A REPORT TO
THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

	Electrical
	Mechanical
	Civil
	Protection & Control
	Transmission & Distribution
	Telecontrol
	System Planning

Replace Site Facilities

Bay d'Espoir

July 2015

newfoundland labrador hydro
a nalcor energy company

SUMMARY

The maintenance garage, carpentry shop and warehouse supporting the Bay d'Espoir Generating Station are essential to the maintenance operations of the power plant. These buildings range in age between 30 and 53 years old and are in a deteriorated condition. The maintenance garage and the carpentry shop were constructed as temporary buildings during the construction of the plant and have outlived their life expectancy.

A condition assessment of the maintenance garage and carpentry shop was completed in 2012. Deficiencies such as structural, life safety, electrical code and health and safety deficiencies were noted in the report and the consultant recommended that these two buildings be replaced.

In 2014, safety, structural and electrical code deficiencies were reviewed for all three buildings, whereby costs to refurbish these deficiencies to extend the life of these buildings to 25 years was developed. A cost estimate outlining refurbishments to add more life to these buildings was completed.

A needs assessment was completed in 2014 whereby it was determined that the warehouse and maintenance garage did not meet the functional needs of the maintenance operation for the plant. A conceptual design was also prepared for a consolidated building that would address all the functional issues.

The results of these reports confirm that these buildings are in a deteriorated state and nearing the end of their life expectancy. The condition of these three buildings has reached a point where safety, electrical and structural deficiencies need to be addressed as they pose a risk to the safety of Hydro's employees should the buildings continue to be utilized for any length of time into the future.

Utilizing these reports, a cost comparison was completed to determine which upgrade

option for the maintenance garage, carpentry shop and warehouse would be the least cost option. Over a 25 year study period, it was determined that replacement of these three buildings with a single consolidated building was the most cost effective. As a result, this report outlines a project to replace these three buildings with a new consolidated building that will serve the needs of the operation while maintaining the safety of our employees.

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1 INTRODUCTION

There are number of operations related buildings supporting the Bay d'Espoir Hydroelectric Generating Station that are used to house replacement parts and facilitate maintenance of equipment that is necessary for the operation of the 604 MW power plant. Many of the buildings currently in use were constructed approximately 50 years ago as temporary buildings that were required during the construction of the Bay d'Espoir plant. A number of these buildings are in poor condition and require refurbishments to address structural, electrical, safety and fire safety problems that pose a risk to the safety of Hydro personnel. The buildings that are most in need of attention include the maintenance garage, the carpentry shop and the warehouse.

This report outlines a proposal to replace the maintenance garage, carpentry shop and warehouse with a new consolidated building that will serve the needs of the operation while maintaining the safety of our employees.

2 PROJECT DESCRIPTION

The project involves the replacement of the maintenance garage, carpentry shop and warehouse with a consolidated building that will contain the functionality of these existing facilities. The scope includes:

- Finalized preliminary design of a new building;
- Detailed engineering and tender document development for the new building; and
- Construction of a new building.

The work will require permitting from Environment and Conservation regarding water servicing as well as the development of a new sanitary treatment system. The design and construction of this new building will begin in 2016 with final commissioning of the building occurring by the end of 2018.

3 JUSTIFICATION

The maintenance garage, carpentry shop and warehouse support maintenance activities such as storage of replacement parts and materials, as well as equipment maintenance which includes, welding and fabrication. These buildings also house maintenance supervisor offices as well as employee personal protective equipment required to perform their jobs. These activities are essential to the repair and operation of the power plant and safe facilities to perform these tasks are critical.

The condition of these three buildings is such that continued use into the future is not appropriate considering the safety, electrical and structural deficiencies that pose a risk to the safety of Hydro's employees. As a result, this project is justified on the requirement to replace failing or deteriorated infrastructure in order for Hydro to provide safe, least-cost, reliable electrical service. A cost benefit analysis has been prepared outlining three acceptable options for upgrading the deteriorated operations buildings in Bay d'Espoir and the solution presented has been determined to be the least cost option over the next 25 years.

3.1 Existing System

These buildings are necessary for the operation of the Bay d'Espoir Hydroelectric Generating Station. They serve as the locations where replacement parts are stored and maintenance is performed on equipment that is essential to the operation of the plant.

Maintenance Garage

The Maintenance Garage was constructed as a temporary building in the early 1960's and is over 50 years old. This building is used to support day to day maintenance operations and includes heavy equipment and vehicle repair garage, machine shop, welding shop, offices, washrooms, employee lockers and lunchrooms. The building is a two story building with a ground floor footprint of 9386 ft^2 and a functional area of 10,904 ft^2. Construction consists of a concrete foundation, concrete slab-on-grade and an ARMCO pre-engineered steel

frame building. A single story concrete masonry lean-to style structure was added to the rear of the building, and a single story metal clad lean-to style structure was added to the northeast corner of the building. The existing building floor plan is shown in Figure 1.

There have been no major upgrades to this building since construction, other than those noted above.

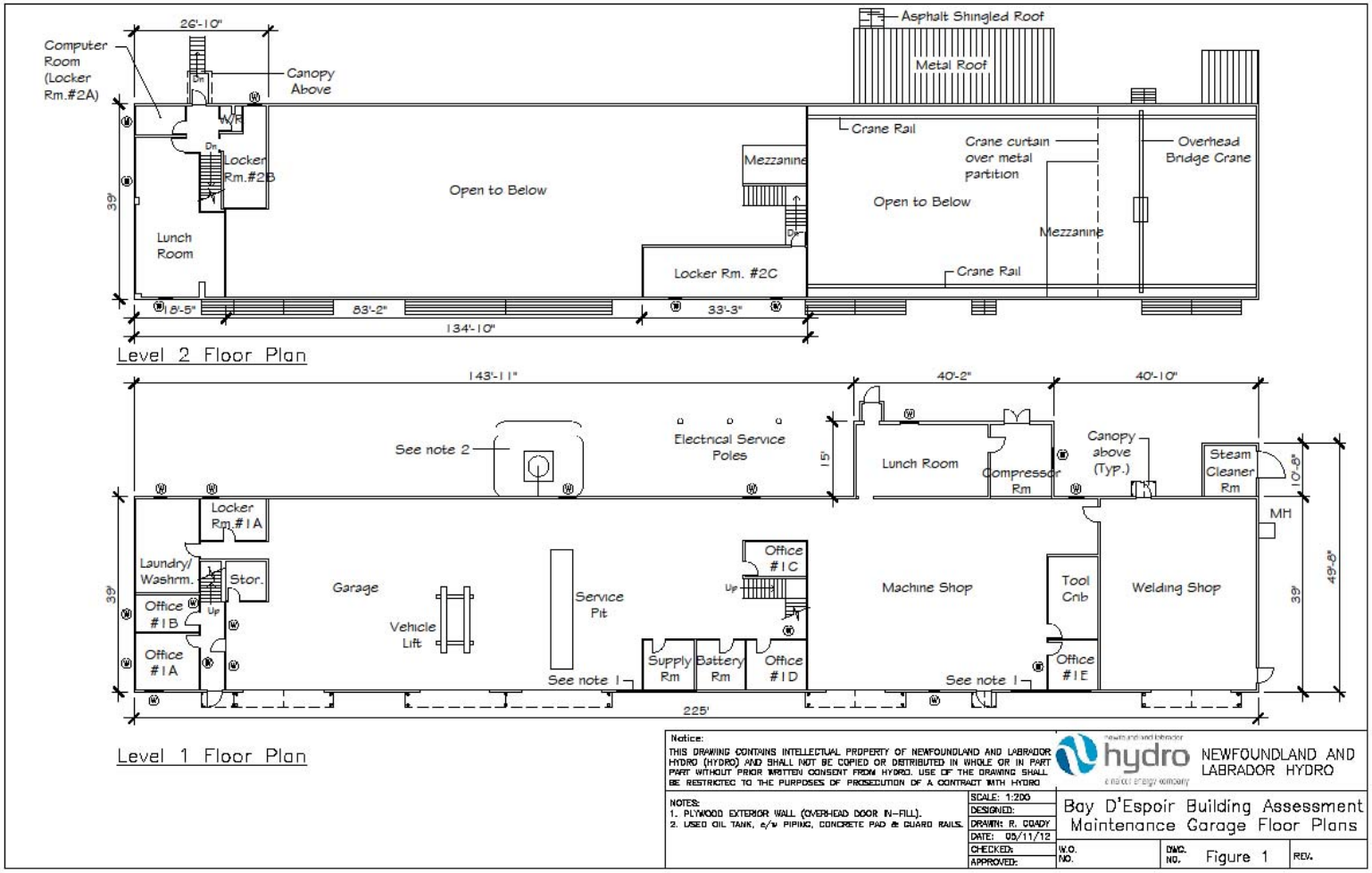


Figure 1: Existing Floor Plan for Maintenance Garage

Carpentry Shop

The Carpentry Shop was constructed as a temporary building in the early 1960's and is over 50 years old. This building is used for carpentry services to support day to day maintenance operations and includes a carpentry shop, tool room, storage room, washroom, dust collection room and chemical storage room. The building is a one storey structure with a building footprint of 3122 ft^2. The original building is an ARMCO pre-engineered steel building supported on wood sleepers. The storage room is a corrugated metal "Quonset hut" supported on a concrete slab on grade. The tool room and north entry additions, constructed in the 1990's, are wood framed structures constructed on wood sleepers. The existing building floor plan is shown in Figure 2.

There have been no major upgrades to this building or additions since construction, other than those noted above.

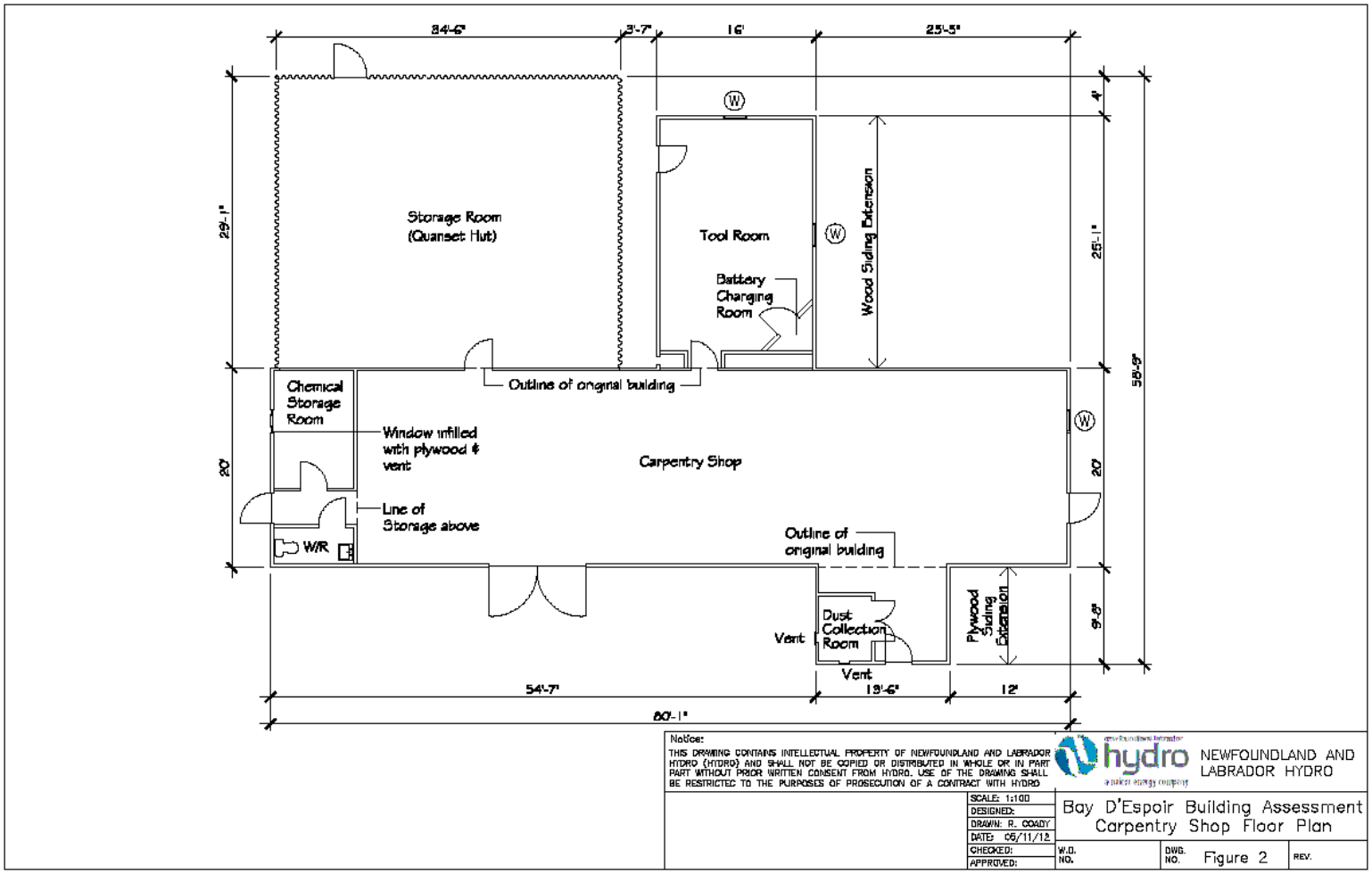


Figure 2: Existing Floor Plan for Carpentry Shop

Warehouse

The Warehouse was constructed in 1985 and is 30 years old. This building is used for storing material required for maintenance and capital work and includes three separate material storage areas, a storage area for gasoline products, a lunch area, washroom and office. The building is a one storey structure with a building footprint of 6274 ft^2. The original building is a corrugated metal "Quonset hut" supported on a concrete slab on grade. The two additions, constructed in the 1990's, are steel framed structures supported on a concrete slab on grade. The existing building floor plan is shown in Figure 3.

There have been no major upgrades to this building since construction, other than those noted above.

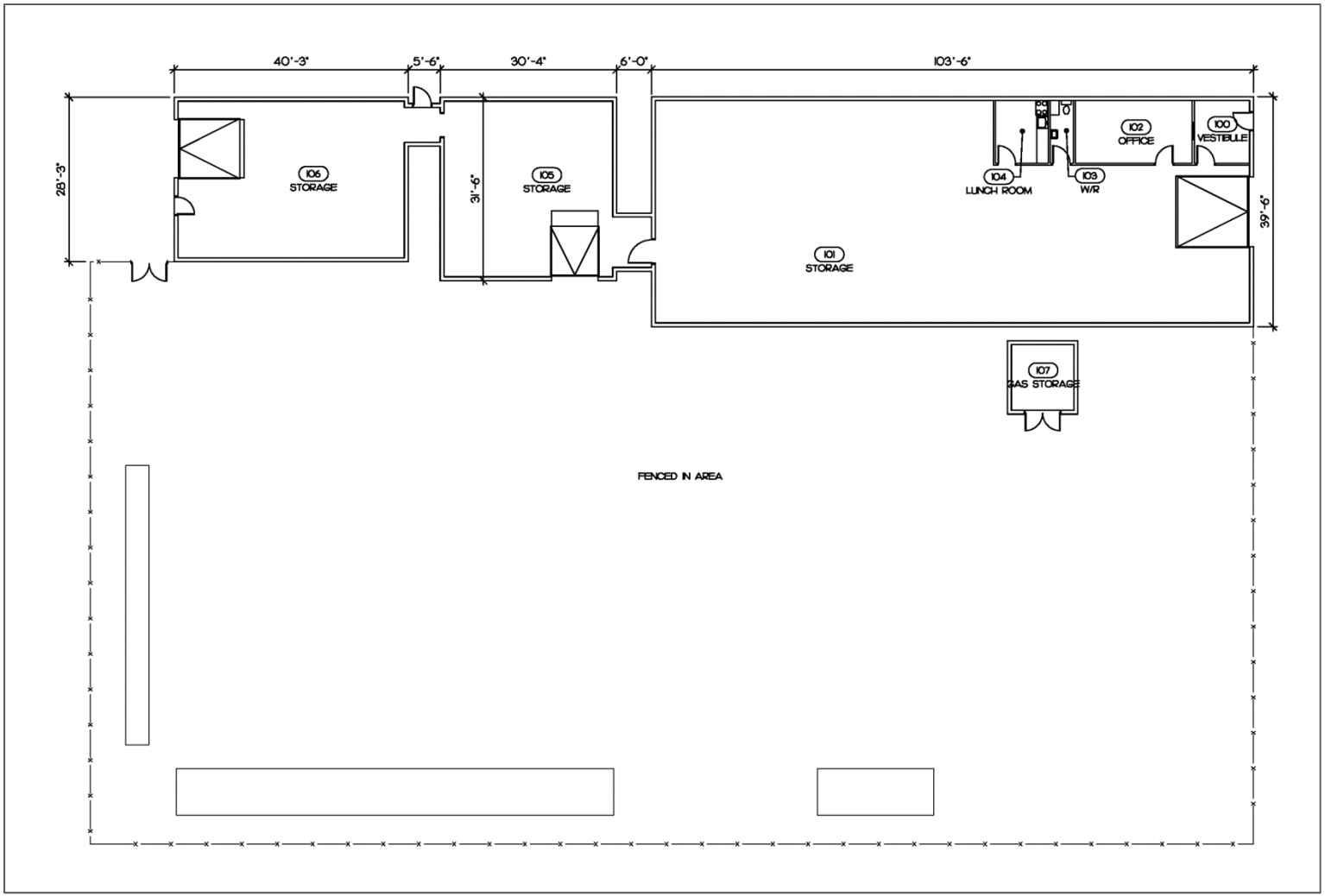


Figure 3: Existing Floor Plan for Warehouse

3.2 Operating Experience

Between 2012 and 2014, the following building assessments were completed for the Bay d'Espoir operating buildings. These are detailed as follows:

- "Building Condition Assessment, Maintenance Garage, Carpentry Shop and Training Centre" was completed in 2012 by RDB Engineering Ltd and Associates. See Appendix A for report.
- "Building Needs Assessment – Selected Structures" was completed in 2014 by Hatch Mott MacDonald in association with exp Architects Inc. See Appendix B for report.

In 2012, the "Building Condition Assessment, Maintenance Garage, Carpentry Shop and Training Centre" report was commissioned to assess the condition of the noted structures. The report outlined deficiencies in all three buildings and due to the number of deficiencies, some considered critical in nature, recommended replacement within three to five years of the maintenance garage and the carpentry shop, complete with Class 5 cost estimates.

With a recommendation to replace the maintenance garage and carpentry shop noted in the 2012 study, in 2014, a needs assessment was commissioned to review the functionality of each building and determine if the existing building space was meeting the needs of the operation and ways to improve operational efficiency. This report includes a review of the functional needs of the security building, carpentry shop, maintenance garage, training centre, warehouse and powerhouse office. During the assessment, it was determined by the consultant that a few of the buildings did not meet functional space requirements and as a result, a conceptual design for a new building to house the functions of all the reviewed buildings, and consolidate all services in one location, complete with a Class 3 cost estimate, was included in this report.

In 2014, a review of the required refurbishments was completed for the maintenance garage, carpentry shop and warehouse based on building code violations as well as safety issues. There is no mechanism with the National Building Code (NBC) that requires a building owner to maintain a building current with the NBC as long as the functional

use/classification of the facility does not change and no significant alterations are made to the building. However, despite this lack of requirement, there still remain occupational health and safety requirements and workplace efficiencies that warrant refurbishments. In addition, it is prudent for Hydro to remedy any code violations deemed to pose a risk to the safety of employees. Such items as inadequate fire separations and aged electrical panels increase the likelihood of fire spreading in a building and pose a risk to Hydro employees. Remediating these types of deficiencies protects workers and is the responsible action to take for a safety leader such as Hydro. Deficiencies were detailed and a cost estimate was developed to refurbish these three structures to provide a safe environment for workers while extending the life expectancy of each building another 25 years.

The above information was used to develop a cost benefit analysis; comparing the cost to replace these three buildings individually, the cost to consolidate these buildings into one facility, and the cost to refurbish these buildings.

Conditions and recommendations from the reports noted above are detailed below for each corresponding building.

3.2.1 Maintenance Garage

Condition Assessments

The initial condition assessment completed in 2012 indicated the following list of significant deficiencies:

- The absence of critical fire separations;
- The lack of adequate ventilation and associated risk;
- Obsolete and inappropriate installation of electrical equipment and electrical code violations; and
- Structural deficiencies and modifications.

Other deficiencies of a less critical nature were noted including life safety code violations, inadequate weather resistance, inadequate thermal resistance and poor moisture control.

As a result of these findings, it was recommended in the 2012 assessment that no further significant investments be considered for the Maintenance Garage and it be considered for replacement within five years.

A condition assessment was completed in 2014 to determine the costs to refurbish the building to extend the life of the structure another 25 years. The refurbishments identified address structural, life safety, Occupational Health and Safety (OHS) related and electrical safety code deficiencies. Although many of the deficiencies are repairable, there are items which require significant work or replacement. Some of the deficiencies and refurbishments are listed in Table 1 below. As outlined in the table, there is a range of deficiencies including structural, electrical, mechanical and life/fire safety. Photos 1 through 7 are examples of the condition within the maintenance garage.

Table 1: Examples of Refurbishments Required

Recommendation	Reason
Structural repairs related to bracing in bays	Structural deficiency and safety issue
Replace roof construction at lean-to structure	Roof leaking heavily and incorrect slope with poor construction.
Replace windows and skylights	Windows at end of life
Install permanent non-combustible wall to replace plastic drapes	Fire Safety
Replace wood doors and frames	Poor condition
Replace steel cast iron piping at water service entrance	Not up to code and safe drinking requirements
Install oil containment system relating to storage of petroleum products	Not meeting GAP regulations
Replace play ford heaters	End of life
Provide ventilation in garage, washrooms, lockers, kitchen and office areas to meet code	Ventilation does not meet building code requirements nor personnel safety requirements for working in a garage environment
Replace battery room fan with a non-sparking type motor	Fire Safety
Replace electrical distribution panels	Beyond useful life. Potential fire hazard
Replace panel boards and disconnects	End of life. Potential fire hazard
Install additional emergency lighting in garage and main floor washroom	Fire safety



Photo 1: Maintenance Garage



Photo 2: Original single glazed exterior window



Photo 3: Concrete block wall with loss of grout



Photo 4: Rotten frame around overhead door



Photo 5: Louvre with improper structural support



Photo 6: Concrete Slab Structural Cracking



Photo 7: Holes incorrectly located in column web

Needs Assessment

The needs assessment indicates that "the building is undersized to meet the present day needs. The structure suffers from a compartmentalized configuration with each functional group having their set of services. This leads to many duplicated services throughout the

building such as locker rooms and wash rooms."

3.2.2 Carpentry Shop

Condition Assessments

The initial condition assessment completed in 2012 indicated the following list of significant deficiencies:

- the absence of critical fire separations and explosion venting of the Dust Collection Room;
- the lack of adequate ventilation and make-up air as it pertains to the dust collection system;
- an inadequate dust collection system with respect to equipment interlocks, the presence of an open-face transformer, and the presence of non-explosion type unit heaters; and
- the absence of a suitable foundation as the existing foundation currently consists of 50 year old wood sleepers that are in poor condition.

Other deficiencies were noted including life safety code violations, electrical code violations, inadequate weather resistance, inadequate thermal resistance, and windows and doors at end of life. As a result of these findings, it was recommended in the 2012 assessment that no further investments be considered for the Carpentry Shop and it be considered for replacement in three years.

A review was completed in 2014 to determine the costs to refurbish the building to extend the life of the structure another 25 years. The refurbishments identified address structural, life safety, OHS related and electrical safety code deficiencies. The assessment identified that the carpentry shop exists well beyond its expected life span and is showing heavy signs of deterioration; some areas non-repairable. The refurbishments will extend the life of the building by 25 years, after which time, the facility will require replacement.
Some of the deficiencies and refurbishments are listed in Table 2 below. As outlined in the table, there is a range of deficiencies including structural, electrical, mechanical and life/fire

safety. Photos 8 through 12 are examples of the condition of the carpentry shop.

Table 2: Examples of Refurbishments Required

Recommendation	Reason
Replace wood foundation with concrete footings and frost walls	Wood foundation is beyond end of life
Replace wood framed floor with new concrete	Floor is beyond end of life
Spray and seal Quonset hut roof	Quonset hut roof is heavily rusted
Replace plywood siding and wood soffits	Poor condition
Demolish and replace north side addition	Possible structural failure /end of life
Replace windows and doors	Disrepair/poor condition
Provide ventilation system in building	OHS requirements for dust control environments
Provide humidifier in building	Humidifier is critical in carpentry shops for spark control



Photo 8: Carpentry Shop with Addition



Photo 9: Dust Collection Room with undersized vent



Photo 10: Deteriorated wall base



Photo 11: Heaving Grounding system



Photo 12: Open faced transformer with dust buildup

Needs Assessment

It was identified in the needs assessment that one area of the carpentry shop was used for storage of herbicides for vegetation control. These chemicals present a hazard and for employees safety, should be relocated outside of the carpentry shop. Otherwise, the building has sufficient space for the specified activities with the exception of missing lockers and lunch area.

3.2.3 Warehouse

Condition Assessments

The warehouse was not included in the 2012 condition assessment but was included in both the needs assessment and the refurbishment review completed in 2014.

The refurbishment review was completed to determine the costs to refurbish the building to extend the life of the structure another 25 years. The refurbishments identified address structural, life safety, OHS related and electrical safety code deficiencies. Although many of the deficiencies identified are repairable, there are items which require modifications to meet electrical code and safety requirements or replacement. Some of the deficiencies and refurbishments are listed in Table 3 below. As outlined in the table, there is a range of deficiencies including structural, electrical, mechanical and life/fire safety. Photos 13 through 17 are examples of the condition of the warehouse.

Table 3: Examples of Refurbishments Required

Recommendation	Reason
Sand Blast and seal Quonset hut roof	Quonset hut roof is rusting
Replace electrical mast to building	End of life
Reinstate insulation and fire protection	Fire protection is missing
Provide separate circuit for air conditioning units	Electrical Code requirement
Provide ventilation system for warehouse and office	Code requirement
Connect explosion proof fan to monitor to prevent buildup of hazardous vapors	Safety
Replace electrical panel boards	Potential fire hazard / end of life
Replace existing emergency lighting wall packs	End of life



Photo 13: Warehouse Quonset hut with additions



Photo 14: Fire protection/insulation is missing and material is singed

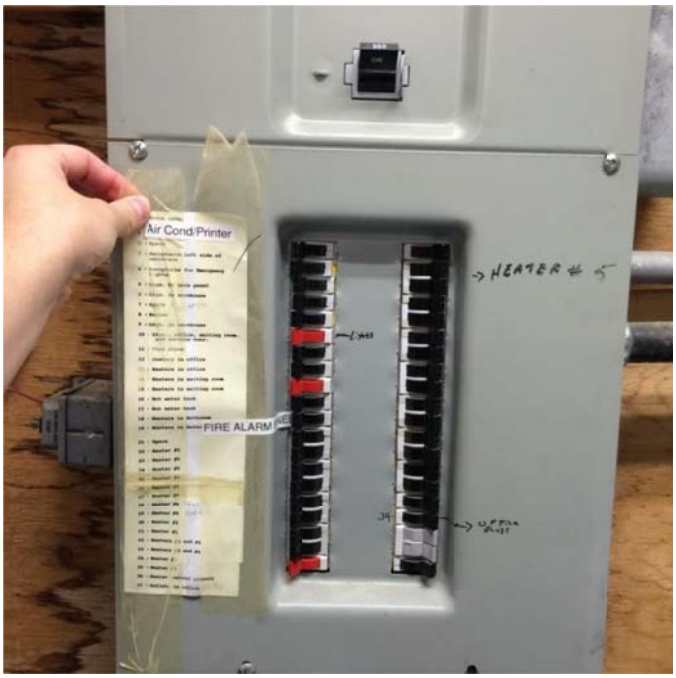


Photo 15: Replace obsolete panel board

Needs Assessment

The following items were identified in the needs assessment for the warehouse.

- The receiving area is undersized;
- The building is undersized to effectively utilize the storage systems;
- Forklift travel is not possible for inventory handling as the aisle widths are too narrow, making material handling slower than if proper space was available, and also requiring more lifting of materials;
- Items have to be lifted by employees onto shelving including heavy items such as motors;
- Many items have to be handled multiple times to gain access to items on the shelves;
- The building is isolated from other functional groups and workers have to travel by vehicle to pick up materials at the warehouse, reducing efficiency; and
- Some items are currently stored in the generator building and should be located at the warehouse for proper inventory control.



Photo 16: Curved ceiling and poor access to shelving



Photo 17: Heavy motors moved by hand to shelves

3.2.4 Anticipated Useful Life

The typical life expectancy for a permanent construction building is in the range of 50 to 75 years. The maintenance garage and the carpentry shop were built in the 1960s during the construction phase of the Bay d'Espoir Generating Station. These buildings were constructed as temporary buildings. As an example, the original portion of the carpentry

shop was constructed on wood sleepers which are not considered to be a permanent foundation. Wood foundations have a life expectancy in the range of 30 years. The building has been in service for over 50 years to date and the wood sleepers require replacement to extend the life of the carpentry shop. Table 4 outlines the life expectancy of a building of typical construction as the maintenance garage, carpentry shop and warehouse.

Table 4: Life Expectancy for Typical Buildings

Building Name	Construction Type of Hydro Facility	Anticipated Life Expectancy (Type)	Existing In Service Life of Hydro Building
Maintenance Garage	Pre-engineered building (Steel framed, metal roof and metal siding) on concrete foundation and slab on grade. Concrete masonry unit addition.	50 years	53 years
Carpentry Shop	Pre-engineered steel frame building plus wood framed building on creosote wood sleepers with Quonset hut on concrete slab on grade	25 years	49 years
Warehouse	Quonset hut and steel framed additions on concrete slab	25-30 years	30 years

3.2.5 Maintenance History

Ongoing maintenance has been completed for these buildings and, as is typical for aging buildings, the amount of money spent for maintenance increases with age.

The five-year maintenance history for the Maintenance Garage, Carpentry Shop and Warehouse is shown in Table 5:

Table 5: Five-Year Maintenance History

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2014	3.9	18.0	21.9
2013	2.2	46.2	48.4
2012	3.2	49.1	52.3
2011	6.2	68.2	74.4
2010	3.1	42.8	45.9
Total	**18.6**	**224.3**	**242.9**

3.3 Development of Alternatives

Three alternatives to resolving these deficiencies were developed and are listed as follows:

1. Replace the existing buildings with a consolidated new building;
2. Replace each building individually with a new same sized building for a total of three new buildings; and
3. Refurbish all three buildings as they are in their current location to increase life expectancy to 25 years.

3.3.1 Replace Existing Buildings with a New Consolidated Building

The needs assessment indicated that there were inefficiencies relating to staff travel between operations buildings and the some of the spaces were undersized for the required functional need. As a result, it was determined that one viable alternative would involve replacing the existing buildings with one new building. This new building would have the same functionality as the existing three buildings while increasing its size to address lack of space as outlined in the needs assessment.

A conceptual design had been developed and presented in the needs assessment, however, this design included not only the maintenance garage, carpentry shop and warehouse functionalities but also the office, training centre and security functions. Since the new building would include just the maintenance garage, carpentry shop and warehouse functions, the conceptual design plan size was reduced to include only the square footage for the intended functions, i.e., the conceptual building size was reduced from the proposed 34,045 sqft to 28,925 sqft.

Ultimately, the functional area of these three existing buildings is 20,300 sqft and the area outlined for the maintenance garage, carpentry shop and warehouse functions in the conceptual plan is 28,925 sqft; an increase of 8625 sqft in the overall functional space.

Table 6 below compares the square footage allotments between the functional area of the existing buildings and the functional area of the new building.

Table 6: Comparison of Functional Area between Existing and New Consolidated Building

Function	Existing Building Area (sqft)	Area in New Building (sqft)
Carpentry Shop	3,122	3,402
Maintenance Shop (including lockers, lunch room, supervisor offices, new P&C shop etc.)	10,904	14,275
Warehouse	6,274	11,248
Total Areas	**20,300**	**28,925**

The costing details developed for the original conceptual can be found in the needs assessment in Appendix B of this report. This estimate in the needs assessment report was reduced to account for the removal of the management offices and the security areas from the conceptual layout.

Table 7 provides a high level outline of the development of the final budget estimate. This high level estimate would include only the activities required to complete engineering, procurement and construction management (EPCM) as well as the construction costs of the project.

Table 7: EPCM and Construction Cost Estimate for New Consolidated Building

	Cost Estimate ($ x 1,000)
Project Management, Engineering, Environmental, On Site Representation	$902.3
Contract Engineering for Design and Inspection	$1,210
Contract Construction – New Building	$7,530
Total EPCM and Construction Cost (no escalation or interest)	$9,642.3

Table 8 outlines the budget estimate to replace the existing buildings with a new consolidated building.

Table 8: Multiyear Budget Estimate for New Consolidated Building

Project Cost: *($ x1,000)*	**2016**	**2017**	**2018**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	220.0	297.0	205.6	722.6
Consultant	0.0	0.0	0.0	0.0
Contract Work	650.0	3,960.0	4,130.0	8,740.0
Other Direct Costs	13.0	83.4	83.4	179.7
Interest and Escalation	45.3	395.9	933.6	1,374.8
Contingency	0.0	0.0	964.2	964.2
TOTAL	**928.3**	**4,736.3**	**6,316.7**	**11,981.3**

As part of the development of the cost benefit analysis, the following items were added to the analysis, in addition to the construction cost estimate:

- Demolition costs of the existing three buildings; and
- Residual benefit of the new consolidated building at the end of the 25 year study period.

Any operating and maintenance costs that would be incurred in all three options, were not included in the cost benefit analysis. These items include such things as replacement of fire hoses and extinguishers as required under the NBC as well as replacement of eye wash station water every six months. Such items would be required no matter which option was selected.

3.3.2 Replace Each Building

Replacement of the three buildings was recommended by RDB Engineering Limited and determined to be a viable option. Cost estimates were developed using square footage costs obtained from RS Means; a recognizable estimating publisher. These costs were developed for base construction only and as such, contractor overhead and profit as well as general requirements, for such items as site offices, safety, mobilization and demobilization, were added to the base construction cost as these would be included in a tender price.

In addition to the above contractor costs, costs for detailed engineering, project management and inspection were added to the building construction as well as contingency for a Class 5 estimate.

Table 9 provides a high level outline of the development of the final budget estimate. This high level estimate would include only the activities required to complete EPCM as well as the construction costs of the project.

Table 9: EPCM and Construction Cost Estimate to Replace Existing with Three Buildings

	Cost Estimate ($ x 1,000)
Project Management, Engineering, Environmental, On Site Representation	$1,151
Contract Engineering for Design and Inspection	$1,716
Contract Construction – New Building	$8,100
Total EPCM and Construction Cost (no escalation or interest)	$10,967

Table 10 outlines the budget estimate to replace all buildings individually.

Table 10: Multiyear Budget Estimate for Individual Replacement of Existing Buildings

Project Cost:*($ x1,000)*	**2016**	**2017**	**2018**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	296.6	301.5	301.5	899.6
Consultant	0.0	0.0	0.0	0.0
Contract Work	820.0	4,448.0	4,548.0	9,186.0
Other Direct Costs	15.0	118.3	118.2	251.5
Interest and Escalation	58.1	453.8	1,060.9	1,572.8
Contingency	0.0	0.0	1,096.7	1,096.7
TOTAL	**1,189.7**	**5,321.6**	**7,125.3**	**13,636.5**

As part of the development of the cost benefit analysis, the following items were added to the analysis, in addition to the construction cost estimate:

- Construction cost of a new 8625 sqft building as outlined above;
- Demolition costs of the existing three buildings; and
- Residual benefit of the new buildings at the end of the 25 year study period.

As noted above, a new building with an area equal to the difference between the new building area and the functional areas of the existing buildings was added to the cost benefit analysis. As noted in section 3.3.1, the new consolidated building area is 28,925 sqft

while the functional area of the existing buildings and thus the three new replacement buildings would be 20,300 sqft. In order to compare size equivalent options, the cost to construct a new 8625 sqft building was added to the cost benefit analysis.

3.3.1 Refurbish Buildings

Refurbishments for the maintenance garage, carpentry shop and warehouse were developed and used to populate the cost benefit analysis (CBA). It should be noted that there is a level of uncertainty with respect to refurbishment costs since unknown conditions can exist behind walls that may not have been observed during the review. End of life and replacement items, fire safety matters, electrical issues, structural deficiencies and health and safety items were carried into the capital expenditure years of the CBA.

A cost has also been added to the construction estimate for relocation of the workers from the maintenance garage during the refurbishments. As noted in the 2012 assessment report in Appendix A, "building envelope, interior fire-separations, mechanical ventilation, etc., …..would effectively render the building unusable during renovation".(RDB, p ii).

A cost estimate was developed for a pre-engineered steel building on temporary foundation as well as pre-fabricated office space providing just under the square footage available in the existing maintenance garage. This cost to relocate workers during refurbishment has also been included in the capital costs of the CBA.

Table 11 provides a high level outline of the development of the final budget estimate. This high level estimate would include only the activities required to complete EPCM as well as the construction costs of the project.

Table 11: EPCM and Construction Cost Estimate to Refurbish the Existing Buildings

	Cost Estimate ($ x 1,000)
Project Management, Engineering, Environmental, On Site Representation	$1,632
Contract Engineering for Design and Inspection	$443
Contract Construction – Temporary Building for relocation	$2,670
Contract Construction – Refurbish Existing Buildings	$3,155
Total EPCM and Construction Cost (no escalation or interest)	$7,900

Tables 12 and 13 outline the capital cost required to complete refurbishments and the costs for relocation of workers during construction.

Table 12: Multiyear Budget Estimate for Refurbishment Option

Project Cost:*($ x1,000)*	**2016**	**2017**	**2018**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	183.5	443.8	443.8	1,071.1
Consultant	0.0	0.0	0.0	0.0
Contract Work	311.0	1,577.5	1,577.5	3,466.0
Other Direct Costs	10.0	142.7	142.8	295.5
Interest and Escalation	26.0	202.9	468.5	697.4
Contingency	0.0	0.0	483.3	483.3
TOTAL	**530.5**	**2,366.9**	**3,115.9**	**6,013.3**

Table 13: Multiyear Budget Estimate for Relocation Costs During Refurbishment Option

Project Cost:*($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	127.0	115.6	0.0	242.6
Consultant	0.0	0.0	0.0	0.0
Contract Work	132.0	2,670.0	0.0	2,802.0
Other Direct Costs	6.0	16.8	0.0	22.8
Interest and Escalation	13.8	281.6	0.0	295.4
Contingency	0.0	613.5	0.0	613.5
TOTAL	**278.8**	**3,697.5**	**0.0**	**3,976.3**

As part of the development of the cost benefit analysis, the following items were added to the analysis, in addition to the construction cost estimate for both the refurbishment and the relocation building:

- Construction cost of a temporary building to accommodate workers during repairs to the maintenance garage. The cost of this building also represents the cost to

provide an additional 8625 sqft of floor space as outlined in section 3.3.1; and

- Operating and maintenance costs that are over and above what would expected to maintain the other new building options.

When calculating the operating and maintenance costs for inclusion in the CBA, it should be noted that some refurbishments will last 20 to 25 years such as roofing replacements, however some refurbishments, such as fin replacement on a 30 year old heater, will extend the life of the item five to ten years, after which the item will require replacement. These costs have been addressed in the cost benefit analysis by including the replacement costs in the operating and maintenance costs some time after the initial refurbishments.

As these refurbished buildings will be up to 75 years old at the end of the study period, there was no residual benefit added to the cost benefit analysis for these existing buildings.

3.5 Evaluation of Alternatives

The three alternatives were evaluated based on least cost. For Hydro, the term "least-cost" refers to the lowest Cumulative Present Worth (CPW) of all capital and operating costs associated with a particular incremental supply source (or portfolio of resources) over its useful economic life, versus competing alternatives or portfolios. CPW concerns itself only with the expenditure side of the financial equation. The lower the CPW, the lower the revenue requirement for the utility.

Based on the CBA completed for the three stated alternatives, the least cost option is shown to be "Replace buildings with a New Consolidated Building" as shown in Table 14.

Table 14: Results of Cost Benefit Analysis of the Three Presented Alternatives

Facility Upgrade - BDE **Alternative Comparison** ***Cumulative Net Present Value*** ***To The Year*** **2015**		
Alternatives	**Cumulative Net Present Value (CPW)**	**CPW Difference between Alternative and the Least Cost Alternative**
New Building	8,749,247	0
Refurb all buildings	9,115,313	366,066
Replace Individual Buildings	11,700,302	2,951,055

4 CONCLUSION

The maintenance buildings supporting the Bay d'Espoir Hydroelectric Generating Station are essential to the operation of the plant, and due to their age have found to be deteriorated in in need of significant refurbishments. Conditions assessments confirm there is safety, structural and electrical code deficiencies that require immediate attention. These deficiencies pose a risk to the safety of our employees and are the justification for upgrading these buildings.

Three alternatives were considered:

- Refurbish all three buildings to increase life expectancy to 25 years;
- Replace each building individually with a new same sized building for a total of three new buildings; and
- Replace the buildings with a consolidated new building.

A cost benefit analysis was completed and the evaluation of the analysis concluded that the least cost option is for replacement of the buildings with a new consolidated building.

This report outlines a project to replace the maintenance garage, carpentry shop and warehouse with a new consolidated building that will serve the needs of the operation while maintaining the safety of our employees.

4.1 Budget Estimate

The budget estimate for the replacement of the existing maintenance garage, carpentry shop and warehouse with one new consolidated building is found in Table 15.

Table 15: Project Budget Estimate

Project Cost: *($ x1,000)*	**2016**	**2017**	**2018**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	220.0	297.0	205.6	722.6
Consultant	0.0	0.0	0.0	0.0
Contract Work	650.0	3,960.0	4,130.0	8,740.0
Other Direct Costs	13.0	83.4	83.4	179.7
Interest and Escalation	45.3	395.9	933.6	1,374.8
Contingency	0.0	0.0	964.2	964.2
TOTAL	**928.3**	**4,736.3**	**6,316.7**	**11,981.3**

4.2 Project Schedule

The following schedule is based on a three year project, whereby detailed engineering occurs in year one and construction begins in year two and continues into year three.

Table 16: Project Schedule

Activity		**Start Date**	**End Date**
Planning	Procure Consultant	Feb 2016	Feb 2016
	Preliminary design	March 2016	June 2016
Design	Detailed design	June 2016	Jan 2017
	Tender documents		March 2017
Procurement	RFP for Construction		March 2017
	Tender and Award	March 2017	April 2017
Construction	Mobilize to site	April 2017	May 2017
	Foundation and superstructure Construction	May 2017	Nov 2017
	Interior Construction	Nov 2017	Sept 2018
	Final Exterior Work	July 2018	Sept 2018
Commissioning	Commissioning	Sept 2018	Nov 2018
Closeout	Final Acceptance		Dec 2018

APPENDIX A

2012 Condition Assessment Report

BUILDING CONDITION ASSESSMENT
MAINTENANCE GARAGE, CARPENTRY SHOP AND TRAINING CENTER

BAY D'ESPOIR HYDROELECTRIC GENERATING STATION
MILLTOWN, BAY D'ESPOIR, NL

PREPARED FOR:

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PREPARED BY:

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IN ASSOCIATION WITH:

Maderra Engineering Inc.
AFN Engineering Inc.
Morrison Hershfield Limited

May 2012

EXECUTIVE SUMMARY

NALCOR Energy – Newfoundland and Labrador Hydro (NL Hydro) is evaluating three (3) existing buildings located at Bay D'Espoir Hydroelectric Generating Station, Newfoundland: Maintenance Garage, Carpentry Shop, and Training Center. These buildings are approximately 50 years old and were originally constructed as temporary buildings during the construction phase of the project. NL Hydro intuitively recognizes that the assets are in need of significant upgrading and/or replacement due to their current physical condition; for aesthetic, operational and functional reasons; as well as to meet present-day building codes. To supplement and validate its own observations and advance the future direction in which to take with these assets, the Owner commissioned a building condition assessment for each.

The building condition assessment was undertaken by RDB Engineering Limited (RDB), in association with Morrison Hershfield Limited (MH), Maderra Engineering Incorporated (Maderra), and AFN Engineering Incorporated (AFN), who provided building design, structural, mechanical and electrical, and environmental services, respectively. The project was completed during the period of December 2011 to May 2012. The scope of work included an assessment of each building in the context of present-day codes, standards and regulations so as to evaluate existing conditions and make recommendations for upgrading.

Maintenance Garage

The Maintenance Garage is approximately 50 years old and was constructed as a temporary building in the early 1960s during the construction phase of Bay D'Espoir. It is used to support day-to-day maintenance operations and includes a vehicle repair garage, machine shop and welding shop, as well as offices, washrooms, lunchrooms, etc. The building is a two (2) storey structure with a building area of 872 m^2. In general, it appears to meet its functional requirements in terms of size, use and occupancy.

A substantial list of deficiencies and other unknowns, which would require significant further site investigations, analysis, sampling, and evaluation to fully define a refurbishment scope of work, were identified for this building. Significant upgrading is required to architectural mechanical, electrical, and structural systems, and must take into consideration asbestos containing materials (ACM) within the building. As stand-alone items, some deficiencies can be readily addressed, but consideration must be given to how these deficiencies interact. For example, it is not possible to undertake a significant upgrading of the building envelope or its interior construction without affecting electrical and mechanical systems, whether they are identified as presently compliant or not. Similarly, upgrading the building`s envelope to address

thermal and moisture issues would require a more detailed field program and analysis of the building`s structural system to consider the additional weights, original steel properties, member sizes, etc. Other issues are not easily remediated, such as building envelope, interior fire-separations, mechanical ventilation, etc., and would effectively render the building unusable during renovation. Notable issues include:

- the absence of critical fire separations;
- the potential lack of adequate ventilation and the associated risk;
- obsolete and inappropriate installation of electrical equipment and code violations and the associated risk; and
- structural deficiencies/modifications.

Though less critical in terms of life safety and code violations, with respect to overall condition, aesthetics and functionality, the building's office space, lunchrooms and washrooms are inadequate; collectively, they are in very poor condition, not barrier-free, and/or have been incorporated into the building ad hoc. With respect to the building envelope, it is also inadequate in regards to weather-resistance, thermal resistance, and moisture control.

As a result of these findings, it is recommended that no further significant investments be considered for this building to bring it up to present-day codes and standards and it be immediately considered for replacement. A budget estimate for replacement of a similar size and type of building is as follows:

• New Building: 872 m^2 at $2,700/m2	= $	2,350,000
• Sitework (Allowance)	= $	300,000
• Demolition of Existing Building (Allowance)	= $	300,000
• Contingency at 20%	= $	590,000
• Project Management/Engineering at 12%	= $	420,000
• **TOTAL PROJECT BUDGET**	**= $**	**3,960,000**

In preparing the above conclusions and recommendation the following is noted:

- Subjectively, "immediate" replacement is viewed as within 5 years.
- The replacement cost assumes that any new building would be of a similar size, type and function as the existing building; however, a needs analysis that evaluates the long-term needs of the Owner should be undertaken.
- A potential location for a new building is unknown, thus an "allowance" is included for sitework.

- The requirements for demolition, and in particular asbestos and other potential environmental abatement is unknown, thus an "allowance" is included.
- Opportunities to combine like-functions from other buildings should be considered.

Carpentry Shop

The Carpentry Shop was constructed as a temporary building in the early 1960s during the construction phase of Bay D'Espoir. Site observations suggest that the main carpentry workshop was the original building, while the three (3) extensions (i.e., north entry, storage room, and tool room) were subsequent additions. The building is used for carpentry services to support day-to-day maintenance operations, and includes a carpentry shop, tool room, storage room, washroom, dust collection room, and chemical storage room. The building is a one (1) storey structure with a building area of 290 m^2. In general, it appears to meet its functional requirements in terms of size, use and occupancy.

Major upgrading is required to the architectural, mechanical, electrical, and structural systems for this building, and must take ACMs into consideration. Significant refurbishment is required to address the building envelope, fire ratings, dust collection system, and ventilation system, at a minimum. Critical short-comings are inherent in the electrical and dust collection systems given the wood processing nature of this building and, of particular significance, is the absence of a suitable foundation. The lack of a suitable foundation (i.e., wood sleepers are currently installed), combined with the building's age and condition precludes any further investment in this structure. Notable issues include:

- the absence of critical fire separations and explosion venting of the Dust Collection Room, as well as dust build-up within the room itself;
- the lack of adequate ventilation and make-up air as it pertains to the dust collection system; and
- an inadequate dust collection system with respect to equipment interlocks, the presence of an open-face transformer (and dust build-up within the transformer itself), and the presence of non-explosion type unit heaters.

A budget estimate for replacement of a similar size and type of building is as follows:

- New Building: 290 m^2 at $2,300/m2 ..... = $ 670,000
- Sitework (Allowance)..... = $ 100,000
- Demolition of Existing Building (Allowance)..... = $ 100,000
- Contingency at 20%..... = $ 170,000

- Project Management/Engineering at 12% ..... = $ 130,000
- **TOTAL PROJECT BUDGET ..... = $ 1,170,000**

In preparing the above conclusions and recommendation, the following is noted:

- Subjectively, "immediate" replacement is viewed as within 3 years.
- The replacement cost assumes that any new building would be of a similar size, type and function as the existing building; however, a needs analysis that evaluates the long-term needs of the Owner should be undertaken.
- A potential location for a new building is unknown, thus an "allowance" is included for sitework.
- The requirements for demolition, and in particular asbestos and other potential environmental abatement is unknown, thus an "allowance" is included.
- Opportunities to combine like-functions from other buildings should be considered.
- The budget does not include for new shop equipment.

Training Center

The Training Center was constructed as a temporary building in the early 1960s during the construction phase of Bay D'Espoir and is approximately 50 years old. While beyond the scope of this study, it appears to have some functional short-comings or is underutilized. The building was originally constructed as a staffhouse, but is currently used for staff functions, office space, and as a training center (which was a change in use and occupancy by Code). It was reported by the Owner that the sleeping quarters is seldom used, perhaps just a couple nights per year. The office space was noted as being not well laid out or functional: cubicles are located immediately adjacent to the entrance, and to move between the main office area and the entry/washroom/training area, one must pass through another office and a meeting room (a functional and exiting issue).

The exterior of this building is noted as being in good condition, with the exception of doors and windows, but this is restricted to surficial observations as no destructive testing was undertaken. Venting issues likely exist within the attic and there are concerns over how refurbishments to the roof may have affected the structure's loadings. The Guest Trailer, an adjacent building, is electrically fed from the Training Center and is a code violation. The crawl space was inaccessible and the flooring system was not inspected, but issues were noted with serviceability (i.e., unevenness, deflection and vibration). Aesthetically, the interior is in good condition except for select areas that are dated and could be upgraded; however, the change in use and occupancy of this building has triggered the requirement for additional fire separations.

Electrically, the building has some short-comings with respect to life safety, fixtures, wiring devices, etc., and these issues may precipitate a more extensive architectural demolition scope of work depending on the extent of work undertaken. Mechanically, the most significant issues that need to be addressed are ventilation throughout, controls, and kitchen exhaust/fire protection associated with the cooking equipment. The extent of this work will have a direct impact on all other disciplines (i.e., does sufficient ceiling space exist for ductwork; electrical tie-ins and associated cutting/patching; structural support for new dead loads and roof-top units) and would effectively render the building unusable during construction, if renovations were subsequently deemed feasible.

Taking these issues into consideration, in conjunction with those relating to mixed-use occupancy and functionality (i.e., configuration of office space, frequency of use of the sleeping quarters and kitchen/dining services), leads to the conclusion that the building be neither recommended for upgrading or replacement at this time. A needs analysis that establishes its permanent end-use and related space requirements, and/or the specific requirements of the building's occupants, would facilitate a more informed decision as to the future of this asset.However, at the Owner's request, a budget estimate that reflects replacement of the offices, training area, washrooms, and lunchroom, with a new building is as follows:

- New Building: 382 m^2 at $2,500/m2 ..... = $ 960,000
- Sitework (Allowance)..... = $ 150,000
- Demolition of Existing Building (Allowance)..... = $ 150,000
- Contingency at 20%..... = $ 250,000
- Project Management/Engineering at 12% ..... = $ 180,000
- **TOTAL PROJECT BUDGET ..... = $ 1,690,000**

In preparing the above conclusions and recommendation the following is noted:

- Replacement of the sleeping quarters, and kitchen/dining facilities is not included; a needs analysis that evaluates the long-term needs of the Owner should be undertaken.
- A potential location for a new building is unknown, thus an "allowance" is included for sitework.
- The requirements for demolition, and in particular asbestos and other potential environmental abatement is unknown, thus an "allowance" is included.
- The budget does not include for new furniture and equipment.
- Opportunities to combine like-functions should be considered in a long-term planning strategy.

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APPENDIX D: Fire and Life Safety Guidance Document

1.0 INTRODUCTION

NALCOR Energy – Newfoundland and Labrador Hydro (NL Hydro) is evaluating three (3) existing buildings located at Bay D'Espoir Hydroelectric Generating Station, Newfoundland: Maintenance Garage, Carpentry Shop, and Training Center.

These buildings are approximately 50 years old and were constructed as temporary buildings in 1962/63. NL Hydro intuitively recognizes that the assets are in need of significant upgrading and/or replacement due to their current physical condition, for aesthetic, operational and functional reasons, as well as to meet present-day building codes. In this regard, NL Hydro procured engineering services to undertake a detailed building condition assessment to document the conditions of the buildings, as well as potential upgrading and/or replacement costs to guide future decisions by NL Hydro with respect to retention (and upgrading to meet present-day codes and operational needs), replacement, or some combination thereof.

The building condition assessment was undertaken by RDB Engineering Limited (RDB), in association with Morrison Hershfield Limited (MH), Maderra Engineering Incorporated (Maderra), and AFN Engineering Incorporated (AFN), who provided building design, structural, mechanical and electrical, and environmental services, respectively.

2.0 OBJECTIVE AND SCOPE OF WORK

The objective of the project was to undertake an engineering condition assessment of three (3) existing buildings (i.e., Maintenance Garage, Carpentry Shop, and Training Center) to document the existing conditions of the buildings, as well as potential upgrading and/or replacement costs so as to guide future decisions by NL Hydro relating to these assets in terms of retention (and upgrading to meet present-day codes and operational needs), replacement, or some combination thereof.

The buildings are approximately 50 years old and are potentially in need of significant upgrading and/or replacement due to their current physical condition; for aesthetic, operational and functional reasons; as well as to meet present-day building codes. The buildings were constructed as temporary structures in 1962/63, and vary with respect to type of construction, including pre-engineered, pre-fabricated, wood-framed, steel-framed, wood and steel clad, and Quonset hut. There have been numerous modifications and additions made to the buildings over the years to keep them in service and to meet on-going operational changes.

Each building was evaluated with respect to building design, structural, mechanical, electrical, and environmental. In general, the assessment considered building construction/condition, use and occupancy, life safety, code compliance, building systems, environmental issues, requirements and costs to bring the buildings up to present-day codes and standards, correction of building deficiencies, cost to replace existing buildings with new, etc., and to make recommendations as to whether or not to invest in existing or new infrastructure.

The project's objective was achieved via the following scope of work:

- review of existing drawings, reports and other available documentation with respect to building design, electrical, mechanical, structural and environmental;
- site visit and inspection of existing buildings;
- compilation of architectural, structural, mechanical, electrical, and environmental existing conditions reports, including overall building condition, code reviews, deficiencies, cost estimates to upgrade, code issues, etc.;
- cost estimates to replace existing buildings with new buildings;
- preparation and submission of a Draft/Final Report.

3.0 METHODOLOGY

The project was completed during the period of December 2011 to May 2012.

As-built drawings of the buildings do not exist, so floor plans of the existing buildings were created by NL Hydro personnel and provided to the project team in advance of the site visit. These drawings were subsequently updated for the report to reflect site observations.

The site visit and inspection was conducted during the week of December 20th, by RDB's Mr. Roger Butt (Building Design), MH's Mr. Aaron Rideout (Structural), and Maderra's Mr. Jason Crawley (Mechanical) and Mr. Shawn McGuire (Electrical).

Assessment of environmental remediation was completed by AFN's Mr. Neil Hunt. A site visit was not required to complete this element of the project as it was based on previous environmental work undertaken by Pinchin Leblanc Environmental Limited, for which the reports were provided to the project team. The previous Pinchin Leblanc report, dated July 2004, was an asbestos materials survey. For the purpose of this report, it is assumed that no other hazardous materials are present in the buildings, such as lead paint, mercury paint or PCBs in light ballasts.

4.0 CODES, STANDARDS AND REGULATIONS

The scope of work included an assessment of each building in the context of present-day codes, standards and regulations so as to evaluate existing conditions and make recommendations for upgrading. Detailed code checks were not specifically part of the scope and could not be completed without as-built information. This section provides a general overview of relevant codes, standards, and regulations applied to the study.

4.1 CODE COMPLIANCE – GENERAL

The desire to make an existing building compliant to present-day codes, standards and regulations, requires special consideration with respect to building condition assessments. Older buildings are often not code compliant in many respects, such as fire and life safety, structural, accessibility, etc., when evaluated against present-day codes since these codes are constantly changing to reflect lessons-learned, new technologies, etc. It is also important to note that existing buildings do not necessarily have to meet present-day codes in terms of constructability, but have to meet code requirements in effect at the time of construction. Post-construction use and occupancy (or alterations affecting use and occupancy) requirements are addressed by present-day codes, and these have to be taken into consideration.

Ultimately, the extent of work recommended and/or required is derived from the owner's preference (i.e., extent of compliance desired), technical/fire/life safety issues identified, and authorities-having-jurisdiction.

4.2 ARCHITECTURAL

4.2.1 Fire and Life Safety

Fire and life safety requirements for buildings are dependent upon whether a building is new construction or being rehabilitated. Specific requirements are governed by the Office of the Fire Commissioner, Department of Municipal Affairs, Government of Newfoundland and Labrador via the Newfoundland and Labrador Fire and Life Safety Guidance Document (see Appendix D).

This document provides clarification on the application of various fire and life safety codes that have been adopted by the Province; namely, the appropriate application of, and compliance with, the National Building Code of Canada (NBCC), the National Fire Code of Canada (NFCC), and the National Fire Protection Association's 101 Life Safety Code (LSC), in the context of new construction or existing construction. In summary, the Fire and Life Safety Guidance Document:

- Provides clarification as to the appropriate codes/section/chapters to be used for the design, construction and operation of new structures, as well as the relevant codes/sections/chapters to be used for the use and operation of existing structures; and
- Identifies the procedures that owners and/or developers shall follow in the repair, renovation, modification, reconstruction, change of use/occupancy classification, and/or addition to an existing structure.

4.2.2 National Building Code of Canada 2010 (NBCC)

NBCC sets out technical provisions for the design and construction of new buildings, as well as the alteration, change of use, and demolition of existing buildings. It establishes requirements to address the following four (4) objectives: safety; health; accessibility for persons with disabilities; and fire and structural protection of buildings.

Application of NBCC requires that a building's use and occupancy be classed according to all major occupancies for which it is used or intended to be used. Major occupancy means the principal occupancy for which a building or part thereof is used or intended to be used, and shall be deemed to include the subsidiary occupancies that are an integral part of the principal occupancy. The major occupancy classifications in NBCC are:

- A1 - Assembly occupancies intended for the production and viewing of the performing arts;
- A2 - Assembly occupancies not elsewhere classified in Group A;
- A3 - Assembly occupancies of the arena type;
- A4 - Assembly occupancies in which the occupants are gathered in the open air;
- B1 - Detention occupancies in which persons are under restraint or are incapable of self-preservation because of security measures not under their control;
- B2 - Treatment occupancies;
- B3 - Care occupancies;
- C - Residential occupancies;
- D - Business and personal services occupancies;
- E - Mercantile occupancies;
- F1 - High-hazard industrial occupancies;
- F2 - Medium-hazard industrial occupancies; and
- F3 - Low-hazard industrial occupancies.

In the case of a building containing more than one (1) major occupancy, the requirements of the most restricted major occupancy shall apply to the whole building. In determining the fire safety requirements, the entire building height and area must be used for each major occupancy being evaluated.

4.2.3 National Fire Code of Canada 2010 (NFCC)

NFCC sets out technical provisions regulating:

- activities related to the construction, use or demolition of buildings and facilities;
- the condition of specific elements of buildings and facilities;
- the design or construction of specific elements of facilities related to certain hazards; and
- protection measures for the current or intended use of buildings.

NFCC establishes requirements to address the following three (3) objectives: safety, health, and fire protection of buildings and facilities.

4.2.4 Relationship Between NBCC and NFCC

NBCC and NFCC each contain provisions that deal with the safety of persons in buildings in the event of a fire, and the protection of buildings from the effects of fire; these codes are developed as complimentary and coordinated documents. The expectation is that buildings comply with both codes. The scope of each of these codes with respect to fire safety and fire protection can be summarized as follows:

- NBCC covers fire safety and fire protection features that are required to be incorporated in a building at the time of its original construction. Building codes typically no longer apply once a building is occupied, unless the building is undergoing alteration or change of use, or being demolished.
- NFCC provides provisions for:
    - on-going maintenance and use of the fire safety and fire protection features incorporated in buildings;
    - the conduct of activities that might cause fire hazards in and around buildings;
    - limitations on hazardous contents in and around buildings;
    - the establishment of fire safety plans;
    - fire safety at construction and demolition sites; and
    - fire safety and fire protection features that must be added to existing buildings when certain hazardous activities or processes are introduced in these buildings.

4.2.5 National Fire Protection Association (NFPA) 101 - Life Safety Code 2012 (LSC)

The LSC, in general, is similar in format and intent to NBCC in that it addresses construction, protection, and occupancy features necessary to minimize danger to life from the effects of fire, including smoke, heat, and toxic gases created during a fire. The LSC is also based on the type of occupancy, similar to those described in Section 4.1.1, but addresses existing construction in more detail than NBCC and NFCC and, for this reason, was adopted by the Province to specifically address the use and occupancy of existing buildings. For new construction the Province also adopted the LSC's requirements for means of egress, in lieu of NBCC.

4.2.6 Buildings Accessibility Act (BAA)

In the case of public buildings, the purpose of the BAA (and associated Buildings Accessibility Regulations (Regulations)) is to require the entrances, parking, walkway, and other facilities available to, and accessible by, members of the public and employees employed in the building, be available to and accessible by persons with disabilities.

The BAA does not apply to buildings existing on December 24, 1981, except buildings (or class of buildings) that the Lieutenant Governor in Council may prescribe by regulation. Where alterations are made to a building existing prior to December 24, 1981, to specifically improve the availability and accessibility of the building to persons with disabilities, the alterations shall comply with the requirements of the BAA and Regulations.

The BAA and Regulations shall apply to the reconstruction of an existing building where the cost of reconstruction of the building is equal to, or exceeds, 50% of the cost of erecting a new building of the same character and dimensions; that cost being calculated without including the cost of reconstructing basements, cellars, or chimneys, and/or site alterations. A public building classified as Group F, Division 1 is exempt from the Act.

4.3 MECHANICAL

4.3.1 National Plumbing Code of Canada 2010 (NPCC)

The National Plumbing Code of Canada sets out technical provisions for the design and installation of new plumbing systems. The Code specifies minimum requirements for drainage systems, venting systems, water service pipes, and water distribution systems. NPCC applies to the extensions, alteration, renewal and repair of existing plumbing systems.

4.3.2 National Energy Code of Canada 2010 (NECC)

The National Energy Code of Canada provides minimum requirements for the design and construction of energy efficient buildings and covers building envelope; systems and equipment

for heating, ventilation and air conditioning; service water heating; lighting; and the provision of electrical power systems and motors. It applies to new buildings, as well as substantial renovations to existing buildings.

4.3.3 National Fire Protection Association (NFPA) 10: Standard for Portable Fire Extinguishers

This standard applies to the selection, installation, inspection, maintenance, and testing of portable fire extinguishing equipment. The selection and installation of extinguishers is independent of whether the building is equipped with automatic sprinklers, standpipe and hose, or other fixed fire protection equipment.

4.3.4 National Fire Protection Association (NFPA) 13: Standard for the Installation of Sprinkler Systems

This standard provides a range of sprinkler system approaches, design development alternatives, and component options that are acceptable. The standard provides the minimum requirements for the design and installation of automatic fire sprinkler systems and exposure protection sprinkler systems covered within this standard.

4.3.5 National Fire Protection Association (NFPA) 96: Standard for Ventilation Control and Fire Protection of Commercial Cooking

This standard provides the minimum fire safety requirements related to the design, installation, operation, inspection, and maintenance of all public and private cooking operations. This standard does not apply to facilities where all of the following are met:

- only residential equipment is being used;
- fire extinguishers are located in all kitchen areas in accordance with NFPA 10;
- the facility is not an assembly occupancy; and
- the authority-having-jurisdiction has approved the installation.

This standard outlines the requirements for:

- all manner of cooking equipment;
- exhaust hoods, fans, ductwork, and dampers;
- grease removal devices;
- fire-extinguishing equipment; and
- and all other auxiliary components that are involved in the capture, containment, and control of grease laden cooking effluent.

4.3.6 National Fire Protection Association (NFPA) 664: Standard for the Prevention of Fires and Explosions in Wood Processing and Woodworking Facilities

This standard establishes the minimum requirements for fire and explosion prevention and protection of industrial, commercial, or institutional facilities that process wood or manufacture wood products, and that process wood, creating wood chips, particles, or dust. This standard applies to woodworking applications that occupy areas more than 465 m^2 (5000 ft^2), or when dust-producing equipment requires an aggregate dust collection flow rate of more than 2 549 cubic meters per hour (1500 cfm).

4.3.7 ASHRAE 62.1: Ventilation for Acceptable Indoor Air Quality

This standard is used to specify minimum ventilation rates and other measures intended to provide indoor air quality that is acceptable to human occupants and minimizes adverse health effects. It is intended to be used to guide the improvement of indoor air quality in existing buildings. This standard outlines requirements for ventilation and air-cleaning system design, installation, commissioning, operation and maintenance. Additional requirements for industrial spaces may be dictated by other standards.

4.3.8 American Conference of Industrial Hygienists (ACGIH): A Manual of Recommended Practice for Design

The Manual is intended to be used as a guide for best practice design, rather than an official standard. It is used by engineers and hygienists to design and evaluate industrial ventilation systems, and includes general information on industrial ventilation, plus guidance on exposure assessment, system design, cost estimating, and energy considerations. This standard outlines recommended airflows and air changes, system configurations, and filtration requirements to reduce the health hazards associated with indoor air quality in industrial spaces.

4.4 ELECTRICAL

4.4.1 Canadian Electrical Code of Canada (CEC) CSA C22.1-06, 21ST Edition

The Canadian Electrical Code of Canada is a set of standards designed and implemented for the prevention of electrical shock and fire hazards. These standards are designed for all consumers, manufacturers, and accredited certification organizations who test and certify products to ensure safety. The CEC is written in three parts: the first part is for the installation of electrical equipment; the second is standards for construction, testing and making of electrical equipment; and the third part is for wiring outside.

4.4.2 Illuminating Engineering Society of North America (IESNA)

IESNA is responsible for over 100 publications on lighting. It is a collection of standards generated through a committee of directors and districts within regions of the world. 25% are made up of manufacturers, 25% are lighting designers and architects, and the remaining consists of a collection of contractors, consultants, utilities, and government.

The handbook is broken out into three sections. Section one deals with the framework behind light. It consists of measurements of light and the link between optics and the brain. The second section deals with the functionality of the building such as lighting controls, types of fixtures, energy management, economics, and sustainability. The final section is based on applications of the building. This consists of everything from artwork to courts and prisons to education, healthcare, offices, and residents.

4.4.3 CAN/CSA-T530-M90: Building Facilities, Design Guidelines for Telecommunications

CAN/CSA-T530-M90 is a standard designed for specifications and guidance for buildings with regards to telecommunications, cabling systems, and components. There are six (6) distinguished components to a building system: building entrance facility, equipment room(s), backbone pathways, telecommunications room(s), horizontal pathways, and work areas. It recommends that the location of the main entrance to the facility should be in a dry location and close to backbone pathways.

4.4.4 CAN/CSA-T529-M: Design Guidelines for Telecommunications Wiring System in Commercial Buildings

CAN/CSA-T529-M is a standard designed for specifications and guidance for buildings with regards to telecommunications, cabling systems, and components within a commercial building. There are six (6) distinguished components to a building system: building entrance facility, Main/Interconnect cross connect, backbone distribution, horizontal cross connect, horizontal distribution, and work area. This code indicates size and lengths of cables allowed under this building system.

4.5 STRUCTURAL

NBCC Part 4 deals with items such as minimum design criteria for loads, load factors, and load combinations, for the design of new buildings and upgrades or additions to existing buildings, but not the structural evaluation of existing buildings. It also includes general performance requirements. With each revision of NBCC, typically every five years, come refinements that may include changes such as required design loads. A change in NBCC does not necessarily mean a building constructed under a previous code must be upgraded to meet new

requirements. Within NBCC is Structural Commentary L - Application of NBCC Part 4 of Division B for the Structural Evaluation and Upgrading of Existing Buildings, which deals with and provides guidance for the evaluation and upgrading of an existing building to determine a level of performance that is suitable based on the intent of the current code.

4.5.1 Part 4 Design Loads

Use and occupancy loads, as spelled out in Part 4, have changed very little over the years. Quite often, issues with evaluating a building for these loads only arise if there is a change in use. Loads, such as snow, rain and wind, are location specific based on climatic data contained within NBCC; over the years there have been some minor changes in this data. A major change in how this data is used for calculating the snow, rain and wind load on a building came about in 2005. Previous versions of the code used a 1/30 year return reference value, whereas in 2005 a 1/50 year return was adopted. Earthquake requirements have changed considerably over the years.

4.5.2 Commentary L

Commentary L provides guidance when evaluating and upgrading an existing building and does not specify when an evaluation is necessary. Some situations when this may be needed include, change in use, damage, deterioration, or where safety is an issue due to known or potential defects. Section 18 of Commentary L deals with evaluation based on satisfactory past performance. In summary, buildings designed and built to a previous code may be considered to have demonstrated satisfactory capacity to resist loads, other than earthquake, provided:

- careful examination by a professional engineer does not expose any evidence of significant damage, distress or deterioration;
- the structural system is reviewed, including examination of critical details and checking them for load transfer;
- the building has demonstrated satisfactory performance for 30 years or more; and
- there have been no changes within the past 30 years that could significantly increase the loads on the building or affect its durability, and no such changes are contemplated.

It is important to clarify, the level of examination conducted as a part of this assessment does not meet the requirement of the first bullet item above; limited viewing and access of specific structural components prevented this during our visit. These limitations are noted in the report for each building.

4.6 ENVIRONMENTAL

Asbestos containing materials (ACMs) are regulated by the Asbestos Abatement Regulations, 1998, under the Occupational Health and Safety Act (O.C. 98-730) in Newfoundland and Labrador. These regulations apply to every workplace covered under occupational health and safety legislation where asbestos or material containing asbestos is likely to be handled, dealt with, disturbed or removed.

The regulations cover all conditions where there is a risk of exposure to airborne asbestos, including during building repairs, operations and maintenance, and demolition work. Where existing ACMs are to remain, or while future asbestos removal plans are being considered, an Asbestos Management Plan (AMP) is a regulatory requirement. An active AMP provides current building occupants with preventative measures to limit exposure to asbestos fibers and ensure compliance with applicable guidelines and regulations.

5.0 CONDITION ASSESSMENT - MAINTENANCE GARAGE

5.1 GENERAL OVERVIEW

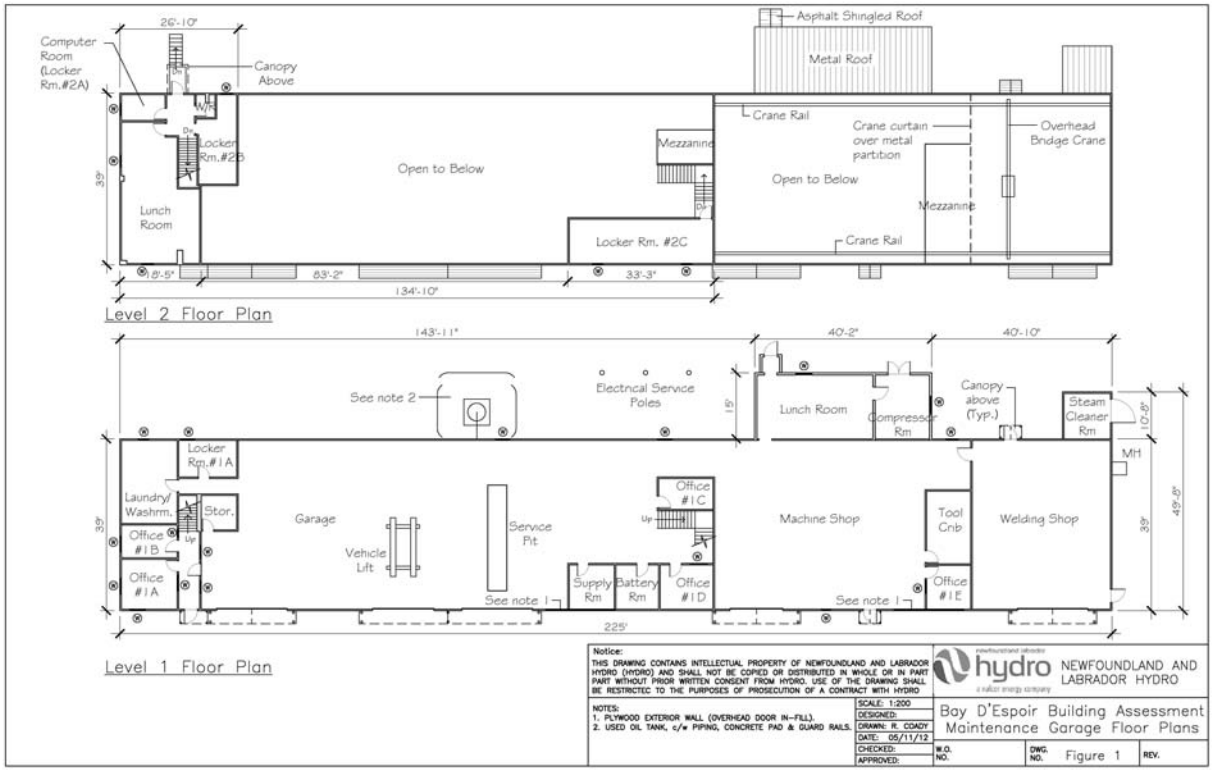
The Maintenance Garage was constructed as a temporary building in the early 1960s during the construction phase of Bay D'Espoir Hydroelectric Generating Station. The building is used to support day-to-day maintenance operations and includes a vehicle repair garage, machine shop and welding shop, as well as offices, washrooms, lunchrooms, etc.

The building is a two (2) storey structure with a building area of 872 m^2 and faces three (3) streets. Construction consists of a concrete foundation, concrete slab-on-grade, and an ARMCO pre-engineered building (i.e., steel-framed superstructure with metal siding and roofing). The interior has been developed using wood-frame construction and includes offices, washrooms, locker rooms, lunch rooms, tool cribs, etc. A single-storey concrete masonry unit (CMU) lean-to structure, which includes a lunch room and compressor room, is appended to the rear of the building. A single-storey metal clad lean-to structure that appears to be part of the original ARMCO structure is appended to the northeast corner of the building.

The Welding Shop and Machine Shop share a 1.5 tonne Richards Wilcox overhead travelling bridge crane. The vehicle repair Garage is equipped with a 7.9 m long x 1.2 m wide x 1.4 m deep in-floor service pit, and a vehicle lift ramp. The building is not sprinklered.

Floor plans of the existing building are provided in Figure 1 and were created for this study; original design or as-built drawings do not exist.

Photographs of the existing building are provided in Appendix A.


Computer Room (Locker Rm.#2A)
26'-10"
Canopy Above
Asphalt Shingled Roof
Metal Roof
Crane Rail
Crane curtain over metal partition
Overhead Bridge Crane
Locker Rm.#2B
Mezzanine
Open to Below
Lunch Room
Locker Rm. #2C
Open to Below
Mezzanine
Crane Rail
39'
8'-5"
83'-2"
33'-3"
134'-10"
Level 2 Floor Plan
143'-11"
40'-2"
40'-10"
See note 2
Electrical Service Poles
15'
Lunch Room
Compressor Rm
Canopy above (Typ.)
Steam Cleaner Rm
10'-8"
MH
Locker Rm.#1A
Laundry/ Washrm.
Stor.
Office #1B
Office #1A
Garage
Vehicle Lift
Service Pit
Office #1C
Machine Shop
Tool Crib
Welding Shop
39'
49'-8"
See note 1
Supply Rm
Battery Rm
Office #1D
See note 1
Office #1E
225'
Level 1 Floor Plan
Notice:
THIS DRAWING CONTAINS INTELLECTUAL PROPERTY OF NEWFOUNDLAND AND LABRADOR HYDRO (HYDRO) AND SHALL NOT BE COPIED OR DISTRIBUTED IN WHOLE OR IN PART PART WITHOUT PRIOR WRITTEN CONSENT FROM HYDRO. USE OF THE DRAWING SHALL BE RESTRICTED TO THE PURPOSES OF PROSECUTION OF A CONTRACT WITH HYDRO
NEWFOUNDLAND AND LABRADOR HYDRO
NOTES:
1. PLYWOOD EXTERIOR WALL (OVERHEAD DOOR IN-FILL).
2. USED OIL TANK, c/w PIPING, CONCRETE PAD & GUARD RAILS.
SCALE: 1:200
DESIGNED:
DRAWN: R. COADY
DATE: 05/11/12
CHECKED:
APPROVED:
Bay D'Espoir Building Assessment
Maintenance Garage Floor Plans
W.O. NO.
DWG. NO. Figure 1
REV.

5.2 ARCHITECTURAL ASSESSMENT

5.2.1 Building Fire Safety (NBCC)

The Maintenance Garage is an industrial building with one (1) principal occupancy and is classified as Group F, Division 2 (Medium Hazard Industrial Occupancy) by NBCC. The offices, lunch rooms, locker rooms, etc., are considered supporting services and therefore not considered a principal occupancy.

To conform to NBCC, Part 3, the building has to meet the requirements of Clause 3.2.2.76 for building fire safety, as follows:

Clause 3.2.2.76 Group F, Division 2, up to 2 Storeys

1) A building classified as Group F, Division 2 is permitted to conform to Sentence (2) provided

a) it is not more than 2 storeys in building height, and

b) it has a building area not more than the value in Table 3.2.2.76.

Table 3.2.2.76
Maximum Building Area, Group F, Division 2, Up to 2 Storeys

No. of Storeys	Maximum Area, m^2		
	Facing 1 Street	Facing 2 Streets	Facing 3 Streets
1	1 000	1 250	1 500
2	600	750	900

2) The building referred to in Sentence (1) is permitted to be of combustible construction or noncombustible construction used singly or in combination, and

a) floor assemblies shall be fire separations and, if of combustible construction, shall have a fire-resistance rating not less than 45 min, and

b) loadbearing walls, columns and arches supporting an assembly required to have a fire-resistance rating shall

i) have a fire-resistance rating not less than 45 mins, or

ii) be of noncombustible construction.

It is important to note that there is not necessarily only one (1) "design" solution for a building. NBCC offers multiple fire and life safety solutions for buildings of the same use, occupancy and size that, for example, may prescribe less stringent fire-separation requirements provided other

measures (e.g.., non-combustible construction, sprinkler system) are incorporated in the solution. The best solution is derived from and cost-benefit analysis.

For the Maintenance Garage, NBCC Clause 3.2.2.77 - Group F, Division 2, Up to 2 Storeys, Sprinklered, does not offer any relief in this regard as the floor assemblies and associated load-bearing elements still have to be fire-rated or of non-combustible construction even with a sprinkler system installed.

5.2.2 Exterior Wall Assembly

While an intrusive/destructive investigation of the exterior wall assembly was not undertaken, it appears that the primary construction of the exterior wall assembly consists of metal cladding, approximately 45 mm of (discontinuous) rigid insulation (as determined via through-wall holes/penetrations), and a painted plywood interior finish.

The metal cladding is original to the building and appears integral to the buildings' structural system. Each panel is 406 mm (16") wide x 76 mm (3") deep and locks together at each seam. The panels exhibit some rusting, particularly where the finished grade is contacting the bottom of the siding; positive drainage is not present around the entire perimeter of the building and would need to be addressed if the structure is retained so as to direct water away from the building. The metal cladding also exhibits numerous holes, dents, and patches that make it ineffective against water penetration and air infiltration at select locations; if the building is retained these issues will have to be addressed.

Rigid polybead insulation has been fitted within each wall panel and is estimated to be 38 mm (1.5") thick. At best, this provides a thermal insulating value of RSI 7, which is substantially less than the expected design criteria of RSI 20 were this building constructed new, or brought up to present-day code. The insulation is also discontinuous at each metal panel joint resulting in thermal bridges, or essentially no insulating value, at these locations (every 406 mm). In summary, the thermal resistance of the buildings' exterior walls is negligible.

In a typical wall assembly, inboard of the insulation an air vapour barrier is required and installed to prevent moisture from migrating from the building's interior through the exterior wall assembly and condensing on the interior face of the exterior siding (or cold surface). No air vapour barrier is present in the wall assembly and would need to be addressed were the building retained and refurbished.

The interior finish is predominantly painted plywood and is acceptable by code given that the building can be of combustible or non-combustible construction. However, while the plywood has served as a suitable finish material for the life of the building, it now exhibits signs of

deterioration, including water damage from exterior wall leaks that is indicative of its long service life.

The concrete block lean-to affixed to the north face of the building, which encompasses the Lunch Room and Compressor Room, is in poor condition. While the Lunch Room has been finished with plywood on the interior, thereby concealing the underlying construction, the exposed concrete block in the Compressor Room exhibits mildew and staining on both the interior and exterior surfaces of the block; a condition that warrants further investigation for air quality and the presence of mould. The Compressor Room is absent of insulation and a water vapour barrier. To facilitate refurbishment, this area will require further destructive investigation and testing.

5.2.3 Roof Assembly

The structure's roof assembly is original to the building and appears integral to the buildings' structural system. The roof was not accessed from above or below for a detailed inspection.

There are two (2) types of roof systems: the Welding Shop and Machine Shop have a spray-on fire retardant and/or insulation applied to the underside of the metal roof deck and exposed to the interior, whereas the remainder of the building contains bag-type insulation overlaid atop the roof purlins and beneath the metal roof deck. The performance properties of both products is unknown but expected to be minimal with respect to thermal resistance and effectiveness as an air vapour barrier; it is unlikely these materials would achieve the thermal resistance required in a building designed to current codes.

Both lean-to structures affixed to the north side of the building have had issues with roof leaks in the past, as evidenced by repairs made at the roof/wall intersections, and it was reported by the Owner that the leaks persist. In addition, the eave of the concrete block annex is not constructed using an appropriate weather-tight detail, lacking suitable closure strips and metal flashings.

5.2.4 Exterior Man-Doors

The exterior steel man-doors are operable, but generally in poor condition. Collectively, the doors have broken weather-stripping, daylight is visible at the edges and sills, and the hardware is dated and worn. For example: the Machine Shop exterior door does not operate smoothly (sticks on opening/closing), has no weather stripping, and both the frame and threshold "move" when the door is opened/closed; daylight is visible at the threshold of the Level 1 Lunch Room door.

The Compressor Room is inadequately fitted with a site-built double-leaf plywood door; the wood frame is rotted at the base.

Essentially, the exterior man-doors have reached their useful life and would need complete replacement if the building was retained and refurbished.

5.2.5 Exterior Overhead Doors

The exterior overhead doors are not original to the building and have been replaced with new sectional doors that are maintained in good working condition with the exception of some issues noted with discontinuous weather stripping. However, as the original doors were replaced with new doors they were down-sized and in all cases the original openings have been in-filled with a plywood wall assembly; this is typically not an acceptable exterior wall finish. In one instance, the original garage door has been completely abandoned and the exterior wall has been reconstructed/in-filled with an exposed plywood assembly. The poor performance of the wall assembly at these locations is evidenced by leaking/staining on the interior, as well as rotted wood door frames.

If this structure was to be retained and refurbished, the issues noted above will need to be addressed, including reconstruction of the plywood wall assemblies with an appropriate weatherproof system.

5.2.6 Exterior Windows

With the exception of some windows that have been replaced as part of on-going upgrading and renovations, the existing windows in the building are beyond their useful service life and not adequate for current building standards or occupant comfort. Many of the windows are original to the building and are single glazed, inoperable, and/or not air-tight; others have been inadequately maintained or lack insect screens and have significant accumulations of dead insects. Some have been modified to accept air-conditioning units, and/or partially in-filled with plywood to accept a smaller size window. Many frames are rotted, exhibit peeling paint, and are poorly caulked (or the caulking has failed). Leaks around the windows are prevalent on the interior.

If the building was to be refurbished to acceptable conditions and meet present-day codes, all windows will need to be replaced.

5.2.7 Interior Floor Assemblies and Finishes

The floor throughout Level 1 is concrete slab-on-grade. It is generally in good condition and it was reported by the Owner to have been resurfaced with a concrete topping since original

construction. Its specific construction is unknown and it is therefore not known whether or not a vapour barrier or insulation exists beneath the slab; insulation was not visible on the exterior foundation wall either. Typically, a building such as this would include rigid insulation at one or more of these locations to minimize heat loss. Consideration of adding thermal insulation to the exterior foundation wall is warranted if the building is retained and undergoes renovation.

Select areas on Level 1, such as corridors, offices and washrooms, have paint, vinyl tiles, or sheet vinyl/rubber flooring, and these are typically in poor condition, except for a recently renovated washroom. If the building is retained, future renovations would include replacement of floor finishes in select areas.

While the specific construction of Level 2 floor assemblies is unknown, all indications are that the interior fit-up has been achieved using wood-frame construction (i.e., wood studs, plywood ceiling, floor joists, plywood subfloor, etc.) as suggested by the presence of wood stairs/handrails, plywood ceiling/floors, etc. While the condition of the plywood finish is fair, of particular significance is the likely absence of a fire-rating as it relates to report Section 5.2.1, Building Fire Safety. In its current configuration, the building's floor assemblies, as well as load-bearing walls/columns, require a 45 minute fire-rating. It is unlikely this is inherent in the existing construction and any proposed renovations to bring this building up to present-day codes would require further investigation and, most likely, significant demolition/modifications in this regard.

Areas on Level 2, such as washrooms, lunchroom, and locker rooms, vary with respect to floor finishes and consist primarily of vinyl tile and plywood. The conditions of these materials vary by area and some are recommended for replacement, subject to the amount of renovations required were the building retained.

5.2.8 Interior Wall Assemblies and Finishes

Further to report Sections 5.2.1 and 5.2.7, load-bearing walls supporting a floor assembly required to have a fire-resistant rating must also be rated for the same amount of time (i.e., 45 minutes), or be of non-combustible construction. It is unlikely the existing plywood sheathed walls are rated for 45 minutes; existing gyproc walls would require further destructive investigation to determine the material properties, if possible. Consequently, the interior walls most likely do not meet present-day codes. Further, some applications of the Code require a 2 hour fire-separation between occupancies adjacent to repair garages.

Notwithstanding the potential requirement to upgrade and/or replace walls with appropriate fire-rated construction, interior painted finishes applied to plywood, gyproc and metal

partitions vary in condition. Select areas have been maintained as part of on-going upkeep, while others have deteriorated to the point of needing significant repairs/repainting, at a minimum, to address holes, water damage, and overall aesthetics.

5.2.9 Interior Man-Doors

With some exceptions, the interior man-doors are operable and in fair condition, at best. They include a mixture of both wood and steel doors, as well as wood and steel frames. Collectively, the doors display obvious signs of excessive wear and tear, extended usage, dents, worn finishes, and hardware that is dated, worn and/or broken. For example, the door between the machine shop and welding shop is completely beyond repair with broken hinges, lockset and closer.

The interior man-doors have reached their useful life and are recommended for complete replacement if the building was retained and refurbished.

5.2.10 Code Issues

While a detailed code check/analysis of the existing building was beyond the scope of work, issues that need to be addressed, or warrant further investigation, to meet present-day codes include:

- Fire-rating of all Level 2 wall and floor assemblies, as well as doors and frames contained therein;
- Fire rating of access to exits/means of egress/exits;
- Door hardware and, in particularly panic hardware from the Level 1 Lunch Room;
- Travel distances and the resultant number and location of exits, particularly in the context of Locker Room #2C;
- Flame Spread Rating (FSR) and Smoke Developed Classification (SDC) of interior finishes;
- Corridor exit widths, in particular the reduced exit capacity of the corridor leading from the Level 2 Lunch Room as a result of the swing/encroachment of the door leading from the Garage;
- Stairs, handrails and guards, in particular stair dimensions, discontinuities in both interior and exterior wood and steel handrails, as well as the structural integrity of interior wood handrails and guards around mezzanines (some were noted as being not "structurally sound");
- 2 hour fire-rating of wall between office area and Garage;
- Positive drainage away from the building's exterior;
- Quantity of washroom fixtures, as well as gender specific washroom requirements;

- Barrier-free design.

A detailed assessment of these issues would require additional knowledge of the building's use and occupancy, occupant load, as-built construction drawings/details (or destructive site investigations), material properties, and discussions with authorities-having-jurisdiction.

5.3 MECHANICAL ASSESSMENT

5.3.1 Storm Drainage

The building has a sloped roof and all water is drained to the site. There are no eaves troughs or downspouts to collect and divert water away from the building, as it should. If the building is retained and refurbished this should be corrected.

5.3.2 Sanitary Drainage

The main sewer piping is located under the concrete slab and extends to all areas of the building. To the best of our knowledge, the system is in working order and can remain in service as is; it is recommended that the lines be snaked and cleaned. Off-site disposal (i.e., beyond the building) was not investigated.

There is a sump pump located at the bottom of the vehicle service pit that collects water run-off from vehicles when they are brought into the shop. This pump diverts water to a collection tank located along the interior of the south wall, with a drainage pipe and isolation valve directed to the outside of the building. All floor drainage in a vehicle repair garage should have a waste oil interceptor, in addition to the storage tank, to prevent oil from contaminating the environment at the discharge of the tank.

5.3.3 Waste Oil

The waste oil system consists of a manually-operated waste oil dispensing unit located along the interior of the north wall, and a 400 L above ground waste oil storage tank complete with piping, concrete pad and guardrails located on the exterior of the north wall. All oil is drained into containers during vehicle repair and is disposed of by this means.

The waste oil tank requires double wall construction and must be registered to ensure it meets the required Government regulations for used oil storage tanks. The tank appears to be of the proper construction; however, it is unknown if the tank has the proper certification.

5.3.4 Compressed Air

The building is equipped with an Atlas Copco GA30 air compressor, receiver tank, and multiple compressed air stations located throughout the shop areas. The air receiver tank has an inspection certificate located on the tank that expired on August 31, 2010, and should be recertified. The air compressor appears to be in good condition; however, the system was not tested during the site visit.

5.3.5 Plumbing

The washroom located on Level 1 was recently refurbished and consists of two (2) water closets, two (2) urinals, hand wash sink, janitor's sink, and hot/cold water connections for laundry. The second level contains a washroom complete with water closet and lavatory, and a kitchen area with sink. All fixtures appear to be functional and in reasonable condition.

5.3.6 Domestic Water System

The water main enters the building through the floor and splits into fire water and domestic water. Domestic hot water is supplied by an electric boiler located under the stairs to the second floor. The existing distribution piping is copper with localized isolation valves at fixture locations. A review of the distribution piping system and sizing, and necessity for replacement and upgrading, will be dependent upon the overall refurbishment strategy recommended, if any, for the building.

5.3.7 Fire Protection

Portable fire extinguishers are installed throughout the building and are mainly the multi-purpose dry chemical type. There are three (3) fire hose cabinets installed throughout the building

The pipe serving the fire hose cabinets does not meet the minimum pipe size of 100 mm requirement per NBCC. There is also no siamese fire department connection and the water entrance is lacking a backflow prevention device. The water system supply should also be checked to ensure adequate flow rates can be maintained to the fire hose cabinets.

5.3.8 Heating and Cooling

The building is heated via a combination of electric baseboard heaters and electric unit heaters. There is no air conditioning (cooling) system in the main shop areas. The office areas are served by plug-in style through-wall air conditioning units.

5.3.9 Air Handling Systems

Ventilation mainly consists of exhaust only with no provision for mechanical ventilation.

The Garage is served by a combination of natural ventilation and a vehicle exhaust system, of which the latter is manually controlled and consists of an exhaust fan connected to a flexible hose reel station. The exhaust is ducted directly to the outside high on the exterior south wall, but the ACGIH Industrial Ventilation Manual recommends the exhaust be discharged above the roof. The exhaust main must also be sized for a maximum velocity of 10.2 m/s (2,000 fpm), and the exhaust ventilation volumes for operating engines connected directly to a tail pipe exhaust system are determined by the engine displacement, engine RPM, and tail pipe exhaust temperature. Therefore, the types of vehicles being serviced in the garage have to be known and reviewed to determine if the system is adequately sized.

The vehicle service pit is classified as a hazardous area even if ventilation is provided. However, if a minimum air change rate of six (6) ACH is not maintained, the classification is upgraded and the electrical requirements are more stringent.

The natural ventilation system consists of two (2) gravity roof ventilators used to promote air exchange in the summer. There are two (2) de-stratification fans located directly below each roof ventilator and these are used to circulate heat throughout the space and prevent the loss of heat during the heating months. These fans may also be used to promote air exchange when natural exhaust capacity is too low; however, these fans are showing signs of considerable wear and are no longer functional.

The Machine Shop ventilation system consists of both mechanical and natural ventilation. The mechanical ventilation system consists of a roof mounted exhaust fan with a motorized damper manually controlled by a disconnect switch located on the south wall. This system did not operate when tested during the site visit. Natural ventilation is achieved in the same way as the Garage, through a gravity roof ventilator and stratification fan. The stratification fan is no longer functioning.

The Welding Shop contains three (3) welding fume extraction arms complete with individual exhaust fans and flexible hose connections. Each fan is individually controlled by a wall-mounted manual starter located adjacent to each unit. The Welding Shop also utilizes a roof-mounted exhaust fan with motorized damper, and an additional wall-mounted motorized fresh air damper located on the east wall. The roof-mounted exhaust fan and both motorized dampers are tied together and controlled by a disconnect switch located on the east wall; this system appeared to be functional. The airflow rates for the welding extraction arms are

unknown at this time and a detailed system review is required to verify that they meet the design recommendations outlined in ACGIH Industrial Ventilation Manual. For the type of extraction arms presently used on site, an airflow of 0.47 m^3/s (1,000 cfm) is recommended when the hood face is 300 mm (12") from the source of the weld. The duct design velocity should be maintained between 12.7 and 15.2 m/s (2,500 to 3,000 fpm) to ensure adequate source capture.

The capacities of the exhaust fans are not known at this time, however, a new ventilation system designed to meet NBCC, ASHRAE 62.1, and ACGIH best practice guidelines and standards would be required. This would likely include a heat recovery ventilator (HRV) to provide fresh air to all occupied spaces, tied to a general exhaust system. The fresh air would be ducted vertically down the walls to ensure the air is distributed to the breathing zone, and the system sized to ensure minimum air change rates maintained. A complete review of the current ventilation configuration would be required to determine if any of the existing infrastructure could be reused if the building is retained and refurbished.

If the garage area is used to store vehicles overnight, or for an extended period of time, this space would require a carbon monoxide/nitrogen dioxide (CO/NO_2) monitoring system. This system would be tied to an exhaust fan, and would regulate the amount of CO/NO_2 in the space to maintain indoor air quality.

The office areas do not have any fresh air supplied to these spaces and would require a new ventilation system designed with minimum airflows to meet ASHRAE 62.1, which outlines the minimum ventilation required based on the number of people in the space and overall floor area.

5.3.10 Controls

The building does not have a building management system, and controls are limited to heating thermostats and manual starters for exhaust fans. If the building is retained and refurbished, the controls system will need to be upgraded. It is also required that the Welding Shop fresh air damper automatically open when the extraction arms are activated so as to provide make-up air to the space.

5.4 ELECTRICAL ASSESSMENT

5.4.1 Electrical Service and Distribution

The maintenance garage is fed aerially from a 3-phase transformer bank mounted on an H-frame pole structure adjacent to the building. The structure appears to be in good condition.

The service masts and mast straps are showing signs of rust and should be replaced. The nuts and bolts securing the main service disconnect and splitter trough is showing signs of rust on the exterior and should be replaced. The door hardware on the main service disconnect is in need of repair according to the site electrician and could not be opened for inspection. Arc flash labels dated 2009 were noted on the main 600 V disconnect and a recently installed 600 V disconnect cluster. This indicates that some analysis of the building`s electrical system has been completed. In accordance with the Canadian Electrical Code (CEC), all electrical equipment that will likely require examination, adjustment, servicing or maintenance while energized shall be field marked to warn of potential shock and arc flash hazards.

Detailed identification of branch and feeder circuits was recently completed. However, a number of circuits could not be traced making it difficult to isolate equipment. There is evidence of abandoned wiring in the ceiling space adjacent to Locker Rooms 2A and 2B and Offices 1A and 1B and should be inspected, de-energized if necessary, and removed.

A mixture of relatively new and originally installed disconnects are installed throughout the building. The majority of the enclosures are general purpose and not well-suited for damp and dust environments. There is at least one reported instance where there is damage to the interior (melted fuse) and another case where one disconnect is used to isolate 2 different loads. Many disconnects would be considered past their useful service life and should be replaced.

While the majority of panels are residential type, there is evidence of recent upgrades. There is one instance where breakers have been removed and the panel converted to a junction box with exposed wiring, which is a code violation.

Concern was expressed by the site electrician regarding the open face transformers installed in the garage area where water spray could result in an electrical hazard.

5.4.2 Telephone Utility Services

Telephone and data service is through an aerial feed. The mast and conduit appear to be recently upgraded and in good condition.

5.4.3 Grounding Systems

There are three (3) ground rods visible, which appear to be bonded together. Spacing appears closer than the 3 m minimum permitted by the electrical code. It is noted that ground rods normally have a service life of 40 years, depending on soil conditions, and it is recommended that the grounding system be inspected and tested.

5.4.4 Lighting

T-12 fluorescent lamps are installed throughout the building, supplemented by high pressure sodium fixtures in the shop areas. Many of the fluorescent fixtures have missing lenses and, in the case of the shop areas, have exposed lamps without wire guards. While illumination levels appear adequate, T-12 systems are being phased out in favour of T-8 and T-5 lamps with energy efficient electronic ballasts.

5.4.5 Heating

The offices, lunch rooms, and locker rooms are primarily heated with residential grade electric baseboard convection heaters, some of which are damaged and in need of replacement. Electric unit heaters are installed throughout the shop areas.

5.4.6 Wiring Devices

Generally, switches, receptacles and data jacks appear to be in good working condition. The upper level lunch room requires GFI receptacles within 1.5 m of the sink. Due to arc flash and shock hazards, branch wiring in panels could not be inspected. It was noted by the site electrician that there are instances of multiple circuits on individual breakers; this warrants further investigation.

5.4.7 Life Safety Systems

A five-zone fire alarm system was recently installed. Heat and smoke detectors are installed throughout and pull stations are installed at building exits. Alarm bells are located in the lunch room, laundry area, shop areas, and on the exterior of the building. While the fire alarm system would meet current code requirements, there is no indication that it has been recently tested.

Emergency lighting is installed over exit doors only and would not likely provide enough illumination for other areas. Most of the lamp heads are obsolete and battery packs would not likely meet the 90 minute uptime standard. The majority of exit signs utilizes incandescent bulbs and should be replaced with LED type.

5.4.8 Communications

A cabinet containing communications equipment has been recently installed in the garage area. The cabinet is not suitably rated for the environment and could result in a shock hazard.

5.4.9 Security Systems

A card access system and surveillance cameras have been recently installed. It is assumed they are in good working condition.

5.4.10 Hazardous Areas

Rules 20-100 through 20-114 of the CEC are applicable to areas where vehicles are repaired or stored. Due to the risk of flammable liquid leaks it is necessary to specify the hazardous areas and the requirements for electrical equipment within the specified hazardous zone and areas above it. Because the main concern is the possibility of gasoline spilling or leaking in relatively small quantities, the hazard is classified as Class 1, Zone 2. In this case, the height of the hazardous area is to extend 50 mm above floor level. With respect to the service pit, the entire space extending up to the garage floor level is also classified as Class 1, Zone 2. All wiring methods, conduit installations and equipment locations must be installed in accordance with Sections 12 and 18 of the electrical code. In addition, areas adjacent to the vehicle repair area are also classified as Class 1, Zone 2 unless the floor height is 50 mm higher than the garage floor or where a 50 mm curb is installed.

While a detailed inspection of all equipment within this area was not considered part of the scope of this assessment, it is likely given the age of the building and modifications carried out over time, that there are instances of code violations. Further investigation is warranted.

5.5 STRUCTURAL ASSESSMENT

The building is a pre-engineered rigid frame type structure with cold form roof purlins and metal roof, and cold form wall girts with metal siding and plywood liner on the inside. Existing structural drawings were not available, therefore the structural assessment was limited to a from grade review of exposed building components in terms of general condition and common construction methods normally present for this type of construction.

5.5.1 Rigid Frames

The rigid frame components include the roof beams, columns, and secondary bracing members. Secondary bracing members are used to provide stability to the flange of columns and beams not connected to girts or purlins. These members connect the inside flange of a column to a girt and the bottom flange of beams to a purlin. They are commonly utilized in pre-engineered structures however the exact location and number is design dependent. Within a particular building their location are generally consistent from frame to frame.

In general, the frames showed no signs of distress or structural defect with the exception of two columns in the garage area. The columns had several rough cut holes in the column web, near the column flange, for conduit to pass. Common construction practice is to locate holes within the middle third of the member depth, to cut smooth edged holes and must be

approved by the engineer of record. The number of holes and their location could possibly require reinforcement to avoid a reduction in the column load carrying capacity.

For the secondary bracing members numerous locations were noted where these were missing based on the assumption that each frame required consistent bracing. In all it was found that 37 locations were missing braces at either column or beam flanges.

Base plates and anchor bolts were not visible at the time of our visit as they were covered by walls in some locations and a concrete floor in others. As a part of any detailed analysis for building certification or upgrades, the base plates and anchor bolts will need to be exposed and their condition assessed.

5.5.2 Primary Bracing System

The primary bracing system is used to resist lateral loads on a building, such as wind or seismic loads. For a pre-engineered building this is normally achieved by the frames for loads parallel to the frame and by X-bracing, horizontally at the roof level and vertically in the walls, for loads perpendicular the frames. This X-bracing is typically round rods for pre-engineered buildings.

Three (3) bays of horizontal rod bracing were noted at the roof level, however no vertical bracing was observed in the walls. Normally, a vertical bay of bracing can be found in each wall where a bay of horizontal bracing is located. Thus the primary bracing system is incomplete in the direction perpendicular to the frames. The owner has advised that some of these braces have been removed over the years. It is unclear how many braced-bays have been removed and a complete analysis of the building will be required to determine where additional bracing is needed to resist the lateral loads applied to the building.

5.5.3 Roof Purlins

There were no apparent signs of structural defect or distress observed with the purlins, noting that the purlins were viewed from grade and the roofing was not be reviewed due to accessibility. The purlins appeared adequately braced.

5.5.4 Wall Girts and Siding

In general, of the girts that could been seen, there were no signs of structural defect or distress. However, it was noted that there were no sag rods present. Sag rods are typical for this type of construction and are used for laterally stability of the girt, in particular, for resisting suction or outward pressure on the walls, which typically govern girt design. A lack of sags rods significantly reduces the load carrying capacity of the girt. Calculations to verify if the omission of sag rods is permissible for this situation would have to be conducted to confirm.

In addition, at the end wall of the Welding Shop it appears a girt was added to enclose an original large bay door opening. This girt was spliced at midspan and the type of splice used is inadequate for this situation and the size of the girt appears insufficient for its span and loading.

The wall siding is showing signs of deterioration and damage in some locations. It was noted that the siding was not properly fastened/spliced in some locations where siding had been replaced. In a number of locations it was noted that the siding was supporting mechanical or electrical equipment, such as electrical panels, louver exhaust vents, and welding exhaust arms, with plates bolted through. This equipment should be supported from girts by proper frames suitable for the applied loading.

5.5.5 Interior Partitions

Inside the building there are two partial height partitions separating the Garage from the Machine Shop, and the Machine Shop from the Welding Shop. The partitions are made from metal siding panels and do not have sufficient lateral support at the top. By pushing on the walls they deflect from 25 to 50 mm.

5.5.6 Wood Floor Framing

Wood floor framing appears to exist in three (3) areas: Level 2 Lunch Room area, Locker Room and Mezzanine in the Garage, and Mezzanine in the Machine Shop. With the exception of the Lunch Room, these floors could only be seen from above due to finished ceilings. For the Lunch Room area, ceiling tiles could be lifted in limited locations and the floor observed from below. There were no apparent signs of structural defect or distress.

In the Mezzanine storage area there is signage noting light storage 25 lb/ft^2 and no concentrated loads. NBCC states a minimum design loading of 100 lb/ft^2 for storage areas. The presence of this signage suggests the floor has been examined in the past and is not suitable for this minimum load requirement. It is imperative that this limitation be strictly adhered to so as to avoid overloading the floor.

5.5.7 Hand Rail and Ladders

The Mezzanine in the Garage is accessed by a fixed step through steel ladder and the floor area is enclosed by a wooden hand rail. This hand rail and its connections in its current condition are not suitable for the required design loads as set in NBCC. In addition, the grab bars of the step through ladder are too large to properly grab, and the bolts fastening the ladder are loose. Further measurements and examination would be required to confirm its adherence to the Occupational Health and Safety Regulations of Newfoundland.

5.5.8 Slab on Grade

There were no signs of structural defect, distress, or significant cracks in the concrete slab-on-grade that would prevent its continuous use under current functions.

5.5.9 Building Foundations

Due to the elevation of the finished grade and bottom of the siding, the top of the exterior foundation could not be seen in most areas. The lean-to additions at the north side of the building for the Lunch Room, Compressor Room, and Steam Cleaning Room appear to be resting on a slab-on-grade. The Steam Cleaning Room shows significant deterioration.

As a part of any further review for building certification or analysis for building upgrades, the foundations will have to be excavated and their condition assessed.

5.5.10 Exterior Block Wall

Block wall was visible at the exterior of the addition for the Lunch Room and Compressor Room. This block shows significant deterioration at the mortar joints.

5.5.11 High-Low Roofs

The lean-to additions at the rear of the building for the Lunch Room, Compressor Room, and Steam Cleaning Room at the north side of the main building have a lower roof elevation than the main building. This creates a potential for a larger snow loading than on the main structure. This can often create roof over-loadings, in particular for older buildings. Further investigation would be required to determine if the existing roof structure is suitable for these potential snow loadings.

5.5.12 Crane Runway

The crane runway was not examined closely as a part of this review. The inspection of the crane runway is included in the crane's certification which is required periodically for continued use. As a part of any upgrade to the building or building certification, items such as how often the crane is used and inspected along with when the crane was last inspected will be required. These items can then be evaluated as a part of a review of the runway beam and the crane's impact on the building structurally.

5.6 ENVIRONMENTAL ASSESSMENT

Based on a review of the previous Pinchin Leblanc survey (July, 2004), the following comments are provided with respect to ACMs in the Maintenance Garage:

- Asbestos is present in the joint filler coat of the drywall surfaces in the lunchroom areas

of the building. The Pinchin Leblanc sampling program (July, 2004) confirmed 1-5% chrysotile asbestos in the drywall joint filler for one (1) sample collected from the wall of the lunchroom (beige color sample). A full sampling program at each joint location was not completed, however all joint filler coats on the drywall surfaces of the lunch rooms should be considered as containing 1-5% chrysotile asbestos. Joint filler products in place are generally treated as non-friable. The total estimated surface area of the drywall surfaces in the lunchroom (combined total area of lunchroom on 1st and 2nd level) is 160m^2.

- Transite Sheeting (cement sheathing) is present on the ceiling of the pressure wash area (assumed to be the Steam Cleaner Room). The transite sheeting is a non-friable material containing 10-25% chrysotile asbestos. The total estimated area of transite on the ceiling of the Steam Cleaner Room is 12m^2.
- There is potential for concealed asbestos materials to be present in: (a) the roofing felts and mastics; (b) components or wiring within motors or lights; (c) high voltage wiring; (d) mechanical packing and gaskets; (e) underground services or piping; (f) fire-doors; (g) window caulking; and (h) concrete leveling compound. In the absence of additional sampling, these materials (if present in the Maintenance Garage) should be considered suspect ACMs during renovation or demolition activities.

With respect to suspect ACMs, the following is noted:

- If the building is to be retained and refurbished, only those suspect materials where renovation work will cause disturbance should be sampled. As part of the Asbestos Management Program document established by Pinchin Leblanc in 2004 for NL Hydro, the Maintenance Garage would be considered as having an asbestos management program in place and in this regard, suspect ACMs do not need to be removed if they are not disturbed during renovation activities.
- If the building is to be demolished, an intrusive sampling program of all suspect ACMs should be completed to ensure these materials are properly removed/handled and disposed of during demolition activities.

Based on the types and quantity of ACMs present in the Maintenance Building, removal efforts would be classified as Type 1, as defined in NL Hydro's Asbestos Management Program (prepared by Pinchin Leblanc in 2004). A Type 1 asbestos removal procedure assumes the non-friable material can be removed with relatively little loose dry dust released. Generation of debris is permissible as long as the debris can be well wetted before being removed. Typical removal procedures include wet cleaning methods (or vacuums equipped with high efficiency particulate arresting filters), use of respirators with HEPA filters and reusable or disposable

clothing. The disposal of asbestos waste removed using Type 1 procedures is via a double bag (labeled and sealed). Disposal of waste is to comply with Service NL's policy on disposal of asbestos waste.

5.7 SUMMARY

The Maintenance Garage is in excess of 50 years old and was originally constructed as a temporary building. While beyond the scope of this study, the building appears to fulfill the primary functional requirements for which it is intended except for short-comings in offices, lunch rooms, washrooms, etc. That being said, changes to codes, the age and wear on the building, as well as additions and modifications undertaken over the years, have culminated in a building that has significant deficiencies with respect to present-day codes and standards. Some of these deficiencies are confirmed in this report, while others that are highly probable would require additional site investigations.

Architecturally, the building is absent some critical fire separations, such as those associated with Level 2 floor assemblies and load-bearing walls, as well as fire-separation of the Garage from adjacent occupancies; these cannot be addressed via sprinklering. The exterior wall assembly is deficient in many respects, including a lack of thermal insulation and an air vapour barrier, it is not weather-tight, and has had significant sections in-filled with unsuitable construction techniques and materials. The concrete block addition on the north side of the building possesses significant short-comings with respect to thermal resistance and moisture control and is suspected of having issues with mould. The roof assembly in all likelihood is also deficient with respect to thermal performance. The exterior man-doors, frames and hardware, have reached, if not exceeded, their useful life. The overhead doors, while in good condition and operational, were down-sized from the original doors and installed in plywood sheathed wood-framed walls; these walls are not suitable as an exterior building envelope. With a few exceptions, the windows are beyond repair and being single-glazed (in most cases) are inappropriate for today`s buildings. Leaks and water damage is prevalent throughout the building around wall penetrations, windows, doors, and plywood sheathed wall assemblies. Interior floor finishes, limited primarily to offices, washrooms, etc., vary in condition with some being relatively new, but older finishes are in need of replacement; in some cases there is no floor finish and the plywood subfloor is painted. Some interior wall assemblies are deficient with respect to fire-rating, while many areas are in poor condition aesthetically. Interior man-doors have reached their useful life and in some cases would not satisfy the fire-resistance ratings of the walls they are contained in. The building`s exterior also lacks positive drainage in some areas. Code issues include, barrier-free design deficiencies, inadequate fire-ratings, corridor exit capacity, handrails and guards, etc.

Mechanically, the building lacks an adequate storm water drainage system to collect and divert rainwater away from the building`s roof. There are potential short-comings in the building`s waste oil management system with respect to a waste oil separator. Water piping serving the fire hose cabinets does not meet the minimum code requirement of 100 mm. Air conditioning units installed in select areas, have been adapted to, and mounted in, windows. Ventilation systems, while not analyzed in detail, are deficient (or suspected as being deficient in whole or in part), due to inoperable equipment and simply not being adequate to meet current codes and standards. For example, in some areas mechanical ventilation is non-existent; minimum air changes are suspected as not being met; fans are no longer operational; offices do not have a fresh air supply; and the space lacks a carbon monoxide - nitrogen dioxide monitoring system. The building also lacks an adequate controls system, including some damper interlocks.

Electrically, the building`s systems consist of both original equipment and some recent additions and upgrades. Some minor issues related to rusting fasteners and straps and broken cover plates were noted with the incoming service and main service disconnect. Circuits are not fully identified making it difficult to trace equipment and some abandoned wiring was noted in a ceiling space. Disconnects are of the general purpose type and not recommended for damp and dusty environments and are considered past their useful life. A majority of the panels are residential type with one being converted to a junction box, which is a code violation. An open face transformer exists in the Garage, which presents an electrical hazard. Issues were noted with ground rod spacing and life expectancy and recommended for further investigation. The fluorescent lighting is considered obsolete and inefficient by current standards. Some residential type heaters were noted has damaged and in need of replacement. Wiring devices were noted as being in good condition, except for issues with GFIs and the potential for multiple circuits on individual breakers. Emergency lighting does not meet current code standards for illumination coverage and the required 90 minute up-time. The communications cabinet, installed in the Garage, is not rated for this type of environment and presents a shock hazard. Further investigation is warranted to determine if sufficient air exchanges exist in specific areas and what, if any, mitigative measures need to be taken.

Structurally, issues were noted with isolated columns that have had holes cut in the webs for conduit runs and what effect, if any, this may have on the load carrying capacity is unknown. Primary bracing appears to be absent from the walls and it is unclear if this is associated with original construction or post-construction alterations. No sag rods were observed in the walls and further analysis would be required to determine if this warrants remedial action. A girt was added to the east wall and appears to be inadequately spliced and insufficient for its span and loading. Metal siding is not properly attached in some locations, while mechanical and electrical equipment have been affixed to the siding at other locations without adequate

structural support and reinforcement. Interior partitions were noted as having insufficient lateral support. Wood-framed mezzanines appear to be under-designed for floor loads. Hand rails and guards were noted has being under-designed.

Environmentally, the building possesses asbestos containing materials (ACMs). Asbestos is confirmed to be present in the joint filler coating of drywall surfaces and cement sheathing, and there is also a potential for ACMs in other building materials, such as roofing, electrical components, mechanical components, underground services, fire doors, caulking, and concrete leveling compounds.

5.8 CONCLUSIONS AND RECOMMENDATION

The issues noted above include a substantial list of deficiencies and other unknowns that would require significant further site investigations, analysis, sampling, and evaluation to fully define a refurbishment scope of work, if practical. Generally, significant upgrading is required to architectural, mechanical, electrical, and structural systems, and must take ACMs into consideration. Of immediate concern is:

- the absence of some critical fire separations;
- the potential lack of adequate ventilation and the risk associated with same (e.g., potential hazardous areas created at the floor level and within the service pit), and undersized piping that supplies fire hose cabinets;
- obsolete and inappropriate installation of electrical equipment and code violations (e.g., unidentified circuits, obsolete/inappropriate use of disconnect switches, panel used as a junction box, existence of an open-face transformer and the resultant shock hazard, inadequate emergency lighting); and
- structural deficiencies/modifications (e.g., removed bracing, inadequate equipment support, inadequate splicing of structural members, insufficient lateral support for interior walls, and inadequate guards and hand rails).

Though less critical in terms of life safety and code violations, with respect to overall condition, aesthetics and functionality, the building's office space, lunchrooms and washrooms are inadequate; collectively, they are in very poor condition, not barrier-free, and/or have been incorporated into the building ad hoc. With respect to the building envelope, it is also insufficient in regards to weather-resistance, thermal and moisture performance; many of the windows are single-glazed, interior leaks are prevalent throughout, insulation is virtually non-existence, and exterior walls have been modified using inappropriate construction methods.

As stand-alone items, some of these deficiencies can be addressed, but consideration must be given to how these deficiencies interact. For example, it is not possible to undertake significant upgrading of the building envelope or its interior construction without affecting electrical and mechanical systems, whether they are presently compliant or not. Similarly, upgrading the building`s envelope to address thermal and moisture issues would require a more detailed field program and analysis of the building`s structural system to consider the additional weights, original steel properties, member sizes, field alterations, removed bracing, etc. Other issues are not easily remediated, such as building envelope, interior fire-separations, mechanical ventilation, etc., and would effectively render the building unusable during construction.

As a result of these findings, it is recommended that no further significant investments be considered for this building to bring it up to present-day codes and standards and it be immediately considered for replacement. A budget estimate for replacement of a similar size and type of building is as follows:

• New Building: 872 m^2 at $2,700/m2	= $	2,350,000
• Sitework (Allowance)	= $	300,000
• Demolition of Existing Building (Allowance)	= $	300,000
• Contingency @ 20%	= $	590,000
• Project Management/Engineering at 12%	= $	420,000
• **TOTAL PROJECT BUDGET**	**= $**	**3,960,000**

In preparing the above conclusions and recommendation, including project budget, the following is noted:

- The building has been identified for "immediate" replacement. Subjectively, we recommend this be viewed as a 0 – 5 year timeline.
- The replacement cost assumes that any new building would be of a similar size, type and function as the existing building. Ideally, a needs analysis that evaluates the long-term needs of the Owner, and the Maintenance Garage user groups in particular, should be undertaken to determine the specific requirements for a new building.
- A potential location for a new building is unknown at present, thus the exact requirements for sitework (e.g., site development, water, sewer, power, etc.) is unknown and the amount carried for same has therefore been identified as an "allowance".
- The precise requirements for demolition, and in particular asbestos and other potential environmental abatement required to facilitate demolition of the existing building, is unknown and the amount carried for same has therefore been identified as an

"allowance".

- Opportunities to combine like-functions (e.g., office space from all three (3) buildings, carpentry with other maintenance groups, etc.) should be considered in a long-term planning strategy.

6.0 CONDITION ASSESSMENT – CARPENTRY SHOP

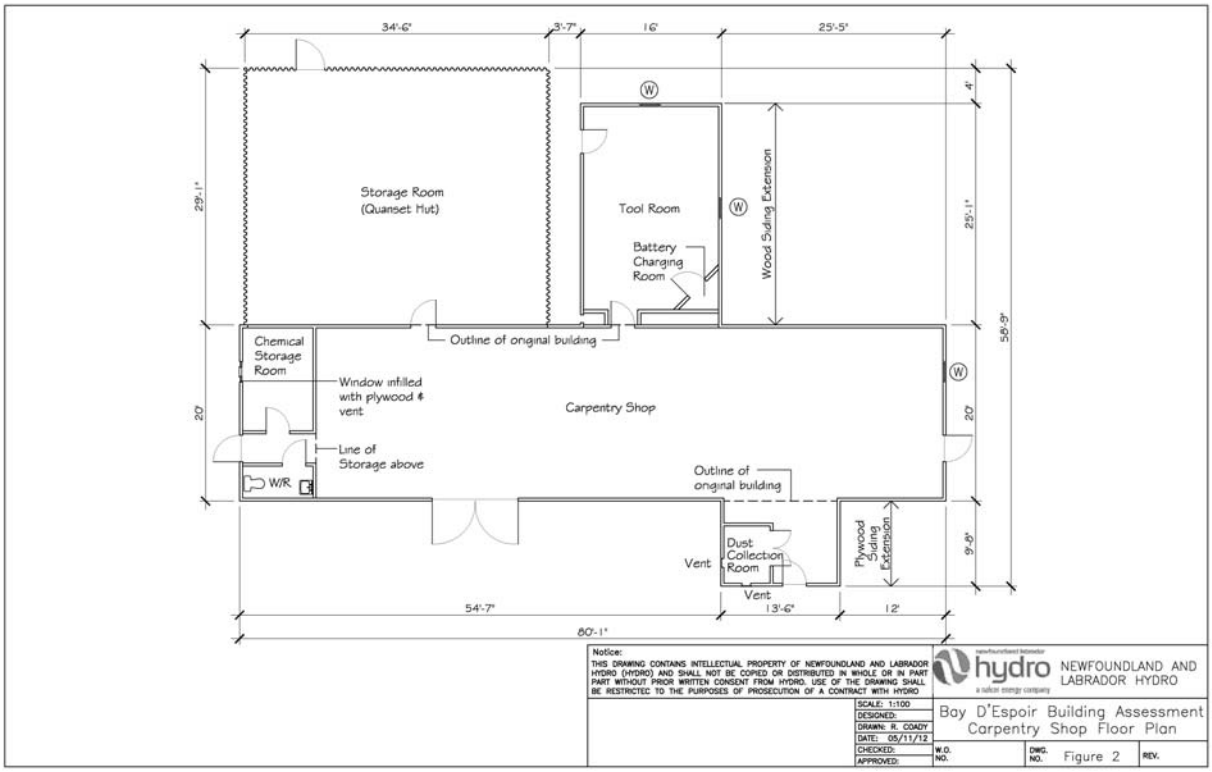
6.1 GENERAL OVERVIEW

The Carpentry Shop was constructed as a temporary building in the early 1960s during the construction phase of Bay D'Espoir Hydroelectric Generating Station. Site observations suggest that the main carpentry workshop was the original building, while the three (3) extensions (i.e., north entry, storage room, and tool room) were subsequent additions. The building is used for carpentry services to support day-to-day maintenance operations, and includes a carpentry shop, tool room, storage room, washroom, dust collection room, and chemical storage room.

The building is a one (1) storey structure with a building area of 290 m^2 and can be considered as facing two (2) streets. The types of foundations vary: the original structure, north entry, and tool room is supported on wood sleepers; the Quonset hut is erected on a concrete slab-on-grade. The original building is an ARMCO pre-engineered building (i.e., steel-framed superstructure with metal siding and roofing). The north entry and tool rooms are wood-framed structures. The storage room is corrugated metal (i.e., Quonset hut). The building is not sprinklered.

Floor plans of the existing building are provided in Figure 2 and were created for this study; original design or as-built drawings do not exist.

Photographs of the existing building are provided in Appendix B.


34'-6"
3'-7"
16'
25'-5"
4"
29'-1"
Storage Room
(Quanset Hut)
Tool Room
Battery
Charging
Room
Wood Siding Extension
25'-1"
58'-9"
Chemical
Storage
Room
Outline of original building
Window infilled
with plywood &
vent
Carpentry Shop
20'
20'
Line of
Storage above
W/R
Outline of
original building
Dust
Collection
Room
Vent
Vent
Plywood
Siding
Extension
9'-8"
54'-7"
13'-6"
12'
80'-1"
Notice:
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DESIGNED:
DRAWN: R. COADY
DATE: 05/11/12
CHECKED:
APPROVED:
Bay D'Espoir Building Assessment
Carpentry Shop Floor Plan
W.O. NO.
DWG. NO. Figure 2
REV.

6.2 ARCHITECTURAL ASSESSMENT

6.2.1 Building Fire Safety (NBCC)

The Carpentry Shop is an industrial building with one (1) principal occupancy that, subject to further discussions with authorities-having-jurisdiction, may be classified as Group F, Division 3 (Low Hazard Industrial Occupancy), or Division 2 (Medium Hazard Industrial Occupancy) by NBCC. For the purpose of this study, we have assumed the more restrictive F2.

To conform to present-day NBCC, Part 3, the building has to meet the requirements of Clause 3.2.2.76 for building fire safety, as follows:

Clause 3.2.2.76 Group F, Division 2, up to 2 Storeys

1) A building classified as Group F, Division 2 is permitted to conform to Sentence (2) provided

a) it is not more than 2 storeys in building height, and

b) it has a building area not more than the value in Table 3.2.2.76.

Table 3.2.2.76
Maximum Building Area, Group F, Division 2, Up to 2 Storeys

No. of Storeys	*Maximum Area, m^2*		
	Facing 1 Street	*Facing 2 Streets*	*Facing 3 Streets*
1	*1 000*	*1 250*	*1 500*
2	*600*	*750*	*900*

2) The building referred to in Sentence (1) is permitted to be of combustible construction or noncombustible construction used singly or in combination, and

a) floor assemblies shall be fire separations and, if of combustible construction, shall have a fire-resistance rating not less than 45 min, and

b) loadbearing walls, columns and arches supporting an assembly required to have a fire-resistance rating shall

i) have a fire-resistance rating not less than 45 mins, or

ii) be of noncombustible construction.

It is important to note that there is not necessarily only one (1) "design" solution for a building. NBCC offers multiple fire and life safety solutions for buildings of the same use, occupancy and

size that, for example, may prescribe less stringent fire-separation requirements provided other measures (e.g.., non-combustible construction, sprinkler system) are incorporated in the solution. The best solution is derived from and cost-benefit analysis.

For the Carpentry Shop, NBCC Clause 3.2.2.77 – Group F, Division 2, Up to 2 Storeys, Sprinklered, does not offer any relief in this regard as the floor assemblies and associated load-bearing elements still have to be fire-rated or of non-combustible construction even with a sprinkler system installed.

6.2.2 Exterior Wall Assembly

While an intrusive/destructive investigation of the exterior wall assembly was not undertaken, the primary construction of the exterior wall assembly for the original ARMCO building consists of metal cladding, approximately 45 mm of (discontinuous) rigid insulation (presumed per Maintenance Garage construction), and a painted plywood interior finish. The building is supported on wood sleepers for a foundation, which is not acceptable for a permanent structure.

The metal cladding is original to the building and appears integral to the buildings' structural system. Each panel is 406 mm (16") wide x 76 mm (3") deep and locks together at each seam. The panels exhibit some rusting, particularly where the finished grade is contacting the bottom of the siding; positive drainage is not present around the entire perimeter of the building and would need to be addressed if the structure is retained so as to direct water away from the building. The metal cladding also exhibits numerous holes and dents; if the building is retained these issues will have to be addressed.

Rigid polybead insulation has been (assumed) fitted within each wall panel and is estimated to be 38 mm (1.5") thick. At best, this provides a thermal insulating value of RSI 7, which is substantially less than the expected design criteria of RSI 20 were this building constructed new, or brought up to present-day code. The insulation is also presumed to be discontinuous at each metal panel joint resulting in thermal bridges, or essentially no insulating value, at these locations (every 406 mm). In summary, the thermal resistance of the buildings' exterior walls is negligible.

In a typical wall assembly, inboard of the insulation an air vapour barrier is required and installed to prevent moisture from migrating from the building's interior through the exterior wall assembly and condensing on the interior face of the exterior siding (or cold surface). It is presumed that no air vapour barrier is present in the wall assembly and would need to be further investigated and addressed were the building retained and refurbished.

The interior finish is predominantly painted plywood, which is acceptable by code given that the building can be of combustible or non-combustible construction. However, while the plywood has served as a suitable finish material for the life of the building it now exhibits signs of deterioration, including water damage from exterior wall, window and door leaks, which is indicative of its long service life and the condition of the exterior of the building.

The north entry, assumed to have been added to the original building at some later date, consists of painted plywood sheathing on both the exterior and interior, and is comprised of wood-frame construction. Plywood is generally not used in an exposed exterior application and, as in this case, exhibits rot and overall deterioration. In particular, the base of the wall adjacent to the door is completely rotted away to the extent that the interior wall components are visible. Were this building retained and refurbished, further investigation of this section of the building would be necessary to determine its internal construction and condition, as well as necessary remedial action (including new siding, at a minimum). This portion of the building is supported on wood sleepers for a foundation, which is not acceptable for a permanent structure.

The tool room, assumed to have been added to the original building at some later date, consists of painted vertical wood siding on the exterior, and painted plywood sheathing on the interior, and is comprised of wood-frame construction. The exterior wood siding, as a building envelope system, has essentially reached its useful life as suggested by the condition of the interior plywood, which exhibits water staining and signs of prolonged leaking. Were this building retained and refurbished, further investigation of this section of the building would be necessary to determine its construction and internal wall condition, as well as necessary remedial action (including new exterior siding, at a minimum). This portion of the building is supported on wood sleepers for a foundation, which is not acceptable for a permanent structure.

The storage room (i.e., Quonset hut), assumed to have been added to the original building at some later date, consists of non-insulated single-skin galvanized corrugated metal founded on a concrete slab-on-grade. The metal exhibits significant surface rusting, but to the extent that it could be refinished if retained. The interface of the Quonset hut with the original building wall appears to have been repaired in the past to stop water leaks, and is need of further repair to correct deteriorated caulking. While this section of the building is founded on a concrete slab, versus wood sleepers, there is no information available to assess its construction, such as thickness, reinforcement, presence/depth of footings (below frost penetration), frost protection, thermal performance, etc. Of particular significance, it was noted that this section of the building is heated yet it contains no insulation.

All of these issues would need to be further investigated were this building retained and refurbished.

6.2.3 Roof Assembly

The original structure's roof is part of the ARMCO building system and appears integral to the buildings' structural system. The north entry and south tool room wood-frame extensions are finished with asphalt shingles. The roof was not accessed from above or below for a detailed inspection.

As observed from a distance, the original exterior metal roof appears in good condition overall with no signs of rusting, but water staining on the interior plywood ceiling finish suggests there have been, or still are, leaks in the roof system. The asphalt shingles have essentially reached their useful life, as evidenced by curling/lifting tabs and water staining on the interior plywood ceiling finish. Wood eaves have also deteriorated to the point of peeling paint and rotted facias.

All of these issues, as well as the underlying conditions, would have to be investigated further using destructive methods if this building was recommended for retention and refurbishment.

6.2.4 Exterior Man-Doors

The building's exterior contains a combination of commercial/industrial type steel doors and frames, wood doors, and a residential type door.

The exterior steel man-doors and pressed steel frames, located on either end of the Carpentry Shop, are operable and generally in good condition and fitted with panic hardware; it was noted that the east door does not operate smoothly ("sticking" on opening/closing) and requires adjustment. The Quonset hut steel door is operable.

While the residential-type door located in the north entry operates adequately, this type of door is not typically found in industrial buildings and would be recommended for replacement if refurbishments were undertaken.

There are two (2) existing exterior wood doors, located in the Carpentry Shop and Tool Room, neither of which is adequate. The Carpentry Shop contains a double leaf "homemade" plywood door 3m wide x 3m high that appears to have been a modification to the original building and is "locked" with a wood cross beam on the inside; the door is far from weathertight and not consistent with that which would be detailed in new construction. The Tool Room door has deteriorated to the point that there are signs of leaking around its frame and the exterior surface is delaminated.

