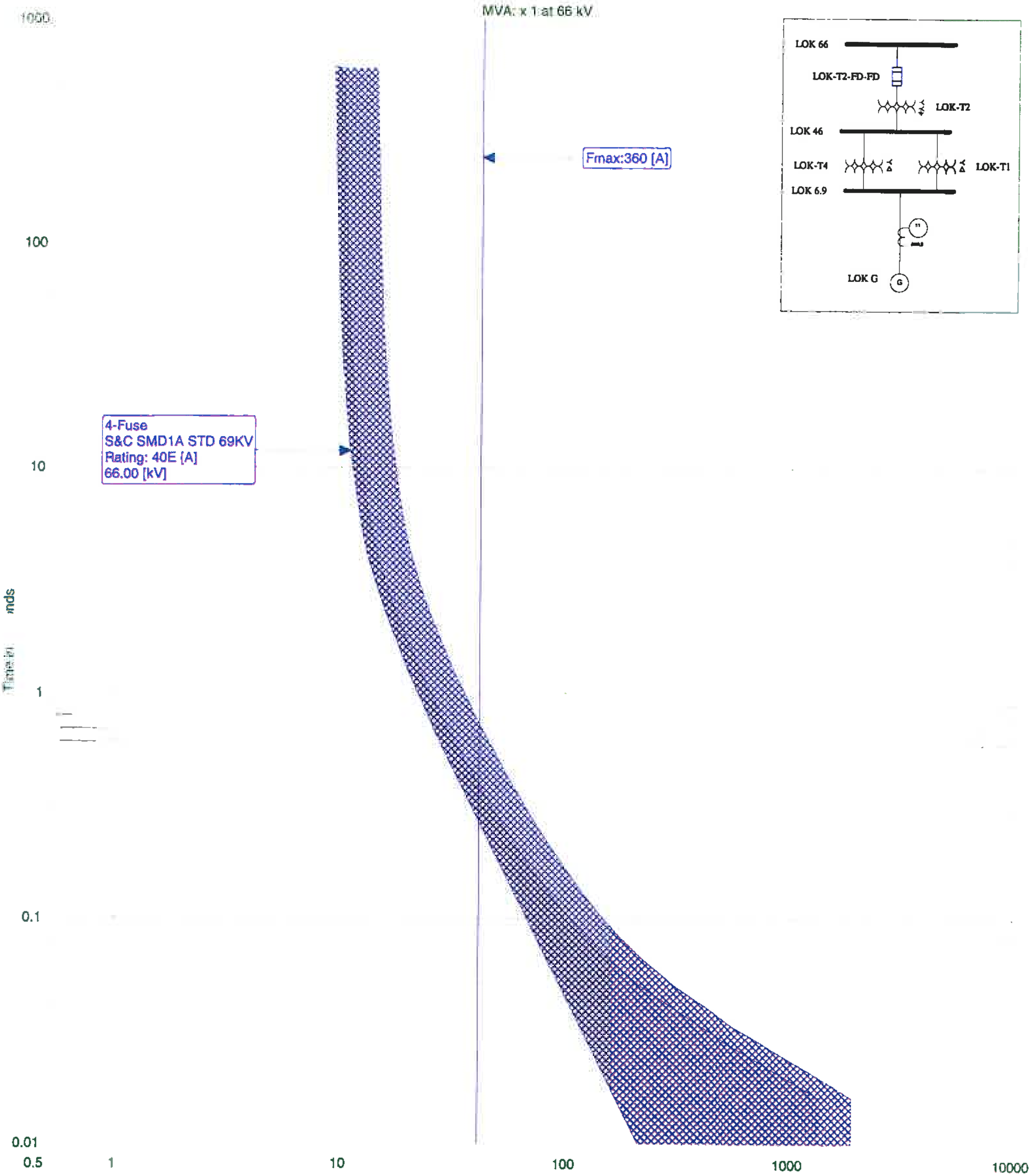
ID	Type	Prefault kV	Angle	Fault type	Fault S [MVA]	Ia [A]	Ia [deg]	Ib [A]	Ib [deg]	Ic [A]	Ic [deg]	In [A]	In [deg]
Faulted Bus ->													
LOK 07		6.9	0	LLL	41	3441.4846	-81.198	3441.4846	158.802	3441.4846	38.802	0	0
First Ring Contributions													
LOK T4	Fixed-Tap Xmer	6.9	0	LLL	14	1204.7335	-77.6356	1204.7335	162.3644	1204.7335	42.3644	0	0
LOK T1	Fixed-Tap Xmer	6.9	0	LLL	15	1221.1073	-77.2894	1221.1073	162.7106	1221.1073	42.7106	0	0
LOK G1	Generator	6.9	0	LLL	12	1033.3733	-90	1033.3733	150	1033.3733	30	0	0

Faulted Bus	Branch id	Type	ault typ	Branch Sid	Ia [A]	Ia [deg]	Ib [A]	Ib [deg]	Ic [A]	Ic [deg]	In [A]	In [deg]
LOK 07	LOK T2	Fixed-Tap Xme	LLL	LOK 66	253.6	132.5382	253.6	12.5382	253.6	-107.4618	0	0
LOK 07	LOK T2	Fixed-Tap Xme	LLL	LOK 46	363.9	-47.4618	363.9	-167.4618	363.9	72.5382	0	0

Current Multiplier for CYMTCC LOK-T2-FD

= 41 MVA / (253.6*66*SQRT3/1000)

Current Multiplier = 1.41



For LLL LOK 6.9 kV fault at Minimum Generation. LOK-T2-FD maximum melting time 0.7292 seconds with existing 40E S&C SMD-1A Standard Speed 69kV fuses.

Dave Jones

March 09, 2006

Study: C:\Arc Flash\Plants\LOK\LOK T1 Fuse Min Gen LLL.tcc

Arc Flash Hazard LOK 6.9 kV
IEEE standard

Faulted Bus	Generation	Fault	Fault Current	CT	CT Plus Fuses	Working Distance	Flash Hazard Boundry	cal / cm2	PPE Level	L.A.B.	R.A.B.	P.A.B.
LOK 6.9	Max	LLL	4107	0.4715	0.4715	16"	91"	6.5	2	60"	26"	7"
LOK 6.9	Min	LLL	3441	0.7292	0.7292	16"	117"	8.3	3	60"	26"	7"

Faulted Bus	Generation	Fault	Fault Current	CT	CT Plus Fuses	Working Distance	Flash Hazard Boundry	cal / cm2	PPE Level	L.A.B.	R.A.B.	P.A.B.
LOK 6.9	Max	LLL	4107	0.4715	0.4715	36"	91"	3.0	1	60"	26"	7"
LOK 6.9	Min	LLL	3441	0.7292	0.7292	36"	117"	3.8	1	60"	26"	7"

***Arc Flash Calculated for Switchgear and fixed conductor.**
Software won't supply Arc Flash results for clearing times over one second.

L.A.B. Limited Approach Boundry
R.A.B. Restricted Approach Boundry
P.A.B. Prohibited Approach Boundry

WARNING

Arc Flash and Shock Hazard Appropriate PPE Required

91 inches	Flash Hazard Boundary
6.5	cal / cm2 Flash Hazard at 16 inches
class 2	PPE Level, Cotton underwear - conventional short sleeve and brief/sh plus FR shirt and FR pants (1 or 2 layers). Hard hat, arc rated face shield, ear, hand and foot protecti
6900 VAC	Shock Hazard
60 inches	Limited Approach
26 inches	Restricted Approach
7 inches	Prohibited Approach

Equipment Name:LOK 07

WARNING

Arc Flash and Shock Hazard Appropriate PPE Required

91 inches Flash Hazard Boundary
6.5 cal / cm2 Flash Hazard at 16 inches
class 2 PPE Level, Cotton underwear - conventional short sleeve and brief/sh plus FR shirt and FR pants (1 or 2 layers). Hard hat, arc rated face shield, ear, hand and foot protecti
6900 VAC Shock Hazard
60 inches Limited Approach
26 inches Restricted Approach
7 inches Prohibited Approach

Equipment Name:LOK 07

WARNING

Arc Flash and Shock Hazard Appropriate PPE Required

91 inches Flash Hazard Boundary
6.5 cal / cm2 Flash Hazard at 16 inches
class 2 PPE Level, Cotton underwear - conventional short sleeve and brief/sh plus FR shirt and FR pants (1 or 2 layers). Hard hat, arc rated face shield, ear, hand and foot protecti
6900 VAC Shock Hazard
60 inches Limited Approach
26 inches Restricted Approach
7 inches Prohibited Approach

Equipment Name:LOK 07

WARNING

Arc Flash and Shock Hazard Appropriate PPE Required

91 inches Flash Hazard Boundary
6.5 cal / cm2 Flash Hazard at 16 inches
class 2 PPE Level, Cotton underwear - conventional short sleeve and brief/sh plus FR shirt and FR pants (1 or 2 layers). Hard hat, arc rated face shield, ear, hand and foot protecti
6900 VAC Shock Hazard
60 inches Limited Approach
26 inches Restricted Approach
7 inches Prohibited Approach

Equipment Name:LOK 07

WARNING

Arc Flash and Shock Hazard
Appropriate PPE Required

117 inches	Flash Hazard Boundary
8.3	cal / cm2 Flash Hazard at 16 inches
class 3	PPE Level, Cotton underwear plus FR shirt and FR pants plus FR coverall, or cotton underwear plus two FR coveralls (2 or 3 layers). FR hard hat, safety glasses or goggles, flash suit hood, ear, hand and foot protection.
6900 VAC	Shock Hazard
60 inches	Limited Approach
26 inches	Restricted Approach
7 inches	Prohibited Approach

Equipment Name:LOK 07

WARNING

Arc Flash and Shock Hazard
Appropriate PPE Required

117 inches	Flash Hazard Boundary
8.3	cal / cm2 Flash Hazard at 16 inches
class 3	PPE Level, Cotton underwear plus FR shirt and FR pants plus FR coverall, or cotton underwear plus two FR coveralls (2 or 3 layers). FR hard hat, safety glasses or goggles, flash suit hood, ear, hand and foot protection.
6900 VAC	Shock Hazard
60 inches	Limited Approach
26 inches	Restricted Approach
7 inches	Prohibited Approach

Equipment Name:LOK 07

WARNING

Arc Flash and Shock Hazard
Appropriate PPE Required

117 inches	Flash Hazard Boundary
8.3	cal / cm2 Flash Hazard at 16 inches
class 3	PPE Level, Cotton underwear plus FR shirt and FR pants plus FR coverall, or cotton underwear plus two FR coveralls (2 or 3 layers). FR hard hat, safety glasses or goggles, flash suit hood, ear, hand and foot protection.
6900 VAC	Shock Hazard
60 inches	Limited Approach
26 inches	Restricted Approach
7 inches	Prohibited Approach

Equipment Name:LOK 07

WARNING

Arc Flash and Shock Hazard
Appropriate PPE Required

117 inches	Flash Hazard Boundary
8.3	cal / cm2 Flash Hazard at 16 inches
class 3	PPE Level, Cotton underwear plus FR shirt and FR pants plus FR coverall, or cotton underwear plus two FR coveralls (2 or 3 layers). FR hard hat, safety glasses or goggles, flash suit hood, ear, hand and foot protection.
6900 VAC	Shock Hazard
60 inches	Limited Approach
26 inches	Restricted Approach
7 inches	Prohibited Approach

Equipment Name:LOK 07

WARNING

Arc Flash and Shock Hazard
Appropriate PPE Required

91 inches	Flash Hazard Boundary
3.0	cal / cm2 Flash Hazard at 36 inches
class 1	PPE Level, FR shirt and FR pants or FR coverall (1 layer). Hard hat and safety glasses.
6900 VAC	Shock Hazard
60 inches	Limited Approach
26 inches	Restricted Approach
7 inches	Prohibited Approach

Equipment Name:LOK 07

WARNING

Arc Flash and Shock Hazard
Appropriate PPE Required

91 inches	Flash Hazard Boundary
3.0	cal / cm2 Flash Hazard at 36 inches
class 1	PPE Level, FR shirt and FR pants or FR coverall (1 layer). Hard hat and safety glasses.
6900 VAC	Shock Hazard
60 inches	Limited Approach
26 inches	Restricted Approach
7 inches	Prohibited Approach

Equipment Name:LOK 07

WARNING

Arc Flash and Shock Hazard
Appropriate PPE Required

91 inches	Flash Hazard Boundary
3.0	cal / cm2 Flash Hazard at 36 inches
class 1	PPE Level, FR shirt and FR pants or FR coverall (1 layer). Hard hat and safety glasses.
6900 VAC	Shock Hazard
60 inches	Limited Approach
26 inches	Restricted Approach
7 inches	Prohibited Approach

Equipment Name:LOK 07

WARNING

Arc Flash and Shock Hazard
Appropriate PPE Required

91 inches	Flash Hazard Boundary
3.0	cal / cm2 Flash Hazard at 36 inches
class 1	PPE Level, FR shirt and FR pants or FR coverall (1 layer). Hard hat and safety glasses.
6900 VAC	Shock Hazard
60 inches	Limited Approach
26 inches	Restricted Approach
7 inches	Prohibited Approach

Equipment Name:LOK 07

WARNING

Arc Flash and Shock Hazard
Appropriate PPE Required

117 inches	Flash Hazard Boundary
3.8	cal / cm2 Flash Hazard at 36 inches
class 1	PPE Level, FR shirt and FR pants or FR coverall (1 layer). Hard hat and safety glasses.
6900 VAC	Shock Hazard
60 inches	Limited Approach
26 inches	Restricted Approach
7 inches	Prohibited Approach

Equipment Name:LOK 07

WARNING

Arc Flash and Shock Hazard
Appropriate PPE Required

117 inches Flash Hazard Boundary
3.8 cal / cm2 Flash Hazard at 36 inches
class 1 PPE Level, FR shirt and FR pants or FR coverall (1 layer). Hard hat and safety glasses.
6900 VAC Shock Hazard
60 inches Limited Approach
26 inches Restricted Approach
7 inches Prohibited Approach

Equipment Name:LOK 07

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Port Union and Lawn Rehabilitation
April 2011

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April 2011
DATE
NEWFOUNDLAND & LABRADOR

NEWFOUNDLAND POWER
A FORTIS COMPANY

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A. BACKGROUND

Introduction

Eastern Newfoundland experienced an extreme weather event related to Hurricane Igor on the evening of Monday September 20th and throughout the day on Tuesday September 21st, 2010. This event caused damage throughout most of Eastern Newfoundland to public infrastructure such as roads and bridges, along with buildings, private homes and businesses. It also caused damage to the Newfoundland Power ("the Company") electricity system.

Damage to the electricity system resulted in immediate service outages to Newfoundland Power's customers. The timely restoration of service was the primary focus of Newfoundland Power's response to Hurricane Igor. The timely restoration of service required the Company to make material operating and capital expenditures in 2010.

The cost and scope of work associated with the timely restoration of service to customers was the subject of an application for supplementary capital expenditure under the Allowance for Unforeseen Items filed by the Company on November 17, 2010 and subsequently approved in Board Order No. P. U. 35 (2010). This urgent service restoration work was completed in 2010.

Hurricane Igor also resulted in material damage to two of Newfoundland Power's hydroelectric generating facilities that was not addressed in 2010. Rainfall in excess of 200 mm which accompanied Hurricane Igor caused extensive damage to both the Port Union and Lawn hydroelectric generating facilities. Flood levels experienced at these two plants exceeded those established by the latest Canadian Dam Association ("CDA") Dam Safety Guidelines.

The rehabilitation work required at these two generating plants was so extensive that complete and immediate restoration was not possible. Temporary work was completed to secure both sites before winter.[1] Port Union plant remains out of service awaiting restoration work to be completed. This report addresses the damage sustained and the work necessary to fully restore both the Port Union and Lawn facilities and to return Port Union plant to service. The report also addresses the abandonment of the 46 year old diesel electric generator at Port Union.

The total capital expenditure associated with the 2011 project is estimated to be $ 1.8 million.

Hurricane Igor

On the afternoon of Tuesday, September 21st, 2010, Hurricane Igor passed east of the Avalon Peninsula maintaining hurricane status until the centre of the storm was located northeast of St. John's, at which time it was downgraded to post-tropical status. This storm caused severe flooding and wind damage due to the combined effect of Hurricane Igor and a stationary front that had previously developed to the north of the hurricane as it approached Newfoundland.

[1] Tenders were issued for the work at Lawn Spillway in October 2010 with only 1 bidder providing a quote. Upon review it was determined that the tender price was not reflective of the work involved. A decision was therefore made to carry out temporary repairs in 2010, and re-tender the work in the spring of 2011 when more competitive bids are anticipated.

Environment Canada has described the storm as the worst in memory and has no records of hurricanes or post tropical events of this magnitude striking Newfoundland in the modern era. It was effectively a 50 to 100 year storm. Rainfall of 238 mm at St. Lawrence on the Burin Peninsula during Hurricane Igor was unprecedented, amounting to a 1-in-10,000 year rainfall event.[2] Maximum recorded wind speed on the Avalon Peninsula was 172 km/hr.

The combination of heavy rainfall and high winds associated with Hurricane Igor impacted Newfoundland Power's electricity system in a number of ways. There were a large number of vegetation related distribution system failures, particularly on the Northeast Avalon Peninsula.

In addition, the record rainfalls caused flooding which eroded civil works, such as roads used to provide access to Company facilities, as well as civil structures employed to provide stability to dams and spillways associated with a number of hydroelectric plants in Eastern Newfoundland. These flood conditions caused material damage to the Company's hydroelectric generating facilities at Port Union and Lawn.

B. SYSTEM DAMAGE

Port Union Hydroelectric Development

Newfoundland Power's Port Union hydroelectric generating facility is located in the community of Port Union on the Bonavista Peninsula. The facility contains three generating units producing approximately 2.3 GWh annually.

Two of these generating units (G1 and G2) are 280 kW hydro units which are supplied by a single woodstave penstock and concrete intake. The penstock is 137 meters long with a diameter of 1.37 meters. Storage reservoirs and diversions are provided by structures located at Whirl Pond, Long Pond, Well's Pond and Halfway Pond.

The third generating unit at Port Union is a 500 kW diesel electric generator.[3] In 1945, Union Electric installed a diesel electric generator at Port Union to backup the hydroelectric generators at times of low water in the reservoir. In 1965, this original diesel generator was replaced by the Caterpillar D398A unit which is being abandoned at this time.

Flood Damage – Port Union

During Hurricane Igor, the Port Union area received more than 200mm of rainfall. As a result, water overtopped the Port Union forebay dam and flooded the powerhouse. The maximum depth of water inside the powerhouse was approximately 2 meters. The water and floating debris caused extensive damage to the generators, switchgear, protection and control equipment, and the building structure including windows, doors and an office inside the powerhouse.

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2 Based on the Canadian Dam Association Dam Safety Guidelines.

3 The 500kW Port Union diesel electric generator is similar in size to the emergency stand-by generator serving the Company's Kenmount Road office building.

As water levels rose in the river adjacent to the plant, extensive damage was caused to the downstream plant access road. The flood waters also caused extensive damage to the Whirl Pond dam, the three Whirl Pond Freeboard dams and the Long Pond outlet structure.

Figure 1 shows water inside the Port Union powerhouse. Figure 2 shows water levels in the river adjacent to the plant.

Figure 1 - 2m of water in the powerhouse (Note: Turbine still spinning)

Figure 2 - Flood Flows at Port Union Plant

The generators, governors, switchgear, control panels, metering panel, battery bank, battery charger, DC distribution panel and AC distribution panel were partially or completely submerged by the approximate 2 metres of water that flowed through the powerhouse.

Flood conditions prevented operation of control systems which would have shut down the two hydroelectric generating units. The water interfered with the operation of the belt-driven governors, resulting in the wicket gates remaining open. The units continued to rotate until the following day when personnel were able to safely enter the plant. The rotation of the generators compounded the damage sustained to the stator windings, rotor windings and exciters by drawing debris into the units.

The damage to generator G2 was more severe as this unit is located closer to the windows where the debris was entering. Eventually the large door in the downstream end of the plant gave way under the pressure of the water inside the building. This resulted in a sudden flow of water out of the powerhouse. This dislodged the wood-frame walls of the interior office space, causing it to strike the manual control wheel for the governor on generator G1. The manual control wheel shaft was bent by the impact.

The diesel electric generator also suffered considerable damage while it was submerged. Water and silt entered the crank case of the Caterpillar D398A engine and alternator. The diesel generator breaker and controls were damaged beyond repair.

Figure 3 - Whirl Pond Dam

Storage structures on Whirl Pond and Long Pond also overtopped causing extensive damage. High flows eroded the abutments at the control gate on Long Pond. At Whirl Pond, the spillway capacity was exceeded by the flood flows that were 2.5 times the 1-in-1000 year flows. As a result Whirl Pond Dam overtopped eroding the crest and downstream side of the dam to the steel core as shown in Figure 3. The three freeboard dams on Whirl Pond were also damaged, with two being significantly eroded with overtopping flows and one receiving minor damage from wave action.

Appendix A contains an engineering assessment of the damage incurred at the Port Union facility as well as the rehabilitation work required.

Lawn Hydroelectric Development

Newfoundland Power's Lawn hydroelectric generating facility, located in the community of Lawn, on the Burin Peninsula, contains one 625 kW generating unit producing approximately 2.5 GWh annually.

The generating unit is supplied by a woodstave penstock fed through an intake in the forebay dam. The penstock is 286 meters long with a diameter of 1.07 meters. The forebay dam is constructed of rock masonry with a concrete base and an upstream and downstream concrete face. The downstream face is covered with a layer of mesh reinforced shotcrete. Additional rockfill was added in 1995 to stabilize the dam.

Flood Damage – Lawn

During Hurricane Igor, rain gauges in nearby St. Lawrence recorded 238 mm of rainfall. Flood water flow at the Lawn development peaked at 284 m^3/s, or 1.5 times the 1-in-1000 year flows. As a result, the Lawn forebay dam was overtopped by 0.45 meters of water.

This overtopping damaged the mesh reinforced shotcrete on the crest and downstream face of the dam and completely washed away the dam's downstream rockfill. The flood water also undermined the penstock, washing away several timber supports, leaving portions of the penstock suspended in the air. The multi-plate culvert along with its concrete foundation, which had protected the woodstave penstock from the downstream rockfill, was also undermined and significantly damaged.[4]

[4] Pictures of the woodstave penstock and culvert are included in Appendix B.

Other damage around the forebay included a bent support strut and damaged cladding on the gatehouse, damaged and missing sections of guard rail and security fence, and partial washouts at the abutments.

Appendix B contains an engineering assessment of the damage incurred at the Lawn facility as well as the rehabilitation work required.

C. PROJECT

Engineering assessments carried out by Newfoundland Power personnel and technical personnel representing the Company's insurers have identified the following work to be completed in 2011.

Project Scope – Port Union

The project in 2011 to rehabilitate the Port Union hydroelectric facility consists of the following scope of work:

1. Civil restoration of the powerhouse building and downstream retaining wall,
2. Mechanical overhaul of the two generators,
3. Replacement of hydraulic governors,
4. Replacement of the generator stator windings, rotor windings and exciter on G1,
5. Refurbishment of the generator stator windings, rotor windings and exciter on G2,
6. Refurbishment of the switchgear and circuit breakers,
7. Replacement of the G1 and G2 control panels, and
8. Replacement of the battery bank and charger.

The new equipment will be consistent with standards employed in the Company's recent hydroelectric facility upgrades. The functionality of the plant will be restored using modern components to replace the damaged equipment.

It has been determined that refurbishing the diesel electric generator would not be cost-effective. Due to its inadequate size and location relative to the Island interconnected system, the diesel electric generator is no longer suited to its original role as a source of standby electricity in the event of an extended outage.. Because it was no longer required for backup generation, and due to its deteriorated condition, the diesel electric generator was already under consideration for retirement before it sustained damage during the flooding associated with Hurricane Igor. The unit was last operated in 2007.[5]

The diesel unit was decommissioned while contractors working on behalf of the Company's insurers were onsite completing flood damage cleanup, and was shipped to a metal recycling facility for disposal.

[5] The estimated cost to refurbish the unit to pre-flood conditions is $131,000. Returning the diesel electric generator to pre-flood condition would involve dismantling the unit, cleaning the engine and generator, and replacing bearings and seals. Also all of the protection and control equipment would need to be replaced. Additional expenditures with respect to the fuel system, breaker and controls would be required to return the unit to service.

Cost Estimate - Port Union

Table 1 provides a breakdown of the estimated cost to rehabilitate the Port Union hydroelectric facility.

Table 1
2011 Port Union Plant Refurbishment
($000's)

Cost Category	Total
Material	630
Labour – Internal	90
Labour – Contractor	510
Engineering	70
Other	50
Total	**1,350**

The estimated project cost in 2011 to refurbish the Port Union plant is $1.3 million.

The Company's total estimate to repair damage incurred at Port Union plant is $1.65 million. This includes approximately $320,000 in 2010 costs related to the refurbishment of various dams, site cleanup and securing the site for the winter. A significant portion of the cost of the project is covered by insurance. This insured loss is subject to a $100,000 deductible.[6]

The total project cost includes several items not fully covered by the Company's insurance. They include items, such as a programmable logic controller, that are necessary for the efficient operation of the plant and are considered as betterment. The net expenditure not covered by the Company's insurance claim is estimated to be $250,000.

Appendix C provides an economic feasibility analysis for the continued operation of the Port Union hydroelectric development. The results of the analysis show that the continued operation of Port Union hydroelectric development is economical over the long term. Investing in the return to service of Port Union plant ensures the continued availability of 2.3 GWh of energy annually to the Island interconnected system.

The estimated levelized cost of energy from the Port Union facility over the next 50 years, including estimated future capital expenditures of $3,532,000, is 7.81¢/kWh. This energy is lower in cost than replacement energy from sources such as new hydroelectric developments or additional Holyrood thermal generation.[7]

[6] Newfoundland Power's insurance coverage is subject to a $200,000 deductible per event. Because Hurricane Igor is considered one event, the deductible is apportioned between the Port Union and Lawn refurbishments.

[7] The cost of electricity from the Holyrood thermal generating station is estimated at 11.63¢ per kWh. This is based upon a 630 kWh/barrel conversion efficiency and oil price forecast from Hydro of $73.30 per barrel for 2010 as per Newfoundland Hydro 2010 Capital Budget Application, Generation Planning Issues 2009 Mid Year Report dated July 2009.

Project Scope – Lawn

The project in 2011 to rehabilitate the Lawn hydroelectric facility consists of the following scope of work:

1. Construct new penstock supports,
2. Replace the mesh reinforced concrete decking and walkway, and
3. Reinstate the downstream rockfill and multi-plate culvert.

The remediation work will take into account the latest CDA Dam Safety Guidelines and the most recent published hydrometric data. These repairs are required to ensure the long term stability and safety of the Lawn Forebay dam.

Cost Estimate - Lawn

The estimated cost in 2011 to rehabilitate the Lawn hydroelectric facility is provided in Table 2.

Table 2
2011 Lawn Plant Refurbishment
($000's)

Cost Category	Total
Material	280
Labour – Internal	-
Labour – Contractor	145
Engineering	15
Other	10
Total	**450**

The total project cost is estimated to be $450,000, all of which is covered by insurance. This insurance coverage is subject to a $100,000 deductible. [8]

Appendix D provides an economic feasibility analysis for the continued operation of Lawn hydroelectric development. The results of the analysis show that the continued operation of Lawn hydroelectric development is economical over the long term. Investing in the return to service of Lawn plant ensures the continued availability of 2.6 GWh of energy annually to the Island interconnected system.

[8] Newfoundland Power's insurance coverage is subject to a $200,000 deductible per event. Because Hurricane Igor is considered one event, the deductible will be split between the Port Union and Lawn facilities rehabilitation.

The estimated levelized cost of energy from the Lawn facility over the next 50 years, including estimated future capital expenditures of $4,547,000, is 6.17 ¢/kWh. This energy is lower in cost than replacement energy from sources such as new hydroelectric developments or additional Holyrood thermal generation.[9]

Project Schedule

The necessary engineering and design work has been ongoing since Hurricane Igor occurred in September 2010. It is anticipated that work at the Port Union site will be completed in September 2011. Work at the Lawn site is anticipated to be completed in August 2011.

[9] See footnote 7.

Appendix A

Damage Assessment
Port Union Plant

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1.0 General

Hurricane Igor brought more than 200mm of rain to the Port Union area resulting in a flood flow that was 1.4 times the 1-in-10,000 year event for that location. As water rose in the river adjacent to the plant, extensive damage was caused to the downstream plant access road. The high waters and associated debris entered the plant through several windows causing extensive damage to the plant equipment and the interior of the powerhouse. Most of the windows and doors will require replacement and an office inside the plant was destroyed.

This engineering assessment identifies the various electrical, civil and mechanical engineering systems that were damaged by the storm and resulting flood conditions.[1]

New equipment identified to replace flood damaged equipment will be consistent with standards employed in the Company's recent hydroelectric facility upgrades. The pre-loss functionality of the plant will be restored using modern components to replace the existing equipment. A significant portion of the cost of the project is covered by insurance.

2.0 Electrical Engineering

Various electrical systems were damaged by the flood waters that entered the powerhouse. Some equipment can be refurbished and returned to service; other systems were damaged so extensively that they will require replacement. The assessment focuses on the six main electrical subsystems that comprise the hydroelectric generating systems.

2.1 Generators

The two generators, G1 and G2, were disassembled, inspected and tested by a third party to determine the extent of the damage.[2] The stators have wood and grass embedded between the laminations. This damage is more extensive on G2 than G1. The G2 stator winding has short circuited to the steel casing. The G2 rotor poles and slip rings were damaged by impact with debris floating in the water. The G2 exciter windings are in poor shape with heat damage and visible burn marks suggesting the unit was energized as water levels rose. The commutator on the exciter has extensive copper damage.

Figure 1 - Damage to G1 Stator and Rotor

[1] An engineering assessment of the civil infrastructure was completed by Gary Humby, P.Eng. and Bill Titford, CET on September 28, 2010. An engineering assessment of the damage to protection and control and electrical systems was completed by Jeremy Decker P. Eng. on October 1, 2010.

[2] The inspection of the 2 generators was completed by Weir Canada, Inc. of LaSalle Quebec.

It was determined that G2 stator winding, rotor winding and exciter will require complete rewinding. As less damage was experienced on generator G1 an overhaul of the stator winding, rotor winding and exciter will be sufficient to refurbish G1. Power cables for the stator and exciter on G1 require replacement. Figure 1 shows damage to the stator and rotor on G1.

