Q. Please provide a copy of the report referred to on page 22 of Volume 1 of Hydro's Report to the Board dated March 24, 2014 that was completed by an external consultant on the electricity system readiness for the 2013-2014 winter season.

A. Please see PUB-NLH-161 Attachment 1 for the requested report. Please note that this report was revised on April 16, 2014, as indicated in AMEC's cover letter, to correct minor factual errors contained within the report.

This facilities winter readiness review was a planned asset management activity initiated by Hydro with AMEC consultants in September of 2013 as a cold eyes, winter preparedness check to identify possible risks or "hot spots" to address before the upcoming winter season. The review focused on the following areas:

- Holyrood Unit 2 (170 MW) and the fuel supply system;
- Hardwoods Gas Turbine (50 MW);
- Bay D'Espoir Unit 7 (154 MW) and auxiliary systems; and
- Terminal Stations at Bay d'Espoir, Sunnyside, Come by Chance, Western Avalon, Holyrood, Hardwoods and Oxen Pond.

This scope of work targeted the largest generating unit in Bay d'Espoir, and all terminal stations involved with the transmission of electricity from Bay d'Espoir to the Avalon Peninsula. The other generating units at Bay d'Espoir are much smaller (75 MW) and present less risk to the electrical system. The scope of work at Holyrood focused on Unit 2 and the fuel supply system. This was a strategic decision as Unit 2 had been unable to undergo a normal summer outage and overhaul due to ongoing repairs on Unit 1 from the January 11, 2013 event. Focused, shorter outages were performed on Unit 2 in November and December 2013 to reduce risks to reliable operation prior to the winter operating season. Units 1 and 3 at Holyrood were not in the scope of the readiness review as they had been extensively maintained and overhauled through the year, ready for operation. The fuel supply system had experienced some blockages from sediment in the supplied fuel. These had been previously addressed and the fuel system was included in the review scope to confirm readiness prior to the winter operating season.

There were five general recommendations made in the report and these are discussed in PUB-NLH-162. The conclusions of the facilities winter readiness review report indicated the equipment was in good shape for the upcoming season.

Some potential risks were also noted and Hydro's actions to mitigate these risks include the following:

- Holyrood Unit 2 carried a moderate risk to overall system reliability due to inability to complete the normal maintenance program. This risk was reduced by performing priority Unit 2 maintenance work in two short outages in November and December.
- Severe weather affecting the Holyrood generating units could pose a significant risk to overall system reliability in winter 2013/14 if Hardwoods was unable to supply black start power. Hydro took the following action:
  a) The Hardwoods alternator was being replaced in the fall under an accelerated schedule;

b) An arrangement was made with Newfoundland Power to place its mobile gas turbine at Holyrood to provide supplemental station service power to enable faster plant restoration; and

c) Hydro initiated the supply of a temporary black start diesel plant for installation during the winter of 2014 until a permanent black start unit is installed.

- Severe weather affecting the Holyrood terminal station could affect system reliability if breakers failed to operate properly. Hydro continues its program at this site to maintain and refurbish breakers, and also coat them with RTV to reduce the risk of flash overs similar to those experienced in the January 11, 2013 event.
- Undetected faults primarily due to aging could result in unexpected failures of critical equipment. This risk is continually being reduced by refurbishing critical equipment based on recommendations from formal condition assessments and advancing the critical spares program to enable faster response to failures.
- It was generally noted that any remaining known and unknown protection and control issues posed a risk of system failures. This risk is continually being reduced by completing recommendations from protection and control system reviews and addressing any findings from root cause failure analysis. The priority of the action related to this item is being further addressed in consideration of the recent system disturbances in January 2014.
- It was also noted that fuel quality issues at Holyrood had been mitigated and that appropriate critical spares and maintenance resources were in place.

16 April 2014

Mr. Nelson Seymour, P. Eng.	Mr. Scott Crosbie
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Hydro Place, 500 Columbus Drive	Hydro Place, 500 Columbus Drive
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Dear Nelson/Scott,

Newfoundland and Labrador Hydro Facilities Winter Readiness Review

As per our Agreement, we have completed the Newfoundland and Labrador Hydro Facilities Winter Readiness Review. I trust that the report satisfies your needs. This Revision 2 reflects some minor changes related to the status of TRO P&C and breaker brainstorming/continuous improvement efforts. It continues to reflect and be consistent with the status of the facilities as of the end of 2013.

Overall it seems that the Bay d'Espoir GS and TS, and the Western Avalon, Come-By-Chance, Sunnyside, Oxen Pond, and Hardwoods TS's appear in good condition for the winter 2013/14. Critical PM and corrective work appears to have been completed to make them ready.

The impact of extreme weather on Holyrood TS and thus subsequently the Holyrood GS remains the largest potential threat, despite completion of many of the action list items resulting from the January 11, 2013 incident. As an example, two of the Holyrood TS breakers have not been coated as had been planned, and the impact of the coating is uncertain.

The fuel handling system at Holyrood seems to have been largely managed, but extended heavy operation could exacerbate the issue and lead to one or more units derates or outages. The station does appreciate the issues, and has critical spares and resources in place. Monitoring of impacts will be critical to ensure any issues do not become unmanageable.

Otherwise it is likely an unexpected/unpredictable failure of critical equipment (generators, transformers, bushings, cables, breakers, relays) at any of the sites due to undetected faults primarily due to aging that would be significant. Nevertheless there is little more that can be done to address this. A significant sized, single contingency failure seems to be within the capability of the system design.

Thank you for the opportunity to work on this very interesting project.
Yours truly,

Blair Seckington

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Newfoundland and Labrador Hydro Facilities Winter Readiness Review

April 16, 2014

Newfoundland and Labrador Hydro Facilities Winter Readiness Review

Prepared by: ______________________ 16 April 2014____
Blair Seckington *Date*

Checked by: ______________________ 16 April 2014____
Ian Leach *Date*

Approved by: ______________________ 16 April 2014____
Blair Seckington *Date*

Rev.	*Description*	*Prepared By:*	*Checked:*	*Approved*	*Date*
A	*Draft Report*	*Blair Seckington*			*15 Dec 13*
0	*Final Report*	*Blair Seckington*	*Ian Leach*	*Blair Seckington*	*20 Dec 13*
1	*Final Report*	*Blair Seckington*	*Ian Leach*	*Blair Seckington*	*31 Dec 13*
2	*Final Report*	*Blair Seckington*	*Ian Leach*	*Blair Seckington*	*16 Apr 14*

IMPORTANT NOTICE

NEWFOUNDLAND AND LABRADOR HYDRO FACILITIES WINTER READINESS REVIEW

EXECUTIVE SUMMARY

INTRODUCTION

Newfoundland and Labrador Hydro (Hydro) have an interest in having an independent third party conduct a review in late 2013 of the readiness of some key generating and terminal stations in Newfoundland for the winter 2013/2014 peak demand season. The work focus is on looking for the "hot spots" to address before peak operating season.

Winter Readiness Assessments were performed at the following Hydro facilities:

- Holyrood Generation Station Unit 2 - 175 MW (Originally 150 MW) & Fuel System
- Hardwoods Gas Turbine 54 MW (Limited to Emergency Service Only to Oct 2013)
- Bay d'Espoir Generating Facility – Unit 7 - 155 MW (in separate building) and Auxiliary Systems
- Terminal Stations/Switchyards from Bay d'Espoir to Oxen Pond inclusive
    - Bay d'Espoir,
    - Sunnyside,
    - Come By Chance
    - Western Avalon,
    - Holyrood,
    - Hardwoods,
    - Oxen Pond

The review of each facility entailed three phases:

- Phase 1 – Pre-Visit Information Assessment
- Phase 2 – Site Visit Information Gathering/Analysis
- Phase 3 – Post Site Visit Analysis and Reporting

WINTER READINESS SUMMARY

Generally the biggest threats to overall readiness are:

1. Extreme weather at Holyrood (both the TS and GS) similar to January 2013 (although likely a 1 in 10 year event, it could be any year)
2. Incomplete PM and corrective maintenance at Holyrood (as a result of other critical work arising there in 2013) resulting in equipment failure
3. Poor Holyrood fuel quality resulting during heavy running periods in multiple unit load reductions or shutdowns (unlikely given measures taken; spares parts to mitigate duration)
4. Unexpected/unpredictable failures due to incomplete critical TRO issues (primarily those in Section 3.2.1 as opposed to individual sites)
5. Unexpected/unpredictable failures of critical equipment (generators, transformers, bushings, cables, breakers, relays) at any of the sites due to undetected faults primarily due to aging, particularly those impacting transmission between Bay d'Espoir and Western Avalon TS and those affecting Holyrood GS operation .

Most are considered very low risk (highest readiness/lowest risk) for the 2013/14 winter period, but any could happen. Significant steps have been taken addressing actions arising from the January 11, 2013 failures that should mitigate such a widespread event. Not all have been completed however.

The impact on overall readiness from unexpected/unpredictable failures of critical equipment (generators, transformers, bushings, cables, switchgear, relays) due to undetected faults primarily due to aging is considered less likely. There is little further action that can be taken now to eliminate those risks. Feasible actions are primarily of a monitoring nature so as to minimize the impact and the duration of any event that does occur. This activity seems to be well in hand as well as also mitigated by the availability of significant critical spares and available maintenance resources to minimize the duration.

For extreme weather, the probability is again very unlikely, but being forewarned is forearmed - monitoring trends in the weather and in system responses will be critical.

For Holyrood Unit 2, a short term (2 week outage) would have been helpful to get some work done that would reduce the risk of a trip. The high priority work done in the November 24th to 27th 2013 four day maintenance outage would likely have significantly reduced the risk, but not all of the Unit 2 high priority corrective/PM work was likely completed. Monitoring and preparing to respond is likely the best action at this point.

CONCLUSIONS

1. In general Bay d'Espoir Unit 7 and common auxiliaries appear in good condition for reliable operation in 2013/14 winter.
2. TS equipment at Bay d'Espoir, Western Avalon, Come-By-Chance, Sunnyside, Oxen Pond, and Hardwoods appear in good condition, with no major hotspots indicating a significant remaining risk
3. TS equipment at Holyrood TS remains a significant risk to overall system reliability in winter 2013/14 in the unlikely event of a weather condition like January 2013,
4. Holyrood Unit 2 remains a moderate risk to overall system reliability (may be acceptable if no other contingency failures occur during recovery) in winter 2013/14 due to the inability to complete all of the planned PM work during 2013 due to critical work undertaken on Unit 1 that had been damaged in the early 2013 system outage. Highest priority Unit 2 work undertaken in short outages in November/December 2013 has reduced the risk.
5. All Holyrood units remain a significant risk to overall system reliability in winter 2013/14 in the unlikely event of a weather condition similar to that of January 2013 - in the event that Holyrood TS experiences similar problems and Hardwoods is also unable to supply black start power
6. Fuel quality related performance issues at Holyrood appear to have been mitigated, but heavy running could result in one or more unit deratings or trips. Critical spares and maintenance resources appear to be in place to mitigate the occurrence and duration.
7. Any generating unit and TS could experience failures of critical equipment (generators, transformers, bushings, cables, breakers, relays, etc.) due to undetected faults primarily due to aging. In most cases, a single contingency would not likely result in a large system failure. Those impacting generation at or transmission between Bay d'Espoir and Western Avalon TS and those affecting Holyrood GS operation would likely be more critical.
8. Remaining issues with known or unknown P&C issues at GS and TS sites (existing or resulting during equipment/logic swap outs) could result in more failures like the second Holyrood Unit 1 turbine lubrication failure or in more widespread cascading failures.

RECOMMENDATIONS

For the 2013/14 winter period:

1. The facilities continue their current program of equipment monitoring and PM maintenance.
2. The facilities re-evaluate and maintain key critical spares and ensure that said spares are both in place and being adequately stored to ensure their condition for use when/if required.
3. Extreme weather responses should be at the ready.
4. Holyrood GS evaluate how it could keep at least one unit running on station load during a major outage to return to service more quickly.
5. Generating Stations and TRO continue its program examining critical system and equipment control/trip logic (and changes in logic) regarding their response to system disruptions re their adequacy (protection, recovery, flexibility) and initiate changes where it is considered necessary and practical.

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GLOSSARY

°F or oF	Degree Fahrenheit
°C or oC	Degree Celsius
A, Ah	Amperes, Ampere-hours
A1	Alternator/Generator Unit 1
ABB	Asea Brown Boveri
BI	Business Interruption
BDE	Bay d'Espoir
BF, BFP	Boiler Feed, Boiler Feed Pump
CBC	Come-By-Chance TS
CGE	Canadian General Electric
CO, CO_2	Carbon Monoxide, Carbon Dioxide
CT	Current Transformer
Cu Ft	Cubic Feet
CW	Circulating or cooling water
DC	Direct Current
DCS	Distributed Control System
DGA	Dissolved Gas Analysis
ECC	Extremely Low, Very Low, Low, Medium, High
EL,VL,L,M,H	Energy Control Centre
ERT	Emergency Response Team
Ft	Feet
GPM	Gallons per minute
GS	Generating Station
GWh	Gigawatthours
H_2	Hydrogen
HP	Horsepower or High Pressure
HRD	Holyrood
HWD	Hardwoods TS
Hrs	Hours
Htr	Heater
HV	High Voltage
IPB	Isolated Phase Bus
IR	Infrared
I/S	In-Service
Km, km^2	Kilometres, Square Kilometers
kV,kVA	Kilovolt, Kilovolt Ampere
kW, kWh	Kilowatt, Kilowatt-hour
LH	Left Hand
LP	Low Pressure
LV	Low Voltage
m, m^3	Meters, Cubic Meters
MCC	Motor Control Centre
Mos	Months
MOV	Motor Operated Valve
MVA, MVAR	Megavolt amperes, Megavolt amperes reactive
MW, MWh	Megawatt, Megawatt-hour
O/H	Overhead
OPD	Oxen Pond TS
P&C	Protection and Control
PCB	Polychlorinated biphenyl
PD	Property Damage
PDA	Partial Discharge Analysis

Ph1, Ph2	Phase1 (Bay d'Espoir 1-6); Phase 2 (Bay d'Espoir Unit #7)
PM	Preventative/Planned Maintenance
Psi	Pounds per square inch
PT	Potential Transformer
%	Percentage
RH	Reheat or Right Hand
RPM	Revolutions per minute
RSV	Relief Safety Valve
Sq Mi	Square Miles
SC	Synchronous Condensing
SF6	Sulfur Hexaflouride
SS (SST)	Station service (Station service transformer)
S/V	Safety Valve
SWGR	Switchgear
T1	Transformer 1
T/G, T.G.	Turbine Generator
TRO	Transmission and Rural Operations
TS	Terminal Station
U2, U#2	Unit 2, Unit Number 2
UB	Unit Breaker
UPS	Uninterruptible Power Supply
V	Volts
Vlv	Valve
WAV	Western Avalon TS
Wks	Weeks
XLPE	Cross-linked polyethylene (cable)

NEWFOUNDLAND AND LABRADOR HYDRO FACILITIES WINTER READINESS REVIEW

1 INTRODUCTION/BACKGROUND

Newfoundland and Labrador Hydro have an interest in having an independent third party conduct a review in late 2013 of the winter readiness of some of its thermal and hydroelectric generating fleet and terminal stations for fall 2013 to spring 2014 peak demand season. The work focus is on looking for the "hot spots" to address before peak operating season.

The work is in part due to concerns with untimely and unexpected failures in past seasons. In particular in January 2013, extended blackouts/brown-outs were experienced in Newfoundland as a result of weather related issues in the Holyrood terminal/switchyard station as well as other parts of the system which also triggered a full station shutdown at the Holyrood Generating Station. A further consequence was that Holyrood Unit 1 experienced steam turbine damage as a result of issues with the emergency start-up of DC lube oil pumps. This left the Newfoundland system with limited generation and transmission contingency capacity through the balance of the winter and highlighted the criticality of a number of issues in the system.

2 SCOPE AND FACILITIES AND METHODOLOGY

Winter Readiness Assessments were performed at the following Hydro facilities:

- Holyrood Generation Station Unit 2 - 175 MW (Originally 150 MW) & Fuel System
- Hardwoods Gas Turbine 54 MW (Limited to Emergency Service Only to Oct 2013)
- Bay d'Espoir Generating Facility – Unit 7 - 155 MW (in separate building) and Auxiliary Systems
- Terminal Stations/Switchyards from Bay d'Espoir to Oxen Pond inclusive
    - Bay d'Espoir,
    - Sunnyside,
    - Come By Chance
    - Western Avalon,
    - Holyrood,
    - Hardwoods,
    - Oxen Pond

The review of each facility entailed three phases:

Phase 1 – Pre-Visit Information Assessment

- A pre-visit review of 2013 overall/maintenance plans and significant recent condition assessments (as provided by Hydro)
- A pre-visit review of facility switchyard information maintenance plans and activities, condition assessments and thermal imaging/inspections (as provided by Hydro)

Phase 2 – Site Visit Information Gathering/Analysis

AMEC team during site visits undertook the following elements of work:

- Perform a walk down and "ears and eyes" evaluation of key generating and terminal facilities systems that could significantly affect winter 2013/14 operating reliability with Hydro knowledgeable staff persons providing support for the site visits;
- Interview key facility staff (i.e. plant manager, maintenance manager) made available by Hydro regarding equipment condition/issues, actual versus planned 2013 maintenance activities and impacts;

- Undertake or oversee Hydro staff thermal imaging of applicable key systems and equipment made safely accessible by Hydro for preliminary identification of potential issues for potential further investigation by Hydro as required (those that could significantly impact plant winter 2013/14 availability. Hydro was responsible for ensuring safe access under direction of Hydro staff, with protection implemented as required by Hydro staff and PPE and training provided as required.

Phase 3 – Post Site Visit Analysis and Reporting
Following completion of all site visits, AMEC/Pennecon will:

- Document key findings of site visits related to 2013-2014 readiness and issues
- Discuss with Newfoundland and Labrador Hydro, the potential availability impacts of potential issues found
- Summarize key findings and assessment of potential impacts on system reliability in draft and final reports

3 KEY RESULTS AND RISKS BY FACILITY

3.1 Generating Station Facilities

3.1.1 Holyrood Thermal Generating Station (Holyrood) – Unit 2 and Fuel Facilities

3.1.1.1 Facility Overview

Holyrood is a three unit, nominally 500 MW, heavy oil fired, steam cycle fossil generating station. It is located on the south shore of Conception Bay in the province of Newfoundland and Labrador, between the towns of Holyrood and Conception Bay South. Holyrood was constructed in two stages. Units 1 and 2 were installed in the late 1960's and are identical units with CE (now Alstom) boilers and GE steam turbine generators. Unit 3 was installed in 1977 with a B&W boiler and a Hitachi steam turbine generator.

Under more extreme winter conditions with all three units are in operation at full MCR (maximum continuous rating), Holyrood is capable of supplying approximately 33% of the Newfoundland and Labrador peak electricity demand. Typically, the units operate in electricity generation mode during the late fall to spring peak period and units supply a minimum load of between 70 MW (typically at night) and 150 MW. While generating, the units can generate MVARS if required for system stability and voltage control, typically about 40 MVARS each in this mode. Holyrood is a critical generation asset in winter. In January 2013, the station experienced a station shutdown as a result of weather related issues in its terminal/switchyard station. Extended blackouts/brown-outs were experienced in Newfoundland as a result. Unit 1 experienced steam turbine damage as a result of issues with the emergency start-up of DC lube oil pumps. The incident highlighted the criticality

Unit 3 was equipped in 1986 to be able to be converted to synchronous condenser mode. The change-over takes about 5 to 7 days each way. This conversion to synchronous condensing and later back to generating mode is typically done once or twice per year, typically at the beginning and end of summer period respectively. During this period, Holyrood is not required to produce very much (often zero) electricity generation. In synchronous generating mode, Unit 3 generator as a synchronous condenser can produce/consume up to +120 (over-excited) MVARS and -50 (under-excited) MVARS respectively as required for grid voltage control and system stability purposes.

Unit 2 at Holyrood was chosen for review given that its annual maintenance outage was postponed in the summer of 2013 due to the length of the Unit 1 repair outage, and the extent of the work carried out on both Units 1 and 3. A subsequent minor 2 week maintenance outage for Unit 2 was also deferred because of generation requirements per the ECC (Energy Control Centre). In November a four day maintenance outage was taken between Nov 24 and Nov 27 2013 to complete high priority work, and some maintenance work was also undertaken during weekend outages. As a result, some but not all Unit 2 critical corrective/PM work was identified as having been completed by year end.

3.1.1.2 Facility Interviews and Walkdown (November 18-19, 2013)

AMEC representatives Blair Seckington (Director, Power Consulting) and Ian Leach (Senior Consultant, Thermal Operations and Maintenance) along with Trevor Arbuckle of Hydro met with Terry LeDrew (Station Manager), Gerrard Cochrane (Ops Mgr), Bob Garland (I&C Asset Specialist), Christian Thangasamy (Plant Engineer- Mechanical), Sean Mullowney (Former Plant Electrical Engineer, Head Office Project Manager), Mike Jones (Planning Supervisor), Evan Cabot (Operations Specialist), Mike Manual, Wayne Rice (Maintenance Planning).

Unit 2

It was noted at the time of the site visits that the majority of the planned 2013 Unit 2 maintenance and overhaul/inspection work was not undertaken due to resource (labour, funding) impacts of unexpected high priority issues/projects at Holyrood. These included: the repair work to Unit 1 steam turbine generator, the major maintenance/spare parts work/costs related to the impacts of poor quality fuel, the replacement of Unit 1 exciter system, and the attempt to install a temporary on-site black start capable system. Nevertheless some boiler inspection and repair work was done as part of a Level 2 condition assessment on Unit 2 boiler. No significant boiler related flaws were found that would likely impact the 2013/14 winter season.

During meetings, it was indicated that a two week Unit 2 outage was likely to be obtained during the last two weeks of November and that remaining key work was expected to be implemented. This was reduced to four days between Nov 24 and Nov 27 2013, and some maintenance work was undertaken during weekend outages. As a result, some but not all Unit 2 critical corrective/PM work was completed by year end.

It was discussed that staffing remains a key issue. Inexperienced operators or others with limited familiarity with the specific equipment increase the risk of operator error both initially and during a failure. The presence of an experienced operator during the January 2013 incident likely prevented Unit 1 damage from being more severe. Experience in maintenance and engineering support staff also impact unit condition and cost, but may be less likely to have a short term impact.

Key issues as to why Unit 1 failed to successfully restart and was damaged were discussed to identify that they had been addressed and would be unlikely to re-occur:

- The inadequate lube oil supplied by the DC lube oil pump due to the motor running at a lower than required speed (possibly an improper setting on the DC lube oil pump motor)
- The response of the emergency generators under brown-out (low voltage) versus black out (no power) conditions which impacted the ability of the AC back-up pump to start
- The lack of a local black start unit to be able to get power back quickly to the unit, given the line failures from Hardwoods (which has two line sources to Holyrood and is considered the black-start unit for Holyrood)
- The wrong setting (power off protection reversed) in the Mark 5 governor on Unit 1 when it was brought back initially from repairs which caused some further damage and further delayed its return to service to November 2013

It was noted that the key immediate issues appear to have been rectified with the Unit 1 lube oil pumps (checked OK on Unit 2) and the Unit 1 Mark V governor control, and work is ongoing to assess and rectify the emergency diesel start up issue.

A consequence of these anomalies that impacted unit availability is a need to more closely look for other anomalies in control relays and breakers and their associated logic that could result in other critical equipment failures – similar to the P&C check done within TRO P&C systems.

It seemed clear that another winter storm similar to that in January 2013 could result in essentially the same result to Holyrood. It was noted that i) two of the breakers in the switchyard had not been treated with a saltwater resistant coating and ii) no local black start capability existed at Holyrood in the event of a failure of the Hardwood to Holyrood lines.

AMEC noted the inability of the Holyrood station to keep at least one unit operational on station service load. It was suggested that this should be examined to enable a more rapid return to service.

A walk-down was undertaken of Unit 2, as well as several parts of Unit1, by Ian Leach and Blair Seckington led by Gerald Cochrane, Plant Operations Manager and accompanied by Trevor Arbuckle of Hydro. It included extensive walkdowns of the boiler and control room as well as areas of the fuel system within the plant and discussions of issues experienced over the past year. Several areas of concern were identified (extensive maintenance tagging, significant economizer non-return valve leaks, potential significant oil heater leaks into blow-down condensate return tank and into WTP retention tanks; boiler feed pump bearing oil contamination). No areas of concern were specifically identified during the walkdown that would likely have an immediate impact affecting winter 2013-14 availability.

3.1.1.3 Thermography/Inspections (November 18-19, 2013)

A thermographic survey of Holyrood Unit 2 focused on the electrical switchgear. It was conducted by David Trask of Pennecon (AMEC subcontractor) with the support and protection of one or two Holyrood electrician staff on November 18th and 19th 2013.

Thermal imaging was taken of key elements of the plant (primarily 600V, 4 kV electrical systems and equipment) that could be accessed. No thermography portals that allow easy viewing are installed on Holyrood units, and as a result the thermal imaging was limited by the existing safe work procedures implemented by station electricians to provide safe access. Two “hotspots” were identified that warrant an immediate check. These are documented in a report by Pennecon which was forwarded to the station and is available as an addendum to this report. Otherwise the systems that could be scanned were in good condition and required no action. A listing is provided below. The hotspots identified are not likely to impact the winter 2013/14 reliability.