Except for the steel doors, essentially the remaining exterior doors have reached their useful life and/or are unsuitable for their application and are in need of complete replacement if the building was retained and refurbished.

6.2.5 Exterior Windows

There are a limited number of windows in the building; three (3) in total. The windows are wood frame, horizontal slider-type, and have reached their useful life, as evidenced by rotted frames, peeling paint, deteriorated caulking, and water staining (leaks) on the interior. If the building was to be retained and refurbished, all windows will need to be replaced.

6.2.6 Interior Floor Assemblies and Finishes

Floor finishes consist of plywood and concrete slab-on-grade. The Storage Room (i.e., Quonset hut) is the only area with concrete. The remainder of the building contains exposed painted plywood, which suggests the underlying construction is wood (and as suggested by the wood sleeper foundation). Other than being worn as a result of its many years in service and an atypical floor finish, the exposed plywood is in a serviceable condition. No information exists with respect to the underlying construction (i.e., type of construction, wood in contact with ground, size of members, presence of insulation and/or vapour barrier, etc.), or its condition as it could not be inspected.

All of these issues would require further investigation were the building retained and refurbished.

6.2.7 Interior Wall Assemblies and Finishes

The interior wall finish is predominantly painted plywood, except that the Washroom and Chemical Storage Room area is painted gyproc. These finishes have reached their useful life and are in need of replacement or significant refinishing as evidenced by water staining due to leaks around doors and windows, and holes through the walls. Furthermore, while the building contains minimal interior partitions, the type of rooms encompassed may have a significant impact on whether or not changes to wall construction are mandated by code and/or authorities-having-jurisdiction.

The walls encompassing the Dust Collection Room are not up to present-day code. NFCC requires this room to have a 1-hour fire separation and explosion vents to the outside. Neither of these conditions exists at present as evidenced by the plywood wall finish, plywood doors, residential type attic vents installed in the walls, and lack of fire dampers at duct penetrations through the interior partitions.

The potential requirement for fire-rating the Battery Charging Room also requires further investigation with authorities-having-jurisdiction as it is not readily apparent in NBCC; existing constructions is not rated.

Similarly, the potential requirement for fire-rating the Chemical Storage Room requires further investigation with authorities-having-jurisdiction, as well as knowledge of the contents (type and volume) stored within. It is possible that NFCC will require this room to be fire-rated and existing constructions suggests it is not.

6.2.8 Interior Doors

The interior doors have reached their useful life, or are not suitable for their application. They are in poor condition with broken frames and hardware and are in need of complete replacement. The Dust Collection Room door is not fire-rated, as it should be, and there is the potential that the Battery Charging Room door and Chemical Storage Room door also be fire-rated. The washroom door also swings into the exit corridor, effectively eliminating the corridor's exit capacity.

6.2.9 Code Issues

While a detailed code check/analysis of the existing building was beyond the scope of work, issues that need to be addressed, or warrant further investigation, to meet present-day codes include:

- Explosion venting and fire-rating of the Dust Collection Room, as well as doors, frames and hardware contained therein;
- Potential fire-rating of the Battery Charging Room and Chemical Storage Room, as well as doors, frames and hardware contained therein;
- Flame spread rating (FSR) and Smoke Developed Classification (SDC) of interior finishes;
- Corridor exit width, more specifically the reduced exit capacity of the corridor leading from the carpenter shop as a result of the swing/encroachment of the Washroom door;
- Positive drainage away from the building's exterior;
- Quantity of washroom fixtures, as well as gender specific washroom requirements (requires knowledge of occupant load); and
- Barrier-free design.

A detailed assessment of these issues would require additional knowledge of the building's use and occupancy, occupant load, as-built construction drawings/details (or destructive site investigations), material properties, and discussions with authorities-having-jurisdiction

6.3 MECHANICAL ASSESSMENT

6.3.1 Storm Drainage

The building has a sloped roof and all water is drained to the site. There are no eaves troughs or downspouts to collect and divert water away from the building, as it should. If the building is retained and refurbished this should be corrected.

6.3.2 Sanitary Drainage

The main sewer piping is located under the slab and serves one washroom. The system is still in working order and could be re-used, but it is recommended that the lines be snaked and cleaned.

6.3.3 Plumbing

There is one washroom that consists of one (1) water closet and one (1) lavatory. All fixtures appear to be functional and in reasonable shape.

6.3.4 Domestic Water System

Domestic hot water is supplied by an electric boiler located in the storage area of the shop. The existing distribution piping is all copper with localized isolation valves at fixture locations. Any proposed renovation will require a review of the distribution piping and system sizing. Existing piping is surface mounted and ideally would be embedded in the walls.

6.3.5 Fire Protection

Portable fire extinguishers are installed throughout the building and are mainly the multi-purpose dry chemical type. There is no hose reel stations or automatic sprinkler system.

6.3.6 Heating and Cooling

The building is heated via a combination of electric baseboard heaters and electric unit heaters. There is no air conditioning (cooling) system in this building.

6.3.7 Air Handling Systems

The building contains a dust collector unit complete with an exhaust fan, collection drum and bag filter. The dust collector is manually controlled and is used to collect dust from the various cutting equipment located throughout the shop. The collection drum is used to capture heavier particles, and the bag filter is used to capture smaller dust particles. This dust collection system can be classified as 'enclosure-less', meaning the filtered air is basically distributed to the surrounding air, and the filtering system is exposed to the working environment. The dust collector unit is located inside the building and therefore must meet the requirements set out

in NFCC. A dust collector with airflow greater than 500 L/s is permitted to be inside a building provided it meets the following:

- It is provided with explosion venting to the outdoors with not less than 0.5 m^2 of vent area per each cubic metre of dust collection enclosure volume;
- Equipped with an automatic explosion prevention system;
- Located in a room with fire separations having a fire resistance rating of not less than one (1) hour and provided with explosion venting to the outdoors;
- Returned air will not create an explosion hazard inside the building; and
- The exhaust fan and ancillary equipment are automatically shut down in the event of a fire or an explosion inside the dust collector.

Based on a visual inspection, it appears unlikely this system contains an automatic shutdown system or an automatic explosion prevention system. The capacity, or enclosure volume, of the dust collection system is unknown at this time; however the venting to the outside is very limited and does not appear to have sufficient venting area.

There are additional requirements for duct collection systems in NFPA 664. This code applies to woodworking areas greater than 5,000 ft^2 (not applicable in this case), or where dust collection flow rates are greater than 1,500 cfm (the capacity of the system is unknown, however based on the woodworking equipment in the space it is suspected the system exceeds 1,500 cfm, therefore this code is relevant). As an example, if using an enclosure-less duct collection system inside a building, the bag filter must be cleaned at least once daily. It was evident from site that this was not the case, which presents a major fire hazard. This code also outlines requirements for inspection, maintenance, record retention and documentation of dust collection systems.

The ACGIH – Industrial Ventilation manual also outlines recommended practice for the design of wood working and dust collection systems. As an example, this manual outlines a minimum duct velocity of 3,500 fpm be maintained to prevent dust settlement in the ducting system, and also outlines minimum recommended exhaust air flow rates for specific saw types and diameters, belt sanders, molders, and wood shapers, to name a few. Since the capacity of the system is unknown at this time, it is unclear whether the dust collection has sufficient capacity or not.

The building also does not have any provisions for fresh during occupied hours or make-up air while the dust collection system is operating. This violates indoor air quality requirements for occupied spaces.

From the above, it is apparent that there are significant upgrades required for the ventilation and dust collection system. A detailed review of the wood cutting equipment used would be required to determine overall exhaust airflow requirements. A new system providing fresh air to the building would also be required.

6.3.8 Controls

The building does not have a building management system and controls are limited to heating thermostats and manual starters for the dust collection system. In any renovation proposal, a new control system would need to be installed. The type and complexity of the control system would depend on the type of heating and ventilation systems that are installed. If renovations to the existing dust collection system are made, or a new system installed, interlocks between the dust collecting system and the equipment requiring dust collection is required. A control to shut the system down in the event of a fire or explosion would also need to be incorporated into the controls design.

6.4 ELECTRICAL ASSESSMENT

6.4.1 Electrical Service and Distribution

The carpentry shop is fed aerially from a pole-mounted 3 phase transformer bank. The service mast, mast straps and supports appear to be in good condition.

The nuts and bolts securing the main service panel are showing signs of rust on the exterior and should be replaced. Arc flash labels dated 2009 can be found on a 600 V disconnect which indicates that some analysis of the building's electrical system has been completed. In accordance with the CEC, all electrical equipment that will likely require examination, adjustment, servicing or maintenance while energized shall be field marked to warn of potential shock and arc flash hazards.

Due to potential shock and arc hazards, no feeder or branch wiring was inspected or verified and requires further investigation.

A mixture of relatively new and originally installed disconnects are installed throughout the building. The vast majority of the disconnect enclosures are designed for general purpose and not suited for dust environments. Many disconnects would be considered past their useful service life and should be replaced.

While the majority of panels are residential type, there is evidence of recent upgrades.

The open faced transformer located in the shop area has a considerable build-up of dust inside it and around the windings and core. This is a code violation since it restricts the ability of the transformer to dissipate heat. In addition, this transformer does not appear to be secured to the floor.

It is recommended to relocate the main service panel, transformers and distribution panels in a segregated dust free room accessible only from the exterior. All disconnects in the shop area should be upgraded to dustproof Type 12 enclosures.

6.4.2 Telephone Utility Services

Telephone and data service is through an aerial feed. The mast, mast straps and supports appear to be in good condition.

6.4.3 Grounding Systems

A single ground rod is visible, which appears to be bonded to other rods. It should be noted that ground rods normally have a service life of 40 years depending on soil conditions. It is recommended that the grounding system is thoroughly inspected and tested.

6.4.4 Lighting

Vapour tight, T-12 fluorescent lamps are installed throughout the building except in the Washroom. While illumination levels appear adequate, T-12 systems are being phased out in favour of T-8 and T-5 lamps with energy efficient electronic ballasts.

6.4.5 Heating

The unit heaters installed in the shop area are not suitable for dust environment and should be replaced with the explosion proof type. The Washroom utilizes a residential electric convection heater which appears to be in good working order.

6.4.6 Wiring Devices

Most light switches located in the shop area are dust proof. Receptacles should be verified to be dust proof. All wiring devices should be in FS type boxes. The damaged GFI receptacle should be replaced with a dust proof device.

6.4.7 Life Safety Systems

No fire alarm system is installed in this facility. 120V AC powered smoke detectors are installed throughout.

Emergency lighting is installed over exit doors only and would not provide adequate illumination coverage. Most of the lamp heads are obsolete and battery packs would not meet the 90 minute uptime standard. The majority of exit signs utilizes incandescent bulbs and should be replaced with LED type.

6.4.8 Communications

There is a wooden data cabinet located in the shop area where cabling associated with the card access and surveillance cameras terminate. There is no telephone service in the building.

6.4.9 Security Systems

A card access and cameras have been recently installed. It is assumed to be in good working order.

6.4.10 Classified Hazardous Areas

Assuming the dust collection system is upgraded to meet NFCC and NFPA 664 requirements, all equipment is to be interlocked to prevent operation if the dust collection system is not in operation. This would require significant upgrades to the electrical system.

6.5 STRUCTURAL ASSESSMENT

The carpentry shop consists of a pre-engineered type metal building for the main workshop; a wood-framed addition to the workshop at the south; a metal Quonset building for storage at the south; and a wood-framed addition to the north. The workshop and its additions rest on wood sleepers on grade as could be seen at the perimeter, while the Quonset metal building is on a concrete slab-on-grade. The pre-engineered building consists of metal roof and wall panels. How these panels were supported and whether the exterior wall contained columns or are load bearing panels, could not been determined due to the presence of plywood on the ceiling and inside of the walls. The plywood would have to be removed to confirm.

The framing for the wood additions could not be seen due to interior finishes. Therefore, the condition of the framing for the workshop area cannot be commented on at this time.

The Quonset storage building consisted of inter-locking curved metal panels along with areas of translucent panels.

6.5.1 Storage Room (Quonset Hut)

In Quonset hut there were no apparent signs of structural defect or distress observed with the metal panels or slab-on-grade. The panels exhibit some signs of minor rusting and the slab exhibits some minor cracking but nothing that would affect the performance of the building.

6.5.2 Carpentry Shop

Two (2) items were noted in the Carpentry Shop. First, the building and its additions are resting on wood sleepers directly on grade. This can lead to building movements and differential settlement, particularly due to frost heave. This type of support is not recommended or necessarily suitable for supporting point loads, which would be the case if the exterior walls have columns rather than a load bearing panel system. Also, wood in constant contact with grade and changing wet and dry conditions is exposed to deterioration due to rotting unless adequately protected or preserved. Second, there are two large openings in the exterior wall of the metal building: at the north entry side addition, and at the plywood door in the north wall. These walls could possibly be load bearing or the openings contain a column and it is unclear if these opening have been adequately supported.

The north side addition consisted of wood framing with painted plywood siding on a concrete slab- on-grade. This addition showed significant signs of deterioration of siding, sill plate and the bottom of studs in some locations.

6.6 ENVIRONMENTAL ASSESSMENT

Based on a review of the previous Pinchin Leblanc survey (July, 2004), the following comments are provided with respect to ACMs in the Carpentry Shop:

- Asbestos is present in the joint filler coat of the drywall surfaces in the Washroom. The previous Pinchin Leblanc sampling program (July, 2004) confirmed 1-5% chrysotile asbestos in the drywall joint filler for one (1) sample collected from the wall of the washroom area (beige color sample). A full sampling program at each joint location was not completed, however all joint filler coats on the drywall surfaces in the washroom area should be considered as containing 1-5% chrysotile asbestos. Joint filler products in place are generally treated as non-friable. The total estimated surface area of the drywall surfaces in the washroom is 16m^2.
- There is potential for concealed asbestos materials to be present in: (a) the roofing felts and mastics; (b) components or wiring within motors or lights; (c) high voltage wiring; (d) mechanical packing and gaskets; € underground services or piping; (f) fire-doors; (g) window caulking; and (h) concrete leveling compound. In the absence of additional sampling, these materials (if present in the Carpentry Shop) should be considered suspect ACMs during renovation or demolition activities.

With respect to suspect ACMs, the following is noted:

- If the building is retained and refurbished, only those suspect materials where renovation work will cause disturbance should be sampled. As part of the Asbestos Management Program document established by Pinchin Leblanc in 2004 for NL Hydro, the Carpentry Shop would be considered as having an asbestos management program in place and, in this regard, suspect ACMs do not need to be removed if they are not disturbed during renovation activities.
- If the building is to be demolished, an intrusive sampling program of all suspect ACMs should be completed to ensure these materials are properly removed/handled and disposed of during demolition activities.

Based on the types and quantity of ACMs present in the Carpentry Shop, removal efforts would be classified as Type 1, as defined in NL Hydro's Asbestos Management Program (prepared by Pinchin Leblanc in 2004). A Type 1 asbestos removal procedure assumes the non-friable material can be removed with relatively little loose dry dust released. Generation of debris is permissible as long as the debris can be well wetted before being removed. Typical removal procedures include wet cleaning methods (or vacuums equipped with high efficiency particulate arresting filters), use of respirators with HEPA filters and reusable or disposable clothing. The disposal of asbestos waste removed using Type 1 procedures is via a double bag (labeled and sealed). Disposal of waste is to comply with Service NL's policy on disposal of asbestos waste.

6.7 SUMMARY

The Carpentry Shop was constructed as a temporary building and is approximately 50 years old and, while beyond the scope of this study, seems to fulfill the primary functional requirements for which it is intended. That being said, changes to codes, original construction methods, the age and wear on the building, as well as additions and modifications undertaken over the years, have culminated in a building that has significant deficiencies with respect to present-day codes and standards. Some of these deficiencies are confirmed in this report, while others that are highly probable would require additional site investigations.

Architecturally, the building inherently contains a significant short-coming in that it does not rest on a permanent foundation; wood sleepers on grade is not an acceptable foundation for a permanent structure. The building is also absent some critical fire separations, such as with the Dust Collection Room and, possibly, the Battery Charging Room and Chemical Storage Room; these cannot be addressed via sprinklering. The building's original exterior wall assembly is deficient in several respects, including a lack of thermal insulation and an air vapour barrier, it is not weather-tight, and has had significant sections removed to accommodate extensions and

doors. Collectively, the north Entry extension and south Tool Room extension were inadequately constructed using wood sleeper and plywood exterior sheathing and have reached their useful life, with some walls rotted away to expose the interior cavity. The roof assembly, particularly the asphalt shingles, is also beyond its useful life and exhibits signs of leaking and is also expected of being deficient with respect to thermal performance. All of the exterior wood doors have exceeded their useful life and/or are inappropriate for the application. The windows are in need of replacement. Leaks and water damage is prevalent throughout the building around wall penetrations, windows, and doors. With the exception of the Quonset hut, which is concrete slab-on-grade, interior floor finishes are non-existent and consist of painted plywood subfloor. Some interior wall assemblies are deficient with respect to fire-rating, while many areas are in poor condition aesthetically. Interior man-doors have reached their useful life and, in the case of the Dust Collection Room, are constructed of plywood; these doors do not satisfy the requisite fire-resistance ratings of the walls they are contained in. The building`s exterior also lacks positive drainage in some areas. Code issues include, barrier-free design deficiencies, inadequate fire-ratings, corridor exit capacity, NFCC provisions related to dust collection, etc.

Mechanically, the building lacks an adequate storm water drainage system to collect and divert rainwater off the building`s roof and away from its foundation. Domestic water piping is exposed and, ideally, would be concealed in the walls. The dust collection system has significant short-comings as it relates to explosion venting, adequate fire protection, and automatic shut-down of equipment. Ventilation is non-existent and there are no provisions for fresh air or make-up air while the dust collection system is operating. The building does not contain any controls.

Electrically, systems consist of both original equipment and some recent additions and upgrades. A majority of disconnects are of the general purpose type and not suited for dusty environments, as well as being past their useful service life; these should be upgraded to Type 12 dustproof enclosures. An open-face transformer located in the shop area was noted as having a considerable build-up of dust inside around the windings and core, which is a code violation. A thorough inspection and testing of the grounding system is recommended. The T-12 fluorescent lighting is considered obsolete and inefficient by current standards. Unit heaters installed in the shop area are not suitable for a dust environment and should be explosion proof type. Emergency lighting does not meet current code standards for illumination coverage levels and the required 90 minute up-time. The building does not meet NFCC or NFPA 664 for the prevention of fires in woodworking facilities. The Chemical Storage Room was not accessed and requires further investigation.

Structurally, the presence of interior finishes and concealment precluded a detailed inspection, but several important issues were noted. Firstly, with the exception of the Quonset hut, the remainder of the building has been constructed on a wood sleeper foundation. This presents concerns with building movements, differential settlements, and the potential rotting of inadequately protected/preserved wood in contact with earth; this type of foundation is not recommended. Secondly, two (2) significant sections of the building's exterior wall have been removed to facilitate installation of the north extension (Entry and Dust Collection Room) and the Carpentry Shop's plywood double door, and it is unclear if the wall/openings have been adequately supported.

Environmentally, the building possesses asbestos containing materials (ACMs). Asbestos is confirmed to be present in the joint filler coating of drywall surfaces, and there is also potential for ACMs in other building materials, such as roofing, electrical components, mechanical components, underground services, fire doors, caulking, and concrete leveling compounds.

6.8 CONCLUSIONS AND RECOMMENDATION

When considered independently, significant upgrading would be required to the architectural, mechanical, electrical, and structural systems in this building if it was retained, and must take ACMs into consideration. However, when considered collectively, the condition and short-comings of this structure and its systems precludes any further investment and it is recommended for immediate replacement. For example, significant refurbishment would be required to address the building envelope, fire ratings, dust collection system, and ventilation system, at a minimum, but of particular significance with respect to retention is the absence of a suitable foundation. Of immediate concern is:

- the absence of critical fire separations and explosion venting of the Dust Collection Room, as well as dust build-up within the room itself;
- the lack of adequate ventilation and make-up air as it pertains to the dust collection system; and
- an inadequate dust collection system with respect to equipment interlocks, the presence of an open-face transformer (and dust build-up within the transformer itself), and the presence of non-explosion type unit heaters.

In summary, the lack of a suitable foundation, combined with the building's deficiencies, age, and condition precludes any further investment in this structure. A budget estimate for replacement of a similar size and type of building is as follows:

• New Building: 290 m^2 at $2,300/m2	= $	670,000
• Sitework (Allowance)	= $	100,000
• Demolition of Existing Building (Allowance)	= $	100,000
• Contingency at 20%	= $	170,000
• Project Management/Engineering at 12%	= $	130,000
• **TOTAL PROJECT BUDGET**	**= $**	**1,170,000**

In preparing the above conclusions and recommendation, including project budget, the following is noted:

- The building has been identified for "immediate" replacement. Subjectively, we recommend this be viewed as a 0 – 3 year timeline.
- The replacement cost assumes that any new building would be of a similar size, type and function as the existing building. Ideally, a needs analysis that evaluates the long-term needs of the Owner, and the Carpentry Shop user group in particular, should be undertaken to determine the specific requirements for a new building.
- A potential location for a new building is unknown at present, thus the exact requirements for sitework (e.g., site development, water, sewer, power, etc.) is unknown and the amount carried for same has therefore been identified as an "allowance".
- The precise requirements for demolition, and in particular asbestos and other potential environmental abatement required to facilitate demolition of the existing building, is unknown and the amount carried for same has therefore been identified as an "allowance".
- The budget does not include for new shop equipment.
- Opportunities to combine like-functions (e.g., carpentry with other maintenance groups) should be considered in a long-term planning strategy.

7.0 CONDITION ASSESSMENT - TRAINING CENTER

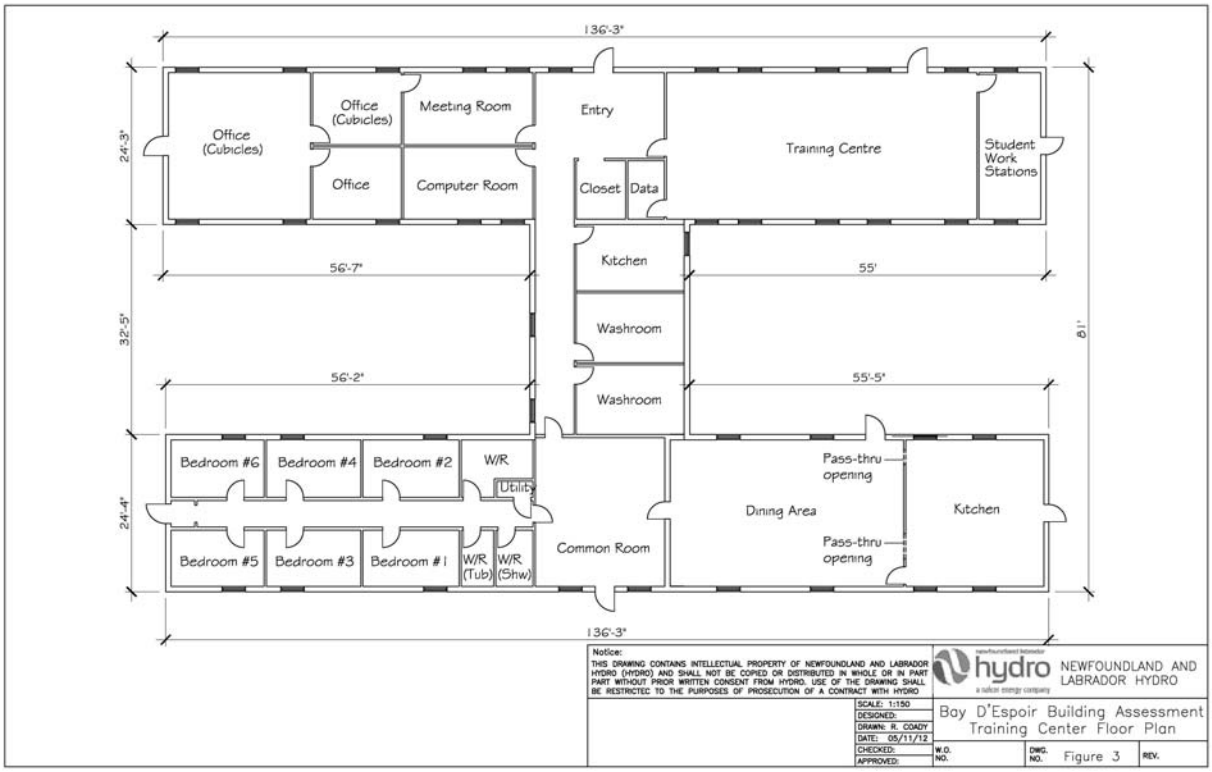
7.1 GENERAL OVERVIEW

The Training Center was constructed as a temporary building in the early 1960s during the construction phase of Bay D'Espoir Hydroelectric Generating Station. It was originally designed and used as a staff house, providing on-site accommodations that included kitchen/dining services. Over the years its space has been reallocated and redeveloped into a mixed-use facility: a portion of the original sleeping quarters have been retained and is used infrequently; the kitchen/dining facilities have been retained and are used for corporate functions; and a portion of the building has been redeveloped into office space and training rooms.

The building is a one (1) storey H-shaped structure with a building area of 686 m^2 and faces three (3) streets. It has a concrete foundation with crawl space, which is inaccessible. The original building is an ARMCO pre-engineered building (i.e., steel-framed superstructure with metal siding and roofing), but has been re-clad with wood siding and asphalt shingles on the roof. The building is not sprinklered.

Floor plans of the existing building are provided in Figure 3 and were created for this study; original design or as-built drawings do not exist.

Photographs of the existing building are provided in Appendix C.


136'-3"
Office (Cubicles)
Office (Cubicles)
Meeting Room
Office
Computer Room
Entry
Closet
Data
Training Centre
Student Work Stations
Kitchen
Washroom
Washroom
56'-7"
55'
56'-2"
55'-5"
24'-3"
32'-5"
24'-4"
61'
Bedroom #6
Bedroom #4
Bedroom #2
W/R
Utility
Bedroom #5
Bedroom #3
Bedroom #1
W/R (Tub)
W/R (Shw)
Common Room
Pass-thru opening
Dining Area
Pass-thru opening
Kitchen
136'-3"
Notice:
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DESIGNED:
DRAWN: R. COADY
DATE: 05/11/12
CHECKED:
APPROVED:
W.O. NO.
DWG. NO.
Figure 3
REV.
hydro
NEWFOUNDLAND AND LABRADOR HYDRO
Bay D'Espoir Building Assessment
Training Center Floor Plan

7.2 ARCHITECTURAL ASSESSMENT

7.2.1 Building Fire Safety (NBCC)

The Training Center is a mixed-use building with three (3) principal occupancies:

- Group A2 – Assembly (kitchen/dining);
- Group C – Residential (sleeping quarters); and
- Group D – Business and Personal Services (offices/training).

As noted in Section 4.2.2, in the case of a building containing more than one (1) major occupancy, the fire safety requirements of the most restricted major occupancy shall apply to the whole building; the entire building height and area must be used for each major occupancy being evaluated. Therefore, to conform to present-day NBCC, Part 3, the entire building must meet the most restrictive requirements of Clause 3.2.2.28, 3.2.2.52, and 3.2.2.60, as follows:

Clause 3.2.2.28 Group A, Division 2, One Storey

1) A building classified as Group A, Division 2 is permitted to be of combustible construction or non-combustible construction, used singly or in combination, provided

a) it is not more than 1 storey in building height, and

b) except as permitted by Sentence (2), it has a building area not more than

i. 400 m^2 if facing one street,

ii. 500 m^2 if facing 2 streets, or

iii. 600 m^2 if facing 3 streets.

2) In a building referred to in Sentence (1) without a basement, the building area limits of Sentence (1) are permitted to be doubled provided a fire separation with a fire-resistance rating not less than 1 h is used to separate the building into fire compartments, each one of which does not exceed the limits of Clause (1)(b).

Clause 3.2.2.52 Group C, up to 3 Storeys

1) A building classified as Group C is permitted to conform to Sentence (2) provided

a) it is not more than 3 storeys in building height, and

b) it has a building area not more than the value in Table 3.2.2.52.

Table 3.2.2.52
Maximum Building Area, Group C, Up to 3 Storeys

No. of Storeys	Maximum Area, m^2		
	Facing 1 Street	Facing 2 Streets	Facing 3 Streets
1	1 800	2 250	2 700
2	900	1 125	1 350
3	600	750	900

2) The building referred to in Sentence (1) is permitted to be of combustible construction or noncombustible construction used singly or in combination, and
   a) except as permitted by Sentences (3) and (4), floor assemblies shall be fire separations with a fire-resistance rating not less than 45 min,
   b) mezzanines shall have, if of combustible construction, a fire-resistance rating not less than 45 min, and
   c) loadbearing walls, columns and arches shall have a fire-resistance rating not less than that required for the supported assembly.

3) In a building that contains dwelling units that have more than one storey, subject to the requirements of Sentence 3.3.4.2.(3), the floor assemblies, including floors over basements, which are entirely contained within these dwelling units, shall have a fire-resistance rating not less than 45 min but need not be constructed as fire separations.

4) In a building in which there is no dwelling unit above another dwelling unit, the fire-resistance rating for floor assemblies entirely within the dwelling unit is waived.

Clause 3.2.2.60 Group D, up to 2 Storeys

1) A building classified as Group D, is permitted to conform to Sentence (2) provided
   a) it is not more than 2 storeys in building height, and
   b) it has a building area not more than the value in Table 3.2.2.60.

Table 3.2.2.60
Maximum Building Area, Group D, Up to 2 Storeys

No. of Storeys	Maximum Area, m^2		
	Facing 1 Street	Facing 2 Streets	Facing 3 Streets
1	1 000	1 250	1 500
2	800	1 000	1 200

2) The building referred to in Sentence (1) is permitted to be of combustible construction or noncombustible construction used singly or in combination, and

a) floor assemblies shall be fire separations and, if of combustible construction, shall have a fire-resistance rating not less than 45 min, and

b) loadbearing walls, columns and arches supporting an assembly required to have a fire-resistance rating shall

i) have a fire-resistance rating not less than 45 mins, or

ii) be of noncombustible construction.

Considering these requirements, the Group A2 condition of limiting the fire compartment size to 600 m^2 so as to permit "doubling of the building area" for evaluation purposes, will need to be met. In this regard, the presence of a 1.5 hour rated fire-door between the common room and sleeping quarters suggests this wall is currently rated and may help satisfy the maximum fire compartment size of 600 m^2. But, an inspection of the wall extending into the attic indicates the fire-rating has not been carried above the ceiling line; the crawl space was inaccessible and whether or not the existing fire separation extends "downward" is unknown.

Other partitions will all also have to be fire-rated to meet present day code with respect to separation of occupancies: A2 and C occupancies have to be separated by a 1-hour fire separation; and A2 and D occupancies have to be separated by a 1-hour fire separation.

It is important to note that there is not necessarily only one (1) "design" solution for a building. NBCC offers multiple fire and life safety solutions for buildings of the same use, occupancy and size that, for example, may prescribe less stringent fire-separation requirements provided other measures (e.g.., non-combustible construction, sprinkler system) are incorporated in the solution. The best solution is derived from and cost-benefit analysis.

For the Training Center, alternate NBCC Clauses 3.2.2.27, 3.2.2.53, and 3.2.2.61, which require the building to be sprinklered, offer relief with respect to the 600 m^2 fire compartment stipulation, but this will still be superseded by the separation of occupancies from each other.

7.2.2 Exterior Wall Assembly

While an intrusive/destructive investigation of the exterior wall assembly was not undertaken, based on the construction of the other ARMCO type buildings and site observations, the exterior wall assembly (is assumed to) consists of wood siding, metal cladding, approximately 45 mm of (discontinuous) rigid insulation, wood-framed interior walls, and painted gyproc interior finish. It is uncertain if additional insulation and/or a vapor barrier is installed on the interior (of the exterior walls), but limited access to a pipe chase in the washroom suggests this was done. If any upgrades are contemplated for this building, construction of the wall assembly should be confirmed. The absence or integrity of components that provide moisture control and thermal resistance would necessitate significantly more interior work to bring the building up to present-day code.

The ranch-style vertical wood siding was affixed to the original ARMCO building some years after original construction and is in reasonably good condition. It appears to have been painted and with on-going maintenance could function adequately for some more years.

The underlying metal cladding is original to the building and is presumed integral to the buildings' structural system; it was not visible or inspected due to the wood siding.

It is assumed that rigid polybead insulation has been fitted within each wall panel and is estimated to be 38 mm (1.5") thick. At best, this provides a thermal insulating value of RSI 7, which is substantially less than the expected design criteria of RSI 20 were this building constructed new, or brought up to present-day code. The insulation is also presumed to be discontinuous at each metal panel joint resulting in thermal bridges, or essentially no insulating value, at these locations (every 406 mm). As noted above, it is uncertain if additional insulation was added to the interior, therefore the total thermal resistance of the wall assembly is unknown.

In a typical wall assembly, inboard of the insulation an air vapour barrier is required and installed to prevent moisture from migrating from the building's interior through the exterior wall assembly and condensing on the interior face of the exterior siding (or cold surface). As noted above, it is uncertain if a vapour barrier is installed on the interior.

The interior finish is predominantly painted gyproc, which is acceptable by code given that the building can be of combustible or non-combustible construction, and is in good condition. Continuous reallocation and redevelopment of space has resulted in this building being maintained aesthetically.

7.2.3 Roof Assembly

The original structure's roof is part of the ARMCO building system and appears integral to the buildings' structural system. The roof was not accessed from above for a detailed inspection and only limited attic access was achieved from below via an access hatch in the sleeping quarters.

The Owner reported that the roof was re-covered some years ago with a wood substrate and asphalt shingles, and re-shingled just recently. It is unknown how the wood substrate was attached to the metal roof (in the context of wind uplift), and no screws or fasteners were observed on the underside of the metal roof. The shingles are new and in good condition and should have a 20 year life. The eaves have been refurbished with vinyl fascia and soffit, which are both in good condition.

The only access to the attic was via a hatch located in the Utility Room in the sleeping quarters. As required by code, a vapour barrier was confirmed on the underside of the insulation, as well as an adequate layer of glass batt insulation. It was noted however, that the insulation fully extends (and butts up against) the underside of the roof deck at the eaves, which suggests that ventilation of the attic via the soffit is ineffective (although there were no signs of moisture/condensation during the site visit). Based on other ARMCO type buildings on site, attic venting is achieved through a "gap" at the roof peak, but recovering of the Training Center roof, the presence of attic (fire) separation(s), and insulation placement may have compromised attic venting, even with the presence of gable end vents.

The interior ceilings consist of T-bar with acoustical tiles in the office/training areas, and painted gyproc in the sleeping quarters/common room/dining/kitchen areas. The ceilings are in good condition.

All of these issues, as well as the underlying conditions, would have to be investigated further using destructive methods if this building was recommended for retention and refurbishment.

7.2.4 Exterior Man-Doors

The building's exterior contains a combination of commercial/industrial type steel doors and frames, and residential type doors.

The exterior steel man-doors, frames and hardware, are generally in good condition and equipped with panic hardware. Only the main entry door was noted has being worn (likely due to its frequency of use), and having a loose frame and the weather-stripping was cut; but otherwise operable.

The residential-type doors vary in condition. While not typical for a non-residential building, generally they are operable, except the Kitchen door which is noted as beyond repair and in need of replacement.

If the building is retained and refurbished, some or all of the residential type doors should be considered for replacement.

7.2.5 Exterior Windows

With the exception of two (2) windows in the office area that are vinyl and have been replaced, the remaining windows are double-glazed wood-frame.

The wood-frame windows are generally intact, but are nearing the end of their useful life. The frames have some isolated rotting, and peeling paint was observed throughout. The caulking is functional, but will soon be in need of replacement. If the building was to be retained and refurbished, all wood-frame windows would be recommended for replacement. Alternatively, the painting and caulking could be addressed to mitigate further deterioration and prolong their service life; severely deteriorated windows/frames could be selectively identified/replaced.

7.2.6 Interior Floor Assemblies and Finishes

Consistent with preceding maintenance and renovations to this building to adapt to its current usage, the floor finishes are generally in good condition. With the exception of the common area and sleeping quarters, which are finished with carpet, the remaining areas are finished with vinyl tile. Select areas of vinyl tile were noted as having some separation in the joints, and the carpet is dated; aesthetic improvements could be made in these areas. The subfloor condition/construction is unknown, but serviceability was a noted issue with an evident "bounce" in the floor.

7.2.7 Interior Wall Assemblies and Finishes

It is presumed that interior partitions are constructed using wood framing and no issues were documented, noting that an intrusive/destructive investigation was not undertaken. The interior wall finish is painted gyproc throughout and has been maintained in good condition.

As noted in Section 7.2.1, to meet the requirements for Group A2 occupancy, Clause 3.2.2.28 requires that the building be separated into fire compartments no larger than 600 m^2. Given that the door, and most likely the wall, between the common room and sleeping quarters is rated, this is the best location to satisfy this requirement. However, the attic inspection suggests it is not rated above the ceiling line and the crawl space was inaccessible. This issue

requires further investigation and it is likely that additional remedial work will be required if the building is retained and brought up to present-day NBCC.

7.2.8 Interior Doors

The interior doors are predominantly wood and are in good condition; no issues were noted with their operation or door hardware. However, most door hardware is of the knob type and would need to be upgraded to lever sets for accessibility requirements. Some doors, such as those in the washrooms, do not have adequate allowances on the pull side and would need to be reconfigured for accessibility. Doors determined to be located in a new fire-separation will also have to be replaced with fire-rated doors, frames and hardware.

7.2.9 Millwork

Vanities exist in all washrooms are not handicap accessible. They do not have sufficient clearances beneath, or maneuvering space in front. New vanities, or wall hung fixtures may alleviate the problem, but detailed checks of dimensional clearances would have to be considered as part of the solutions considered. The potential exists for significant washroom upgrading to meet accessibility requirements. Similar accessibility issues may have to be addressed in the service window between the Dining Room/(commercial)Kitchen, as well as the (private) Kitchen's countertop and cabinets.

7.2.10 Code Issues

While a detailed code check/analysis of the existing building was beyond the scope of work, issues that need to be addressed, or warrant further investigation, to meet present-day codes include:

- Potential upgrading/fire-rating of the wall separating the Common Room and sleeping quarters, including above the ceiling line and in the crawl space, to meet the maximum 600 m^2 requirement;
- Separation of occupancies: A2 to C by 1 hour; and A2 to D by 1 hour;
- Flame spread rating (FSR) and Smoke Developed Classification (SDC) of interior finishes;
- Access to crawl space and attics;
- Means of egress within the office area as it relates to having to exit through other rooms/offices;
- Exterior ramps in the context of principal entrances/occupancies;
- Positive drainage away from the building's exterior;
- Attic ventilation;
- Barrier-free design (e.g., millwork, door clearances, hardware, fixtures).

A detailed assessment of these issues would require additional knowledge of the building's use and occupancy, as-built construction drawings/details (or destructive site investigations), and discussions with authorities-having jurisdiction.

7.3 MECHANICAL ASSESSMENT

7.3.1 Storm Drainage

The building has a sloped roof and all water is drained to the site. There are no eaves troughs or downspouts to collect and divert water away from the building, as it should. If the building is retained and refurbished this should be corrected.

7.3.2 Sanitary Drainage

The main sewer piping is located under the floor and extends to all areas of the building. The system is still in working order and could be re-used in any renovation proposal but it is recommended that the lines be snaked and cleaned. However, there was a very noticeable stale smell in the sleeping quarter's wing that may be attributed to dry traps in the drainage system; further investigation is required.

The kitchen area consists of multiple sinks. The main dish washing sink does not have a grease interceptor located on the drainage system, so, depending on the cooking operations a grease interceptor may be required. If not required, it is normally good engineering practice, and recommended, to have one installed in a commercial setting.

7.3.3 Plumbing

The building consists of public washrooms in both the common areas and sleeping quarter. The male and female washrooms contain multiple water closets, urinals, and lavatories. The washrooms in the sleeping quarter also consist of bathtub and shower facilities. The majority of the washroom fixtures were operational, with the exception of a few which were tagged as "out of order". The fixtures are not accessible.

7.3.4 Domestic Water System

Domestic hot water is provided by two (2) electric hot water tanks: one (1) serving the common areas, and another serving the sleeping quarters. The existing distribution piping is copper with localized isolation valves at fixture locations. Any proposed renovation will require a review of the distribution piping and system sizing.

7.3.5 Fire Protection

Portable fire extinguishers are installed throughout the building and are mainly the multi-purpose dry chemical type. There are two (2) fire hose cabinets installed throughout the building. The fire water entrance could not be located; therefore its compliance with NFPA and CSA standards could not be determined.

The positioning of the fire hose cabinets appear to allow for sufficient coverage of the entire building. However, the building does not have appears to have a siamese connection, the system should be reviewed to ensure adequate hose length, and to ensure adequate flow rates can be maintained from the water supply system.

7.3.6 Heating and Cooling

Heating is provided by electric baseboard heaters. The condition of the electric heaters is covered in the electrical section of the report.

There is a Carrier cooling only split system which provides air conditioning to the training centre space. This unit appears to be fairly new and is in good condition; however, the functionality of the unit was not tested.

The meeting room and office spaces contain plug-in style through-the-wall air conditioning units. The functionality of these units was not tested.

There is a computer room located in the interior of the building which does not have any air conditioning. A review of the equipment located in this room would be required to determine if a dedicated air conditioning unit is needed.

7.3.7 Air Handling Systems

There is no mechanical means of providing fresh air to the building. This is very noticeable as you walk throughout the building; the air is stagnant and smells stale.

There are two (2) exhaust hoods with roof mounted fans that serve the kitchen area. The electrical wiring for one fan was disconnected, and the other fan was controlled directly from the electrical panel located in the kitchen area.

The fan capacities are unknown; however, the hood size and construction do not meet any standard and would require replacement in any renovation proposal. The type of cooking equipment being used will determine the exhaust and hood requirements. If using grease cooking equipment, then a grease hood designed to meet NFPA standards is required. This requires a hood with adequate coverage over the cooking equipment, airflow and filtration, as

well as a dedicated standalone fire suppression system. If grease equipment is not used, then a moisture and heat rejection hood would be required and the requirements for this type of system are less stringent.

The remainder of the building, including the bedrooms, offices, and other occupied spaces, require mechanical ventilation as per NBCC and ASHRAE standards. This would likely include two (2) heat recovery ventilators: one (1) unit serving the bedroom wing, and a second unit serving the remaining spaces. If air conditioning is required in these spaces, then a packaged rooftop system could be used. The amount of ceiling space would potentially determine the system configuration, including type, size, and routing of ductwork.

7.3.8 Controls

The building does not have a building management system, and controls are limited to heating thermostats and manual starters for exhaust fans.

In any renovation proposal, a new control system would need to be installed. The type and complexity of the control system would depend on the type of heating and ventilation systems installed.

7.4 ELECTRICAL ASSESSMENT

7.4.1 Electrical Service and Distribution

The building is fed aerially from a pole-mounted 3 phase transformer bank. The service mast and straps appear to be in fair condition, but the service mast has dropped causing stress on the LB at the base of the pole and requires further inspection.

The main disconnect, splitter tough, and distribution equipment appear to be in good condition, however, most panels are obsolete. NMD90 and BX wiring appears to be installed throughout the facility although some wiring methods would not meet current code requirements.

External feeds are provided to both the jet fuel pumps (underground) and the Guest Trailer (aerial), of which the latter isa detached building. The configuration of the aerial feed to the detached building violates the electrical code. All wiring should be installed in conduit up to mast heads before transitioning aerially. The current configuration is exposed and could pose a shock hazard if damaged. It appears that the detached building does not have a proper service mast installed.

7.4.2 Telephone Utility Services

Telephone and data service is via two (2) aerial feeds. The masts and conduit appear to be in good condition.

7.4.3 Grounding Systems

A single ground rod is visible, which appears to be bonded to other rods. It is noted that ground rods normally have a service life of 40 years, depending on soil conditions, and it is recommended that the grounding system be thoroughly inspected and tested.

7.4.4 Lighting

Lighting in the facility consists of T-8 and T-12 fluorescent fixtures, as well as incandescent fixtures. T-12 systems are being phased out in favour of T-8 and T-5 lamps with energy efficient electronic ballasts. The exterior High Pressure Sodium (HPS) wall packs are in good condition and installed at all exits.

7.4.5 Heating

Residential electric convection heaters are used primarily throughout the building. Forced air heaters are installed in the bathrooms and some offices. In some areas, thermostats have been upgraded to low voltage electronic devices with control relays installed adjacent to electrical panels.

7.4.6 Wiring Devices

With the exception of the bedroom area, most wiring devices appear to be in good condition. The switches and receptacles in the bedroom areas appear to be over 30 years old and should be replaced. Dedicated Arc Fault Circuit Interrupting (AFCI) circuits are required for all bedroom receptacles. All wiring in the bedroom area should be inspected to ensure it meets current code requirements.

The electrical code requires that GFCI receptacles are required when located within 1.5 m of sinks. There are a number of instances in the bathrooms and kitchen where this violation occurs.

7.4.7 Life Safety Systems

A three-zone fire alarm panel was recently installed. Heat and smoke detectors are installed throughout, and pull stations are installed at building exits. Alarm bells are located throughout the interior and on the exterior of the building. While the fire alarm system would meet current code requirements, there is no indication that it has been recently tested. It would be recommended to upgrade to an addressable system with new pull stations and detectors. The

bells should be replaced with combination horn strobes. It is also recommended that smoke detectors be installed in all bedrooms.

Emergency lighting consists of new and older units. Most of the lamp heads are obsolete and battery packs would not likely meet the 90 minute up-time standard. The majority of exit signs utilizes incandescent bulbs and should be replaced with the LED type.

7.4.8 Communications

A segregated data room is used for terminating LAN, card access, and surveillance camera circuits. Cable runs are primarily in the ceiling space and do not utilize any zone conduits. The wall jacks appear to be in good condition and sufficient in number to serve the facility.

7.4.9 Security Systems

A card access system and surveillance cameras have been recently installed. They are assumed to be in good working order.

7.5 STRUCTURAL ASSESSMENT

The Training Center consists of two pre-engineered type metal buildings on a concrete foundation with a wood floor, connected by a link sitting on a slab-on-grade. There were no structural drawings available and very little of the metal building was visible due to interior finishes. In addition, the original walls and roofing have been covered with a new cladding and roofing system. Therefore, the general condition of the metal cannot be commented on without the removal of these finishes.

The pre-engineered building consists of metal roof panels with a ridge beam, and evenly spaced center posts. Though not visible, it is assumed that these posts are support by a tie that spans from the exterior wall located above the ceiling level. These ties likely connect to columns located within the outside metal wall panel. The type of construction for the link is unclear but may be a similar pre-engineered type metal build or of wood construction. The original metal roof has been covered with plywood and a shingle roof.

7.5.1 Floors

The floors in the main building consist of wood construction, assumed to be plywood on wood joists. The type and location of the supports and joists were not visible. The floor itself shows sign of unevenness and deflection, and vibration can be felt when walking in some areas. The floor in the link consisted of a concrete slab-on-grade and no signs of cracking in the floor tile or differential settlement was noted.

7.5.2 Foundations

The foundation walls were raised above grade and a crawl space is located under the floor; this space was not accessible. There are openings in the foundation wall at various locations to allow air flow beneath. The openings are covered with a wire screen and the concrete shows signs of deterioration and spalling at some locations.

7.5.3 Roof Loadings

In general, pre-engineered buildings constructed in earlier years were designed by considering only minimal dead loads and sometimes considering their self-weight only. In addition, they were quite often designed for a roof snow load that considers the roof to be wind swept, thus a reduced value of snow load was used. The addition of new roofing, plywood and shingles, does a couple of things. It increases the dead load on the roof and makes the roof "less slippery" than a metal roof. In addition, if any insulation was added it will result in less heat loss, thus less snow melt on the roof. All of these items can contribute to a higher loading on the structure than originally designed. It is also important to note that even though these structures have been in place since original construction, their modifications and possible change in roof loadings are recent.

7.6 ENVIRONMENTAL ASSESSMENT

Based on a review of the previous Pinchin Leblanc survey (July, 2004), the following comments are provided with respect to ACMs in the Training Centre:

- Asbestos is present in the reflective gaskets in incandescent light fixtures. The previous Pinchin Leblanc sampling program (July, 2004) confirmed 25-50% chrysotile asbestos in one (1) bulk sample of the heat shield for the lights in the hallway outside the bedroom area. The material was described as an off-white layered paper material. Reflective gaskets in incandescent light fixtures are generally treated as non-friable. The total number of lights containing similar heat shield material to those noted above were not provided in the previous Pinchin Leblanc report (July, 2004). For budgeting exercises, all incandescent light fixtures in the building should be assumed as containing asbestos containing reflective gaskets.
- There is potential for concealed asbestos materials to be present in: (a) the roofing felts and mastics; (b) components or wiring within motors or lights; (c) high voltage wiring; (d) mechanical packing and gaskets; (e) underground services or piping; (f) fire-doors; (g) window caulking; and (h) concrete leveling compound. In the absence of additional sampling, these materials (if present in the Training Centre) should be considered suspect ACMs during renovation or demolition activities.

With respect to suspect ACMs, the following is noted:

- If the building is to be retained and refurbished, only those suspect materials where renovation work will cause disturbance should be sampled. As part of the Asbestos Management Program document established by Pinchin Leblanc in 2004 for NL Hydro, the Training Centre would be considered as having an asbestos management program in place and in this regard, suspect ACMs do not need to be removed if they are not disturbed during renovation activities.
- If the building is to be demolished, an intrusive sampling program of all suspect ACMs should be completed to ensure these materials are properly removed/handled and disposed of during demolition activities.

Based on the types and quantity of ACMs present in the Training Centre, removal efforts would be classified as Type 1, as defined in NL Hydro's Asbestos Management Program (prepared by Pinchin Leblanc in 2004). A Type 1 asbestos removal procedure assumes the non-friable material can be removed with relatively little loose dry dust released. Generation of debris is permissible as long as the debris can be well wetted before being removed. Typical removal procedures include wet cleaning methods (or vacuums equipped with high efficiency particulate arresting filters), use of respirators with HEPA filters and reusable or disposable clothing. The disposal of asbestos waste removed using Type 1 procedures is via a double bag (labeled and sealed). Disposal of waste is to comply with Service NL's policy on disposal of asbestos waste.

7.7 SUMMARY

The Training Center is approximately 50 years old and was constructed as a temporary building. While beyond the scope of this study, it appears to have some functional short-comings. The building was originally constructed as a staff house, but is also currently used for staff functions, office space, and as a training center (which is a change in use and occupancy by Code). It was reported by the Owner that the sleeping quarters is seldom used, perhaps just a couple nights per year, so its usage may justify a review or needs assessment. The office space was noted as being not well laid out or functional: cubicles are located immediately adjacent to the entrance (to which staff commented on the area being cold), and to move between the main office area and the entry/washroom/training area, one must pass through another office and a meeting room.

Architecturally, the building is absent some critical fire separations, such as those required to meet code for a non-sprinklered building of this size and mixed-use occupancy, as well as the separations required between different occupancies. The exterior wall assemblies are

presumed to be similar in nature to the Maintenance Garage and Carpentry Shop, so it is uncertain whether or not adequate thermal and moisture controls are in place. The roof assembly has been re-roofed on at least two (2) occasions, which is in indication of past leaking, but the condition of the underlying structure is unknown. The attic is most likely not adequately vented as a result of the re-roofing work and placement of insulation. Exterior doors vary in condition from those requiring minor repairs to those requiring complete replacement. The wood-frame windows are nearing the end of their useful life and will soon need to be replaced. The carpeted areas are recommended for replacement. Interior doors are in good condition, but those located in walls to be fire-rated will have to be replaced. Door hardware will need to be replaced with lever sets. Millwork (e.g., kitchen and bathroom vanities) is not accessible and in need of replacement. Code issues include: fire-rating of select walls, access to crawl space and attic, exterior ramps to principle entrances, positive drainage, attic ventilation, and barrier free design.

Mechanically, the building lacks an adequate storm water drainage system to collect and divert rainwater off the building`s roof and away from its foundation. A grease interceptor is recommended for the Kitchen. The building does not have a Siamese connection as it relates to fire protection. There is no fresh air supplied to the building as is required by code and a new ventilation system is required. The existing Kitchen hood exhaust system is not to current standards and, depending on the type of cooking operations, a new exhaust system is required and may have to include a dedicated stand-alone fire suppression system. The building does not have a building management system and controls are limited; a new system is recommended, compatible with the type of ventilation system installed.

Electrically, it was noted that an external aerial feed is provided to a detached building (i.e., Guest Trailer), which is a code violation and in its current configuration presents a shock hazard if damaged. The service mast has also dropped and is stressing the LB at the base of the pole. Most panels within the building are noted as obsolete and some wiring methods do not meet code. A thorough inspection and testing of the grounding system is recommended. T12 fluorescent lighting is considered obsolete and inefficient by current standards and recommended for replacement. Switches and receptacles in the bedrooms are recommended for replacement, while receptacles located in kitchens and washrooms need to be upgraded to GFCI. The alarm system is recommended for upgrading to an addressable system with new pull stations and detectors, bells replaced with horn strobes, and smoke detectors installed in all bedrooms. The emergency lighting does not meet current code standards for the required 90 minute up-time.

Structurally, the presence of interior and exterior finishes, lack of attic access, and no access to the crawl space precluded a detailed inspection. However, the floor was noted as being uneven in areas and exhibited issues with serviceability, at a minimum (i.e., deflection and vibration); this warrants a more detailed inspection of the floor system. Some concrete spalling was noted around vents in the foundation wall. While no signs of structural distress were noted with the roof, there is some concern over what impact refurbishments may have had on the original design. For example, the original building had a metal roof and would have had appropriate design measures incorporated for wind sweep and sliding snow; asphalt shingles affect these allowances. And there is also the additional dead load added by the new roof system and it is unknown if this was taken into consideration.

Environmentally, the building possesses asbestos containing materials (ACMs). Asbestos is confirmed to be present in the reflective gaskets in incandescent light fixtures, and there is also potential for ACMs in other building materials, such as roofing, electrical components, mechanical components, underground services, fire doors, caulking, and concrete leveling compounds.

7.8 CONCLUSIONS AND RECOMMENDATION

The exterior of this building is noted as being in good condition, with the exception of doors and windows, but this is strictly restricted to surficial observations as no destructive testing was undertaken. Venting issues likely exist within the attic and there are concerns over how refurbishments to the roof may have affected the structure's loadings. The Guest Trailer, a detached adjacent building, is electrically fed from the Training Center, which is a code violation. The crawl space was inaccessible and the flooring system was not accessible, but issues were noted with serviceability (i.e., unevenness, deflection and vibration). Aesthetically, the interior is in good condition, except for select areas that are dated and could be upgraded; however, the condition of the interior is a result of the upkeep and change in use and occupancy of this building, which has therefore triggered the requirement for additional fire separations. Electrically, the building has some short-comings with respect to life safety, fixtures, wiring devices, etc., and these issues may precipitate a more extensive architectural demolition scope of work depending on the extent of work undertaken. Mechanically, the most significant issues that need to be addressed are ventilation throughout, controls, and Kitchen exhaust/fire protection. Again, the extent of this work will have a direct impact on all other disciplines (i.e., does sufficient ceiling space exist for ductwork; electrical tie-ins and associated cutting/patching; structural support for new dead loads and roof-top units) and would effectively render the building unusable during renovation, if subsequently deemed feasible.

Taking these issues into consideration, in conjunction with those relating to mixed-use occupancy and functionality (i.e., configuration of office space, frequency of use of the sleeping quarters and kitchen/dining services), leads to the conclusion that the building be neither recommended for upgrading or replacement at this time. A needs analysis that establishes its permanent end-use and space requirements, and/or the specific requirements of the occupants, would facilitate a more informed decision as to the future of this asset. However, at the Owner's request, a budget estimate that reflects replacement of the offices, training area, washrooms, and lunchroom, with a new building is as follows:

- New Building: 382 m^2 at $2,500/m2 ..... = $ 960,000
- Sitework (Allowance)..... = $ 150,000
- Demolition of Existing Building (Allowance)..... = $ 150,000
- Contingency at 20%..... = $ 250,000
- Project Management/Engineering at 12% ..... = $ 180,000
- **TOTAL PROJECT BUDGET ..... = $ 1,690,000**

In preparing the above conclusions and recommendation, including project budget, the following is noted:

- The replacement cost assumes that any new building would replace the office space, training area and supplementary service areas only; replacement of the sleeping quarters, and kitchen/dining facilities is not included. Ideally, a needs analysis that evaluates the long-term needs of the Owner, and the current user groups in particular, should be undertaken to determine the specific requirements for a new building.
- A potential location for a new building is unknown at present, thus the exact requirements for sitework (e.g., site development, water, sewer, power, etc.) is unknown and the amount carried for same has therefore been identified as an "allowance".
- The precise requirements for demolition, and in particular asbestos and other potential environmental abatement required to facilitate demolition of the existing building, is unknown and the amount carried for same has therefore been identified as an "allowance".
- The budget does not include for new furniture and equipment.
- Opportunities to combine like-functions (e.g., with office space in other buildings) should be considered in a long-term planning strategy.

APPENDIX A

PHOTOGRAPHS – MAINTENANCE GARAGE



Photo A1: Front (South) elevation



Photo A2: Rear (North) elevation



Photo A3: Left side (West) elevation



Photo A4: Right side (East) elevation



Photo A5: Exit stairs from Level 2



Photo A6: Exit stairs from Level 2



Photo A7: Level 1 Lunch Room and Compressor Room annex; concrete block construction



Photo A8: Steam Cleaner Room at northeast corner



Photo A9: Steam Cleaner Room



Photo A10: Northwest corner; note finished grade above bottom of siding



Photo A11: Retrofitted and resized exterior window infilled with plywood



Photo A12: Original single-glazed exterior window



Photo A13: Original single-glazed exterior window



Photo A14: Exterior window retrofitted for AC unit



Photo A15: Used oil disposal/storage tank



Photo A16: Rusting at bottom of metal cladding; finished grade up to bottom of cladding



Photo A17: Hole through exterior wall



Photo A18: Dents in exterior wall



Photo A19: Exit from Level 1 Lunch Room; note condition of concrete block



Photo A20: Level 1 Lunch Room annex; note condition of concrete block and single-glazed exterior window



Photo A21: Compressor Room exterior plywood door; note rotted door frame at bottom



Photo A22: Person-door at south-east corner; note damaged siding



Photo A23: Hole in exterior cladding; note polybead rigid insulation in wall cavity



Photo A24: Typical retrofitted and resized overhead door with plywood infill



Photo A25: Typical retrofitted and resized overhead doors with plywood infill



Photo A26: Overhead door removed and exterior wall in-filled with plywood



Photo A27: Rotted frame around overhead door



Photo A28: Former wall cladding repair; note that lap joint will direct water into wall cavity



Photo A29: Exterior horizontal slider type window; note rotted sill



Photo A30: Exterior grade above bottom of siding



Photo A31: East (end) wall in Welding Shop



Photo A32: West wall in Welding Shop; metal partition with crane curtain between Welding Shop and Machine Shop



Photo A33: Rear (north) wall in Welding Shop



Photo A34: Front (south) wall in Welding Shop



Photo A35: Welding Shop ceiling and overhead bridge crane



Photo A36: Welding Shop/Machine Shop door; all hardware is broken and inoperable



Photo A37: East wall in Machine Shop; metal partition with crane curtain between Machine Shop and Welding Shop



Photo A38: Machine Shop - Tool Crib and Office with Mezzanine over



Photo A39: West wall in Machine Shop; partition between Machine Shop and Garage



Photo A40: Machine Shop – Office door/window and ladder to Mezzanine



Photo A41: Machine Shop – Office interior indicating typical poor condition of finishes, fixtures and furnishings



Photo A42: Machine Shop – Tool Crib



Photo A43: Machine Shop window; typical condition of leaking windows



Photo A44: Machine Shop Mezzanine over Tool Crib and Office



Photo A45: Level 1 Lunch Room looking east towards Compressor Room door



Photo A46: Level 1 Lunch Room looking east



Photo A47: Compressor Room; note condition of concrete block walls



Photo A48: East wall of Garage - metal partition between Garage and Machine Shop; Office and stairs to Locker Room



Photo A49: Southeast corner of Garage – Office, Battery Room, Supply Room, and Locker Room (above)



Photo A50: Garage Mezzanine over Office



Photo A51: Interior of Locker Room



Photo A52: Locker Room window; note broken screen, water damage to sill, and dead insects



Photo A53: Garage ceiling insulation, roof venting, and circulation fans



Photo A54: Garage service pit



Photo A55: Garage service pit



Photo A56: Typical interior of single-glazed window



Photo A57: Garage vehicle lift and overhead door



Photo A58: View across Garage, looking west



Photo A59: Partition, exit door, and glazing between Garage and corridor/office area



Photo A60: Partition between Garage and Office and Level 1 and 2 Locker Rooms



Photo A61: Level 1 Washroom, wash station



Photo A62: Level 1 Washroom, toilet stalls



Photo A63: Level 1 Washroom, washer and dryer



Photo A64: Level 1 Washroom, urinals



Photo A65: Level 1 Locker Room, at window



Photo A66: Locker Room #1A



Photo A67: Exit door from Garage swinging into Corridor



Photo A68: Office #1A



Photo A69: Office #1B



Photo A70: Level 1 Storage Room



Photo A71: Exit door from Level 1 Corridor



Photo A72: Stairs from Corridor to Level 2



Photo A73: Level 2 rear exit door



Photo A74: Level 2 Lunch Room



Photo A75: Level 2 Lunch Room



Photo A76: Level 2 Lunch Room



Photo A77: Level 2 Locker Room #2A



Photo A78: Level 2 Washroom



Photo A79: Level 2 Washroom



Photo A80: Level 2 Locker Room #2B



Photo A81: Welding exhaust arm supported from siding



Photo A82: Louvre supported from siding



Photo A83: Louvre supported from siding



Photo A84: Welding exhaust arm supported from siding



Photo A85: Holes incorrectly located in column web



Photo A86: Holes incorrectly located in column web



Photo A87: Water Entrance



Photo A88: Typical Water Closet



Photo A89: Hand Wash Sink



Photo A90: Janitor's Sink



Photo A91: Typical Hose Reel Station



Photo A92: Urinals on Level 1



Photo A93: Waste Oil Storage Tank



Photo A94: Waste Oil Dispensing Unit



Photo A95: Water Storage Tank



Photo A96: Vehicle Pit Sump Pump



Photo A97: Vehicle Exhaust System



Photo A98: Vehicle Exhaust Duct to Outside



Photo A99: Air Compressor



Photo A100: Typical Office AC Unit



Photo A101: Stratification Fan and Roof Ventilator



Photo A102: Air Receiver Tank



Photo A103: Receiver Tank Certificate



Photo A104: Roof Ventilator and Exhaust Fans



Photo A105: Welding Extraction Arm



Photo A106: Older Model Extraction Arm



Photo A107: Motorized Damper for Fresh Air Intake



Photo A108: Roof Mounted Motorized Damper



Photo A109: Kitchen A/C unit



Photo A110: Communications Rack in Garage



Photo A111: Transformer bank



Photo A112: Main service entrance



Photo A113: Grounding system



Photo A114: Telephone and data service



Photo A115: Typical disconnect arrangement



Photo A116: Main service disconnect



Photo A117: Panel used as junction box



Photo A118: Damaged convection heater



Photo A119: Typical unit heater



Photo A120: Typical residential convection heater



Photo A121: T-12 luminaires



Photo A122: High Pressure Sodium (HPS) luminaires



Photo A123: Typical exit configuration



Photo A124: Typical emergency light

APPENDIX B

PHOTOGRAPHS – CARPENTRY SHOP



Photo B1: North elevation



Photo B2: Northwest elevation



Photo B3: Southwest elevation



Photo B4: Northeast elevation



Photo B5: Southeast elevation



Photo B6: Quonset hut/Armco building interface



Photo B7: Quonset hut end wall



Photo B8: (Partial) South elevation

		
Photo B9: (Partial) South elevation		Photo B10: (Partial) West elevation
		
Photo B11: Plywood doors (North elevation)		Photo B12: Plywood add-on, North elevation; note vent to Dust Collection Room



Photo B13: Base of wall at North person-door



Photo B14: Northeast corner



Photo B15: Base of wall at Northeast corner; note finished grade above base of metal cladding



Photo B16: Asphalt shingles



Photo B17: Wood sill



Photo B18: Exterior window



Photo B19: Exterior wood person-door



Photo B20: Plywood annex/Armco building interface



Photo B21: Quonset hut/Armco building interface



Photo B22: Damaged metal cladding and wood sleeper at Northeast corner



Photo B23: Carpentry Shop looking West



Photo B24: Carpentry Shop looking east



Photo B25: Carpentry Shop looking east towards entrance and Washroom



Photo B26: West entrance



Photo B27: Washroom sink



Photo B28: Washroom toilet



Photo B29: Washroom vanity



Photo B30: Carpentry Shop plywood doors



Photo B31: East entrance



Photo B32: Carpentry Shop window



Photo B33: North entrance; note plywood doors to Dust Collection room on right



Photo B34: Dust Collection Room



Photo B35: Dust collection equipment



Photo B36: Quonset hut interior looking South



Photo B37: Quonset hut interior looking North



Photo B38: Tool Crib looking South



Photo B39: Tool Crib looking North



Photo B40: Battery Charging Room



Photo B41: Exterior Door from Tool Crib



Photo B42: Duct penetrating Dust Collection Room



Photo B43: Dust Collection Room vent



Photo B44: Hole in gypsum board wall



Photo B45: Sill/threshold at plywood doors



Photo B46: Ceiling recess at translucent panels



Photo B47: Quonset hut rusting



Photo B48: Foundation cracks

		
Photo B49: Wood sleeper foundation		Photo B50: Opening at north addition
		
Photo B51: Opening at door		Photo B52: Deteriorated wall base at north side addition



Photo B53: Dust collection system



Photo B54: Dust collector and collection drum



Photo B55: Fire extinguisher and portable eyewash



Photo B56: Typical intake for dust collector



Photo B57: Water closet and domestic water piping



Photo B58: New main panel



Photo B59: Transformer bank



Photo B60: Service entrance with rusted nuts/bolts



Photo B61: Grounding system



Photo B62: Telephone and data service



Photo B63: General purpose enclosure



Photo B64: Open-faced transformer dust build-up



Photo B65: Typical explosion proof switch



Photo B66: Damaged GFI receptacle



Photo B67: Damage flexible conduit



Photo B68: Older style lamps

		
Photo B69: Non-sealed fixture		Photo B70: Vapour tight T-12 fixture

APPENDIX C

PHOTOGRAPHS – TRAINING CENTER



Photo C1: West elevation



Photo C2: Partial South elevation (office door)



Photo C3: Partial South elevation



Photo C4: Partial South elevation (sleeping quarters door)

		
Photo C5: East elevation		Photo C6: Partial North elevation (kitchen door)
		
Photo C7: Partial North elevation		Photo C8: Partial North elevation (student workstations door)

		
Photo C9: Main entrance (North elevation)		Photo C10: North elevation with grade sloping towards building
		
Photo C11: Typical soffit/eave construction		Photo C12: Typical crawl space vent (note spalling concrete)



Photo C13: Typical gable end vent



Photo C14: Typical condition of wood-frame windows



Photo C15: Typical condition of wood-frame windows



Photo C16: Exit door from Common Room



Photo C17: North elevation with grade sloping towards building



Photo C18: Student workstations



Photo C19: Exit door from Student workstations



Photo C20: Typical interior window finishes



Photo C21: Training Center (looking south)



Photo C22: Training Center (looking north)



Photo C23: Training Center exit door



Photo C24: Data Room

		
Photo C25: Entry door (main entrance)		Photo C26: Entry (Meeting Room beyond)
		
Photo C27: Meeting Room		Photo C28: Meeting Room



Photo C29: Office (cubicle)



Photo C30: Office area (cubicles and exit door)



Photo C31: Office area (exit door)



Photo C32: Closet and Corridor to Kitchen/Washrooms/Common Area



Photo C33: Kitchen



Photo C34: Kitchen



Photo C35: Male Washroom - urinals



Photo C36: Male Washroom – vanity/stalls

		
Photo C37: Male Washroom – interior of door		Photo C38: Male Washroom – Utility Room
		
Photo C39: Male Washroom – H/C stall		Photo C40: Female Washroom – vanity/stalls

		
Photo C41: Female Washroom – H/C stall		Photo C42: Corridor (looking towards Entry)
		
Photo C43: Common Area (door to Kitchen/exit door)		Photo C44: Common Area (fire door to Sleeping Quarters/door to Corridor)



Photo C45: Dining Area (Kitchen beyond)



Photo C46: Dining Area (Common Area beyond)



Photo C47: Kitchen (Dining Area beyond)



Photo C48: Kitchen



Photo C49: Kitchen



Photo C50: Kitchen exit door



Photo C51: Sleeping Quarters corridor (exit door to exterior beyond)



Photo C52: Sleeping Quarters exit door



Photo C53: Sleeping Quarters corridor (exit door to Common Room beyond)



Photo C54: Sleeping Quarters exit door to Common Room



Photo C55: Typical Bedroom



Photo C56: Typical Bedroom

		
Photo C57: Sleeping Quarters Washroom		Photo C58: Attic above Sleeping Quarters
		
Photo C59: Attic partition above fire separation between Common Area and Sleeping Quarters		Photo C60: Attic insulation installed to eave



Photo C61: Typical hose reel station



Photo C62: Typical fire extinguisher



Photo C63: Evaporator for AC unit



Photo C64: Condenser for AC unit



Photo C65: Controller for AC unit



Photo C66: Meeting Room AC unit



Photo C67: Domestic hot water tank



Photo C68: Kitchen



Photo C69: Kitchen exhaust hood



Photo C70: Kitchen exhaust fans



Photo C71: Kitchen sink



Photo C72: Typical bathtub



Photo C73: Typical shower



Photo C74: Typical shower drain



Photo C75: Washroom lavatories



Photo C76: Aerial feed to detached building



Photo C77: Transformer bank



Photo C78: Service mast and data telephone entrance



Photo C79: Dropped service entrance with ground



Photo C80: 400A main disconnect and splitter



Photo C81: Aerial feed to detached building



Photo C82: Abandoned wiring



Photo C83: Multiple cables in single hole



Photo C84: Missing exit sign



Photo C85: Panel and heating controls



Photo C86: Obsolete panel and heating controls



Photo C87: Older style emergency lamps

APPENDIX D

FIRE AND LIFE SAFETY GUIDANCE DOCUMENT

Newfoundland Labrador

Government of Newfoundland and Labrador
Department of Municipal Affairs
Office of the Fire Commissioner

Memo

To: Building and fire code users

From: Frederick G. Hollett, Fire Commissioner

Date: January 18, 2007

Re: Notice of adoption of building and fire codes;

National Building Code of Canada, 2005 edition
National Fire Code of Canada, 2005 edition
National Fire Protection Association 101, Life Safety Code, 2006 edition

Pursuant to *Consolidated Newfoundland and Labrador Regulation 9/96, Fire Prevention Regulations*[i] under the *Fire Prevention Act, 1991*[ii], please be advised that the following codes have been adopted:

1. the National Building Code of Canada[iii] , 2005 edition, except;
   a. Part 9 where relative to one and two family dwellings within Group C
   b. Means of egress, which shall comply with the NFPA 101, Life Safety Code

2. the National Fire Code of Canada[iv], 2005 edition

3. the National Fire Protection Association, 101, Life Safety Code, 2006 edition[v]

Effective April 1, 2007 all submissions for the plan review process should meet the requirements of the Newfoundland Labrador Fire and Life Safety Guidance Document[vi].

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[i] Queen's Printer, St. John's, Newfoundland and Labrador, Canada
[ii] Queen's Printer, St. John's, Newfoundland and Labrador, Canada
[iii] Canadian Commission on Building and Fire Codes (National Research Council of Canada), Ottawa, Ontario, K1A 0R6
[iv] Canadian Commission on Building and Fire Codes (National Research Council of Canada), Ottawa, Ontario, K1A 0R6
[v] National Fire Protection Association, 1 Batterymarch Park, Quincy, MA, 02169-7471
[vi] Office of the Fire Commissioner, 50 Parade Street, St. John's, Newfoundland and Labrador

50 Parade Street, P.O. Box 8700, St. John's, NL, Canada A1B 4J6 Telephone (709) 729-3703 Fax (709) 729-3857

Newfoundland Labrador

Government of Newfoundland and Labrador
Department of Municipal Affairs
Office of the Fire Commissioner

To: Users of the NBCC/NFCC/LSC

Fr: Frederick G. Hollett, Fire Commissioner

Date: January 18, 2007

Re: Newfoundland and Labrador Fire and Life Safety Guidance Document

As you are aware NL Regulation 9/96 has adopted various codes including the NBCC 2005, NFCC 2005, and LSC 2006.

The regulation denotes the applications of the adopted codes. From time to time, we have encountered conflicts between the codes and in particular as it relates to existing construction.

To address the conflicts encountered and to provide clarification for the use and application of the currently adopted codes we have created the Newfoundland and Labrador Fire and Life Safety Guidance Document.

Effective January 17, 2007, I have adopted the guidance document for application in this province.

Effective April 1, 2007, all development construction, and renovation submitted for plan approval shall meet the requirement of the Newfoundland and Labrador Fire and Life Safety Guidance Document.

Yours truly,

Frederick G. Hollett
Fire Commissioner

P.O. Box 8700, St. John's, NL, Canada A1B 4J6 Telephone 709.729.1608 Fax 709.729.2524

Office of the Fire Commissioner

Newfoundland and Labrador
Fire and Life Safety
Guidance Document

Preface

The Office of the Fire Commissioner (OFC) has adopted, by way of Consolidated Newfoundland and Labrador Regulation 9/96, the *National Building Code of Canada* (*NBCC*), *National Fire Code of Canada* (*NFCC*), and National Fire Protection Association (NFPA) 101, *Life Safety Code* (*LSC*).

The adoption of *NBCC* was intended to ensure compliance with fire and life safety requirements in new construction. The use and occupancy of *existing buildings/structures*, and process would be controlled with the application of the *NFCC* and NFPA 101, *LSC*. The NFPA 101, *LSC* addresses many items that the *NFCC* is silent on regarding use and occupancy. CNLR 9/96 provides a means to resolve conflicts between *NBCC* and *LSC* as it relates to new construction. However the same could not be said for existing construction.

In April of 2005, OFC sponsored a three day seminar conducted by NFPA on the use and application of the *LSC*. During the seminar Fire Commissioner Hollett committed to finding a means to resolve the conflicts between the codes. In late April Fire Commissioner Hollett approached a number of Government Departments seeking representatives to serve on a working group.

Dept. of Education
Dept. of Government Services
Dept. of Transportation & Works

The mandate of the working group was;

Maintain adoption of all existing codes.
Provide a working document addressing fire and life safety concerns of the province.
Draft document with stakeholder input.
Administrative process for conflict resolution.
Final document to serve as fire and life safety code for the Province of NL.

Working group started in May 2005 and examined many formats to meet the mandate;

Most restrictive code – least restrictive code.
Dropping either *NFCC* or *LSC*, PEI example.
Developing NL Code using Florida model.
Develop working document to clarify the use and application of the current adopted codes.

After much consideration and consultation the working group agreed that we would develop a working document to clarify the use and application of the currently adopted codes. Final document will be a Guidance Document adopted by the Fire Commissioner.

NBCC/LSC Working Group Members

Ingrid Clarke, P.Eng.
Dept. of Education

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Dept. Government Services

Dave G. Dewling, MNAA
Dept. of Transportation & Works

William L. Pippy, CTech, CCPI
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Derek Simmons
Chair
Office of the Fire Commissioner

Tina Marie English
Emergency Measures Organization

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1. Definitions / Abbreviations

1.1 Non-defined Terms
Definitions of words and phrases used in this guidance document that are not included in the list of definitions in this Part, shall have the meanings which are commonly assigned to them in the context in which they are used in this guidance document, taking into account the specialized use of terms with the various trades and professions to which the terminology applies.

1.2 Definitions. The following words and terms in italics in this guidance document have the following meanings:

Addition - means an increase in building area, aggregate floor area, height, or number of stories of a structure.

Authority Having Jurisdiction (AHJ) – The government body responsible for the enforcement of any part of the referenced *Code(s)* or the official or agency designated by that body to exercise such a function.

Change of Use - means a change in the purpose or level of activity within a structure that involves a change in application of the requirements of the Act and Regulations, and *Code*s.

Change of Occupancy Classification - means a change in the occupancy classification of a structure or portion of a structure.

Code – The *Code*s referenced in this guidance document are the applicable *Code*s that have been adopted by the *AHJ*.

Existing building / structure – Building/structure approved for occupancy by the *AHJ* or building/structure currently occupied.

Historic Building - means a building or facility deemed to have historical, architectural, or cultural significance by a local, regional, or national authority.

Modification - means the reconfiguration of any space, the addition or elimination of any door or window; the addition or elimination of load-bearing elements; the reconfiguration or extension of any system, or the installation of any additional equipment.

New construction – Building / structure under construction and/or not approved for occupancy by the *AHJ*.

Reconstruction – means the reconfiguration of a space that affects an exit, or a corridor shared by more than a single tenant; or reconfiguration of space such that the *rehabilitation* work area is not permitted to be occupied because existing means of egress and fire protection systems, or their equivalent, are not in place or continuously maintained.

Rehabilitation – means any work on an *existing building* and shall be classified as one of the following work categories: *repair, renovation, modification, reconstruction, change of use or occupancy, or addition.*

Renovation - means the replacement in kind or strengthening of load bearing elements; or the refinishing, replacement, bracing, strengthening, or upgrading of existing materials, elements, equipment or fixtures, without involving the reconfiguration of spaces.

Repair - means the patching, restoration, or painting of materials, elements, equipment, or fixtures for the purpose of maintaining such materials, elements, equipment or fixtures in good or sound condition.

Reserved - No Provincial requirements at this time.

1.3. Abbreviations

AHJ	Authority Having Jurisdiction
LSC	NFPA 101 *LSC*
NBCC	*National Building Code of Canada*
NFCC	*National Fire Code of Canada*
NFPA	National Fire Protection Association
NLFLSGD	Newfoundland and Labrador Fire and Life Safety Guidance Document

1.4. References

Canadian Commission on Building and Fire Codes (National Research Council of Canada), Ottawa, Ontario, K1A 0R6;

National Building Code of Canada, as adopted
National Fire Code of Canada, as adopted

National Fire Protection Association, 1 Batterymarch Park, P.O. Box 9101, Quincy, MA 02269-9101;

NFPA 101, LSC, as adopted
NFPA 914, Code for Fire Protection of Historic Structures

Government of Newfoundland and Labrador, P.O. Box 8700, St. John's, NL, A1B 4J6;

Department of Municipal Affairs, Newfoundland and Labrador Provincial Land Use Policy Flood Risk Areas.

City of St. John's, Division of Building and Property Management, 15 New Gower Street, St. John's, NL, A1C 5M2;

Fire Safety Alternatives for Heritage Buildings in Downtown St. John's, NL.

2. Administration

2.1 Purpose

2.1.1. The purpose of this guidance document is to provide clarification on the application and use of the various fire and life safety codes that have been adopted by the Province of Newfoundland and Labrador under the Fire Prevention Act, 1991.

2.1.2. The Province has adopted under the authority of the Fire Prevention Act, 1991, Consolidated Newfoundland and Labrador Regulation (CNLR) 9/96 and may be cited as the Fire Prevention Regulations, see appendix A.

2.1.3. In short, Regulation (CNLR) 9/96, Fire Prevention Regulation adopts the following codes:
National Building Code of Canada (*NBCC*);
National Fire Code of Canada (*NFCC*);
National Fire Protection Association (NFPA) 101 – *Life Safety Code* (*LSC*);
Installation Code for Propane Burning Appliances and Equipment;
Installation Code for Oil Burning Equipment;
Installation Code for Solid Fuel Burning Appliances and Equipment.

2.1.4. This guidance document will provide clarification as to the appropriate codes and sections/chapters that shall be used for the design/construction/operation of new structures and as well as the relevant codes and sections/chapters that shall be used for the use and operation of *existing* structures.

2.1.5. This guidance document will also identify the procedures that owner(s) and/or developer(s) shall follow in the *repair*, *renovation*, *modification*, *reconstruction*, *change of use* or *change of occupancy classification*, and *addition* to *existing* structures including *historic buildings*.

2.2. Building *Rehabilitation*

2.2.1 Intent.

2.2.1.1. The intent of this Section is to permit *repairs*, *renovations*, *modifications*, *reconstructions*, *additions*, and *changes of use* that maintain or improve the health, safety, and welfare of occupants in *existing* buildings, without requiring full compliance with the other Act and Regulations, and *Codes* except for proportional additional work as specified in this document and the *LSC*.

2.2.1.2. Nothing in Section 5 shall be interpreted as requiring the *repair*, *renovation*, *modification* or *reconstruction* of *existing* buildings.

2.2.1.3. All work shall be classified into categories for *repair*, *renovation*, *modification*, *reconstruction*, *change of use*, and *addition*, with specific requirements established for each category as per the *LSC*.

2.2.2. Compliance.

2.2.2.1. Existing life safety features obvious to the public, if not required by the *Codes*, shall be either maintained or removed.

2.2.2.2. The provisions of this document shall not supersede any codes or ordinances that address dangerous or unsafe buildings.

2.2.2.3. Buildings and structures located in whole or in part in a floodway or floodway fringe shall conform to the *Newfoundland and Labrador Provincial Land Use Policy Flood Risk Areas.*

2.2.2.4. Structural Requirements. The minimum design loads for the structure shall be the loads applicable at the time the building was constructed, provided that no structurally deficient condition is created. Structural elements that are uncovered during the course of the building *rehabilitation*, that are found to be unsound or structurally deficient shall comply with the load requirements of *NBCC*.

2.2.2.5. Where the *rehabilitation* work area includes a commercial kitchen and the work includes reconfiguration or extension of cooking equipment, or the installation of additional cooking equipment, existing grease ducts, exhaust equipment, and kitchen hoods shall be brought into compliance with all the requirements of *NBCC*.

2.2.2.6. Plumbing Requirements. Where the *rehabilitation* work area is more than 50 percent of the gross floor area, and / or the occupant load will be increased by at least 20 percent as a result of the *rehabilitation* work, the plumbing system shall be upgraded to the *NBCC*.

2.2.2.7. Nonconformity. The *rehabilitation* work including an *addition* shall not create or extend any nonconformity in the *existing building* to which the *rehabilitation* work or the *addition* is constructed with regard to any adopted codes or regulations.

2.2.3. Preliminary Meeting.

2.2.3.1. If a building permit is required for a complex *rehabilitation* project involving multiple *code*s, the *AHJ* or its designee, and representatives from all necessary agencies, should meet with the prospective permit applicant at the request of the prospective applicant and, upon payment of a fee if required by the *AHJ*, prior to the submission of the construction permit application. The purpose of such meeting should be to discuss plans for any proposed work or *change of occupancy* under this document prior to the application for the permit.

2.2.3.1.1. The preliminary meeting, to the extent possible, should include the officials responsible for permit approval and enforcement with respect to the following, as applicable to the *rehabilitation* project:

(1) *National Building Code of Canada*
(2) *National Plumbing Code of Canada*
(3) NFPA 101, *LSC*

(4) Canadian Electrical Code
(5) *National Fire Code of Canada*
(6) NL Public Safety Act
(7) NL Building Accessibility Act
(8) NL Historic Resources Act

2.2.3.1.2. Decisions made at the preliminary meeting shall be documented and circulated to those in attendance.

2.2.3.2. For a *rehabilitation* project or portion thereof that is in the *repair*, *renovation*, or *modification* category of work, a preliminary meeting may be permitted to be granted at the discretion of the *AHJ* when a request for a preliminary meeting is made by the prospective applicant prior to the submission of the construction permit application.

2.2.4. Permits. The *rehabilitation* work area shall be clearly identified on all construction permit applications, construction documents, and permits required by the *AHJ*.

3. Design, Construction, Use & Occupancy – *New construction*.

3.1 Effective April 1, 2007, all buildings submitted for plan approval shall meet the requirements of the Newfoundland and Labrador Fire and Life Safety Guidance Document.

3.2 All *new construction*, including construction / development under the Newfoundland and Labrador Fire and Life Safety Guidance Document shall meet the requirements as outlined in Table 3.2.2

Table 3.2.2

OCCUPANCY TYPE		**DESIGN, CONSTRUCTION, USE & OCCUPANCY**
GENERAL NOTES		**NEW 2006**
NBCC Occupancy Classification	**LSC Occupancy Classification**	
Group A – Division 1,2,3,4 Assembly	ASSEMBLY	NBCC, NFCC AND CHAPTER 12 LSC
Group A – Division 2 Assembly	EDUCATION	NBCC, NFCC AND CHAPTER 14 LSC
Group A – Division 2 Assembly	DAY-CARE	NBCC, NFCC AND CHAPTER 16 LSC AND DAY-CARE REGS.
Group B – Division 1 Care or detention	DETENTION & CORRECTIONAL	NBCC, NFCC AND CHAPTER 22 LSC
Group B – Division 2 Care or detention	HEALTH CARE	NBCC, NFCC AND CHAPTER 18 LSC
Group B – Division 2 Care or detention	RESIDENTIAL BOARD & CARE	NBCC, NFCC AND CHAPTER 32 LSC AND PERSONAL CARE HOME POLICY MANUAL
Group C Residential	ONE & TWO FAMILY DWELLINGS	NO REQUIREMENTS
Group C Residential	LODGING & ROOMING HOUSES	NBCC, NFCC AND CHAPTER 26 LSC
Group C Residential	HOTELS & DORMITORIES	NBCC, NFCC AND CHAPTER 28 LSC
Group C Residential	APARTMENT BUILDINGS	NBCC, NFCC AND CHAPTER 30 LSC
Group D Business and personal services	AMBULATORY HEALTH CARE	NBCC, NFCC AND CHAPTER 20 LSC
Group D Business and personal services	BUSINESS	NBCC, NFCC AND CHAPTER 38 LSC
Group E Mercantile	MERCANTILE	NBCC, NFCC AND CHAPTER 36 LSC
Group F – Division 1,2,3 Industrial	INDUSTRIAL	NBCC, NFCC AND CHAPTER 40 LSC
Group F – Division 2,3 Industrial	STORAGE	NBCC, NFCC AND CHAPTER 42 LSC

3.3 Effective April 1, 2007, all *new construction*, shall follow the *NBCC* for design and construction with the only exception of the means of egress. Means of egress for *new construction* shall comply with Chapter 7 of the *LSC* unless otherwise provided for or modified by the individual occupancy chapters. In addition, the requirements for the use and occupancy of the building shall follow the *NFCC* and the applicable occupancy chapter for *new construction* requirements in the NFPA 101, *LSC*. Therefore the use and occupancy requirements shall be incorporated into the design and construction of the building.

3.4 There shall be no use and occupancy requirement for design and construction that exceeds the requirements of the *NBCC* or Section 2 Means of Egress, of the applicable occupancy chapter of the NFPA 101, *LSC*.

4. Use and Occupancy - *Existing* Buildings

4.1 Effective immediately, all *existing buildings* shall meet the requirements for *existing building* as per Section 4 and as outlined in Table 4.2.2.

Exception: The requirements of Chapter 4 shall not apply to *historic buildings* that are not undergoing *rehabilitation.*

Table 4.2.2.

OCCUPANCY TYPE	**USE & OCCUPANCY**
GENERAL NOTES	*EXISTING*
ASSEMBLY	NFCC AND CHAPTER 13 LSC
EDUCATION	NFCC AND CHAPTER 15 LSC
DAY-CARE	NFCC AND CHAPTER 17 LSC AND DAY-CARE REGULATIONS
HEALTH CARE	NFCC AND CHAPTER 19 LSC
AMBULATORY HEALTH CARE	NFCC AND CHAPTER 21 LSC
DETENTION & CORRECTIONAL	NFCC AND CHAPTER 23 LSC
ONE & TWO FAMILY DWELLINGS	NO REQUIREMENTS
LODGING & ROOMING HOUSES	NFCC AND CHAPTER 27 LSC
HOTELS & DORMITORIES	NFCC AND CHAPTER 29 LSC
APARTMENT BUILDINGS	NFCC AND CHAPTER 31 LSC
RESIDENTIAL BOARD & CARE	NFCC AND CHAPTER 33 LSC AND PERSONAL CARE HOME POLICY MANUAL
MERCENTILE	NFCC AND CHAPTER 37 LSC
BUSINESS	NFCC AND CHAPTER 39 LSC
INDUSTRIAL	NFCC AND CHAPTER 41 LSC
STORAGE	NFCC AND CHAPTER 43 LSC

4.2 All *existing buildings* shall meet the requirements of *NFCC*; and the applicable chapter for existing buildings in the NFPA 101, *LSC*. Means of egress for existing buildings shall comply with Chapter 7 of the *LSC* unless otherwise provided for or modified by the individual occupancy chapters.

4.3 There shall be no use and occupancy requirement for *existing buildings* that exceeds the requirements of the *NBCC* or the applicable existing occupancy chapter of the NFPA 101, *LSC*.

4.4 Where an *existing building* requires upgrading to meet the requirements in 4.2 the owner may be subject to a Fire Commissioners' Order to correct any deficiencies. Such order shall be implemented in accordance with Section 5, Building Rehabilitation.

4.5 Subject to the approval of the *AHJ*, upon identification of a deficiency and a directive being submitted, the period for compliance to meet 4.2 may be extended as follows;

Fire Protection Features	5 years
Structural Requirements	5 years
Means of Egress Requirements	2 years
Fire Alarm Systems	2 years

Exception: The owner may submit a Life Safety Evaluation, as per Section 8 to meet compliance as required in 4.2

5. Building *Rehabilitation*

5.1 General

5.1.1. All work shall be classified into categories for *repair*, *renovation*, *modification*, *reconstruction*, *change of use*, and *addition*, with specific requirements established for each category as outlined in *LSC*.

5.1.2. Fire Detection Systems.

5.1.2.1 Where the *rehabilitation* work area is in a building that is required to have a fire detection system in accordance with NBCC, the fire detection system shall be installed throughout the entire building.

5.1.2.2. Where the rehabilitation work area is in a building that is not equipped with a fire detection system, and the rehabilitation work when completed, changes the occupancy classification and/or the occupant loading a fire detection system shall be installed throughout the entire building in accordance with NBCC

5.1.3 Fire Sprinkler Systems

5.1.3.1 Where the *rehabilitation* work area is in a building that is required to have a fire sprinkler system in accordance with NBCC, the fire sprinkler system shall be installed throughout the entire building.

5.1.3.2 Where the rehabilitation work area is in a building that is not equipped with a fire sprinkler system, and the rehabilitation work when completed, changes the occupancy classification, building area, and/or number of stories a fire sprinkler system shall be installed throughout the entire building in accordance with NBCC.

5.1.3.3 Where the rehabilitation work area is in a building that is not equipped with a fire sprinkler system and the rehabilitation work is less than 50% of the aggregate floor area a fire safety evaluation may be provided in accordance with Section 8.

5.1.4 *Additions*.

5.1.4.1 An *addition* shall not create or extend any nonconformity in the existing building to which the *addition* is constructed with regard to accessibility; structural strength; fire safety; means of egress; or capacity of mechanical, plumbing, or electrical systems.

5.1.1. All work shall be classified into categories for *repair*, *renovation*, *modification*, *reconstruction*, *change of use*, and *addition*, with specific requirements established for each category as outlined in *LSC* .

5.2. *Historic Buildings*

5.2.1 General Requirements.

5.2.1.1 General. *Historic buildings* shall comply with the provisions of one of the following applicable documents;

a. NFPA 101, *LSC*
b. NFPA 914, Code for Fire Protection of Historic Structures
c. Fire Safety Alternatives for Heritage Buildings in St. John's, NL

relating to their *repair*, *renovation*, *modification*, *reconstruction*, and *change of use or occupancy*.

5.2.1.3 Flood Hazard Areas. For *historic buildings* or structures located in whole or in part in floodway or floodway fringe, work on the building or structure shall be permitted, provided that both of the following are met:

(1) The proposed work will not preclude continued designation as a historic building or structure.

(2) Approval is given by the Department of Municipal Affairs under the *Newfoundland and Labrador Provincial Land Use Policy, Flood Risk Areas.*

6. *Code* Interpretation and *Code* Conflicts

6.1 *Code* Interpretation

6.1.1 This section deals with the process that shall be followed to receive a formal *code* interpretation of a *code* requirement. While the Government Service Centre or Office of the Fire Commissioner staff may provide guidance on a particular *code* issue, a formal *code* interpretation is the only binding decision of the Fire Commissioner.

6.1.2 All requests for formal *code* interpretation shall be submitted in writing completing *Formal Code Interpretation – Conflict Resolutions Request Form*, see Appendix B.

6.1.3. A formal *code* interpretation will be issued, where practical, within 15 business days after receipt of request at the Office of the Fire Commissioner.

6.1.4. A person disagreeing with the formal *code* interpretation may file a request for review subject to the provisions of the Fire Prevention Act, 1991.

6.2 *Code* Conflicts

6.2.1. Where there appears to exist a conflict between two or more *code* requirements the following requirements shall apply;

6.2.1.1 *New Construction*

6.2.1.1.2 Effective April 1, 2007, the primary design and construction *code* shall be the *NBCC* except for Means of Egress. Means of egress for *new construction* shall comply with Chapter 7 of the *LSC* unless otherwise provided for or modified by the individual occupancy chapters. For the use and occupancy of these buildings the *NFCC* and applicable Chapter for *new construction* in the NFPA 101, *LSC* shall apply. Where the *NBCC/NFCC* does not address an issue or does not provide detail requirements, the applicable Chapter for *new construction* of NFPA 101, *LSC* shall apply, except as may be determined otherwise by the Fire Commissioner.

6.2.1.2 There shall be no use and occupancy requirement for *new construction* that exceeds the requirements of the *NBCC* or Section 2 of the applicable occupancy chapter for *new construction* of the NFPA 101, *LSC*.

6.2.2 *Existing Building/structures*

6.2.2.1 For use and occupancy of *existing building/structures*, the *NFCC* and the applicable Chapter of NFPA 101, *LSC* for existing buildings shall apply. Means of egress for *existing buildings* shall comply with Chapter 7 of the *LSC* unless otherwise provided for or modified by the individual occupancy chapters. Where the *NFCC* does not address an issue or does not provide detail requirements, the applicable Chapter for existing construction of NFPA 101, *LSC* shall apply, except as may be determined otherwise by the Fire Commissioner.

6.2.2.2 There shall be no use and occupancy requirement for *existing buildings* that exceeds the requirements of the *NBCC* or Section 2 of the applicable occupancy chapter for existing construction of the NFPA 101, *LSC*.

6.3. A person aggrieved by a notice, decision, or direction made under this section may appeal subject to the provisions of the Fire Prevention Act, 1991.

7. Review Process – Reserved

8. Life Safety Evaluation

8.1 Life Safety Evaluation. Where the owner of an *existing building* feels it is impractical to upgrade to meet *code* compliance, the owner may submit, to the *AHJ* for approval, a life safety evaluation to meet fire and life safety equivalency as outlined in this section.

8.2 Where the owner requests approval of a life safety evaluation by the *AHJ* under Section 8.1 it shall meet the following requirements:

8.2.1. The life safety evaluation shall be performed by persons acceptable to the *AHJ*.

8.2.2. The life safety evaluation shall include a written assessment of safety measures.

8.2.3. The life safety evaluation shall be approved by the *AHJ* and shall be updated for special or unusual conditions.

8.3. Life safety evaluations may include, but are not to be limited to, an assessment of the following conditions and the related appropriate safety measures:

(1) Nature of the event including participants and attendees
(2) Access and egress movement, including crowd density problems
(3) Medical emergencies
(4) Fire hazards
(5) Permanent and temporary structural systems
(6) Severe weather conditions
(7) Earthquakes
(8) Disturbances
(9) Hazardous materials incidents within and near the facility
(10) Relationships among facility management, event participants, emergency response agencies, and others having a role in the events accommodated in the facility.

8.4. Life safety evaluations may include, but are not to be limited to, assessments of both building systems and management features upon which reliance is placed for the safety of facility occupants, and such assessments shall consider scenarios appropriate to the facility.

8.5. Further information and guidance on the life safety evaluations may be found in NFPA 101, *LSC* and its appendices.

APPENDIX "A"

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Important Information
(Includes disclaimer and copyright information and details about the availability of printed and electronic versions of the Statutes.)

Table of Regulations **Main Site** **How current is this regulation?**

CONSOLIDATED NEWFOUNDLAND AND LABRADOR REGULATION 9/96

Fire Prevention Regulations
under the
Fire Prevention Act, 1991
(O.C. 96-213)

Amended by:

104/03

CONSOLIDATED NEWFOUNDLAND AND LABRADOR REGULATION 9/96

Fire Prevention Regulations
under the
Fire Prevention Act, 1991
(O.C. 96-213)

Under the authority of section 26 of the *Fire Prevention Act, 1991,* and the *Subordinate Legislation Revision and Consolidation Act,* the Lieutenant-Governor in Council makes the following regulations.

REGULATIONS

Analysis

1. Short title
2. Codes adopted
3. Conflict
4. Repeal

Short title

1. These regulations may be cited as the *Fire Prevention Regulations.*

287/82 s1

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Codes adopted

2. The following codes and all revisions and amendments as are made are adopted:

(a) for the construction of all buildings after the commencement of these regulations

(i) the National Building Code of Canada (except Part 9 where relative to one and 2 family dwellings within Group C),

(ii) the National Fire Code of Canada;

(b) for the use and operation of all buildings, processes, areas and vehicles

(i) the National Fire Code of Canada ,

(ii) the Life Safety Code (N.F.P.A. No. 101) as published by the National Fire Association (U.S.A.);

(c) the Installation Code for Propane Burning Appliances and Equipment (CAN 1 - B149.2) as published by the Canadian Gas Association;

(d) the Installation Code for Oil Burning Equipment (C.S.A. B139) as published by the Canadian Standards Association, excluding the application of clause 3.4.2 of that Code to a person or his or her agent who installs a system as defined in the *Heating Oil Storage Tank System Regulations, 2003* , for that person's own use; and

(e) the Installation Code for Solid Fuel Burning Appliances and Equipment (C.S.A., B365) as published by the Canadian Standards Association.

287/82 s2; 104/03 s1

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Conflict

3. In the event of conflict between the Life Safety Code (N.F.P.A. 101) and the National Building Code of Canada with regard to design and construction, the provisions of the National Building Code of Canada shall prevail, except as may be determined otherwise by the fire commissioner.

287/82 s3

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Repeal

4. The Fire Prevention Regulations, 1982, Newfoundland Regulation 287/82, are repealed.

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APPENDIX "B"

Newfoundland and Labrador Office of the Fire Commissioner

Code Interpretation – Conflict Resolutions Request Form

Name	
Organization	
Address	
Phone	
Code Reference	
Did this question arise from an actual field situation?	☐ Yes ☐ No
Please state your interest in the matter and identify other parties involved:	
Question (should be worded so that it can be answered with either yes or no):	
Signature:	Date:
Mail Request to:	Office of the Fire Commissioner, 50 Parade Street, St. John's, NL A1B 4J6
Fax Request to:	(709)729-3857/2524

APPENDIX B

2014 Needs Assessment Report



Newfoundland and Labrador Hydro

Building Needs Assessment – Select Structures
Bay d'Espoir Generating Station

Revised Draft Report

May 12, 2014

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Newfoundland and Labrador Hydro

Building Needs Assessment – Select Structures, Bay d'Espoir Generating Station

Revised Draft Report
Rev. P2

HMM # 325593

May 12, 2014

This document contains confidential information intended only for the person(s) to whom it is addressed. The information in this document may not be disclosed to, or used by, any other person without Hatch Mott MacDonald's prior written consent.

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Disclaimer

This report is prepared for Newfoundland and Labrador Hydro (the "Client") by Hatch Mott MacDonald (the "CONSULTANT") and is subject to the following limitations, qualifications and disclaimers:

1. The report is intended for the exclusive use of the Client and it may not be used or relied upon in any manner or for any purpose whatsoever by any other party.

2. The report is titled, Building Needs Assessment – Select Structures (the "Project"). Data required to support detailed engineering assessments have not always been available and in such cases, engineering judgements have been made which may subsequently turn out to be inaccurate. There are, therefore, risks inherent in the Project which are outlined in the report. The CONSULTANT accepts no liability beyond using reasonable diligence, professional skill and care in preparing the report in accordance with the standard of care, skill, and diligence expected of professional engineering firms performing substantially similar work at the time such work is performed, based on the circumstances the CONSULTANT knew or ought to have known based on the information it had at the date the report was written and after due inquiry based on that information.

3. The CONSULTANT shall not be responsible or liable for any interpretation or recommendation made by others including any determination in respect of any sale by the Client or any purchase by any third party or any valuation in respect of the Project based in whole or in part on the data, interpretations and/or recommendations generated by the CONSULTANT in the report.

4. The investigation described in this report is based solely on (a) the site visit carried out on October 23-24, 2013 by the CONSULTANT, and (b) information received from the Client, the accuracy of which has not been verified by the CONSULTANT.

5. The report speaks only as of its date and to conditions observed at that time, which conditions may change (or may have changed) by virtue of the passage of time or due to direct or indirect human intervention causing any one or more changes in plans or procedures or due to other factors.

6. The report does not extend to any latent defect or other deficiency in the Project that could not have been reasonably discoverable or discovered by such observation, with the exception of any latent defect or other such deficiency of which the CONSULTANT had actual knowledge.

7. The report is to be read in conjunction with all other data and information received and referenced throughout the report, and all correspondence between the Client and the CONSULTANT. Except as stated in the report, the CONSULTANT has not made any independent verification of such data and information and does not have responsibility for the accuracy or completeness thereof.

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1. Introduction

Hatch Mott MacDonald (HMM) was engaged by Newfoundland and Labrador Hydro (NLH) in September 2013 to conduct a Building Needs Assessment for select structures at the Bay d'Espoir Generating Station under purchase order number 20299-000 OB. This was in response to the HMM proposal dated June 12, 2013 under ***Request for Proposal (RFP) #2013-54689, dated May 22, 2013.***

Hatch Mott MacDonald engaged the services of exp Architects to assist in the building needs assessment, functional programming and concept planning and the Altus Group in providing third-party costing of the concept plans.

Originally planned as a mid-summer and early fall project, Newfoundland and Labrador Hydro awarded this work in early September with a tight timeframe to have the project substantially complete by the end of 2013. After the preliminary findings of the site visit were communicated, email correspondence and conference calls were used to zero-in on the objectives as is typical of the reiterative nature of this type of exercise.

1.1 Purpose

As identified in the RFP, the purpose of this building needs assessment is to assess the existing facilities' dimensional and spatial interrelation against the perceived functional and usage pattern requirements. As required, the following eight functional areas are to be addressed:

- Powerhouse Control Room,
- Electrical Shop & Office Area,
- Training Centre,
- Maintenance Garage,
- Bunkhouse for Accommodation,
- Security Building,
- Carpentry Shop, and
- Warehouse and Storage Building.

Also as required, it is important that this report identify potential spaces or entire buildings that can be renovated and/or reused to assist NLH in meeting its current and future needs. The final purpose of this report is to provide Class 3 third-party cost estimates for all proposed recommendations.

1.2 Background

Within the Newfoundland and Labrador Hydro hydroelectric generating system, the Bay d'Espoir plant plays a pivotal role. Not only is the Bay d'Espoir plant the largest generating station within the Newfoundland and Labrador Hydro operation, it also serves as the operating and maintenance hub for Hydro's remote generating stations on the island from which operating and maintenance personnel are dispatched to plants throughout the province. This role has evolved over the years as new generating facilities have been added to the system and continues to respond to new challenges. Throughout this evolution, the facilities at the Bay d'Espoir plant

have experienced growing pains both from a spatial standpoint but functionally as well, as work volumes increase and work practices change.

Further exacerbating the functional and spatial shortcomings is the fact that many of the facilities at the Bay d'Espoir site are over 50 years old and are at or near the end of their design lives. Moreover, many of the facilities, being built during the construction phase of the original plant as temporary structures to support field activities at that time, were not specifically designed for the post–construction operations and maintenance environment. This Building Needs Assessment is Newfoundland and Labrador Hydro's response to these deficiencies.

1.3 Methodology

Before travelling to site, all available documentation associated with the project submitted by Newfoundland and Labrador Hydro to Hatch Mott MacDonald was reviewed. These documents, as listed in Section 4.0, included a collection of various building floor plans, a building condition assessment report of select structures from 2012, and other pertinent information.

On October 23 and 24, 2013, a site visit was made by Mr. Michael Spencer, P. Eng of Hatch Mott MacDonald and Mr. Gary Walsh, NLAA of **exp** Architects Inc. The visit included meetings with senior management and a tour of all buildings listed in the *request for proposals*. Interviews were carried out with on-site staff at each of the noted facilities towards establishing a reference point upon which the *need* could be defined and a functional program developed. During the preparation of the report, numerous conference calls and written correspondence between Newfoundland and Labrador Hydro and the consultants were required. From the needs information gathered, a functional program, concept floor plans and Class 3 third-party cost estimates have been prepared.

2. Building Needs Assessment

2.1 Functional Requirements

The following key functional guidelines were established by NLH Bay d'Espoir management either during the site visit or during the conversations and correspondence that ensued after the initial visit.

- It is of utmost importance that this exercise seek out the *need* opposed to the *want*.
- In the interest of optimizing workflow, related functional groups must be located in close proximity as much as possible.
- A centrally located single complex containing the office and maintenance facilities has been deemed the most efficient configuration by Bay d'Espoir management.
- It is important that this single complex does not compartmentalize services by trade or some other functional grouping. Instead, services such as lunchrooms, locker rooms, washrooms, meeting rooms, etc. should be shared across functional groups.
- For the purposes of this analysis, the Bay d'Espoir Plant will be treated as if it were a "remote" plant.
- Indications are that the workforce will be stable at current levels over the next 5 years or so.
- Provisions for a female workforce within the trades should be incorporated as a *need*.
- Office space for outside workers such as contractors and consultants should be incorporated.
- Where appropriate, accessibility provisions shall be incorporated within the concept plans.

2.2 Available Building Condition Assessment Review

A building condition assessment ***(BCA)*** was conducted by RDB Engineering Limited in May 2012. This condition assessment concerned itself with the maintenance garage, the carpentry shop and the training centre. No other structures were assessed at that time. Pertinent to the current work, the final report by RDB Engineering made the following conclusions/recommendations:

Existing Building	Concluding Condition/Recommendation Statement
Maintenance Garage	"…it is recommended that no further significant investments be considered for this building to bring it up to present-day codes and standards and it be immediately considered for replacement."
Carpentry Shop	"…when considered collectively, the condition and shortcomings of this structure and its systems precludes any further investment and it is recommended for immediate replacement."

Training Centre	"…the building be neither recommended for upgrading or replacement at this time. A needs analysis that establishes its permanent end-use and space requirements, and/or the specific requirements of the occupants, would facilitate a more informed decision as to the future of this asset."

Condition reports were not available for the remaining structures on the list (powerhouse control room, electrical shop & office area, security building, bunkhouse, warehouse and storage building).

Generally, the RDB Engineering report highlighted that the three structures in and of themselves functioned adequately, however, each structure had numerous building envelope, mechanical, electrical or structural deficiencies and shortcomings including the presence of *asbestos containing materials* (ACM).

The other structures being of similar vintage would most likely have similar building systems issues, code compliance issues and hazardous materials contamination issues and would therefore likely require substantial renovation/retrofit work to bring them to today's standards or more likely full replacement would be required.

The issue unaddressed by the RDB report at the condition assessment stage is one of efficacy of function and fit for purpose. The existing buildings, in most cases, were never intended to function within an operational environment. The buildings were not designed solely with the current use in mind. The staff at Bay d'Espoir has managed to make do with the existing facilities in their current configuration, but at the expense of inefficiencies of operation and function.

The BCA report states clearly that the Maintenance Garage and the Carpentry Shop be replaced immediately, and subjectively, the recommended timelines are 0-5 years and 0-3 years respectively. As the BCA was submitted two years ago, it is our opinion that these two buildings do not have any long term use and they should not be renovated or upgraded, but replaced as per the recommendations of the BCA. The required Class 3 cost estimates, as referenced in the RFP, states that the costing be based on the "proposed recommendations" of the consultant. The cost estimate enclosed in Appendix E – Third Party Costing, is based on total building replacement costs only.

Cost estimates for proposed renovations and upgrades to the Training Centre are also listed in Appendix E.

2.3 Field Observations

The following observations were made during the site visit. These notes have been summarized from the field survey located in Appendix A and the site visit photographs in Appendix B. Please note that this survey summary is a compilation of comments made by both management and unionized workers at each functional location. As such, it represents the starting point for

the functional analysis and needs assessment upon which further definition is possible and necessary.

2.3.1 Security Building

1. **Existing Building**: Consists of the original gatehouse and a modular building added later.
2. **Operational Hours & Staffing**: This facility is manned 24-hours per day by one (1) security attendant working 12-hours per shift.
3. **Site Location:** The location of the existing structure is directly across from the main gated access to the Bay d'Espoir site. The security station in its current configuration has clear view of the gate and main road into the site. There is only a limited view of the maintenance garage that is located behind and to the North of the existing security building.

4. **General Observations:**
    1. ***The building serves several functions including the following: Location of the main entrance to site for all staff and visitors with security gate; Sign-in and sign-out location with small reception area for all visitors; Location of main security desk for full time security attendants with panoramic view of main road leading into and out of the site; First Aid centre; Storage and holding area for water bottle samples for off-site testing; Headquarters for fire-fighting and emergency operations and storage area for fire and safety equipment.***
    2. ***The building is equipped with security monitors for site surveillance.***
    3. ***The building is not barrier-free accessible. The key accessibility deficiencies are: main entrance door, security/check-in counter, washroom undersized, interior door widths and hardware not compliant and the building has two levels with a floor differential of approximately 150 mm (6"). The building should be barrier-free.***
    4. ***There is a lack of general storage space for items such as sample water bottles, cleaning supplies & equipment and office supplies, an individual First Aid Room is recommended, a separate room for fire-fighting and emergency equipment and lockers is required, the reception area for visitors needs to be larger.***
    5. ***With the number of functional deficiencies, it is recommended to replace the building and incorporate the various functions into a new Complex. It is estimated the cost to renovate, upgrade and expand the building with be similar or more costly that constructing new space.***

2.3.2 Carpentry Shop

1. **Existing Building:** Original structure built is 1960's, one floor, slab on grade, rectangular in shape with add on areas (see floor plan), large open workshop area, washroom, woodworking equipment placed throughout the facility, tool storage room, chemical storage room, dust collection mechanical room, battery charging room and Quonset hut used for storage of scaffolding, ladders and other larger equipment. ***The original building footprint is approximately 6.1 m x 24.4 m for an area of 148.8 m2 (20 ft x 80 ft =1,600 ft^2). The Quonset hut, tool storage room and dust collection area were added later. The total building area, including additions, is 291 m2 (3,131 ft2).***
2. **Building Usage:** For carpentry, maintenance and woodworking purposes such as making cabinets, shelving, casings, painting, construction of signs up to ***2.4 m x 6.1 m (8 ft x 20 ft)*** in area made outside, tools storage, scaffolding & ladders storage, paint storage. Plumbing services are also based in the building. One area of the building is used for storage of herbicides for vegetation control. These herbicides represent a chemical hazard.
3. **Operational Hours & Staffing:** A maximum of six (6) staff including one full-time carpenter are based in the building and provide carpentry services throughout the site. Staff lockers and lunchroom are located in the nearby existing Maintenance Garage.
4. **Site Location:** This building is a stand-alone structure located across the gravel parking lot from the existing Maintenance Garage.
5. **General Observations:**
    a. The equipment within the carpenter shop is stationary and fixed into position.
    b. The building has sufficient space for the ongoing activities if not more than necessary.
    c. ***The architectural, structural, mechanical and electrical systems are old and inadequate. For a detailed description of these systems and recommendations, see BCA report, Section 6.0 Condition Assessment – Carpentry Shop***

2.3.3 Maintenance Garage

1. ***Existing Building: Steel frame structure built in the early1960's, slab on grade, rectangular in shape (see floor plan) with add-on areas for a lunch room/meeting room/compressor room off the machine shop and steam cleaner room adjacent to the welding shop (see floor plan). There is a second floor at one end with a locker room, lunch room and computer room plus a mezzanine used as a locker room. The original building, without add-ons, is approximately 68.6 m x 11.9 m (225 ft x 39 ft). The approximate area of the first floor, including add-ons, is 882 m2 (9,493 ft2). The approximate area of the second floor is 82.5 m2 (888 ft2) and the mezzanine has an approximate floor area of 31.6 m2 (340 ft2). The usable floor area of the total building is approximately 996 m2 (10,722 ft2).***

2. **Building Usage:** Includes the following areas (a) vehicle repair with floor pit in one bay, (b) machine shop with tool room and office, (c) welding shop with manual painting services within (d) lunch room & kitchen on second floor and (e) private offices on first and second floors.
3. **Operational Hours & Staffing:** Approximately 25 workers are based in the existing maintenance garage including heavy-duty mechanics, machinists and welders.
4. **Site Location:** This building is a stand-alone structure located near the Security Building and front gate.
5. **General Observations:**
    a. The building is undersized to meet present day needs.
    b. ***The architectural, ventilation, mechanical and electrical systems are inadequate or nonexistent and many systems of the systems do not meet present day code standards. For a detailed description of these systems and recommendations, see BCA report, Section 5.0 Condition Assessment – Maintenance Garage***
    c. The structure suffers from a compartmentalized configuration with each functional group having their set of services. This leads to many duplicated services throughout the building (ie., locker rooms, lunchrooms, washrooms, etc.).

2.3.4 Training Centre

1. **Existing Building**: A one storey, ***steel frame (pre-engineered) and wood infill*** walls, wood frame floor in office area, training centre, dining room and sleeping quarters and concrete slab on grade in washrooms section. The plan layout is in the shape of an "H".
2. **Building Usage**: The existing building is a multi-use facility with office space for the Short-Term Work Planning and Scheduling Group, a large meeting room for training activities, one conference room, a computer training room, the office for the Tech/Operations Eastern Group, an underutilized accommodations area of six (6) rooms, a lounge area and a large kitchen/dining area for employee functions.
3. **Operational Hours & Staffing:** On a regular basis the building is staffed by the Short-Term Work Planning Group of approximately six (6) people plus the staff associated with the Tech/Operations Eastern Group that uses the building as their home base in travelling to remote sites. Otherwise, the facility is used intermittently as required for training or meeting purposes.
4. **Site Location:** This building is a stand-alone structure located near the Warehouse and roughly halfway between the front gate and the powerhouse.
5. **General Observations:**
    a. The Short-Term Work Planning Group is isolated from the management group in this building and does not have ready access to other functional groups other than through email and phone.

b. The building is poorly situated with respect to other structures making communication difficult.
c. The area being used by the Tech/Operations Eastern Group is undersized and can be improved upon in terms of storage and work space.
d. Other areas are large and sufficient if not fully utilized (the training centre room, kitchen, lounge and dining area.
e. Some areas are underutilized such as the accommodations area which is used only once annually by visiting members of the Dyke Board. NLH believes that it is more cost effective to use local hotels for accommodations services.

6. ***Potential for Renovations: The BCA describes a series of building deficiencies, and include: presence of hazardous materials, facility is not barrier-free, building code violations (fire separations), roof structure is possibly undersized, condition of wood floor structure is unknown and potentially undersized due to noticeable deflection, condition of exterior wall assembly not fully known and possibly lacks proper insulation, air and vapour barriers, non-presence of mechanical ventilation system, non-functional layout of office area, wood windows need replacement, a lack of head room in corridors to install a mechanical ducting and site drainage needs upgrading.***

   It is the understanding the sleeping quarters are no longer required, and the existing office area has an inefficient layout and the staff in the office can be relocated to a new Complex. There are known deficiencies as listed in the BCA, and with all 50 year old buildings, there are certainly other unknown problems to be found should major renovations be undertaken. Problems such as rot and deterioration of the wood floors and steel structure can lead to expensive overruns and drive the project over budget.

   The wood frame floors are most likely not designed for storage type loading and sufficient only for office, and possibly, assembly type uses. To bring the building up to code standards and develop new layouts for possible office and meeting room use, the building needed to be skinned out inside and rebuilt.

   With the known deficiencies and the likely additional unknown construction problems, there will not be any cost savings in renovating the Training Centre versus developing similar type spaces in a new Complex. The down side of renovating the Training Centre is the extent of the required upgrades can even exceed the cost or a new building.

2.3.5 Bunkhouse for Accommodations

1. **Existing Building:** There is a small wood frame hostel type bunkhouse.
2. **Building Usage:** The building reported is being used for temporary accommodations for visiting workers.

1. **Operational Hours & Staffing:** Not applicable.
2. **Site Location:** This building is a stand-alone structure located near the Training Centre.
3. **General Observations:**
   a. Note that this structure was not inspected during the site visit and has been removed from the scope of this work by NLH.

2.3.6 Warehouse and Storage Building

1. ***Existing Building: One level, slab on grade and consists of an original Quonset hut and two pre-engineered sections added later with an outdoor yard. The building floor area is approximately 604 m2 (6,502 ft2). The yard are is approximately 1,500 m2 (16,150 ft2).***
2. **Building Usage:** The existing building is used for receiving and storage of inventory items needed in the routine operation and maintenance of the Bay d'Espoir generating station as well as other plants and other segments of the Hydro Generation operation. Beyond storing O&M inventory items, the warehouse also stores a selection of capital project items.
3. **Operational Hours & Staffing:** The warehouse is manned on a daily basis by two (2) permanent and one (1) temporary staff members.
4. **Site Location:** This building is a stand-alone structure located near the Training Centre and roughly halfway between the front gate and the powerhouse.
5. **General Observations:**
   a. The receiving area is undersized to allow proper counting and recording of all materials, parts and equipment arriving. ***A minimum area of 172 m2 (1,851 ft2) is recommended and listed in section 2.6.4 Warehouse (Net and Gross Areas) of this report. (See concept floor plan of new Complex).***
   b. The existing insulation in certain roof areas is constantly falling off and has to be continually repaired.
   c. The building is undersized and poorly proportioned to effectively utilize the storage rack systems. ***The curved roof /walls (Quonset hut shape) creates reduced head room at grade level and minimizes storage use along the sides.***
   d. Forklift truck travel is not possible for inventory handling. Aisle widths are too narrow.
   e. Most, if not all, items have to be man-handled onto the shelves including heavy items such as motors.

f. There is an Inventory Management System in the building, but it appears it is not operational.

g. The storage of the capital items in the rear of the building is poorly arranged. Many items have to be handled multiple times to gain access to items on the shelves.

h. The building is isolated from other functional groups and workers have to travel by vehicle to pick up materials. This is inefficient.

i. The Quonset hut is older that the pre-engineered sections and is not in as good as condition as the new sections. With upgrades, the building can be modified and utilized for cool temperature storage items that do not need to be accessed on a regular basis. See Section 2.7.2.

j. The pre-engineered sections are in good condition and can also be utilized for various storage items that do not need to be accessed on a weekly, or even monthly basis by warehouse staff. Potentially, some long term items that are presently stored in Generator Building #7 could be located here.

k. It is recommended a thorough analysis of the total NLH warehousing and storage requirements be carried. This report to include the types and sizes of all materials, supplies, parts and tools needed on site, with recommendations how best to be stored (i.e. racking systems and environmental conditions).

2.3.7 Powerhouse (South Wing – First and Second Floors)

1. **Existing Building**: The identified functional areas (Control Room, Electrical Shop, Office area) are within or attached to the main powerhouse. ***The South Wing structure is built of non-combustible construction (concrete and steel) with exterior pre-cast concrete panels.***

2. **Building Usage:** The Control Room area is the operational centre of the Generating System. This includes the control room itself, a locker area, and a recently renovated lunchroom. The electrical shop area includes cubicle areas for both the electricians and P&C technologists and a work shop/storage area. The office area is split over two floors and includes office space, meeting space, and lunch room and wash room facilities.
3. **Operational Hours & Staffing:** The Control Room is manned 24-hours per day while the electrical shop and office area are manned during normal business hours.
4. **Site Location:** The powerhouse is located on the north end of the site approximately 1.3 km from the main access gate for the site.
5. **General Observations:**
    a. **Control Room:** Functionally, the Control Room cannot change and is adequate. The recently renovated lunchroom is attractive and provides sufficient space for operators on shift. There were some concerns expressed over the noise experienced by the operators. There was a need expressed for storage space for the files for the Granite Canal project files.

b. **Electrical/P&C Shop**: Both the electrical and P&C cubicle spaces are overcrowded and congested. The shop area is undersized and lacking in adequate storage and work space.
c. **Office Area:** The Office area is generally functional adequate. There is a disconnect between upper management, the Long Term Asset Planning Group and other functional groups which are dispersed throughout the site. The meeting space/library is undersized.
d. **Accessibility**: The building is not registered as barrier-free with the Government of NL and does not have an elevator.

e. ***Building Expansion: Enlarging the South Wing was considered and three options were evaluated.***
Option # 1: Add a third and/or fourth floor above the existing building footprint.
Option # 2: Construct an addition to the east onto the existing parking lot.
Option # 3: Add a third and/or fourth floor over the existing South Wing and add one to four floors onto the east parking lot.

The concept of constructing an addition to the south was eliminated, as this space is required for the turning of large trucks that travel on the access road at the back of the powerhouse.

The most practical and functional use of space for an enlarged South Wing would be offices, meeting rooms, training rooms, library, resources centre rooms, lunch rooms & kitchen on the upper floors. The lowers floor (first level) could be used for service areas, meeting rooms, offices, storage, locker rooms, lunch room and kitchenette.

By increasing the usable floor area, the project will be considered a major project and both the new and existing areas will have to be built and renovated to standards of the latest building codes, and will prove challenging and costly. The design challenges are:

1. ***Occupied Building: Due to the nature of the work being carried out in the Control Room, the South Wing has to be occupied on a continuous cannot be vacated and shut down for renovations. The length of the construction period to renovate and add on to an occupied building is always longer than developing an existing unoccupied building. The on-going noise, vibrations and dust***

generated by the construction can negatively affect the operational performance and present potential safety hazards for staff.

he carrying out of heavy construction work in the vicinity of the Control Room, such as adding floors above or in the renovating in adjacent areas on the same floor, presents serious logistical issues. Should there be a roof leak, a fire or the knocking out of power to the building occur, the consequences are potentially very serious and costly with power distribution possibly being affected?

A project with the potential for such serious and costly problems may not be of interest to many general contractors (GC's). Qualified GC's would need the approval of their bonding and insurance companies to guarantee coverage's , and should they be willing to bid, it is certain that a large premium and mark-up would be carried in their tenders to cover such risks.

2. ***Accessibility & Barrier-Free: The South Wing is not a registered barrier-free building with the Government of NL, as it was constructed well before the NL Building Accessibility Act (Act) was adopted, and has not been upgraded to the Act's standards. Carrying out a major renovation as described the three options listed above, will most likely require the design standards of the Act to be applied. It is also recommended that for a new building it is a good corporate policy to develop it to barrier-free standards. The necessary barrier-free upgrades include, but not limited to, are: (a) main entrance needs a ramp, (b) a vertical mechanical lift (elevator, chair lift or stair lift) is required, (c) accessible washrooms are needed, preferably one per floor, (d) all interior doorways to have a minimum clear opening of 800 mm with lever hardware, € reception counter to have barrier-free section and (f) all doors to have a minimum clearance of 300 mm (1'-0") on the push side of the latch and 600 mm (2'-0") on the pull side."***

   As described in Section 2.9, there are logistical and maintenance issues with an elevator is a rural area. When a break down occurs, it may be a few days before a service technician can be on site.

3. ***Fire and Life Safety: This building was designed on codes that are now over 50 years old, and the latest codes have many upgrades and changes since the original ones. Reviews of the NBC, LSC, National***

Fire Code and the Act, plus all other applicable codes are required to determine the deficiencies such as fire ratings, exiting, inter connected floors, sprinklers, stand pipes and fire alarms. Most likely there are deficiencies that will have to be dealt.

4. *Structural: A thorough investigation of the existing structural system is needed (foundations, exterior walls, load bearing walls, columns, beams, floor system and roof). The loading capacity of the adjacent roofs also need to be evaluated as a potential two floor addition over the South Wing will create new snow drifting patterns on the adjacent roofs. The structural section of the latest NBC has upgrades from the codes of the 1960's.*

   The existing structural frame and foundations may not have the capacity to carry additional loads and a new foundation and framing system may be required. This will prove to be very inconvenient to do in an occupied building. A geo-technical report of the east parking lot would be needed should Options #'s 2 and 3 were considered.

5. *Mechanical Systems: An assessment of the existing systems is required (ventilation, plumbing) and some of these systems may be original and may need replacement or upgraded due to code deficiencies or deterioration. The building should also be air-conditioned and an enlarged building will certainly require larger ventilation units and possibly a great water supply.*
6. *Electrical Systems: An assessment of the existing electrical systems is required (heating, lighting, power, controls and data and communications), and some of these systems may be original and may need to be replaced due to code deficiencies or deterioration. An enlarged building will most likely require an enlarged electrical service.*

7. *Site, Water and Sewer Systems: Enlarging the building onto the east parking lot will require modifications to the lot section to remain. A capacity analysis needs to be done to ensure the lot provides a sufficient number of parking stalls (including the necessary of barrier-free stalls) to meet staffing demands.*

A bigger building area will increase the loads on the water supply and sewage disposal systems and an evaluation of these systems is necessary.

8. **Noise and Vibrations**: There are issues with both these matters in the existing building. Constructing new areas and upgrading existing ones with the intent of eliminating these problems requires specialized design. An acoustic consultant would have to be engaged to develop construction systems and details and it often requires an isolated structural framing system with heavy concrete components. An analysis of the existing conditions may prove that the noise and vibrations in certain areas cannot be totally eliminated but only minimized.

9. **Underground Systems**: ***The location of any underground electrical, telephone, mechanical and water and sewer systems below the east parking lot needs to be identified. If there, it may prove to impractical and costly to relocate them and this will eliminate any building expansion in the area, as described in Option #' s 2 & 3.***

10. ***Non-Combustible Construction: The South Wing and the remainder of the powerhouse were constructed as a non-combustible building (steel & concrete). This is a code requirement due to the nature of the building use and minimizes the potential for fire. Any new addition would also have to be constructed as non-combustible, and wood frame is not permitted. The cost of non-combustible construction is more costly that wood frame.***

11. ***Construction Methods: Adding a third and/or fourth floor as described in Options #'s 1 & 3 will require a large crane to lift the heavy exterior concrete panels or steel structure into place. This is an costly construction method to develop offices, meeting rooms, libraries and resource centre type rooms. These type of spaces can be more economically built in a one storey wood frame structure, as is proposed for the new Complex.***

12. ***Consultants Fees: Based on the Newfoundland & Labrador Association of Architects (NLAA) Minimum Fee Schedule, a building renovation project is recommended to be 30% higher for a similar new building. The fees for building assessment reports, as***

described above, are over and above the base fee and add extra costs to the project.

13. *Costing: The estimated cost to add on to and renovate the South Wing versus providing similar space in a one storey, wood frame office block in a new Complex, is approximately double.*

14. *Existing Building Renovations: Carrying out renovations and adding new sections to an existing fifty (50) year old building always has unknowns and uncertainties, and only become apparent after the demolition and renovations has started. This often leads to expensive change orders and delays the completion date.*

15. *Conclusion and Recommendations: Based on the criteria described above, it is recommended the South Wing not be added on to, but only the interior renovations within the existing footprint be done, as described in Section 2.7.*

2.4 Building Design Concept

The maintenance garage, training centre and carpentry shop are individual buildings located throughout the site and were erected over fifty years ago as temporary buildings during the construction phase, as described in the BCA report. The powerhouse was built at the same time as a permanent structure and the nearest buildings, the Training Centre & Quonset hut/warehouse are approximately 800 meters (half a mile) away. It is understood the Quonset hut/warehouse was also constructed in the early 1960's with steel frame additions added over time. The separation of building creates operational inefficiencies, such as travel time from one building to another, with this being an expanded issue during the winter months.

The location of the buildings was planned mainly for use during the construction period and not specifically placed for use during the operation phase, which is now the situation. Since the project completion in the 1960's, other NL Hydro sites have been developed and are serviced from the Bay d'Espoir facility, creating a larger demand on the existing buildings.

The BCA lists a series of deficiencies with the maintenance, training centre and carpentry shop and recommends immediate replacement of the maintenance garage and carpentry shop. The BCA also recommends that a needs assessment be carried out to determine its permanent end use before making an informed decision on what to do with the building.

Based on the operational inefficiencies and the condition of the existing buildings, it is recommended that a new singular complex (the Complex), centrally located and under one roof be constructed. The Complex would be designed to meet the functional programming (spatial needs) requirements of NLH and constructed to the design standards of all governing codes, (latest editions) such as: The National Building Code of Canada, Life Safety Code, National Fire Code, National Model Energy Code and the NL Buildings Accessibility Act.

The Complex to include: security/gatehouse, office block, carpentry shop, warehouse and all associated spaces. Developing a new Complex under one roof will reduce travel time between separated buildings, reduce reliance on transportation vehicles, increase safety, save energy, lower operational costs and reduce greenhouse gases.

For the purpose of this report, the new Complex shall be referred to as the **New Office/Maintenance Garage/Warehouse Complex.**
The Complex has four main building sections and they are:

1. Office Block
2. Utility Block
3. Maintenance Garage
4. Warehouse

A description of the usages and construction of the four different sections is included in the report.

The office areas in the Powerhouse and the existing Warehouse are to be reused, as described in Section 2.7 (Existing Buildings to be Re-developed).

2.5 Building Codes and Accessibility Act

The concept architectural floor plans were developed based on the functional programming (needs) requirements and to the building standards adopted by the Province of Newfoundland & Labrador. These reference building standards include the latest editions of The National Building Code of Canada ***(NBC)***, the NFPA 101 Life Safety Code ***(LSC)*** and the NL Buildings Accessibility Act. A building code review of these reference standards was completed based on the proposed concept design, the building type, the various occupancies, and the configuration of the building. The details of the code review can be found in Appendix C. The proposed Complex design is based on all sections of the building being ***non-sprinklered***

The plans incorporate life safety and health standards such as Building occupancy types, exit travel distances, access to exits, number of exits, dead end corridors, fire compartments, fire rating between suites, location of firewalls between compartments and the number of washroom fixtures.