2.2 Governors

When the powerhouse became flooded, the water interfered with the normal operation of the belt-driven governors on both units, resulting in the failure of the governor to close the wicket gates as required. While submerged, both generators continued to rotate, damaging various governor components.

The manual control wheel for the governor on G1 was damaged by collision with the plant office structure, which had been dislodged by the flow of water exiting the powerhouse.

These governors are original to the plant's 1917 construction, and replacement parts are no longer available from the manufacturer, the Pelton Water Wheel Company. It is recommended that the governors be removed and replaced with a programmable logic controller-based system to control the speed of the units during synchronizing and loading.

2.3 Switchgear

The generator breakers were completely submerged and will require refurbishment at a facility with the specialized test equipment, parts and skills to complete this work. All switchgear compartments and control wiring will be cleaned and dried on site. The CTs were submerged but are sealed units that will be reused after cleaning, drying and testing. The generator PTs are located in the top compartments of the switchgear and were not submerged. They will be reused. The bus PT is located in the bottom of the metering cubicle that was completely submerged. It will be tested and reused if possible. If not, it will be replaced by the generator PT that is currently on the diesel unit, generator G3, which is being retired.

Figure 2 - Damaged Switchgear

2.4 Protection and Control

Figure 3 - Damaged Protection and Control

The protective relays, voltage regulators, controls switches and bottom row of meters were all submerged causing the mechanisms and electrical contacts in this equipment to corrode. As a result, they are no longer serviceable. Figure 3 shows the high water mark relative to the equipment mounted in the panels.

Panels will be replaced with new cabinets and installed in a location away from the switchgear.[3]

The new control panels will contain digital voltage regulators incorporated into Combination Generator Control Modules (CGCMs). The CGCM modules will also provide synchronizing and metering functionality.

The original generator protection scheme included only a voltage restrained overcurrent element. Generator multifunction relays will be used to provide increased generator protection. This will include instantaneous overcurrent, under-voltage, over-voltage, loss of potential, reverse power, under frequency, volts per hertz, loss of field and thermal protection elements in addition to voltage-restrained overcurrent protection.[4]

A new plant revenue meter will be installed to replace the existing unit that was submerged. A programmable logic controller (PLC) with interactive display will be installed to provide metering information, unit instrumentation data, to automate plant control functions and provide water management to maximize and improve the efficiency of the plant. All the existing metering will be replaced by the CGCM module and the PLC.

2.5 AC Distribution

The AC panel and distribution system has been cleaned, dried and returned to service. The panel is currently energized, and is providing electricity to some of the equipment in the powerhouse. There will be no additional work associated with refurbishing the AC panel and distribution system.

3 The Company locates equipment panels that require operator intervention away from switchgear cubicles to minimize the exposure of employees to arc flash hazards.

4 These protection elements are consistent with similar protection schemes put in place for generators of similar size during recent refurbishment projects.

2.6 DC System

Figure 4 - DC Distribution Panel and Battery Charger

The DC panel and distribution system has been cleaned, dried and returned to service.

Water damage to the battery bank and battery charger equipment was substantial. These components will require replacement.

A gel-type battery bank, which eliminates the environmental and safety concerns associated with lead-acid wet-cell batteries, will be used.

3.0 Civil Engineering

Damage from the flood waters was experienced by various civil engineering systems, both inside the powerhouse and elsewhere on the site. The powerhouse building windows, doors and office were extensively damaged and require replacement.

3.1 Building Damage

The powerhouse windows are used for ventilation when the generators are running. Flood waters entering the powerhouse damaged the lower portion of 15 windows as water passed through the plant. These wooden windows range in size from 1100 mm x 1400 mm to 1490 mm x 2775 mm. They were constructed in place with panes of glass measuring approximately 300 mm x 300 mm.

Figure 5 - Damaged Plant Windows

Immediately after the flood, the windows were temporarily boarded up to secure the plant and make it weather tight. The damaged windows are not repairable and therefore require complete replacement. The new sliding windows will be of vinyl construction.

The exterior door of the powerhouse was damaged beyond repair and was replaced immediately after the flood to secure the plant.

The interior office was also damaged beyond repair. It will be rebuilt to include the control room for the plant.

3.2 Site Damage

Figure 6 - Erosion, Plant Access Road (Downstream of Plant)

The high flood waters in the channel adjacent to the powerhouse caused severe erosion of the access road. The road has been temporarily restored to allow access to the plant during the winter season. Additional work is required to permanently stabilize the road and provide long term access to the plant.

The required work includes the widening of the road to its previous width, slope stabilization using gabions and rip rap, and the reinstatement of the security fence.

4.0 Mechanical Engineering

4.1 Mechanical Work

Figure 7 - Turbine guide bearing showing filiform corrosion. Depth of defect is about 0.0005"

Figure 8 – Scoring on Babbitt

Figure 9 – Delaminating of Babbitt

As a result of the high water levels present, both units ran with no oil in the bearings for an extended period. Both units were disassembled, inspected and tested by a third party to determine the extent of the damage. Inspections revealed that water entered the bearings and caused corrosion and scoring. The bearings will be refurbished and bored to an adequate size. Bearing housings also show radial cracking of the threaded bolt holes, which will be repaired.

Some bearings were found to be misaligned by amounts that approach the allowable clearance. Bearing housings will be machined to correct alignment issues.

Both units will be reassembled using modern laser alignment techniques. This will ensure continued reliability of the refurbished components.

4.2 Diesel Electric Generator

The diesel electric generator at Port Union was installed by Union Electric in 1945 as a backup to the hydroelectric generators when water levels in the reservoir were low. In 1965, the original unit was replaced by a Caterpillar D398A engine and a General Electric 675 kVA generator. It is this equipment which is now being retired from service.

When it was installed in 1945, the Port Union diesel generator was an adequate source of standby electricity in the event of unavailability of the local hydroelectric plant. Since the development of the Island interconnected grid, a backup generator is no longer required, and the cost of refurbishing the Port Union diesel is not justified. The unit was already being considered for abandonment before it sustained damage during Hurricane Igor.

Several refits of the unit have been completed, with the most recent being in 1998. The 1998 refit replaced four of the six cylinder heads and the engine fuel lines. Repairs were also made at the time to the starboard turbo charger, and the UG8 Woodward governor was overhauled. The two remaining heads and four pistons had been replaced in 1986 during a previous refit. The off-engine controls, instrumentation, and unit breaker were replaced in 1987 as part of a plant switchgear replacement.

Inspections completed prior to the flood identified deficiencies with the diesel generator. The photographs on the next page were taken during a site inspection in February 2010.

The February 2010 inspection identified oil leaks due to cracks in the cylinder head and oil pump housing, which required containment and absorbent materials in close proximity with the hot sections of the engine. Corrosion was prevalent, particularly on the exhaust system. Originally the engine cooling system used a mixture of water and glycol. Due to environmental concerns regarding the release of glycol into the local water system, the cooling system had previously been modified to use only water cooling. The modified cooling water system had experienced regular failures. The unit was last operated in 2007, at which time it had approximately 800 operating hours.


Fuel Leaks in the Engine Vee


Corroded Exhaust Muffler


Hole In Muffler


Engine Tube Cooler

The inspection completed following the September 2010 flood identified water damage and silt contamination in the alternator, engine, generator breaker, and controls. The two options investigated with respect to the diesel generator involved either returning the unit to pre-flood condition or decommissioning it.

The estimated cost to return the unit to pre-flood condition was $131,000.[5] Additional work estimated at approximately $150,000 would be required to ensure the unit's operational reliability.[6] In light of the age and condition of the unit, and because it was no longer required as a backup to the hydroelectric plant, it was determined that refurbishing the diesel electric generator would not be cost-effective. The diesel unit was decommissioned while contractors working on behalf of the Company's insurers were onsite completing flood damage cleanup.

[5] Returning the diesel electric generator to pre-flood condition would involve dismantling the unit, cleaning the engine and generator, and replacing the bearings and seals and all of the protection and control equipment.

[6] This additional work included engine overhaul, exhaust replacement and fuel system replacement.

Appendix B

Damage Assessment
Lawn Plant

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1.0 General

During Hurricane Igor, rain gauges in nearby St. Lawrence recorded 238 mm of rain. The Lawn hydroelectric development saw a peak flood flow of 284 m^3/s. This flood flow was 1.5 times the 1-in-10,000 year flood for the Lawn dam.[1] As water levels rose in the Lawn forebay, spillway capacity was exceeded and water began to overtop the dam.

The Lawn Forebay Dam was overtopped by 0.45 meters of water, causing damage to the concrete face of the dam, erosion of the downstream rockfill, undermining of the woodstave penstock and destruction of the multi-plate culvert protecting the penstock. This damage must be repaired to ensure the long term stability and safety of the Lawn Forebay Dam.

This engineering assessment identifies the various systems that were affected by the storm and resulting flood conditions.[2]

2.0 Work Completed in 2010

Shortly after the storm, measures were taken to begin the process of rehabilitating the Lawn Forebay dam and penstock. Several timber penstock supports were washed out, leaving the penstock unsupported and sagging. Temporary stabilization was provided by timber cribbing, allowing the operation of the plant to continue while plans for permanent repairs were being developed.

In the fall of 2010, an effort was made to tender the rehabilitation project. However, the proposed costs were significantly over budget, due in part to the construction climate following Hurricane Igor as well as the plan to complete the work prior to the onset of winter.

Ice load is the governing load on the design of this dam. With winter approaching and rehabilitation work not complete, a decision was made to install a temporary water recirculation system that would ensure there is no ice build-up in the water nearest the dam. This type of remediation is only temporary, as it requires significant monitoring and maintenance to ensure the system continues to function properly. Permanent work to reinstate the dam will be completed after the spring runoff in 2011.

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[1] In accordance with CDA Dam Safety Guidelines, the dam is classified as a low consequence structure. The spillway and dam would therefore be designed to handle a 100 year return period storm.

[2] An engineering assessment of the damage was completed on September 29, 2010 by Perry Mitchelmore, P.Eng. of Mitchelmore Engineering Company Ltd. (MECO), Gary Humby, P.Eng. of Newfoundland Power and Bill Titford, CET of Newfoundland Power.

3.0 Civil Engineering

3.1 Penstock Supports

Figure 1 - Undermined Penstock

The flood washed out six of the original timber penstock supports and eroded the underlying fill. Immediately after the flood, the penstock was temporarily supported with timber cribbing, stabilizing the penstock and allowing the plant to operate safely.

The temporary timber cribbing will be replaced in 2011 with timber supports replicating the original design. The subgrade will be returned to its pre-storm elevation. These repairs will ensure the long term stability of the penstock.

3.2 Rockfill and Culvert

Rockfill was placed downstream at this dam in 1995 to provide extra sliding and overturning resistance in accordance with Canadian Dam Association guidelines. The multi-plate culvert was constructed to protect the woodstave penstock from the rockfill.

As the flood waters overtopped the Lawn dam, the rockfill was washed away and the culvert's concrete foundations were undermined, causing them to be displaced and damaging the culvert. The damaged concrete and culvert were removed as part of the temporary repair work in 2010.

In 2011, new downstream rockfill and a new multi-plate culvert will be installed. The material used for the rockfill will be of sufficient size to withstand the wave overtopping that would result from a 1-in-500 year return period storm.

Figure 2 - Damaged multi-plate culvert (Rust indicates extent of the rockfill)

3.3 Concrete Overlay and Walkway

The reinforced concrete overlay on the downstream side of the Lawn dam was damaged when 0.45 metres of water overtopped the dam. The loose concrete poses a safety hazard to the other components of this project, and will be removed as part of the rehabilitation work in 2011.

The concrete walkway on the dam crest is damaged and loose in several places. The concrete will be rehabilitated by chipping and grouting the loose concrete, and placing a reinforced concrete overlay along the crest. This will provide a safe walking surface on the crest of the dam.

3.4 Miscellaneous

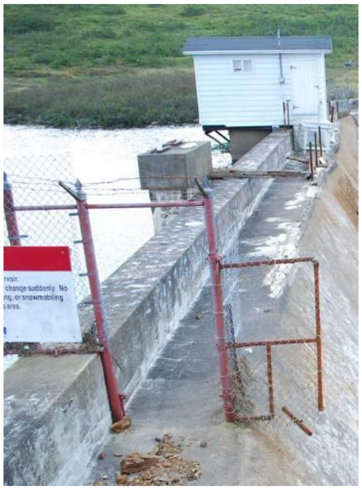

Figure 3 - Damage to Fence

The overtopping waters caused erosion at the abutments. Repairs to the abutments will be completed at the same time as the rockfill is being replaced.

The gatehouse support struts and cladding were damaged by the force of the water. The gatehouse will be refurbished to return it to structurally sound and weathertight condition. The security fence that limits public access to the dam was damaged and will require replacement.

Appendix C

Feasibility Analysis
Port Union

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1.0 Introduction

This feasibility analysis examines the future viability of generation at Newfoundland Power's Port Union hydroelectric plant (the "Plant"). The continued long-term operation of the Plant is reliant on the completion of capital improvements in 2011.

With investment required in 2011 to permit the continued reliable operation of the 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 Plant over the next 25 years have been identified. The capital expenditures required to maintain the safe and reliable operation of the facilities are summarized in Table 1.

Table 1
Port Union
Hydroelectric Plant
Capital Expenditures

Year	($000s)
2011	350[1]
2013	100
2022	250
2026	181
2031	1,190
2036	680
Total	**$2,751**

The total capital expenditure for the Plant until 2036 is $2,751,000 in 2011 dollars. A more comprehensive breakdown of capital costs is provided in Attachment A.

[1] Estimated capital expenditures in 2011 include the cost of betterment (approximately $250,000) and the deductible payable to the Company's insurer (approximately $100,000).

3.0 Operating Costs

Operating costs for the Plant are estimated to be approximately $60,624 per year.[2] This estimate is based primarily upon recent historical operating experience. The operating cost represents both direct charges for operations and maintenance at the Plant as well as indirect costs such as those related to managing the environment, safety, dam safety inspections and staff training. 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 based on yearly hydro plant generation/output.

4.0 Benefits

The maximum output from the Plant is 0.6 MW. The Plant normally operates at this load to maximize the energy from the water.

The estimated long-term normal production at the Plant under present operating conditions is 2.3 GWh per year. This estimate is based on the results of the Water Management Study completed by SGE Acres in 2005.

5.0 Financial Analysis

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

The estimated levelized cost of energy from the Plant over the next 50 years is 7.81¢/kWh. This figure includes all projected capital and operating costs necessary to operate and maintain the facility. Energy from Port Union can be produced at a lower price than the cost of electricity currently supplied from Newfoundland and Labrador Hydro's Holyrood thermal generating station at 11.63¢/kWh.[3]

The future capacity benefits of the continued availability of the 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.

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2 2011 dollars.

3 The cost of electricity from the Holyrood thermal generating station is estimated at 11.63¢ per kWh. This is based upon a 630 kWh/barrel conversion efficiency and oil price forecast from Hydro of $73.30 per barrel for 2010 as per Newfoundland Hydro 2010 Capital Budget Application, Generation Planning Issues 2009 Mid Year Report dated July 2009.

6.0 Recommendation

The results of this feasibility analysis show that the continued operation of the Plant is economically viable. Investing in the return to service of Port Union plant ensures the continued availability of low cost energy to Newfoundland Power's electricity customers. Otherwise, the annual production of 2.3 GWh would be replaced by more expensive energy sources. The project will benefit the Company and its customers by providing least cost, reliable energy for years to come.

Attachment A
Summary of Capital Costs

Port Union Feasibility Analysis Summary of Capital Costs in 2011 Dollars ($000s)						
Description	**2011**	**2013**	**2022**	**2026**	**2031**	**2036**
Rebuild, Deductible & Betterment	350					
Civil						
Dams & Control Structures		100	250		100	
Penstock					500	
Powerhouse				100	50	
Mechanical						
Mechanical Refurbishment					100	150
Turbine					300	
Governor					50	
Electrical						
Controls				30	50	200
AC/DC Systems				51	40	
Switchgear						330
Substation						
Annual Totals	**350**	**100**	**250**	**181**	**1,190**	**680**

Attachment B
Summary of Operating Costs

Port Union Feasibility Analysis
Summary of Operating Costs

Actual Annual Operating Costs

Year	Amount
2005	$ 66,396
2006	$ 43,858
2007	$ 52,897
2008	$ 54,708
2009	$ 76,060
Average	**$ 58,784**

Forecast Annual Operating Cost Estimate

5 -Year Average Operating Cost	$58,784[1]
Water Power Rental Rate	$ 1,840[2]
Total Forecast Annual Operating Cost	**$ 60,624**

[1] 2011 dollars.
[2] Provincial Department of Environment and Conservation annual fee based on $ 0.80 per MWh.

Attachment C
Calculation of Levelized Cost of Energy

Port Union and Lawn Rehabilitation **Schedule A**

Present Worth Analysis

Weighted Average Incremental Cost of Capital 7.68%

PW Year 2,010

YEAR	Generation Hydro 64.4yrs 8% CCA	Generation Hydro 64.4yrs 50% CCA	Capital Revenue Requirement	Operating Costs	Operating Benefits	Net Benefit	Present Worth Benefit	Cumulative Present Worth Benefit	Rev Rqmt (¢/kWhr)	Levelized Rev Rqmt (¢/kWhr) 50 years
2011	350,000	0	31,489	60,624	0	-92,113	-85,544	-85,544	4.112	7.813
2012	0	0	30,263	61,908	0	-92,171	-79,492	-165,036	4.115	7.813
2013	104,381	0	39,924	63,280	0	-103,203	-82,659	-247,694	4.607	7.813
2014	0	0	39,757	64,474	0	-104,231	-77,528	-325,222	4.653	7.813
2015	0	0	39,972	65,726	0	-105,699	-73,012	-398,234	4.719	7.813
2016	0	0	40,107	66,892	0	-106,999	-68,639	-466,873	4.777	7.813
2017	0	0	40,168	68,112	0	-108,280	-64,506	-531,379	4.834	7.813
2018	0	0	40,161	69,360	0	-109,521	-60,592	-591,971	4.889	7.813
2019	0	0	40,091	70,662	0	-110,752	-56,903	-648,875	4.944	7.813
2020	0	0	39,963	71,972	0	-111,935	-53,409	-702,284	4.997	7.813
2021	0	0	39,782	73,325	0	-113,107	-50,119	-752,403	5.049	7.813
2022	307,996	0	67,263	74,688	0	-141,951	-58,414	-810,817	6.337	7.813
2023	0	0	65,910	76,078	0	-141,988	-54,262	-865,079	6.339	7.813
2024	0	0	65,832	77,458	0	-143,290	-50,854	-915,933	6.397	7.813
2025	0	0	65,654	78,926	0	-144,579	-47,652	-963,585	6.454	7.813
2026	240,044	0	86,980	80,400	0	-167,380	-51,232	-1,014,817	7.472	7.813
2027	0	0	85,785	81,887	0	-167,672	-47,661	-1,062,479	7.485	7.813
2028	0	0	85,538	83,416	0	-168,954	-44,600	-1,107,079	7.543	7.813
2029	0	0	85,171	84,994	0	-170,165	-41,716	-1,148,795	7.597	7.813
2030	0	0	84,694	86,622	0	-171,316	-39,003	-1,187,798	7.648	7.813
2031	1,004,783	728,104	172,923	88,281	0	-261,204	-55,226	-1,243,024	11.661	7.813
2032	0	0	144,596	89,972	0	-234,567	-46,057	-1,289,081	10.472	7.813
2033	0	0	199,108	91,695	0	-290,803	-53,026	-1,342,107	12.982	7.813
2034	0	0	225,459	93,451	0	-318,910	-54,004	-1,396,112	14.237	7.813
2035	0	0	237,611	95,240	0	-332,852	-52,345	-1,448,456	14.859	7.813
2036	1,088,740	0	340,510	97,064	0	-437,574	-63,906	-1,512,362	19.535	7.813
2037	0	0	337,935	98,923	0	-436,858	-59,251	-1,571,613	19.503	7.813
2038	0	0	338,072	100,818	0	-438,889	-55,281	-1,626,894	19.593	7.813
2039	0	0	336,933	102,748	0	-439,681	-51,431	-1,678,324	19.629	7.813
2040	0	0	334,988	104,716	0	-439,704	-47,765	-1,726,089	19.630	7.813
2041	142,591	0	345,312	106,721	0	-452,033	-45,602	-1,771,691	20.180	7.813
2042	0	0	341,885	108,765	0	-450,650	-42,220	-1,813,911	20.118	7.813
2043	0	0	338,723	110,848	0	-449,571	-39,115	-1,853,026	20.070	7.813
2044	0	0	335,240	112,971	0	-448,211	-36,215	-1,889,241	20.009	7.813
2045	0	0	331,472	115,134	0	-446,606	-33,512	-1,922,753	19.938	7.813
2046	0	0	327,448	117,339	0	-444,787	-30,995	-1,953,748	19.857	7.813
2047	0	0	323,191	119,586	0	-442,778	-28,654	-1,982,402	19.767	7.813
2048	0	0	318,722	121,877	0	-440,598	-26,480	-2,008,882	19.670	7.813
2049	0	0	314,057	124,211	0	-438,268	-24,461	-2,033,343	19.566	7.813
2050	417,622	0	346,787	126,589	0	-473,376	-24,536	-2,057,879	21.133	7.813
2051	0	0	340,315	129,014	0	-469,329	-22,591	-2,080,470	20.952	7.813
2052	0	0	335,477	131,484	0	-466,962	-20,874	-2,101,344	20.847	7.813
2053	0	0	330,417	134,002	0	-464,419	-19,280	-2,120,624	20.733	7.813
2054	0	0	325,151	136,569	0	-461,720	-17,801	-2,138,425	20.612	7.813
2055	0	0	319,696	139,184	0	-458,880	-16,429	-2,154,854	20.486	7.813
2056	0	0	314,068	141,849	0	-455,918	-15,159	-2,170,013	20.353	7.813
2057	0	0	308,281	144,566	0	-452,847	-13,983	-2,183,996	20.216	7.813
2058	0	0	302,346	147,335	0	-449,680	-12,895	-2,196,891	20.075	7.813

Port Union and Lawn Rehabilitation

Feasibility Analysis
Major Inputs and Assumptions

Specific assumptions include:

Income Tax: Income tax expense reflects a statutory income tax rate of 32%.

Operating Costs: Operating costs were assumed to be in 2011 dollars escalated yearly using the GDP Deflator for Canada.

Average Incremental Cost of Capital:

	Capital Structure	Return	Weighted Cost
Debt	55.00%	6.61%	3.63%
Common Equity	45.00%	9.0%	4.05%
Total	**100.00%**		**7.68%**

CCA Rates:

Class	Rate	Details
17	8.00%	Expenditures related to the betterment of electrical generating facilities.
43.2	50.00%	Equipment designed to produce energy in a more efficient way.

Escalation Factors: Conference Board of Canada GDP deflator, February 16, 2010.

Appendix D

Feasibility Analysis
Lawn

Table of Contents

1.0 Introduction

This feasibility analysis examines the future viability of generation at Newfoundland Power's Lawn hydroelectric plant (the "Plant"). The continued long-term operation of the Plant is reliant on the completion of capital improvements in 2011.

With investment required in 2011 to permit the continued reliable operation of the 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 Plant over the next 25 years have been identified. The capital expenditures required to maintain the safe and reliable operation of the facilities are summarized in Table 1.

Table 1
Lawn
Hydroelectric Plant
Capital Expenditures

Year	($000s)
2011	100[1]
2018	27
2022	100
2025	1,370
2030	1,700
2035	650
Total	**3,947**

The total capital expenditure for the Plant until 2036 is $3,947,000 in 2011 dollars. A more comprehensive breakdown of capital costs is provided in Attachment A.

[1] Estimated capital expenditures in 2011 include the cost of the deductible payable to the Company's insurer (approximately $100,000).

3.0 Operating Costs

Operating costs for the Plant are estimated to be approximately $36,732 per year.[2] This estimate is based primarily upon recent historical operating experience. The operating cost represents both direct charges for operations and maintenance at the Plant as well as indirect costs such as those related to managing the environment, safety, dam safety inspections and staff training. 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 based on yearly hydro plant generation/output.

4.0 Benefits

The maximum output from the Plant is 0.6 MW. The Plant normally operates at this load to maximize the energy from the water.

The estimated long-term normal production at the Plant under present operating conditions is 2.6 GWh per year. This estimate is based on the results of the Water Management Study completed by SGE Acres in 2005.

5.0 Financial Analysis

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

The estimated levelized cost of energy from the Plant over the next 50 years is 6.17¢/kWh. This figure includes all projected capital and operating costs necessary to operate and maintain the facility. Energy from Lawn can be produced at a lower price than the cost of electricity currently supplied from Newfoundland and Labrador Hydro’s Holyrood thermal generating station at 11.63¢/kWh.[3]

The future capacity benefits of the continued availability of the 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.

[2] 2011 dollars.

[3] The cost of electricity from the Holyrood thermal generating station is estimated at 11.63¢ per kWh. This is based upon a 630 kWh/barrel conversion efficiency and oil price forecast from Hydro of $73.30 per barrel for 2010 as per Newfoundland Hydro 2010 Capital Budget Application, Generation Planning Issues 2009 Mid Year Report dated July 2009.

6.0 Recommendation

The results of this feasibility analysis show that the continued operation of the Plant is economically viable. Investing in the current upgrades of the facilities at Lawn plant ensures the continued availability of low cost energy to Newfoundland Power's electricity customers. Otherwise, the annual production of 2.6 GWh would be replaced by more expensive energy sources. The project will benefit the Company and its customers by providing least cost, reliable energy for years to come.

Attachment A
Summary of Capital Costs

Lawn Feasibility Analysis
Summary of Capital Costs in 2011 Dollars
($000s)

Description	**2011**	**2018**	**2022**	**2025**	**2030**	**2035**
Rebuild, Deductible & Betterment	100					
Civil						
Dams & Control Structures						200
Penstock					1,700	
Powerhouse			100			
Mechanical						
Mechanical Refurbishment						250
Turbine				300		
Governor				100		
Electrical						
Controls				400		
Generator Rewind				500		
AC/DC Systems		27		70		
Switchgear						200
Annual Totals	**100**	**27**	**100**	**1,370**	**1,700**	**650**

Attachment B
Summary of Operating Costs

Lawn Feasibility Analysis
Summary of Operating Costs

Actual Annual Operating Costs

Year	Amount
2005	$ 29,864
2006	$ 42,510
2007	$ 28,223
2008	$ 30,002
2009	$ 42,660
Average	**$ 34,652**

Forecast Annual Operating Cost Estimate

5 -Year Average Operating Cost	$34,652[26]
Water Power Rental Rate	$ 2,080[27]
Total Forecast Annual Operating Cost	**$ 36,732**

26 2011 dollars.
27 Provincial Department of Environment and Conservation annual fee based on $ 0.80 per MWh.

Attachment C
Calculation of Levelized Cost of Energy

Port Union and Lawn Rehabilitation **Schedule A**

Present Worth Analysis

Weighted Average Incremental Cost of Capital						7.68%				
PW Year						2,010				
YEAR	**Generation Hydro** 64.4yrs 8% CCA	**Generation Hydro** 64.4yrs 50% CCA	**Capital Revenue Requirement**	**Operating Costs**	**Operating Benefits**	**Net Benefit**	**Present Worth Benefit**	**Cumulative Present Worth Benefit**	**Rev Rqmt (¢/kWhr)**	**Levelized Rev Rqmt (¢/kWhr) 50 years**
2011	100,000	0	8,997	36,732	0	-45,729	-42,468	-42,468	1.686	6.167
2012	0	0	8,647	37,510	0	-46,157	-39,807	-82,275	1.702	6.167
2013	0	0	8,724	38,341	0	-47,065	-37,696	-119,970	1.735	6.167
2014	0	0	8,781	39,065	0	-47,845	-35,588	-155,558	1.764	6.167
2015	0	0	8,819	39,824	0	-48,643	-33,600	-189,158	1.793	6.167
2016	0	0	8,841	40,530	0	-49,371	-31,671	-220,829	1.820	6.167
2017	0	0	8,846	41,269	0	-50,115	-29,856	-250,685	1.848	6.167
2018	30,891	0	11,617	42,025	0	-53,643	-29,678	-280,362	1.978	6.167
2019	0	0	11,487	42,814	0	-54,301	-27,899	-308,262	2.002	6.167
2020	0	0	11,477	43,608	0	-55,085	-26,283	-334,545	2.031	6.167
2021	0	0	11,450	44,427	0	-55,877	-24,760	-359,305	2.060	6.167
2022	123,198	0	22,490	45,253	0	-67,743	-27,877	-387,182	2.498	6.167
2023	0	0	22,000	46,096	0	-68,096	-26,023	-413,205	2.511	6.167
2024	0	0	22,023	46,932	0	-68,955	-24,472	-437,678	2.542	6.167
2025	1,783,590	0	182,479	47,821	0	-230,300	-75,904	-513,582	8.491	6.167
2026	0	0	176,179	48,714	0	-224,894	-68,836	-582,418	8.292	6.167
2027	0	0	177,474	49,616	0	-227,089	-64,551	-646,969	8.373	6.167
2028	0	0	178,381	50,542	0	-228,923	-60,431	-707,400	8.440	6.167
2029	0	0	178,932	51,498	0	-230,430	-56,490	-763,890	8.496	6.167
2030	0	2,429,034	173,840	52,484	0	-226,325	-51,527	-815,417	8.345	6.167
2031	0	0	93,249	53,489	0	-146,738	-31,025	-846,441	5.410	6.167
2032	0	0	274,696	54,514	0	-329,210	-64,640	-911,081	12.138	6.167
2033	0	0	362,875	55,558	0	-418,433	-76,299	-987,380	15.428	6.167
2034	0	0	404,313	56,622	0	-460,934	-78,055	-1,065,435	16.995	6.167
2035	1,021,152	0	514,154	57,706	0	-571,860	-89,932	-1,155,367	21.084	6.167
2036	0	0	516,718	58,811	0	-575,529	-84,054	-1,239,420	21.220	6.167
2037	0	0	517,652	59,937	0	-577,590	-78,338	-1,317,759	21.296	6.167
2038	0	0	515,306	61,085	0	-576,392	-72,600	-1,390,358	21.251	6.167
2039	0	0	511,164	62,255	0	-573,419	-67,074	-1,457,433	21.142	6.167
2040	172,730	0	521,519	63,447	0	-584,967	-63,545	-1,520,977	21.568	6.167
2041	0	0	515,075	64,662	0	-579,737	-58,485	-1,579,462	21.375	6.167
2042	0	0	508,920	65,901	0	-574,821	-53,853	-1,633,316	21.194	6.167
2043	0	0	502,394	67,163	0	-569,557	-49,554	-1,682,870	20.999	6.167
2044	0	0	495,564	68,449	0	-564,013	-45,572	-1,728,442	20.795	6.167
2045	0	0	488,474	69,760	0	-558,234	-41,888	-1,770,330	20.582	6.167
2046	0	0	481,154	71,096	0	-552,250	-38,483	-1,808,813	20.361	6.167
2047	0	0	473,627	72,457	0	-546,085	-35,340	-1,844,153	20.134	6.167
2048	0	0	465,913	73,845	0	-539,758	-32,439	-1,876,592	19.901	6.167
2049	0	0	458,027	75,259	0	-533,286	-29,764	-1,906,356	19.662	6.167
2050	417,622	0	487,557	76,700	0	-564,258	-29,247	-1,935,603	20.804	6.167
2051	0	0	477,906	78,169	0	-556,076	-26,767	-1,962,370	20.502	6.167
2052	0	0	469,908	79,666	0	-549,574	-24,567	-1,986,937	20.263	6.167
2053	0	0	461,703	81,192	0	-542,895	-22,538	-2,009,474	20.016	6.167
2054	0	0	453,310	82,747	0	-536,057	-20,667	-2,030,141	19.764	6.167
2055	0	0	444,742	84,332	0	-529,074	-18,943	-2,049,083	19.507	6.167
2056	0	0	436,014	85,947	0	-521,961	-17,355	-2,066,439	19.245	6.167
2057	0	0	427,139	87,593	0	-514,731	-15,894	-2,082,333	18.978	6.167
2058	0	0	418,128	89,270	0	-507,398	-14,550	-2,096,883	18.708	6.167

Feasibility Analysis
Major Inputs and Assumptions

Specific assumptions include:

Income Tax: Income tax expense reflects a statutory income tax rate of 32%.