Section	Equipment	Fault	Recommendation
MCC B1	Igniter Air Booster	Phase A on OL	Check Connection
MCC C4 -11th FL	Unit 1 Boiler Rm	Terminal T1	Check Connection
MCC B1 Sect 10B Back	Cell A Main Fuel	No Fault	No action
MCC B1 Sect 10B Front	Feeder Stage 1 Pumphouse	No Fault	No action
MCC C1 Sect B7 Back	Main Feeder	No Fault	No action
MCC C1 Sect 4B	Light Oil Pump	No Fault	No action
MCC C1 Sect 4C	Seal Oil Pump.	No Fault	No action
Power Centre B	Breaker B1	No Fault	No action
Unit 2	Aux Transformer	No Fault	No action
Power centre B	Breaker B5	No Fault	No action
Power Center C	All Breakers	No Fault	No action
4160V Unit #2	UB2-5	No Fault	No action
Unit #2 4160V	UB2-7	No Fault	No action
Unit #2 4160V	UB2-9	No Fault	No action
Unit #2 4160V	UB2-10	No Fault	No action
Unit #2 4160V	SSB-4 Stn Serv	No Fault	No action
Unit #2	Unit 2 Transformer	No Fault	No action
Unit #2	Station Services	No fault	No action

In addition a larger number of items were visually inspected and thermographs taken. These are listed as follows:

UNIT IDENTIFICATION	CIRCUIT IDENTIFICATION	Scanned 2013
UB - 2	Boiler Feed Pump No.2 - West	X
UB - 2	Boiler Feed Pump No.2 - East	
UB - 2	Forced Draft Fan No.2 - West	X
UB - 2	Forced Draft Fan No.2 - East	
UB - 2	Circ Water Pump No. 2 - West	
UB - 2	Circ Water Pump No. 2 - East	X
UB - 2	Condensate Ext. Pump - North Unit No.2	X
UB - 2	Condensate Ext. Pump - South Unit No.2	
UB - 2	Auxiliary Transf. AT-B 4160 / 600 Y	
UB - 2	UB2-1	
UB - 2	UB2-12	
Unit #2 Power Centre B	Breaker B5 Feed to MCC B1	X
Unit #2 Power Centre B	Breaker B1 Main	X
Unit #2 Power Centre C	C2	X
Unit #2 Power Centre C	C3	X
Unit #2 Power Centre C	C4	X
Unit #2 Power Centre C	C5	X
Unit #2 Power Centre C	C6	X
Unit #2 Power Centre C	C7	X
Unit #2 Power Centre C	C8	X
Unit #2 Power Centre C	C10	X
Unit #2 Power Centre C	C11	X
Unit #2 Power Centre C	C12	X
Unit #2 4160V SWGR	UB2-1	X
Unit #2 4160V SWGR	UB2-2	X
Unit #2 4160V SWGR	UB2-5	X
Unit #2 4160V SWGR	UB2-7	X
Unit #2 4160V SWGR	UB2-9	X
Unit #2 4160V SWGR	UB2-10	X
Unit #2 4160V SWGR	SSB-3	X
Unit #2 4160V SWGR	SSB-4	X
MCC C6-2 Pumphouse	F2D	X
MCC C6-2 Pumphouse	F3B	X
MCC C6-2 Pumphouse	F5B	X
MCC C6-2 Pumphouse	F5C	X

Scanned 2013	MCC	Equipment to be SWITCHED ON
	MCC-B1	Air Preheater Cond. Pump North 15 HP
	MCC-B1	Turbine Casing Drain MOV 0.133 HP
	MCC-B1	Reheat Bowl Drain MOV 0.133 HP
	MCC-B1	Main Steam Pipe Drains To Start - Up De Sup MOV 0.133 HP
	MCC-B1	Main Steam Pipe Drains To Boiler BD Tank MOV 0.133 HP
	MCC-B1	RH RSV Below Seat Drain MOV 0.133 HP
	MCC-B1	LH RSV Below Seat Drain MOV 0.133 HP
	MCC-B1	RH RSV Above Seat Drain MOV 0.133 HP
	MCC-B1	LD RSV Above Seat Drain MOV 0.133 HP
	MCC-B1	RH Hot Reheat Pipe Drain MOV 0.133 HP
	MCC-B1	LH Hot Reheat Pipe Drain MOV 0.133 HP
	MCC-B1	RH Cold Reheat Pipe Drain MOV 0.133 HP
	MCC-B1	LH Cold Reheat Pipe Drain MOV 0.133 HP
	MCC-B1	Start-Up De Sup Spray Water Valve 0.133 HP
	MCC-B1	Turb. Stop Valve Below Seat Drain MOV 0.133 HP
	MCC-B1	Turb. Stop Valve Above Seat Drain MOV 0.133 HP
	MCC-B1	Main Steam Pipe Drain MOV 0.133 HP
	MCC-B1	Steam Seal Regulator Inlet MOV 0.133 HP
	MCC-B1	Steam Seal Regulator Bypass MOV 0.133 HP
	MCC-B1	Steam Seal Regulator Drain MOV 0.133 HP
	MCC-B1	Steam Seal Reg. Manifold Dran MOV 0.133 HP
X	MCC-B1	Unit 2 Condensate Polishers
	MCC-B1	Oil Conditioner Return Pump 1.0 HP

	MCC-B1	Oil Conditioner Transfer Pump 1.0 HP
X	MCC-B1	Mech. Vacuum Recirc. Seal Pump North, 1.0 HP
X	MCC-B1	A.C. Oil Pump A North, 20 HP
X	MCC-B1	Hydraulic Fluid Pump North, 15 HP
X	MCC-B1	T.G. C.W. Pump North, 30 HP
X	MCC-B1	Mech. Vacuum Pump North, 50 HP
	MCC-B1	Seal Air Booster Fan 5 HP
X	MCC-B1	B.F. Pump - East Aux. Oil Pump 3/4 HP
X	MCC-B1	B.F. Pump - West Aux. Oil Pump 3/4 HP
X	MCC-B1	Glandseal Condenser Exhauster North, 3 HP
	MCC-B1	Glandseal Water Emerg. Pump 30 HP
	MCC-B1	Glandseal Water Transfer Pump 5 HP
	MCC-B1	HP Heater Drain Pump 10 HP
X	MCC-B1	Main Fuel Oil Pump East, 75 HP
X	MCC-B1	Reserve Feedwater Transfer Pump 60 HP
	MCC-B1	B.F. Pump - East Discharge MOV 1.0 HP
	MCC-B1	B.F. Pump - East Discharge Bypass MOV 1.0 HP
	MCC-B1	B.F. Pump - West Discharge MOV 1.0 HP
	MCC-B1	B.F. Pump - West Discharge Bypass MOV 1.0 HP
	MCC-B1	Condenser Outlet Valve North, 1.0 HP
	MCC-B1	Condenser Outlet Valve South, 1.0 HP
	MCC-B1	Low Load Feedwater MOV 1.0 HP
	MCC-B1	Exhaust Hood Spray Water Bypass 0.133 HP
	MCC-B1	Main Feedwater Isolator MOV 1.0 HP
	MCC-B1	Main Feedwater Isolator Bypass MOV 1.0 HP
	MCC-B1	Boiler Stop Value 1.0 HP
	MCC-B1	Boiler Stop Valve Bypass 1.0 HP
X	MCC-B1	Ignitor Air Booster Fan 15 HP
	MCC-B1	HP Heater MCC B1-1
	MCC-B1	Soot Blower MCC B1-2
X	MCC-B1	Main Transformer T2 Auxilaries 8 HP
X	MCC-B1	Lube Oil Centrifuge (Port) 68kW
X	MCC-B1	Seal Oil Vac Pump Skid Unit No.2, 1 HP
X	MCC-B1	Seal Oil Pump East Skid Unit No.2, 5 HP
X	MCC-B1	Fuel Additive System 0.75 HP
	MCC-B1	Welding Receptacle 23kVA
	MCC-B1	Air Preheater Cond. Pump South 15 HP
	MCC-B1	Air Preheater Cond. Pump North 15 HP
X	MCC-B1	UNIT 2 CONDENSER INLET VALVE NORTH
X	MCC-B1	UNIT 2 CONDENSER INLET VALVE SOUTH
X	MCC-B1	UNIT 2 CONDENSER BACKWASH VALVE SOUTH
X	MCC-B1	UNIT 2 CONDENSER BACKWASH VALVE NORTH
X	MCC-B1	UNIT 2 CONDENSER CROSSOVER VALVE
	MCC-B1	COLD REHEAT CONDENSATE POT DRAIN VALVE EAST
	MCC-B1	COLD REHEAT CONDENSATE POT DRAIN VALVE WEST

Scanned 2013	MCC	Equipment to be SWITCHED ON	COMMENTS
	MCC-C1	LIGHT OIL PUMP UNIT NO 1 EAST	
X	MCC-C1	SEAL OIL PUMP SKID UNIT 2 WEST	
X	MCC-C1	LIGHT OIL PUMP UNIT NO 2 EAST	
X	MCC-C1	GAS TURBINE TRANSFORMER AUXILIARIES	
X	MCC-C1	STATION SERVICES TRANSFORMER AUXILIARIES	
X	MCC-C1	TANK FARM FEEDER	
	MCC-C1	UNIT 1 EXCITER TEST SUPPLY	
X	MCC-C1	UNIT 2 EXCITER TEST SUPPLY	
X	MCC-C1	VACUUM CLEANER EXHAUST	
	MCC-C1	CONTROL ROOM HEATER	
X	MCC-C1	BATTERY CHARGE No. 2	
X	MCC-C1	CONTROL ROOM A/C UNIT NORTH	
X	MCC-C1	CONTROL ROOM A/C UNIT SOUTH	
	MCC-C1	CONTROL ROOM A/C UNIT WEST	
	MCC-C1	CONTROL ROOM A/C UNIT EAST	
X	MCC-C1	TURBINE HALL CRANE FEEDER	
X	MCC-C1	SWITCHYARD FEEDER	
X	MCC-C1	FIBRE OPTIC ROOM	
X	MCC-C1	UPS No. 1 BYPASS AC SUPPLY	
X	MCC-C1	UPS No. 2 BYPASS AC SUPPLY	
X	MCC-C1	UPS No. 1 ROOM AIR CONDITIONER	
X	MCC-C1	C8-FUEL ADDITIVE SLOPS TANK	
X	MCC-C1	C9-WORK SHOP AREA	
X	MCC-C1	C7-ADMINSTRATION AREA	
	MCC-C1	C6-CW PUMPHOSE STAGE 1	

Scanned 2013	MCC	Equipment to be SWITCHED ON	COMMENTS
X	MCC-C3	Septic System Manhole 7A 1.5 HP Pump	
	MCC-C3	Sample Cooling Pump West, 1.5 HP	
X	MCC-C3	Scanner Air Fan East, 2.0 HP Unit 2	
	MCC-C3	Gland Seal Condenser Exhaust South, 3.0 HP	
X	MCC-C3	Mech. Vacuum Pump South, 50 HP Unit 2	
X	MCC-C3	Mech. Vacuum Recirc. Seal Pump South, 1.0 HP	
	MCC-C3	Hydraulic Fluid Pump South, 15 HP Unit 2	
	MCC-C3	T.G. Aux. Cooling Water Pump South, 30 HP	
	MCC-C3	Main Fuel Pump West, 75 HP Unit 2	
X	MCC-C3	Unit No.2 Exciter Field Flashing Source 15A	
	MCC-C3	Welding Outlet 60A, 23kVA	
	MCC-C3	Fuel Additive Transfer Pump 5 HP	
	MCC-C3	Ammonia And Control Skid	

Scanned 2013	MCC	Equipment to be SWITCHED ON	COMMENTS
X	MCC C4	Unit No.1 Boiler Rm. Vent Fans 1&2, 7.5 HP Each	
X	MCC C4	Unit No.2 Boiler Rm. Vent Fans 7&8, 7.5 HP Each	
X	MCC C4	Unit No.1 Boiler Rm. Vent Fans 3&4, 7.5 HP Each	
X	MCC C4	Unit No.2 Boiler Rm. Vent Fans 9&10, 7.5 HP Each	
X	MCC C4	Unit No.1 Boiler Rm. Vent Fans 5&6, 7.5 HP Each	
X	MCC C4	Unit No.2 Boiler Rm. Vent Fans 11&12, 7.5 HP Each	
X	MCC C4	Unit No.1 Roof Exhaust Fan No.1, 5 HP, West	
X	MCC C4	Unit No.1 Roof Exhaust Fan No.2, 5 HP, East	
X	MCC C4	Unit No.2 Roof Exhaust Fan No.2, 5 HP, West	
X	MCC C4	Unit No. 2 Roof Exhaust Fan No. 2, HP, East	
	MCC C4	Boiler Room Hoist (Units 1&2) 2x14.5	

Scanned 2013	MCC	Equipment to be SWITCHED ON	COMMENTS
	MCC-E1	Seal Oil Pump Skid Unit No.1 West	
	MCC-E1	Flame Scanner Fan West Unit No.1, 2.0 HP	
	MCC-E1	Flame Scanner Fan West Unit No.2, 2.0 HP	
X	MCC-E1	Unit No. 1 Air Pre-Heater West, 5.0 HP	
X	MCC-E1	Unit No. 1 Air Pre-Heater East, 5.0 HP	
X	MCC-E1	Unit No.2 Air Pre-Heater West, 5.0 HP	
X	MCC-E1	Unit No. 2 Air Pre-Heater East, 5.0 HP	
	MCC-E1	Unit No. 1 Turbine Turning Gear 100 HP	
	MCC-E1	Unit No. 2 Turbine Turning Gear 100 HP	
	MCC-E1	Unit No.1 Lub. Oil Tank Vapour Extractor 3/4 HP	
X	MCC-E1	Unit No.2 Lub. Oil Tank Vapour Extractor 3/4 HP	
X	MCC-E1	Unit No.1 A.C. Oil Pump 'B' South 20 HP	
X	MCC-E1	Unit No.2 A.C. Oil Pump 'B' South 20 HP	
X	MCC-E1	Unit No.2 258 V D.C. Battery Charger (100A)	
X	MCC-E1	Main Transformer T1 Auxiliaries 15 HP	
X	MCC-E1	Main Transformer T2 Auxiliaries 8 HP	
X	MCC-E1	Battery Charger No.1 129V D.C. 10kVA	
X	MCC-E1	Unit No.1 258 V D.C. Battery Charger (100A)	
X	MCC-E1	G.T. Start-up Supply 110kVA	
X	MCC-E1	Light Oil Pump Unit 1 West, 2.0 HP	
	MCC-E1	Light Oil Pump Unit 2 West, 2.0 HP	
X	MCC-E1	Passagener Elevator Boiler House 35 HP	
X	MCC-E1	UPS No. 2 Main A.C. Supply (30kVA)	
X	MCC-E1	UPS No. 1 Main A.C. Supply (30kVA)	

No major issues were identified. Overall the thermal scans and inspections would suggest that electrical equipment (breakers, disconnects, connectors) are in reasonable “electrical/mechanical” condition for the 2013/14 winter season.

3.1.1.4 Facility Maintenance and Winter Readiness Overview

Unit 2

The planned 2013 Unit 2 maintenance and overhaul/inspection work originally planned for the summer of 2103 was delayed, primarily due to resource (labour, funding) impacts of unexpected high priority issues/projects at Holyrood. These included: the repair work to Unit 1 steam turbine generator, the major maintenance/spare parts work/costs related to the impacts of poor quality fuel, the replacement of Unit 1 exciter system, and the attempts to install a local black start capable system.

Some boiler and high pressure feedwater and steam line inspection and repair work was done as part of a Level 2 condition assessment on Unit 2 boiler. This found no significant flaws that would likely impact the 2013/14 winter season.

At the time of the site visit, it appeared that a two week Unit 2 outage was likely to be obtained during the last two weeks of November. The highest priority, critical PM work was planned to be completed during this time. This was reduced to a four day maintenance outage between Nov 24 and Nov 27 2013, supplemented with some maintenance work undertaken during weekend outages. As a result, some but not all Unit 2 most important corrective/PM work was completed by year end.

Staffing remains a key issue. Inexperienced operators or others with limited familiarity with the specific equipment increase the risk of operator error both initially and during a failure. The presence of an experienced operator during the January incident likely prevented Unit 1 damage from being more severe. Experience in maintenance and engineering support staff also impact unit condition and cost, but may be less likely to have a short term impact.

Given the similarity of Units 1 and 2, the issues associated with the January 2013 failure of Unit 1 to successfully restart and subsequent damage to Unit 1 were considered. It appeared that several issues were involved:

- The inadequate lube oil supplied by the DC lube oil pump due to the motor running at a lower than required speed (possibly an improper setting on the DC lube oil pump motor)
- The response of the emergency generators under brown-out (low voltage) versus black out (no power) conditions which impacted the ability of the AC back-up pump to start
- The lack of a local black start unit to be able to get power back quickly to the unit, given the line failures from Hardwoods (which has two line sources to Holyrood and is considered the black-start unit for Holyrood)
- The wrong setting (power off protection reversed) in the Mark 5 governor on Unit 1 when it was brought back initially from repairs which caused some further damage and further delayed its return to service to November 2013

Key immediate issues have been rectified with the Unit 1 lube oil pumps (checked OK on Unit 2) and emergency diesel start-up are being or have been rectified. A consequence of these anomalies that impacted unit availability is a need to more closely look for other anomalies in control relays and breakers that could result in other critical equipment failures – similar to the P&C check done within Transmission system.

The following tables summarize the overall 2013 Unit 2 Co-ordinated Maintenance and Capital Works as of December 30, 2013. A considerable amount of higher priority PM/corrective work had been completed at that time, significantly more than at the site visit in November. There did remain lower considerable lower priority.

2013 HRD COORDINATED MAINTENANCE SCHEDULE

As of Dec. 30, 2013 (Unit #2)

Black - Permits Tasks & Corrective Maintenance Activities

Green - Approved Capital Work for 2013

Blue - Preventative Maintenance Activities

% Complete	Task Name	% Complete	Task Name
23%	**#2 Planned Minor Repairs & Capital Work**	0%	Replace Condensate Polisher Annunicator Panels
10%	Unit #2 Outage	100%	Install Variable Speed Drives on FD Fans
		100%	Upgrade Hydrogen System - Unit #2 Connections
60%	Pre-Permit	0%	Complete Condition Assessment, Phase 2
10%	Install Work Protection Permits	0%	Complete Condition Assessment, Phase 3
0%	Boiler Overhaul (Minor)	0%	Boiler Feedpump East Overhaul
22%	**Preventative & Corrective Maintenance Tasks**	0%	Extraction Pump South Overhaul
27%	Turbine/Generator System - Zone 10 -	0%	Replace Flash Tank
34%	Boiler System - Zone 20 -	100%	Remove Work Protection Permitry
11%	Feedwater System - Zone 30 -	50%	Upgrade Hydrogen System - Online Commissioning Activities
9%	CW System & Generation Services - HGS -	60%	Start-Up
6%	Miscelaneous - No Zone (50) -		

The following documents the "remaining work" as of December 30, 2013 for Unit 2, in terms of corrective as well as preventative work.

2013 HRD COORDINATED MAINTENANCE SCHEDULE

As of Dec. 30, 2013 (Unit #2)

Black - Permits Tasks & Corrective Maintenance Activities

Green - Approved Capital Work for 2013

Blue - Preventative Maintenance Activities

% Complete	Task Name	% Complete	Task Name	% Complete	Task Name
23%	**#2 Planned Minor Repairs & Capital Work**	34%	Boiler System - Zone 20 -	11%	Feedwater System - Zone 30 -
10%	Unit #2 Outage	0%	U#2 4R RETRACTABLE SOOTBLOWER	0%	#2 HIGH/LOW RFW TANKS
		0%	U#2 7T FL 18L SOOTBLOWER	0%	#2 DEWATER CW SUMP(STOP LOGS)
60%	Pre-Permit	0%	U#2 9TH FL 2R SOOTBLOWER	0%	#2 CW PIPING(PUMP OUT/CLEAN)
10%	Install Work Protection Permits	0%	U#2 FL 1L SOOTBLOWER	0%	#2 COMMON HIGH LEVEL TANK
0%	Boiler Overhaul (Minor)	0%	U#2 17R RETRACTABLE SOOTBLOWER	0%	#2 ECONOMIZER INLET VALVE
22%	**Preventative & Corrective Maintenance Tasks**	0%	UNIT #2 SOOTBLOWER 2R 9TH FL	0%	REPLACE LEAKING GATE VALVE
27%	Turbine/Generator System - Zone 10 -	100%	IGNITOR BOOSTER FAN - REPLACE MOTOR	0%	#2 LP HTR#1 TRANSMITTER BLDOWN
100%	#2 GENERATOR BRUSH GEAR	0%	U#2 WINDBOX DAMPER POSITIONER	0%	U#2 WEST BFP DISCH.VLV
0%	#2 GENERATOR PT CUBICLE INSPECTION	0%	U#2 WINDBOX DAMPER POSITIONER	100%	4 #2 WEST B.F.P. LUBE OIL LEAK
0%	#2 GENERATOR ROTOR IMPEDANCE CHECK	0%	#2 CAL.FO.HEADER PRES.SWITCHES	100%	NO.6 HP HEATER WATERSIDE
0%	U2 HYDRAULIC SKID	100%	U2 LIGHT OIL LINE HYDROPAD	0%	EAST LP DRAIN PUMP 1ST FLOOR
0%	OVERHAUL STARTER-N. LUBE PUMP	0%	U#2 LIGHT OIL HEADER PRESSURE	0%	MAIN CTRL VLV (FEEDWATER)
0%	OVERHAUL STARTER-N. HYD PUMP	100%	U#2 F.O. ACCUMULATOR BLADDER	100%	WEST BFP SUCTION VALVE - HARD TO OPERATE
0%	#2 TURB/GEN TSI CALIBRATION	0%	#2 INSPECT ATTEMP T/C'S	0%	BOILER FEED PUMP WEST RECIRC
0%	#2 TURB/GEN.INSTRUMENT.EQUIP.	0%	U#2 FUEL OIL SYSTEM HYDROPAD	0%	U2 BFP EAST RECIRC CHECK VALVE
0%	#2 TURB.COND.AIR EXTRACT.CONT	0%	REMOVE EVERCOOL GUN 2013	0%	SANDBLAST & PAINT HL&LL TANKS
0%	#2 T/G COOLING TEMP.CONTR.VLV	0%	U#2 SOUTH/WEST OF BOILER	9%	CW System & Generation Services - HGS -
0%	#2 HOTWELL SWITCHES /GSCW	0%	#2 BOILER SAFETY VLV. OVERHAUL	0%	#2 E&W CW DISCH.VALVE MOTORS
100%	#2 EXCITER OVERHAUL	0%	#2 EAST HEAVY FUEL OIL PUMP PM	0%	STG 1 PUMPHOUSE REPLACE CONDUI
0%	U2 HOT REHEAT OUT T/C	0%	#2 WEST HEAVY FUEL OIL PUMP PM	0%	#2 CW PUMPS COOLING FLOW IND.
0%	U#2 ROD END ON INNER CTRL.VLV	0%	SH 4 BLOCK VALVE PASSING	0%	#2 EAST/WEST CW SCREEN
0%	U2 EXCITER BRIDGE PANEL	0%	U2 APS HIGH SIDE TRAPPING STAT	0%	#2 E. C.W.PUMP YEARLY PM

2013 HRD COORDINATED MAINTENANCE SCHEDULE

As of Dec. 30, 2013 (Unit #2)

Black - Permits Tasks & Corrective Maintenance Activities

Green - Approved Capital Work for 2013

Blue - Preventative Maintenance Activities

Task Name	% Complete	Task Name	% Complete	Task Name
U2 EXCITER DOOR LATCHES	0%	U2 AUX STEAM HIGH SIDE TRAPPIN	0%	#2 W. C.W.PUMP YEARLY PM
U2 EXCITER BREAKER	100%	STEAM LEAK, 11TH FLOOR DRAIN	0%	#2 E. CW SCREEN WASH PUMP PM
UNIT#2 BAD THERMOCOUPLE	100%	IGNITOR BOOSTER FAN - REPLACE MOTOR	0%	#2 W. CW SCREEN WASH PUMP PM
U2 HYDRAULIC SKID	100%	U2 AUX STEAM HIGH SIDE TRAPPIN	50%	EAST & WEST CW PUMPS D VALVE
U2 TSI VALVE POSITION MONITOR	100%	U#2 ATOMIZING ROOT VALVE	0%	#2 E & W CW SCREEN & PIPING
#2 CONDENSER HOTWELL	0%	U#2 D.A. DRAIN VALVE PASSING	0%	U#2 CW OUTLET PIPING - REPAIR
#2 CONDENSER PARTITION VLVS	0%	REPLACE VALVE 2-HFW-V108	6%	Miscelaneous - No Zone (50) -
#2 CONDENSER ANODES CHECK	0%	U2 SOOTBLOWER SUPPLY BLOCK VLV	50%	UNIT #2 CONTROL BOARD LIGHTS
#2 CONDENSER TUBE LEAKS	100%	TRAP STATION ON 2-APS-03-L101	0%	UNIT BOARD UB2 MAJOR PM
#2 VACUUM PUMPS COOLERS	100%	U2 F.O. PRESSURE CONTROL VALVE	0%	#2 PWR CTR B (UAB-2) MINOR O/H
#2 TG COOLER DOORS/ANODES	100%	U2 F.O. HEATERS ON HEATING SET	50%	U2 POLISHER W SER OUT ACTUATR
#2 T.G. HEAD TANK	100%	U2 E. FUEL HEATER STEAM BLOCK	0%	U2 POLISHER CONTROL PANEL AIR
#2 TURBINE OIL VAPOUR EXT. PM	0%	U2 FO ACCUMULATOR BLOCK VALVE	0%	#2 FLOW ORIFACE PLATES INSP.
U2 HYDRAULIC SET	0%	U #2 Above Seat Drain Line	0%	ANALYTICAL RACK OVERHAUL
U2 HYDRAULIC OIL COOLER	0%	U2 FUEL OIL PUMP RELIEF VALVES	50%	#2 POLISHER VALVE OPERATORS
#2GENERATOR HYDROGEN/CO2 SPOOL	100%	U2 A/H CONDENSATE LINE TO DA	0%	U2 FERROUS SULFATE DAY TANK
#2 N. EXTRACTION PUMP INSP.	100%	UNIT #2 CONTINUOUS BLOWDOWN	0%	GLAND SEAL STRAINER E LEAKING
#2 S. EXTRACTION PUMP INSP.	0%	SH-4 2-BD-V140 LEAKING	0%	U2 POLISHER INLET & OUTLET VLV
#2 NORTH VACUUM PUMP INSP.	0%	U2 SH VENT ON TOP OF BOILER	0%	U#2 FERROUS SULFATE DAY TANK
#2 SOUTH VACUUM PUMP INSP.	0%	U2 DRUM VENT EAST INSIDE V111	0%	Replace Condensate Polisher Annunicator Panels
#2 CW PIPING INSPECTION	0%	U2 DRUM VENT WEST INSIDE V113	100%	Install Variable Speed Drives on FD Fans
#2 HOTWELL LEVEL BLOWDOWN	0%	SH-6 ON 8TH FL. SOUTHEAST	100%	Upgrade Hydrogen System - Unit #2 Connections
UNIT # 2 HYD.FLUID SET	100%	AIR HEATER DRAINS TO BD VALVE 285/286 - REPLACE	0%	Complete Condition Assessment, Phase 2
UNIT #2 LUBE OIL SYSTEM	100%	10TH FLOOR LEAK ON LINE 2-BD-10-L126	0%	Complete Condition Assessment, Phase 3
U # 2SOUTH COND.DISC LINE	100%	ECONOMIZER CHECK VALVE COVER LEAK	0%	Boiler Feedpump East Overhaul
U#2 LEFT HAND REHEAT STOP VLV	100%	UNIT#2 EAST AND WEST FO HEATER	0%	Extraction Pump South Overhaul
U2 NORTH VACUUM PUMP SHAFT	0%	AUX STEAM HIGH SIDE TRAP DRAIN	0%	Replace Flash Tank
U2 SOUTH VACUUM PUMP	11%	Feedwater System - Zone 30 -	100%	Remove Work Protection Permitry
UNIT#1 H2 COOLER VALVES	0%	UNIT #2 HP HEATER CONTROLS	50%	Upgrade Hydrogen System - Online Commissioning Activities
MOTIVE AIR VALVE N. VAC PUMP/OVERHAUL	100%	EAST BFP - DISCHARGE VALVE WILL NOT OPEN	60%	Start-Up
MOTIVE AIR VALVE S. VAC PUMP/OVERHAUL	0%	#2 WEST BFP GAUGES CAL.	0%	ANALYTICAL RACK POST START-UP
#2 BRUSH GEAR MAINTENANCE	0%	#2 EAST BFP GAUGES CAL.	100%	#2 EVT SAFETY VALVES
#2 CONDENSER HOTWELL	0%	#2 CONT.B/D TANK LEVEL SWITCH	100%	#2 GEN.H2 PURITY MET.(START UP
#2 CONDENSER TUBES	0%	U2 CONDENSATE EXTRACTION PUMP	0%	#2 FOLLOW-UP S/B PACKING
#2 TG COOLER CLEANING	0%	#2 HP HEATERS LEVEL PROBE CHK	100%	#2 BOILER SAFETY VLV. EVT
U2 TURBINE HYDRAULIC SYSTEM	0%	U#2 WEST BFP OUTBOARD BEARING		
Boiler System - Zone 20 -	0%	U2 D.A. LOW LVL.TRIP SWITCH		
#2 BURNER SCANNER CHECKS	0%	#2 H.P.HTR DRAINS CHECK VLV		
#2 BURNER ASSEMBLIES	0%	U2 BOILER FEED PUMP		
#2 BOILER BURNER IGNITORS INSP	0%	#2 WEST BOILER FEEDPUMP PM		
REMOVE EVERCOOL GUN 2013	0%	#2 EAST BOILER FEEDPUMP PM		

A review was undertaken by Ian Leach in November 2013 after the site visit of the outstanding work orders in the station's maintenance tracking database (JD Edwards System). Certainly not all of the identified work items represent an uncertainty as to the unit's generating capability over the 2013/2014 winter operating season however there are items here which may cause unit outages, trips or deratings of Unit #2 if the work was not carried out.