The main office block (suite), the locker rooms & washrooms, lunchroom and fitness room are designed to the standards of NL Buildings Accessibility Act (the Act).

The warehouse, vehicle maintenance garage, the machine shop, welding shop, carpentry shop, & P&C shop are considered exempt from the Act and are not designed to meet these standards.

Masonry firewalls (minimum 2 hour rating) are located between the Utility Block and the Welding Shop and between the Vehicle Maintenance and Warehouse.

2.6 Functional Programming

The listed rooms are the proposed programed spaces for each section of the Complex. The noted spaces indicate approximate clear room dimensions in meters and areas in square meters.

2.6.1 Office Block – Net & Gross Areas

The Concept Floor Plan (Drawing A-104) has a color code legend illustrating rooms and spaces for the various work groups. These groups are noted on the Needs Program (Remarks) listed below and include: Management Group (MG); Long-Term Asset Planning Group (LTAPG); Short-Term Work Planning Group (STWPG); Front Line Supervisor Group (FLSG); Tech/Operations-Eastern (TOE) and Tech/Operations-Western (TOW). The gross area of the Office Block (including corridors and wall thicknesses) is approximately 632 m^2 (6,803 ft^2).

#	Name	Length (m)	Width (m)	Area (m^2)	Remarks
1	Vestibule (Security Office)	2.2	1.8	3.7	Visitor's Entry
2	Waiting (Security Office)	2.8	2.8	7.8	

3	Security Office	4.6	3.8	17.7	
4	First Aid Room	3.4	2.9	9.9	
5	Lockers/Fire Response	3.1	5.0	15.5	
6	Office #1	3.8	3.0	11.4	MG
7	Office #2	3.8	3.0	11.4	FLSG
8	Office #3	3.8	3.0	11.4	MG
9	Files Room	3.6	1.7	6.1	
10	Work Room	2.9	2.3	6.7	
11	Meeting Room	4.3	3.6	15.5	
12	Office #4	2.9	2.6	7.5	MG
13	Office #5	5.1	3.6	18.4	MG
14	Office #6	3.1	3.6	11.2	MG
15	Office #7	3.1	3.6	11.2	MG
16	Vest/Waiting	4.3	4.8	20.6	
17	Reception	3.2	3.8	12.2	
18	Storage Room/Coffee	3.8	1.7	6.5	
19	Male WC	2.6	2.1	5.5	Barrier-free
20	Female WC	2.6	2.1	5.5	Barrier-free
21	Meeting Room #1	5.2	4.2	21.8	Folding wall
22	Meeting Room #2	5.2	4.2	21.8	Folding wall
23	Photocopy Room	4.4	2.4	10.6	
24	Workstations (1-6)	7.1	4.1	29.1	STWPG
25	Office #8	3.1	3.0	9.3	Visitor office
26	Office #9	3.1	3.0	9.3	MG
27	Office #10	3.1	3.0	9.3	STWPG
28	T/O Office West	3.3	3.1	9.3	TOW
29	T/O Office East	3.3	3.1	9.3	TOE
30	T/O Crew West	4.9	4.0	18.7	TOW
31	T/O Crew East	4.9	4.0	18.7	TOE
32	Storage Room	3.4	1.6	5.4	
33	Janitor Room	1.6	1.5	2.4	
34	Server Room	1.6	1.4	2.2	
35	Office #11	3.7	3.1	11.5	FLSG
36	Workstations (7-10)	4.8	3.8	18.2	Aisle extra
37	Library	6.0	3.8	22.8	

2.6.2 Utility Block – Net & Gross Areas

The Concept Floor Plan (Drawing A-104) has a color code legend illustrating rooms and spaces for the various work groups. These groups are noted on the Needs Program (Remarks) listed below and include the Front Line Supervisor Group (FLSG). The gross area of the Utility Block (including corridors and wall thicknesses) is approximately 742 m^2 (7,987 ft^2).

#	Name	Length (m)	Width (m)	Area (m^2)	Remarks
1	Storage Room	4.9	2.3	11.3	
2	Chlorinator Room	2.3	2.3	5.3	
3	Male Locker Room	10.5	9.1	95.6	
4	Male WC	9.1	3.0	27.3	
5	Female Locker Room	7.1	3.4	24.1	
6	Female WC	7.1	3.0	19.3	
7	Hot Water Tank Closet	1.4	1.4	2.0	See Note #1
8	Washers/Dryers Room	4.0	2.1	8.4	
9	Fitness Room	6.0	4.7	28.2	
10	Telephone Room	3.1	2.3	7.1	See Note #1
11	Mechanical/Electrical Room	6.6	3.1	20.5	See Note #1
12	Office #12	4.2	3.1	13.0	FLSG
13	Computer Office	3.1	3.0	9.3	
14	Storage Room	3.4	3.0	10.2	
15	Electric Workstations	7.4	7.0	39.0	
16	Elect/P&C Shop	9.1	6.6	60.1	
17	Computer Office	5.0	3.0	15.0	
18	Meeting Room	5.0	4.3	21.5	
19	Carpentry Shop	11.7	9	94.4	
20	Office #13	3.1	3.1	9.6	FLSG

Notes
Note #1: Room to be sized by electrical and mechanical consultants.

2.6.3 Maintenance Garage (Net and Gross Areas)

The Concept Floor Plan (Drawing A-103) illustrates the proposed layout of the Maintenance Garage and the gross area (including corridors and wall thicknesses) is approximately 758.2 m^2 (8,161 ft^2).

#	Name	Length (m)	Width (m)	Area (m^2)	Remarks
1	Welding Shop	14.1	7.3	103.0	See Note #1
2	Machine Shop	15.6	14.4	209.2	See Note #2
3	Tool Room	4.8	3.1	14.9	

4	Vehicle Maintenance Garage	26.7	15.6	410.0	See Note #2
5	Compressor Room	2.4	2.4	24.1	See Note #3

Notes
Note #1: Area does not include Travel Lane & 1 hr fire rating required
Note #2: Area includes Travel Lane
Note #3: Room to be sized by electrical and mechanical consultants.

2.6.4 Warehouse (Net and Gross Areas)

The Concept Floor Plan (Drawing A-102) illustrates the proposed layout of the Warehouse and the gross area (including corridors and wall thicknesses) is approximately 1,045.2 m^2 (11,250 ft^2).

#	Name	Length (m)	Width (m)	Area (m^2)	Remarks
1	Office	4.8	3.6	17.3	
2	General Office	5.3	4.8	25.4	
3	Storage Room	4.3	2.9	15.0	
4	Washroom	2.8	1.7	4.8	
5	Lunch Room	2.9	2.8	8.1	
6	Receiving Area	16.2	10.8	172.0	
7	Main Warehouse Area	34.6	22.8	788.0	See Note #1
8	Electrical Room	3.8	3.2	12.2	See Note #2

Notes
Note #1: Room size to be based on a comprehensive investigation of Hydro's storage needs.
Note #2: Room to be sized by electrical and mechanical consultants.

2.7 Existing Buildings to be Re-Developed

2.7.1 Powerhouse

Built in the early 1960's, the powerhouse is the location of six turbines and the control room, plus support areas that include offices for senior management and long-term asset planning staff. The powerhouse offices like other functional group offices on site are islanded alone in the powerhouse. Newfoundland and Labrador Hydro (Hydro) in order to improve efficiencies, realizes that all the office must be consolidated into a new single centrally located complex.

The new center complex (home base) is proposed to include the following: an office block, maintenance garage, carpentry shop, warehouse and all associated support spaces. The senior managers, asset planning staff and reception staff would be relocated to the office block and their vacated space can be renovated for the proposed new uses.

Upper Floor: The administration area is in good condition and the existing offices, meeting room, reception office, washrooms, foyer/waiting area and other spaces require only minor

modifications. These spaces are practical for use used by supervisors, Project, Execution and Technical Services (PETS) and other contractors and staff for on-going work in the plant. The proposed renovation will see the retention of the six individual offices, meeting room, and lunchroom and establishment of a reference library in the existing reception office and reuse the existing office adjacent to powerhouse as storage room. The existing foyer/waiting area, washrooms, lunchroom and control room to remain as is.

Lower Floor: The renovated vacant space to include: a meeting room, a reference library, storage rooms, a washroom and satellite shop areas.

Existing floor plans and proposed new plans for both floors are included. See Appendix D.

2.7.2 Warehouse & Storage Building

Consisting of a Quonset hut and two steel frame structures, this facility has approximately 604 m^2 (6,502 ft^2) of usable space with headroom of about 3.65 m (12 ft). The Quonset hut appears to be an original building and the two steel frame structures added later. There are two overhead doors, located at the front and rear elevations. There is also an exterior fenced-in yard. The Quonset hut has water infiltration issues through the roof and the blown-on insulation falls off regularly and has to be repaired. The newer sections of the building are in better condition. It is proposed that this facility be upgraded and reused as a facility for storage of larger items.

2.8 New Office/Maintenance Garage/Warehouse Complex

The proposed new building complex shall provide developed space on one floor within the same structure (under one roof) for the various uses as identified in the email of November 18, 2013 from Mr. Matthew Lambert. The main required uses and building types are:

- Security Office
- Office Area
- Support Areas (Change Rooms, Fitness Room & Service Rooms)
- Lunch Room
- Carpentry Shop
- P & C Shop & Electricians
- Welding Shop
- Machine Shop
- Vehicle Maintenance
- Warehouse

For the purpose of this report, the **New Office/Maintenance Garage/Warehouse Complex** (the Complex), is described in four different sections. They are:

1. Office Block
2. Utility Block
3. Maintenance Garage
4. Warehouse

A description of the usages and construction of the three different sections is as noted.

Office Block

This building section includes the Security Office and Office Area. For cost efficiency, the proposed construction is a combination of wood frame & steel structure, exterior metal siding, combination of metal stud and concrete block partitions, wood roof trusses, asphalt shingles, a combination of T-bar and gypsum board ceilings with a floor to underside of roof truss height of approximately 3.2 m (10.5 ft).

Utility Block

This building section includes the Male & Female Change Rooms, Washrooms, Lunch Room, Fitness Room, Mechanical & Electrical Utility Room, Electrical/P & C Shop area, and Carpentry Shop. The proposed construction is a combination of wood frame & steel structure, exterior metal siding, combination of metal stud and concrete block partitions, wood roof trusses, asphalt shingles, a combination of T-bar and gypsum board ceilings with a floor to underside of roof truss height of approximately 3.2 m (10.5 ft).

Maintenance Garage

This building section includes the Welding Shop, Machine Shop and Vehicle Repair Garage. This building section is proposed to be a steel frame structure (Pre-engineered or conventional steel frame) with exterior metal siding, standing seam metal roof, overhead doors with a minimum clearance from the finish floor to the lowest section of the steel structure of 6.1 m (20 ft).

Warehouse

This building section includes only the Warehouse and is proposed to be a steel frame structure (Pre-engineered or conventional steel frame) with exterior metal siding, standing seam metal roof, overhead doors with a minimum clearance from the finish floor to the lowest section of the steel structure of 6.1 m (20 ft).

2.8.1 Office Block

2.8.1.1 Security Office

The first contact all staff and visitors have before entering on to the power-plant site is the security office, as all visitors must park their vehicles on the "outside" of the security gate and register inside the security office before heading onto the site. First time visitors are required to participate in a safety orientation presentation. All certified staff are to use an automatic electronic security card access system. Security staff is responsible for recording all persons and vehicles entering and leaving the site, monitor on-site security matters and act as first responders to health, safety and emergency incidents.

The Security Office and security gate are located in the Office Block and immediately adjacent to the access road main road with panorama views of the site entrance. TV monitors providing surveillance of the site shall be located in the Security Office. The main programmed spaces are:

- Reception/Waiting
- Security Office
- First Aid Room
- Lockers/Fire Response Room

See enclosed concept floor plan.

2.8.1.2 Office Area

The new office block shall include programmed spaces for the following five groups: Management Group, Long-Term Asset Planning, Short-Term Work Planning, Front Line Supervisors and Technical/Operations (Eastern & Western). This area of the building shall be located adjacent to the Security Office and Utility Block. The main programmed spaces are:

- Reception/Waiting
- Library
- Three (3) meeting rooms (two adjacent meeting rooms to have movable partition)
- Twelve (12) individual offices
- Ten (10) work stations
- Two (2) Technical Operations crews general offices
- Work Room
- Photocopy/Fax Room
- Male & Female washrooms
- Storage Rooms & Files Room
- Janitor Closet
- Server Room

The spaces for each of the five noted groups are color coded on the enclosed concept floor plan.

2.8.2 Utility Block

Located between the Office Block and the Maintenance Garage, this area includes programmed spaces for:

- Male & Female Change/Locker Rooms
- Male & Female Washrooms
- Lunch Room
- P & C Shop and support spaces
- Carpentry Shop
- Two (2) individual offices
- Two (2) computer offices
- One (1) meeting room
- Washer & Dryers Room
- Fitness Room

- Storage Rooms
- Electrical & Mechanical Room
- Chlorinator Room

Design & Programming Notes: The following design criteria was used in the planning of the listed rooms.

- Male Locker Room: An evaluation of the Operations Chart suggested 38 individual lockers are needed. Each locker is 915 mm x 810 mm (3'-0" wide x 2'-8" deep) .

- Female Locker Room: Seven lockers are shown and this number is based on a concept model for the Vale site in Long Harbour, NL where approximately 20% of staff will be female.

- Lunch Room: The Lunch Room in the existing Maintenance Garage is approximately 46.5 m^2 (501 ft^2) () and was noted during the site visit it was of a sufficient size. As there will be staff from the Office Block using the new Lunch Room, it is proposed it be increased to approximately 69.0 m^2 (742 ft^2).

- Carpentry Shop: Approximately 84.0 m^2 (900 ft^2) was recommended by Hydro and this is smaller than the existing Carpentry Shop. The size shown is 102.2 m^2 (1,100 ft^2) and this includes space for tool and materials storage and an office.

- Electrical/P&C Shop: The existing Electrical/P&C shop in the Powerhouse is approximately 48.3 m^2 (520 ft^2) and is considered undersized. To accommodate present day usage and provide space for potential future needs, the area in the new building was increased to 55.7 m^2 (600 ft^2) plus a 9.3 m^2 (100 ft^2) storage room was added.

2.8.3 Maintenance Garage

2.8.3.1 Welding Shop

Located between the Utility Block and the Machine Shop, this area includes space for the equipment and tools to carry out the necessary work. This room requires a one (1) hour fire separation and is adjacent to the Machine Shop with access through an overhead door and man door. The Welding Shop in the existing Maintenance Garage has an area of approximately 107.6 m^2 (1,158 ft^2) and the programmed area for the new Welding Shop is 103.1 m^2 (1,110 ft^2) and does not include the adjacent Travel Lane.

An overhead crane, exterior man door and exterior overhead door are included in the concept design.

2.8.3.2 Machine Shop

Located between the Welding Shop and the Vehicle Maintenance Shop, this area includes space for the equipment and tools to carry out the necessary work. This room is open to the Vehicle Maintenance Area and has access to the Welding Shop through an overhead door and man door. The Machine Shop in the existing Maintenance Garage has a floor area of approximately 211.4 m^2 (2,275 ft^2)- not including the Lunch Room. The proposed area for the new Machine Shop is 225.8 m^2 (2,430 ft^2). To accommodate present requirements and to provide space for potential future needs, the area in the new building was increased was increased. This space also includes for a potential tool room and storage area.

A wall between the Machine Shop and Vehicle Maintenance Shop (i.e. 2.4 m or 8 ft high) with an overhead door can be constructed, if required.

An overhead crane, exterior man door and exterior overhead doors are included in the concept design.

2.8.3.3 Vehicle Maintenance Garage

Consisting of four bays, the width of the garage was based on the number and type of vehicles needed to be serviced and stored. A major design requirement is the size of the John Deere 772D grader that has an overall length of approximately. 11.7 m (38.5 ft) with accessories added such as the plow. A building width of 15.2 m (50 ft) allows for the grader to be properly serviced on all sides when indoors and works well structurally and space wise with the remainder of Vehicle Garage and the Machine Shop and Welding Shop.

The garage area is programmed to include a service pit, hydraulic lifting hoist, and additional repair space and vehicle storage space plus tools and parts storage. The requirement of two drive-thru bays with overhead doors is included.

The vehicle service area in the existing Maintenance garage has an approximate floor area of 413.0 m^2 (4,446 ft^2) . This includes the work floor area, offices, locker room and battery room. The new Garage area is 410.0 m^2 (4,413 ft^2). The new space is considered more functional due to the width and drive-thru features.

2.8.4 Warehouse

This section of the Complex is programmed and planned to receive, record and store all items (materials, supplies, parts, tools, etc.) arriving on site. The proposed building area is 1,045.0 m^2 (11,248 ft^2). The existing warehouse has an approximate floor area of 604 m2 (6,502 ft2), including office area and receiving. Based on the amount of materials stored in the existing warehouse and other locations about the site, an warehouse area approximately 75% larger is proposed. The concept design plan addresses the deficiencies of the existing warehouse/storage building by including the following:

- Receiving Area of sufficient size
- Building height with a minimum of 6.1 m (20 ft) clearance designed for a racking system

- Building laid out for a racking system designed to meet Hydro requirements
- Corridor aisles designed for forklifts
- Overhead doors at each end of the building
- Office area sized for required number of staff
- Building designed for installation of an inventory management system
- End of building designed to be accommodate future expansion
- Proposed building footprint easily reduced in size, if required

In order to properly size and plan the racking and shelving systems of the Warehouse, a thorough evaluation of the size and types of inventoried materials, supplies, parts and tools needs to be carried out by NLH. Consideration to any special environmental conditions for certain items needs to be addressed such as exposure to heat, cold humidity or sun light.

2.9 Location Considerations

The concept floor plans and construction estimates were prepared based on the remoteness of the site. Two key design elements were:

***Non-Sprinklered Building:** The NBC is the governing building code and describes the major occupancy classifications (i.e. assembly, detention, treatment, care, residential, business and personal services, mercantile and industrial hazards). It also describes fire and life safety requirements that are based on occupancy use and size, such as: fire ratings, permitted combustible and non-combustible structures, buildings that are permitted to be non-sprinklered, buildings that are required to be sprinklered and requirements for fire alarm systems. A building the size of the Complex requires a sprinkler*

The site does not have a municipal water system and it is understood water is provided by a series of wells. A sprinkler system for a large building like the proposed new Complex requires a large capacity of water with sufficient pressure, and this cannot be provided by the existing wells. The cost to install a municipal water system or develop a water reservoir and a pumping system for the new Complex would be extensive, and is considered impractical.

To meet the NBC requirements for a non-sprinklered building, the Complex was planned to be built in three different sections with each section designed to a size where a sprinkler is not required. To achieve this criteria, two permitted masonry fire walls (concrete block) are located to provide the fire needed protection. On each side of the fire wall, the building structure is independent of the structure on the other side of the wall. All doors leading in the fire walls leading from one section to the other to have the needed fire ratings.

The concept floor plan of the Complex is shown on the drawings (See Appendix D).

Elevator: The entire new Complex is proposed to be on one floor only (slab on grade). The construction of a second floor in the office block would require an elevator plus two stairwells, with an estimated additional cost of $125,000 ***for an*** elevator (elevator cab, motor and hoistway). Other factors associated with an elevator are the on-going maintenance and service costs plus the

inconvenience of an unexpected breakdown. When a breakdown occurs in a remote location, the length of time the unit is out of service is normally longer than in an urban area due to the immediate availability of service technicians.

Fortunately, the Bay d'Espoir Generating Station Site is relatively flat and there are several locations which might work to achieve the operational objectives outlined by NLH. Two such locations have been indicated on the site plan included with Appendix D. The first is located adjacent to the existing main access gate where the current security building is located. This location would function well for security purposes but also position the new complex on a cleared and level lot. The second location indicated on the site plan is near the existing helicopter pads across the road from the existing warehouse and training centre. Again, this is another readily accessible and cleared lot. Further analysis of topographic and geotechnical conditions are required to fully ascertain the optimum location for the proposed structure. These details would be available at the pre-design stage.

2.10 Cost Estimate

Detailed third-party costing for the developed concept plans is included in Appendix E, but has been summarized as follows:

Component	GFA (m^2)	GFA (ft^2)	$/$m^2$	$/$ft^2$	Estimated Cost
Warehouse (excluding racking)	1,045	11,248	$2,168	$201	$2,265,560
Maintenance Shop (excluding hydraulic lifts)	892	9,601	$2,620	$243	$2,337,040
Ancillary Services (excluding fitness equipment)	605	6,512	$2,648	$246	$1,602,040
Office (excluding furniture)	557	5,995	$2,634	$245	$1,467,138
Security (excluding security equipment)	64	689	$3,053	$284	$195,392
Powerhouse Office Renovations	200	2,153	$1,698	$158	$339,600
Site Development					$792,263
Total (EXCLUDING HST)	**3,363**	**36,198**	**$2,676**	**$249**	**$9,000,000**

Notes:

a. The above Class 3 estimate total has been rounded to the nearest thousand for estimating purposes and includes an amount for design allowance, contingencies and an amount for owner's equipment.
b. Among other things, LEED Certification and demolition/removal of existing facilities has not been included in the estimate. Refer to the detailed estimate for further exclusions.

3. Conclusions and Recommendations

The ancillary structures associated with the Bay d'Espoir Generating Station, owned and operated by Newfoundland and Labrador Hydro, have been in operation for over 50 years. In general, these structures were originally constructed to fulfill a support role for the construction activities ongoing at that time. However, over the years, Newfoundland and Labrador Hydro has adapted these structures to function in an operations and maintenance environment. This evolution in function for these structures has led to certain operational and maintenance inefficiencies. Due to the fact that the current structures are now nearing or at the end of their recognized serviceable life and have been recommended for replacement, NLH now has the opportunity to design the solution for these operational issues into the new structures.

Hatch Mott MacDonald with assistance from exp Architects and the Altus Group has provided concept plans and construction estimates meeting the outlined objectives by offering the following benefits:

- A single complex containing a warehouse block, maintenance garage block, utility block and office block all under one roof, where the reliance on vehicular travel to get from one building to the next is eliminated,
- Expanded facilities with additional work and storage space (where required by the functional program),
- Shared centralized services such as locker rooms, lunchrooms, washrooms, meeting rooms, computer workstations, etc.,
- Accessibility provisions included within the main office block, locker rooms & washrooms, lunchroom and fitness room according to the NL Buildings Accessibility Act,
- Concept plans that incorporate life safety and health standards such as: Building occupancy types, exit travel distances, access to exits, number of exits, dead end corridors, fire compartments, fire rating between suites, location of fire walls between compartments and the number of washroom fixtures,
- Female locker room and washroom facilities in anticipation of future work force diversification, and
- Renovated powerhouse office and shop area providing an office area for outside contractors/consultants while working at the plant (second floor) and a renovated first floor providing secondary shop space for the maintenance staff on "remote" location from the home base of the new Maintenance Centre.

During this building condition assessment exercise, one item arose outside the current scope of service that requires further exploration by Newfoundland and Labrador Hydro as follows.

- To properly size and plan the inventory shelving system required in the new Warehouse a thorough evaluation of the size and type of materials, supplies, parts and tools stored within the inventory system needs to be assessed. This would also include an analysis of what type of material handling equipment would be used in storing materials. It is recommended that NLH undertake this assessment prior to moving forward with the detailed design of the proposed warehouse facility.

4. List of Reference Material

Reports

RDB Engineering Limited, "Building Condition Assessment, Maintenance Garage, Carpentry Shop and Training Centre, Bay d'Espoir Hydroelectric Generating Station, Milltown, Bay d'Espoir, NL", 2012.

Drawings

B1-2107-A-17, Rev 2 – Bay d'Espoir Powerhouse – North End Lunchroom – Plan & Details El.21'-0", Newfoundland and Labrador Hydro, August 1982,

F-107-A-2 – Bay d'Espoir Development – Powerhouse Office Layout, Newfoundland and Labrador Power Commission, May 1966.

F-2000-C-120, Rev 3 – Site Plan of Hydro's Land for Power Canal, Intakes, Surge Tanks, Tailrace – Bay d'Espoir, Newfoundland, Newfoundland and Labrador Hydro, December 1978.

Bay d'Espoir Garage – Main Level Floorplan, Newfoundland and Labrador Hydro, November 2005.

Bay d'Espoir Powehouse No. 1 Evacuation Plan, Newfoundland and Labrador Hydro

Bay d'Espoir Training Centre Floorplan, Newfoundland and Labrador Hydro, November 2005.

B1-010-C-1 - Bay d'Espoir Development – Staff House – Plan & Elevations, Newfoundland and Labrador Hydro, May 1986.

Bay d'Espoir Carpenter Shop Floorplan, Newfoundland and Labrador Hydro, November 2005.

Other

Regulated Operations - Hydro Operations, (Organizational Chart) Newfoundland and Labrador Hydro, September 2013.

Hydro Generation Fleet Inventory (2012), Newfoundland and Labrador Hydro.

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Appendix A

Summary of Field Survey Notes - October 23 & 24, 2013

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Newfoundland and Labrador Hydro - Bay d'Espoir Building Needs Assessment

Summary of Field Survey Notes

Site Meetings: October 23 & 24, 2013

Opening Meeting Comments (October 23, 2013)

Present:
Levison Kearley, Bob Woodman, Karl Inkpen, Roberta Coady, Matthew Lambert (Newfoundland and Labrador Hydro)
Mike Spencer (Hatch Mott MacDonald)
Gary Walsh (exp Architects Inc.)

1. **Storage:** Lack of is huge on-site issue (problem).
2. **Existing Buildings:** Were constructed as temporary facilities at time of construction in the 1960's and taken over by NL Power after completion of construction. All need replacement except the Powerhouse.
3. **Modifications:** Many upgrades done to existing buildings over the years.
4. **Garage:** Needs to be replaced, to small, inadequate ventilation, change rooms cramped, office space limited, electrical in poor condition.
5. **Maintenance Centre:** A new building to include: repair of trucks & other vehicles, carpentry shop, welding shop, paint booth with associated change rooms, offices, kitchen/lunch rooms, storage rooms, service rooms (electrical room, compressor room), washers & dryers, tool crib, multi-purpose rooms are needed. To be properly sized and programmed, and constructed to the latest code standards for architectural, mechanical, electrical, structural and site systems. There are approximately 16 outside workers.
6. **Office Space:** Is inadequate and addition offices (private and open workstation areas) are needed.
7. **Training Centre:** The existing building is one floor, wood frame and inadequate for present day needs. There is a lack of offices, meeting rooms, and work areas.
8. **Confined Space:** Many areas on site are considered confined spaces and create access problems for staff. All new buildings to be designed to minimize confined space areas.
9. **Concept Floor Plans:** Concept plans illustrating design of new buildings and proposed renovations to any existing buildings (existing powerhouse) are required. This shall be done as part of the RFP terms of reference.
10. **Operations Staff:** The existing number of staff on-site (inside the gate) is anticipated to remain stable for the foreseeable future.
11. **Temporary Space:** The use of trailers is not considered practical.

12. **Accommodations, Offices & Drawing Storage:** Spaces for these type uses are required on site to meet present day uses and shall be included in the concept floor plans to be developed.
13. **Safety:** This is paramount on site at all times, and all procedures must be followed and Personal Protective Equipment (PPE) to be worn as required.
14. **Meeting Rooms:** The only meeting room on site is in the powerhouse where the opening meeting was held. Additional meeting rooms designed with modern ventilation, lighting, electrical, communication and acoustic systems are needed.
15. **Powerhouse Offices:** The existing offices and work areas are subject to noise and vibration interference. This is an undesired working environment and is causing fatigue and lower productivity among staff. Office and work areas isolated from the noise and vibrations are required.
16. **Programming:** In order to prepare concept floor plans and construction budgets, a functional program has to be developed for new buildings. Senior management and staff shall be interviewed regarding their specific needs and a correlation chart listing the interrelationships and recommended adjacencies to be provided by NLH.
17. **Multi-Purpose Rooms:** Need at various locations on site
18. **Main Staff:** Are located in the Powerhouse.
19. **Short-Term Planning:** Located in Training Centre.
20. **Total # of Staff:** There is approximately 80 staff on site including 7 or 8 females.
21. **Fitness Centre:** A gym with exercise and weight lifting equipment is a good idea to encourage staff well-being, fitness and overall worker satisfaction.

Security Building

1. **Existing Building:** Consists of the original gatehouse and a modular building added later. There is an approximate 6 inch differential in floor levels; the building is not barrier-free; is undersized to meet present day needs and does not have a panoramic view of the maintenance garage and carpentry shop behind. A new barrier-free designed building is required and the functional space requirements are listed below.
2. **Operational Hours & Staffing:** Is manned 24 hours per day with one (1) security attendant working a 12 hour shift.
3. **Site Location:** A new building should be constructed directly across the main road from the existing Gatehouse with a panoramic view of the main road, security gate and the existing site of the maintenance garage and carpentry shop.
4. **Design & Needs Requirements**
    - **Security /Viewing Office:** Located adjacent to the main door and Waiting Area with counters, security monitors and large windows for panoramic view of main road and adjacent site.
    - **Waiting Room:** For up to 10 visitors and furnished with chairs.
    - **Lockers:** Install a minimum of 5 lockers of sufficient size to store all clothing and equipment for all safety and security staff who are based in the Gatehouse.
    - **Fire Responders Gear:** Provide adequate space for all gear and equipment for the fire-fighting responders who are based in the gatehouse.
    - **Private Office:** Provide 1 (one) private large office sized for use by staff with door and communication services.
    - **Storage Room:** Sized to store and stack all equipment & materials needed to run the operations and activities associated with the staff of the gatehouse.
    - **First Aid:** Provide an area or room for medical equipment (examination table) and to administer first aid.
    - **Work Area:** Space needed to prepare reports and to include table, desk and shelving.
    - **Washroom:** One barrier-free washroom required.
    - **Kitchenette:** Provide area with counters and space for small fridge, microwave, sink, shelving, eating area and possibly small stove.
    - **Server Room/Closet:** Provide space for server and telephone equipment.
    - **Electrical Room/Closet:** Provide space for electrical panel.
    - **Sample Storage Room/Closet:** Provide space for water samples to be taken for off-site testing.
    - **Meeting Room:** Provide room for safety meetings. For up to six (6) persons.
    - **Janitor's Closet:** For mop, broom, bucket and cleaning supplies.

Carpentry Shop

1. **Existing Building:** Original structure built is 1960's, one floor, slab on grade, rectangular in shape with add on areas (see floor plan), large open workshop area, washroom, woodworking equipment placed throughout the facility, tool storage room, chemical storage room, dust collection mechanical room, battery charging room and Quonset hut added later and used for storage of scaffolding, ladders and other equipment. The building is considered inadequate and should be replaced. The original building footprint is approximately 20' x 80' (1,600 ft^2) and the architectural, mechanical & electrical systems are old and inadequate.
2. **Building Usage:** For carpentry, maintenance and woodworking purposes such as making cabinets, shelving, casings, painting, construction of signs up to 20' x 8' in area made outside, tools storage, scaffolding & ladders storage, paint storage. Plumbing services are also based in the building.
3. **Staffing:** A maximum of six (6) staff including one full-time carpenter are based in the building and provide carpentry services throughout the site. Staff take lunch in the maintenance garage.
4. **Location:** Placed in a new large multi-purpose maintenance building housing other services such as the vehicle repair, machine shop, welding shop, lunch room, washrooms and not located in a separate stand-alone building. This shall be more functional for staff and operational activities.

5. **Design & Needs Requirements:**
    - **Carpentry Shop Work Area:** A floor plan that is squarer than rectangular and more functional for the layout out equipment such as table saws, drills, counters, etc. A private office is also recommended and located off the shop area. An overhead crane sized to suit is recommended and these ideas were proposed by the staff.
    - **Tool Crib Room:** With shelving for storage of tools and certain parts. An inventory of all tools, parts and equipment to be is needed to determine the proper size of room.
    - **Offsite Equipment Storage Room:** For storage of scaffolding, ladders, tarpaulins and other equipment and materials that are typically used for outdoor and indoor service work such as painting. An overhead door is required and an inventory of all tools, parts and equipment to be is needed to determine the proper size of room.
    - **General Storage Room:** For standard items such as building materials, plumbing supplies, paint brushes, brooms/mops, cleaning materials, etc.

- **Chemical Storage Room:** For storing paints, solvents and all associated materials for services provided based in the Carpentry Shop.
- **Battery Charging Room/Closet:** A small space with shelving is needed.
- **Sign Painting Room:** Located indoors adjacent to the Carpentry Shop Work Area for the purpose of having all painting carried indoors under controlled conditions and not done outdoor as is the present situation. Either a small overhead door or double man doors with direct access to the outside is recommended.
- **Lockers:** Located either in a new Multi-Purpose Building or within the Carpentry Shop.
- **Service Rooms:** Electrical & mechanical shall be determined if need by engineers.
- **Washroom:** Located off the Work Area floor or staff directed to common washroom adjacent to change rooms.

Multi-Purpose Maintenance Garage

1. **Existing Building:** Steel frame structure built in 1960's, slab on grade, rectangular in shape with add on areas for a lunch room/meeting room/compressor room off the machine shop (see floor plan), with a second floor at one end for locker rooms, and an addition used off the machine room for kitchen/lunchroom and mezzanine area in the center of the building used as a locker room. The approximate first floor size (not including add-on) is 225' x 39' (8,775 ft^2). The building is undersized to meet present day needs and the architectural, ventilation, mechanical and electrical conditions are inadequate and many of the systems do not meet present day code standards. It is recommended that the building be replaced and potentially redeveloped into a storage facility.
2. **Building Usage:** Includes the following areas (a) vehicle repair with floor pit in one bay, (b) machine shop with tool room and office, (c) welding shop with manual painting services within (d) lunch room & kitchen on second floor and (e) private offices on first and second floors.
3. **Staffing:** Approximately 25 staff is based in the existing maintenance garage including heavy duty mechanics, machinists and welders.
4. **New Building:** Construct a new multi-purposed maintenance garage to include the following: (a) vehicle maintenance & repair shop, (b) machine shop, (c) welding shop, (d) carpentry shop and (e) associated common spaces such as: private offices, multi-purpose rooms (for preparing time sheets, work orders and conducting safety meetings), change/locker rooms, washrooms, washer & dryers, lunch room & kitchen, storage rooms, service rooms (electrical, mechanical, compressor) battery charging rooms.
5. **Design & Needs Requirements**

   Vehicle Maintenance Repair Shop

   - **Staffing:** There is a maximum of 4 mechanics on site.
   - **Repair Shop Garage**: The existing shop area is approximately 105' x 39' (4,095 ft2) including shop floor and associated rooms with four service bays accessed by three (3) overhead doors on one side (south). The present day requirements is for double the floor area (8,190 ft2) with overhead doors (minimum 20" high) and on both sides (north and south facades) for drive thru convenience and to create a safety condition where vehicles drive forward out of the building as opposed to backing out. Overhead door sizes (height & width) to be specified to provide sufficient clearances for all vehicles. An inventory of vehicles sizes to be carried to ensure proper doors are installed.

- **Service Bays**: Four bays are required with individual overhead door access and designed to be longer and wider than the existing bays to create space to service modern day vehicle sizes. One bay to have service pit and a second bay to have hydraulic lift (18,000 lbs-to be confirmed). An overhead crane (2,500 lbs-to be confirmed) is needed to service the garage bays. One bay to have a minimum ceiling clearance height of 30' in order to work on largest boom truck. Install sufficient work counters about bays. Provide space for welding equipment. It is desirable for service bays to have its' own welding equipment so not to have to transport it back and forth from the Welding Shop on a regular basis.
- **Storage Room:** Used to store a variety of items such as tires, parts and materials and to be a minimum of twice the size of existing storage room with shelving.
- **Tools Storage Room:** All tools in existing building kept in cabinets on shop floor. Provide new room with shelving to store all tools. An inventory of all tools, parts and equipment to be is needed to determine the proper size of room.
- **Fall Arrest Training Area:** Provide space adjacent to one of the service bays for the installation of fall arrest equipment and training.
- **Fall Arrest Anchor Points:** Provide anchor points on roof in all service bays.
- **Janitor's Closet:** For mop, broom, bucket and cleaning supplies.

6. **Machine Shop (Sandy Organ & Lorne Oxford)**

- **Staffing:** There are approximately 14 millwrights and welders employed on site.
- **Machine Shop Work Area:** The existing shop area is considered too small, lacks storage areas and paint booth and also has insufficient mechanical ventilation. A space approximately double the size of the existing floor area (39'x 48' =1,872 ft^2) is desirable and result in a proposed a work area of 3,744 ft^2. This will create additional space about existing machinery and provide more floor area to install new machinery such as a steel sheet bending press. An overhead crane (approximate capacity of 4,500 lbs-to be confirmed) is required and needs to travel between the Machine Shop and Welding Shop. Two overhead doors are recommended on one side only and lined up with steel cutting saw tables.
- **Paint/Spray Booth:** A paint booth with proper ventilation is recommended and placed adjacent to the Work Area. A recommended size: 20' x 35' (700 ft^2).
- **Storage Room:** To be double size of existing room. A recommended size: 20 'x 30' (600 ft^2) with shelving.
- **Lockers:** The machine shop has a separate locker room (mezzanine) off the Vehicle Service Bays designated used by the machinists and welders. A separate Locker Room with large lockers (total 14) is recommended to be provided in new building.

- **Lunch Room:** The existing building has a lunch room/meeting room off the Machine Shop and it is suggested to provide a similar type and size room in the new building. A recommended size: 15' x 27' (405 ft^2).
- **Washrooms:** A male and female washroom is recommended adjacent to the Vehicle Maintenance Repair Shop and the Machine Shop.
- **Office:** Provide one (1) general office with four or five computers for staff to issue work orders, purchase orders and prepare time sheets.
- **Compressor Room:** The existing room is adjacent to the Lunch Room/Meeting Room and is very noisy. In a new building, the compressor and all loud and noisy equipment to be separated from work areas and placed in acoustically treated rooms.
- **Janitor's Closet:** For mop, broom, bucket and cleaning supplies.

7. **Welding Shop**

    - **Location:** Placed immediately adjacent to Machine Shop with the overhead crane rails running between both areas.
    - **Work Area:** Develop a curtain system between both areas to minimize movement of fumes. A direct access at the floor level between both areas is necessary. Access doors large enough to move materials for cutting and painting are needed. The existing work area is considered undersized and needs to be doubled. Recommended size: (30' x 60' = 2,340 ft^2). Overhead doors to the outside are required.
    - **Storage Room:** Provide space with shelving. Recommended size: 15' x 20' (300 ft^2)
    - **Associated Rooms:** The staff based in the Welding Shop to use the areas associated with the Machine Shop: lunch room/meeting room, washrooms, paint booth.

Training Centre

- **Existing Building**: A one storey, wood frame structure that is considered to small and inadequate to meet present day needs. A new one storey building is recommended, with the listed areas and spaces.
- **Training Room:** To accommodate up to eighty (80) persons. A seminar/classroom type space with sufficient lighting, data, power and communications systems. Recommended size: 24' x 50' (1,200 ft^2 – to be confirmed). Provide adjacent Storage Room for tables, chairs, etc. Proposed size: 10' x 15' (300 ft^2).
- **Meeting Room/Library:** To store books, computers and hold meetings for up to 10 persons. Proposed size: 15' x 20' (300 ft^2).
- **Supervisor Office:** A private office. Proposed size: 12' x 16' (192 ft^2)
- **Planners Office:** Consisting of 4 workstations (6'x 8' each). Proposed size: 25' x 25' (625 ft^2).
- **Computer Room:** Provide six (6) desks. Proposed size: 18'x 12' (216 ft^2).
- **Plotter/Printer Room:** Provide space for printing equipment and counters off Planners Office. Proposed Size: 12' x 18' (216 ft^2).
- **Lounge:** For staff and visitors for breaks during seminars and work. Proposed size: 20' x 20' (400 ft^2).
- **General Office:** Provide six (6) workstations to complete work orders, issue purchase orders and complete time sheets. Proposed size: 25 ' x 30' (750 ft^2).
- **Kitchenette:** Provide space in a central location for a fridge, microwave, sink, coffee maker, counters and seating area. Proposed size: 12' x 20' (240 ft^2).
- **General Storage Room:** Multi-purpose storage space with shelving for various materials and supplies. Proposed size: 12' x 20' (240 ft^2).
- **Washrooms:** Provide barrier fee male and female washrooms.
- **Janitor's Closet:** For mop, broom, bucket and cleaning supplies.

Warehouse & Storage Building

- **Existing Building**: Consists of a Quonset hut and a pre-engineered building with an outdoor yard. The building is undersized in area and height and the existing insulation in certain roof areas is constantly falling off and has to be continually repaired. A new building programmed to suit is recommended. The suggested areas are listed.
- **Staffing**: There is four (4) staff based in the warehouse.
- **Receiving Area**: Located at the main delivery overhead door and requires clear layout space for arriving all materials, parts and equipment to be recorded and counted. A recommended minimum size: 30' x 40' (1,200 ft2).
- **Private Office**: Adjacent to Receiving Area and for use by warehouse manager. Proposed size: 12" x 15" (180 ft2).
- **General Office**: For use by other three staff, furnished with desks, computers, filing cabinets and counters. Propped size: 16' x 24' (384 ft2).
- **Office Storage Room**: For office supplies. Proposed size: 8' x 10' (80 ft2).
- **Main Storage Area**: Immediately adjacent to Receiving Area and up to 20 feet in height. To include stacking shelves wide enough for pallets and hand placed items. Aisles widths designed to accommodate fork lifts. A security inventory control monitory system is recommended. Proposed size: 75' x 250 (18,750 ft2)'.
- **Washrooms:** Provide one (1) barrier fee washroom.
- **Janitor's Closet:** For mop, broom, bucket and cleaning supplies.

Bunkhouse for Accommodation

- **Existing Building:** There is a small wood frame hostel type bunkhouse but an interior visit was not carried out. It is suggested it be replaced with a new one storey building designed to barrier-free standards and include the following spaces.
- **Bedrooms:** Provide four (4) guest rooms for visiting staff and contractors. Proposed size: 12'x16' with closet, bed, dresser, chair and work table.
- **Living Room:** Supply with standard furniture and television.
- **Kitchen:** Supply with fridge, range/stove, microwave, double sink, dishwasher, counters and cupboards & pantry closet.
- **Dining Area:** A room with a table and chairs for six persons.
- **Washroom:** Provide one (1) with water-closet, lavatory, tub/shower & vanity.
- **General Storage/Laundry Room:** For multi-purpose use (towels, washroom & kitchen supplies, cleaning supplies, washer & dryer).
- **Linen Closet:** For sheets, blankets and pillows.

Powerhouse (South Wing – First and Second floors)

- **Existing Building:** To be kept and the Control Room to remain in existing location.
- **Existing Lunch Room:** Located on the second floor and has been recently renovated and to remain.
- **Managers Offices Suite & Foyer:** Located on second floor and to remain. The offices immediately adjacent to the turbines room is subject to sound and vibration interference and should be relocated.
- **Electricians:** Are based on the first floor to be relocated to another new building. There are a maximum of 11 workers on site sharing 4 workstations. The existing space is undersized and needs to be increased in area
- **P&C Office Space:** Located on the first floor, it is undersized and needs to be doubled in area.
- **Repair Space:** Is undersized and additional space is required for the work area and storage area. An area a minimum of double the size is recommended.
- **Existing Planning Office Space Suite (first floor):** Undersized and needs to be increased in area. Associated spaces include a larger meeting room and library resource room.
- **Recommendations:**
  - **Second Floor:** Managers offices suite, Control Room and Lunch Room to remain. An acoustical study to improve sound and vibration control is recommended to be carried out.
  - **First Floor:** Relocate Planners offices to new office building; relocated P&C office space to new office building and relocate electricians offices (workstations) to new office building. In vacant space, develop a meeting room, library resource room, larger Repair Space and Storage Room.

Powerhouse (North Wing – First and Second floors)

- **Lunch Room:** Located on the second floor, this space is not heavily used and is subject to noise and vibration interference.
- **Storage Room:** Located on the first floor, this space experiences leaks through the foundation walls permanently occupied and is only used as secondary storage space.

Close Out Meeting

October 24, 2013

Present:
Levison Kearley, Bob Woodman, Karl Inkpen, Derek Maye, Alvin Crant, Matthew Lambert (Newfoundland and Labrador Hydro)
Mike Spencer (Hatch Mott MacDonald)
Gary Walsh (exp Architects Inc.)

- Future needs have been addressed and discussed over the past two days and a functional program shall be developed and forwarded for review and comments.
- Additional staff is required on site for certain positions.
- Supervisors maintain direct contact with most staff in their divisions.
- Planners and schedulers should be located in same office area.
- Planners and schedulers require direct lines of communications to supervisors.
- Certain staff in Powerhouse could be relocated to new office building.
- Consolidating office space is considered a good planning concept.
- NLH to provide HMM with organizational chart listing the required adjacencies and direct relations of each department and division to one another. This is critical in preparing concept floor plans and construction budgets.
- All division managers to contact Mike Spencer or Gary Walsh regarding other design and planning ideas that they consider important within the near future.
- New Maintenance Garage should be located as close as possible to Powerhouse. This will reduce travel time.
- Plant maintenance staff in Powerhouse could possibly relocated to new a building.

Appendix B

Site Photos – October 23 & 24, 2013

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Security Building

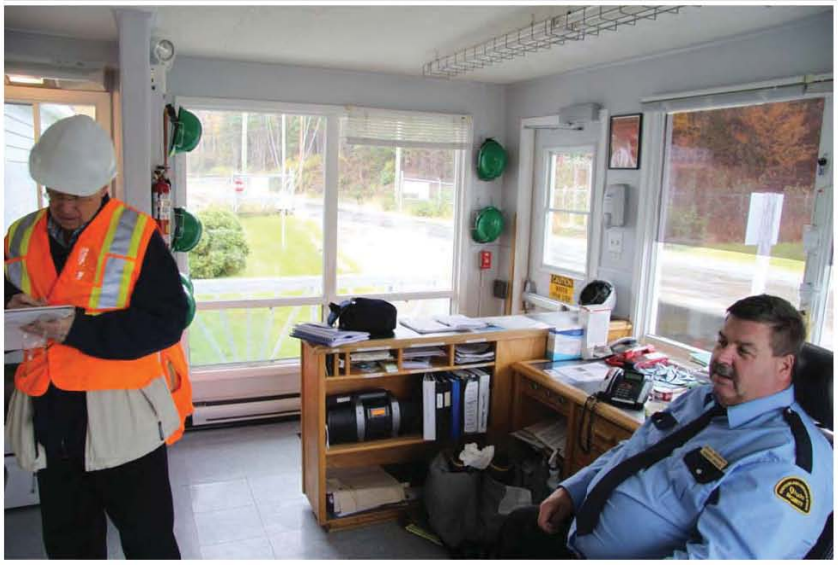


Picture 1 – Rear of Security Building

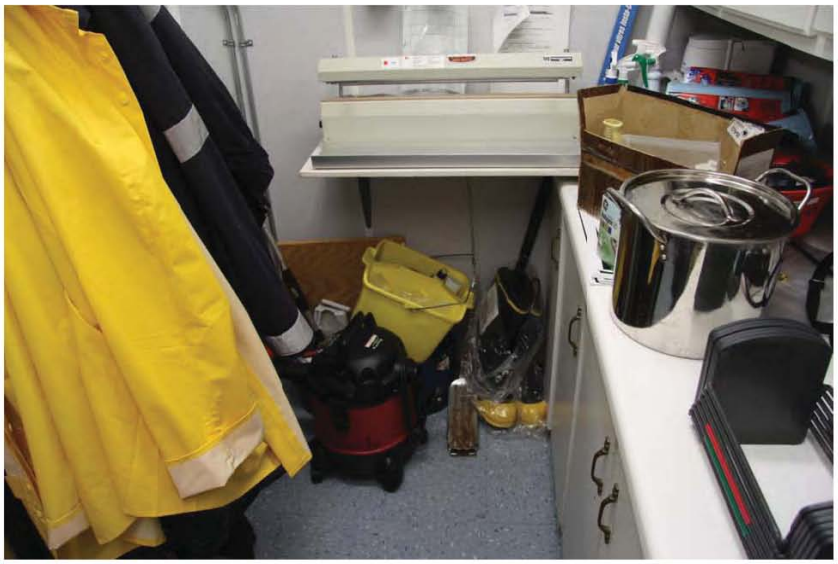


Picture 2 – Office of Security Attendant

Security Building



Picture 3 – View of Visitors Entrance



Picture 4 – The building lacks adequate storage.

Security Building

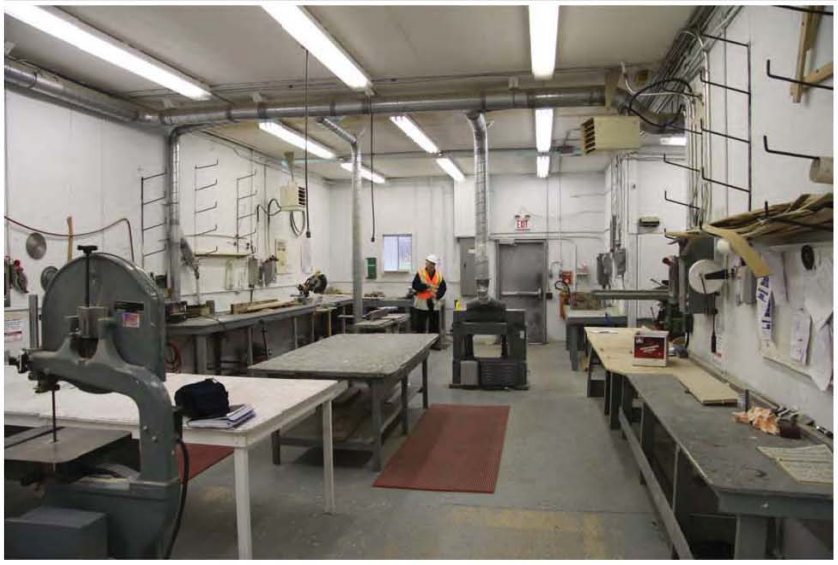


Picture 5 – The rear room is used for multiple purposes including emergency first aid services, a meeting room, storage area, etc.

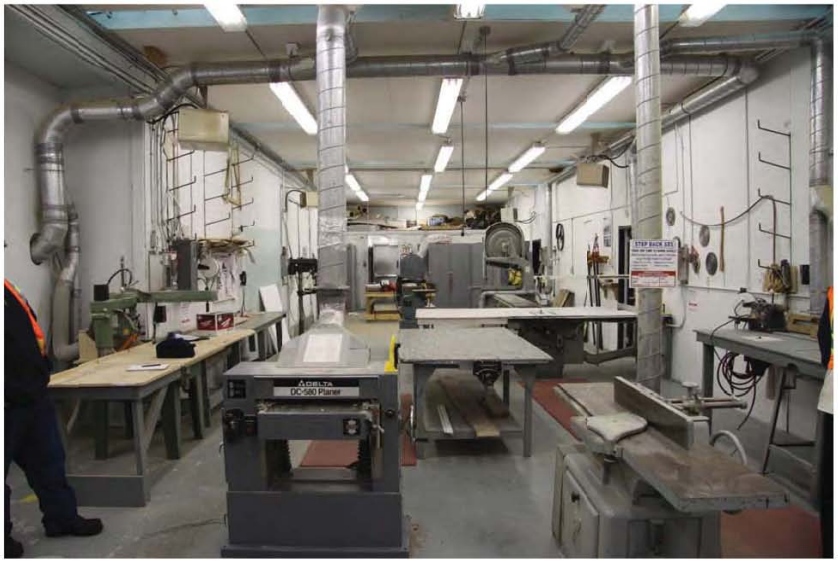


Picture 6 – Environmental monitoring sample storage

Carpentry Shop



Picture 1 – View of Large Work Shop Area



Picture 2 – View of Stationary Carpentry Equipment

Carpentry Shop



Picture 3 – View of Tool and Small Equipment Storage Area



Picture 4 – Quonset Hut Storage Area for Larger Equipment and Materials

Carpentry Shop



Picture 5 – View of Door into Vegetation Control Chemical Storage Room

Maintenance Garage

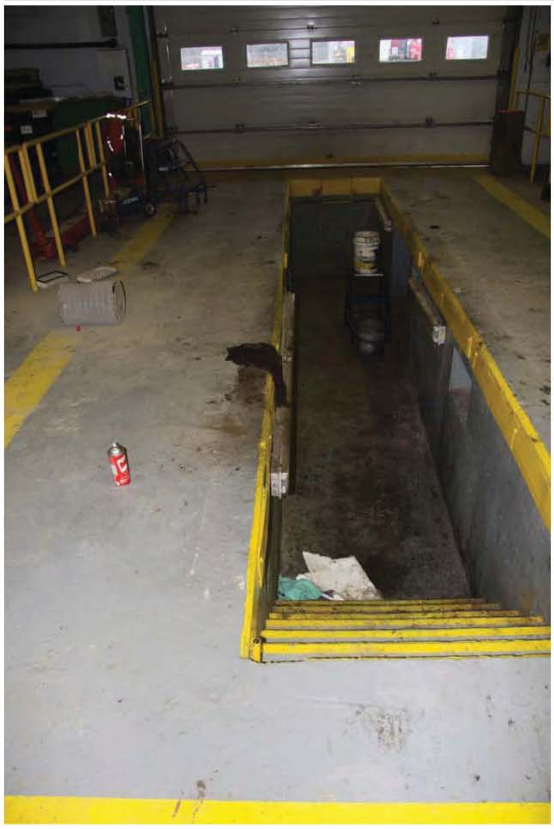


Picture 1 – South elevation of Existing Maintenance Garage



Picture 2 – Vehicle Maintenance Area – Note Maintenance Pit and Offices and Mezzanine in Background

Maintenance Garage



Picture 3 – Vehicle Maintenance Pit

Maintenance Garage



Picture 4 – Dover Company Rotary Automotive Lift, 18,000 lbs



Picture 5 – Name Plate on Automotive Lift

Maintenance Garage



Picture 6 – Spacious Lunchroom for General Maintenance Workers



Picture 7 – Kitchen Area of Lunchroom

Maintenance Garage

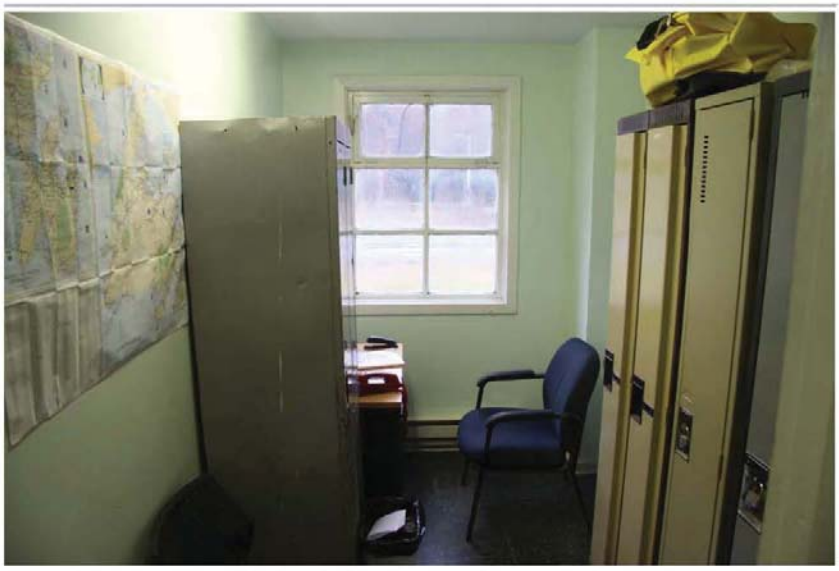


Picture 8 – Locker Area for General Maintenance Workers



Picture 9 – Large Lockers used by Heavy Duty Mechanics and General Maintenance Workers to Store Personal Effects, PPE and Work Clothes – Size: 30" W x 18" D x 72" H

Maintenance Garage



Picture 10 – Time Entry/Work Order Work Station in General Maintenance & Heavy Duty Mechanical Area (Note the presence of more lockers)



Picture 11 – One workstation services approximately 14 workers



Picture 12 – Washer and Dryer near North end of Garage.



Picture 13 – Washroom on North end.

Maintenance Garage



Picture 14 – General Maintenance Lockers – First Floor North End



Picture 15 –More General Maintenance Lockers on first floor – North end

Maintenance Garage



Picture 16 – View of Garage looking towards Machine Shop



Picture 17 – Storage Rooms and Mezzanine on South end of Vehicle Maintenance Area

Maintenance Garage



Picture 18 – Mechanical Maintenance "A" Locker Room



Picture 19 – Storage Area on Top of First Floor Office

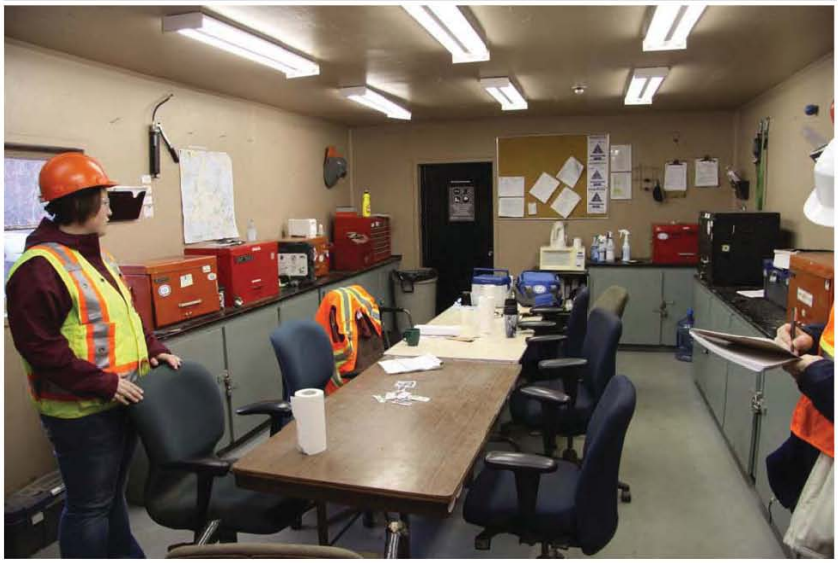


Picture 20 – Fall Arrest/Ladder Safety Training Area



Picture 21 – Parts Storage for Vehicle Maintenance

Maintenance Garage



Picture 22 – Makeshift Mech. Maintenance "A" Lunchroom/Tool Storage Area



Picture 23 – Another view of Maintenance "A" lunchroom. Note coverall rack on back wall.

Maintenance Garage

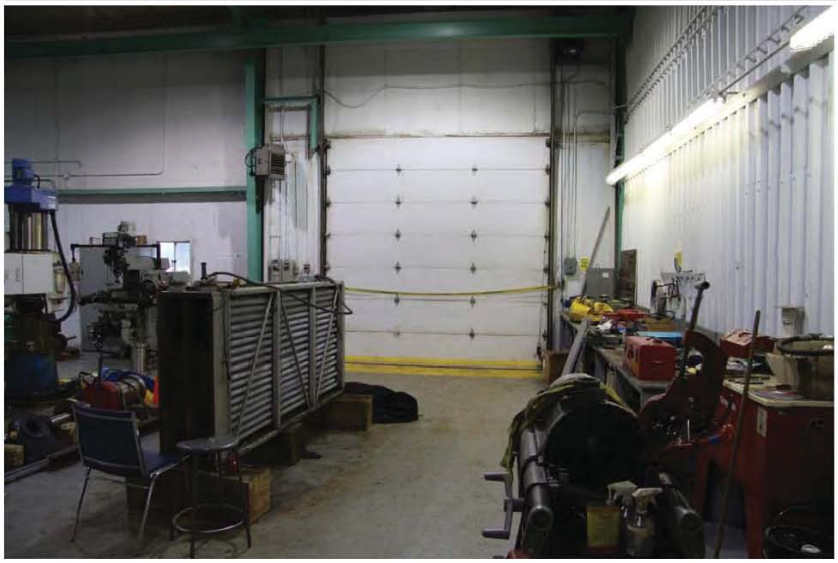


Picture 24 – Service Air Supply Room off the Lunchroom



Picture 25 – Machine Shop with tool room and small office in background

Maintenance Garage



Picture 26 – Overhead Door in Machine Shop



Picture 27 – Another view of Machine Shop

Maintenance Garage



Picture 28 – Office off Machine Shop with three computer terminals



Picture 29 – Tool Room off Machine Shop

Maintenance Garage



Picture 30 – Another view of the Tool Room



Picture 31 – Welding Shop at South End of Garage

Maintenance Garage



Picture 32 – Another view of the Welding Shop



Picture 33 – 1.5MT Overhead Crane servicing Welding and Machine Shops



Picture 1 – Freightliner M2, 52K Chassis 119 CA Dump Truck (Fleet #4485)



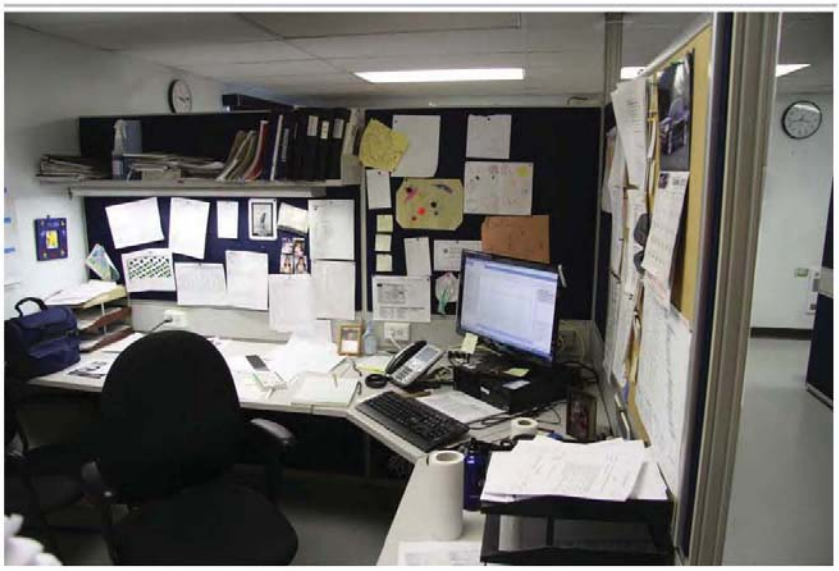
Picture 2 – Freightliner FL80 Boom Truck (Fleet # 4473) – ***Non Hydro Generation Asset***

Heavy Equipment



Picture 3 – JCB Backhoe Loader, 214S, 25,000 kg, 4X4 (Fleet #9628)

Training Centre

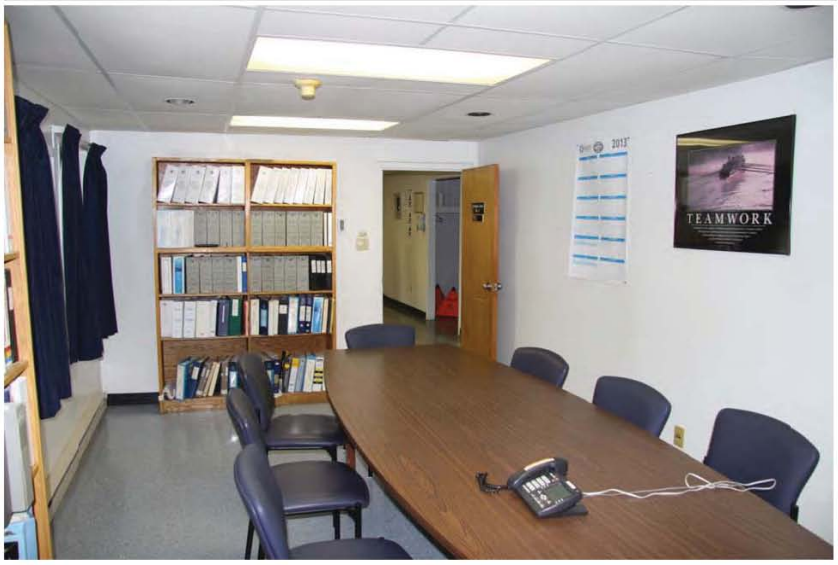


Picture 1 – Short–Term Work Planning Group in Training Centre



Picture 2 – Cubicles housing Short–Term Planning Group

Training Centre



Picture 3 – Conference Room No. 3 off Short-Term Planning Area. Note that traffic must travel through conference room to areas beyond

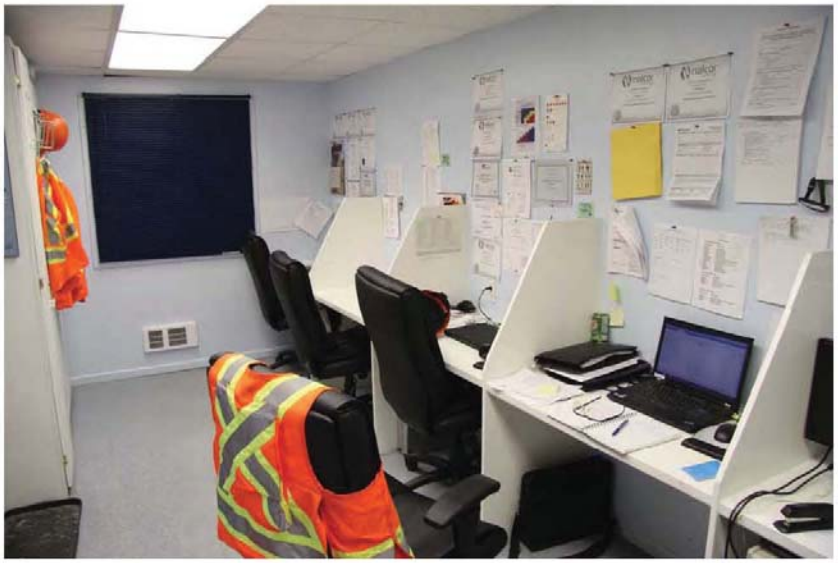


Picture 4 – Computer Training Area

Training Centre

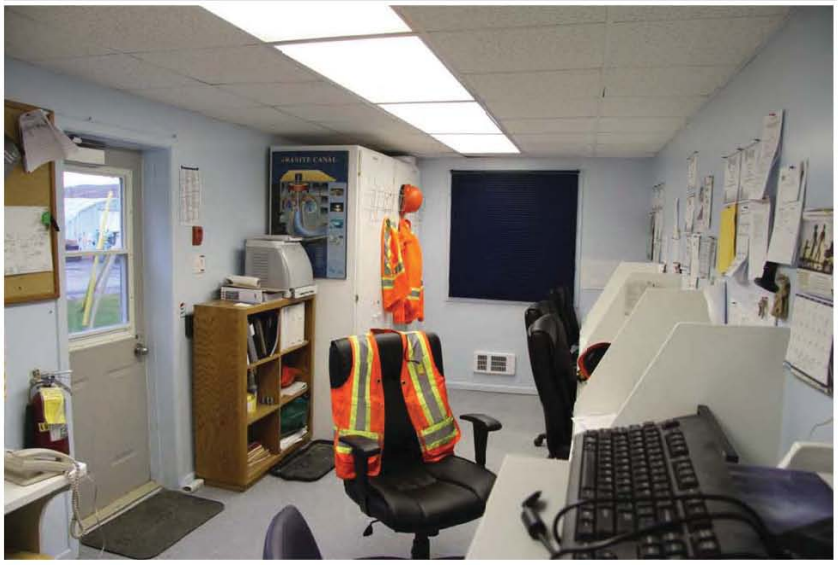


Picture 5 – Large Meeting Area



Picture 6 – Tech/Operations (Eastern) Office

Training Centre



Picture 7 – Tech/Operations (Eastern) Office



Picture 8 – Lunchroom/Kitchen

Training Centre



Picture 9 – Washroom



Picture 10 – Employee Lounge Area

Training Centre



Picture 11 – Dining Area used for functions



Picture 12 – Commercial Sized Kitchen associated with Dining Area



Picture 13 – Hallway into former employee sleeping accommodations area



Picture 14 – One of the bedrooms

Warehouse



Picture 1 – Quonset Hut Style Warehouse as viewed from receiving area



Picture 2 – The curved roof line limits storage capability of shelving units. All items are man-handled onto and out-of shelving units including heavy motors.

Warehouse



Picture 3 – View of storage over office area



Picture 4 – Capital equipment storage area in rear of warehouse. Much of the storage is ineffective and not readily accessible.



Picture 5 – Lunchroom/Kitchen area



Picture 6 – Washroom

Warehouse



Picture 7 – Computerized Inventory Workstation

Powerhouse Offices/Control Room Area



Picture 1 – View of Office Area from Parking Lot. Note that the entrances are not wheelchair accessible.



Picture 2 – Main Foyer into Second Floor Office area at Powerhouse

Powerhouse Offices/Control Room Area



Picture 3 – Another view of main foyer looking at reception desk



Picture 4 – Typical Second Floor Office

Powerhouse Offices/Control Room Area



Picture 5 – Lunchroom for Second Floor office area

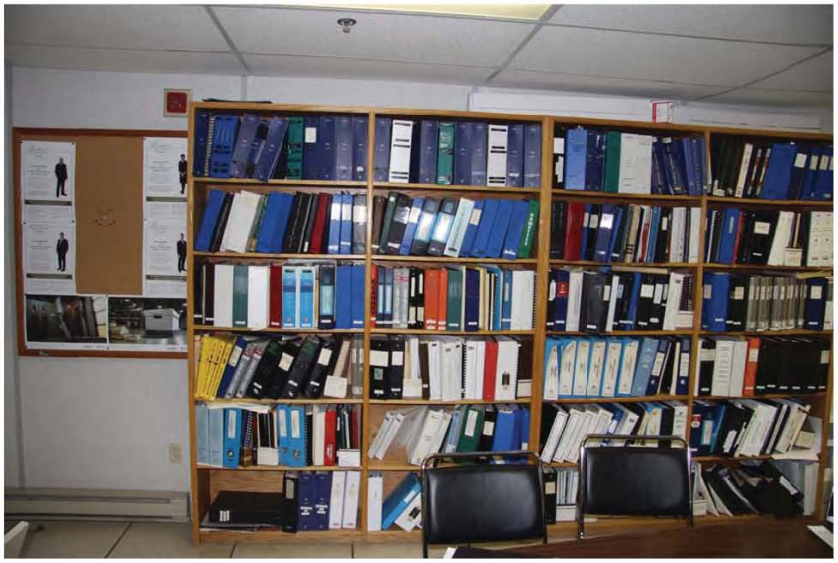


Picture 6 – Dedication Plaque in Main Foyer

Powerhouse Offices/Control Room Area

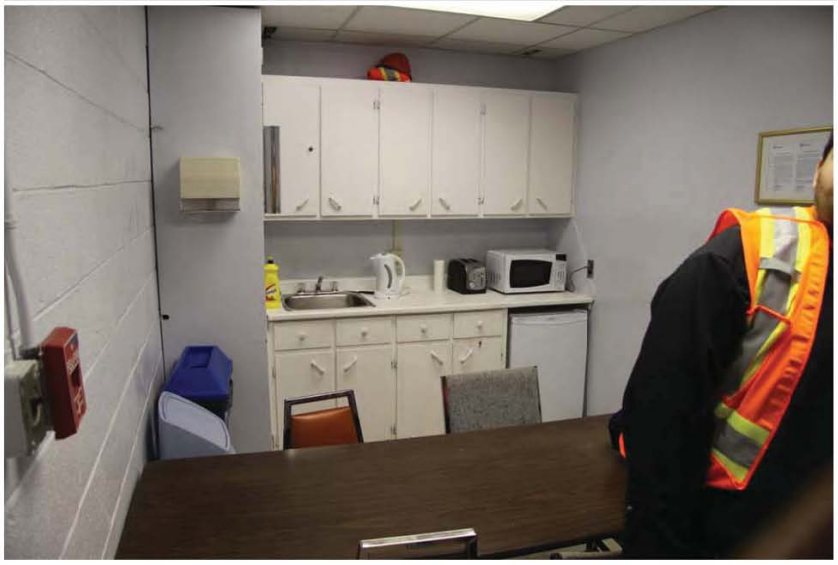


Picture 7 – Library/Conference Room on First Floor



Picture 8 – Another view of library

Powerhouse Offices/Control Room Area



Picture 9 – First Floor Lunchroom



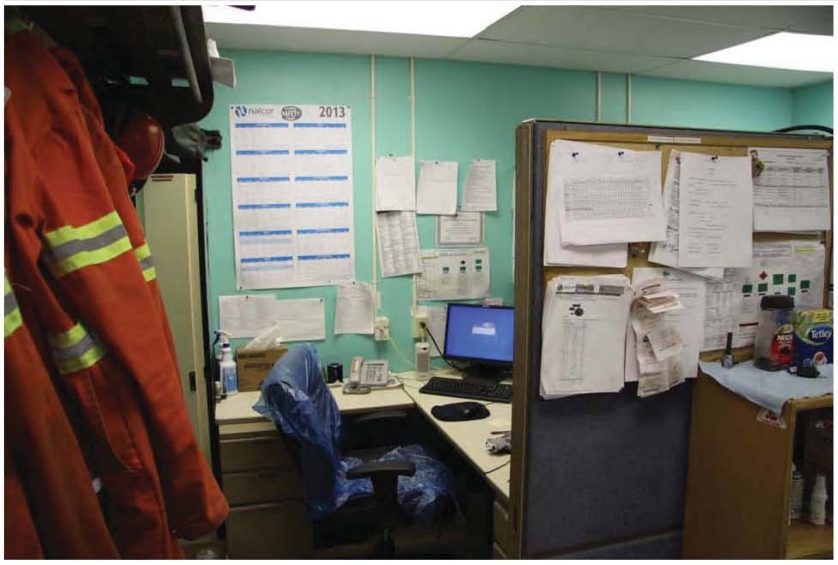
Picture 10 – Control Room Kitchen/Lunchroom

Powerhouse Offices/Control Room Area



Picture 11 – Control Room Storage Lockers

Powerhouse Electrical Shop



Picture 1 – Electrical Cubical Area



Picture 2 – Another view of the Electrical Cubical Area. This area is very congested.

Powerhouse Electrical Shop



Picture 3 – Coverall storage along walls in cubical area



Picture 4 – Electrical/P&C Shop Area

Powerhouse Electrical Shop



Picture 5 – P&C Technologists Work Desk



Picture 6 – Storage Area and Work Area is insufficient

Powerhouse Electrical Shop



Picture 7 – P&C Technologists Cubical Area



Picture 8 – Storage Locker for P&C Technologists tucked in corner of space. This area is very congested.

Appendix C

Building Code Review

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NALCOR – Bay D'Espoir	**Building Code Review**	2013-12-19

Code references are for the National Building Code (NBC) Division B, except where noted otherwise. References to the NFPA Life Safety Code are referenced (LSC).

Observations:

GENERAL

BUILDING TYPE	Multi-purpose
OCCUPANCIES	Group D, *business and personal services occupancy* (offices and other activities such as fitness areas) Ref. A-3.1.2.1.(1)
	Group F, Division 2, *medium hazard industrial occupancy* (warehouse, and shops) Ref. A-3.1.2.1.(1)
TOTAL BUILDING AREA	~ 3055 m² Ref. NBC Division A 1.4.1.2
No. STOREYS	1 Ref. NBC Division A 1.4.1.2
No. STREETS	3 *streets.*
NON-SPRINKLERED	No sprinkler system. (Given)
COMBUSTIBITY	*Combustible* and *noncombustible* (pre-engineered building, wood frame construction, some concrete block)
PART 3 BUILDING	Because of the *floor areas* and the *occupancies* the overall *building* is considered to be a Part 3 Building. Ref. NBC Division A 1.3.3.2.(1)(c)
MAJOR OCCUPANCY	This *building* contains more than one *major occupancy*. Ref. 3.2.2.8.(1)

DRAFT

OVERRIDING OCCUPANCY

Where a building contains more than one *major occupancy*, the most restricted *occupancy* shall apply to the whole *building*.
Ref. 3.2.2.6.(1)

In determining the fire safety requirements of a *building* in relation to each of the *major occupancies* contained therein, the *building height* and *building area* of the entire *building* shall be used.
Ref. 3.2.2.5.(1)

In the case of the whole building, the Group F, Division 2 *occupancy* maybe the most restrictive.

GOVERNING ARTICLES (1)

The closest governing Article to cover the Group F, Division 2, *medium hazard industrial occupancy* is 3.2.2.76. This *building* meets all the requirements of this Article except that the total *floor area* of this *occupancy* is ~ 3055 m^2 which is in excess of the maximum permitted floor area of 1500 m^2.

DIVIDED BUILDING

A structure can be divided into smaller portions creating (for the purposes of the building code) separate *'buildings'*. These *'buildings'*, because they are smaller, are easier to make meet the requirements of the building code.

The 'dividers' are called *'firewalls'*.

FIREWALL LOCATION (1)

A possible location would be to put a *firewall* between the Group D *occupancy* and the Group F, Division 2 *occupancies*. However, there is a change in *building* construction type at the interface of the Welding Shop and the Carpentry Shop. This is still an acceptable location because most of the industrial activities would be in one *'building'* while the other would contain mostly *business and personal services occupancies*. (See firewall FW1 on drawing SK2.)

DRAFT

GOVERNING ARTICLES (2)

With the addition of the Carpentry Shop and the P & C Shop into the *building* containing the Group D *occupancy* the floor area of this *occupancy* is ~ 1268 m^2.

The closest governing article to cover the Group D, *business and personal services occupancy* is 3.2.2.60. This building meets all the requirements of this Article including the floor area of ~ 1268 m^2 which is in less than the maximum permitted floor area of 1500 m^2.

GOVERNING ARTICLES (3)

With the loss of the Carpentry Shop to the Group D side of the *firewall* the total floor area of the Group F, Division 2 *occupancy* is ~ 1788 m^2 which still does not meet the floor area limit (1500 m^2) of Article 3.2.2.76.

This means a second *firewall* will have to be used.

FIREWALL LOCATION (2)

The next appropriate location to put a *firewall* is between the Warehouse and the Shops again creating two *buildings*. The area of the Warehouse would now be ~ 1033 m^2 and the area of the Shops would be ~ 755 m^2 both of which are less than 1500 m^2 and meet the requirements of Article 3.2.2.76.
(See *firewall* FW2 on drawing SK2.)

DIVIDED BUILDING

The *building* is now divided into 3 portions which can now be treated as separate *buildings* each one meeting the code requirements.

One *'building'* contains the Warehouse and has a Group F, Division 2 *medium hazard industrial occupancy*.

The second *'building'* contains the Vehicle Maintenance and has a Group F, Division 2 *medium hazard industrial occupancy*.

The third *'building'* contains the Offices and has a Group D *business and personal services occupancy*.

(See drawing SK1.)

DRAFT

'OFFICE BUILDING'

The 'office *building'* is made up primarily of offices but still has the Carpentry Shop and P&C Shop.

The area of these shops is ~ 170 m^2. The area of the entire 'office *building'* is ~ 1268 m^2.

This means that the area of the shops (Group F, Division 2 *occupancy*) is greater than 10 % of the entire office floor area making the shops a major occupancy.

Ref. 3.2.2.8.(1)

As previously discussed in 'OVERRIDING OCCUPANCY' the fire safety requirements must take on those of the most restrictive occupancy.

Ref. 3.2.2.6.(1)

The 'Office building' (Group D) is governed by Article 3.2.2.60 and the shops (Group F, Division 2) are governed by Article 3.2.2.76. For the purposes of this building the requirements are identical therefore there are no overriding requirements.

FIREWALLS

FIRE-RESISTANCE RATING

The *firewalls* separate '*buildings'* containing a Group F, Division 2 *major occupancy*.

Therefore the *firewalls* must have a *fire-resistance rating* of not less than 4 h.

Ref. 3.1.10.2.(1)

CONSTRUCTION

Firewalls must be of *noncombustible construction* and except for closures, receive their *fire-resistance rating* from masonry or concrete.

Ref. 3.1.10.2.(1) and (3)

DRAFT

CONTINUITY

The *firewalls* must extend from the ground continuously through, or adjacent to, all *'buildings'* so separated.

Because the *buildings* are not of reinforced concrete the *firewall* cannot terminate at the underside of the roof structure and therefore will have to continue up to form a parapet.

Ref. 3.1.10.3.(1) and (2)

PARAPETS

Because the *firewalls* have to have a *fire-resistance rating* of 4 h the parapets will have to extend not less than 900 mm above the roof surface.

Ref. 3.1.10.4.(1)(b) and (2)

FIRE-RESISTANCE RATINGS

FIRE SEPARATION

A *fire separation* is a construction assembly that acts as a barrier against the spread of fire. It may, or may not, be required to have a *fire-resistance rating*.

Ref. NBC Division A 1.4.1.2

Fire separations are required to be constructed as continuous elements e.g. from floor to underside of a floor or roof assembly.

Ref. 3.1.8.3

WELDING SHOP

Welding operations shall be carried out in a room with a minimum fire-resistance rating of 1 h.

Ref. 3.3.1.25.(1)(a)

VEHICLE MAINTENANCE (Repair Garage)

In this project the Vehicle Maintenance area has been combined with the machine shop and will take on the requirements of a *repair garage*.

DRAFT

A *repair garage* and its ancillary spaces must be separated from other *occupancies* by a *fire separation* having a *fire-resistance rating* not less than 2 h.

Ref. 3.3.5.5.(1)

As the Welding Shop is adjacent to the Vehicle Maintenance the walls will now have a *fire separation* with a *fire-resistance rating* of 2 h instead of the 1 h rating previously determined.
(See FS on drawing SK2. Welding Shop is identified as WS on drawing.)

JANITORS' ROOM

This room requires a *fire separation* with a minimum *fire-resistance rating* of 45 min.

Ref. 3.3.1.21

ELECTRICAL ROOM

The Electrical Room does not require a fire-resistance rating unless it contains electrical equipment required to be in a service room in accordance with CSA C22.1 CANADIAN ELECTRICAL CODE.

This does not include rooms which only contain electrical panels.

Therefore, no *fire-resistance rating* is required.

FIRE SEPARATIONS – MAJOR OCCUPANCIES

Major occupancies must be separated from adjoining *major occupancies* by *fire separations* having a *fire resistance rating* conforming to Table 3.1.3.1.

Ref. 3.1.3.1.(1)

The *fire separation* between the Carpentry Shop/P&C Shop does not require a *fire-resistance rating*.

Ref Table 3.1.3.1

Firewall FW1 provides the other *fire separation*.

DRAFT

EXITING - (WAREHOUSE)

NUMBER OF EXITS

Minimum of two *exits* required.

Ref. 3.4.2.1 (1)

Actual numbers and locations of *exits* will be determined at a later date.

MINIMUM DISTANCE BETWEEN EXITS

Floor area does not have *public corridors*.

Division A 1.4.1.2.(1)

Minimum distance is ½ the maximum diagonal dimension of the *floor area* (but not less than 9 m – not a *public corridor*).

Ref. 3.4.2.3.(1)(b)

Maximum diagonal distance is ~ 51 m.

½ x 51 m = 25.5 m (which is greater than 9 m)

MAXIMUM TRAVEL DISTANCE TO EXITS

Maximum permissible travel distance from anywhere in the floor area to an *exit* is 30 m

Ref. 3.4.2.5 (1)(f)

This requirement will result in a number of pedestrian doors around the perimeter of the Warehouse for exiting purposes. Overhead doors cannot be included in this number.

It is recommended that the *horizontal exit* in the *firewall* FW1 (to the Vehicle Maintenance area) not be included in this number as there may be times when it is locked.

See NFPA Life Safety Code Handbook 2009 for requirements for travel distance.

LSC 7.6.1
A-7.6.1
Discussion

DRAFT

EXITING - (VEHICLE MAINTENANCE AND SHOPS)

NUMBER OF EXITS

Minimum of two *exits* required.

Ref. 3.4.2.1 (1)

Actual numbers and locations of *exits* will be determined at a later date.

MINIMUM DISTANCE BETWEEN EXITS

Floor area does not have *public corridors.*

Division A 1.4.1.2.(1)

Minimum distance is ½ the maximum diagonal dimension of the *floor area* (but not less than 9 m – not a *public corridor*).

Ref. 3.4.2.3.(1)(b)

Maximum diagonal distance is ~ 51 m.

½ x 51 m = 25.5 m (which is greater than 9 m)

MAXIMUM TRAVEL DISTANCE TO EXITS

Maximum permissible travel distance from anywhere in the *floor area* to an *exit* is 30 m

Ref. 3.4.2.5 (1)(f)

This requirement will result in a number of pedestrian doors around the perimeter of the Vehicle Maintenance area for *exiting* purposes. Overhead doors cannot be included in this number.

It is recommended that the horizontal exit in the *firewalls* FW1 (to the Warehouse) and FW2 (to the Offices) not be included in this number as there may be times when they are locked.

See NFPA Life Safety Code Handbook 2009 for requirements for travel distance.

LSC 7.6.1
A-7.6.1
Discussion

DRAFT

EXITING - (OFFICES)

NUMBER OF EXITS

Minimum of two *exits* required.

Ref. 3.4.2.1 (1)

MINIMUM DISTANCE BETWEEN EXITS

Floor area does not have *public corridors*.

Division A 1.4.1.2.(1)

Minimum distance is ½ the maximum diagonal dimension of the *floor area* (but not less than 9 m – not a *public corridor*).

Ref. 3.4.2.3.(1)(b)

Maximum diagonal distance is ~ 67 m.

½ x 67 m = 33.5 m (which is greater than 9 m)

This requirement is met.

MAXIMUM TRAVEL DISTANCE TO EXITS

Maximum permissible travel distance from anywhere in the *floor area* to an *exit* is 40 m

Ref. 3.4.2.5 (1)(b)

This requirement seems to be met in the office area.

It is recommended that the *horizontal exit* in the *firewall* FW1 (to the Vehicle Maintenance) not be included in this number as there may be times when it is locked.

The corridor leading from the Offices toward the Vehicle Maintenance could become a dead end corridor with a length exceeding that permitted by Article 3.3.1.9.(7).

DRAFT

It is possible if the *horizontal exit* at FW1 is locked along with the doors to the Carpentry Shop and P&C Work Room. It is recommended that an *exit* door (D) be installed where shown on drawing SK2.

See NFPA Life Safety Code Handbook 2009 for requirements for travel distance.

LSC 7.6.1
A-7.6.1
Discussion

LIMITING DISTANCE

EXPOSURE PROTECTION

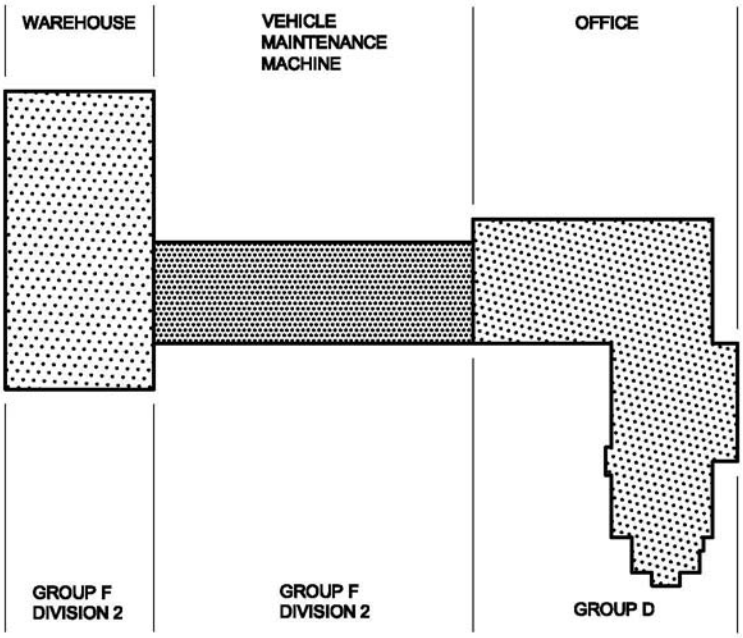
Where adjacent exterior walls in separate *fire compartments* are exposed to fire from each compartment then these walls and any *unprotected openings* in them will have to be protected in accordance with Article 3.1.10.6., Article 3.2.3.1., Article 3.2.3.12., and Article 3.2.3.14.

This may mean limited opening sizes, openings with wired glass, and an increased *fire-resistance rating* for the exposed walls.

Because the openings have not yet been finalized the *limiting distance* requirements cannot be finalized.

The areas of concern are identified as LD on drawing SK2.

DRAFT



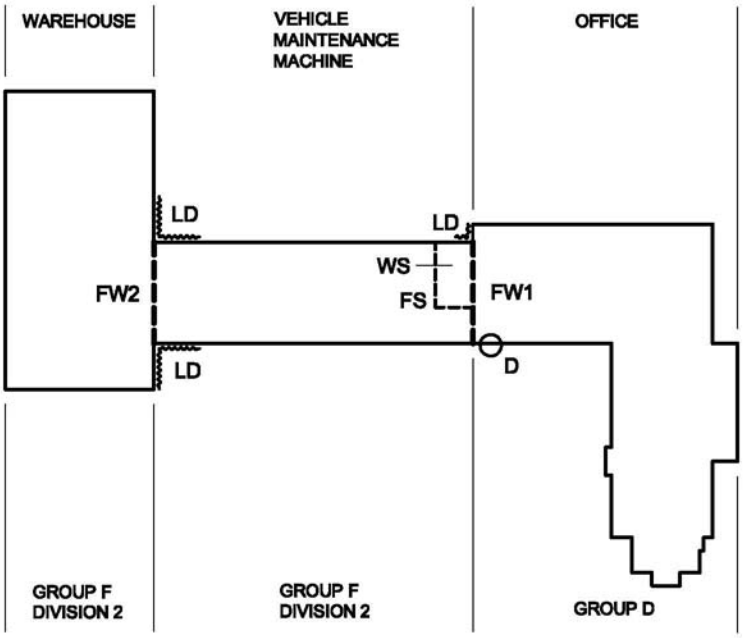
SCHEMATIC

BUILDING FOR NALCOR - BAY D'ESPOIR

BUILDING USES - SEPARATIONS - BUILDING OCCUPANCIES

SK-1

WALSH & PETERS ARCHITECTS INC



SCHEMATIC

BUILDING FOR NALCOR - BAY D'ESPOIR

FIREWALLS - FIRE SEPARATIONS - LIMITING DISTANCE - DOOR

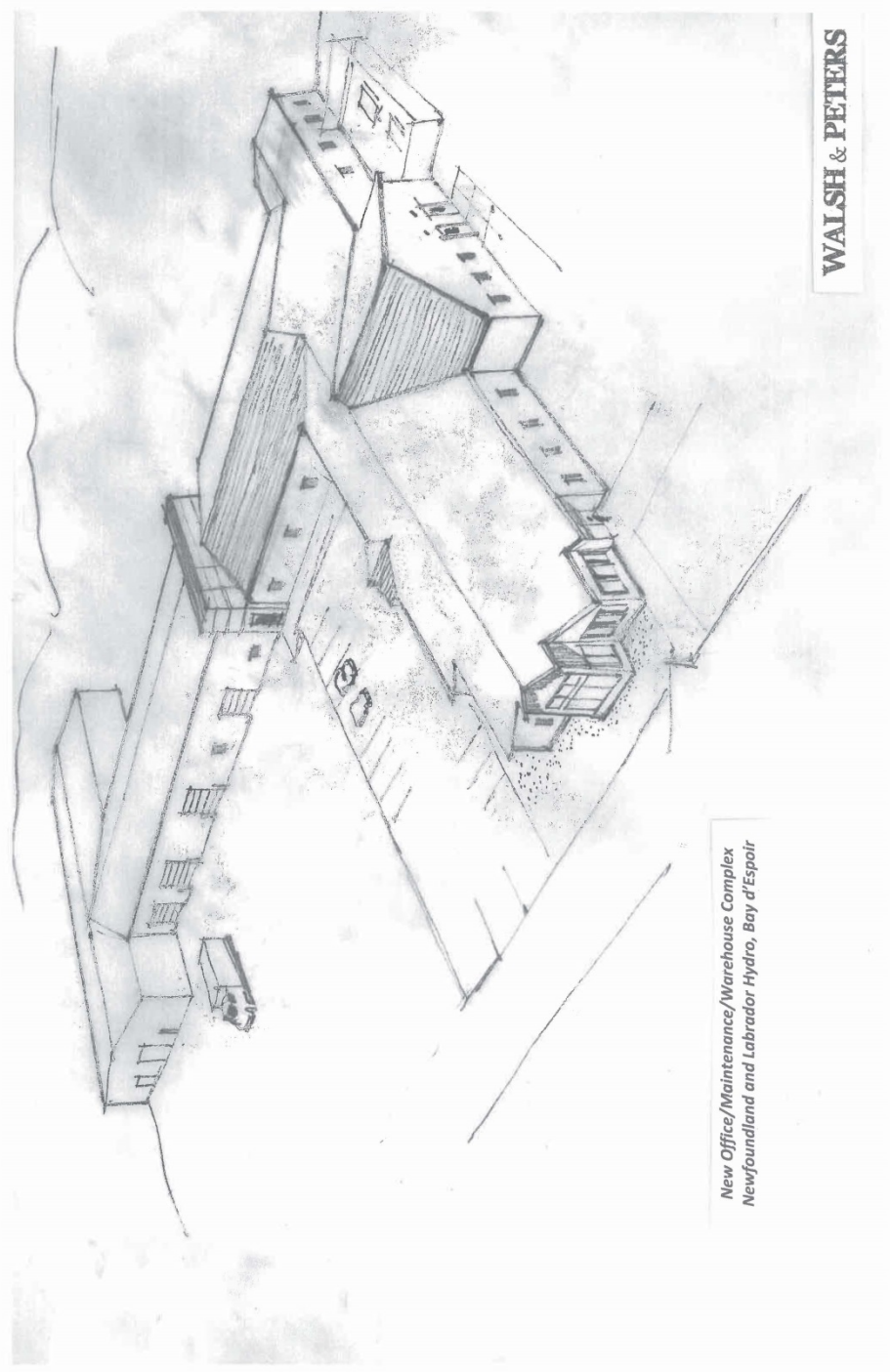
SK-2

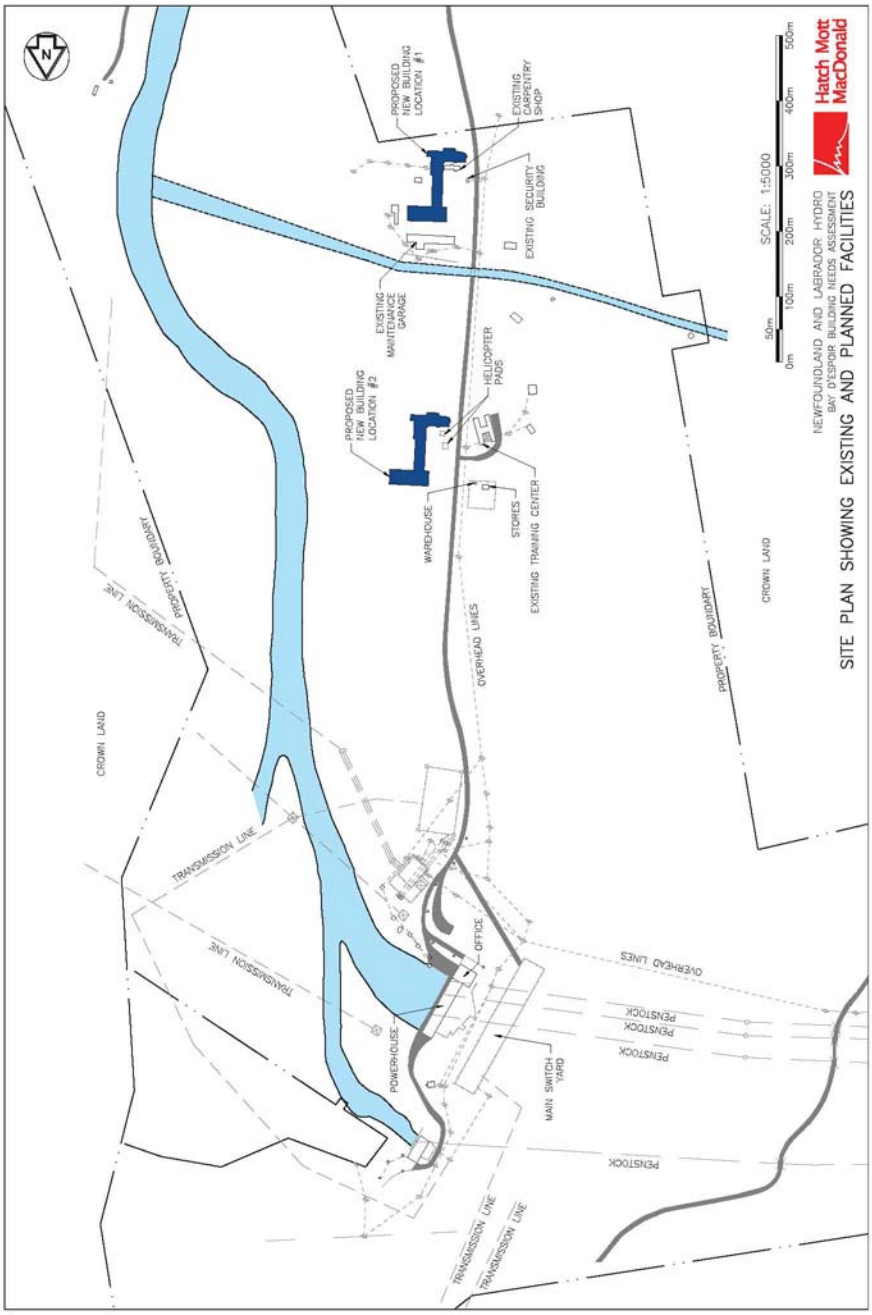
WALSH & PETERS ARCHITECTS INC

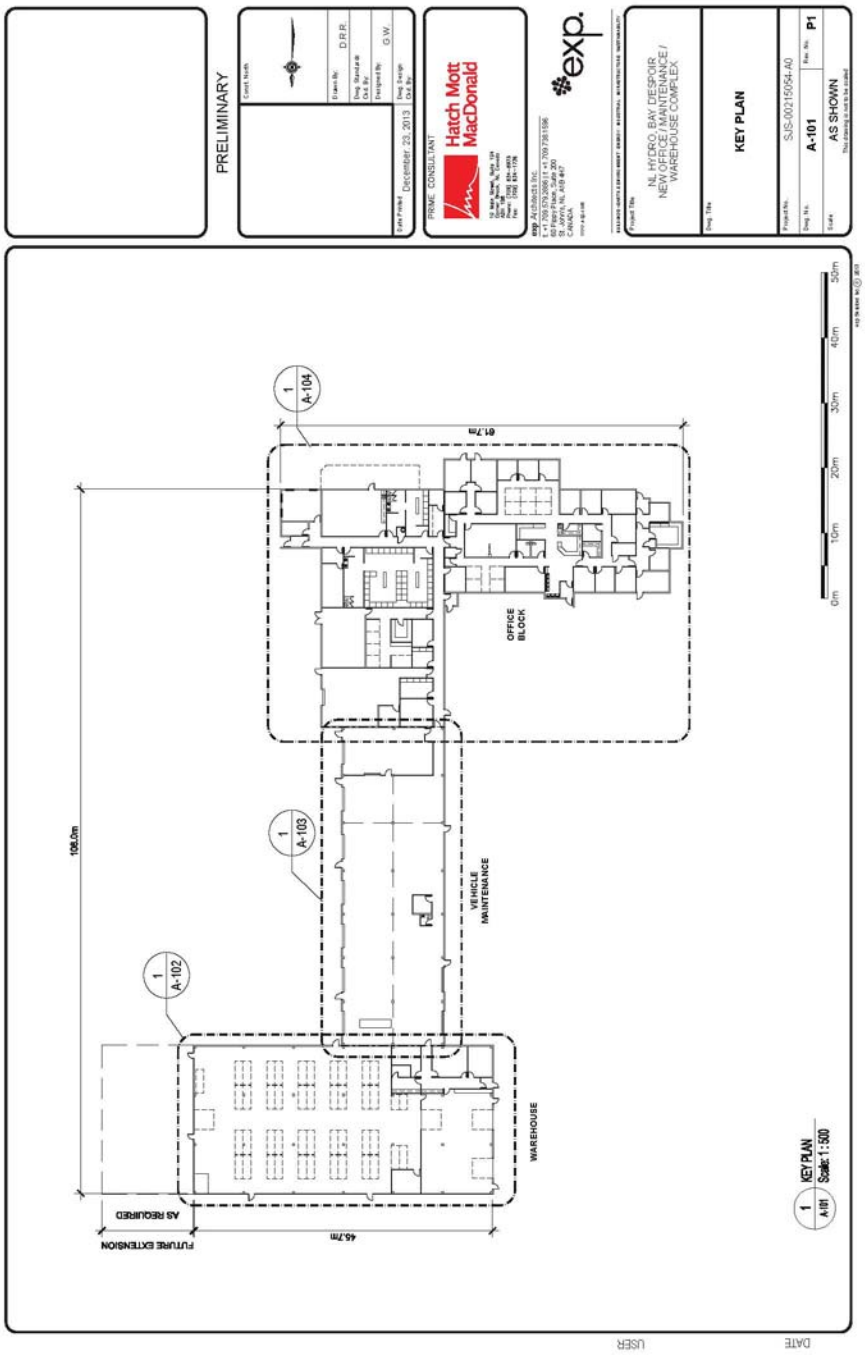
Appendix D

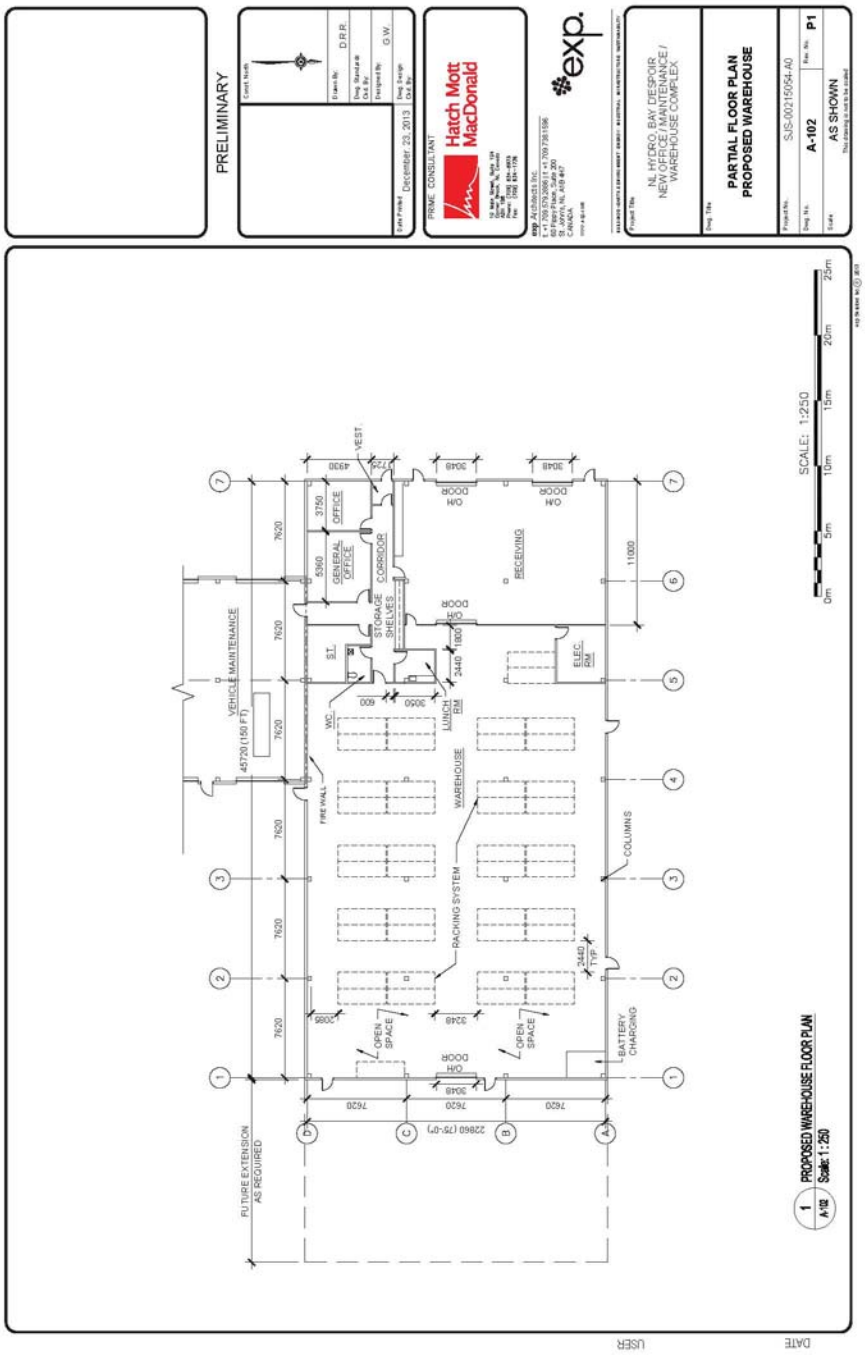
Concept Plans

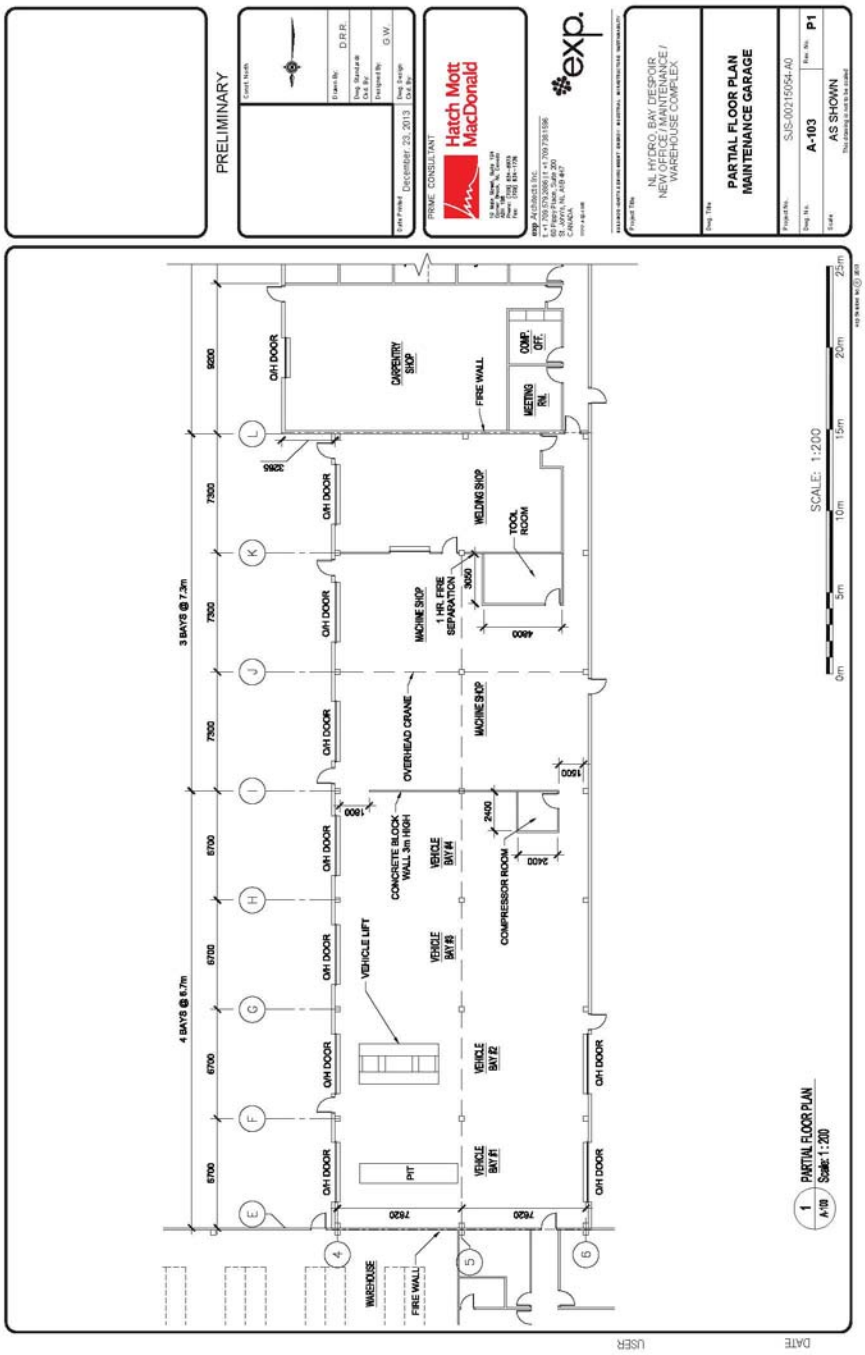
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WALSH & PETERS
New Office/Maintenance/Warehouse Complex
Newfoundland and Labrador Hydro, Bay d'Espoir

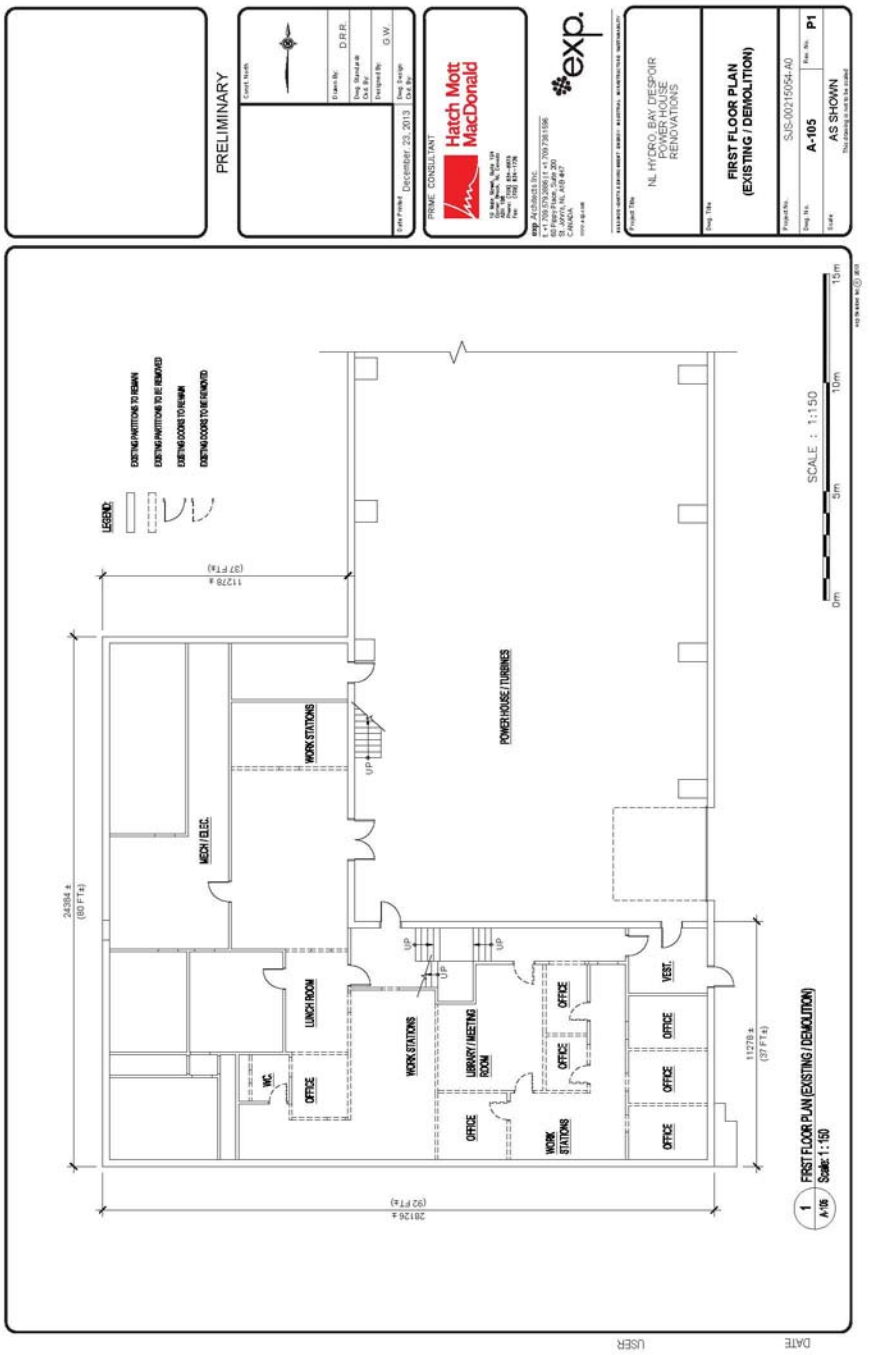

SITE PLAN SHOWING EXISTING AND PLANNED FACILITIES
NEWFOUNDLAND AND LABRADOR HYDRO
BAY D'ESPOIR BUILDING NEEDS ASSESSMENT
Hatch Mott MacDonald
SCALE: 1:5000
0m 50m 100m 200m 300m 400m 500m
PROPOSED NEW BUILDING LOCATION #1
EXISTING CARPENTRY SHOP
EXISTING SECURITY BUILDING
EXISTING MAINTENANCE GARAGE
PROPOSED NEW BUILDING LOCATION #2
HELIDOPTER PADS
WAREHOUSE
STORES
EXISTING TRAINING CENTER
OVERHEAD LINES
PROPERTY BOUNDARY
CROWN LAND
TRANSMISSION LINE
PROPERTY BOUNDARY
CROWN LAND
TRANSMISSION LINE
OFFICE
POWERHOUSE
MAIN SWITCH YARD
PENSTOCK
PENSTOCK
PENSTOCK
PENSTOCK
OVERHEAD LINES
TRANSMISSION LINE
TRANSMISSION LINE

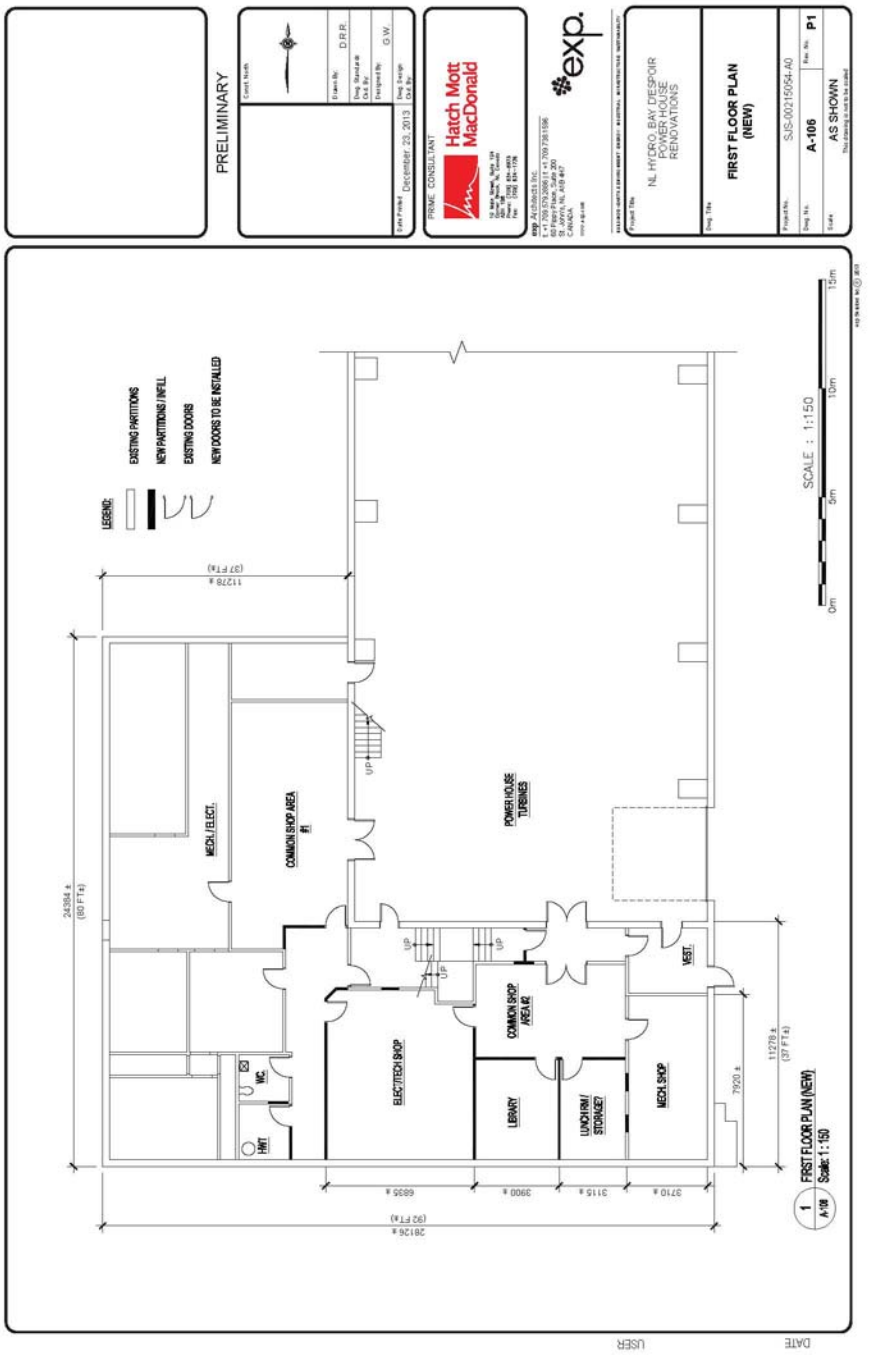

PRELIMINARY
December 23, 2013
PRIME CONSULTANT
Hatch Mott MacDonald
exp.
NL HYDRO, BAY D'ESPOIR
NEW OFFICE / MAINTENANCE / WAREHOUSE COMPLEX
KEY PLAN
SJS-00215054-A0
A-101
P1
AS SHOWN
OFFICE BLOCK
VEHICLE MAINTENANCE
WAREHOUSE
AS REQUIRED
FUTURE EXTENSION
108.0m
65.73m
61.73m
1 A-104
1 A-103
1 A-102
1 A101 KEY PLAN Scale: 1 : 500
0m 10m 20m 30m 40m 50m
USER
DATE

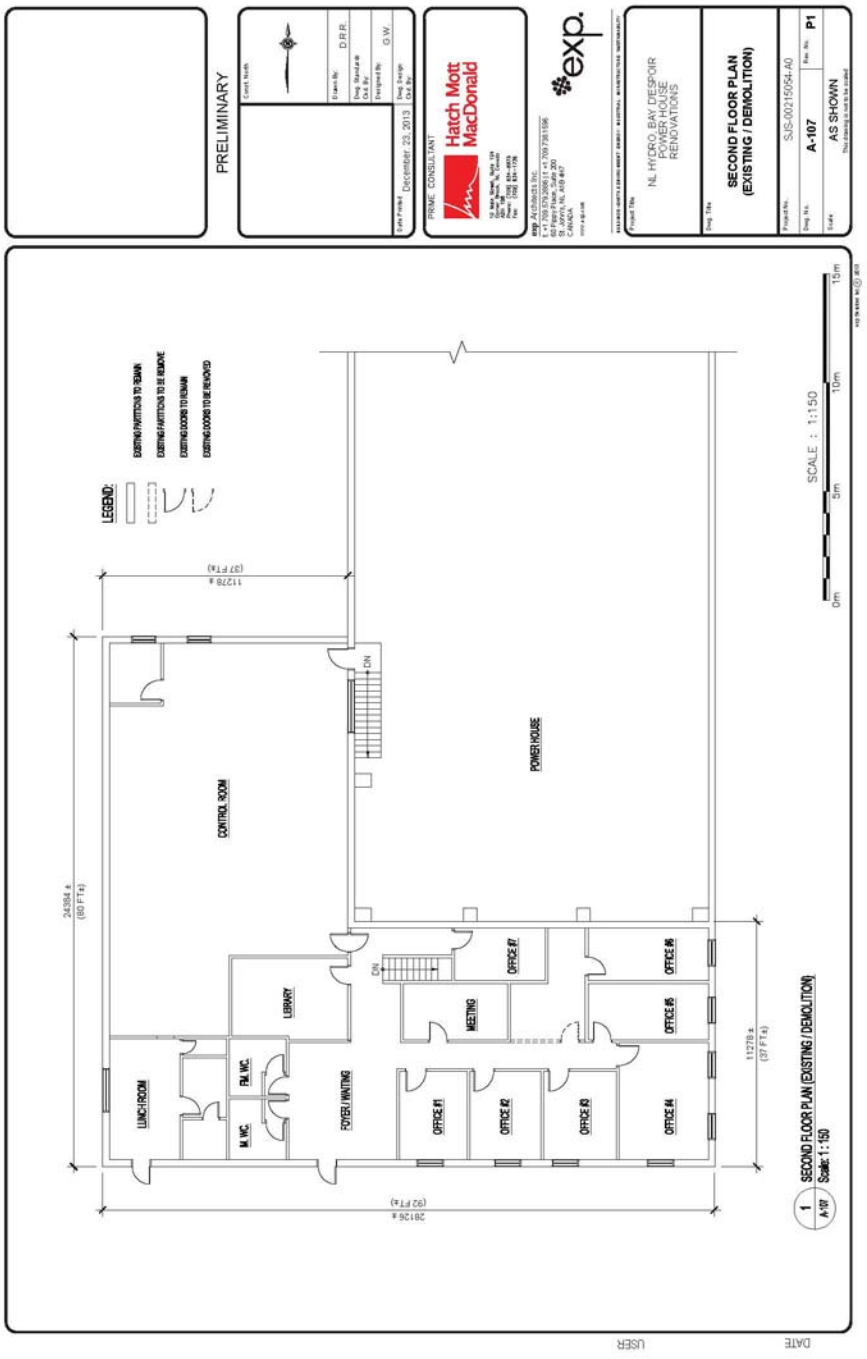

PRELIMINARY
December 23, 2013
PRIME CONSULTANT
Hatch Mott MacDonald
exp.
NL HYDRO, BAY D'ESPOIR
NEW OFFICE / MAINTENANCE /
WAREHOUSE COMPLEX
PARTIAL FLOOR PLAN
PROPOSED WAREHOUSE
SJS-00215054-A0
A-102
P1
AS SHOWN
SCALE: 1:250
0m
5m
10m
15m
20m
25m
PROPOSED WAREHOUSE FLOOR PLAN
Scale: 1 : 250
VEST.
OFFICE
GENERAL OFFICE
CORRIDOR
STORAGE SHELVES
RECEIVING
O/H DOOR
VEHICLE MAINTENANCE
45720 (150 FT)
FIRE WALL
WAREHOUSE
RACKING SYSTEM
COLUMNS
OPEN SPACE
BATTERY CHARGING
LUNCH RM
WC
ELEC. RM
S.T.
FUTURE EXTENSION AS REQUIRED
22860 (75'-0")
USER
DATE

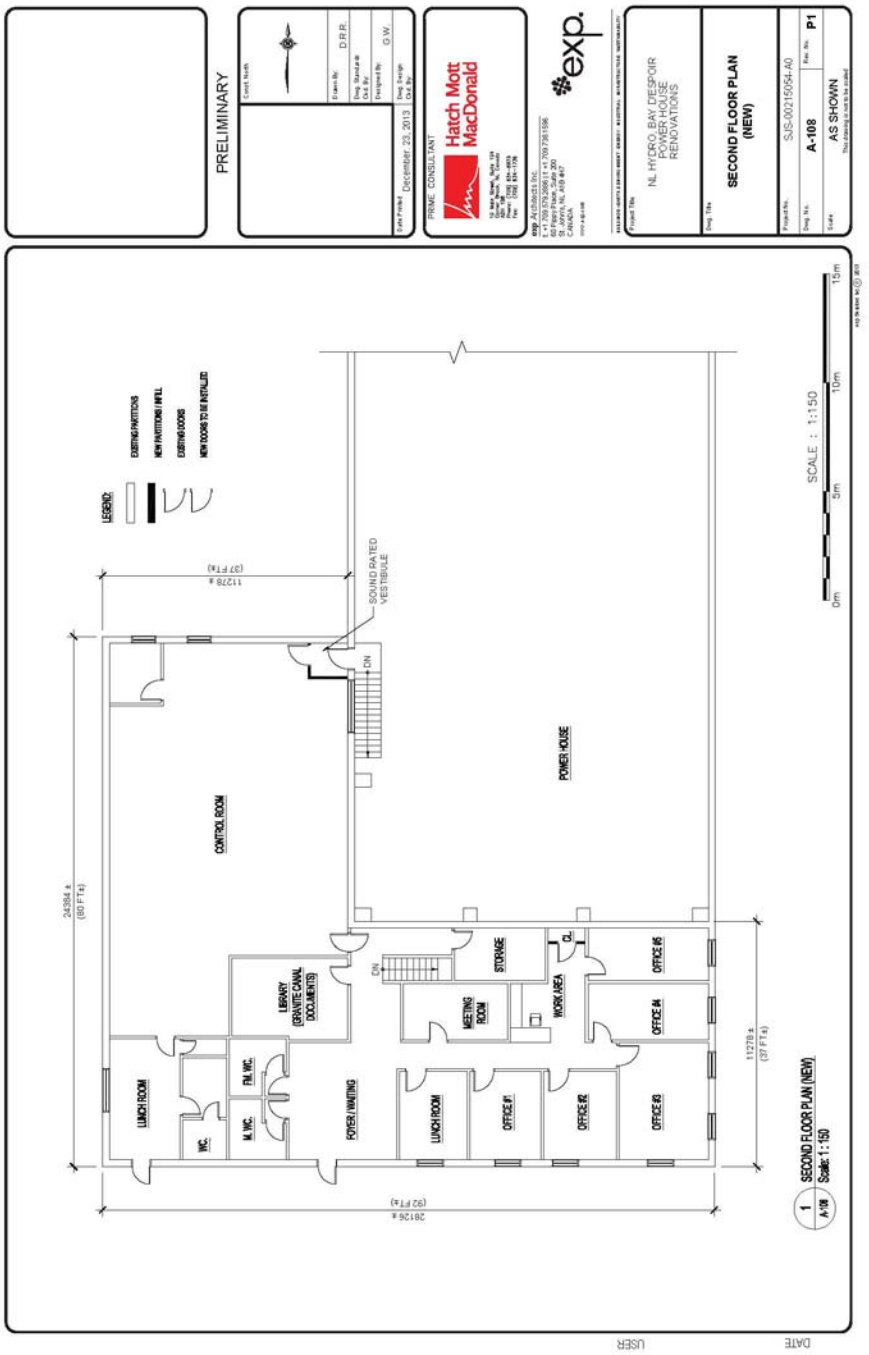

PRELIMINARY
December 23, 2013
Hatch Mott MacDonald
exp.
NL HYDRO, BAY D'ESPOIR
NEW OFFICE / MAINTENANCE / WAREHOUSE COMPLEX
PARTIAL FLOOR PLAN
MAINTENANCE GARAGE
SJS-00215054-A0
A-103
P1
AS SHOWN
SCALE: 1:200
0m 5m 10m 15m 20m 25m
1 PARTIAL FLOOR PLAN
Scale: 1:200
A-103
4 BAYS @ 6.7m
3 BAYS @ 7.3m
OH DOOR
CARPENTRY SHOP
FIRE WALL
COMP. OFF.
MEETING RM.
WELDING SHOP
TOOL ROOM
MACHINE SHOP
1 HR. FIRE SEPARATION
OVERHEAD CRANE
CONCRETE BLOCK WALL 3m HIGH
VEHICLE BAY #4
VEHICLE BAY #3
VEHICLE BAY #2
VEHICLE BAY #1
VEHICLE LIFT
PIT
COMPRESSOR ROOM
WAREHOUSE
FIRE WALL
USER
DATE


PRELIMINARY
December 23, 2013
PRIME CONSULTANT
Hatch Mott MacDonald
exp.
NL HYDRO, BAY DESPOIR
NEW OFFICE / MAINTENANCE / WAREHOUSE COMPLEX
PARTIAL FLOOR PLAN
OFFICE BLOCK / CHANGE ROOMS
SJS-00215054-A0
A-104
P1
AS SHOWN
LEGEND:
MANAGEMENT GROUP
LONG - TERM ASSET PLANNING GROUP
SHORT - TERM WORK PLANNING GROUP
FRONT LINE SUPERVISOR GROUP
TECH / OPERATIONS - EASTERN
TECH / OPERATIONS - WESTERN
SCALE: 1:200
1 PARTIAL FLOOR PLAN
Scale: 1:200
OFF. #1
OFF. #2
OFF. #3
OFF. #4
OFF. #5
OFF. #6
OFF. #7
OFF. #8
OFF. #9
OFF. #10
OFF. #11
OFF. #12
OFF. #13
MEETING RM.
COMP. OFF.
CARPENTRY SHOP
ELECTR. A.C. SHOP
LOCKERS
LUNCH ROOM
PATIO
FITNESS
WASHER DRYER
LIBRARY
PHOTO COPY
WORK STATIONS
MTG RM. #1
MTG RM. #2
MTG RM. #3
RECEPT.
WAITING
VEST.
FILES
WORK
SECURITY OFFICE
FIRST AID
LOCKERS / FIRE RESPONSE
VISITORS ENTRANCE
SERVER
JAN.
TO EASTERN SUPERVISOR
TO CREW EASTERN
TO WESTERN SUPERVISOR
TO CREW WESTERN
FIRE WALL
OH DOOR
20200
15600


PRELIMINARY
Hatch Mott MacDonald
exp.
NL HYDRO, BAY D'ESPOIR POWER HOUSE RENOVATIONS
FIRST FLOOR PLAN (EXISTING / DEMOLITION)
SJS-00215054-A0
A-105
P1
AS SHOWN
December 23, 2013
LEGEND
EXISTING PARTITIONS TO REMAIN
EXISTING PARTITIONS TO BE REMOVED
EXISTING DOORS TO REMAIN
EXISTING DOORS TO BE REMOVED
SCALE : 1:150
0m
5m
10m
15m
POWER HOUSE / TURBINES
WORK STATIONS
MECH / ELEC.
LUNCH ROOM
WC.
OFFICE
LIBRARY / MEETING ROOM
VEST.
UP
24384 ± (80 FT ±)
20126 ± (92 FT ±)
11278 ± (37 FT ±)
1 A-105 FIRST FLOOR PLAN (EXISTING / DEMOLITION) Scale: 1:150
USER
DATE


PRELIMINARY
Hatch Mott MacDonald
exp.
NL HYDRO, BAY D'ESPOIR POWER HOUSE RENOVATIONS
FIRST FLOOR PLAN (NEW)
SJS-00215054-A0
A-106
P1
AS SHOWN
December 23, 2013
LEGEND:
EXISTING PARTITIONS
NEW PARTITIONS / INFILL
EXISTING DOORS
NEW DOORS TO BE INSTALLED
SCALE : 1:150
0m
5m
10m
15m
MECH / ELECT.
COMMON SHOP AREA #1
POWER HOUSE TURBINES
UP
ELEC/TECH SHOP
LIBRARY
LUNCH RM / STORAGE
MECH SHOP
COMMON SHOP AREA #2
VEST.
WC.
HWT
24384 ± (80 FT ±)
11278 ± (37 FT ±)
28126 ± (92 FT ±)
6835 ±
3900 ±
3115 ±
3710 ±
7920 ±
1 A-106 FIRST FLOOR PLAN (NEW) Scale: 1:150
USER
DATE


PRELIMINARY
December 23, 2013
PRIME CONSULTANT
Hatch Mott MacDonald
exp.
NL HYDRO, BAY D'ESPOIR
POWER HOUSE
RENOVATIONS
SECOND FLOOR PLAN
(EXISTING / DEMOLITION)
SJS-00215054-A0
A-107
P1
AS SHOWN
LEGEND:
EXISTING PARTITIONS TO REMAIN
EXISTING PARTITIONS TO BE REMOVE
EXISTING DOORS TO REMAIN
EXISTING DOORS TO BE REMOVED
SCALE : 1:150
0m
5m
10m
15m
CONTROL ROOM
POWER HOUSE
LUNCHROOM
LIBRARY
MEETING
OFFICE #1
OFFICE #2
OFFICE #3
OFFICE #4
OFFICE #5
OFFICE #6
OFFICE #7
FOYER / WAITING
M. WC.
FEM. WC.
DN
SECOND FLOOR PLAN (EXISTING / DEMOLITION)
Scale: 1 : 150
USER
DATE


PRELIMINARY
December 23, 2013
Hatch Mott MacDonald
exp.
NL HYDRO, BAY D'ESPOIR
POWER HOUSE
RENOVATIONS
SECOND FLOOR PLAN
(NEW)
SJS-00215054-A0
A-108
P1
AS SHOWN
LEGEND:
EXISTING PARTITIONS
NEW PARTITIONS / INFILL
EXISTING DOORS
NEW DOORS TO BE INSTALLED
SCALE : 1:150
0m
5m
10m
15m
SOUND RATED VESTIBULE
CONTROL ROOM
POWER HOUSE
LIBRARY (GRANITE CANAL DOCUMENTS)
MEETING ROOM
STORAGE
WORK AREA
OFFICE #6
OFFICE #4
OFFICE #5
OFFICE #3
OFFICE #2
OFFICE #1
LUNCH ROOM
POYER / WAITING
LUNCH ROOM
FM. WC.
M. WC.
WC.
1 SECOND FLOOR PLAN (NEW)
Scale: 1 : 150
USER
DATE

Appendix E

Third Party Costing

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BUILDING NEEDS ASSESSMENT

Bay D'Espoir, NL

Functional Area Estimate
Job No. 28530.100079.000

Prepared for:

HATCH MOTT MACDONALD/EXP ARCHITECTS

Prepared by:
ALTUS GROUP COST CONSULTING
& PROJECT MANAGEMENT

Issued: 2 January 2014

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January 2, 2014

Job No.28530.100079.000

Hatch Mott MacDonald.
10 Main Street, Suite 104
Corner Brook, NL A2H 1B8

Attn: Michael Spencer

exp Architects
60 Pippy Place, Suite 200
St. John's, NL A1B 4H7

Gary Walsh

Re: Building Needs Assessment, Bay d'Espoir NL

Dear Sirs,

We submit for your review our "Functional Area Estimate" based on the referenced buildings, in accordance with the terms of our engagement.