Operating Costs: Operating costs were assumed to be in 2011 dollars escalated yearly using the GDP Deflator for Canada.

Average Incremental Cost of Capital:

	Capital Structure	Return	Weighted Cost
Debt	55.00%	6.61%	3.63%
Common Equity	45.00%	9.0%	4.05%
Total	**100.00%**		**7.68%**

CCA Rates:

Class	Rate	Details
17	8.00%	Expenditures related to the betterment of electrical generating facilities.
43.2	50.00%	Equipment designed to produce energy in a more efficient way.

Escalation Factors: Conference Board of Canada GDP deflator, February 16, 2010.

Project Title: **Port Union and Lawn Rehabilitation**

Project Cost: **$1,800,000**

Project Description

On Monday, September 20th and Tuesday, September 21st, 2010, the Avalon, Bonavista and Burin Peninsulas were affected by extreme weather, including high winds, record rainfalls and severe flooding, associated with Hurricane Igor. As a result of the storm, some of Newfoundland Power's generation infrastructure in Eastern Newfoundland was severely damaged.

The Lawn hydro plant on the Burin Peninsula and the Port Union hydro plant on the Bonavista Peninsula experienced severe damage. At Lawn, the spillway and the penstock support structures require significant capital work. At Port Union, the plant was flooded, causing damage to electrical and mechanical systems.

Capital expenditures are necessary to address identified damage. The report titled *Port Union and Lawn Rehabilitation: April 2011*, included as Schedule A to the Application, provides detailed information on the project.

Justification

The project is justified on the basis of the need to restore and maintain safe, reliable electrical service to customers. Because the project involves essential repairs to existing generation infrastructure, it cannot be delayed.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2011 and a projection of expenditures through 2015.

Table 1
Project Cost
(000s)

Cost Category	2011	2012	2013 - 2015	Total
Material	$910	-	-	$910
Labour – Internal	90	-	-	90
Labour – Contractor	655	-	-	655
Engineering	85	-	-	85
Other	60	-	-	60
Total	**$1,800**	**$0**	**$0**	**$1,800**

Costing Methodology

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

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

Future Commitments

This is not a multi-year project.

NEWFOUNDLAND AND LABRADOR

AN ORDER OF THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

NO. P.U. ___ (2011)

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

IN THE MATTER OF an Application by Newfoundland Power Inc. for:

(i) approval of capital expenditure for the construction and purchase of certain improvements and additions to its property pursuant to Section 41(3) of the Act; and

(ii) consent to remove from service a diesel electric generator located at Port Union pursuant to Section 38 of the Act.

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

WHEREAS the Applicant owns and operates generation facilities at Port Union on the Bonavista Peninsula and Lawn on the Burin Peninsula (the “Hydro Plants”), and a diesel electric generator located at the Applicant’s Port Union Hydro Plant in the municipality of Trinity Bay North (the “Diesel Generator”); and

WHEREAS on September 20th and 21st, 2010, the Bonavista and Burin Peninsulas were affected by extreme weather, including damaging winds and severe flooding, all associated with Hurricane Igor (the "Storm"); and

WHEREAS as a result of the Storm, the Hydro Plants and Diesel Generator were damaged, including damage that compromised the safety and integrity of certain civil works, which were immediately addressed in accordance with the Allowance for Unforeseen Items, and damage that was expected to require further capital work in 2011; and

WHEREAS Section 41(3) of the Act states that a public utility shall not proceed with the construction, purchase or lease of improvements or additions to its property where:

(a) the cost of the construction or purchase is in excess of $50,000; or

(b) the cost of the lease is in excess of $5,000 in a year of the lease,

without the prior approval of the Board; and

WHEREAS Section 38 of the Act states that a public utility shall not abandon a part of its line, or works, after they have been operated, without notice to the Board and without the written consent of the Board, which consent shall only be given after notice to an incorporated municipal body interested, and after there has been an inquiry; and

WHEREAS on April 8, 2011, the Applicant filed the Application with the Board for approval of the capital expenditure of $1,800,000 associated with the repair of generation infrastructure at the Hydro Plants and for the consent of the Board to the decommissioning of the Diesel Generator; and

WHEREAS the estimated capital expenditure associated with the repair of the Hydro Plants and returning them to service is $1,800,000, and

WHEREAS in Order No. P.U. 28 (2010), the Board approved, *inter alia*, the Applicant's 2011 Capital Budget of $72,969,000, and

WHEREAS the expenditures associated with the repair of the Hydro Plants are necessary for the Applicant to provide service and facilities which are reasonably safe and adequate and just and reasonable as required pursuant to Section 37 of the Act; and

WHEREAS the Diesel Generator was in an aged and deteriorated condition and sustained further damage as a result of the Storm, and

WHEREAS the Diesel Generator offers relatively insignificant system benefits and was originally installed as a backup to the Port Union Hydro Plant, which backup is no longer required; and

WHEREAS notice of the Application has been provided to the municipality of Trinity Bay North; and

WHEREAS the Board is satisfied that it is reasonable and prudent to approve the proposed expenditures for the repair of the Hydro Plants and to consent to the removal from service of the Diesel Generator as proposed by the Applicant.

<u>IT IS THEREFORE ORDERED THAT</u>:

1. Pursuant to Section 41 (3) of the Act, the proposed capital expenditure of $1,800,000 to repair the Applicant's Hydro Plants at Port Union and Lawn is approved; and

2. Pursuant to Section 38 of the Act, the Board consents to the removal from service of the Diesel Generator at the Applicant's Port Union Hydro Plant.

DATED at St. John's, Newfoundland and Labrador, this ______ day of , 2011.

____

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____

G. Cheryl Blundon
Board Secretary

Sandy Brook Hydro Plant Refurbishment
June 2010

Sandy Brook Hydro Plant

Refurbishment

June 2010

Prepared by:

Jeremy Decker, P. Eng.

REGISTERED PROFESSIONAL ENGINEER
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NEWFOUNDLAND & LABRADOR

NEWFOUNDLAND POWER
A FORTIS COMPANY

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1.0 Introduction

The Sandy Brook hydroelectric generating plant (the "Plant"), located in central Newfoundland near the town of Grand Falls-Windsor, was commissioned in 1963 with a capacity of 6.4 MW. The plant contains a single vertical 8,000 hp Francis turbine manufactured by Dominion Engineering and a Canadian Westinghouse generator. The unit is automated and controlled remotely through the SCADA system. The Plant is connected to the Island interconnected electrical system at Grand Falls substation via Newfoundland Power's transmission line 105L.

There have been a number of upgrades to the original plant and equipment. The following is a list of the upgrades that have been completed in the past 25 years:

1986 – Capacitors replaced
1997 – Brush temperature sensors, and vibration sensors added
1999 – Cooling water system upgraded
2000 – Station service transfer switch installed
2001 – Instrumentation and Programmable Logic Controller ("PLC") installed
2001 – Power cables, runner and wicket gates replaced
2004 – Bearing oil level sensors added
2007 – Battery bank and charger replaced

This assessment is based upon a site inspection completed on March 4, 2010.

2.0 Governor

The governor is a Woodward Model HR size 10 x 14 gate shaft hydraulic unit. It has a rated torque of 16,300 ft-lbs and pressure supplied by a size 27 gear pump. The unit was reconditioned in 2001. The original equipment manufacturer discontinued supplying replacement parts for these units as of July 1, 2008. Due to its robust design with no parts exposed to excessive wear, the hydraulic power portion of the governor will remain serviceable for many years.[1]

Figure 1 - Woodward Governor

The governor speed control is motorized and can be operated remotely using electromechanical relay logic to control the load on the unit. There are no gate position or limit setpoint transducers. There is no feedback of gate position or limit for unit control or remote indication. More advanced control of the governor setpoints is required to implement a water management system in the unit control PLC. This will optimize energy production from the available water increasing the energy output of the plant.

[1] Recent plant refurbishment projects have replaced the hydraulic control portion of these governors with digital systems that provide enhanced control and feedback capabilities.

Figure 2 - Governor Control

The governor consists of two sections, the power piston and the control head. The power piston provides the force necessary to operate the wicket gates under load. The control head adjusts the position of the power piston to maintain system frequency through varying load conditions.

The control head will be replaced as far as the relay valve, which initiates the movement of the power piston, with a PLC based digital control system. The fly ball governor head, pilot valve assembly, mechanical restoring linkages and permanent magnet generator, used for speed sensing, will be removed. The new governor control system will facilitate the implementation of a water management system.

The existing hydraulic power piston assembly will be retained, along with the relay valve, hand wheel, and gate operating linkages. Reconditioning of all seals, bushings and other components, that have deteriorated over the past 48 years, will be required. This will eliminate leakage and extend the life of the power piston and relay valve assemblies.

3.0 Generator

Upgrading the electrical and mechanical protection of the 47 year old generator will extend the remaining life of the asset. The generator windings are original to the 1963 installation but there is no evidence that they require upgrading at this time. Temperature signals from the resistance temperature detectors (“RTDs”) installed in the stator windings will be monitored by the new control system.

The generator neutral is solidly connected to ground through a disconnect switch. This method of grounding does not provide optimum protection of the generator windings as it permits large ground fault currents to flow. To minimize the magnitude of fault currents, high impedance grounding is the preferred method of generator neutral connection. A neutral grounding transformer with secondary resistor will be installed to provide this protection.

Generators are shut down when there is inadequate water available for production. This usually occurs during the summer and early fall when humidity in the plants is high. As a result, moisture accumulation on the stator windings compromises the winding insulation. Energizing the generator with moisture present could result in an electrical flashover and permanent winding damage. A MegAlert® stator insulation testing system will be installed to provide a warning and prompt corrective action when the insulation value is reduced. It will also prevent re-energization of the generator should the insulation value fall below a safe value. It will continuously monitor the integrity of the insulation while the unit is shut down, ensuring it can be re-energized when required. Since the generator is grounded, a neutral contactor is required. The contactor will automatically disconnect the windings from ground to facilitate insulation testing. It will also reconnect the neutral to ground before the unit is re-energized. The neutral contactor will replace the existing neutral disconnect switch referred to above.

The surge protection is located in the termination cabinet attached to the generator. The surge capacitors, which were installed in 1986, will be replaced with two-bushing units to facilitate the operation of the MegAlert® insulation tester. To ensure the surge protection system continues to protect the generator windings from electric system surges, the lightning arresters, which are original, will be replaced with intermediate class MOV type surge arrestors.

The installation of new switchgear will necessitate reconfiguration of the power cables to the generator. Because the cables between the generator and switchgear are not long enough to be re-terminated in the new switchgear and the cables and terminations are over 40 years old, they will be replaced. The power cables between the switchgear and power transformer, which were installed in 2001, will be re-terminated in the new switchgear cubicle.

4.0 Excitation System

The exciter was originally supplied with the Westinghouse generator in 1963. Infrared brush temperature sensors were added in 1997. The exciter is regularly maintained and will not be considered for rewinding or replacement until the generator stator requires rewinding at some point in the future.

The voltage regulator is the original Brown Boveri Model AB2/1 with mechanical operating mechanisms. It has been discontinued for many years. It cannot be integrated into the upgraded control system to accomplish the required automated control. It will be replaced with a digital voltage regulator incorporated into the Combination Generator Control Module ("CGCM") located in the unit control panel. The CGCM is designed to be easily integrated into the control system and provide improved voltage regulation under varying system conditions.

The field breaker is the original Westinghouse Model DBF-6 and is beyond its expected service life. It is no longer supported by the original manufacturer, making it very expensive to overhaul and maintain. A new field breaker will be installed in a cabinet located near the generator. The power cables from the exciter to the rotor via the field breaker were installed in 2001 and will be reused.

5.0 Switchgear

The generator breaker, emergency station service transformer, potential transformers (PTs) and current transformers (CTs) are integral to the switchgear and are original units installed in 1963. Concerns of failure exist because of the condition and age of this equipment. The existing Westinghouse Type DH generator breaker is at the end of its service life and must be replaced. The PTs and CTs must also be replaced. They are all critical to electrical protection of the generator. The emergency station service transformer bank consists of two single phase 120/240 V transformers connected in an open delta configuration. This is no longer standard. It will be replaced with a three phase 120/208 V wye connect unit.

Figure 3 - Switchgear and Control Panels

The protective relays and control switches are incorporated into the switchgear doors, which greatly increases arc flash hazards for personnel operating these control switches. A path is provided for an electric arc and hot gases to exit the switchgear directly towards personnel who may be standing in front of the door operating the control switches.

The existing switchgear will be replaced with an arc flash rated cubicle with breakers that require minimum maintenance. Higher accuracy instrument transformers for improved protection and metering will be supplied with the switchgear. The control switches and associated wiring will be relocated to a new unit control panel remote from the switchgear and outside the arc flash zone of influence, providing increased employee safety. A 120/208 V three phase emergency station service transformer will be incorporated into the new switchgear.

As a result of the fault levels and clearing times at this location there is a high arc flash hazard associated with this switchgear. It requires an arc flash boundary of 2.1 m. To provide protection from this hazard, walls will be constructed to separate the switchgear from the control room and the generator gallery.

6.0 AC Distribution System

The main AC service entrance from the substation, the essential services panel and transfer switch were installed in 2000 and do not require any modification. The main service is supplied from the original 120/240 V closed delta transformer bank located in the substation, which will be replaced with a standard 120/208 V transformer bank.

Figure 4 - Station Service Transformers

The non-essential services panel is the original AC panel located in the switchgear and replacement breakers are not readily available. It will be replaced with a standard 60-circuit 120/208V AC panel located on the switchgear room wall near the AC service entrance.

Under normal conditions service to all AC loads will be supplied from the normal station service transformers located in the substation.

7.0 DC System

The existing GNB Exide gel-cell battery bank and C-Can battery charger were installed in 2007 and do not require any modifications.

The 8-circuit DC distribution panel with separate main breaker is original. Currently, there are not enough circuits to accommodate each device in the protection and control system. Items have been paralleled together which is not normal practice. A new 60-circuit panel will be installed to provide adequate capacity, improved circuit isolation and ensure the availability of replacement circuit breakers.

Figure 5 - DC Panel

8.0 Protective Relaying

The generator electrical protection is provided by CGE/GEC electromechanical relays. The following protective elements are in service:

40	Loss of Field
49	Thermal Protection
51N	Overcurrent
51V	Backup Protection – Voltage Controlled Overcurrent
59	Overvoltage
64F	Voltage Relay for Rotor Ground Fault
87	Differential

The existing protective relays at Sandy Brook plant lack three elements[2] of the minimum protection set. In addition to not meeting the minimum recommended protection level, the existing electromechanical relays are corroded and no longer satisfactory.

The existing generator protective relays will be replaced with modern digital relays to provide the minimum protection set. Improved generator protection reduces stresses due to electrical faults and in turn extends the life of the generator.

In addition to the enhanced generator protection, bus differential and arc flash protection will be added with the new switchgear to provide improved equipment protection and reduce the arc flash hazard to employees working in the vicinity of the switchgear.

9.0 Plant Control

The existing Allan-Bradley SLC 5/03 programmable logic controller (PLC) was installed in 1997. It monitors vibration and bearing temperatures, controls the cooling water system and provides annunciation of a number of trip and alarm conditions. The PLC is not capable of complete unit control. This is done through various electromagnetic relays and switches from the original installation. An Allan-Bradley ControlLogix® programmable logic controller will be installed to replace this unit.[3] It will provide local and remote control of the generator and plant functions. The SLC 5/03 will be utilized to provide spares for other in-service units.

The plant is remotely monitored from the System Control Centre. The unit has remote control functions that are limited to start, stop and loading capability. At present, there is no automation with respect to water management and the setting of machine loads to optimize the use of the water resources. The installation of a PLC with increased processing power will greatly improve the local and remote monitoring and control functionality. It will facilitate the implementation of

[2] The existing generator protection does not include Stator Unbalance 46, Frequency 81 and sensitive Ground Fault 87GN elements which are recommended by the IEEE for these generators.

[3] The Allan-Bradley ControlLogix® programmable logic controller will provide functionality similar to that provided at Rattling Brook plant when it was upgraded in 2007. Both Sandy Brook plant and Rattling Brook plant are operated and maintained by Company staff stationed in Norris Arm South in Central Newfoundland.

a variety of control modes to ensure the efficient operation of the plant and utilization of available water.

The new unit control panel will contain the processor, associated monitoring and control equipment and control switches. The following equipment will be located there:

a) AB ControlLogix® PLC
b) Industrial Computer HMI with keyboard
c) Ethernet Switch
d) Combination Generator Control Module (CGCM)
e) Synchro Check Relay
f) MegAlert® remote LED display and switch board meter
g) Synchroscope
h) Emergency stop pushbutton (latching)
i) Start pushbutton
j) Stop pushbutton
k) Alarm reset pushbutton
l) Generator breaker control switch (ANSI device No. 52CS)
m) Field breaker control switch (ANSI device No. 41CS; LBK-G3 only)
n) Speed raise/lower control switch (ANSI device No. 15CS)
o) Gate limit control switch (ANSI device No. 65CS)
p) Voltage raise/lower control switch (ANSI device No. 70CS)
q) Automatic/manual synchronizing control switch (ANSI device No. 25CS)
r) Generator lock out relay (ANSI Device No. 86G)
s) Three position local/remote control switch (ANSI Device No. 43CS)

A new Gateway data concentrator will be installed to replace the existing RTU, improving communications to the SCADA system. This communications system in conjunction with the upgraded processor will enhance plant operations. It will provide additional information about the performance of key plant components. Improved communications infrastructure will also permit remote administration of the PLC and digital relays by head office engineering staff that would normally require a time consuming and costly site visit.

The Westinghouse XT7 auto-synchronizer is an electromechanical relay utilizing vacuum tube technology included with the original installation. It is no longer supported by the manufacturer and will be replaced. A synchrocheck relay will be installed to supervise both automatic and manual synchronizing. It will ensure unit speed and voltage are within acceptable limits before the generator breaker closure is permitted. The synchronizing function will be incorporated in CGCM Module located in the unit control panel.

Figure 6 - XT7 Auto-synchronizer

10.0 Instrumentation

The instrumentation has been upgraded over the past number of years with brush temperature and vibration monitoring installed in 1997, the cooling water system upgraded in 1999, bearing temperature sensors installed in 2001 and bearing oil level sensors installed in 2004.

Except for the speed switch and vibration monitor, all instrumentation will be maintained and integrated into the new control system. The speed switch will be removed and dual speed sensors installed on the existing PMG toothgear to provide analogue speed signals to the governor and unit control PLCs. The unit control PLC will perform the speed processing functions previously performed by the speed switch. The vibration sensors will be reused but the monitor will be replaced with a Rockwell Entek system, designed to be seamlessly integrated into the Allan-Bradley ControlLogix PLC.

11.0 Heating and Ventilation

There are no infrared heaters installed over the unit. The anti-condensation blower type heaters in the turbine pit are located in the air intake plenum and controlled by a humidistat located in the generator room. There are two exhaust fans located in the building that are in good condition.

Figure 7 - Anti-condensation Heaters

The heat and ventilation controls will be consolidated into one plant control panel and integrated with the plant control PLC. Temperature and humidity sensors will be installed in the generator room and turbine pit. Infrared heaters will be installed and new blower heaters will be mounted under the generator windings. This will help prevent condensation on the generator windings when the unit is not operating.

12.0 Cooling Water

The cooling water system was upgraded and PLC control added in 1999. A duplex strainer was installed in 2001. Except for the replacement of a small amount of piping no further upgrading is required. The control of the cooling water system will be integrated into the new ControLogix PLC but no other modifications are required.

13.0 Air Compressor

The air compressor used to operate the generator braking system is original and will be replaced.

14.0 Water Level Monitoring and Control


Figure 8 - Forebay Water Level System

The forebay water level system is critical to the implementation of the Water Management System in the PLC. The water level probe was replaced in 2006 and does not require any work. The water level and trash rack signals are transmitted to the plant utilizing pulse modulated and hard wired signals over a 25 year old copper communications cable which is susceptible to lightning damage. The communications cable has 3 of its 11 pairs made unusable by lightning. To improve reliability, eliminate legacy equipment with its inherent maintenance problems and to facilitate the use of more reliable technology, the copper cable will be replaced with a fibre optic cable. The existing communications system will be upgraded to technology compatible with the new control system.

The plant PLC will use the water level signals to control the Water Management System. High level (spill) and low level alarms will also be initiated when specified levels are reached.

The Water Management System will optimize the efficiency of the plant by controlling the load on the unit based upon the following water level, inflow, wicket gate position and control mode setpoints:

a) Peak Water Level
b) Low Inflow Peak Water Level
c) Efficient Water Level
d) Low Inflow Efficient Water Level
e) Partial Water Level
f) Low Inflow Partial Water Level
g) Shutdown Water Level
h) Low Inflow Shutdown Water Level
i) Water Level Deadband
j) Start-up Water Level
k) Peak Gate Position
l) Efficient Gate Position
m) Partial Gate Position
n) Gate Position Deadband
o) Rate of Rise (Bump)
p) Water Elevation Mode Water Level
q) Water Elevation Mode Gate Shutdown Level
r) Load Control Mode Voltage Level
s) Load Control Mode Kilowatt Level
t) Load Control Mode Kilowatt Deadband

15.0 Project Cost

The total project cost is estimated at $1,560,000. Table 1 below provides the cost breakdown by cost category.

Table 1
Projected Expenditures

Cost Category	Estimated Cost
Material	$779,000
Labour - Internal	122,000
Labour - Contract	438,000
Engineering	133,000
Other	88,000
Total	**$1,560,000**

16.0 Summary of Work

The following is a summary of the work proposed to be completed during the 2011 refurbishment project:

a) Install programmable logic controller based digital control systems to replace the hydraulic control portion of the governors.
b) Complete mechanical modifications to governor.
c) Install neutral grounding transformer and resistor.
d) Install automatic stator insulation testing system.
e) Replace surge protection.
f) Replace power cables between the generator and switchgear as required.
g) Replace the automatic voltage regulator.
h) Replace the field breaker and power cables between switchgear and generator.
i) Replace the switchgear complete with breaker, potential transformers and current transformers and emergency service transformer.
j) Modify the control room to provide a switchgear room.
k) Replace the non-essential AC distribution panel.
l) Replace station service transformer bank in substation.
m) Replace the DC distribution panel.
n) Replace generator protective relaying.
o) Add bus differential and arc flash relaying.
p) Replace the existing programmable logic controller with a programmable logic controller system that will monitor and control plant functions and the unit.
q) Install a Gateway data concentrator to communicate with SCADA and provide remote administration of the new equipment.
r) Replace the auto-synchronizer.
s) Upgrade speed sensing and bearing vibration system.

t) Modify the plant heating and ventilation system and upgraded controls.
u) Upgrade cooling water piping.
v) Replace air compressor.
w) Replace forebay communications cable and communications equipment.
x) Implement a water management system in the Plant programmable logic controller including upgraded communications to the forebay.

17.0 Economic Feasibility

Appendix A provides an economic feasibility analysis for the continued operation of the Plant. It is based on the latest forecast of total capital expenditure of $10,964,000. The results of the analysis show that the continued operation of the Plant is economical over the long term. Investing in the life extension of the Plant ensures the continued availability of 30.2 GWh of energy to the Island Interconnected electrical system.

The estimated levelized cost of energy from the Plant over the next 50 years, including the capital expenditure of $10,964,000, is 2.37 cents per kWh. This energy is lower in cost than replacement energy from sources such as new hydroelectric developments or additional Holyrood thermal generation[4].

[4] The cost of electricity from the Holyrood thermal generating plant is estimated at 11.63 ¢/kWh. This is based upon a 630 kWh/barrel conversion efficiency and oil price forecast from Hydro of $73.30/barrel for 2010 as per Newfoundland Hydro 2010 Capital Budget Application, Generating Planning Issues 2009 Mid Year Report dated July 2009.

Appendix A
Feasibility Analysis

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1.0 Introduction

This feasibility analysis examines the future viability of generation at Newfoundland Power's Sandy Brook hydroelectric plant (the "Plant"). The continued long-term operation of the Plant is reliant on the completion of capital improvements in 2011.

With investment required in 2011 to permit the continued reliable operation of the 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 Plant over the next 25 years have been identified. The capital expenditures required to maintain the safe and reliable operation of the facilities are summarized in Table 1.

Table 1
Sandy Brook Hydroelectric Plant
Capital Expenditures

Year	($000s)
2011	2,234
2017	700
2020	4,387
2023	1,608
2026	227
2036	1,808
Total	**10,964**

The estimated capital expenditure for the Plant over the next 25 years is $10,964,000 in 2011 dollars. A more comprehensive breakdown of capital costs is provided in Attachment A.

3.0 Operating Costs

Operating costs for the Plant are estimated to be approximately $141,261[1] per year. This estimate is based primarily upon recent historical operating experience. The operating cost represents both direct charges for operations and maintenance at the Plant as well as indirect costs such as those related to managing the environment, safety, dam safety inspections and staff training. A summary of operating costs is provided in Attachment B.

The annual operating cost also includes an estimated water use licence fee of $24,160[2] applicable to the licence being applied for in 2010. This fee is paid annually to the Provincial Department of

[1] 2011 dollars.
[2] Newfoundland Power is anticipating receiving a new water use licence for Sandy Brook in 2010.

Environment and Conservation (Water Resources Management Division). This charge is not reflected in the historical annual operating costs for the Plant. An adjustment beyond lease expiry will have to be applied to account for the associated increased operating expenses on a go-forward basis.

4.0 Benefits

The maximum output from the Plant is 6.4 MW. The Plant normally operates at an efficient load of 5.7 MW to maximize the energy from the water.

The estimated long-term normal production at the Plant under present operating conditions is 30.2 GWh per year. This estimate is based on the average production for the past five years.

5.0 Financial Analysis

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

The estimated levelized cost of energy from the Plant over the next 25 years is 2.37 cents per kWh. This figure includes all projected capital and operating costs necessary to operate and maintain the facility. Energy from Sandy 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.[3]

The future capacity benefits of the continued availability of the 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.

6.0 Concluding

The results indicate that continued operation of the Plant is economically viable. Investing in the current upgrades of the facilities at Sandy Brook guarantees the availability of low cost energy to the Province. Otherwise, the annual production of 30.2 GWh would be replaced by more expensive energy sources such as new generation or additional production from the Holyrood thermal generating station. The project will benefit the Company and its customers by providing least cost, reliable energy for years to come.

[3] The cost of electricity from the Holyrood thermal generating station is estimated at 11.63¢ per kWh. This is based upon a 630 kWh/barrel conversion efficiency and oil price forecast from Hydro of $73.30 per barrel for 2010 as per Newfoundland Hydro 2010 Capital Budget Application, Generation Planning Issues 2009 Mid Year Report dated July 2009.

Attachment A
Summary of Capital Costs

Sandy Brook Feasibility Analysis Summary of Capital Costs ($000s)						
Description	**2011**	**2017**	**2020**	**2023**	**2026**	**2036**
Civil						
Dam, Spillways and Control Structures	100	700				100
Penstock			3,749			
Surge Tank			638			
Powerhouse					79	
Increase Storage	575					
Mechanical						
Mechanical	42					
Turbine Upgrades						1,651
Governor Upgrades	126				30	
Electrical						
Controls Upgrade	933			29	118	57
Generator Rewind				1,497		
Exciter				82		
Switchgear	458					
Annual Totals	**2,234**	**700**	**4,387**	**1,608**	**227**	**1,808**

Attachment B
Summary of Operating Costs

Sandy Brook Feasibility Analysis
Summary of Operating Costs

Actual Annual Operating Costs

Year	Amount
2005	$ 98,499
2006	$ 92,014
2007	$ 118,221
2008	$ 147,150
2009	$ 129,622
Average	**$** 117,101

5 -Year Average Operating Cost	$117,101[1]
Water Use Rental Fee	$ 24,160[2]
Total Forecast Annual Operating Cost	$ 141,261

[1] 2011 dollars.
[2] Estimated fee for licence being applied for in 2010.