As noted, communication from the station staff subsequent to the site visit and reviews indicates that much of the high priority work was completed during short outages in November and December. Some of the work may also have been completed while the unit was online. No updated list or detailed information was available at the time of this report.

Areas of direct concern to AMEC staff regarding the reliability of Holyrood Unit 2 during the winter season revolve around a number of the items where the possibility exists that they could cause unexpected outages or deratings because of deterioration that has occurred over time. Normally those would have been detected during the annual maintenance outage and were listed to be checked. Some of these include the integrity of large 4 KV motor windings which if they fail will cause outages, trips, or derating of the unit.

In order to identify the direct concerns, the Work Plan number along with the deficiency listed above along with the possible problems that could occur were provided for the major issues as of the site visit. Some of these were addressed in the Nov 24 to 27 four day outage and have been removed from this revision of the report. The remaining most obvious concerns are highlighted below. There were however many other defects that existed that would require short term weekend outages at Holyrood if the overall winter season is to be successful. The extent to which these were addressed in November and December outages was not available to AMEC as of this report.

Possible Outage/Trips/Derate Issues

Work Plan # 13 Turbine Turning Gear Motor Breaker Trips. The turning gear motor breaker trips during operation. The problem could be breaker related or motor related. If it was to fail after a unit shutdown and the operators were unable to rotate the hot turbine shaft, the shaft would bow upward and seize the LP Turbine rotor. Before the unit could be put back on line the LP Turbine rotor would have to cool out completely which takes a period of many days and hopefully while cooling, the weight of the rotor will begin to sag enough to free it allowing the unit to go back on turning gear and the damage assessed. A long term outage would ensue.

Work Plan # 166 East Boiler Feed Pump Overhaul. Presently the outboard gland on the east BFP is leaking water into the lubricating oil system of the pump. As long as the oil is changed frequently the lubrication value should not be a problem. If the gland leak worsens loss of lubrication could occur and the pump forced out of service causing the unit to be derated to 50% MCR. (Not Completed - scheduled for 2014 outage)

Work Plan # 183 Main Boiler Feedwater High Flow Control Valve. The high flow boiler feedwater control valve passes significantly. Presently when the high flow valve is indicating closed a noticed position reduction has been identified by Operations with the Low Flow control valve. Because the high flow valve passes, high drum level boiler trips have occurred in the past and if allowed to continue will cause even more boiler trips.

Work Plan #72 Main Unit Exciter Door Latches. The main unit exciter door latches on the Stage 1 Exciters require modification to prevent shorting out the buss bar if the latch arm fails. If the latch fails the exciter will trip causing an outage on Unit 2.

Work Plan # 73 Generator Exciter Field Breaker. Unit 2 Field Breaker has a linkage issue which may prevent the breaker from being "racked in" which may cause an extended outage until the problem is resolved. This has been partially completed, linkage checked & lubricated. Follow-up required in 2014 outage.)

Work Plan # 199 Unit 2 Condenser Circulating Water Outlet Pipe repair. See copies of this report in HYDRO's Engineering Office. Unit 2 could be forced out of service requiring an outage to fix the leak. The immediate leak was repaired during Nov 24 to 27 outage. Further repairs or replacement are required - pending engineering.

Due to the reduced Holyrood Unit 2 maintenance work during 2013, a higher degree of failure than normal is likely whether it is in the form of a complete unit long duration outage or a long term derating of up to 50% MCR or spurious unit trips which may or may not be recoverable during the winter season 2013/2014.

It is believed that Holyrood staff has taken all steps within their control to prevent the possibility of major damage similar to that experienced this past January on Unit #1 from happening again.

Fuel System

Holyrood's heavy fuel oil system experienced extensive difficulties in late 2012/early 2013 due to poor fuel quality associated with fuel delivered under a new supply contract. Several issues arose:

– fuel silica and alumina content (likely from fuel refining process) resulted in high wear and failures throughout the system from the delivery point to the burners
– fuel heavy hydrocarbons/stability resulted in equipment plugging and extensive solids build up in the main and day tank
– segregated delivery and offloading of fuel (mixing of fuel in large storage tanks assumed, but not present) essentially aggravated the previous two issues

As a result over $1 million in maintenance work was required, and additional spare parts for various elements of the system were used and purchased.

Currently several actions have been taken that appear at least initially to have reduced the potential impacts:

– the supplier has agreed to eliminate segregated fuel delivery and off-loading
– the supplier has agreed to work with Holyrood to reduce silica and alumina content, with monitoring at ship loading and off-loading
– the procurement of parts of equipment at risk to reduce likelihood of need for outage time

These key changes have been made to reduce unit or multi-unit failure risks substantially. Nevertheless the units have not yet been pushed and may experience component failures again this winter when loads and duration increase. Spare part maintenance and quick response/monitoring will be critical.

FM Global May 2013 Insurance Provider Review

A review was undertaken of the assessment in May 2013 by FM Global. Several were initially noted that could impact 2013/14 winter readiness. At the time of writing this report, it was noted that several of these had been addressed. The status of the work to rectify the remaining items below is unclear:

1. Water induction from Heaters and 2. Water in Generator

Water induction protection at this facility should be improved by testing the high-high level switches on the feedwater heaters and by installing a drain pot with a high level switch on the cold reheat line of Unit No. 3. Testing should be implemented this year on Unit Nos. 1 and 2 feedwater heaters. A cold reheat line drain pot will be installed next year on Unit No. 3.

The pressure of the water in the hydrogen coolers is higher than the hydrogen, which exposes the generators to a major fault in the event of a leak. Although there are positive factors already in place, installing continuous hydrogen dew point monitoring will help mitigate the potential. This will be completed this year.

On a positive note, online partial discharge monitoring was re-instated for all three generators and indicates good condition so far in terms of partial discharge.

07-10-001 Take steps to mitigate the risk of a water leak inside a generator.

The Hazard	Although the generator's electrical protection is adequate, the potential for water, with hydrogen, getting into the generator winding exists since the hydrogen cooler water pressure is significantly higher (100 psi) than the hydrogen pressure (45 psi). Positive factors include good history (no leaks), quality control of the water (would reduce contamination risk), liquid level indicators in the generator casing, replacement of 18-5 retaining rings and hydrostatic tests every six years. However, the risk of a leak cannot be eliminated. The hazard is that should a leak occur, the pressure dispersal of the water at 100 psi and the windage inside the generator would cause a very quick dispersal of water throughout the generator, which would quickly lead to an insulation failure.

06-01-003A continued

The Hazard	The admission of water into the hot turbine, valves and piping can cause premature failure of critical components, and feedwater heaters in particular represent the most frequent source of potential water induction. If a high-high water alarm is not quickly detected in a feedwater heater and the protection interlocks do not operate as designed, water can get through the block valve and reach the extraction nonreturn valve (NRV). This valve could be distorted by thermal shock, allowing water to enter and damage rotating components of the turbine. In the worst case, thermal shock and distortion may result in rubbing or blade failure and downstream damage. Testing the feedwater heaters' safety devices will help ensure that all components operate as designed to prevent such an event.	
Technical Detail	Simulation of a high water level condition can be done by means of a two-way valve (try cock) or the isolation and vent valves on the steam side of the switch. The steam chamber can be isolated from the heater and, at the same time, be vented to the atmosphere, reducing the pressure above the condensate in the gauge and permitting the condensate level to rise and actuate the level switch at alarm level. Prior to and upon completion of the test, make sure to test/inspect the heaters to confirm the normal water level is in range. Upon completion of the test, restore the equipment to its original condition of operation. So far, the modifications to allow this test were completed on Unit Nos. 1 and 2. **The completion of either on or offline functional tests on these protection devices has become urgent and long overdue. Much energy should be devoted to the completion of these testing starting this year to avoid a water induction event from the feedwater heaters.**	
Loss Expectancies	Acting on this item would reduce the probability or severity of loss. Exposure to Loss if Completed is approximately:	Minimal PD Minimal BI
Status	The test is considered warranted by management. An offline test will be conducted twice a year as agreed by FM Global. The Unit Nos. 1 and 2 feedwater heaters will be tested this year following receipt of information from Engineering. However, a procedure is still required. The Unit No. 3 feedwater heaters will have the same modifications in 2014-2015.	

Technical Detail	The generators are fitted with hydrogen purity monitors. This instrumentation looks only at the gas concentration (to avoid the explosive range), measuring the hydrogen concentration by analyzing the thermal conductivity of the gas. However, it cannot detect moisture or other contaminants. This instrumentation cannot be credited for detecting cooler leaks. The insured will acquire a hydrogen generator from Proton Energy. The unit will have some built-in redundancy to maximize its reliability and will consist of a new dryer, purifier and dew point monitoring. The battery room was chosen for the installation of the hydrogen generator.	
Loss Expectancies (USD)	Exposure to Loss is approximately: Exposure to Loss if Completed is approximately:	5,000,000 PD Minimal BI Minimal PD Minimal BI
Status	Hydrogen dew point monitoring will be installed in 2013 per Mr. Jeff Vincent. The work includes the installation of a hydrogen electrolyzer complete with a low-pressure hydrogen bulk storage tank and replacement of three hydrogen gas control panels (one per unit).	

3. Diesel Start-Up – Has HRD and TRO concluded assessment per below and implemented a solution?

13-05-001 **Improve the existing automatic startup requirements for the station service diesel generator.**

As a result of the recent lack of lubrication for the Unit No. 1 bearing following a severe winter storm, the current diesel emergency generator feeding the station service bus should have its automatic startup voltage requirement reviewed to start under a depressed voltage on the station service bus. This will help ensure faster startup and reliability of the alternating current (AC) standby lube oil pumps during the worst meteorological conditions.

Loss Expectancies	Acting on this item would reduce the probability or severity of loss. Exposure to Loss if Completed is approximately:	 Minimal PD Minimal BI

13-05-001 continued

Status	Manager, Thermal Generation Mr. Terry LeDrew indicated that the Transmission Group personnel will participate in an inquiry with the thermal group to ensure improvement of the current protection systems to prevent recurrence.

2. Critical Device Testing

13-05-003 **Verify if other critical devices are being tested.**

An enquiry should be made regarding periodic testing of other critical protection devices to verify if there is a need to revise the testing procedure in terms of intent (hazard to be prevented) and required data display for plant operators. Verify the need for training on these testing procedures. Ensure that set points are present on check sheets.

Loss Expectancies	Acting on this item would reduce the probability or severity of loss. Exposure to Loss if Completed is approximately:	 Minimal PD Minimal BI
Status	This was discussed with operation personnel and will be completed.	

3.1.1.5 Facility Risk Assessment

Weather and fire remain key risks that could impact Holyrood in the winter of 2013/14. Equipment risks are higher than would normally be true because not all Unit 2 outage inspections were completed as planned. Nevertheless, equipment failure is more likely to be due to an unexpected/unpredictable failure due to equipment age or undetected condition.

A storm similar to that of January 2013 has a low probability of occurrence (possibly 1 in 10 years), but would have a high probability of causing the same result of a station shutdown and system full/partial blackout/brownout. The station switchyard is still vulnerable (to failure due to salt water icing - only 4 of 6 breakers coated; the effectiveness of coating is also uncertain). The transmission capability between Western Avalon and Holyrood and between Holyrood and Hardwoods still seems vulnerable. Positive steps have been taken by Holyrood staff to reduce the risk of major damage to all 3 Holyrood units. A review of the unit's trip protection scheme as it relates to breaker failures in the Holyrood switchyard is recommended in order to further minimize the risk of the extensive damage that occurred on Holyrood Unit # 1 on January 11, 2013. A station operating practice or equipment scheme that would allow at least one unit in the station to stay on to provide station load is highly desirable and should be looked at. While unlikely in time for winter 2013/14, the need for on-site black start unit should be reconsidered.

A significant fire in the powerhouse is always a possibility, although the fire system is quite extensive. Ongoing checking to verify its readiness and that of the ERT is critical.

For Unit 2 itself, the potential for a Unit 2 outage/derating or trip is considered to have increased moderately from normal levels. Not performing a significant portion of the work in the major overhaul has placed the unit in a more tenuous than normal position during the winter season 2013/2014. Performing the higher priority outage work between November 24th and 27th and on some weekends has reduced the risk of an unexpected loss.

The fuel oil contamination issue that caused a number of operational issues on all 3 Holyrood units late in 2012 and earlier in 2013 appears to be largely under control. The supplier has agreed to work with Holyrood to reduce silica and alumina content, with monitoring at ship loading and off-loading and to eliminate segregated fuel delivery and off-loading. The station has also procured parts of equipment at risk to reduce likelihood of need for outage time. Nevertheless the units have not yet been pushed and may experience component failures again this winter when loads and duration increase. Spare part maintenance and quick response/monitoring will be critical.

3.1.2 Bay d'Espoir Generating Facility – Unit 7 and Auxiliary Systems

3.1.2.1 Facility Overview

Bay d'Espoir Generating Station is a manned hydroelectric generating station. The seven generating units at this facility have a combined generating capacity of approximately 604 MW to produce an average of 2,657 GWh annually, making it the largest hydroelectric plant on the island of Newfoundland. The units use approximately 176 m of head with a rated flow of 397 m^3/s to produce its rated output of 604 MW.

The sustained power production is critical to the island and a prolonged outage could become a safety issue during peak periods. It supplies about 50% of the island's power demand during the winter It is critical to avoid unexpected failures of this power plant in winter peak periods.

Units 1 through 4 went online between 1967 and 1968, with each unit having a rated capacity of 75 MW. The generator for generating unit 2 underwent a major refurbishment during the summer of 2010, including a stator rewind, rotor pole re-insulation and protection upgrade. Similar work was done on unit 4 in 2012 and Unit 1 in 2013. Unit 3 is scheduled for 2014. The main reason was to replace the generators' aging asphalt windings. Units 5 and 6, also with a rated capacity of 75 MW, went into service about 1970.

Unit 7 was constructed in a separate powerhouse and went into service about 1977. It has a capacity of 172 MVA, or about 155 MW at 0.9 Power factor. The CGE unit includes a vertical Francis type turbine rotating at 225 rpm which drives an air cooled generator at 172 MVA at 13.8kV. The generator can also operate as a synchronous condenser. It is epoxy-mica insulated. As of 2010 it had operated about 55, 000 hours, including about 7000 as a synchronous generator.

3.1.2.2 Pre-Visit Information

Limited information was available prior to the site visit, given the time available and the scope of potential PM information that might be available. It was agreed that information would be exchanged during the visit/interviews and post the site visit as practical.

The capital work in 2012 and 2103 on all of Bay d'Espoir are as follows, with Unit 7 items shown in green.

2012
BDE - Rewind Unit #4 Stator (contract)
BDE - Install Dynamic Air Gap Monitoring Sys. Unit #4 (contract as part of rewind)
BDE- Upgrade Unit #2 Generator Bearing
BDE - Upgrade Intake Gate Controls - Intake #2 and #3 (year 2 of 2-yr plan)
BDE- Automate Generator Deluge Systems Units 1-4 (Needs to be revised to include all 7 units)
BDE - Burnt Spillway- Install Automated Fuel Monitoring System
BDE- Replace Cooling Water Pumps 2 & 4 in Powerhouse 1
BDE - Upgrade Station Service System P.H #1 and #2
BDE- Upgrade Rip-Rap on Dams LD-3 and LD-4

2013 Capital work

BDE- Replace Emergency Diesel Generator PH#1 (program - year 2 of 2)
BDE - Upgrade Intake Gate Controls - Intake #2 (program - year 3 of 3)
BDE - Replace PH 1 North End Door
BDE - Replace Fall Arrest System Surge Tank 2
BDE - Overhaul Unit #1
BDE - Install Battery Bank 2 in PH2 (originally set for 2015)
BDE- Burnt Spillway Upgrades (Hatch Recs.) (program - year 3 of 4)
BDE - Automate Generator Deluge Systems Units 1 - 6 (program - year 1 of 3)
BDE - Rewind Unit #1 Stator/Air Gap Monitoring/PDA /Protection Upgrade/Rotor Refurbish
BDE - Replace Units 1 - 6 Autogreasing Systems (program - year 1 of 3)
BDE- Install Automatic Sprinkler System Office Area
BDE - Upgrade Units 1 - 6 S/V By-pass Valves (program - year 1 of 3)
BDE - Modify Generator Bearings, Units 1 - 4 (program - year 1 of 3)
BDE - Install Waste Oil Storage tank for PCB's
BDE - Replace Cooling Water Pumps 2 & 4 in Powerhouse 1
BDE - Purchase LP Screw Compressor Set

As can be see, very little capital work was undertaken for Powerhouse #2/Unit 7. It is in good condition and therefore in the overall capital prioritization program hasn't resulted in significant capital being allocated in this period.

May 2013 FM Global Insurance Report

From the May 2013 FM Global insurance report several statements are relevant:

1. Infrared Scanning of Generating Equipment

No infrared survey of the internal electrical production and distribution equipment has been performed such as for the switchyard equipment. A view port installation program has been established. Without proper funding, this well-planned program will most probably be never completed.

05-08-003 **Conduct regular infrared thermographic surveys.**

Infrared scanning should be conducted at this facility on all 600-V and 13.8-kV station service and generation electrical equipment. This should include the switchgear, interior dry-type transformers, motor control centers, and electrical panels.

The equipment that would benefit the most from such scans is the ultra-critical 600-V switchgear. As such, priority should be given to the following order:

1. **Station service switchgear for Unit 7**
2. **Station service switchgear for Units 1 and 6**
3. **Station service switchgear for remote locations**
4. **Excitation switchgear for Unit 7**
5. **Excitation switchgear for Units 1 and 6**
6. **Excitation switchgear for remote locations**
7. **Isophase bus for Bay D'Espoir generators**
8. **Isophase bus for remote generators**

Risk*Mark* Points	To significantly increase the location Risk*Mark* score, multiple recommendations must be completed.
Status	Mr. Bob Woodman indicated that two exciter cabinets had been equipped with view ports for trial and that the purchase of additional view ports would have to be approved in order for this project to go ahead as planned.

2. Fire Water Supply – Supply Reliability and Valve Testing

This facility is provided with the least reliable water supply for fire protection out of all five hydro stations on the island. Power House No. 1, which is occupied by six generators, is only provided with a water supply coming from the two penstocks through pressure reducing valves. These valves have proven to be unreliable over the years. The insured has recently completed the installation of a proper water flow testing apparatus and started using it in early 2013. During this visit, the testing apparatus was used to flow test each of the two water supplies for Power House No. 1. Results show that one of the two failed to operate properly when first tested but, after maintenance, did operate properly. As such, the insured is now equipped with the necessary tools to exercise these valves on a regular basis to ensure their reliable operation. In addition, the newly installed equipment allowed to discover that the fire protection piping is showing serious signs of needing proper flushing investigation.

13-05-002 **Increase the Singer valves testing frequency to monthly.**

Increase the Singer valves testing frequency to monthly throughout the year, not just during warm weather.

As seen during this visit, when the Singer valve on the south-end water supply fails to open during the flow test, regular exercising of the valve is crucial. This valve had been reportedly exercised one month before this visit.

Technical Detail	As seen from the review of water flow testing records, the tests were conducted as follows in 2013: Power House No. 1: - None in January - February 27 - None in March - None in April - May 5 Power House No. 2: - January 2nd - February 21st - None in March - None in April - May 11th - May 21st
Risk*Mark* Points	To significantly increase the location Risk*Mark* score, multiple recommendations must be completed.
Status	The insured understands the hazard and also has a better understanding of how the flow tests could be done without exposing the employees to the cold weather and without jeopardizing the condition of the equipment.

11-06-004 **Conduct a flushing investigation on all fire protection systems at a frequency of five years.**

Conduct a flushing investigation on all fire protection systems at a maximum frequency of every five years.

11-06-004 continued

The Hazard	The facility's water supply for fire protection is coming from an open body of water. From this, debris in the water can be pushed to the automatic sprinkler systems and can create obstruction and restrictions in the piping. If water cannot reach the fused sprinkler heads at a predetermined flow and pressure, the fire could spread uncontrolled inside the facility, leading to significant property damage not expected if the systems work as designed.
Technical Detail	During this visit, water flow test through the newly installed test header with the water supply coming solely from the south connection to the penstock water supply - Valve No. F14 in the closed position - and taking water pressure reading at the bottom of the riser of Sprinkler System Nos. 1 and 2 in the service tunnel led to the discovery of a potentially badly obstructed fire protection main. The 6-in. overhead main, based on the below calculation, no longer has an internal diameter of a 6-in. pipe. Measuring a water flow of 1,356 gpm at the test header dropped a residual pressure of 55 psi at Riser No. 2 down to 44 psi at Riser No. 1 and this over a 38-ft. length of 6-in. piping, as such, a pressure drop of 11 psi over 38 ft. With a new pipe of the same diameter, being 6 in., the pressure drop would have been of only 2.5 psi.
Risk*Mark* Points	To significantly increase the location Risk*Mark* score, multiple recommendations must be completed.
Status	The insured was surprised to see the water flow test results and now has a better understanding of the possible debris accumulation in the fire protection piping.

The "flushing program" has not started, but work to install the appropriate flushing valves and piping is in progress.

3.1.2.3 **Thermography** (Nov 13-14, 2013)

Limited thermography of the Bay d'Espoir Generating Station was practical. The station is in the initial stages of a process of installing customized camera viewing ports on key equipment. They have few installed ports and have not yet started the program to utilize these. Dave Trask of Pennecon used the existing ports with both his camera as well as the station's camera which has a special fish eye type lens designed for the small port size. Unfortunately the camera does only provide a normal picture of what it views as well as the thermographic image.

Although the station does not have a specific protocol for thermography associated with opening equipment cabinets under power, some limited work was done under the direction and protection of a station electrician.

Two Unit 7 "hotspots" were identified that should be investigated, although not until after the winter 2013/14 generating season. These are documented in a report by Pennecon which was forwarded to the station and is available as an addendum to this report. Otherwise the systems that could be scanned were in good condition and required no action. A listing is provided below. The hotspots identified are not likely to impact the winter 2013/14 reliability.

Section	Equipment	Fault	Recommendation
Gen. Unit #7	Bus Duct	Enclosure Heating	Investigate
Gen Unit #7	Bus Duct	Mating Surfaces	Investigate
#7 Gen Floor	Charger #1	No Fault	No action
#7 Gen Floor	Charger #1	No Fault	No action
#7 Gen Floor	Panel #5 SWB	No Fault	No action
#7 Gen Floor	120/240	No fault	No action
#7 Gen Floor	Panel 7400	No Fault	No action
#7 Unit	#7 Transformer	No Fault	No action
#7 Unit	PH#2 Transformers	No Fault	No action
Main Gen Plant	Heating Panel	No Fault	No action
Main Gen Plant	Dist Panel	No Fault	No action

In addition a larger number of items were visually inspected. These are listed as follows:

Unit #7 Generator Floor:

- EG1 Bridge #1
- EG2 Bridge #2
- EC Breaker Shunt DC Connection
- Disconnect Switch 7108-1
- Unit 7 Static Exciter Field
- Battery Charger #1
- Battery Charger #2
- Station Services Switchboard Panel #1 & #5
- Panel 7400 C/O Switch
- Powerhouse 600V Panel 7400

Unit #7 Turbine Floor:

- Panel 7500 C/O Switch
- 120/240V Splitter
- Powerhouse 600V Panel 7500
- Emergency Supply 600V Panel 7200
- Unit #7 600V Panel 7100
- BDE PH No. 2 Air Compressor
- Governor Pump Control Panel
- Sump Pump
- Unit 7 Alarm & Control Panel

Main Powerhouse

- Unit #1 Alarm / DC Distribution Panel & Auto Control Aux Panel
- Unit #2 Alarm / DC Distribution Panel & Auto Control Aux Panel
- Unit #3 Alarm / DC Distribution Panel & Auto Control Aux Panel
- Unit #4 Alarm / DC Distribution Panel & Auto Control Aux Panel
- Unit #5 Alarm / DC Distribution Panel & Auto Control Aux Panel
- Unit #6 Alarm / DC Distribution Panel & Auto Control Aux Panel
- 600V Heating Panel 7400
- Distribution Panel 6700

In addition, Pennecon used the Bay d'Espoir camera for thermographics of Units 1 to 6 and had the following comments. The report provided to the station included this information.