The estimate includes all direct and indirect construction costs and general conditions, as well as, contractors overheads and profit.

The estimate includes allowances of $250,000 for post-contract contingency, an allowance of $300,000 for scope creep, and an allowance of $800,000 for design contingency. Escalation contingency to 2015 is included in an allowance of $350,000.

We recommend that the owner and/or design team review the estimate detail including line item descriptions, unit prices, assumptions and inclusions, exclusions, contingencies, and escalation to ensure the design intent has been accurately captured within the report.

It should be noted that this report is not intended for general circulation, publication or reproduction for any other person or purpose without express written permission to each specific instance. Furthermore, our report is written for the exclusive use of "Hatch Mott MacDonald/Exp Architects" and not to be relied upon by any other party. Altus Group Limited does not hold any reporting responsibility to any other party.

Yours truly,

ALTUS GROUP LIMITED

Tammy Stockley

Per: Tammy Stockley, PQS, MRICS
Senior Cost Consultant

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1 Introduction

1.1 Scope

This project consists of a building needs assessment on a combined new office/maintenance/warehouse complex and a renovated powerhouse. The scope of work covers a total area of 3,363m2 (36,199 sf).

The "Functional Area Estimate" is intended to provide a realistic budget based on the information provided. The estimate reflects our opinion as to the fair market value for the construction of this proposed project, associated renovations/demolition as required and is not intended to predict the lowest bid.

2 Project Details

2.1 General Information

From the information provided, we have measured quantities where possible were applied unit rates for the specific elements based on historical and current cost data for this type of project. Where design information was limited, we made assumptions based on our experience with projects of a similar scope and design.

2.2 Location

The cost base for this location is the Bay d'Espoir area.

2.3 Unit Rates

The rates in the estimate where applicable include labour and material, equipment, and subcontractor's overheads and profit. We have assumed that unionized contractors would perform the work. This estimate is not intended to be a prediction of the lowest bid and assumes competitive bidding for all aspects of the work.

2.4 Taxes

All our estimates exclude (HST) Harmonized Sales Tax.

2.5 Fees and General Requirements

The fees for the General Contractor or Construction Manager are included as a percentage of the hard construction cost. The general requirements are based on our assumptions of the anticipated construction approach and schedule.

The estimate excludes premiums associated with bonding.



2.6 Procurement Methodology

We have assumed that the project would be procured with a General Contractor or Construction Management approach under a CCDC standard form of contract. We have assumed a minimum of three bids would be received for all trade categories to establish competitive bidding and tender results. The estimate is a determination of fair market pricing and not a prediction of lowest bid in any trade category.

2.7 Schedule / Phasing

The project has been priced to be completed as a single phase. The estimate is based on a schedule of approximately 12 months with a construction start in 2013 (or unknown construction start).

2.8 Area / Project Statistics

The areas have been measured in accordance with the Canadian Institute of Quantity Surveyors Standard Method of Measurement. Detailed areas and project statistics are included in Appendix A.

3 Contingency

3.1 Design and Pricing

A design and pricing contingency of $800,000 is included in the estimate. This allowance is meant to cover pricing and design unknowns during the preparation of this estimate.

3.2 Escalation

An allowance of $350,000 for escalation to 2015 is included in the estimate.

3.3 Scope Creep

An allowance of $300,000 for scope creep is included in the estimate. This covers changes in scope parameters as project progresses.

3.4 Construction Contingency (Post Contract)

A post contract contingency of $250,000 has been included to cover change orders during construction.

4 General Statement of Liability

4.1 Statement of Probable Costs

Altus Group Cost Consulting does not guarantee that tenders or actual construction costs will not vary from this estimate. Acute market conditions, proprietary specifications, or severe undercutting among contractors may cause tenders to vary from reasonable estimates based on normal and abnormal competitive conditions.

4.2 Ongoing Cost Control

Altus Group Cost Consulting recommends the owner review the cost estimate report including allowances and assumptions to ensure the appropriate design intent is captured.

5 Scope and Specification Assumptions

5.1 Inclusions

The estimate includes all direct construction costs as described within the estimate report.

5.2 Exclusions

The following items are excluded from the estimate:

1. Land and associated costs
2. Removal and/or handling of hazardous/contaminated material
3. Abnormal soil conditions
4. Utility connection costs/charges
5. Soft costs
6. Legal fees
7. Marketing/promotion
8. Realty taxes, levies, insurance
9. Operating expenses
10. Interest/finance charges
11. Remedial work to existing buildings/structures/property
12. Vibration/noise control premiums
13. Owner supplied FF&E
14. HST
15. Retail level finishes
16. LEED certification

6 List of Appendices

The following appendices are enclosed:

A – Executive Summary
B – Elemental Summaries



Appendix A – Executive Summary

AltusGroup

23 Dec 13
28530.100079.000
File #: 13-201

Building Needs Assessment
Bay d'Espoir, NL

Functional Area Estimate

EXECUTIVE SUMMARY

The 'Hard' Construction Cost Estimate can be summarized as follows :

Component		GFA(M2)	GFA(SF)	$/m2	$/SF	$ BUDGET
Option 1:						
Warehouse (excluding racking)		1,045	11,248	$1,074	$100	$1,122,325
Maintenace Shop (excluding hydraulic lifts)		892	9,601	$1,526	$142	$1,361,172
Ancillary Services (excluding fitness equipment)		605	6,512	$1,554	$144	$940,130
Office (excluding furniture)		557	5,995	$1,540	$143	$857,920
Security (excluding security equipment)		64	689	$1,959	$182	$125,390
Powerhouse Office Renovations		200	2,153	$604	$56	$120,800
Site Development						$792,263
Sub Total (Excluding Contingencies Allowance)		**3,363**	**36,199**	**$1,582**	**$147**	**$5,320,000**
General Requirements	16.00%	3,363	36,199	$253	$24	$851,200
Fee	10.00%	3,363	36,199	$165	$15	$555,027
Sub Total - GLA (Including Design Allowance)		**3,363**	**36,199**	**$2,000**	**$186**	**$6,726,227**
Contingencies:						
Design & Pricing Contingency	8.89%	3,363	36,199	$238	$22	$800,000
Escalation Contingency (2015)	3.89%	3,363	36,199	$104	$10	$350,000
Scope Creep	3.33%	3,363	36,199	$89	$8	$300,000
Construction Contingency	2.78%	3,363	36,199	$74	$7	$250,000
TOTAL CONSTRUCTION COST (Excluding HST)		**3,363**	**36,199**	**$2,506**	**$233**	**$8,426,000**
Owner Equipment	6.38%	3,363	36,199	$171	$16	$574,000
HST	0%					EXCLUDED
TOTAL CONSTRUCTION COST(Excluding HST)		**3,363**	**36,199**	**$2,676**	**$249**	**9,000,000**

Notes and Assumptions:

1. Refer to Estimate Summaries for breakdown of estimated costs by component.
2. Premium for LEED Certification is excluded.
3. Removal and/or handling of any contaminated and/or hazardous material and abnormal soil conditions are excluded except as noted
4. Dewatering allowance carried.
5. Utility connection charges/costs and/or relocations are excluded.
6. FF&E is included. (Millwork & washroom accessories).
7. Soft costs are excluded from above estimate.
8. Premiums for bonds and insurances are included.
9. Owners Equipment included. (Workstations, hydraulic lift, exercise equipment, window treatment, lunch room equipment, warehouse racking is included in Exec. Summary).
10. Demolition is included
11. Allowance for Design & Pricing (8.9%) and Construction Contingency for Change Orders (2.8%) are included.
12. Construction cost escalation beyond 2013 to mid 2015 is included (3.9%).
13. Scope creep is included (3.3%).
14. HST is excluded



Appendix B – Elemental Summaries

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ELEMENTAL COST SUMMARY

Project:	Building Needs Assessment	Project #:	28530.100079.000
Location:	Bay d'Espoir, NL	Date:	23 Dec 13
Owner/Client:	Newfoundland & Labrador Hydro	File #:	13-201
Architect:	Hatch Mott MacDonald/Exp. Architects	Gross Floor Area:	1,045 m2

WAREHOUSE - FUNCTIONAL AREA ESTIMATE

Element	Ratio to GFA	Elemental Quantity	Elemental Unit Rate	Elemental Amount	Cost/m2	Total	%
A SHELL							
A1 SUBSTRUCTURE					$140.00		
A11 Foundation	1.00	1,045 m2	$140.00	$146,300	$140.00		
A12 Basement Excavation	0.00	m3		$0	$0.00	$146,300	13.0%
A2 STRUCTURE					$363.32		
A21 Lowest Floor Construction	0.97	1,018 m2	$65.00	$66,170	$63.32		
A22 Upper Floor Construction	0.00	m2		$0	$0.00		
A23 Roof Construction	1.00	1,045 m2	$300.00	$313,500	$300.00		
A24 Stair Construction	0.00					$379,670	33.8%
A3 EXTERIOR ENCLOSURE					$184.17		
A31 Walls Below Grade	0.00	m2		$0	$0.00		
A32 Walls Above Grade	0.69	717 m2	$90.00	$64,530	$61.75		
A33 Windows & Entrance	0.05	48 m2	$600.00	$28,800	$27.56		
A34 Roof Covering	1.01	1,055 m2	$75.00	$79,125	$75.72		
A35 Projections	0.00	1 Sum	$20,000.00	$20,000	$19.14	$192,455	17.1%
B INTERIORS							
B1 PARTITIONS & DOORS					$46.17		
B11 Partitions	0.33	340 m2	$95.00	$32,300	$30.91		
B12 Doors	0.03	29 m2	$550.00	$15,950	$15.26	$48,250	4.3%
B2 FINISHES					$40.33		
B21 Floor Finishes	0.97	1,010 m2	$25.00	$25,250	$24.16		
B22 Ceiling Finishes	0.10	106 m2	$50.00	$5,300	$5.07		
B23 Wall Finishes	0.56	580 m2	$20.00	$11,600	$11.10	$42,150	3.8%
B3 FITTING & EQUIPMENT					$6.00		
B31 Fitting & Fixtures	1.00	1,045 m2	$6.00	$6,270	$6.00		
B32 Equipment	0.00	m2		$0	$0.00		
B33 Conveying Systems	0.00	no		$0	$0.00	$6,270	0.6%
C SERVICES							
C1 MECHANICAL					$134.00		
C11 Plumbing & Drainage	1.00	1,045 m2	$13.00	$13,585	$13.00		
C21 Fire Protection	1.00	1,045 m2	$1.00	$1,045	$1.00		
C13 HVAC	1.00	1,045 m2	$100.00	$104,500	$100.00		
C14 Controls	1.00	1,045 m2	$20.00	$20,900	$20.00	$140,030	12.5%
C2 ELECTRICAL					$160.00		
C21 Service & distribution	1.00	1,045 m2	$65.00	$67,925	$65.00		
C22 Lighting, Devices & Heating	1.00	1,045 m2	$70.00	$73,150	$70.00		
C23 Systems & Ancillaries	1.00	1,045 m2	$25.00	$26,125	$25.00	$167,200	14.9%
NET BUILDING COST (Excluding Site)					$1,074.00	$1,122,325	100.0%

GFA:	1,045 m2	per m2	$1,074.00
GFA:	11,248 sf	per sf	$99.78

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ELEMENTAL COST SUMMARY

Project:	Building Needs Assessment	Project #:	28530.100079.000
Location:	Bay d'Espoir, NL	Date:	23 Dec 13
Owner/Client:	Newfoundland & Labrador Hydro	File #:	13-201
Architect:	Hatch Mott MacDonald/Exp. Architects	Gross Floor Area:	892 m2

MAINTENANCE SHOPS - FUNCTIONAL AREA ESTIMATE

Element	Ratio to GFA	Elemental Quantity	Elemental Unit Rate	Elemental Amount	Cost/m2	Total	%
A SHELL							
A1 SUBSTRUCTURE					$145.00		
A11 Foundation	1.00	892 m2	$145.00	$129,340	$145.00		
A12 Basement Excavation	0.00	m3		$0	$0.00	$129,340	9.5%
A2 STRUCTURE					$442.83		
A21 Lowest Floor Construction	0.96	860 m2	$150.00	$129,000	$144.62		
A22 Upper Floor Construction	0.00	m2		$0	$0.00		
A23 Roof Construction	1.01	900 m2	$290.00	$261,000	$292.60		
A24 Stair Construction	0.00	1 Sum	$5,000.00	$5,000	$5.61	$395,000	29.0%
A3 EXTERIOR ENCLOSURE					$263.28		
A31 Walls Below Grade	0.02	20 m2	300.00	$6,000	$6.73		
A32 Walls Above Grade	0.18	160 m2	$265.00	$42,400	$47.53		
A33 Windows & Entrance	0.21	183 m2	$650.00	$118,950	$133.35		
A34 Roof Covering	1.01	900 m2	$75.00	$67,500	$75.67		
A35 Projections	0.00	Sum		$0	$0.00	$234,850	17.3%
B INTERIORS							
B1 PARTITIONS & DOORS					$81.39		
B11 Partitions	0.46	412 m2	$150.00	$61,800	$69.28		
B12 Doors	0.02	18 m2	$600.00	$10,800	$12.11	$72,600	5.3%
B2 FINISHES					$39.98		
B21 Floor Finishes	0.94	842 m2	$30.00	$25,260	$28.32		
B22 Ceiling Finishes	0.01	12 m2	$50.00	$600	$0.67		
B23 Wall Finishes	1.10	980 m2	$10.00	$9,800	$10.99	$35,660	2.6%
B3 FITTING & EQUIPMENT					$66.00		
B31 Fitting & Fixtures	1.00	892 m2	$6.00	$5,352	$6.00		
B32 Equipment	1.00	892 m2	$60.00	$53,520	$60.00		
B33 Conveying Systems	0.00	no		$0	$0.00	$58,872	4.3%
C SERVICES							
C1 MECHANICAL					$332.50		
C11 Plumbing & Drainage	1.00	892 m2	$70.00	$62,440	$70.00		
C21 Fire Protection	1.00	892 m2	$2.50	$2,230	$2.50		
C13 HVAC	1.00	892 m2	$230.00	$205,160	$230.00		
C14 Controls	1.00	892 m2	$30.00	$26,760	$30.00	$296,590	21.8%
C2 ELECTRICAL					$155.00		
C21 Service & distribution	1.00	892 m2	$60.00	$53,520	$60.00		
C22 Lighting, Devices & Heating	1.00	892 m2	$80.00	$71,360	$80.00		
C23 Systems & Ancillaries	1.00	892 m2	$15.00	$13,380	$15.00	$138,260	10.2%
NET BUILDING COST (Excluding Site)					**$1,525.98**	**$1,361,172**	**100.0%**

GFA:	892 m2	per m2	$1,525.98
GFA:	9,601 sf	per sf	$141.77

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ELEMENTAL COST SUMMARY

Project:	Building Needs Assessment	Project #:	28530.100079.000
Location:	Bay d'Espoir, NL	Date:	23 Dec 13
Owner/Client:	Newfoundland & Labrador Hydro	File #:	13-201
Architect:	Hatch Mott MacDonald/Exp. Architects	Gross Floor Area:	657 m2

ANCILLARY SERVICES - FUNCTIONAL AREA ESTIMATE

Element	Ratio to GFA	Elemental Quantity	Elemental Unit Rate	Elemental Amount	Cost/m2	Total	%
A SHELL							
A1 SUBSTRUCTURE					**$110.00**		
A11 Foundation	1.00	657 m2	$110.00	$72,270	$110.00		
A12 Basement Excavation	0.00	m3		$0	$0.00	$72,270	7.7%
A2 STRUCTURE					**$252.91**		
A21 Lowest Floor Construction	0.90	590 m2	$60.00	$35,400	$53.88		
A22 Upper Floor Construction	0.05	33 m2	$220.00	$7,260	$11.05		
A23 Roof Construction	1.20	790 m2	$150.00	$118,500	$180.37		
A24 Stair Construction	0.00	1 no	$5,000.00	$5,000	$7.61	$166,160	17.7%
A3 EXTERIOR ENCLOSURE					**$209.89**		
A31 Walls Below Grade	0.00	m2		$0	$0.00		
A32 Walls Above Grade	0.40	260 m2	$150.00	$39,000	$59.36		
A33 Windows & Entrance	0.04	26 m2	$575.00	$14,950	$22.75		
A34 Roof Covering	1.20	790 m2	$85.00	$67,150	$102.21		
A35 Projections	0.15	96 m2	$175.00	$16,800	$25.57	$137,900	14.7%
B INTERIORS							
B1 PARTITIONS & DOORS					**$149.51**		
B11 Partitions	1.08	710 m2	$93.00	$66,030	$100.50		
B12 Doors	0.04	23 no	$1,400.00	$32,200	$49.01	$98,230	10.4%
B2 FINISHES					**$185.69**		
B21 Floor Finishes	0.85	560 m2	$80.00	$44,800	$68.19		
B22 Ceiling Finishes	0.85	560 m2	$65.00	$36,400	$55.40		
B23 Wall Finishes	2.59	1,700 m2	$24.00	$40,800	$62.10	$122,000	13.0%
B3 FITTING & EQUIPMENT					**$55.44**		
B31 Fitting & Fixtures	1.00	657 m2	$55.44	$36,422	$55.44		
B32 Equipment	0.00	m2		$0	$0.00		
B33 Conveying Systems	0.00	no		$0	$0.00	$36,422	3.9%
C SERVICES							
C1 MECHANICAL					**$282.50**		
C11 Plumbing & Drainage	1.00	657 m2	$100.00	$65,700	$100.00		
C21 Fire Protection	1.00	657 m2	$2.50	$1,643	$2.50		
C13 HVAC	1.00	657 m2	$150.00	$98,550	$150.00		
C14 Controls	1.00	657 m2	$30.00	$19,710	$30.00	$185,603	19.7%
C2 ELECTRICAL					**$185.00**		
C21 Service & distribution	1.00	657 m2	$60.00	$39,420	$60.00		
C22 Lighting, Devices & Heating	1.00	657 m2	$100.00	$65,700	$100.00		
C23 Systems & Ancillaries	1.00	657 m2	$25.00	$16,425	$25.00	$121,545	12.9%
NET BUILDING COST (Excluding Site)					**$1,430.94**	**$940,130**	**100.0%**

GFA:	657 m2	per m2	$1,430.94
GFA:	7,072 sf	per sf	$132.94

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ELEMENTAL COST SUMMARY

Project:	Building Needs Assessment	Project #:	28530.100079.000
Location:	Bay d'Espoir, NL	Date:	23 Dec 13
Owner/Client:	Newfoundland & Labrador Hydro	File #:	13-201
Architect:	Hatch Mott MacDonald/Exp. Architects	Gross Floor Area:	557 m2

OFFICE - FUNCTIONAL AREA ESTIMATE

Element	Ratio to GFA	Elemental Quantity	Elemental Unit Rate	Elemental Amount	Cost/m2	Total	%
A SHELL							
A1 SUBSTRUCTURE					**$190.00**		
A11 Foundation	1.00	557 m2	$190.00	$105,830	$190.00		
A12 Basement Excavation	0.00	m3		$0	$0.00	$105,830	12.3%
A2 STRUCTURE					**$233.21**		
A21 Lowest Floor Construction	0.97	540 m2	$65.00	$35,100	$63.02		
A22 Upper Floor Construction	0.00	m2		$0	$0.00		
A23 Roof Construction	1.13	632 m2	$150.00	$94,800	$170.20		
A24 Stair Construction	0.00	m2		$0	$0.00	$129,900	15.1%
A3 EXTERIOR ENCLOSURE					**$156.05**		
A31 Walls Below Grade	0.00	m2		$0	$0.00		
A32 Walls Above Grade	0.18	100 m2	$150.00	$15,000	$26.93		
A33 Windows & Entrance	0.04	24 m2	$550.00	$13,200	$23.70		
A34 Roof Covering	1.13	632 m2	$85.00	$53,720	$96.45		
A35 Projections	0.00	1 Sum	$5,000.00	$5,000	$8.98	$86,920	10.1%
B INTERIORS							
B1 PARTITIONS & DOORS					**$249.08**		
B11 Partitions	1.96	1,092 m2	$95.00	$103,740	$186.25		
B12 Doors	0.04	25 no	$1,400.00	$35,000	$62.84	$138,740	16.2%
B2 FINISHES					**$210.20**		
B21 Floor Finishes	0.92	514 m2	$70.00	$35,980	$64.60		
B22 Ceiling Finishes	0.92	514 m2	$70.00	$35,980	$64.60		
B23 Wall Finishes	4.05	2,256 m2	$20.00	$45,120	$81.01	$117,080	13.6%
B3 FITTING & EQUIPMENT					**$77.56**		
B31 Fitting & Fixtures	0.97	540 m2	$80.00	$43,200	$77.56		
B32 Equipment	0.00	m2		$0	$0.00		
B33 Conveying Systems	0.00	no		$0	$0.00	$43,200	5.0%
C SERVICES							
C1 MECHANICAL					**$230.25**		
C11 Plumbing & Drainage	0.97	540 m2	$55.00	$29,700	$53.32		
C21 Fire Protection	0.97	540 m2	$2.50	$1,350	$2.42		
C13 HVAC	0.97	540 m2	$150.00	$81,000	$145.42		
C14 Controls	0.97	540 m2	$30.00	$16,200	$29.08	$128,250	14.9%
C2 ELECTRICAL					**$193.90**		
C21 Service & distribution	0.97	540 m2	$50.00	$27,000	$48.47		
C22 Lighting, Devices & Heating	0.97	540 m2	$110.00	$59,400	$106.64		
C23 Systems & Ancillaries	0.97	540 m2	$40.00	$21,600	$38.78	$108,000	12.6%
NET BUILDING COST (Excluding Site)					**$1,540.25**	**$857,920**	**100.0%**

GFA:	557 m2	per m2	$1,540.25
GFA:	5,995 sf	per sf	$143.09

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ELEMENTAL COST SUMMARY

Project:	Building Needs Assessment	Project #:	28530.100079.000
Location:	Bay d'Espoir, NL	Date:	23 Dec 13
Owner/Client:	Newfoundland & Labrador Hydro	File #:	13-201
Architect:	Hatch Mott MacDonald/Exp. Architects	Gross Floor Area:	64 m2

SECURITY - FUNCTIONAL AREA ESTIMATE

Element	Ratio to GFA	Elemental Quantity	Elemental Unit Rate	Elemental Amount	Cost/m2	Total	%
A SHELL							
A1 SUBSTRUCTURE					$130.00		
A11 Foundation	1.00	64 m2	$130.00	$8,320	$130.00		
A12 Basement Excavation	0.00	m3		$0	$0.00	$8,320	6.6%
A2 STRUCTURE					$248.44		
A21 Lowest Floor Construction	0.94	60 m2	$65.00	$3,900	$60.94		
A22 Upper Floor Construction	0.00	m2		$0	$0.00		
A23 Roof Construction	1.25	80 m2	$150.00	$12,000	$187.50		
A24 Stair Construction	0.00	m2		$0	$0.00	$15,900	12.7%
A3 EXTERIOR ENCLOSURE					$289.53		
A31 Walls Below Grade	0.00	m2		$0	$0.00		
A32 Walls Above Grade	0.22	14 m2	$170.00	$2,380	$37.19		
A33 Windows & Entrance	0.17	11 m2	$850.00	$9,350	$146.09		
A34 Roof Covering	1.25	80 m2	$85.00	$6,800	$106.25		
A35 Projections	0.00	Sum		$0	$0.00	$18,530	14.8%
B INTERIORS							
B1 PARTITIONS & DOORS					$398.44		
B11 Partitions	1.41	90 m2	$150.00	$13,500	$210.94		
B12 Doors	0.09	6 no	$2,000.00	$12,000	$187.50	$25,500	20.3%
B2 FINISHES					$185.00		
B21 Floor Finishes	0.89	57 m2	$80.00	$4,560	$71.25		
B22 Ceiling Finishes	0.89	57 m2	$70.00	$3,990	$62.34		
B23 Wall Finishes	1.47	94 m2	$35.00	$3,290	$51.41	$11,840	9.4%
B3 FITTING & EQUIPMENT					$150.00		
B31 Fitting & Fixtures	1.00	64 m2	$150.00	$9,600	$150.00		
B32 Equipment	0.00	m2		$0	$0.00		
B33 Conveying Systems	0.00	no		$0	$0.00	$9,600	7.7%
C SERVICES							
C1 MECHANICAL					$337.81		
C11 Plumbing & Drainage	1.00	64 m2	$150.00	$9,600	$150.00		
C21 Fire Protection	1.00	64 m2	$8.00	$500	$7.81		
C13 HVAC	1.00	64 m2	$150.00	$9,600	$150.00		
C14 Controls	1.00	64 m2	$30.00	$1,920	$30.00	$21,620	17.2%
C2 ELECTRICAL					$220.00		
C21 Service & distribution	1.00	64 m2	$50.00	$3,200	$50.00		
C22 Lighting, Devices & Heating	1.00	64 m2	$120.00	$7,680	$120.00		
C23 Systems & Ancillaries	1.00	64 m2	$50.00	$3,200	$50.00	$14,080	11.2%
NET BUILDING COST (Excluding Site)					$1,959.22	$125,390	100.0%

GFA:	64 m2	per m2	$1,959.22
GFA:	689 sf	per sf	$182.02

AltusGroup

ELEMENTAL COST SUMMARY

Project:	Building Needs Assessment	Project #:	28530.100079.000
Location:	Bay d'Espoir, NL	Date:	23 Dec 13
Owner/Client:	Newfoundland & Labrador Hydro	File #:	13-201
Architect:	Hatch Mott MacDonald/Exp. Architects	Gross Floor Area:	200 m2

POWERHOUSE OFFICE RENOVATIONS - FUNCTIONAL AREA ESTIMATE

Element	Ratio to GFA	Elemental Quantity	Elemental Unit Rate	Elemental Amount	Cost/m2	Total	%
A SHELL							
A1 SUBSTRUCTURE					$0.00		
A11 Foundation	0.00	0 m2	$0.00	$0	$0.00		
A12 Basement Excavation	0.00	m3		$0	$0.00	$0	0.0%
A2 STRUCTURE					$0.00		
A21 Lowest Floor Construction	0.00	0 m2	$0.00	$0	$0.00		
A22 Upper Floor Construction	0.00	m2		$0	$0.00		
A23 Roof Construction	0.00	0 m2	$0.00	$0	$0.00		
A24 Stair Construction	0.00	m2		$0	$0.00	$0	0.0%
A3 EXTERIOR ENCLOSURE					$0.00		
A31 Walls Below Grade	0.00	m2		$0	$0.00		
A32 Walls Above Grade	0.00	0 m2	$0.00	$0	$0.00		
A33 Windows & Entrance	0.00	0 m2	$0.00	$0	$0.00		
A34 Roof Covering	0.00	0 m2	$0.00	$0	$0.00		
A35 Projections	0.00	Sum		$0	$0.00	$0	0.0%
B INTERIORS							
B1 PARTITIONS & DOORS					$144.00		
B11 Partitions	0.60	120 m2	$90.00	$10,800	$54.00		
B12 Doors	0.06	12 no	$1,500.00	$18,000	$90.00	$28,800	27.0%
B2 FINISHES					$160.00		
B21 Floor Finishes	1.00	200 m2	$80.00	$16,000	$80.00		
B22 Ceiling Finishes	1.00	200 m2	$50.00	$10,000	$50.00		
B23 Wall Finishes	1.50	300 m2	$20.00	$6,000	$30.00	$32,000	30.0%
B3 FITTING & EQUIPMENT					$10.00		
B31 Fitting & Fixtures	1.00	200 m2	$10.00	$2,000	$10.00		
B32 Equipment	0.00	m2		$0	$0.00		
B33 Conveying Systems	0.00	no		$0	$0.00	$2,000	1.9%
C SERVICES							
C1 MECHANICAL					$60.00		
C11 Plumbing & Drainage	1.00	200 m2	$0.00	$0	$0.00		
C21 Fire Protection	1.00	200 m2	$0.00	$0	$0.00		
C13 HVAC	1.00	200 m2	$50.00	$10,000	$50.00		
C14 Controls	1.00	200 m2	$10.00	$2,000	$10.00	$12,000	11.2%
C2 ELECTRICAL					$160.00		
C21 Service & distribution	1.00	200 m2	$0.00	$0	$0.00		
C22 Lighting, Devices & Heating	1.00	200 m2	$120.00	$24,000	$120.00		
C23 Systems & Ancillaries	1.00	200 m2	$40.00	$8,000	$40.00	$32,000	30.0%
NET BUILDING COST (Excluding Site)					$534.00	$106,800	100.0%
D2 ANCILLARY WORK					$70.00		
D21 Demolition	1.00	200 m2	$70.00	$14,000	$70.00		
D22 Alterations	0.00	0 m2	$0.00	$0	$0.00	$14,000	9.7%
NET BUILDING COST (Including Site)					$604.00	$120,800	307.2%

GFA:	200 m2	per m2	$534.00
GFA:	2,153 sf	per sf	$49.61

A REPORT TO
THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

	Electrical
	Mechanical
	Civil
	Protection & Control
	Transmission & Distribution
	Telecontrol
	System Planning

Upgrade Powerhouse Building Envelope

Holyrood

July 2015

newfoundland labrador hydro
a nalcor energy company

SUMMARY

The Holyrood Thermal Generating Station (Holyrood) powerhouse was constructed in two stages. Stage 1 was completed in 1968 and houses Generating Units 1 and 2. Construction of the Stage 2 powerhouse extension followed in 1976 and contains Generating Unit 3.

The vast majority of the powerhouse building envelope is original to the facility, prior to the 2015 roof replacements approved under Board Order No. P.U. 50(2014), portions of the powerhouse roofing system were last upgraded in 2005 and the only notable siding upgrades were completed in the early 1990's. A Level 2 condition assessment, completed by AMEC in 2013 and 2014, has concluded that various sections of the powerhouse roof and siding systems are at the end of their service life. The upgrades, outlined in this proposal, include the replacement of those siding and roof areas which have deteriorated to the point in which their integrity has been compromised.

Hydro requires that Holyrood continue to operate as a generating facility until the Labrador Island Link brings power to the island. Beyond that time, Unit 3 will remain vital to the Island Interconnected System and will continue to serve as a synchronous condenser[1] until 2041. To ensure the reliable operation of the facility, the proposed powerhouse roofing and siding upgrades are required.

[1] A synchronous condenser is a device identical to a synchronous motor, whose shaft is not connected to anything but spins freely. Iits purpose is not to convert electric power to mechanical power or vice versa, but to adjust conditions on the electric power transmission grid. Its field is controlled by a voltage regulator to either generate or absorb reactive power as needed to adjust the grid's voltage, or to improve power factor. The condenser's installation and operation are identical to large electric motors.

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1 INTRODUCTION

The Holyrood Thermal Generating Station (Holyrood) consists of three oil-fired generating units with a total net generating capacity of 465 MW. These units are vital to the Island Interconnected System and will be required to continue generating electricity until the Labrador Island Link brings power to the island. Beyond that time, Unit 3 will continue to be operated as a synchronous condenser.

The Holyrood powerhouse is required to continue as a functional operating facility until its anticipated end of service in 2041. The proposed upgrades are necessary to restore the integrity of the powerhouse building envelope. This multi-year program involves the replacement of all roofing areas, identified by AMEC as having a remaining service life of five years or less, at the time of the 2013 roof assessment (see Appendix A), and the replacement of deteriorated sections of siding, recommended for replacement in the 2014 siding assessment (see Appendix B).

2 PROJECT DESCRIPTION

This project is a multi-year program for the completion of upgrades to the Holyrood powerhouse building envelope. Upgrades will consist of the replacement of all Holyrood powerhouse roofing areas, deemed to have a remaining service life of less than two years, and the replacement of siding sections which are at the end of their service life.

The project scope includes:

- the replacement of deteriorated wood blocking;
- reinforcement of all perimeters, projections, and roof/wall junctions;
- supply and installation of new projection sleeves and insert drains;
- supply and installation of new vapour barrier and composite insulation;
- supply and installation of a new cold-applied roofing system;
- the installation of new flashing;
- replacement of existing notched z-bars;
- replacement of existing insulation;
- replacement of exterior siding panels; and
- supply and installation of trim around perimeter of new siding panels.

3 JUSTIFICATION

The Holyrood powerhouse contains the three oil-fired generating units and their associated controls equipment. This equipment is vital to the Island Interconnected System and the continued performance of the powerhouse building envelope is essential to ensure that the equipment is protected from the elements, enabling it to be operated in a safe and reliable manner.

In 2013, Hydro engaged AMEC to complete a Level 2 condition assessment of various civil structures and the Unit 3 generator. When completing the assessment, AMEC considered the future of the plant and optimization of the recommendations for investment to maintain a serviceable facility when identifying the prioritized list of replacement items. The assessment found that the majority of the powerhouse's 23 roofing areas are at the end of their service life and their replacement was recommended within five years from the time of the assessment.

Following the completion of the 2013 condition assessment, a large metal siding panel was ripped from the south side of powerhouse during a winter storm, see photo 1.



Photo 1: Location of Detached Siding Panel

While it is fortunate that there was no damage to persons or property, the event highlighted issues with the exterior siding and necessitated a closer look at the siding system. Consequently, Hydro engaged AMEC to further assess the powerhouse siding during the spring of 2014. The assessment found that various sections of the siding are at the end of their service life and their replacement was recommended. See photos 2 and 3.



Photo 2: Typical Siding Deterioration



Photo 3: Typical Siding Deterioration

Given the age and noted condition of the powerhouse building envelope components, the occurrence of leaks is imminent and the probability of a repeat “blow-off”, whereby components the envelope system could become completely detached from the structure, during periods of high wind, is greatly increased. While spot repairs can be enacted to address the occurrence of leaks, any repairs completed would be topical in nature and will not address the risk associated with the complete failure of the envelope components. Detachment of the envelope components could prove disastrous, leaving the building contents fully exposed and/or resulting in significant damage to persons and/or equipment. A proactive approach is required to ensure that the envelope upgrades can be completed prior to its failure.

3.1 Existing System

The Holyrood powerhouse roof is comprised of 23 distinct roofing areas (see Figure 1). The primary roofing types consist of Conventional Built-Up Roofs and Inverted Roofing Membrane Assemblies, the majority of which are nearing the end of their service life.

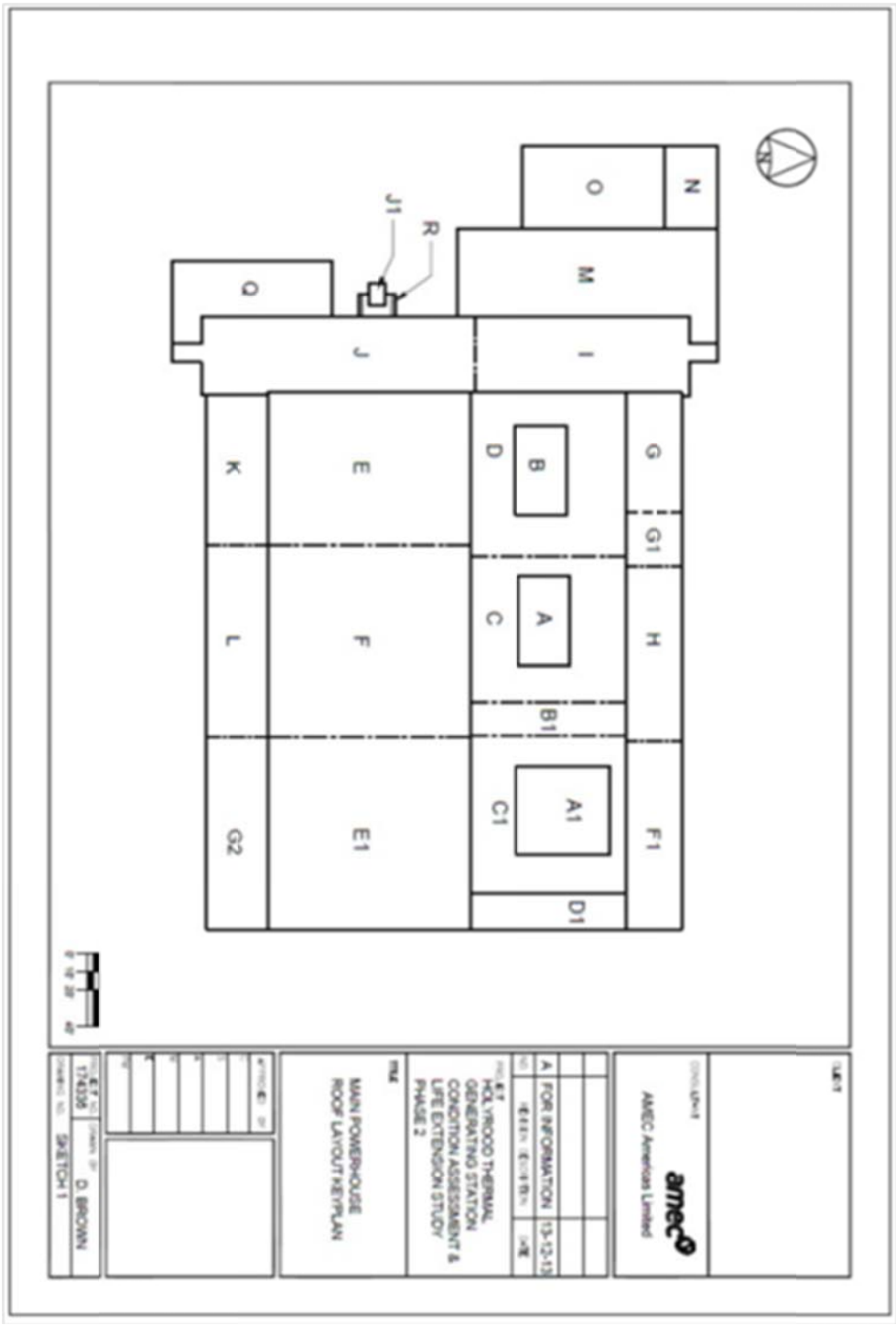


Figure 1: Holyrood Powerhouse Roof Plan

The building's exterior siding is comprised of an insulated steel siding system which spans, both vertically and horizontally, between the facility's primary structural members. Siding systems of this nature are typically installed by securing a steel liner panel directly to the

horizontal steel structural members. Notched Z-bars, fastened to the liner panel at four foot intervals, serve as the anchorage point to which the exterior siding panels are fastened. A common method of cladding industrial buildings, during the time period for construction of the thermal generating station, it is seldom used today.

The Holyrood Thermal Generating Station is approximately 40 years old. The majority of the exterior building envelope is original to the facility. Prior to the roofing replacement, approved under Board Order No. P.U. 50(2014), portions of the powerhouse roofing system were last upgraded in 2005 and the only notable siding upgrades were completed in 1993.

Siding upgrades were relatively minimal and consisted of the replacement of sections of siding along the upper level of the North and South sides of the plant and the replacement of fascia and soffit for the entire structure.

A summary of the major work and upgrades for the powerhouse roof are contained in Table 1.

Table 1: Major Work or Upgrades

Year	Major Work or Upgrade	Comments
2005	Miscellaneous repairs	Roof A
2005	1500 square feet of roof replaced	Roof G
2005	Roof Scanned, Miscellaneous Roof Repairs	Roof B
2005	Roof Scanned, Miscellaneous Roof Repairs	Roof B1
2005	Roof Scanned, Miscellaneous Roof Repairs	Roof C
2005	Miscellaneous Roof Repairs	Roof D
2005	Flashing repairs, re-application of coating and gravel	J1
2005	Reinforcement of rubber flashing, re-application of coating and gravel	Roof G2
2004	Repair of minor deficiencies	Roof H
2004	Rubber flashing repairs	Roof G1
2004	Spot applications of penefelt and gravel	Roof G
2004	Flashing repairs, penefelt patching	Roof F1
2004	Roof patching	Roof J
2004	16 ft2 wet insulation replaced, rubber flashing repairs, penefelt patching	Roof I
2004	Flashing repairs, roof patching	Roof K
2004	Flashing repairs, roof patching	Roof L
2003	Area of wet insulation replaced	Roof F
2003	Re-application of coating	Roof F1
2002	1800 ft2 of roof replaced	Roof F1
2002	375 square feet of wet insulation replaced	Roof G
2002	3 Ply walkway membrane installed	Roof G1
2000	Flashing repairs, Re-application of coating	Roof C
2000	Stones removed, coating applied	Roof B
2000	Re-application of coating	Roof G
2000	Re-application of coating system	Roof E
2000	Re-application of coating	Roof F

3.2 Operating Experience

The Holyrood powerhouse is required to be available for operation year round to service customers, as required.

The facility is exposed to strong, onshore winds on a regular basis. Continued battering of the weakened building envelope components by these winds creates a high potential for a repeat occurrence of the siding failure experienced in 2013.

3.2.1 Reliability Performance

While the powerhouse building envelope has performed well, it is nearing the end of its

service life and is starting to show signs of deterioration. Given the age and condition of the various envelope components, their integrity has been compromised.

Though the condition of the powerhouse building envelope is not directly related to the reliability of the Holyrood generating units, failure of the envelope components could potentially damage sensitive electronic equipment which may jeopardize the reliability of the units and, consequently, disrupt power supply to the Island Interconnected System.

3.2.2 Safety Performance

Sections of the powerhouse building envelope have exceeded their useful service life and, consequently, their integrity has been compromised. In 2013, a large piece of siding detached from the powerhouse during a winter storm and, while no one was injured, the outcome could have proved disastrous. The large piece of siding, carried by the wind, could have resulted in a serious injury and/or fatality were it to strike a person, or come into contact with critical equipment.

3.2.3 Vendor Recommendations

Condition assessments, completed by AMEC in 2013 and 2014, noted that the powerhouse building envelope is nearing the end of its service life. Based on the age and noted condition of the envelope, the implementation of a proactive replacement strategy was recommended.

3.2.4 Maintenance or Support Arrangements

Routine maintenance work for this asset is typically completed by Holyrood services personnel with any significant maintenance requirements being carried out by external contractors.

3.2.5 Maintenance History

The only maintenance recorded pertaining to the siding for the HRD Main Powerhouse,

involved the replacement of the siding panel which had become detached from the powerhouse in 2014. The corrective maintenance costs to complete this replacement totaled $25,300.

There has been no corrective or preventive maintenance completed on the powerhouse roof within the past five years. Capital investment in the powerhouse roof is approved for 2015, and a portion of the roof is to be replaced in this year.

3.2.6 Historical Information

There is no recent historical information relevant to the proposed siding replacement.

Recent roof replacement work, completed by Hydro, consists solely of the Hydro Place mechanical penthouse roof replacement. Information pertaining to this work is outlined in Table 2 below.

Table 2: Historical Information

Year	Capital Budget ($000)	Actual Expenditures ($000)	Units(m^2)	Cost per unit ($000)	Comments
2015B	1,047.8	-	1918		Upgrade Powerhouse , Roof Holyrood(Year 1)
2015B	671.9	-	1393		Replace Roof, Hydro Place(Year 1)
2013	199.7	162.9	450	0.4	Replace Penthouse Roof, Hydro Place

3.2.7 Anticipated Useful Life

Roofing systems typically carry an anticipated useful life of 25 years. Metal siding systems, such as those utilized at the Holyrood Thermal Generating Station, typically have an estimated service life of approximately 40 years.

3.3 Development of Alternatives

The powerhouse building envelope components, designated to be replaced under this proposal, are at the end of their service life. Given their age and current condition, the completion of repairs would not be appropriate.

While isolated repairs can be completed to address the occurrence of leaks, any such repairs are topical in nature and will not address concerns pertaining to the ability of the building envelope components to adhere to the structure. Replacement is the only viable alternative to ensure that the powerhouse envelope's' integrity is restored.

4 CONCLUSION

The building envelope components designated for replacement under this proposal are nearing the end of their service life. They are starting to show signs of deterioration, typical of their age, and will continue to deteriorate over the next few years. If left unaddressed, the building envelope will inevitably form leaks and is at risk of failing completely.

Given the findings of the AMEC condition assessments, a proactive approach is required to restore the integrity of the powerhouse building envelope.

4.1 Budget Estimate

The budget estimate for this project is shown in Table 3.

Table 3: Project Budget Estimate

Project Cost:*($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	492.7	492.7	259.4	1,244.7
Consultant	90.0	90.0	30.0	210.0
Contract Work	1,462.5	1,605.9	250.0	3,318.4
Other Direct Costs	111.4	112.4	52.9	276.7
Interest and Escalation	136.1	208.8	73.3	418.2
Contingency	431.2	460.1	118.5	1,009.8
TOTAL	**2,723.8**	**2,969.9**	**784.1**	**6,477.8**

4.2 Project Schedule

The anticipated project schedule for this work is provided in Table 4.

Table 4: Project Schedule

Activity		Start Date	End Date
Planning	Project Start-Up, Scope Statement, Schedule	February 2016	March 2016
Consultant Engagement	Issue RFP and Select Consultant	March 2016	April 2016
Design	Preparation of Tender Package	April 2016	May 2016
Procurement	Tender and Award (Year 1)	May 2016	June 2016
	Tender and Award (Year 2)	March 2017	April 2017
	Tender and Award (Year 3)	March 2018	April 2018
Construction	Building Envelope Upgrades (Year 1)	June 2016	October 2016
	Building Envelope Upgrades (Year 2)	June 2017	October 2017
	Building Envelope Upgrades (Year 3)	June 2018	August 2018
Commissioning	Final Inspection and Acceptance (Year 1)	-	October 2016
	Final Inspection and Acceptance (Year 2)	-	October 2017
	Final Inspection and Acceptance (Year 3)	-	August 2018
Closeout	Interest Cut-Off, Certificate of Completion, PIR	-	October 2018

APPENDIX A

Holyrood Thermal Generating Station

Level 2 Condition Assessment

Civil Structures and Unit 3 Generator (Roof Condition and Risk Summary)

6.0 CONDITION AND RISK SUMMARY

The following table summarizes component level condition, and the technical and safety risk for the components addressed in the current report for Holyrood TGS. It is to be noted that the desired remaining life for the components assessed in this report is 30 years (to 2041).

The risk rankings and mitigating actions considered the 30 year life horizon. Risk is assessed relative to technical and economic (Techno-Eco) risk, and Safety risk. Techno-Eco risk includes repair and lost generation revenue (outage time). The likelihood ranking (and risk) is biased to the near term generating period.

Safety risk represents safety to site based personnel.

Where identified, asset designation is provided based on the asset register identified in the Phase 1 final report [R-1].

Asset Register

Asset Class:	BU 1296 Assets Generation
	BU 1297 Assets Commons
	BU 1325 Assets Holyrood Switchyard
Asset Level 2	7635 #2 (Unit 2), 6690 #1 (Unit 1)
	Buildings and Site – 7255
	Water Treatment and Environment – 9739
	Unit 3 Generator – 8193
Asset Level 3:	Buildings – 272255
	Waste Water Treatment System – 10038
	Drainage – 6781 #1, 7699 #2, 8257 #3
	Unit 3 Generator – 8194

Asset number beyond Level 3 is provided in Table 4. For each risk ranking, the expected failure event is described. Mitigating actions are also described. The actions are intended to reflect the component level recommendations in Section 7.

Table 4 Condition Summary and Risk Assessment

Asset # 3	Asset # 4	Asset # 5	Description	Component	Major Issues	Remaining Life Years[2]		Remaining Life Comments	TECHNO-ECONOMIC ASSESSMENT MODEL			SAFETY RISK ASSESSMENT MODEL			Possible Failure Event	HS Ignition
						Un-sufficient Info - Inspection Required			Likelihood	Consequence	Risk Level	Likelihood	Consequence	Safety Risk		
Main Powerhouse Roof Assessment																
272285	3263	0	Roof A - BUR w/ aluminized coating	epoxied to view roofing membrane	hairline cracks in aluminized coating	2		2 to likely that cracks will spread and deepen to the desktop	3	A	LOW	2	C	MED	failure could include leaking and/or blow-off. Leaking could be detrimental to electrical equipment while flying debris could be injurious to persons and equipment.	Immediate spot repairs recommended - annual inspection thereafter
272285	3263	0	Roof A1 - Inverted roofing system	roofing membrane below insulation and stone ballast - cannot be seen	minor damage to counter flashing - light failure bolted through parapet	10		this roof should perform well as long as the minor issues indicated are addressed quickly	2	A	LOW	2	D	HIGH	failure could include leaking and/or blow-off. Leaking could be detrimental to electrical equipment while flying debris could be injurious to persons and equipment.	annual inspection to ensure adequate depth of stone ballast + condition of penetrations
272285	3263	0	Roof B - BUR w/ aluminized coating	epoxied to view roofing membrane	insulation board shapes fdisplaced through membrane - membrane cracking evident	2		it is likely that cracks will spread and deepen to the extent that leaks will develop	3	A	LOW	2	C	MED	failure could include leaking and/or blow-off. Leaking could be detrimental to electrical equipment while flying debris could be injurious to persons and equipment.	Immediate spot repairs recommended - annual inspection thereafter
272285	3263	0	Roof B1 - BUR w/ aluminized coating	epoxied to view roofing membrane	hairline cracks in aluminized coating	5		it is likely that cracks will spread and deepen to the extent that leaks will develop	2	A	LOW	2	C	MED	failure could include leaking and/or blow-off. Leaking could be detrimental to electrical equipment while flying debris could be injurious to persons and equipment.	Immediate spot repairs recommended - annual inspection thereafter
272285	3263	0	Roof C - BUR w/ aluminized coating	epoxied to view roofing membrane	large asphalt patch on roof - stain showing from centre of 3 roof drain	5		though this roof is in fair condition, it is likely to develop cracking in the relatively near future	2	A	LOW	2	C	MED	failure could include leaking and/or blow-off. Leaking could be detrimental to electrical equipment while flying debris could be injurious to persons and equipment.	annual ffs could be performed to spot repairs and re flooding/ponding
272285	3263	0	Roof C1 - Inverted roofing system	roofing membrane below insulation and stone ballast - cannot be seen	filter fabric not evident - minor wind scouring considered	8		as the roof is missing filter fabric and there has been wind scouring of stone ballast, it is possible that this roof will fail prematurely	2	A	LOW	2	D	HIGH	failure could include leaking and/or blow-off. Leaking could be detrimental to electrical equipment while flying debris could be injurious to persons and equipment.	inspect insulation and EPDM membrane and check for and replace filter fabric. Add stone ballast to ensure required coverage and depth. Annual inspection thereafter.
272285	3263	0	Roof D - BUR w/ aluminized coating	epoxied to view roofing membrane	Partial denuding - evidence of screening prior to coating application - ridging and cracking evident	2		it is likely that cracks will spread and deepen to the extent that leaks will develop	3	A	LOW	2	C	MED	failure could include leaking and/or blow-off. Leaking could be detrimental to electrical equipment while flying debris could be injurious to persons and equipment.	Immediate spot repairs recommended - annual inspection thereafter

[2] It is assumed the units have and will continue to be operated within limits (temperatures and pressures) specified by operating procedures.

Asset # 3	Asset # 4	Asset # 5	Description	Component	Major Issues	Remaining Life Years		Remaining Life Comments	TECHNO-ECO RISK ASSESSMENT MODEL			SAFETY RISK ASSESSMENT MODEL			Possible Failure Event	Mitigation
						(Cost Efficient Life - Investigation Required)			Likelihood	Consequence	Risk Level	Likelihood	Consequence	Safety Risk		
272.255	7203	0	Roof D1 - Inverted roofing system	roofing membrane below insulation and stone ballast - carried to min	roof drain - grassed over - several protruding building columns cape exposed - - litter/debris needs replacement in areas - stone ballast evident to rear/flat fabric - patch pockets at steps from interior of building to roof	10		this roof is in fair condition and should perform well with suggested mitigation	2	A	LOW	2	D	HIGH	flakes cold/chokes leaking and/or blows-off. Leaking could be detrimental to electrical equipment while flaking debris could be injurious to persons and equipment.	rake existing stone ballast and add additional ballast to ensure required coverage and depth - annual inspection there
272.255	7203	0	Roof E - BUR w/ aluminized coating	exposed to view roofing membrane	some ridging and denuding - - broken light fixture not well secured - steam from one roof drain	5		it is likely that cracks will spread and deepen to the extent that leaks will develop	2	A	LOW	2	C	MED	flakes cold/chokes leaking and/or blows-off. Leaking could be detrimental to electrical equipment while flaking debris could be injurious to persons and equipment.	immediate spot repairs recommended - annual inspection thereafter
272.255	7203	0	Roof E1 - Inverted roofing system	roofing membrane below insulation and stone ballast - carried to min	minor denuding - varying thickness patio slabs - stone ballast requires raking	10		this roof should perform well as long as the minor issues noted are corrected relatively quickly	2	A	LOW	2	D	HIGH	flakes cold/chokes leaking and/or blows-off. Leaking could be detrimental to electrical equipment while flaking debris could be injurious to persons and equipment.	rake existing stone ballast and add additional ballast to ensure required coverage and depth - annual inspection there
272.255	7203	0	Roof P - BUR w/ aluminized coating	exposed to view roofing membrane	10 m x 15 m patch of unknown material - 1 x 3 metre asphalt patch at east roof divider - minor membrane cracking evident - insulation board shapes	2		it is likely that cracks will spread and deepen to the extent that leaks will develop	3	A	LOW	2	C	MED	flakes cold/chokes leaking and/or blows-off. Leaking could be detrimental to electrical equipment while flaking debris could be injurious to persons and equipment.	immediate spot repairs recommended - annual inspection thereafter
272.255	7203	0	Roof F1 - unknown fully adhered membrane w/ aluminized coating	exposed to view roofing membrane	50% of roof is unknown membrane - 5% of roof is BUR w/o coating - there is standing water at parapet	2		membrane (other than the portion which is BUR) is very soft and susceptible to penetration by slight impact - both membranes in poor condition.	3	A	LOW	2	C	MED	flakes cold/chokes leaking and/or blows-off. Leaking could be detrimental to electrical equipment while flaking debris could be injurious to persons and equipment.	immediate assessment recommended - remedial action to be based on outcome of assessment - annual inspection thereafter
272.255	7203	0	Roof G - unknown fully adhered membrane w/ aluminized coating	exposed to view roofing membrane - 5 traffic pads around to membrane	unknown membrane type - soft - susceptible to puncturing	2		unknown membrane type - soft - susceptible to puncturing	3	A	LOW	2	C	MED	flakes cold/chokes leaking and/or blows-off. Leaking could be detrimental to electrical equipment while flaking debris could be injurious to persons and equipment.	immediate assessment recommended remedial action to be based on outcome of assessment - annual inspection thereafter
272.255	7203	0	Roof G1 - unknown fully adhered membrane w/ aluminized coating	exposed to view roofing membrane	unknown membrane type - soft - susceptible to puncturing	2		unknown membrane type - soft - susceptible to puncturing	3	A	LOW	2	C	MED	flakes cold/chokes leaking and/or blows-off. Leaking could be detrimental to electrical equipment while flaking debris could be injurious to persons and equipment.	immediate assessment recommended remedial action to be based on outcome of assessment - annual inspection thereafter
272.255	7203	0	Roof G2 - unknown fully adhered membrane w/ aluminized coating		50% of roof is unknown membrane - 50 % of roof is BUR w/o coating - there is standing water at parapet	2		membrane (other than the portion which is BUR) is very soft and susceptible to penetration by slight impact - both membranes in poor condition.	3	A	LOW	2	C	MED	flakes cold/chokes leaking and/or blows-off. Leaking could be detrimental to electrical equipment while flaking debris could be injurious to persons and equipment.	immediate assessment recommended remedial action to be based on outcome of assessment - annual inspection thereafter
272.255	7203	0	Roof H - unknown fully adhered membrane w/ aluminized coating	exposed to view roofing membrane - 5 traffic pads around to membrane	unknown membrane type - soft - susceptible to puncturing	2		unknown membrane type - soft - susceptible to puncturing	3	A	LOW	2	C	MED	flakes cold/chokes leaking and/or blows-off. Leaking could be detrimental to electrical equipment while flaking debris could be injurious to persons and equipment.	immediate assessment recommended remedial action to be based on outcome of assessment - annual inspection thereafter

AMEC NSS Limited
AM141/R/0002 R00

Asset # 3	Asset # 4	Asset # 5	Description	Component	Major Issues	Remaining Life Years		Remaining Life Comments	TECHNO-ECO RISK ASSESSMENT MODEL			SAFETY RISK ASSESSMENT MODEL			Possible Failure Event	Mitigation
						(Insufficient Info - Inspection Required)			Likelihood	Consequence	Risk Level	Likelihood	Consequence	Safety Risk		
272.255	7263	0	Roof I - BUR - no coating	exposed to view roofing membrane	roof does not drain well - standing water - ridging evident - partial denuding		5	It is likely that denuding will spread over time thus exposing more of the felt roofing membrane to UV rays and therefore degradation	2	A	LOW	2	C	MED	Blaire cold lockjab leaking and/or blow-off. Leaking could be detrimental to electrical equipment while flying debris could be injurious to persons and equipment.	immediate spot repairs recommended - annual inspection thereafter
272.255	7263	0	Roof J - BUR - no coating	exposed to view roofing membrane	minor denuding - 14 concrete anchor fence supports laid on roofing membrane - standing water - ridging		5	It is likely that denuding will spread over time, thus exposing more of the felt roofing membrane to UV rays and therefore degradation	2	A	LOW	2	C	MED	Blaire cold lockjab leaking and/or blow-off. Leaking could be detrimental to electrical equipment while flying debris could be injurious to persons and equipment.	immediate spot repairs recommended - annual inspection thereafter
272.255	7263	0	Roof JL - BUR - no coating	exposed to view roofing membrane	Roof generally in poor condition - roof access hatch open - scupper - does not drain well		4	The roof is likely to have its service life reached and roof upgrading is carried out to it	2	A	LOW	2	C	MED	Blaire cold lockjab leaking and/or blow-off. Leaking could be detrimental to electrical equipment while flying debris could be injurious to persons and equipment.	
272.255	7263	0	Roof K - BUR - no coating	exposed to view roofing membrane	1 x 1.2 x 1.2 m high hydrogen piping penetration enclosures - minor denuding - ridging and scouring - sleepers for 2 cooling units - penetrations for hydrogen gas pipes		5	It is likely that denuding and scouring will spread over time, thus exposing more of the felt roofing membranes to UV rays and therefore degradation - sleeper and penetration flashing to be checked	2	A	LOW	2	C	MED	Blaire cold lockjab leaking and/or blow-off. Leaking could be detrimental to electrical equipment while flying debris could be injurious to persons and equipment.	immediate spot repairs recommended - annual inspection thereafter
272.255	7263	0	Roof L - BUR - no coating	Exposed to view roofing membrane	1 x 1.2 x 1.2 m high hydrogen piping penetration enclosures - minor denuding, ridging and scouring - sleepers for 2 cooling units - penetrations for hydrogen gas pipes		5	It is likely that denuding and scouring will spread over time, thus exposing more of the felt roofing membranes to UV rays and therefore degradation - sleeper and penetration flashing to be checked	2	A	LOW	2	C	MED	Blaire cold lockjab leaking and/or blow-off. Leaking could be detrimental to electrical equipment while flying debris could be injurious to persons and equipment.	immediate spot repairs recommended - annual inspection thereafter
272.255	7263	0	Roof M - Inverted roofing system	roofing membrane below and insulation and stone ballast - cannot be seen	ballast depth good in order - minor denuding - ridges, cracks and insulation visible		10	this roof should perform well as long as the minor issues indicated are addressed quickly	2	A	LOW	2	D	HIGH	Blaire cold lockjab leaking and/or blow-off. Leaking could be detrimental to electrical equipment while flying debris could be injurious to persons and equipment.	Inspect insulation and EPDM membrane and repair as necessary - check for and replace displaced insulation. Re-ballast to ensure required coverage and depth. Annual inspection thereafter.
272.255	7263	0	Roof N - BUR - no coating	Exposed to view roofing membrane	minor denuding - roof sloped to gravel stop roof edge to drain through 2 scuppers		10	this roof should perform well as long as the minor issues indicated are addressed quickly	2	A	LOW	2	C	MED	Blaire cold lockjab leaking and/or blow-off. Leaking could be detrimental to electrical equipment while flying debris could be injurious to persons and equipment.	immediate spot repairs recommended - annual inspection thereafter
272.255	7263	0	Roof O - standing seam metal roof	visible steel roof with visible standing seams at 600 mm cc.	evidence of field applied repair on small portion of roof - some paint missing from roof panels - evidence of rust in some locations		10	this roof should perform well as long as the minor issues indicated are addressed quickly	2	A	LOW	2	D	HIGH	Blaire cold lockjab leaking and/or blow-off. Leaking could be detrimental to electrical equipment while flying debris could be injurious to persons and equipment.	address rusting of steel roof panels and apply protective coating or paint

Asset # 3	Asset # 4	Asset # 5	Description	Component	Major Issues	Remaining Life Years		Remaining Life Comments	TECHNO-ECO RISK ASSESSMENT MODEL			SAFETY RISK ASSESSMENT MODEL			Possible Failure Event	Mitigation
						Client/Most Likely Remaining	Engineering Required		Likelihood	Consequence	Risk Level	Likelihood	Consequence	Safety Risk		
272255	7283	0	Roof Q - standing seam metal roof	exposed to unheated roof with visible standing seams at 600 mm o/c.	some paint missing from roof panels - evidence of rust in some locations - multi penetrations through this roof	10		the roof should perform well as long as the minor issues indicated are addressed quickly	2	A	LOW	2	D	HIGH	failure could include leaking and/or blow-off. Leaking could be detrimental to electrical equipment while blow offs could be a hazard to persons and equipment.	address rusting of steel roof panels and apply protective coating or paint
Overhead Door Assessment																
272255	35796	35795	Door # 1	insulated multi-blade - power operated - auxiliary chain operation - safety feature	auxiliary chain mechanism inoperable - chain not tethered - significant rust to door panels - weatherstripping requires replacement - door remains open 130 mm at the bottom	15		rust may increase - inoperable chain hoist will render door out of service during power outage - draft, and rain / snow drift through door perimeter where weatherstripping is defective	1	A	LOW	2	D	HIGH	door failure could result in open door free falling onto persons or equipment - door jamming in partial or full open position causing inclement weather to affect the interior of the plant	annual inspection to ensure proper operation - including lubrication, tension adjustments, motor, control and safety feature. inspection and part/unit replacement.
272255	35796	35795	Door # 2	insulated multi-blade - power operated - auxiliary chain operation - safety feature	noisy / erratic operation - significant rust to door panels - no weatherstripping - water ingress at door bottom - significant rust to door panels and steel frame	10		rust may increase - draft, and rain / snow drift through door perimeter where weatherstripping is defective - door may jam open or closed	2	A	LOW	2	D	HIGH	door failure could result in open door free falling onto persons or equipment - door jamming in partial or full open position causing inclement weather to affect the interior of the plant	immediate attention required to address identified issue - annual inspection thereafter to ensure proper operation - including lubrication, tension adjustments, motor, control and safety feature. inspection and part/unit replacement.
272255	35796	35795	Door # 2A	insulated sectional overhead door - power operated - auxiliary chain operation - safety feature	door rail out of alignment and required technician to adjust - minor rust to door panels - door was never painted	15		rust may increase - door may jam partially open or closed	1	A	LOW	2	D	HIGH	door failure could result in open door free falling onto persons or equipment - door jamming in partial or full open position causing inclement weather to affect the interior of the plant	annual inspection to ensure proper operation - including lubrication, tension adjustments, motor, control and safety feature. inspection and part/unit replacement.
272255	35796	35795	door # 3	uninsulated steel roll-up door - manual chain operation only - no safety feature	exterior and interior door surfaces exceedingly rusty - door bows inwards in strong wind - door excessively difficult to operate - weatherstripping in poor condition	3		rust may increase - draft, and rain / snow drift through door perimeter where weatherstripping is defective - door may jam open or closed	2	A	HIGH	2	D	HIGH	door failure could result in door blow-out - door jamming in partial or full open position causing inclement weather to affect the interior of the plant	immediate attention required to address identified issue - annual inspection thereafter to ensure proper operation - including lubrication, tension adjustments, motor, control and safety feature. inspection and part/unit replacement.
272255	35796	35795	Door # 4	insulated multi-blade - power operated - auxiliary chain operation - safety feature	door rail out of alignment and required technician to adjust. - surface rust to outside of door panels - no weatherstripping	15		rust may increase - draft, and rain / snow drift through door perimeter where weatherstripping is defective - door may jam open or closed	1	A	LOW	2	D	HIGH	door failure could result in open door free falling onto persons or equipment - door jamming in partial or full open position causing inclement weather to affect the interior of the plant	annual inspection to ensure proper operation - including lubrication, tension adjustments, motor, control and safety feature. inspection and

APPENDIX B

Existing Siding Assessment

Holyrood Thermal Generating Station

Condition Assessment & Life Extension Study

Phase 2

EXISTING SIDING ASSESSMENT
HOLYROOD THERMAL GENERATING STATION
CONDITION ASSESSMENT & LIFE EXTENSION STUDY
PHASE 2

FOR

NALCOR ENERGY

Prepared for:

Newfoundland and Labrador Hydro
PO Box 12400
500 Columbus Drive
St. John's, NL

Prepared by:

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Suite 2002
St. John's, NL
A1A 3C1

Date: **July 22, 2014**

AMEC Ref. No.: **176690-0000-CD10-RPT-0001**

Existing Siding Assessment
Holyrood Thermal Generating Station
Condition Assessment & Life Extension Study
Phase 2

FOR

Nalcor Energy

PROVINCE OF NEWFOUNDLAND AND LABRADOR
PEG Newfoundland and Labrador
PROFESSIONAL ENGINEERS AND GEOSCIENTISTS
PERMIT HOLDER
This Permit Allows
AMEC AMERICAS LIMITED
To practice Professional Engineering
in Newfoundland and Labrador.
Permit No. as issued by PEG D0018
which is valid for the year 2014 .

REGISTERED PROFESSIONAL ENGINEER
PEG Newfoundland and Labrador
KIRK D. KENDALL
SIGNATURE
DATE
NEWFOUNDLAND & LABRADOR

REV.	DATE	REVISION(S)	PREPARED BY	CHECK	APP	CLIENT
C	July 22, 2014	Final Report Re-Issued	LR	KK	KK	
B	July 2, 2014	Final Report Issued	LR	KK	KK	
A	June 18, 2014	Issued for Review	LR	KK	KK	

amec	Existing Siding Assessment Holyrood Thermal Generating Station Condition Assessment & Life Extension Study Phase 2	AMEC JOB NO. 176690
		REPORT NO. 176690-0000-CD10-RPT-0001 / REV. C
		PAGE 1 OF 1

IMPORTANT NOTICE

This Report was prepared exclusively for **NALCOR ENERGY,** AMEC Americas Limited, a wholly owned subsidiary of AMEC Inc. The quality of information contained herein is consistent with the level of effort involved in AMEC Americas Limited and based on : i) information available at the time of preparation, ii) data supplied by outside sources, and iii) the assumptions, conditions and qualifications set forth in this report. This report is intended to be used by **NALCOR ENERGY** only, subject to the terms and conditions of its contract with AMEC. Any other use of, or reliance on, this report by any third party is at that party's sole risk.

ENF.04 Rev. 2

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1.0 GENERAL

The following are recommendations stemming from AMEC's evaluation of the condition of the original siding system of the Holyrood Thermal Generating Plant. This set of recommendations is based on what was visibly identifiable during three site visits made by David Osborne and Leo Reddy of AMEC Power and Process, St. John's, NL Office, on May 07, May 13 and June 05, 2014.

Given its extensive experience with the design of steel clad buildings and observation of weathering and damage to siding over its service lifetime on other projects, AMEC bases its recommendations on visual analysis and, when accessible, physically handling siding to ascertain its condition.

2.0 HISTORY

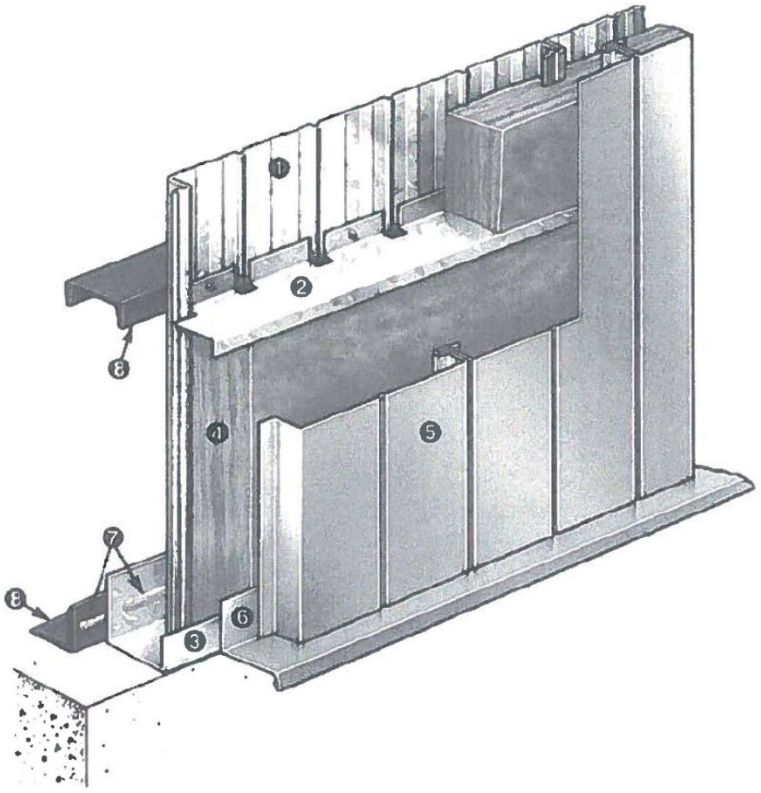
Holyrood Thermal Generating Station's Plant Building is approximately 40 years old. The original building's exterior wall is comprised of an insulated steel siding system which spans vertically between the Plant's horizontal structural members. Spans vary but can be seen to be approximately 2.1 metres (7'-0") on centre. This type of wall system was assembled by securing a steel liner panel directly to the horizontal steel members. Then, horizontal notched Z-bars were secured to the liner sheet at approximately 1200 mm o.c. vertically as intermediate members. Finally, the exterior steel siding paneling was secured to the notched Z-bars with the space between the sheets filled with batt insulation. Note that the spanning ability of two steel panels acting in tandem as described above affords a greater vertical span that single sheet steel siding acting alone. A common method of cladding industrial buildings in that era, this method of cladding is seldomly used today.

See the attached details, identified as Detail "A" and Detail "B", which illustrate the type of siding system employed on the Plant.

2.1 DETAIL "A"

INSULATED METAL SIDING SYSTEM – exterior view

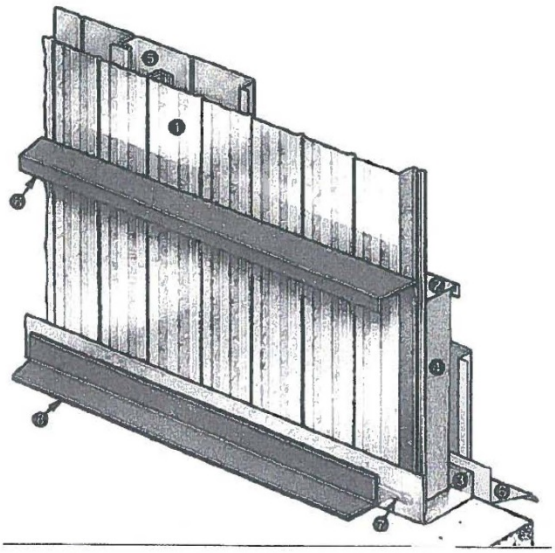
1. Interior steel liner sheet
2. Notched steel Z bars @ 1200 mm o.c. +/-
3. U-channel or other shape structural girt
4. Fibreglass insulation
5. Exterior steel cladding
6. Exterior metal drip
7. Sealant
8. Structural steel building frame @ 2100 mm o.c. ±vertically.

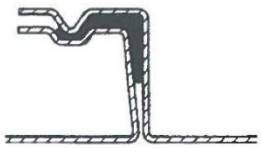


2.2 DETAIL "B"

INSULATED METAL SIDING SYSTEM – interior view

1. Interior steel liner sheet
2. Notched steel Z bars @ 1200 mm o.c. +/-
3. U-channel sub-girt
4. Fibreglass insulation
5. Exterior steel cladding
6. Exterior metal drip
7. Sealant
8. Structural steel building frame @ 2100 mm o.c. ±vertically.
9. See side lap detail below for interior liner sheet





Side Lap Detail
with factory (or field)
applied caulking

3.0 FINDINGS

Visual examination of the wall system revealed:

- There is a section of steel siding missing from the South Elevation, which is approximately 2.13m x 4.6m (7'-0 x 5'-0). AMEC was advised that this siding was dislodged from the building face during the previous winter and was blown off the roof.
  - A piece of siding carried by the wind could seriously injure a person upon impact.
  - Additionally, had this siding come in contact with electrical equipment, power outages could have occurred.
- Exterior steel siding varies in condition from small areas of non-existent material to extremely rusty to solid construction.
- The siding's original paint finish, Galbestos, varies in condition from flaky to good.
- Previously replaced siding is in good condition except in one location where it has sustained impact damage.
- The interior steel liner sheet appears to be in good condition throughout.
- Notched Z bars, from the few that were visible, appear to be in good condition.
- Most of the deteriorated siding appears along the Building's south elevation.
- Deteriorated siding appears mostly at the bottom of walls and over openings in the wall system, such as at doors, windows, louvres and the like.
- The original exterior siding profile is 38 mm deep and is of a common configuration.
- Previous repairs to the original siding appear to have been made by cutting away the affected area and providing new material which would span from the base of the affected wall to the nearest horizontal structural member.
- The perimeter of repair infills were trimmed using standard trim or drip pieces, which is a common approach to this type of repair/replacement work.
- AMEC's recommended replacement of existing rusted siding will follow the repair methods previously used, that is.
  - Replacement siding will span between horizontal structural steel members.
  - Note that replacement of siding in lengths which would not span between structural members is not recommended.

4.0 DEFINITIONS, COSTS AND DELIVERY TIME

4.1 DEFINITION

- Work means the removal (abatement) and disposal of existing steel siding, notched Z-bars and insulation, and,
- The installation of replacement notched Z-bars, insulation and steel siding.

4.2 REPLACEMENT COST:

- AMEC recommends a budget price of $155 per m2 ($14 per ft.2) to $200 per m2 ($18 per ft.2) for the replacement of steel siding as defined above.
  - Source: Trico Limited, St. John's.

4.3 DELIVERY TIME

- Replacement siding is expected to be in St. John's 4 - 6 weeks after order placement.
- Longest anticipated delivery time is 6 – 8 weeks.
  - Source: Trico Limited, St. John's.

5.0 RECOMMENDATIONS

5.1 DRAWINGS – APPENDIX A:

See attached drawings for locations of areas recommended for replacement this year. Replacement is recommended to exterior steel sheet siding only.

As the existing siding was finished with asbestos –containing coating (Galbestos), its removal will constitute an asbestos abatement process which will need to be performed by a licensed contractor, in accordance with authorities having jurisdiction.

5.2 PHOTOGRAPHS – APPENDIX B:

See attached photographs as referred to on the drawings

5.3 PRIORITIES

AMEC recommends the following order of priority;

Priority 1

All that work recommended for the **South Elevation**, namely;
Area 3: see photos 3519 and 3521.
Area 7: see photos 3586 and 3588
Area 9: see photos P5070019, P5070020, P5070021, P5070036, P5070022 and P5070031
Areas 12, 13, 14, 15, 16, 17: see photos 3689, 3690, 3691 and 3692.

The South Elevation is the side of the Plant facing the Switch Yard. There are minor entrances/exits on this building face as well as an overhead door so there is a potential for personal injury should siding become airborne. Since there is also critical equipment adjacent to the south building face, it is best to reduce the possibility of siding blow-off from this elevation which could cause major interruption to power generation if siding debris comes in contact with power generating equipment.

Recommended Time Frame

2014 construction season.

Project estimate: $435,000.00 including HST.

Priority 2

All that work recommended for the **East and West Elevations**, namely;

East Elevation:

Area 2: see photos 3519 and 3521.

Area 6: see photos 3598 and 3600.

Area 11: see photos 3664 and 3665.

The east elevation contains multiple overhead doors and minor person entrance doors. There is the possibility of personal injury if siding was to blow off this building face.

West Elevation

Area 8: see photos 3554, 3558, 3548 and 3552

It is considered moderately less likely that a siding blow-off from the East and West Elevations could affect the Plant as described above.

The plant office main entrance is located on the West building face, in addition to overhead doors and minor person entrances. Therefore, person traffic can be dense at times with the likelihood of multiple personal injuries in the event of siding blow-off.

Recommended Time Frame

2015 construction season.

Project estimate: $450,000.00 including HST.

Priority 3

All that work recommended for the North Elevation, namely;

Area 1: see photos 3519 and 3521.

Area 5: see photos 3529, and 3537

Area 10: see photos 3668 and 3671

The North Elevation is considered the rear of the Plant in the context of this report. A siding blow-off from this side of the Plant which could cause damage to power generation is unlikely. But since these are minor person doors and overhead doors, there could be a risk to persons.

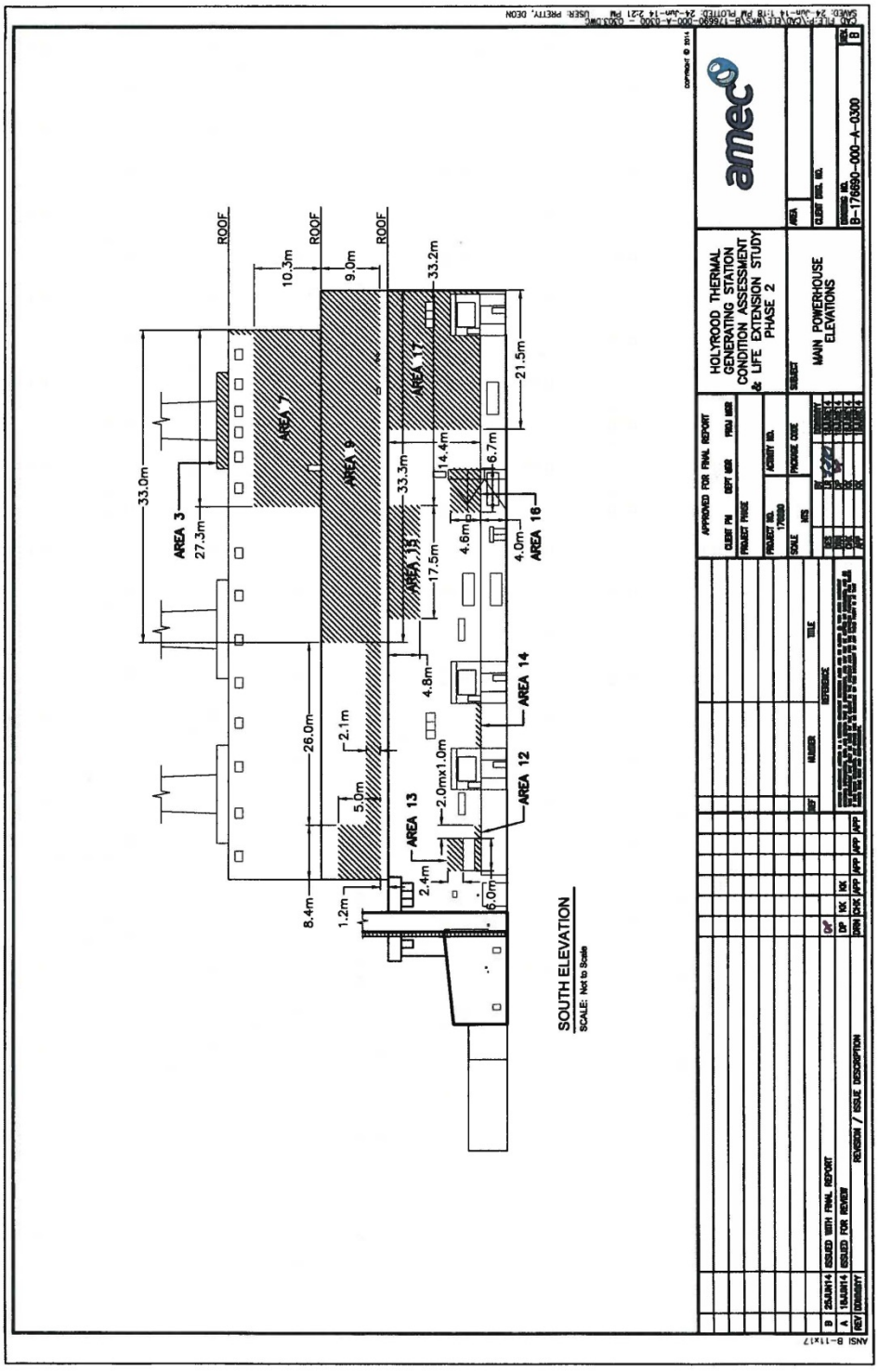
Recommended Time Frame

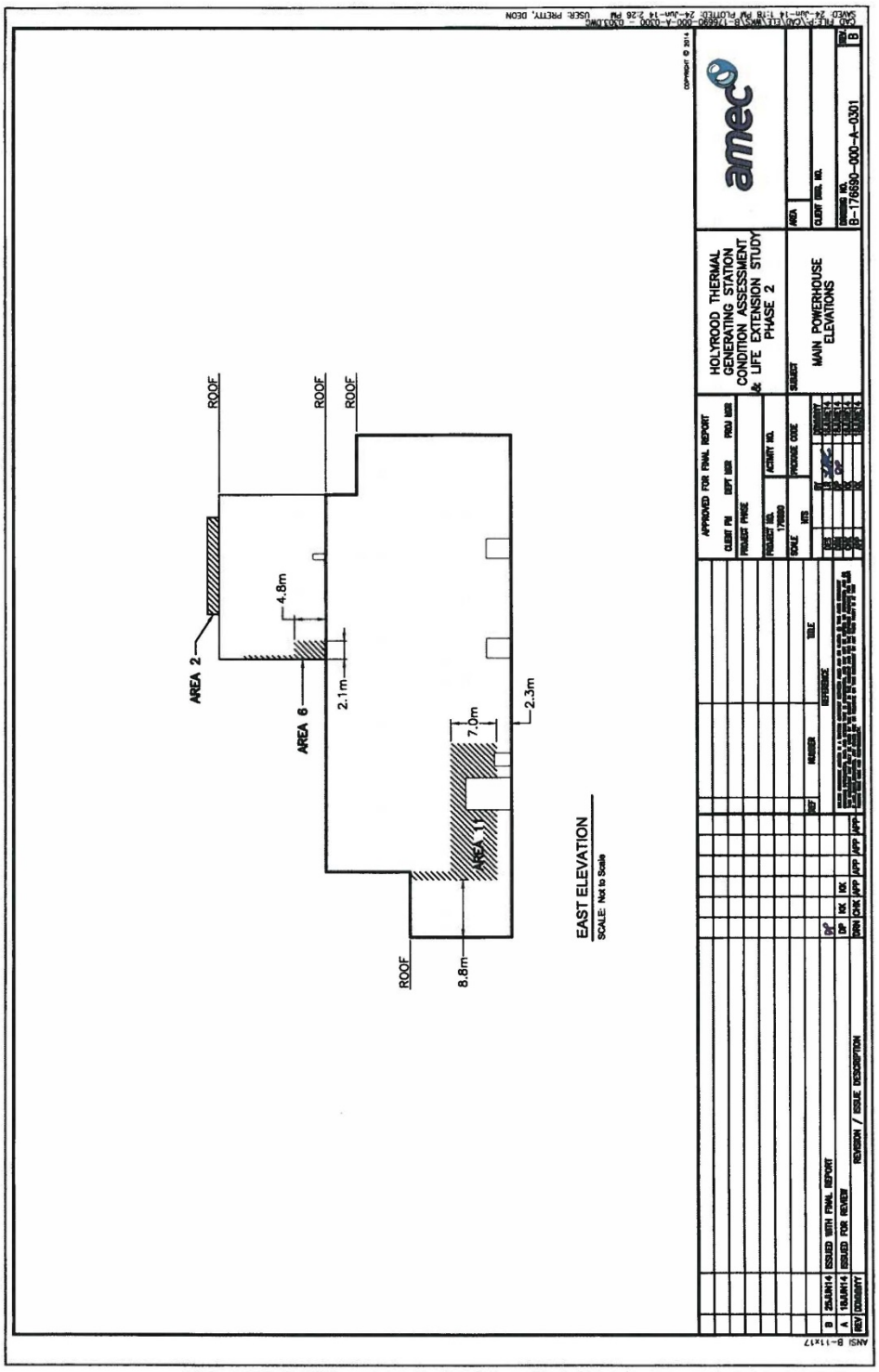
2015 construction season.

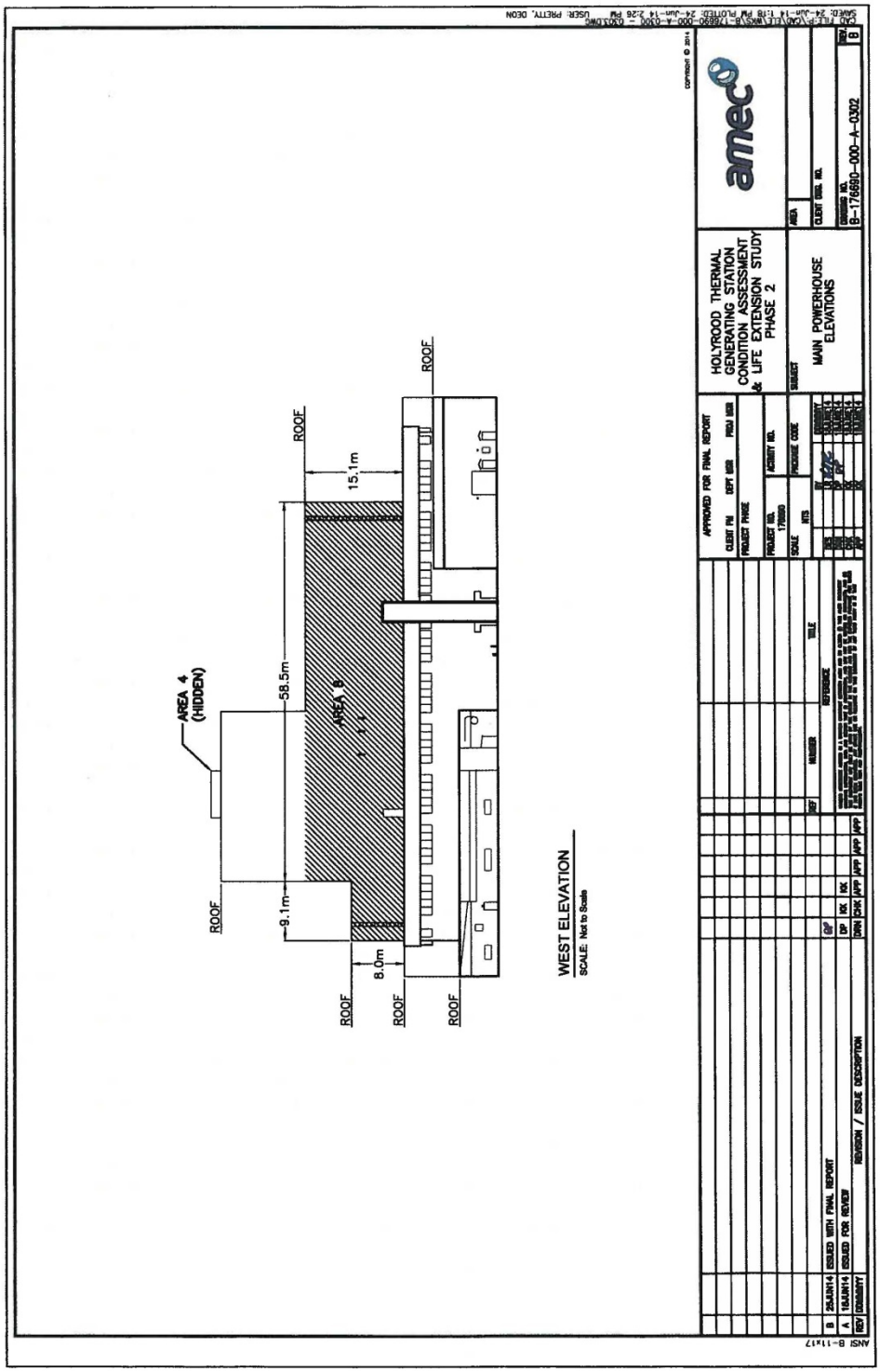
Project estimate: $220,000.00 including HST.

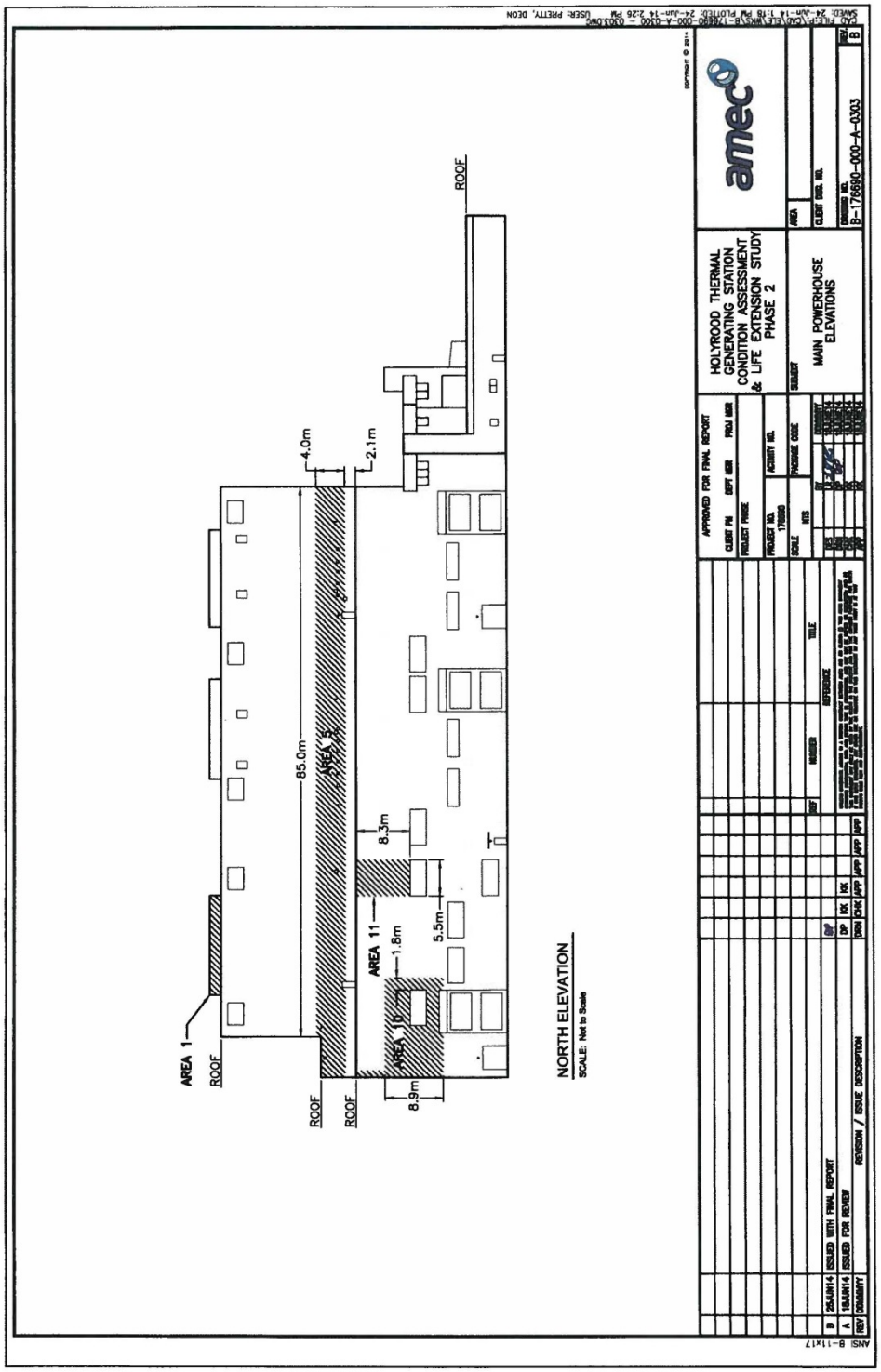
APPENDIX A

ELEVATION DRAWINGS


ROOF
ROOF
ROOF
10.3m
9.0m
33.2m
21.5m
33.0m
AREA 3
27.3m
AREA 7
AREA 9
AREA 11
33.3m
14.4m
6.7m
4.6m
AREA 15
17.5m
4.0m
AREA 16
26.0m
2.1m
4.8m
AREA 14
5.0m
2.0mx1.0m
AREA 12
AREA 13
2.4m
8.4m
1.2m
6.0m
SOUTH ELEVATION
SCALE: Not to Scale
HOLYROOD THERMAL GENERATING STATION CONDITION ASSESSMENT & LIFE EXTENSION STUDY PHASE 2
MAIN POWERHOUSE ELEVATIONS
APPROVED FOR FINAL REPORT
B 25JAN14 ISSUED WITH FINAL REPORT
A 15JAN14 ISSUED FOR REVIEW
REV COMMENT REVISION / ISSUE DESCRIPTION
B-176890-000-A-0300
ANSI B-11x17


ROOF
ROOF
ROOF
4.8m
AREA 2
AREA 6
2.1m
7.0m
2.3m
AREA 1
ROOF
8.8m
EAST ELEVATION
SCALE: Not to Scale
HOLYROOD THERMAL GENERATING STATION
CONDITION ASSESSMENT & LIFE EXTENSION STUDY PHASE 2
MAIN POWERHOUSE ELEVATIONS
amec
B-176690-000-A-0301


AREA 4
(HIDDEN)
AREA B
58.5m
9.1m
8.0m
15.1m
ROOF
ROOF
ROOF
ROOF
ROOF
WEST ELEVATION
SCALE: Not to Scale
HOLYROOD THERMAL GENERATING STATION
CONDITION ASSESSMENT & LIFE EXTENSION STUDY PHASE 2
MAIN POWERHOUSE ELEVATIONS
amec
APPROVED FOR FINAL REPORT
B-176690-000-A-0302
B
28JAN14 ISSUED WITH FINAL REPORT
A
15JAN14 ISSUED FOR REVIEW
REVISION / ISSUE DESCRIPTION
ANSI B-11X17


ROOF
4.0m
2.1m
85.0m
AREA 2
8.3m
AREA 11
1.8m
5.5m
AREA 10
8.9m
AREA 1
ROOF
ROOF
ROOF
NORTH ELEVATION
SCALE: Not to Scale
HOLYROOD THERMAL GENERATING STATION CONDITION ASSESSMENT & LIFE EXTENSION STUDY PHASE 2
MAIN POWERHOUSE ELEVATIONS
amec
B-176680-000-A-0303

APPENDIX B

PHOTOGRAPHS



AREA 1, 2, 3 & 4 - 3519



AREA 1, 2, 3 & 4 - 3521



AREA 5 – 3529



AREA 5 – 3537



AREA 6 – 3598



AREA 6 – 3600



AREA 7 – 3588



AREA 7 – 3586



AREA 7 – 3590



AREA 7 – 3592



AREA 8 – 3554



AREA 8 – 3558



AREA 8 – 3548



AREA 8 – 3552



AREA 9 – P5070019



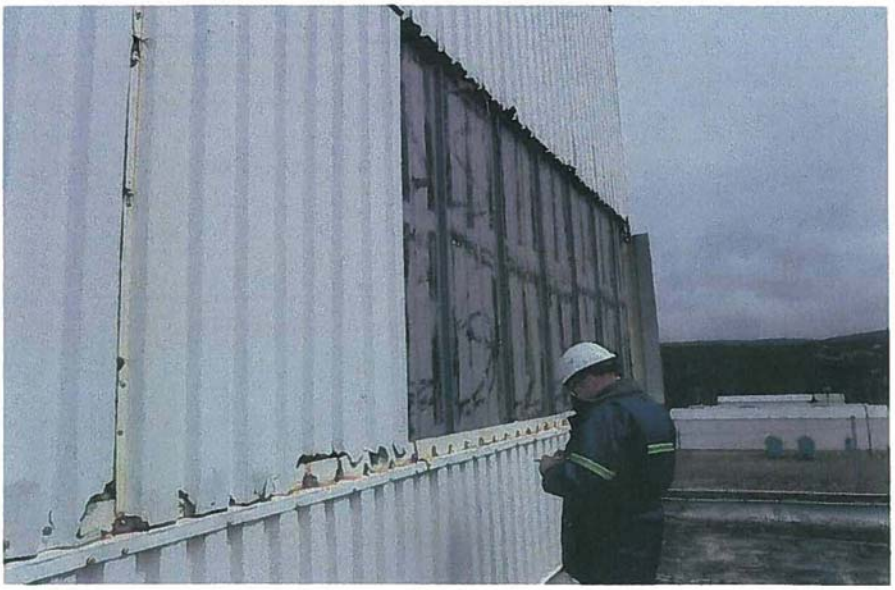
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AREA 9 – P5070021



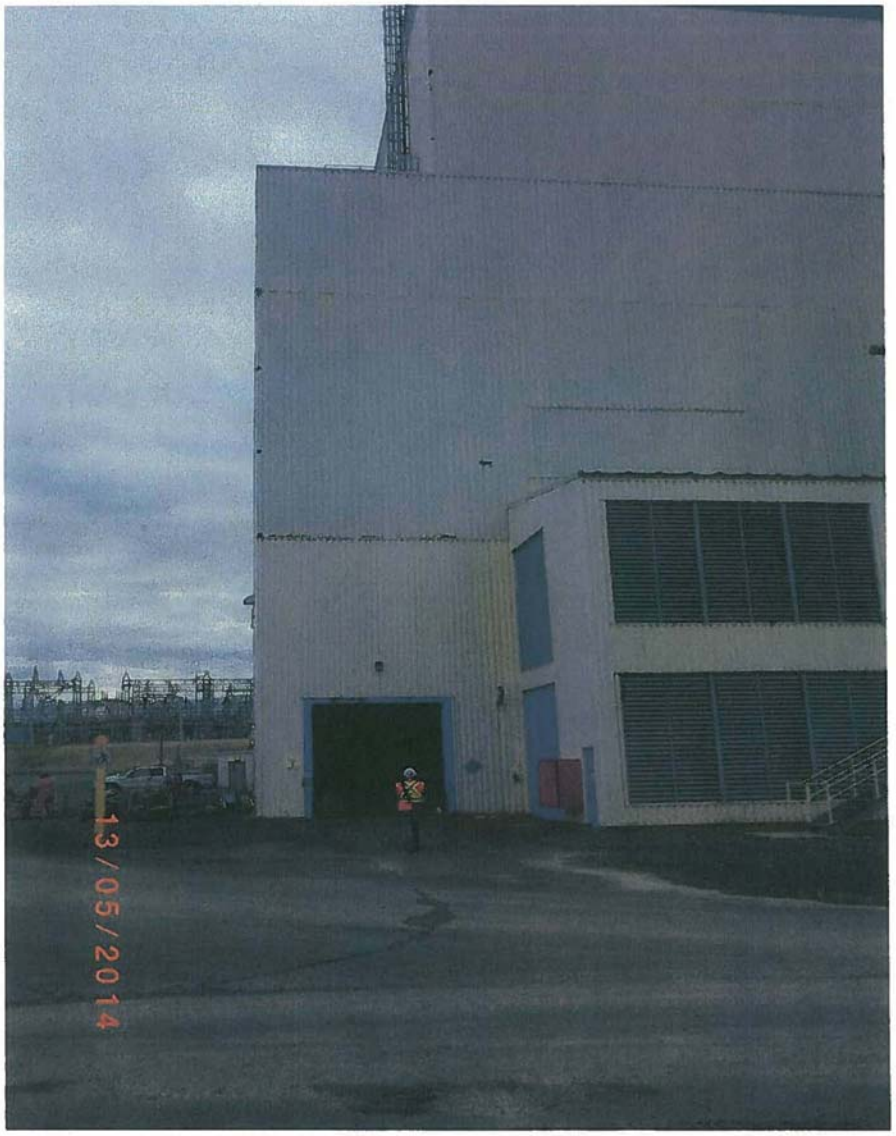
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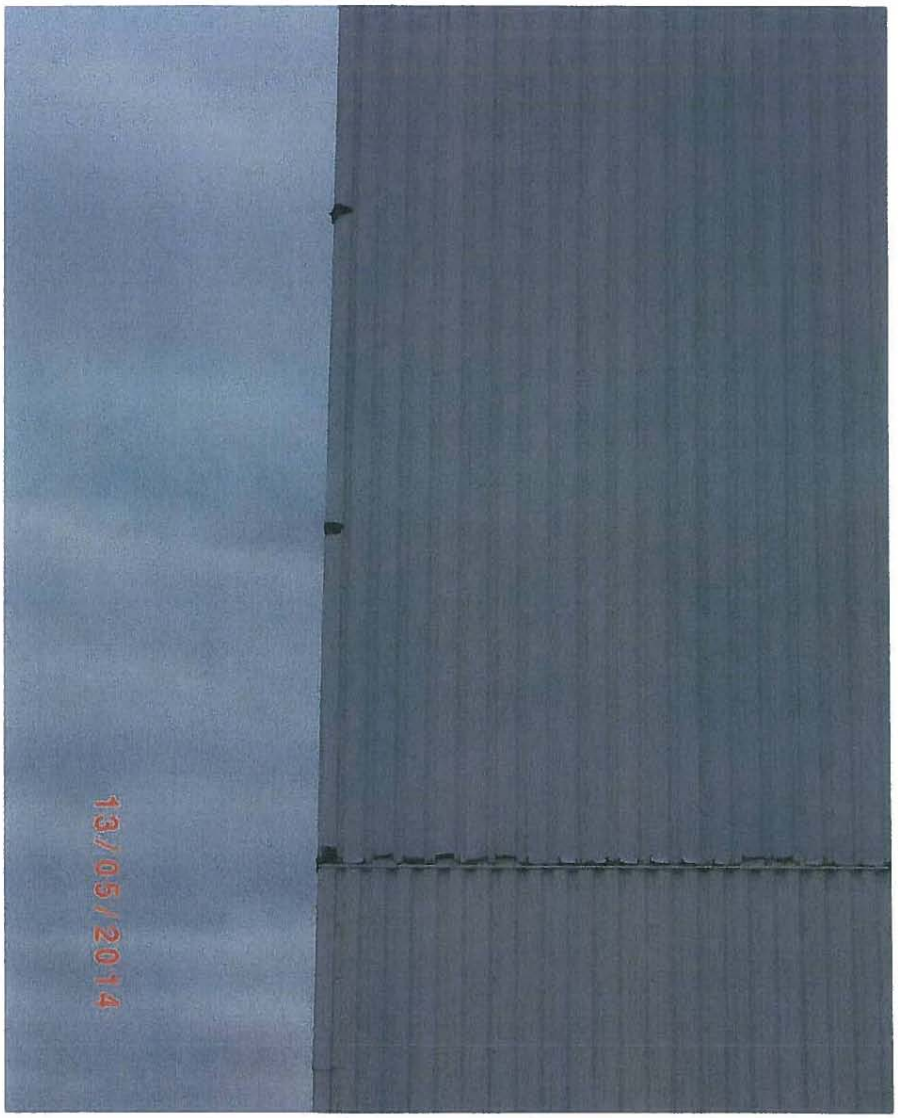
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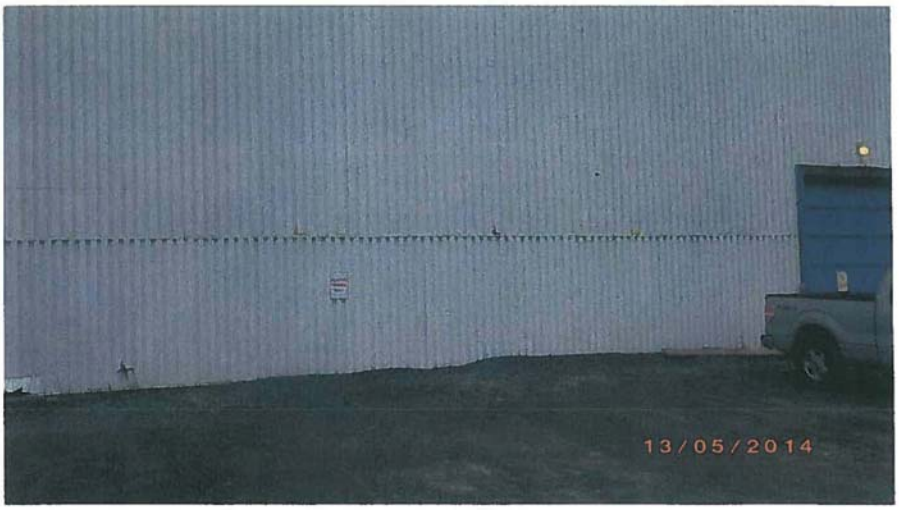
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AREA 10 – 3671



AREA 11 – 3664



AREA 11 – 3665



AREA 12, 13, 14, 15 & 16 – 3689



AREA 12, 13, 14, 15 & 16 – 3690



AREA 12, 13, 14, 15 & 16 – 3691



AREA 12, 13, 14, 15 & 16 – 3692

A REPORT TO
THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

	Electrical
	Mechanical
	Civil
	Protection & Control
	Transmission & Distribution
	Telecontrol
	System Planning

Overhaul Steam Turbine Generator – Unit 3

Holyrood Thermal Generating Station

July 2015

newfoundland labrador hydro
a nalcor energy company

SUMMARY

This project for Unit 3 at Holyrood Thermal Generating Station is to perform a major overhaul of the turbine, generator and auxiliary systems. The purpose is to return the turbine, generator and auxiliary systems back to design specifications, such that the equipment can operate safely, efficiently and reliably until the next scheduled overhaul. In addition, it will identify any unusual findings, internally and/or externally, that if not corrected or controlled, could lead to premature failure of the equipment.

The major overhaul of Unit 3 would entail complete dismantling of all the turbine stages, removing the rotor from the generator and internal inspections of all systems and auxiliary equipment. The overhaul is to mainly be completed by contacted services, consisting of technical services, labour, materials and supervision. As required, plant personnel will provide assistance for application of work protection and services, parts procurement, removal of specific monitoring and control systems, overall contract management and technical liaison with Hydro's management personnel.

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1 INTRODUCTION

The three major components of the thermal generating units are the power boiler, turbine and generator. Through combustion of No. 6 fuel oil, the power boiler provides high energy steam to the turbine. The turbine is directly coupled to the generator and provides the rotating energy necessary for the generator to produce rated output power. The Unit 3 turbine is made up of three stages, each designed to extract maximum energy from the high pressure steam and in turn to provide maximum rotational energy to the generator. Each turbine is constructed of three sections**:** a single flow high pressure section, a single flow intermediate section (both in one high pressure-high temperature casing) and a separate double flow low pressure section. The high, intermediate and low pressure sections of the turbine rotor are built on a single shaft with solid couplings to form what is known as a tandem compound, double flow, reheat turbine. Each stage is designed such that it extracts energy from the supplied steam as efficiently as possible converting it into rotational energy.

The electrical generator is coupled to the steam turbine and converts the rotating energy into electrical power. It is pressurized and cooled by hydrogen gas to provide maximum efficiency both in heat transfer and windage losses.

The generator has two basic components; a rotational excitation field and three stationary stator coils. The rotational field, through magnetic coupling, induces a high voltage into the stationary stator coils. The stator coils are connected via a step-up transformer to the main Holyrood terminal sub-station and then to the Island Interconnected System.

2 PROJECT DESCRIPTION

This project is to perform a scheduled major overhaul of Unit 3 turbine, generator and auxiliary systems located at the Holyrood Thermal Generating Station (HTGS). The turbine is constructed of special metal alloys to withstand the extreme temperatures and pressures and must conform to very close tolerances in order to convert the steam energy as efficiently as possible. The generator is subjected to electrical and magnetic stresses while providing megawatt and megavar power for the Island grid. The generator stator windings have increased forces and loading induced upon them during system faults. Unit 3 is no exception and encounters system faults and swings in load during system events. To ensure that these units operate at peak performance and provide maximum energy on demand, it is necessary that they undergo major overhauls on a scheduled basis to return the equipment to design specification. The last major overhaul took place in 2007 and was completed by General Electric.

This major overhaul consists of a total dismantling of all turbine stages, removal of the generator rotor, and internal inspections of all systems including auxiliary equipment. The work will mainly be completed by contracted services with assistance from plant personnel when required. The contracted work consists of technical services, labour, materials and supervision. Plant support is required for work protection application and services, parts procurement, removal of specific monitoring and control systems, overall contract management, and technical liaison with Hydro's management personnel.

The work to be completed consists of three types: Routine *Standard Work* (Appendix B) that is defined by the equipment manufacturer, *Defined Work* which is extra to the standard work and identified prior to the overhaul, and *Unforeseen Work* which may result from examination of the equipment during the internal inspection. The contractor is responsible to schedule and complete the standard and defined work within the specified overhaul period. The unforeseen work and associated repair schedule is determined by the contractor in consultation with Hydro. The major overhaul requires approximately 12

weeks to complete using crews working two shifts (Appendix B). Unforeseen work coupled with the transport of "out of province" repairs could alter the schedule. The cost of this unforeseen work is expected to be contained with the project contingency. The Turbine also undergoes a valve overhaul at a three year frequency to inspect control and stop valves and related auxiliary equipment. This overhaul work is included as part of the work schedule for the nine year major overhaul, utilizing the same outage, isolation and disassembly of the equipment to perform both overhauls.

In 2003, Holyrood undertook an initiative and contracted Hartford Steam Boiler Inspection and Insurance Company (HSB) to review Hydro's turbine generation operation using HSB's proprietary Turbine Outage Optimization Program (TOOP) to determine if Holyrood could extend its overhaul program to a longer interval. All aspects of the turbine generator were reviewed; design, construction, historical experience, operation, maintenance, inspections and monitoring. HSB concluded that all three units could extend major overhaul frequency from six years to nine years provided some upgrading and repairs were completed and instrumentation installed to enhance the existing turbine monitoring program. (Appendix C). Hydro completed an analysis of the reports and determined that the upgrades and improved monitoring required to extend the major overall frequency was warranted as a cost savings measure without jeopardizing the safe and reliable operation of either unit. The necessary upgrades were completed for all three units and the maintenance plan for major overhauls revised to the nine year frequency.

In January 2010, AMEC Americas Limited (AMEC) was contracted by Hydro to conduct a Phase 1 Condition Assessment and Life Extension Study of the Holyrood Generating facility. This was a non-intrusive assessment concentrating on historical data, maintenance reports, operations logs, existing maintenance and inspection plans and reviews with operations staff. The investigation took a year to complete with a final report delivered to Holyrood management in March 2011 (Appendix D). The study agreed with the 2003 TOOP (HSB) report to extend the major overhaul schedule for the turbine to the nine year frequency but

recommended that overhauls on the generators revert back to the six year interval. This specific recommendation will be further reviewed by Hydro before a final decision is made.

The first major overhaul since the nine year extension decision is scheduled for Unit 3 in 2016. The last major overhaul of Unit 3 was completed in 2007. Over the past eight years (2007 – 2014), Unit 3 has seen 27,421 operating hours or 3.13 unit years, and approximately eight unit starts per year. This overhaul is necessary to inspect the turbine components for wear, to inspect the generator for its electrical and mechanical condition, and to inspect all auxiliary equipment and will coincide with the rewind of the Unit 3 generator rotor proposed project located in Volume II, Tab 5.

3 JUSTIFICATION

This project is justified on the requirement to maintain the generating equipment in its optimal operating condition for Hydro to provide safe, least-cost, reliable electrical service to its customers. The purpose of the major overhaul is to return the turbine, generator and auxiliary systems to design specifications such that they can perform safely, efficiently, and reliably to meet system demands until the next major overhaul. It will also identify any unusual findings (internally or externally) that if not corrected or controlled could lead to premature failure of the equipment. Since the installation of Unit 3 in 1979, major overhauls of the turbine, generator and auxiliaries have been performed on a scheduled basis that reflected industry standards. Holyrood supplies approximately 33% of the Island Interconnected System's capacity and is particularly important due to its location on the Avalon Peninsula close to the large customer base. A loss of Unit 3 generation during high load requirements could have a significant impact on the Island Interconnected System's ability to meet demand.

Under the previous GAAP accounting guidelines, major unit overhauls were deemed an operating and maintenance cost and formed part of Holyrood's Operating Budget. In 2012, Hydro implemented new accounting standards under which all major overhauls are to be completed using the Capital Budget process. Since its installation, Unit 3 major overhauls have been completed on a frequency consistent with industry standards.

3.1 Existing System

Unit 3 is designed for continuous operation with varying loads. It is typically operated as a seasonally base-loaded unit (November to March) to meet system requirements. It, together with the other two generating units, typically provides about 33% of the Island Interconnected System load during the crucial winter peak period. Maintenance outages are taken during the summer months when its capacity is not required. Unit 3 has been operating in this mode, within design capability, since it was commissioned in 1979.

Table 2 shows the overhauls on Unit 3 since 2000.

Table 2: Unit 3 Turbine Generator - Major Overhauls

Year	Major Work
2007	Major Overhaul; Full stator re-wedge; Turbine diaphragms repaired.
2001	Major Overhaul

3.2 Operating Experience

Unit 3 turbine generator was installed and commissioned in 1979. The Unit 3 operating hours to the end of June 2015 were 145,579. Assuming the generator operates for approximately 3,400 hours per year until 2016, it is expected to attain approximately 149,000 hours before the next major overhaul in 2016. Due mainly to system requirements, the unit has averaged about eight starts per year which when projected to 2016 will total about 73 for the nine year operating period.

3.2.1 Reliability Performance

Following the last major overhaul on Unit 3 in 2007, there have been no forced outages for Unit 3 due to the turbine or generator.

Table 3 shows Unit 3 and plant performance for a five year period (2010-2014).

Table 3: Holyrood Unit 3 and Plant Performance

Five Year Average 2010-2014	All Causes		
Unit	**Capability Factor (%)**	**DAFOR (%)**	**Failure Rate**
Holyrood Unit 3	59.59	12.72	7.15
Holyrood Plant	65.09	15.79	7.84
CEA (2009-2013)	73.24	12.69	7.12

Capability Factor is defined as unit available time. It is the ratio of the unit's available time to the total number of unit hours.

DAFOR is defined as Derated Adjusted Forced Outage Rate. It is the ratio of equivalent forced outage time to equivalent forced outage time plus the total equivalent operating time.

Failure Rate is defined as the rate at which the generating unit encounters a forced outage. It is calculated by dividing the number of transitions from an Operating state to a forced outage by the total operating time.

3.2.2 Legislative or Regulatory Requirements

There are no legislative or regulatory requirements that would make this capital budget proposal necessary.

3.2.3 Safety Performance

Unit 3 turbine operates at very high steam flows which, combined with high pressures and temperatures, contribute to the wear and tear of internal components. The combined turbine generator weight is approximately 60 tons, 80 feet in length and rotates at 3,600 rpm requiring specific speed governing and tripping mechanisms to eliminate any possibility of over-speed. The generator itself operates at high voltages and uses hydrogen gas as a coolant both requiring special containment mechanisms to prevent exposure to personnel and the environment. Maintenance of these systems is vital to ensure the unit's safety performance and as such forms part of the major overhaul scope. There are, however, no specific safety performance regulations or codes requiring compliance.

3.2.4 Industry Experience

Traditionally, the North American standard for turbine and generator major overhauls was based on a six year cycle. This frequency was in agreement with the original equipment manufacturer's guidelines and was acceptable to the utility industry in general. In an effort to reduce operating costs, utilities began to scrutinize the turbine generator major overhauls, in particular the six year schedules, to determine the viability of increasing the major overhaul frequency. Following comprehensive reviews internally as well as through external expertise many utilities endorsed this recommendation and the standard frequency for major overhauls for many North American utilities was changed from the traditional six years to nine years.

3.2.5 Vendor Recommendations

In 2003, Holyrood contracted Hartford Steam Boiler (HSB) to investigate the possibility of extending the traditional overhaul interval of six years to a nine year frequency. Holyrood accepted the recommendation and revised all major overhauls to the extended frequency. The Original Equipment Manufacturer (OEM), General Electric verbally indicated that they did not endorse the six year overhaul frequency. In 2011, AMEC's Condition Assessment and Life Extension study agreed with the 2003 TOOP (HSB) report to extend the major overhaul schedule for the turbine to the nine year frequency but recommended that overhauls on the generator revert back to the six year interval.

3.2.6 Maintenance or Support Arrangements

All major turbine generator overhauls have been performed by an OEM. Prior to 2011, General Electric had been contracted by Hydro under a maintenance services agreement to perform all major and minor overhauls on the Holyrood turbine generator units. In 2011, Hydro retendered its requirement for another three year period. Plant personnel assist the OEM when required, overs the work protection application and provide overall management and liaison for the overhaul work.

3.2.7 Maintenance History

There have been no maintenance costs specifically identified for the turbine generator of Unit 3 in the last five years.

3.2.8 Historical Information

As noted previously, since 1979, major overhauls of Unit 3 turbine, generator and auxiliaries have been performed on a frequency that matched industry standards, at a six year frequency prior to 2006. Valve overhauls have taken place on a three year frequency, one of which is typically included in the six year major overhaul schedule. Table 4 details costs incurred for major overhauls on all units since 1992. Note that the $3,297,000 cost of Unit 3 in 2007 was escalated due to extra repairs noted by General Electric in their 2001 overhaul report. The primary cause was exfoliation carry-over from the power boiler.

Table 4: Historical Information

Year	Unit	Type of Overhaul	Costs ($000)
2014	2	Major	5,147
2012	1	Major	4,193
2007	3	Major	3,297
2005	2	Major	2,609
2003	1	Major	2,404
2001	3	Major	2,381
1999	2	Major	1,849
1997	1	Major	1,600
1994	3	Major	1,262
1993	2	Major	1,287
1992	1	Major	559

3.2.9 Anticipated Useful Life

In the 2010 Holyrood Condition Assessment, AMEC concluded that Unit 3 turbine has a reliable remaining life in the order of ten years (to 2020), provided that sufficient inspection and testing is performed during the 2016 major overhaul. AMEC also concluded that Unit 3 generator has a reliable remaining life in the order of seven years (to 2017) due to the condition of the stator and rotor windings. Due to the condition of the windings, Hydro is

applying for a rotor rewind in 2016 and a rewind of the generator to be completed based upon the stator condition observed during the 2016 rotor rewind. The Life cycle curves for Unit 3 turbine and generator (as presented in the AMEC report) are illustrated in Figures 1 and 2 below. These curves have a plot of current and projected operating hours on the Y-axis and calendar years on the X-axis. The vertical lines represent different nominal age limits for various components and the horizontal lines represent a range of practical operating-hour life limits based on historical information and expert opinions. The risk boxes provide an indication of potential issues either from an age or operating-hour perspective. The major overhaul scheduled for 2016 will extend Unit 3 turbine generator's remaining life to the desired 2020 end of life date. The turbine will be at end of life in 2020 while the generator will continue operating in sync condenser operation.

3.3 Forecast Customer Growth

This project is being completed strictly to maintain Unit 3 turbine generator in optimal condition to provide safe, least-cost, reliable electrical service to Hydro's existing customers. Forecast customer growth is not a consideration for this project.

3.4 Development of Alternatives

There are no alternatives to this project other than to delay the major overhaul which based on the manufacturers' (GE) reports, independent expert reviews, and operations experience would not be acceptable.

3.5 Evaluation of Alternatives

As there are no alternative to this project, no evaluation is required. A net present value calculation was not performed as there are no viable alternatives to performing an overhaul. As this project does not involve new generation sources, a levelized cost of energy analysis is not applicable.

3.5.1 Energy Efficiency Benefits

This project will not provide any energy efficiency benefits other than to restore the turbine generator its optimal performance condition.

3.5.2 Economic Analysis

A cost benefit analysis is not required for this project. There are no alternatives to this project other than to delay the major overhaul which based on the manufacturers' (GE) reports, independent expert reviews, and operations experience would not be acceptable.

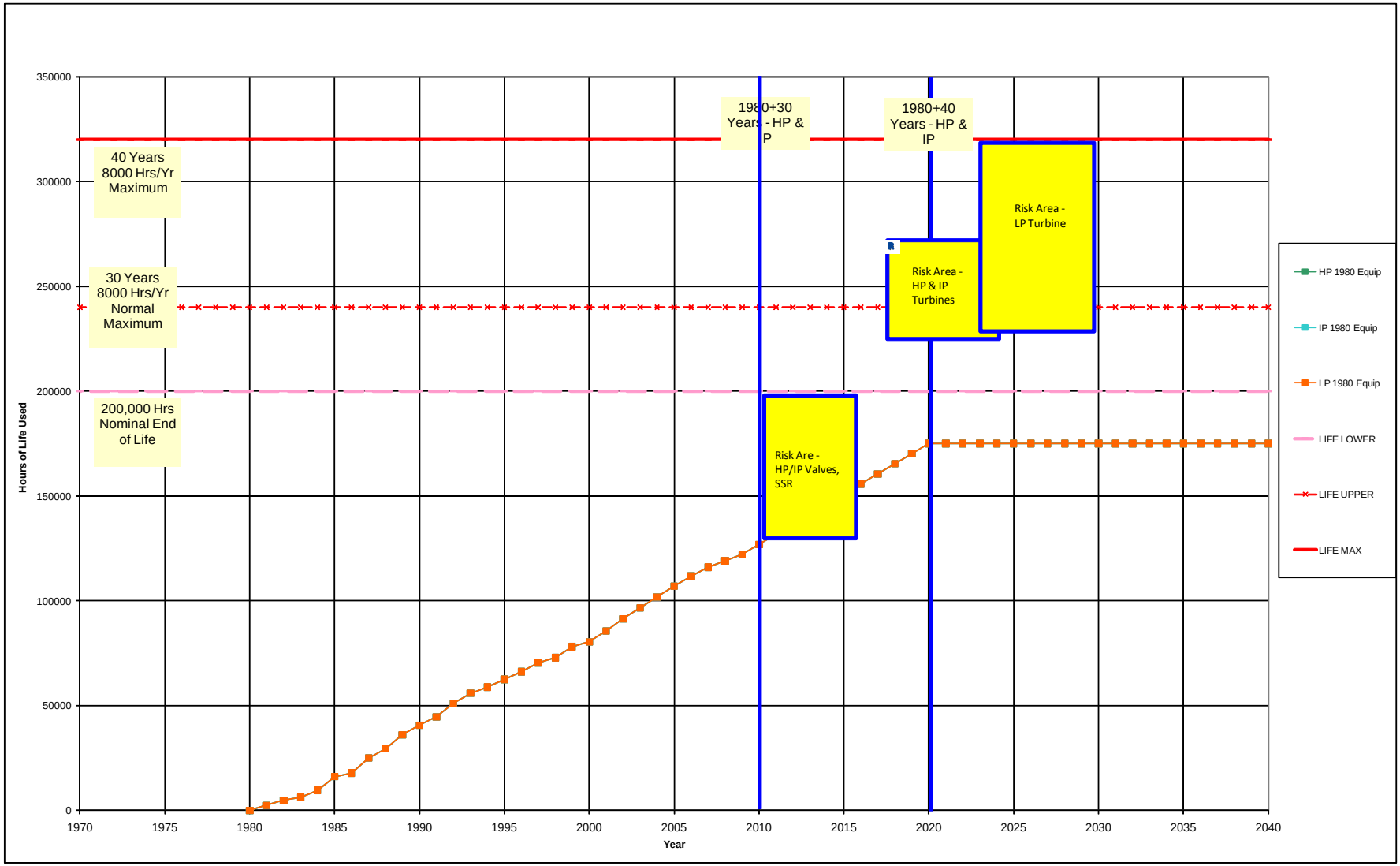


Figure 1: Life Cycle Curve – Unit 3 Steam Turbine

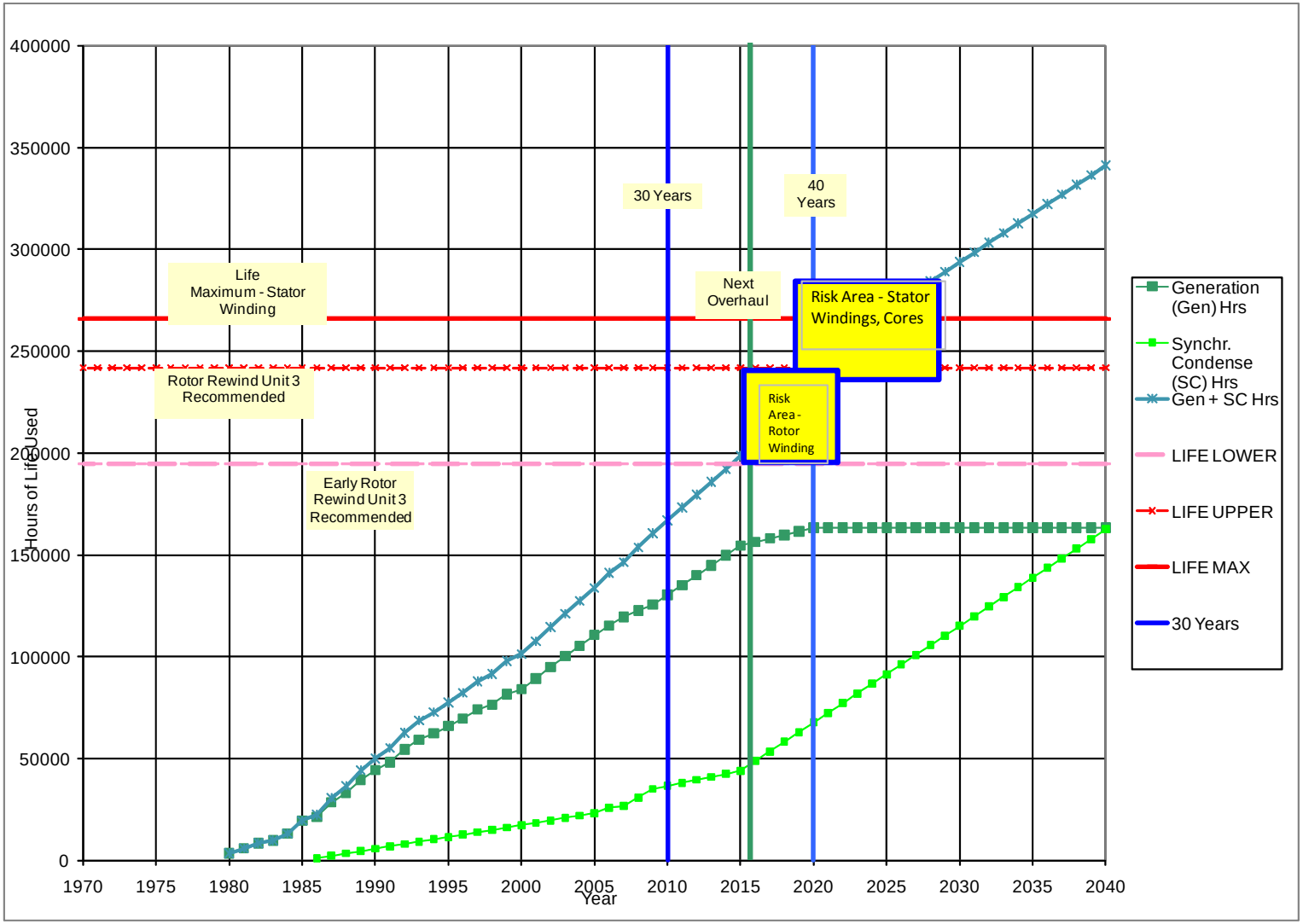


Figure 2: Life Cycle Curve – Unit 3 Generator

4 CONCLUSION

This project is justified on the requirement to maintain the generating equipment in its optimal operating condition for Hydro to provide safe, least-cost, reliable electrical service to its customers. The purpose of the major overhaul is to return the turbine, generator and auxiliary systems to design specifications such that they can perform safely, efficiently, and reliably to meet system demands until the next major overhaul. It will also identify any unusual findings (internally or externally) that if not corrected or controlled could lead to premature failure of the equipment.