Attachment C
Calculation of Levelized Cost of Energy

Present Worth Analysis

Weighted Average Incremental Cost of Capital - 7.68%
Present Worth Year - 2010

Year	Capital Revenue Requirement	Operating Costs	Operating Benefits	Net Benefit	Present Worth Benefit	Cumulative Present Worth Benefit	Rev Rqmt (¢/kWhr)	Levelized Rev Rqmt (¢/kWhr) 50 years
2011	134,086	141,261	0	-275,347	-255,708	-255,708	0.912	2.368
2012	104,736	144,253	0	-248,989	-214,739	-470,447	0.824	2.368
2013	160,236	147,449	0	-307,685	-246,435	-716,882	1.019	2.368
2014	187,633	150,232	0	-337,865	-251,306	-968,188	1.119	2.368
2015	200,851	153,151	0	-354,001	-244,529	-1,212,717	1.172	2.368
2016	206,863	155,867	0	-362,730	-232,688	-1,445,404	1.201	2.368
2017	207,443	158,708	0	-366,151	-218,130	-1,663,534	1.212	2.368
2018	181,721	161,618	0	-343,339	-189,951	-1,853,486	1.137	2.368
2019	239,862	164,650	0	-404,512	-207,834	-2,061,320	1.339	2.368
2020	666,048	167,703	0	-833,752	-397,820	-2,459,139	2.761	2.368
2021	637,308	170,856	0	-808,163	-358,108	-2,817,247	2.676	2.368
2022	701,598	174,031	0	-875,630	-360,330	-3,177,576	2.899	2.368
2023	904,098	177,271	0	-1,081,370	-413,255	-3,590,832	3.581	2.368
2024	907,043	180,487	0	-1,087,530	-385,967	-3,976,799	3.601	2.368
2025	920,205	183,906	0	-1,104,111	-363,904	-4,340,703	3.656	2.368
2026	923,473	187,342	0	-1,110,814	-340,001	-4,680,705	3.678	2.368
2027	912,303	190,808	0	-1,103,111	-313,562	-4,994,267	3.653	2.368
2028	930,625	194,370	0	-1,124,995	-296,975	-5,291,241	3.725	2.368
2029	935,486	198,047	0	-1,133,533	-277,887	-5,569,128	3.753	2.368
2030	933,226	201,840	0	-1,135,066	-258,417	-5,827,545	3.758	2.368
2031	927,048	205,705	0	-1,132,754	-239,497	-6,067,042	3.751	2.368
2032	918,581	209,645	0	-1,128,226	-221,526	-6,288,568	3.736	2.368
2033	908,666	213,660	0	-1,122,325	-204,650	-6,493,218	3.716	2.368
2034	897,747	217,751	0	-1,115,499	-188,898	-6,682,116	3.694	2.368
2035	886,070	221,921	0	-1,107,992	-174,245	-6,856,362	3.669	2.368
2036	1,134,220	226,171	0	-1,360,391	-198,679	-7,055,041	4.505	2.368
2037	1,111,257	230,503	0	-1,341,759	-181,982	-7,237,023	4.443	2.368
2038	1,100,207	234,917	0	-1,335,124	-168,167	-7,405,190	4.421	2.368
2039	1,088,161	239,416	0	-1,327,576	-155,290	-7,560,479	4.396	2.368
2040	1,075,203	244,001	0	-1,319,204	-143,305	-7,703,784	4.368	2.368
2041	1,060,708	248,674	0	-1,309,381	-132,093	-7,835,877	4.336	2.368
2042	1,035,526	253,436	0	-1,288,962	-120,759	-7,956,636	4.268	2.368
2043	1,044,238	258,289	0	-1,302,527	-113,326	-8,069,962	4.313	2.368
2044	1,040,032	263,236	0	-1,303,268	-105,303	-8,175,265	4.315	2.368
2045	1,029,096	268,277	0	-1,297,373	-97,350	-8,272,616	4.296	2.368
2046	1,014,543	273,415	0	-1,287,957	-89,751	-8,362,367	4.265	2.368
2047	997,632	278,651	0	-1,276,282	-82,594	-8,444,961	4.226	2.368
2048	974,970	283,987	0	-1,258,957	-75,662	-8,520,623	4.169	2.368
2049	967,261	289,426	0	-1,256,687	-70,139	-8,590,763	4.161	2.368
2050	953,378	294,968	0	-1,248,346	-64,704	-8,655,467	4.134	2.368
2051	936,242	300,617	0	-1,236,859	-59,537	-8,715,003	4.096	2.368
2052	917,328	306,374	0	-1,223,702	-54,702	-8,769,705	4.052	2.368
2053	897,385	312,242	0	-1,209,626	-50,216	-8,819,922	4.005	2.368
2054	876,799	318,221	0	-1,195,020	-46,072	-8,865,993	3.957	2.368
2055	855,772	324,315	0	-1,180,088	-42,251	-8,908,244	3.908	2.368
2056	834,418	330,526	0	-1,164,944	-38,734	-8,946,978	3.857	2.368
2057	803,379	336,856	0	-1,140,235	-35,208	-8,982,187	3.776	2.368
2058	638,863	343,307	0	-982,171	-28,165	-9,010,352	3.252	2.368
2059	938,977	349,882	0	-1,288,859	-34,323	-9,044,675	4.268	2.368
2060	1,074,095	356,582	0	-1,430,677	-35,383	-9,080,057	4.737	2.368
2061	1,126,642	363,411	0	-1,490,053	-34,223	-9,114,280	4.934	2.368

Feasibility Analysis
Major Inputs and Assumptions

Specific assumptions include:

Income Tax: Income tax expense reflects a statutory income tax rate of 32%.

Operating Costs: Operating costs were assumed to be in 2010 dollars escalated yearly using the GDP Deflator for Canada.

Average Incremental Cost of Capital:

	Capital Structure	Return	Weighted Cost
Debt	55.00%	6.606%	3.63%
Common Equity	45.00%	9.00%	4.05%
Total	**100.00%**		**7.68%**

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.

Escalation Factors: Conference Board of Canada GDP deflator, February 16, 2010.

Appendix B
Sandy Brook Switchgear Arc Flash Study

ELECTRICAL ENGINEERING

ARC FLASH HAZARD STUDY

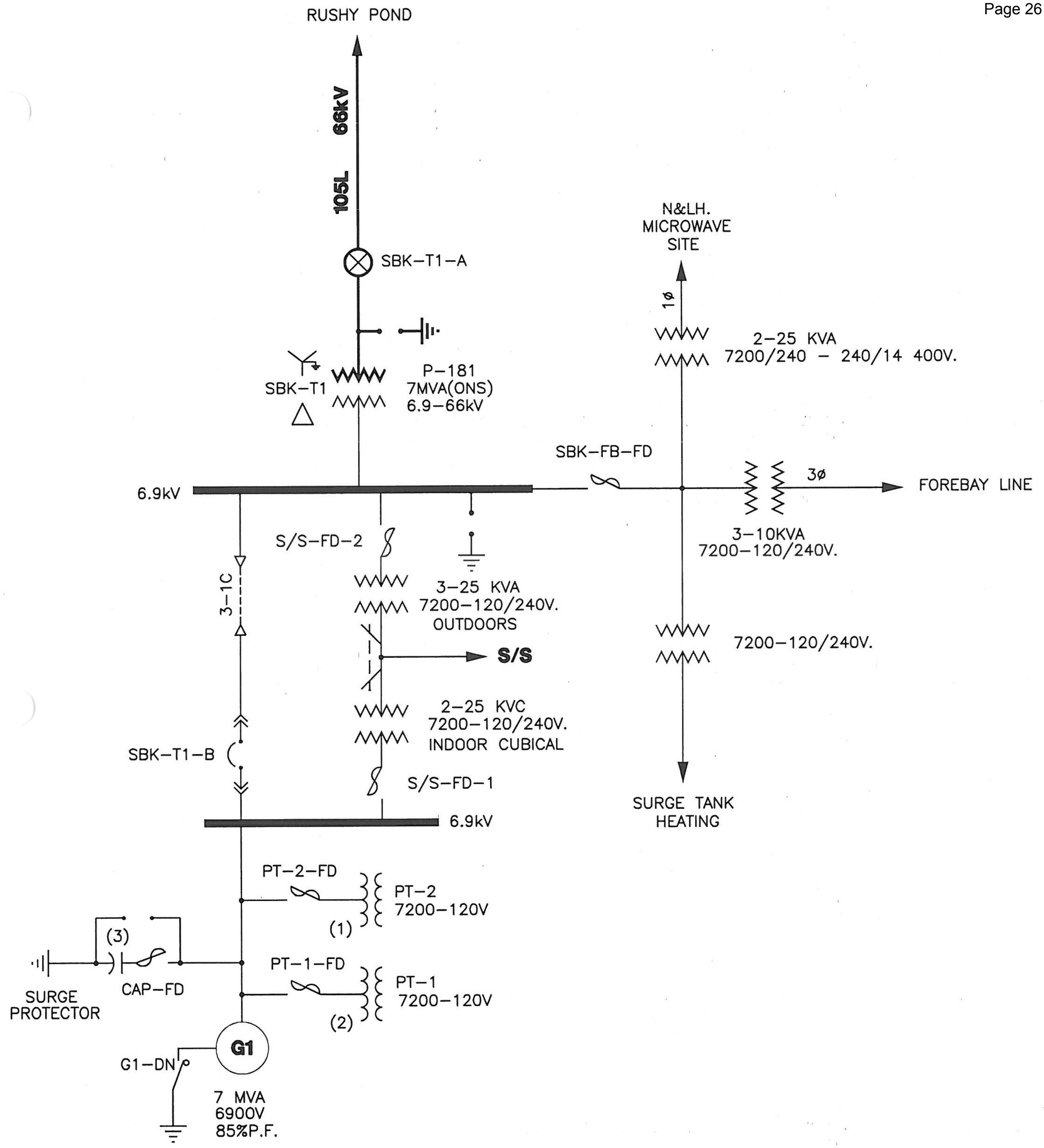
Company Area:	Grand Falls		
Switchgear Included:	SBK 07		
Prepared by:	D. Hopkins	**Date:**	3/8/2006

REASON FOR ARC FLASH HAZARD STUDY

Arc Flash Hazard calculations to be done for all Metal Clad Switrchgear.

POINTS TO NOTE

1. PPE level class 2 at 16 inches (working inside switchgear).
2. PPE level class 1 at 36 inches (racking out breaker).



REGISTERED PROFESSIONAL ENGINEER
G. Richard Spurrell
SIGNATURE
2002-06-12
DATE
PROVINCE OF NEWFOUNDLAND

SINGLE LINE DIAGRAM

NEWFOUNDLAND POWER
A FORTIS COMPANY

PROVINCE OF NEWFOUNDLAND
PERMIT HOLDER
This Permit Allows
NEWFOUNDLAND POWER INC.
To practice Professional Engineering in Newfoundland and Labrador.
Permit No. as issued by APEGN R0140 which is valid for the year 2002.

SANDY BROOK (SBK)

Date: 2002-06-12	Page 1 Of 1
App:	SLD No. **6-910**

NF POWER- RELAY REPORT 1

Wednesday, March 08, 20

Region: 6

Eqpt code: -GFS-105L-

Setting group:

		kV						Date	PT	CT	Remarks	Range	Power Supply
67	JBC51H	66	MVA= 10.3	P/U= 1.5	TD= 1.0	Pri amps= 90	TCC=	3/20/85		60	DIR PHASE O/C	1.5-6	
67/50	JBC51H	66	MVA= 54.9	P/U= 8	TD=	Pri amps= 480	TCC=	3/20/85		60	DIR PH INST O/C	2-8	
67N	IBCG51	66	MVA= 3.4	P/U= 0.5	TD= 1.5	Pri amps= 30	TCC=	3/20/85		60	DIR GND O/C	0.5-2	

Eqpt code: -SBK-6.9B-

Setting group:

		kV						Date	PT	CT	Remarks	Range	Power Supply
27L-1	SV-1	6.9	MVA=	P/U= 100	TD=	Pri amps=	TCC=	8/24/87				70-160	

Eqpt code: -SBK-G1 -

Setting group:

		kV						Date	PT	CT	Remarks	Range	Power Supply
40X	CV-2	6.9	MVA=	P/U= 93.0	TD= 2.0	Pri amps=	TCC=	8/26/87				55-140	
49	CT	6.9									SETTING= 100DGC TD=5		
64GF	DGF	6.9									(-75)-(+75) SETTING= (-0.3)-		
25L	CV-7	6.9	MVA=	P/U= 105	TD= 1.0	Pri amps=	TCC=	8/24/87			OVER/UNDER VOLTAGE	55-140	
40	D-3	6.9									(-5)-(+5)MV SETTING= (-3)-(		
27L-1	SV-7	6.9	MVA=	P/U=	TD=	Pri amps=	TCC=	8/24/87		100		70-160	
51GG	CO-8	6.9	MVA=	P/U= 1.0	TD= 1.0	Pri amps=	TCC=	8/24/87				0.5-2.5	
51N	CO-8	6.9	MVA= 1.4	P/U= 1.0	TD= 1.0	Pri amps= 120	TCC=	8/24/87		120	GEN GND O/C	4-12	
51V	COR	6.9	MVA= 14.3	P/U= 10	TD= 8.0	Pri amps= 1200	TCC=	8/24/87		120	PH O/C VOLT REST	4-12	
59	ROV	6.9	MVA=	P/U= 134	TD=	Pri amps=	TCC=	8/24/87			OVERVOLTAGE	120-160	
87	CA	6.9	MVA=	P/U=	TD=	Pri amps=	TCC=	8/24/87			FACTORY ADJUSTED	10% REST	
87S	CO-2	6.9	MVA= 0.12	P/U= 0.5	TD= 0.5	Pri amps= 10	TCC=	8/24/87		20	SPLIT PHASE O/C	0.5-2.5	
87S/50	CO-2	6.9	MVA= 0.96	P/U= 4	TD=	Pri amps= 80	TCC=	8/24/87		20	SPLIT PHASE O/C	4-16	
25Z	CV-7	6.9	MVA=	P/U= 105	TD= 2.0	Pri amps=	TCC=	8/24/87			OVER/UNDER VOLTAGE	55-140	

Eqpt code: -SBK-T1 -

Setting group:

		kV						Date	PT	CT	Remarks	Range	Power Supply
51TN	CO-8	66	MVA= 5.7	P/U= 2.5	TD= 6.0	Pri amps= 50	TCC=	8/24/87		20	GEN XFMR GND O/C	0.5-2.5	

Maximum Generation Fault SBK 6.9kV

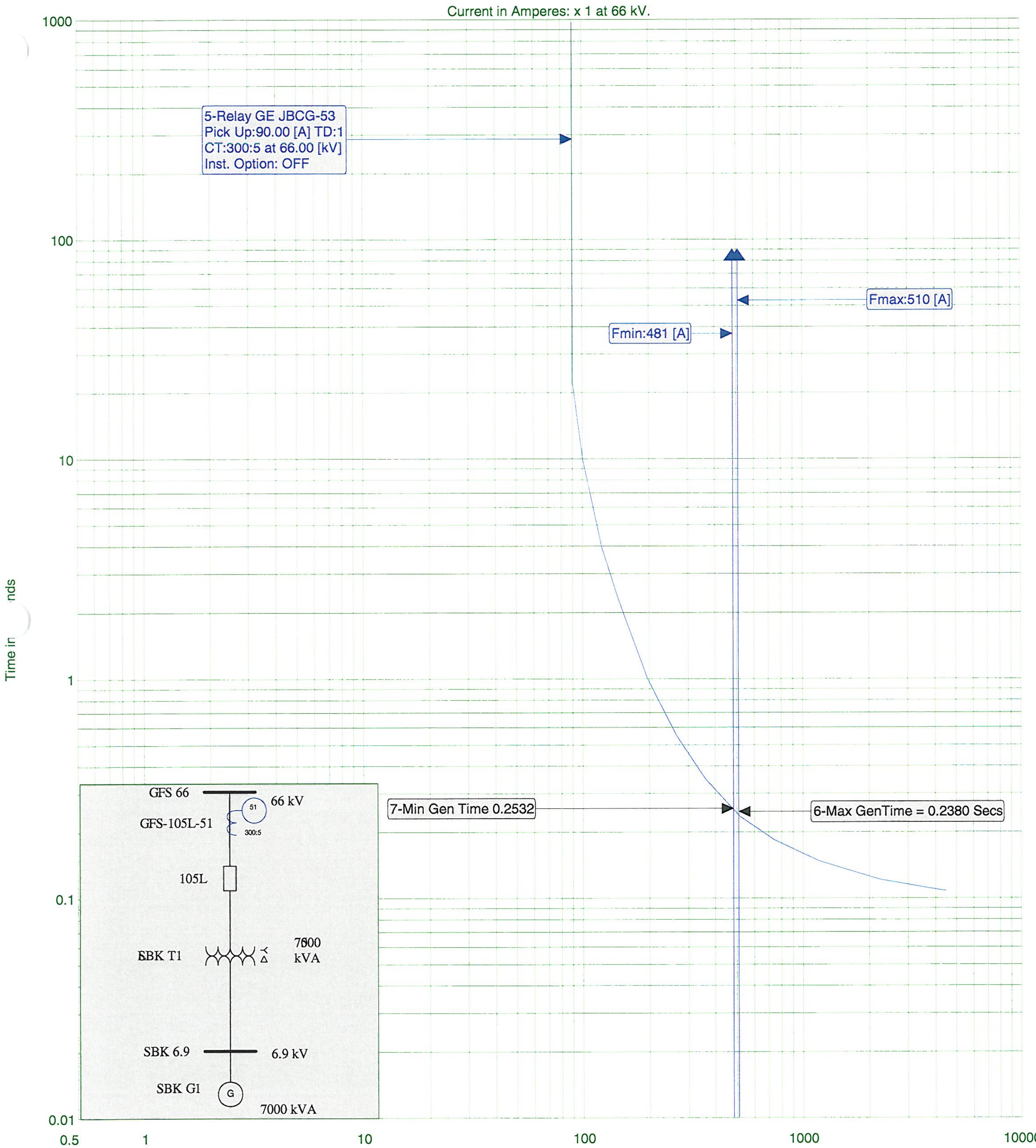
ID	Type	Prefault kV	Angle	Fault type	Fault S [MVA]	Ia [A]	Ia [deg]	Ib [A]	Ib [deg]	Ic [A]	Ic [deg]	In [A]	In [deg]
Faulted Bus ->													
SBK 07		6.9	0	LLL	83	6960.7527	-83.4695	6960.7527	156.5305	6960.7527	36.5305	0	0
First Ring Contributions													
SBK G1	Generator	6.9	0	LLL	25	2091.8489	-90	2091.8489	150	2091.8489	30	0	0
SBK T1	Fixed-Tap Xmer	6.9	0	LLL	58	4888.2476	-80.68	4888.2476	159.32	4888.2476	39.32	0	0

Faulted Bus	Branch id	Type	ault typ	Branch Sid	Ia [A]	Ia [deg]	Ib [A]	Ib [deg]	Ic [A]	Ic [deg]	In [A]	In [deg]
SBK 07	105L	Line	LLL	GFS 66	510.6	129.3203	510.6	9.3203	510.6	-110.6797	0	0
SBK 07	105L	Line	LLL	SBK 66	512	-50.6967	512	-170.6967	512	69.3033	0	0

Minimum Generation Fault SBK 6.9kV

ID	Type	Prefault kV	Angle	Fault type	Fault S [MVA]	Ia [A]	Ia [deg]	Ib [A]	Ib [deg]	Ic [A]	Ic [deg]	In [A]	In [deg]
Faulted Bus ->													
SBK 07		6.9	0	LLL	80	6676.5957	-83.9024	6676.5957	156.0976	6676.5957	36.0976	0	0
First Ring Contributions													
SBK T1	Fixed-Tap Xmer	6.9	0	LLL	55	4601.9882	-81.1347	4601.9882	158.8653	4601.9882	38.8653	0	0
SBK G1	Generator	6.9	0	LLL	25	2091.8489	-90	2091.8489	150	2091.8489	30	0	0

Faulted Bus	Branch id	Type	ault typ	Branch Sid	Ia [A]	Ia [deg]	Ib [A]	Ib [deg]	Ic [A]	Ic [deg]	In [A]	In [deg]
SBK 07	105L	Line	LLL	GFS 66	480.8	128.8656	480.8	8.8656	480.8	-111.1344	0	0
SBK 07	105L	Line	LLL	SBK 66	482.1	-51.1522	482.1	-171.1522	482.1	68.8478	0	0



For LLL SBK 6.9 kV fault at Maximun Generation CT = 0.2380

For LLL SBK 6.9 kV fault at Minimum Generation CT = 0.2532

PLOTTING VOLTAGE:66 kV

BY: D. Hopkins

NO:

DATE: 3-8-2006

Study: H:\COMM\Arc Flash\Plants\SBK\SBK 6.9 kV fault Max and Min Gen.tcc

Arc Flash Hazard SBK 6.9 kV
IEEE standard

Faulted Bus	Generation	Fault	Fault Current	CT	CT Plus Fuses	Working Distance	Flash Hazard Boundry	cal / cm2	PPE Level	L.A.B.	R.A.B.	P.A.B.
SBK 6.9	Max	LLL	6961	0.2380	0.2380	16"	56	4.0	2	60"	26"	7"
SBK 6.9	Min	LLL	6677	0.2532	0.2532	16"	82	5.9	2	60"	26"	7"

Faulted Bus	Generation	Fault	Fault Current	CT	CT Plus Fuses	Working Distance	Flash Hazard Boundry	cal / cm2	PPE Level	L.A.B.	R.A.B.	P.A.B.
SBK 6.9	Max	LLL	6961	0.2380	0.2380	36"	56	1.8	1	60"	26"	7"
SBK 6.9	Min	LLL	6677	0.2532	0.2532	36"	82	2.7	1	60"	26"	7"

***Arc Flash Calculated for Switchgear and fixed conductor.**
Software won't supply Arc Flash results for clearing times over one second.

L.A.B. Limited Approach Boundry
R.A.B. Restricted Approach Boundry
P.A.B. Prohibited Approach Boundry

WARNING

Arc Flash and Shock Hazard Appropriate PPE Required

82 inches	Flash Hazard Boundary
2.7	cal / cm2 Flash Hazard at 36 inches
class 1	PPE Level, FR shirt and FR pants or FR coverall (1 layer). Hard hat and safety glasses.
6900 VAC	Shock Hazard
60 inches	Limited Approach
26 inches	Restricted Approach
7 inches	Prohibited Approach

Equipment Name:SBK 07

WARNING

Arc Flash and Shock Hazard Appropriate PPE Required

82 inches	Flash Hazard Boundary
2.7	cal / cm2 Flash Hazard at 36 inches
class 1	PPE Level, FR shirt and FR pants or FR coverall (1 layer). Hard hat and safety glasses.
6900 VAC	Shock Hazard
60 inches	Limited Approach
26 inches	Restricted Approach
7 inches	Prohibited Approach

Equipment Name:SBK 07

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Equipment Name:SBK 07

WARNING

Arc Flash and Shock Hazard Appropriate PPE Required

82 inches	Flash Hazard Boundary
2.7	cal / cm2 Flash Hazard at 36 inches
class 1	PPE Level, FR shirt and FR pants or FR coverall (1 layer). Hard hat and safety glasses.
6900 VAC	Shock Hazard
60 inches	Limited Approach
26 inches	Restricted Approach
7 inches	Prohibited Approach

Equipment Name:SBK 07

WARNING

Arc Flash and Shock Hazard
Appropriate PPE Required

56 inches	Flash Hazard Boundary
1.8	cal / cm2 Flash Hazard at 36 inches
class ~~0~~ 1	PPE Level, Non-melting, flammable materials (i.e., untreated cotton, wool, rayo or blends of these materials) with a fabric weight at least 4.5 oz/yd2 Safety glasses.
6900 VAC	Shock Hazard
60 inches	Limited Approach
26 inches	Restricted Approach
7 inches	Prohibited Approach

Equipment Name:SBK 07

WARNING

Arc Flash and Shock Hazard
Appropriate PPE Required

56 inches	Flash Hazard Boundary
1.8	cal / cm2 Flash Hazard at 36 inches
class ~~0~~ 1	PPE Level, Non-melting, flammable materials (i.e., untreated cotton, wool, rayo or blends of these materials) with a fabric weight at least 4.5 oz/yd2 Safety glasses.
6900 VAC	Shock Hazard
60 inches	Limited Approach
26 inches	Restricted Approach
7 inches	Prohibited Approach

Equipment Name:SBK 07

WARNING

Arc Flash and Shock Hazard
Appropriate PPE Required

56 inches	Flash Hazard Boundary
1.8	cal / cm2 Flash Hazard at 36 inches
class ~~0~~ 1	PPE Level, Non-melting, flammable materials (i.e., untreated cotton, wool, rayo or blends of these materials) with a fabric weight at least 4.5 oz/yd2 Safety glasses.
6900 VAC	Shock Hazard
60 inches	Limited Approach
26 inches	Restricted Approach
7 inches	Prohibited Approach

Equipment Name:SBK 07

WARNING

Arc Flash and Shock Hazard
Appropriate PPE Required

56 inches	Flash Hazard Boundary
1.8	cal / cm2 Flash Hazard at 36 inches
class ~~0~~ 1	PPE Level, Non-melting, flammable materials (i.e., untreated cotton, wool, rayo or blends of these materials) with a fabric weight at least 4.5 oz/yd2 Safety glasses.
6900 VAC	Shock Hazard
60 inches	Limited Approach
26 inches	Restricted Approach
7 inches	Prohibited Approach

Equipment Name:SBK 07

WARNING

Arc Flash and Shock Hazard Appropriate PPE Required

56 inches	Flash Hazard Boundary
4.0	cal / cm2 Flash Hazard at 16 inches
class 2	PPE Level, Cotton underwear - conventional short sleeve and brief/sh plus FR shirt and FR pants (1 or 2 layers). Hard hat, arc rated face shield, ear, hand and foot protecti
6900 VAC	Shock Hazard
60 inches	Limited Approach
26 inches	Restricted Approach
7 inches	Prohibited Approach

Equipment Name:SBK 07

WARNING

Arc Flash and Shock Hazard Appropriate PPE Required

56 inches Flash Hazard Boundary
4.0 cal / cm2 Flash Hazard at 16 inches
class 2 PPE Level, Cotton underwear - conventional short sleeve and brief/sh plus FR shirt and FR pants (1 or 2 layers). Hard hat, arc rated face shield, ear, hand and foot protecti
6900 VAC Shock Hazard
60 inches Limited Approach
26 inches Restricted Approach
7 inches Prohibited Approach

Equipment Name:SBK 07

WARNING

Arc Flash and Shock Hazard Appropriate PPE Required

56 inches Flash Hazard Boundary
4.0 cal / cm2 Flash Hazard at 16 inches
class 2 PPE Level, Cotton underwear - conventional short sleeve and brief/sh plus FR shirt and FR pants (1 or 2 layers). Hard hat, arc rated face shield, ear, hand and foot protecti
6900 VAC Shock Hazard
60 inches Limited Approach
26 inches Restricted Approach
7 inches Prohibited Approach

Equipment Name:SBK 07

WARNING

Arc Flash and Shock Hazard Appropriate PPE Required

56 inches Flash Hazard Boundary
4.0 cal / cm2 Flash Hazard at 16 inches
class 2 PPE Level, Cotton underwear - conventional short sleeve and brief/sh plus FR shirt and FR pants (1 or 2 layers). Hard hat, arc rated face shield, ear, hand and foot protecti
6900 VAC Shock Hazard
60 inches Limited Approach
26 inches Restricted Approach
7 inches Prohibited Approach

Equipment Name:SBK 07

WARNING

Arc Flash and Shock Hazard Appropriate PPE Required

82 inches	Flash Hazard Boundary
5.9	cal / cm2 Flash Hazard at 16 inches
class 2	PPE Level, Cotton underwear - conventional short sleeve and brief/sh plus FR shirt and FR pants (1 or 2 layers). Hard hat, arc rated face shield, ear, hand and foot protecti
6900 VAC	Shock Hazard
60 inches	Limited Approach
26 inches	Restricted Approach
7 inches	Prohibited Approach

Equipment Name:SBK 07

WARNING

Arc Flash and Shock Hazard Appropriate PPE Required

82 inches	Flash Hazard Boundary
5.9	cal / cm2 Flash Hazard at 16 inches
class 2	PPE Level, Cotton underwear - conventional short sleeve and brief/sh plus FR shirt and FR pants (1 or 2 layers). Hard hat, arc rated face shield, ear, hand and foot protecti
6900 VAC	Shock Hazard
60 inches	Limited Approach
26 inches	Restricted Approach
7 inches	Prohibited Approach

Equipment Name:SBK 07

WARNING

Arc Flash and Shock Hazard Appropriate PPE Required

82 inches	Flash Hazard Boundary
5.9	cal / cm2 Flash Hazard at 16 inches
class 2	PPE Level, Cotton underwear - conventional short sleeve and brief/sh plus FR shirt and FR pants (1 or 2 layers). Hard hat, arc rated face shield, ear, hand and foot protecti
6900 VAC	Shock Hazard
60 inches	Limited Approach
26 inches	Restricted Approach
7 inches	Prohibited Approach

Equipment Name:SBK 07

WARNING

Arc Flash and Shock Hazard Appropriate PPE Required

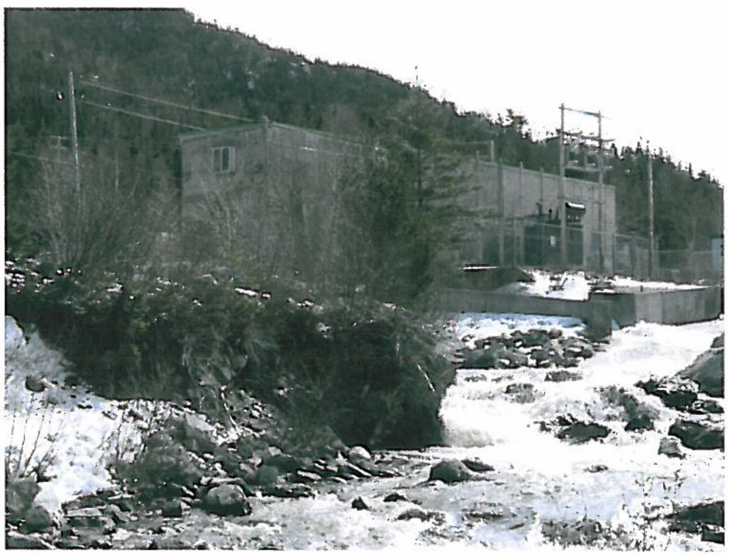
82 inches	Flash Hazard Boundary
5.9	cal / cm2 Flash Hazard at 16 inches
class 2	PPE Level, Cotton underwear - conventional short sleeve and brief/sh plus FR shirt and FR pants (1 or 2 layers). Hard hat, arc rated face shield, ear, hand and foot protecti
6900 VAC	Shock Hazard
60 inches	Limited Approach
26 inches	Restricted Approach
7 inches	Prohibited Approach

Equipment Name:SBK 07

Lookout Brook Hydro Plant Refurbishment
June 2009

Lookout Brook Hydro Plant Refurbishment

June 2009



Prepared by:

John Pardy, P.Eng.

REGISTERED PROFESSIONAL ENGINEER
J. W. PARDY
SIGNATURE
2009-06-15
PROVINCE OF NEWFOUNDLAND

NEWFOUNDLAND POWER
A FORTIS COMPANY

Table of Contents

1.0 Introduction

The Lookout Brook hydroelectric plant (the "Plant") is located in Western Newfoundland near the community of St. George's. The two original generating units ("G1 and G2") were commissioned in 1946 with a third unit ("G3") added in 1958. The two original units were replaced by a single larger generator ("G4") in 1984, resulting in the current unit designations of G3 and G4. The present capacity of the Plant is 6.2 MW under a net head of 154.6 metres. The normal annual production from the plant is 30.1 GWH or approximately 7.0% of Newfoundland Power's annual hydroelectric production.