> This report is provided upon completing the infrared inspection at the Bay D'Espoire Generating Station. Pennecon completed the inspection using Nalcor's camera, Infrec IR Camera Model R300. Our camera could not adequately view the cell interiors using the installed IR viewing ports. Also, we could only take the infrared image, no visible image was possible through the view port. I would recommend taking matching visible images of the cell interior with reference to the view ports when the units are off-line. This would be very helpful when analyzing IR images and when trying to distinguish individual components. I have flagged several images for your investigation where higher temperatures were found. Most of these points of interest may be normal conditions and easily qualified by Nalcor staff familiar with the equipment (ie. CT's, contactor coils, etc) Details of the problems found and recommendations can be found in the following pages.

Generator Floor	**Section**
	Unit #1 Cells EE, EG1 & EG2
	Unit #3 Cells EE, EG1 & EG2
	Unit #4 Cells EE, EG1 & EG2
	Unit #5 Cells EE, EG1 & EG2
	Unit #6 Cells EE, EG1 & EG2
	Unit #7 Cells EE, EG1 & EG2

3.1.2.4 Facility Walk-Down & Interviews (Nov 13-14, 2013)

The station interviews were with Lev Kearley (BDE Plant Manager), Alvin Crant (Ops Manager), Rod Willcott (Specialist – Long term Asset Planning, Maintenance/Equipment Specialist), Bob Woodman (Manager, Long Term Asset Planning), Roland Fudge (Apprentice Operator) and Jason Duffney of TRO Central (Switchyard Thermography) with Trevor Arbuckle of Hydro and Blair Seckington and David Jones of AMEC and David Trask of Pennecon (thermal Imaging).

The facility walk-down was managed by Rod Willcott (Maintenance/Equipment Specialist). It encompassed most parts of the generating station, but not specifically the intake gates or structures or penstocks or tailrace. It was discussed that the Unit 7 had little maintenance other than basic PM's undertaken and that it had been running very reliably.

The Unit 7 turbine generator (CGE) is considered in very good condition. The generator has not experienced vibration (some start-up) or other electrical issues in regular PM testing. The excitation system, controls, governor and relays are considered in good condition, with no significant reliability issues. The excitation system uses an ABB system installed in the late 1990's. Spare parts are available. The governor is a mechanical flywheel type. While essentially obsolete, it is kept in excellent condition and not seen as an issue. The unit as a whole is not likely to give any significant issues in 2013/14 given its age (middle age) and history.

The unit was inspected and tested in July 2010. Generator Stator DC Hi-Pot testing (10 to 38kV DC at 2kV stops) was good (conducted every six years. Annual rotor winding tests have been satisfactory Jumper insulation and main lead insulation was doble tested "good". The Polarization Index since 2010 has been very good. The generator bearing coolers are stainless steel and have had no issues. No cavitation issues were noted with the runners. Some start-up vibration is evident and at very low loads, but this is not considered significant and very infrequent.

The Unit 7 transformer, based on PM testing, appears to be in good condition as would be expected given its relatively middle age. Annual DGA and three year Doble tests have shown no immediate significant issues. The transformer is equipped with water deluge and blast walls, as well as an oil retention area.

The plant has an electric emergency fire pump as back up to the main fire water supply from the penstock. The fire pump is primarily used when the penstock is dewatered. The system is also tied into the Powerhouse 1 system. Several issues have been identified with the fire water system in the FM Global report that requires attention to ensure adequate system reliability in the event of a fire.

Both unit dewatering pumps were out of service at the time of the visit. The drainage pumps were available to fill that role, but would take much longer. Although significant, this was not considered critical. Replacements and/or refurbishments were in the planning stage.

No issues were identified with the intake control structure, gates, penstocks, and equipment or with the station outfall. The gates are inspected every six years. The penstock internals PM indicates an inspection every five years, but due to access and safety the schedule can slip.

Recent capital included the station battery and compressed air (redundant) systems were in good condition and redundant capacity. A second battery bank was added in 2013 and the original replaced in 2012. The cooling water piping was replaced about six years ago. The station service auto-transfer switch was replaced in 2011. The generator deluge water system was automated in 2013.

3.1.2.5 Facility Maintenance and Winter Readiness Overview

Maintenance includes:

- Operations daily inspections/data collection
- Extensive inspections before the winter period to allow for repairs

- Transformer testing yearly, continuous DGA monitoring, Water in Oil monitoring;
- PM work (JD Edwards System) – annual and other period checks and repairs
- Corrective maintenance
- Capital refurbishments/enhancements

The last major generator inspection (PM9) was in June/July 2010. At that time the unit was found in good condition, and the end windings had only to be wiped clean. The high pot testing was good, four poles were removed and wedges tightened, The PI testing was good (3.3). In PM6 testing in 2011 and 2012 the PI had deteriorated slightly, but still was satisfactory. No results were available for 2013.

An extensive PM program appears evident to ensure as best as practical that issues will not arise to reduce generation availability during the winter peak period. Critical PM's appear to have been completed.

The PM binders (using JD Edwards system) were reviewed for Unit 7 and auxiliary systems. The review included PM6 and PM9 items in the Mechanical, Electrical and P&C areas. The Unit 7 PM's included primarily: the turbine, the generator, the exciter system, the governor system, isolated phase bus system, rectifier transformer and annunciation system. The auxiliary PM's included: compressors, fire protection, ventilation services, drainage systems, overhead cranes, draft tube cranes, water level systems, synchronous condenser controls, emergency lighting, battery banks and chargers, diesel systems.

Most PM's appear to have been completed or of lower priority. Based on Work Order Listing as of November 13, 2013, the following Unit 7 PM's had not been completed and were waiting to be scheduled (Priority 3 or higher – all were 3):

- WO 986264 Unit 7 Exciter Inspection PM6/9
- WO 987508/979323 Unit 7 IPB inspection PM1/ Phase B higher temp
- WO 1001520 Unit 7 Deceleration Curve PM6
- WO 1001521 Unit 7 Generator Deluge PM6
- WO 975689 Unit 7 PDA Stator PM5 (Semi-Annual)

The following Auxiliary (Unit 7/Common) PM's had not been completed and were waiting to be scheduled. (Priority 3 or higher – all were 3 except as noted):

- WO 991805 Unit 7 fire protection – neon light on control panel to show non-operation
- WO 987659 SST3 PCB Oil Sample to analysis
- WO 987785 Unit 7 Vibration Alarm – Channel 1 reached 4 (Priority 1)
- WO 994531 Synchronous Condenser PM6 inspection on controls
- WO997471 PM6 inspection of Ph2 Draft tube Crane
- WO1003406 SST3 Visual Inspection
- WO1011037 Flow test of fire water system
- WO 961920 Drainage System PM6 inspection --- NOTE: Dewatering Pumps 1 and 2 out of service. Drainage pumps can replace, takes longer
- WO1004768 PM3 Monthly Interceptor inspection (Priority 2)
- WO988098 Ph 2 Station service alarm misc fault – stuck contactor? (Priority 2)

3.1.2.6 Facility Risk Assessment

Key risks are likely associated with i) unexpected failures of older equipment (bushings, electro-mechanical relays, disconnects), and ii) fire simultaneously with a fire suppression failure. The station appears to have taken measures to mitigate against them as much as practical. Suitable ongoing monitoring and adequate spares and resources are in place to address and respond to unexpected failures.

Generally, Bay d'Espoir Generating Station Unit 7 appears to have no major issues identified which should interfere with reliable operation this winter.

- PM's on unit 7 and auxiliaries appear completed; modest #7 planned work completed
- Temporary Unit 7 IPB grounding system is in place as insulators are used elsewhere while awaiting replacements (OK, parts ordered, monitor)
- One PM over-speed relay setting seemed unreasonably high and significant change – station checking rationale
- No vibration or other issues which would suggest any #7 generator or turbine issues
- Some manual intervention required on intake valve operation (mtce and operation issue – checking on this, not sure I have it right)
- Auxiliary systems appear to be in good condition
- Transformer appears to be in good condition for this year (TRO results)
- Staffing changes – operator, mtce and management staff changes and shortages raises issue of familiarity and error

The readiness/risk of major systems at Bay d'Espoir is reviewed in the following table. Several aspects presented in the table are of a qualitative nature and intended to provide an indicative assessment. In the table, the "2013/14 Winter Period Likelihood" values are highly subjective, but in general terms should be taken to mean:

EL:	Extremely Low	Essentially no likelihood of occurring in the winter peak timeframe based on current knowledge of condition, monitoring in place, suppression, equipment/system redundancy
VL	Very Low	Almost no chance that this failure will occur in this timeframe based on current knowledge of condition, monitoring in place, suppression, equipment/system redundancy
L	Low	Possibility though unlikely that a failure could happen in this timeframe, based on recent history and age/condition of equipment/systems, but offset by monitoring in place, suppression, equipment/system redundancy
M	Medium	A definite possibility of an occurrence in this timeframe, based on recent history and age/condition of equipment/systems
H	High	A reasonably probable occurrence in this timeframe, based on recent history and age/condition of equipment/systems

The readiness scale is on a scale of 1 to 5 (one being highest readiness/lowest risk). The data should be considered qualitative and indicative, based on information from the site visits or other sites. Most are considered very low risk. For the purposes of this assessment, the values can be taken to mean:

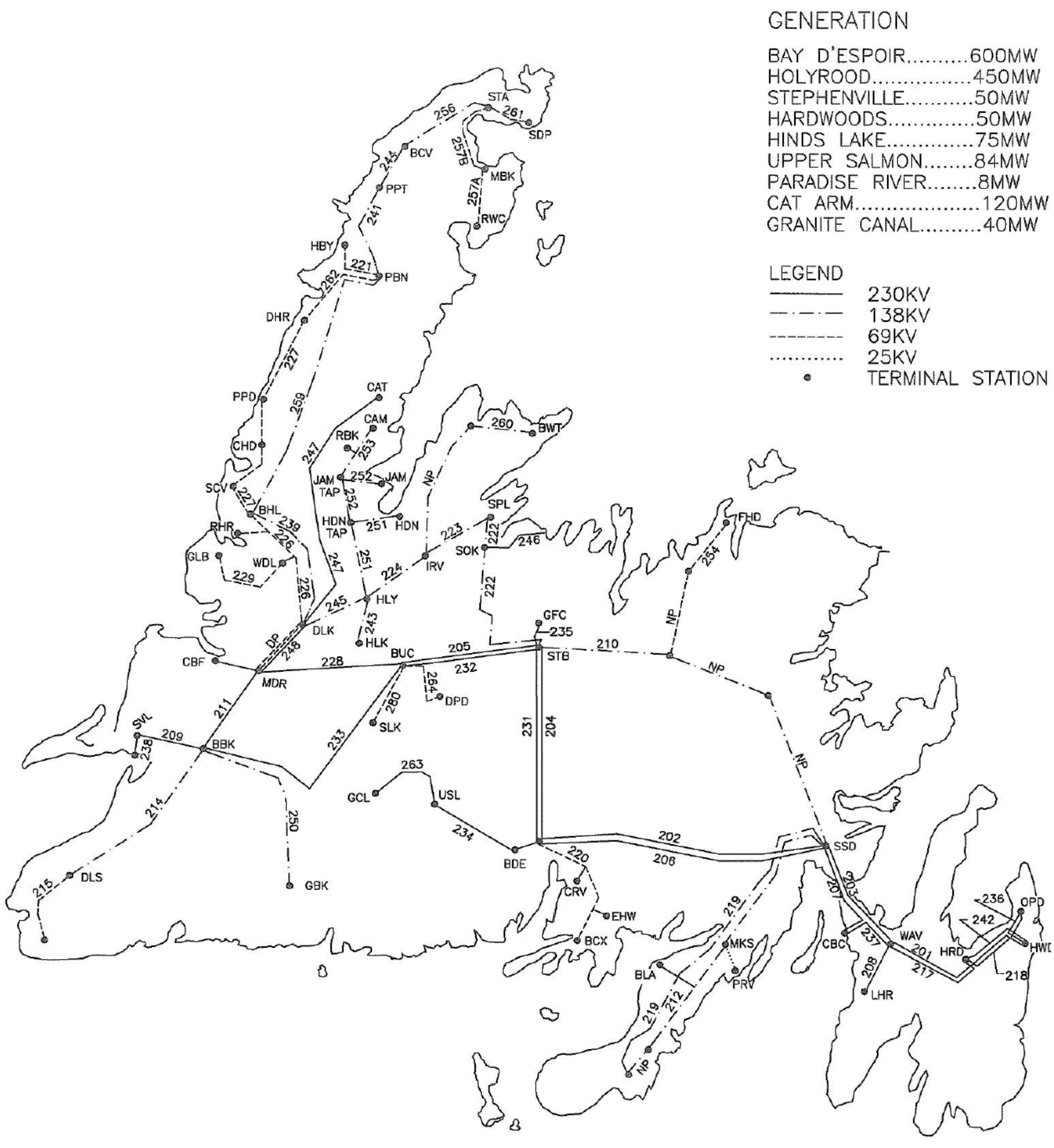
1	No significant risk, and addressed with existing readiness programs during time period. Not included in listings.
2	Possible but in most cases very unlikely issue in this timeframe. Well addressed by existing readiness programs.
3	Possible but in most cases very unlikely issue in this timeframe. Well addressed by existing readiness programs, but some enhancement may be desirable.
4	Possible issue in this timeframe. Addressed by existing readiness programs, but some immediate enhancements strongly recommended.
5	Significant issue in this timeframe. Inadequately addressed by existing readiness programs. Immediate enhancement is critical.

At this stage in time there is little further action that can be taken to eliminate the risks. Feasible actions are primarily of a monitoring nature so as to minimize the impact and the duration of any event that does/may occur.

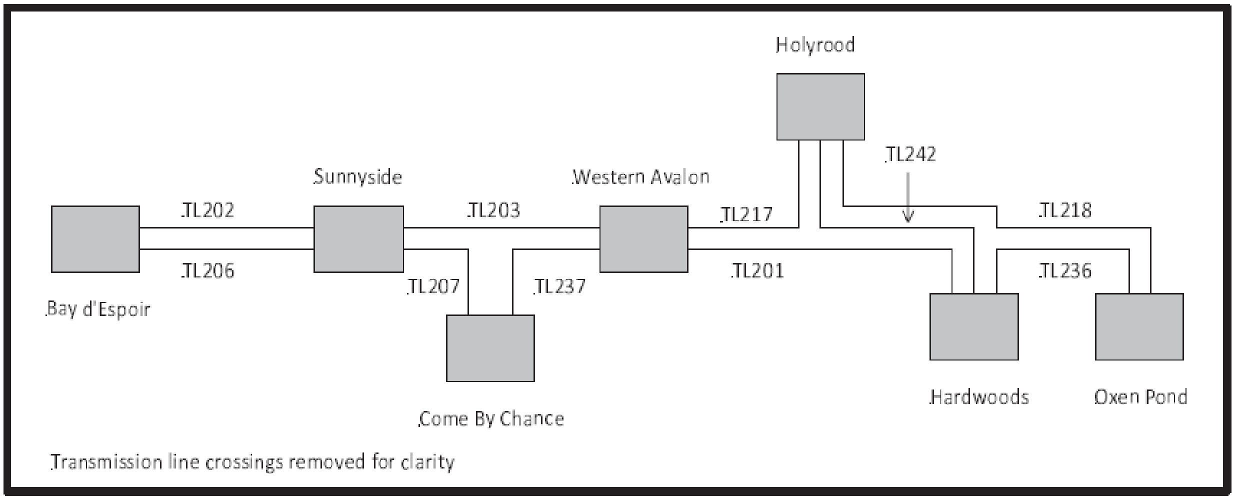
Item	2013/14 Winter Peak Period Consequence	Likely Duration	Spare/Redundancy Available	Critical 2013 PM's, Inspections, Tests & Capital projects Done	2013/2014 Winter Peak Period Likelihood	2013 Mitigation	2013/14 Readiness 1 to 5 1 is Highest
Control Structures/Spillways/Gates Icing/Failure	155 MW Loss	1-4 wks	Limited	Yes	EL	Mtce/Monitor	1
Generator Failure (Modest)	155 MW Loss	1- 4 wks	Spare windings, parts available	Yes	EL	Vib/PD/Other Monitors; Ops Monitor; Mtce Readiness	2
Generator Failure (Major)	155 MW Loss	Months	Limited	Yes	EL	Vib/PD/Other Monitors; Ops Monitor; Mtce Readiness	1
Turbine wicket gates	155 MW Loss	1-2 Mos	Spares/parts available	Yes	EL	Vib//Other Monitors; Ops Monitor; Mtce Readiness	1
Turbine runners/penstocks/tailrace	155 MW Loss	Wks to Mos	Limited	Yes	EL	Vib/Other Monitors; Ops Monitor;	1
Exciter System (transformer; electronics, etc.)	155 MW Loss	1-2 wks	Spares/parts available	Yes	EL	Vib//Other Monitors; Ops Monitor; Mtce Readiness	1
Governor System (governor, oil system, flywheel, electronics, etc.)	155 MW Loss	1-2 wks	Spares/parts available/Mtce expertise	Yes	EL	Vib//Other Monitors; Ops Monitor; Mtce Readiness	1
Cooling Water Supply	155 MW Loss	0-2 wks	Redundancy, spares, interconnection	Yes	EL	Ops monitor	1
Compressed air system – compressor failure	155 MW Loss	2-4 wks	Redundancy	Yes	EL	Ops monitor	1
Unit Power Transformer Fire/Explosion	155 MW Loss	12-24 Mos	None	Yes	EL	Thermography; DGA monitoring; Ops Monitor	1
Unit Power Transformer Bushing Failure	155 MW Loss	1-2 Mos	Parts	Yes	EL	Thermography; DGA monitoring; Ops Monitor	2
P&C Failures (Relays)	155 MW Loss	0 to 1 wk	Spares	Yes	VL	Mtce/Monitor	2
Lube & Governor Oil Systems – /Fire	155 MW Loss	1 to 4 wk	Spares	Yes	EL	Mtce/Monitor	2
Fire Detection and Suppression System Failure	155 MW Loss	0 to Many Months	Spare/Emergency Fire Water Pump system	Yes	EL	Ops monitor and testing	3
Powerhouse Structure	155 MW Loss	0 to many months	None	Yes	EL	Ops monitor	1
13.8kV Station Service system	155 MW Loss	1 month	Redundant Supply	Yes	EL	Ops Monitor	1
Overall		**0 to Many Months**	**Limited Spares and/or redundancy particularly for most critical major equipment**	Yes	**EL to VL**		**1**

Note: It should be noted that the item "Fire Detection and Suppression System Failure" is identified as a "3" in terms of "readiness". It does however require two events to occur simultaneously and is considered to have an EL likelihood of occurring, but if it were to occur the impacts could be significant. Given the existing equipment and programs, there is little more that could be done to mitigate this other than increasing the frequency of system monitoring and testing.

3.2 Terminal Stations/Switchyards from Bay d'Espoir to Oxen Pond inclusive



DRAWN BY: J.T.	REVISED BY:D.R.	NEWFOUNDLAND AND LABRADOR HYDRO	DWG NO 100-3
APPROVED BY: C.Q.		SYSTEM OPERATING DIAGRAMS	REV NO
DATE: 2008/02/04		STATION LOCATION	7



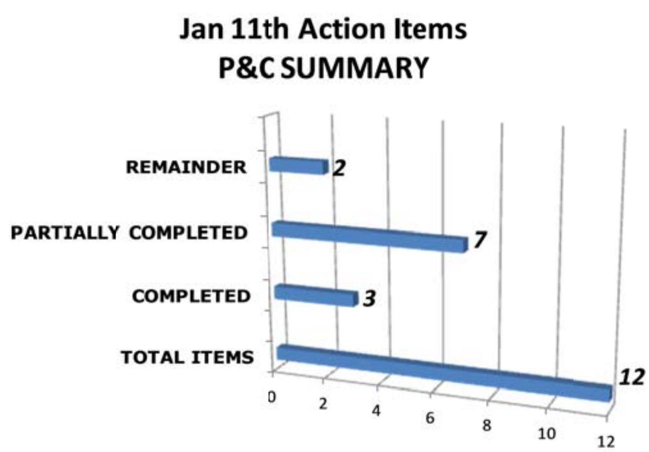
3.2.1 Transmission & Rural Operations Terminal Station Program

3.2.1.1 TRO Interviews

Blair Seckington and Trevor Arbuckle met at TRO's office in Bishop's Falls with Hughie Ireland (Long Term Asset Planning Manager), Rob Cater (Manager, TRO Central Region), Gary Broderick (Superintendent – Generation & Terminals), Scott Slade (Supervisor – Short Term Work Planning TRO Central) and Blane Piercey.

3.2.1.2 Facility Maintenance and Winter Readiness Overview

TRO have established a process to resolve P&C system issues associated with the January 11, 2013 system failure. They produced a prioritized list of work to be done to correct/enhance the protection and control systems in the TRO system. The status of the highest priority is summarized as follows:



The remaining highest priority (Priority A) items are as follows:

Action Items - January 11, 2013 Report - Highest Priority
05-Sep-13
TRO P&C Items

Updated: 9 Dec 2013

Action #	Action	Priority/Target Date	Updates
	PRIORITY A		
23	The lockouts from Unit 1 and 2 which trip the unit breakers, should be added into the Holyrood breaker fail scheme design of the terminal station for the required breakers. A review of all breaker fail designs schemes on the system should be conducted to ensure that all schemes are adequate, in that they have the correct initiating inputs such as the lockouts, and trip the required breakers in the event of a breaker failure.	End of June 2014	**Status:** from the initial review, existing circuits are not adequate for the modifications. Additional relays are required to be purchased. More detailed investigation is required to determine what additional relays are required. This is one of the tasks that Jeffrey will investigate. **Oct. 2 Update:** Extra investigation is expected to be completed by Oct. 11. Order devices and discussion with Operations on the schedule and outage issues are required. **Oct. 3 Update:** Estimation by TRO Central (Conference call with Gary Broderick, Ryan Steele, Derrick King, Barry Wellman & Rodney Champion on Oct. 3)- Two Scenarios were discussed. **1.** If no extra hardware is required. Field installation and commisioning will be completed by the end of December, 2013, assuming that the Unit outages are approved. **2.** If extra hardware is required. Field work will not be completed until the end of June, 2014. **Nov. 12 Update:** It has been decided not to pursue #1 above, but ensure the solution is a standard design. This requires new cable from plant to the TS bldg. **Dec 9 Update:** No change in status.
25	The application of appropriate settings for the load encroachment feature on all SEL 321 relays should be done to prevent operation during off-frequency events. A review of SEL's final recommendation report (pending) should also be carried out. A setting of 100 ohms primary for all lines is recommended based on the protection settings for the longest line on the system, TL206. This setting will accommodate a load of 529 MVA before blocking. The angles settings are PLAF=90, NLAF=-90, PLAR=90, NLAR=270. This approach is preferred over the setting of the 50PP1 current monitor as it is independent of minimum fault levels.	End of Nov 2013	Status: There are around 25 230kV lines in our island system. In order to implement the changes, we need to change around 40 relay settings and the field personnel needs to enter the new settings. The plan is to issue several settings at a time to each area. I expect we will issue all the changes before the end of this year. However, I am not sure if the field personnel can implement all changes this year. Oct.2 Update: Settings will be done by Alex and they will be sent in 4 groups. First group will be done on Oct. 11. Second group will be due on Oct. 18. Third group is scheduled on Oct. 25 and the last group is targeted on Nov. 1. Oct. 3 Update: Estimation by TRO Central - relay settings revision and verification will be completed by November 30, 2014. Dec 9 Update: P&C Central - COMPLETED; P&C West - COMPLETED; P&C East - NOT Completed
27	The Zone 2 protection reaches on TL218, TL242 and TL217 need to be increased to ensure that they operate for faults at the remote terminal end. The second zone timers for TL218 and TL242 should also be decreased from 60 cycles to 18 cycles.	End of Nov 2013	Status: (Oct.2) Setting changes will be done by Alex and will be incorporated with the task #25 (see above) i.e. completed by Nov. 1. Oct. 3 Update: Estimation by TRO Central - relay settings revised and verified will be completed by November 30, 2014. Dec 9 Update: P&C Central - COMPLETED; P&C West - COMPLETED; P&C East - NOT Completed
30	The Zone 1 distance protection settings on TL218 and TL242 (presently set at 88% and 82% of line lengths, respectively) should be decreased to a suitable level. A maximum 75% setting is recommended to ensure the protection does not overreach as occurred during these events. Previous studies have recommended a maximum setting of 80%.	End of Nov 2013	**Status: (Oct.2)** Setting changes will be done by Alex and will be incorporated with the task #25 (see above) i.e. completed by Nov. 1. **Oct. 3 Update:** Estimation by TRO Central - relay settings revised and verified will be completed by November 30, 2014. **Dec 9 Update: P&C Central - COMPLETED; P&C West - COMPLETED; P&C East - NOT Completed**
32	The recommended firmware upgrades should be implemented in the LPRO2100 relays. Testing should be done on the relays following the firmware upgrades to verify that the relays will no longer operate for these events. This can be performed by testing the relays with the file captured on January 11 as the input to control the test set.	End of Nov 2013	Status: The relay manufacturer was contacted. The new firmware was received. An e-mail has been sent to associated asset/field/planning personnel for scheduling upgrading the relays. Since all the upgraded relays (around 11 relays) are needed to be re-calibrated and re-entering the settings, I would expect that the whole process will take some time to complete. Oct. 3 Update: Estimation by TRO Central - relay firmware and settings verification will be completed by November 30, 2014. Note: time investigating on how to "performing testing the relays with the file captured on January 11 as the input to control the test set" is required as this hasn't been done before. Dec 9 Update: P&C Central - COMPLETED; P&C West - COMPLETED; P&C East - NOT Completed
35	Further investigation into the tripping of TL236 at Oxen Pond should be conducted to ensure that the permissive overreaching logic is working properly on the P2 protection (SEL) relays. This protection tripped the Oxen Pond end during the 0742 hour event (trip of TL201). This was a nuisance trip of little significance at the time but could result in something of consequence in the future.	End of Nov 2013	Status: TRO – Clif - This has to be completed before #25 is completed… Dec 9 Update: P&C Central - COMPLETED; P&C West - COMPLETED;P&C East - NOT Completed
37	A timer should be added to extend the duration of the transfer trip signal from the STB TL235 protection which picks up the 85X at GFL FRC and provides for a direct trip of the three low side breakers 252T-1, 252T-2 and 252T-3 at GFL FRC.	End of Nov 2013	**Status: (Oct. 2)** James Nugent of P&C will look at this. Timer is required to be picked and ordered. It is possible that Telecontrol can implement this at their end. **Oct. 3 Update:** Estimation by TRO Central - If timer is available by the mid-Nov, field installation and commissioning will be completed by the end of December, 2013. **Dec 9 Update:** Investigation on the pulse width from NWS system (ie transfer trip signal) into GGFFC system has shown its NOT long enough. The pulse for this signal will have to be increased by NWS - planned to be done by Jan 2014.
40	Consideration should be given to timer setting changes for the Come By Chance capacitor banks in order to stagger the tripping of the banks for the first level (110%) overvoltage trip. Currently all banks have 10 cycle trip timers. These could be changed to 10, 20, 30 and 40 cycles for banks C1, C2, C3 and C4, respectively, or some other suitable times.	End of Nov 2013	Status: (Oct.2) Setting changes will be done by Alex and will be incorporated with the task #25 (see above) i.e. completed by Nov. 1. Oct. 3 Update: Estimation by TRO Central - relay settings revised and verified will be completed by November 30, 2014. Dec 9 Update: No change in status.
41	Timers should be installed in the control circuits of the Come by Chance capacitor banks to block closure until at least five minutes have elapsed from the time of breaker opening. This would allow for the manufacturer's recommended discharge time.	End of Nov 2013	Status: Consultation with the Capacitor/Breaker manufacturer has been established. Several design options have been evaluated and a final option recommended by the manufacturer has been selected. We are in the process of selecting an appropriate timer. I need to communicate with asset people to have a work order cut for purchasing material and schedule the circuit modifications. Breaker outages are required for the work. Oct. 3 Update: Estimation by TRO Central – Installation and commissioning of the modification circuits will not be done until the end of April, 2014. However, according to TRO Central, there are some temporary measures in place. Operations has tag on the breakers and ECC has their procedure on these breakers as well. Dec 9 Update: No change in status.