There is a significant risk involved if the turbine, generator or any of the auxiliary systems should fail during periods when its generation is required.

4.1 Budget Estimate

The budget estimate for the project is $5,868.6 million. The budget estimate is shown in Table 5.

Table 5: Project Budget Estimate

Project Cost:*($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	420.0	0.0	0.0	420.0
Labour	500.0	0.0	0.0	500.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	3,800.0	0.0	0.0	3,800.0
Other Direct Costs	0.0	0.0	0.0	0.0
Interest and Escalation	204.6	0.0	0.0	204.6
Contingency	944.0	0.0	0.0	944.0
TOTAL	**5,868.6**	**0.0**	**0.0**	**5,868.6**

4.2 Project Schedule

The anticipated project schedule is shown in Table 6.

Table 6: Project Schedule

Activity	Date
Pre-shutdown Checks	May 2016
Mobilize	June 2016
Dismantle turbine, Generator, valves, and auxiliary equipment	June-July 2016
Equipment inspection	June-July 2016
Equipment repairs	July-August 2016
Assemble turbine, generator, valves, and auxiliary equipment	August 2016
Operational checks	August 2016
Demobilize	September 2016

APPENDIX A

General Electric Major Overhaul Report

FRS Number 20351250

Unit 3 Steam Turbine Inspection Report

May – September 2007



GE Energy Services

JOB SUMMARY

This report covers a major inspection of Hitachi Steam Turbine 191641 and associated Hitachi Generator 16286-1. GE has assigned the serial # HTS0004 to this turbine. The inspection was conducted over 12 weeks on a two shift basis working 10 hours per day, 5 days per week. There were some exceptions to this where some work was performed on weekends. The equipment overhauled included: High Pressure, Reheat and Low Pressure turbine sections, Generator inspection with rewedge, Main Stop Valves (2), Upper and Lower Turbine Control Valves (4), Combined Reheat Valves (2), Extraction Non-Return Valves (7), Emergency Blowdown Valve (1), Steam Seal Regulator (1), Various lube and seal oil pumps.
General Electric Canada provided project management and technical direction for the inspection. GE Service Center technicians performed all diaphragm repairs and generator wedging services on site. GE Preferred provided onsite machining and turbine rotor technicians. Craft Labour was provided by GETSCO. Machine shop services were provided by TRT Services for on site and local service and by GE for specialty service and parts. Blast Cleaning service was provided by ARCO Enterprises. NDT services were supplied by Aitec through Newfoundland & Labrador Hydro.
During this major inspection laser alignment was performed with TOPS-ON and TOPS-OFF under direction of GE specialist, Doug Earnest. A GE team from Burlington service shop performed re-wedging at the stator under direction of GE generator specialists Pradeep Tandon and Aaron Nafziger. Four of the HP/Reheat diaphragms were sent off site for major repairs including stage 7 which had GE Diamond Tuff HVOF coating applied. The buckets on Stage 7, first reheat, were replaced and these were HVOF coated as well. LP journals 3 and 4 were polished and both turbine rotors were low speed balanced before being returned to service.



RECOMMENDATIONS

SHOULD BE DONE AT THE NEXT OUTAGE...

1. Buckets, LP; Assembly; L-0

During the next inspection the following work should be planned for stage 18 TE and GE buckets.
It is recommended that the trailing edge erosion be polished out on all buckets vanes and bucket vane trailing edges cutback as required restoring the vane edges.
Of particular concern is the deep erosion cutting at the vane tip radii into the stellite nosepiece on several bucket vanes. Consultation with the turbine OEM is warranted for possible localized TIG weld repair or silver soldering fill of these isolated deep erosion cuts to retard further development.

2. Shell, HP Outer; Horizontal Joint;

Due to the distortion found at the HP outer shell horizontal joint, it is recommended to continue a program of tops-on tops-off laser alignment during future major inspections.

3. Bearing, Turbine Journal; Babbitt; 2,3,4,5

During startup it was discovered that some of the existing and replaced journal bearings were missing a plug in the bearing used to block the jacking oil from spraying at the oil deflectors. These missing plugs caused an oil spray to leak out at the oil deflectors when the turbine was rotating at speeds above 1500 RPM. Ensure that all bearings installed at future inspections have this plug installed as well as the teflon bushings for the Bentley Nevada vibration probes as described in the 2001 inspection report.

4. Diaphragm, HP; Assembly;

The tip spill strips for stages 3, 4, 5, and 6 are damaged at the bottom and consideration should be given to replace them at the next major inspection.



RECOMMENDATIONS

5. Steam Seal Regulator; Assembly;

Consideration should be given to replacing the steam seal regulator on this unit with the 2 control valve type. This upgrade would be very similar to the systems already proposed for units 1 and 2 for this station.

During startup it was found that the cams on the control portion of the steam seal regulator had flat spots worn on them. New cams should be available during the valve inspection if the steam seal regulator is not going to be replaced with a two control valve system.

6. Shell, HP Outer; Chest; lower

Continue to inspect the upper steam chest at each overhaul to identify any cracks that may develop. This can be checked with dye penetrant. Since there are already cracks in the lower steam chest, a modified NDT program should be used for the lower chest only. This program would include Ultrasonic readings to check crack propagation, but need not include a detailed Finite Element Analysis of the results, unless a substantial increase in crack size from the previous inspection is noticed.

7. Main Operating Cylinder; Assembly;

New piston rings for the Main Operating Cylinder should be on hand for the next major inspection.

8. Shell, HP Inner; Ring; all

Inspect the control valve snout rings during the next major inspection to ensure that they are free and movable.

9. Shell; Assembly;

Ensure that the HP outer casing is jacked toward the front standard when removing or installing turbine rotors. There is a jacking device in the turbine specialty tools for this operation.

RECOMMENDATIONS

10. Diaphragm, RHT: Assembly:

The root radial and tip spill strips on stage 9 diaphragm should be replaced at the next inspection as lower segments are rubbed away. Repair of the root radial tooth would require a major repair and should be considered for the next inspection.

11. Oil Tank: Reservoir:

Due to increased flow during flushing, it is recommended to not install any strainer finer than the permanent 60 mesh at the return flow to the oil tank.

Holyrood Rewedge and Repair

Overview:

The as found test shows that the Stator on Unit #3 had loose wedges, a Damaged Series Loop, and a Damaged Phase Joint. The Field also show some migrations on the end wedges where somewhere making contact with the Retaining Ring.

As we started to disassemble the stator, under the gas baffle on the DE we found slight damage on the stator bar.

After rewedging the stator the tightness of the wedges all where found to be over 760 with the EQUOTIP Tightness and recorded on a wedge map program. The Damaged Series Loop was repaired as well as the Phase joint and the damage under the gas baffle. The field end wedges we moved back into place and restaked.

Summary of Inspections:

When the initial wedge tightness was performed it was found that 12% of the flat wedges were loose, 4% were hallow, with the worst slot having 10 loose wedges of 25 wedges.

The Megger PI shows an average of 7.7 GΩ to 7.9GΩ with a PI of 4.2 to 4.3.

The DC Leakage shows a PI of 4.78 to 5.0 and N of 3 to 4, and then ramped up to 34 KV.

The Winding resistance corrected to 25C ranged from 0.001350Ω to 0.001354Ω.

An EL CID was performed and found all slots were well under 100 mA.

The Field had a PI of 1.4 with an insulation resistance of 5.9GΩ.

The Field winding resistance was found 0.1441Ω corrected to 25C.

APPENDIX B

Unit 3 Major Overhaul

Turbine Generator Standard Overhaul Work

Turbine Generator Major Overhaul

Standard Outage Work:

A. Generator

1.	Pre-shutdown Checks	(5 Days)
2.	Mobilize	(4 Days)
3.	Remove Lagging	(3 Days)
4.	Disassemble Generator	(15 Days)
5.	Inspection	(10 Days)
6.	Electrical Tests (Stator & Rotor)	(5 Days)
7.	Visual Inspection	(2 Days)
8.	Assemble Generator	(25 Days)
9.	Excitation Inspection	(3 Days)
10.	Assemble Lagging	(4 Days)
11.	Pre-start and Operational Checks	(5 Days)
12.	Demobilize	(5 Days)

B. Steam Turbine

1.	Pre-shutdown Checks	(5 Days)
2.	Mobilize	(6 Days)
3.	Remove Lagging	(5 Days)
3.	Disassemble Turbine (HP/IP/LP)	(20 Days)
4.	Disassemble Valves (Main Stop/Control, Reheat Stops/Intercepts & Non-Return Valves)	(20 Days)
5.	Bearing Inspection including Thrust	(5 Days)

B. Steam Turbine (cont'd)

6.	Turbine Controls (Actuators, Hydraulics)	(7 Days)
7.	Lube Oil System	(10 Days)
8.	Turning Gear	(6 Days)
9.	Steam Seal System	(5 Days)
10.	Turbine Supervisory Instrumentation	(6 Days)
11.	Assemble Turbine	(25 Days)
12.	Assemble Valves	(20 Days)
13.	Install Lagging	(6 Days)
14.	Pre-Start and Operational Checks	(5 Days)
15.	Demobilize	(6 Days)

APPENDIX C

Hartford Steam Boiler (HSB)

Turbine Outage Optimization Program (TOOP)

Newfoundland & Labrador Hydro Holyrood Station Turbine Generator Unit 3

Executive Summary

Turbine Outage Optimization Program (TOOP) analyses were conducted on Newfoundland & Labrador Hydro's Holyrood Station Unit 3 turbine generator to determine the optimum interval of conducting major outages on this 1979 vintage Hitachi, 150 MW unit. The unit was last overhauled in April-July 2001. Since that time, the unit has accumulated approximately 11,657 total equivalent operating hours (EOH). The TOOP analysis results have indicated the following:

- ***High Pressure (HP) Turbine*** - This turbine is average or median in risk when compared to other industry HP turbines analyzed by TOOP. Currently, the primary risk drivers are: erosion of diaphragms, impulse wheel, and blade foils, shrouds, and tenons; foreign object damage (FOD) to diaphragms, impulse wheel, blade foils and shrouds; rubbing/distortion of tenons; and fatigue cracking of disc steeples and discs. Based on the operating profile for the unit, this turbine would typically be expected to run to **40,190 EOH** or approximately **8.9 years** between outages. However, given the past condition of the upper/lower nozzle plates, steam chest cracks, shell distortion, and valve wear, the currently planned overhaul of the HP turbine in 2007 should be conducted. After review/repair/replacement of damaged areas, the 8.9 years would apply to subsequent overhauls.
- ***Intermediate Pressure (IP) Turbine*** - This turbine is high in risk when compared to other industry IP turbines analyzed by TOOP. The primary risk drivers are: erosion of diaphragms, shrouds, and tenons; FOD damage to blade foils and tenons; rubbing/distortion to blade shrouds and tenons; and fatigue cracks to disk steeples and blade roots. Based on the operating profile for the unit, it would be expected this turbine would typically be expected to run to **21,524 EOH** or approximately **4.7 years** between outages. However, given the past FOD/erosion damage to several stages in the IP turbines, problems with past reheat steam control and erosion/FOD of IP stages, particularly stage 7, the currently planned overhaul of the IP turbine in 2007 should be conducted. After review/repair/replacement of residual flowpath damage, the interval would increase to **41,422 EOH** or approximately **9.1 years** and would apply to subsequent overhauls.
- ***Low Pressure (LP) Turbine*** - The turbine is considered to be average to low in risk when compared to all other LP turbines analyzed by TOOP as well as by OEM and by size class. The primary risk drivers are: stress corrosion cracking (SCC) of discs, disc steeples, rotor; and FOD and erosion damage to blade foils and shrouds. . Based on the operating profile for the unit, it is expected that the LP turbine can be run to **33,503 EOH** or approximately **7.4 years** until the next outage. If continuous Cation conductivity monitoring is added to the main steam inlet to the turbine, the LP turbine can be run to **43,192 EOH** or approximately **9.5 years** between outages. This interval would apply after review/repair of erosion/FOD damage in the LP turbine at the currently planned 2007 outage.
- ***Generator*** - The generator is considered to be very low in risk when compared to all other generators analyzed by TOOP as well as by OEM and by size class. The primary risk drivers are: electrical breakdown of rotor and stator windings; fretting of retaining rings, the rotor, and rotor core/teeth; and overload of the retaining rings. Based on the operating profile, it is expected that the generator can be run to **44,384 EOH** or approximately **9.8 years** between outages. As with the turbine sections, there are areas that need to be addressed at the 2007 outage including wedge looseness and hydrogen seal condition.

In summary, if past problems in this unit are corrected at the 2007 outage, the failure mechanisms acting on the various sections of this unit should be slow acting with no accelerating wear or damage that would preclude running the unit longer between outages (i.e., going from 6 years today to 9 years for subsequent outages). This increase in major outage interval is also the result of the investment the plant has made in updated controls, operating procedures, and monitoring. To provide continued assurance of achieving this interval, there are several refinements which should be implemented with regards to inspection, operation, and monitoring to enhance the ability to detect changes in the health of the machine for preventing or minimizing any machine damage. These items are discussed in the Recommendations Section of this report.

This program does not purport to set forth all hazards nor to indicate that other hazards do not exist. By issuing this report, neither the Company nor any of its employees makes any warranty, expressed or implied, concerning the content of the report and object (objects) described. Furthermore, neither the Company, nor any of its employees shall be liable in any manner (other than liability that may be expressed in any policy of insurance that may be issued by the Company), for personal injury or property damage or loss of any kind arising from or connected with this program.

APPENDIX D

AMEC

Condition Assessment

and

Life Assessment Study

There are also options for improving the efficiency of the facility in the short term such as:

a) Addition of reheat boiler tubes to improve reheat steam conditions and cycle efficiency; and

b) Repairing previously damaged (but not fully repaired) steam turbine elements or upgrading existing elements with more efficient designs

14.6 Unit 3

1. The generator is in reasonable condition. Its next overhaul is in 2016. Nevertheless, it has a significant likelihood of encountering rotor winding issues prior to its next currently scheduled outage in 2025. Given an end date of 2041, a rotor rewind may be warranted in 2016 or earlier than 2025.

2. The steam turbine is in generally good condition and is expected to make the 2020 generation end date. It continues to have main and intercept valve issues, as well as stud bolt issues. Its mechanical governor system also experiences some control issues. These should be examined further and/or addressed at the next 2016 major overhaul.

3. The boiler is generally in good shape, especially with the change in fuels. Some legacy effects of history of high sulphur, high vanadium oil use is likely to continue – tube leaks and thinness. Others such as economizer plugging, air preheater corrosion and plugging are expected to continue to diminish.

4. The stack breeching requires an upgrade or replacement. The steel casing and support structure has localized corrosion and the internal insulating liner has significant deterioration.

5. The Unit 3 control room relay panels cannot accommodate the current and required wiring and need to be replaced for safety reasons.

6. When decoupled from the turbine, Unit 3 generator has no thrust bearing to address lateral movement during synchronous condensing operation and requires modification to reduce long term vibration and damage.

7. Unit 3 Exciter is considered at end of life and the entire system should be replaced.

14.7 Black Start Gas Turbine

1. The black start gas turbine is 42 years old, but with few operating hours and several thousand starts and stops.

2. The unit is experiencing significant reliability (starts/stops, operation) and safety problems.

3. The gearbox has been a source of oil leaks and fires, likely a seal issue that has existed for some time. As a result, recent fires have limited the unit's use.

4. The power turbine, gas turbine, gearbox, and generator are overdue for a major inspection/overhaul, based on recent boroscope and on-site power turbine inspections and industry practice.

5. The stack is badly corroded and appears to be leaking water into the back end of the gas turbine.

15 RECOMMENDATIONS

15.1 Overall and Station Wide

1. Implement the recommended Level 1 and 2 condition assessment tasks identified in Chapters 8 to 11 and summarized in Chapter 12, including augmented steam turbine and generator overhauls at their next normal overhaul date to the extent economically practical.

2. Retain the 9 year major inspection/overhaul interval and minor 3 year valve outage timing for the steam turbines, subject to any unexpected changes in conditions found at their inspection/overhauls and, in particular, at their next inspection/overhaul. Undertake the steam turbine pre-outage actions identified in Chapters 8 to 10.

3. Modify the generator inspection and overhaul interval back to every six years. Address the specific actions identified in Chapters 8 to 10, in particular those permitting better performance baselining in the balance of 2010 and 2011.

4. Perform in 2011 limited generator testing, with rotor in and on all units but particularly on Unit 1, to the extent safe and economically practical to obtain baseline data. Undertake work needed to scope out the details of the inspection/testing and stator rewind during the 2012 Unit 1 outage.

5. In 2011 and 2012, carry out a detailed condition assessment of high pressure and temperature feedwater and steam lines on all units as a very high priority safety and reliability due diligence task. Plan and implement an extensive high pressure and temperature pipe hanger inspection program as part of the plant's PM, safety, and reliability due diligence programs.

6. Carry out Level 2 inspections and testing in 2012, 2013, and 2014 for Units 1, 2, and 3 respectively on boiler components identified in Chapters 8 to 10.

7. Carry out Level 2 inspections and testing in 2012, 2013, and 2014 for Units 1, 2, and 3 respectively on high pressure heater components identified in Chapters 8 to 10.

8. Carry out Level 2 inspections and testing in 2012, 2013, and 2014 for Units 1, 2, and 3 respectively on deaerator components identified in Chapters 8 to 10.

9. Carry out Level 2 inspections and testing on low pressure heaters in 2011 for Units 1, 2, and 3.

10. Maintain existing programs for major equipment, pumps, and motor inspection scheduling and overall PM process.

11. Procure one spare 4 kV motor for each of the boiler feedwater pumps, the forced draft fans, condensate extraction pumps, and the cooling water pumps – primarily designed for Units 1 and 2, but with plans on how to use them with Unit 3 as necessary.

12. Develop and implement an optimized plan for station switchgear (all units, common facilities), primarily breakers and motor control centres, addressing a combination of extensive replacement and sparing to maintain station reliability without interrupting normal unit operation.

13. Inspect all condensate polishers in 2011. Replace Units 1 and 2 remaining enunciator panels (Unit 3 enunciator panel was replaced in 2007). Assess the cost-benefit of replacing polisher control panels on all units considered obsolete in light of generation end of service timeline.

13. Replace the Stage 2 diesel generator in or about 2014.

14. Replace the Stage 1 air compressors that are near their end of life in 2014 and 2015.

15.4 Unit 1

1. Undertake a generator stator rewind as part of the 2012 generator overhaul. Initiate planning early in 2011. Undertake the generator actions list in 2010 and 2011.

2. Address issues and action with steam turbine, including wok on main and intercept valve issues, stud bolt issues, and turning gear issues as per sections 8, 9, and 10 of this report.

3. Refurbish stack breeching per current plans.

Where economically feasible, assess and implement those efficiency improvement options for the facility which have short term economic benefits, e.g.:

a) Addition of reheat boiler tubes to improve reheat steam conditions and cycle efficiency.

b) Repair of previously damaged (but not fully repaired) steam turbine elements or upgrading existing elements with more efficient designs.

15.5 Unit 2

1. Undertake a generator stator rewind as part of 2014 generator overhaul. Initiate pre-work early in 2013. Undertake early generator actions list in 2011.

2. Address issues and actions with steam turbine, including work on main and intercept valve issues, stud bolt issues, and turning gear issues.

3. Refurbish stack breeching per current plans.

Where economically feasible, assess and implement those efficiency improvement options for the facility which have short term economic benefits, e.g.:

a) Addition of reheat boiler tubes to improve reheat steam conditions and cycle efficiency.

b) Repair of previously damaged (but not fully repaired) steam turbine elements or upgrading existing elements with more efficient designs.

15.6 Unit 3

1. Undertake a generator rotor rewind at the next generator overhaul in 2016 or, with some additional reliability risk, between 2020 and 2022 subject to the findings of the 2016 inspection.

2. Address issues and actions with the steam turbine, including work on main and intercept valve issues, and stud bolt issues.

3. Assess the cost-benefit of replacing the existing steam turbine mechanical governor system in 2011 for implementation during the 2013 minor valve outage.

4. Refurbish stack breeching per current plans.

5. For safety reasons, replace the Unit 3 control room relay panels as soon as practical to accommodate the current and required wiring.

6. Implement Unit 3 generator thrust bearing retrofit to address lateral movement during synchronous generator operation to eliminate long term vibration and damage.

15.7 Black Start Gas Turbine

1. In 2010 inspect/assess the power turbine, gas turbine, gearbox, and generator without removing the unit to confirm major inspection/overhaul requirement.

2. Complete 2010 boroscope inspections on gas and power turbine, combustor, and gearbox.

3. Inspect and assess in 2010 the air intake and exhaust stack structure.

4. Undertake in 2010 off-site overhaul of power turbine and gas turbine, and on-site or off-site gear-box inspection and gearbox seal replacement.

5. Undertake in 2011 detailed inspection/testing of generator and electrical auxiliaries.

6. Develop a design and implement the replacement the fuel handling and lube oil coolers inside an enclosure.

7. Assess in 2010 the alternative of replacing the black start generator with a new or newer unit.

15.8 Switchyard

1. Implement identified Level 2 transformer gas in oil testing in 2010 and 2011. Catch up on backlogged electrical testing using full Hydro test protocol and report during these and future regularly scheduled electrical testing periods.

2. Considering the requirements going forward, assess the cost-benefit of additional transformer equipment sparing and configurational sparing possibilities. Undertake more frequent and complete Hydro condition monitoring.

3. Maintaining station reliability without interrupting normal unit operation, develop and implement an optimized plan for switchyard equipment such as switchgear (primarily older breakers) as well as other components such as potential transformers (PT's) and current transformers (CT's), addressing a combination of extensive refurbishment and/or replacement and sparing.

15.9 Management

1. Upgrade the existing document management procedures, systems, and resources at the plant

2. Implement current station staffing plan, including some moderate additions in operational, on-site engineering support. Develop and implement a succession planning process.

A REPORT TO
THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES



Electrical
Mechanical
Civil
Protection & Control
Transmission & Distribution
Telecontrol
System Planning

Replace Interior and Exterior Coating on Surge Tank 2

Bay d'Espoir

July 2015

newfoundland labrador hydro
a nalcor energy company

SUMMARY

The surge tanks at the Bay d'Espoir Hydroelectric Generating Station are critical to Hydro's ability to meet the province's energy demands. Surge Tank 2, which provides surge protection for Units 3 and 4, is currently 45 years old and the existing coating system was applied 30 years ago. In 2014, Hydro engaged the engineering firm Hatch to perform a condition assessment of Surge Tank 2 at the Bay d'Espoir Hydroelectric Generating Station.

A report was prepared with recommendations to extend the service life of the surge tank through exterior and interior recoating as well as structural repairs. A cathodic protection (CP) system failure in conjunction with areas of partial and full coating failure has resulted in widespread corrosion both inside and outside the surge tank. Ultrasonic testing (UT) identified that corrosion has resulted in material loss of the steel, particularly in the surge tank bowl area, where structural reinforcement is now required to address structural instability issues.

A cost comparison between full coating application and a combination of full and localized coating application was developed, with both options including structural repairs, to determine which alternative would be the least cost option over a 25 year study period. It was determined that a full coating application on all affected surfaces is the most cost effective solution. As a result, this project includes a refurbishment of all interior and exposed exterior surfaces of the surge tank and riser with a full coating application as well as structural repairs.

Hydro has planned this project to ensure the continued uninterrupted operation of this structure and to avoid a potential structural failure of the tank which would result in a loss of 150 MW of generation from Units 3 and 4 at the Bay d'Espoir Hydroelectric Generating Station.

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1 INTRODUCTION

Bay d'Espoir includes three hydroelectric generating stations, six reservoirs, and associated dykes, dams, canals and hydraulic structures. The headwaters of the Bay d'Espoir Development begin at the Victoria Lake reservoir at an approximate elevation of 320 meters. The water travels through the Granite Canal Hydroelectric Generating Station (Granite Canal), Upper Salmon Hydroelectric Generating Station (Upper Salmon) and finally through the Bay d'Espoir Hydroelectric Generating Station (Bay d'Espoir) where it discharges at sea level.

The generating stations comprising the Bay d'Espoir Development were built over a number of years with the Bay d'Espoir Generating Station being the oldest, dating back to 1967. During Stage I construction of the Bay d'Espoir Generating Station, Surge Tanks 1 and 2 were built in conjunction with the installation of two penstocks to provide water to Generating Units 1, 2, 3 and 4. Surge Tank 3 was constructed in 1970 as part of Stage II construction of the Bay d'Espoir Generating Station. Stage II included the installation of a third penstock which provides water to Generating Units 5 and 6 at the Bay d'Espoir Powerhouse. All three surge tanks are located approximately 645 metres downstream of the penstock intakes. See Figures 1 and 2.

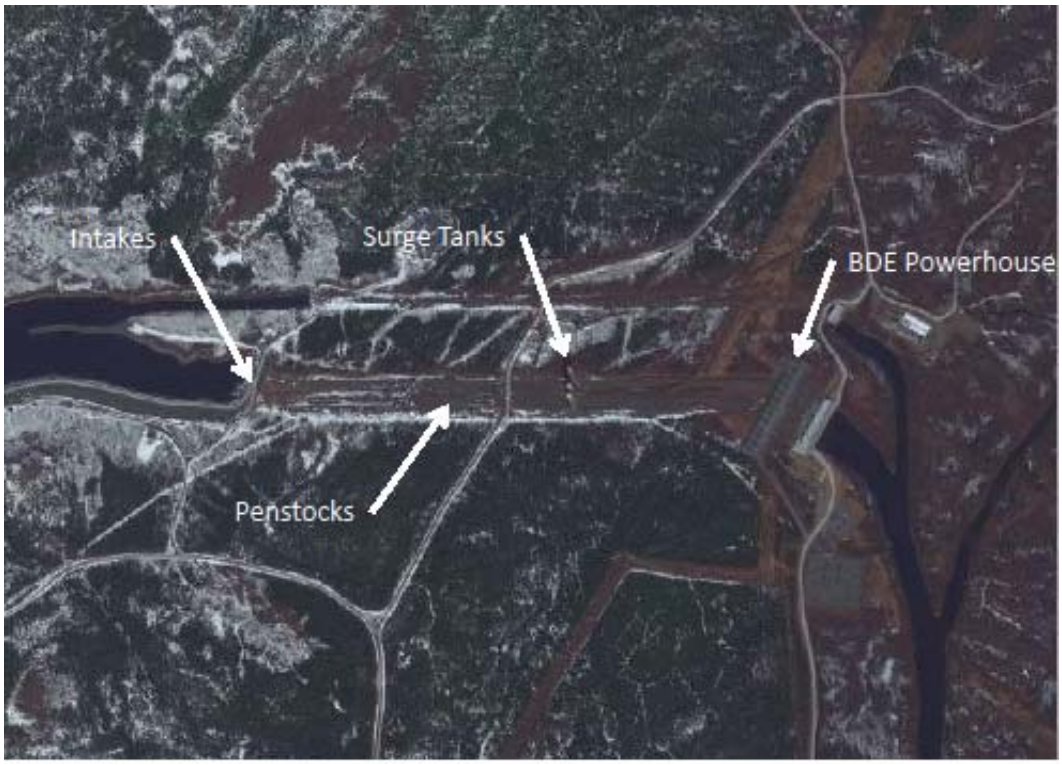


Figure 1: General Layout near Powerhouse



Figure 2: Photograph of Bay d'Espoir Surge Tanks

This project is planned as a result of recommendations from a condition assessment conducted by an engineering consultant in 2014. Based on the report findings and recommendations, Surge Tank 2 is in need of refurbishment to protect the steel components from further corrosion and to ensure its continued operation. The report recommended refurbishments for both the interior and exterior of Surge Tank 2 as well as structural refurbishment.

Work is progressing relating to the other two tanks. A condition assessment for Surge Tank 1 was completed earlier in 2015. Interior coating and structural repair work is being completed during the summer of 2015 on Surge Tank 3, as previously approved in the 2015 Capital Budget Application.

2 PROJECT DESCRIPTION

This project involves interior and exterior refurbishment of Surge Tank 2 at the Bay d'Espoir Hydroelectric Generating Station. The scope of this project involves the following:

- Refurbishing all interior surfaces including surface preparation and coating of the surge tank and riser interior;
- Refurbishing the exterior surfaces above the tank insulation including surface preparation, spot prime and coating;
- Refurbishing exterior side of expansion joint at lower balcony under insulation;
- Analyzing the structural integrity of surge tank bottom bowl and completing structural design and rehabilitation; and
- Refurbishing the exterior ladder and fall arrest anchor points to facilitate safe work at heights.

The budget estimate for this project is $2.6 million. Engineering is scheduled to start in February 2016 with construction starting late May or early June 2016 and ending in late September 2016; an estimated 19 week construction period. The construction schedule is broken into nine weeks for exterior work and ten weeks for interior work with some potential for overlapping activities. The interior coating and inspection work must be completed from inside the tank and riser and as a result, the ten week construction period will require an outage to Units 3 and 4 for that period of time.

3 JUSTIFICATION

This project is justified on the requirement to replace failing or deteriorated infrastructure in order for Hydro to provide the safe and reliable operation of Surge Tank 2 and the Generating Units 3 and 4 at the Bay d'Espoir Hydroelectric Generating Station.

A condition assessment was completed of Surge Tank 2 and areas of full and partial coating failure were observed. Failure of the coating system leaves the steel vulnerable to corrosion, especially inside the tank where there is a continual cycling between a wet and dry environment. Corrosion in the surge tank and/or riser section can result in leaks, and if severe enough, structural failure of the metal and/or welds. A significant leak in this structure would require immediate repair. This repair effort would require the surge tank as well as the associated penstock and units to be taken out of service for an unscheduled outage which, depending on the magnitude of the problem and timing, could be four to eight weeks in duration. Leaks or structural metal failure would have an impact on Hydro's ability to meet the electrical demand on the Island Interconnected System. As this surge tank is located on the penstock supplying water to Generating Units 3 and 4, a failure of the tank and the resulting outage would affect both Units 3 and 4 with a combined maximum generation capacity of 150 MW.

Removing the exterior and interior corrosion, completing structural repairs and recoating the tank and riser will extend the life and reliability of the structure. According to the manufacturer of a similar epoxy system to the one that was applied in 1985, these coating systems typically last between 15 to 25 years. The existing coating system is 30 years old and is degraded. This work is considered high priority due to the potential loss of generation given the deteriorated condition of the surge tank.

3.1 Existing System

The main powerhouse at Bay d'Espoir contains six generating units. There are three penstocks that transport water to these six units. Each penstock has a surge tank installed

on the line to protect the system against increased pressure, such as water hammer, resulting from generator load rejection. Surge Tank 2 is located on the second penstock which supplies water to Generating Units 3 and 4 in the Bay d'Espoir powerhouse. These two units together can generate a maximum of 150 MW.

Each surge tank is approximately 112 metres above the ground. The tanks are supported by braced legs designed to resist hurricane force winds and earthquakes. The diameter of each tank is 7.6 metres and each tank contains approximately 1,300 tons of steel. The surge tanks and risers are insulated up to the static water level and are electrically heated in winter to prevent icing.

The surge tank was installed in 1967 and the interior was coated with an epoxy system in 1985. It has been 30 years since this coating was applied and there have been no touch-ups or recoats since that time. This life span exceeds the coating manufacturer's life expectancy of 15 to 25 years for the product that was applied in 1985.

3.1.1 Condition Assessment

A condition assessment of the tank and riser interior was completed by a professional engineering consultant in 2014 as attached in Appendix A. This assessment included a visual inspection by a certified NACE and welding inspector of the condition of the interior and exterior surfaces, as well as UT of the remaining gauge thickness of the surge tank bowl. The consultant identified significant deterioration and corrosion of the interior surge tank coating, and localized corrosion on the exterior of the surge tank and structural components such as legs, bracing and compression rings as shown in Photos 1 through 5. A coating failure on the interior of the surge tank has left the metal exposed and corroded. In addition, the cathodic protection system is not functioning as evidenced by the level of observed corrosion in the tank. The exterior of the surge tank and the interior of the riser also show signs of partial coating failure.

The assessment report also identified that there was steel thickness loss in the tank bowl that ranged between 1% and 30% material loss compared to the design gauge thickness of the steel. This material loss will require structural rehabilitation to ensure the integrity of the structure. Deficiencies in the fall protection system were also noted.

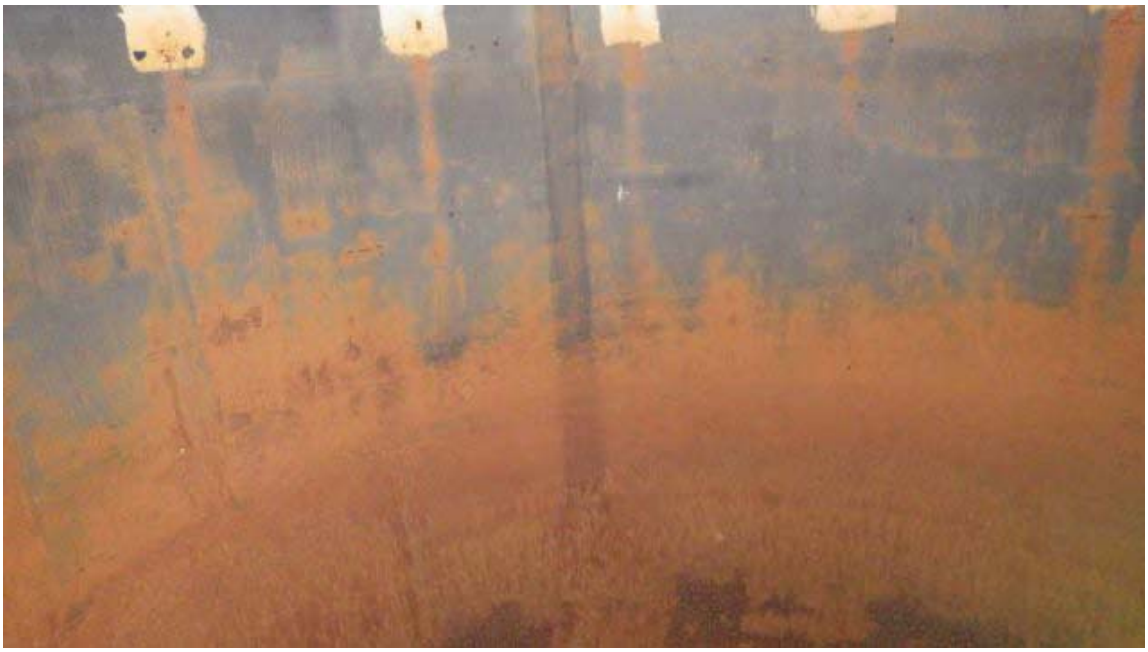


Photo 1: Corrosion in surge tank



Photo 2: Pitting in Surge Tank



Photo 3: Corrosion with Scaling on Upper Compression Ring of Tank

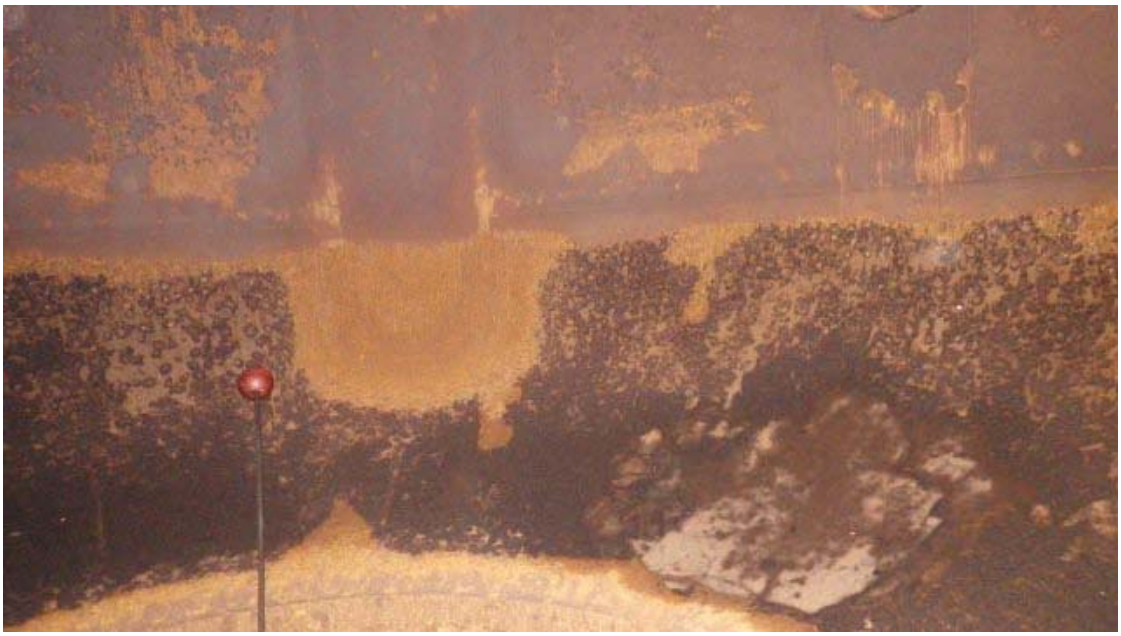


Photo 4: Corrosion in Surge Tank Bowl

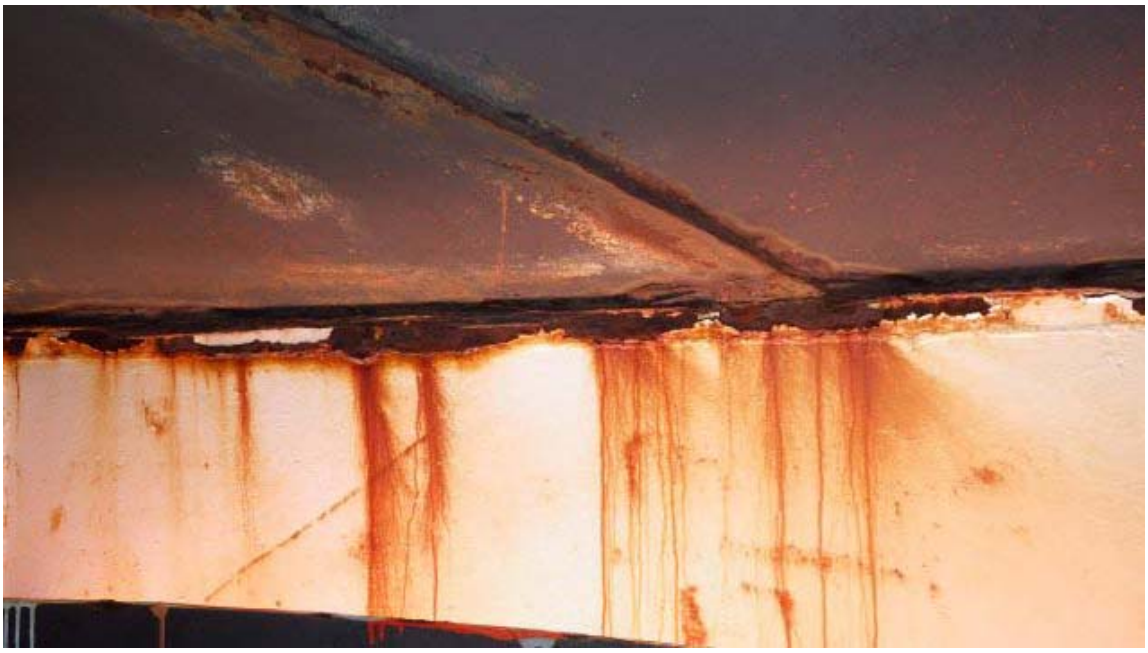


Photo 5: Heavy Corrosion and Scaling Along Edge of Surge Tank Top

The consultant report recommended, at a minimum, corrosion removal and full recoating of the interior of the surge tank as well as localized recoating of the exterior of the surge tank and the interior of the riser.

As scaffolding and set up make up the majority of the costs involved in recoating the surge tank and are the same for both spot repair and full coating repair, a cost benefit analysis was completed to compare a full recoat of the interior and exterior versus a combination of full and localized(spot) recoat. These results are presented in section 3.5 of this report.

3.2 Operating Experience

The surge tanks are an integral part of the hydraulic system of the plant with their primary function being for water pressure protection of the penstock. During a sudden increase in water pressure in the penstock, the water in the surge tank rises quickly to release the water pressure and prevent water hammer damage to the penstock. As a result of this function, the interior surface of the surge tank is subject to frequently changing wet and dry conditions producing an environment ideal for corrosion. A corrosion protection system (Cathodic Protection System (CP)) is located within the tank but the condition assessment

completed in 2014 confirmed that the system is not functioning properly and as a result, the interior of the tank is corroding. An investigation revealed that the present CP system was under-designed and a larger system would provide marginal value. It was determined that the most reasonable solution to address the interior tank corrosion in future would be through application of a protective coating.

Outages to the associated generating units are required to complete maintenance work on the tank and riser interior. Maintenance is a challenge due to the height of the tank as well as the limited access ports on the structure.

3.2.1 Reliability Performance

There are currently no reliability issues with this surge tank, however, if this planned work is not completed within the next few years, corrosion will continue and leaks and/or structural issues will eventually develop. With leaks and structural failure comes the potential for outages on Units 3 and 4 which would impact Hydro's ability to meet the electrical demand on the Island Interconnected System. By undertaking the work in 2016, before the condition deteriorates further, the surge tanks can be restored to reliable service.

3.2.2 Industry Experience

Coatings used in industry today to protect steel structures from corrosion typically have different service lives depending on the type of surface preparation and the type of coating. There will be on-going inspection and maintenance with any coating system and recoats will be required, but with the surface preparation method and coating system being proposed, this system will last approximately 15 to 25 years before the next recoat is anticipated.

3.2.3 Maintenance History

The total maintenance cost for Surge Tank 2 over the past five years has been approximately $13.605 million. None of this cost has been associated with work on the interior coating or welds of the surge tank or riser.

The five-year maintenance history for Surge Tank 2 is shown in Table 1.

Table 1: Five-Year Maintenance History

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2014	0.3	0.0	0.3
2013	0.1	3.2	3.3
2012	0.7	2.5	3.2
2011	0.3	5.2	5.5
2010	0.2	1.0	1.2

3.2.4 Historical Information

There has been no significant work, similar in nature as outlined in this project, completed on the surge tank in the past five years. The interior of the riser was coated 30 years ago but no interior or exterior coating touch ups have been completed since that time.

3.2.5 Anticipated Useful Life

The anticipated useful life of the new interior and exterior coating is 15 to 25 years.

3.3 Development of Alternatives

The condition assessment indicated localized repair for the exterior surfaces and interior riser, with full recoating repair for the interior tank surface. Since scaffolding and set up make up the majority of the costs involved for both localized repair and full coating, it was concluded that a full coating replacement of both interior and exterior was ultimately the least cost option, however a cost benefit analysis was completed to confirm. The two alternatives were developed and are listed as follows:

1. Full recoating on interior tank and riser, as well as full recoating on exterior, and
2. Full recoating on interior tank plus localized coating on interior riser and exterior.

The period used for the study was 25 years. This time frame was chosen because it is the vendor's minimum recommended time period when a full recoat would be required on the surge tank.

3.3.1 Full Recoating on Interior Tank and Riser as well as Full Recoating on Exterior

This option involves the full recoating of interior and exposed exterior surface of surge tank 2 and riser.

- Refurbishing all interior and exterior surfaces including surface preparation and coating of the surge tank and riser;
- Refurbishing exterior side of expansion joint at lower balcony under insulation;
- Analyzing the structural integrity of surge tank bottom bowl and completing structural design and rehabilitation; and
- Refurbishing the exterior ladder and fall arrest anchor points to facilitate safe work at heights.

A full coating repair will consist of the following steps:

1. Water blast surface preparation;
2. Spot or full prime as required;
3. Full intermediate coat; and
4. Full top coat.

This option will require a ten week outage to complete the interior portion of the work.

According to the vendor, this treatment will require a full recoat in approximately 25 years and an inspection of the coating will be required every five years. A one week outage will be required during each coating inspection.

Table 2 outlines the budget estimate to complete a full recoating on the interior and exposed exterior of the surge tank and riser.

Table 2: Budget Estimate for Full Recoat

Project Cost: *($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	185.7	0.0	0.0	185.7
Consultant	0.0	0.0	0.0	0.0
Contract Work	2,309.4	0.0	0.0	2,309.4
Other Direct Costs	16.2	0.0	0.0	16.2
Interest and Escalation	190.7	0.0	0.0	190.7
Contingency	257.5	0.0	0.0	257.5
TOTAL	**2,959.6**	**0.0**	**0.0**	**2,959.6**

3.3.2 Full Recoating on Interior Tank and Localized Coating on Interior Riser and Exterior

This option involves the full recoating of interior as well as localized coating of the riser and exterior surface of the surge tank.

- Refurbishing all interior surfaces including surface preparation and full coating of the surge tank interior;
- Refurbishing the exterior surfaces above the tank insulation including surface preparation, spot prime and localized coating;
- Refurbishing the interior surface of the riser including surface preparation, spot prime and localized coating;
- Refurbishing exterior side of expansion joint at lower balcony under insulation;
- Analysis of structural integrity of surge tank bottom bowl and completion of structural design and rehabilitation; and
- Refurbishing the exterior ladder and fall arrest anchor points to facilitate safe work at heights.

The coating repairs consist of the following:

<u>Full coating repair on the interior tank:</u>

1. Water blast surface preparation;
2. Spot or full prime as required;
3. Full intermediate coat; and
4. Full top coat.

Localized coating repair on the exterior surface and interior riser:

1. Water blast surface preparation;
2. Spot prime;
3. Spot intermediate coat; and
4. Spot top coat.

This option will require a ten week outage to complete the interior portion of the work similar to option 1. The outage time will be the same since the surface preparation as well as the spot priming is the same for both localized coating and full coating. As well, both options require the tank interior to receive a full coating treatment, while the interior riser coating differs between the two options; resulting in minimal difference in interior application time.

According to the vendor, the localized treatment will require an inspection of the exterior of the tank and interior riser every one or two years to ensure the integrity of the existing coating that remains exposed to the elements. A one week outage will be required during each interior coating inspection. It is uncertain what the life expectancy of the existing coating would be if left exposed to the interior tank conditions, and it is presumed that localized repairs of the remaining existing interior coating will be required every five to ten years depending on results of the inspections. The interior of the surge tank will require a full recoat in approximately 25 years and an inspection of the full recoat will be required every five years, similar to option 1.

Table 3 outlines the budget estimate to complete a full recoating on the interior of the surge tank and a localized coating of the interior of the riser as well as the exposed exterior of the surge tank.

Table 3: Budget Estimate for Full and Localized Recoat Combination

Project Cost: *($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	185.7	0.0	0.0	185.7
Consultant	0.0	0.0	0.0	0.0
Contract Work	2,159.4	0.0	0.0	2,159.4
Other Direct Costs	16.2	0.0	0.0	16.2
Interest and Escalation	179.3	0.0	0.0	179.3
Contingency	242.5	0.0	0.0	242.5
TOTAL	**2,783.2**	**0.0**	**0.0**	**2,783.2**

3.5 Evaluation of Alternatives

The two alternatives were evaluated based on least cost. For Hydro, the term "least-cost" refers to the lowest Cumulative Present Worth (CPW) of all capital and operating costs associated with a particular incremental supply source (or portfolio of resources) over its useful economic life, versus competing alternatives or portfolios. CPW concerns itself only with the expenditure side of the financial equation. The lower the CPW, the lower the revenue requirement for the utility and hence, the lower the electricity rates will be.

Based on the CBA completed for the two stated alternatives, the least cost option is shown to be “Full recoating of interior tank and riser as well as exposed exterior” as shown in Table 4.

Table 4: Results of Cost Benefit Analysis of the Two Presented Alternatives

Coating and Structural Upgrades to Surge Tank 2 - BDE **Alternative Comparison** ***Cumulative Net Present Value*** ***To The Year*** **2015**		
Alternatives	**Cumulative Net Present Value (CPW)**	**CPW Difference between Alternative and the Least Cost Alternative**
Full Recoating	2,714,494	0
Combination of Partial and Full Recoating	7,267,528	4,553,035

4 CONCLUSION

The surge tanks at the Bay d'Espoir Hydroelectric Generating Station are critical to Hydro's ability to meet the province's energy demands. A CP system failure in conjunction with areas of partial and full coating failure has resulted in widespread corrosion both inside and outside the surge tank. UT identified that corrosion has resulted in material loss of the steel, particularly in the surge tank bowl area, where structural reinforcement is now required to address structural instability issues. These corrosion issues must be addressed to prevent further deterioration of the surge tank and the potential for significant leakage or structural failure. A failure of a weld or steel section would result in an emergency repair whereby the tank would be taken out of service and Hydro would lose the ability to generate power from Units 3 and 4 at the Bay d'Espoir Hydroelectric Generating Station, resulting in a loss of 150 MW from Hydro's generating capacity. This loss of generating capacity could happen unexpectedly at any time during the year thus potentially affecting wintertime reliability.

4.1 Budget Estimate

The budget proposal estimate for this project is shown in Table 5.

Table 5: Project Budget Estimate

Project Cost: *($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	185.7	0.0	0.0	185.7
Consultant	0.0	0.0	0.0	0.0
Contract Work	2,309.4	0.0	0.0	2,309.4
Other Direct Costs	16.2	0.0	0.0	16.2
Interest and Escalation	190.7	0.0	0.0	190.7
Contingency	257.5	0.0	0.0	257.5
TOTAL	**2,959.6**	**0.0**	**0.0**	**2,959.6**

4.2 Project Schedule

The anticipated schedule for this project is shown in Table 6.

Table 6: Project Schedule

Activity		Start Date	End Date
Planning	Project start up, scheduling, risk management	January 2016	February 2016
Design	Select proper coating system and develop tender documents, complete structural analysis of bowl and develop structural repair design	February 2016	April 2016
Tender	Tender and Award	April 2016	May 2016
Construction	Mobilize to site	May 2016	June 2016
	Cleaning, welding and recoating	June 2016	September 2016
Commissioning	Final Inspection and Acceptance	September 2016	October 2016
Closeout	Certificate of Completion		November 2016

APPENDIX A

Condition Assessment Report

HATCH

Newfoundland and Labrador Hydro

Bay d'Espoir Surge Tank No. 2 Condition Assessment

Final Report

H347346-0000-00-124-0001
Rev. 1
December 11, 2014

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Newfoundland and Labrador Hydro

Bay d'Espoir Surge Tank No. 2 Condition Assessment

Final Report

H347346-0000-00-124-0001
Rev. 1
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Newfoundland and Labrador Hydro
Bay d'Espoir Surge Tank No. 2 Condition Assessment

Final Report

PROVINCE OF NEWFOUNDLAND AND LABRADOR
PEG Newfoundland and Labrador
PERMIT HOLDER
This Permit Allows
HATCH LTD.
To practice Professional Engineering in Newfoundland and Labrador.
Permit No. as issued by PEG D0090
which is valid for the year 2014

REGISTERED PROFESSIONAL ENGINEER
J.E. SNOOK
SIGNATURE
DATE Dec 11/14
NEWFOUNDLAND & LABRADOR

2014-12-11	1	Approved for Use	J. Snook	J. Snook	G. Saunders	
Date	Rev.	Status	Prepared By	Checked By	Approved By	Approved By
			HATCH			Client

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Appendix A Surge Tank Inspection Report (RAT)

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Executive Summary

In July 2014, Hatch was engaged by Newfoundland and Labrador Hydro (NL Hydro) to perform a condition assessment of Surge Tank #2 at the Bay d'Espoir (BDE) hydroelectric generating station. Hatch engaged Remote Access Technology (RAT) to perform the inspection.

The external inspection revealed minor coating breakdown on the tank roof, tank shell above the cladded section, ladder, access platforms and entire structural support system. With the exception of the coating breakdown, the tank, ladder, access platforms and structural support system appeared to be in good condition. All welds appear to be in good condition. The walkway from the ladder to the lower balcony does not have a gate or chain at the ladder access point. One ladder rung located on the south west column leg is bent. Another rung is missing on the tank ladder.

The diagonal cross bracing had wear plates installed at the intersections. The wear plates were misaligned and some had become snagged.

The internal inspection revealed minor coating system breakdown on the interior of the tank roof and the tank shell above the hot water heating system inlets. Below the hot water heating system inlets on the tank shell and the bowl, there was complete coating system breakdown. The coating system on the riser is in good condition with some minor localized breakdown.

The cathodic protection (CP) system is intended to provide a secondary corrosion protection to the steel. A functional analysis of the CP system was not performed during the site inspection. Based on the RAT inspection report, the anodes, cabling, etc. have become intertwined and one structural support member had detached completely from the riser and was dangling by a wire. This member was removed by RAT. It is our opinion the CP system is not functional and poses a hazard to the turbine runner and other system components.

The hot water heating system piping insulation appears to be in good condition with the exception of a few areas.

Based on the condition assessment, the following are recommended.

1. As a minimum, repair localized areas of coating breakdown on exterior surfaces and riser. However, it is highly recommended a life cycle cost analysis be performed to assess the merit of a full coating repair. Scaffolding and set-up are the majority of costs involved and are the same for both spot repairs and full coating. Additionally, an inspection of the coating is recommended every 1-2 years with spot repairs, vs. 4-6 years for full coating repairs. Full coating repairs may be preferred.
2. Refurbish the interior of the roof, tank shell and bowl with a full coating repair in accordance with SSPC 10 and apply a full new coating system.
3. Implement a program of regular detailed inspections of the tank interior coating system. See note 1 above regarding recommended inspection intervals.

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4. Complete a detailed analysis of the surge tank bowl to determine the integrity of the structure considering the current state of material loss.
5. Complete a structural assessment of the existing vertical ladder to confirm its suitability for use with the new fall arrest system.
6. The existing roof anchors should be taken out of service immediately and removed at next opportunity.
7. Install a gate or chain at the ladder access point to the lower balcony to ensure the handrail is continuous.
8. Replace the roof ladder including the painters post with a fixed ladder and new painters post.
9. Remove the existing CP system and all associated components and supporting system.
10. Repair all areas of damaged insulation on the hot water heating system piping.
11. Conduct testing of the electrical ground system to determine if the concrete structure is adequate to be used as a grounding electrode. If not, proper ground electrodes should be installed and tested as per current standards.

Preliminary (+30/-20%) cost estimates were prepared for these recommendations. All cost estimates exclude owners cost.

- Painting of the exterior/interior of the tank and interior riser (Recommendation #1), $ 1,000,000
- Desktop studies/design reviews (Recommendations #4 & #5), $30,000
- Structural upgrades (Recommendations #6 - #10), $142,025
- Grounding Testing (Recommendations #11), $16,405

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1. Introduction

In July 2014, Hatch was engaged by Newfoundland and Labrador Hydro (NL Hydro) to perform a condition assessment of Surge Tank #2 at the Bay d'Espoir (BDE) hydroelectric generating station. The BDE hydroelectric generating station main powerhouse consists of six generating units fed from three penstocks. Each penstock has a surge tank, numbered #1, 2 and 3. Surge Tank #2 is connected to generating Units #3 and 4 penstock.

The objectives of the study were as follows.

1. Perform an internal inspection of the tank and riser with focus on plate thickness, welds, coatings, internal structural members, and cathodic protection system. Particular attention should be given to the bowl (bottom dished head), its leg support connection points, and the riser expansion joint.
2. Perform an external inspection of the tank and riser including the structural support system, thermal insulation system, hot water heating system, tank cap, rotating ladder, foundations, and electrical grounding.
3. Develop recommendations with Class 3 cost estimates to carry out each of the recommendations.

Hatch engaged Remote Access Technology (RAT) to perform the inspection. See Appendix A for RAT's inspection report. Site inspections were conducted from July 14 to 18, 2014, by James Foucault (Welding Inspector), Darrell Coupland (NACE) and Darren Riley (Welding Inspector) of RAT. Scott Hancock of Hatch was on site during the inspection. Eric King of NL Hydro was the confined space attendant during the inspection. The inspection was mostly visual with some ultrasonic thickness (UT) readings taken on the tank top, tank shell at the top balcony, tank bowl and the expansion joint. RAT's inspection report was used to develop the condition assessment final report.

In addition to the site inspections, Hatch reviewed existing drawings as provided by NL Hydro. The drawings were primarily used in developing a familiarity with the surge tank for the site visits.

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2. Internal Inspection

2.1 Tank Top

The tank top as shown in Figure 2-1 is constructed with a series of stiffener ribs covered with lap jointed plates. The original drawings show a 1" (25 mm) lap between the roof plates, welded on the outside only. It was observed that the inside lap has opened up. It is unknown if this occurred during construction or if this occurred over time due to plate sagging.

The coating system on the tank top interior appears to be in good condition with some minor localized coating breakdown as shown in Figure 2-1.

Around the interior of the tank top perimeter vent, there appears to be some significant coating breakdown and corrosion as shown in Figure 2-2.

It is recommended that all areas of the tank top interior be refurbished in accordance with SSPC-SP 10 and a coating system be applied.



Figure 2-1: Tank Top Interior

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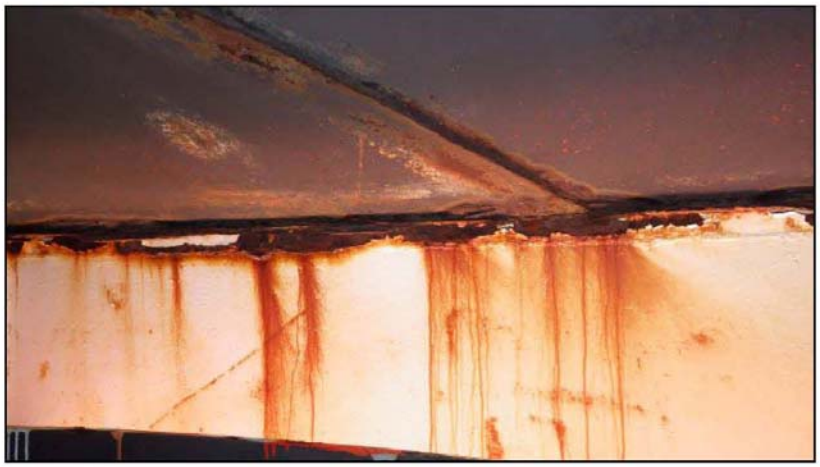


Figure 2-2: Tank Top Perimeter Vent Interior

2.2 Shell

From the top of the shell to roughly the mid-height as shown in Figure 2-3, the coating system appears to be intact with some minor localized breakdown.

At roughly the mid-height, there are two sets of inlet ports for the hot water heating system, one above the other as shown in Figure 2-3. The bottom ports, installed during the original construction of the surge tank are plugged and no longer operational. The top ports are operational. They were installed when the dams were raised around the head pond, which raised the operating level of the surge tank above the bottom ports.

There was coating breakdown and corrosion along the weld seams with water staining and rust bleeding from the ports. The inlet piping to the bottom ports was disconnected on the outside of the tank.

From the inlet ports to the bottom of the tank shell as shown in Figure 2-4, there appears to be complete loss of coating.

It is recommended that all areas of the tank shell interior be refurbished in accordance with SSPC-SP 10 and a coating system be applied.

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Figure 2-3: Tank Shell Interior at Mid-height Near Hot Water Heating System Inlets



Figure 2-4: Tank Shell Below Hot Water Heating System Inlets

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2.3 Tank Bowl

As shown in Figure 2-5 and Figure 2-6 below, there appears to be complete loss of coating on the tank bowl.

The reference drawings indicate the thickness of the roof bowl was originally 0.64" (16mm) plate. Fifteen UT readings were taken on the tank bowl (see Section 4.6 of the RAT report). The UT readings ranged from 11.00mm (approximately 30% material loss) to 15.85mm (approximately 1% material loss).

It is recommended that a detailed analysis of the surge tank bowl be performed to determine the effect of material loss.

It is recommended that all areas of the tank bowl interior be refurbished in accordance with SSPC-SP 10 and a coating system be applied.

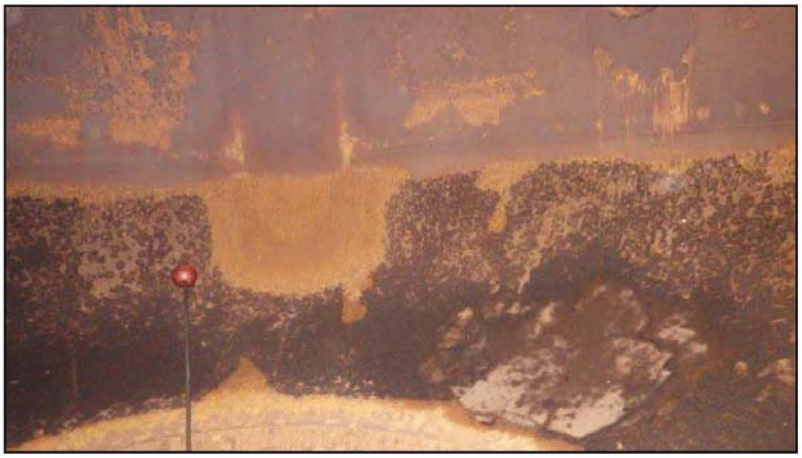


Figure 2-5: Interior of Tank Bowl

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Figure 2-6: Interior of Tank Bowl to Riser Connection

2.4 Riser

The riser appears to have experienced some corrosion prior to the application of the most recent coating system as shown in Figure 2-7 and Figure 2-8. The steel surface beneath the coating system is not smooth. This coating system appears to be in good condition.

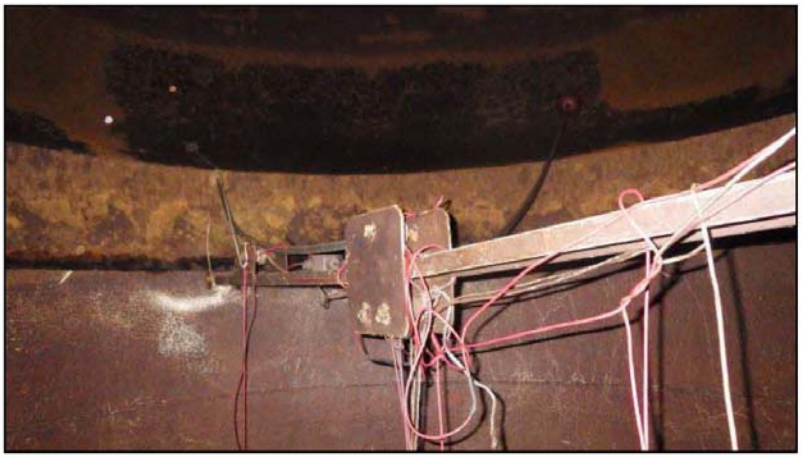


Figure 2-7: Interior of Riser (Showing Cathodic Protection System)

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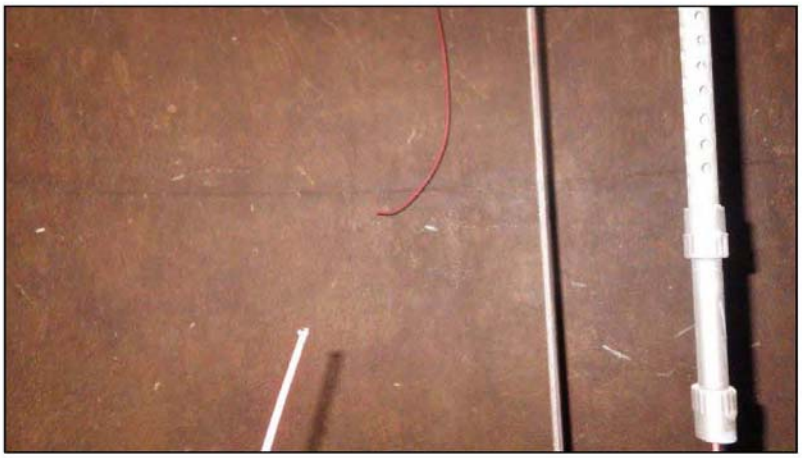


Figure 2-8: Interior of Riser

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3. External Inspection

3.1 Roof

The coating system on the exterior of the tank top as seen in Figure 3-1 appears to be mainly intact.

UT readings were taken on the tank top (see Section 4.1 of the RAT report). The reference drawings did not indicate the thickness of the roof top plate. The UT readings were consistent and suggest 1/4" (6.4 mm) plate.

The existing roof anchors are welded to the tank top plate only and not to any structural sections.

It is recommended that the roof anchors be taken out of service and removed.

It is recommended that the areas of localized coating breakdown and corrosion be refurbished in accordance with SSPC-SP 11 and a compatible coating system be applied with minimum coating breakdown and minimal corrosion, it can be concluded that the measured thickness of the roof is as per original design.



Figure 3-1: Tank Top

3.2 Shell

The surge tank shell above the external insulation system has minor coating breakdown as shown in Figure 3-2.

It is recommended that as a minimum, the areas of localized coating breakdown and corrosion be refurbished in accordance with SSPC-SP 11 and a compatible coating system be applied.

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Cladding and insulation was removed adjacent to the west leg on the upper balcony to expose the exterior of the surge tank shell bottom course and leg attachment as seen in Figure 3-3. There were no visible signs of corrosion in this area.

UT readings in a three by four grid pattern were taken in this area (see Section 4.2 of the RAT report). The twelve UT readings were taken on the shell plate (bottom course). The reference drawings indicate the bottom course of the surge tank is 9/16" (14.3 mm) thick. The UT results are consistent with the reference drawings and show little to no corrosion.



Figure 3-2: Surge Tank #2 (Left) Shell Above External Insulation

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Figure 3-3: Cladding Removed Adjacent to Leg

3.3 External cladding

Overall, the external cladding was intact as shown in Figure 3-4.

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Figure 3-4: Riser and Structural Support

3.4 Compression Ring / Upper Balcony

The compression ring is a critical structural element located at the attachment of the legs to the surge tank shell, which also functions as the upper balcony. In general and as shown in Figure 3-5, there was minor coating breakdown on the compression ring which has resulted in corrosion caused by pooled water. RAT identified one area on the north side of the compression ring where the corrosion is more significant. UT readings confirm loss of material in this area.

To prevent further loss of material, it is recommended that the compression ring be surface cleaned in accordance with SSPC-SP 11 and a coating system applied.

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Figure 3-5: Compression Ring / Upper Balcony

3.5 Expansion Joint

External cladding and insulation was removed on the lower balcony exposing the expansion joint as shown in Figure 3-6.

UT readings were taken in this area (see section 4.3 of the RAT inspection report). A series of 16 readings were taken in a 4x4 grid. Readings 1a, 2a, 3a and 4a (taken above the weld seam) were taken on 1/2" (12.7 mm) thick plate. The remaining readings were taken on 3/8" (9.5 mm) thick plate (below the weld seam). The results are consistent and show little to no corrosion in this area.

It is recommended that the expansion joint steel be surface cleaned in accordance with SSPC-SP11 and a coating system applied.

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Figure 3-6: Cladding Removed Showing Expansion Joint at Lower Balcony

3.6 Lower Balcony

The lower balcony as shown in Figure 3-7, appears to be in good condition with some localized coating breakdown and corrosion, likely resulting from water build-up. It was in better condition than the upper balcony. The walkway from the ladder to the lower balcony shown does not have a gate or chain at the ladder access point, which is a safety issue that should be corrected.

It is recommended that the lower balcony be surface cleaned in accordance with SSPC-SP 11 and a coating system applied.

It is also recommended to install a safety chain at the ladder access point.

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Figure 3-7: Lower Balcony

3.7 Lower Rest Platform (Crow's Nest)

Lower rest platform (referred to as the crow's nest by NL Hydro personnel) had some minor surface corrosion as shown in Figure 3-8. The grating hatch was functional.

It is recommended that the areas of localized coating breakdown and corrosion be refurbished in accordance with SSPC-SP 11 and a compatible coating system be applied.

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Figure 3-8: Lower Rest Platform (Crow's Nest)

3.8 Structural Support

3.8.1 Legs and Struts

The legs and struts had some coating breakdown as shown in Figure 3-9.

It is recommended that the areas of coating breaking be refurbished in accordance with SSPC-SP 11 and a compatible coating system be applied.

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Figure 3-9: Legs and Struts

3.8.2 *Diagonal Bracing*

The diagonal bracing had some coating breakdown as shown in Figure 3-10.

All diagonal bracing have plates installed at the intersection to prevent wear. Some of these plates have become misaligned and have snagged together as shown in Figure 3-11.

It is recommended the wear plates be removed and replaced with longer plates.

It is recommended that the areas of coating breaking be refurbished in accordance with SSPC-SP 11 and a compatible coating system be applied.

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Figure 3-10: Cross Bracing Showing Bent Rod



Figure 3-11: Cross Member with Misaligned Wear Plates

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3.8.3 *Connections*

The connections appear to be in good condition with some minor coating breakdown as shown in Figure 3-12.

It is recommended that the areas of coating breaking be refurbished in accordance with SSPC-SP 11 and a compatible coating system be applied.



Figure 3-12: Typical Structural Support Connection

3.8.4 *Foundations (Above Grade)*

The inspection of the riser and leg foundations was limited to a visual inspection of the portion above grade. No excavation was performed to inspect below grade and no destructive testing (i.e., cores for compression testing) was carried out.

As shown in Figure 3-13 and Figure 3-14, the concrete appears to be in generally good condition with some cracking that in most cases has been filled with a sealant. In a few areas sections of cracks are not sealed and have some efflorescence and minor surface concrete deterioration that should be repaired and sealed. It was reported that crack sealing was carried out on a regular basis during routine maintenance. The sealant prevents water infiltration and further deterioration; however, it also prevents inspection of the cracks to determine width and depth. No reports were provided indicating when the cracks developed or probable cause of the cracking. Cracks should be monitored to determine if they are getting larger or more numerous.

There are no visible signs of overstressing or areas where the concrete has deteriorated to a point where significant portions of concrete have spalled off. It was noted that the foundations

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for Surge Tank 2 were generally less deteriorated in comparison to Surge Tank 3 inspected previously.

Overall the visible foundation concrete appears to be in satisfactory condition.



Figure 3-13: Riser Foundation



Figure 3-14: Leg Foundation and Anchor Bolt Arrangement

3.8.5 *Anchor Bolts*

Most anchor bolts appear to be in good condition as shown in Figure 3-15 with some minor coating breakdown in a few areas. It is recommended that any anchor bolts with coating breakdown be refurbished in accordance with SSPC-SP 11 with a new coating system applied.

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Figure 3-15: Leg Foundation and Anchor Bolts

3.9 Ladder

The tank ladder had a loose rung, 19th from the upper balcony. There was also a bent rung on the south west column leg, near the second horizontal cross member.

The ladder had some minor coating breakdown as shown in Figure 3-16.

It is recommended that the loose rung be re-welded.

The roof ladder is a revolving ladder approximately 14 ft long which is attached to and rotates about the existing painter's post.

It is recommended the existing roof ladder and painters post be replaced with a fixed ladder and new painters post.

It is recommended that the areas of coating breakdown be refurbished in accordance with SSPC-SP 11 and a compatible coating system be applied.

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Figure 3-16: Access Ladder on Leg

3.10 Fall Arrest System

The existing fall arrest system was installed in 2012. RAT identified a bolt on the roof ladder fall arrest system that prevented its use, as shown in Figure 3-17.

It is recommended this bolt be replaced with a shorter bolt.

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Figure 3-17: Painters Post for Ladder on Tank Top

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4. Ancillary Items

4.1 Cathodic Protection

The cathodic protection (CP) system is intended to provide a secondary corrosion protection to the steel. The coating system on the interior of the riser appears to have performed well and is still in good condition, but the lower half of tank shell and bowl have complete coating system failure.

A functional analysis of the CP system was not performed during the site inspection. As shown in Figure 4-1, the anodes, cabling, etc. have become intertwined. As shown in Figure 4-2, one CP support member had completely detached from the riser and was hanging by the wiring only. This was removed for safety and operational reasons.

As stated in the 2012 Surge Tank #3 Condition Assessment Report, tangling of the CP system is common each time the surge tank is dewatered. In addition, we understand the float support system never worked properly. It is our opinion the CP system is not functional and poses a hazard to the turbine runner and other components.

The following is recommended:

- Remove the existing CP system and all associated components and supporting system.
- Surface prepare the tank shell interior (including bowl) in accordance with SSPC-SP 11 and apply a coating system.
- Implement a program whereby a detailed inspection of the tank interior coating system is performed regularly. See Summary of Recommendations for discussion.

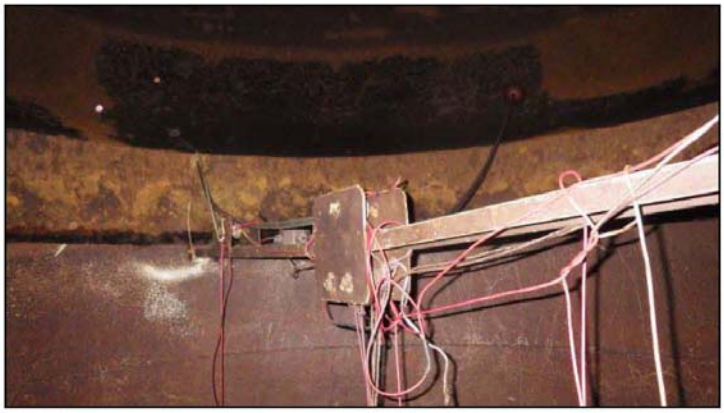


Figure 4-1: Tangled Cathodic Protection System at Top of Riser

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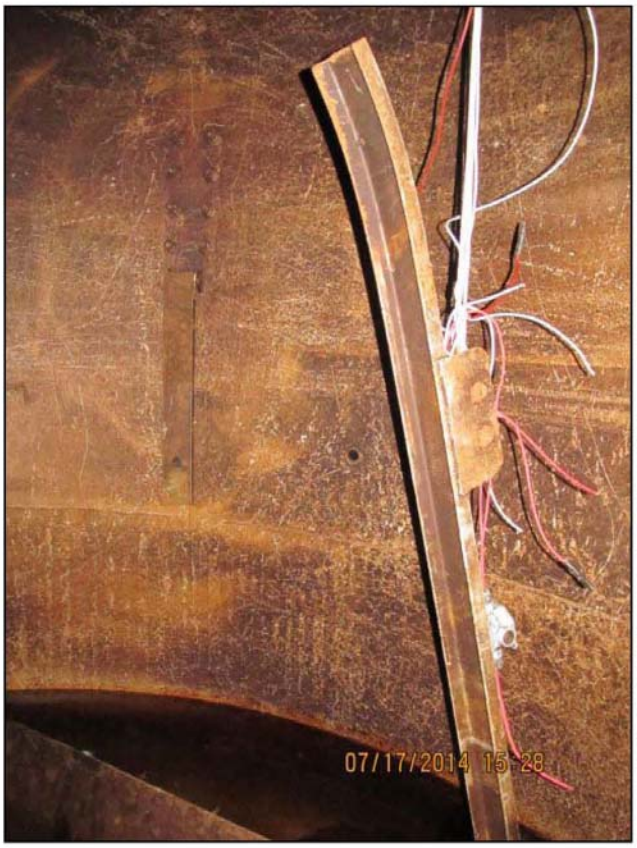


Figure 4-2: Cathodic Protection System on Tank Riser

4.2 Hot Water Heating System

The hot water heating system piping insulation appears to be in good condition with the exception of some improper insulation as shown in Figure 4-3.

It is recommended that the areas of damaged insulation be repaired.

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Figure 4-3: Insulation on the Hot Water Heating System Piping

4.3 Electrical Grounding

It appears that the concrete foundation which supports the electrical shed is being used as the 'ground' reference electrode. It is recommended that proper resistance to ground testing be conducted in order to confirm if this installation satisfies the grounding requirements of current standards.

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5. Summary of Recommendations

Based on the condition assessment, the following are recommended:

1. As a minimum, repair localized areas of coating breakdown on exterior surfaces and riser. However, it is highly recommended a life cycle cost analysis be performed to assess the merit of a full coating repair. Scaffolding and set-up are the majority of costs involved and are the same for both spot repairs and full coating. Additionally, an inspection of the coating is recommended every 1-2 years with spot repairs, vs. 4-6 years for full coating repairs. Full coating repairs may be preferred.
2. Refurbish the interior of the roof, tank shell and bowl with a full coating repair in accordance with SSPC 10 and apply a full new coating system.
3. Implement a program of regular detailed inspections of the tank interior coating system. See note 1 above regarding recommended inspection intervals.
4. Complete a detailed analysis of the surge tank bowl to determine the integrity of the structure considering the current state of material loss.
5. Complete a structural assessment of the existing vertical ladder to confirm its suitability for use with the new fall arrest system.
6. The existing roof anchors should be taken out of service immediately and removed at next opportunity.
7. Install a gate or chain at the ladder access point to the lower balcony to ensure the handrail is continuous.
8. Replace the roof ladder including the painters post with a fixed ladder and new painters post.
9. Remove the existing CP system and all associated components and supporting system.
10. Repair all areas of damaged insulation on the hot water heating system piping.
11. Conduct testing of the electrical ground system to determine if the concrete structure is adequate to be used as a grounding electrode. If not, proper ground electrodes should be installed and tested as per current standards.

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6. Cost Estimates

Preliminary (+30/-20%) cost estimates were prepared for the recommendations outlined in Section 6. A 25% contingency is included. All cost estimates exclude owners cost, such as procurement and construction management.

Cost estimates for painting the exterior of the surge tank and structural supports (Recommendation #1) and interior of the surge tank (Recommendation #2) are presented in Table 6-1. It is assumed that painting will be completed under a standalone contract.

The cost estimates for the desktop studies/design reviews (Recommendations #4 and #5) are presented in Table 6-2. The cost estimates for desktop studies/design reviews excludes any cost associated with the findings of these studies/reviews, i.e. replacement/upgrade cost.

The cost estimates for the structural/ mechanical upgrades (Recommendations #6 to #10) are presented in Table 6-3. The cost estimates for the grounding tests (Recommendation #11) is presented in Table 6-4.

It is assumed the structural upgrades and painting will be executed under separate contracts with one mobilization and demobilization for each. Weather will be a major cost and schedule risk during the execution of this work. This estimate assumes no weather related issues or delays.

Table 6-1: Coating and Coating Inspection Cost

	Direct Cost	Contingency (25%)	Total Cost
Surface Preparation and Painting of Interior/Exterior	$1,000,000	$250,000	$1,250,000

Table 6-2: Desktop Study/Design Review Cost

	Direct Cost	Contingency (25%)	Total Cost
Analysis of Tank Bowl	$12,000	$3,000	$15,000
Design Review of Existing Tank Ladder	$12,000	$3,000	$15,000
		Total	**$30,000**

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Table 6-3: Structural/Mechanical Upgrades Cost

Description	Total
Construction Costs	
Mobilization/ Demobilization	$10,000
New Gate on Lower Balcony	$4,100
Replace Existing Roof Ladder	$41,000
Repair Damaged Insulation on Piping	$11,300
Remove CP System	$28,800
Remove Roof Anchors	$3,600
Sub-Total	**$98,800**
Contingency (25%)	$24,700
Sub-Total	**$123,500**
Engineering & Construction Supervision (15%)	$18,525
Total Estimated Construction Cost	**$142,025**

Table 6-4: Grounding Test Cost

Description	Total
Construction Costs	
Mobilization/ Demobilization	$10,000
Grounding Test	$500
Sub-Total	**$10,500**
Contingency (25%)	$2,625
Sub-Total	**$13,125**
Engineering & Construction Supervision (25%)	$3,280
Total Estimated Construction Cost	**$16,405**

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Appendix A
Surge Tank Inspection Report (RAT)



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1.0 Introduction

Remote Access Technology (RAT) inspected the Bay d'Espoir hydroelectric power station surge tank #2 from July 15th – 17rd, 2014. Using rope access, it included a visual inspection on the internal & external condition of tank as well as ultrasonic inspection at various locations.

1.1 Inspection Summary

The external visual inspection was performed on surge tank #2, concentrating on the checkered portion of the tank shell, tank riser, tank top, thermal insulation system, ladder system including the rotating ladder at the tank top, hot water heating system, legs, cross braces and structural connections.

The internal inspection of the tank included the tank top, bowl, internal structural members, cathodic protection system, and riser.

Ultrasonic inspection was carried out on the tank top, expansion joint on the lower balcony, on the surge tank on the upper balcony, and on the bowl inside the bottom of the tank. In order to perform the UT on the balconies the cladding and insulation was removed and reinstated afterwards. There are two different coatings inside the tank. The vertical section of the tank has a grey coating and the bowl has a yellow coating. The transition between the two systems is at the interface between the bowl and the vertical sections of the tank. Photos of the bowl are located in section 3.1 of this report.

A general inspection was performed on the ladder system and hot water heating system. Overall the ladder system was in good condition, coating breakdown and minor corrosion was present. One ladder rung located on the south west leg was bent while another located on the tank was loose. The swivel ladder on the roof was of some concern as it had a bolt through the rail runner preventing use. The lower walkway around the tank had no safety chain at the ladder access point. A few areas on the insulation of the hot water heating system indicated potential areas of water ingress. The insulation on the hot water heating system piping from the utility shed to the west leg shows signs of damage.

The tank top had coating breakdown and corrosion. The aviation lights

had no power to verify if they worked. The swivel ladder and hatch opening for the tank were all operational. Around the tank top were pad eyes, however they were welded directly to the tank top with no structural stiffening.

The interior of the tank riser appear to have sustained pitting throughout prior to being coated. The interior inspection of the surge tank shell and the bowl showed that the coating was failing with major pitting resulting.

The cathodic protection system is damaged and the wiring is severed.

One cross member inside the tank was bent downwards and another was completely detached from the Riser and hanging from the cathode wiring. It was removed for safety reasons.

The exterior of the surge tank had minor coating breakdown and showed signs of minor corrosion. The riser was found to be in good condition with exception of some water staining. The rest area, upper and lower balconies had coating breakdown and corrosion. The bottom balcony braces all showed signs of warping and corrosion. The Tank legs, horizontal steel beams were found to be in good structural condition all showed coating breakdown, all cross bracing showed signs of friction at the intersections.

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2.0 External Inspection Results

2.1 Ladder System

Location: Tank top ladder
Description: Bolt preventing the use of the rail runner.



Location: Surge tank ladder
Description: Loose rung, 19th up from upper balcony.

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Location: South-west leg ladder, near the second horizontal cross member
Description: Bent rung.



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2.2 Hot Water Heating System

Location: Surge tank exterior
Description: General condition of insulated piping, organic growth on insulation bags. No other issues were found.

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2.3 Rest Area and Balconies

Location: Lower Balcony
Description: General coating breakdown and minor corrosion on the underside. Stud bolt missing on the outer L bracket.

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Location: Lower Balcony
Description: Coating breakdown and minor corrosion on the top side.



Location: Upper Balcony
Description: Typical condition of handrails, minor coating breakdown and minor corrosion. Locking bar was missing a lanyard to prevent dropping.

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Location: Upper balcony
Description: General coating breakdown and minor corrosion found on the top side. One anomaly was found, for details see section 4.4.



Location: First landing
Description: Minor coating breakdown and minor corrosion found.

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2.4 Tank Top

Location: Tank top

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Description: General photo of tank top condition and ladder swivel system, minor coating breakdown and minor corrosion.



Location: Tank top
Description: Aviation lights box had no cover, temporarily sealed with duct tape.



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Location: Tank Top
Description: Steel plates were used to cover the drill holes, attached with epoxy.



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2.5 Surge tank legs & Cross Braces

Location: Surge tank legs

Description: General Photo. Typical view of coating breakdown and corrosion.



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Location: Surge tank legs
Description: Typical coating breakdown and minor corrosion at the connections.



Location: Surge tank legs
Description: Most cross members had some level of deflection.



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Location: The first top cross member on the east side by the south-east leg.
Description: Pitting of 1.2mm to 2.2 mm at the upper end.



Location: East side, 3rd cross member down from the top.
Description: Misalignment, friction plates locked into each other.



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Location: North side, 3rd cross member down from the top.
Description: Misalignment, friction plates to not touch.



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3.0 Internal Inspection Results

3.1 Tank Top

Location: Surge tank top, interior.
Description: Minor corrosion found in the crevices and edges.

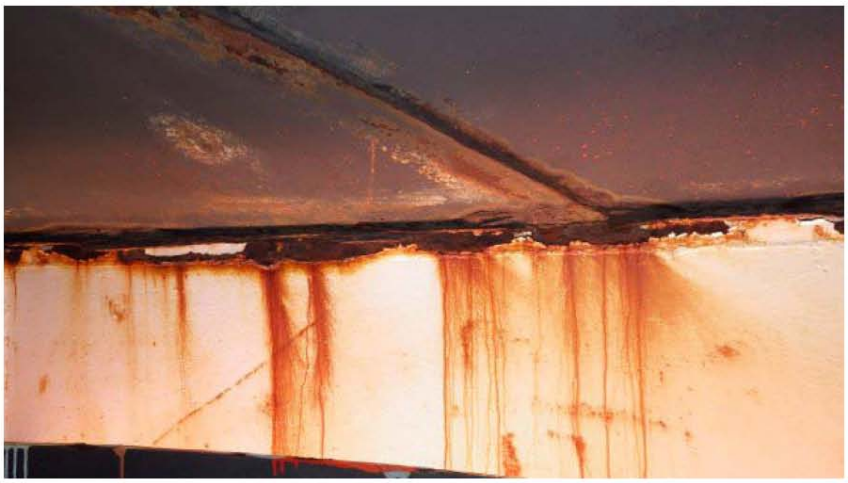


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Location: Surge tank top, interior edge.
Description: Coating breakdown, heavy corrosion and scaling found all along the edge.



Location: Access hatch, interior.
Description: Coating breakdown and moderate corrosion found, some scaling.



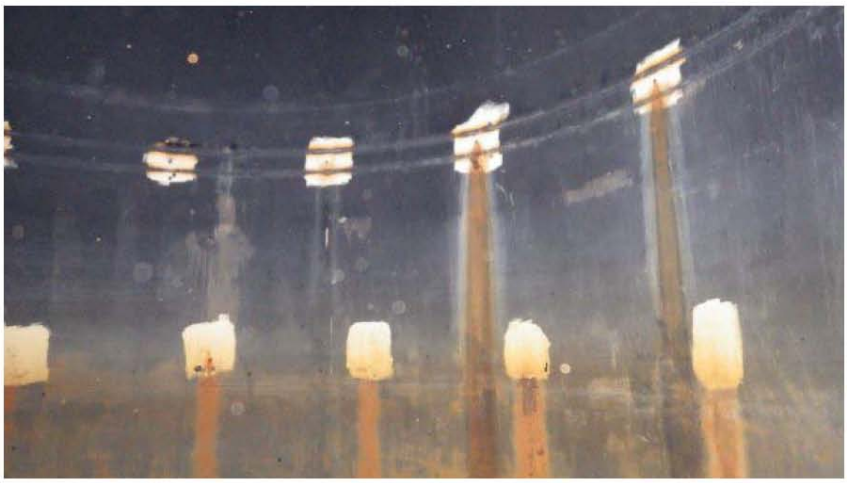
17

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3.2 Tank Shell

Location: Surge tank wall, interior.
Description: Rust staining from the penetrations.



Location: Surge tank wall, interior.
Description: Large scale coating breakdown and corrosion, pitting found. See section 4.5 for details.



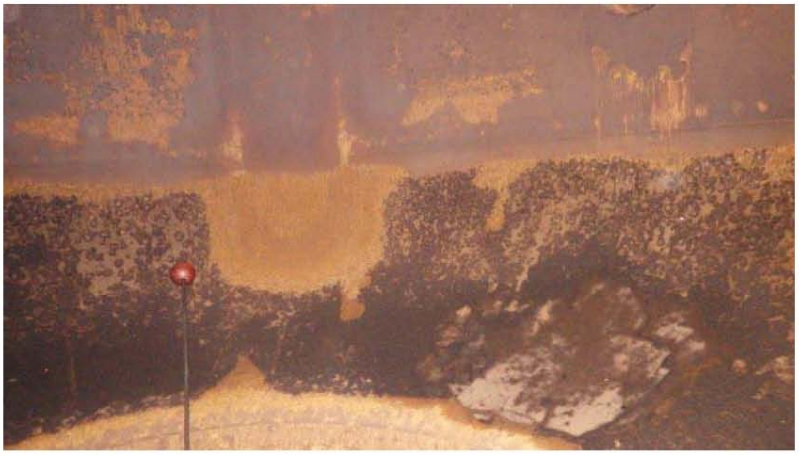
18

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3.3 Tank Bowl

Location: Bowl, interior.
Description: Large scale coating breakdown with corrosion, pitting found. See section 4.6 for more detail.



Location: Lower Bowl, interior.
Description: Large scale coating breakdown with corrosion, pitting found. See section 4.6 for more detail.



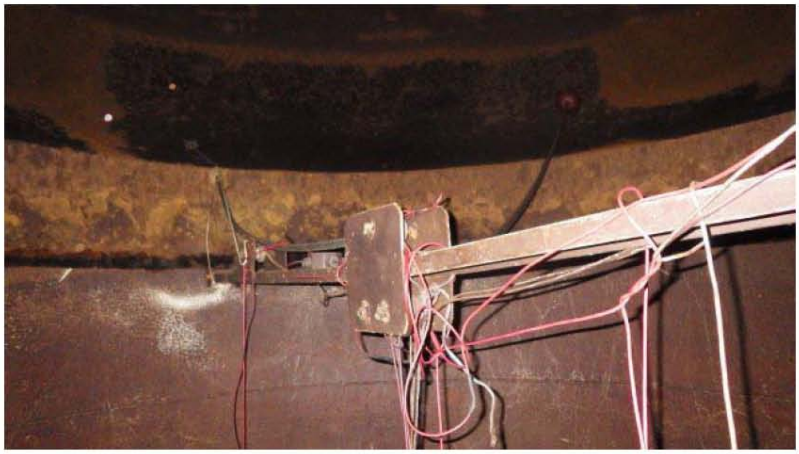
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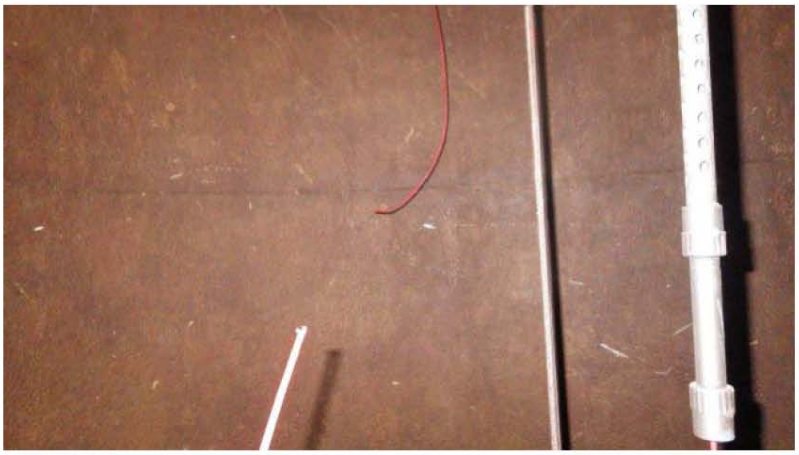
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3.4 Riser & Cathodic System

Location: Riser top
Description: C channel for cathodic system showing damage, including damage to the cathodic system



Location: Riser middle
Description: Severed cathodic system wiring, common. Riser coating was intact throughout.

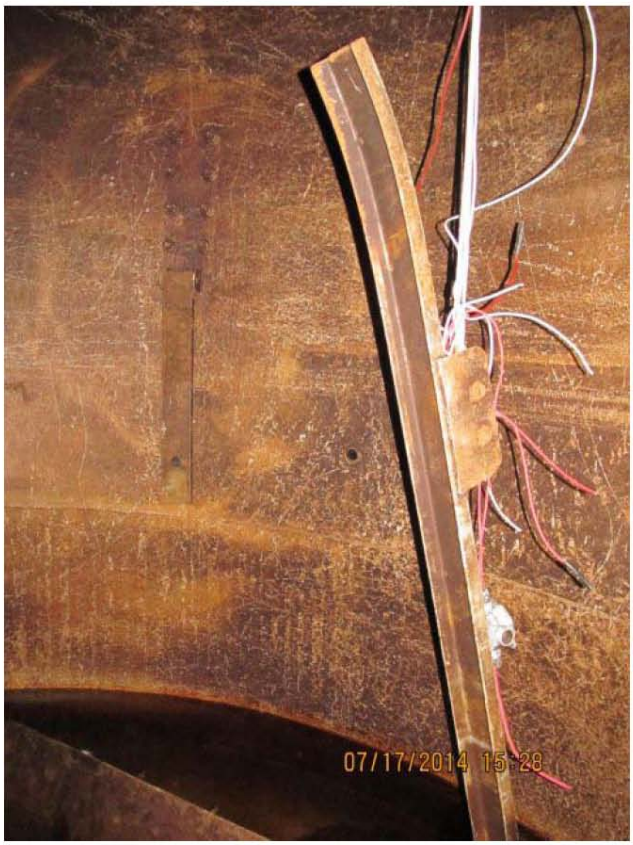


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Location: Riser bottom.
Description: Severed C channel beam, was removed from the Riser for safety reasons.



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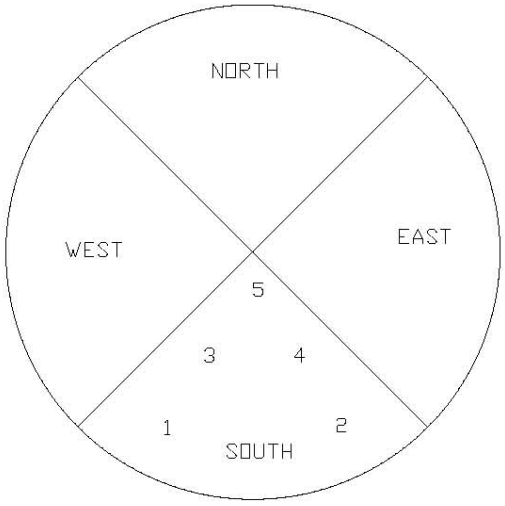
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4.0 Ultrasonic Thickness Gauging

Calibration Block CS: #09-1266
Probe: KBA560 #01YC278
Ultrasonic Machine: Krautkramer DMS2 #12544

4.1 Tank Top

Description: Readings were recorded in the four quadrants of the tank top. The readings were taken in the following pattern shown below.



Location	North (mm)	East (mm)	South (mm)	West (mm)
1	6.60	6.60	6.80	6.60
2	6.60	6.50	6.46	6.70
3	6.60	6.60	6.56	6.50
4	6.80	6.60	6.60	6.46
5	6.40	6.45	6.77	6.40

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4.2 Surge Tank (exterior)

Description: Readings were taking on the exterior of the surge tank at the upper balcony level. Some cladding and insulation was removed to gain access to the area. The following images show the removed cladding and the repair.

Location: Upper Balcony



1A	14.80mm	**2A**	14.70mm	**3A**	14.67mm
1B	14.75mm	**2B**	14.67mm	**3B**	14.65mm
1C	14.74mm	**2C**	14.66mm	**3C**	14.74mm
1D	14.77mm	**2D**	14.63mm	**3D**	14.64mm

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Location: Upper Balcony

Description: Reinstatement of insulation and cladding.



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4.3 Expansion Joint (exterior)

Description: Readings (above and below the weld) were taking on the exterior of the expansion joint at the lower balcony level. Some cladding and insulation was removed to gain access to the area. The following images show the removed cladding and the repair.

Location: Expansion Joint Lower Balcony



Note – All measurements in mm

1A	12.40	**2A**	12.70	**3A**	12.80	**4A**	12.50
1B	9.70	**2B**	10.10	**3B**	9.00	**4B**	9.70
1C	9.20	**2C**	9.00	**3C**	9.40	**4C**	9.70
1D	9.90	**2D**	9.40	**3D**	9.30	**4D**	9.00

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Location: Expansion Joint Lower Balcony

Description: Reinstatement of insulation and cladding.



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4.4 Compression Ring (North side)

Location: The top side of the compression ring on the web, north side.
Description: An isolated area of moderate to heavy corrosion with scaling was found, the total area of corrosion was approx. 15cm by 138cm.



Good steel (Nominal)	13.10mm
Corroded steel	9.70mm

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4.5 Surge Tank (Interior)

Location: 9th seam down, south-west side. The first photo was a general view only.
The second was a close up.
Description: The first or upper band of corrosion around the inside of the tank had pitting of **2.8mm**, nominal steel when UT was performed was **10.06mm.**



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4.6 Surge Tank Bowl (interior)

Location: North-west bowl, upper area and lower area.
Description: UT was performed on the interior bowl on the north-east side and south-west side when possible. This was due to the location of the hatch and opposing holes cut in the Tank Top.

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Note = All measurements in mm

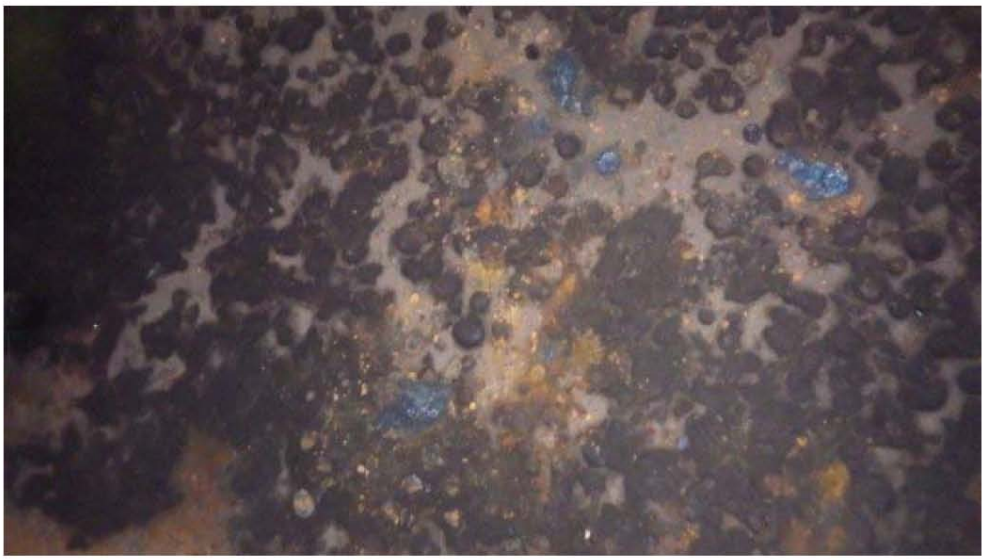
Upper Bowl	12.30	11.00	12.20	12.60	12.80
Lower Bowl	13.80	13.60	14.80	14.50	14.25

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Location: South-west bowl, interior.
Description: UT was performed on the lower to mid level of the bowl where readings were possible.



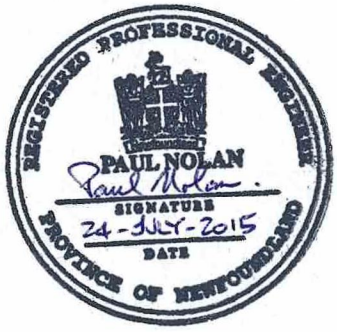
Note – All measurements in mm

Lower/Middle	15.02	14.73	14.75	14.20	15.85

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A REPORT TO
THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

	Electrical
	Mechanical
	Civil
	Protection & Control
	Transmission & Distribution
	Telecontrol
	System Planning

Rewind Rotor and Install Flux Probe Unit 3

Holyrood Thermal Generating Station

July 2015

newfoundland labrador hydro
a nalcor energy company

SUMMARY

Hydro's Holyrood Thermal Generating Station has a total capacity of 500 MW. This generating station consists of three oil fueled units which produce approximately 33% of the energy required for the Island Interconnected System. Units 1, 2 and 3 were commissioned in 1969, 1970, and 1979, respectively. Units 1 and 2 have rated maximum ratings of 175 MW. Unit 3 is rated at 150 MW.

Hydro requires that Holyrood continue to operate as a generating facility until the Labrador Island Link brings power to the island. Beyond that time, Unit 3 will remain vital to the Island Interconnected System and will continue to serve as a synchronous condenser[1] until 2041. (Unit 3 was modified to provide it with the capability to operate as a synchronous condenser in 1986.)

This proposal is requesting the approval of a one year project to rewind the rotor on Unit 3 and to install a flux probe on this unit to monitor the status of the rotor poles in the future. Testing of the rotor has confirmed that there is an electrical short within the rotor winding, which is indicative of insulation degradation. The rewinding of the rotor will address this issue, decrease the potential of damage due to the failure of the rotor, and improve the reliability of the generating station.

The total estimated cost of this project is $2,755,500.

[1] A synchronous condenser is a device identical to a synchronous motor, whose shaft is not connected to anything but spins freely. Its purpose is not to convert electric power to mechanical power or vice versa, but to adjust conditions on the electric power transmission grid. Its field is controlled by a voltage regulator to either generate or absorb reactive power as needed to adjust the grid's voltage, or to improve power factor. The condenser's installation and operation are identical to large electric motors.

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1 INTRODUCTION

Hydro's Holyrood Thermal Generating Station has a total capacity of 500 MW. This generating station consists of three oil fueled units which produce approximately 33% of the energy required for the Island Interconnected System. Units 1, 2 and 3 were commissioned in 1969, 1970, and 1979, respectively. Units 1 and 2 have rated maximum ratings of 175 MW. Unit 3 is rated at 150 MW. In 1986 Unit 3 was modified to provide it with the capability to operate as a synchronous condenser.

Each generating unit in Holyrood consists of two main components: the stator and the rotor. The rotor is connected to a steam turbine and rotates because of the force of high pressure, high temperature steam on the turbine blades. The stator is the stationary part of the generator. As the rotor spins inside the stator, electricity is produced.

As the insulation levels of the rotor diminishes over time, the occurrences of electrical faults become increasingly more probable. These faults lead to operating issues with the rotor, such as the development of vibration issues which will eventually lead to limited operation and, if left unrepaired, the complete failure of the generating unit. The rewinding of the rotor would ideally be completed prior to a failure, as the failure would result in the unavailability of the generating unit with costly repairs and the requirement for additional sources of power to replace the power output of the failed unit.

Inspections were completed on Unit 3 in 2013 and 2014 by Alstom. These findings were reviewed by AMEC and IRIS Power in 2014, and FM Global in 2015. The Alstom inspections recommend a rotor rewind during the upcoming major outage to Unit 3 in 2016.

2 PROJECT DESCRIPTION

The replacement is planned to mitigate the risk of unit failure and the proposed schedule is based around major unit outages. As such, Hydro's intention is to rewind the rotor of Unit 3 in 2016.

The proposed work schedule includes:

- In early 2016, tendering for the contract work associated with rewind of the rotor;
- In 2016, completion of the contract work during the summer outage period coincident with the planned major turbine generator maintenance for Unit 3; and
- The installation of the flux probe prior to the reinstallation of the rotor.

3 JUSTIFICATION

This proposal is justified to maintain system reliability by rewinding the rotor of Unit 3 before a failure occurs. The most appropriate timing would see this work being completed during the next generator outage in 2016. Should the rotor fail while in service, it could cause significant damage to the generating unit, impairing Hydro's ability to provide cost effective power and reliable electrical service to the Island Interconnected System.

The rotor's insulation is nearing the end of its useful service life. Electrical testing performed in 2013 has confirmed the existence of a shorted turn which had not been noted in previous tests. While a shorted turn is indicative of rotor winding insulation issues in the long run, these tests did not show that the generator was in immediate distress for short term (five years) operation, and thus the generating unit has remained in service.

Inspections were completed on Unit 3 in 2013 and 2014 by Alstom. The findings from these inspections were reviewed by independent consultants (AMEC and IRIS Power) in 2014 and FM Global in 2015. These reviews state that a rotor rewind should be completed in the near future. In order to minimize costs and reduce the risk of a forced outage and/or failure, Hydro proposes that the rewind work be completed in 2016. In the risk review completed by Hydro's insurance provider, FM Global, it has been recommended that Hydro rewind the generating Unit #3 during the planned outage in 2016. FM Global states that "it is necessary to repair the rotor at the earliest opportunity to avoid bearing damage and in the worst case, rubbing of the stator"[2] It was also recommended that Hydro install a flux probe at the earliest opportunity, to "better monitor the rotor poles in the future".

3.1 Existing System

The existing insulation on Unit 3's rotor is nearing the end of its service life. As per AMEC's independent review, this unit has been in service for 34 years, exceeding the 25 to 30 year normal life of a large generator.

[2] See Appendix A: FM Global Risk Report.

In 2013, Unit 3 was inspected to establish the condition of the generator. The inspection included a visual inspection, a visual inspection of the surface of the rotor with a probe which includes a camera and digital recording system, a check of the shaft insulation quality, a rotor inter-turn short circuit test, a measurement of the charging current, a measurement of the winding resistance, and a measurement of the insulation resistance. The results of these tests indicate that a rewind of the rotor is required. Although there are no known issues with the stator, the stator is expected to require rewinding by 2022. During the 2016 major unit overhaul, testing and inspection will determine the timeline of a stator rewind.

In 2014, further tests were conducted to further assess the condition of the inter-turn short and to measure the magnitude of any changes. These tests included repetitive surge oscillograph (RSO) tests which look for shorted turns using time domain reflectometry. Time domain reflectometry works on the principle of creating a traveling wave and measuring the timing of reflections which are created when the wave hits a change in impedance (for example a shorted turn). These tests confirmed that the inter-turn fault is still present, and long-term operation could result in an increased risk of online issues.

Major work or upgrades on Unit 3 in Holyrood are summarized in Table 1.

Table 1: Major Work or Upgrades

Year	Major Work/Upgrade	Comments
2014	Completed dynamic tests of the rotor including shaft voltage testing at load and RSO testing at full speed no load	Completed with no issues
2013	Generator bump testing, electrical testing, and rotor in-situ core iron and visual inspection. Collector rings machined in-situ.	Completed with no issues
2012	New thrust bearing installed	Required for synchronous condenser operation
2011	Repaired the collector rings after flash-over event	Completed with no issues

3.2 Operating Experience

Unit 3 of the Holyrood Generating Station is designed for continuous operation with varying loads. It is typically operated as a generator in the November to March period to meet system peak winter requirements. It is typically operated as a synchronous condenser during the summer months. This unit has been operating in this mode, within its design capabilities, since 1986. Into the future, Unit 3 will operate in generate mode until the Labrador Island Link beings power to the island. Unit 3 will then be in standby mode for a period of time, and then the unit will be in synchronous condense mode until 2041.

3.2.1 Reliability Performance

Not applicable.

3.2.1.1 Outage Statistics

In the last five years, there have been no outages which were the direct result of the condition of the rotor.

3.2.2 Environmental Performance

As Hydro has no record or indication of asbestos abatement for this unit, the possible presence of asbestos will be remedied in a safe and prudent manner. There are no other known environmental issues related to this project.

3.2.3 Industry Experience

Not applicable.

3.2.4 Vendor Recommendations

Not applicable.

3.2.5 Maintenance or Support Arrangements

All maintenance performed on the rotor has been conducted using contracted staff and

experts with support and supervision by Hydro personnel.

3.2.6 Maintenance History

The five-year maintenance history for the Unit 3 rotor is shown in the following table:

Table 3: Five-Year Maintenance History

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2014	38.3	0.0	38.3
2013	114.0	27.2	141.2
2012	0.0	0.0	0.0
2011	3.6	102.9	106.5
2010	1.3	0.0	1.3

3.2.7 Anticipated Useful Life

Rotor windings typically have an estimated service life of approximately 30 years depending upon operating conditions and maintenance.

3.3 Development of Alternatives

The purpose of this project is to ensure the reliability of Unit 3 in Holyrood by completing the rewinding of the rotor. Based upon the analysis of the test results which indicate that the rewind work should be completed, the evaluation of alternatives is an analysis of the scheduling of the work and the risks associated risks with each of the three alternatives:

1. Rewind the rotor in 2016 during a scheduled major overhaul and carry out inspections to determine the time frame for a future stator rewind (risk level considered low);
2. Rewind the rotor and stator in 2019 during an additional outage – have rotor and stator rewind kits available (risk level considered low to medium); and
3. Rewind the rotor and stator in 2022 during a scheduled overhaul – have rotor and stator rewind kits available (risk level considered medium to high).

3.4 Evaluation of Alternatives

Alstom recommends installing a flux probe for shorted turn monitoring at the next available opportunity (the 2016 outage). This is due to the shorted turn found on the rotor through RSO testing. AMEC NSS agrees with this recommendation. FM Global supports the installation of a flux probe next year to better monitor the rotor poles in the future.
A significant factor determining Hydro's selection of the most appropriate option is the level of risk associated with each option. Hydro's insurance provider, FM Global, carried out a risk assessment in 2015. In this report, FM Global recommends Hydro rewind the rotor in 2016. FM Global states:

> "According to the Iris Power report from October 2014, the rotor winding insulation is not expected to provide for reliable service up to 2041. The rotor duty in the condenser mode operation at rated MVAR output will be the same as at rated output in generating mode. FM Global agrees with the recommendations for reinsulating or complete rewind of the rotor in 2016 or before the release to condenser operation. FM Global supports the 2016 rotor rewind option. In the short term (i.e., the next five years), Alstom recommends to install a flux probe for shorted turn monitoring at the next available opportunity (the 2016 outage). This is due to the shorted turn found on the rotor through RSO testing. AMEC NSS agrees with this recommendation. FM Global supports the installation of a flux probe next year to better monitor the rotor poles in the future."

As it has been recommended that the stator be rewound by 2022, Hydro intends to carry out testing of the stator in 2016, to determine the feasibility of deferring the stator rewind until the 2022 major unit outage. Hydro will certainly take action before 2022 on the stator if the 2016 testing results show such action to be necessary before that time. FM Global supports this course of action in the risk report found in Appendix A: FM Global Risk Report. FM global states:

> "Based on Alstom's report, there is a medium to high likelihood for a stator winding failure and forced outage in the next five years. AMEC NSS's opinion is that the stator and rotor should be rewound at the same time during a planned outage within the next five years (2019). Carrying out the following 2016 outage inspection and testing work scope listed below would help to verify this. According to Alstom's report, Alstom requires additional measurements to manufacture a suitable stator winding that would fit the existing stator. This is planned to be done during the 2016 outage. As with rotors, generally, no stator will operate for two lifetimes without rewinding and the outage schedule does not appear to be optimal for the stator situation either."

Options 1 and 3 take advantage of scheduled maintenance work, including overhaul, in 2016 which consists of the removal of the rotor. Not coordinating with a major scheduled outage (currently in 2016 and 2022) means having to open the generator and to remove the rotor an additional time in a seven year period. The extra handling of the rotor would require additional costs and would introduce risks to workers and equipment. Again, if the 2016 test results indicate the stator must be addressed before the planned major overhaul in 2022, Hydro would undertake the required work at the required time.

Based on these recommendations, Hydro proposes option 1.

4 CONCLUSION

Unit 3 of the Holyrood Generating Station has been in service since it was commissioned in 1979. The rotor windings of this unit are at the end of its service life. According to recent testing and inspections of the unit, there is a significant potential for winding failures. If the windings are left in service and run to failure, it is likely that significant damage would occur. For these reasons, the rotor windings of Unit 3 should be rewound during the planned outage season in 2016. At this time, a flux probe will be installed to monitor the condition of the rotor in the future.

The rewinding of the rotor on Unit 3 will decrease the risk of a significant failure to the unit and improve the reliability of this generating unit and the generating station.

Testing on the stator and gathering of information on the stator will also occur during the 2016 outage, to ascertain if the stator can indeed wait to be rewound until the planned outage of 2022.

4.1 Budget Estimate

The estimated cost to complete the work associated with this project $2,755,500. Table 4 provides a detailed breakdown of the budgeted costs.

Table 4: Project Budget Estimate

Project Cost:*($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	90.0	0.0	0.0	90.0
Labour	467.0	0.0	0.0	467.0
Consultant	14.8	0.0	0.0	14.8
Contract Work	1,600.0	0.0	0.0	1,600.0
Other Direct Costs	10.6	0.0	0.0	10.6
Interest and Escalation	136.6	0.0	0.0	136.6
Contingency	436.5	0.0	0.0	436.5
TOTAL	**2,755.5**	**0.0**	**0.0**	**2,755.5**

4.2 Project Schedule

The anticipated project schedule is shown in Table 5.

Table 5: Project Schedule

Activity		Start Date	End Date
Planning	Project initiation and planning	Jan 2016	Feb 2016
Procurement	Detailed design, tendering and Award	Feb 2016	Mar 2016
Construction	Rotor removal, rewind work, testing and verification	Apr 2016	July 2016
Commissioning	Rotor installation, testing, commissioning	July 2016	Aug 2016
Closeout	As built drawings, project completion	Sept 2016	Dec 2016

APPENDIX A

FM Global Risk Report

FM Global Risk Report

Location Findings

Nalcor Energy

Holyrood Thermal Plant
Route 60
Holyrood, Newfoundland and Labrador A0A 2R0
Canada

All in One
Regular Risk Evaluation

Visit by:	Joanne M. D'Abreu and Michel N. Burbaud
Visit date:	02 April 2015
Conference with:	Mr. Jeff Vincent, P.Eng, Manager, Thermal Generation

Index: 000009.36-02 / Account: 1-74568 / Order ID: 676515-82

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FM Global Risk Report — Nalcor Energy

Principal Site Activity

This is a 500-MW oil-fired, thermal power plant.

Understanding the Risk at this Facility

This well-maintained thermal station feeds 40 percent of the island's power demand during the winter, and no other feed can compensate for the sudden loss of one unit. Reliability of critical systems at this station remains crucial to avoid unexpected trips or downtime during the winter.

Equipment Hazards

This station was subjected to an EPRI Level 2 Life Assessment survey in 2010. Recently, following some failures at this plant and other stations, a winter readiness plan was put in place to increase reliability of the station. As an example, a new 123-MW peaking diesel combustion turbine was installed to provide stability and black start capability. A cold reheat line drain pot was approved for Unit 3 and some maintenance scope of activities was increased, and all three synchronous generators were extensively evaluated. As result, the Generator No. 3 rotor is planned for a rewind next year.

To improve water induction protection at this facility, testing of the high-high level switches on the feedwater heaters of Units 1 and 2 will be started, and the automatic drainage of the condensate drain pot for the Units 1 and 2 cold reheat lines will be made active this year Unit 3 will be fitted with the same provision.

An AC power factor searching test should be made part of the three-year scope of generator testing to complement the online data being collected.

The client will implement capacity discharge testing this year on the flooded lead-acid battery banks routine maintenance to conform to the Institute of Electrical and Electronic Engineers (IEEE) Standard 450 as recommended.

Regardless of the few years of remaining operation of the steam cycles, the corporation still has a strong interest in the reliability of this station as demonstrated by some enhanced maintenance scope and ongoing improvements to the equipment protection.

Fire/Natural Hazards

A major improvement was made, whereby a new motorized valve was installed on the 16-in. bunker C fuel oil line. In a fire, the valve can be automatically shut off by an operator in the control room. Curbing was installed around the fuel oil pumping Skid Nos. 1 and 3.

Factory Mutual Insurance Company (FM Global) has developed this report for insurance underwriting purposes. The report is provided to you for informational purposes only to reduce the possibility of loss to insured property by bringing to your attention certain potential hazards or conditions. Life, safety, or health issues are not addressed. You must make the decision whether to take any action. FM Global undertakes no duty to you or any other party by providing this report or the activities on which it is based. The liability of FM Global is limited to that contained in its insurance policies.

Summary of Recommendations continued

Rec Number	Recommendation Synopsis	Loss Expectancies (USD)
14-04-003 Priority 1	Implement AC power factor and power factor tip-up tests as part of the three-yr. testing of stators.	Reduces probability or severity.
13-05-007 Priority 1	Complete testing of the 600-V feeder breakers as planned.	Reduces probability or severity.
12-04-004 Target Priority 1	Expand the fire protection inspection program to include monthly physical checks of curb valves.	Reduces probability or severity.
11-05-002 Priority 1	Conduct a flushing investigation on all wet-pipe automatic sprinkler systems.	Reduces probability or severity.
07-10-005	Improve automatic sprinkler protection in the various storage areas.	
Part A. Priority 2	Upgrade protection in the Main Warehouse Building.	5,900,000 PD Minimal BI
Part B. Priority 3	Improve automatic sprinklers in the Tool Crib area of the Main Building.	5,000,000 PD Minimal BI
11-05-001 Priority 2	Isolate the control room from the turbine building with fire-rated construction.	2,500,000 PD Minimal BI
15-04-003	Ensure that cable penetrations on mezzanine level are properly sealed with fire-retardant material.	2,500,000 PD Minimal BI
12-04-003 Priority 1	Install sprinkler protection in the enclosure used for storage on the basement level.	2,200,000 PD Minimal BI
15-04-004	Implement a monthly autostart of the AC aux. and DC emerg. oil pumps for the new combustion turbine.	Reduces probability or severity.
15-04-005	Install partial discharge monitoring on the new combustion turbine generator stator.	Reduces probability or severity.

15-04-001 continued

Technical Detail	**2016 rotor rewind option.** In the short term (i.e., the next five years), Alstom recommends to install a flux probe for shorted turn monitoring at the next available opportunity (the 2016 outage). This is due to the shorted turn found on the rotor through RSO testing. AMEC NSS agrees with this recommendation. **FM Global supports the installation of a flux probe next year to better monitor the rotor poles in the future.** As no rotor vibration issues are noted in the report, AMEC NSS assumes that there are no thermal vibration issues limiting operation of the generator. As the RSO test indicates only one minor short and there is no limiting vibration, the rotor will likely operate for a number of years before it will start to show further signs of deterioration and require a rewind. **This assessment dates from 2014.** According to AMEC, in the long term, more shorts are expected, and a rewind will be required. Generally, no rotor can operate for two periods without rewinding. The question is "when is the best time to do the rewind". Alstom recommendation (ii), to "perform a routine rotor inspection during the upcoming major outage in 2016 and plan an additional outage for a rotor rewind within the next 3 years" i.e., 2019, appears to be the most sensible option. "Rewinding the rotor in 2016", recommendation (i) is reasonable, but AMEC NSS's opinion is option ii makes more sense based on the condition reported to date. Currently, the risk of a rotor failure is considered low. The risk of limited operation due to additional shorted turns causing thermal vibration issues will increase with time, but is considered low to medium over the next five years. AMEC NSS would not let operation continue for more than five years beyond 2014 before rewinding the rotor on a planned basis. However, because the next rewind opportunity would be at the 2022 outage, there is a medium to high probability for the rotor to sustain more shorted turns, increased lateral vibration issues, and perhaps be taken out of service on high vibration, requiring a rewind. The outage schedules are not optimal for the current situation, and another rewind outage would be required in 2019. The rotor is 35 years old, has run for almost 200,000 hours and has a confirmed shorted turn. **STATOR** Regarding the stator, there does not appear to be any identifiable major issue to call for a stator rewind during the 2016 outage. Alstom's recommendation, "advance purchase of a rewind kit, including a complete set of stator bars and plan an outage to rewind the stator before a failure occurs" appears to be the

15-04-001 continued

Technical Detail	most sensible option. Based on Alstom's report, there is a medium to high likelihood for a stator winding failure and forced outage in the next five years. AMEC NSS's opinion is that the stator and rotor should be rewound at the same time during a planned outage within the next five years (2019). Carrying out the following 2016 outage inspection and testing work scope listed below would help to verify this. According to Alstom's report, Alstom requires additional measurements to manufacture a suitable stator winding that would fit the existing stator. This is planned to be done during the 2016 outage. **As with rotors, generally, no stator will operate for two lifetimes without rewinding** and the outage schedule does not appear to be optimal for the stator situation either. If Holyrood wishes to defer rewinding of the stator and rotor until the 2022 outage, the risk of a forced outage and/or failure increases. Carrying out a more detailed inspection and test plan in 2016 may provide better information that confirms whether waiting until 2022 is reasonable. Deferring to 2022 may be possible, but AMEC NSS cannot confirm any time frame and scenario because of the limited data available.	
Loss Expectancies (USD)	Exposure to Loss is approximately:	8,560,000 PD Minimal BI
	Exposure to Loss if Completed is approximately:	Minimal PD Minimal BI
Status	Considering the turn-to-turn fault in the rotor winding, which might increase over time, plans would be to rewind the rotor of Generator No. 3 pending budget approval.	

13-05-001
Target
Priority 1

Improve the automatic startup requirements for the station service diesel generator.

As a result of the recent lack of lubrication for the Unit 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	Mr. Jeff Vincent, manager, long-term asset planning, indicated that no physical change has been made yet, but this is the responsibility of the Transmission Group and a study will be conducted. Mr. Jonathan Wheeler, plant engineer - electrical will follow-up with Mr. Shawn Mullowney on this issue.

06-01-003 **Improve protection against steam turbine water induction.**

Part A. Target Priority 1

Test the high and high-high level switches on the feedwater heaters.

The high and high-high level switches on the boiler's high-pressure feedwater heaters should be tested at least quarterly using the simulation method. A device to test the high water level alarms and interlocks was provided on Unit Nos. 1 and 2. However, a testing procedure remains to be established.

The switches that show inconsistent test results should be repaired or replaced.

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 using 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 allowing 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 that 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 to be conducted on Units 1 and 2 are completed.

06-01-003A continued

Technical Detail	**The completion of either online or offline functional tests on these protection devices is urgent and long overdue. Much energy should be put toward completion of these tests 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. Procedures and O&M manuals for Units 1 and 2 are being developed, and the modifications on the Unit 3 feedwater heaters are planned to be done this year. The goal is to have the testing done this fall on all three units and every few months thereafter.

Part B. Priority 2

Install a drain pot with a high level switch on the cold reheat lines of Unit 3.

The cold reheat drain line should be modified to provide a drain pot at the low point of each cold reheat line. These should be physically located as close as possible to the turbine and should be fitted to provide a signal to permit operator action to stop water inflow.

The Hazard	Numerous occurrences of turbine water induction damage were attributed to the presence of water in the cold reheat line. This water is introduced into the system from the reheat attemperators spray station, the feedwater heaters extracting steam from the cold reheat line or condensation forming in the line and being introduced during startup. The recommended modifications will help prevent damage to the turbine from the above-mentioned sources.
Technical Detail	The drain pot should be fabricated from 6-in. or larger diameter piping and be no longer than what is required to install level sensing equipment. If there is a low point in the cold reheat line other than that near the turbine, which is upstream of the attemperator or the extraction supply to the feedwater heaters, then an additional drain pot should be installed for increased protection. Each pot should be provided with a drain line of nominal 2-in. minimum size and a full-size and full-ported automatic power-operated drain valve, arranged to fail open if possible. To prevent condensation, all lines should be fully insulated. Each drain pot should be provided with a minimum of two level sensing devices. The first (high level) should actuate the drain valve to fully open and send an alarm, notifying that the valve has opened. The second (high-high) should initiate an alarm in the control room. Also discussed was that a motorized drain valve that can be operated remotely from the control room upon indication of a high level alarm can be

06-01-003B continued

Technical Detail	considered a less desirable, yet tolerable, alternative to automatic actuation. For more details, please refer to the American Society of Mechanical Engineers' (ASME) TDP-1-2006, Section 3.3.8. **The operation on the drain pots for Units 1 and 2 to ensure water induction protection from the cold reheat lines is long overdue and should be completed this year.**	
Loss Expectancies (USD)	Exposure to Loss is approximately:	3,000,000 PD Minimal BI
	Exposure to Loss if Completed is approximately:	Minimal PD Minimal BI
Status	Mr. Jeff Vincent, manager, long-term asset planning, indicated that the installation is complete for Units 1 and 2 and testing will be implemented this summer. The project for Unit 3 was approved; design and procurement will occur in 2014 with an installation in 2015.	

07-10-002
Target
Priority 1

Conduct capacity discharge testing on station service batteries every five years.

A formal battery maintenance and operational testing program should be implemented for the various station service battery banks. This should include capacity discharge testing once every five years on the lead-acid flooded cell battery banks and annually on the VRLA (sealed battery banks of the UPS). Records of such testing should be kept for future reference.

07-10-002 continued

The Hazard	By supplying the power needed to trip circuit breakers and run emergency DC pumps, batteries are critical. When a battery fails, it prevents a circuit breaker from clearing an electrical fault, resulting in severe arcing, equipment damage and power interruption. Another scenario is that DC lube oil pumps are required, but unavailable because of failed batteries. Such an event would result in severe bearing damage and potentially radial rubbing of turbine parts, which could cause major steam turbine damage.  **Unit 3 Battery Bank with Some Corroded Poles**
Technical Detail	**A capacity test (full-load discharge test) for flooded lead acid batteries is only recommended every five years** . When deterioration in capacity is noticed, increase the frequency of testing to once every year. Replace the battery when its measured capacity approaches 80 percent of rated capacity. The testing procedure should respect the IEEE Standard 450-2002, a copy of which was given to the client. **A load test seems to have been conducted by Universal Power Services in August 2014, but this is not a capacity discharge test.** Currently, the flooded battery banks are subjected to a formal monthly visual inspection to check for evidence of corrosion, cover integrity and leakage of electrolyte. **DONE** A quarterly documented inspection should consist of some cell voltage and specific gravity, with checks for the electrolyte level and use of the infrared camera to look for cell temperatures. **DONE** Currently, all cell voltage, specific gravity and the inter-cell resistance are checked annually. **DONE** **For the sealed valve-regulated, lead-acid (VRLA) batteries for the diesel emergency generators,** reportedly, no interim maintenance is done, except for systematic replacement after five years.

07-10-002 continued

Technical Detail

The VRLA and regular vented-type lead acid batteries operate the same way. In vented-type batteries, water is lost and periodically replaced by topping off with distilled water. In a sealed VRLA battery, there is no way to top off the battery. In this battery, oxygen generated at the positive plate is transported across the electrolyte where it combines with lead and sulphuric acid to form lead sulphate and water.

The common causes of VRLA battery degradation and failure are:

- Dryout caused by normal corrosion of the battery plate, periodic venting of gas from battery overcharging and evaporation of water vapor through the seals, pressure relief valve and battery case.
- Float voltage variation - This battery is sensitive to float voltage variations. If the float voltage is too high, the rate of internal gas generation will exceed the cell's recombination ability. Excess gas vented through the pressure relief valve will lead to dry out.
- Temperature - VRLA batteries are sensitive to heat and will degrade at an accelerated rate if operated at a high temperature. Operating batteries at elevated temperatures can also lead to thermal runaway. High battery temperatures require more current to maintain float voltage. High currents increase heat generation, which in turn results in higher currents. This cycle eventually causes the case to rupture.

The following testing program should be adhered to for VRLA batteries:

- Monthly - Check and record charger voltage and current. Check ambient temperature and for evidence of corrosion, leaks, overheating and distorted cases.
- Quarterly - In addition to monthly inspection, check the internal cell resistance and negative terminal temperature of the cells. Check the individual cell voltages of all cells.
- Annually - In addition to quarterly inspections, perform a capacity test (full-load discharge test). **This test could be done at the half-life of the replacement frequency proposed by the client every 2-1/2 yr.** Check the inter-cell resistances and the amount of ripple in the charger waveform.

Note the following acceptance criteria for battery tests:

- Cell voltages - Cell voltages must compare well with the rated voltage and be within 0.05 V of each other.

07-10-002 continued

Technical Detail	• Ripple in the charger waveform must be within the manufacturer's tolerance for sealed VRLA batteries. (Usually about 5 or 5 A for every 100 A of battery capacity. Excessive ripple will lead to overheating and loss of battery life.) • Float current - Float current must remain constant. Increase in float current of 50% to 400% indicates the possibility of thermal runaway in VRLA batteries (vented batteries will not experience thermal runaway because of the large volume of electrolyte acting as a heat sink). • Internal resistance - Internal cell resistances must not vary by more than 25 between identical cells. • Inter-cell connections - Inter-cell connection resistances must not vary by more than 50 of the lowest value. • Capacity discharge test - When deterioration in capacity is noticed, increase the frequency of testing to once every six months. Replace the battery when its measured capacity approaches 80% of rated capacity. UPS batteries are adequately maintained and supervised by a battery monitoring system that supervises cell voltage and impedance. Annual load tests are done by the maintenance firm and the batteries are replaced every five years.
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	Mr. Jeff Vincent, plant manager, indicated that the contractor who appears to have done a load test on three flooded battery banks will be contacted to ensure that a capacity discharge test is done. Monthly, quarterly and annual maintenance activities as per IEEE Std 450 were re-instated. Note that a capacity discharge test every five years at mid-life of the UPS sealed battery banks replacement can be performed, between each 5 year replacements.

15-04-002 **Improve the current jumper management program.**

Technical Detail	Better form filling and completion, tracking of overdue jumpers and due dates should be implemented. Useless jumpers on unnecessary alarms or interlocks should be removed and treated as a management of change and stated as permanent. This will increase awareness of the operators about the other jumpers.

15-04-002 continued

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 recommendation was discussed with Mr. Glen Kennedy, shift supervisor - thermal, who will reduce the number of jumpers.

14-04-003
Priority 1

Implement AC power factor and power factor tip-up tests as part of the three-yr. testing of stators.

Implement off-line partial discharge tests, such as AC power factor at 10 KV and power factor tip-up tests at 2 KV and 10 kV, to seek for potential partial discharge every three years.

Technical Detail	**Power factor test:** Apply an AC voltage and measure the power factor of each stator winding (one phase at a time with the other two phases grounded). This is to detect stator windings ground wall insulation deterioration due to thermal degradation or water ingress. Acceptance Criteria: Epoxy-mica = maximum power factor of 0.5% Asphaltic-mica = maximum power factor of 3% to 5% A 1% increase in trended power factor is serious. Increasing power factor with decreasing capacitance indicates thermal deterioration. Increasing power factor with increasing capacitance indicates water absorption. **Power factor tip-up**: Measure the power factor of each stator winding phase at about 20 line-to-ground voltage and then again at 100 line-to-ground voltage. The tip-up is the difference between the two power factors. This is to detect stator windings partial discharge activity due to ground wall insulation deterioration from thermal degradation or load cycling. Acceptance criteria: Trend tip-up values. An increasing trend indicates increasing partial discharge activity.
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

14-04-003 continued

Status	This additional stator winding test could be done during the valves overhaul; the scope of the generator test consists of ac searching tests and should be done every three years, as agreed with Mr. Jeff Vincent, plant manager.