The Plant contains two horizontal Francis turbines, one connected to a General Electric generator and the other connected to an Ideal Electric generator. The Plant is connected to the Island interconnected system at Stephenville Gas Turbine substation via Newfoundland Power's transmission lines 403L and 407L.

The Plant is located approximately fourteen kilometres from the Trans Canada Highway at the end of a private road. Snow is not cleared from the road restricting access to the Plant during the winter and spring months. Thus responding to operational issues during this period of time is difficult.

Newfoundland Power ("the Company") has determined that the switchgear requires replacement, the existing protection and control schemes, including the governor, generator protection, voltage regulation and the plant control systems are in need of modernization. The Plant AC and DC systems do not have sufficient capacity to supply the heating requirements and to accommodate the existing protection and control systems. Replacement of the forebay cable and upgrades to the communication equipment will be completed.

Replacement of the switchgear will provide adequate arc flash clearances for employees working near energized equipment. Upgrading the PLC and communication system will enhance plant operations and permit remote operation of devices that would normally require a site visit. This will reduce the need for maintenance personnel to travel to this remote plant, which for a portion of the year is only accessible by snowmobile. Improvements to the protective relaying systems will enhance the protection of the plant electrical equipment.

In addition to the above upgrades a Water Management System will also be implemented, ensuring the efficient operation of the plant and efficient utilization of available water resources.

Results of the feasibility analysis conclude that the continued operation of Lookout Brook plant, including the planned 2010 refurbishment, is economically viable over the long term. This project will allow Newfoundland Power to continue to operate this facility into the future, maximizing the benefits of this renewable resource for its customers.

2.0 Governors

2.1 Unit No. 3 - G3

The Gilkes governor was installed in 1958 as part of the installation of G3. The original control mechanism and pumping unit were replaced in 1980. The main actuator, hand wheel control, Giljet[1] impulse turbine and dashpot are original to the 1958 installation.

On unit start up there are excessive operations of the impulse turbine controls. The surfaces of the cover and bottom casing have been eroded by frequent exposure to high pressure water spray. Dashpot operating mechanisms for the Giljet impulse turbine require modification to integrate with the new governor controls.

The existing mechanical controls will be replaced with digital controls interfaced to a new proportional valve. This will improve the generator speed control to minimize the number of operations of the impulse turbine during start up. A reduction in the number of impulse turbine operations will extend the life of the unit. To implement this new arrangement the unit will require additional instrumentation to monitor operating conditions. In addition, the flexible hydraulic lines are deteriorated on the governor and will be replaced to ensure continued reliable operation.

2.2 Unit No. 4 - G4

The governor for G4 was installed in 1984 and is currently 25 years old. G4 governor consists of two sections, a Voist-Alpine electronic control unit and high pressure pumping unit (“HPU”).

The governor control unit is unable to effectively control unit speed. In addition, the supply of spare parts has been exhausted.[2] The unavailability of replacement parts from the original manufacturer has necessitated some governor control functionality being transferred to a programmable logic controller (“PLC”). This has resulted in control limitations with the governor system. The electronic controls for the governor will be replaced with a PLC governor controller and interfaced to the existing HPU.

The HPU, which supplies high pressure oil to the main valve and gate actuator, is in good condition and will not be replaced. The hydraulic control valves on the HPU are not functioning properly. In addition they are not compatible with the new controls that will be implemented for the governor. They will be replaced with valves compatible with the new governor controls.

The new governor control makes possible the implementation of a water management algorithm in the plant control system to optimize energy production from the water available.

---

[1] A hydraulic impulse brake system using a water jet directed towards a pelton wheel to retard the generator rotation. The name was given to this governing system by Gilbert Gilkes & Gordon Ltd. This is one of three such systems that are in use at Newfoundland Power.

[2] A flood in 1992 damaged the electronics resulting in the installation of some spare components that were included with the initial purchase of the equipment. The remaining spares have been used to address in service failures since 1992.

3.0 Generators

The generator windings are original to both units. There is no evidence that the windings require any upgrading at this time. Temperature signals from the existing resistance temperature detectors (RTDs) installed in the stator windings will be monitored by the new control system.

The neutral points on both generators are solidly bonded to ground. This method of grounding does not provide optimum protection of the generator windings as it permits large currents to flow through the generator windings under fault conditions. To minimize the magnitude of fault currents, a high impedance grounding system will be installed to connect the generator neutral to ground. Neutral grounding transformers with secondary resistors will be installed to provide this protection.

To monitor the insulation integrity of the generator windings a MegAlert® continuous stator insulation testing system[3] will be installed. The original lighting arresters and surge capacitors on both units will be replaced to provide protection for the generator windings from electric surges.

The installation of new switchgear will necessitate the reconfiguration of power cables to both generators. This reconfiguration requires replacement of the cables and terminations from the switchgear to the generator and substation.

4.0 Voltage Regulators

4.1 Unit No. 3 - G3

G3 has a Brown Boveri voltage regulator (Figure 1) with a mechanical operating mechanism. The mechanical operating mechanism is worn from 50 years of operation affecting responsiveness of the regulator. The voltage regulator is manufacturer discontinued and cannot be integrated into the upgraded control system. The existing voltage regulator will become redundant[4] with the installation of a modern PLC providing plant control.

Figure 1 - BB Voltage Regulator

[3] The MegAlert® continuous stator insulation testing system has been installed at other Newfoundland Power hydroelectric plants. This provides protection from inadvertent starting of generators contaminated with moisture.

[4] The ControlLogix PLC incorporates the digital voltage regulator functionality into the Combination Generator Control Module ("CGCM"). The CGCM is specifically designed to monitor and control a three phase alternating current generator through PLC logic.

4.2 Unit No. 4 - G4

Unit G4 has a Basler MVC108 solid state voltage regulator original to the unit which is manufacturer discontinued. Similar to the voltage regulator on unit G3, integration of this device into the upgraded plant control system is not possible. This voltage regulator will also be replaced with a digital voltage regulator incorporated in the plant control PLC.

5.0 Switchgear

The existing switchgear is a combination of the original G3 switchgear that was installed in 1958 and the switchgear installed as part of the installation of G4 in 1984. When the G4 switchgear was installed field modifications were made to the bus to connect the different switchgear cabinets. Protective devices and control switches for each unit are presently mounted in the front door of the switchgear cabinet.

The G3 generator breaker cannot be removed from the switchgear to provide electrical isolation from the generator when performing maintenance. This introduces an arc flash hazard for employees operating and performing maintenance on the equipment. The G4 generator breaker is original to the 1984 installation and spare parts for maintaining this breaker are not available.[5] The replacement of the switchgear will address the arc flash hazard and maintenance issues.

The replacement switchgear will be arc flash rated with breakers that require minimum maintenance. The new switchgear design will permit isolation of one breaker while the other generator remains online. Higher accuracy instrument transformers for improved protection and metering will be supplied with the switchgear. The potential transformers will have a disconnect mechanism to permit isolation for improved employee safety during maintenance. The control switches and associated wiring will be relocated to a new unit control panel remote from the switchgear and outside the arc flash zone of influence, improving employee safety.

There is currently no emergency station service transformer to supply essential plant services while placing a generator online during a system outage. To provide this capability an emergency station service transformer and transfer switch will be included in the new switchgear.

6.0 AC Distribution

The AC service is comprised of the main service entrance panel and subpanels located throughout the Plant. Some panels are original while others have been installed during various plant modifications. The capacity of the existing AC electrical service is not sufficient to supply the amount of heat required to avoid condensation[6] and prevent freezing of cooling water piping. A new service entrance with two AC distribution panels will provide increased capacity and consolidate all AC circuits. An automatic transfer switch will be installed in conjunction with an

[5] The G4 generator breaker is similar to the breaker that failed in service at Rocky Pond Hydro Plant in 2005 which resulted in extensive fire damage to the plant.

[6] High humidity levels appear to be a contributing factor to the corrosion experienced on some electrical equipment.

emergency station service transformer to supply AC power to critical plant loads from either generator during a system outage.

7.0 DC Distribution

The existing 12 circuit DC distribution panel is original to the plant construction in 1958 and does not have enough capacity to accommodate the existing protection and control equipment. As a result control circuits for different functions have been paralleled on the same circuit breaker. Thus, when one piece of equipment requires maintenance several pieces of equipment have to be taken out of service to complete the maintenance work. A new 60-circuit panel will be installed to provide adequate capacity, improved circuit isolation and ensure the availability of replacement circuit breakers.

8.0 Battery Bank

The C&D Technologies lead-antimony battery bank was installed in 1996. This type of battery bank produces hydrogen gas during charging and is currently located in the main generator hall. The generator hall is not properly ventilated to dispose of hydrogen gas that is produced when the batteries are charging. To eliminate the requirement to construct a separate battery room the battery bank will be replaced with gel cell technology.

9.0 Main and By-Pass Valves

9.1 Unit No. 3 - G3

Both the main valve and actuator for G3 were replaced in 1998 and are in good condition. The electrical contactors in the valve control cabinet are worn and will be replaced

9.2 Unit No. 4 - G4

Both the main valve and actuator for G4 are original to the 1984 installation and are in good condition. The bypass valve leaks and will be replaced. The flexible high pressure hydraulic hoses that run from the pumping unit to the hydraulic cylinder are deteriorated and will be replaced.

10.0 Protective Relaying

Protective relaying systems provide protection for equipment and personnel during abnormal loading and fault conditions. Protective relaying elements are critical to protecting generators and other electrical equipment against hazardous conditions that occur on the power system. The evaluation of the protective relays considers age of the relay, its reliability and the extent to which the protection provided meets current protection standards.

The following protective relaying elements are currently in service at Lookout Brook Plant:

40	Loss of Field
49	Thermal Protection
50/51N	Overcurrent
51V	Backup Protection – Voltage Controlled Overcurrent
59	Overvoltage
64	Voltage Relay for Rotor Ground Fault
87	Differential

The existing protective relays at Lookout Brook plant lack seven elements[7] of the minimum protection set. In addition to not meeting the minimum recommended protection level, the existing electromechanical relays are no longer satisfactory and are corroded.

The existing generator protective relays will be replaced with modern digital relays to provide the minimum protection set. Improved generator protection reduces stresses due to electrical faults and in turn extends the life of the generator.

In addition to the enhanced generator protection, bus differential and arc flash protection will be added with the new switchgear to provide improved equipment protection and reduce the arc flash hazard to employees working in the vicinity of the switchgear.

11.0 Plant Control

Currently, the generators at the Plant are controlled through various electromagnetic relays and switches which were installed in 1958. This equipment controls the generator exciters, the main unit valves, and the generators' mechanical protection. It shows signs of corrosion and deterioration.

An existing PLC installed in 1994 is an Allan-Bradley SLC 5/03 which is interfaced to G4. It was initially installed to control unit speed as a result of the problems experienced with the original governor controls. However, since that time annunciation of some unit alarms have been moved to the PLC due to the failure of the original alarm annunciation equipment. This PLC is at its capacity limitations and is not capable of more fully controlling the generators.

Plant control will provided by an Allan-Bradley ControlLogix PLC. The new PLC will provide automated local and remote control of both generators and plant functions. Modern industrial human-machine interfaces will be installed in the unit control panels to provide improved alarm annunciation and control functionality.

Although the Plant is remotely controlled and monitored from SCADA, remote control functions are limited to basic unit start and stop capability. At present, there is no automation with respect to water management and the setting of machine loads to optimize the use of the available water.

[7] The existing generator protection does not include Volts/Hz 24, Reverse Power 32, Stator Unbalance 46, Voltage Balance 60, Loss of Synchronization 78, Frequency 81 and sensitive Ground Fault 87GN elements which are recommended by the IEEE for these generators.

The new plant control PLC will greatly improve the local and remote monitoring and control functionality. It will facilitate the implementation of a variety of control modes to ensure the efficient operation of the plant and efficient utilization of available water resources.

A new gateway data concentrator will be installed to enhance the communications to the SCADA system and facilitate remote administration[8] of the PLC and protection relays provided with the controls upgrade.

Control switches, protection relays and associated wiring will be removed from the switchgear. These devices will need to be relocated to separate protection and control panels which will be located outside the switchgear arc flash zone of influence. This will minimize the arc flash hazard to employees in the plant during switching operations.

12.0 Synchronizing

The existing Basler Electric PRS170 synchronizer[9] will be taken out of service and kept as a spare for other in-service units.[10] A synchrocheck relay will be installed to supervise both automatic and manual synchronizing.

13.0 Instrumentation

The existing instrumentation is original to the generator installations in 1958 and 1984. The instrumentation is worn from many years of service and the interface cables are frayed.

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

The following instrumentation will be added or replaced on each unit:

- Cooling water temperature sensing
- Cooling water solenoids
- Cooling water flow meters
- Brushgear infrared detection
- Bearing thermocouples
- Bearing oil level
- Governor oil level
- Governor oil pressure
- Governor oil temperature

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8 Remote administration of intelligent devices will reduce the need to travel to site to diagnose events that happen through the normal course of operation.

9 A synchronizer monitors the power system and the generator coming on line to ensure that unit speed and voltage are within acceptable limits before breaker closure is permitted.

10 The synchronizer is redundant with a modern ControlLogix PLC equipped with a CGCM module.

- Scroll case pressure
- Speed sensing tooth gear

14.0 Heating and Ventilation

There are infrared heaters installed over each generator with both blower type and convection heat in the valve and generator pits. There are three exhaust fans (Figure 2) located in the building. The outside louvers have no operating mechanism, making it difficult to control plant heating and ventilation.

The amount of installed plant heat is inadequate due to the size of the electrical service and distribution panels.

The heating and ventilation controls will be consolidated into a common heating control panel and integrated with the plant control PLC. Additional heat will be installed to prevent condensation on the generators and freezing of the cooling water pipes in the winter when the units are not operating. Louvers will be replaced and controls added to better manage plant heating and cooling cycles.

15.0 Cooling Water

The existing cooling water system is antiquated with deteriorated piping to the individual bearings requiring replacement.

A header system will be installed on both units to ensure adequate flows to the individual bearings are maintained. This header arrangement will permit the installation of monitoring and control devices for the cooling water system that will be integrated with the plant control PLC.

16.0 Forebay Water Level Monitoring and Control

The existing water level signal from the forebay is transmitted to the plant on a communications cable with copper wire conductors. The existing forebay communications cable has been damaged resulting in the loss of signal quality. The current damage makes the forebay cable susceptible to further damage from water ingress, lightning strikes and ground potential rise.

The existing water level probe is corroded and requires replacement.

The forebay water level system is critical to the implementation of the Water Management System in the plant control PLC. The plant control PLC will use the water level signals to control the Water Management System. High level and low level alarms will also be initiated when specified water levels are reached. The Water Management System will optimize the efficiency of the plant by controlling the load on the unit based upon water level, inflow, wicket gate position and control mode set points.

The communications cable will be upgraded to a fibre optic cable between the plant and the forebay to ensure reliability of the water level signal.

17.0 Control Room Extension

The existing powerhouse does not have adequate space to install the new switchgear and control panels while maintaining a lay down area to perform maintenance on generator G4 turbine and valve. In addition, the installation of protection and control panels in any of the existing floor space would prevent removal of major components of the G4 generator from the building.

A 26 m^2 extension to the powerhouse will be required to provide the additional space required for this equipment.

18.0 Project Cost

The total project cost is estimated at $2,342,000. Table 1 below provides the cost breakdown by major components.

Table 1
Lookout Brook Hydro Plant Refurbishment
Estimated Cost

Civil	
Control Room Extension	$ 166,900
Mechanical	
Cooling Water and Governor Upgrade	$ 27,900
Electrical	
Engineering (All disciplines) & Supervision	$ 243,000
Generator Upgrades	$ 59,400
Governor Upgrades	$ 210,200
Plant Control	$ 530,100
Protective Relaying & Communications	$ 91,100
Instrumentation	$ 81,000
AC & DC Systems	$ 110,100
Commissioning	$ 112,400
Heating and Ventilation	$ 19,100
Switchgear	$ 417,300
Forebay Cable	$ 86,500
Plant Subtotal	**$ 2,155,000**
Substation	$ 187,000
Total Project Cost	**$ 2,342,000**

19.0 Recommendations

The following major systems are recommended to be replaced or modified during the 2010 refurbishment project:

1. Upgrade the governor control;
2. Install high impedance grounding system on both generators;
3. Replace voltage regulators on both generators;
4. Replace the switchgear and generator power cables;
5. Replace the AC and DC distribution panel;
6. Replace the battery bank;
7. Upgrade protective relays for both generators and switchgear;
8. Replace the existing programmable logic controller;
9. Upgrade and or replace instrumentation on both units;
10. Upgrade the heating and ventilation equipment and controls;
11. Upgrade the cooling water system;
12. Replace forebay communication cable;
13. Install a new water management system; and
14. Build an extension on the plant.

20.0 Economic Feasibility

Appendix A provides an economic feasibility analysis for the continued operation of Lookout Brook hydroelectric development. The results of the analysis show that the continued operation of Lookout Brook hydroelectric development is economical over the long term. Investing in the life extension of Lookout Brook ensures the continued availability of 30.1 GWh of annual energy to the Island interconnected system.

The estimated levelized cost of energy from the Lookout Brook over the next 50 years associated with future capital and operating expenditures as outlined in Appendix A is 2.68 ¢/kWh. This energy is lower in cost than replacement energy from sources such as new hydroelectric developments or additional Holyrood thermal generation[11].

[11] The cost of electricity from the Holyrood thermal generating plant is estimated at 12.06 ¢/kWh. This is based upon a 630 kWh/barrel conversion efficiency and oil forecast from Hydro of $75.95/barrel dated March 31, 2009.

Appendix A
Feasibility Analysis

Table of Contents

1.0 Introduction

This feasibility analysis examines the future viability of generation at Newfoundland Power's Lookout Brook hydroelectric plant (the "Plant"). The continued long-term operation of the Plant is reliant on the completion of capital improvements in 2010.

With investment required in 2010 to permit the continued reliable operation of the 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 Plant over the next 25 years have been identified. The capital expenditures required to maintain the safe and reliable operation of the facilities are summarized in Table 1.

Table 1
Lookout Brook
Hydroelectric Plant
Capital Expenditures

Year	**(000s)**
2010	$2,342
2015	1,400
2018	760
2019	100
2020	750
2021	400
2025	5,033
2030	52
2034	1,165
2035	540
Total	**$12,542**

The total capital expenditure for the Plant until 2035 is $12,542,000 in 2010 dollars. A more comprehensive breakdown of capital costs is provided in Attachment A.

3.0 Operating Costs

Operating costs for the Plant are estimated to be approximately $118,052[1] per year. This estimate is based primarily upon recent historical operating experience. The operating cost represents both direct charges for operations and maintenance at the Plant as well as indirect costs such as those related to managing the environment, safety, dam safety inspections and staff training. A summary of operating costs is provided in Attachment B.

4.0 Benefits

The maximum output from the Plant is 5.9 MW. The Plant normally operates at an efficient load of 5.3 MW to maximize the energy from the water.

The estimated long-term normal production at the Plant under present operating conditions is 30.1 GWh per year. This estimate is based on the results of the Water Management Study completed by SGE Acres in 2005.

5.0 Financial Analysis

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

The estimated levelized cost of energy from the Plant over the next 50 years is 2.68 ¢/kWh. This figure includes all projected capital and operating costs necessary to operate and maintain the facility. Energy from Lookout Brook can be produced at a significantly lower price than the cost of electricity currently supplied from Newfoundland and Labrador Hydro's Holyrood thermal generating station at 12.06 ¢/kWh[2].

The future capacity benefits of the continued availability of the 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.

6.0 Recommendation

The results of this feasibility analysis show that the continued operation of the Plant is economically viable. Investing in the current upgrades of the facilities at Lookout Brook ensures the availability of low cost energy to the Province. Otherwise, the annual production of 30.1 GWh would be replaced by more expensive energy sources from the Holyrood thermal generating station. The project will benefit the Company and its customers by providing least cost, reliable energy for years to come.

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1 2009 dollars

2 Based on 630 kWh/barrel conversion efficiency of Holyrood and oil forecast from Hydro of $75.95/barrel dated March 19, 2009

Attachment A
Summary of Capital Costs

Lookout Brook Feasibility Analysis
Summary of Capital Costs
($000s)

Description	**2010**	**2015**	**2018**	**2019**	**2020**	**2021**	**2025**	**2030**	**2034**	**2035**
Civil										
Dam, Spillways and Control Structures		1,400			750					
Penstock							5,000			
Powerhouse	202		100						50	
Plant Access				100						
Mechanical										
Mechanical Refurbishment									515	
Turbine Upgrades										
Governor			55							
Upgrades	256									
Electrical										
Controls Upgrade	1,064						33	52		540
Generator Rewind			565						570	
Exciter			40						30	
Switchgear	520									
Forebay Cable	90									
Substation	210					400				
Annual Totals	**2,342**	**1,400**	**760**	**100**	**750**	**400**	**5,033**	**52**	**1,165**	**540**

Attachment B
Summary of Operating Costs

Lookout Brook Feasibility Analysis
Summary of Operating Costs

Actual Annual Operating Costs

Year	Amount
2004	$180,347
2005	134,639
2006	82,942
2007	86,523
2008	105,808
Average	**$118,052**

5 -Year Average Operating Cost	$118,052[1]
Total Forecast Annual Operating Cost	$118,052

[1] 2009 dollars

Attachment C
Calculation of Levelized Cost of Energy

Present Worth Analysis

Weighted Average Incremental Cost of Capital 8.58%
PW Year 2009

Year	Generation Hydro 64.4yrs 8% CCA	Substation 46.2 yrs 8% CCA	Building 53.6 yrs 4% CCA	Capital Revenue Rqmt	Operating Costs	Operating Benefits	Net Benefit	Present Worth Benefit	Cumulative Present Worth Benefit	Rev Rqmt (¢/kWhr)	Levelized Rev Rqmt (¢/kWhr) 50 years
2010	1,988,000	187,000	167,000	244,609	118,052	0	-362,661	-334,004	-334,004	1.20	2.68
2011	0	0	0	235,111	120,185	0	-355,296	-301,363	-635,367	1.18	2.68
2012	0	0	0	236,402	122,290	0	-358,692	-280,203	-915,570	1.19	2.68
2013	0	0	0	236,790	124,731	0	-361,521	-260,096	-1,175,666	1.20	2.68
2014	0	0	0	236,772	127,153	0	-363,925	-241,136	-1,416,802	1.21	2.68
2015	1,533,746	0	0	395,064	129,330	0	-524,394	-320,006	-1,736,809	1.74	2.68
2016	0	0	0	386,911	131,608	0	-518,519	-291,418	-2,028,226	1.72	2.68
2017	0	0	0	387,126	133,888	0	-521,013	-269,681	-2,297,907	1.73	2.68
2018	876,933	0	0	477,022	136,215	0	-613,238	-292,335	-2,590,242	2.04	2.68
2019	117,447	0	0	483,549	138,648	0	-622,198	-273,168	-2,863,410	2.07	2.68
2020	896,852	0	0	574,604	141,167	0	-715,771	-289,418	-3,152,828	2.38	2.68
2021	487,278	0	0	618,712	143,810	0	-762,523	-283,958	-3,436,786	2.53	2.68
2022	0	0	0	614,478	146,415	0	-760,894	-260,961	-3,697,748	2.53	2.68
2023	0	0	0	611,996	149,116	0	-761,112	-240,409	-3,938,157	2.53	2.68
2024	0	0	0	608,587	151,929	0	-760,516	-221,239	-4,159,395	2.53	2.68
2025	6,599,120	0	0	1,287,207	154,786	0	-1,441,993	-386,337	-4,545,732	4.79	2.68
2026	0	0	0	1,250,495	157,566	0	-1,408,061	-347,435	-4,893,167	4.68	2.68
2027	0	0	0	1,250,537	160,423	0	-1,410,961	-320,640	-5,213,807	4.69	2.68
2028	0	0	0	1,246,768	163,292	0	-1,410,060	-295,115	-5,508,922	4.68	2.68
2029	0	0	0	1,241,263	166,268	0	-1,407,531	-271,307	-5,780,229	4.68	2.68
2030	74,588	0	0	1,241,877	169,332	0	-1,411,209	-250,521	-6,030,750	4.69	2.68
2031	0	0	0	1,232,944	172,380	0	-1,405,323	-229,763	-6,260,513	4.67	2.68
2032	0	0	0	1,223,080	175,482	0	-1,398,562	-210,589	-6,471,102	4.65	2.68
2033	0	0	0	1,211,936	178,641	0	-1,390,577	-192,841	-6,663,943	4.62	2.68
2034	1,794,658	0	0	1,385,310	181,857	0	-1,567,167	-200,156	-6,864,099	5.21	2.68
2035	846,832	0	0	1,450,875	185,130	0	-1,636,005	-192,437	-7,056,536	5.44	2.68
2036	0	0	0	1,433,912	225,053	0	-1,658,965	-179,718	-7,236,254	5.51	2.68
2037	0	0	0	1,419,958	229,104	0	-1,649,061	-164,529	-7,400,783	5.48	2.68
2038	0	0	0	1,404,425	233,227	0	-1,637,652	-150,479	-7,551,262	5.44	2.68
2039	0	0	0	1,387,667	237,426	0	-1,625,092	-137,525	-7,688,787	5.40	2.68
2040	73,724	0	0	1,377,409	241,699	0	-1,619,108	-126,192	-7,814,979	5.38	2.68
2041	0	0	0	1,358,130	246,050	0	-1,604,180	-115,148	-7,930,128	5.33	2.68
2042	0	0	0	1,338,314	250,479	0	-1,588,793	-105,032	-8,035,160	5.28	2.68
2043	0	0	0	1,317,584	254,987	0	-1,572,571	-95,745	-8,130,905	5.22	2.68
2044	0	0	0	1,296,033	259,577	0	-1,555,610	-87,228	-8,218,133	5.17	2.68
2045	0	0	0	1,273,726	264,249	0	-1,537,975	-79,425	-8,297,558	5.11	2.68
2046	0	0	0	1,250,723	269,006	0	-1,519,729	-72,281	-8,369,838	5.05	2.68
2047	0	0	0	1,227,081	273,848	0	-1,500,929	-65,746	-8,435,584	4.99	2.68
2048	0	0	0	1,202,851	278,777	0	-1,481,628	-59,772	-8,495,355	4.92	2.68
2049	1,610,506	0	0	1,344,703	283,795	0	-1,628,498	-60,505	-8,555,861	5.41	2.68
2050	12,915,124	0	0	2,647,854	288,904	0	-2,936,758	-100,490	-8,656,351	9.76	2.68
2051	0	0	0	2,560,990	294,104	0	-2,855,094	-89,976	-8,746,327	9.49	2.68
2052	0	0	0	2,546,041	299,398	0	-2,845,438	-82,586	-8,828,913	9.45	2.68
2053	0	0	0	2,524,046	304,787	0	-2,828,833	-75,616	-8,904,529	9.40	2.68
2054	0	0	0	2,499,035	310,273	0	-2,809,308	-69,160	-8,973,690	9.33	2.68
2055	73,939	0	0	2,478,899	315,858	0	-2,794,757	-63,365	-9,037,055	9.28	2.68
2056	0	0	0	2,442,619	321,543	0	-2,764,162	-57,719	-9,094,774	9.18	2.68
2057	0	0	0	2,411,792	327,331	0	-2,739,123	-52,677	-9,147,451	9.10	2.68
2058	0	0	0	2,377,430	333,223	0	-2,710,654	-48,010	-9,195,461	9.01	2.68
2059	0	0	0	2,341,068	339,221	0	-2,680,289	-43,721	-9,239,182	8.90	2.68
2060	1,322,793	0	0	2,439,722	345,327	0	-2,785,049	-41,840	-9,281,022	9.25	2.68

Feasibility Analysis
Major Inputs and Assumptions

Specific assumptions include:

Income Tax: Income tax expense reflects a statutory income tax rate of 32%.

Operating Costs: Operating costs were assumed to be in 2009 dollars escalated yearly using the GDP Deflator for Canada.

Average Incremental Cost of Capital:

	Capital Structure	Return	Weighted Cost
Debt	55.00%	6.60%	3.63%
Common Equity	45.00%	11.0%	4.95%
Total	**100.00%**		**8.58%**

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.

Escalation Factors: Conference Board of Canada GDP deflator, January 29, 2009.

Petty Harbour Hydro Plant Refurbishment
June 2005

Petty Harbour Hydro Plant Refurbishment

June 2005

Prepared by:

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1.0 Introduction

The Petty Harbour hydroelectric power plant is located on the east coast of the Avalon Peninsula in the community of Petty Harbour. Commissioned in 1900 the plant contains three generating units. The generating station has undergone a number of changes since it was originally commissioned. The current configuration includes three horizontal generating units with an installed capacity of 5,300 kW under a net head of approximately 57.9 m.

The most recent overhaul of the facility was completed in 1986. Work on unit 2 included replacements of the main valve, flywheel, generator, turbine and governor. Work on unit 3 included replacements of the main valve, turbine, shaft, wicket gates, and governor. The stator of unit 3 was rewound in 1994. Unit 1 operates with the original governor installed in 1910 and is operated infrequently; only as water is available. The existing control panels, switchgear, and protection systems were installed on all three units in 1978. Units 2 and 3 underwent automation upgrades between 1986 and 1988. The Petty Harbour plant was the first Newfoundland Power plant to be controlled using Programmable Logic Controller Technology (PLC). The Square D Sy/Max PLCs installed on Unit Nos. 2 and 3 are now obsolete.

The justification for the refurbishment project is based on the plants continued ability to provide low cost electricity to the island electrical system.

The requirement for the refurbishment project is based upon the deficiencies identified in the site assessments and the number of maintenance issues being experienced with the existing PLC control system, voltage regulation equipment and Voith electronic governors. In recent years the plant has had a number of forced outages related to these plant components.

The refurbishment will provide improved electrical and mechanical protection as well as standardization with other plants in the system.

2.0 Role in Power System

The normal annual production at Petty Harbour Hydro Plant is approximately 15.9 GWh of energy or 3.7 % of the total hydroelectric production of Newfoundland Power. It has a peak power output of 5.3 MW and can supply the communities of Petty Harbour and Maddox Cove when isolated from the Island Interconnected System.

3.0 Project Scope of Work

The scope of this project includes work recommended in the site assessment included as Appendix A of this report. The following is a summary of the work to be undertaken.