TRO have also brainstormed issues for continuous improvement of their overall P&C system logic/configurations. It has resulted in a preliminary prioritized list of potential work that should be further evaluated and where warranted undertaken to correct/enhance the protection and control systems in the TRO system. As an example of the outcome of this process, the highest priority including locations and preliminary target completion dates is summarized below. Most could not be assessed and undertaken for winter readiness 2013/14.

No.	LOCATION	SHORT TERM	STATUS	Revised Target Date
1	BDE	Sync setting for TL206 (40° SSD vs 30° BDE) and TL202. ECC cannot close TL202 or TL206 at BDE with other line in & heavily loaded & SSD closed in first. They can close in at SSD with BDE end closed in first. SSD = 40° closing angle & BDE is at 30°. Would need 3 MAVS at BDE changed to 40° (TS2, TS1,&G7)	**9 Dec Update:** Need Cut sheet entered for Engineering assistance.	Dec 2014
2	BDE	L06L34 Locking out (Order replacement timer & press. Sw. to replace/test). L06L34 at BDE has been looking out for loss of N2, each time we have had a line fault on TL206. SIEMENS recommends changing pressure guage & contacts. (B2) & the timer that runs the hydraulic pump. (k15). N2 has been tested to be ok, and we could not duplicate lockout after many attempts.	**9 Dec Update:** Materials now setup in warehouse. Schedule to complete the installation early in 2014.	Dec 2014
3	BDE	TL206 Optimho input from breakers - needs investigating. (Input opened). This is currently removed based upon a note from Chris Walsh. Switch onto fault feature may not operate correctly. Optimho input consists of 2 breaker inputs in series. The two breaker inputs are derived from the 2-3Ø conversion cct. In each breaker. Relay would be told that all breakers were open when it could be only 2-phases open...Input could be derived from the Red light circuit...ie. only operates when all poles are open, if this is the requirement for the optimho.	**9 Dec Update:** Need Cut sheet entered for Engineering assistance.	Dec 2014
4	BDE	TL202 SEL 321 input from breakers - needs investigating. SEL321 inputs from most if not all breakers is derived from 'any pole open' which is a 52B across the green light. SEL literature indicates that if using only one input vs 3Ø input, the other two follows the single input ie. if it sees 1 pole open it assumes 3 pole open. Is this ok?	**9 Dec Update:** Need Cut sheet entered for Engineering assistance.	Dec 2014
12	HWDTS	CT's on B9 leaking. HWD B9 CT One is leaking, and new ones are too high to fit in same location. Structure needs modification.	**9 Dec Update:** Temporary Design near complete - Schedule to install as soon as Design completed.	Mar 2014
14	CBCTS	Annuciator failing quite aften...loses programming and fails. No idication of Annuc failed.	LTAP to investigate issue.	Dec 2014
26	HRDTS	B15T7 Disconnect burnt	**9 Dec Update:** Waiting to be schedule.	Apr 2013
28	WAV	B1B3 check out disagreement circuit and test - See W/O #327012. WAV B1B3 - Check what is problem - time, etc...ftn test.	**9 Dec Update:** Need to be scheduled.	Jun 2014
29	VARIOUS STATIONS:	Bkr fail monitors - Check for dropout/sticking & clean armature and contacts of RX1L if applicable. Check BCD 94X for retention. See Breaker Fail review sheets.	**9 Dec Update:** BF Current Monitors Function testing are being planned, schedule with a number of them completd in BDE TS .	Jan 2014 In all areas.
31	VARIOUS STATIONS:	Diodes in prot. & B. fail ccts .... Check for short/open Bkr fail and Optimho ccts re: TT. Diodes - check using diode Check ftn. on multimeter. Remove DC.	**9 Dec Update:** Not completed.. W/O to be created to capture the stations, bus, and areas so it will be easier to track.	Apr 2014
32	VARIOUS STATIONS:	Review breakers that are common to BUS/Trf & Lines for timing of Bkr Fail vs. disagreement vs. reclose time. (TL209 SVL...WAV-CBC-SSD-)(USL).	**9 Dec Update:** Need to further discuss. Some are looked at and confirmed. (CQ notes)	Apr 2014
34	VARIOUS STATIONS:	Check jct. boxes for corrosion, fuse connections etc.	**9 Dec Update:** This is partially completed - there were 3-4 stations on east coast evaluated - waiting for confirmation from planner and supervisor. This can be scheduled during the terminal station inspection.	Dec 2014
35	VARIOUS STATIONS:	Replace pneumatic timers on lines that have Generation USL, CAT, HLK, review dwg for this. See e-mail CQ-HI Sept. 19, 2007. (62, 62A,B etc...) Re: pneumatic timers...focus on timers that need to be accurate and repeatable and where timing is critical. 62 A/B eg. on TL protection	**9 Dec Update:** Review of the scope of this project hasn't been finalized.	Sept 2014
39	VARIOUS STATIONS:	Henville report re: setting changes to SSD/CBC/WAV & Stns. East . ACW supports this.		

TRO have also undertaken some initial brainstorming on potential breaker failure protection issues for the stations considered in this study. The following tables present some of the equipment at various sites and some notes on potential protection issues that are relevant to this assessment, but for which a detailed assessment and potential resulting actions are unlikely to be able to be addressed for winter readiness 2013/14.

Breaker Fail Protection √ = Yes				
Station	Diodes	BCD-BCD3	RX1L IMon	Issues with Design
OPD- 230			√	
-66				
HWD- 230	√		√	
-66				√ See note 1
HRD 230,138,66		√		√ See note 2
WAV 230, 66	√		√	
138				√ See note 3
CBC				
BDE TS1	√		√	√ See note 4
BDE TS2			√	

Issues for Discussion B. Fail		
	Station	Issue
	All	No Xfer trips to remote line ends (Infeeds between bkrs.)
#1	HWD (Dwg 146)66kv	Npower 86 B9 should operate into Breaker Fail for B8B9 (Not in service).
#2	HRD #198	We don't send B. Fail trips to plant to trip gens…We trust Gen protection to pick up troubles. Problem could be out on TL…and Line Bkrs have to go to BU tripping, (Back up prot on trf…may sense….these do trip into plant gen prot.)Trf. Back-up protection sends trips to generator lockouts, so breaker fail trips could be paralleled onto these. 230 Bus L/0 B11B13, B12 and B15 do not go into TF B7T5, B6T10, and TF138 resp. Low side breakers are tripped by 230 Bus L/0 but not tried by B. Fail(that's the idea of BF) Low side breakers are only tripped if current still in High Side? All these have potential for infeed through low side breakers. TRF lockouts do not go to LS B-Fail. 86B6B7 should go to TF/B7T5, and TF/B6T10
#3	WAV 230	B Fail does not try to re-trip own bkr just adj…ok if initial trip is into TC1 & TC2 most stn's are this way. 86 B1 into B. Fail - 2 contacts into TF B1 & TF TL208 only. It should be into TFBIB3 & TFT1 & TFT2 also ,or have its own 86 BF/B1 & go from there. (Note…no B Fail on low side of T1 and T2) 86B4 should be brought in same as 86B3 into 86BFB1B3/TFB1B3
	138	138 B Fail is only initiated by 94L (64L)…it should be inititated for trf prot.trips also and B3 & B4 lockouts. (86T3, 86T4, and 86T5) and trip into a TC2 if available for B4L64 (OCB) (or at least try a re-trip…bad 94L contact eg.) Current monitors would have to be installed in TRF low side (T3, T4, T5).
	B1B2	TC2 is not used for prot. tripping…just disagreement only.
#4	BDE TS1	If 86 B1, 86B2,86B3 operate…we will not do anything B. Fail wise to help out Gen Breakers. If Gen prot operates…B Fail will trip BUS prot if current still flows in Gen Breaker but when BUS L/O operates, we don't send trips to Gen protection. (HRD same) BUS Lockouts B1,B2,B3 should come into 94BFG1,2, & 3,4 & 5,6 respectively and the 94 BF relays have contacts to Gen prot. (Bkrs)*BDE TS2...we do send trips to G7 prot from Breaker Fail in TS2.

<u>2013 PM Work</u>

The following illustrates the PM work undertaken at the various Terminal Stations in this review. It is indicative that critical planned 2013 PM work has been completed.

782148 OPDTS B2B3 CTS CT DOBLE PM APR 20,13.PDF.pdf
886185,HWDGT BATTERY PM MAINT JAN 08, 13.PDF
890348 CBCTS BATTERY PM MAINT JUN 25,13.PDF.pdf
908555 HWDGT OSPEED PROT ANNUAL PM APR 01,13.PDF.pdf
919489 WAVTS TL201 APH PT DOBLE PM OCT. 09,13.pdf
919490 WAVTS TL201 BHP PT DOBLE PM OCT. 09,13.pdf
919491 WAVTS TL201 CPH PT DOBLE PM OCT. 09,13.pdf
931616, BDETS1, T6, XFMR PM MTNCE, OCT 13, 13.pdf
941180 HWDGT ANNUAL PM CHECKS FEB 18,13.PDF.pdf
955066 HWDGT AIR SYSTEM ANN PM MAINT JAN. 24, 13.PDF.pdf
955103 SSDTS BATTERY PM MAINT FEB. 11,13.PDF.pdf
955546 HWDGT FIRE EXT ANN PM MAINT JAN 16, 13.PDF
955580,SSDTS AIR SYS ANN PM MAINT JAN 09 13.PDF
955581 HRDTS AIR SYS ANNUAL PM JAN 17 13.PDF
956084, HWDTS AIR SYSTEM ANN PM MAINT, JAN 21,13.PDF
956087 OPDTS AIR SYS ANN PM MAINT JAN 15 13.PDF
956090 WAVTS AIR SYS ANN PM MAINT JAN 08 13.PDF
956486 OPDTS BATTERY PM MAINT JAN 12, 13.PDF
956499, HWDGT,BATTERY PM MAINT JAN 09 13.PDF
959816 HRDTS B12L17 BREAKER PM MTNCE OCT. 05,13.pdf
963994 HRDTS B1L17 BREAKER PM MTNCE APR 07,13.PDF.pdf
965601 WAVTS BATTERY PM MAINT. JUN 27,13.PDF.pdf
967577 HRDTS B1B11 BREAKER PM MAINT, APR. 05,13.PDF.pdf
972343 HRDTS T1 XFMR PM MTNCE JUL 02,13.PDF.pdf
974927 HRDTS T1 TRF DOBLE PM JUL 11,13.PDF.pdf
975808 HWDTS AIR SYS ULTRA SOUND ANNUAL APR05,13.PDF.pdf
975809 OPDTS AIR SYS ULTRA SOUND ANNUAL APR. 04,13.PDF.pdf
977858 HWDTS T5 TRF DOBLE PM JUL 04,13.PDF.pdf
979288, BDETS1, B2T4 BREAKER PM MTNCE, APR 29, 13.pdf
979291, BDETS1, T4, XFMR PM MTNCE, APR 26, 13.pdf
979485 SSDTS TL202 PTS DOBLE PM APR 24,13.PDF.pdf
980267 HWDTS TL236 230KV LINE DISC PM JUN26,13.PDF.pdf
980269 HWDTS TL236 A PH PT DOBLE PM JUN 12,13.PDF.pdf
980270 HWDTS TL236 B PH PT DOBLE PM JUN 12,13.PDF.pdf
980271 HWDTS TL236 C PH PT DOBLE PM JUN 12,13.PDF.pdf
980277 OPDTS TL236 LINE DISC PM JUNE 18,13.PDF.pdf
980278 OPDTS B1L36 CTS CT DOBLE PM JUN 10,13.PDF.pdf
980279 OPDTS TL236 PT DOBLE PM JUN 10,13.PDF.pdf
986278 WAVTS, B4L64 AIR SYS MTNCE JUN 05,13.PDF.pdf
987616 HWDTS B8B9 AIR SYS MTNCE JUN 16,13.PDF.pdf
990289 HWDTS B1 B PH PT DOBLE PM OCT. 09,13.pdf
991218, BDETS1, T1, XFMR PM MTNCE, AUG 15, 2013.pdf
993125 HWDTS T2 TRF DOBLE PM JUL 17,13.PDF.pdf
993127 HWDTS T2 PT DOBLE PM JUL 17,13.PDF.pdf
997136 HRDTS B3L18 BREAKER PM MTNCE SEPT. 01,13.pdf
999728 HRDTS B3B13 BREAKER PM MTNCE SEPT 01,13.pdf
1005366 HRDTS B1T1 DISC PM OCT. 06,13.pdf
1007362 HWDS TL201 PT B PH DOBLE PM OCT. 08,13.pdf
1007363 HWDS TL201 PT A PHASE DOBLE PM OCT. 08,13.pdf
1007365 HWDS TL201 PT C PH DOBLE PM OCT. 08,13.pdf
1009084 WAVTS T1 TRF DOBLE PM OCT. 20,13.pdf

It was indicated during the site visit at the TRO office that the critical PM's scheduled for 2013 have been completed.

TRO Thermography (Guidelines are as follows):

"When performing thermovision checks of Newfoundland & Labrador Hydro Terminal Stations, the severity of a hot spot depends on other factors such as ambient temperature and loading and not solely on the temperature of the object above reference. Each case must be reviewed by the operator and management personnel to assign the level of response required. Once the level of response has been assigned the following guidelines will be used to determine the required response time.

Priority	Temp. Difference (ΔT Phase to Phase)	Respond Within
1 (Emergency)	Visually Hot	24 hours
2	Above 50^{o}C	1 week
3	20^{0}C to 50^{o}C	1 month
4	Below 20^{0}C	1 year

When hot spots are identified as per the above guidelines it should be discussed immediately with the Asset Manager or delegate to determine an action plan depending on outage availability, customers affected, and resources."

3.2.2 Bay d'Espoir Terminal Station

3.2.2.1 Facility Overview

Two terminal stations make up the Terminal Station facility at Bay d'Espoir - Terminal Station #2 associated with Bay d'Espoir Phase 2 (i.e Unit 7) and Terminal Station #1 associated with Bay d'Espoir Phase 1 (i.e Units 1 to 6)

BDE TS#1 has two 230 kV lines has two lines (TL 204, TL 231) to Stony Brook; a 230kV link to Bus 10 in BDE TS#2, and a 230kV line (TL202) to Sunnyside TS.

BDE TS #2 has a 230kV line (TL234) to Upper Salmon; a 230kV line (TL206) to Sunnyside TS, one 230kV line to Bus 10 in BDE TS#1; a 69kV line (TL220) to Conne River Tap/English Harbour West/Barachox; two 25kV lines to St Albans (L1) and to its Intake (L2), and a 600V line to Powerhouse #1 station service

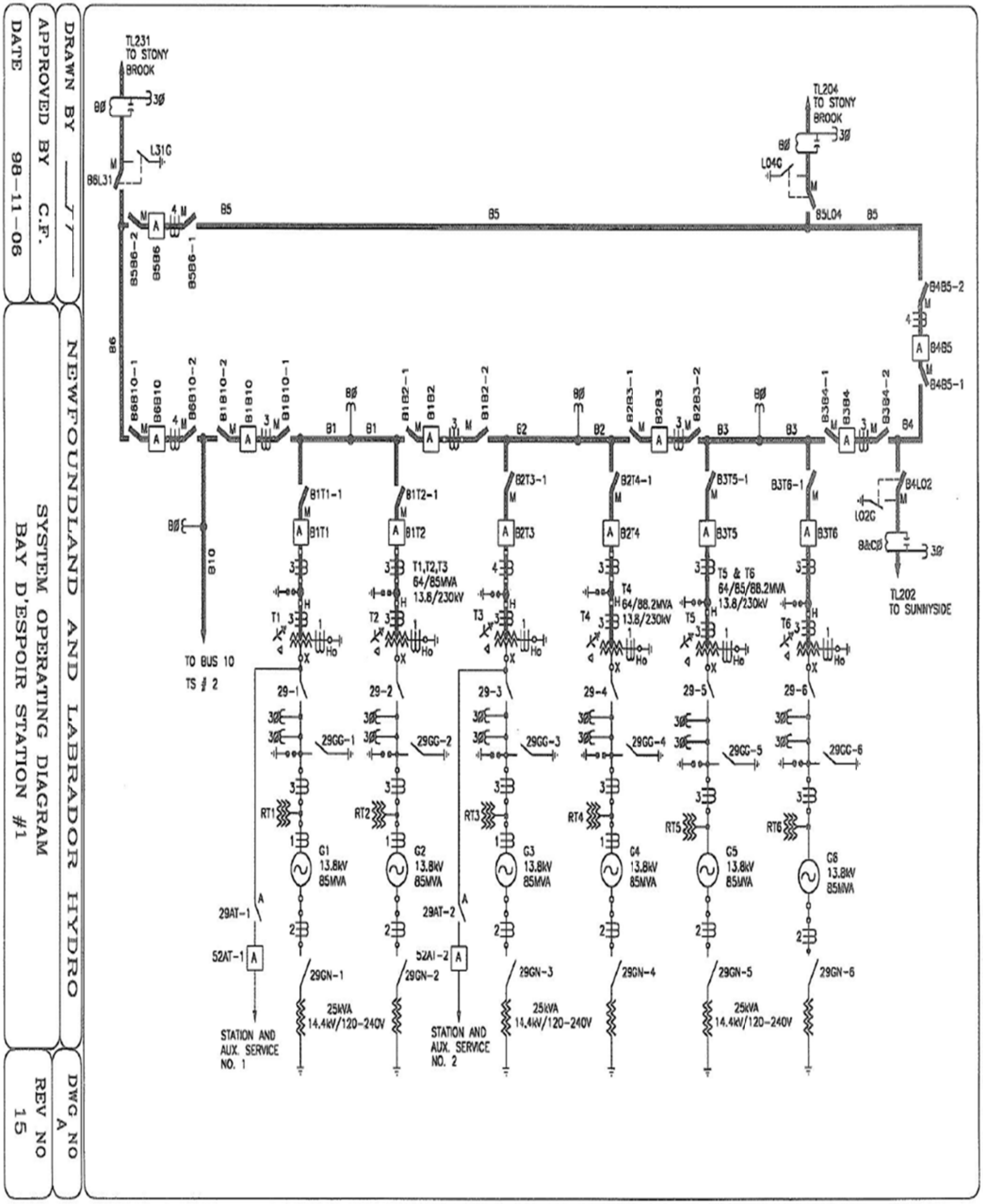
The Bay d'Espoir TS#1 includes:

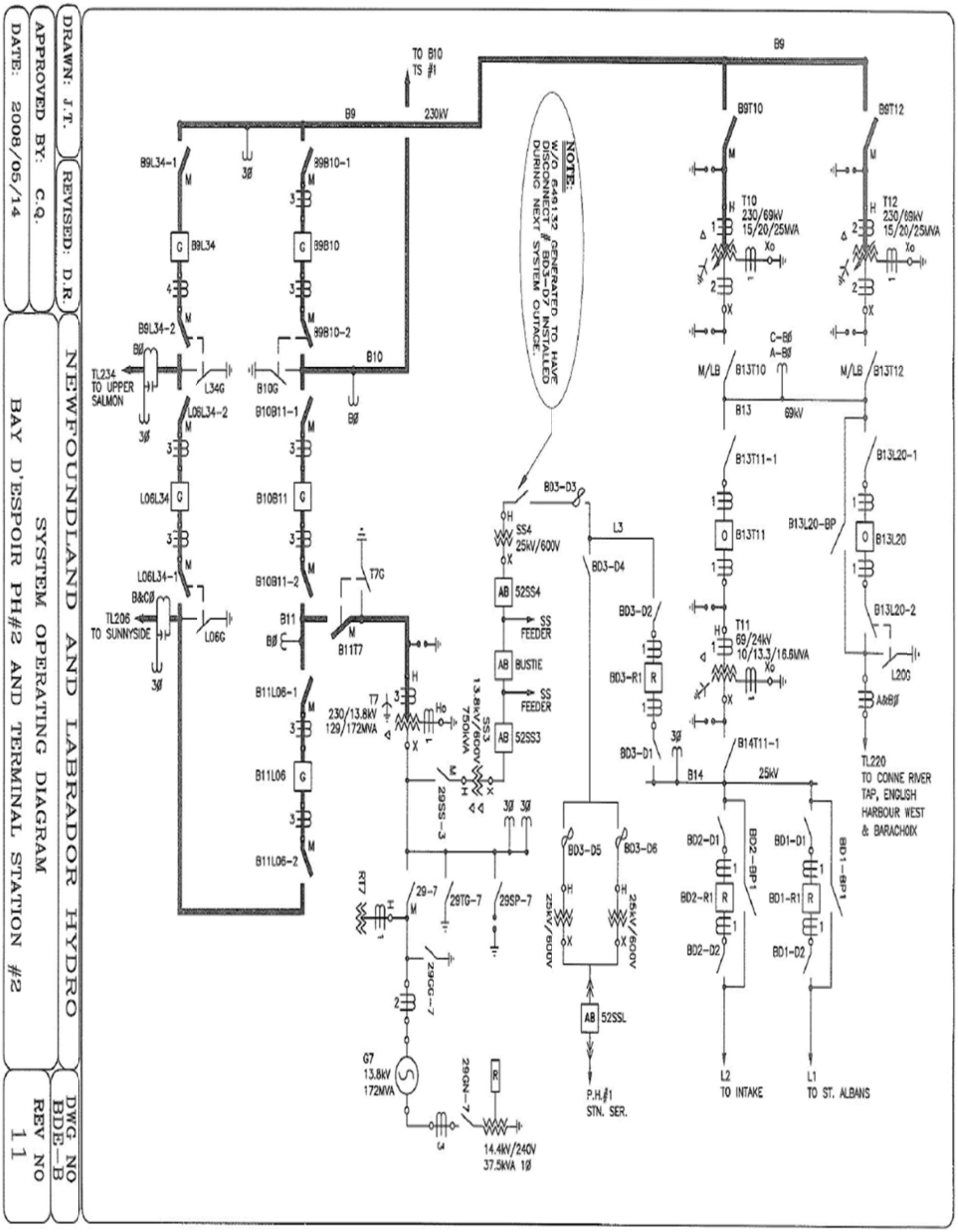
- two 230 kV lines has two lines (TL 204, TL 231) to Stony Brook; a 230kV link to Bus 10 in BDE TS#2, and a 230kV line (TL202) to Sunnyside TS
- 230kV ring bus (B1, B2, B3, B4, B5, B6 ring arrangement)
  - Thirteen 230kV air blast breakers associated with 230kV busses
  - Twenty-three 230kV disconnects – overhauled/replaced as required
  - Associated 230kV PT's, CT's , Grounds
- Three 13.8kV (64/85MVA) transformers (T1, T2, T3) associated with G1, G2, G3
- One 13.8kV (64/88.2MVA) transformers (T4) associated with G4
- Two 13.8kV (64/85/88.2MVA) transformers (T5, T6) associated with G5, G6
- Six 13.8 disconnects associated with T1 to T6
- Six 14.4kV/120-240V unit station service transformers
- Two 13.8 air circuit breakers and disconnects associated station and auxiliary service #1 and #2 from T1 and T3

The Bay d'Espoir TS#2 includes:

- a 230kV line (TL234) to Upper Salmon; a 230kV line (TL206) to Sunnyside TS, one 230kV line to Bus 10 in BDE TS#1; a 69kV line (TL220) to Conne River Tap/English Harbour West/Barachox; two 25kV lines to St Albans)L1) and to its Intake (L2), and a 600V line to Powerhouse #1 station service
- 230kV busses (B9, B10, B11)
- Five 230kV SF6 breakers associated with 230kV busses
- Thirteen 230kV disconnects – overhauled/replaced as required
- Associated 230kV PT's, CT's , Grounds disconnects
- One 230/13.8kV (129/172MVA) transformer from G7 (T7),
- Two 230/69kV (15/20/25MVA) transformers(T10, T11)
- One 13.8kV/600V 750kVA station service transformer (SS3) and associated disconnects, PT's CT's, grounds
- Six 69kV disconnects
- Two 69kV oil circuit breakers
- One 69/25kV transformer (10/13.3/16.6MVA) T11
- Ten 25kV disconnects

Single lines of the terminal station are presented in the following two figures.


NEWFOUNDLAND AND LABRADOR HYDRO
SYSTEM OPERATING DIAGRAM
BAY D'ESPOIR STATION #1
DRAWN BY
APPROVED BY C.F.
DATE 98-11-06
DWG NO A
REV NO 15
TL231 TO STONY BROOK
TL204 TO STONY BROOK
TL202 TO SUNNYSIDE
TO BUS 10 TS # 2
T1,T2,T3 64/85MVA 13.8/230kV
T4 64/88.2MVA 13.8/230kV
T5 & T6 64/85/88.2MVA 13.8/230kV
G1 13.8kV 85MVA
G2 13.8kV 85MVA
G3 13.8kV 85MVA
G4 13.8kV 85MVA
G5 13.8kV 85MVA
G6 13.8kV 85MVA
25kVA 14.4kV/120-240V
STATION AND AUX. SERVICE NO. 1
STATION AND AUX. SERVICE NO. 2


DRAWN: J.T.
APPROVED BY: C.Q.
DATE: 2008/05/14
REVISED: D.R.
NEWFOUNDLAND AND LABRADOR HYDRO
SYSTEM OPERATING DIAGRAM
BAY D'ESPOIR PH#2 AND TERMINAL STATION #2
DWG NO BDE-B
REV NO 11
NOTE: W/O 646132 GENERATED TO HAVE DISCONNECT # BD3-D7 INSTALLED DURING NEXT SYSTEM OUTAGE.
TO B10 TS #1
B9
230kV
B10
B11
B13
69kV
B14
25kV
L3
TL234 TO UPPER SALMON
TL206 TO SUNNYSIDE
TL220 TO CONNE RIVER TAP, ENGLISH HARBOUR WEST & BARACHOIX
T10 230/69kV 15/20/25MVA
T12 230/69kV 15/20/25MVA
T11 69/24kV 10/13.3/16.6MVA
T7 230/13.8kV 129/172MVA
G7 13.8kV 172MVA
SS4 25kV/600V
SS3 13.8kV/600V 750kVA
14.4kV/240V 37.5kVA 1Ø
L2 TO INTAKE
L1 TO ST. ALBANS
P.H.#1 STN. SER.