13-05-007
Priority 1

Complete testing of the 600-V feeder breakers as planned.

Technical Detail	All main 600-V circuit breakers were mechanically inspected; insulation resistance testing and contact resistance testing was also done on the 4.16-kV circuit breakers at the same time in 2014. The only work remaining is either the primary or secondary current injection on the 600-V main feeder breakers to verify their built-in overcurrent relays short and long delays.
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	According to Mr. Jonathan Wheeler, plant engineer - electrical, the 600-V feeder breakers will be subjected to primary current injection in August.

12-04-004
Target
Priority 1

Expand the fire protection inspection program to include monthly physical checks of curb valves.

Presently, the program for physical checks of all outside post-indicator valves (PIVs) and curb box valves is only carried out from May to October (as indicated on the forms).

This program should be improved to indicate that monthly checks be made. At various times over the winter months, it may be a challenge; however, attempts should be made to complete this on a monthly basis overall.

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	Mr. Ron LeDrew stated that this is still difficult to achieve in the winter months, but more efforts will be made.

11-05-002
Priority 1

Conduct a flushing investigation on all wet-pipe automatic sprinkler systems.

A flushing investigation should be conducted on all wet-pipe automatic sprinkler systems every five years. Where automatic sprinkler systems are of the pendent style, physically remove several sprinklers at multiple locations on the system and check for obstructions in the sprinkler and any pipe drops.

Where the second flushing investigation (at 10 yr.) determines there are no obstruction problems in the automatic sprinkler systems, the investigation frequency can be extended to every 10 yr. However, if problems are observed while flowing water through fire pumps, yard mains, 2-in. drains or inspector's rest connections, the five-year flushing investigation frequency should be reinstated.

The Hazard	Whenever water for fire protection service is supplied from an open body of water, the potential for obstructing material to enter fire protection piping systems will exist. The exposure level will vary depending on multiple factors, such as construction features of the water containment body, arrangement and protection features of the intake piping/wet pits, surrounding terrain, frequency of cleaning activities, etc.
Technical Detail	FM Global Property Loss Prevention Data Sheet 2-81, *Fire Protection System Inspections, Testing and Maintenance,* and a flushing job aid were previously forwarded to Mr. Ron LeDrew.
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	Mr. Ron LeDrew completed this on Wet System Nos. 19-2 and 19-3, but still needs to complete this on System No. 19-1. About eight out of 15 systems were completed. This is ongoing. A flushing investigation on four to fire more wet systems will be carried out by the end of the year, 2015.

07-10-005

Improve automatic sprinkler protection in the various storage areas.

Adequate sprinkler protection is needed for storage areas, namely the Main Warehouse and the Tool Crib in the Main Building.

The Hazard	The presence of solid shelving, a metal grated mezzanine or storage of boxes arranged such that it creates solid shelves, will all restrict proper water flow distribution from overhead ceiling sprinklers. Therefore, a fire in lower tiers will grow horizontally rapidly and thus involve the entire rack structure before ceiling sprinklers can operate and provide the proper control. This will lead to more damage and an excessive amount of sprinklers operating. With proper flue spaces in the racks, the fire will grow vertically, and allow the overhead ceiling sprinklers to quickly penetrate the fire plume and provide adequate control.

07-10-005 continued

Part A.
Priority 2

Upgrade protection in the Main Warehouse Building.

a. Install automatic sprinkler protection below the metal grated mezzanine.

b. Remove solid shelving in the racks such that there are adequate flue spaces (continuous from floor to top of rack - at least 6 in. net every 9 ft.) and a maximum solid shelf area of 64 sq. ft.

Note: All plans of the proposed sprinkler system improvement should be forwarded to FM Global for review prior to the letting of contracts.

The Hazard	 **Grated Mezzanine in the Main Warehouse - Sprinklers Needed**
Technical Detail	The Main Warehouse Building is referred to as Warehouse Building No. 3 on the FM Global sketch. Apart from the area occupied by the grated mezzanine, there are two racks along each side wall. Storage is mostly metal parts in boxes or other Class II and III commodities. The overhead ceiling sprinkler system can protect Class II and III commodities to a height of approximately 15 ft. If any plastic material is stored in these racks, the sprinkler system will need to be reinforced for adequate protection. Solid shelving should be removed as recommended, and adequate flue spaces maintained. Sprinkler system requirements are as follows below the grated mezzanine for a dry-pipe sprinkler system (which exists in the warehouse): It is preferable to install upright K11.2 (requiring 25 heads at 16 psi) or upright K16.8 heads (requiring 25 heads at 7 psi) for sprinklers beneath the 8-ft. 2-in. high mezzanine. As the mezzanine area is only about 1,500 sq. ft. in area, there will not be 25

07-10-005A continued

	Technical Detail	heads (as outlined in the design requirement) below the mezzanine. There may be less than 25 heads installed, therefore, the sprinkler density requirement should be for all heads (if less than 25 heads installed) at the pressure requirement indicated. For adequate protection, there should be an 18-in. clearance between the top of storage and ceiling sprinkler deflectors below this mezzanine. Proper flue spaces are needed as indicated. The key issue is that there should be a maximum solid-shelf area of 64 sq. ft. This would probably mean that in the center section of the racks below the mezzanine, a 6-in. flue spaces should be created from the floor to the ceiling. In all other sections of the warehouse, the overall ceiling system should be tolerable if the following conditions are always maintained: 1. The solid shelves should be removed and the client provides 6-in. flue spaces around a maximum 64-sq. ft. solid shelf area. 2. There is a limited amount of plastic material (i.e., blue plastic bins) in the two single-row racks along the walls and on top of the mezzanine.
	Loss Expectancies (USD)	Exposure to Loss is approximately: 5,900,000 PD Minimal BI Exposure to Loss if Completed is approximately: 600,000 PD Minimal BI
	Status	A quotation will be obtained for this work that should be completed in 2015.
Part B. Priority 3	**Improve automatic sprinklers in the Tool Crib area of the Main Building.** Because of the excessive clearance to the overhead ceiling sprinkler system, one level of in-rack automatic sprinkler protection should be provided at the approximate mid-height or above the 8-ft. high racks. Alternatively, the ceiling sprinkler system should be reinforced (this may require removing open-top plastic trays from the top tiers).	

07-10-005B continued

The Hazard	There are various types of commodities; however, a large amount of storage is in open-top plastic trays.
Technical Detail	This Tool Crib area in the Main Building consists of an approximate 43-ft. x 22-ft. storage area that includes four 16-ft. 8-in. long single-row racks x 3 ft. wide. This amounts to a maximum solid-shelf area of about 50 sq. ft. Storage in these racks consists mainly of Class I, II or III commodities in plastic bins (commodity is classified as uncartoned unexpanded plastic) to a maximum height of 8 ft. There remains excessive clearance to the overhead ceiling sprinkler system. The small quantities of ignitable liquid were placed inside FM Approved cabinets.
Loss Expectancies (USD)	Exposure to Loss is approximately: 5,000,000 PD Minimal BI Exposure to Loss if Completed is approximately: 600,000 PD Minimal BI
Status	This will need to be further studied, but is not considered a priority.



Parts in Plastic Trays in Racks in Stores Room

11-05-001
Priority 2

Isolate the control room from the turbine building with fire-rated construction.

The control room should be isolated from the turbine building with one-hour fire-rated walls and ceiling. Wired glass or rolling steel fire-rated shutters or an automatic water spray protection system should be provided for any windows facing the interior of the turbine building.

11-05-001 continued

The Hazard	The control room is located in the turbine building. The operators are expected to remain in the control room during a fire. There are large regular windows facing the turbine/generators.	
Loss Expectancies (USD)	Exposure to Loss is approximately:	2,500,000 PD Minimal BI
	Exposure to Loss if Completed is approximately:	100,000 PD Minimal BI
Status	There are no current plans to complete this, but the hazard is understood.	

15-04-003

Ensure that cable penetrations on mezzanine level are properly sealed with fire-retardant material.

Ensure that all cable penetrations in the area below the control room are sealed with an FM Approved floor penetration fire stop.

A program should be put in place whereby this is always maintained after changes are made in the area.

Loss Expectancies (USD)	Exposure to Loss is approximately:	2,500,000 PD Minimal BI
	Exposure to Loss if Completed is approximately:	600,000 PD Minimal BI
Status	According to Mr. Jeff Vincent, the recommendation will be completed by June 2015.	

12-04-003
Priority 1

Install sprinkler protection in the enclosure used for storage on the basement level.

Sprinkler protection (about three sprinklers) should be dropped inside the approximate 12-ft. x 28-ft. x 10-ft. high enclosure between Units 2 and 3 on the basement level and used for mechanical storage and pipe insulation.

The Hazard	A fire in this room would cause heavy smoke and would damage the bus duct. There is some sprinkler protection in the area, but sprinklers were not installed within the rooms.	
Loss Expectancies (USD)	Exposure to Loss is approximately:	2,200,000 PD Minimal BI
	Exposure to Loss if Completed is approximately:	400,000 PD Minimal BI

12-04-003 continued

Status	Mr. Ron LeDrew stated that this is planned to be completed, but no time frame was given.

15-04-004 **Implement a monthly autostart of the AC aux. and DC emerg. oil pumps for the new combustion turbine.**

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 presented to Mr. Stephen Parsons, project manager. This will be transferred to Ms. Alberta Marsh, manager of combustion turbines.

15-04-005 **Install partial discharge monitoring on the new combustion turbine generator stator.**

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 presented to Mr. Stephen Parsons, project manager during the project review, but was not included in this project. The recommendation will be transferred to Ms. Alberta Marsh, manager of combustion turbines.

Risk Reduction

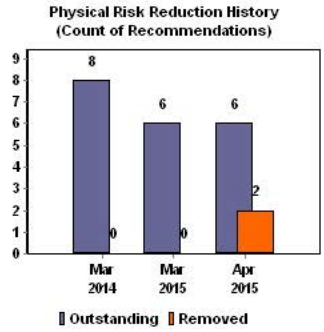
Recommendations that have been completed or otherwise removed are summarized in this section. Risk Reduction involving **Physical Recommendations** is quantified in this report by counting the completed recommendations. **Human Element Recommendations** that have been completed often do not have an associated loss estimate since they usually serve to lower the frequency and/or severity of a loss. For this reason, we quantify them by counting the number of such items that have been completed.

The "Counts" of recommendations referenced in this section include each part of multi-part recommendations except in cases where each part represents options to address a single deficiency. In such cases, the recommendation is only counted once.

Physical Recommendations

The following **Physical** recommendations have been completed or removed as a result of this evaluation:

Rec Number	Recommendation Synopsis *Reason for Deletion/Completion*	Removal Method
00-11-004	Provide remote hydrogen venting capability.	Completed 02 Apr 15
08-10-001	Provide automatic fuel oil shutoff valves. *Reportedly completed as per Account Engineer Francisco Garcia, as of February 20, 2015 (RY)*	Completed 20 Feb 15



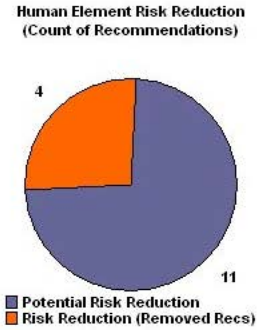
Human Element Recommendations

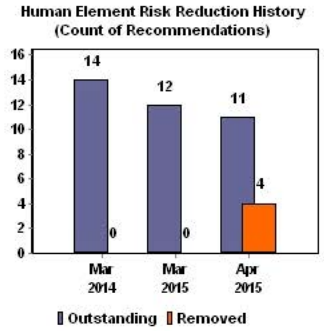
The following **Human Element** recommendations have been completed or removed as a result of this evaluation:

Rec Number	Recommendation Synopsis *Reason for Deletion/Completion*	Removal Method
12-10-001	Visually inspect and exercise all circuit breakers. *An annual preventive maintenance activity is now implemented to see the breakers closing and opening in the field at the Holyrood Terminal Station.*	Completed 02 Apr 15
13-05-006	Implement a testing program for the air system safety valves. *All air system safety valves were replaced with new ones.*	Completed 03 Nov 14
14-04-001	Reinstate weekly fire pump tests and keep records of the checks.	Completed 02 Apr 15

Human Element Recommendations continued

Rec Number	Recommendation Synopsis *Reason for Deletion/Completion*	Removal Method
14-04-002	Reinstate partial discharge results interpretation for the generator collected data. *This testing was reinstated recently and will be conducted every six months.*	Completed 02 Apr 15





Comments

This station is planned to generate electricity up until the spring of 2018 using all three units. Afterwards, it would be put on standby mode for a few years until steam and electricity generation would be stopped. It is believed that one unit, likely Unit 3, will remain as a standby unit to generate power for the grid during winter months around 2021-2022. Following that period, only the Unit 3 generator would be kept as a synchronous condenser to generate VARS for the grid to help with voltage control. The client considers making the new peaking combustion turbogenerator able to generate VARs or converting one in addition to Unit 3 to help with the grid voltage control.

There seems to be a need to reinforce refresher training on emergency procedures with the operators. Refresher training on critical items, such as a suspected water leak in a generator, a suspected rotor ground fault, black-outs, etc., should be provided. This will be further looked at during the next visit.

The electrical distribution system is due for a thermographic survey, which is planned for this spring. The client is encouraged to pursue efforts for the installation of FM approved infrared windows, as planned, for Unit 3.

The battery poles of the Unit 3 lead-acid flooded battery banks are showing significant corrosion on

Comments continued

some cells and this should be addressed. Several broken vents and top valves were noticed, which should be replaced.

Units 1 and 2 were provided with a new automatic synchronize. These are now synchronized to the grid automatically rather than manually. The goal is still to revise the standard operating procedures every three years.

Extensive nondestructive examination will be continued in 2015 for the units' boilers, deaerators, blowdown tanks, high-energy piping for potential creep damage, and low-pressure piping for potential flow-assisted corrosion (FAC). These inspections were implemented following an EPRI Level 2 life assessment survey made in 2010.

This year, some areas of the main steam piping and hot reheat piping of Unit 3 will be inspected for potential creep. Some identified areas on the feedwater piping will be inspected for potential FAC. One area of Unit 2 low-pressure piping will be inspected for FAC, as well as the stop valve upper weld on Unit 1 for potential creep.

Testing the generators isophase busses should be looked at for all three units. Potentially, the isophase busses of Unit 3 could be tested next year. Information on testing conducted by a large power generation corporation will be provided.

The Unit 2 superheater attemperator was last inspected in 2005. As per a technical bulleting issued by the firm Babcock 7 Wilson, this inspection should be conducted every 1- years. It should be done again. This allows to assess the condition of the inside liner and the spray nozzle.

The auxiliary ac and emergency dc lube oil pumps of the peaking diesel-fired pumps should be tested by pressure drop monthly, or at each startups, or prior to each shutdown.

Comments continued



Michel Burbaud, ing. / Eng., OIQ #99065

Montreal Operations

Several of the following items were discussed with Mr. Ron Ledrew who stated that they will be addressed:

1. Improvements were made such that two sprinklers were dropped inside the approximate 12-ft. x 20-ft. room near Unit 1 on Level 2 where archive files are stored. However, the new sprinklers were incorrectly installed as upright heads are in the pendant position. This was mentioned to Mr. Ron LeDrew who stated that this will be corrected as soon as possible.

2. In an area on the basement level, the fire system is being used for process water. This was brought to the client's attention. The client understands the hazards associated with this practice and stated that this will be discontinued immediately.

3. With the installation of the new motorized valve on the fuel oil line, with control by operators in the control room in an emergency, the emergency response plan will be updated to include new procedures.

Managing Change

Next year, the Unit 3 Steam turbine will be subjected to a major dismantling inspection and the critical valves will be overhauled at the same time. In 2015, the critical valves of Unit 1 will be overhauled and Bearing No. 1 will be verified again due to past problems.

Unit 3 Boiler will be subjected to a major inspection this year with a full scaffolding allowing to inspect the waterwalls and the fuel burners. Unit 1 Boiler will be subjected to a minor inspection in 2015 and a tube sample will be extracted to perform a DWD test.

A Low Temperature Superheater spacer bar failure due to fatigue cracking occurred in 2014 on Unit 2 due to repetitive service high pressure tests and shutdown of the unit over the years. Consequently, all spacers bars will be NDEusing MT in 2015 to detect any cracking on filler welds and repair. This will be made also on Unit 1. This will be repeated every year on the bottom part.

Ongoing Services

FM Global is available to provide support in all areas of property loss prevention. These services include:

- Development of specifications for projects such as new construction, automatic protection systems and process safeguards
- Review of related project plans
- Assistance in implementing and managing loss prevention programs
- On site review and acceptance of completed projects
- Assistance in managing impaired protection systems

Depending on your organization's insurance program, you may also have access to the FM Global *My*Risk website. If so, you will find additional risk management tools that can help with your risk improvement strategy at:

https://myrisk.fmglobal.com

For access to these services, contact one of the following:

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Francisco J. Garcia, Account Engineer:
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Suite 500
Thornhill, Ontario, L3T 7V8
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[1] (905) 763 5555

Reference Information

Location Findings

Nalcor Energy
Holyrood Thermal Plant
Route 60
Holyrood, Newfoundland and Labrador A0A 2R0
Canada

All in One
Regular Risk Evaluation

Visit by:	Joanne M. D'Abreu and Michel N. Burbaud
Visit date:	02 April 2015
Site Contact:	Mr. Darren Marsh, Manager, Corporate Risk and Insurance at +1 709 7335323, darren.marsh@aon.ca
Final Conference Attendees:	Mr. Jeff Vincent, P.Eng, Manager, Thermal Generation; Mr. John Adams, Manager, Long Term Asset Planning; Mr. Wayne P. Rice, Manager of Work Execution; Mr. Ron LeDrew, Emergency Response Coordinator; Mr. Jamie Curtis, Plant Engineer - Quality Assurance; Mr. Christian Thangasamy, Plant Mechanical Engineer; Mr. Alonzo Pollard, Performance Specialist; Mr. Darren Marsh, Manager, Corporate Risk and Insurance; Ms. Angelina Vavasour, CRO - Chief Risk Officer; Mr. Jonathan Whelan, Pant Engineer - Electrical; Mr. Scott M. Crosbie, Manager, Office of Asset Management; Mr. Glen Kennedy, Shift Supervisor, Thermal; Mr. Steve Connolly, Team Lead Support Services; Mr. Mike Manuel, Manager, Safety, Health and Environment

Reference Information continued

Location Index Number:	000009.36-02
Account Number:	1-74568

APPENDIX B

Iris Power Holyrood Unit 3 Review Report

QUALITROL
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Email:info.iris@qualitrolcorp.com **www.irispower.com**

October 21, 2014

Newfoundland & Labrador Hydro
Holyrood Thermal Generating Station
Duffs Road, PO box 29
Holyrood, Conception Bay
NL, A0A 2R0

Newfoundland&Labrador Hydro
Holyrood Unit 3
Review of Inspection, Test and Assessment Reports from Alstom and AMEC

Attached please find a copy of our Review of Alstom and AMECAssessment Reports for the work carried out at Newfoundland&Labrador Hydro on the generator Unit 3, at Holyrood. The report concludes that the condition assessment and recommended maintenance strategies are reasonable, based on off-line generator tests and inspections with rotor in place.

The Rotating Machine Technical Service Group at Iris Power LP is committed to providing you with superior service. We value your business and any input you have that can enhance our service to customers. If you require further information or have any questions, please do not hesitate to contact us.

Yours Sincerely,

Mladen Sasic
Manager RMTS

Iris: 50174668

Type of Service

Newfoundland&Labrador Hydro

Holyrood Unit 3
Review of Inspection, Test and Assessment Reports from Alstom and AMEC

Client Purchase Order No:	21485-00 OB
IRIS RMTS Reference No:	50174668
Issue No:	1
Revision No:	1
Date:	October 21, 2014

Prepared by: **Signature** _____

Joe Kapler **Date:** **October 17, 2014**

Reviewed by: **Signature** _____

Ian Culbert **Date** **October 20, 2015**

Reviewed by: **Signature** _____

Greg Stone: **Date** **October 20, 2015**

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Disclaimer: It is impossible to predict time to failure.

Iris Power LP - Rotating Machine Technical Services
3110 American Drive, Mississauga, ON L4V 1T2

Iris: 50174668
Iris|RMTS|V3

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1.0 Introduction

Newfoundland and Labrador Hydro, Holyrood Generating Station, requested Iris Power LP to carry out a condition assessment of the Generators Unit 3 stator and rotor windings, based on:

1) Alstom Field Service Reports FSRG019866 and FSRG020035 of visual inspections and tests on Unit 3 generator in June 2013,

2) Alstom Recommendations Report UTGE672108, October 6, 2014

3) Alstom Generator Unit 3 Condition Assessment Summary Report, September 4, 2013,

4) Generator Diagnostics Rotor Electrical Test Report S481/14/038, April 2014, and

5) AMEC Report AM160-09, August 2014

The Assessment was carried out under Iris Power task references No: 50174668.

Machine Type	*Turbine-Generator*	RPM	*3600*
Voltage/PF	*16.0 kV/0.85*	Manufacturer	*Hitachi*
KVA	*177235*	Date Manufactured	*1980*
Insulation /Class	*Epoxy mica, F*	Serial Number	*TFLQQ*
Cooling	*Hydrogen*	Stator Slots/ Winding Circuits	*60/2*

The stator winding is indirectly hydrogen cooled, the rotor winding is directly hydrogen cooled.

2.0 Assessment

2.1 Operational Period for Unit 3 generator is designated for service in partly generating mode, partly in condenser mode until 2017 and then will be converted for full synchronous condenser operation in 2018 for projected service to 2041. The generator has an accumulated service in the order of 190 000 hours in generating and condenser modes.

2.2 Alstom Field Service Reports FSRG019866 and FSRG020035, Unit 3, June 20, 2013

The reports cover a visual inspection of the stator core and winding with rotor in the bore, DIRIS air gap robot inspection, DIRIS low flux test of the core, stator winding frequency response test & modal analysis, and electrical tests on the stator and rotor windings.

The visual inspection does not report any significant degradation in the stator windings insulation or mechanical damage. Only minor surface contamination and a small surface corona mark at one

location in the end winding area were reported. The picture of this location indicates a low clearance between two bars of different phases which may be the reason for discharges.

A limited rotor visual inspection with boroscope under retaining rings detected a detached piece of insulation at the drive end of the rotor and light dust contamination.

The RSO test for shorted turn detection in rotor windings indicated one shorted turns at standstill. Further RSO tests in April 2014 in stages from zero speed to full speed confirmed the shorted turn at a single location.

The insulation resistance (IR) tests of the stator winding phases at 5000 VDC gave values in the Giga Ohm range; the polarization index (PI) was calculated between 2.8 and 3.2, although in our opinion PI does not have much meaning at such high IR. The insulation surface appears to be in good condition, with no indications of significant contamination. There is no indication of any maintenance high potential (Hipot) tests being performed. We assume none had been done.

The DIRIS bore inspection does not show any dusting or greasing along the winding wedges indicting that the winding in slot section of the core is mechanically stable; thus there is low probability of bar vibration and insulation abrasion even though this is one of the more likely deterioration processes in this type of stator.

The DIRIS low flux test of the stator core (Alstom variant of El-Cid) indicates the results are within Alstom's acceptable range, although we do not know of any independent validation of this acceptance criteria. However Alstom has no commercial reason to say the core is good, if there would be indication that it is bad.

The frequency response test (bump test) and modal analyses at both end windings (EW) do not indicate any natural frequencies in the ranges that would result in resonances at the 60 and 120 Hz excitation forces. The tangential vibration magnitudes on some end caps and phase connections were identified as high, but visual inspections have indicated that this has not caused any apparent damage in 30 year-plus service.

The limited rotor visual inspection was done without retaining rings removal and thus assessment of the rotor condition remains less certain.

The rotor winding insulation resistance at a voltage of 500V DC was measured in Giga Ohm range with PI of 1.3, indicating acceptable ground insulation condition with essentially no contamination.

The recommended maintenance activities on the stator and rotor components during the 2013 outage were limited to the cleanup of stator end winding, rotor surfaces and slip rings, removal of loose strip of insulation from rotor end winding and cleanup of oil in the end section of the casing. We understand that the recommended maintenance was completed.

Report S481 14 038, April 20, 2014 confirms the finding of rotor shorted turn at several speeds up to the rated speed.

Report UTG 672108 describes summary of recommendations for long term maintenance of Unit 3 generator. The summary outlines reasonable maintenance alternatives. They are well presented and logical.

2.3 AMEC Generator Assessment, Units 3, August 22, 2014

The report was completed by Mr. G. Klempner, a respected generator specialist well known to us. His condition assessment conclusions from the test results and recommended long term options generally agree with Alstom strategy options for the operating life of Unit 3 generator as synchronous condenser to year 2041. The table of maintenance options and their risk assessment appears reasonable.

The recommended lists of generator tests prior to shutdown of the unit for major inspection in 2016 and inspection program are comprehensive and complete. The references to water cooled stator windings do not apply to the indirect hydrogen cooled Unit 3 generator at Holyrood. We strongly agree with the recommendation of obtaining all possible operational readings from the available generator monitoring sensors prior to unit shutdown in 2016, possibly at full and half of unit rated load. Such results may provide substantial support to subsequent condition assessment from visual inspection and off-line tests.

2.4 Partial Discharge (PD) Data Analyses

We reviewed the on-line stator winding PD test results from 2011 to 2013. The test results were recorded at about half load and an overvoltage from approximately 2 to 5%. The recorded stator winding temperatures and hydrogen gas pressures on the test sheets appear much lower than the design values. The maximum Qm magnitude from these tests was 5mV which ranks as Typical when compared to other stator windings in the Iris database with similar operating voltages and hydrogen pressures. This together with no discernible rising trend over the almost 3 years [3] indicates the stator winding insulation to be in relatively good and stable condition. So, reliable stator winding insulation life is probable. The on-line testing frequency of once or twice a year should continue in order to detect any unexpected and rapid rise in PD magnitudes indicating insulation degradation. Normally there are several years between the onset of high PD and high risk of stator winding failure.

2.5 Risk assessment of major generator components from typical major failure mechanisms

The following risk assessments of severe degradation or failure of Unit 3 generator from major failure mechanisms in the planned operation as synchronous condenser to 2041 were considered [4], [5]:

a) *Design and manufacturing deficiencies*

No major design or manufacturing problems, neither generic nor specific to these generators, have been identified from the inspection and test reports. The gradual relaxation of the stator winding in core slots and in end winding is a recognized and

expected aging mechanism. No signs of insulation wear, neither in the slot section nor in the end winding of the stator winding, have been identified by visual inspection or tests.

One shorted turn has been confirmed in the rotor winding. It is not clear if the short had been introduced during the original assembly, but had not been noted before the 2013tests.

b) *Stator thermal aging of insulation*

Insulation overheating and thermal damage can occur due to extended operation at high current (e.g. overload, system voltage unbalance above 3%) or due to loss or reduction of cooling (locally or globally). Extended operation at winding temperatures near or above the insulation temperature class the thermal aging rapidly increases and shortens the life of insulation. Neither the visual inspections nor the on-line PD tests detected stator winding thermal aging. It seems the stator winding had been operating well below its thermal class, making thermal aging unlikely.

One location of electrical discharges has been identified, possibly at a reduced clearance between two adjacent bars in different phases. The photograph of that location appears to indicate a lack of clearance between the two bars.

c) *Loose winding in stator slots*

Excessive loss of stator winding wedging pressures leads to relative bar motions and insulation abrasion on core slot walls. In addition to a loss of the bar voltage suppression coatings and slot discharges, the thinning of ground wall can lead to insulation ground failures.

No signs of insulation abrasion or greasing along the slot wedges have been reported in DIRIS report, indicating stable winding condition. The on-line PD tests also indicated no sign of loose windings. Wedge tightness test should be completed during major inspection in 2016.

d) *Stator Winding Contamination, End Winding Tracking*

In hydrogen cooled machines severe winding contamination is not normally expected. On Unit 3 generator only light surface dusting has been reported. Therefore the winding surface tracking to core and insulation erosion at phase-phase inter-phase blocking is unlikely. In any case, such surface discharges can be identified by PD monitoring and the winding cleaned as necessary, since the deterioration process is normally very slow.

e) *Stator End Winding Vibration*

End winding vibration is a recognized generic problem on a number of newer generators. The main reason has been identified as a lighter end winding support structure and unstable ties binding the winding bars to the support rings. The relaxation in service causes a shift of the natural vibration frequencies of the end winding basket to drift closer

to the electromagnetic forcing frequency at 120 Hz (100 Hz in 50 Hz systems). The increased vibrations result in rubbing and abrasion of the bar insulation at support interfaces.

The Unit 3 inspection report does not indicate any dusting of insulation from vibration induced motion in the end winding. The bump testing also indicated no dangerous natural frequencies. One cannot predict if further relaxation may occur, causing winding damage. End winding vibration monitoring can be effective for detection of changes in vibration levels and indicate the need for corrective maintenance.

f) Stator Core Insulation Degradation, Loss of Core Pressure

The visual inspection and DIRIS test of Unit 3 core reports a core in good condition after more than 30 year service. In normal service, severe core degradation is not expected in the service period to 2022 and beyond.

g) Rotor Winding Insulation

It is unknown if thermal aging or thermo-mechanical aging has occurred on the rotor winding, since the limited inspection of the rotor did not permit evaluation of this mechanism.

The result of rotor winding RSO shorted turns test on Unit 3 indicates one confirmed shorted turn in the rotor winding. There is no indication that this shorted turn causes any operational problems such as noticeable increase in rotor unbalance and bearing vibrations. Usually a single shorted turn does not increase bearing vibration. It is not clear when and why this short occurred. If it is the result of significant insulation degradation from mechanical of thermal causes, then further future shorts are possible and probable. A detailed rotor winding inspection as indicated in AMEC report would be required to assess the condition of the winding insulation. This needs to be confirmed in the 2016 overhaul. If the insulation degradation is found, a reliable rotor service beyond 2017 could not be confirmed. Application of rotor shorted turn detectors (flux monitors) would provide assurance that future additional turn shorts would be reliably detected and repaired as required.

h) Retaining Rings and Forging Surface Inspection

Visual inspections of 18-18 retaining rings and rotor forging surface on Unit 3 did not reveal any evidence of overheating or electrical sparking on the rings or at wedge to ring interfaces. Such indications would be expected, if the rotor was subjected to excessive negative sequence currents (I_2). The retaining ring and rotor forging appear sound and suitable for future service.

3.0 Recommendations

1. A retrofit of the rotor shorted turn detectors for positive detection of shorted turns with rotors at full speed is recommended since the condition of the rotor insulation is essentially unknown. Although this generator may operate successfully with a small number of shorted turns, an increase in the number of shorts over time may cause intolerable shaft vibrations and lead to a rotor ground fault.

2. For added assurance that the stator windings are suitable for operation after each overhaul, high voltage potential tests should be considered at the conclusion of overhauls on each generator. Although the AC high potential test (Hipot) is generally more effective to find insulation weakness and is preferred, the DC Hipot or DC ramp tests are easier to perform. The tests should be conducted according to IEEE 95. The risk with the Hipot tests is a possibility of the winding insulation failure, which requires immediate winding repair. Such risk is reduced in the DC ramp test where the DC voltage and current are automatically displayed. If a disproportional current rise is detected the test can be terminated before the insulation fault occurs. Based on the visual inspections and test results, the risk of failure in a maintenance level hipot is low.

4.0 Conclusions:

The above assessments are based exclusively on the submitted test reports and inspections on Unit 3 by Alstom and AMEC. Additional information used to assess the stator windings insulation condition was the on-line PD test results obtained between 2011 and 2013. The generator condition assessments in both reports are sound, based on off-line tests and inspection in June 2013 and April 2014. They provide reasonable risk assessments and maintenance options for operation of Unit 3 generator in the synchronous condenser operation to year 2041.

In addition to the reviewed reports we offer the following comments for your consideration:

A rapid global deterioration of the stator winding insulation is not indicated from the recent inspection and test report on Unit 3 generator. Although the future degradation cannot be reliably assessed and the end of winding life cannot be predicted, we conclude that a stator rewind may not be required at this time for service to 2022. It is assumed that any gradual winding deterioration in normal service will be detected by condition monitoring and condition restored by preventive and corrective maintenance, if required.

We estimate that the Unit 3 generator projected service as synchronous condenser will be at about 140 MVAR rated output, assuming the rated short circuit ratio (SCR) of the generator at 0.5. This will result in 20% reduction in the stator winding current and temperature rise, and about 40% reduction in the stator winding mechanical forces from current magnetic interaction. The risks of the winding insulation thermal aging and abrasion from bar vibration in slots and in the end winding will thus become significantly lower. This could extend the life of the stator winding to the end of the expected service life to 2041. We note that the epoxy mica winding insulation is operating well below its class F

temperature limit of 155° C and if free of wear does not have a defined end of life. Monitoring for winding temperatures, periodic testing or on-line PD monitoring and periodic end winding bump testing should provide a timely warning of an unusual accelerated winding aging. A purchase of a set of spare bars sufficient to wind any three consecutive slots would provide for additional backup for unforeseen winding ground fault. We therefore consider that the decision for stator winding replacement can be delayed to 2022 and possibly beyond. The results of complete winding inspection in 2016 should provide for additional information in regard to stator winding replacement.

The rotor winding insulation is not expected to provide for reliable service to 2041. The rotor duty in the condenser mode operation at rated MVAR output will be the same as at rated output in the generating mode. We agree with the recommendations for rotor re-insulation or complete rewind in 2016 or at some time before the release to condenser operation.

It should be noted that this assessment is valid for normal expected unit service. The consequences of abnormal operation or unpredictable system stress events cannot be predicted.

5.0 References:

1. *IEEE 43 – 2013 Recommended Practice for Testing Insulation Resistance of Electric Machinery*

2. *IEEE 56 –1977 Guide for Insulation Maintenance of Large Alternating-Current Rotating Machinery (10 000kVA and Larger)*

3. *V. Warren, "How Much PD is Too Much PD", Iris Machine Conference, Las Vegas, June 20122*

4. *G. C. Stone, et all, "Electrical Insulation for Rotating Machines", Second Edition, Wiley – IEEE Press, 2014*

5. *Geoff Klempner, Isidor Kerszenbaum, Operation and Maintenance of Large Turbo-generators, IEEE Press, A John Wiley & Sons Publishers, 2008*

APPENDIX C

AMEC Condition Assessment

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AMEC NSS Reference: AM160-09
Security Class: AMEC NSS Confidential

August 22, 2014

Mr. Jeff Vincent
Asset Manager
Holyrood Thermal Generating Station

Dear Mr. Vincent,

Re: Holyrood Thermal Generating Station, Unit 3 Main Generator
Alstom Condition Assessment Report UTGE672108 and
2016 Major Overhaul Scope Recommendations

This letter is in reference to our conference call on July 9, 2014 regarding condition assessment and major outage scope of work for the Holyrood Unit 3 generator. Information regarding the recent activities for generator inspections and testing was discussed and the Alstom Condition Assessment Report #UTGE672108 was provided for review. The following is AMEC NSS's opinion of the Alstom report recommendations and a summary of the general activities required to provide a further detailed condition assessment of the generator. The scope of work for the next outage in 2016 can be based on a selection of these activities but the overall quality of the assessment will depend on the extent of the actions adopted. AMEC NSS Ltd can assist in further refinement of the scope, in analysis of the information gathered from these activities, and can also assist with the collection of the information.

If you require more detail or wish to discuss any specific items further, please contact us at your earliest convenience.

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cc: Kirk Kendall AMEC NL

Holyrood TGS Unit 3 Main Generator
Alstom Recommendations for Long Term integrity of the Unit 3 Main Generator

Alstom Condition Assessment Report #UTGE672108 was reviewed in terms of providing an opinion on the recommendations for the short and long term integrity of the main generator.

The overall opinion of Alstom is that the generator is in reasonably satisfactory condition for its age and its operational duty to date. It has been in operation since 1980 and therefore achieved approximately 34 years of operation. This is well over the 25 to 30 year normal life expectancy of a large generator. There were no major issues observed or discovered by testing that show the generator is in immediate distress for short term operation but a rotor shorted turn has been discovered that indicates some likely rotor winding insulation issues in the long run.

Rotor For the short term (i.e. next 5 years), Alstom are recommending to install a flux probe for shorted turn monitoring at the next available opportunity (the 2016 outage). This is due to the shorted turn found on the rotor by RSO testing. AMEC NSS is in agreement with this recommendation.

Further, since no rotor vibration issues are noted in the report, AMEC NSS assumes that there are no thermal vibration issues limiting operation of the generator at this time. Since the RSO test seems to be indicating only one short of a minor nature and there are no limiting vibrations, the rotor would likely able to operate for a number of years before it will start to show further signs of deterioration and require a rewind.

In the long run, it is expected that additional shorts will occur and a rewind will be required. Generally, no rotor can operate for 2 lifetimes without rewinding. The question is "when is the best time to do the rewind". Alstom recommendation (ii), to "perform a routine rotor inspection during the upcoming major outage in 2016 and plan an additional outage for a rotor rewind within the next 3 years" i.e. 2019, appears to be the most sensible option.

"Rewinding the rotor in 2016", recommendation (i) is reasonable, but AMEC NSS's opinion is that option ii makes the most sense based on the condition reported to date.

At this time, the risk of a rotor failure is deemed to be low. The risk of limited operation due to additional shorted turns causing thermal vibration issues will get higher as time goes by, but is considered low to medium over the next 5 years. AMEC NSS would not let operation continue for more than 5 years beyond 2014 before rewinding the rotor on a planned basis. However, recognizing the fact that the next rewind opportunity would be at the 2022 outage, then the rotor would have medium to high probability of having more shorted turns, increased lateral vibration issues and perhaps even be forced out of service on "high vibration", requiring a rewind. The outage schedules are not optimal for the situation at hand and an additional rewind outage for the rotor would be required in 2019.

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Stator With regard to the stator, there does not appear to be any identifiable major issue to call for a stator rewind during the 2016 outage. Alstom recommendation i, "advance purchase of a rewind kit, including a complete set of stator bars and plan an outage to rewind the stator before a failure occurs" appears to be the most sensible option. However, based on the Alstom report, it is expected that the likelihood of a stator winding failure and forced outage in the next 5 years is in the low to medium probability range. Therefore, AMEC NSS's opinion is that the stator and rotor should be rewound at the same time under a planned outage at no longer than 5 years from now (i.e.2019).

Carrying out the following 2016 outage inspection and testing work scope listed below would assist in verifying this opinion. It is also recognized (from the Alstom report) that additional measurements are required by Alstom to manufacture a suitable stator winding that would fit the existing stator. This is planned to be done during the 2016 outage. Note: As with rotors, generally, no stator will operate for 2 lifetimes without rewinding and the outage schedule does not appear to be optimal for the stator situation either.

If Holyrood wish to try and defer rewinding of the stator and rotor until the 2022 outage, the risk of a forced outage and/or failure become much higher. Carrying out a more detailed inspection and test plan in 2016, as outlined below, may provide better information that confirms whether waiting until 2022 is reasonable. Deferring to 2022 may be possible but AMEC NSS is not prepared to speculate at this particular time on that time frame and scenario with the limited data available.

The following table is a summary of the basic options available, as AMEC NSS see it.

Option 1 - 2016	**Option 2 - 2019**	**Option 3 - 2022**
Rewind the rotor on a planned basis and carry out testing, inspections and measurements on the stator to determine the time frame for a future stator rewind.	Have rotor and stator rewind "kits" available in advance. Rewind the rotor and the stator on a planned basis during this additional outage.	Rewind the rotor and the stator on a planned basis, based on the information gathered at the 2016 outage. Have rotor and stator rewind "kits" available in advance based on the 2016 data and estimated risk.
Risk level considered low	Risk level considered low to medium	Risk level considered to be medium to high

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Holyrood TGS Unit 3 Main Generator 2016 Outage Work Scope Options

On-Line Tests Prior to Shut-Down (2 weeks before shut-down)

1) Heat-run data at maximum load to check for any components with abnormal parameters during operation. Helps determine items that require additional inspection or testing in the off-line condition. Record operating data (as per the list below) at full load, to check for any components with abnormal; temperatures, pressures, flows, voltage, current, etc. Check that all parameters are within the normal operating range. Compare the present readings to manufacturer's expected values. Also compare to previously recorded values from the past, to look for unusual trends.

   Parameters to be recorded at full load:

   - MW
   - MVars
   - Stator Terminal Voltage
   - Stator Current (all 3 phases)
   - Field Current
   - Field Voltage
   - Shaft Voltage
   - Rotor Temperature
   - Excitation Power
   - Generator Casing Hydrogen Pressure
   - Hydrogen Purity
   - Hydrogen Dewpoint Temperature
   - Cold Hydrogen Gas Temperatures
   - Hot Hydrogen Gas Temperatures
   - Cooling Water Inlet Temperature to the Hydrogen Coolers
   - Cooling Water Outlet Temperatures from each Hydrogen Cooler
   - Lube Oil Inlet Temperature to the Bearings
   - Lube Oil Outlet Temperature from each Bearing
   - Bearing Metal Temperatures for each Bearing
   - Bearing Vibration Readings for each Bearing
   - Seal Oil Inlet Temperature to the Hydrogen Seals
   - Seal Oil Outlet Temperature from each Hydrogen Seal
   - Seal Oil Inlet Pressure to the Hydrogen Seals
   - Seal Oil Outlet Pressure from the Hydrogen Seals
   - Seal Oil / Hydrogen – Differential Pressure
   - All Stator Winding Temperature Measurements
   - All Stator Core Temperature Measurements
   - All Stator Core Flux Shield Temperature Measurements
   - Stator Cooling Water Inlet Temperature to Stator Winding
   - Stator Cooling Water Outlet Temperature from Stator Winding
   - Stator Cooling Water Flow
   - Stator Cooling Water Pressure
   - Stator Cooling Water Conductivity

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2) On-line Partial Discharge tests at 3 conditions
   - open circuit rated terminal voltage
   - minimum load
   - full load

   Used to determine if the stator winding requires additional inspection or testing in the off-line condition.

3) Endwinding vibration tests at low load and maximum load. Only if problems are noted. And only machines with installed EW vibration sensors.

Statistical Data Review

Data Required:
- total operating hours since last inspection,
- number of start/stops,
- number and type of operating incidents,
- operational history,
- maintenance problems since last inspection

Review all of the above information prior to the outage to look for suspected problems, which may require additional testing and/or inspections during the outage.

Shut-Down Inspection (minor outage)

→ Rotor is NOT removed.
→ End doors at both ends are removed.
→ Terminal enclosure is opened.

- Inspect all visible stator components at both ends. This includes; the stator endwinding, support structure, frame and casing, internal instrumentation and conduits.
- Inspect the lower terminal enclosure and the high voltage bushings.
- Inspect all visible parts of the rotor.
- IR and PI of the stator winding on each phase.
- IR and PI of the rotor winding.
- Additional electrical testing only if required by either; the pre-shut down on-line tests, the off-line electrical tests, or by visual inspection.

Shut-Down Inspection (major outage)

→ Rotor IS removed.
→ H2 coolers are removed.
→ Terminal enclosure is opened.

- The rotor should be removed to make access for full inspection of all the generator components, including the rotor itself.

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- Additional electrical testing should be scheduled, if shown to be required by either; the pre-shutdown on-line tests, review of the operational and maintenance data, scheduled off-line electrical tests, or by the visual inspection.

1) Stator
   - With the generator rotor removed, perform a complete visual inspection. Inspect all visible and accessible stator components. This includes:
     - stator endwinding
     - endwinding support structure
     - stator phase connections, high voltage bushings and associated support structures.
     - stator core in the bore, including all space blocks for looseness or migration
     - stator core at the back of core area where accessible
     - stator core endplates and flux screens
     - frame and casing
     - internal instrumentation and conduits
     - lower terminal enclosure
     - all generator internal instrumentation and conduits, i.e. thermocouples, RTD's etc.
   - Stator core tightness survey by knife test.
   - Perform stator winding, wedge tightness survey. Ensure that sufficient wedging materials are available prior to the outage, in case a full or partial stator re-wedge is required (i.e. wedges, sliders and packing material)
   - Inspect the stator frame and casing where the hydrogen coolers were removed. Look for cracks in the frame and welds, and any other signs of distress.
   - Open any small ports in the stator casing for inspection of the generator stator internals.
   - IR and PI of the stator phases (separated) at 1000 to 2500 V DC.
   - Perform a DC ramp test to (V_{LL} x 1.5 x 1.7) KV DC on each phase.
   - Perform EI-CID test on stator core
   - Perform off-line Partial Discharge (PD) and PD probe on the stator winding, if indicated to be necessary by the on-line PD tests.

2) Rotor
   - Perform a complete visual inspection of all accessible parts of the rotor, including:
     - main rotor body
     - shaft
     - bearing journals
     - coupling
     - seals
     - rotor slot wedges
     - vent ducts
     - subslots and gas passages
     - balance weights, bolts and screws
     - rotor endwinding and endwinding blocking where accessible
     - retaining rings
     - fans
     - sliprings

   Visual inspection of all accessible areas of the forging for cracks, fretting, arcing, overheating, etc. This includes for example; the tooth wedge lands, coupling holes and coupling face, bearing journals, H2 seal running surfaces, etc. Visual inspection of the rotor

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fan, balance weights, sliprings and brushgear. Visual inspection of the rotor endwinding and associated packing blocks and inter-turn insulation.

- IR and PI of the rotor winding at 1000 V DC.
- RSO of rotor winding, for shorted turns.
- Remove both retaining rings for full NDE inspection by surface dye penetrant and eddy current.
- Remove 10% of the rotor wedges for inspection of the rotor slots.
- Remove the upshaft lead for visual inspection of the lead and insulation condition.
- Perform a boresonic (NDE) inspection of the rotor.

3) Generator CT's and Terminal Bushings
   - Visual inspection of all generator CT's and terminal bushings.
   - IR on the generator CT's at 500 V DC.

4) Generator Hydrogen Coolers
   - Remove all H2 coolers for visual and NDE inspection.
   - Visual inspection of the H2 coolers.
   - Perform hydrostatic leak test using fluorescent dye for detection.
   - Perform a sample eddy current inspection for tube wall thickness on all coolers.

5) Generator Hydrogen Seals
   - Visual inspection of the H2 seals and oil wipers.
   - Dimension checks on all running surfaces.

6) Generator Rotor Bearings
   - Visual inspection of the rotor bearings.
   - NDE to determine the condition of the bearing babbitt, (surface penetrant for cracks and UT for bonding to the shell).

7) Auxiliary Systems
   - Complete inspection of all components of the;
     - hydrogen system
     - lube oil system
     - seal oil system
     - stator cooling water system
     - excitation system

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APPENDIX D

Alstom UTGE672108 Holyrood #3 Maintenance Recommendations

ALSTOM	Generator Services		Document No. UTGE672108	
Prepared: J. Jensen 06/010/14	Checked: A. Sowell 06/10/14	Std. Checked:		Approved: J. Fiaux 06/10/14
Revision:	Rev. Prepared:	Rev. Checked:		Rev. Approved:
Resp. Dept.: 6104	Reference:	Language: English	Page No.: 1	Total Pages: 5

Recommendations for Newfoundland & Labrador Hydro

Holyrood #3 Generator

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1. Purpose

This document provides recommendations for the long term maintenance of the Holyrood #3 generator. The recommendations are based on the results of the minor inspection completed during the Spring 2013 outage, the Spring 2014 electrical testing on the rotor, the operational history and the anticipated future operating characteristics of the generator.

2. Applicability

This document is applicable to the Holyrood #3 generator.

3. References

S481/14/038, 2014 Rotor Electrical Test Report

FSRG 019866, 2013 DIRIS Inspection Report

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4. Inspection Findings

4.1. 2013 DIRIS Inspection (as reported in FSRG 019866)

A thorough inspection of the generator stator and rotor were performed in accordance with Alstom's WIDIPRO inspection program utilizing the DIRIS robot to perform complete visual inspection of the generator rotor and stator, and a low flux test on the stator core. A detailed description of the tests performed and the results are reported in FSRG 019866.

The inspections and tests performed found the generator to be in generally good condition. The findings are summarized below:

- The RSO measurement (inter-turn short circuit test) shows that the rotor winding has a turn to turn short at stand still
- In the DE rotor end winding is a loose insulation ribbon
- The end windings have minor contamination from dry dust
- The end winding housings are contaminated with small pools of oil
- Between two high voltage bars at the NDE end winding a small amount of corona was visible
- DIRIS video inspection has revealed a normal dirt contamination of the air gap
- DIRIS low flux iron core test showed no critical interlamination short circuits
- The bearing insulation tests show that the bearing insulation is in an acceptable range

The required maintenance work was started immediately to ensure the generator could run without problems for the next operating period.

On the generator rotor further monitoring was recommended due to the turn to turn short.

4.2. Rotor Electrical Test (as reported in S481/14/038)

Shaft voltage measurements were performed with the unit on-load; indications show the distribution of the harmonics to be poor. Magnitudes were difficult to analyze. Actual AC wave shapes captured were of poor quality.

The RSO tests were performed at various speeds as per previous tests on previous units. The inter-turn fault that was detected previously is still present. The inter-turn fault doesn't change state with respect to speed. The fault is

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indicated to be an inter-turn fault approximately 2-3 coils into the winding on the second pole of the rotor.

The insulation resistances indicate that there is a low leakage path to earth; this could be put down to contamination dust being present as it was unstable. But the limits are within Alstom's specifications therefore acceptable for service.

5. Operational Considerations

5.1. Prior operating history (as of Feb 24, 2014)

- Operating hours in generation mode: 138,172
- Operating hours in synchronous condenser mode: 47,603
- Total hours: 185775
- Total starts since 1991: 230 (no data prior to 1991. Starts include hot and cold, no data exists to distinguish)

5.2. Long term operation plan

- Next major – 2016 summer
- End of steam (generation mode) – end of 2017
- End of life – 2041
- Major outage frequency going forward from 2016 – 6 year intervals
- 2014 to end 2017 – 4 months per year in generation mode (base loaded), 8 months per year in synchronous condenser mode
- 2018 to 2041 – 12 months per year in synchronous condenser mode

6. Recommendations

6.1. Short term (up to 2016 major outage)

- The inspections and tests performed on the stator found relatively minor issues which are generally confined to what would normally be expected for a unit of this age. None of these findings pose a significant risk for the operation of the generator in the near term. It is recommended to install a wedge mounted flux probe at the next opportunity. This will allow on-line monitoring of the condition of the rotor winding
- The inspections and tests performed on the rotor confirmed the presence of a turn-turn short as well as some loose endwinding blocking. It is not uncommon for generator rotors to operate with shorted turns and this does not seem to have had any negative effect on the generator

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operation to this point. It is recommended to continue regular testing of the rotor for turn-turn shorts at least on an annual basis to monitor the rotor winding and ensure the condition is not worsening.

6.2. Long Term

- The generator is expected to continue operating as a synchronous condenser from 2017 until 2041. Given that the unit has been in operation since 1980 with almost 200,000 Equivalent Operating Hours (EOH) it should be expected that at some point in the near future the unit will require a stator rewind. Based on Alstom's experience with similar generators it is anticipated that this would be in the next 5-10 years. It is recommended that the generator continue to be inspected on a regular basis in accordance with the OEM recommendations in order to look for indications of deterioration of the stator winding. Depending on the criticality of the unit operation it is recommended to select one of the three options below:

  i. Advance purchase of a rewind kit, including a complete set of stator bars. Plan an outage to rewind the stator before a failure occurs.

  ii. Advance purchase of a rewind kit, including a complete set of stator bars. This will ensure that a stator rewind can be executed immediately after an operational failure.

  iii. Advance purchase of spare stator bars sufficient to support replacement of two bottom bars. In this machine the recommended bars would comprise 1 bottom series bar, 1 bottom phase bar, 9 top series bars and 1 top phase bars. This will allow for quick repair of the generator in the event of a failure. A complete rewind kit could then be purchased for installation at a later planned outage.

  Option i avoids the issues associated with an unplanned outage. Option ii avoids the expense of an additional outage to repair the stator after an operational failure. Option iii defers the expense of a complete rewind kit until such time as it is needed.

  Please note that additional measurements of the stator will need to be taken during the 2016 major outage (due to limited access during 2007 measurement) to ensure all rewind kit components can be supplied.

- Given the age and operating history of the generator and in order to ensure satisfactory long term operation of the generator rotor it is recommended to perform a rotor rewind within the next 5 years. Although this may not be immediately necessary it would be prudent to

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perform this work proactively to minimize the risk of an operational failure of the generator. Depending on the criticality of the unit operation it is recommended to select one of the two options below:

i. Perform the rotor rewind during the upcoming major outage in 2016.

ii. Perform a routine rotor inspection during the upcoming major outage in 2016 and plan an additional outage for a rotor rewind within the next 3 years.

Option i would avoid the expense of an additional major outage to perform the rotor rewind and minimize the risk of an operational failure. Option ii would defer the cost of the rotor rewind.

7. Conclusion

7.1. The recent inspections on this generator show that it is currently in satisfactory operational condition with only relatively minor issues which are often associated with generators of this age. However, given the long term operational plans for this unit it is likely that major repair work, including a rotor and stator rewind, will be required to ensure reliable operation for the next 27 years. In order to minimize the disruptions caused by forced outages it is recommended to perform this work proactively during planned outages.

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APPENDIX E

Alstom Holyrood Unit 3 Rotor Electrical Test Report

Generator Diagnostics
Rotor Electrical Test Report

Holyrood U3
10th – 12th April 2014
S481/14/038



POWER
THERMAL SERVICES
United Kingdom

ALSTOM

newfoundland labrador hydro
a nalcor energy company

HOLYROOD GENERATING STATION

ALSTOM PROJECT NO. IE0-000914

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1. Introduction

This report details tests carried out between April 10th - 12th 2014 at Holyrood Power Plant by Mr David Smith of Alstom Power, Generator Diagnostics UK.

2. SUMMARY

Unit 3

These tests are a further investigation from a previous outage.
The previous outage was on this unit (3) in June 2013.
It was highlighted that the rotor had an inter-turn short present.
Therefore these tests were recommended to further assess the condition of the interturn short and to measure the magnitude of any changes.
Due to different methods of the RSO tests being conducted it would be useful in the future to follow a single method of performing the test. This RSO method being performed and documented in this report is the most flexible in terms of analysis, online speed measurements etc. So therefore it would be recommended for future tests to apply this principle.

The shaft voltage measurements were performed with the unit on load; indications show the distribution of the harmonics to be poor. Magnitudes were difficult to analyse. Actual AC wave shapes captured were of poor quality. Recommendations on the shaft earthing arrangement & system will be made.

The RSO tests were performed at various speeds as per previous tests on previous units.
The interturn fault that was detected previously is still present. The interturn fault doesn't change state with respect to speed. The fault is indicated to be an interturn fault approx. 2-3 coils into the winding on the second pole or opposite Z pole of the rotor. Recommendations will be made.

The insulation resistances indicate that there is a low leakage path to earth; this could be put down to contamination dust being present as it was unstable. But the limits are within Alstom's specifications therefore acceptable for service.

3. RECOMMENDATIONS

Alstom recommends as per unit 1 on a previous outage, that the client to consider a better solution for protection & monitoring of the shaft earthing system. The preferred option for this design & construction of machine would either be the shaft braid system or the earthing ring system coupled with the ability to monitor & measure the shaft earthing performance easier. Voltage measured at the DE of the shaft will be increased at the NDE of the generator due to the single positional earthing.
Therefore it is very important to consider a better method of protection for the shaft & bearings etc.

The rotor has an established interturn fault. The fault is of a type that might increase in magnitude giving an increased risk of online issues.

A study has been undertaken on the materials that are incorporated in this particular rotor's end windings. It appears that on this unit the interturn insulation is some type of asbestos based material. Unit 1 has an epoxy resin glass fibre interturn insulation.
The asbestos historically from our experience has very good characteristics to become stabilised and less prone to growth due to degradation of the material from any localised heating. From our experience rotors have run with issues like this for further periods and experienced no operational issues.
Therefore Alstom would recommend to Nalcor Hydro to consider the following options.

1. To consider when this unit has a rotor removed outage, installation of an air gap search coil. After studying the slot design and the cooling system of the machine (in-direct cooling) it would hinder performance to have a rod type search coil. So it is recommended to install a wedge type search coil either built into the wedge or mounted on top of the wedge. This will further assist online studies of the rotor to monitor the interturn short.
2. Periodic monitoring and testing of the rotor to assess the magnitude of the interturn short. It would be recommended with the operating regime of this machine to test every 6 months.(a full suite of shutdown measurements as per this report)
   To continually trend the rotor windings it would be advised to use the same method of RSO system as this can be trended easier results interpreted better thus giving an improved insight into the fault.
3. When this unit has a rotor removed outage with the retaining rings also removed for inspection. Perform reference trace measurements these results can be cross referenced against. The advantage of this is to enable more accurate predictions, the severity and location of the interturn short.

4. PLANT DETAILS

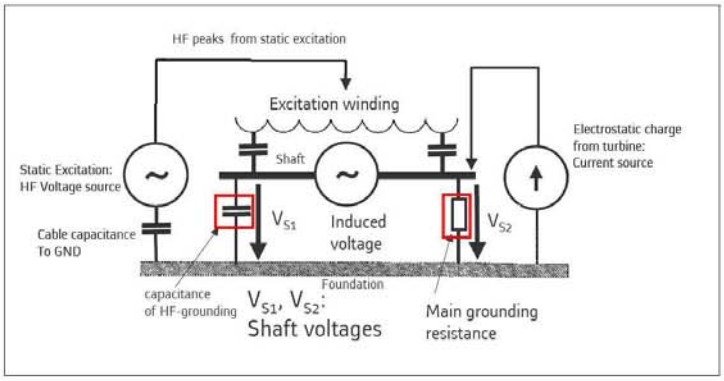
CUSTOMER	Nalcor Hydro
PLANT	Holyrood
UNIT ID	U3
GENERATOR MANUFACTURER	Hitachi, Tokyo, Japan
GENERATOR TYPE	TFL QQ FORM K
STATOR SERIAL NUMBER	162861-1
STATOR VOLTAGE	16.0 kV
RATED POWER	177 MVA
FREQUENCY	60 Hz
SPEED	3600 rpm
COOLING SYSTEM	H2
INSULATION	Class B
POWER FACTOR	0.85
WCC (winding Configuration Code)	Unknown

5. ELECTRICAL TESTS

Shaft Voltage Measurements

Induced shaft voltages are a magnitude of the magnetic features / structures that make up the machine.
These voltages are characteristics of the machine and the conditions in which it operates within.
They are influenced by the load type, power levels active and reactive.
Characteristics that are measured can be said to be a magnetic fingerprint of the machine.

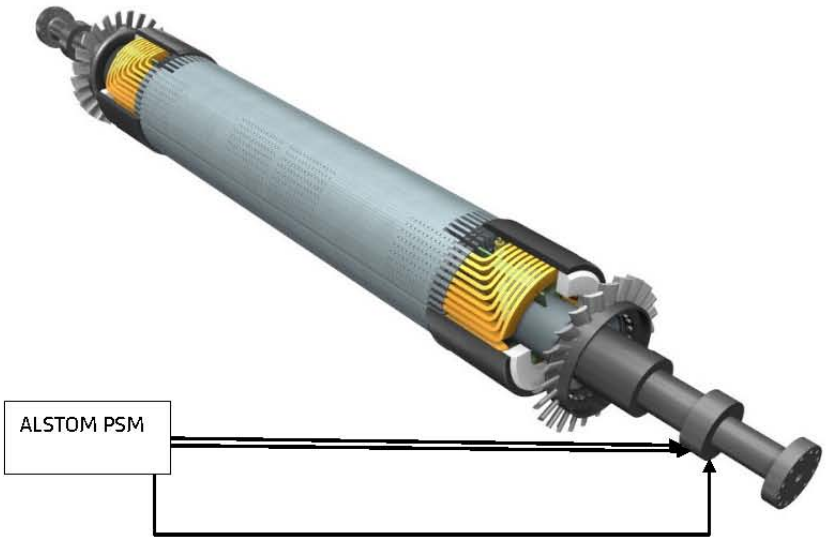
The ring flux that is circulating induces an emf (Electro Motive Force).
The emf is present in the loop created by the shaft & generator housing, thus potential differences arise.
These rises in voltage are referenced between the shaft & ground potential.



Monitoring of the shaft voltages can trend the characteristics.
Working to specific criteria the voltage levels can be tracked & highlight issues before problems occur.
The main issues that can occur are capacitive coupling on the bearing surface area due to rubbing resulting in electro-erosion and pitting.

Sweep Frequency Response Analysis Measurements (SFRA)

The Frequency response test method is a low voltage non-destructive insulation analysis tool.
The sweep frequency response analysis phase sensitive multimeter (SFRA PSM) supplies a voltage from its output channel designated to a zero volt point on the rotor winding of the generator.
Channel 1 of the unit measures & references the output voltage (Vout) that is applied directly to the zero voltage side of the winding (via slip rings & insulated brushes).
Channel 2 of the PSM measures the voltage that is coming in (Vin); from the end of the rotor winding at its designated return point (again via slip rings).
The PSM monitors the response from the voltage over a pre-defined frequency range.
This voltage data is represented as gain in dB due to there being a potential phase angular deviation.
The reference of the gain is with respect to the generator earth plane.
In its most basic state this consists of the stator core, inner frame & structural supports. In this instance the rotor windings will reference to the earthed body & shaft.
When the unit is assembled & ready for service the earth plane increases considerably with additional equipment, structures & chambers, water paths etc. (If applicable).



It is important to note that the test leads are factory matched which have equal impedance (including the loading resistors) with the measuring channel (Vin), this negates an im balance and therefore signal reflections unwanted / erroneous results are not linked to the test leads or circuit setup.

The SFRA will detect disruption to the insulation system of the stator or rotor.
It can sense an electrical disturbance by way of flash over's, loose connections etc. or mechanical movement of the conductors if machine may of seen a fault condition.
It is highly recommended to perform a SFRA measurement when the stator or rotor is in a known good condition. This finger print can be used for future reference.

Repetitive Surge Oscillograph (RSO)

The test consists of injecting pulses simultaneously into both ends of the rotor winding via the slip rings. The two injected signals are displayed as an oscillograph. Any differences in the two traces represent a mismatched rotor winding surge impedance, indicating a discontinuity in the rotor winding.

The signal waveforms are analysed and displayed using an ADC unit and laptop computer.

Rotor Winding Insulation Resistance Measurements

The rotor winding insulation resistances shall be performed at various speeds of the rotor.
The insulation resistance will give a level / resistance of a path to earth from the copper conductors.
The information that these levels will indicate also can be related to moisture and contamination levels

6. DISCUSSION

Shaft Voltage Measurements

The shaft voltage measurements were taken via the brushes located at the DE of the generator.
The shaft earthing brush design & holder arrangement meant that isolation from the multiple earth planes had to be made to a spare set of brushes.
The voltages could then be measured. The current design means that no shaft currents could be measured.
Measurements were taken at 74.2 MW, 30.5 MW and 0.5 MW.
AC & DC voltages were measured.
The shaft earthing system was then re-instated to its original design for future operation.
It was noted that the two brush system currently has contact issues on one brush approx. 25% and on the second approx. 75% the surface of the shaft looked slightly contaminated and it was noted a small amount of sparking present.

The results are shown in the Appendix. pg 11

Sweep Frequency Response Analysis Measurements (SFRA)

SFRA measurement were taken at Full Speed No Load (FSNL 3600RPM) prior to any tests being performed on the rotor so an as found condition. Other measurements that followed were taken at barring speed (3 RPM) and then when the unit was at standstill.
An equipment calibration was performed prior to any testing on the rotor windings.

The results are shown in the Appendix. pg 17

Repetitive Surge Oscillograph (RSO)

The measurements were performed via a set of insulated test brushes.
An initial measurement at FSNL was performed. The unit was then tripped and the resultant traces were viewed all the way down the speed range to barring speed.
Measurements were also performed when the system had cooled enough to enable the static measurements to be taken.

The results are shown in the Appendix. Pg 20

Rotor Winding Insulation Resistance Measurements

Insulation resistance measurements were carried out on the rotor windings using an insulation resistance tester at 500V DC for a period of one minute with respect to the earth plane thus being the shaft and frame of the machine.

The results are shown in the Appendix. Pg 36

Performance Data Study

A defined set of data bundles were requested by Alstom from the station.
This data included the following in a duration of 3hours during a typical shutdown period and the same again over a 7 day operating period.

DE bearing pedestal vibrations
NDE bearing pedestal vibrations.
X4 stator core temperatures.
Voltage & current loadings
Shaft speed
Power outputs, MW & Mvars.

All of the above have been studied and show the machine to be in a reasonable condition.
No excessive levels were noted and also interviewing the operations personnel, they didn't report any live issues with the machine. It was noted that this machine behaves the best with respect to all of the performance criteria.
Importantly there have been no increased levels of excitation and no excessive vibrations with respect to the load conditions.

The results for the data study have been taken but not included in this report due to their size. They are stored in our departments archive for traceability.

REFERENCES

Alstom process specification Generator Diagnostics SFRA	[1]
Previous measurement report eFSR June 2013	[2]
Alstom internal documentation: Assessment of interturn indications	[3]

7. APPENDICES

Appendix - Shaft Voltage Measurements	pg 12
Appendix - Sweep Frequency Response Analysis Measurements (SFRA)	pg 18
Appendix - Repetitive Surge Oscillograph (RSO)	pg 211
Appendix - Rotor Winding Insulation Resistance Measurements	pg 37
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Appendix - Shaft Voltage Measurements

Test Certificate	Title: AC Shaft Voltage Measurement	Reference: S481/14/038	Enclosure: E2

Measurement execution:

Oscilloscope serial No.:	GCM052	ROMON serial No.:	N/A

Measurement conditions:

Active power P [MW]:	31	Nominal speed n [rpm]:	3600
Reactive power Q [MVar]:	23.5	Rotor current I [A]:	751.5

☒ **Static excitation**
☐ **Rotating excitation (brushless)**

Measurement results:

Harmonic analysis of shaft voltages

f [Hz]	U_W [mV]	f [Hz]	U_W [mV]	f [Hz]	U_W [mV]
60	5.365187	720	3.807044		
120	11.17246	780	5.765187		
180	16.27214	840	4.048357		
240	14.08704	900	2.239062		
300	4.419154	960	6.357376		
360	8.508576	1020	1.492559		
420	3.06089	1080	2.415048		
480	3.051137	1140	2.82313		
540	6.239825	1200	1.497429		
600	2.030414				
660	3.748377				

Pic. No.	File Name	U_W peak-peak [V]	Remarks:
1			AC shaft voltage measured at NDE over 2 – 3 revolution
2			AC shaft voltage measured at NDE over 1 revolution with peak detection
3			Ac shaft voltage measured at NDE in frequency range

Remarks:

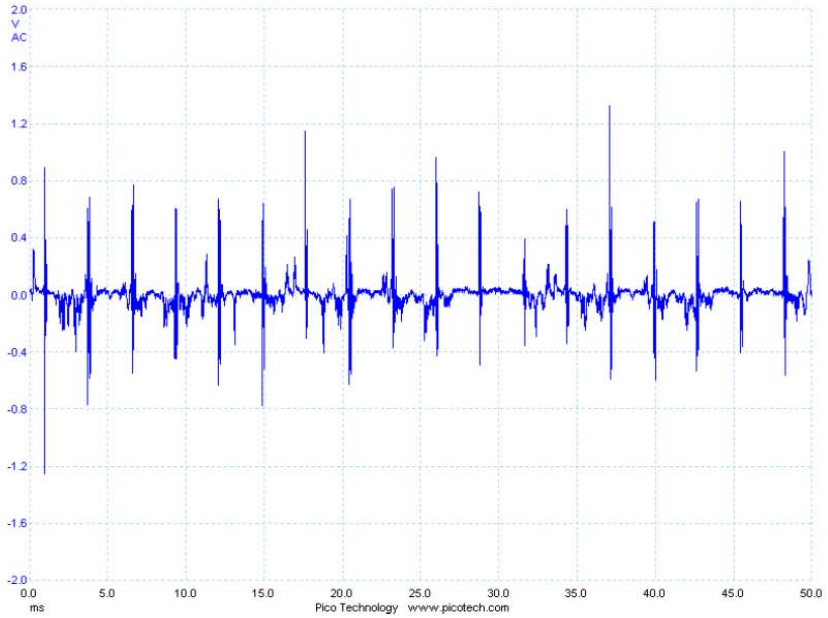
Test Decision (as required/acc. to specification)	Accepted* / NC-Report*		Rejected* / Rework*		Unit/ System Name: Unit 3 / Holyrood	
NCR No.*				Part Text: TFLQQ (Hitachi)		Quantity: 1
Checked by**				Part Idnr: 162861-1	Rev.	Power Station Designation: GT
Approved by**: D.Smith / APUK / 12/04/14				I & T Plan ID	Rev.	Test Step: 10.5 / Material Test No.
Authority / Customer**: Nalcor Hydro / Holyrood				Order No.		Factory Order
ALSTOM		Sheet No.: 12	No. of Sh.: 42	Document No.: HTCZ656937		Rev.: -

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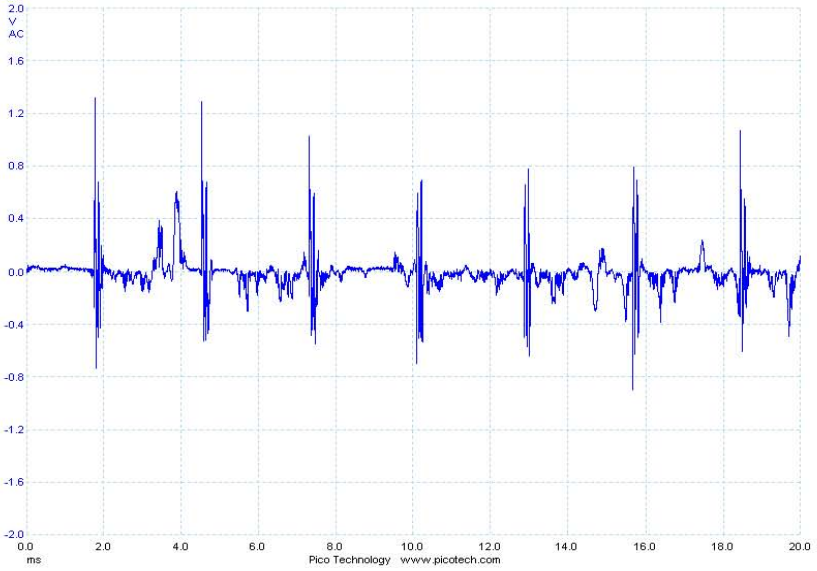
Report Number S481/14/038 Page 12/42

Measurement results continuation:

Picture 1:



Picture 2



Measurement results continuation:

Picture 3:



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Rotor Electrical Test Report: 20th April 2014.
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Test Certificate	Title: AC Shaft Voltage Measurement	Reference: S481/14/038	Enclosure: E1

Measurement execution:

Oscilloscope serial No.:	GCM052	ROMON serial No.:	N/A

Measurement conditions:

Active power P [MW]:	74.29	Nominal speed n [rpm]:	3600
Reactive power Q [MVar]:	62.0	Rotor current I [A]:	1114.0

☒ **Static excitation**
☐ **Rotating excitation (brushless)**

Measurement results:

Harmonic analysis of shaft voltages

f [Hz]	U_W [mV]	f [Hz]	U_W [mV]	f [Hz]	U_W [mV]
60	84.95156	720	125.6208		
120	33.34861	780	46.78412		
180	167.1543	840	23.41867		
240	69.65506	900	88.70503		
300	64.49113	960	57.07406		
360	277.3633	1020	17.51769		
420	67.04877	1080	8.68011		
480	3.6184	1140	38.36768		
540	197.0002	1200	15.59525		
600	114.0358				
660	33.98947				

Pic. No.	File Name	U_W peak-peak [V]	Remarks:
1			AC shaft voltage measured at NDE over 2 – 3 revolution
2			AC shaft voltage measured at NDE over 1 revolution with peak detection
3			Ac shaft voltage measured at NDE in frequency range

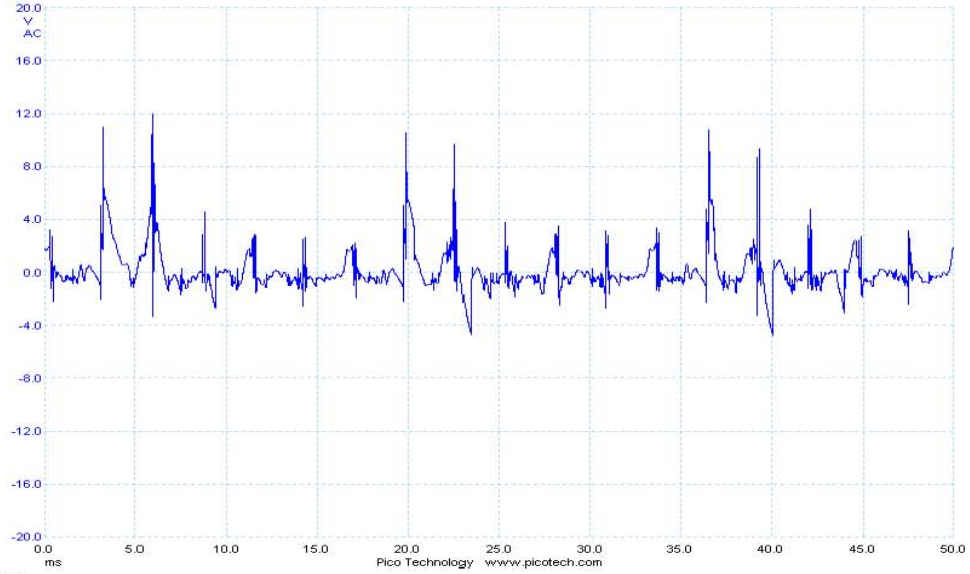
Remarks:

Test Decision (as required/acc. to specification)	Accepted* ☐	Rejected* ☐	Unit / System Name: Unit 3 / Holyrood	
	NC-Report* ☐	Rework* ☐		
NCR No.*			Part Text: TFLQQ (Hitachi)	Quantity: 1
Checked by**			Part Idnr: 162861-1 / Rev.	Power Station Designation: GT
Approved by**: D.Smith / APUK / 12/04/14			T & T Plan ID / Rev.	Test Step: 10.5 / Material Test No.
Authority / Customer**: Nalcor Hydro / Holyrood			Order No.	Factory Order
ALSTOM			Sheet No.: 15 / No. of Sh.: 42	Document No.: HTCZ656937 / Rev.: -

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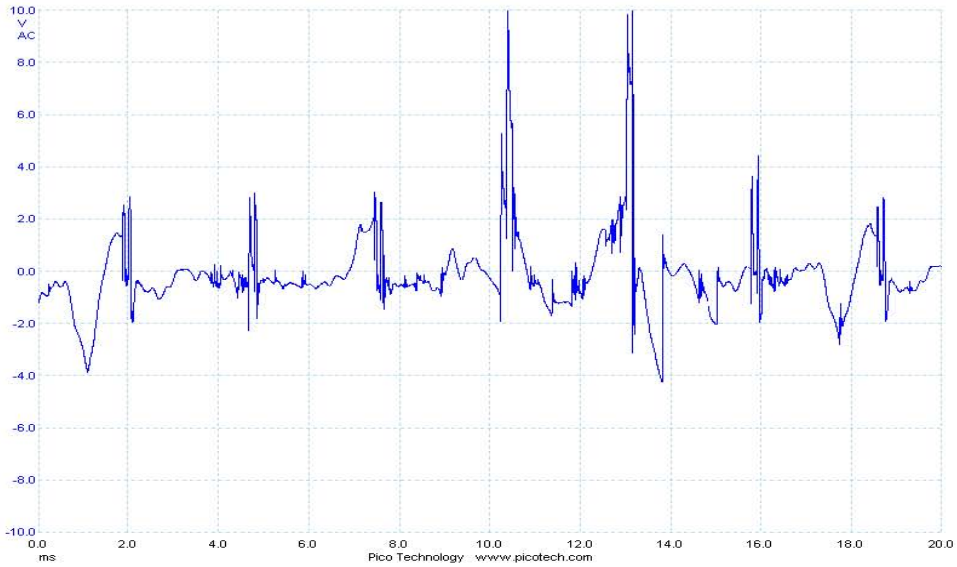
Measurement results continuation:

Picture 1:

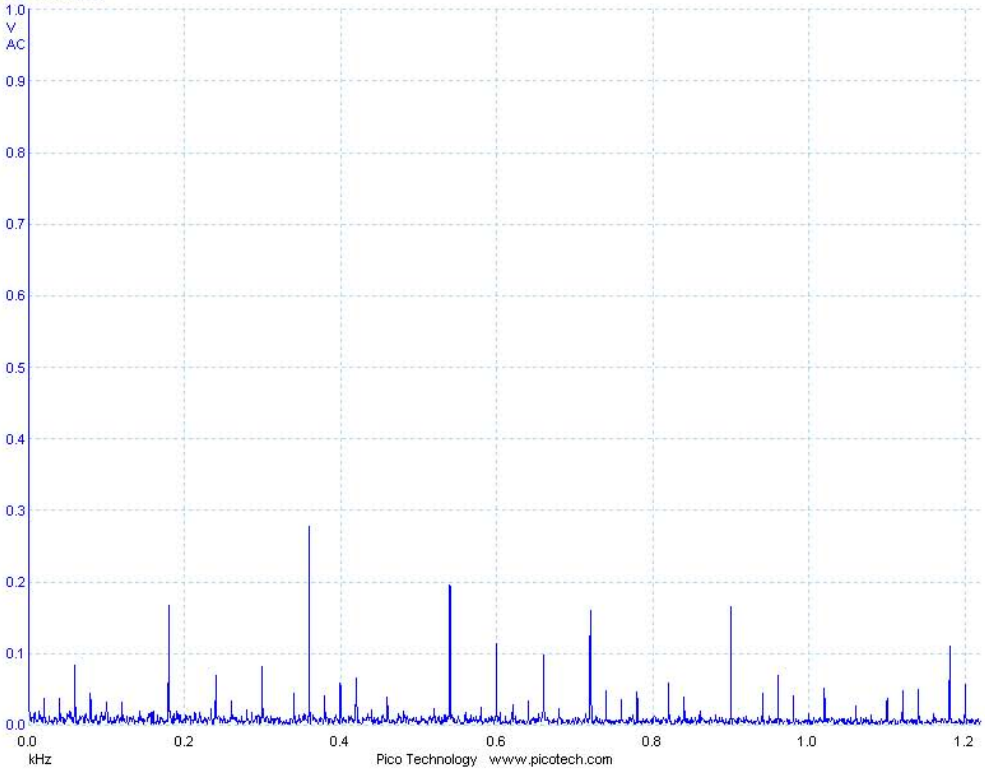


Picture 2

Measurement results continuation:

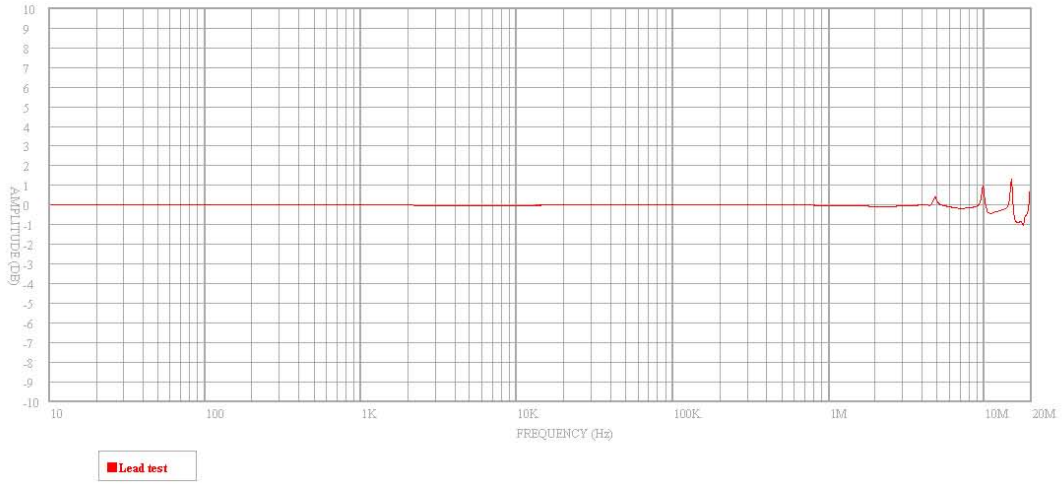


Picture 3:
Measurement results continuation:

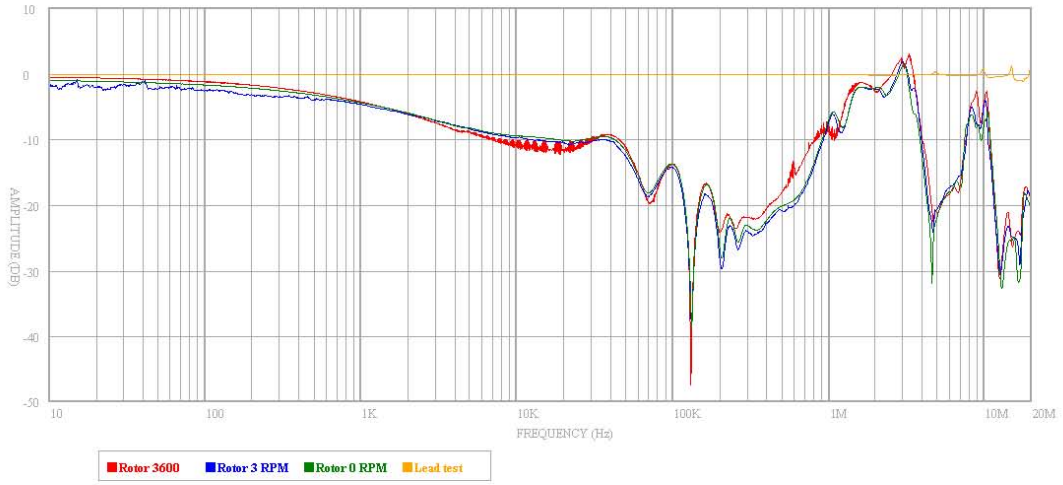


Appendix - Sweep Frequency Response Analysis Measurements (SFRA)

Lead test – Prior to performing running tests.

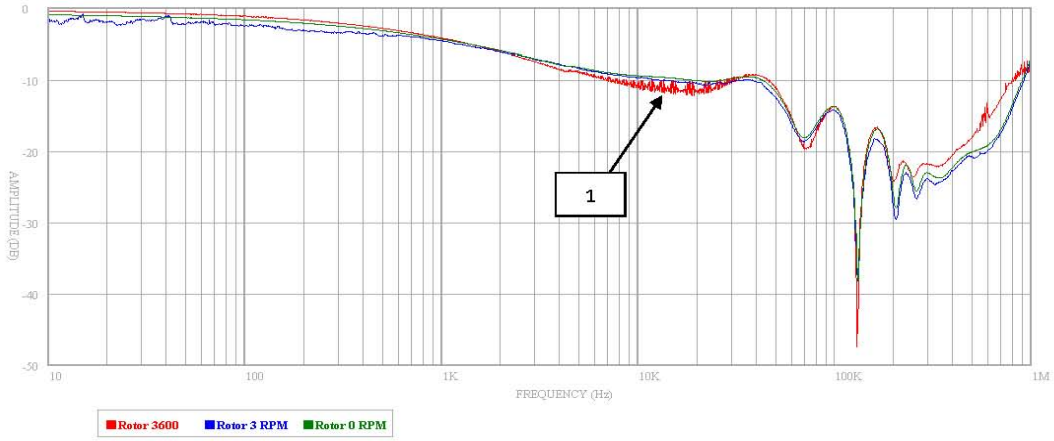


Rotor tests- At various speeds.

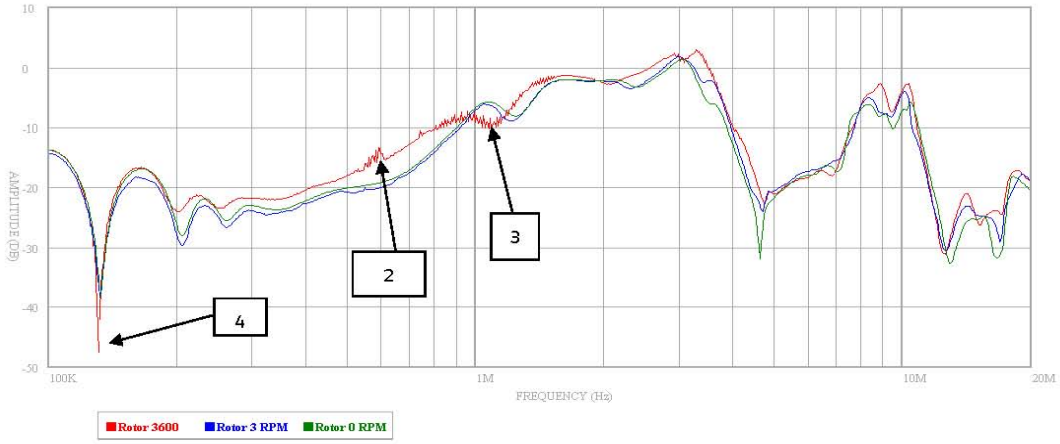


SFRA Continued

Close up showing low frequency range.



Close up showing High frequency range

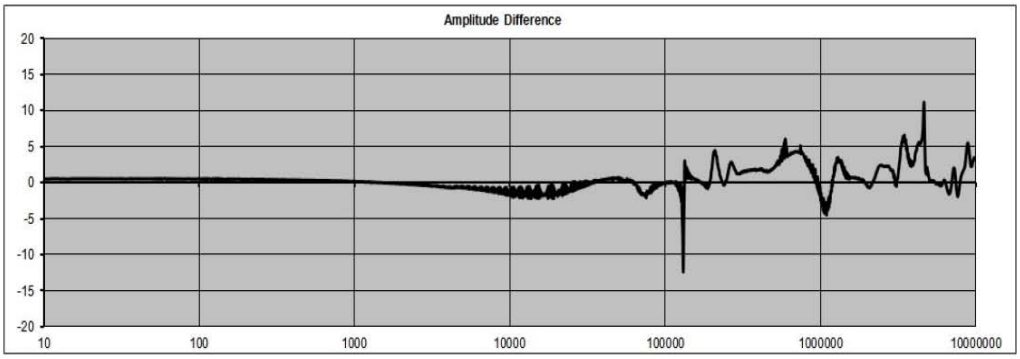


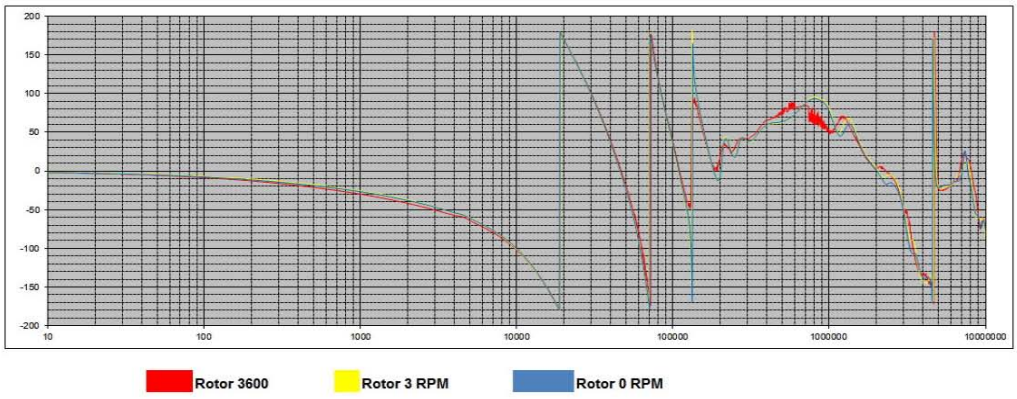
1. Disturbance and signal reflections midpoint 15KHz.
2. Abnormal spike 600KHz.
3. Anti-resonance peak approx. 180 degrees out of phase 1.2 MHz
4. Elevated response peak due to different position of windings and forced onto earth plane thus capacitance change.

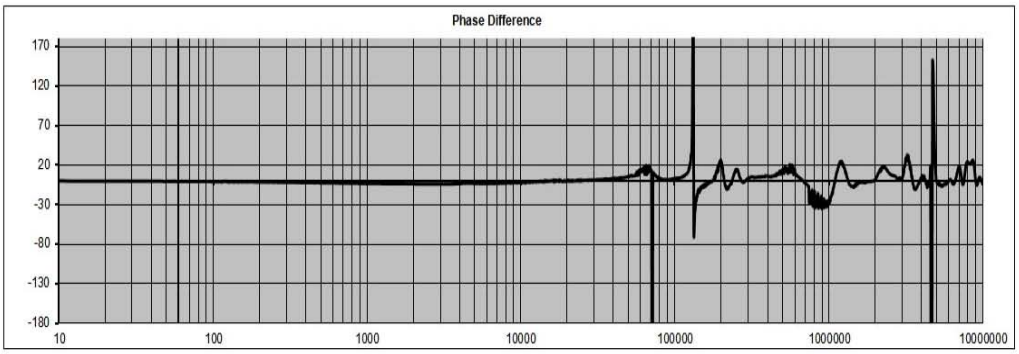
Overall observations

Due to no measurement been taken with the rotor to be in a known good condition only comparisons can be made between speeds.

Contact resistance and speed related mechanical forces are the major difference between the traces resulting in capacitive changes area to note is position 1a standard indication of contamination being present.


Amplitude Difference
20
15
10
5
0
-5
-10
-15
-20
10
100
1000
10000
100000
1000000
10000000


200
150
100
50
0
-50
-100
-150
-200
10
100
1000
10000
100000
1000000
10000000
Rotor 3600
Rotor 3 RPM
Rotor 0 RPM


Phase Difference
170
120
70
20
-30
-80
-130
-180
10
100
1000
10000
100000
1000000
10000000

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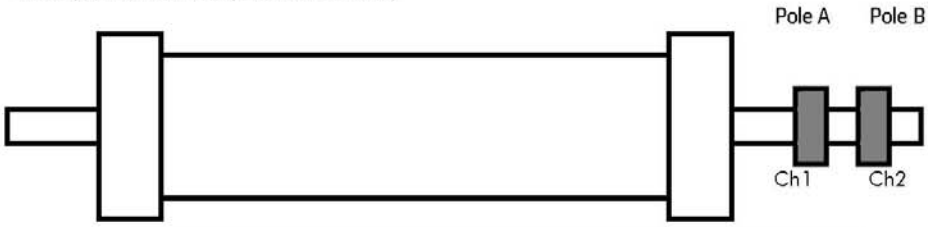
Appendix - Repetitive Surge Oscillograph (RSO)

Condition during test: 01 *Insert condition code*

Remarks: Turbo Generator Unit ran up to 3600 RPM. Measurements taken at FSNL and after the unit was tripped measurements taken down to barring and static tests included. Test brushes made on site.
Speed during test and detailed state of disassembly

Condition Codes:

01 = Generator at nominal speed, 02 = Generator at other speeds (see remarks), 03 = Generator at standstill but housing is closed, 04 = Generator at standstill and housing is opened, 05 = Rotor is removed but still complete, 06 = Rotor is partially or complete disassembled (details see Remarks)



Remarks: Two rings per pole. 4 insulated test brushes used 2 per pole at 45 deg separations.
Special slip ring arrangements and connections on disassembled rotor

Picture 1	RSO results, Channel 1 and Channel 2, traces superimposed, time base 5µs
Picture 2	RSO results, Channel 1 and Channel 2, traces subtracted, time base 5µs
Picture 3	RSO results, Channel 1 and Channel 2, traces separated, time base 5µs
Picture 4	RSO results, Channel 1 and Channel 2, pulse propagation time 10µs

Interturn short circuit is present: Y Yes = Y; No = N

Remarks: Short appears to be on pole 2 (O/B slip ring) around coils 2 -3.
Insert shorted coils if known or other comments regarding the taken decision

Vibration behaviour: 1 1 = normal; 2 = suspicious; 3 = > alarm level; 4 = > trip level

Remarks: No excessive levels reported from the client, excitation levels reported to be normal.
Insert vibration levels, dependency on excitation current or reference to other measurements

Equipment used: Oscilloscope: HS3 / 23221 / 20/03/14
Type/number/valid until

Pulse generator: Stafford RSO/0406-007/ 06-06-14
Type/number/valid until

Matching resistance: RV1 50.0 , RV2 49.6
Setting (Ohm)

Performed by: David Smith
First name, surname

Date / time: 2014-04-12, 14:18
YYYY-MM-DD-hh:mm

Decision: [ ] Pass [X] To be confirmed [ ] Failed

Remarks: Previous RSO tests had identified this inter-turn short during an outage in June 2013.

Site / plant / unit	Report	Enclosure	Sheet	Of
Nalcor Hydro / Holyrood / Unit 3	S481 /14/038	E4	1	16

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Picture 1	RSO results, Channel 1 and Channel 2, traces superimposed, time base 5µs.



Picture 2	RSO results, Channel 1 and Channel 2, traces subtracted, time base 5µs.



Condition during test: 01 *Insert condition code*

Remarks: FSNL 3600 RPM
RV1 50.0 , RV2 49.6

For condition codes see user instructions.

Speed during test and detailed state of disassembly

Site / plant / unit	Report	Enclosure	Sheet	Of
Nalcor Hydro / Holyrood / Unit 3	S481 /14/038	E4	2	16

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Picture 3	RSO results, Channel 1 and Channel 2, traces separated, time base 5µs.



Picture 4	RSO results, Channel 1 and Channel 2, pulse propagation time, time base 10µs



Condition during test: 01 *Insert condition code*

Remarks: 3600 RPM *Speed during test and detailed state of disassembly*

For condition codes see user instructions.

Site / plant / unit	Report	Enclosure	Sheet	Of
Nalcor Hydro / Holyrood / Unit 3	S481 /14/038	E4	3	16

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Picture 1	RSO results, Channel 1 and Channel 2, traces superimposed, time base 5µs.



Picture 2	RSO results, Channel 1 and Channel 2, traces subtracted, time base 5µs.



Condition during test: 02 *Insert condition code*

Remarks: 3000 RPM
RV1 50.0 , RV2 49.6
Speed during test and detailed state of disassembly

For condition codes see user instructions.

Site / plant / unit	Report	Enclosure	Sheet	Of
Nalcor Hydro / Holyrood / Unit 3	S481 /14/038	E4	4	16

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Rotor Electrical Test Report: 20th April 2014.
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Picture 1	RSO results, Channel 1 and Channel 2, traces superimposed, time base 5µs.



Picture 2	RSO results, Channel 1 and Channel 2, traces subtracted, time base 5µs.



Condition during test: 02 *Insert condition code*

Remarks: 2000 RPM
RV1 50.0 , RV2 49.9

For condition codes see user instructions.

Speed during test and detailed state of disassembly

Site / plant / unit	Report	Enclosure	Sheet	Of
Nalcor Hydro / Holyrood / Unit 3	S481 /14/038	E4	5	16

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Rotor Electrical Test Report: 20th April 2014.
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Picture 1	RSO results, Channel 1 and Channel 2, traces superimposed, time base 5µs.



Picture 2	RSO results, Channel 1 and Channel 2, traces subtracted, time base 5µs.



Condition during test: 02 *Insert condition code*

Remarks: 1500 RPM
RV1 50.0 , RV2 49.3
Speed during test and detailed state of disassembly

For condition codes see user instructions.

Site / plant / unit	Report	Enclosure	Sheet	Of
Nalcor Hydro / Holyrood / Unit 3	S481 /14/038	E4	6	16

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Rotor Electrical Test Report: 20th April 2014.
Holyrood Power Plant – U3

Picture 1	RSO results, Channel 1 and Channel 2, traces superimposed, time base 5µs.



Picture 2	RSO results, Channel 1 and Channel 2, traces subtracted, time base 5µs.



Condition during test: 02 *Insert condition code*

Remarks: 1000 RPM
RV1 50.0 , RV2 49.3
Speed during test and detailed state of disassembly

For condition codes see user instructions.

Site / plant / unit	Report	Enclosure	Sheet	Of
Nalcor Hydro / Holyrood / Unit 3	S481 /14/038	E4	7	16

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Rotor Electrical Test Report: 20th April 2014.
Holyrood Power Plant – U3

Picture 1	RSO results, Channel 1 and Channel 2, traces superimposed, time base 5µs.



Picture 2	RSO results, Channel 1 and Channel 2, traces subtracted, time base 5µs.



Condition during test: 02 *Insert condition code*

Remarks: 500 RPM
RV1 50.0 , RV2 50.8
Speed during test and detailed state of disassembly

For condition codes see user instructions.

Site / plant / unit	Report	Enclosure	Sheet	Of
Nalcor Hydro / Holyrood / Unit 3	S481 /14/038	E4	8	16

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Rotor Electrical Test Report: 20th April 2014.
Holyrood Power Plant – U3

Picture 1	RSO results, Channel 1 and Channel 2, traces superimposed, time base 5µs.



Picture 2	RSO results, Channel 1 and Channel 2, traces subtracted, time base 5µs.



Condition during test: 02 *Insert condition code*

Remarks: 400 RPM
RV1 50.0 , RV2 50.8
Speed during test and detailed state of disassembly

For condition codes see user instructions.

Site / plant / unit	Report	Enclosure	Sheet	Of
Nalcor Hydro / Holyrood / Unit 3	S481 /14/038	E4	9	16

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Rotor Electrical Test Report: 20th April 2014.
Holyrood Power Plant – U3

Picture 1	RSO results, Channel 1 and Channel 2, traces superimposed, time base 5µs.



Picture 2	RSO results, Channel 1 and Channel 2, traces subtracted, time base 5µs.



Condition during test: 02 *Insert condition code*

Remarks: 300 RPM
RV1 50.0 , RV2 50.9
Speed during test and detailed state of disassembly

For condition codes see user instructions.

Site / plant / unit	Report	Enclosure	Sheet	Of
Nalcor Hydro / Holyrood / Unit 3	S481 /14/038	E4	10	16

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Rotor Electrical Test Report: 20th April 2014.
Holyrood Power Plant – U3

Picture 1	RSO results, Channel 1 and Channel 2, traces superimposed, time base 5µs.



Picture 2	RSO results, Channel 1 and Channel 2, traces subtracted, time base 5µs.



Condition during test: 02 *Insert condition code*

Remarks: 200 RPM
RV1 50.0 , RV2 50.9
Speed during test and detailed state of disassembly

For condition codes see user instructions.

Site / plant / unit	Report	Enclosure	Sheet	Of
Nalcor Hydro / Holyrood / Unit 3	S481 /14/038	E4	11	16

Picture 1	RSO results, Channel 1 and Channel 2, traces superimposed, time base 5µs.



Picture 2	RSO results, Channel 1 and Channel 2, traces subtracted, time base 5µs.



Condition during test: 02 *Insert condition code*

Remarks: 100 RPM
RV1 50.0 , RV2 50.9
Speed during test and detailed state of disassembly

For condition codes see user instructions.

Site / plant / unit	Report	Enclosure	Sheet	Of
Nalcor Hydro / Holyrood / Unit 3	S481 /14/038	E4	12	16

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Rotor Electrical Test Report: 20th April 2014.
Holyrood Power Plant – U3

Picture 1	RSO results, Channel 1 and Channel 2, traces superimposed, time base 5µs.



Picture 2	RSO results, Channel 1 and Channel 2, traces subtracted, time base 5µs.



Condition during test: 02 *Insert condition code*

Remarks: On barring gear 3 RPM
RV1 50.0 , RV2 51.0

Speed during test and detailed state of disassembly

For condition codes see user instructions.

Site / plant / unit	Report	Enclosure	Sheet	Of
Nalcor Hydro / Holyrood / Unit 3	S481 /14/038	E4	13	16

ALSTOM

Rotor Electrical Test Report: 20th April 2014.
Holyrood Power Plant – U3

Picture 3	RSO results, Channel 1 and Channel 2, traces separated, time base 5µs.



Picture 4	RSO results, Channel 1 and Channel 2, pulse propagation time, time base 10µs



Condition during test: 02 *Insert condition code*

Remarks: Rotor on barring gear 3 RPM

For condition codes see user instructions.

Speed during test and detailed state of disassembly

Site / plant / unit	Report	Enclosure	Sheet	Of
Nalcor Hydro / Holyrood / Unit 3	S481 /14/038	E4	14	16

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Rotor Electrical Test Report: 20th April 2014.
Holyrood Power Plant – U3

Picture 1	RSO results, Channel 1 and Channel 2, traces superimposed, time base 5µs.



Picture 2	RSO results, Channel 1 and Channel 2, traces subtracted, time base 5µs.



Condition during test: 03 *Insert condition code*

Remarks: 0 RPM
RV1 50.0 , RV2 51.0
Speed during test and detailed state of disassembly

For condition codes see user instructions.

Site / plant / unit	Report	Enclosure	Sheet	Of
Nalcor Hydro / Holyrood / Unit 3	S481 /14/038	E4	15	16

Picture 3	RSO results, Channel 1 and Channel 2, traces separated, time base 5µs.



Picture 4	RSO results, Channel 1 and Channel 2, pulse propagation time, time base 10µs



Condition during test: 03 *Insert condition code*

Remarks: Holyrood U3 RSO at standstill 0RPM *Speed during test and detailed state of disassembly*

For condition codes see user instructions.

Site / plant / unit	Report	Enclosure	Sheet	Of
Nalcor Hydro / Holyrood / Unit 3	S481 /14/038	E4	16	16

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Rotor Electrical Test Report: 20th April 2014.
Holyrood Power Plant – U3

Appendix - Rotor Winding Insulation Resistance Measurements

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Test Certificate	Title: Rotor winding insulation resistance measurement	Report No. S481/14/038	Enclosure E3

Measurement execution:

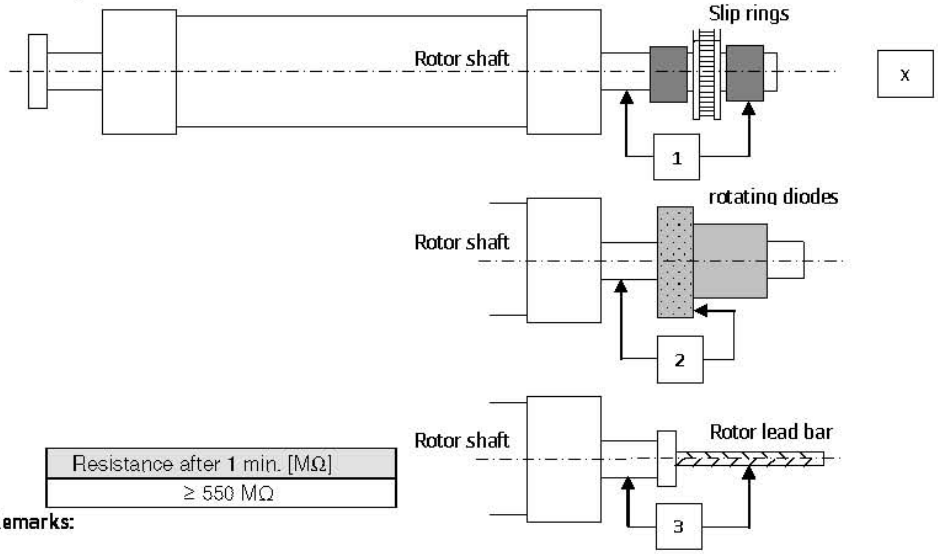
Measurement voltage U [V]	500V DC	Measurement instrument:	Nalcor Hydro Fluke IR tester

Measurement conditions:

Ambient temperature [°C] :	29.7	Relative humidity [%] :	≤ 20
Winding temperature [°C]	42.0	Test duration t [Min.]	1 Min

Rotor at idle speed ☒ Rotor at standstill ☐

Test point:



Resistance after 1 min. [MΩ]
≥ 550 MΩ

Remarks:

IR Test @ 3600 RPM.

Test Decision (as required/acc. to specification)	Accepted*		Rejected*		Unit / System Name: Unit 3 / Holyrood		
	NC-Report*		Rework*				
NCR No.*					Part Text: TFLQQ (Hitachi)		Quantity: 3
Checked by**					Part Idnr: 162861-1	Rev.	Power Station Designation: GT
Approved by**: D.Smith / APUK / 10/04/14					I & T Plan ID	Rev.	Test Step / Material Test No.
Authority / Customer**: Nalcor Hydro / Holyrood					Order No.		Factory Order
ALSTOM					Sheet No.: 37	No. of Sh.: 42	Document No.: HTCZ656969 / Rev.: -

Dept: 9539 | Document No.: HTCZ656969 | Type: FA | Rev.: - | Released: 2010-01-08 | Lng: EN | Status: Approved

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Rotor Electrical Test Report: 20th April 2014.
Holyrood Power Plant – U3

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Test Certificate	Title: Rotor winding insulation resistance measurement	Report No. S481/14/038	Enclosure E5

Measurement execution:

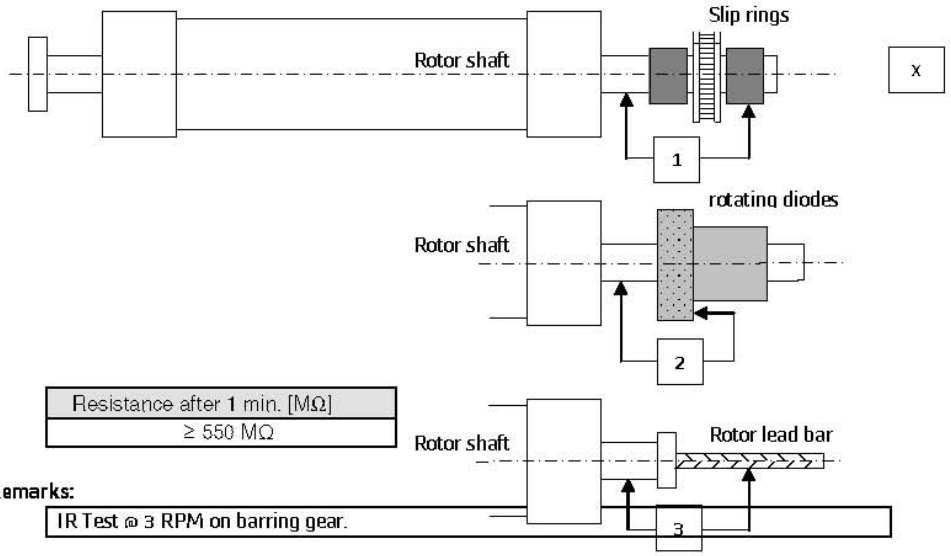
Measurement voltage U [V]	500V DC	Measurement instrument:	Nalcor Hydro Fluke IR tester

Measurement conditions:

Ambient temperature [°C] :	29.7	Relative humidity [%] :	23
Winding temperature [°C]	34.0	Test duration t [Min.]	1 Min

Rotor at idle speed ☐ Rotor at standstill ☐

Test point:



Resistance after 1 min. [MΩ]
≥ 550 MΩ

Remarks:

IR Test @ 3 RPM on barring gear.

Dept	Document No.	Type	Rev	Released	Lng	Status
9539	HTCZ656969	FA	-	2010-01-08	EN	Approved

Test Decision (as required/acc. to specification)	Accepted* / NC-Report*	Rejected* / Rework*	Unit / System Name: Unit 3 / Holyrood	
NCR No.*			Part Text: TFLQQ (Hitachi)	Quantity: 3
Checked by**			Part Idnr: 162861-1 / Rev.	Power Station Designation: GT
Approved by**: D.Smith / APUK / 11/04/14			I & T Plan ID / Rev.	Test Step / Material Test No.
Authority / Customer**: Nalcor Hydro / Holyrood			Order No.	Factory Order
ALSTOM			Sheet No.: 38 / No. of Sh.: 42	Document No.: HTCZ656969 / Rev.: -

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Rotor Electrical Test Report: 20th April 2014.
Holyrood Power Plant – U3

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Test Certificate	Title: Rotor winding Insulation resistance measurement	Report No. S481/14/038	Enclosure E6

Measurement execution:

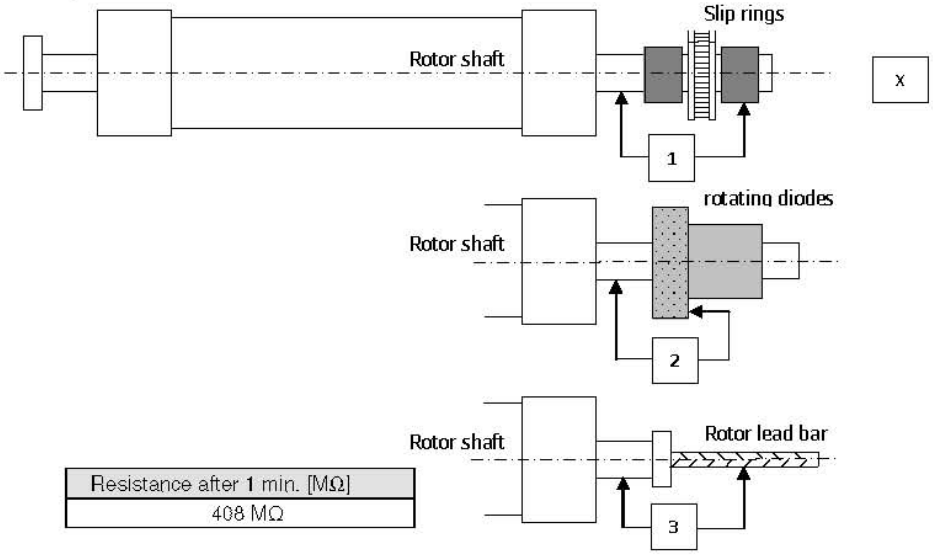
Measurement voltage U [V]	500V DC	Measurement instrument:	Nalcor Hydro Fluke IR tester

Measurement conditions:

Ambient temperature [°C] :	28.2	Relative humidity [%] :	22
Winding temperature [°C]	33.0	Test duration t [Min.]	1 Min

Rotor at idle speed ☐ Rotor at standstill ☒

Test point:



Resistance after 1 min. [MΩ]
408 MΩ

Dept.	Document No.	Type	Rev.	Released	Lng	Status
9539	HTCZ656969	FA	-	2010-01-08	EN	Approved

Test Decision (as required/acc. to specification)	Accepted* / NC-Report*	Rejected* / Rework*	Unit / System Name: Unit 3 / Holyrood			
NCR No.*			Part Text: TFLQQ (Hitachi)			Quantity: 3
Checked by**			Part Idnr: 162861-1	Rev.	Power Station Designation: GT	
Approved by**	D.Smith / APUK / 12/04/14		I & T Plan ID	Rev.	Test Step	Material Test No.
Authority / Customer**	Nalcor Hydro / Holyrood		Order No.		Factory Order	
ALSTOM			Sheet No.: 39	No. of Sh.: 42	Document No.: HTCZ656969	Rev.: -

Report Number S481/14/038 Page 39/42

Appendix - Equipment used

Type	Manufacturer	Serial No.	Calibration due date
Insulation Tester	Fluke	Provided by Nalcor	N/A
Thermo/hygrometer	Testo	7202	Indication only
Alstom PSM	N4L	1701/IAI1713	04/09/15
Alstom Signal Generator	Stafford	0606-007	06/06/14
Scope	HS	23221	17/04/15
Shaft voltage scope	Pico	UAT93/011	19/06/14

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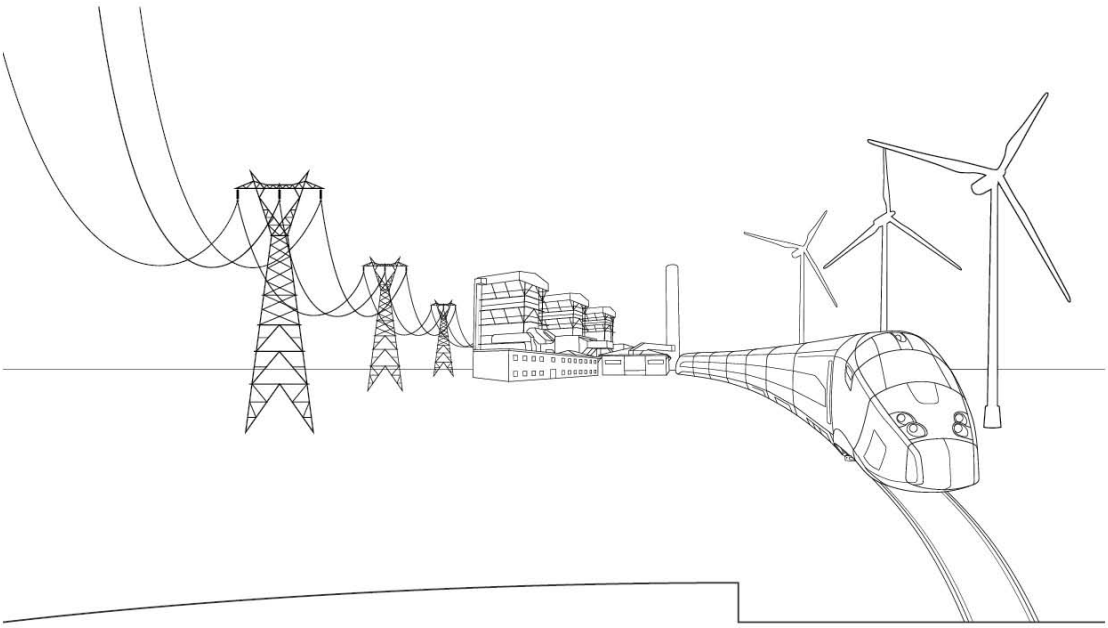
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APPENDIX F

Alstom Holyrood Unit 3 Generator Condition Assessment Summary Report



Nalcor Holyrood Unit 3
Generator Condition Assessment
Summary Report

September 4, 2013

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Shaping the future

Nalcor Holyrood Unit 3 Generator - Condition Assessment Summary Report

September 4, 2013

Alstom Power performed a condition assessment of the Holyrood #3 generator during the spring outage in June 2013. The results of this assessment have been reported to Newfoundland and Labrador Hydro in Field Service Report FSRG 019866. The discrepancies found are summarized below.

Stator

- The endwinding housings are contaminated with small pools oil.
- Between two high voltage bars at the NDE end winding small corona was visible.
- DIRIS video inspection revealed normal dirt contamination of the air gap.

Rotor

- The RSO measurement (inter-turn short circuit test) shows that the rotor winding has a turn to turn short at standstill.
- The DE rotor endwinding has a loose insulation ribbon.
- The endwindings have minor contamination from dry dust.
- The slip ring unit is dirty by dry carbon dust.
- The slip rings were found out of round by up to 4 Mils.
- The brushes were visually inspected and were in normal condition.

Based on these findings the following recommendations were made.

Stator

- Clean the whole stator as far as possible.
- Clean the small corona marks between the NDE high voltage top bars at 11 o'clock as far as possible.
- Clean the small pools of oil in the end winding housing.
- Install a flux probe

Rotor

- Clean the whole rotor as far as possible.
- Rework the slip rings to restore roundness
- Cut the loose insulation ribbon at the DE rotor end winding and seal it with epoxy.
- Perform an RSO test at nominal speed
- Take shaft voltage measurements during operation

Exciter

- Clean the brush bridge as far as possible, especially the carbon dust, dirt and deposits.

Other Work

- Clean the grounding brushes.

Nalcor Holyrood Unit 3 Generator - Condition Assessment Summary Report
September 4, 2013

These actions were completed during the spring 2013 outage with the following exceptions.

- Brush gear and brush cleaning

  This is responsibility of the customer's Electrical Department

- Install a flux probe

  A flux probe was recommended to help characterize the shorted turn. A "normal" flux probe installation could not be performed because the rotor was not removed from the generator. A back-of-core flux probe installation was investigated however it was determined that this would not be feasible. It is therefore recommended that the flux probe be installed during the next major outage with the rotor removed (scheduled for 2016).

- Rework the slip rings to correct roundness

  Grind the slip rings to achieve less than 0.0005" out of roundness. Surface finish should be maintained to 8 micro inch standard. This should be done at the earliest opportunity.

- Perform an RSO test at nominal speed

  This test will show if the shorted turn is present at speed as it is not uncommon for turn to turn shorts to be present in one condition and not the other. This test requires the machine to be operational and therefore it is recommended that it be completed at the next opportunity after the outage.

- Take shaft voltage measurements during operation

  The shaft voltage test looks at the condition of the shaft grounding and is another method of identifying turn to turn shorts. This test also requires the machine to be operational and access to an exposed portion of the rotor shaft between the slip rings and the bearing. It is recommended to perform this test at the next available opportunity.

The actions recommended above will help to ensure the satisfactory operation of the unit until the next inspection period and will allow better characterization of the rotor turn to turn short or any change in the condition of the shorted turn.

APPENDIX G

Alstom Field Service Report FSRG020035

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Field Service Report (FSR)	Related CFSR issued ☐ Y ☒ N	Total pages without enclosures	Total pages enclosures
Report No. **FSRG020035**		5	63

Location	Department	Author	Date	Page No.
US	Thermal Services	Shahram Elmi	09.07.2013	1

Site Information

Customer: Newfoundland And Labrador Hydro	File Name: FSRG020035_Test_130709_Elmi.pdf	
Site: **HOLYROOD**	Country Name: CANADA	PDM Event No.
Plant: **HOLYROOD 3**	Plant Type: FO	Outage code
Unit: **HOLYROOD 3**	Service Ref No.	Order No.

System / Machine	System / Machine Type	System / Machine Serial No.
Generator	GE-Hitachi	191641

Task Information

Business Case: A/B- Inspection

Task: Test (Analysis)

Task description:

Generator End Winding Bump Test

Distribution of FSR

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US	Thermal Services	Reviewed by: John A Jensen	Date: 09.07.2013
US	Thermal Services	Approved by: Jean Fiaux	Date: 10.07.2013
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2.	Summary	3
3.	Work carried out	3
3.1.	Bump Testing	3
4.	Personnel involved	4
5.	Technical information	4
6.	Enclosure	5

1. Purpose and duration of assignment

Purpose of assignment	Arrival Date	Departure Date
To perform bumptesting of the NDE and DE end windings	11.06.2013	13.06.2013

2. Summary

Holyrood unit #3 is Hitachi hydrogen cooled 2-pole generator. The stator is rated at 157 MW and has 60 slots. Tangential blockings are not used between the series bars of the Driven End (DE) or the series bars of the Non-Driven End (NDE). The top bar and bottom bar phase bars are tied together at one location in the straight section of the bars after the involute. During a scheduled outage in June 2013, bump testing of the Non Driven End (NDE) and Driven End (DE) of the end windings were performed. The bump testing included:

- NDE Global modal analysis
- NDE Driving point measurement of the SERIES BARS
- NDE Driving point measurements of the phase connections
- DE Global modal analysis
- DE Driving point measurement of the SERIES BARS

The purpose of this report is to describe the procedure and equipments used, and present the results obtained.

3. Work carried out

3.1. Bump Testing

During a scheduled outage in June 2013, bump testing of the Non Driven End (NDE) and Driven End (DE) of the end windings were performed. The bump testing included:

- NDE Global modal analysis
- NDE Driving point measurement of the SERIES BARS
- NDE Driving point measurements of the phase connections
- DE Global modal analysis
- DE Driving point measurement of the SERIES BARS

The measurements were performed according to ALSTOM document number UTGE602042. However, the following exceptions to the requirements in the above procedure were taken:

- For the Global modal analyses of both the NDE and DE sides, only the plane of the end of the bars are chosen since the rotor was installed and the planes at slot exit and middle of the involutes were not accessible. The number of measurement points was 18 for the NDE side and to 20 for the DE side.

- The phase bars were bumped separately from the series bars of the NDE side.

- The phase bars and the corresponding arms were bumped in radial, tangential, and axial directions and response was measured in all three directions. On each phase bar, the vibration responses were measured at two different points, one after the first bend and the second point between after the second bend.

- Only the accessible series bars of the DE side and the top half of the series bars of the NDE side were bumped in radial directions and their responses were measured in radial, tangential, and axial directions.

For the complete report, list of equipment, and the graphs of the test results, refer to the enclosure section at the end of this report.

4. Personnel involved

Unit		HOLYROOD 3					
No.	Name	Department	Code	Function	Position	Arrival Date	Departure Date
1	Shahram Elmi	Gen Eng	CGD	Commissioning Generator Diagnostics	Engineer	11.06.2013	13.06.2013

5. Technical information

Unit		HOLYROOD 3		
Type of data		Technical Information Generator		
No.	Description	Unit	Reading / Value	Remarks
1	Type	-	TFLQQ	
2	Generator / Stator Serial No.	-	191641	
3	Manufacturer (OEM) / Supplier	-	Hitachi	
4	Rotor Serial No.	-		
5	Rated Speed	rpm	3600	
6	Rated Frequency	Hz	60	
7	Rated Apparent Power	kVA	185000	
8	Rated Power Factor	-	0.85	
9	Rated Stator Voltage	kV	16.00	
10	Rated Stator Current	A	6676	
11	Rated Field Voltage	kV_{DC}	375.000	
12	Rated Field Current	A_{DC}	1582	
13	Insulation system	(stator wind.)		
14	Insulation class	(stator wind.)	B	
15	Cooling System (medium)	(rotor/stator)	H2-Indirect	
16	Excitation System	-		
17	Exciter Type	-		
18	Exciter Fabrication No.	-		

6. Enclosure

No.	1
Description	Complete Report
Reference Number	
Pages	63

ALSTOM
Field Service Report FSRG020035

NALCOR ENERGY COMPANY

HOLYROOD UNIT #3

Modal Analyses of DE and NDE End Windings,
Driving Point Measurements of Phase Connections and SERIES BARS

By:
Shahram Elmi

June 20, 2013

Table of Content:

1 Introduction 2
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3 Equipments 6
4 NDE Measurements 6
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6 Conclusion 63

Enclosure Page 1 of 63

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Field Service Report FSRG020035

1. Introduction

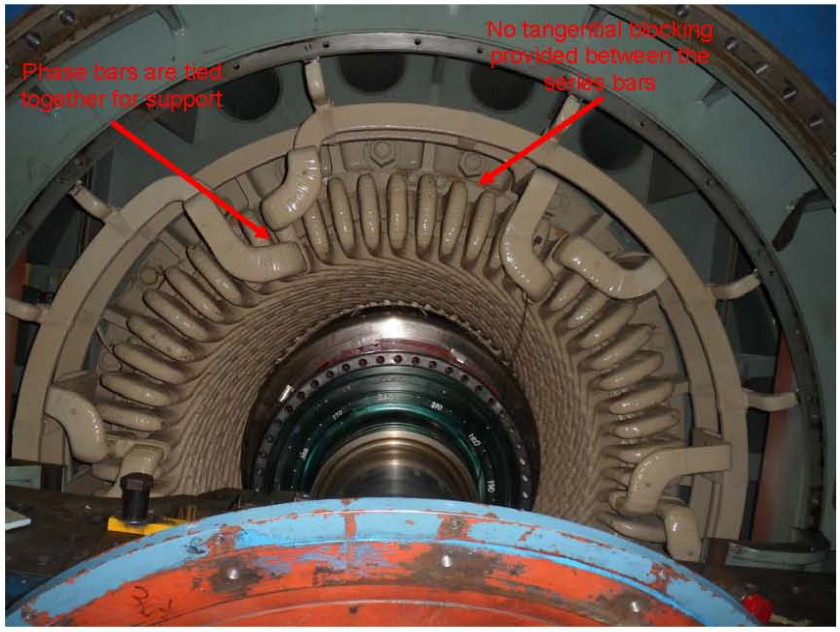
Holyrood unit #3 is Hitachi hydrogen cooled 2-pole generator. The stator is rated at 157 MW and has 60 slots. Tangential blockings are not used between the series bars of the Driven End (DE) or the series bars of the Non-Driven End (NDE). The top bar and bottom bar phase bars are tied together at one location in the straight section of the bars after the involute. During a scheduled outage in June 2013, bump testing of the Non Driven End (NDE) and Driven End (DE) of the end windings were performed. The NDE and DE end windings are shown in Figures 1 and 2, respectively. The bump testing included:

- NDE Global modal analysis
- NDE Driving point measurement of the SERIES BARS
- NDE Driving point measurements of the phase connections
- DE Global modal analysis
- DE Driving point measurement of the SERIES BARS

The purpose of this report is to describe the procedure and equipments used, and present the results obtained.

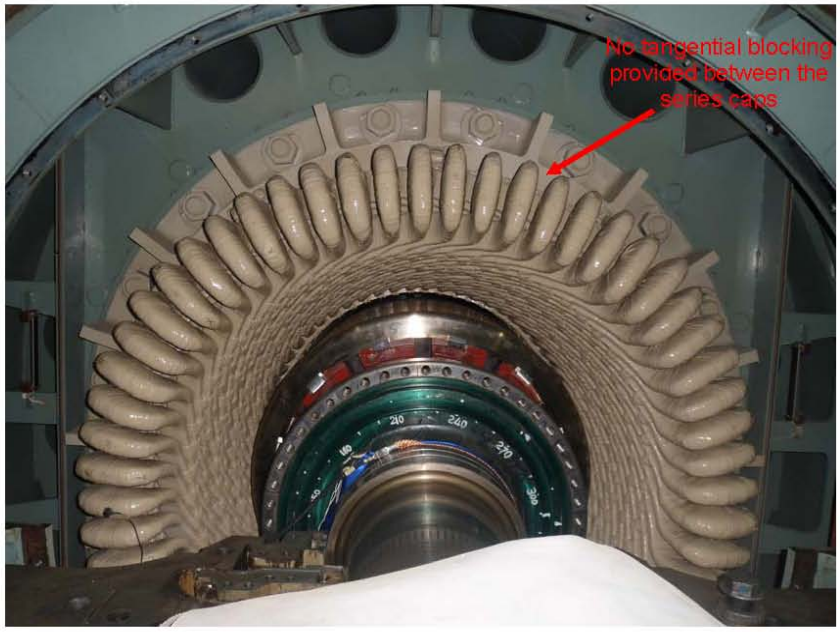
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Field Service Report FSRG020035

Figure 1 View of the NDE end winding



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Field Service Report FSRG020035

Figure 2 View of the DE end winding



2. Setup and Procedures

The measurements were performed according to ALSTOM document number UTGE602042. However, the following exceptions to the requirements in the above procedure were taken:

- For the Global modal analyses of both the NDE and DE sides, only the plane of the end of the bars are chosen since the rotor was installed and the planes at slot exit and middle of the involutes were not accessible. The number of measurement points was 18 for the NDE side and to 20 for the DE side.
- The phase bars were bumped separately from the series bars of the NDE side.
- The phase bars and the corresponding arms were bumped in radial, tangential, and axial directions and response was measured in all three directions. On each phase bar, the vibration responses were measured at two different points, one after the first bend and the second point between after the second bend. Figure 3 shows the locations of the accelerometer on a typical phase bar and its corresponding arm.
- Only accessible DE series bars and the top half of the NDE series bars were bumped in radial directions and their responses were measured in radial, tangential, and axial directions.

Figure 3 Accelerometer locations for the driving point Measurements on a typical phase connection



3. Equipments

The following equipments were used during measurements:

- HP controller #1 with ME Scope software version 5.1.2011.0701
- OROS data acquisition model OR36-8, system #1
- Dytran impact hammer model #582AT, S/N: 1951
- Dytran Tri-axial accelerometer model #3093BIT, S/N: 2510
- ME Scope analysis software version 6.0.2013.0531

4. NDE Measurements

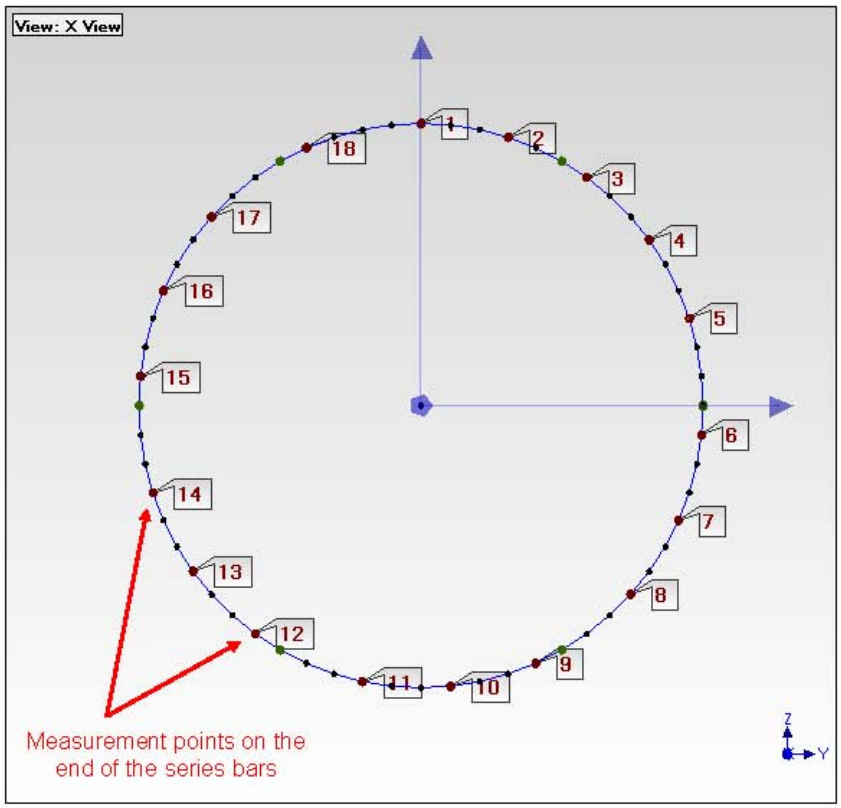
NDE Global Modal Analysis

The global modal analysis of the NDE end winding was performed by impacting at the plane of the end of the bars at 10:30 o'clock (see Figure 4) and measuring the vibrations of the bars in the same plane. The plane of the end of the bars was the only plane available since the rotor was installed and the planes at slot exit and the plane of the middle of the involutes were not accessible. The total number of measurement points was 18. The circumferential location of the measurement points are shown in Figure 5.

Figure 4 Impacting point for the NDE global modal analysis



Figure 5 Circumferential locations of the NDE end windings



Figures 6-1 shows a well-established elliptical mode shape at frequency of 60 Hz. Figure 6-2 shows a 3-Lobe triangular mode shape at 84 Hz, while Figure 6-3 shows a 4-Lobe mode shape at the frequency of 98 Hz. The rotating field will not excite any of the above mode shapes.