3.1 Electrical

Unit 1

- Replace voltage regulator
- Install grounding transformer
- Install partial discharge testing
- Install condensation protection

Unit 2 and 3

- Replace voltage regulator
- Replace unit control PLC
- Replace electronic governor
- Install automatic synchronizer
- Instrumentation upgrade
- Integrate cooling water monitoring and control
- Integrate plant heating and ventilation
- Upgrade generator protection
- Install grounding transformer unit 3
- Install partial discharge testing
- Install condensation protection
- Replace forebay elevation probe

3.2 Mechanical

- Overhaul turbine #2

3.3 Penstock

- Replace coating system

4.0 Project Assessment

4.1 Electrical

As outlined in the Site Assessment in Appendix A the 2 PLCs, electronic governor controls, voltage regulators and auto-synchronizer at the Petty Harbour Plant are obsolete and require replacement. The equipment has undergone a number of upgrades throughout its 105 year life, the most recent upgrade occurring 20 years ago when the facility was commissioned for remote operation through the Supervisory Control and Data Acquisition (SCADA) system. The three subsystems of most concern are the PLCs, the voltage regulators and the automatic synchronizer. These three systems are critical to the operation of the individual generators. A complete failure of either subsystem would force an outage on the associated generator. Depending upon the circumstance the loss of a generator could result in lost energy at times of high water elevations or the inability to supply customer load when operating the community of Petty Harbour isolated from the grid.

The Square D Sy/Max PLC's installed between 1986 and 1988 to monitor and control units 2 and 3 have been discontinued by the manufacturer for many years and supplies of replacement parts have been exhausted. There are ongoing problems with the units failing to pick up load, offloading and changing operating modes.

Voltage and power factor control is an ongoing issue at Petty Harbour causing power quality concerns when operating as an isolated system. The voltage regulators are unable to meet the current standards for maintaining system voltage. Replacing the voltage regulators on the units will ensure voltages in all operating modes meet the current CSA standard.

The existing Westinghouse electromechanical auto-synchronizer, installed in 1978, is also obsolete and will be replaced by a stand-alone digital model. The operation of the auto-synchronizer is critical when placing the generators on line remotely.

In addition, the generators must be properly protected in the event that electrical or mechanical problems develop. Detecting these problems and removing the generator from service as quickly as possible is essential to minimize potential damage and avoid costly repairs.

The electromechanical relays presently used to protect all three units lack many of the IEEE recommended minimum set of protection elements. With the installation of a digital multifunction generator protection relay and relay grade current and potential transformers in the switchgear, additional protection elements will be provided. Enhancing the electrical and mechanical protection of the generators will reduce the risk of failure of the generator windings by earlier detection of fault conditions. The result is a less costly minor repair as opposed to the cost of a complete generator rewind.

There is presently no vibration protection on either unit and, with the exception of temperature switches on unit 2, no bearing temperature protection. Instrumentation for these and other monitoring functions will be installed for early detection of conditions that could lead to mechanical failure of key components. Similarly, the benefit here is a lower cost repair as opposed to the cost of an unplanned repair due to failure.

4.2 Mechanical

Unit 2 requires a turbine overhaul to ensure its safe operation and to enable it to produce its rated power output. When the wicket gates were replaced in 1985, the head and bottom covers had to be bored to accept the new gate stems. Since 1985 the gate stems have worn and when the unit has been running at greater than 80% load, the gates have dropped down in the elongated holes and have become stuck. In these instances it has been necessary to use the main valve to shut the unit down. Using the main valve to stop a unit is unacceptable as it exposes it to an increased risk of damage. The time delays associated with closing the main valve results in the unit going into overspeed. As a result of this problem with the wicket gates the unit has been restricted to less than 80% opening at the gate with a corresponding full load reduction from 1350 kW to less than 1000 kW.

To correct this problem, the existing wicket gates and bushings will have to be removed and the head and bottom covers machined to ensure alignment and to accept new bushing. New bushings will also have to be fabricated and installed along with the gates and covers.

4.3 Penstock

The woodstave penstock at the Petty Harbour plant was replaced with a steel penstock in 1999. The steel penstock was supplied with a two coat mastic epoxy paint system. Since that time the paint system on the penstock has deteriorated to the point where the coating system requires replacement.

Operating experience of both Newfoundland Power and the industry at large has revealed that two coat mastic epoxy systems in marine environments are known to break down after only 3-5 years of service life. Originally the manufacturers promoted this type of coating system to have a normal life expectancy of 15 years in the marine environment. Based on the findings it is now an industry recommendation that a two coat epoxy system be top coated with polyurethane to provide added protection and extend the life of the paint system. Since 2004 new steel penstocks installed in the Newfoundland Power system are painted with one coat zinc rich epoxy primer, an epoxy intermediate coat, and polyurethane topcoat.

5.0 Plant Reliability

All three units and in particular unit 2, have recently experienced forced and maintenance outages due to governor, control system and instrumentation problems.

Over the past three years, unit 2 has experienced the greatest percentage of forced downtime of all of Newfoundland Power’s generators at 5.98% downtime. Unit 3 is the fifth worse generator in the fleet.

Replacing the manufacturer-discontinued equipment with commercially available equipment will reduce the duration of unscheduled downtime. This will improve customer reliability when the plant is required to supply local generation and plant reliability by increasing availability and maximizing output.

6.0 Recommendations

The following is a list of the major recommendations that will be addressed as part of this refurbishment project:

- Replace AC & DC distribution panels.
- Install continuous partial discharge monitoring equipment on all units.
- Replace condensation monitoring protection on all units.
- Install digital voltage regulation on all units.
- Install additional potential and current transformers in switchgear for protection and synchronizing.
- Install grounding transformers for units 1 and 3.
- Upgrade generator protection and relaying on units 2 and 3.
- Install new industrial computer Human Machine Interfaces (HMIs) to replace existing annunciators and provide improved indication and control functionality
- Replace the existing Voith electronic governor controller for units 2 and 3 with a PLC based algorithm in the unit control PLCs.
- Replace the existing Square D Sy/Max PLC control systems with Allan-Bradley ControlLogix models to provide improved protection, control and reliability.
- Replace existing auto-synchronizer.
- Install/upgrade generator instrumentation.
- Integrate bearing cooling water system into PLC control system.
- Upgrade the heating/ventilation controls and integrate into PLC control system.
- Replace existing forebay water level monitoring equipment.
- Overhaul unit #2 turbine to restore full power output.
- Recoat the penstock.

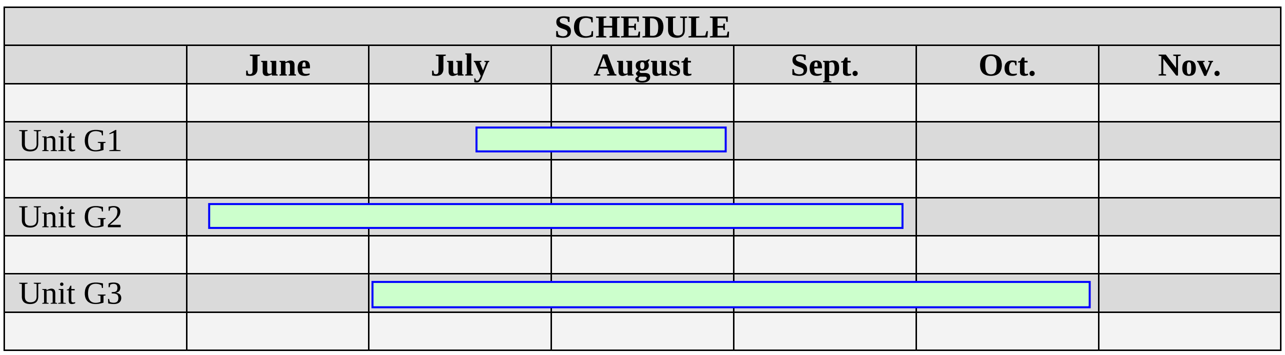
Obsolete, high-maintenance equipment places the reliability and availability of the plant at risk. In addition, inadequate electrical and mechanical protection could result in a sudden failure with subsequent repair costs and extended downtime. Loss of a PLC could result in a unit or plant being out of service until a new PLC is procured and installed. Therefore, action should be taken to mitigate this risk and ensure that the PLCs and other obsolete components are replaced in a planned manner. The replacement of the unit 2 and 3 PLCs, electronic governor controls, voltage regulators and auto-synchronizers should be completed in 2006.

There are no feasible alternatives to the refurbishment of existing hydroelectric facilities that continue to provide a low cost source of electricity. The poor reliability experienced cannot be effectively addressed through other means.

7.0 Implementation

The refurbishment project will involve the disassembly of the existing protection and control system and removal from site. There is turbine work required on unit 2 and the recoating of the penstock that requires the pipeline to be dewatered. The scheduling of the work can be accomplished such that there is at least one unit available to operate in late spring and early fall when there is water available to the plant. In addition, unit 1 will be available to generate electricity until the penstock is dewatered for painting. Since the plant would only be shut down for 8 to10 weeks in the summer period there would be an insignificant amount of spill, based on normal inflows, into the system during this time.

The high level schedule is as follows:



Appendix A

Site Assessment

General

The site assessment at the Petty Harbour generating station was completed in April 2004 and reviewed again in April 2005. This report documents the findings of these two site assessments. As part of this site assessment a review of the forced outage log was completed. Thirteen of the thirty eight forced outages recorded on unit 2 from February 2003 to May 2005 were directly related to voltage regulation problems. Five forced outages were related to electronic governor malfunctions while three were PLC related.

The electronic governors have suffered heat damage to the backplane and printed circuit boards. Replacement parts are not available, so, soldered "jumper" repairs have been made. These repairs will eventually fail and there will be no practical means to make another repair.

The Square D programming interface terminal has faulted so programming of the PLC is now done using laptop computers. As a result communication and compatibility problems have been experienced with the laptop computers and PLC software. This has extended repair and troubleshooting time and restricted upgrading of the sequencing and control functions. The annunciator display has a number of the light emitting diodes burnt out making the display unreadable. The PLC components are no longer supported by the manufacturer.

AC Distribution

The AC distribution system consists of multiple panels located throughout the plant. In addition to the original 120/208V 3-phase AC service panel, installed in 1978, there are three auxiliary panels at various other locations within the building. It is recommended that a new AC panel be installed with sufficient capacity to replace all existing panels and provide additional spare capacity. The AC distribution system does not currently meet CSA standards. The new system will be designed to CSA standards.

Station Service

The station service consists of two 37.5 KVA 2400-120/240V transformers located in the switchgear cabinet. These transformers are in good condition with spare units available. It is recommended that the station service not be replaced.

DC Distribution

The existing DC distribution panel was installed in 1978. Replacement breakers are no longer available. The panel has insufficient spare circuits to accommodate the refurbishment of the protection and control equipment. It is recommended that the DC distribution panel be replaced.

Battery Plant and Charger

A review of maintenance records for the battery bank indicates it has remaining service life. The battery charger was replaced in 2003. It is recommended that both the existing battery bank and charger remain in service.

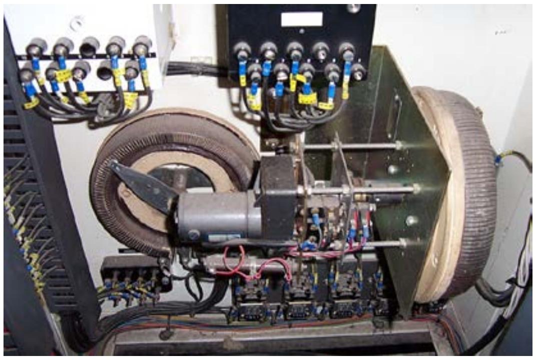
Generators

Unit 1 was rewound in 1970, unit 3 in 1994, and unit 2 in 1986. There are no indications that the generator windings have deteriorated. The addition of continuous partial discharge testing equipment on each generating unit is recommended to monitor the condition of the windings to facilitate scheduled replacement before failure. The integration of the MegAlert stator insulation resistance monitors with the unit control panels is recommended to ensure the units are not started with condensation on the windings which could result in failure.

Excitation Systems

The field breakers on unit 1 and unit 3 were replaced in 1993 and 1995 respectively. The excitation system on unit 2 was replaced in 1986 with a brushless exciter and is in good condition. The excitation systems on unit 1 and unit 3 are original equipment and with proper maintenance will remain serviceable. The excitation systems do not need to be replaced at this time.

Voltage Regulation



There is difficulty in regulating voltage on the units, particularly when operating an isolated system during outages to transmission line 3L. Also, the inability to match machine voltage to system voltage has created situations where the units have tripped while attempting to synchronize with the system. Units 1 and 3 have Brown-Boveri model AB2/1 voltage regulators and unit 2 has a Basler model SR-8 voltage regulator. It is recommended that the voltage regulators on all three units be replaced with digital technology to eliminate the voltage regulation problems.

Switchgear

The inspection of the switchgear identified that the bus work and breakers are in good condition and do not need to be replaced. It is recommended that revenue class current and potential transformers be added to the switchgear to provide accurate metering data from these units.

Power Cables

The power cables were installed in 1978 and remain in serviceable condition.

Generator Grounding

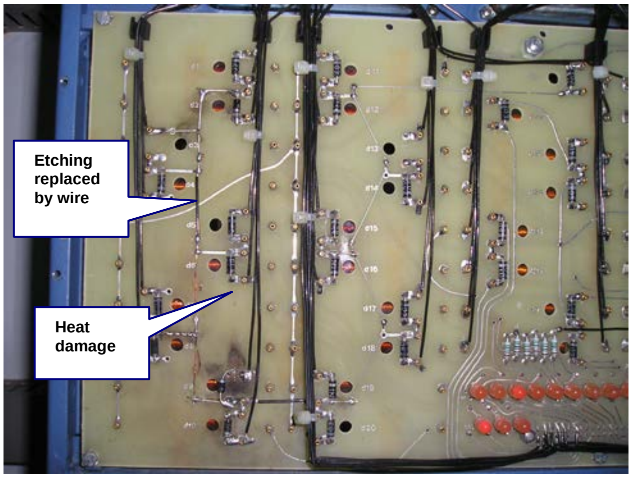
The grounding system for unit 2 includes a high impedance grounding transformer. Units 1 and 3 are solidly bonded to ground and as a result their windings would be exposed to high level fault currents should a ground fault occur. It is recommended that units 1 and 3 be equipped with grounding transformers to protect the windings from high level ground fault currents.

Protective Relays

All three generators are protected by electromechanical relays. The protection scheme of each unit utilizes different elements as outlined in the table below. It is recommended that the unit 2 and 3 protection be upgraded with digital, multifunction generator protection relays. A protection study will determine the protection elements to be implemented in the relays.

Generator	Protection Provided
Unit 1	51V Voltage restrained time delay overcurrent 87G Generator differential relay
Unit 2	40 Loss of field 46 Negative Phase Sequence (Stator unbalanced current) 51V Voltage restrained time delay overcurrent 64G Stator ground faults 87G Generator differential relay
Unit 3	40 Loss of field 46 Negative Phase Sequence (Stator unbalanced current) 51V Voltage restrained time delay overcurrent 87G Generator differential relay

Governors



Unit 1 is controlled by a belt-driven governor system. It is recommended that it continue to operate in this manner as unit 1 only runs infrequently, as water is available.

Units 2 and 3 have Voith EHR 530 electronic governors and associated high pressure hydraulic systems installed in 1986. The hydraulic systems are in good condition and continue to be serviceable. The manufacturer of the electronic governor that controls the hydraulic system has discontinued manufacturing replacement parts and no longer supports this equipment. Thus no spare parts are available to facilitate repairs. The copper etching on the circuit boards has cracked. Repairing the circuit boards is difficult as the heat from soldering tends to make the etchings even more brittle. The problems experienced in maintaining system frequency when operating as an isolated system can be attributed to the electronic governor no longer meeting original specifications. It is recommended that the hydraulic power units be maintained and the electronic governors be replaced with PLCs.

Plant Control

Unit 1 is controlled by discrete relays and is operated under manual control. The controls for units 2 and 3 were retrofitted with Square D SY/Max PLCs between 1986 and 1988. The PLCs provide alarm monitoring of generator and turbine instrumentation, sequencing and operator interfaces. These PLCs are no longer supported by the manufacturer. The programming interface terminal has failed and now a laptop computer provides limited programming capability. Programming expertise is limited and recent equipment failures have consumed the supply of spare parts. It is recommended that the PLC equipment on units 2 and 3 be replaced with current technology.

Instrumentation

Reliable monitoring and control of the generating units requires that the following instrumentation be installed on units 2 and 3:

- Speed switch
- Vibration sensors
- Bearing surface temperature sensors (thermocouples or resistive temperature devices)
- Bearing oil level sensors
- Stator temperature sensors
- Brush gear temperature sensors
- Scroll case pressure gauge
- Wicket gate position transducer and limit switches
- Pit flood sensors

Bearing Cooling Water Control

All three units presently have cooling water control valves and flow meters. The controls for the systems must be integrated with any new PLC control system.

Heating and Ventilation

The anti-condensation heaters and infrared heaters for each unit are controlled by hand operated humidistat and thermostats respectively. The ventilation system composed of fans and louvers installed in 1986 remain in serviceable condition. It is recommended the controls for the heating and ventilation equipment be integrated with the unit control PLCs.

Forebay Water Level Monitoring and Control

The forebay communications cable is in good condition. The water level probe and transducer are no longer supported by the manufacturer. Also, there have been unit trips resulting from loss of water level signal. It is recommended that the probe and transducer be replaced with a 4 to 20 milliamp water level probe and associated transmission equipment.

Penstock

The penstock was replaced in 1999. In 2002 the penstock paint system started to show signs of deterioration and over the last year the level of deterioration has increased. Most of the surface area has significant rust staining indicating that the surface is permeable and not protecting the steel as intended. Water and oxygen are able to penetrate the coating system and are causing the penstock to rust. The entire steel penstock should be recoated.

Mechanical

The G2 turbine was overhauled in 1985 replacing the runner, wicket gate and stationary seals. The top and bottom covers were machined to accept the new wicket gate bushings. Since 1985 the gate stems have worn and the seats are now elongated. When the unit has been running at greater than 80% load, the gates have dropped down in the elongated holes and have become stuck. This can create a situation where if the unit were to trip, the gate would not be able to close and the unit would go into overspeed. The unit needs to be dismantled to replace the bushings and allow the gates to operate through their full range. Presently the gates are restricted to less than 80% opening to prevent them from sticking.

Appendix B

Budget Estimates

2006 Capital Budget Estimate

Description	Cost Estimate
Upgrade Controls G1	$ 80,000
Replace Unit Control PLCs G2	372,000
Replace Electronic Governor G2	86,000
Upgrade Generator Protection and Control G2	184,000
Replace Unit Control PLCs G3	372,000
Replace Electronic Governor G3	86,000
Upgrade Generator Protection and Control G3	191,000
Upgrade Plant AC and DC Systems	79,000
Turbine Overhaul	153,000
Penstock Coating Replacement	226,000
Total	**$1,829,000**

Appendix C

Feasibility Analysis

Introduction

This feasibility analysis examines the future viability of the Petty Harbour hydro plant. In addition to the capital expenditures proposed for 2006, all capital and operating expenditures required to maintain the safe and reliable operation of the plant for the next 25 years are estimated. A present-worth analysis is used to determine the revenue requirement and levelized cost of energy from the Petty Harbour plant. To evaluate the financial feasibility of the project proposed for 2006 and the overall viability of the plant, the levelized cost of energy is compared with the cost of replacement energy from Newfoundland and Labrador Hydro's Holyrood Generating Facility.

Capital Costs

All significant capital costs foreseen for the Petty Harbour hydroelectric plant over the next 25 years have been identified. The majority of these expenditures are currently planned for 2006 and 2015, and the remaining expenditures are distributed throughout the 25 year period from 2006 to 2030. The capital expenditures, in 2005 dollars, required to maintain the safe and reliable operation of the facilities are summarized in the following table:

Petty Harbour Hydro Plant Future Capital Costs	
Year	**Cost**
2006	$ 1,829,000
2007	50,000
2010	20,000
2011	285,000
2012	175,000
2015	1,100,000
2020	300,000
2025	170,000
2026	770,000
Total	**$ 4,699,000**

Operating Costs

Operating costs for this hydroelectric system are estimated to be $127,000 per year. The operating costs represent both direct charges for operations and maintenance at this plant as well as indirect costs related to activities associated with managing the environment, safety, dam safety inspections and staff training.

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 based on yearly hydro plant generation/output.

Financial Analysis

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

The estimated levelized cost of energy from the Petty Harbour plant is 2.8 cents per kWh. This figure includes all projected capital and operating costs necessary to operate and maintain the facility. Energy from Petty Harbour can be produced at a significantly lower price than the cost of replacement energy, that would come from Newfoundland and Labrador Hydro's Holyrood Generating Station. Based on information provided in Newfoundland Hydro's fuel price projection as of March 31, 2005 and Newfoundland Hydro's 2003 GRA, incremental energy is estimated to cost 5.8 cents per kWh in the short term (assuming $36.85 per barrel and 630 kWh/barrel, respectively), with an associated levelized cost of 6.9 cents per kWh assuming a 2% long-term escalation rate. Table A provides details of the financial analysis.

Recommendation

Newfoundland Power should proceed with this project in 2006 as planned. The results of this feasibility analysis show that that the continued operation of the Petty Harbour hydroelectric development is economically viable over the long term. Investing in the life extension of facilities at Petty Harbour guarantees the availability of low cost energy to customers. Otherwise the annual production of nearly 15.9 GWh would be replaced by more expensive energy sources such as new generation or additional production from the Holyrood Generating Station.

Table A
Present Worth Analysis – Petty Harbour Hydro Plant

Weighted Average Incremental Cost of Capital 8.29%

PW Year 2005

Year	Capital Expenditure In Year By Asset Type: Generation (Hydro, 49.26 yrs, 4% CCA)	Generation (Hydro, 49.26 yrs, 50% CCA)	Buildings (33 yrs, 4% CCA)	Capital Revenue Requirement	Operating Revenue Requirement	Benefits	Net Benefit	Present Worth Benefit	Cumulative Present Worth Benefit	Rev Rqmt (¢/kWhr)	Levelized Cost (¢/kWhr)
2006	1,829,000	0	0	230,161	127,175	0	-357,336	-329,981	-329,981	2.247	2.777
2007	50,900	0	0	212,758	129,464	0	-342,222	-291,831	-621,812	2.152	2.777
2008	0	0	0	209,765	131,665	0	-341,429	-268,866	-890,678	2.147	2.777
2009	0	0	0	207,304	133,903	0	-341,207	-248,122	-1,138,799	2.146	2.777
2010	21,416	0	0	207,474	136,180	0	-343,654	-230,770	-1,369,569	2.161	2.777
2011	310,368	0	0	243,666	138,495	0	-382,161	-236,982	-1,606,552	2.404	2.777
2012	193,626	0	0	261,319	140,711	0	-402,030	-230,218	-1,836,770	2.528	2.777
2013	0	0	0	255,674	142,962	0	-398,636	-210,799	-2,047,570	2.507	2.777
2014	0	0	0	252,235	145,249	0	-397,485	-194,100	-2,241,669	2.500	2.777
2015	580,769	696,923	0	318,876	147,719	0	-466,595	-210,405	-2,452,075	2.935	2.777
2016	0	0	0	256,976	150,378	0	-407,353	-169,629	-2,621,703	2.562	2.777
2017	0	0	0	324,976	153,084	0	-478,060	-183,833	-2,805,536	3.007	2.777
2018	0	0	0	355,949	155,840	0	-511,789	-181,737	-2,987,273	3.219	2.777
2019	0	0	0	368,372	158,489	0	-526,861	-172,766	-3,160,039	3.314	2.777
2020	253,483	0	126,742	421,169	161,183	0	-582,352	-176,344	-3,336,383	3.663	2.777
2021	0	0	0	414,508	163,924	0	-578,432	-161,748	-3,498,131	3.638	2.777
2022	0	0	0	409,934	166,874	0	-576,808	-148,946	-3,647,077	3.628	2.777
2023	0	0	0	404,123	170,045	0	-574,168	-136,914	-3,783,991	3.611	2.777
2024	0	0	0	397,658	173,106	0	-570,764	-125,683	-3,909,674	3.590	2.777
2025	235,331	0	0	420,443	176,048	0	-596,492	-121,293	-4,030,968	3.752	2.777
2026	1,084,032	0	0	546,750	179,041	0	-725,791	-136,288	-4,167,255	4.565	2.777
2027	0	0	0	525,153	182,085	0	-707,238	-122,637	-4,289,892	4.448	2.777
2028	0	0	0	516,176	185,180	0	-701,356	-112,307	-4,402,199	4.411	2.777
2029	0	0	0	507,070	188,328	0	-695,398	-102,828	-4,505,028	4.374	2.777
2030	0	0	0	497,850	191,530	0	-689,380	-94,135	-4,599,162	4.336	2.777

Thermal Generation Refurbishment
June 2014

Thermal Generation Refurbishment

June 2014

Prepared by:

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PROVINCE OF NEWFOUNDLAND

NEWFOUNDLAND POWER
A FORTIS COMPANY

Table of Contents

1.0 Introduction

In this 2014 Capital Budget Supplemental Application (the "Application"), Newfoundland Power Inc. ("Newfoundland Power" or the "Company") proposes to address the in-service failure of the Rolls Royce AVON gas generator at the Wesleyville gas turbine facility, and other issues identified in engineering assessments completed on 2 of its thermal generation facilities following the winter of 2013/2014.[1]

In its 2014 Capital Plan filed with its 2014 Capital Budget Application, Newfoundland Power had identified approximately $5 million in expenditures associated with the refurbishment of its Wesleyville and Greenhill gas turbines in the 2017 /2018 time frame. This planned refurbishment was based upon historical operating experience.[2] During the 2013/2014 winter season, Newfoundland Power was required to run its generation plants more frequently.[3]

Newfoundland Power's Wesleyville gas turbine is a thermal generator located in the Bonavista North area providing 10 MW of capacity in support of the Island Interconnected System. On the early morning of March 5, 2014, Newfoundland & Labrador Hydro ("Hydro") requested that Newfoundland Power operate its Wesleyville gas turbine in support of the Island Interconnected System. The unit shut down shortly after start-up due to high vibration on the power turbine gearbox.[4] On restart at 8:27 AM, the unit tripped again with high vibration levels this time in the gas generator. Upon investigation following the 2nd trip, the rotating members were found to have failed and the gas turbine could not be restarted.

Newfoundland Power's Greenhill Gas Turbine is a thermal generator on the Burin Peninsula providing 20 MW of capacity in support of the Island Interconnected System. For 39½ hours on January 3-5, 2014 the Greenhill Gas Turbine was shut down because its fuel supply was exhausted.[5] Otherwise the gas turbine system operated effectively throughout the winter of 2013/2014 and is currently available for service.[6]

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1 The system events experienced during the winter of 2013/2014 are fully described in Newfoundland Power's *Interim Report,* March 24, 2014 in *An Investigation and Hearing into Supply Issues and Power Outages on the Island Interconnected System by the Board of Commissioners of Public Utilities of Newfoundland and Labrador.*

2 Historically, Newfoundland Power has run its 41.5 MW of thermal generation minimally for supporting system peaks and local generation for planned and unplanned transmission outages. Table 1 provides data on the generation run time hours for both the Wesleyville and Greenhill gas turbines.

3 Hydro requested Newfoundland Power to run its generation resources on 29 days in December 2013 and January 2014. Hydro typically requests Newfoundland Power to run its generation for a number of reasons. One is economic dispatch for the Island Interconnected System. Another is peak management. A third is to relieve short-term system limitations (i.e. voltage support).

4 Vibration is a known problem on the unit, and is the result of run-out and swash of the bull gear. The problem has been present since the unit was relocated from Salt Pond in 2003.

5 The Greenhill gas turbine is equipped with effective fuel oil capacity of 190,000 litres. This provides 24 to 32 hours of continuous operation. A blizzard on January 3rd and 4th, 2014 closed the highway access to the Burin Peninsula where the turbine is located, delaying fuel deliveries.

6 The Mobile Gas Turbine ("MGT") is a 6.5 MW gas turbine mounted on 2 trailers. The MGT was located at Holyrood Thermal Generating Station during the 2013/2014 winter season to provide backup power for loss of station service. The MGT operated effectively throughout the winter season. The 2014 Capital Plan has identified the purchase of a replacement unit for the MGT in the 2016/2017 timeframe.

Following the winter of 2013/2014 Newfoundland Power engaged the necessary engineering expertise to complete assessments on its thermal generation facilities at Wesleyville and Greenhill. These assessments identified a number of issues that need to be addressed prior to the 2014/2015 winter season.

The assessments also identified additional work to be considered over the next 3 year time horizon. This work will be considered as part of a broader assessment of the long-term viability of these assets.

The refurbishment proposed in this Application includes the following:

Wesleyville Gas Turbine ($1,345,000)

- (i) Complete overhaul of the Rolls Royce AVON gas generator,
- (ii) Refurbishment of the power turbine including replacement of insulating blanket and weld repairs to the power turbine disc and shroud,
- (iii) Replacement of the automatic voltage regulator,
- (iv) Minor repairs to the building roof, and
- (v) Replacement of the lubricating oil cooler.

Greenhill Gas Turbine ($353,000)

- (i) Refurbishment of the power turbine including replacement of the insulating blanket and repairs to the power turbine labyrinth seal and replacement of the inlet housing shroud,
- (ii) Replace exhaust gas thermocouple wiring harness,
- (iii) Minor repairs to the building enclosure, and
- (iv) Installation of a new 100,000 litre fuel tank and associated piping.

The total estimated cost of the work is $1,698,000.

2.0 Background

Newfoundland Power operates 3 gas turbine generators. These include the Greenhill Gas Turbine located on the Burin Peninsula, the Wesleyville Gas Turbine located in the Bonavista North area, and the Mobile Gas Turbine normally located at Grand Bay Substation in Port aux Basques.

The Greenhill and Wesleyville gas turbine generating facilities consist of: (1) a gas generator, which is an aircraft engine producing exhaust gases that power the unit; (2) a power turbine, which uses the energy from the exhaust gases to turn a shaft, and (3) the electric generator, which converts mechanical energy from the turbine to electricity, and associated equipment.

Newfoundland Power's gas turbines range in age from 39 years to 45 years.[7] Historically, these

[7] The Greenhill Gas Turbine is 39 years old, the Wesleyville Gas Turbine is 45 years old and the Mobile Gas Turbine is 40 years old. There was no engineering assessment completed, or additional refurbishment planned in 2014, for the Mobile Gas Turbine. The refurbishment of the Mobile Gas Turbine's weather-tight enclosure was included in the approved 2014 capital budget as part of the *Facility Rehabilitation Thermal* project.

plants have been used to support system peaks for very limited periods of time each year, to allow for local system maintenance, and to provide backup in the event of localized outages. Increased use of the gas turbines in December 2013 and January 2014 is a significant change in usage.[8]

Table 1 provides a summary of the run time history for the past 5 years for the Greenhill and Wesleyville facilities.