3.2.2.2 Pre-Visit Information Review

Information had been received on recent Bay d'Espoir transformer testing (DGA, Fluid condition, Water in Oil, Furan analysis).

- T1 (64 MVA - 1992), T2 (64 MVA - 1966), T3 (64 MVA - 1967), T4 (64 MVA - 1968), T5 (64 MW – 1968), T6 (64 MW -1969), T7 (129 MVA - 1977)

All had been tested in 2013 and were considered to be in reasonable condition to operate over the 2013/14 winter. Units T1, T3, and T7 were identified in PM write-ups by technicians to be redone again in 2013 due to moderately high acetylene/CO DGA values or Furan values. It is not clear from available information if this occurred.

3.2.2.3 Facility Walkdown/Thermography

Thermography had previously been done by TRO in 2013 and no hot spots found. For this project, thermography was undertaken by TRO staff using their handheld infrared cameras with direction/documentation by David Jones of AMEC.

1.2 Conditions: Windy. Temperature -5°C, Wind Chill -10°C to -12°C

1.3 Loads at times of imagery.

- T1 65MW.
- T2 58MW.
- T3 58MW.
- T4 57MW.
- T5 59MW.
- T6 58MW.

1.4 Bay D'Espoir Asset Priority Chart (Images 175 through 280)

Asset Description	Image Identity	Priority	Comments
		1 and 2	No propriety 1 or 2 found
		3	No priority 3 found
		4	All Assets found in priority 4 with a question of the following
	177, 183, 213, 215, 224, 225, 252		177, 183, 213, 215, 224, 225, 252. Need to be re-done, some cross-hairs out of alignment.

3.2.2.4 Facility Maintenance and Winter Readiness Overview

Generally the key issues associated with this Terminal Station are addressed in Section 3.2.1 addressing general TRO conditions. The maintenance at the TS site does include:

- Operations daily inspections/data collection
- Extensive inspections before the winter period to allow for repairs

- Transformer testing yearly - DGA monitoring, Water in Oil monitoring;
- PM work (JD Edwards System) – annual and other period checks and repairs
- Corrective maintenance as required
- Capital refurbishments/enhancements

As noted critical PM and corrective work appear to have been completed or of lower priority that shouldn't impact winter 2013/14 reliability.

FM Global had identified in May 2013 some specific issues associated with the TS. They are not expected to be critical to 2013/14 performance, but could and may be in process of being resolved.

12-06-001 **Repair the oil leak on step-up Transformer T1.**

During the visit, for a third year, an active oil leak was found on this critical transformer. The leak is believed to originate at the top of the transformer.

The Hazard	Failures are relatively rare on a transformer. However, it will fail if the oil level becomes low, resulting in the expulsion of burning oil through the pressure relief device or rupture of the tank. The ensuing fire will be intense and may cause extensive damage to the adjacent equipment and electrical switchgear. The liquid level indication may be defective and give a false reading. Once the leaks have been fixed, the transformer should be cleaned of its leaked oil to ensure that any recurrence is noticed.
Status	Mr. Ireland indicated that the gasket and low-voltage bushing of the transformer were scheduled for replacement in 2013.

This work was planned to be completed in 2013. A tender was let for which Alstom was the low bidder. There were issues with the terms and conditions from Alstom and before that could be rectified, the outage window associated with T1 (which was coordinated with Unit 1 rewind) had passed. A subsequent request for an outage to complete this work was turned down by the Energy Control Centre due to system requirements. As a result, this work is now moved to 2014. The installation of new bushings and regasketing for both the HV and LV bushings on T1 (which will help with leak mitigation) were completed, but the overall leak repair which would include, repairing any leaks identified during a pressure test was not completed

11-06-003 **Reinstall missing spray nozzles for the outside step-up transformer's deluge fire protection.**

Part A. **Reinstall the missing nozzle for the Transformer No. 1 deluge system.**

Reinstall the missing spray nozzle for the Transformer No. 1 deluge sprinkler system. The missing nozzle is located under the east side radiator.

The Hazard	 **Missing Spray Nozzle on Transformer No. 1**

Reinstall the missing nozzle for the Transformer No. 4 deluge system.

Reinstall the missing spray nozzle for the Transformer No. 4 deluge sprinkler system. The missing nozzle is located under the south-side radiator.

The Hazard	 **Missing Nozzle Transformer No. 4**

This work has not been completed, but the spray nozzles are on order and will be done in the new year.

3.2.2.5 Facility Risk Assessment

Key risks are likely associated with i) unexpected failures of older equipment (bushings, electro-mechanical relays, disconnects), and ii) fire simultaneously with a fire suppression failure. TRO appears to have taken measures to mitigate against them as much as practical, subject to any remaining work discussed in Section 3.2.1. Suitable ongoing monitoring and adequate spares and resources are in place to address and respond to unexpected failures.

Generally, Bay d'Espoir TS appears to have no major issues identified aside from those identified in Section 3.2.1 which should interfere with reliable operation this winter.

- Critical 2013 PM's and planned 2013 capital and corrective work appear largely completed

- Transformer appears to be in good condition for this year
- No major hotspots identified

3.2.3 Sunnyside Terminal Station

3.2.3.1 Facility Overview

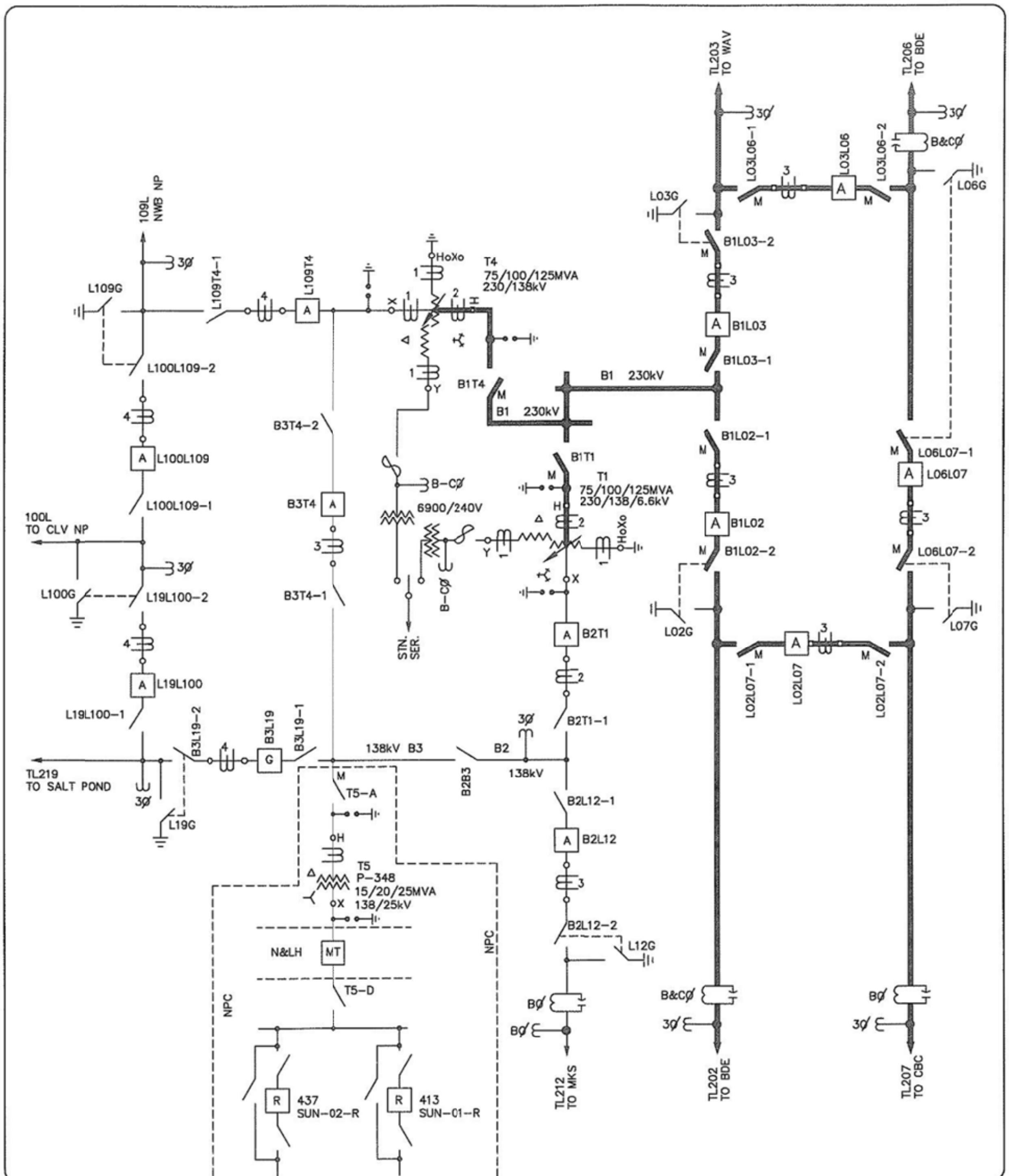
Sunnyside TS has 230 kV lines from Bay d'Espoir TS (BDE - TL202, TL206), and one 230 kV line each to Come-By Chance TS (CBC -TL207) and to Western Avalon (WAV - TL203). There is considerable flexibility from these to supply the Sunnyside 230 kV Bus (B).

Transformers T1 (230/138/6.6 kV – 75/100/125 MVA) and T4 (230/138kV – 75/100/125 MVA) are utilized to supply 138 kV supplies to Monkstown TS (TL212), Salt Pond (TL219), and several Newfoundland Power connections (100L to CLV NP, 109L NWB NP, T5138/25kV).

The switchyard equipment includes:

- Ten 230 kV disconnects for lines from BDE - TL202, TL206; CBC -TL207 and WAV - TL203
- Ten 230 kV disconnects B1T4, B1T1
- Five 230kV air blast breakers for lines from BDE - TL202, TL206; CBC -TL207 and WAV - TL203
- Two 230/138kV transformers T1 (230/138/6.6 kV – 75/100/125 MVA) and T4 (230/138kV – 75/100/125 MVA)
- Two 38 kV Busses
- Six 138kV air blast breakers
- One 138kV SF6 breaker B3L19
- Eighteen 138 kV disconnects
- Two 6.9kV/240V station service transformers
- Other equipment – CT's PT's, lightning arrestors
- Multiple spare breakers, disconnects, bushings

A single line of the terminal station follows.



DRAWN BY	D.R.	NEWFOUNDLAND AND LABRADOR HYDRO	DWG NO SSD-1
APPROVED BY	B. STOYLES	SYSTEM OPERATING DIAGRAM	REV NO
DATE	2008/01/30	SUNNYSIDE TERMINAL STATION	10

3.2.3.2 Pre-Visit Information

Information had been received on recent Sunnyside TS transformer testing (DGA, Fluid condition, Water in Oil, Furan analysis).

- T1 (125MVA - 1978), T2 (125 MVA – 1977)

Both had been tested in September 2013 and were considered to be in reasonable condition to operate over the 2013/14 winter. Both were identified in PM write-ups by technicians to be redone again in 2013 but it is not clear from available information if this occurred.

3.2.3.3 Facility Walkdown/Thermography

Thermography had previously been done by TRO in December 2012 and no hot spots found. For this project, thermography was undertaken by TRO staff using their handheld infrared cameras with direction/documentation by David Jones of AMEC.

5.2 Conditions: wind. Temperature: 0°C. Wind Chill: -8°C.

5.3 Loads at times of imagery:

- TL202 to Bay D'Espoir 200MW.
- TL203 to Western Avalon 159MW.
- TL206 to Bay D'Espoir 200MW.
- TL207 to Come-by-Chance 170MW.
- T1 30MW.
- T4 35MW.

Sunnyside Asset Priority Chart (Images 323 through 389)

Asset Description	Image Identity	Priority	Comments
		1 and 2	No priority 1 or 2 found
L02L07-1	326		Disconnect in bad state of repair. Disconnect and ground witch operator linkages have been removed. Switch is secured closed on all phases with rope.
L06L07-2	328	3	12.2°C on A phase. Jaw. Also on terminal away from CT.
B1L02-3	338	3	15.3°C on C phase. On outer Swivel.
B1L02-1	342	3	24.4°C on C phase. Jaw.
		4	All Assets other than 328, 338, 342 above found in priority 4.

3.2.3.4 Facility Maintenance and Winter Readiness Overview

Generally the key issues associated with this Terminal Station are addressed in Section 3.2.1 addressing general TRO conditions. The maintenance at the TS site does include:

- Operations daily inspections/data collection
- Extensive inspections before the winter period to allow for repairs
- Transformer testing yearly - DGA monitoring, Water in Oil monitoring;
- PM work (JD Edwards System) – annual and other period checks and repairs
- Corrective maintenance as required
- Capital refurbishments/enhancements

As noted critical PM and corrective work appear to have been completed or of lower priority that shouldn't impact winter 2013/14 reliability.

No FM Global insurance report was available for the facility.

3.2.3.5 Facility Risk Assessment

Key risks are likely associated with i) unexpected failures of older equipment (bushings, electro-mechanical relays, disconnects), and ii) fire simultaneously with a fire suppression failure. TRO appears to have taken measures to mitigate against them as much as practical, subject to any remaining work discussed in Section 3.2.1. Suitable ongoing monitoring and adequate spares and resources are in place to address and respond to unexpected failures.

Generally, Sunnyside TS appears to have no major issues identified aside from those identified in Section 3.2.1 which should interfere with reliable operation this winter.

- Critical 2013 PM's and planned 2013 capital and corrective work appear largely completed
- Transformer appears to be in good condition for this year
- No major hotspots identified

3.2.4 Come By Chance Terminal Station

3.2.4.1 Facility Overview

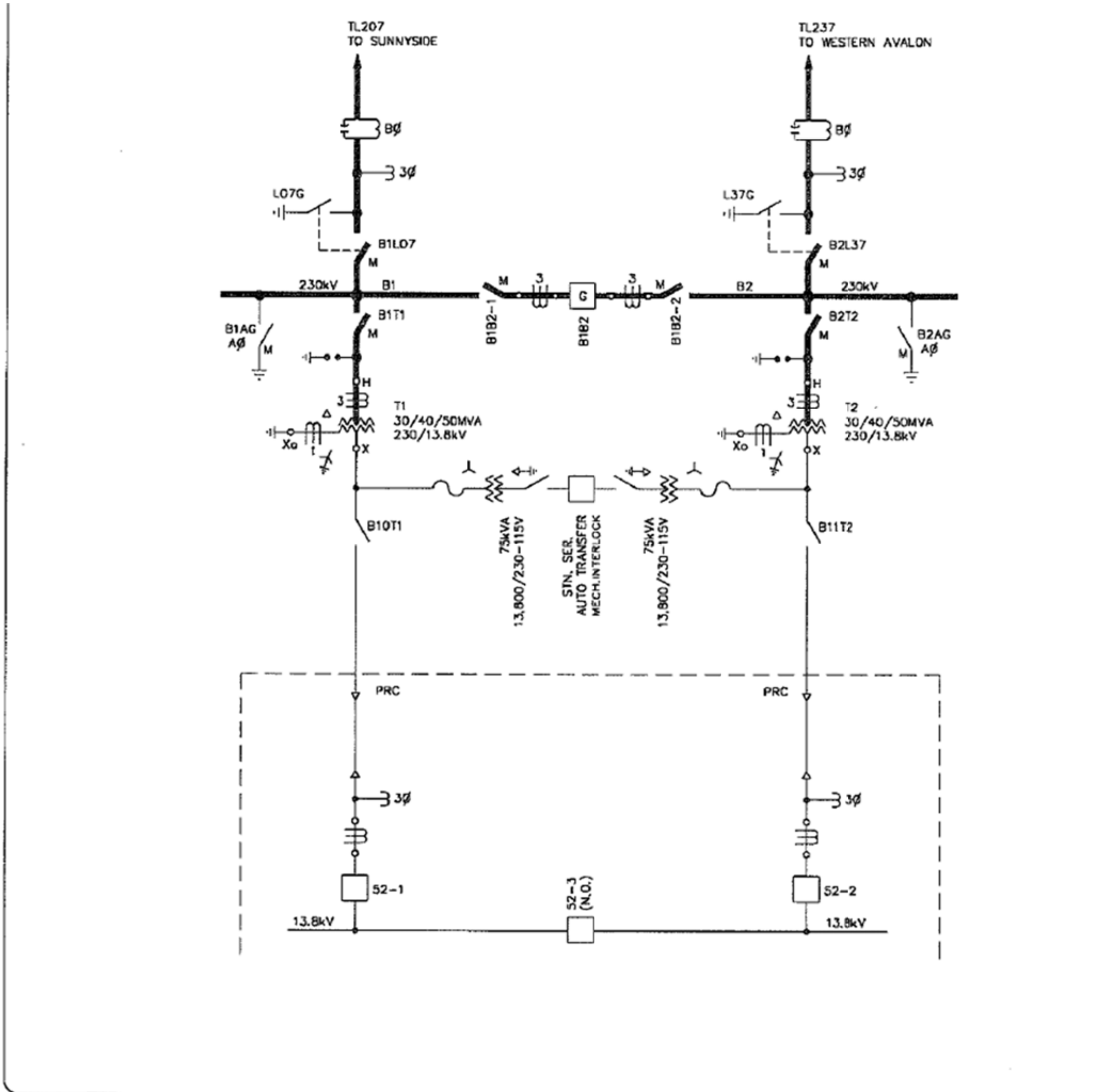
Come-By-Chance TS has 230 kV lines from Sunnyside TS (TL 207) and from Western Avalon (WAV - TL237) into a split B1/B2 230kV bus separated by two disconnects (B1B2-1 and B1B2-2 and a 230kV SF6 breaker.

Within the switchyard 230/13.8kV transformers T1 and T2 (30/40/50 MVA each) that provide power to the CBC refinery two 13.8kV disconnect s B10T1 and B11T2 and via three 13.8kV breakers 52-1, 52-2, 52-3. Two 75kVA 13.8kV/230-115V transformers provide TS station service.

The switchyard equipment includes:

- Ten 230 kV disconnects
- One 230kV SF6 breaker splitting the bus into two parts
- Two 230/13.8kV transformers T1 and T2 (each 30/40/50MVA)
- Three 13.8kV breakers
- Two 13.8 kV disconnects
- Two 75kVA 13.8kV/230-115V transformers
- Other equipment – CT's PT's, lightning arrestors

A single line of the terminal station follows.



DRAWN BY JT	NEWFOUNDLAND AND LABRADOR HYDRO	DWG NO
APPROVED BY J.F.	SYSTEM OPERATING DIAGRAM	REV NO
DATE 2000-01-24	COME BY CHANCE TERMINAL STATION	1

3.2.4.2 Pre-Visit Information

Information had been received on recent Come-By-Chance TS transformer testing (DGA, Fluid condition, Water in Oil, Furan analysis).

- T1 (50MVA - 1972), T2 (50 MW – 1972)

Both had been tested in June 2013 and were considered to be in reasonable condition to operate over the 2013/14 winter. No additional testing in 2013 was recommended in PM write-ups by technicians.

3.2.4.3 Facility Walkdown/Thermography

Thermography had previously been done by TRO in January 2012 and no hot spots found. For this project, thermography was undertaken by TRO staff using their handheld infrared cameras with direction/documentation by David Jones of AMEC.

4.2 Conditions: Windy. Temperature: -2°C, Wind Chill -10°C.

4.3 Loads at times of imagery.

- TL207 from Sunnyside 170MW.
- TL237 from Western Avalon 150MW

4.4 Come-by-Chance Asset Priority Chart (Images 390 through 407)

Asset Description	Image Identity	Priority	Comments
		1 and 2	No priority 1 or 2 found.
	401	3	28.9°C on line termination above PT.
		4	All Assets other than 401 above found in priority 4.

3.2.4.4 Facility Maintenance and Winter Readiness Overview

Generally the key issues associated with this Terminal Station are addressed in Section 3.2.1 addressing general TRO conditions. The maintenance at the TS site does include:

- Operations daily inspections/data collection
- Extensive inspections before the winter period to allow for repairs
- Transformer testing yearly - DGA monitoring, Water in Oil monitoring;
- PM work (JD Edwards System) – annual and other period checks and repairs
- Corrective maintenance as required
- Capital refurbishments/enhancements

As noted critical PM and corrective work appear to have been completed or of lower priority that shouldn't impact winter 2013/14 reliability.

No FM Global insurance report was available for the facility.

3.2.4.5 Facility Risk Assessment

Key risks are likely associated with i) unexpected failures of older equipment (bushings, electro-mechanical relays, disconnects), and ii) fire simultaneously with a fire suppression failure. TRO appears to have taken measures to mitigate against them as much as practical, subject to any remaining work discussed in Section 3.2.1. Suitable ongoing monitoring and adequate spares and resources are in place to address and respond to unexpected failures.

Generally, Come By Chance TS appears to have no major issues identified aside from those identified in Section 3.2.1 which should interfere with reliable operation this winter.

- Critical 2013 PM's and planned 2013 capital and corrective work appear largely completed
- Transformer appears to be in good condition for this year
- No major hotspots identified

3.2.5 Western Avalon, Terminal Station

3.2.5.1 Facility Overview

Western Avalon TS has 230 kV lines from CBC TS (TL237), Hardwoods TS (TL201), Sunnyside TS (TL 203), and Holyrood (TL2317), as well as LHR (TL208).

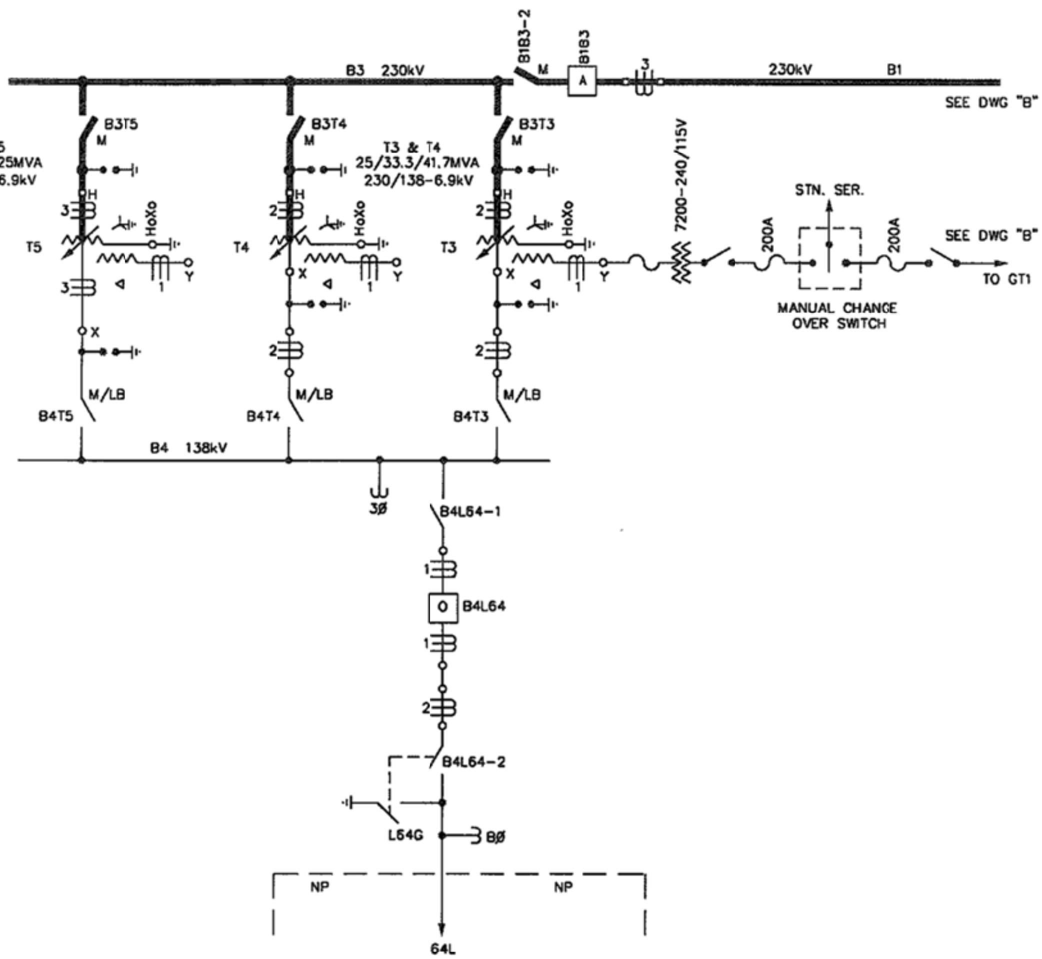
The WAV TS supplies power through two 230/66kV transformers (T1, T2 – each 15/20/25 MVA) to a split 66kV bus that provides power to Newfoundland Power and to its own station service. Newfoundland Power feeds BTN with 66kV power and through a 66/25-12.5kV transformer to Long Harbour and Chapel Arm. The 66kV bus also feeds the TS station service through a 66kV/6.9kV transformer (GT1) and 6.9kV/230-115V transformer (X).

The WAV TS supplies power through three 230/138-6.9kV transformers (T3, T4 – each 25/33.3/41.7MVA and T5 – 75/100/125MVA). These provide a 138kV feed Newfoundland Power line 64L.