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Figure 6-1 NDE mode shape at 60 Hz

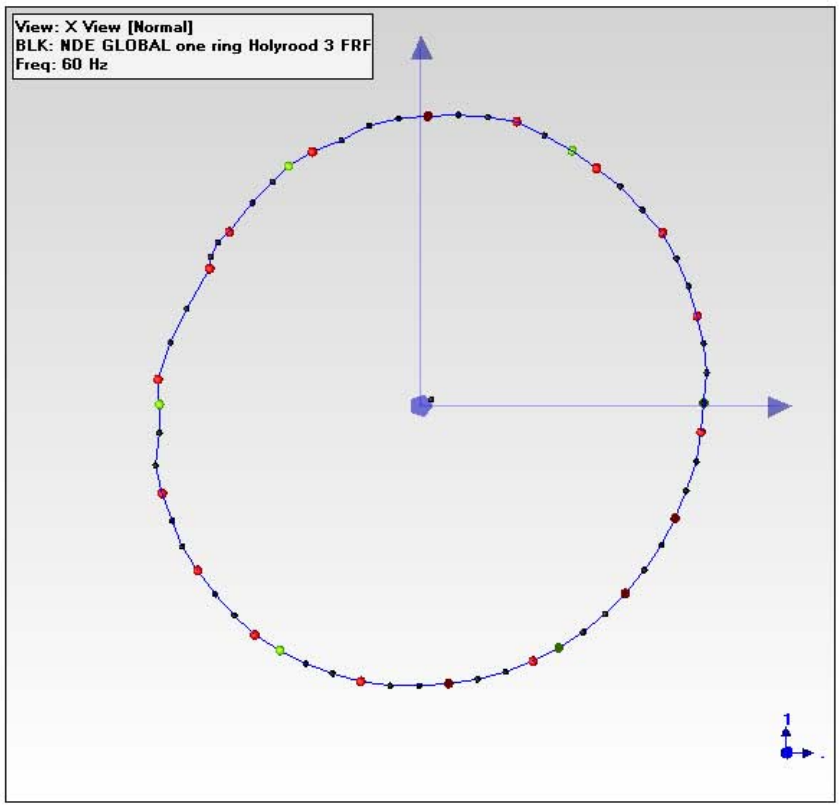


Figure 6-2 NDE mode shape at 84 Hz

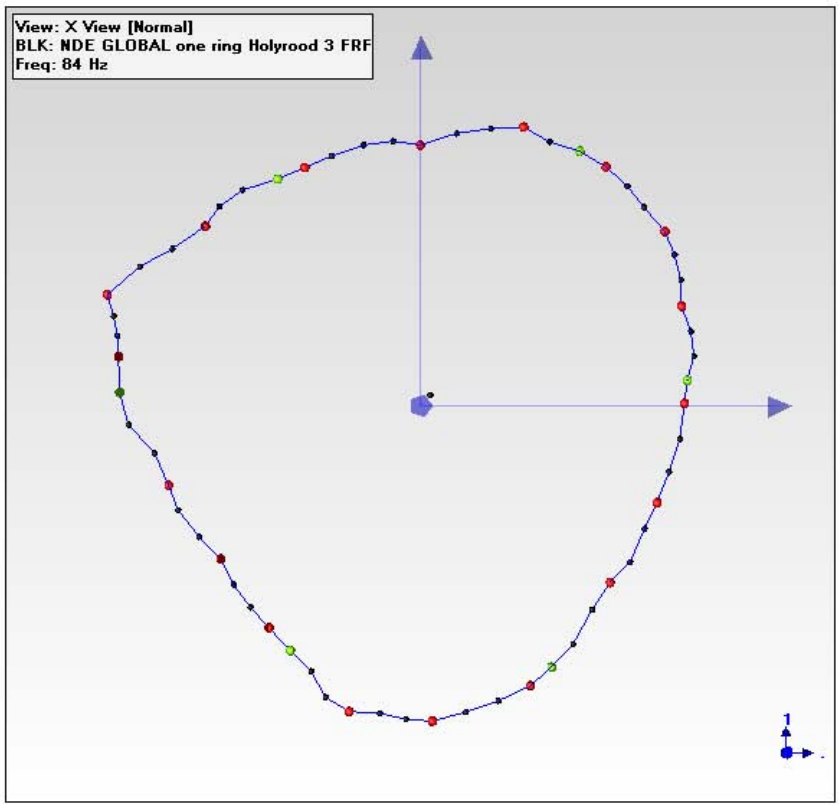
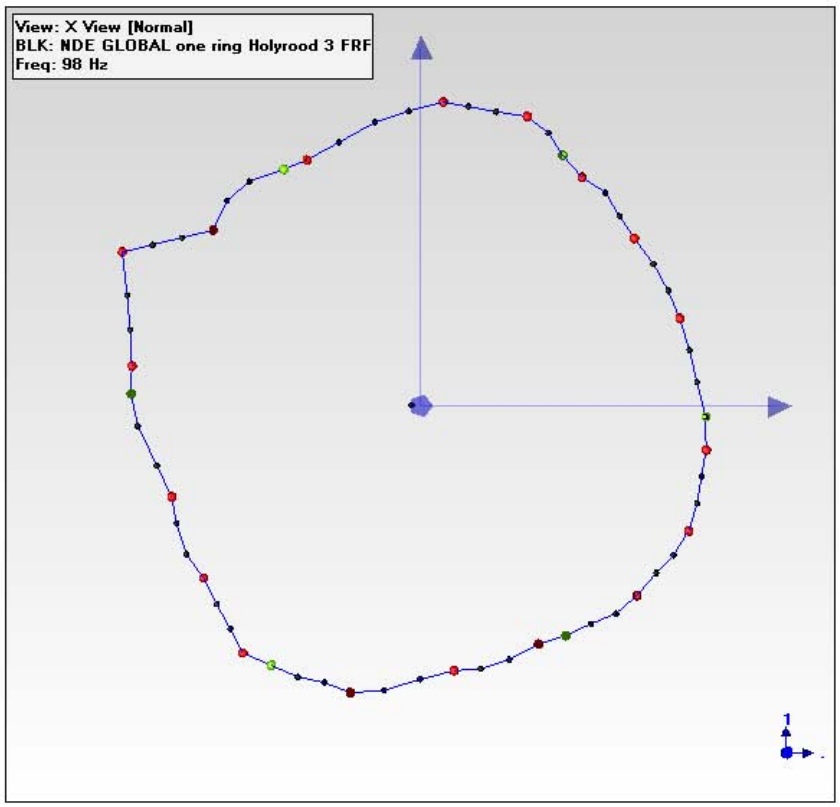


Figure 6-3 NDE mode shape at 98 Hz



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NDE Driving Point Measurements of Series Bars

The driving point measurements of the series bars were performed by impacting the end of each bar and measuring the vibrations on the face of the corresponding bar. The bars are impacted in the radial direction while measuring the vibrations in the radial, tangential, and axial directions. The circumferential locations of the series bars are shown in Figure 7. Since the rotor was in place, the bottom half of the series bars were not accessible, and only the top half (number 1 through number 27) were impacted. The results are plotted in Figures 8-1 through 8-9. The results in these Figures are plotted from 20 Hz to 200 Hz in the horizontal axis, and from 1E-9 m/N (1 nm/N) to 1E-5 m/N (10000 nm/N) in the vertical axis. As shown in these figures, the magnitudes of vibrations at 120 Hz for the tested bars are more than 500 nm/N with the largest magnitude approximately equals to 5000 nm/N, and therefore exceed ALSTOM acceptance criterion.

Figure 7 Locations of the NDE series bars around the circumference

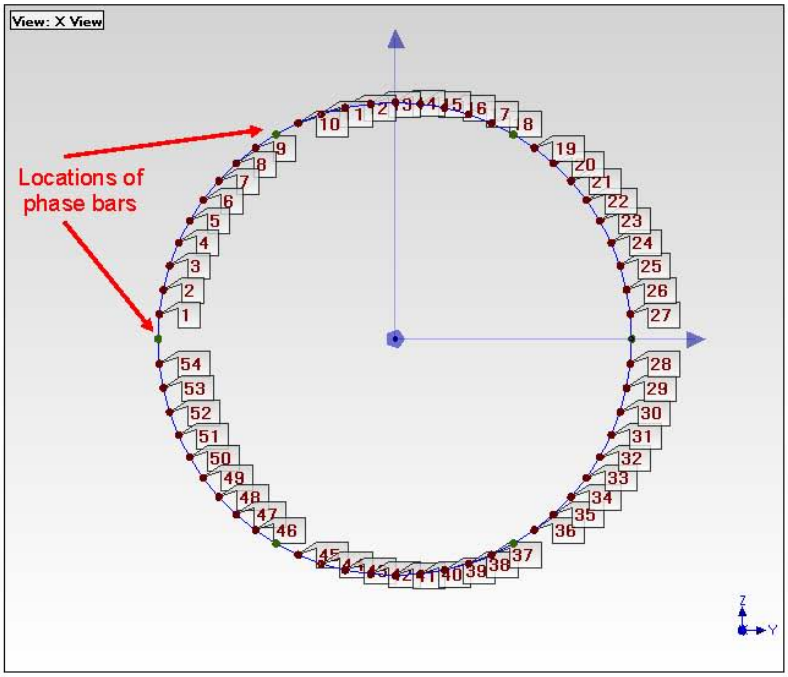
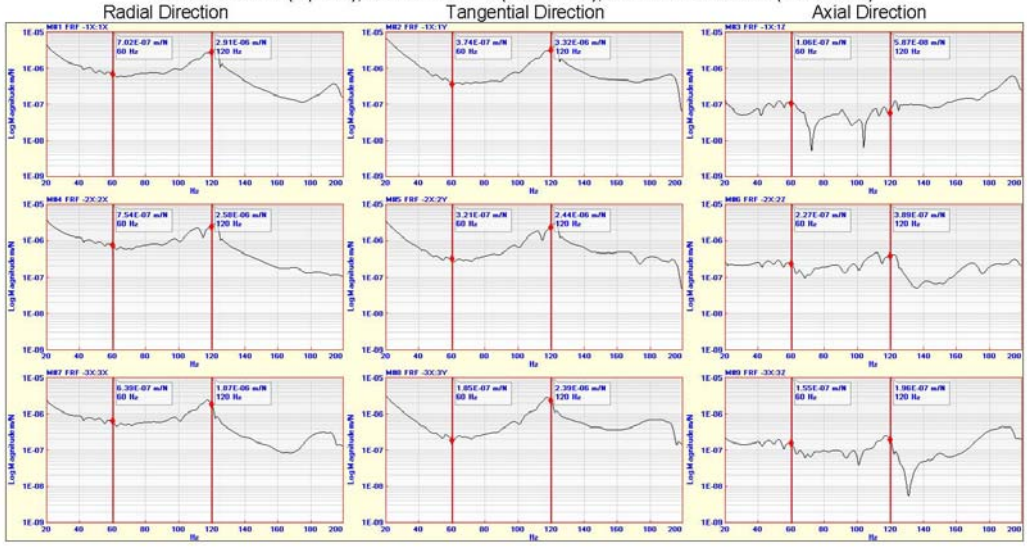


Figure 8-1 Driving point measurements of NDE SERIES BARS
Bar numbered 1 (top row), Bar numbered 2 (middle row), and Bar numbered 3 (bottom row)
Radial Direction Tangential Direction Axial Direction

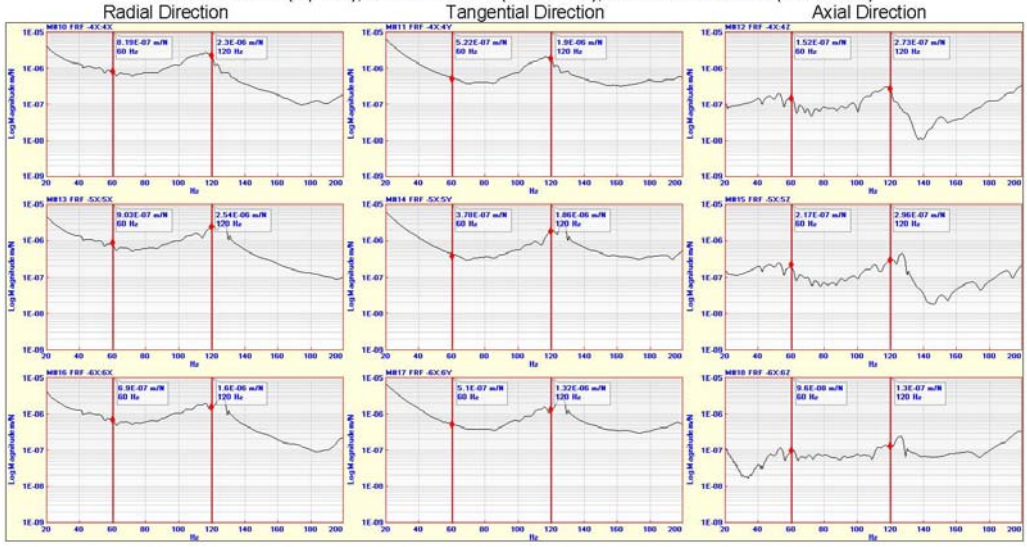


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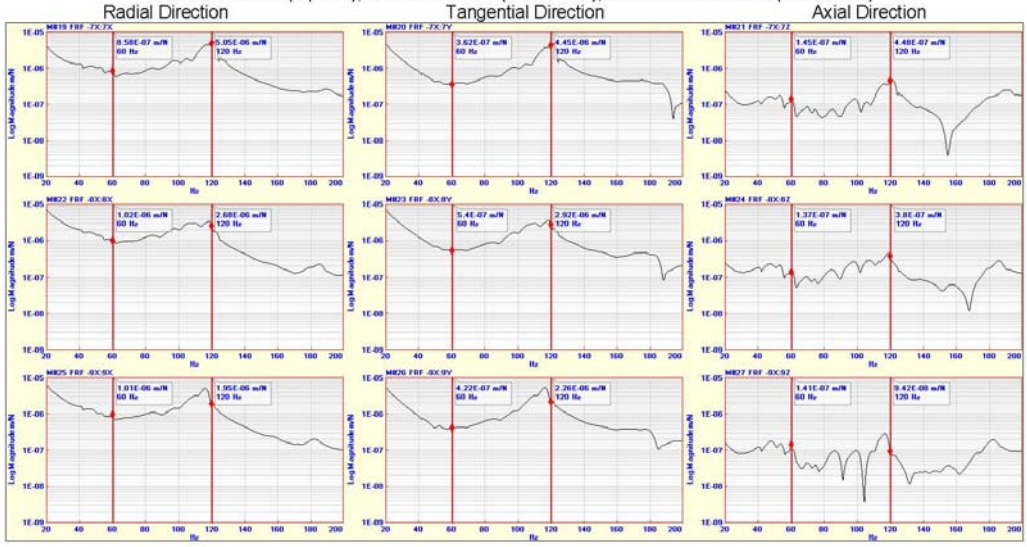
Figure 8-2 Driving point measurements of NDE SERIES BARS
Bar numbered 4 (top row), Bar numbered 5 (middle row), and Bar numbered 6 (bottom row)

Radial Direction | Tangential Direction | Axial Direction



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Figure 8-3 Driving point measurements of NDE SERIES BARS
Bar numbered 7 (top row), Bar numbered 8 (middle row), and Bar numbered 9 (bottom row)

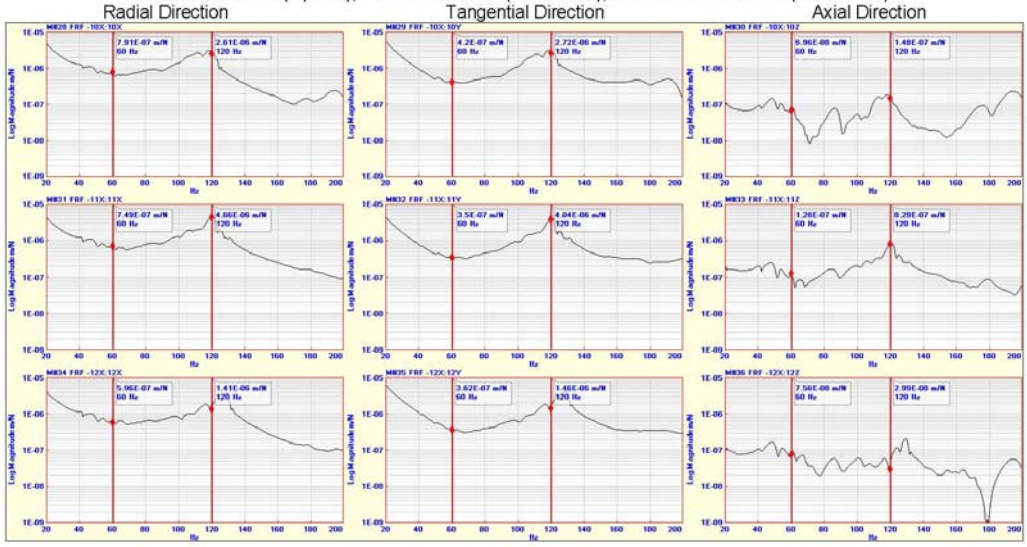


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Figure 8-4 Driving point measurements of NDE SERIES BARS
Bar numbered 10 (top row), Bar numbered 11 (middle row), and Bar numbered 12 (bottom row)

Radial Direction | Tangential Direction | Axial Direction



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Figure 8-5 Driving point measurements of NDE SERIES BARS
Bar numbered 13 (top row), Bar numbered 14 (middle row), and Bar numbered 15 (bottom row)
Radial Direction Tangential Direction Axial Direction

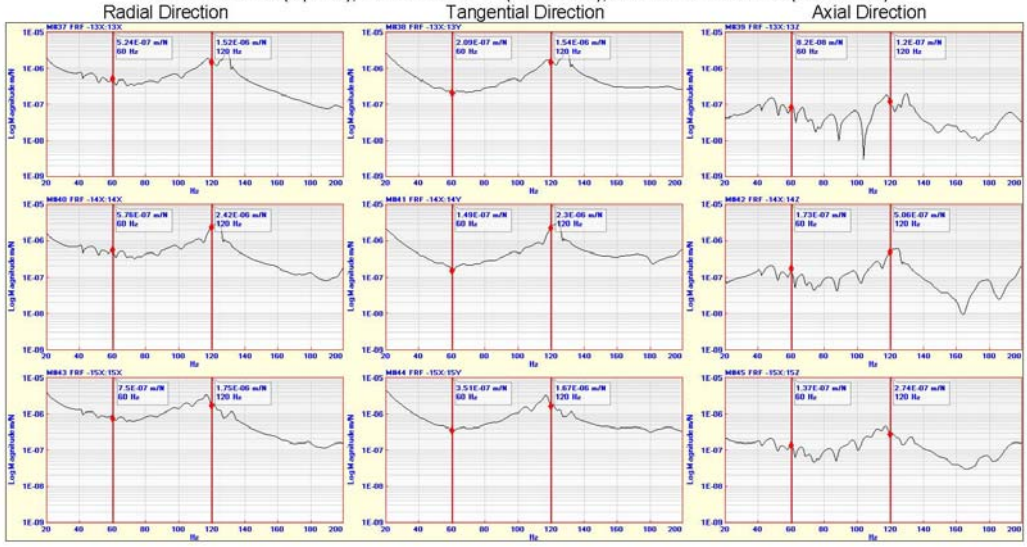


Figure 8-6 Driving point measurements of NDE SERIES BARS
Bar numbered 16 (top row), Bar numbered 17 (middle row), and Bar numbered 18 (bottom row)

Radial Direction | Tangential Direction | Axial Direction

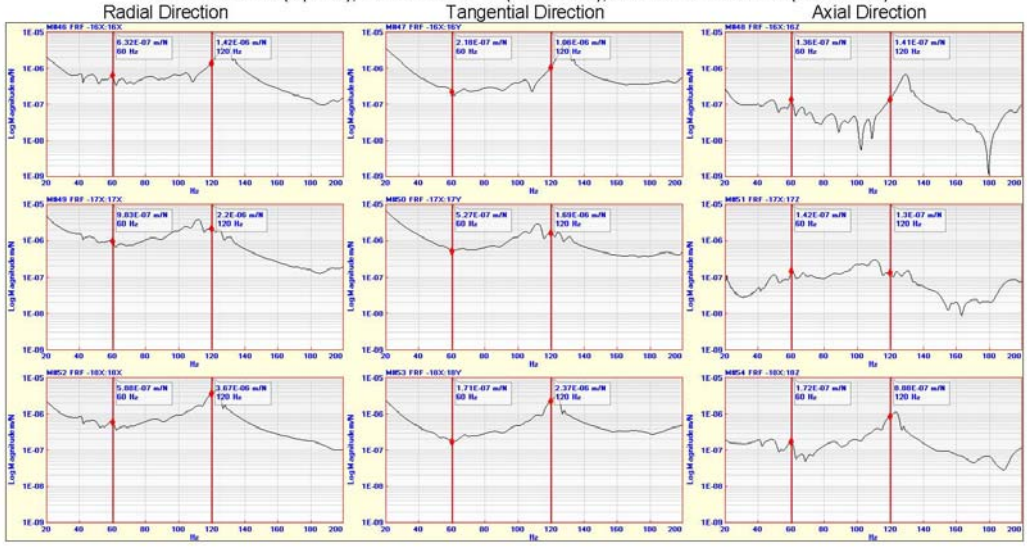
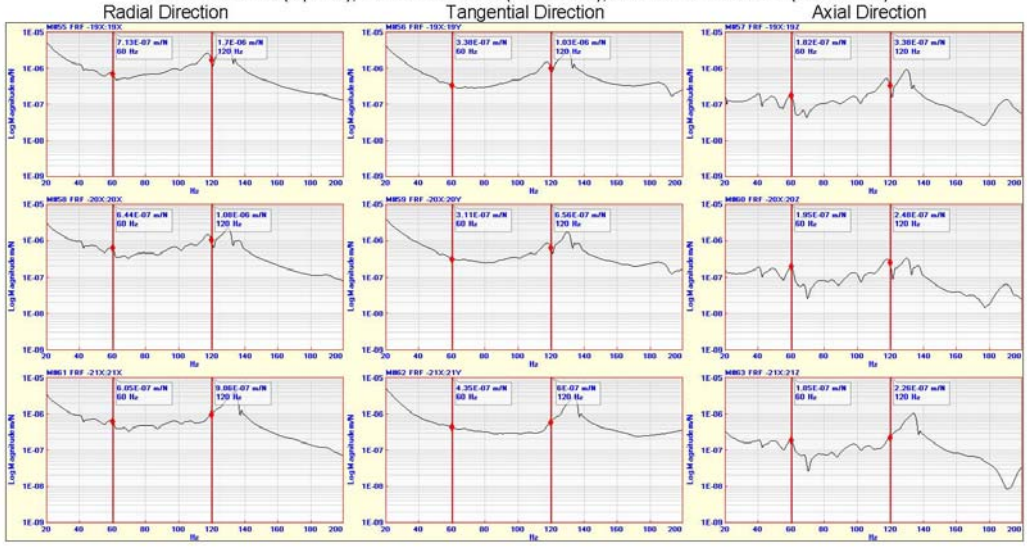


Figure 8-7 Driving point measurements of NDE SERIES BARS
Bar numbered 19 (top row), Bar numbered 20 (middle row), and Bar numbered 21 (bottom row)

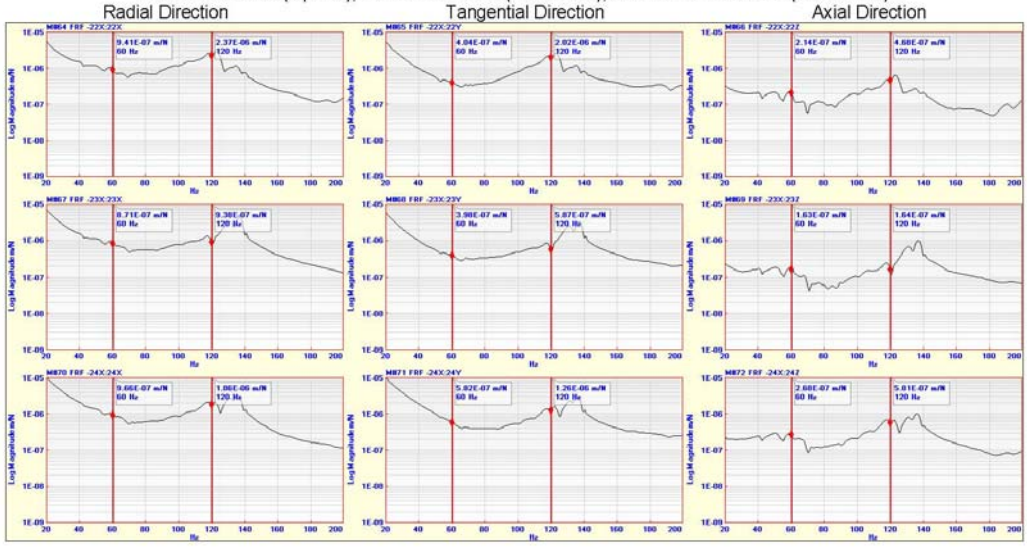


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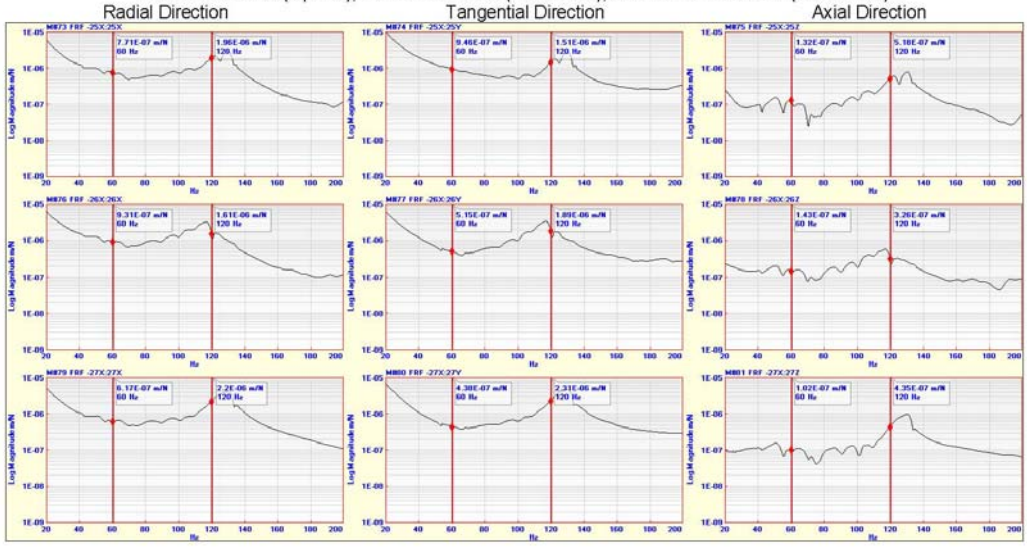
Figure 8-8 Driving point measurements of NDE SERIES BARS
Bar numbered 22 (top row), Bar numbered 23 (middle row), and Bar numbered 24 (bottom row)

Radial Direction | Tangential Direction | Axial Direction



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Figure 8-9 Driving point measurements of NDE SERIES BARS
Bar numbered 25 (top row), Bar numbered 26 (middle row), and Bar numbered 27 (bottom row)

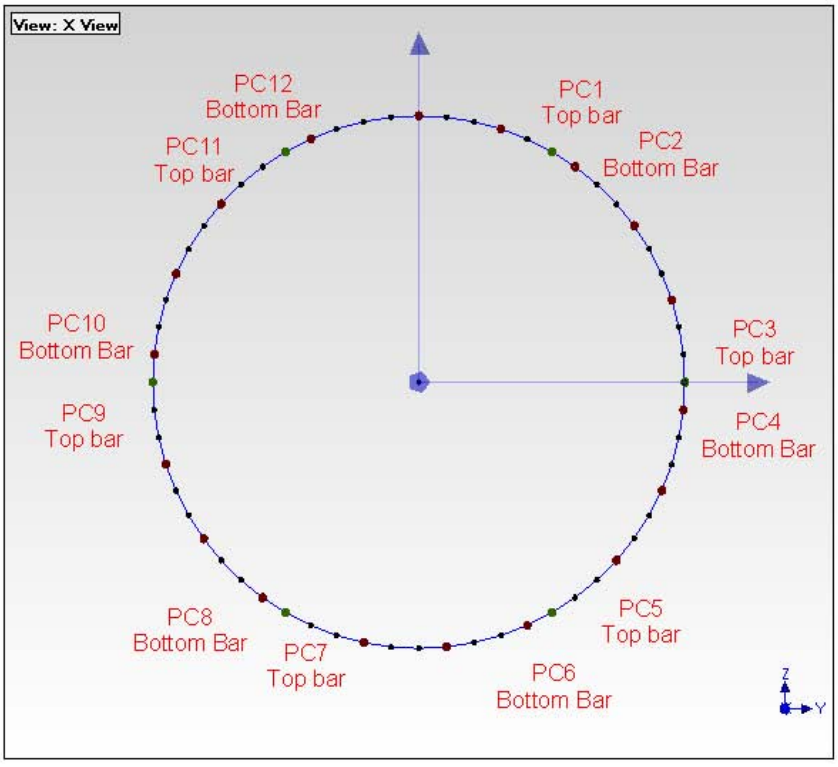


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NDE Driving Point Measurements of Phase Connection

The driving point measurements of the phase connections (PC) were performed by impacting at the vicinity of each measurement point on the connection in radial, tangential, and axial directions and measuring the vibrations at point A, and at point B on the arm of the phase connection after the first bend. The numbering of each phase connection and the measuring points are shown in Figure 9-1, and the locations of the accelerometer on a typical phase connection cap and arm are shown in Figure 9-2. Since the shaft was in place, the measurements for the PC6 and PC7 were not possible. The results are plotted in Figures 10-1 through 10-12. As shown in these figures, for most of the connectors, the magnitudes of vibrations are less than 500 nm/N. But, for the several connectors such as PC1, PC3, PC5, and PC8, the magnitude of vibrations are more than the 500 nm/N (for at least one of the directions) with the largest magnitude equals to 800 nm/N, and therefore exceed ALSTOM acceptance criterion.

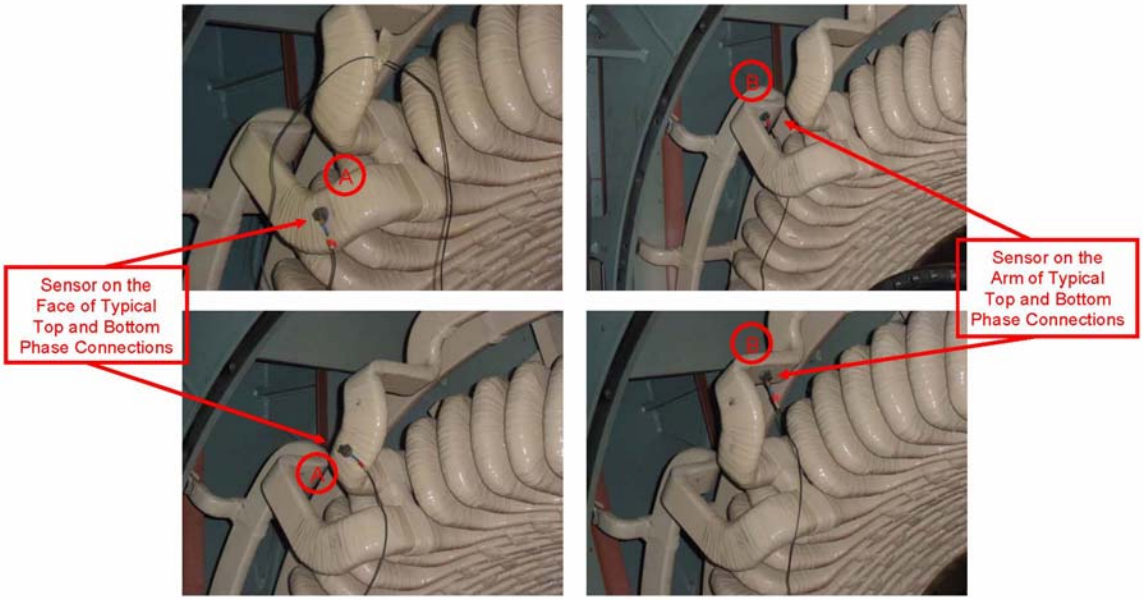
Figure 9-1 Numbering of each phase connection



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Figure 9-2 Accelerometer locations on typical phase connection (point A) and corresponding Arm (point B)

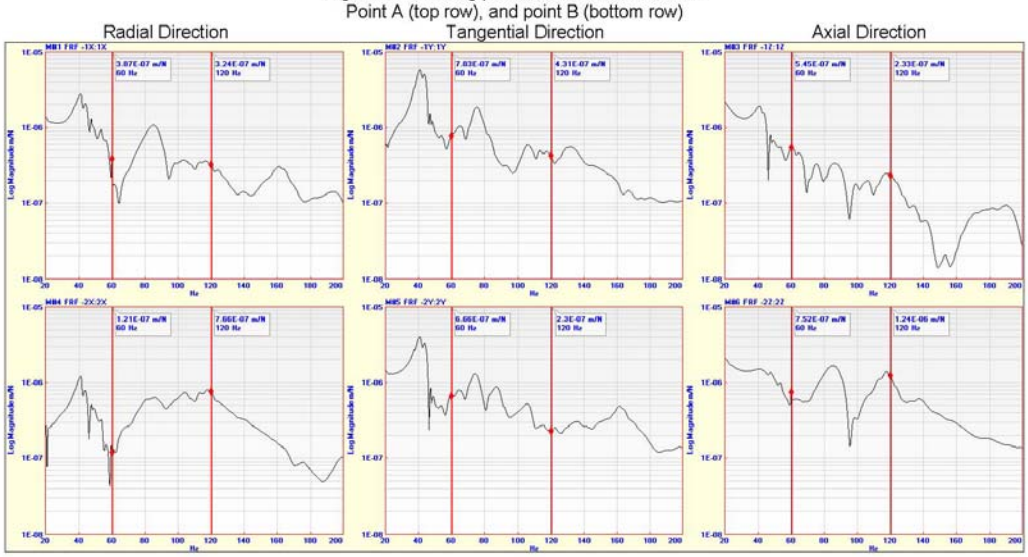


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Figure 10-1 Driving point measurements of PC1
Point A (top row), and point B (bottom row)

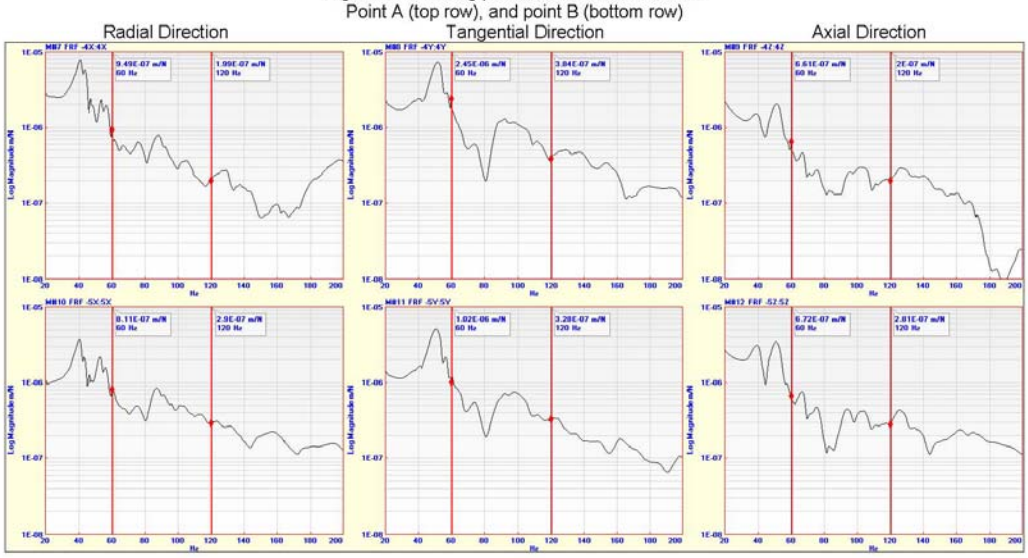


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Figure 10-2 Driving point measurements of PC2
Point A (top row), and point B (bottom row)



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Figure 10-3 Driving point measurements of PC3
Point A (top row), and point B (bottom row)

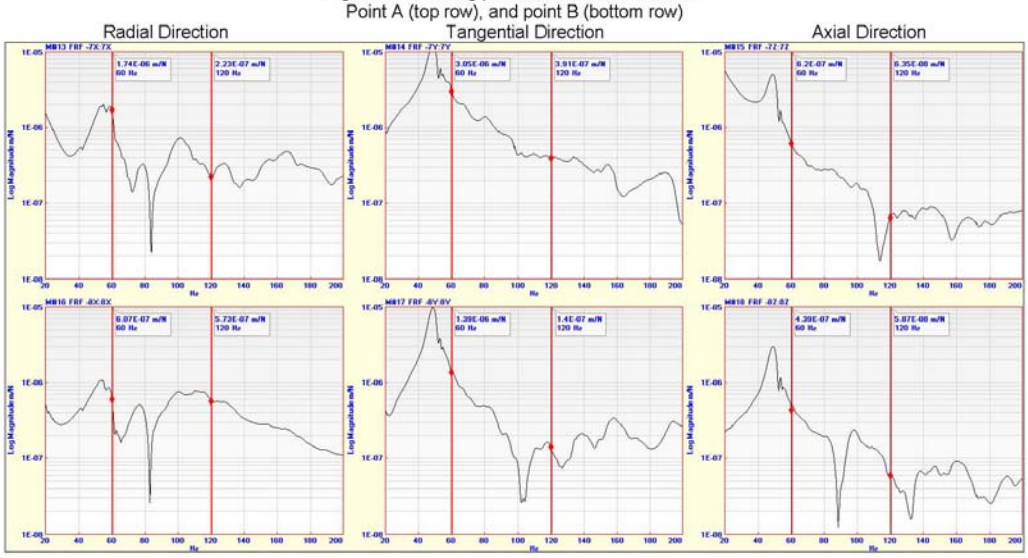


Figure 10-4 Driving point measurements of PC4
Point A (top row), and point B (bottom row)

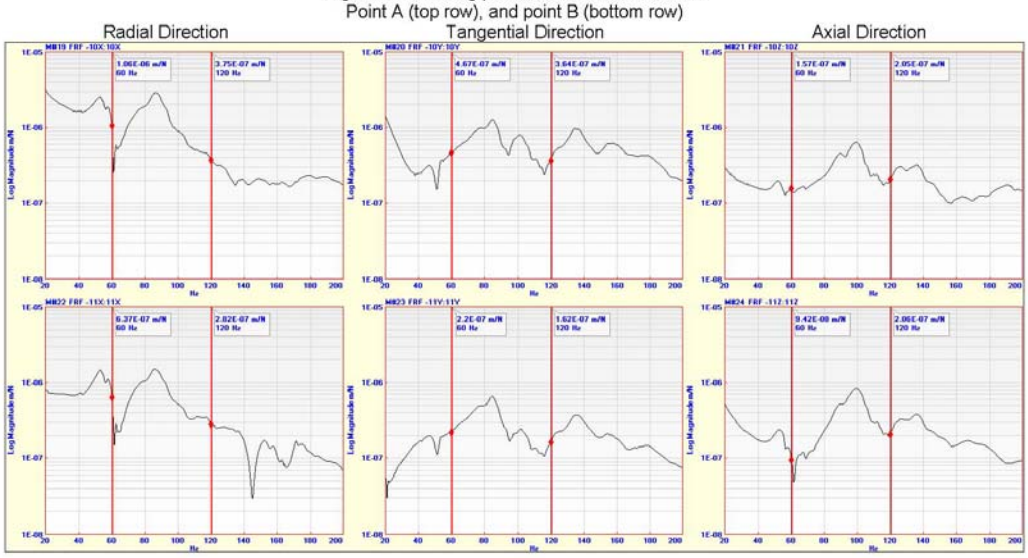


Figure 10-5 Driving point measurements of PC5
Point A (top row), and point B (bottom row)

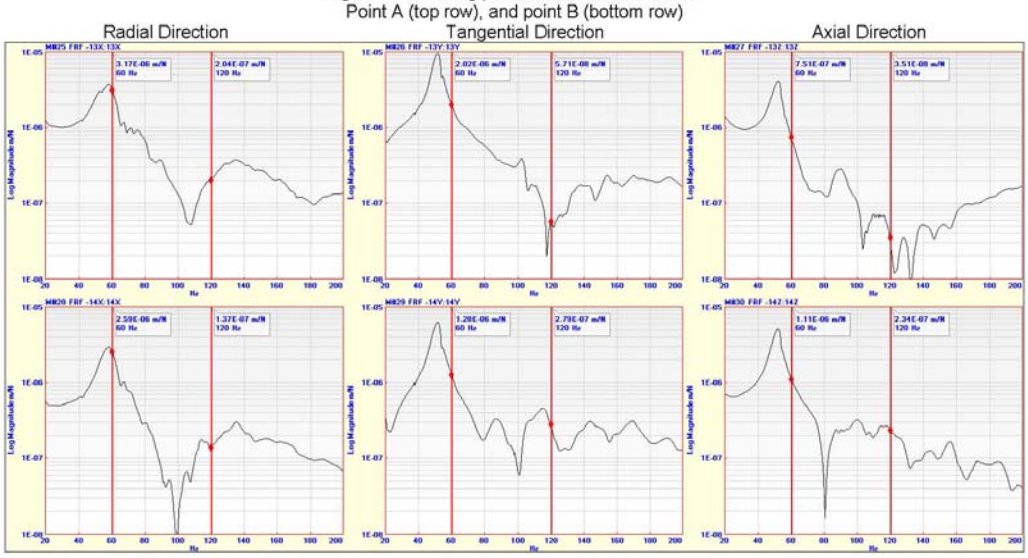


Figure 10-6 Driving point measurements of PC6
Point A (top row), and point B (bottom row)

Radial Direction | Tangential Direction | Axial Direction

NOT ACCESSIBLE

Figure 10-7 Driving point measurements of PC7
Point A (top row), and point B (bottom row)

Radial Direction | Tangential Direction | Axial Direction

NOT ACCESSIBLE

Figure 10-8 Driving point measurements of PC8
Point A (top row), and point B (bottom row)

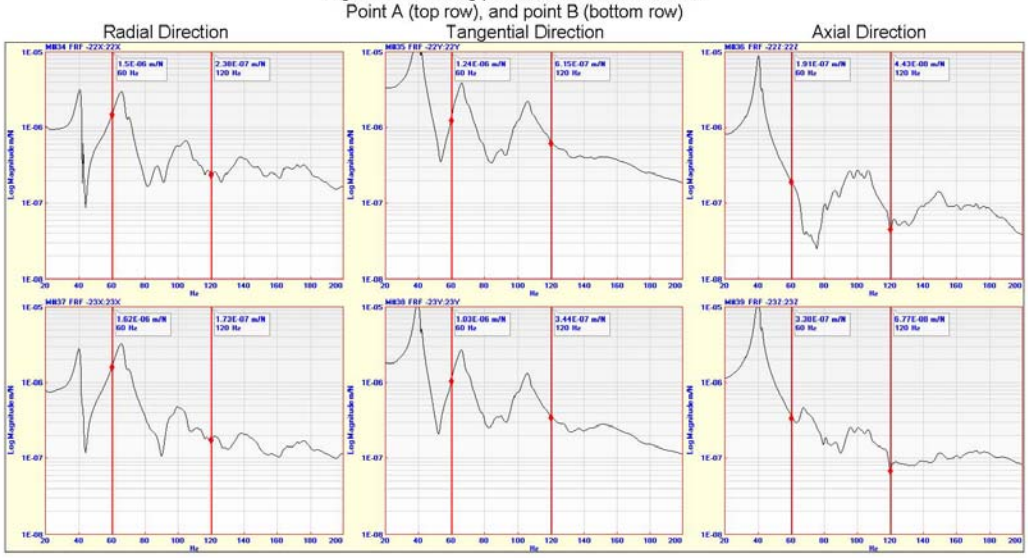


Figure 10-9 Driving point measurements of PC9
Point A (top row), and point B (bottom row)

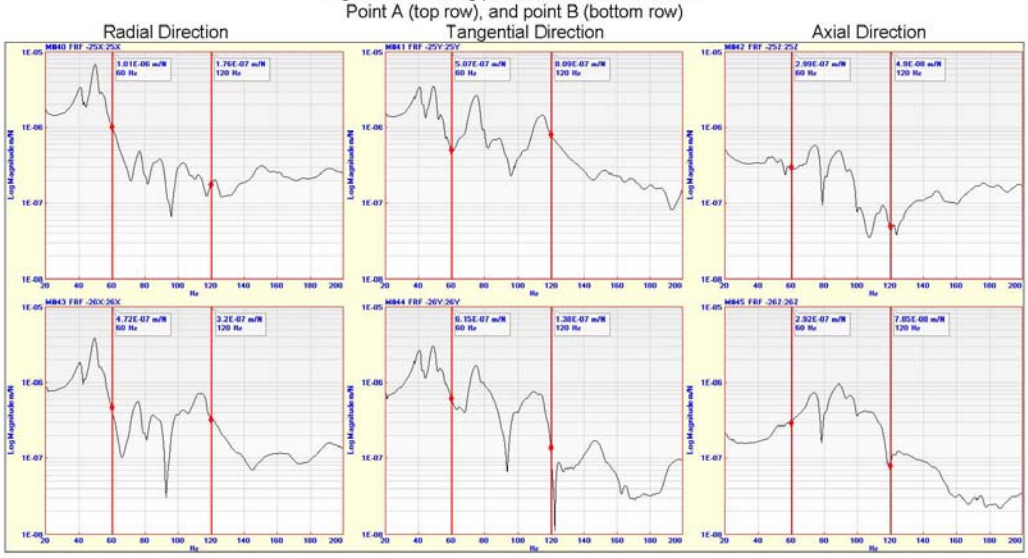


Figure 10-10 Driving point measurements of PC10
Point A (top row), and point B (bottom row)

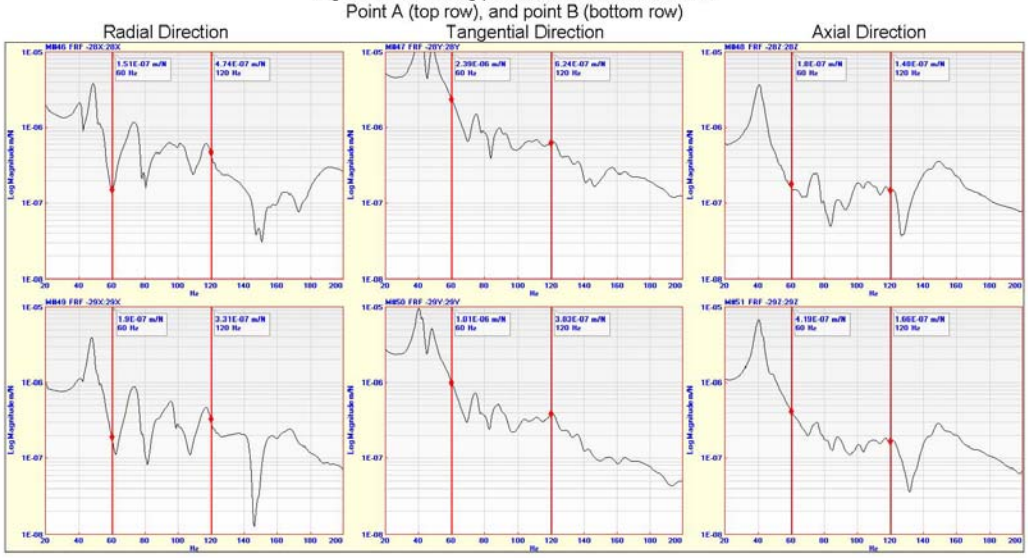


Figure 10-11 Driving point measurements of PC11
Point A (top row), and point B (bottom row)

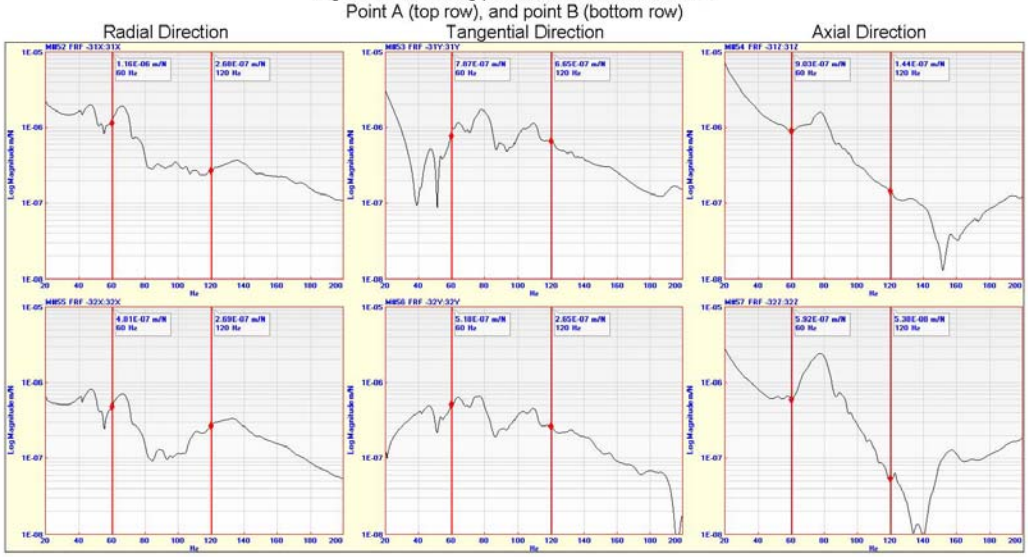
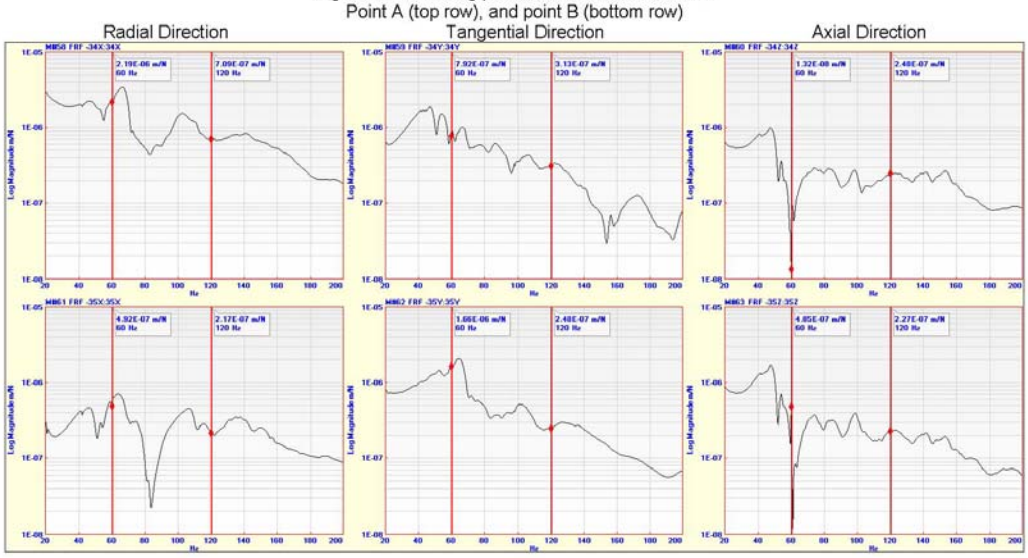


Figure 10-12 Driving point measurements of PC12
Point A (top row), and point B (bottom row)



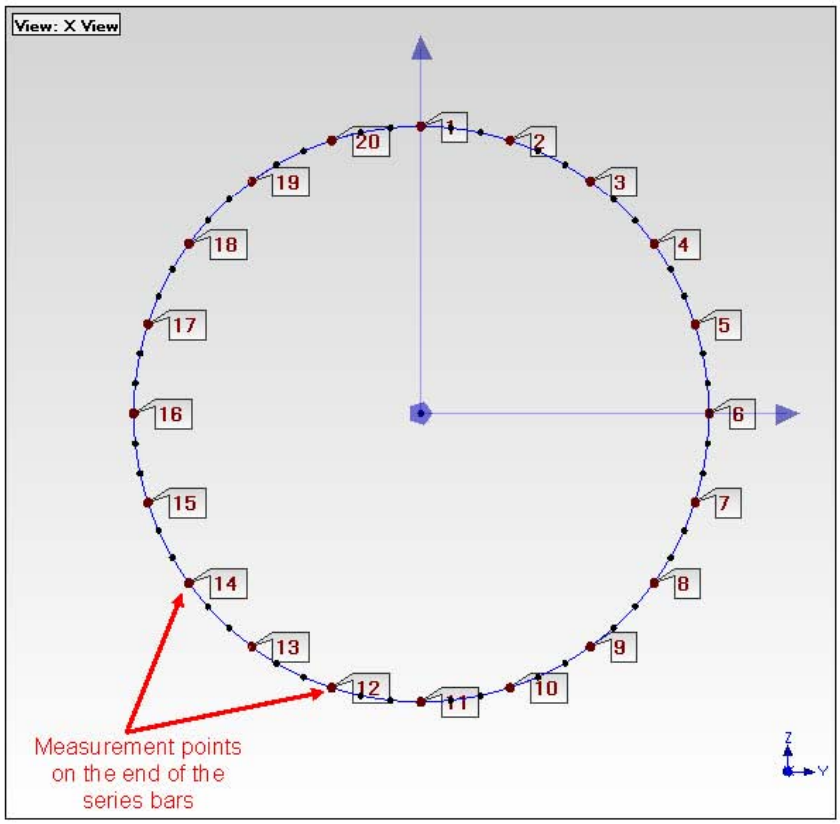
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5. DE Measurements

DE Global Modal Analysis

The global modal analysis of the DE end winding was performed by impacting at end of the bar at 10:30 o'clock and measuring the vibrations at the end of the bars. As shown in Figure 11 the vibrations at the slot exit, at the midsection of the involutes, and on the SERIES BARS are measured on every third bar for a total of 66 measurement points. The vibrations of the bracket were measured on six out of twelve brackets.

Figure 11 Measurement locations of the DE global modal analysis



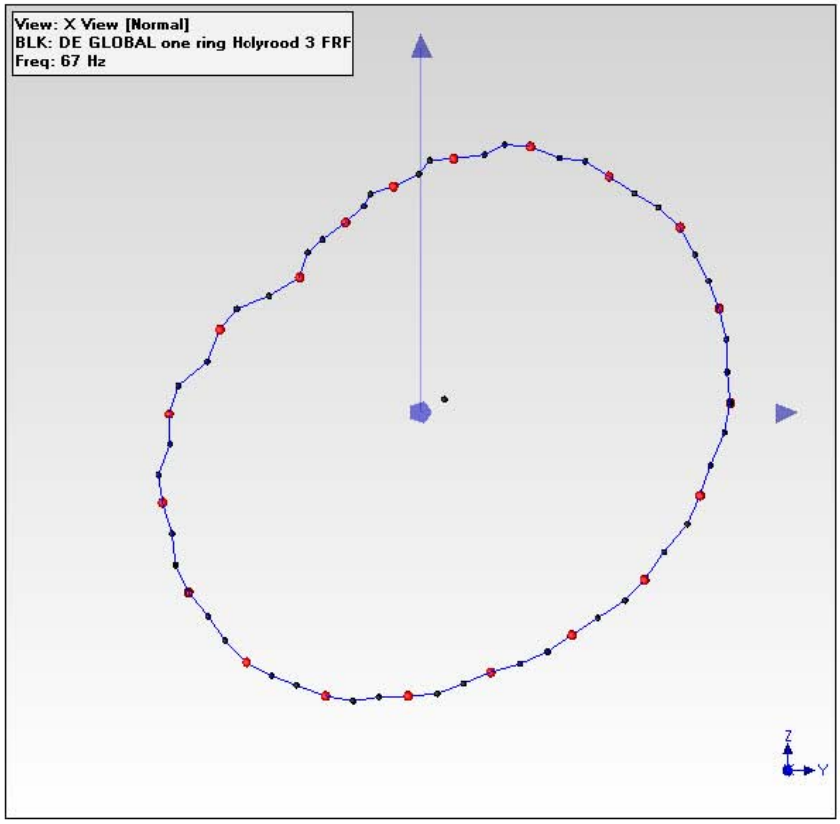
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Figures 12-1 and 12-2 show a well-established elliptical mode shape at the frequencies of 67 Hz, and 70.5 Hz, respectively. The frequencies of these mode shapes are well below the critical range of 115 Hz to 135 Hz.

The mode shapes shown in Figures 12-3 and 12-4 are 6-node, 3-Lobe mode shape, which the end winding retains a triangular shape. The natural frequencies for these mode shapes occur at 78 Hz and 87 Hz. Figure 12-5 shows an 8-node, 4-Lobe mode shape at the frequency of 98.5 Hz. The rotating field cannot excite these mode shapes.

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Figure 12-1 DE Mode Shape at 67 Hz



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Figure 12-2 DE Mode Shape at 70.5 Hz

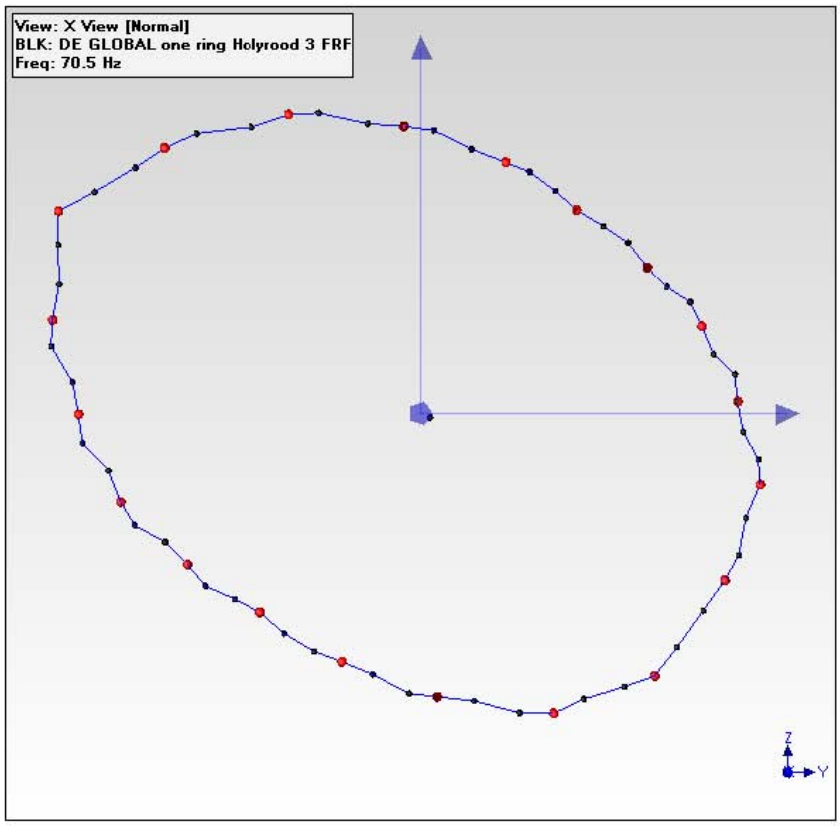


Figure 12-3 DE Mode Shape at 78 Hz

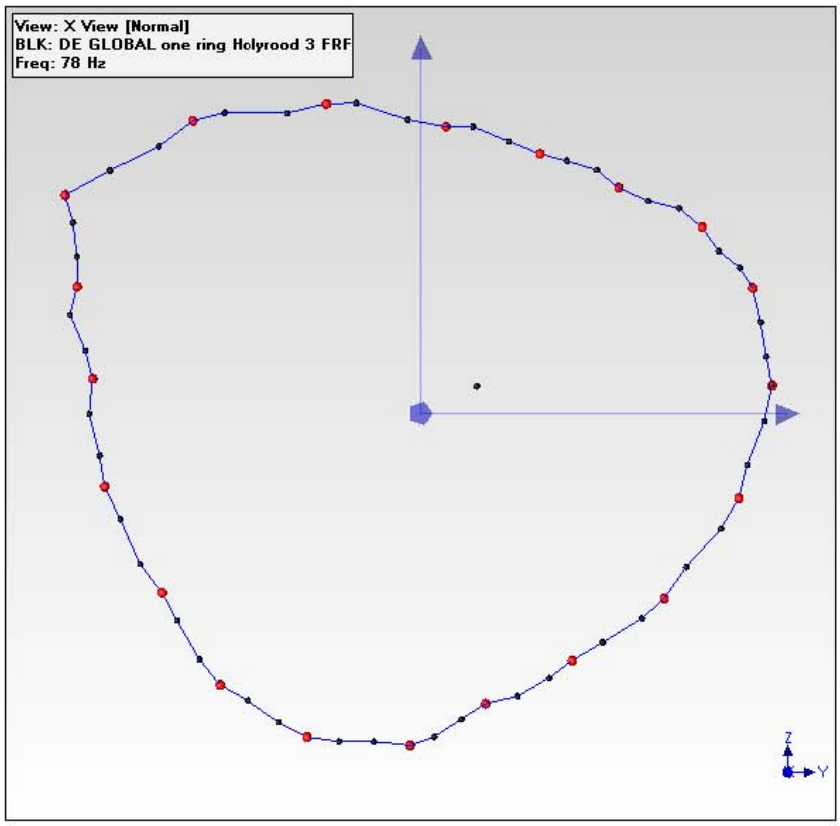


Figure 12-4 DE Mode Shape at 87 Hz

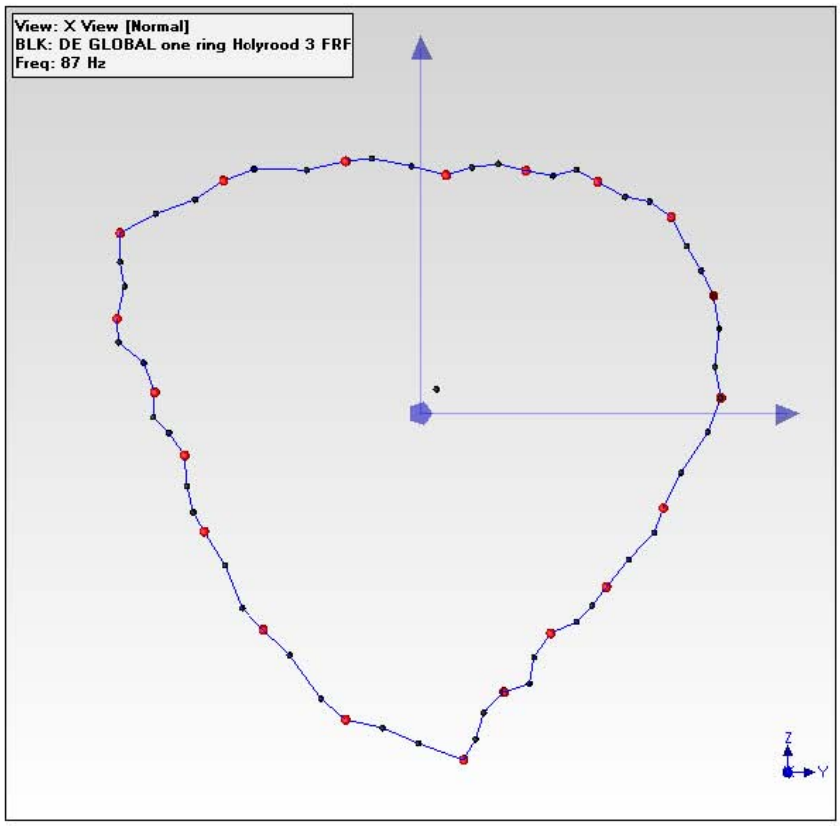
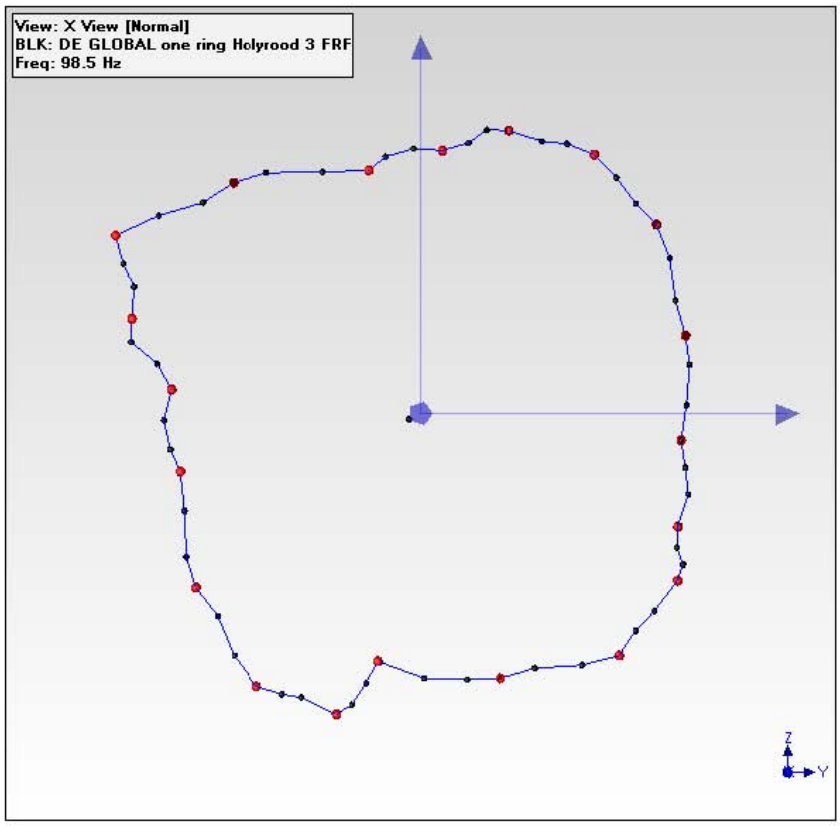


Figure 12-5 DE Mode Shape at 98.5 Hz

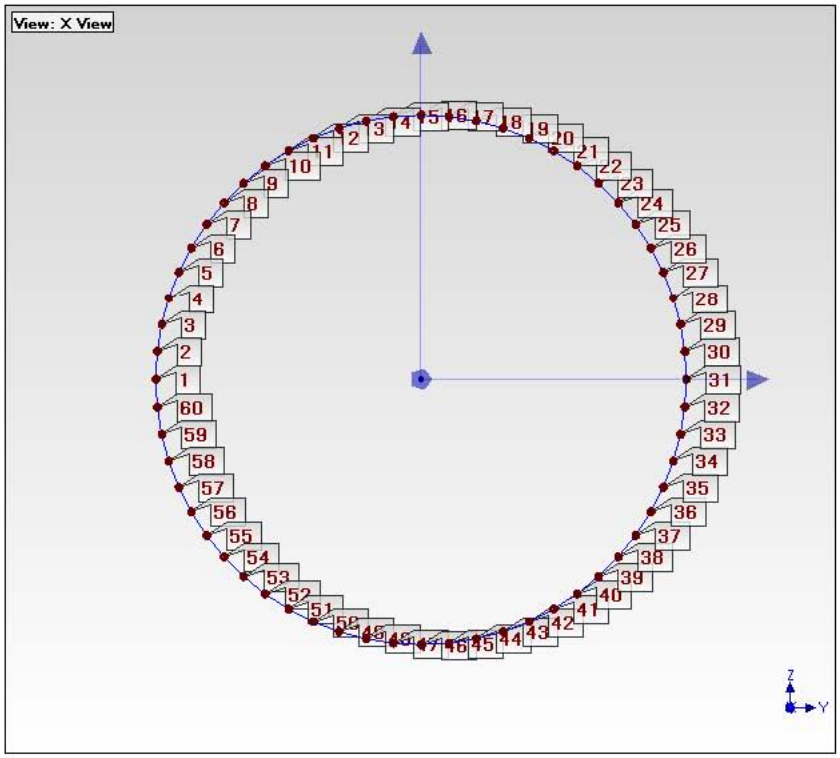


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DE Driving Point Measurements of the Series Bars

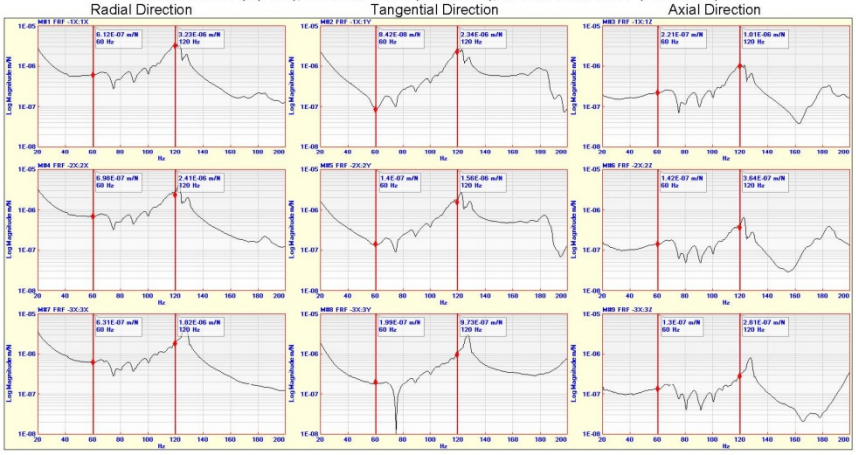
The driving point measurements of the series bars were performed by impacting each end of the bar in radial direction and measuring the vibrations on the end of the corresponding bar in radial, tangential, and axial directions. The circumferential locations of the series bars are shown in Figure 13. The results are plotted in Figures 14-1 through 14-20. Since the rotor was in place, the bars numbered 40 through 51 were not accessible. As shown in these figures, the magnitudes of vibrations are relatively high at 120 Hz with the largest magnitude equal to 6500 nm/N, and exceed the ALSTOM acceptance criterion of 500 nm/N.

Figure 13 Locations of the DE caps around the circumference



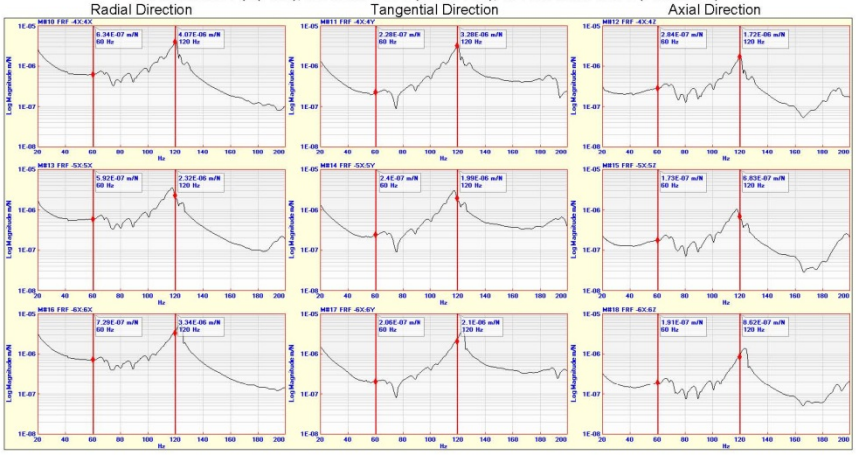
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Figure 14-1 Driving point measurements of DE SERIES BARS
Bar numbered 1 (top row), Bar numbered 2 (middle row), and Bar numbered 3 (bottom row)
Radial Direction Tangential Direction Axial Direction



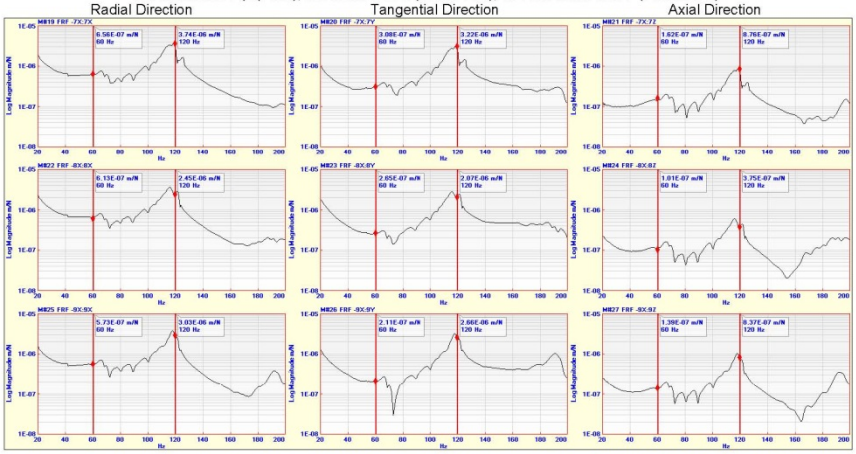
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Figure 14-2 Driving point measurements of DE SERIES BARS
Bar numbered 4 (top row), Bar numbered 5 (middle row), and Bar numbered 6 (bottom row)
Radial Direction Tangential Direction Axial Direction



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Figure 14-3 Driving point measurements of DE SERIES BARS
Bar numbered 7 (top row), Bar numbered 8 (middle row), and Bar numbered 9 (bottom row)
Radial Direction Tangential Direction Axial Direction



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Figure 14-4 Driving point measurements of DE SERIES BARS
Bar numbered 10 (top row), Bar numbered 11 (middle row), and Bar numbered 12 (bottom row)
Radial Direction Tangential Direction Axial Direction

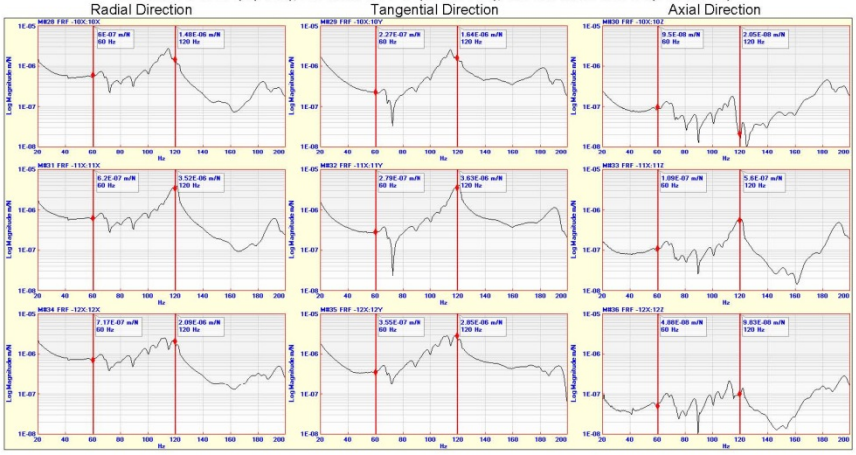


Figure 14-5 Driving point measurements of DE SERIES BARS
Bar numbered 13 (top row), Bar numbered 14 (middle row), and Bar numbered 15 (bottom row)
Radial Direction Tangential Direction Axial Direction

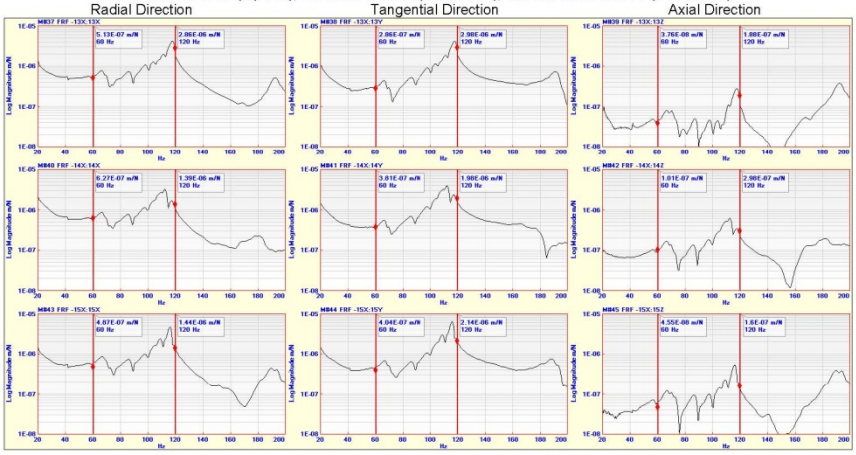


Figure 14-6 Driving point measurements of DE SERIES BARS
Bar numbered 16 (top row), Bar numbered 17 (middle row), and Bar numbered 18 (bottom row)
Radial Direction Tangential Direction Axial Direction

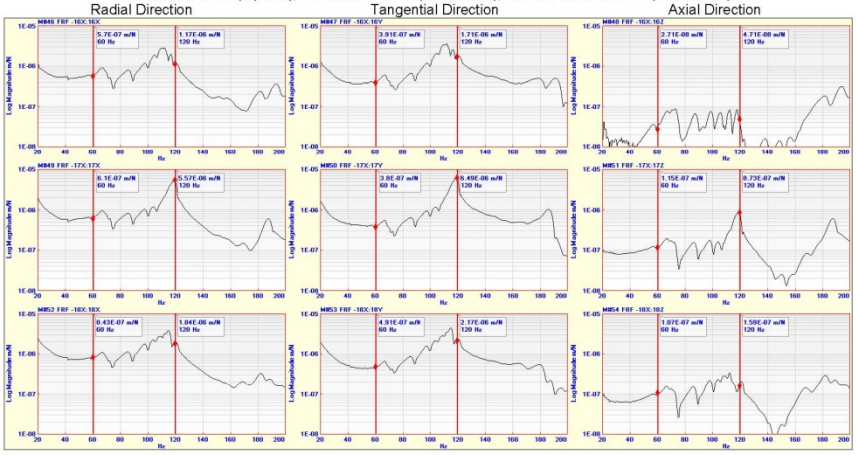


Figure 14-7 Driving point measurements of DE SERIES BARS
Bar numbered 19 (top row), Bar numbered 20 (middle row), and Bar numbered 21 (bottom row)
Radial Direction Tangential Direction Axial Direction

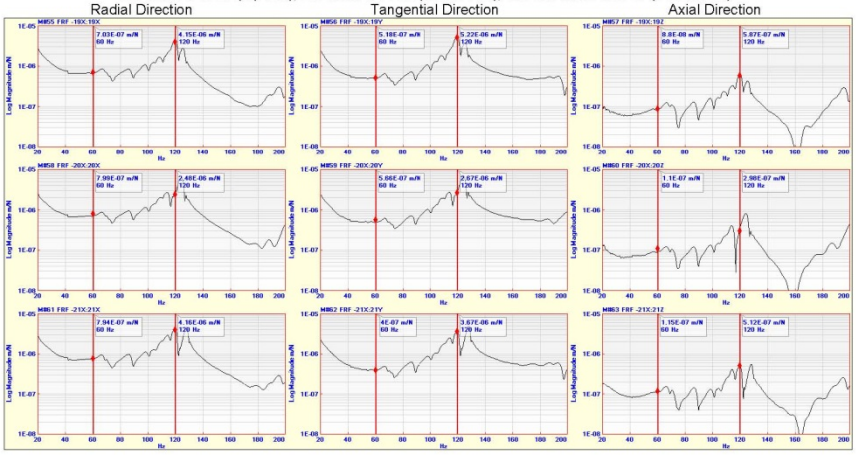
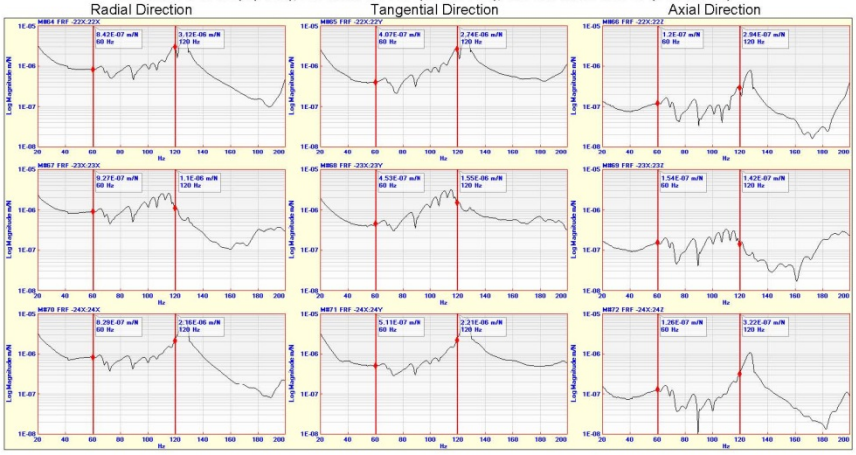
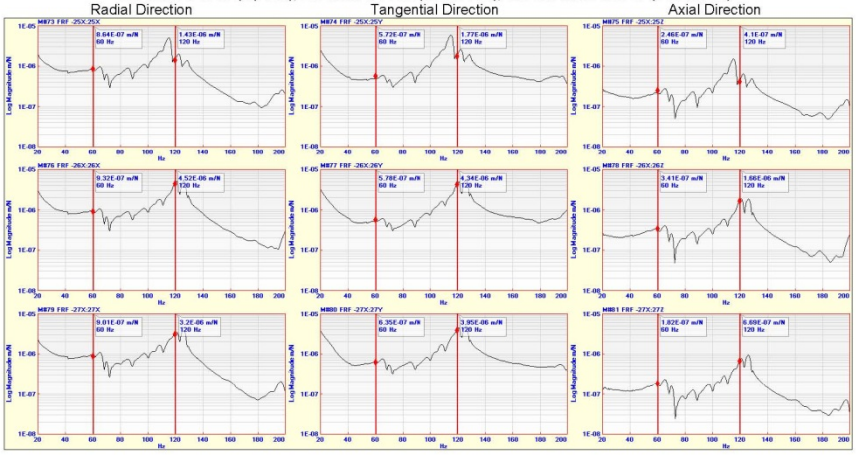


Figure 14-8 Driving point measurements of DE SERIES BARS
Bar numbered 22 (top row), Bar numbered 23 (middle row), and Bar numbered 24 (bottom row)
Radial Direction Tangential Direction Axial Direction



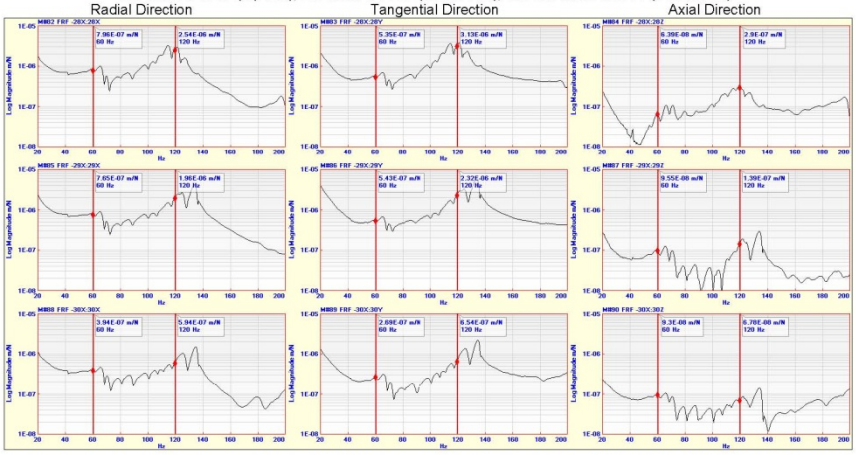
ALSTOM
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Figure 14-9 Driving point measurements of DE SERIES BARS
Bar numbered 25 (top row), Bar numbered 26 (middle row), and Bar numbered 27 (bottom row)
Radial Direction Tangential Direction Axial Direction



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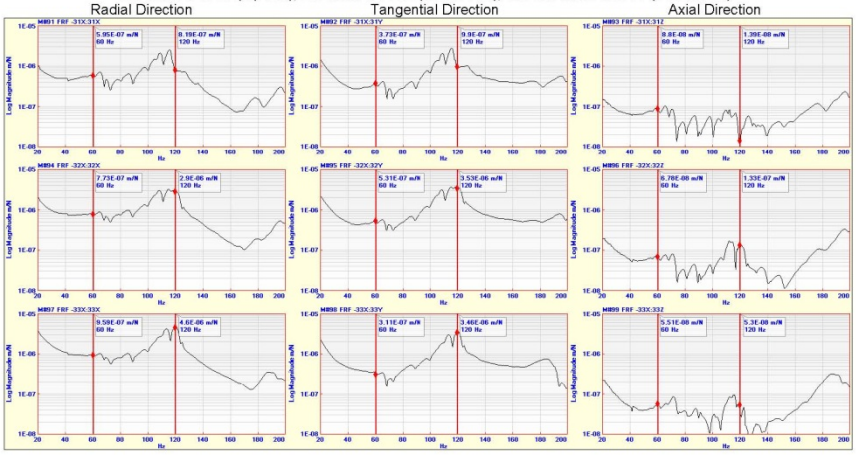
Figure 14-10 Driving point measurements of DE SERIES BARS
Bar numbered 28 (top row), Bar numbered 29 (middle row), and Bar numbered 30 (bottom row)
Radial Direction Tangential Direction Axial Direction



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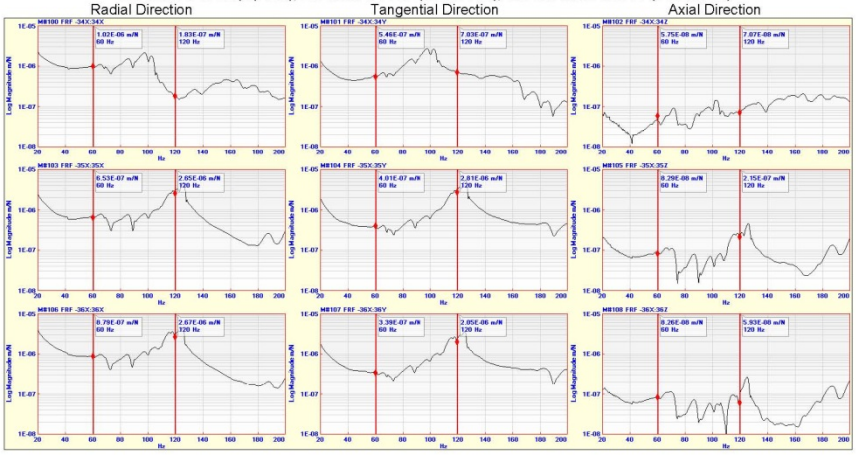
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Figure 14-11 Driving point measurements of DE SERIES BARS
Bar numbered 31 (top row), Bar numbered 32 (middle row), and Bar numbered 33 (bottom row)
Radial Direction Tangential Direction Axial Direction



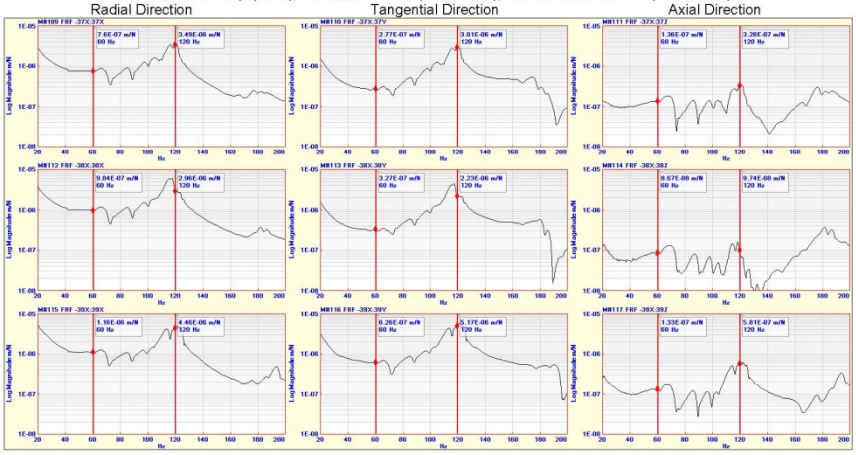
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Figure 14-12 Driving point measurements of DE SERIES BARS
Bar numbered 34 (top row), Bar numbered 35 (middle row), and Bar numbered 36 (bottom row)
Radial Direction Tangential Direction Axial Direction



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Figure 14-13 Driving point measurements of DE SERIES BARS
Bar numbered 37 (top row), Bar numbered 38 (middle row), and Bar numbered 39 (bottom row)
Radial Direction Tangential Direction Axial Direction



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Figure 14-14 Driving point measurements of DE SERIES BARS
Bar numbered 40 (top row), Bar numbered 41 (middle row), and Bar numbered 42 (bottom row)
Radial Direction Tangential Direction Axial Direction

NOT ACCESSIBLE

Figure 14-15 Driving point measurements of DE SERIES BARS
Bar numbered 43 (top row), Bar numbered 44 (middle row), and Bar numbered 45 (bottom row)
Radial Direction Tangential Direction Axial Direction

NOT ACCESSIBLE

Figure 14-16 Driving point measurements of DE SERIES BARS
Bar numbered 46 (top row), Bar numbered 47 (middle row), and Bar numbered 48 (bottom row)
Radial Direction Tangential Direction Axial Direction

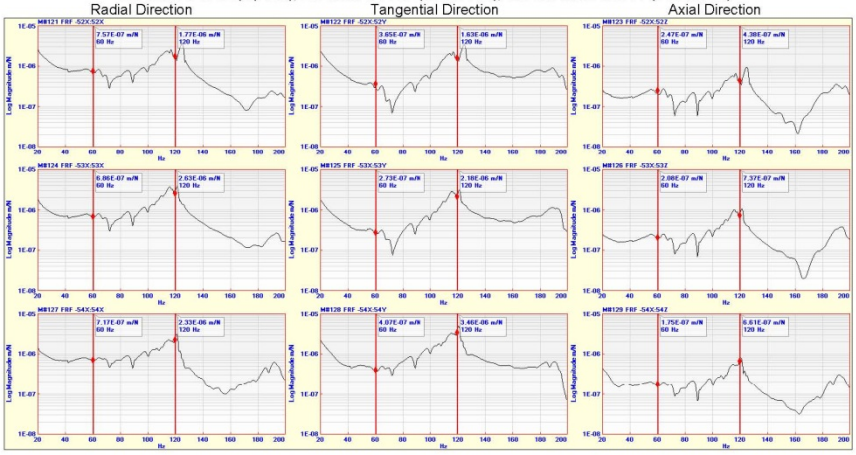
NOT ACCESSIBLE

Figure 14-17 Driving point measurements of DE SERIES BARS
Bar numbered 49 (top row), Bar numbered 50 (middle row), and Bar numbered 51 (bottom row)
Radial Direction Tangential Direction Axial Direction

NOT ACCESSIBLE

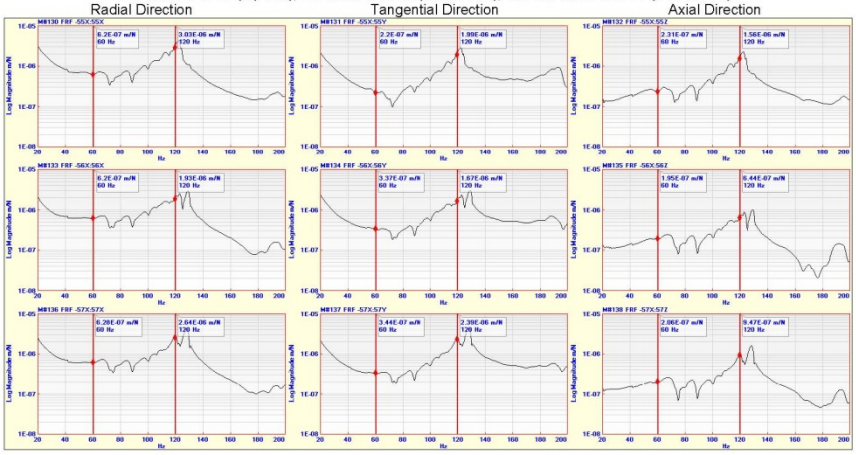
ALSTOM
Field Service Report FSRG020035

Figure 14-18 Driving point measurements of DE SERIES BARS
Bar numbered 52 (top row), Bar numbered 53 (middle row), and Bar numbered 54 (bottom row)
Radial Direction Tangential Direction Axial Direction



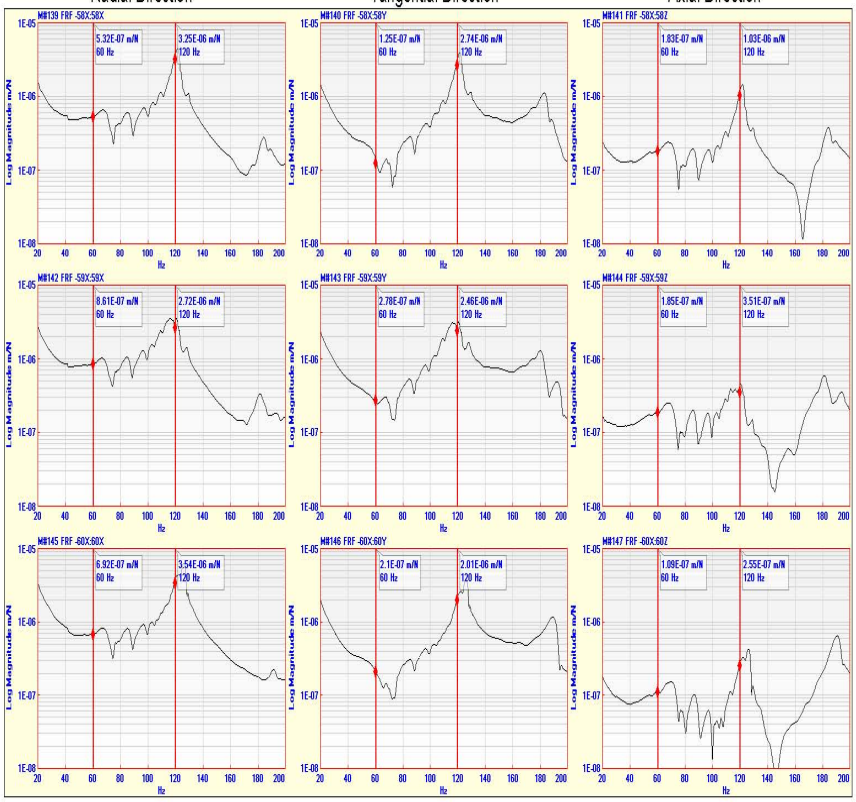
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Figure 14-19 Driving point measurements of DE SERIES BARS
Bar numbered 55 (top row), Bar numbered 56 (middle row), and Bar numbered 57 (bottom row)
Radial Direction Tangential Direction Axial Direction



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Figure 14-20 Driving point measurements of DE SERIES BARS
Bar numbered 58 (top row), Bar numbered 59 (middle row), and Bar numbered 60 (bottom row)
Radial Direction Tangential Direction Axial Direction



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6. Conclusion

During an inspection of the generator, the global modal analyses and the driving point measurements of the series bars of both NDE and DE end windings were performed. Since the rotor was in place, the planes at the slot exit and the involutes were not accessible and the global modal analysis was only performed on the plane of the end of the bars. The results from the global modal analyses indicated that the frequencies of the 4-node elliptical mode shape occurred at 60 Hz for the NDE end winding. In the case of the DE end winding, the frequencies of the elliptical mode shapes occurred at 67 Hz, and 70.5 Hz. All the natural frequencies corresponding to the elliptical mode shapes were well below the critical range of 115 Hz to 135 Hz, and therefore were within ALSTOM acceptance criterion.

The magnitudes of vibration of the driving point measurements of the series bars of the NDE and DE end windings were much larger than 500 nm/N with the largest magnitude of vibration for the NDE was approximately 5000 nm/N for the NDE and approximately 6500 nm/N for the DE. These magnitudes of vibrations exceeded ALSTOM acceptance criterion.

The magnitudes of vibration for most of the phase connections and their corresponding phase arms were less than 500 nm/N, but for several connectors such as PC1, PC3, PC5, and PC8, the magnitude of vibrations for at least one of the directions was more than 500 nm/N (with the largest magnitude equaled to 800 nm/N) and therefore exceeded ALSTOM acceptance criterion.

The reason of the high magnitude of vibrations for both the phase bars and the series bars were due to fact that there were not any tangential blocking between the bars and therefore making the bars more flexible than the bars that tangential blocking had been used between the caps. But, since the elliptical mode shapes of the end windings were well below the critical range of 115 Hz to 135 Hz and there were not any evidence of excessive greasing, ALSTOM did not recommend any modification to be performed on the end windings at the time. However, the characteristic of the end windings would change over time since the end windings are subjected to the mechanical and thermal stresses during start-stops and operation. Hence the magnitudes of vibration may increase and the natural frequencies may shift to the critical range. Therefore, ALSTOM recommends that the bump testing of the end windings be repeated during next opportunity.

APPENDIX H

Alstom Field Service Report FSRG019866

ALSTOM

Field Service Report (FSR)	Related CFSR issued ☐ Y ☒ N	Total pages without enclosures	Total pages enclosures
Report No. **FSRG019866**		10	11

Location	Department	Author	Date	Page No.
CH	Thermal Services	Nico Luterbacher	20.06.2013	1

Site Information

Customer: Newfoundland And Labrador Hydro	File Name: FSRG019866_Others_130620_Luterbacher.pdf	
Site: **HOLYROOD**	Country Name: CANADA	PDM Event No.
Plant: **HOLYROOD 3**	Plant Type: Fossil	Outage code
Unit: **HOLYROOD 3**	Service Ref No.	Order No.

System / Machine	System / Machine Type	System / Machine Serial No.
Generator	x	x

Task Information

Business Case: Others

Task: Others

Task description: **DIRIS - Inpection**

Distribution of FSR

Authors Distribution List				Official Distribution List			
Loc.	Dept.	Name	Notes	Loc.	Dept.	Name	Notes
				US	Thermal	Richard D Gupton	

US	Thermal Services	Reviewed by: John A Jensen	Date: 09.07.2013
US	Thermal Services	Approved by: Richard D Gupton	Date: 09.07.2013
US	Thermal Services	Archived by: Bianca K Figueroa	Date: 09.07.2013

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2.	Summary	3
3.	Work carried out	3
3.1.	Inspection after shutdown - Stator	3
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1. Purpose and duration of assignment

Purpose of assignment	Arrival Date	Departure Date
A generator inspection was performed, in order to establish the current condition of the generator.		

2. Summary

The generator was opened for an overhaul inspection. The rotor remained in-place during the inspection. The generator (stator, rotor) and in particular the stator winding, were thoroughly inspected. The inspection was carried out on the stator and rotor winding within the scope of general machine service to the ALSTOM - WIDIPRO (Winding Diagnostic Program). Additionally the inspection was performed using the DIRIS (Diagnostic Inspection Rotor In Situ) air gap robot.

The electrical tests and visual inspections have uncovered the following information which should be noted for the purposes of long term asset management:

- The RSO measurement (interturn short circuit test) shows that the rotor winding has a turn to turn short at stand still;
- In the DE rotor end winding is a loose insulation ribbon;
- The end windings have minor contamination from dry dust;
- The end winding housings are contaminated with small pools of oil;
- Between two high voltage bars at the NDE end winding was small corona visible;
- DIRIS video inspection has revealed a normal dirt contamination of the air gap;
- DIRIS low flux iron core test showed no critical interlamination short circuits;
- The bearing insulation tests show that the bearing insulation is in an acceptable range;

The required maintenance work was started immediately (enclosure **E1**). The work performed should allow the generator stator to run without problems for the next operating period. On the generator rotor further monitoring is required as a turn to turn short is present.

3. Work carried out

3.1. Inspection after shutdown - Stator

3.1.1. Visual inspection

- The end windings have minor contamination from dry dust. **(Appendix 1)**
- The end winding housings are contaminated with small pools of oil.
- The phase separations are in order. **(Appendix 2)**
- The visual inspection of the stator end winding support system shows no signs of extensive wear. **(Appendix 3 and 4)**
- The stator winding insulation showed small corona marks between the bars in the area of the phase separations at the NDE end winding (12 o'clock). **(Appendix 5)**
- Nothing inadmissible was found during the visual inspection of the insulation caps.
- The generator terminals (insulation, corona protection) are in normal condition.
- The air/water coolers were dismantled and withdrawn. The coolers are fully functional.

3.1.2. Visual inspection with DIRIS video robot

The visual inspection of the stator bore and the surface of the rotor was performed with a self-driven probe **(Appendix 8)**, which includes a camera, a mirror and a digital video recording system. The recorded tapes are stored in our department.

No deficiencies were found on the surface of the stator bore. **(Appendix 9)**

3.1.3. Low flux iron core test with DIRIS System

A low flux was induced in the stator core by use of the rotor as an excitation coil (energized on NDE and grounded on DE). The self-driven measuring unit travels along the stator surface and is recording the stray flux above of the core teeth. The measured signal is processed in an electronic data system and gives an assessment of the core lamination insulation. Defective laminations can be detected by comparing the measuring signal with the signal from the calibration measurement. The calibration measurement simulates a defined insulation defect.

Neither critical interlamination short circuits nor abnormal irregularities in the magnetic field were detected in the accessible area. Under ordinary running conditions, an operational period without any interruptions, regarding the lamination insulation, can be expected.

==> The test certificate is presented in the enclosure **E1**

3.1.4. Winding resistance measurement

Stator winding resistance measurement was carried out on each phase and the values recorded are as shown below.

Resistance A1-A2: 2.137 mΩ
Resistance B1-B2: 2.355 mΩ
Resistance C1-C2: 2.548 mΩ

3.1.5. Charging current measurement

The charging current was measured as in function of time with a constant DC voltage from 5000 V_{DC} on each phase.

The test results showed that the insulation surface is in a faultless and dry condition. The measured values are acceptable and lead to the statement that the stator winding insulation is reliable.

==> The test certificate is presented in the enclosure **E2**

3.1.6. Leakage current measurement

The leakage current was measured as in function of DC voltage with exactly defined intervals of time up to 9 kV (limited by the customer) on each phase.

The characteristic of the measured currents I_1 per phase and the discharge currents I_2 on the other two phases give no indication of irregularities in the insulation.

==> The test certificate is presented in the enclosure **E3**

3.1.7. Insulation resistance measurement

The insulation resistance was measured with 5000V_{DC} for 1 minute on each phase separately.

The measurement shows that the condition of the winding insulation is in a good range.

==> The test certificate is presented in the enclosure **E2**

3.2. Inspection after shutdown - Rotor

3.2.1. Visual inspection

The rotor end winding was inspected visually and with the aid of a boroscope as far as accessible.

- Nothing inadmissible was found on the air chamber guides and on the end winding fixing.
- At the DE end winding is a loose insulation ribbon visible. **(Appendix 6 and 7)**
- The slip ring unit is dirty by dry carbon dust.

- Both slip rings are a little bit rusty.

3.2.2. Visual inspection with DIRIS video robot

The visual inspection of the stator bore and the surface of the rotor was performed with a self-driven probe **(Appendix 8)**, which includes a camera, a mirror and a digital video recording system. The recorded tapes are stored in our department.

Nothing inadmissible was found on the rotor surface and retaining rings and as well all balancing screws are secured. **(Appendix 10)**

3.2.3. Check of shaft insulation quality

The measured values of the shaft insulation are in a good range. No critical leakage currents were measured.

==> The test certificate is presented in the enclosure **E4**

3.2.4. RSO, Rotor interturn short circuit test

The test was performed at stand still (0 min^{-1}).

The rotor winding has, on measurement condition, a turn to turn short. No winding to ground fault is present.

As the short is not posing any operational problems to the customer at this point, such as thermal sensitivity, it is recommend to leave the turn to turn short and do further monitoring such as a RSO test at nominal speed and measurements of the shaft voltage during operation or if possible installing a flux probe measurement. This to get more information about the turn to turn short.

If the turn to turn short can be confirmed at nominal speed and if it is a low resistive turn to turn short a rewinding has to be considered in order to enhance the reliability. This because a turn to turn shorts may get worse during increasing operation hours.

==> The test certificate is presented in the enclosure **E5**

3.2.5. Charging current measurement

The charging current was measured as in function of time with a constant DC voltage from 500 V_{DC} on the rotor.

The test results showed that the insulation surface is in a faultless and dry condition. The measured values are acceptable and lead to the statement that the rotor winding insulation is reliable.

==> The test certificate is presented in the enclosure **E6**

3.2.6. Winding resistance measurement

The rotor winding resistance was measured after disconnecting the diode circuit. The value is shown below.

Resistance rotor winding: 396.0 mΩ

3.2.7. Insulation resistance measurement

The insulation resistance was measured with 500V_{DC} for 1 minute on the rotor winding.

The measurement shows that the condition of the rotor winding insulation is in a good range.

==> The test certificate is presented in the enclosure **E6**

4. Milestones

Unit	HOLYROOD 3		
No.	Milestone	Planned Date	Actual Date
1	Traveling to site	11.06.2013	11.06.2013
2	Visual inspection of stator and rotor	11.06.2013	11.06.2013
3	Visual inspection of stator and rotor, Electrical tests on rotor	12.06.2013	12.06.2013
4	Installation of DIRIS equipment, Low flux measurement	13.06.2013	13.06.2013
5	Visual inspection and installation of DIRIS equipment	13.06.2013	13.06.2013
6	Low flux measurement and removal of DIRIS equipment	14.06.2013	14.06.2013
7	Reporting	16.06.2013	15.06.2013
8	Electrical tests on stator	15.06.2013	18.06.2013
9	Leaving site	17.06.2013	17.06.2013

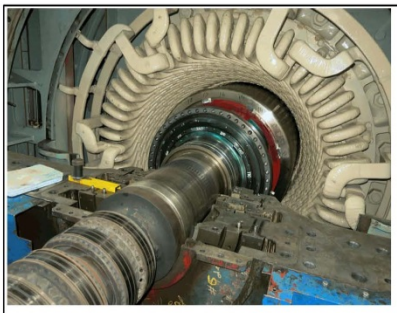
5. Personnel involved

Unit		HOLYROOD 3					
No.	Name	Department	Code	Function	Position	Arrival Date	Departure Date
1	Corey Fortier	LSN NAM Gen Eng	CGD	Commissioning Generator Diagnostics	Engineer	11.06.2013	17.06.2013
2	Nico Luterbacher	TSG-FNBR24	CGD	Commissioning Generator Diagnostics	Engineer	11.06.2013	18.06.2013

6. Technical information

Unit		HOLYROOD 3		
Type of data		Technical Information Generator		
No.	Description	Unit	Reading / Value	Remarks
1	Type	-	TFLQQ	
2	Generator / Stator Serial No.	-	162861-1	
3	Manufacturer (OEM) / Supplier	-	Hitachi	
4	Rotor Serial No.	-		
5	Rated Speed	rpm	3600	
6	Rated Frequency	Hz	60	
7	Rated Apparent Power	kVA	177235	
8	Rated Power Factor	-	0.85	
9	Rated Stator Voltage	kV	16.00	
10	Rated Stator Current	A	6395	
11	Rated Field Voltage	kV_{DC}	0.375	
12	Rated Field Current	A_{DC}	1530	
13	Insulation system	(stator wind.)	UNK	
14	Insulation class	(stator wind.)	B	
15	Cooling System (medium)	(rotor/stator)	H2-Indirect	
16	Excitation System	-	Static w. shunt supply	
17	Exciter Type	-	UNK	
18	Exciter Fabrication No.	-	UNK	

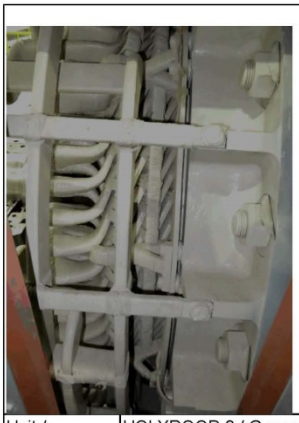
7. Appendix



Unit / Component	HOLYROOD 3 / Generator NDE end winding
Appendix No.	1
Description	Generator NDE end winding



Unit / Component	HOLYROOD 3 / Generator NDE end winding
Appendix No.	2
Description	Phase separation

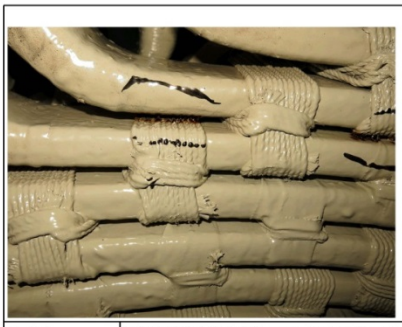


Unit / Component	HOLYROOD 3 / Generator NDE end winding
Appendix No.	3
Description	End winding support

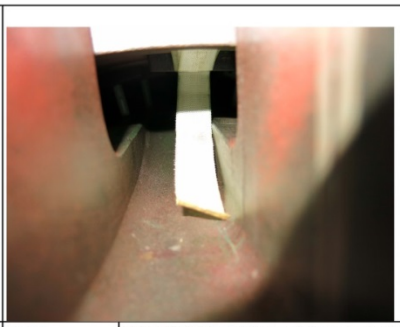


Unit / Component	HOLYROOD 3 / Generator DE end winding
Appendix No.	4
Description	End winding support

ALSTOM HOLYROOD 3
FSRG019866 20.06.2013



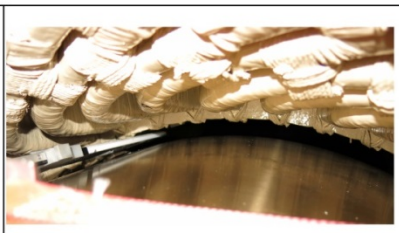
Unit / Component	HOLYROOD 3 / Generator NDE end winding
Appendix No.	5
Description	Small corona between high voltage phases



Unit / Component	HOLYROOD 3 / Rotor DE end winding
Appendix No.	6
Description	Loose insulation ribbon



Unit / Component	HOLYROOD 3 / Rotor DE end winding
Appendix No.	7
Description	Loose insulation ribbon



Unit / Component	HOLYROOD 3 / Generator DE air gap
Appendix No.	8
Description	DIRIS robot probe

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ALSTOM HOLYROOD 3
FSRG019866 20.06.2013

			
Unit / Component	HOLYROOD 3 / Generator air gap	Unit / Component	HOLYROOD 3 / Generator air gap
Appendix No.	9	Appendix No.	10
Description	Stator cooling duct	Description	Rotor balancing weight

Unit / Component	HOLYROOD 3 / -	Unit / Component	HOLYROOD 3 / -
Appendix No.	-	Appendix No.	-
Description		Description	

8. Enclosure

No.	E1
Description	DIRIS Flux test on stator iron core
Reference Number	HTCZ656981
Pages	1

No.	E2
Description	Charging current measurement
Reference Number	HTCZ656925
Pages	1

No.	E3
Description	Leakage current measurement
Reference Number	HTCZ656929
Pages	1

No.	E4
Description	Bearings insulation test
Reference Number	HTCZ656933
Pages	1

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No.	E5
Description	Rotor interturn short circuit test (RSO Test)
Reference Number	HTCZ656968
Pages	4

No.	E6
Description	Rotor winding charging current measurement
Reference Number	HTCZ657049
Pages	1

No.	E7
Description	Maintenance Working Order
Reference Number	HTCZ657019
Pages	2

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Test Certificate	Title: *DIRIS*® low flux measurement on stator core	Report No.: CFRG019866	Enclosure: E1

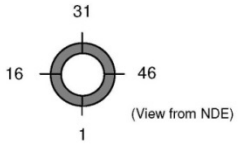
Measurement execution:

Magnetization unit:	S/N 1063-2001/009	Voltmeter:	Fluke 117
DIRIS Data Acquisition Unit:	S/N 1064-3012/014	Ampèremeter:	Fluke 322 20850980
Probe:	S/N 1039-2251/003		

Measurement settings:

Number of windings:	1	Iron length, L [mm]:	4260
Frequency [Hz]:	60	Effective core cross-section, A_{Fe} [m^2]:	1.470
Magnetization voltage [V]:	50	Single turn voltage, U [V]:	50
Magnetisation current [A] :	34.7	Calculated induction, $\hat{B}_{Mess}$ [T]:	0.1276
Probe speed:	0.4	Number of slots:	60

Data file:	LF_Holyrood 3_2013.dp3



Measurement results:

Calibration table:

Slot Number	Position from NDE [mm]	Length [mm]	Current [A]	Power at rated induction [W]
10	340	3	2.3	17.6

Fault table:

Slot Number	Position from NDE [mm]	Power at rated induction [W]

Maximum single permissible lamination short-circuit power dissipation (at rated induction): 15 W

Remarks:

No critical interlamination short circuits were found.

Test Decision (as required/acc. to specification)	**Accepted***	X	**Rejected***		Unit / System Name: Holyrood #3 / Generator	
	NC-Report*		**Rework***			
NCR No.*				Part Text: Hitachi TFLQQ		Quantity: 1
Checked by**: C. Fortier / LSN NAM Gen Eng / 2013-06-14				Part Idnr: 162861-1	Rev.	Power Station Designation: CCPP
Approved by**: N. Luterbacher / TSG-FNBR24 / 2013-06-14				I & T Plan ID: UTGE622300	Rev.: A	Test Step: 6.0020 / Material Test No.
Authority / Customer**: hydro				Order No.		Factory Order
ALSTOM				Sheet No.: 1 / No. of Sh.: 1	Document No.: HTCZ656981	Rev.: -

* Mark/Fill in if applicable ** Name / dept. / date / initials

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Dept.	Document No.	Type	Rev.	Released	Lng	Status
9539	HTCZ656925	FA	-	2009-06-26	EN	Approved

Test Certificate

Title: **Stator winding: Charging current measurement**

Report No.: **CFRG019866**

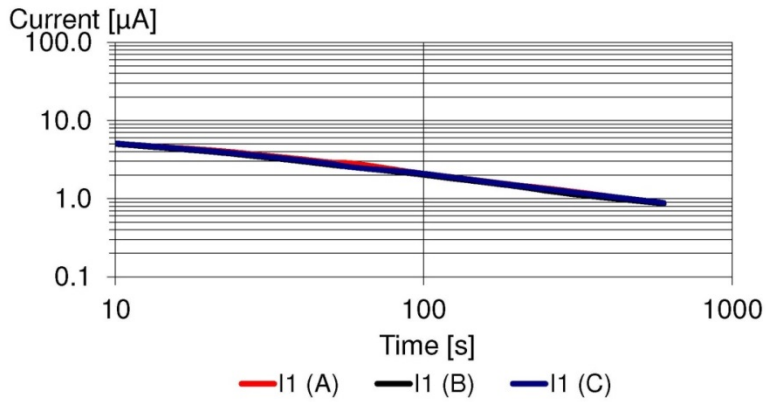
Enclosure: **E2**

Measurement conditions:

Rated voltage U_N:	16 kV	Charging time [Min.] :	10 Min.
Charging voltage U:	5 kV	Test instrument:	FUG high voltage DC test set

Phase:	A	B	C
Ambient temperature [°C] :	15	15	15
Winding temperature [°C] :	15	15	15
Relative humidity [%] :	UNK	UNK	UNK

Charging current diagram stator winding:



Characteristic values calculated:

Phase	A	B	C
1 min Insulation resistance $R_{1\ min}$ [MΩ] :	1786	2000	2000
10 min Insulation resistance $R_{10\ min}$ [MΩ] :	5780	5821	5650
Polarisation index (PI)	3.2	2.9	2.8

Remarks:

Test Decision (as required/acc. to specification)	**Accepted***	X	**Rejected***		Unit / System Name: Holyrood #3 / Generator	
	NC-Report*		**Rework***			
NCR No.*					Part Text: Hitachi TFLQQ	Quantity: 1
Checked by**: N. Luterbacher / TSG-FNBR24 / 2013-06-18					Part Idnr: 162861-1	Rev.:	Power Station Designation:
Approved by**: N. Luterbacher / TSG-FNBR24 / 2013-06-18					I & T Plan ID: UTGE622300	Rev.: A	Test Step: 5.0020	Material Test No.:
Authority / Customer**: hydro					Order No.:		Factory Order:
ALSTOM					Sheet No.: 1	No. of Sh.: 1	Document No.: HTCZ656925	Rev.: -

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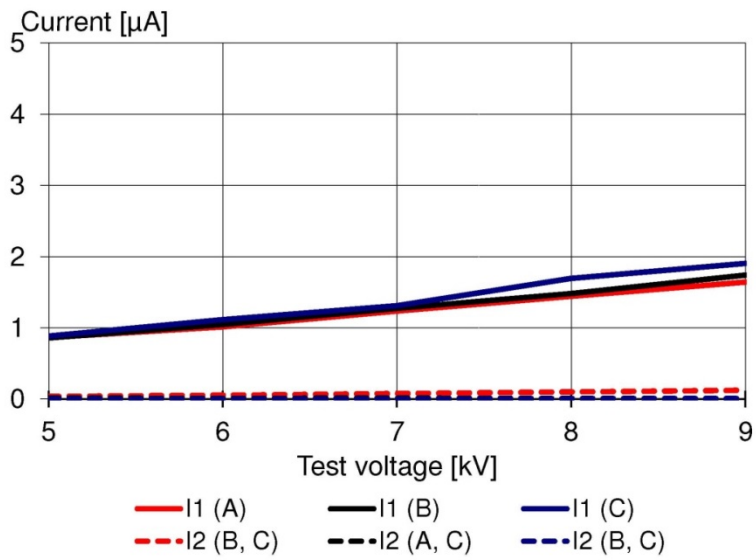
Test Certificate	Title: Stator winding: Leakage current measurement	Report No.: CFRG019866	Enclosure: E3

Measurement conditions:

Rated voltage U_N:	16 kV		
Test voltage U_p:	9 kV	Test instrument:	FUG high voltage DC test set

Phase:	A	B	C
Ambient temperature [°C] :	15	15	15
Winding temperature [°C] :	15	15	15
Relative humidity [%] :	UNK	UNK	UNK
Absorption factor N = $(I_{(1:00)}-I_{(0:10)})^2 / (I_{(3:10)}-I_{(1:00)})^2$	3.7	2.8	2.4

Leakage current diagram stator winding:



Remarks: Test limited to 9 kV by the customer.

Test Decision (as required/acc. to specification)	Accepted*	X	Rejected*		Unit / System Name: Holyrood #3 / Generator	
	NC-Report*		Rework*			
NCR No.*				Part Text: Hitachi TFLQQ		Quantity: 1
Checked by**: N. Luterbacher / TSG-FNBR24 / 2013-06-18				Part Idnr: 162861-1	Rev.	Power Station Designation
Approved by**: N. Luterbacher / TSG-FNBR24 / 2013-06-18				I & T Plan ID: UTGE622300	Rev.: A	Test Step: 5.0040 / Material Test No.
Authority / Customer**: hydro				Order No.		Factory Order
ALSTOM				Sheet No.: 1 / No. of Sh.: 1	Document No.: HTCZ656929	Rev.: -

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Unit: 9539 | Document No.: HTCZ656929 | Type: FA | Rev.: - | Released: 2009-06-26 | Lng: EN | Status: Approved

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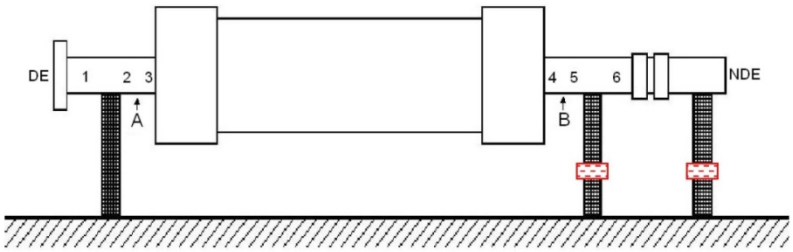
Test Certificate	Title: Bearing insulation test	Report No.: CFRG019866	Enclosure: E4

Test execution:

Rogowski coil:	CHAUVIN ARNOUX A 100	Voltmeter:	Fluke 117
Variac:	S/N 1063 2001/009	Amperemeter:	Fluke 322 20850980
Transformer:	S/N 1063 2002/009	Current clamp:	-

Test conditions:

Ambient temperature [°C] :	UNK	Excitation current I_{err} [A]:	35.0
Relative humidity [%] :	UNK	Excitation voltage U_{err} [V]:	50
Excitation feeding point:	☐ A ☒ B	Excitation grounding point:	☒ A ☐ B



Test results:

Current at position 1: [A]:	-	Current at position 4: [A]:	34.4
Current at position 2: [A]:	0	Current at position 5: [A]:	0
Current at position 3: [A]:	34.7	Current at position 6: [A]:	-

Bearing insulation NDE	☒ OK ☐ Not OK ☐ Not checked	Bearing insulation DE	☒ OK ☐ Not OK ☐ Not checked

Remarks:

Test Decision (as required/acc. to specification)	Accepted*	X	Rejected*		Unit / System Name: Holyrood #3 / Generator			
	NC-Report*		Rework*					
NCR No.*					Part Text: Hitachi TFLQQ			Quantity: 1
Checked by**: C. Fortier / LSN NAM Gen Eng / 2013-06-12					Part Idnr: 162861-1	Rev.	Power Station Designation	
Approved by**: N. Luterbacher / TSG-FNBR24 / 2013-06-12					I & T Plan ID: UTGE622300	Rev.: A	Test Step: 6.0020	Material Test No.
Authority / Customer**: hydro					Order No.		Factory Order	
ALSTOM					Sheet No.: 1	No. of Sh.: 1	Document No.: HTCZ656933	Rev.: -

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Test Certificate	Title: Rotor interturn short circuit test (RSO Test)	Report No.: CFRG019866	Enclosure: E5

Measurement execution:

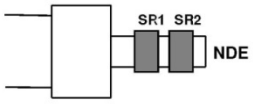
Fabrication No. rotor:		Surge generator serial No.:	JD-9704-00028
Number of poles:	2	Oscilloscope serial No.:	Flule 192C S/N 10790022

Measurement conditions:

Nominal speed [rpm] :	0
Surge generator setting RE [Ω]:	2200
Surge generator setting RV [Ω]:	110

Rotor: ☒ installed ☐ removed

Retaining ring: ☒ Installed ☐ removed



Measurement results:

Impuls transition time:	$T = \frac{T_R}{2}$ [µs]	**20.4 µs**
Discharge time constant:	T_E [ms]	**0.72 ms**
Winding-grounding capacitance:	$C_E = \frac{T_E}{R_E + R_V}$ [µF]	**0.31 µF**
Surge impedance:	$R_W = \frac{T}{C_E}$ [Ω]	**65.8 Ω**

Measurement files:

Pic. No.	File Name	SR1	SR2	Remarks:
1	Rise 2V 20us parallel	☒	☒	Ref. SR1, CH1 SR2
2	Rise 2V 10us parallel	☒	☒	Ref. SR1, CH1 SR2
	Rise 1V 5us	☒	☒	Ref. SR1, CH1 SR2
4	Rise 1V 2us	☒	☒	Ref. SR1, CH1 SR2
	Fall 2V 500us parallel	☒	☒	Ref. SR1, CH1 SR2

Remarks:

Test Decision (as required/acc. to specification)	Accepted*	X	Rejected*	Unit / System Name: Holyrood #3 / Generator	
	NC-Report*		Rework*		
NCR No.*				Part Text: Hitachi TFLQQ	Quantity
Checked by**: C. Fortier / LSN NAM Gen Eng / 2013-06-12				Part Idnr: 162861-1 / Rev. / Power Station Designation	
Approved by**: N. Luterbacher / TSG-FNBR24 / 2013-06-12				I & T Plan ID: UTGE622300 / Rev.: A / Test Step: 4.0020 / Material Test No.	
Authority / Customer**: hydro				Order No. / Factory Order	
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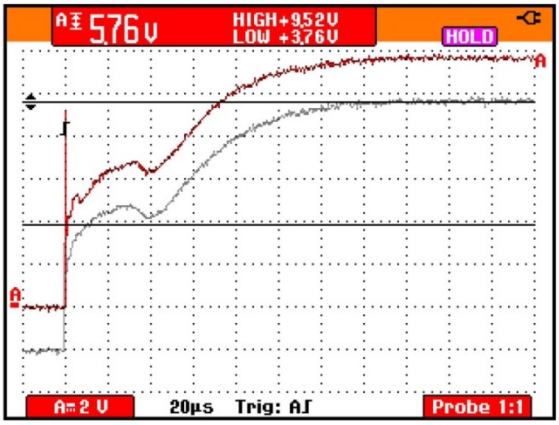
Dept. 9.SSV | Document No. HTCZ656968 | Type FA | Rev. - | Released 2010-01-08 | By EH | Status Approved

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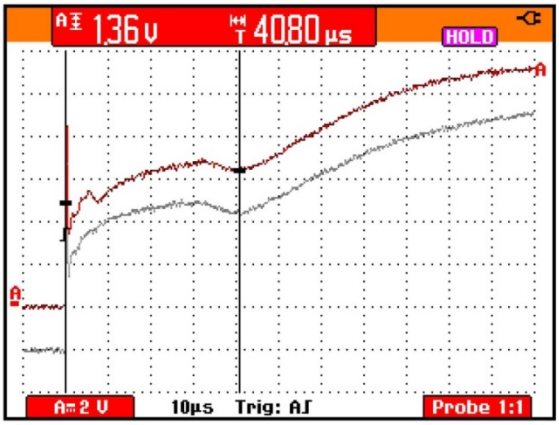
Test Certificate	Title: Rotor interturn short circuit test (RSO Test)	Report No.: CFRG019866	Enclosure: E5

Measurement results continuation:

Picture 1:



Picture 2:



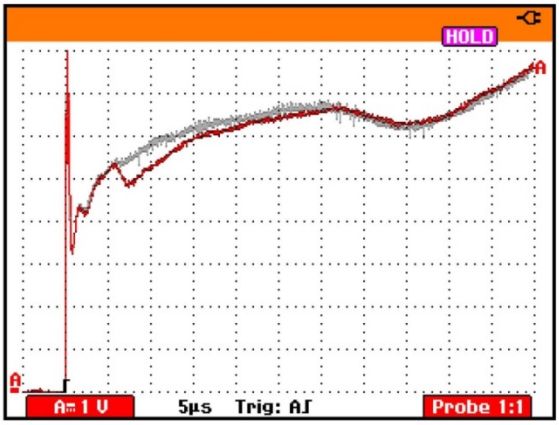
Unit / System Name	Order No.	Factory Order			
Holyrood #3 / Generator					
ALSTOM	Sheet No. 2	No. of Sh. 4	Document No. HTCZ656968		Rev. -

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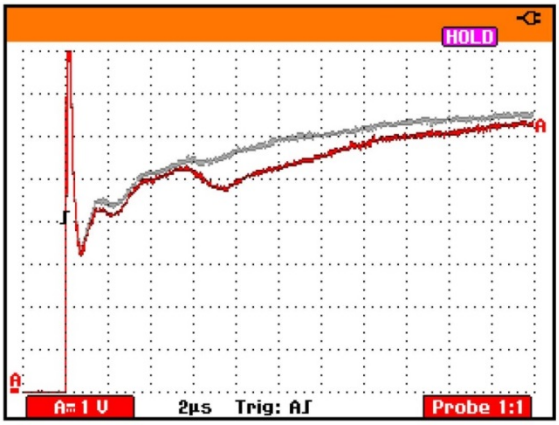
Test Certificate	Title: Rotor interturn short circuit test (RSO Test)	Report No.: CFRG019866	Enclosure: E5

Measurement results continuation:

Picture 3:



Picture 4:



Unit / System Name	Order No.	Factory Order
Holyrood #3 / Generator		

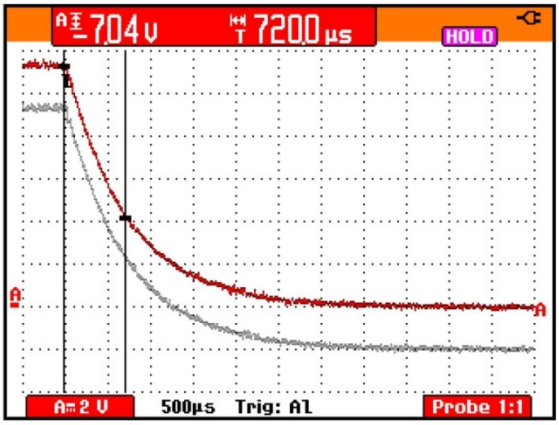
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Test Certificate	Title: Rotor interturn short circuit test (RSO Test)	Report No.: CFRG019866	Enclosure: E5

Measurement results continuation:

Picture 5:



Unit / System Name	Order No.	Factory Order
Holyrood #3 / Generator		

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Test Certificate	Title: Rotor winding charging current measurement	Report No.: CFRG019866	Enclosure: E6

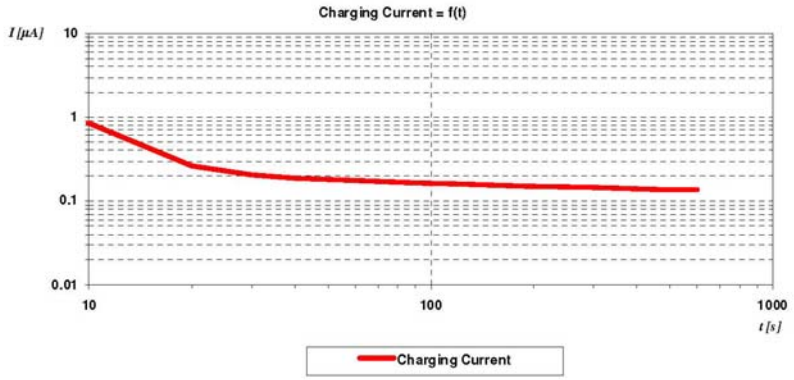
Measurement execution:

Field voltage U [kV]:	375		
Field current I [A]:	1530	Measurement instrument:	TG00308

Measurement conditions:

Ambient temperature [°C] :	UNK	Charging voltage [V]:	511
Winding temperature [°C] :	UNK	Charging time [Min.]:	10
Relative humidity [%] :	UNK		

Measurement results:



1 min Insulation resistance $R_{1\,min}$ [MΩ] :	2900
10 min Insulation resistance $R_{10\,min}$ [MΩ] :	3780
Charge factor N (Polarisation index) :	1.3

Remarks:

Test Decision (as required/acc. to specification)	Accepted*		Rejected*		Unit / System Name: Holyrood #3 / Generator	
	NC-Report*		Rework*			
NCR No.*					Part Text: Hitachi TFLQQ	Quantity
Checked by**: C. Fortier / LSN NAM Gen Eng / 2013-06-12					Part Idnr: 162861-1	Rev. / Power Station Designation
Approved by**: N. Luterbacher / TSG-FNBR24 / 2013-06-12					I & T Plan ID: UTGE622300	Rev.: A / Test Step: 4.0030 / Material Test No.
Authority / Customer**: hydro					Order No.	Factory Order
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Test Certificate	Title: Maintenance work order	Report No.: CFRG019866	Enclosure: E7

a) Stator

- Clean the whole stator as far as possible.
- Clean the small corona marks between the NDE high voltage top bars 11 o'clock as far as possible.
- Clean the small pools of oil in the end winding housing.

b) Rotor

- Clean the whole rotor as far as possible.
- Clean the slip rings.
- Cut the loose insulation ribbon at the DE rotor end winding and seal it with epoxy.