Table 1
Thermal Generation Run Time
(Hours)

Unit	2009	2010	2011	2012	2013	2014 YTD[9]
Greenhill Gas Turbine	26.8	10.5	3.8	15.4	75.2	119.3
Wesleyville Gas Turbine	67.3	147.2[10]	68.0	35.1	70.5	32.8

The Wesleyville Gas Turbine is powered by a Rolls Royce AVON aero-derivative gas generator packaged by Associated Electrical Industries ("AEI").[11] The system is located near the Town of New-Wes-Valley in Bonavista North. The Wesleyville facility has been de-rated from 14.7 MW to 10.0 MW as a result of long-term vibration issues in the power turbine gearbox.[12] The system was originally installed in Salt Pond Burin in 1969. It was relocated to Wesleyville in 2003. At that time, the system underwent refurbishment at Wesleyville. A new building was constructed to house the equipment, and the balance of plant was upgraded.[13] In 2005, the Rolls Royce gas generator was replaced with a refurbished unit.

The Greenhill Gas Turbine is powered by a Rolls Royce OLYMPUS aero-derivative gas generator packaged by Curtis Wright Corporation. The system is located at Grand Bank on the Burin Peninsula. The Greenhill facility has been de-rated from 25 MW to 20 MW as a result of long-term issues with cracks in the power turbine casing. The protection, controls and governor were upgraded in 2002. During the January 2-8, 2014 period, Newfoundland Power's Greenhill

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8 The rate of wear in a gas turbine is significantly affected by the number of times the turbine is stopped and started as each stop/start cycle involves extreme temperature changes and material expansion and contraction within the turbine. See, for example, *Technology Characterization: Gas Turbines* prepared for the Environmental Protection Agency, Washington, DC, December 2008, at page 18.

9 The 2014 YTD data covers the period from January 1, 2014 to May 31, 2014. The Wesleyville Gas Turbine was not available from January 5, 2014 to January 22, 2014 and after March 5, 2014.

10 During the March 2010 ice storm the Wesleyville Gas Turbine operated for 115.5 hours while repairs to transmission line 116L were undertaken. The damage to the transmission line was described on page 7 of Schedule A to the 2010 Capital Budget Supplemental Application file by the Company on April 30, 2010.

11 An aero-derivative gas generator is an aircraft jet engine adapted for use in electricity generation.

12 The gearbox suffers from higher than normal vibration levels due to run-out and bull gear swash. Essentially, this means that misalignment of parts that are rotating at high speed is resulting in increased vibration in the machinery.

13 "Balance of plant" refers to fuel system, motor control center, protection equipment, controls and governor.

facility was unavailable for a period because of unavailability of fuel delivery. The Rolls Royce OLYMPUS gas generator was last refurbished in 1995.

Newfoundland Power's 2014 Five Year Capital Plan included budgetary cost estimates for the anticipated overhaul of the Greenhill Gas Turbine in 2017 and the Wesleyville Gas Turbine in 2018. The timing, estimated scope of work and cost estimates for these overhauls was based upon the historical level of usage of the units. In light of recent events, there is potential for increased use of these units. Due to their age and present condition, it has been determined that condition assessments of the gas turbines are necessary to ensure their continued availability in support of the Island Interconnected System.

3.0 Engineering Assessment

Newfoundland Power has engaged experts to assess the condition of the thermal generating equipment at the Wesleyville and Greenhill facilities.

During the week of March 17, 2014, field service staff from Alba Power completed internal inspections of the Rolls Royce gas generators at both facilities. During the week of April 28, 2014, field service staff from Greenray Turbines completed internal inspections of the power turbines at both facilities.[14]

The results of these inspections are contained in Appendices C through F.

3.1 Wesleyville Facility

Gas Generator
The Wesleyville gas generator has been in service since 2005.[15]

A borescope inspection of the Rolls Royce AVON gas generator was completed on March 17th and 18th, 2014 on site at the Wesleyville facility.[16] As a result of damage sustained on March 5, 2014, the compressor was unable to rotate. This limited the scope of the inspection. The inspection identified areas where there was a loss of coating on the blades, stator and turbine sections of the gas generator. Rivets from the main line front bearing were found inside the gas generator. The failure of this bearing caused the gas generator failure. Based on the inspection results, it was determined that the gas generator must be removed and transported to an authorized repair facility for a complete overhaul.

[14] The purpose of these assessments was to identify the refurbishment necessary to have these 2 facilities ready for service in advance of the 2014/2015 winter season. No consideration was given to upgrades to increase output or extend service life. There is a separate assessment that will be ready in the 3rd quarter of 2014 that will examine the longer term need for gas turbine generation.

[15] In its 2005 capital budget Newfoundland Power included a project to replace the original 36 year old Rolls Royce AVON gas generator with a refurbished unit. The original gas generator had been overhauled in 1987 at 18 years of age and was due for another overhaul in 2005.

[16] A borescope is an optical device placed at the end of a flexible tube. A borescope is used to conduct visual inspections where the area to be inspected is inaccessible by other means.

Power Turbine
An inspection of the power turbine, gear box and all auxiliary systems was completed on May 2nd and 3rd, 2014 on site at the Wesleyville facility.

The power turbine inspection identified several cracks in the shrouds on the power turbine inlet duct. The power turbine inlet duct will have to be removed and weld-repaired. The power turbine insulating blankets require replacement as the cloth and refractory is broken away in several locations.[17]

The gearbox inspection did not show any additional wear to the bull gear or high speed pinion since it was last inspected in 2004. The gearbox vibration problems are the result of run out and swash of the bull gear. Previous repairs were unsuccessful in eliminating the vibration problem entirely. Unless the vibration problem is corrected, the unit will continue to be de-rated.

Other Plant & Equipment
On January 5th, 2014 the lubricating oil cooler developed leaks in the junction between the core and the expansion tanks. Repairs were completed and the cooler returned to service on January 22nd, 2014. Since the cooler was returned to service, other leaks have developed. On that basis, it has been determined that the cooler must be replaced.

The exhaust stack is in good condition with heavy surface corrosion due to the quality of steel used during manufacture. The roof flashing needs to be replaced in the area of the exhaust stack and cooling fans to prevent leaks.

The automatic voltage regulator incorporated with the unit control panel has failed and needs to be replaced.

3.2 Greenhill Facility

Gas Generator
The Greenhill gas generator has been in service since 1975 with no significant issues. The gas generator was last overhauled in 1995.

A borescope inspection of the Rolls Royce OLYMPUS gas generator was completed on March 19th and 20th, 2014 on site at the Greenhill facility. Debris found in the air intake plenum is attributable to corrosion of the walls and other surfaces. This debris could enter the gas generator and cause impact damage. The internal inspection of the gas generator identified many areas where there is a loss of coating. Some corrosion was found in the HP compressor and on the stators. The combustion chambers are showing carbon buildup and experiencing corrosion. Blades in the turbine section have lost coating and the leading edges are showing signs of degradation. The signs of wear and extensive coating loss throughout are consistent with the amount of time since the last overhaul. However, if this deterioration is allowed to continue indefinitely, it could lead to catastrophic failure of the gas generator.

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[17] A refractory material is one that retains its strength at high temperatures. Refractory materials are used in linings for furnaces, kilns, incinerators and reactors. Power turbine insulating blankets are necessary to reduce the impact of heat from the power turbine on other equipment in the same enclosure.

The exhaust gas temperature thermocouple wiring harness is in need of replacement.

Based on the inspection results, the gas generator at Greenhill is serviceable in the immediate term; but, action will soon be required. It is therefore recommended that a plan be put in place for the gas generator be removed and transported to an authorized repair facility for a complete overhaul at an appropriate time subsequent to the next winter season.

Power Turbine

An inspection of the power turbine and all auxiliary systems was completed between April 29th and May 1st, 2014 on site at the Greenhill facility.

The power turbine inspection identified issues with the labyrinth seal and the inlet housing rear outer flange retaining ring. The front labyrinth seal clearance is outside the recommended tolerance and there is some material loss at the 6 o'clock position. The clearance needs to be re-established.[18] The power turbine inlet housing rear outer flange retaining ring has suffered some heat distortion and has migrated into the hot gas path. To avoid further deterioration, oil leaks and failure of the seal, the inlet housing shroud that includes the retaining ring should be replaced.

The power turbine insulating blankets require replacement as the cloth and refractory is broken away in several locations.

The inspection verified that the cracks in the power turbine casing have not migrated since the last inspection. Unless the power turbine casing is replaced, the de-rating of the unit should continue.

Other Plant & Equipment

During the January 2-8, 2014 period, the Greenhill Gas Turbine was unavailable for a period of approximately 39½ hours due to lack of fuel.[19] The Greenhill facility is equipped with effective fuel capacity of 190,000 litres. This provided approximately 24 to 32 hours of operation, depending upon the generator output. Increasing the fuel storage at the Greenhill facility will increase the duration of availability of the gas turbine during emergency situations.[20]

The building enclosure is original to the 1975 installation and has deteriorated from 40 years of normal use and exposure to the elements. The intake plenum door and frame need to be replaced. Some of the welds inside the intake plenum have cracked and need to be repaired.

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[18] The clearance can be re-established by either (i) re-machining the seal or (ii) using a manufacturer's modification involving eccentric locating pins.

[19] A blizzard on January 3rd and 4th, 2014 closed the highway access to the Burin Peninsula where the turbine is located, preventing fuel deliveries to the facility.

[20] For example, increasing storage by an additional 100,000 litres will provide sufficient fuel to operate the gas turbine for approximately an additional 12 to 18 hours under normal operating conditions.

3.3 Conclusion

The results of inspections indicate that some refurbishment work is required at this time to ensure safe and reliable service of Newfoundland Power's Wesleyville and Greenhill gas turbine facilities for the upcoming winter season.

Both gas turbine systems are in advanced stages of deterioration as a result of their relatively long time in service. However, the historic duty cycles for both units have not been severe. As a result, these units have outlived other units manufactured at the same time. With reasonable expenditure, they can offer reasonable back-up generating capacity for the Island Interconnected System for the immediate term.

4.0 Continued Operation

The Company's gas turbines have provided reliable service for the past 4 decades. Table 2 shows the age, and the nameplate and de-rated capacity of the Wesleyville and Greenhill gas turbine systems.

Table 2
Year Commissioned and Capacity

Unit	Year Commissioned	Capacity (MW)	Notes
Wesleyville Gas Turbine	1969	14.7	De-rated to 10 MW
Greenhill Gas Turbine	1975	25.0	De-rated to 20 MW

Based on the engineering assessments completed in 2014, refurbishment of the Wesleyville and Greenhill gas turbines is necessary for their continued safe and reliable operation in the immediate term. The work proposed at this time is expected to ensure the availability of these systems to provide capacity support to the Island Interconnected System for at least the next 2 to 3 years.

Because of the age of the 2 systems, a further review is necessary to determine the long-term viability of continued investment in these assets. Newfoundland Power has commenced a process to identify an engineering firm with expertise in thermal generation systems to review the engineering assessments completed in 2014 and assess the long-term viability of continued investment in the 2 systems.[21] The review is expected to be completed in the 3rd quarter of 2014. The results of any recommendations will be reflected in the 2016 Capital Plan to be filed with the Company's 2016 Capital Budget Application.

[21] In May 2014, Newfoundland Power issued a Request for Information to various engineering consulting firms to identify a qualified consultant to assist in the review. Three proposals are currently under consideration.

5.0 Project Description

This Application involves refurbishment of the Wesleyville and Greenhill gas turbine systems as necessary to prepare them for availability in the 2014/2015 winter season. The refurbishment identified in this Application includes:

Wesleyville Gas Turbine ($1,345,000)

(i) Complete overhaul of the Rolls Royce AVON gas generator ($999,000);
(ii) Refurbishment of the power turbine including replacement of the insulating blanket, internal inspection of the power turbine disc and weld repairs to the shroud ($137,000);
(iii) Replacement of the automatic voltage regulator ($25,000);
(iv) Repairs to the building roof ($21,000); and
(v) Replacement of the lubricating oil cooler ($163,000).

Greenhill Gas Turbine ($353,000)

(i) Refurbishment of the power turbine including replacement of the insulating blanket and repairs to the power turbine labyrinth seal and replacement of the inlet housing shroud ($153,000);
(ii) Replace the exhaust gas thermocouple wiring harness ($26,000);
(iii) Minor repairs to the building enclosure ($21,000); and
(iv) New 100,000 litre fuel tank and associated piping ($153,000).

The engineering assessment also identified other impending issues including the need for an overhaul of the Greenhill Rolls Royce OLYMPUS gas generator, cracks in the Greenhill power turbine and the deterioration of the Wesleyville exhaust stack. Work associated with these items will be addressed, if necessary, following the review to be completed in the 3rd quarter of 2014, and included in the 2016 Capital Plan to be filed with the Company's 2016 Capital Budget Application.

6.0 Project Cost

6.1 Request for Proposals

The budget estimate for this project is based on engineering estimates for the cost of the individual items identified in **5.0 Project Description**. The largest cost item is the overhaul of the Rolls Royce AVON gas generator.

To facilitate approval of the associated capital expenditures by the Board, Newfoundland Power proceeded in 2014 with the engineering assessments and the soliciting of proposals from qualified repair facilities to develop an accurate estimate of the project costs.

In April 2014, Newfoundland Power issued a Request for Proposals (the "RFP") seeking proposals from qualified repair facilities for the overhaul of the Rolls Royce AVON gas generator at Wesleyville. Included in the RFP process was the opportunity for potential bidders to conduct a site visit and inspect the gas generator prior to submitting a proposal. The date set for receipt of proposals under the RFP was April 25th, 2014. On that date, Newfoundland Power received 3 proposals. Following a detailed evaluation of the proposals received, the lowest priced technically compliant proposal was used as the basis of the project cost estimate.[22]

6.2 Estimated Costs

The estimated cost to complete all work associated with the Application is $1,698,000. Table 3 provides a detailed breakdown of the costs to be incurred.

Table 3
2014 Cost Estimate

Cost Category	Amount
Material	$1,250,000
Labour Internal	166,000
Engineering	96,000
Other	186,000
Total	**$1,698,000**

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

6.3 Estimated Benefits

The current cost of avoiding additional capacity for the Island Interconnected System for 1 year appears to be approximately $55/kW.[23] This value can be used as a proxy to estimate the benefit of ensuring the availability of the 30 MW of back up generation which will result from the projects included in this Application.

At $55/kW, the benefit associated with the projects proposed in the Application would be approximately $1.65 million/year.[24] This indicates the benefit of refurbishing the existing 30 MW of back up generation justifies the cost of refurbishment.

7.0 Project Schedule

The projects included in this Application are being proposed to refurbish the Company's thermal generation in advance of the 2014/2015 winter season. At Wesleyville the long delivery item is the overhaul of the gas generator which will take approximately 4 months to complete. The

[22] The awarding of the contract to complete the overhaul of the Rolls Royce AVON gas generator will take place following Board approval of this Application.

[23] This estimate is based upon Hydro's planned addition of 113 MW of combustion turbine back-up capacity in 2014. This capacity addition is forecast to cost $118,900,000. The $55/kW avoided cost estimate is based upon a 35 year life; a discount rate of 5.76%; and an assumed annual cost escalation of 2%; which yields an economic carrying charge of 5.23% for 1 year ($118,900,000 ÷ 113,000 kW x 5.23% = $55).

[24] $55/kW/yr x 30,000 kW = $1,650,000/yr.

remaining balance of plant and power turbine items will be completed during the period when the gas generator is off site being overhauled. The gas turbine will be returned and the entire system commissioned in early November 2014.

The Greenhill fuel tank will take approximately 3 months to manufacture and install on site. The power turbine refurbishment will take approximately 3 weeks to complete. This work will be undertaken simultaneously. The system will be commissioned in early November 2014.

To ensure all equipment is delivered and installed before the 2014/2015 winter season, timely approval of the Application by the Board is required.

8.0 Concluding

During December 2013 and January 2014, Newfoundland Power was required to run its generation plants more frequently. This trend of increased operating requests has been ongoing for the past 2 winter seasons and is expected to continue until the establishment of the Labrador infeed.

The engineering assessments completed in 2014 have determined that some refurbishment work is necessary for continued safe and reliable operation of the Wesleyville and Greenhill gas turbine facilities for the immediate future. The refurbishment included in this Application is necessary to return the Wesleyville Gas Turbine to service in advance of the 2014/2015 winter season, and to ensure the safe and reliable operation of the Wesleyville and Greenhill gas turbine system for the 2014/2015 and 2015/2016 winter seasons.

The age of the 2 gas turbine systems requires a review of the long-term viability of continued investment in these assets. To assist in determining the extent to which additional life extension can be achieved, Newfoundland Power will engage an engineering firm with expertise in thermal generation systems to review the engineering assessments completed in 2014 and make recommendations on the long-term viability of these assets.

The estimated cost to complete the 2014 refurbishment of the Wesleyville and Greenhill gas turbine systems proposed in this Application is $1,698,000.

Appendix A
Wesleyville Gas Turbine Photographs

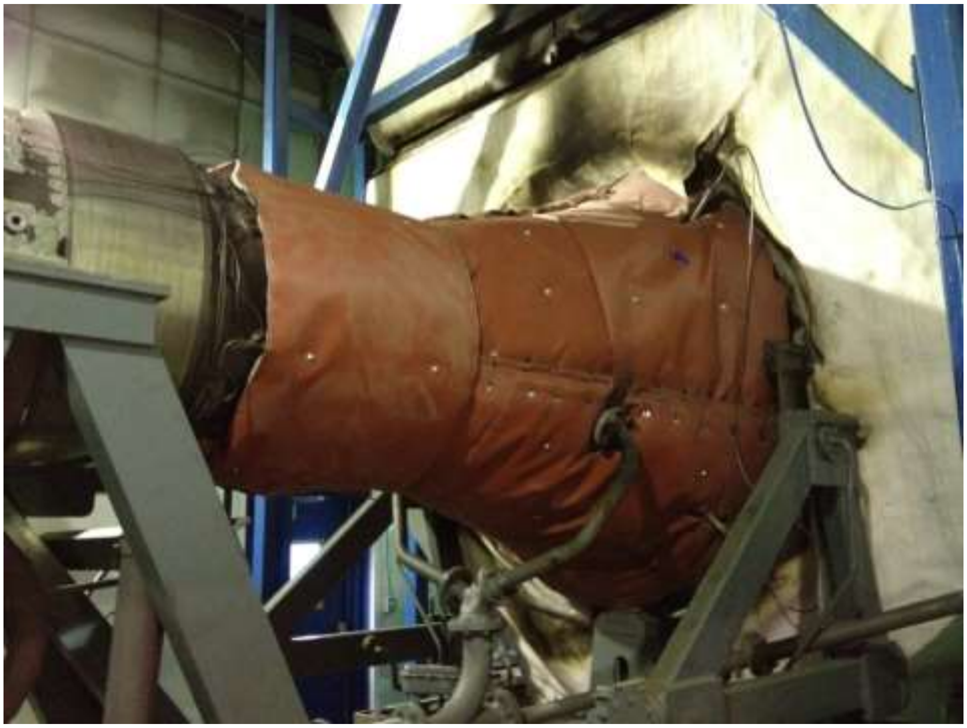


Figure 1 – Power Turbine Exterior View

Figure 2 – Lubricating Oil Cooler

Figure 3 – Crack in Power Turbine Inlet Duct

Figure 4 – Damaged Front Bearing

Appendix B
Greenhill Gas Turbine Photographs

Figure 1 – Air Intake Plenum

Figure 2 – Corrosion Damage Intake Plenum Door

Figure 3 – Insulating Blanket Damage

Figure 4 – Retaining Ring Distortion

Appendix C
Borescope Inspection Report
Wesleyville AVON Gas Turbine

Borescope Inspection Report For Avon Gas Turbine Serial No: 37116

Customer: Newfoundland Power

Date: 24th March 2014

Project Number: 4176

Table of contents

Introduction

Mr Steven Collie was mobilised out to Wesleyville, Newfoundland and Labrador to the Wesleyville generating site for Newfoundland Power.

1 Purpose

The Purpose of the task was to carry out a borescope inspection on the Avon gas turbine serial number 37116 and to investigate why the compressor rotor does not rotate.

2 Introductory Summary

The gas turbine had been running for a period of time with no issues, the gas turbine then tripped as a result of vibration indicated on the gearbox. The gas turbine was then started and as the rpm increased to 4500rpm the gas turbine tripped with the centre vibration reaching 100mm/s, all other parameters were reading normal at this time.

3 Onsite Personnel

Steven Collie (Senior Field Service Technician Alba Power)
John Budgell (Maintenance Supervisor Newfoundland power)
Rick Tobin (Newfoundland Power)
Danny Shanahan (Newfoundland Power)

4 Daily Report

4.1 Monday 17th March

Onsite start 15:00Hrs Finish 19:00Hrs.

Travelled from St John's to Wesleyville, after the isolations and permits were in place Steven commenced the borescope inspection.

With the compressor not able to rotate this had an effect on how far back the borescope was able to go, just up to stage 6, no visible signs of any damaged blades or stators.

The front bearing housing is very pitted and heavily corroded especially around the VIGV bushes. The fuel nozzles were then removed from numbers 2 and 7 positions to inspect the combustion chamber areas and also the stage 15 compressor blades; and then the turbine section looking for any damage.

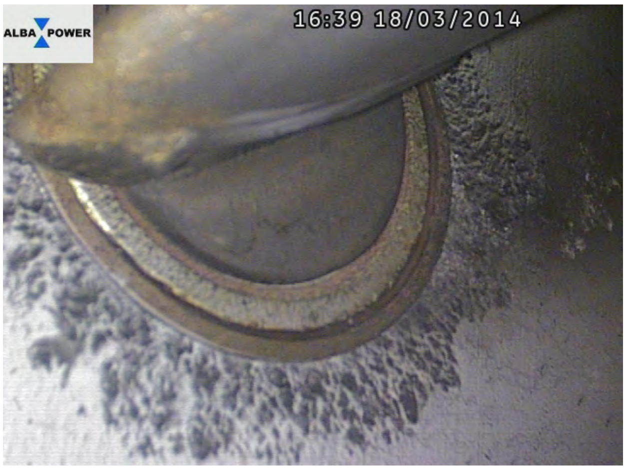
4.2 Tuesday 18th March

Onsite start 08:00Hrs Finish 13:30Hrs

Continued the borescope inspection of the gas turbine, all throughout the gas turbine there is coating loss on the compressor and turbine sections. The transition duct was removed from the exhaust to gain access and inspect the rear of the turbine section. There are slight rub indications on the HP turbine blades although not critical this will need to be inspected further.

With nothing conclusive being noted with the inside of the gas turbine my attention was now to remove the electric starter and inspect the planet gear, and pawl carrier. The starter bolt flange had to be heated to soften the Hylomar gasket sealant, once the starter was removed there were three small rivets lying inside the planet gear. The gear was removed to find all but two rivets were missing from the gas turbines mainline front bearing. It was at this point it was decided that the gas turbine would need to be removed for repair and that it be sent to Alba Power. Steven after completion of the Avon gas turbine inspection then travelled down to Marystown that afternoon.

5 Digital Images

	
Air intake housing (Corrosion)	VIGV bush location (Corrosion)
	
Stage 00 blades (worn)	Stage 00 blades (worn)

Coating degradation

Corrosion on stage 15 stators

Carbon build up on combustion chamber

Carbon build up on combustion chamber

Bridge piece on the combustion chamber

Bridge piece on the combustion chamber

Discharge nozzle and HP NGV

HP NGV

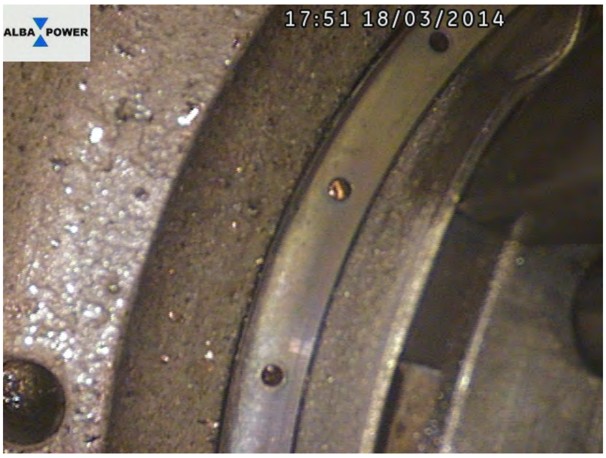
Rub on HP turbine blade

Rub on HP turbine blade

LP NGV (old repair)

LP NGV (old repair)

	
LP turbine blades (worn fir tree roots)	The hard face coating on the exhaust is very worn

	
Rivets missing from front bearing	Rivets lying next to the oil scavenge drain
	
Front bearing failure	Front bearing failure

6 Recommendations

To remove the failed Avon gas turbine 37116 and ship to the Alba Power facility for a bulk strip, detailed strip, and an investigation as to the cause for the front bearing to fail. At this time Alba Power would strongly recommend a full overhaul of all coatings on blades, stators and turbine sections. Also to inspect the entire gas turbine concentrating on the compressor discs and pin locations as there is extensive wear noted, also on the turbine blades and discs. For the package the entire off gas turbine oil system will need to be removed and flushed out eradicating any possible chance of contaminates getting back into the gas turbine when the reinstatement and commissioning is carried out, this is a standard practice when there is any bearing failure. Alba Power can assist with the removal and shipment of the gas turbine.

7 Conclusion

Is that the Avon gas turbine has suffered a catastrophic main line front bearing, causing the compressor to seize. The exact cause at this time is unknown and a detail strip of the gas turbine will need to be carried out within the Alba Power facility to determine the cause.

8 Customer Sign Off

Mill of Monquich
Netherley
ABERDEENSHIRE
AB39 3QR
Scotland

Tel: (44) 01569 730088
Fax: (44) 01569 730099
ISO 9001 2008
ISO 14001 2004
OHSAS 18001 2007

8 Customer sign off sheet

Customer Acceptance Sign Off Sheet

ALBA Job No: CO4176

Description of Works: Borescope Inspection

Site: Newfoundland Power, Wesleyville Site

Customer: Newfoundland Power

Designate: Avon

Manufacture: Rolls Royce

Eng. Serial No: 37116

Having witnessed the Borescope Inspection on Rolls Royce Avon S/N 37116 gas turbine, I the under signed, am satisfied with the work carried out and that it complies with the works being completed within the boundaries of the contract.

Signed: [signature]
Print: John Budgell
Position: Maintenance Supervisor
Date: Mar 21/14
For: Newfoundland Power

Signed: S. Collie
Print: STEVEN COLLIE
Position: SENIOR FIELD SERVICE TECHNICIAN
Date: 21/03/14
For: Alba Power Ltd

Alba Fitter 4

9 Report compiled by

Alba Power onsite personnel	Steven Collie	17st – 21st March2014
Report compiled by	Steven Collie	21st March 2014
Report Approved by	Grahame Martin	22nd March 2014

Appendix D
Borescope Inspection Report
Greenhill OLYMPUS Gas Turbine

Borescope Inspection Report For Olympus Gas Turbine Serial No: 202203

Customer: Newfoundland Power

Date: 24th March 2014

Project Number: 4176

Table of contents

Introduction

Mr Steven Collie was mobilised out to Newfoundland and Labrador to the Grand Bank site for Newfoundland Power.

1 Purpose

The Purpose of the task was to carry out a borescope inspection on Olympus gas turbine serial number 202203, providing a condition report on the serviceability of the gas turbine.

2 Introductory Summary

The gas turbine has been in service since 1995.

Although there have been no recorded issues with the gas turbine there are obvious signs of wear and extensive coating loss throughout. Alba Power would recommended that a plan be put into place to allow the release of the gas turbine to the Alba Power facility for a detailed inspection to assess the extent of the wear, and also to safe guard the gas turbine against a potential failure, thus giving the gas turbine long serviceability.

3 Onsite Personnel

Steven Collie (Senior Field Service Technician Alba Power)
John Budgell (Maintenance Supervisor Newfoundland power)
Rick Tobin (Newfoundland Power)
Danny Shanahan (Newfoundland Power)

4 Daily Report

4.1 Wednesday 19th March

Onsite start 08:00Hrs Finish 18:00Hrs.

Travelled from Wesleyville to Grand Bank, after the isolations and permits were in place Steven commenced the borescope inspection.

The intake plenum had a lot of rust debris in the corners; also the walls within the plenum chamber need repairing to stop the rust from falling.

The air intake casing has coating loss on the struts leaving it exposed to the elements and salt air, IGV's and the compressor section are in a clean condition although with coating loss on the stators. The internal starter drive, and fuel pump bearings were found to be in a satisfactory condition, the HP compressor and stators are showing some signs of corrosion at this time, number 1&2 intermediate casing vane covers were removed to inspect the number seven bearing housing section. This was found to be in a good clean condition, all oil feed and scavenge pipes were also in a good clean order.

The fuel nozzles were removed to gain access to the turbine section, the combustion chambers were all showing carbon build up, but more importantly the chambers all look to be suffering from corrosion due to the length of time that they have been in service. It also looks like as some of the hard face coating on the air intake snouts is breaking up; images to follow in later section.

4.2 Thursday 20th March

Onsite start 08:00Hrs Finish 13:30Hrs

Continued the borescope inspection of the turbine section of the gas turbine. It was noted that the HP NGV's have total coating loss and the leading edges are showing signs of degradation. There was a blade pass carried out on the HP turbine blades and these were found to be in a serviceable condition. The LP NGV's have coating loss but at this time are also in a serviceable condition. A blade pass was carried out on the LP turbine blades and these are also in a serviceable condition.

Although most components are in a serviceable condition apart from the HP NGV's there is limited life remaining on these components. The exterior of the gas turbine is in a good order throughout.