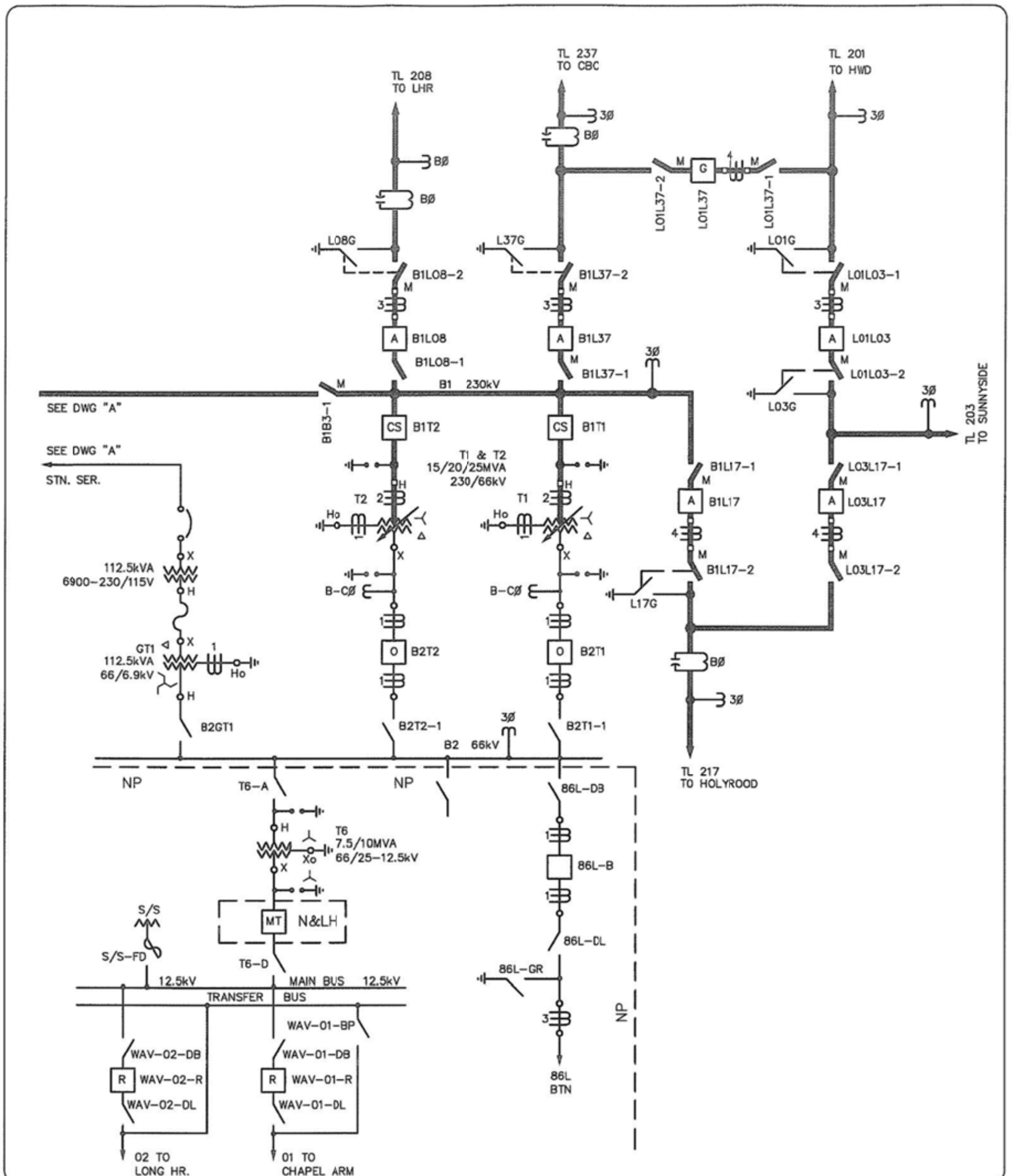
The switchyard equipment (excluding Newfoundland Power equipment) includes:

- Seventeen 230kV disconnects
- Six 230kVair blast circuit breakers and one SF6 230kV circuit breaker
- Five 230KV ground disconnects
- Two 230 Circuit Switchers
- Two 230/66kV transformers (T1, T2 – each 15/20/25 MVA)
- One 230kV SF6 breaker splitting the bus into two parts
- Two 230/13.8kV transformers T1 and T2 (each 30/40/50MVA)
- Three 230/138-6.9kV transformers (T3, T4,– each 25/33.3/41.7MVA and T5 – 75/100/125MVA)
- Five 138 disconnects
- One 66kV/6.9kV transformer (GT1) and one 6.9kV/230-115V transformer (X).
- Three 66kV disconnects
- One station service circuit breaker and two fuses
- Two station service disconnects

Two single lines of the terminal station follow.



DRAWN BY	JT	NEWFOUNDLAND AND LABRADOR HYDRO	DWG NO A
APPROVED BY	J.FOLEY	SYSTEM OPERATING DIAGRAM	REV NO
DATE	98-11-05	WESTERN AVALON TERMINAL STATION (A)	4



DRAWN BY: J.T.	REVISED BY: D.R.	NEWFOUNDLAND AND LABRADOR HYDRO	DWG NO WAV-B
APPROVED BY: R.S.		SYSTEM OPERATING DIAGRAM	REV NO
DATE: 2007/08/13		WESTERN AVALON TERMINAL STATION (B)	11

3.2.5.2 Pre-Visit Information

Information had been received on recent Western Avalon TS transformer testing (DGA, Fluid condition, Water in Oil, Furan analysis).

- T1 (25 MVA - 1968), T2 (25 MVA – 1968), T3 (15 MVA - 1978), T4 (41.7 MVA – 1977), T5 (125 MVA - 1969)

All had been tested in June 2013 and were considered to be in reasonable condition to operate over the 2013/14 winter. T1, T3, T4, and T5 were identified in PM write-ups by technicians as recommended to be redone again in 2013 primarily due to moderate DGA levels and T1 because of oil quality issues, but it is not clear from available information if this occurred.

From the September 2011 "Upgrade Transmission Line Corridor" submission to the Board of Commissioners of Public Utilities, it is evident that transmission line capability between Bay d'Espoir and Western Avalon" is a critical issue in the event of a single contingency failure at Bay d'Espoir or Holyrood.

3.2.5.3 Facility Walkdown/Thermography

Thermography had previously been done by TRO in December 2012 and no hot spots found. For this project, thermography was undertaken by TRO staff using their handheld infrared cameras with direction/documentation by David Jones of AMEC.

6.2 Conditions: Misty, Gusting. Temperature: 2°C. Wind Chill: xxxxxxx

6.3 Loads at times of tests:

- TL 201 to Hardwoods. 125MW.
- TL 203 to Sunnyside. 170MW.
- TL 208 to Long Harbour. 4MW.
- TL 217 to Holyrood. 84MW.
- TL 237 to Come-by-Chance. 150MW.
- T1. 12MW
- T2. 12MW.

6.4 Western Avalon Asset Priority Chart (Images 408 through 489)

Asset Description	Image Identity	Priority	Comments
		1 and 2	No priority 1 or 2 found
B4L64	0433	3	31.6°C on B phase source side bushing. GE OCB.
B4L64	0434	3	18.1°C on C phase on source side bushing GE OCB
		4	All Assets other than those above found in priority 4

3.2.5.4 Facility Maintenance and Winter Readiness Overview

Generally the key issues associated with this Terminal Station are addressed in Section 3.2.1 addressing general TRO conditions. The maintenance at the TS site does include:

- Operations daily inspections/data collection
- Extensive inspections before the winter period to allow for repairs
- Transformer testing yearly - DGA monitoring, Water in Oil monitoring;
- PM work (JD Edwards System) – annual and other period checks and repairs
- Corrective maintenance as required
- Capital refurbishments/enhancements

As noted critical PM and corrective work appear to have been completed or of lower priority that shouldn't impact winter 2013/14 reliability.

No FM Global insurance report was available for the facility.

3.2.5.5 Facility Risk Assessment

Key risks are likely associated with i) unexpected failures of older equipment (bushings, electro-mechanical relays, disconnects), and ii) fire simultaneously with a fire suppression failure. TRO appears to have taken measures to mitigate against them as much as practical, subject to any remaining work discussed in Section 3.2.1. Suitable ongoing monitoring and adequate spares and resources are in place to address and respond to unexpected failures.

Generally, Western Avalon TS appears to have no major issues identified aside from those identified in Section 3.2.1 which should interfere with reliable operation this winter.

- Critical 2013 PM's and planned 2013 capital and corrective work appear largely completed
- Transformer appears to be in good condition for this year
- No major hotspots identified

3.2.6 Holyrood, Terminal Station

3.2.6.1 Facility Overview

Holyrood TS has 230 kV lines from Western Avalon (TL217), and 138kV line from Newfoundland Power (B15, 39L) and 38L), and a 69kV from Newfoundland & Labrador Power to/from Holyrood Substation to

The switchyard equipment (excluding Newfoundland Power equipment) includes:

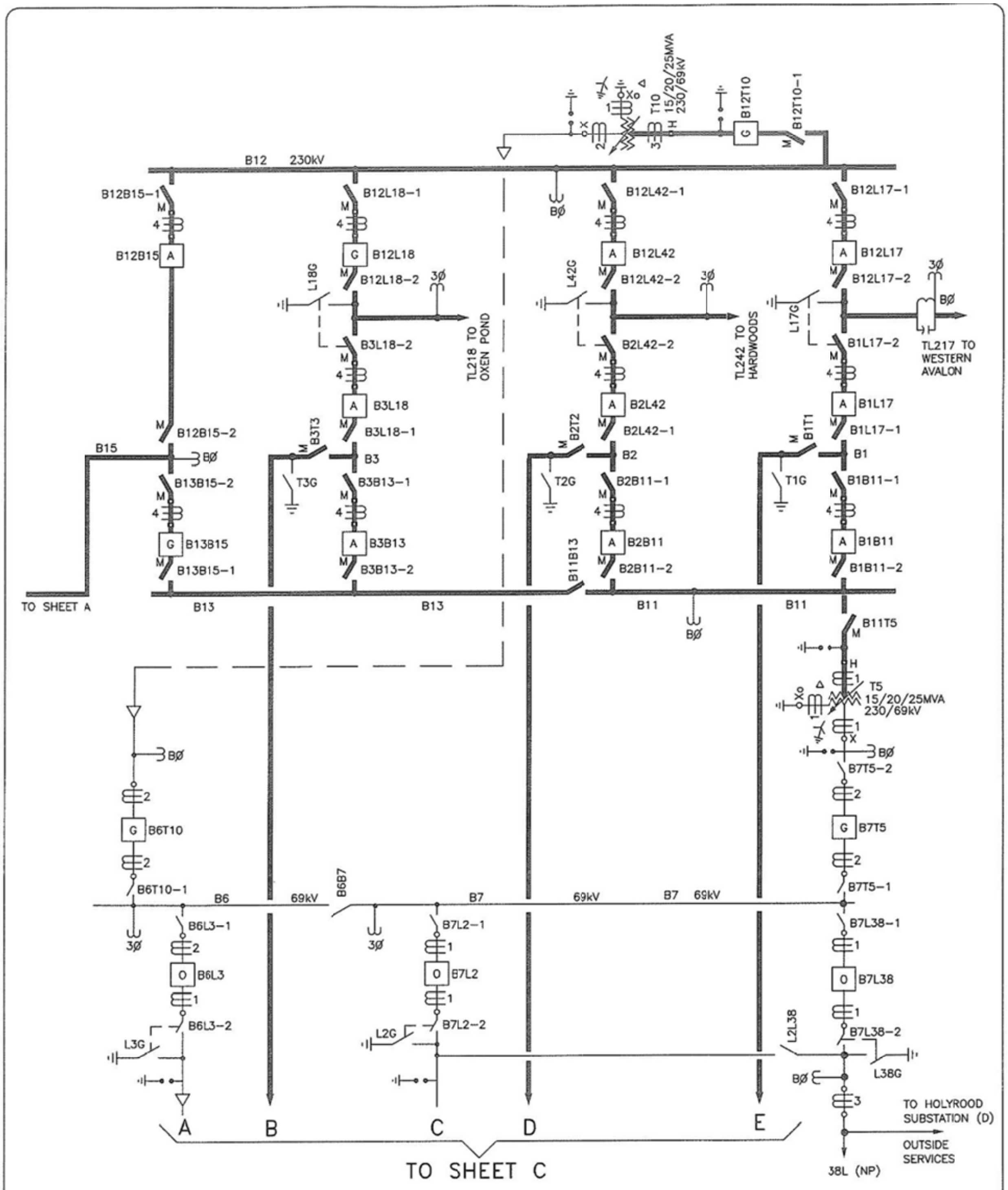
- One 230kV bus (B15) supplying one 138kV bus (B8) feeding Newfoundland Power Line 39L
  - One 230/138kV transformer T8 (75/100/125MVA)
  - Two 230/138kV transformers T6 and T7 (25/33.3/41.7MVA)
  - Three 230kV disconnect switches
  - Five 138kV disconnect switches
  - One oil breaker B8L39

- One 230kV Ring bus (B1, B2, B3, B11, B12, B13, B1) with connections to 69kV bus; to 230kV bus B15; and to TL217 to Western Avalon, to TL242 to Hardwoods TS, and to TL218 to Oxen Pond TS
  - Three 230/16kV transformers - T3 off Bus B3 (170MVA); T2 off Bus B2 (115/152/190MVA); and T1 off Bus B1(105/140/180MVA)
  - Nine 230kVair blast circuit breakers
  - Three SF6 230kV circuit breakers
  - Twenty-seven 230kV disconnects
  - Associated 230KV ground disconnects, CT's, PT's etc.

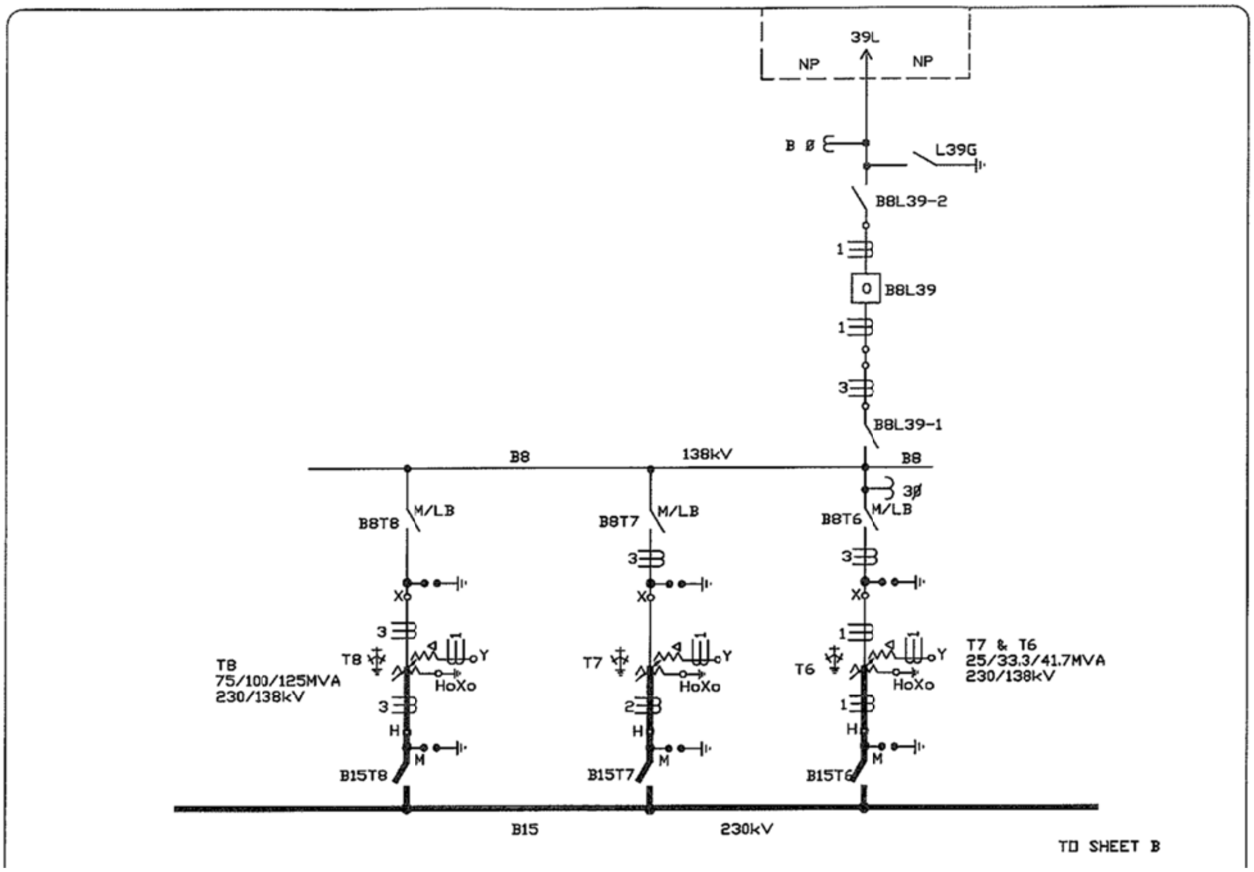
- One 69kV bus supplied from 230kV busses B11 and B12
  - Two 230/69kV transformers -T10 off Bus B12 (15/20/25MVA) and T2 off Bus B11 (15/20/25MVA)
  - Two SF6 69kV circuit breakers
  - Three 69kV oil circuit breakers
  - Eleven 69kV disconnects
  - Two 69/4.16kV Station Service transformers (SST-34 from B6, SST-12 from B7 – 10.5/14MVA each)
  - Associated ground disconnects, CT's, PT's etc.
  - One 69kV line (38L) serving Newfoundland & Labrador Hydro distribution and Holyrood Outside Services (Holyrood Substation)
    - One 69kV disconnect
    - One 69/2.4/4.16kV transformer (T1)

- Three 16kV lines from Generators G1, G2, G3 and one 13.8kV line from blackstart GT (17MVA)
  - Three 16/4.16kV Unit Station Service transformers (UST-1,2,3 – 10MVA)
  - One 13.8/4.16kV transformer T9 (10.5/14MVA) from Gas Turbine
  - Eleven 4.16kV air blast breakers
  - Associated ground disconnects, CT's, PT's etc.

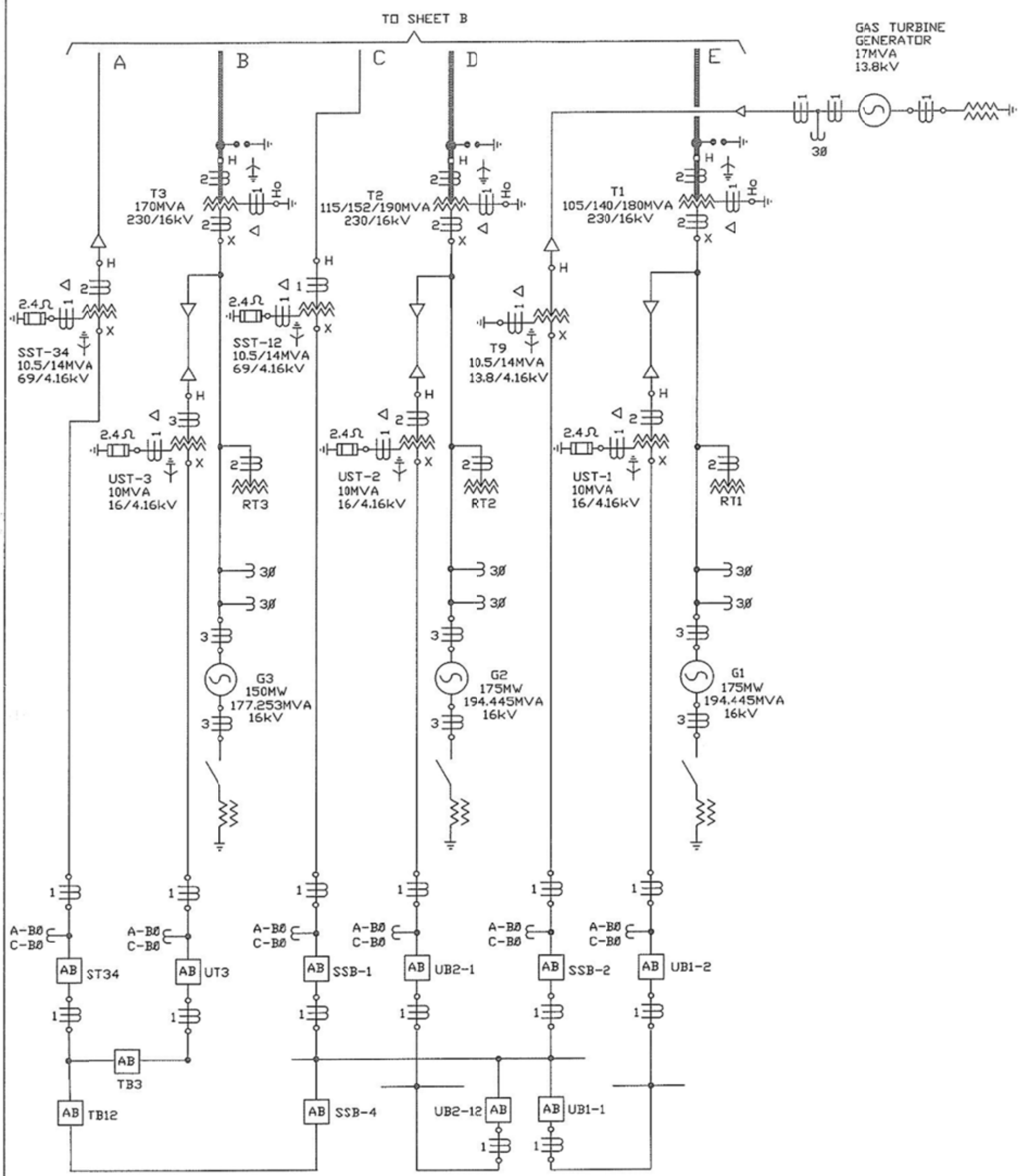
Four single lines of the terminal station follow.



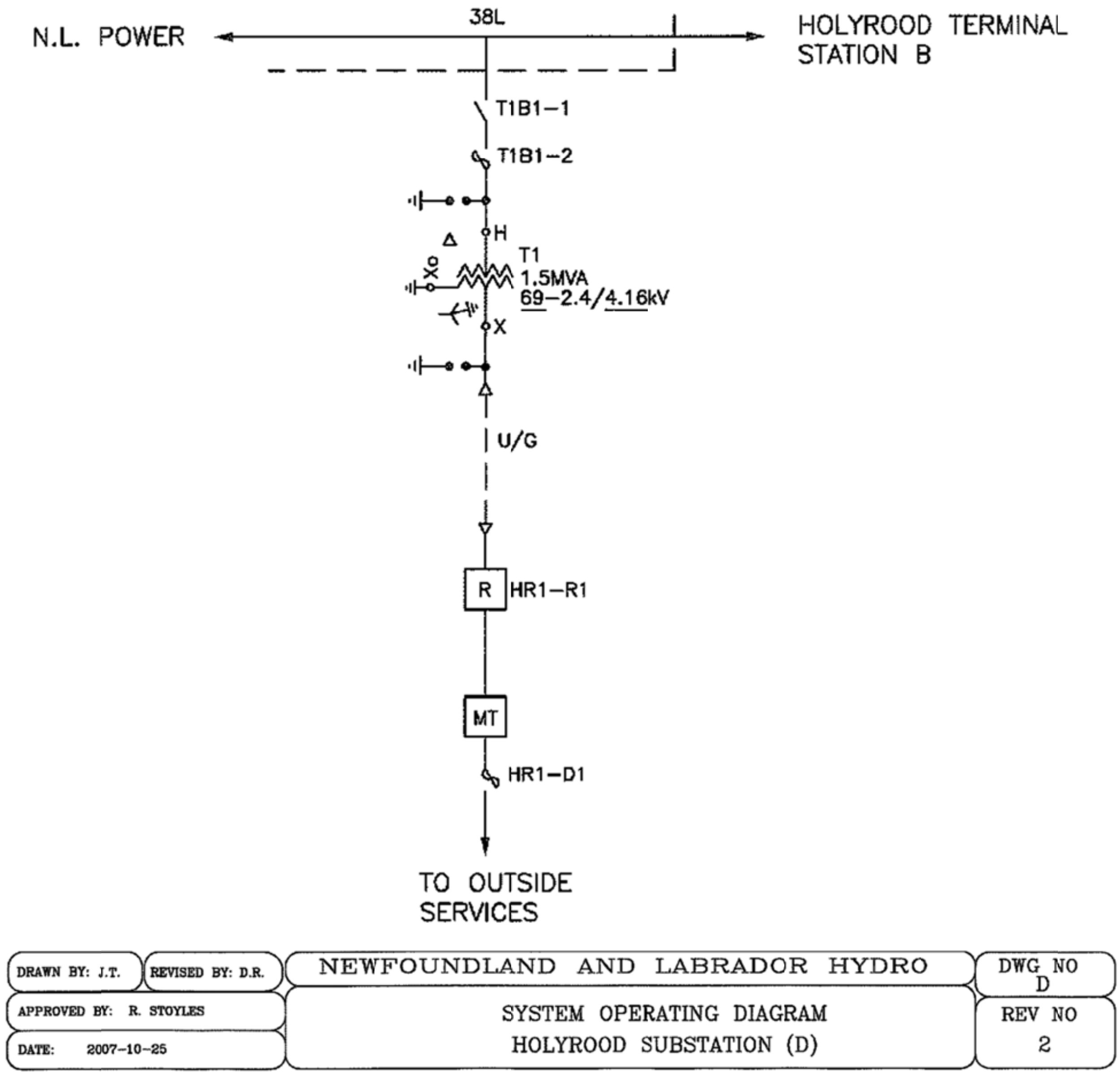
DRAWN BY: J.T.	REVISED BY: D.R.	NEWFOUNDLAND AND LABRADOR HYDRO	DWG. NO. HRD-B
APPROVED BY: J.F.		SYSTEM OPERATING DIAGRAM	REV. NO.
DATE: 05-03-16		HOLYROOD TERMINAL STATION (B)	10



DRAWN BY	JT	NEWFOUNDLAND AND LABRADOR HYDRO	DWG NO A
APPROVED BY	D.CULL	SYSTEM OPERATING DIAGRAM	REV NO
DATE	91-06-14	HOLYROOD TERMINAL STATION (A)	1



DRAWN BY: J.T.	REVISED BY: D.R.	NEWFOUNDLAND AND LABRADOR HYDRO	DWG NO HRD-C
APPROVED BY:	B.S.	SYSTEM OPERATING DIAGRAM	REV NO 3
DATE:	06-09-22	HOLYROOD GENERATING STATION (C)	



3.2.6.2 Pre-Visit Information

A December 2012 report by Hatch Consultants indicated that some of the aluminum structures (piers, baseplates, anchors) had significant flaws that required repair. They examined 235 structural bases over three days. They identified four items that should be addressed immediately – D1, D3, J1, R2 as they were parts that either essentially failing (D1 Section 1), or missing more than one component (i.e. bolt) and were associated with Class II (230 Bus or 69kV Box structures subject to live loads as well as dead weight – six) or Class III (230 kV Take-off Structures subject to higher horizontal loads than Class II – four) structures. No information was received on how much of the repairs were completed in 2013.

Information had also been received on recent Holyrood TS transformer testing (DGA, Fluid condition, Water in Oil, Furan analysis).

- T1 (80 MVA - 1992), T2 (190 MVA – 1989), T3 (170 MVA - 1970), T6 (41.7 MVA – 1979), T7 (41.7 MVA - 1977), T8 (125 MVA – 1989)

All had been tested in June 2013 and were considered to be in reasonable condition to operate over the 2013/14 winter. T2 and T7 were identified in PM write-ups by technicians as recommended to be redone again in 2013 primarily due to moderate DGA levels, but it is not clear from available information if this occurred.

3.2.6.3 Facility Walkdown/Thermography

Thermography had previously been done by TRO in December 2012 and two hot spots found associated with T2, one significant was A phase Pad connection (34.6°C). No indication if or how this was addressed. For this project, thermography was undertaken by TRO staff using their handheld infrared cameras with direction/documentation by David Jones of AMEC.

2.2 Conditions: Windy. Temperature -2°C, Wind Chill -6°C

2.3 Loads at times of imagery.

- TL 217 to Western Avalon 100MW.
- TL 218 to Oxen Pond 104MW.
- TL 242 to Hardwoods 107MW.

2.4 Holyrood Asset Priority Chart (Images 309 through 408)

Asset Description	Image Identity	Priority	Comments
		1 and 2	No priority 1 and 2 found.
B11B13	403	3	31.5°C on A phase. B&C phase above 30°C.
		4	All Assets other than ~~those~~ 403 above found in priority 4.

3.2.6.4 Facility Maintenance and Winter Readiness Overview

Generally the key issues associated with this Terminal Station are addressed in Section 3.2.1 addressing general TRO conditions. The maintenance at the TS site does include:

- Operations daily inspections/data collection
- Extensive inspections before the winter period to allow for repairs
- Transformer testing yearly - DGA monitoring, Water in Oil monitoring;
- PM work (JD Edwards System) – annual and other period checks and repairs
- Corrective maintenance as required
- Capital refurbishments/enhancements

As noted critical PM and corrective work appear to have been completed or of lower priority. A key exception is the coating of two of the TS breakers to better withstand salt water icing issues, or other measures to reduce the likelihood of multiple trips. Weather would likely be primary factor that could negatively impact winter 2013/14 reliability.

No FM Global insurance report was available for the facility.

3.2.6.5 Facility Risk Assessment

The key risk for the Holyrood TS is extreme weather. A storm similar to the one in January 2013 would likely have a similar effect on the Holyrood TS - given that two of the TS breakers have not been coated and that the impact of the coating is uncertain. Improvements elsewhere in the system may result in less overall impact. The impact on Holyrood GS may depend on measures between Holyrood and Hardwoods since no other black start capability will be in place in winter 2013/14.

Other key risks are likely associated with i) unexpected failures of older equipment (bushings, electro-mechanical relays, disconnects), and ii) fire simultaneously with a fire suppression failure. TRO appears to have taken measures to mitigate against these as much as practical, subject to any remaining work discussed in Section 3.2.1. Suitable ongoing monitoring and adequate spares and resources are in place to address and respond to unexpected failures.

Generally, the main risk associated with Holyrood TS appears to be extreme weather. No other major issues are identified, aside from those general TRO issue identified in Section 3.2.1, which should interfere with reliable operation this winter.

- Critical 2013 PM's and planned 2013 capital and corrective work appear largely completed
- Transformers appear to be in good condition for this year
- No major hotspots identified

3.2.7 Hardwoods, Terminal Station

3.2.7.1 Facility Overview

Hardwoods TS has 230 kV lines from Oxen Pond (TL236) and Western Avalon (TL201) through two 230kV air blast breakers, and Holyrood TS (TL242) through a 230kV SF6 breaker to a split bus. Each bus (B1, B2) feeds through two 230/66kV transformers (T1 – 40/53.3/66.6MVA and T2 – 40/53.3/66.6MVA to Bus B1; T3 – 40/53.3/66.6MVA and T4 – 75/100/125MVA to Bus B2).

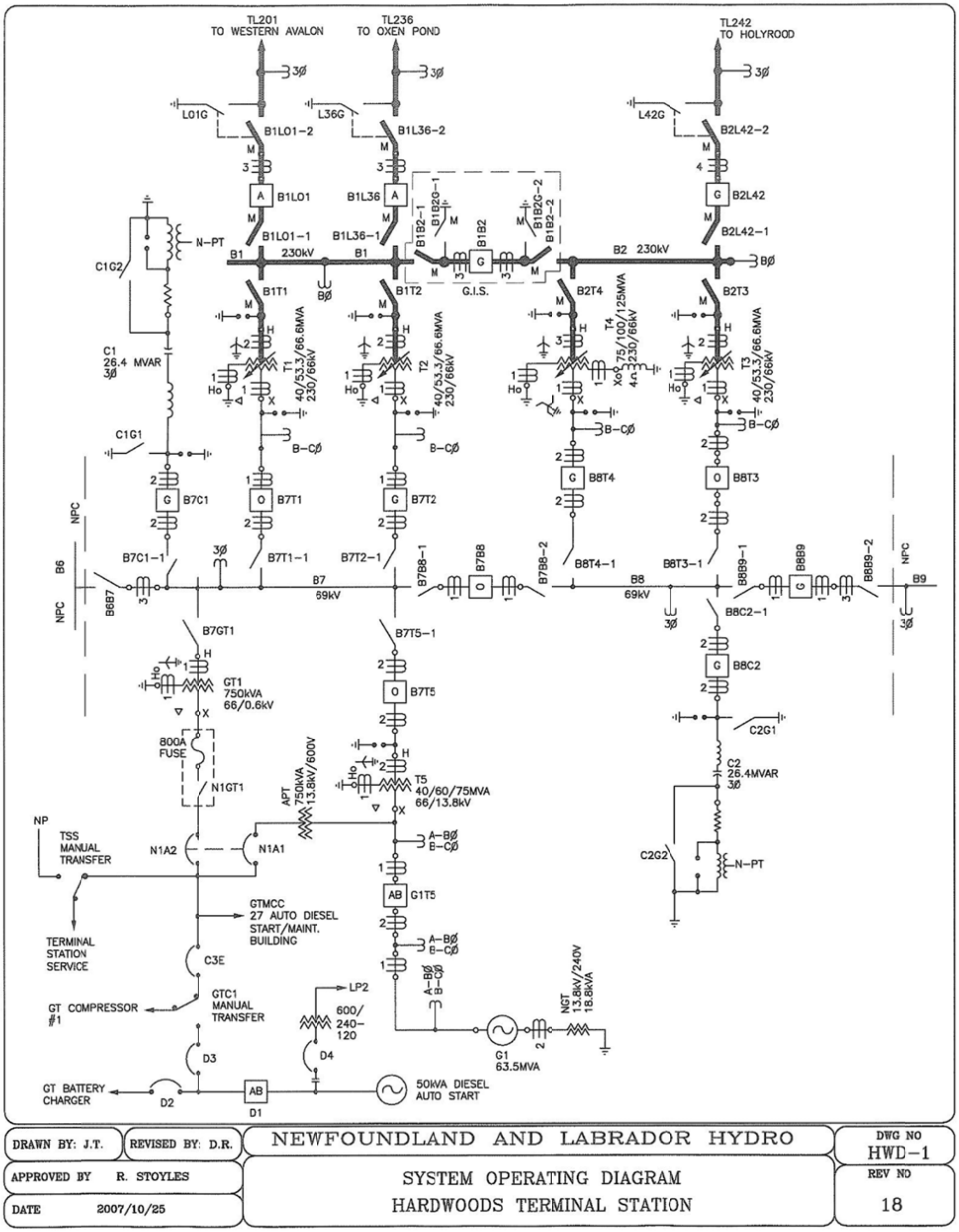
From the 69kV bus, power is supplied to:

- Two Newfoundland Power 69 kV Busses (B6 through a disconnect; B9 through an SF6 breaker and a disconnect)
- One 750kVA 66/0.6kVransformer for station service and connection to 50kVA auto start diesel
- One 66/13.8kV T5 transformer (40/60/75 MVA)
- One 63.5MVA aeroderivative gas turbine at 13.8kV
- Two 69kV 26.4MVAR capacitor banks

The switchyard equipment (excluding 66 and 69kV power to Newfoundland Light and Power distribution equipment) includes:

- One split 230 kV bus (B1, B2)
- Twelve 230kV disconnects
- Two 230kVair blast circuit breakers
- Two SF6 230kV circuit breakers
- Three 230KV ground disconnects
- Four 230/66kV transformers (T1 – 40/53.3/66.6MVA and T2 – 40/53.3/66.6MVA to Bus B1; T3 – 40/53.3/66.6MVA and T4 – 75/100/125MVA to Bus B2)
- One split 69 kV bus (B7, B8)
- Five 69kV SF6 breakers, Four 69kV Oil circuit breakers
- Thirteen 69kV disconnects
- One 750kVA 66/0.6kVransformer for station service and connection to 50kVA auto start diesel
- One 66/13.8kV T5 transformer (40/60/75 MVA)
- One 63.5MVA aeroderivative gas turbine at 13.8kV
- Two 69kV 26.4MVAR capacitor banks
- Eight 69kV ground disconnects
- Other misc parts – PT's CT's, fuses, Grounds, Lightning arrestors,

A single line of the terminal station follows.



3.2.7.2 Pre-Visit Information

A condition assessment (and UHF PD measurement) was undertaken on the Hardwoods Substation SF6 system by Alstom in October 2011. It indicated that there were no discharge signals from the switchgear measured, that the SF6 equipment was within manufacturer's criteria, and that circuit breakers were within vendor criteria. The conclusion was that the facility was in good condition. It did recommend:

- some additional circuit breaker maintenance be done (greasing, seals, moisture absorber on outdoor pressure switches, internal heater replacement)
- external earthing be made compliant (indoor is good)
- That additional strategic spare parts be procured, especially one spare circuit breaker active part since the GIS type has not been manufactured since 2008 and if one phase fails then all three phases would have to be replaced by a new GIS type with a lead time of up to 12 months

Information had also been received on recent Hardwoods TS transformer testing (DGA, Fluid condition, Water in Oil, Furan analysis).

- T1 (66.6 MVA - 1972), T2 (66.6 MVA – 1973), T3 (66.6 MVA - 1986), T4 (125MVA – 1987), T5 (75MVA - 1985)

All had been tested in February 2012. They were considered in reasonable condition, although T2, T3, and T4 were identified in PM write-ups by technicians as recommended to be redone again later in 2012 primarily due to moderate DGA levels. It is not clear from available information if this follow-up occurred in 2012 and no data was received from 2013 testing. Nevertheless given the 2012 results and equipment age, the transformers are considered to be in reasonable condition to operate over the 2013/14 winter.

3.2.7.3 Facility Walkdown/Thermography

Thermography had previously been done by TRO in October 2012 and one hot spot found associated with a B Phase jaw connection (lower priority issue at 15.6^{o}C). No indication if or how this was addressed. For this project, thermography was undertaken by TRO staff using their handheld infrared cameras with direction/documentation by David Jones of AMEC.

3.2 Conditions: Temperature -0°C. Wind Chill -6°C to -12°C.

3.3 Loads at times of imagery.

- TL 201 to Western Avalon 125MW.
- TL 236 to Oxen Pond 75MW.
- TL 242 to Holyrood 150MW.
- T1 40MW.
- T2 35MW.
- T3 45MW.
- T4 65MW.

3.4 Hardwoods Asset Priority Chart (Images 283 through 322)

Asset Description	Image Identity	Priority	Comments
		1 and 2	No propriety 1 or 2 found
		3	No priority 3 found
		4	All Assets found in priority 4 with a question of the following
	285, 294, 304, 305, 308, 315, 317, 320		285, 294, 304, 305, 308, 315, 317, 320. Need to be re-done, some cross-hairs out of alignment.

3.2.7.4 Facility Maintenance and Winter Readiness Overview

Generally the key issues associated with this Terminal Station are addressed in Section 3.2.1 addressing general TRO conditions. The maintenance at the TS site does include:

- Operations daily inspections/data collection
- Extensive inspections before the winter period to allow for repairs
- Transformer testing yearly - DGA monitoring, Water in Oil monitoring;
- PM work (JD Edwards System) – annual and other period checks and repairs
- Corrective maintenance as required
- Capital refurbishments/enhancements

A key issue is the availability of Hardwoods to supply black start power to Holyrood in the event of that station tripping off. Some of the TRO work completed in 2013 should enhance that capability but extreme weather impacts on the lines or simultaneous failures elsewhere may have the same effect as in January 2013.

As noted otherwise, critical PM and corrective work at the TS itself appear to have been completed or of lower priority that shouldn't impact winter 2013/14 reliability.

No FM Global insurance report was available for the facility.

3.2.7.5 Facility Risk Assessment

The key risk for the Hardwoods TS is extreme weather. A storm similar to the one in January 2013 could likely have a similar effect on the Hardwoods TS and its line connections to Holyrood TS.

Other key risks are likely associated with i) unexpected failures of older equipment (bushings, electro-mechanical relays, gas turbine, disconnects), and ii) fire simultaneously with a fire suppression failure. TRO appears to have taken measures to mitigate against these as much as practical, subject to any remaining work discussed in Section 3.2.1. Suitable ongoing monitoring and adequate spares and resources are in place to address and respond to unexpected failures.

Generally, the main risk associated with Hardwoods TS appears to be extreme weather. Redundancy in terms of capacity and synchronous condensing capability should mitigate other risks. Thus no other major issues are identified, aside from those general TRO issue identified in Section 3.2.1, which should interfere with reliable operation this winter.

- Critical 2013 PM's and planned 2013 capital and corrective work appear largely completed
- Transformers appear to be in good condition for this year
- No major hotspots identified

3.2.8 Oxen Pond Terminal Station

3.2.8.1 Facility Overview

Oxen Pond TS has 230 kV lines from Hardwoods (TL236), and Holyrood TS (TL218) to a single 230kV bus. The bus supplies three 230/66kV transformers (T1 – 40/53.3/66.6MVA; T2 – 75/100/125MVA; T3 – 75/100/125MVA). These feed a split 66kV bus (B2, B5).

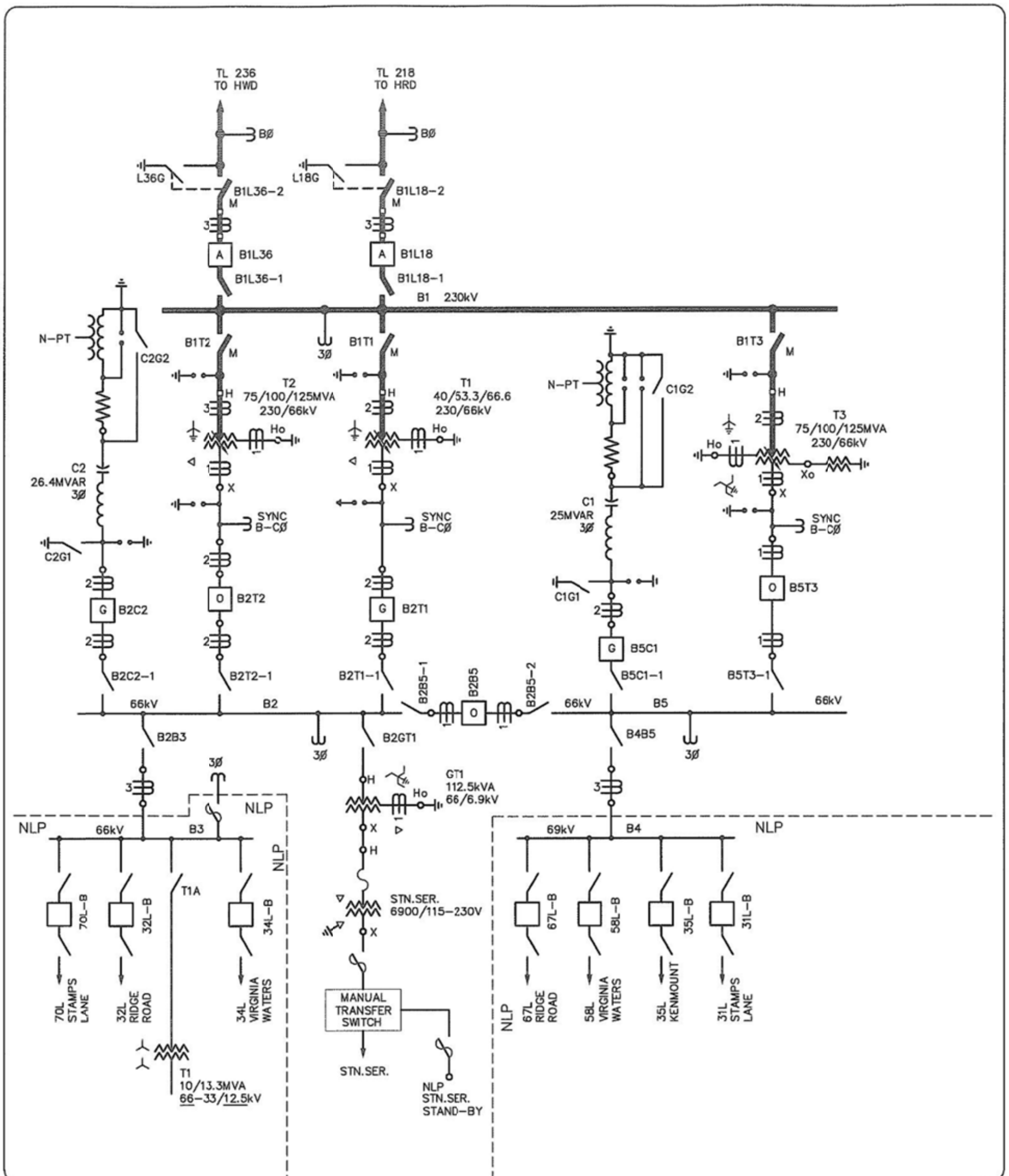
From the 66kV bus, power is supplied to Newfoundland Light and Power feeds to Stamps Lane, Ridge Road, Virginia Waters(2), Ridge Road, Kenmount, Stamps Lane. There is also a take-off through an 112.5kVA 66/6.9kV and 6.9kV/115-230V transformer for station service. There is also a connection for a 26.4MVAR capacitor bank.

The switchyard equipment (excluding 66 and 69kV power to Newfoundland Light and Power distribution equipment) includes:

- Seven 230kV disconnects

- Three 230/66kV transformers (T1 – 40/53.3/66.6MVA; T2 – 75/100/125MVA; T3 – 75/100/125MVA).
- Two 230kVair blast circuit breakers and one SF6 230kV circuit breaker
- Two 230KV ground disconnects
- One 66kV 26.4MVAR capacitor bank
- Eight 66kV disconnects
- Two 66KV ground disconnects
- One 112.5kVA 66/6.9kV and 6.9kV/115-230V transformer for station service
- One station service fuse

A single line of the terminal station follows.



DRAWN BY: J.T.	REVISED BY: D.R.	NEWFOUNDLAND AND LABRADOR HYDRO	DWG NO OPD-1
APPROVED BY: R.S.		SYSTEM OPERATING DIAGRAM OXEN POND TERMINAL STATION	REV NO 11
DATE : 2007/08/13			

3.2.8.2 Pre-Visit Information

Information had also been received on recent Oxen Pond Avalon TS transformer testing (DGA, Fluid condition, Water in Oil, Furan analysis).

- T1 (66.6MVA - 1970), T2 (125MVA – 1986), T3 (125MVA - 1979)

All had been tested in July 2013 and were considered to be in reasonable condition to operate over the 2013/14 winter. All three however were identified in PM write-ups by technicians as recommended to be redone again in 2013 primarily due to moderate DGA levels, but it is not clear from available information if this occurred.

From the August 2011 "Install Additional 230 kV Transformer – Oxen Pond Terminal Station" submission to the Board of Commissioners of Public Utilities, it is evident that the transformer capability of the existing Oxen Pond transformers could be exceeded in 2014 or thereabouts making its reliability more critical in winter 2013/14.

3.2.8.3 Facility Walkdown/Thermography

Thermography had previously been done by TRO in December 2012 and three hot spots found – B2C2 C Phase Jaw connector (19.7 °C), B253-3 B Phase Load side (14.8 °C), and B553-1 C Phase Breaker side (52°C). NO indication if or how this was addressed. For this project, thermography was undertaken by TRO staff using their handheld infrared cameras with direction/documentation by David Jones of AMEC.

7.2 Conditions: Overcast, Windy, Gusting. Temperature: 2°C.

7.3 Loads at times of tests:

- TL 218 to Holyrood. 110MW.
- TL 236 to Hardwoods. 80MW.
- T1. 39MW
- T2. 70MW.
- T3. 78MW.

7.4 Oxen Pond Asset Priority Chart (Images 490 through 546)

Asset Description	Image Identity	Priority	Comments
		1	No priority 1 found.
		2	No priority 2 found
B2T2 CT's	0495	3	25°C on A phase, source side. B&C phases above 15°C.
B2T2 CT's	0497	3	26.1°C on C phase, load side.
B2T2-1	0500	3	20.8°C on C phase on jaw.
B5T3-1	0517	3	10°C on A phase. 20.5°C on B phase. 19°C on C phase.
		4	All Assets priority 4 other than those above

3.2.8.4 Facility Maintenance and Winter Readiness Overview

Generally the key issues associated with this Terminal Station are addressed in Section 3.2.1 addressing general TRO conditions. The maintenance at the TS site does include:

- Operations daily inspections/data collection
- Extensive inspections before the winter period to allow for repairs

- Transformer testing yearly - DGA monitoring, Water in Oil monitoring;
- PM work (JD Edwards System) – annual and other period checks and repairs
- Corrective maintenance as required
- Capital refurbishments/enhancements

As noted critical PM and corrective work appear to have been completed or of lower priority that shouldn't impact winter 2013/14 reliability.

No FM Global insurance report was available for the facility.

3.2.8.5 Facility Risk Assessment

Key risks are likely associated with i) unexpected failures of older equipment (bushings, electro-mechanical relays, disconnects), and ii) fire simultaneously with a fire suppression failure. TRO appears to have taken measures to mitigate against them as much as practical, subject to any remaining work discussed in Section 3.2.1. Suitable ongoing monitoring and adequate spares and resources are in place to address and respond to unexpected failures.

Generally, Oxen Pond TS appears to have no major issues identified aside from those identified in Section 3.2.1 which should interfere with reliable operation this winter.

- Critical 2013 PM's and planned 2013 capital and corrective work appear largely completed
- Transformer appears to be in good condition for this year
- No major hotspots identified

4 ISSUES/POTENTIAL SYSTEM RELIABILITY IMPACTS

Generally the biggest threats to overall readiness are:

1. Extreme weather at Holyrood (both the TS and GS) similar to January 2013 (although likely a 1 in 10 year event, it could be any year)
2. Incomplete PM and corrective maintenance at Holyrood GS (as a result of other critical work arising there in 2013) resulting in equipment failure
3. Poor Holyrood GS fuel quality resulting during heavy running periods in multiple unit load reductions or shutdowns (unlikely given measures taken; spares parts to mitigate duration)
4. Unexpected/unpredictable failures due to incomplete critical TRO issues (primarily those in Section 3.2.1 as opposed to individual sites)
5. Unexpected/unpredictable failures of critical equipment (generators, transformers, bushings, cables, breakers, relays) at any of the sites due to undetected faults primarily due to aging, particularly those impacting transmission between Bay d'Espoir and Western Avalon TS and those affecting Holyrood GS operation .

On a scale of 1 to 5 (one being highest readiness/lowest risk), most are considered very low risk for the 2013/14 winter period, but any could happen. Significant steps have been taken addressing actions arising from the January 11, 2013 failures that should mitigate such a widespread event. Not all have been completed however.

The impact on overall readiness from unexpected/unpredictable failures of critical equipment (generators, transformers, bushings, cables, switchgear, relays) due to undetected faults primarily due to aging is considered less likely. There is little further action that can be taken now to eliminate those risks. Feasible actions are primarily of a monitoring nature so as to minimize the impact and the duration of any event that does occur. This activity seems to be well in hand as well as also mitigated by the availability of significant critical spares and available maintenance resources to minimize the duration.

For extreme weather, the probability is again very unlikely, but being forewarned is forearmed - monitoring trends in the weather and in system responses will be critical.

For Holyrood Unit 2, a short term (2 week outage) would have been helpful to get some work done that would reduce the risk of a trip. The high priority work done in the November 24th to 27th 2013 four day maintenance outage would likely have significantly reduced the risk, but not all of the Unit 2 high priority corrective/PM work was likely completed. Monitoring and preparing to respond is likely the best action at this point.

5 CONCLUSIONS

1. In general Bay d'Espoir Unit 7 and common auxiliaries appear in good condition for reliable operation in 2013/14 winter.
2. TS equipment at Bay d'Espoir, Western Avalon, Come-By-Chance, Sunnyside, Oxen Pond, and Hardwoods appear in good condition, with no major hotspots indicating a significant remaining risk
3. TS equipment at Holyrood TS remains a significant risk to overall system reliability in winter 2013/14 in the unlikely event of a weather condition like January 2013,
4. Holyrood Unit 2 remains a moderate risk to overall system reliability (may be acceptable if no other contingency failures occur during recovery) in winter 2013/14 due to the inability to complete all of the planned PM work during 2013 due to critical work undertaken on Unit 1 that had been damaged in the early 2013 system outage. Highest priority Unit 2 PM work undertaken in short outages in November/December 2013 has reduced the risk.
5. All Holyrood units remain a significant risk to overall system reliability in winter 2013/14 in the unlikely event of a weather condition similar to that of January 2013 - in the event that Holyrood TS experiences similar problems and Hardwoods is also unable to supply black start power
6. Fuel quality related performance issues at Holyrood appear to have been mitigated, but heavy running could result in one or more unit deratings or trips. Critical spares and maintenance resources appear to be in place to mitigate the occurrence and duration.
7. Any generating unit and TS could experience failures of critical equipment (generators, transformers, bushings, cables, breakers, relays, etc.) due to undetected faults primarily due to aging. In most cases, a single contingency would not likely result in a large system failure. Those impacting generation at or transmission between Bay d'Espoir and Western Avalon TS and those affecting Holyrood GS operation would likely be more critical.
8. Remaining issues with known or unknown P&C issues at GS and TS sites (existing or resulting during equipment/logic swap outs) could result in more failures like the second Holyrood Unit 1 turbine lubrication failure or in more widespread cascading failures.

6 RECOMMENDATIONS

For the 2013/14 winter period:

1. The facilities continue their current program of equipment monitoring and PM maintenance.
2. The facilities re-evaluate and maintain key critical spares and ensure that said spares are both in place and being adequately stored to ensure their condition for use when/if required.
3. Extreme weather responses should be at the ready.
4. Holyrood GS evaluate how it could keep at least one unit running on station load during a major outage to return to service more quickly.

5. Generating Stations and TRO continue its program examining critical system and equipment control/trip logic (and changes in logic) regarding their response to system disruptions re their adequacy (protection, recovery, flexibility) and initiate changes where it is considered necessary and practical.