5 Running Data

Date:	20/03/2014		20/03/2014	
Time:	10:10		10:30	
N1:	4460		4384	
N2:	6250		6153	
N3:	3597		3599	
GG Inlet ^oF:	28		29	
GG Exhaust Temp ^oF:	777		765	
Gen Mw:	3.30		2.67	
CDP:	55		55	
GG Exhaust Temp:				
Actual:	Actual:	Diff:	Actual:	Diff:
1.	752	-28	734	-30
2.	781	0	767	-2
3.	821	33	816	39
4.	775	-14	757	-11
5.	815	26	789	22
6.	806	17	783	16
7.	776	-7	761	-7
8.	753	-29	739	-29

6 Digital Images

	
Air intake plenum (rust debris)	Air intake plenum (rust debris)
	
Air intake casing	Air intake casing with IGV’s

Coating degradation on LP stators

Coating loss on the leading edge LP stators

Oil pipes inside the delivery casing

Number 7 bearing oil feed pipe

Carbon build up combustion chamber

Carbon build up combustion chamber

Combustion chamber corrosion

Combustion chamber corrosion

Old repair on No.5 combustion chamber

Old repair on No.5 interconnector

Leading edge HP NGV

Leading edge HP NGV

7 Recommendations

Alba Power’s recommendation would be to check the magnetic chip detectors after every fired run, whether the gas turbine has run for 1 hour or 10 hours. This is to build on historical data. This would more importantly catch any early signs of possible bearing or gearing debris build up and this would help reduce further damage to the rest of the gas turbine if there were to be a failure.

The intake plenum needs work to eradicate the problem of rust falling from the walls which could be ingested into the gas turbine.

It would be a good idea to have the gas turbine lubricating oil pressure on the HMI to see if there are any changes in pressure, to also monitor the oil level to get a more accurate usage analysis.

Although the gas turbine starts and runs well, the fact that the gas turbine has coating loss throughout especially in the turbine section, should not be over shadowed and consideration should be made to remove the gas turbine and send it to the Alba Power Facility for overhaul or an exchange gas turbine can be arranged.

8 Conclusion

The gas turbine is serviceable for a time; there are some actions that need to be addressed in the near future to ensure the longevity of the Olympus gas turbine.

alba power
your power is our priority

9 Customer Sign Off

Mill of Monquich
Netherley
ABERDEENSHIRE
AB39 3QR
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ISO 9001:2008
ISO 14001:2004
OHSAS18001:2007

alba power

Customer Acceptance Sign Off Sheet

ALBA Job No: CO-4176

Description of Works: Olympus Borescope

Site: Newfoundland Power. Grand Back Site

Customer: Newfoundland Power

Designate: Olympus

Manufacture: Rolls Royce

Eng. Serial No: 202203

Having witnessed the Borescope on Rolls Royce Olympus S/N 202203 gas turbine, I the under signed, am satisfied with the work carried out and that it complies with the works being completed within the boundaries of the contract.

Signed:
Print: John Badgett
Position: Maintenance Supervisor
Date: Mar 21/14
For: Newfoundland Power

Signed:
Print: Steven Cotter
Position: Senior Field Service Technician
Date: 21/03/14
For: Alba Power Ltd

Alba Fitter 4

10 Report compiled by

Alba Power onsite personnel	Steven Collie	17st – 21st March2014
Report compiled by	Steven Collie	21st March 2014
Report Approved by	Grahame Martin	25th March 2014

Appendix E
Turbine Service Report
Wesleyville AVON Gas Turbine

GREENRAY

TURBINE SERVICE REPORT

TITLE	Package Inspection
REPORT BY	Stuart McLaren
DATE	03/05/14

REPORT NUMBER	60303
SERVICE REPRESENTATIVE	Stuart McLaren
POSITION	Senior Service Engineer
SERVICE ORDER NUMBER	GLL 11427
PERIOD OF VISIT	02/05/14 – 03/05/14
CUSTOMER	Newfoundland Power
SITE	Wesleyville
ENGINE TYPE	Avon
TURBINE SERIAL NUMBER	
CUSTOMER DESIGNATION	G330
GAS GENERATOR SERIAL NO.	37116
POWER TURBINE SERIAL NO	

Equipment overview

Equipment Details:

AVON	
Model	- 1535-52L-10
Serial No	- 37116
Total Hours Run	- 592.35
Peak running hours	- 0
No of starts	- 288
Hours since last overhaul	- 529.35
POWER TURBINE	
Model	- AP1
Serial No	-
Total Hours Run	-
Hours since last overhaul	-
GEARBOX	
Make	-
Model	-
Serial No	-
ALTERNATOR	
Make	- AE1
Model	- R 230435
Serial No	- AG 80/100
MAIN AIR INLET FILTERS	
Make	- Farr
Model	- Camfill
Serial No	- R30/30WR

GREENRAY

Work scope

Greenray Service Engineer was to be mobilised to Newfoundland Canada, where the AEI package located at the site in Wesleyville was to be inspected. This unit is utilised for peak power operation during periods of high demand, and is also run once a month for approximately 1 hour.

Work Carried Out

Visited the site in Wesleyville where the following areas were inspected:-

- Main combustion inlet system
- Power Turbine exhaust system
- Power Turbine gas path
- Power Turbine ducting
- Gearbox

The machine had been isolated prior to arrival, as the Gas Generator had failed due to a front end bearing failure. The Power Turbine transition piece and Gearbox top casings had already been removed to allow access for inspection. When asked, NP reported no running and/or operational issues with the machine prior to the bearing failure, other than the known vibration associated with the Gearbox. There had been history of high bearing temperatures on the non-drive end Power Turbine bearing however this has since been removed, cleaned, scraped and refitted with the result that it is now showing lower bearing temperatures.

Main Combustion Air Intake System

When this unit was relocated from Salt Pond to Wesleyville it had a new Air Intake System installed and is currently in good condition, however there are some areas of corrosion starting to appear which require cleaning and painting.

Exhaust System

Exhaust stack is the original unit with silencers and is in good condition with no signs of distortion or cracking. Due to the poor steel quality used, there is heavy surface corrosion present. The transition piece is believed to have been replaced when the unit was relocated, however this is not confirmed. The transition piece is in a good condition with no cracking and only minor distortion to the expansion piece.

Exhaust Volute externals are lagged with Plaster of Paris type lagging, which is in a fair condition, with all lagging material in place and no signs of flammable fluid contamination.

Exhaust Volute to exhaust stack transition does not have a flexible bellow/duct, meaning that there is an air gap around the circumference of the joint. This will allow hot gases to escape with the potential to increase the turbine hall temperatures to unacceptable levels during prolonged operational runs.

Exhaust Volute internals are in good condition with only surface corrosion being noted. The welded seams exhibited the heaviest corrosion and. although there was no cracking noted as being present, the corrosion may have weakened these areas and monitoring is recommended. There was no evidence of pooled fluids in the bottom of the volute.

Overall condition of the Exhaust System was good. See Fig 1 in appendices.

<u>Power Turbine Gas Path</u>

Visual inspections were carried using boroscope equipment and a camera for the Power Turbine gas path inspection.

There were no signs of cracking to the blading however foreign object damage to the rotor and stator blades was evident. Due to the physical location, and access limitations, it is difficult to assess the full extent of the damage to the blading.

The rotor disc exhibits heavy pitting around the blade root areas and is assumed to be the condition of the disc faces. During operation disc/blade roots operate under high stress and pitting/corrosion in this area increases the risk of cracking. See recommendations and Fig 2/Fig 3 in appendices.

<u>Power Turbine Inlet Ducting</u>

Inlet ducting consist of a sliding transition piece with an outer piston ring at either end, an outer ring with internal ceramic coating for the transition piece along with a one piece inner (cone) and outer ducts with 6 support struts.

The transition piece, outer ring and outer duct were in a good condition however the inner duct (cone) has five cracks at the downstream side of where the support struts pass through the inner duct. These cracks varied between 1”- 3” in length. The cone was also distorted around the 10 o’clock position (air craft convention) See Fig 4 in appendices

<u>Gearbox</u>

The Power Turbine is connected to the High speed pinion shaft via a single disc coupling, which in turns drives the low speed gear wheel. There is an auxiliary drive off the rear of the pinion which provides drive to the lubrication oil pump.

Both the high speed pinion and the low speed gears were found to have erosion marks believed to be from an earlier reported breakdown in the insulation between some lube oil pipework on the alternator allowing eddy currents to circulate. Newfoundland Power have set a load limit on this machine and do not run above 10Mw as vibration levels start to increase to an unacceptable level. When comparing the current erosion levels to those seen previously it is apparent that some areas have since polished up due to running of the machine.

The reported vibration levels have not increased since the visit from Greenray in 2004, and bearing temperatures are all normal. Due to the current running conditions and regime it was thought that a bearing inspection would not be a worthwhile exercise at this time.

The Lubrication oil pump flexible drive coupling membranes were showing signs of bowing. Checks were carried out and no cracks were noted o.
Although bowing is not reason to reject them, they should be checked for cracking on a regular basis as this would pose a risk of losing drive to the pump.

The gearbox internals were checked for any insecure items. Instrumentation was in a good condition and in general the gearbox was in a good condition with no oil leaks reported or witnessed.

Spares Used

None

Recommendations

1. Repair is required to the small areas of corrosion within the air intake plenum.
2. Installation of a flexible bellow between the Volute and exhaust stack if enclosure temperature become an issue. This will involve fabrication works.
3. Monitoring of corrosion and deterioration on exhaust volute welds is required.
4. Due to the heavy pitting seen on the rotor disc root areas and foreign object damage to the blading it is recommended that non-destructive testing is carried out to the rotor disk and blades. Particular attention should be made to inspection of the rotor disc, blade roots and lower portions of the blades and roots. Disc replacement should also be considered, dependant on the NDT results.
5. The cracking found to the inner duct (cone) requires repair. Removal of the duct to allow the cracks to be repaired will be required. In the current condition the inner duct is unserviceable due to risk of further fatigue failure/damage to the PT, and should be removed from service. When carrying out repairs welding procedures from the manufacturer should be closely followed as inappropriate repairs may cause further cracking and distortion.
6. Remove the EDLOP coupling and check the membranes for cracking on an annual basis. Replace as required.
7. Continue to observe Newfoundland Power requirement for maximum 10Mw load limit on this machine to maintain vibration levels within acceptable limits.

Appendices

Photographs of inspected items.

Fig 1 Corrosion in exhaust system.

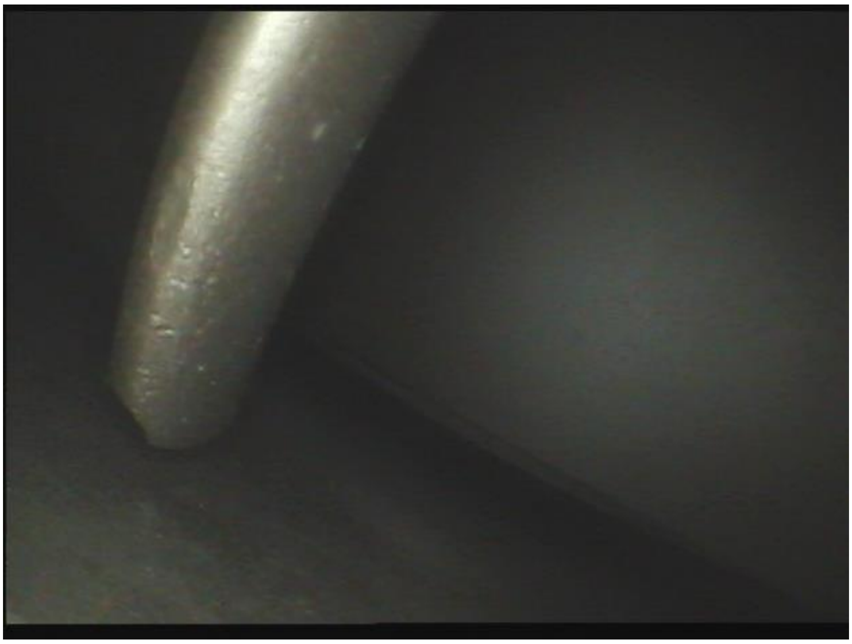

Fig 2 Blade impact damage and pitting

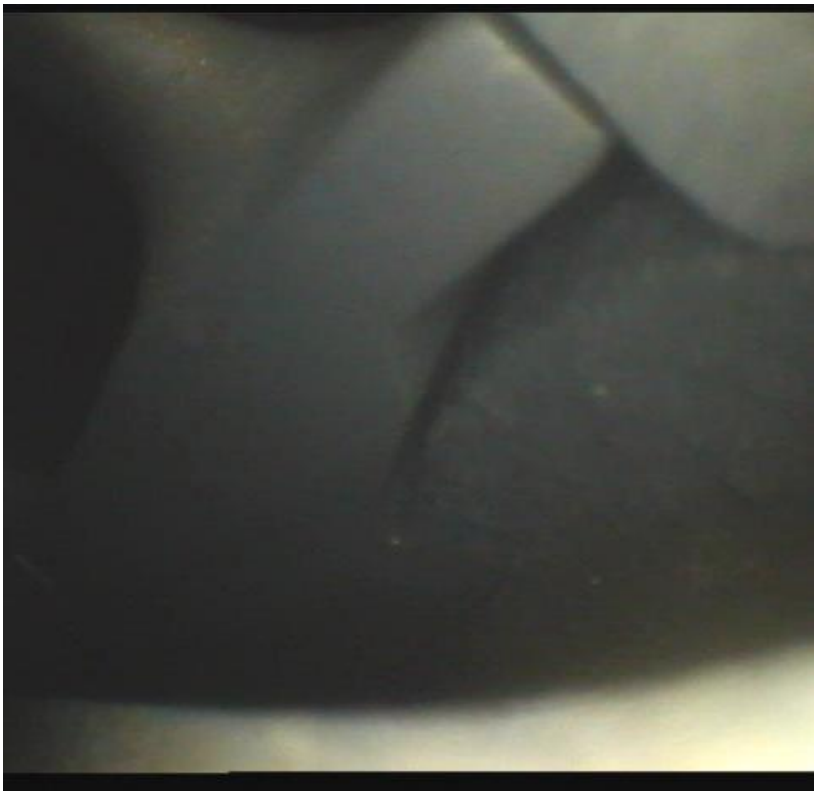

Fig 3 Blade and disc pitting at roots.

Fig 4 Crack in inner duct

GREENRAY

Daily Logs

02/05/14

- Carried out borescope inspection to Power Turbine gas path, found cracking to the inlet inner duct cone. Requires welding.
- Carried out visual inspect to gearbox - ok
- Carried out exhaust volute inspection – ok
- Carried out air intake inspection – ok
- Refitted one of three gearbox covers.

03/05/14

- Refitted remaining gearbox covers
- Departed site.

S.McLaren
Senior Service Engineer

R.Lingard
Service Manager

Appendix F
Turbine Service Report
Greenhill OLYMPUS Gas Turbine

GREENRAY

TURBINE SERVICE REPORT

TITLE	Package Inspection
REPORT BY	Stuart McLaren
DATE	01/05/14

REPORT NUMBER	60302
SERVICE REPRESENTATIVE	Stuart McLaren
POSITION	Senior Service Engineer
SERVICE ORDER NUMBER	GLL 11427
PERIOD OF VISIT	29/04/14 - 01/05/14
CUSTOMER	Newfoundland Power
SITE	Green Hill
ENGINE TYPE	Olympus
TURBINE SERIAL NUMBER	
CUSTOMER DESIGNATION	
GAS GENERATOR SERIAL NO.	OL202203
POWER TURBINE SERIAL NO	

GREENRAY

Equipment overview

Equipment Details:

OLYMPUS	
Model	- 2022
Serial No	- OL202203
Total Hours Run	- 4401
Peak running hours	- 446
No of starts	- 2813
Hours since last overhaul	- 2230
POWER TURBINE	
Model	- Curtis Wright, CT2 MOD25
Serial No	-
Total Hours Run	-
Hours since last overhaul	-
GEARBOX	
Make	-
Model	-
Serial No	-
ALTERNATOR	
Make	- Brush
Model	- BD.A.X.70.76
Serial No	- 753641
MAIN AIR INLET FILTERS	
Make	- Farr
Model	- HP
Serial No	- P85GT

GREENRAY

Work scope

Greenray Service Engineer was to be mobilised to Newfoundland Canada, where the Curtis Wright CT2 package located at the Greenhill site in Grand Bank was to be inspected. This unit is utilised for peak power operation during periods of high demand, and is also run once a month for approximately 1 hour.

Work Carried Out

Visited Newfoundland Power (now referred to as NP) main office in ST. Johns 29/04/14 to carry out Health and Safety inductions relevant to NP, once completed visited Greenhill where the following areas were inspected:-

- Main combustion inlet system
- Power Turbine exhaust system
- Power Turbine gas path
- Power Turbine ducting
- Power Turbine Stators pressure casings
- Rotor Upstream Shroud Labyrinth Gland

When asked, NP reported no running and/or operational issues with the machine prior to shut down for maintenance.
The machine had been isolated prior to arrival to allow planned maintenance to be carried out.

Main Combustion Air Intake System

The air intake system has been refurbished within the last 7 years. Work included blasting and repainting of all internal and external surfaces. There is evidence of patch work repairs to several areas where it is assumed these had been holed due to corrosion.

The floor area (pre filtration) has galvanised steel sheeting fixed to it with stainless steel self-tapping screws. This has been done due to the floor being badly corroded pre blast cleaning and painting. The filtration consists of 48 x panel type filters of which are in a like new condition.

Post filtration, several holes were noted on the floor directly beneath the filter panel housings. This allows unfiltered air to enter the system, although this will be minimal. There were also 2 x blow in doors, however operation of these was not determined.

Overall condition of the air intake system was good with exception to the holed floor area post filtration.

Exhaust System

Exhaust stack has been replaced in the last 10 years for a like for like replacement and is currently in excellent condition. This consists of weather doors on top and an internal silencer. The internal bottom corners of the stack have previously been weld repaired and three of the four corners exhibit fresh cracking, all of which are very small, in the region of 1” to 3”and and are not considered to be cause for concern at this time, but require monitoring on a regular basis.

Exhaust Volute externals are lagged in blankets held in place with wire and lagging clips, the lagging materials are in a fair condition with all lagging in place and no signs of flammable fluid contamination.

Exhaust Volute to Exhaust stack bellow joint is in a like new condition.

Exhaust Volute internals are in good condition with only surface corrosion being noted, which is to be expected. There were small markings of pooled fluids which have since drained or evaporated.

Overall condition of the Exhaust System was good with only the cracks requiring to be monitored for further propagation. See Fig 1 in appendices.

Power Turbine Gas Path

Visual inspections were carried using boroscope equipment and a camera for the Power Turbine blades. The blading consisted of 1st stage stator, 1st stage rotor, 2nd stage stator and 2nd stage rotor. Fixing of the stator blades was not visible. Fixing of the 2nd stage rotor blades were seen to be typical fir tree roots with a locking strip to hold in the correct axial position, and it is assumed the first stage is a similar configuration.

Blading was viewed from the Inlet cone using the boroscope. Blades were inspected for foreign object damage, corrosion and for signs of cracking. All viewed blades were in a good condition with no obvious signs of cracking, however foreign object damaged was noted to the stator and rotor blades, along with some surface pitting which is likely to be due to corrosion. The blades also appeared to have salt deposit trails seen along various areas of the blade faces. There were also some slight signs of surface corrosion to the blading but this is to be expected with the running regime of the machine. See Fig 2 in appendices.

Upstream of the 1st stage stator blades there is an outer shroud ring that is made up of two halves, and is fixed in place by means of locating lugs and being clamped between the stator casing and the outer inlet cone. At the 3 o'clock position (aircraft convention) the shroud has broken loose encroaching into the gas path by approximately 3/8", and when pressure is applied it can be pushed back into position. This poses concern as continued running would allow the outer shroud to resonate in the turbulent air and could cause the shroud to fatigue and encroach further into the gas path, or worse case scenario of eventual failure causing catastrophic damage to the machine. During a previous report viewed on site, the shroud movement was also highlighted and measured to be encroaching into the gas path by 1/8". See Fig 3 in appendices.

Without reference to the manufacturer's guidelines on impact damage and surface pitting to blading, it is not possible to accurately state whether the unit is serviceable or if the damage seen can be construed as requiring immediate repair. However due to the physical size and robustness of the blading it is expected that the machine is serviceable, subject to continued maintenance and monitoring regimes. This is based upon experience and knowledge gained on many types of equipment of this type over several years, however Greenray cannot be held liable for any damage and/or consequential loss due to failure.

GREENRAY

Power Turbine Inlet Ducting

Inlet ducting consists of a flexible bellow (Fern Duct) between the Gas Generator and Power Turbine. This has been replaced in the last 7 years and is in a like new condition, however two small leaks have been identified around the inlet circumference between the 7 and 8 o'clock position (aircraft convention) where the flexible bellow is fixed to the mating flange. There is an internal weld that runs round the circumference. This was checked for cracking and none were found. The leak is thought to be fed from the exit side of the Fern duct and back feeding to the leaking joint.

The inner and outer duct work is in a good condition with no signs of distortion or cracking.

Power Turbine Stators Pressure Casing

During a previous inspection surface cracking was found to the bottom half forward side of the casing at the 3 o'clock position (aircraft convention), as a result of this the machine was down rated from 25Mw to 20Mw. The pressure casing lagging blankets were removed and the horizontal casing joints were crack detected to identify any new cracks and to compare the known cracks current condition. The crack was not found to have propagated any further. See Fig 4 in appendices.

Rotor Upstream Shroud Labyrinth Gland

The opportunity was taken to measure the Rotor Upstream Shroud Labyrinth Gland as this had been done during a previous inspection. This required removing the Inner duct end cover **P/N: 494003** which was held in place with 36 bolts **P/N: MS9491-14** and 18 tab washers **P/N: 1523 P1.** Removal gave access to the disc cooling air pipework internal of the inner duct this was held in place with 16 Bolts **P/N: MS9490-18** and 16 nuts **P/N: 982D4** and 2 sealing rings **P/N: 181333.** After removal of the pipe, access was gained to allow removal of the diaphragm **P/N: 181329** which was held in place with 26 bolts **P/N: 181662** and 14 tab washers **P/N: 1525 P1.** This then exposed the shroud Labyrinth seal **P/N: 181327** which required to be measured. The labyrinth seal was in good condition with only minor wear seen. See clearances in appendices.

Spares Used

NP are to source replacement spares for the rebuild works.

Recommendations

1. Holes and heavy corrosion found within the air intake plenum should be cut out and patched to prevent further corrosion and ingress of particles to the filters and gas generator as a short term improvement. If the life of the machine was to be extended significantly then a replacement air intake plenum would be advised.
2. Continue to monitor cracks found in the exhaust for further propagation. Annual inspections, based on current running regime, are advised.

3. Outer shroud ring should be replaced/repaired on an urgent basis, as this poses a potential for catastrophic failure to the machine. This will involve removing the inlet outer ducting to allow removal of the shroud ring.
4. Repair is required to the Gas Generator to Power Turbine Inlet flexible joint (Fern Duct) to stop the current hot air leak, as this poses a potential fire hazard.
5. Continue to monitor cracking to the Power Turbine Stator pressure casings.
6. Monitor impact damage/corrosion of PT blading for further deterioration, and trend data. Annual inspection is advised.

Appendices

Photographs of inspected items.

Fig 1 Crack on weld in exhaust.

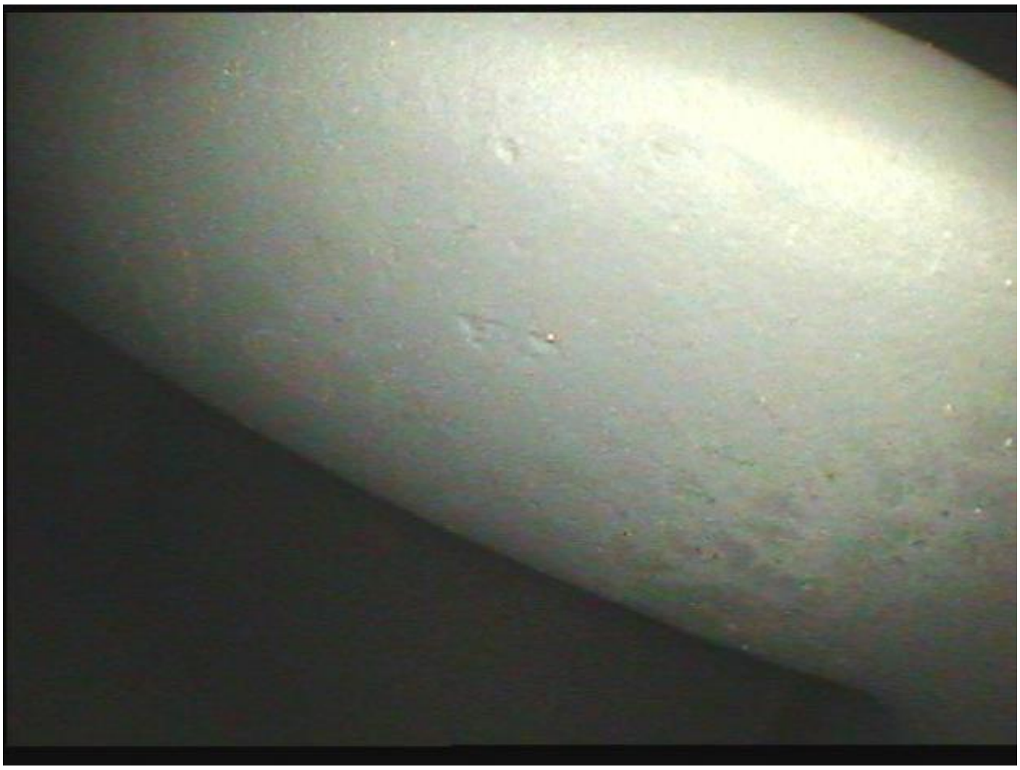

Fig 2 Typical Foreign Object Damage

Fig 3 Protrusion of stator shroud


Fig 4 Crack in pressure casing

Clearance figures

Shroud Labyrinth	12 o'clock	3 o'clock	6 o'clock	9 o'clock
Previous	0.087"	0.065"	0.060"	0.057"
Current	0.080"	0.055"	0.055"	0.077"

*Air Craft Convention

Inlet Inner Duct Support Lugs	12 o'clock	3 o'clock	6 o'clock	9 o'clock
Previous Axial	0.215"	0.117"	0.131"	0.128"
Previous Radial	-	0.020"	-	0.020"
Current Axial	0.234"	0.125"	0.191"	0.143"
Current Radial	0.020"	0.019"	0.022"	0.021"

*Air Craft Convention

Daily Log

29/04/14

- Arrived at site Green Hill site.
- Had a general look over unit in readiness for commencing work tomorrow.

30/04/14

- Carried out combustion plenum inspections – ok
- Carried out Exhaust Volute inspections – ok
- Carried out Power Turbine gas path inspection - ok
- Removed Power Turbine end cover to carry out labyrinth clearances checks on the 1st stage rotor disc.

01/05/14

- Removed lagging from Power Turbine Pressure casings to carry out dye penetrant checks on the casings themselves. Cracks were present, but these were identified during a previous inspection.
- Tidied site and travelled to Wesleyville.

S.McLaren
Senior Service Engineer

R.Lingard
Service Manager

Project Title: **2014 Thermal Generation Refurbishment**

Project Cost: **$1,698,000**

Project Description

This Generation project consists of expenditures to address thermal generation equipment issues that have become evident following the winter of 2013/2014. The Rolls Royce AVON gas generator at Wesleyville failed in service on March 5, 2014 while operating in support of system peak load conditions. A subsequent investigation has identified the failure of a bearing which has removed the Wesleyville Gas Turbine facility from service until the gas generator is refurbished.

Following the winter season, the Company engaged technical experts to assess the gas turbine facilities at Wesleyville and Greenhill to determine the necessary work to ensure the readiness of both facilities in advance of the 2014/2015 winter season. These assessments have identified the following work:

1. The refurbishment of the Rolls Royce AVON gas generator at an authorized Rolls Royce overhaul and maintenance facility ($999,000);

2. The refurbishment of the AEI power turbine and auxiliary systems on site at the Wesleyville Gas Turbine facility ($346,000); and

3. The installation of additional fuel storage capacity, refurbishment of the Curtis Wright power turbine and auxiliary systems on site at the Greenhill Gas Turbine facility ($353,000).

Details on the proposed expenditures are included in *Schedule A, Thermal Generation Refurbishment, June 2014*.

Justification

Newfoundland Power's thermal generation at Wesleyville and Greenhill is generally used to provide generation, both locally and for the Island Interconnected System, and to facilitate scheduled maintenance on transmission lines. These projects are necessary for the continued operation of thermal generation facilities in a safe, reliable and environmentally compliant manner.

Projected Expenditures

Table 1 provides a breakdown of the proposed supplemental expenditures for 2014 and a projection of expenditures through 2018.

Table 1
Project Cost
(000s)

Cost Category	2014	2015	2016 - 2018	Total
Material	$1,250	-	-	$1,250
Labour – Internal	166	-	-	166
Labour – Contract	-	-	-	-
Engineering	96	-	-	96
Other	186	-	-	186
Total	**$1,698**	**$0**	**$0**	**$1,698**

Costing Methodology

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

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

Future Commitments

This is not a multi-year project.

NEWFOUNDLAND AND LABRADOR

AN ORDER OF THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

NO. P.U. ___ (2014)

IN THE MATTER OF THE PUBLIC UTILITIES ACT, R.S.N. 1990, CHAPTER P-47 (THE "ACT")

AND

IN THE MATTER OF AN APPLICATION BY NEWFOUNDLAND POWER INC. (THE "APPLICANT") FOR APPROVAL TO PROCEED WITH THE CONSTRUCTION AND PURCHASE OF CERTAIN IMPROVEMENTS AND ADDITIONS TO ITS PROPERTY PURSUANT TO SECTION 41(3) OF THE ACT.

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

WHEREAS the Applicant operates thermal generation to deliver electricity to customers during emergencies, at time of high system demand and to support transmission and distribution work throughout its service territory on the island portion of the Province of Newfoundland and Labrador, and

WHEREAS on January 2nd through 8th, 2014, as a result of peak load conditions, a shortfall in available supply and a winter storm, the electricity system throughout the island of Newfoundland was stressed, and

WHEREAS throughout the winter of 2013/2014 Newfoundland Power's thermal generation was called upon to support peak load conditions, and

WHEREAS subsequent to the winter of 2013/2014 Newfoundland Power engaged experts to assess the thermal generation equipment at Wesleyville and Grand Bank, and

WHEREAS the Applicant through the expert assessments has identified refurbishments to the Applicant's thermal generation equipment necessary to return its thermal generation to normal service condition, and

WHEREAS the estimated capital expenditure to complete the refurbishment of the Applicant's property as proposed in the Application is $1,698,000, and

WHEREAS the proposed expenditure is necessary for the Applicant to provide service and facilities which are reasonably safe and adequate and just and reasonable pursuant to Section 37 of the Act.

IT IS THEREFORE ORDERED THAT: Pursuant to Section 41 (3) of the Act, the Board approves the capital expenditure of $1,698,000 associated with the improvements and additions to the Applicant's property as proposed in the Application.

DATED at St. John's, Newfoundland and Labrador, this ______ day of   , 2014.

____

____

____
G. Cheryl Blundon
Board Secretary