Test Decision (as required/acc. to specification)	Accepted*	X	Rejected*		Unit / System Name: Holyrood #3 / Generator	
	NC-Report*		Rework*			
NCR No.*				Part Text: Hitachi TFLQQ		Quantity: 1
Checked by**: C. Fortier / LSN NAM Gen Eng / 2013-06-12				Part Idnr: 162861-1	Rev.	Power Station Designation
Approved by**: N. Luterbacher / TSG-FNBR24 / 2013-06-12				I & T Plan ID: UTGE622300	Rev.	Test Step / Material Test No.
Authority / Customer**: hydro				Order No.		Factory Order
ALSTOM				Sheet No.: 1 / No. of Sh.: 2	Document No.: HTCZ657019	Rev.: -

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Test Certificate	Title: Maintenance work order	Report No.: CFRG019866	Enclosure: E7

c) Exciter

- Clean the brush bridge as far as possible, especially the carbon dust, dirty and deposits.

d) Other works

- Clean the grounding brushes.

Date of test :		Tested by :		Dept :	

For generator overhaul personal

Date: ..... *Name:* ..... *Sign:* .....

Remarks

Unit / System Name	Order No.	Factory Order			
Holyrood #3 / Generator					
ALSTOM	Sheet No. 2	No. of Sh. 2	Document No. HTCZ657019		Rev. -

A REPORT TO

THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES



Electrical
Mechanical MK
Civil
Protection & Control
Transmission & Distribution
Telecontrol
System Planning

Upgrade Work for Cat Arm, Units 1 and 2

Cat Arm

July 2015

newfoundland labrador hydro
a nalcor energy company

SUMMARY

This two year project will upgrade the spherical valve control system and replace the deflector servomotors on both Generating Units 1 and 2 at the Cat Arm Generating Station. The project scope of work will include the replacement of hydraulic control valves and piping and upgrading the control panel on the spherical valve control system. Included in this project is the design and fabrication of both deflector servomotors, and delivery to site.

A condition assessment to the spherical valve control system was carried out by an engineering firm and concluded that the current condition of the spherical valve control system does not meet the design requirements and could cause major damages and accidents.

The existing servomotors on both Generating Units 1 and 2 are aged and deteriorated. If the servomotor fails on either unit, that unit will be out of operation until the servomotor is repaired or a replacement servomotor is installed.

The upgrade of spherical valve control system and deflector servomotors is required to maintain a reliable and safe operation of the Cat Arm generating station.

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1 INTRODUCTION

The Cat Arm Generating Station (Cat Arm) is located on the Northern Peninsula between the reservoir and White Bay (Figure 1).

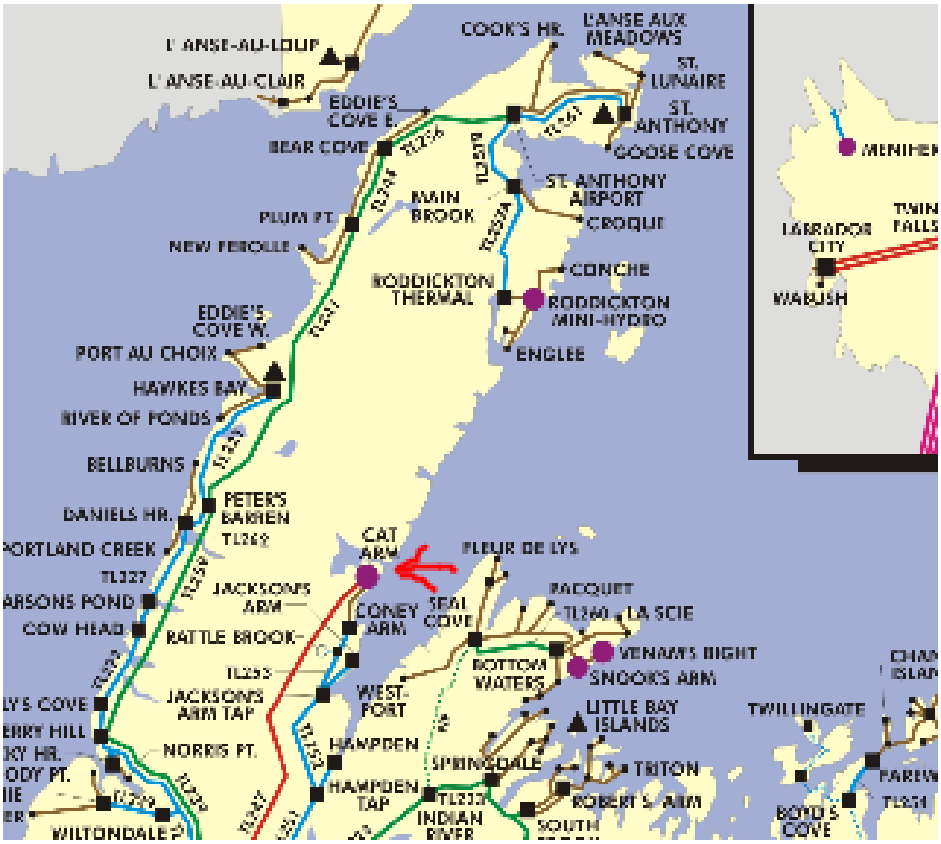


Figure 1: Cat Arm Generating Plant Location.

The powerhouse has two generating units, each has a turbine-generator set comprising a six jet vertical shaft Pelton turbine rated at 68.2 MW (at 380.5 m net head and flow of 20 m^3/s) direct coupled to an air/water cooled generator rated at 75.5 MVA, 0.95 power factor, and having a rotational speed of 327.5 rpm.

The rated plant capacity is 127 MW. The plant was commissioned in 1985.

2 PROJECT DESCRIPTION

This two year project is for upgrade work at Cat Arm. The project scope of work will include the following:

a) Upgrade the spherical valve control system on both Generating Units 1 and 2

i. Control panel:
   - Replace the three solenoid valves and pressure differential switch in the hydraulic control panel.
   - Replace the relay box and timer from the electric control. Instead of replacing the relay and timer, it is also possible to install a programmable logic controller (PLC).
   - Replace the two air release valves by new components with equivalent features.

ii. Service seal pressure:
   - Replace the hydraulic actuated valve.

iii. Bypass:
   - Replace the hydraulic actuated valve.

iv. Spherical valve servomotor:
   - Replace the hydraulic control valves with one hydraulic actuated 3-way 2-position valve.

v. Maintenance utility:
   - Replace the four manual valves for the upstream seal control with one 4-way 2-position valve.

vi. Piping:
   - Replace the entire control system pipelines with piping made of corrosion-resistant material.

b) Replacement of the deflector servomotors on both Generating Units 1 and 2

i. Design and fabrication of both deflector servomotors, and delivery to site.

ii. Installation of both deflector servomotors.

The upgrade work will take place during the annual maintenance of the generating units and will be performed by Hydro personnel.

3 JUSTIFICATION

The project is justified on the requirement to maintain a reliable and safe operation at Cat Arm.

The spherical valve is considered a critical isolation point and protection device for the generating units. Should the automatic control fail to close the spherical valve in an emergency situation, the damage to the power plant and penstock could be catastrophic. The spherical valves also allow maintenance crews to perform work safely on the generating units without dewatering the penstock. During maintenance work, a malfunction of the spherical valve control system can create hazardous conditions to operating staff. Also, the consequences of failure of spherical valve control system may have a substantial impact on power generation and revenues.

A condition assessment on the spherical valve control system on both Generating Units 1 and 2 was carried out by an engineering firm, Worley Parsons, to investigate the current condition and recommend necessary actions to maintain the integrity and resolve operational issues of the spherical valve control system. It was concluded in the condition assessment report (Appendix A) that the current condition of the spherical valve control system does not meet the design requirements. The status quo of the spherical valve control system can lead to operation problems and accidents. Being a remote plant, accessible only by snow machines in winter, response times to alarms are not immediate. Further, due to the deteriorated condition, an additional risk is leakage of the pipes (30 years old). Leakage of the pipes and valves (at 550 psi) over a period of time before an operator arrives on site may cause a significant flooding in the plant.

Currently, the existing deflector servomotors on both generating units are deteriorated and there are no spare deflector servomotors on site. If the deflector servomotor fails on either generating unit, that unit will be out of operation until the servomotor is repaired or a replacement servomotor is installed. Hydro is proposing to purchase a spare deflector

servomotor as part of a supplemental application in 2015 that requests approval to purchase critical spare components for its generating facilities.

3.1 Existing System

The generating units located in Cat Arm were placed in service in 1985 and are 30 years old.

The spherical valve control system is used to operate the spherical valve. The spherical valve is a 90 degree ball valve that weighs 9500 Kg, has an inside diameter of 1500mm and a design pressure of 4.8Mpa (Figure 2). Two hydraulically movable seals and a piston type servomotor are used to operate the valve and seal off the penstock pressure. The control pressure to operate these devices is supplied via the penstock at 550 psi. A bypass line is used to pressurize the downstream side of the valve and an air venting system releases the air to allow for safe operation of the valve in the high pressure conditions.



Figure 2: Spherical Valve at Cat Arm.

The spherical valve hydraulic control panel and the electric panel (relays) can be operated locally (Figure 3) and remotely from the control room.



Figure 3: Spherical Valve Control Panels.

The downstream hydraulically operated seal (service seal) is applied and removed during every operation. This seal can be operated manually or automatically. The upstream seal (maintenance seal) is only used for maintenance and is a critical isolation point that helps ensure worker safety. This maintenance seal is only operated manually. The rotating plug (90 degrees) inside the spherical valve is operated by a servomotor and can be used manually or automatically. The timing of this servomotor is adjustable with the in line flow control valves. Two sets of duplex strainers are used to clean control water being supplied from the penstock both upstream and downstream of the valve. Water can be supplied from an auxiliary source (pumping unit) in the event that the penstock is dewatered and the valve is required to be operated.

Three DC solenoid valves (directional valves) are installed for automatic operation of the valve. These solenoid valves can also be operated manually with levers if required. The solenoid valves operate hydraulically controlled ball valves which control the spherical servomotor, bypass, and seals. Limit switches, pressure switches, relays, timers, and valve position indicating system are incorporated in the design to allow for safe automatic operation of the spherical valve.
The spherical valve control system diagram at Cat Arm is provided in Appendix B.

The major work/upgrade carried out on the spherical valve control system since the plant

commissioning in 1985 is provided in Table 1.

Table 1: Major Work/Upgrade

Year	Major Work/Upgrade
2008	Upgrade spherical valve maintenance seals - Units 1 and 2
2006	Upgrade the governor - Unit 1
2006	Repair spherical valve seals– Units 1 and 2
1999	Repair spherical valves seals – Units 1 and 2.

The turbines of both Generating Units 1 and 2 are of the Pelton type, see Figure 4. A Pelton Wheel is a type of impulse turbine and is usually operated from a high-head source ranging from 200 to 1,800 meters when the volume of water available is relatively small. The gross developed head at Cat Arm is 386.5 m.



Figure 4: Spare Pelton Wheel in Cat Arm.

The water under pressure which is introduced into the casing of the Pelton wheel is accelerated when it is forced to flow through a needle valve and then the resulting high-velocity jet impinges on the buckets of the turbine wheel or runner, whereby the runner is rotated. A deflector is located at the discharge end of needle valve so that in the case of an emergency, the high-velocity jet emerging from the needle valve is deflected and thereby

prevented from impinging on the buckets of the runner, see Figure 5.

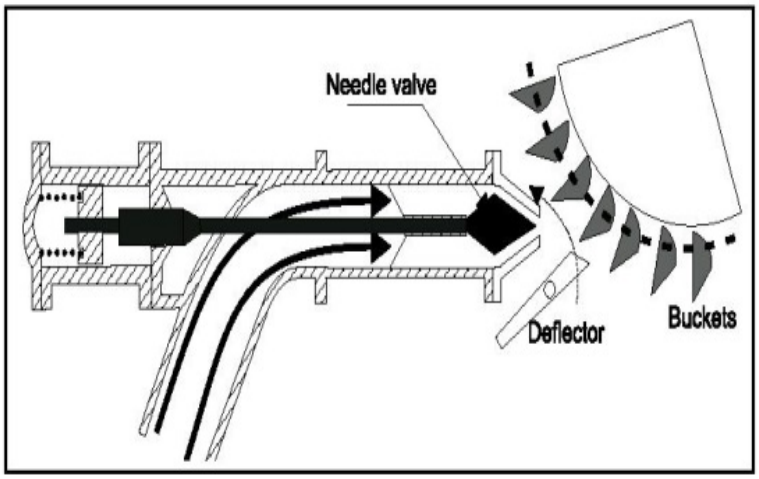


Figure 5: Deflector, Needle Valve and Pelton Wheel Arrangement.



Figure 6: Deflector Replaceable Stainless Steel Blades



Figure 7: Deflector Servomotor.

The single deflector servomotor is operated by using governor oil for the opening and penstock water for the closing. This special dual fluid (oil and water) configuration ensures the safety of the generating unit. If governor pressure is lost, the servomotor will close and deflect the water jet to the buckets on the runner.

3.2 Operating Experience

The spherical valve control valve system was commissioned in 1985 and has reached the end of its useful life. This system is in a deteriorated condition and no longer can ensure that the spherical valve functions properly and closes automatically when required.

The solenoid actuated valves that control the opening and closing of the spherical valve do not always respond correctly. During normal operations the relay control panel has experienced malfunctions. In an emergency situation these malfunctions could prevent the spherical valve from closing. Incomplete sequences are a regular occurrence when these systems are being utilized for plant operations, maintenance, and isolation procedures. The spherical valves have closed with the unit online causing the loss of generation and the resulting system reliability issues. Jumpers have been used in the relay control panel to

complete the opening and closing operation which is exposing operators and maintenance crews to unnecessary hazards. Failures of these main penstock pressure shut off valves can result in serious damages or injuries. At a generating station that requires the intake head gate be locked in position due to the length and design of the penstock, these valves are the only means of stopping the flow of water in the event of the loss of governor hydraulic oil pressure.

The hydraulic control valves are sometimes sticking, slow to operate and leaking. Sometimes the operators have to tap valve bodies with a hammer to release sticking valve plugs which allows the hydraulic control valves to operate. The three solenoid actuated valves (directional valves) are also sticking and do not work automatically. These directional valves are obsolete and no longer available. Internal inspection of these valves has shown that the valve bodies have corroded which is the cause of the valve malfunctions.

The stainless steel balls inside the air release pressure valves have jammed in both open and closed positions. The seals in these valves have also failed. Manual valves are used by operators to vent air manually; then jumpers are used to complete the sequence of operation.

Also, some devices such as limit switches and pressure switches are not working properly. The pressure differential switch that monitors pressure on both sides of the spherical valve and is critical to the safe operation, considering the high operating pressure (550psi) at this plant, has malfunctioned during normal operations and has proved to be unreliable. Malfunctions of limit switches and other pressure switches have caused incomplete sequences that prevent the automatic operation of the spherical valve.

The deflector servomotors on both Generating Units 1 and 2 are original equipment to the construction of Cat Arm back in 1985 and have reached the end of their useful life. The deflector servomotors are constantly leaking water. The red circle, as seen in Figure 7, is

showing the bubbles of the leaking water and the pit, where the servomotor is located, has water on the floor due to this leakage. In 2012, the spare deflector servomotor was installed on Generating Unit 1. After a few months of operation, there were problems with the spare servomotor. After an inspection, it was determined that the spare servomotor had machined pieces left inside the servomotor causing major damage to the internal surfaces and required replacement. The old servomotor at that time was still on site and was reinstalled on Generating Unit 1**.**

3.2.1 Reliability Performance

Over years of operation the deflector servomotors have become worn due to normal operational use. Once these servomotors become worn, the seals in the mechanism become less effective and wear out faster. Generating Unit 1 had to be taken out of service twice in the past five years to address the sealing problems.

3.2.1.1 Outage Statistics

In the past five years there have been two outages attributed to the deflector servomotor on Generating Unit 1. The first failure was in 2011. Operators found water spraying from Generating Unit 1 turbine pit. Generating Unit 1 was down for approximately 62 hours for the seals on the servomotor to be replaced. In 2014, Generating Unit 1 servomotor failed again due to failed seals causing water leakage through the vent outlets on the deflector servomotor.

3.2.2 Vendor Recommendations

The Original Equipment Manufacturer (OEM) has been involved with sourcing these deflector servomotors where they are not a standard configuration. In 2014, one of the old deflector servomotors were sent to the OEM for an inspection and it was noted that due to the condition of the servomotors they should be replaced. The OEM did explore the refurbishment option however this option was more costly due to the required replacement of some parts and the fine finish required on other parts that were damaged.

3.2.3 Safety Performance

When workers are working downstream of the spherical valve, a malfunction of the spherical valve control system can cause major damages to the power plant and penstock under a load rejection coincidence with turbine injector malfunction and cause threats to human lives.

Part IX of the Occupational Health & Safety Regulations of Newfoundland and Labrador (NL 5/12) explains the requirement for de-energizing and lockout. General requirement as per article 128, states that the energy source shall be isolated and effectively controlled. Control system shall provide lockout protection at all times.

The project will improve the safety performance of workers during operation and maintenance.

3.2.4 Maintenance or Support Arrangements

The routine maintenance for the spherical valve control system is carried out by Hydro personnel.

3.2.5 Maintenance History

The maintenance history for the spherical valve control system and deflector servomotors were not tracked and; therefore, unknown.

3.2.6 Historical Information

Similar upgrade work was carried out on spherical valve control system for six generating units at Bay d'Espoir generating station (Bay d'Espoir) in 2001 for Generating Unit 4, 2002 for Generating Units 5 and 6, 2003 for Generating Units 1 and 2, and 2004 for Generating Unit 3. The spherical valve control system at Bay d'Espoir was commissioned in 1967 on Generating Units 1, 2 and 3; in 1968 on the generating unit 4 and in 1970 on Generating Units 5 and 6.

3.2.7 Anticipated Useful Life

The anticipated useful life for the spherical valve control system and servomotor is 25-30 years.

3.3 Development of Alternatives

There is no alternative to the upgrade of the spherical valve control system.

The refurbishment of the servomotors was studied as an alternative to the replacement with new servomotors in consultation with the original equipment manufacturer (OEM). The servomotor was sent to the OEM for an inspection and the refurbishment estimate exceeded the replacement cost, based on an assessment of the existing servomotor. In addition, a new servomotor will be supplied with warranty, and the refurbished one would not. Therefore, the refurbishment alternative was deemed not practical and the replacement of the servomotor was the only viable alternative.

4 CONCLUSION

This two year project is required to upgrade the spherical valve control system and replace the deflector servomotors on both Generating Units 1 and 2 in order to maintain a reliable and safe operation at Cat Arm.

The spherical valve control system and deflector servomotors on both Generating Units 1 and 2 have been placed in service since the commissioning of Cat Arm in 1985 and have reached the end of their useful life.

There have been concerns in the past with the spherical valve control system. A condition assessment to the spherical valve control system for both Generating Units 1 and 2 was carried out by an engineering firm, Worley Parsons, concluded that the current condition of the spherical valve control system does not meet the design requirements and could cause major damages and accidents.

The deflector servomotors on both Generating Units 1 and 2 are in a deteriorated condition. If the deflector servomotor fails on either generating unit, that unit will be out of operation until the servomotor is repaired or a replacement servomotor is installed.

4.1 Budget Estimate

The project budget estimate is provided in Table 4.

Table 4: Project Budget Estimate

Project Cost:*($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	314.1	110	0.0	424.1
Labour	75.5	638.3	0.0	713.8
Consultant	133.2	0.0	0.0	133.2
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	0.0	174.4	0.0	174.4
Interest and Escalation	35.5	141.3	0.0	176.8
Contingency	0.0	289.1	0.0	289.1
TOTAL	**558.3**	**1,353.0**	**0.0**	**1,911.3**

4.2 Project Schedule

The anticipated project schedule is provided in Table 5.

Table 5: Project Schedule.

Activity		Start Date	End Date
Planning	Open Project; and Prepare scope statement.	February 2016	February 2016
Design	Prepare detailed design and tender technical conditions by consultant for the upgrade of spherical valve control system; and Consult with servomotors' OEM on design.	May 2016	June 2016
Procurement	Prepare request for proposals (RFP) and award consultant contract.	February 2016	April 2016
	Prepare material requisitions and purchase orders.	June 2016	June 2016
	Receive materials and two new servomotors on site.	October 2016	October 2016
Construction	Upgrade spherical valve control system and replace deflector servomotor on Generating Unit 1.	June 2017	June 2017
	Upgrade spherical valve control system and replace deflector servomotor on Generating Unit 2.	July 2017	July 2017
Commissioning	Commission spherical valve control system and deflector servomotor on Generating Unit 1.	June 2017	June 2017
	Commission spherical valve control system and deflector servomotor on Generating Unit 2.	July 2017	July 2017
Closeout	Prepare closeout package.	September 2017	September 2017

APPENDIX A

Condition Assessment

Spherical Valve Control System at Cat Arm

WorleyParsons
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EcoNomics

NEWFOUNDLAND LABRADOR HYDRO
A NALCOR ENERGY COMPANY

Condition Assessment of the Cat Arm Spherical Valve Controls

OUR FILE: 22502

FINAL REPORT

April 7, 2015

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Executive summary

NL Hydro, owner of the Cat Arm Hydro Generating Station, has mandated WorleyParsons to perform a condition assessment of the spherical valve control system. This assessment will allow NL Hydro planning for short-term or long-term maintenance and refurbishment activities that may be needed.

Prior to a site visit, a data review was done on valve control system which includes electric and hydraulic powered valves, piping, strainers, servomotor operation system, and control panels. A site visit was performed by a WorleyParsons Engineer and NL Hydro staff. Five parameters (physical condition, age, technology level, operating restriction and maintenance requirement) were evaluated for each component, based on observations during site visit. Historical O&M records, drawings, interviews with plant staff and NL Hydro project manager were also performed.

After analyzing all available data, it was concluded that the spherical valve control system does not meet the recommended requirements. There have been important issues in the past with the spherical valve control system. Jumpers have been used in the electric control panel to complete the opening and closing operation. Also, the solenoid actuated valves that control the opening and closing do not always respond correctly and have reached the end of their useful life. This is unusual for this type of equipment.

Unforeseen failure of the control and spherical valves during the emergency closing can cause major damages to the power plant and penstock under a load rejection coincidence with injectors and deflectors malfunction. Not only can it cause damage to the power plant but it can cause threats to human lives as well. The spherical valve is the ultimate protection in case of sustained overspeed caused by a low hydraulic pressure in the governor or a broken injector. Should the automatic control fail to close in an emergency situation, the damage to the unit (and the adjacent unit) will be catastrophic.

Status quo on the actual spherical valve control system can lead to medium-term operation problems and accidents.

Following is a list of recommendations that will bring the control system to an acceptable level of reliability and significantly reduce the risk of seal damage and/or catastrophic failure of the spherical valves.

- **Control panel**: It is recommended to replace the three solenoid valves and pressure differential switch in the hydraulic control panel. Furthermore, it is also recommended to replace the relay box and timer from the electric control panel to restore the original reliability and to change the two air release valves by new components with equivalent features.
- **Service seal pressure:** It is recommended to replace the hydraulic actuated valve to ensure a long-term reliability.

- **Bypass:** It is recommended to change the hydraulic actuated valve to restore the original reliability. An inspection of the welding and pipe condition between the penstock and manual valve (#113) by non-destructive testing (NDT) shall be performed.
- **Servomotor:** It is recommended to replace the hydraulic control valves. Since there is a timing problem following the closing or opening operation, we recommend changing the two actual valves with one hydraulic actuated 3-way 2-position valve. This change will need adjustment in the control logic however it will eliminate all possible errors and timing problems.
- **Maintenance utility:** To simplify the operation and the risk of operation error, it is recommended to change the four manual valves for the upstream seal control by one 4-way 2-position valve.

The servomotor, the spherical valve, bypass piping and penstock were not part of the current condition assessment scope.

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NL HYDRO

Condition Assessment of the Cat Arm Spherical Valve Controls

Transmittal Register

PROJECT 22502

Rev.	Description	Prepared by	Verified by	Approved by	Date
A	Issued for client review	T. Chevrier/ J-M Gauthier	Ugo Velicogna	J-R Tremblay	March 26, 2015
0	Issued final	T. Chevrier/ J-M Gauthier	Ugo Velicogna	J-R Tremblay	April 7, 2015

CWP. 22502

EcoNomics

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1. INTRODUCTION

NL Hydro, a Nalcor Energy company, is the owner of the Cat Arm Hydro Generating Station. Each of the two units operates with a rated flow of 20 m^3/s to generate a total of 127 MW electrical power. One penstock provides water (550 psi) to two Pelton turbines. Two spherical valves are installed upstream of the turbines for isolation and protection.

NL Hydro has mandated WorleyParsons to perform a condition assessment of the spherical valve control system. This assessment will allow NL Hydro planning for short-term or long-term maintenance and refurbishment activities that may be needed.

In the framework of the project described above, WorleyParsons scope includes:

- Visit of the Cat Arm Generating Station site with 1 Mechanical Engineer;
- Condition assessment of the control system of the 2 units which includes:
  - observed defects and deficiencies;
  - refurbishment options;
  - safety requirements;
  - cost estimate ±30%;
  - master schedule.

WorleyParsons recommendations are made subsequent to the site visit and after observing the control valve operating system. During the visit, available maintenance records have been reviewed and the operating and management NL Hydro staff was interviewed. All verifications performed by WorleyParsons are based on the site visit, drawings and data, and relevant information provided by NL Hydro. WorleyParsons has assumed that the information provided by NL Hydro is correct.

2. METHODOLOGY

2.1 Review of existing documentation

The review of the existing documents was performed before the site visit and customized inspection templates were made to facilitate the inspection and to keep track of all components condition. The data review was done on valve control system which includes electric and hydraulic powered valves, piping, strainers, servomotor operation system and control panels.

2.2 Site inspection

An 8-hour site visit was performed by a WorleyParsons Engineer and NL Hydro staff. A general visual inspection of the spherical valve controls was executed using inspection sheets. Our visual observations and staff interviews were performed to make a high-level assessment of material's condition and behavior of each component.

Staff involved in the site visit:

- Mr. Jean-Michel Gauthier, Mechanical Engineer, WorleyParsons;
- Mr. Rodney Willcott, Long-Term Asset Planner, NL Hydro;
- Mr. Mohamed Khalifa - Project execution/Technical service;
- Mr. Dave Royle – Project execution/Technical service; and
- two NL Hydro operators.

During the visit, an investigation was performed on the spherical valve controls existing condition. Investigation purpose was to evaluate the integrity, age, operational restrictions, maintenance issues and understanding of the NL Hydro operation and control requirements. Review of the relevant data and documentation obtained prior and during the field reconnaissance was performed. All components of the controls system were assessed with a detailed inspection sheet to keep an inspection history. No equipment was dismantled or operated to demonstrate any operating issues or performance during this visit due to the electrical system demand.

According to us, the methodology described by the Hydro Power Advancement Project concurs with well-established existing standards and focuses on the following specific criteria:

- potential to restore or replace;
- failure of major equipment, maintenance issues;
- operating restrictions;
- undesirable safety and security concerns;
- availability of spare parts.

This assessment is based on:

- site visits and visual observations;
- inspection sheets with specific observation, condition rating;
- drawings;
- pictures;
- maintenance documentation;
- specific equipment records;
- operational history and restrictions;
- spare parts availability.

2.3 Condition rating framework

The condition assessment of the control system is based on five parameters:

- physical condition;
- age;
- installed technology level;
- operating restrictions;
- maintenance requirement.

These five parameters are evaluated for each component, based on observations during site visit, historical O&M records, drawings, interviews with plant staff and NL Hydro project manager.

For the evaluation, the parameters affecting the condition of the valve control system are weighted. Idem with each component; some of them are more or less important.

2.3.1 Condition assessment criteria

Category	Rating	Description
Physical condition		
Good	7-10	Limited corrosion on valve, piping; coating is in good condition, no leakage. Pressure gauges, indicators, and controls switch are in good condition.
Fair	4-7	Moderate corrosion on valve, piping; coating is in fair condition, trace of leakage. Pressure gauges, indicators, and controls switch are in moderate condition.
Poor	0-3	Severe corrosion on valve, piping; coating is in deteriorated condition, presence of water leakage (more than 50% of surface). Pressure gauges, indicators, and controls switch are in bad condition.
Age		
< 10 years	7-10	Less than 10 years
10-30 years	4-7	Between 10-30 years
Since construction	0-3	>30 years
Technology/Brand name		
Good	7-10	The technology has not changed significantly since the valve control system was installed; the installed technology was supplied by known and still active companies.
Fair	4-7	Old technology but no problem to supply the matching parts in next 5-10 years. Change of technology has little effect on the efficiency and reliability of the controls systems.
Poor	0-3	Installed technology is unavailable and supply spare parts cannot be supplied in reasonable order time. The installed technology can affect reliability and security of power plant. Unknown supplying company.
Operation restrictions		
No	7-10	No constraints on the required operation.
Minimal restraints	4-7	Manual operations are required to avoid malfunction.
Yes, important limitations	0-3	The equipment does not meet the operational and safety criteria.

Category	Rating	Description
Maintenance issues		
Low	7-10	Routine maintenance is required.
Moderate	4-7	Routine maintenance and small correction occasionally.
High	0-3	Important maintenance, frequent repairs, planned shutdown.
Relevant importance of the components (weighting factor)		
Normal	1	Normal importance.
Moderate	2-4	Moderate importance (safety, normal operating).
High	5	Critical importance (safety, emergency operating).

Table 1 Condition assessment criteria

2.4 Records

To allow NL Hydro to keep track of our condition assessment and inspection, details of each component of the control systems have been recorded. Each component was noted according to the condition criteria with referenced pictures. Pictures will be available on CDs with a final paper version. Refer to Appendix 1 for the inspection records and Appendix 5 for the most relevant pictures.

3. CONDITION ASSESSMENT

3.1 General description

Description below was taken from NL Hydro RFP #2015-61201.

"Having only one penstock feeding both units at this powerhouse, spherical valves are used for isolation and protection at this plant, enabling one unit to run when the other is shut-down for maintenance. These valves also allow maintenance crews to perform work safely on the generating units without dewatering the penstock. The valves are considered a critical isolation point and unit protection device (over speed and creep) at this generating station therefore a reliable operating system must be maintained. The spherical valves are 90 degree ball valves that weigh 9500 kg, have an inside diameter of 1500 mm and a design pressure of 4.8 MPa. Two hydraulically movable seals and a piston type servomotor are used to operate the valve and seal off the penstock pressure. The control pressure to operate these devices is supplied via the penstock at 550 psi. A bypass line is used to pressurize the downstream side of the valve and an air venting system releases the air to allow for safe operation of the valve in the high pressure conditions.

The control systems on these valves are used to operate the valve in both automatic and manual modes. The valves can be operated locally at the control panel and remotely from control room. The downstream hydraulically operated seal (service seal) is applied and removed during every operation. This seal can be operated manually and automatically. The upstream seal (maintenance seal) is only used for maintenance and is a critical isolation point that helps ensure worker safety. This maintenance seal is only operated manually. The rotating plug (90 degrees) found inside the valve is operated by the servomotor and can be used manually or automatically. The timing of this servomotor is adjustable with the in line flow control valves. Two sets of duplex strainers are used to clean control water being supplied from the penstock both upstream and downstream of the valve. Water can be supplied from an auxiliary source (pumping unit) in the event that the penstock is dewatered and the valve is required to be operated."

3.2 Importance of the control systems

Spherical valves are used to isolate energy source from the penstock during outage and/or maintenance. In closed position, the seal applications stop leakage through the valve and provide a double blockage of the pressure source. The downstream seal is the service seal activated by the control panel and the upstream seal is used for maintenance and it is activated manually only. The spherical valve is the ultimate protection if the equipment is running in over speed. Although this function is normally performed by the turbine injectors and deflectors, a low oil pressure in the turbine governor and/or an injector failure could lead to an uncontrollable situation during a load rejection. The spherical valve control system reliability during emergency closure is very important to limit possible damage. Due to the design and length of the penstock, the head gate cannot be used for protection at this plant.

Unforeseen failure of the control and spherical valves can cause major damages to the power plant and penstock under a load rejection coincidence with turbine injector malfunction. Not only can it cause damage to the power plant but it can cause threats to human lives. During maintenance work, malfunction of the control system can create hazardous conditions to operating staff, such conditions are therefore unacceptable. Also, any failure may have a substantial impact on power generation and revenues.

Consequently, maintaining the controls system in good operating condition is essential.

3.3 Condition of the control system

The methodology used allows to rate each part according to its condition. Considering a weight factor for each part allows obtaining an overall rating of the various assemblies. With these results, it is possible to notice the overall condition of the spherical valve control system in the table below. Refer to detailed observation in Appendix 2. The score is a value between 0 and 10, 10 being a brand new fully operating system.

Parent assembly	Component description/function	Condition indicator
Duplex strainer	Water filter, provides clean water to the hydraulic system	9.7
Control panel	Controls the spherical valve closing and opening. Also controls the bypass line and the pressure variation	6.1
Service seal pressure	Controls the downstream pressure seal	7.3
Bypass line	Bypass line is used to balance downstream pressure with the upstream prior valve plug opening	6.8
Servomotor control	Allows the closing and opening of the valve plug	7.2
Other components required for maintenance and/or inspection	Used to activate upstream seal or lockdown the spherical valve for maintenance work	8.2

Table 2 Condition of the control system

Details of the results are available in Appendix 2.

3.3.1 Duplex strainers

To operate, the control system is pressurized with water (550 psi) from the penstock. A duplex strainer upstream and downstream provides clean water to operate. They were replaced in 2008 and the overall condition is very good.

Recommendation: There are no issues reported with both duplex strainers, thus routine maintenance and inspection is recommended.

3.3.2 Control panels

The valve control system is used to operate the valve in both automatic and manual modes. We consider the control panels to be the hydraulic control panel and the electric panel (relays). They can be operated locally at the control panel and remotely from the control room. The three solenoid actuated valves (#110, 310 and 410) are showing signs of failure and are not reliable for remote control. Also, there are malfunction issues with the pressure differential switch (#201) during the opening sequence of the spherical valve. The pressure differential switch is set to open when the pressure differential exceeds 15 psi but does not always open. Also, there have been mechanical and electrical issues with the operation of the air release pressure valve.

Past events have been reported about the sequence of operation coming from the relay box which is not always working correctly; during maintenance work, maintenance crews had to use jumpers in the relay box to complete the sequence control, which is a risky situation for items of this importance in a power plant. However, the emergency closing of the spherical valve is still working and it is the most important feature to avoid significant damages to the power plant. The relay control panel presents signs of failure which can prevent an emergency closure and cause serious damages. Maintenance team shall be aware of this situation and schedule a routine inspection of the closing sequence, and if necessary change the faulty relay in the critical path.

***Recommendation**: It is recommended to replace the three solenoid valves and pressure differential switch in the hydraulic control panel. Also, it is recommended to replace the relay box and timer from the electric control panel to restore the original reliability. Finally, it is recommended to change the two air release valves with equivalent features.*

3.3.3 Service seal pressure

The downstream service pressure is required during the spherical valve closing and opening operation. It can be activated manually or automatically from the control panel. Its role is to apply pressure on the plug seal to allow the movement of the seal. The overall condition of the system is fair to good. There have been issues reported about the hydraulic actuated valve (#312) which are the most important part of the system. The cylinder that actuates the control valve is sometimes very slow and is not assuring proper functioning.

***Recommendation**: It is recommended to replace the hydraulic actuated valve with equivalent features to ensure long-term reliability.*

3.3.4 Bypass line

The spherical valve is generally open and the bypass line closed. The bypass valve is used to balance pressure before opening the valve. It can be activated manually or automatically from the control panel with valve (#110). The overall condition of the system is fair to good. There have been issues reported about the hydraulic control valve (#112) which is used to open the bypass. The bypass line needs to work properly for maintenance work and suitable valve operation.

Since the bypass inlet pipe is welded to the upstream penstock, a failure in the pipe between the penstock and valve (#113) would be important to the plant. In case of failure, the only solution will be to close the intake gates and allow the penstock to dewater. Depending of the degree of damage, this can cause significant flooding in the plant. During the visit, the visual condition of the pipe was good.

***Recommendation**: It is recommended to change the hydraulic actuated valve with a new valve to restore the original reliability. It is also recommended to schedule an inspection of the welding and pipe condition between the penstock and manual valve (#113) by non-destructive testing (NDT).*

3.3.5 Servomotor control

The servomotor is using pressurized water from upstream and the downstream of the penstock. The pressure connection for the cylinder closing operation is taken upstream of the spherical valve. The spherical valve closing is the most important function to ensure equipment and workers safety in case of sustained overspeed event. The pressure connection for opening is taken from downstream of the valve, that feature assuring there is pressure on both sides of the valve before opening. During maintenance servomotor shall be locked out to prevent any damages to equipment or harm to workers.

The overall condition of the servomotor control system is fair to good. There have been issues reported about the hydraulic control valves (#412 and 412a) which are used during opening and closing operations. Since each operation of pressurizing/draining of the cylinder chambers is performed by two separate valves, the timing between those two valves shall be accurately adjusted.

Past events with those valves have caused the control supply water to discharge into the valve pit. Being a remote (unmanned) plant, accessible only by snow machine in winter, response times to alarms are slow. Leakage at 550 psi over an extended period of time may cause flooding issues in the plant. Considering the importance of the valve for the emergency closing operation, it is essential to have it replaced.

The speed control of the servomotor with flow control valves is working correctly and its condition is good.

***Recommendation**: It is recommended to replace the hydraulic control valves. Since there is a timing problem following the closing or opening operation, we recommend changing the two actual valves with one hydraulically actuated 3-way/2-position valves (valves #412, 412a, 512 and 512a). This change will need adjustment in the control logic however it will eliminate possible errors or timing problems.*

3.3.6 Other components required for maintenance and/or inspection

The other components required for maintenance and/or inspection are used to isolate or lockdown the spherical valve for maintenance work. They control the upstream seal joint when a double block and bleed is required to work safely on the downstream components (turbine or generator). The upstream joint was rehabilitated in 2008 with a new configuration that applies pressure evenly over the joint. The system works with four manual ball valves and the overall condition of the maintenance/inspection components is good.

***Recommendation**: It is recommended to replace the four manual valves by only one 4-way/2-position manual valve to avoid operator errors.*

3.3.7 Piping

The overall condition of the piping is fair to good. Internal condition of the pipe is unknown.

***Recommendation**: We suggest doing a non-destructive examination (NDE) by ultrasonic testing (UT) to determine the level of pipe corrosion and pipe fooling in various sections, including the section between the penstock and isolating valve. With pipe fooling being an issue at that plant, the piping will have to be dismantled in various strategic locations to determine the current condition. With testing, dismantling and having to adapt the pipe to the new components, replacement of the piping with stainless steel is recommended to ensure long term reliability.*

3.4 Safety requirement

Spherical valves are used to isolate energy source from the penstock for outage and/or maintenance; it also protects the power plant under a load rejection. Spherical valve control system provides important safety features.

Part IX of the Occupational Health & Safety Regulations of Newfoundland Labrador (NL 5/12) explains the requirement for de-energizing and lockout. General requirement as per article 128, states that the energy source shall be isolated and effectively controlled. Control system shall respect and provide lockout protection at all times, this is why lockable valves shall be specified.

When workers are working downstream of the valve, a malfunction of the system is likely to create a hazard that has the potential of becoming deadly. Lockdown of the valve control system including the upstream and downstream seals will provide a double block and bleed protection. The double block and bleed protection, although not required by law, is the best practice to protect workers from any hazards.

4. RECOMMANDATIONS SUMMARY

4.1 Rehabilitation options

Rehabilitation options can be regrouped in two main categories:

- Mandatory: short-term mandatory work, recommended for obtaining reliable operation of the spherical valves (over the next 30 years). This rehabilitation option shall significantly reduce the risk of seal damage and/or major failure of the spherical valves.
- Optional: optional work for long-term reliability.
- Both mandatory and optional work are for the two spherical valve control systems.

4.1.1 Status quo

Following a decision to keep status quo on the actual spherical valve control system can lead to short-term or medium-term operation problems, considering the use of jumpers in the electric control box to complete the opening and closing operation sequence is unusual for this type of equipment. Also, the solenoid actuated valve conditions have reached their useful life. During the emergency closing, this

kind of problem can lead to incomplete sequence of the spherical valve and can possibly cause major damages and substantial loss of revenues. This is not considered a viable option.

4.1.2 Mandatory

Mandatory work is applicable for both unit 1 and unit 2. Hydraulic and electric control panels shall be rehabilitated by changing the solenoid actuated valve and pressure differential switch in the hydraulic panel. Since there have been issues with the relay, it is recommended to replace all timers and old relays in the electric control panel. The logic operation is known and can be programmed in advance. Since space is limited in the electric control panel, additional sequence can be added in another panel as an alarm for the incomplete sequence (drawing A0-1602-107-E-485, note 3). The addition of a small electric panel is probably not necessary but shall be evaluated in the preliminary engineering.

It is recommended to change the existing hydraulic actuated control valve. Those valves are currently at their end of operating life and have caused some issues to the maintenance staff in the past. New available hydraulic actuated valves can work with a small cylinder stroke and can ensure a long-term reliability and meet best industry standards.

For the upstream seal control, in order to simplify the operation and the risk of operation error it is recommended to change the four manual valves with one manual 4-way/2-position valve.

There have been mechanical and electrical issues with the air release pressure valve, for long term rehabilitee, we suggest installing two valves with equivalent features.

We recommend a non-destructive examination (NDE) by ultrasonic testing (UT) to determine the level of pipe corrosion. The inspection could be performed by an inspection firm. This inspection was added to the cost estimate.

Rehabilitation requirement does not request a penstock dewatering.

In table below, mandatory work is detailed.

Mandatory – Equipment/Task	Item number	Location	Description
Replace all the relays and timers		Electric control panel	Allan Bradley following OEM technical specification
Replace solenoid valves	110, 310, 410	Hydraulic control panel	Solenoid 125 VDC 4-way/2-position valve following OEM technical specification
Replace pressure differential switch	201	Hydraulic control panel	Barksdale bourdon tube switch following OEM technical specification
Air release valves	N/A	On top of the valve body and on top of the penstock downstream of the spherical valve	Actual Val-Matic air release valve following OEM technical specification

Mandatory – Equipment/Task	Item number	Location	Description
Replace hydraulic actuated 3-way/2-position valve	111, 312, 512, 512a, 411, 411a	Bypass downstream seal pressure joint Servomotor control (2 valves)	Barksdale hydraulic actuated valve following OEM technical specification
Replace (4) upstream manual valves with 4-way/2-position valve		Upstream seal	4-way/2-position manual valve
Non-destructive examination (NDE) UT and VT on piping	N/A		N/A
NDT on bypass upstream connection to penstock		Between penstock and valve 113	N/A
Partial cable replacement	N/A	All pressure switches	N/A

Table 3 Mandatory rehabilitation

Instead of changing the relay and timer, it is also possible to install a programmable logic controller (PLC). It is believed that relay technology is the most robust system for this type of application; however considering NL Hydro's experience with PLC's operating similar valves at another plant reliably, a PLC can simplify maintenance operation and rehabilitation cost shall probably be less or equal. NL Hydro shall consult the original equipment manufacturer (OEM) to design or guarantee the use of a PLC for this kind of operation.

4.1.3 Optional

Considering the generating station as a long-term asset for NL Hydro, we are suggesting they shall consider the replacement of the entire control system piping. The best practice in hydro is to install stainless pipes and valves to ensure a long-time reliability. Before doing so, we suggest NL Hydro to perform an assessment on the piping condition with a NDT firm. Depending on the level of corrosion and the remaining pipe thickness, it will be possible to determine the need to replace the pipes. The formal estimate for the replacement will be approximatively $130 000 for each unit. This price includes detailed engineering, required material, 8-day shutdown (four pipe fitters 24/7, one welder, one foreman and one project manager/quality inspector). We recommended doing a pipe detailed inspection as well as finalizing conceptual assessment to determine a budgetary price for the piping replacement.

4.2 Cost estimate

The mandatory works cost estimate is for both spherical valve control systems. The total cost has been divided in two separate years for the construction works (2017-2018). It is planned to have approximately two workers teams at site using NL Hydro on-site accommodations.

Description	2017 (unit #1)	2018 (unit #2)	Total for 2 units
Procurement cost	$92 776	$92 776	$185 553
Rental cost	$14 950	$14 950	$29 900
Work at site cost	$252 678	$241 178	$493 856
Engineering cost	$138 000	0	$138 000
Total costs	$598 085	$418 685	$1 016 770

Notes:
1. Costs are estimated in 2015 Canadian dollars. No escalation is included.
2. Excluded costs to be considered by the Owner: project management, owner cost, etc.
3. Contingency cover risks (20%)
4. Allowances (15%) cover the cost of items/details not known at this stage.

Table 4 – Cost estimate summary

For detailed cost estimate, refer to Appendix 3.

4.3 Schedule

The project schedule presents two outages, one in 2017 and one in 2018. The outage is scheduled to be between August and November with duration of approximately 12 days (two shifts/seven days per week).

For schedule, refer to Appendix 4.

5. REFERENCES

Reference standards and guidelines for the condition assessment of spherical valve control system.

Electrical

- Motor control centers: IEEE Std. 493-1997 - IEEE Recommended Practice for the Design of Reliable Industrial and Commercial Power Systems.

Mechanical

- General guidelines: IEEE Std. 1147-2005 - IEEE Guide for the Rehabilitation of Hydroelectric Power Plants
- Condition assessment: HAP Publication "Condition Assessment Manual Appendix 1.03 – Guide for Control/Shut-Off Valve Condition Assessment Revision 1.0" (2012)

Appendix 1 Site inspection report

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Site Inspection Report

Project: Cat Arm Spherical Valves Controls Condition Assessment
Customer: NL Hydro

Project No: 25502
Inspection Date: 2015-03-03
Inspector: Jean-Michel Gauthier, Eng.
NL Hydro representative: Rodney Willcott

No.	Turbine	Discipline	Panel / Assembly	Component	Component Description / Function	ID number	Physical Condition	Age	Technologies Based cards	Any Operating Restrictions	Maintenance Issues	Comments or Actions Required	Photo ID
1	1	Mechanical	Duplex Upstream Strainer 400	Strainer	Upstream water strainer overall condition	420		☐ Since construction: ☒ Others: 2008	Bolt and Kinch	No	No	Recent Duplex Strainer without any problem	6806 / 6825
2	1	Mechanical	Duplex Upstream Strainer 400	Manual Valve	Manual valve, normally open. Upstream of strainer #420	400	Corrosion: ☒ M H Leakage: ☒ M H	☒ Since construction: ☐ Others:_____	NCS	No	No	Have not been rehabilitated	664
3	1	Mechanical	Duplex Upstream Strainer 400	Manual Valve	Manual valve, normally open. Strainer #420	454	Corrosion: ☒ M H Leakage: ☒ M H	☐ Since construction: ☒ Others: 2008		No	No		606
4	1	Mechanical	Duplex Upstream Strainer 400	Filter	Water filter	402-405	Corrosion: ☒ M H Leakage: ☒ M H Filtration media:_____	☐ Since construction: ☒ Others: 2008		No	No		606
4	1	Mechanical	Duplex Upstream Strainer 400	2 inch pipe	Water pipes	N/A		☐ Since construction: ☒ Others: 2008		No	No		663
4	1	Electrical	Duplex Upstream Strainer 400	Control Switch	Control system	403		☐ Since construction: ☒ Others: 2008	Bolt and Kinch	No	No		535/677 8
4	1	Mechanical	Duplex Downstream Strainer 516	Strainer	Downstream water strainer overall condition	516		☐ Since construction: ☒ Others: 2008	Bolt and Kinch	No	No	Recent Duplex Strainer without any problem	667
5	1	Mechanical	Duplex Downstream Strainer 516	Manual Valve	Manual valve, normally open. Upstream of strainer #420	500		☐ Since construction: ☒ Others: 2008		No	No		
6	1	Mechanical	Duplex Downstream Strainer 516	Manual Valve	Manual valve, normally open. Strainer #420	504		☐ Since construction: ☒ Others: 2008		No	No		
7	1	Mechanical	Duplex Downstream Strainer 516	Filter	Water filter	502-505		☐ Since construction: ☒ Others: 2008		No	No		
4	1	Mechanical	Duplex Downstream Strainer 516	2 inch pipe	Water pipes	N/A		☐ Since construction: ☒ Others: 2008		No	No		
8	1	Electrical	Duplex Downstream Strainer 516	Control Switch	Control system	503		☐ Since construction: ☒ Others: 2008	Bolt Filter	No	No		
9	1	Mechanical	Duplex Downstream Strainer 516	Manual Valves	Normally open, downstream strainer 420 to supply pressurized water to control panel	414		☒ Since construction: ☐ Others:_____	NCS	No	No		

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Project: Cat Arm Spherical Valves Controls Condition Assessment
Customer: NL Hydro

Project No: 2502
Inspection Date: 2015-03-03
Inspector: Jean-Michel Gauthier, Eng.
NL Hydro representative: Rodney Wilcott

Item	Unit No.	Discipline	Panel/Assembly	Component	Component Description / Function	ID number	Physical Condition	Age	Technologist Based rules	Any Operating Restrictions	Maintenance Issues	Comments or Action Required	Photo ID
10	1	Mechanical	Control Panel	Electrical Control Valve	Solenoid Valve for bypass, x/2 with limit switch and manual push button for service skid pressure	110	Corrosion: L M H Leakage: L M H Control Issue:	☑ Since construction: ☐ Others:	Hemscheidt	Mechanical jamming during operation		Discontinued valve, liability problem, Mechanical malfunction can occur in position during remote operation	671 / 687
11	1	Mechanical	Control Panel	Electrical Control Valve	Skid mnt Valve for downstream isol. 4"2 with limit switch and manual push button. Manual lock include.	310	Corrosion: L M H Leakage: L M H Control Issue:	☑ Since construction: ☐ Others:	Hemscheidt	Flability issues		Discontinued valve, liability problem	672
12	1	Mechanical	Control Panel	Electrical Control Valve	Solenoid Valve for opening and closing sequence, 4"2 with limit switch and manual push button. Manual lock include	410	Corrosion: L M H Leakage: L M H Control Issue:	☑ Since construction: ☐ Others:	Hemscheidt	Flability issues		Discontinued valve, liability problem	673
13	1	Electrical	Control Panel	Control Switch		316		☒ Since construction: ☐ Others:	Thomas Magnete	No	No		
14	1	Electrical	Control Panel	Control Switch	Solvomotor control valve	417		☑ Since construction: ☐ Others:	Thomas Magnete	No	No		
15	1	Electrical	Control Panel	Control Switch				☑ Since construction: ☐ Others:	Thomas Magnete	No	No		
16	1	Mechanical	Control Panel	Gauge	4" pressure gauge	203	Corrosion: L M H Leakage: L M H Calibration:	☑ Since construction: ☐ Others:	H.B. Tennis	No	No		
17	1	Mechanical	Control Panel	Manual Valves	1/2" normally open	204		☑ Since construction: ☐ Others:		No	No		
18	1	Mechanical	Control Panel	Gauge	4" pressure gauge, service seal pressure line	303		☑ Since construction: ☐ Others:	H.B. Tennis	No	No		
19	1	Mechanical	Control Panel	Manual Valve	1/2" normally open, service seal pressure line	306		☑ Since construction: ☐ Others:		No	No		
20	1	Mechanical	Control Panel	Gauge	4" pressure gauge	206		☑ Since construction: ☐ Others:	H.B. Tennis	No	No		
21	1	Mechanical	Control Panel	Manual Valve	1/2" normally open	207		☑ Since construction: ☐ Others:		No	No	Carbon steel piping, longterm reliability issues	696
22	1	Mechanical	Control Panel	1/2 inch pipe	Upstream water supply to pressure gauge 203 and 206			☑ Since construction: ☐ Others:		No	No	Carbon steel piping, longterm reliability issues	
23	1	Mechanical	Control Panel	1/2 inch pipe	Upstream water supply to pressure gauge 303			☑ Since construction: ☐ Others:		No	No	Carbon steel piping, long reliability issues	
24	1	Mechanical	Control Panel	1/2 inch pipe	Downstream water supply to pressure gauge 206			☑ Since construction: ☐ Others:		No	No		
25	1	Electrical	Control Panel	Control Switch	Pressure differential switch, normally closed, opens when pressure differential exceeds 15 psi	201		☑ Since construction: ☐ Others:	Barksdale	No	Yes	Caused problems during spherical valve opening	674
26	1	Mechanical	Control Panel	Manual Valve	Acrylic pressurized water to control panel	202	Corrosion: L M H Leakage: No M H	☑ Since construction: ☐ Others:	Standard Ball Valve	No	No		675
27	1	Mechanical	Control Panel	Manual Valve	Acrylic pressurized water to control panel	205	Corrosion: L M H Leakage: L M H	☐ Since construction: ☑ Others: ?	Standard Ball Valve	No	No		687
28		Electrical	Control Panel	Electrical control panel	Relay Control panel			☑ Since construction: Others:		Yes	No	Problem with the operations sequence, jumper installed during shutdown	639/651

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Project: Cat Arm Spherical Valves Controls Condition Assessment
Customer: NL Hydro

Project No: 22503
Inspection Date: 2015.03.03
Inspector: Jean-Michel Gauthier, Eng.
NL Hydro representative: Rickey Wilson

Item	Tubine	Discipline	Panel Assembly	Component	Component Description / Function	ID number	Physical Condition	Age	Technologic Based data	Any Operating Restrictions	Maintenance Issues	Comments or Actions Required	Photo ID
29	1	Mechanical	Service Seal Pressure	Manual Valve	Apply service seal water pressure to control panel	304	Corrosion: ⓝ M H Leakage: ⓝ M H	☒ Since construction: ☐ Others:	Worcester Ball Valve	No	No		679160
30	1	Mechanical	Service Seal Pressure	Hydraulics Control Valve	When bypass is open, valve is used to depressurized the Switch 301-302	311,312	Corrosion: ⓝ M H Leakage: ⓝ M H Control issue:	☐ Since construction: ☒ Others:	NAK	No	Yes	Cylindar is very long to operate	691 692
31	1	Mechanical	Service Seal Pressure	2 inch pipe	2" pipe to seal		Corrosion: ⓝ M H Leakage: ⓝ M H	☒ Since construction: ☐ Others:		No	No	Probably Carbon steel, long reliability issues	693
32	1	Mechanical	Service Seal Pressure	Manual Valve	3/4" normally close	314	Corrosion: ⓝ M H Leakage: ⓝ M H	☒ Since construction: ☐ Others:	NAK	No	No		694 695
33	1	Mechanical	Service Seal Pressure	Control Switch	Switch	315		☒ Since construction: ☐ Others:	Barksdale	No	No		696
34	1	Mechanical	Service Seal Pressure	Manual Valve	1/2" normally open	305	Corrosion: ⓝ M H Leakage: ⓝ M H	☒ Since construction: ☐ Others:		No	No		698 697
35	1	Mechanical	Service Seal Pressure	Manual Valve	3/4" normally open	614	Corrosion: ⓝ M H Leakage: ⓝ M H	☒ Since construction: ☐ Others:		No	No		698
36	1	Mechanical	Bypass	Hydraulics Control Valve	Open bypass line, switch 101-102	111,112	Corrosion: ⓝ M H Leakage: ⓝ M H Control issue:	☒ Since construction: ☐ Others:		No	No	Can be problematic long term	699 700
37	1	Mechanical	Bypass	Manual Valve	6" normally open	113	Corrosion: ⓝ M H Leakage: ⓝ M H	☒ Since construction: ☐ Others:	KF 600 WCB	No	No		701 702
38	1	Mechanical	Bypass	Manual Valve	6" normally open	114	Corrosion: ⓝ M H Leakage: ⓝ M H	☒ Since construction: ☐ Others:	WCB 600	No	No		703 704
39	1	Mechanical	Bypass	3/4 inch pipe	Downstrs arm pipe connect to valve #314			☐ Since construction: ☐ Others:				Probably Carbon steel, long-term reliability issues	
40	1	Mechanical	Bypass	6 inch pipe	Bypass piping with flanged connection	412		☒ Since construction: ☐ Others:		No	No	Good Conditions, would recommend UT inspection upstream valve, #113	705

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Project: Cat Arm Spherical Valves Controls Condition Assessment
Customer: NL Hydro

Project No: 22502
Inspection Date: 2015-03-03
Inspector: Jean-Michel Gauthier, Eng.
NL Hydro representative: Rodney Wilcott

Item	Turbine	Discipline	Parent Assembly	Component	Component Description / Function	ID number	Physical Condition	Age	Technologies' based calls	Any Operating Restrictions	Maintenance Issues	Comments or Actions Required	Photo ID
41	1	Mechanical	Servomotor Control	Hydraulics control Valve	Normally open to apply pressure for closing position	412	Corrosion: (L) M H Leakage: (L) M H Controls issues	☑ Since construction: Others:_____ ☐ since overhaul/ref: Others:_____	NAK	No	Yes	Caused problems during spherical valve rotation, timing problem	706 to 709
42	1	Mechanical	Servomotor Control	Hydraulics Control Valve	Normally close, Valve use to rele ase pressure from downstream during opening	412a	Corrosion: (L) M H Leakage: (L) M H Controls issues	☑ Since construction: Others:_____ ☐ since overhaul/ref: Others:_____	NAK	No	Yes	The opening is faster than the closing of the drain 1 Immobilation + Non closing	
43	1	Mechanical	Servomotor Control	Flow control	Flow control for valve 412a	411c	Corrosion: (L) M H Leakage: (L) M H	☑ Since construction: Others:_____ ☐ since overhaul/ref: Others:_____	Parker F8008	No	No		
44	1	Mechanical	Servomotor Control	Flow control	Flow control for valve 412	411b	Corrosion: (L) M H Leakage: (L) M H	☑ Since construction: Others:_____ ☐ since overhaul/ref: Others:_____	Parker F8008	No	No		
45	1	Electrical	Servomotor Control	Control Switch		412b		☑ Since construction: Others:_____ ☐ since overhaul/ref: Others:_____	Jamesbury	No	No		
46	1	Electrical	Servomotor Control	Control Switch		412c		☑ Since construction: Others:_____ ☐ since overhaul/ref: Others:_____	Jamesbury	No	No		
47	1	Mechanical	Servomotor Control	Hydraulics Control Valve	Normally close, use to apply pressure for opening Switch 512c	511-512		☑ Since construction: Others:_____ ☐ since overhaul/ref: Others:_____		No	No		711 to 714
48	1	Mechanical	Servomotor Control	Hydraulics Control Valve	Normally open, Valve use to release pressure from downstream during closing Switch 512a	512a		☑ Since construction: Others:_____ ☐ since overhaul/ref: Others:_____		No	No		
49	1	Mechanical	Servomotor Control	Flow control	Flow control for valve 511	511b		☑ Since construction: Others:_____ ☐ since overhaul/ref: Others:_____		No	No		
50	1	Mechanical	Servomotor Control	Flow control	Flow control for valve 512a	511c		☑ Since construction: Others:_____ ☐ since overhaul/ref: Others:_____		No	No		
51	1	Mechanical	Servomotor Control	Flow control	Flow control for closing	413		☑ Since construction: Others:_____ ☐ since overhaul/ref: Others:_____		No	No		
52	1	Mechanical	Servomotor Control	Flow control	Flow control for opening	513a		☑ Since construction: Others:_____ ☐ since overhaul/ref: Others:_____		No	No		
53	1	Mechanical	Servomotor Control	Manual Valve	Valve opening line	712	Corrosion: (L) M H Leakage: (L) M H	☑ Since construction: Others:_____ ☐ since overhaul/ref: Others:_____	NAK	No	No	Rigid = Steel pipe Flat Bite = Rubber hose	715
54	1	Mechanical	Servomotor Control	Manual Valve	Valve for pressure gauge #414	414	Corrosion: (L) M H Leakage: (L) M H	☐ Since construction: Others:_____ ☑ since overhaul/ref: Others:_____	NAS	No	No		715
55	1	Mechanical	Servomotor Control	Manual Valve	Valve opening line	716	Corrosion: (L) M H Leakage: (L) M H	☑ Since construction: Others:_____ ☐ since overhaul/ref: Others:_____	NAK	No	No		716717
56	1	Mechanical	Servomotor Control	Manual Valve	Valve for pressure gauge #515	517	Corrosion: (L) M H Leakage: (L) M H	☑ Since construction: Others:_____ ☐ since overhaul/ref: Others:_____	NAS	No	No		716717
57	1	Mechanical	Servomotor Control	Gauge	Pressure gauge opening line	515	Corrosion: (L) M H Leakage: (L) M H Calibration:	☑ Since construction: Others:_____ ☐ since overhaul/ref: Others:_____	US gauge	No	No		716717
58	1	Mechanical	Servomotor Control	Gauge	Pressure gauge closing line	419	Corrosion: (L) M H Leakage: (L) M H Calibration:	☑ Since construction: Others:_____ ☐ since overhaul/ref: Others:_____	US gauge	No	No		718
59	1	Mechanical	Servomotor Control	2 inch pipe	Opening line		Corrosion: (L) M H Leakage: (L) M H	☑ Since construction: Others:_____ ☐ since overhaul/ref: Others:_____		No	No	Probably Carbon steel, long term reliability issues	
60	1	Mechanical	Servomotor Control	2 inch pipe	Closing line		Corrosion: (L) M H Leakage: (L) M H	☑ Since construction: Others:_____ ☐ since overhaul/ref: Others:_____		No	No	Probably Carbon steel, long termreliability issues	

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Project: Cat Arm Spherical Valves Controls Condition Assessment
Customer: NL Hydro

Project No: 2502
Inspection Date: 2015.03.03
Inspector: Jean-Michel Gauthier, Eng.
NL Hydro representative: Rodney Wilcott

Item	Turbine	Discipline	Parent Assembly	Component	Component Description / Function	ID number	Physical Condition	Age	Technologist Used Data	Any Operating Restrictions	Maintenance Issues	Comments or Action Required	Photo ID
61	1	Mechanical	Other components required for maintenance and/or inspection	Manual Valve	Normally close, 1" valve	710	Corrosion: L M H Leakage: L M H	☐ Since construction: Others:_____	NAS	no	no	Ok	719720
62	1	Mechanical	Other components required for maintenance and/or inspection	Manual Valve	Normally close, 1" valve	711	Corrosion: L M H Leakage: L M H	☐ Since construction: Others:_____	NAS	No	No		719725
63	1	Mechanical	Other components required for maintenance and/or inspection	Manual Valve	Normally close, 1" valve	714	Corrosion: L M H Leakage: L M H	☐ Since construction: Others:_____	NAS	No	No		721
64	1	Mechanical	Other components required for maintenance and/or inspection	Manual Valve	Normally open, 1" valve	713	Corrosion: L M H Leakage: L M H	☐ Since construction: Others:_____		No	No		722
65	1	Mechanical	Other components required for maintenance and/or inspection	1 inch pipe	For maintenance purpose		Corrosion: L M H Leakage: L M H	☐ Since construction: Others:_____		No	No		722
66	1	Mechanical	Other components required for maintenance and/or inspection	Manual Valve	Normally open, 2" valve	615	Corrosion: L M H Leakage: L M H	☐ Since construction: Others:_____	NAS	No	No		723725
67	1	Mechanical	Other components required for maintenance and/or inspection	Manual Valve	Normally close, 2" valve	616	Corrosion: L M H Leakage: L M H	☐ Since construction: Others:_____		No	No		724725
68	1	Mechanical	Other components required for maintenance and/or inspection	Manual Valve	Normally close 3/4" valve	613	Corrosion: L M H Leakage: L M H	☐ _____		No	No		726
69	1	Mechanical	Other components required for maintenance and/or inspection	Gauge	Downstream pressure gauge	620		☐ Since construction: Others:_____		No	No		725
70	1	Mechanical	Other components required for maintenance and/or inspection	Manual Valve	Normally closed, 1"/2" valve	305		☐ Since construction: Others:_____		No	No		728
71	1	Mechanical	Other components required for maintenance and/or inspection	Manual Valve	Normally close, 2" valve	612		☐ Since construction: Others:_____		No	No	Have been replace	
72	1	Mechanical	Other components required for maintenance and/or inspection	Manual Valve	Normally close, 2" valve	610		☐ since construction: Others:_____		No	No	Have been replace	
73	1	Mechanical	Other components required for maintenance and/or inspection	Manual Valve	Normally open, 2" valve	611		☐ Since construction: Others:_____		No	No	Have been replace	
74	1	Mechanical	Other components required for maintenance and/or inspection	Manual Valve	Normally open valve on servo motor	710	Corrosion: L M H Leakage: L M H	☐ since construction: Others:_____		no	no		727
75	1	Mechanical	Other components required for maintenance and/or inspection	Manual Valve	4 manual valves - upstream seal operating		Corrosion: L M H Leakage: L M H	☐ Since construction: Others: <5 years		No	No	Should use a Chubb, security issues. Would be easier to secure the valve during maintenance, less chance of error.	599

Appendix 2 Control system detailed condition

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Control system detailed condition

Item	Plants Assembly	Component	Component Description / Function	ID number	Physical Condition Score Good: 7-10 Fair: 4-7 Poor: 0-3	Age Score <10 years: 7-10 10-30 years: 4-7 Contuction: 0-3	Installed Technology Score Good: 7-10 Fair: 4-7 Poor: 0-3	Operating Restrictions Score No: 7-10 Minimal : 4-7 Yes: 0-3	Maintenance Requirement Score Low: 7-10 Moderate: 4-7 High: 0-3	Relative importance of part Normal: 1 Moderate: 2-4 High: 5	Condition Indicator	Assembly Average Indicator
1	Duplex Upstream Strainer 420	Strainer	Upstream water strainer overall condition	420	10	10	10	10	10	1	10	9.7
2	Duplex Upstream Strainer 420	Manual Valve	Manual valve, normally open. Upstream of strainer #420	400	10	3	8	10	8	1	8	
3	Duplex Upstream Strainer 420	Manual Valve	Manual valve, normally open. Strainer #420	404	10	10	10	10	10	1	10	
4	Duplex Upstream Strainer 420	Filter	Water filter	402 405	10	10	10	10	10	1	10	
4	Duplex Upstream Strainer 420	Water pipes		N/A	10	10	10	10	10	1	10	
4	Duplex Upstream Strainer 420	2 inch pipe		403	10	10	10	10	10	1	10	
4	Duplex Upstream Strainer 420	Control Switch	Control system	516	10	10	10	10	10	1	10	
4	Duplex Downstream Strainer 516	Strainer	Downstream water strainer overall condition									
5	Duplex Downstream Strainer 516	Manual Valve	Manual valve, normally open. Upstream of strainer #420	500	10	10	10	10	10	1	10	
6	Duplex Downstream Strainer 516	Manual Valve	Manual valve, normally open. Strainer #420	504	10	10	10	10	10	1	10	
7	Duplex Downstream Strainer 516	Filter	Water filter	502 505	10	10	10	10	10	1	10	
4	Duplex Downstream Strainer 516	Water pipes		N/A	10	10	10	10	10	1	10	
8	Duplex Downstream Strainer 516	2 inch pipe		503	10	10	10	10	10	1	10	
4	Duplex Downstream Strainer 516	Control Switch	Control system									
9	Duplex Downstream Strainer 516	Manual Valves	Normally open, downstream strainer 420 to supply pressurized water to control panel	414	10	3	8	10	8	1	8	

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Control system detailed condition

Item	Plants Assembly	Component	Component Description / Function	ID number	Physical Condition Score Good: 7-10 Fair: 4-7 Poor: 0-3	Age Score <10 years: 7-10 10-30 years: 4-7 Construction.: 0-3	Installed Technology Score Good: 7-10 Fair: 4-7 Poor: 0-3	Operating Restrictions Score No: 7-10 Minimal : 4-7 Yes: 0-3	Maintenance Requirement Score Low: 7-10 Moderate: 4-7 High: 0-3	Relative importance of part Normal: 1 Moderate: 2-4 High: 5	Condition Indicator	Assembly Average Indicator
10	Control Panel	Electrical Control Valve	Solenoid Valve for bypass. 4/2 with limit switch and manual push button for service seal pressure	110	10	3	5	1	3	3	4	6.1
11	Control Panel	Electrical Control Valve	Solenoid Valve for downstream seal. 4/2 with limit switch and manual push button. Manual lock include	310	10	3	5	1	3	3	4	
12	Control Panel	Electrical Control Valve	Solenoid Valve for opening and closing sequence. 4/2 with limit switch and manual push button. Manual lock include	410	10	3	5	1	3	3	4	
13	Control Panel	Control Switch		316	10	3	5	5	8	2	8	
14	Control Panel	Control Switch	Servomotor control valve	417	10	3	5	5	8	2	8	
15	Control Panel	Control Switch		0	10	3	5	5	8	2	8	
16	Control Panel	Gauge	4" pressure gauge	203	10	3	8	10	10	1	8	
17	Control Panel	Manual Valves	1/2" normally open	204	10	3	10	10	10	1	9	
18	Control Panel	Gauge	4" pressure gauge. service seal pressure line	303	10	3	8	10	10	1	8	
19	Control Panel	Manual Valve	1/2" normally open. service seal pressure line	306	10	3	10	10	10	1	9	
20	Control Panel	Gauge	4" pressure gauge	206	10	3	8	10	10	1	8	
21	Control Panel	Manual Valve	1/2" normally open	207	10	3	10	10	10	1	9	
22	Control Panel	1/2 inch pipe	Upstream water supply to pressure gauge 203 and 206		10	3	5	10	5	1	7	
23	Control Panel	1/2 inch pipe	Upstream water supply to pressure gauge 303		10	3	5	10	5	1	7	
24	Control Panel	1/2 inch pipe	Downstream water supply to pressure gauge 206		10	3	5	10	5	1	7	
25	Control Panel	Control Switch	Pressure differential switch, normally closed, opens when pressure differencial exceeds 15 psi	201	10	3	7	6	6	3	8	7.3
26	Control Panel	Manual Valve	Apply pressurized water to control pannel	202	10	3	8	10	10	1	8	
27	Control Panel	Manual Valve	Apply pressurized water to control pannel	205	10	3	8	10	10	1	8	
28	Control Panel	Electri control panel	Relay (Control pannel		10	3	5	3	5	5	5	
29	Service Seal Pressure	Manual Valve	Apply service seal water pressure to control pannel	304	10	3	10	10	10	1	9	
30	Service Seal Pressure	Hydraulics Control Valve	When bypass is open, valve is used to depressurized line. Switch 301-302	311 312	10	3	4	3	7	3	5	
31	Service Seal Pressure	2 inch pipe	2" pipe to seal		10	3	5	10	5	1	7	
32	Service Seal Pressure	Manual Valve	3/4" normally close	314	10	3	8	10	10	1	8	
33	Service Seal Pressure	Control Switch	Switch	315	10	3	7	10	10	1	8	
34	Service Seal Pressure	Manual Valve	1/2" normally open	305	10	3	8	10	10	1	9	
35	Service Seal Pressure	Manual Valve	3/4" normally open	614	10	3	8	10	10	1	9	
36	Bypass	Hydraulics Control Valve	Open bypass line, switch 101-102	111 112	10	3	10	3	8	3	7	6.8
37	Bypass	Manual Valve	6" normally open	113	10	3	10	10	8	1	8	
38	Bypass	Manual Valve	6" normally open	114	10	3	10	10	8	1	8	
39	Bypass	3/4 inch pipe	Downstream pipe connect to valve #614		10	3	5	10	5	1	7	
40	Bypass	6 inch pipe	bypass piping with flanged connection	412	10	3	10	10	10	1	9	

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Control system detailed condition

Item	Parent Assembly	Component	Component Description / Function	ID number	Physical Condition Score Good: 7-10 Fair: 4-7 Poor: 0-3	Age Score <10 years: 7-10 10 -30 years: 4-7 Construction: 0-3	Installed Technology Score Good: 7-10 Fair: 4-7 Poor: 0-3	Operating Restrictions Score No: 7-10 Minimal : 4-7 Yes: 0-3	Maintenance Requirement Score Low: 7-10 Moderate: 4-7 High: 0-3	Relative importance of part Normal: 1 Moderate: 2-4 High: 5	Condition Indicator	Assembly Average Indicator
41	Servomotor Control	Hydraulics Control Valve	Normally open to apply pressure for closing position	412	10	3	4	3	7	3	5	7.2
42	Servomotor Control	Hydraulics Control Valve	Normally close, valve use to release pressure from downstream during opening	412a	10	3	4	3	7	3	5	
43	Servomotor Control	Flow control	Flow control for valve 412a	411c	10	3	10	10	10	1	9	
44	Servomotor Control	Flow control	Flow control for valve 412	411b	10	3	10	10	10	1	9	
45	Servomotor Control	Control Switch		412b	10	3	10	8	8	1	8	
46	Servomotor Control	Control Switch		412c	10	3	10	8	8	1	8	
47	Servomotor Control	Hydraulics Control Valve	Normally close, use to apply pressure for opening. Switch 512c	511-512	10	3	4	5	7	3	6	
48	Servomotor Control	Hydraulics Control Valve	Normally open, valve use to release pressure from downstream during closing. Switch 512b	512a	10	3	4	5	7	3	6	
49	Servomotor Control	Flow control	Flow control for valve 511	511b	10	3	10	10	10	1	9	
50	Servomotor Control	Flow control	Flow control for valve 512a	511c	10	3	10	10	10	1	9	
51	Servomotor Control	Flow control	Flow control for closing	413	10	3	10	10	10	1	9	
52	Servomotor Control	Flow control	Flow control for opening	513a	10	3	10	10	10	1	9	
53	Servomotor Control	Manual Valve	Valve opening line	712	10	3	10	10	10	1	9	
54	Servomotor Control	Manual Valve	Valve for pressure gauge #419	418	10	10	10	10	10	1	10	
55	Servomotor Control	Manual Valve	Valve opening line	716	10	10	10	10	10	1	10	
56	Servomotor Control	Manual Valve	Valve for pressure gauge #515	517	10	3	10	10	10	1	9	
57	Servomotor Control	Gauge	Pressure gauge opening line	515	10	3	8	10	10	1	8	
58	Servomotor Control	Gauge	Pressure gauge closing line	419	10	3	8	10	10	1	8	
59	Servomotor Control	2 inch pipe	Opening line		10	3	5	10	5	1	7	
60	Servomotor Control	2 inch pipe	Closing line		10	3	5	10	5	1	7	

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Control system detailed condition

Item	Parent Assembly	Component	Component Description / Function	ID number	Physical Condition Score Good: 7-10 Fair: 4-7 Poor: 0-3	Age Score <10 years: 7-10 10 -30 years: 4-7 Construction.: 0-3	Installed Technology Score Good: 7-10 Fair: 4-7 Poor: 0-3	Operating Restrictions Score No: 7-10 Minimal : 4-7 Yes: 0-3	Maintenance Requirement Score Low: 7-10 Moderate: 4-7 High: 0-3	Relative importance of part Normal: 1 Moderate: 2-4 High: 5	Condition Indicator	Assembly Average Indicator
61	Other components required for maintenance and/or inspection	Manual Valve	Normally close, 1" valve	715	10	3	10	10	10	1	9	8.2
62	Other components required for maintenance and/or inspection	Manual Valve	Normally close, 1" valve	711	10	3	10	10	10	1	9	
63	Other components required for maintenance and/or inspection	Manual Valve	Normally close, 1" valve	714	10	3	10	10	10	1	9	
64	Other components required for maintenance and/or inspection	Manual Valve	Normally open, 1" valve	713	10	3	10	10	10	1	9	
65	Other components required for maintenance and/or inspection	1 inch pipe	For maintenance purpose		10	3	7	10	10	1	8	
66	Other components required for maintenance and/or inspection	Manual Valve	Normally open, 2" valve	615	10	10	10	10	10	1	10	
67	Other components required for maintenance and/or inspection	Manual Valve	Normally close, 2" valve	616	10	3	10	10	10	1	9	
68	Other components required for maintenance and/or inspection	Manual Valve	Normally close 3/4" valve	613	10	3	10	10	10	1	9	
69	Other components required for maintenance and/or inspection	Gauge	Downstream pressure gauge	620	10	10	10	10	10	1	10	
70	Other components required for maintenance and/or inspection	Normally closed, 1" valve	Normally close, 1/2" valve	305	10	3	10	10	10	1	9	
71	Other components required for maintenance and/or inspection	Manual Valve	Normally close, 2" valve	612	10	10	10	10	10	1	10	
72	Other components required for maintenance and/or inspection	Manual Valve	Normally close, 2" valve	610	10	10	10	10	10	1	10	
73	Other components required for maintenance and/or inspection	Manual Valve	Normally open, 2" valve	611	10	10	10	10	10	1	10	
74	Other components required for maintenance and/or inspection	Manual Valve	Normally open, 2" valve	611	10	3	10	10	10	1	9	
75	Other components required for maintenance and/or inspection	Manual Valve	4 manual valves- upstream seal operating		10	10	3	3	3	5	6	
			Weighting Factors for Condition Parameters		1	1	1	2	1			

Appendix 3 Cost estimate

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Project Cost Estimate +/- 30%
Cat Arm Sphere Valve Controls (2 units)
Mandatory

April 07, 2015
Rev 0

Description		Days	hrs./day	Rate	Qty	Unit cost	TOTAL	2 017	2 018	Summary
DIRECT										
Procurement										
Valves	Solenoid valve 4/2 - Hydraulic Control Panel				6	1 500 $	9 000 $	50%	50%	
	Manifold for solenoid valve - Hydraulic Control Panel				6	500 $	3 000 $	50%	50%	
	Pressure differential switch, 125VDC- Hydraulic Control Panel				2	755 $	1 510 $	50%	50%	
	Hydraulic actuated valve 3/2 with position indicator - Servomotor Control				4	6 500 $	26 000 $	50%	50%	
	Hydraulic actuated valve 3/2 with position indicator - Bypass and Downstream Seal Control				4	6 500 $	26 000 $	50%	50%	
	Manually actuated Heavy duty Valves 4/2, position indicator - Upstream Seal Control				2	5 000 $	10 000 $	50%	50%	
	Pressure Switch				20	577 $	11 540 $	50%	50%	
	Air release valve (2 per Shertcal Valve)				4	8 500 $	34 000 $	50%	50%	
I & C	Existing control panels modifications:									
	Electro-Pneumatic timer relays				12	450 $	5 400 $	50%	50%	
	Allen-Bradley HO 700-P Relays 4PDT				50	250 $	12 500 $	50%	50%	
	New junction box near control valves (4 per Shertcal Valve)				8	300 $	2 400 $	50%	50%	
	Electric material (connectors, conduit, conductors,...)				2	5 000 $	10 000 $	50%	50%	
Piping	Pipe retrofitting materials				2	5 000 $	10 000 $	50%	50%	
						Sub-Total	**161 350 $**	80 675 $	80 675 $	
						Allowance (15%)[3]	24 203 $	12 101 $	12 101 $	
	Total Procurement					TOTAL	**185 553 $**	**92 776 $**	**92 776 $**	**185 553 $**
Rentals	4 Pick-up trucks 1 month (gas included)				8	3 250 $	26 000 $	50%	50%	
						Sub-Total	**26 000 $**	13 000 $	13 000 $	
						Allowance (15%)[3]	3 900 $	1 950 $	1 950 $	
	Total Rentals					TOTAL	**29 900 $**	**14 950 $**	**14 950 $**	**29 900 $**
Work on site (10 days per outage + 2 days of travelling = 12 days total		**Qty**	**Days**	**hrs./day**	**Rate**					
	Transportation of parts & tools	2				5 000 $	10 000 $	50%	50%	
	NDE	1				10 000 $	10 000 $	100%	0%	
	Millwright,welder (2 workers 12h/days)	2	24	12	90.00 $		51 840 $	50%	50%	
	Pipe Fitter (4 workers 12h/days)	4	24	12	90.00 $		103 680 $	50%	50%	
	Electricians (2 electricians 12h/days)	4	24	12	90.00 $		103 680 $	50%	50%	
	Contractor foreman 12h/day	1	24	12	100.00 $		28 800 $	50%	50%	
	Contractor PM / Quality Insurance 12h/day	1	24	12	130.00 $		37 440 $	50%	50%	
	Overtime (10 workers - 4 hours/day)	10	24	4	50.00 $		48 000 $	50%	50%	
	Cost living allowance (150$ per days)	10	24		150.00 $		36 000 $	50%	50%	
						Sub-Total	**429 440 $**	219 720 $	209 720 $	
						Allowance (15%)[3]	64 416 $	32 958 $	31 458 $	
	Total Work at Site					TOTAL	**493 856 $**	**252 678 $**	**241 178 $**	**493 856 $**
TOTAL DIRECT COSTS								**360 404 $**	**348 904 $**	**709 309 $**
INDIRECT COSTS										
	Preliminary engineering						40 000 $	100%	0%	
	Execution engineering						80 000 $	100%	0%	
						SUB	**120 000 $**	120 000 $	0 $	
						Allowance (15%)[3]	18 000 $	18 000 $	0 $	
	Total Engineering					TOTAL	**138 000 $**	**138 000 $**	**0 $**	**138 000 $**
TOTAL INDIRECT COSTS								**138 000 $**	**0 $**	**138 000 $**
							subtotal	**498 404 $**	**348 904 $**	**847 308 $**
	Contingency (% to be confirmed when risk reviews are completed)[3]						**20%**	**99 681 $**	**69 781 $**	**169 461.70 $**
								YEAR 2017	YEAR 2018	2017-2018
TOTAL								**598 085 $**	**418 685 $**	**1 016 770 $**

1: Costs are estimated in 2015 Canadian dollars. No escalation is included.
2: Excluded costs to be considered by the owner: Project management, owner cost,...
3: Contingency cover risks
4: Allowances cover the cost of items/details not known at this stage

Appendix 4 Project schedule

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Cat Arm Spherical Valve Controls
Project Schedule

newfoundland labrador hydro
a nalcor energy company

ID	Task Name	Duration	Start	Finish
1	NL Hydro financial approval	0 days	2016-06-03	2016-06-03
2	Engineering tender period	4 wks	2016-08-01	2016-08-26
3	Preliminary engineering	12 wks	2016-09-05	2016-11-25
4	Tendering period (electrical & mechanical equipments)	9 wks	2016-11-28	2017-01-27
5	Supply contract award	4 wks	2017-01-30	2017-02-24
6	Detailed engineering	17 wks	2017-02-27	2017-06-23
7	Equipment supply	12 wks	2017-03-27	2017-06-16
8	Preparatory work (unit 1)	1 wk	2017-08-21	2017-08-25
9	Outage (unit 1)	10 days	2017-09-04	2017-09-15
10	Commissioning (unit 1)	2 days	2017-09-14	2017-09-15
11	Lessons learned with supplier	1 day	2017-09-20	2017-09-20
12	Preparatory work (unit 2)	1 wk	2018-08-20	2018-08-24
13	Outage (unit 2)	10 days	2018-09-03	2018-09-14
14	Commissioning (unit 2)	2 days	2018-09-13	2018-09-14

Appendix 5 Pictures


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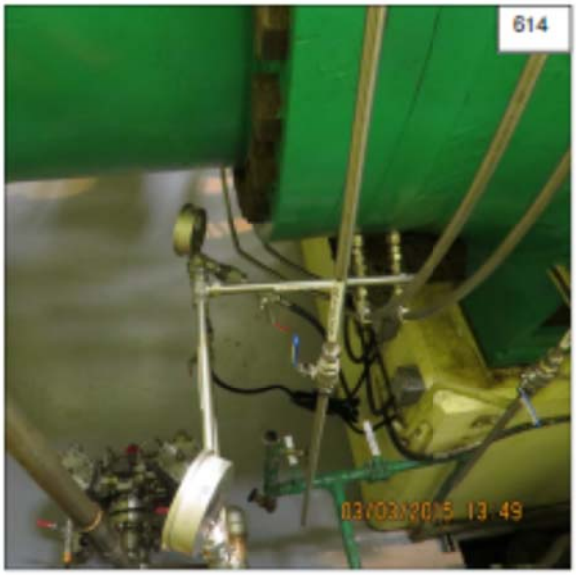

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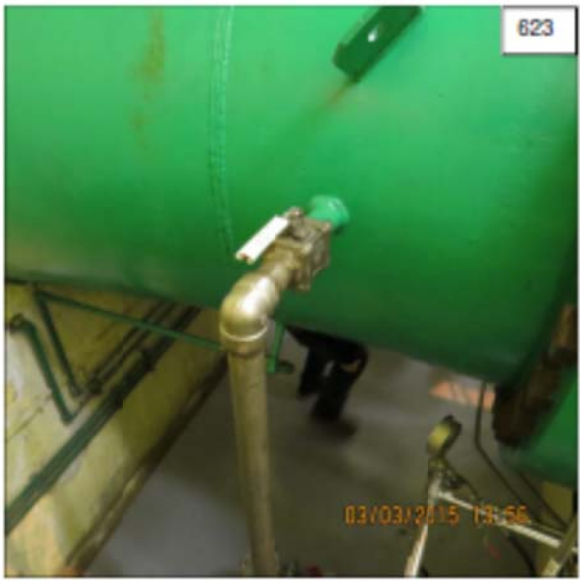

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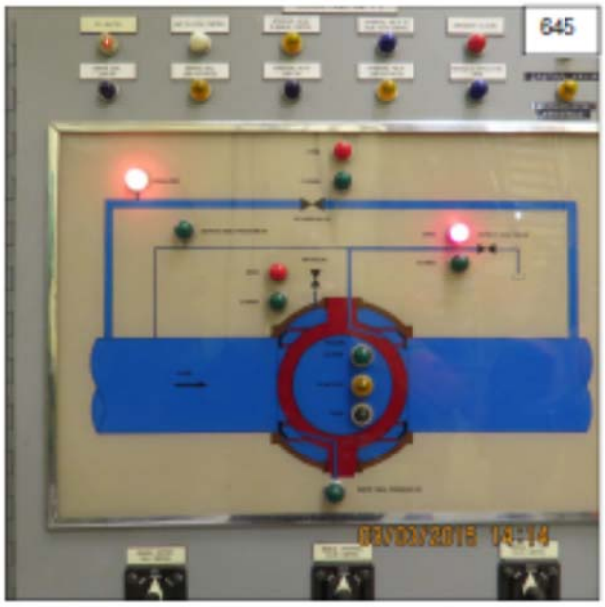

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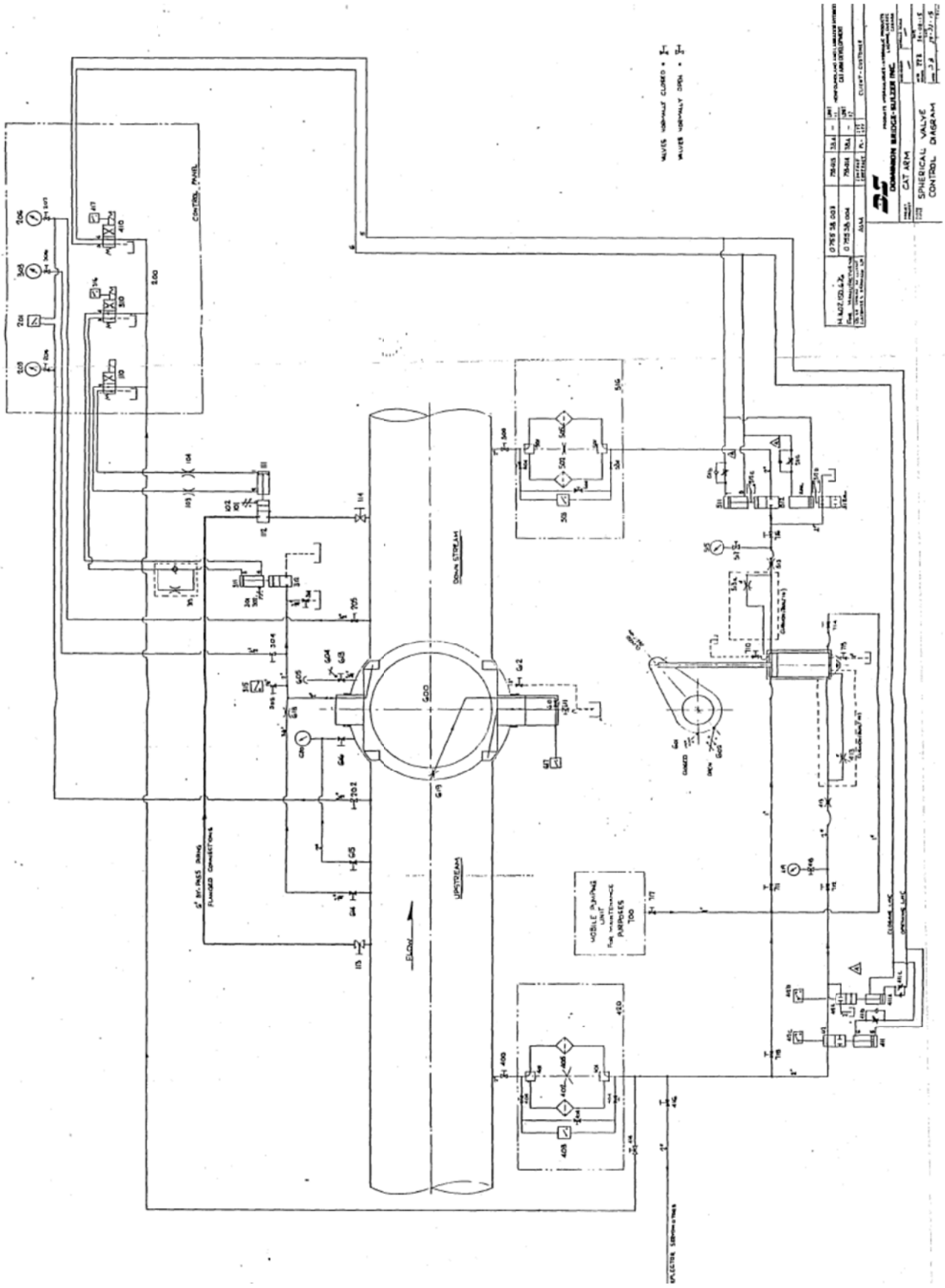

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APPENDIX B

Spherical Valve Control Diagram – Cat Arm


CONTROL PANEL
DOWN STREAM
UPSTREAM
FLOW
VALVES NORMALLY CLOSED
VALVES NORMALLY OPEN
DOMINION BRIDGE-SULZER INC.
CAT ARM
SPHERICAL VALVE
CONTROL DIAGRAM

A REPORT TO
THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

	Electrical
	Mechanical
	Civil
	Protection & Control
	Transmission & Distribution
	Telecontrol
	System Planning

Rehabilitate Shoreline Protection

Cat Arm

July 2015

newfoundland labrador hydro
a nalcor energy company

SUMMARY

Hydro has been visually monitoring roadway embankment erosion along a section of the Cat Arm Access Road since it was originally completed in 1984. This section of road is situated in a harsh environment, directly exposed to the Atlantic Ocean, and is subject to sizeable wave action. Consequently, the embankment is experiencing significant erosion and has been the subject of previous rehabilitation efforts.

A significant rehabilitation of this section of road was previously undertaken in 2005. The rehabilitation effort consisted of the placement of armour stone along the face of the embankment and is shown in Figure 1 below. Armour stone consists of large rock particles placed at a sloped angle, that is ideally designed to dissipate wave energy. It is widely used in hydraulic protection applications as it is typically cost effective.



Figure 1: Rehabilitated Section of Cat Arm Access Road

A portion of this rehabilitated section has eroded to the point that remedial action is required to prevent continued embankment erosion and to offset a more extensive future rehabilitation effort. A 90m section of heavy armour stone, placed near the water's edge during the 2005 rehabilitation has been washed out into the ocean. This loss of armour

stone has resulted in the degradation of smaller aggregate material, placed to stabilize the road embankment. Without the armour stone, there is no protection to support the finer rock fill and filter materials which are now easily eroded by wind and wave action (see Figure 2).



Figure 2: Eroded Section of Road Embankment

In 2014, Hydro engaged AMEC Environment and Infrastructure (AMEC) to assess the embankment erosion and conduct a feasibility study of the various repair alternatives, which could be implemented to remediate the eroded section. A copy of the AMEC report, titled, *"Feasibility Study to Address Rock Armour Erosion, Cat Arm Access Road"* is contained in Appendix A.

This proposal is for a two-year project to upgrade the shoreline protection, as recommended in the report. Year one will see the finalization of the detailed design, the preparation of tender documentation, and the acquisition of all required environmental permits. Construction of the proposed embankment stabilization and shoreline protection will take place in year two. Completion of this project will ensure continued, uninterrupted use of the Cat Arm access road, which is travelled by Hydro's operational and maintenance staff on a regular basis.

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APPENDIX A A1

1 INTRODUCTION

The Cat Arm Development, on the Northern Peninsula, includes two reservoirs, ten dams and dykes, two overflow spillways, one fore bay tunnel, one intake structure and one powerhouse, located at sea level. Access to the powerhouse is via a 25km long gravel road off route 420 near Jackson's Arm. A 90m section of the road embankment near the powerhouse at Devil's Cove is seriously deteriorated and requires rehabilitation.

This access road and the Cat Arm Development were completed in the early 1980's. There have been continual erosion problems along various sections of the road over the years, stemming from loss of foundation material at sea level as a result of wind and wave attack from the ocean. Rehabilitation works, enacted to address the embankment stability issues include: the installation of bin-walls[1] to shore up isolated sections of the upper road embankment and the construction of a shoreline protection barrier to stabilize a portion of the access road embankment near the powerhouse. Severe environmental conditions have caused new damage to this shoreline protection barrier resulting in road embankment damage and it needs to be addressed before further damage occurs.

The Cat Arm Development is critical to Hydro to ensure that the Island Interconnected System power demands are reliably met. The Cat Arm Hydroelectric Generating Station has a net output of 127 MW with an annual energy production of 710 GWh. This plant produces approximately 14% of Hydro's hydroelectric power capacity and comprises 16% of the Island Interconnected System's energy capability. It is imperative that access to this facility be maintained to allow operations and maintenance activities to be carried out.

[1] Bin-Walls are a versatile gravity retaining wall system comprised of rugged galvanized steel components. The system consists of adjoining, closed-face steel bins, filled with compacted granular material, and designed to the height and depth needed to resist overturning and sliding forces typical of gravity wall systems. Their unique design enables Bin-Walls to adjust to minor ground movement without cracking or bulging.

2 PROJECT DESCRIPTION

This proposal is for a two-year project to complete the shoreline protection upgrades, as recommended by AMEC. Work will consist of the of the completion of upgrades over a 90m section of roadway embankment near the Cat Arm powerhouse in Devil's Cove, which has deteriorated and requires attention.

The scope of work generally consists of the completion of upgrades to the existing armour stone wave barrier and the placement of rock fill material to re-establish a stable roadway embankment.

The project will require approvals from the Provincial Department of Environment and Conservation, Provincial Department of Natural resources and the Federal Department of Fisheries and Oceans.

3 JUSTIFICATION

The Cat Arm Hydroelectric Generating Station access road is the only viable access available to the powerhouse. The road is used on a daily basis by Hydro's operating staff and at regular intervals by the maintenance personnel. Vehicles transporting personnel and maintenance material must travel this access road. The road is essential for operations and maintenance of the plant. The road must be kept in a safe and passable condition to ensure both employee and public safety.

Wind and wave action on this coast continues to cause significant erosion along various sections of this road. One of these areas is located along an armour stone shoreline protection barrier, constructed in 2005. Extreme environmental conditions in the area have damaged the shoreline protection barrier along an 80m section. This shoreline protection barrier provides protection for the blast rock and filter material in the upgraded road embankment section. With the protection material removed, the remaining blast rock and filter material is left unprotected and erodes easily into the ocean.

A review of the shoreline protection barrier by Hydro staff and AMEC in 2014 (See Appendix A) concluded that continued erosion is anticipated during periods of high waves, combined with storm surges or higher tides, and the road embankment should be repaired to prevent further erosion.

Failure to complete the recommended upgrade will result in continued road embankment erosion, likely leading to an increase in rate of failure and increased cost to repair. This potential slope failure could lead to possible road embankment collapse, to a point where the road will become impassible or unsafe. This will result in a loss of access to the powerhouse for operational and maintenance work and would have an impact on plant reliability and power supply to Hydro's customers.

A permanent and safe access road is required for the long term reliable operation of Cat Arm.

3.1 Existing System

The Cat Arm Hydroelectric Generating Station contains two generating units, each rated at 67.5 MW, with a maximum production output of 63.5 MW when running simultaneously. Situated on the east side of the Northern Peninsula, the Cat Arm Hydroelectric Development was completed in 1984. Access to the plant is via a 25km long gravel road off route 420 near Jackson's Arm.

As part of other road work undertaken in 2012, Hydro submitted an application for Permission to Occupy to Crown Lands in 2012. Hydro subsequently applied for and received a Crown Easement to the road lands. This easement form of title has been determined to be appropriate for Hydro's needs as Hydro does not need to exclude others from using the road but it does require the legal right to have secure access over it, to make improvements to the road and to build and maintain structures such as guide rails, bridges and culverts. This is the form of title upon which Hydro holds a significant amount of its distribution and transmission plants.

The Cat Arm Hydroelectric Generating Station is a critical component of Hydro's available hydraulic resources and is in continuous operation. The access road was originally completed in 1982/83 and is now 33 years old.

Major work and upgrades completed on the Cat Arm access road since original construction consist of road repairs and slope stabilization measures, completed on isolated sections of the roadway, as detailed in Table 1.

Table 1: Major Work or Upgrades

Year	Major Work/Upgrade	Cost
2015B	Culvert Replacement and Road Resurfacing	$990,000
2012	Slope Stabilization (Install Bin-Walls)	$235,000
2005	Construction of Armour Stone Embankment	$1,358,300
1993	Bin-wall Installation	$50,000

3.2 Operating Experience

Approximately one kilometer of the Cat Arm access road, in the vicinity of the powerhouse, was constructed on an exposed sea cliff. This section of road has experienced erosion since the road's completion in 1984.

An armour stone shoreline protection barrier, which was completed in 2005, has eroded over a portion of its length (See Figures 3, 4, 5 and 6 below which demonstrate the deterioration over time). The loss of the protective armour stone layer has left the remaining rock fill and filter material exposed to the elements. This smaller material is easily eroded by the wave action to which it is exposed. If left unattended, the roadway's driving surface will be impacted by the loss of foundation support.

The current embankment erosion is a result of movement within the original rock armour layer, which has resulted in subsequent erosion and undermining of the underlying embankment surface. Plausible theories as to what may have resulted in the armour stone movement include:

- Amplified and deflected wave action caused by bedrock outcrops which extend beyond the existing shoreline protection;
- Increased localized wave energy as a result of confinement and run-up along partially submerged bedrock outcrops;
- Possible deep deposit of uncontrolled fill during the initial road construction and the subsequent development of a sandy shoreline may have experienced some settlement due to increased loading resulting from the 2005 construction; and
- Pack ice and freezing ocean spray.



Figure 3: 2008



Figure 4: 2009



Figure 5: 2011



Figure 6: 2012

3.2.1 Safety Performance

The loss of embankment material will progress to the point in which the roadway is impacted, posing a safety risk to those who utilize the road on a regular basis.

3.2.2 Maintenance or Support Arrangements

Routine maintenance of the Cat Arm access road is performed by Hydro personnel. Snow clearing and road rehabilitation are performed by external contractors with access to equipment suitable for work of this nature.

3.2.3 Maintenance History

A summary of the maintenance expenditure history for the Cat Arm Hydroelectric Generating Plant Access Road is shown in Table 2 below.

Table 2: Five-Year Maintenance History

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2014	0.0	0.0	0.0
2013	0.2	45.8	46.0
2012	0.0	0.0	0.0
2011	36.1	0.0	36.1
2010	0.0	1.5	1.5

3.2.4 Historical Information

Concerns over the loss of embankment material, along the section re-constructed in 2005, were first identified in 2008. As a result, Hydro engaged AMEC to assess the erosion and recommend a mitigation strategy. Based on their assessment findings, AMEC recommended that a survey be completed to establish the quantity of lost embankment material. It was also recommended that annual monitoring of the embankment be completed in an effort to establish the rate of erosion. Surveys were completed in 2008 and 2009. The loss of material in 2008 was determined to be 1,650 cubic meters and in 2009 the loss had increased to 1,950 cubic meters.

As a result of the continued loss of material, AMEC were again consulted, in 2010, to conduct further investigation. Hydro requested that AMEC reassess the access roadway embankment and determine the mode(s) of failure which might have attributed to the failure of the armour stone. Pending the assessment findings AMEC was required to provide a recommendation for the slope rehabilitation and develop a cost estimate to complete the work.

A final field survey was completed in 2011, following the AMEC assessment. The survey showed that the material loss had increased to 5,900 cubic meters. The substantial increase in the rate of erosion, evident through the survey data, confirmed that the embankment erosion is progressive, thus, substantiating the requirement to complete remedial measures in an effort to mitigate the problem.

In 2014, due in large part to their familiarity with the embankment erosion history, Hydro commissioned AMEC to complete a feasibility study of various embankment repair alternatives. This feasibility study was requested by Hydro to ensure that all viable upgrade alternatives garnered appropriate consideration, thus, ensuring that the most viable alternative was selected. The parameters, considered during the ranking of each alternative, included: local availability, constructability, environmental impact, visual appearance, serviceability, and cost. The feasibility study report is contained in Appendix A and forms the basis of the estimate for this project.

3.2.5 Anticipated Useful Life

The shoreline protection has an anticipated useful life of 20 years.

3.3 Development of Alternatives

In 2014, Hydro commissioned AMEC to assess the embankment erosion and investigate the shoreline protection upgrade alternatives. Alternatives considered in the report include:

- Regular Upkeep;
- Rock Armour Upgrades;
- Installation of Gabion retention structures;
- Installation of anchor wall structures;
- Installation of pre-cast concrete armour units;
- Installation of a breakwater;
- Installation of a concrete seawall;
- Installation of steel piles;
- Installation of a bridge to span the affected area;
- Realignment of the existing access road; and
- Construction of a new access road.

3.4 Evaluation of Alternatives

The alternatives, considered for the slope rehabilitation, are common industry methods employed to address the occurrence of erosion similar to that experienced on the Cat Arm

access road. As part of their evaluation, AMEC conducted a thorough analysis of each alternative taking into consideration a number of factors, including: local availability, constructability, environment, aesthetics, viability and cost.

Alternative #1: Regular Upkeep. This option involves the completion of regular inspection and maintenance of the both the access road and the rock armour defense. This option would not involve any changes to the existing shoreline protection design. Initial embankment reshaping would be completed with reoccurring, remedial rock armour placement required, likely every 2 to 5 years.

Alternative #2: Rock Armour Rehabilitation. Rock armour is a commonly utilized form of slope protection. This alternative is favourable given that the rock material, required to complete the work, can be readily obtained through a local quarry. The proposed rock armour will be developed through the application of design philosophy, which differs from that utilized during the 2005 installation. Consisting of larger rock particles, placed at a reduced slope angle, the rock armour layer will be better suited to dissipate the energy generated by breaking waves and pack ice which are believed to have caused the recent shoreline protection damage.

Alternative #3: Installation of Gabion Retention Structures. Gabions are wire mesh baskets that are filled with crushed rock. While gabions are commonly utilized as a means of slope protection and stabilization, they are not suited for use in high energy wave environments. Located in a corrosive marine environment and subject to repeated battering by high energy waves the service life for gabions is substantially reduced.

Alternative #4: Installation of Anchor Wall Structures. There are many different types of anchor wall structures available in today's market. As they are readily available, and come in many forms, they prove to be a cost competitive option. While it is not uncommon to see anchor wall structures utilized in shoreline protection applications, they are not typically relied upon in high energy sea states. Anchor wall structures are rather utilized in sheltered

harbors and inlets, in which the frequency and energy of the waves to which they are exposed is substantially reduced. Utilized in the high energy sea state, present at Cat Arm, the anchor walls will provide a lesser service life than the proposed rock armour.

Alternative #5: Installation of Pre-Cast Concrete Armour Units. These units are becoming increasingly popular, particularly in geographic areas deficient in rock. Placed along the face of the protection slope, these units essentially perform the same function as rock armour. Given the abundance of rock and the local unavailability of these concrete units, this is not considered to be viable alternative.

Alternative #6: Installation of a Breakwater. Breakwaters are utilized to dissipate wave energy prior to making landfall. They are typically constructed from large rock units, similar to rock armour stone, and orientated to provide protection against the prevailing sea state. They are primarily utilized in shallow waters where a limited quantity of materials would be required for their construction.

It is anticipated that a breakwater would provide a similar service life to that of the rock armour alternative. Given the higher initial construction costs, difficulties associated with breakwater construction and no additional benefits, this is not considered to be a viable alternative.

Alternative #7: Installation of a Concrete Seawall. Seawalls offer another form of shoreline protection and can be utilized on exposed and moderately exposed coasts. Although they may appear to be stronger than the other viable alternatives, their rigid nature provides little to no flexibility. Consequently, seawalls are subject to damage should they experience differential settlement.

Given their rigidity and inability to follow the existing contours of the shoreline, seawalls may accelerate erosion of adjacent, unprotected coastlines due to their effect on the

natural longshore drift[2] process. Considering the substantial construction costs, in conjunction with the uncertainty surrounding the potential impacts imposed along the adjacent coastline sections, this alternative is not considered to be viable.

Alternative #8: Installation of Steel Piles. This alternative would see steel piles driven into the ground or anchored in series and fitted with steel panels to form a wall. The wall serves to protect the shoreline from the effects of erosion and retain the existing embankment material. This method is typically utilized in areas of deep sea sediments, where the piles can be easily placed at the required depth. Given the abundance of rock along the Cat Arm shoreline, the installation of piles would prove to be difficult and costly. It is not considered to be a viable alternative to address the shoreline protection issues in Cat Arm.

Alternative #9: Installation of a Bridge. A conventional column and multi-span bridge was considered to straddle the affected shoreline area, thus, eliminating the requirement to complete full blown shoreline protection rehabilitation. With this in mind, some facet of shoreline protection remediation would need to be completed to ensure that the embankment erosion is not permitted to migrate beyond the limits of the bridge.

Concerns surrounding the high construction costs and potential impacts of pack ice and wave action scouring on the bridge columns have deemed this alternative to be unviable.

Alternative #10: Realignment of Existing Access Road. Under this option, the realignment of the existing access road to bypass the affected embankment section was considered. Due to the topography and geographic make-up in this area, the challenges and costs associated with completing the roadway realignment is deemed to be unfeasible.

[2] **Longshore drift** consists of the transportation of sediments (clay, silt, sand and shingle) along a coast at an angle to the shoreline, which is dependent on prevailing wind direction, swash and backwash. This process occurs in the littoral zone, and in or close to the surf zone. The process is also known as **littoral drift**, **longshore current** or **longshore transport**. Longshore drift is influenced by numerous aspects of the coastal system, with processes that occur within the surf zone largely influencing the deposition and erosion of sediments. Longshore currents can generate oblique breaking waves which result in longshore transport.

Alternative #11: Construction of New Access Road. This option analyzed the construction of an alternative route to the powerhouse, allowing the existing road to be decommissioned. As with the previous alternative, the surrounding topography and geographic make-up makes this alternative extremely challenging and unfeasible.

A cost benefit analysis was completed to compare the viable alternatives. The study period for the cost benefit analysis was 20 years, as this is the anticipated service life for the upgrades. Alternative 2 is the least cost option and is, consequently, the recommended alternative. The cost benefit analysis supports AMEC's recommendation for the completion of upgrades to the armour stone wave barrier. The results of the cost benefit analysis are illustrated in Table 3.

Table 3: Cost Benefit Analysis Summary Table

Refurbish Shoreline Protection		
Alternative Comparison ***Cumulative Net Present Value*** ***To The Year*** **2015**		
Alternatives	**Cumulative Net Present Value (CPW)**	**CPW Difference between Alternative and the Least Cost Alternative**
Alt. #2 - Rock Armour	1,046,965	0
Alt. # 1 - Regular Upkeep	1,179,250	132,284
Alt. #4 - Anchor Wall	1,322,811	275,845
Alt. #3 - Gabion Retention Structure	1,433,006	386,041

4 CONCLUSION

The Cat Arm access road is a vital access to the Cat Arm Hydroelectric Generating Station. It is used by Hydro personnel all year round for access to the plant by operations personnel as well as periodically by maintenance personnel. A 90 m section of the Cat Arm access road embankment has deteriorated to the point in which there is a risk of partial or complete loss of the roadway's driving surface, if rehabilitation measures to stabilize this erosion are not undertaken.

The road provides the only feasible access to the plant and is travelled daily by plant operating staff and on a regular basis by plant maintenance personnel. The proposed embankment stabilization must be completed to ensure that safe reliable access is maintained to the plant.

4.1 Budget Estimate

The budget estimate for the project is shown in Table 4.

Table 4: Project Budget Estimate

Project Cost:*($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	56.5	84.8	0.0	141.2
Consultant	44.0	56.0	0.0	100.0
Contract Work	0.0	602.6	0.0	602.6
Other Direct Costs	4.0	25.2	0.0	29.2
Interest and Escalation	7.7	87.6	0.0	95.3
Contingency	0.0	174.6	0.0	174.6
TOTAL	**112.2**	**1,030.7**	**0.0**	**1,142.9**

4.2 Project Schedule

The anticipated project schedule for this project is presented in Table 5.

Table 5: Project Schedule

Activity		Start Date	End Date
Planning		February 2016	February 2016
Detailed Engineering	Engage Consultant, Survey, Technical Specification Preparation, Construction Drawings	March 2016	August 2016
Permitting	Application and Receipt of Environmental Permits	September 2016	October 2016
Tender	Tender and Award Shoreline Protection Upgrade Contract	February 2017	March 2017
Construction	Complete Shoreline Protection Upgrades	July 2017	August 2017
Commissioning	Final Inspection and Acceptance	-	August 2017
Closeout	Project Closeout	-	October 2017

APPENDIX A

Feasibility Study to Address Rock Armour Erosion

Cat Arm Access Road

FINAL

Feasibility Study to Address Rock Armour Erosion
Cat Arm Access Road

Submitted to:

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ISO 9001:2008 Quality Management System (St. John's, NL)

IMPORTANT NOTICE

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ISO 9001:2008 Quality Management System (St. John's, NL)

Feasibility Study to Address Rock Armour Erosion
Cat Arm Access Road
Newfoundland and Labrador Hydro
March 2015

amec

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1.0 INTRODUCTION

1.1 Background

The Cat Arm Access Road was completed in 1984 as part of the Cat Arm Hydroelectric Development to construct and provide access to the powerhouse and tailrace. In 2004, AMEC was retained by Newfoundland and Labrador Hydro (Hydro) to address the erosion of the shoreline along a section of this access road. The shoreline erosion had resulted in over steepening of the road embankment resulting in localized failures along the edge of the roadway. This work included geotechnical investigations, design solution, cost estimates, tender assistance, and construction monitoring. Construction of a rock armour embankment was completed in the fall of 2005.

In 2008, Hydro's operational staff noticed erosion at the toe of the rock armour embankment. AMEC was requested by Hydro to assess this erosion. A subsequent site visit in 2010 was made to further observe the ongoing erosion. In February of 2014, Hydro retained AMEC to conduct a desktop study on the previous works in the area and to provide feasible options of addressing the problem of erosion including slope rehabilitation.

1.2 Location

The Cat Arm Hydroelectric Development is situated on the western shore of White Bay, on the Northern Peninsula of Newfoundland. The study area is the coastal erosion of the rock armour approximately 600 m south of the powerhouse as shown below in Figure 1-1.

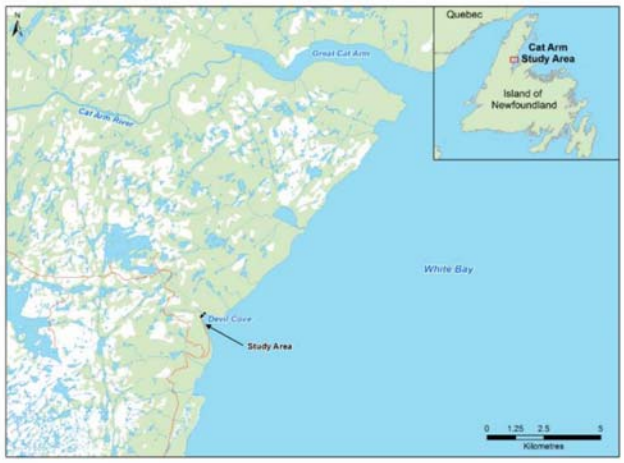


Figure 1-1: Location of Study Area

2.0 SCOPE OF WORK

The scope of this study is as follows:

- Review the previous design including drawings and calculations, supplemented by as-built records;
- Desktop interpretation of current conditions via ground photographs, aerial photographs and various documented works of the area to estimate:
    - the amount of material which has been eroded or lost;
    - the geometry of the slope as of December 2013; and
    - other influencing data.
- Review effects or events that may have occurred since construction, including the review of weather patterns, sea conditions and any outstanding effects which may have led to the loss of material;
- Review of feasible industry best practise and its detailed design; and,
- Provide, with Class D cost estimates of feasible options to rehabilitate the affected area.

3.0 REVIEW OF PRIOR WORKS

3.1 Previous Design

In 2004 AMEC was approached by Hydro to begin investigations for shoreline protection along the Cat Arm Access Road. Following a site visit AMEC developed a design in consultation with Hydro to address the areas of concern which was presented in a design brief.

Design criteria and recommendations of this design included:

- Construct an engineered armoured slope with a face angle of 28° (approximately 2H:1V);
- Establish a quarry that is able to produce rock armour of 8 tonnes or greater, including various sizes of filter and blast rock fill;
- Design for a non breaking wave (breaking would have required 10.5 tonne armour, deemed unfeasible at the time)
- Construct a bench along the slope to assist with extending the embankment out into the water, while minimizing the amount of material needed and to assist with access during construction;

- Construct the embankment below the bench with an armour thickness of two stones, including associated filter and core materials;
- Construct the embankment above the bench of blast rock fill with the larger stones at the surface to assist with preventing erosion and vegetative growth; and,
- Dowel armour units to bedrock in an area of a bedrock ledge at the south end of the embankment.

For the design of the rock armour, the Hudson Formula was used to provide preliminary values on armour size. Hudson's Formula, further discussed in Section 5.1, utilizes various factors such as; slope angle, thickness of armour, and wave height/action.

A significant wave height was needed for input into the Hudson Formula, but no local real data was available. Wind and wave modelling was conducted by AMEC using available information at that time to calculate a significant wave height. This model indicated it was possible for a 3.7 m wave to occur in the area during a 1 in 50 year storm. Due to limited data available and multiple factors involved in the calculation an additional 0.5 m was added to the significant wave height, and a 4.2 m high wave was used for the armour design.

Other parameters required in the Hudson Formula include the type of wave and the acceptable damage factor. For the design the wave action was assumed to be non breaking *(note: a non breaking wave can be realised as a wave which rolls or laps onto the shoreline in a relatively gentle fashion, by comparison a breaking wave be may illustrated as one which crashes onto the shoreline)*. A breaking wave would have required a much larger stone (10.5 tonnes). The Hudson Formula also includes a coefficient to account for the amount of damage that is acceptable during a storm event. For the design a damage of 10 to 15 percent by volume was deemed acceptable during the 1 in 50 year storm. Lesser amount of damage would have required larger stone sizes. These larger stone sizes would have been difficult to produce in the quarry and much more difficult to place, possibly requiring alternate placement methods.

Construction drawings and tender specifications were developed in accordance with the design brief and construction was completed in 2005. Refer to Drawing 1 in Appendix A for as-built conditions of study area. Figure 3-1, below shows the completed shoreline protection in June of 2006.

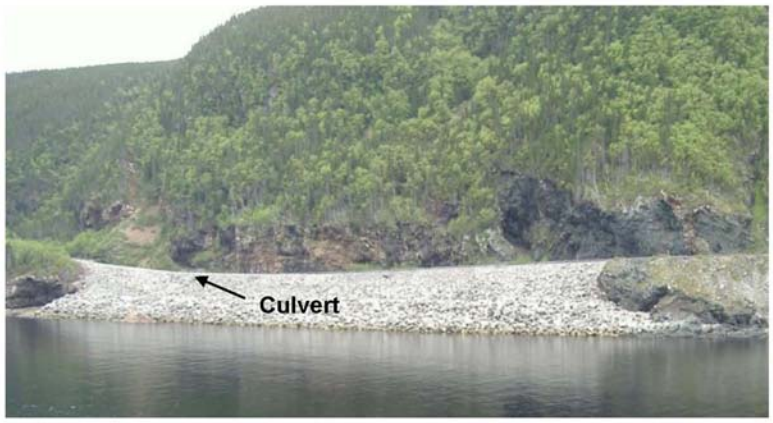


Figure 3-1: View of Completed Shoreline Protection (Photo taken Spring of 2006)

3.2 Review of Site Visits, Inspections, and Surveys

3.2.1 AMEC Site Visit 2008

In 2008 Hydro's operational staff identified erosion within the toe of the embankment. The erosion apparently occurred between September 2007 and June 2008. Hydro contacted AMEC regarding this erosion and a field investigation was conducted by AMEC. A survey was also conducted by Hydro on the embankment at the areas of concern. During AMEC's site visit three areas of concern were identified and investigated (see figure 3-2). These areas are:

Area 1: This area encompasses the lower slope between stations 0+190 and 0+230 as identified in the design brief. A comparison of the as-built and the Hydro survey, indicated that approximately 1,640 m^3 of material including rock armour, filter and core material had been eroded.

Area 2: A smaller eroded area was identified in the lower slope, approximately 15 m south of Area 1. A comparison of the as-built and the Hydro survey, indicated that approximately 100 m^3 of material including rock armour, filter and core material had been eroded.

Area 3: AMEC identified Area 3 during the site visit, which was located along the southern end of the embankment. Observations showed displacement of doweled rock armour, where the dowels had been bent and dislodged from the bedrock but remained in the rock armour.

Figure 3-2 below shows the location on the area addressed in the 2008 investigation.



Figure 3-2: Areas of Erosion Identified during a 2008 Site Visit

3.2.2 AMEC Site Visit 2010

In 2010 AMEC was retained by Hydro to investigate the rate of ongoing erosion at the damaged areas and to provide comment on remedial options.

During the site visit AMEC identified further erosion between Areas 1 and 2 (as identified in Figure 3-2), the visual estimate of eroded material was an additional 200 m^3. In addition, the upper slope, in local areas, was becoming undermined. It was observed during the site visit that the exposed shoreline was layered with various sized stones (armour sized to gravel). These stone appear to originate from the embankment construction, the stones were angular but have since been rounded to sub angular due to wave action. It was observed that waves would deflect from the partially submerged outcrop as shown in Figure 3-2 and run up the beach 2 - 3 m more than adjacent areas.

Area 3 as identified in the 2008 site visit showed no apparent visual increased erosion of the armour units.

The 2010 report recommended further study of erosional mechanisms, additional surveys be conducted on the embankment, and rehabilitation. In order to further understand the wave action caused by the submerged bedrock, it was recommended that detailed topographic survey and hydrographical surveys be performed. In addition to the survey, it was recommended to rehabilitate the slope to a reduced angle to 3H:1V from the previously constructed slope of 2H:1V.

3.2.3 Hydro Topographical Survey 2011

Hydro performed a subsequent topographical survey of the affected area in 2011. This survey predicted a total loss of material of approximately 6,000m³.

This value has been adopted as the maximum current loss of armour material.

3.3 Review of Wind and Wave Modelling

As part of the 2008 program, AMEC reviewed the wind and wave data that was gathered between September 2007 and June 2008. A previous inspection by Hydro in September of 2007 had not identified any areas of erosion, therefore data prior to this date was not collected. Available weather data was limited to stations at La Scie and St. Anthony. The calculated maximum wave heights via hindcasting were between 2 – 3 m during the worst storm events during this time. This indicates that the design wave height may not have been encountered.

AMEC became aware of new wind and wave data published by Environment Canada since the data that was used to model and predict the maximum wave height in 2005. This new data was also a numeritcal model that utilized hindcasting. The model looked at a number of locations within White Bay. The nearest location to the site showed that a 1 in 50 event may develop a 4.3m wave height (note: this is a 0.1 m increase on the 4.2 m design wave height). Given the complexitity of the models and the lack of local physical data, the original 4.2 m design wave height is deemed suitable for the original design.

3.4 Discussion

Slope geometry and the volume of shoreline material eroded was estimated using survey data, existing documents and related photos.

Within the study area, three Cross Sections (see Figure 3-3 for location of Cross Sections and Drawing 2 in Appendix A for Cross Sections) were created for comparison with the as-built Cross Sections produced in 2005. Cross Sections 1, 2, and 3, in Drawing 2 depict the approximated slope conditions. Cross Section 2 is in the area of the most damage from erosion.

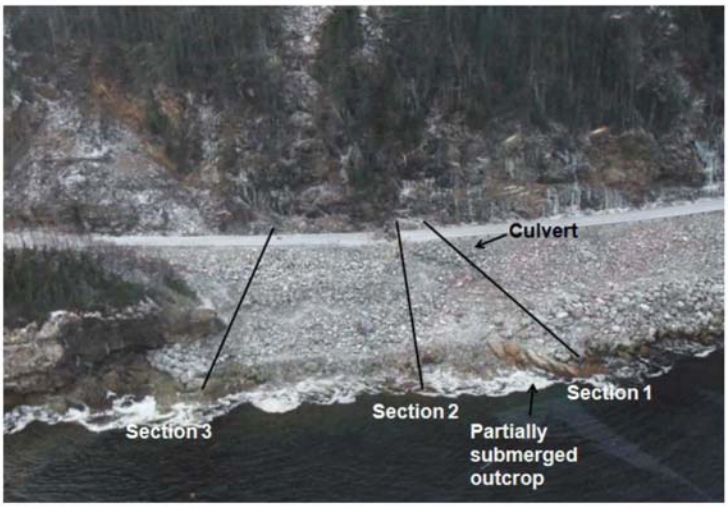


Figure 3-3: Aerial Photo (2013) of Cross Section Locations

Through a review of photos and notes taken during site visits, accompanied by survey data from Hydro suggests a total of 6,000m³ has been eroded.

3.4.1 Possible Erosion Mechanisms

It appears that the erosion to the embankment was due to movement within the armour and subsequent erosion and undermining. (Note: no real data exists on the wave breaking mechanisms at this particular area). Possible erosion mechanisms (listed from most likely to least likely) include the following:

- Amplified and deflected wave action due to the bedrock outcrop extending further than the constructed embankment.
- Increased localized wave energy due to confinement and run-up along the partially submerged outcrops of bedrock.
- The possible deep deposit of uncontrolled fill during the initial road construction (1980's) and the subsequent development of a sandy shoreline, may have observed some settlement due to the increase loading from the 2005 embankment.
- Pack ice and freezing ocean spray (and its associated pressures) may be responsible for slight movement of the outer armour stones.

It is not anticipated that one erosion mechanism is responsible for triggering the initial erosion but a combination of mechanisms. It is likely that the bedrock outcrop has resulted in increased localized wave energy that caused movement in the outer armour stone. This movement, in addition to any slight movement due to settlement, freeze/thaw, and pack ice, may have caused small localized areas of armour to move, exposing the inter filter and core material. Once exposed, this smaller stone is susceptible to smaller waves, causing continued erosion.

4.0 REVIEW OF REMEDIAL MEASURE AND OPTIONS

It is known that this area is suffering deterioration on a regular basis, a number of options present themselves on how to combat, control or manage this deterioration. The following section presents industry practices and construction techniques of sea defences and remedial measure that can be adopted.

4.1 Management Options

4.1.1 Status Quo

This option limits remediation and ultimately may allow the deterioration to reach a state where the infrastructure becomes unusable. This requires regular assessment to ensure the safe passage of road users by inspecting the integrity of the road and embankment.

Keeping in mind that this is an access road to a powerhouse where regular maintenance is required, careful consideration and protocols should be in place for regular monitoring if this option should be advanced. At this time it is deemed not a viable option.

4.1.2 Regular upkeep

This option affords regular inspection and maintenance of both the access road and the rock armour defence. Such maintenance may include the production and provision of rock armour placement on a regular basis (including a general reshaping of the embankment), likely every two to five years.

Consideration should be given to the cost of mobilization of equipment on an as needed frequency exacerbated by the remote location of the site.

4.2 Permanent Fixture

Several options exist to provide and construct a permanent solution to offer shoreline protection:

4.2.1 Rock Armour

The armour stone solution includes the placement of large rock particles at a slope angle that is ideally designed to dissipate wave energy. The commonly used Hudson Formula was adopted

previously to design the embankment in 2005. Armour stone protection can be designed to resist the expected wave energy, using rock that has been blasted from a local quarry to be appropriately sized to resist wave energy.

Another method of rock armour protection was developed by Baird and Hall. This method requires substantially more material than the Hudson Formula but utilizes smaller sizes and less control during placement, it focuses on developing a longer shallower shore angle increasing the area on which a potential wave can dissipate its energy.

4.2.2 Gabions

Gabions are wire mesh baskets that are filled with cobbles and/or crushed rock. They are typically filled on site, often with locally available material and therefore have a relatively low cost. Gabions are flexible and porous and can absorb some wave and wind energy, thereby reducing the scour problems associated with impermeable sea defences such as concrete seawalls.

Gabions can be placed as sloping "mattresses" or as near vertical cubic baskets.

Gabions can be used along with other permanent fixture measures however consideration has to be given to the anchoring or knitting together of the units to ensure they remain in place.

4.2.3 Anchor wall structures

This market has many forms, types, manufacturers and suppliers and is extremely competitive. There are a number of suppliers to the local market.

Traditional timber crib walls have evolved to adopting precast concrete members and steel sections (often referred to as bin walls). These can be used in coastal applications as an erosion protection measure and/or can be used as an embankment stabilization technique. Both uses are applicable in this case.

4.2.4 Concrete Armour units (tetrapods)

There are several different concrete armour designs available; one common design is random or uniform tetrapods. The four-legged tetrapod structure is designed to disperse wave energy by allowing water to flow between and around the structures, instead of breaking against them. This prevents the units from being dislodged from the shore protection slope, which is a common problem with blasted rock. The units can be placed either in a uniform array or in a random order. These are not available locally and at this time are deemed not a viable option.

4.2.5 Breakwaters

The utilisation of breakwaters is to dissipate the wave energy prior to landfall. Typically breakwaters are constructed with large rock units akin to rock armour stone and are laid in a direction against the prevailing sea state.

They are mainly used in shallow waters where limited quantity of material would be required for their construction. This application may not be feasible due to the lack of detailed underwater information are not recommended at this time.

4.2.6 Concrete seawall

A seawall is usually a concrete structure that is backfilled with granular material to resist horizontal earth pressure from the shore, and wave action. It is usually anchored to prevent both toe scour from wave action and horizontal sliding from earth pressure (US Army Corp 1995). Seawalls can be constructed on exposed or moderately exposed coasts. Although seawalls may appear to be stronger, they have limited or no flexibility, therefore often suffer damage if they undergo differential settlement. Seawalls can accelerate erosion of the adjacent shoreline.

4.2.7 Piles

Concrete or steel piles are used in many sea defences, mainly in docks and fenders. The piles are driven or anchored in series into competent material to allow the pile wall at act as a cantilever to retain the intended backfill.

Typically this method is applied in deep sediments where the piles can be easily placed to the required depth. This is a specialised work practice, requiring mobilization of equipment and materials to the site. Due to the complexity and practicality of providing this option it is deemed unfeasible at this time.

4.2.8 Bridge/Viaduct

A conventional column and multi-span beam bridge system may be utilized here. The bridge would straddle the affected area. Considerable investigation, planning and design would be required during the preliminary stages. Design consideration such as pack ice scabbling and scouring of piers (columns) should be considered.

4.2.9 Realignment of the access road

This option analyses the realignment of the access road from its current location slightly further inland away from the point of concern. Due to the immediate adjacent topography in this area (i.e. the substantial rock face), considerable work would be required to advance this option, it is deemed unfeasible.

4.2.10 Construct a new access road

This option analyses the construction of an alternative route to the desired location whilst allowing the existing route to be decommissioned or abandoned. Planning and design must consider the vertical alignment of the route as prime importance due to the requirement of large and heavy loaded vehicles to access the powerhouse. The surrounding topography makes this option extremely challenging.

4.3 Evaluation and discussion of remedial options

AMEC has summarized the aforementioned options in the table presented in Appendix D and has presented a feasibility matrix to illustrate rankings of each option in various categories. The allocated ranking is provided to portray the feasibility of the option.

It can be noticed that the Status Quo option is exempt from all categories however the ultimate effect, including the potential complete loss of the infrastructure should be kept in mind. For this reason alone, it is not recommended that the status quo (do nothing) option is viable.

The permanent fixture measures presented are common industry methods, it is known that the practicality of constructing some of these options on the northern peninsula of Newfoundland will pose extreme difficulty and ultimately cost. For example, the construction of concrete armour units; these are not manufactured here in Newfoundland, they would have to be shipped to site (by road or barge). This option is highly unlikely to be anyway feasible purely based on practicality and the fiscal disbenefits. This is also compounded by the cost of construction at this remote location; both the cost of concrete and the cost of seaward access via a barge or shore access using a large crane or other specialised heavy equipment will significantly increase the cost.

On the other hand the use of; rock armour, gabions and/or crib wall structures seem to be feasible for a number of reasons. They are available, can be constructed with a local workforce, and utilize standard heavy equipment. As presented in the feasibility matrix in Appendix D, the rock armour design and reconstruction was deemed the most feasible long term option with gabions and crib walls scoring shightly less feasible.

Section 5 discusses the detailed design of rock armor protection methods that can be applied to this particular area.

5.0 DETAILED DESIGN OPTIONS

To address an approach for rehabilitation a review of current procedures was conducted to assess the best practices and any alternative technology for shoreline erosion. At this time, it is deemed that rock armour design and reconstruction remains the feasible option and is advanced below.

Two methods were evaluated, the Hudson Formula and the Baird and Hall method.

5.1 Hudson Formula

Traditional rock armour design predominately utilizes the Hudson Formula (1958). It was developed to be used as a preliminary design to determine the mass of rock armour needed for shoreline protection. The Hudson Formula was presented in the Shoreline Protection Manual Volume II produced by the US Army Corps of Engineers in 1984. Equation 1 shows the Hudson Formula and the various factors involved.

Equation 1: Hudson Formula

$$W = (H_s^3 w_r) / (k_d(S_r-1)^3 \cot\Theta$$

W	= Mass of rock armour (kg)
Hs	= Significant wave height (m)
wr	= Unit weight of rock armour (kg/m^3)
kd	= Stability coefficient
Sr	= Specific gravity of rock armour
Θ	= Slope of the embankment (degrees)

All of the variables in the equation are determined before a design is developed. The unit weight and specific gravity are assumed constant for the quarry used to create the rock armour. Wave heights at the location of the shoreline protection are constant in the various designs. These variables determine the location-specific effects on the design.

One of the more complex variables is the stability coefficient which is determined by the embankment geometry, type of armour, thickness of armour, the wave action, and the damage factor. Hudson developed a flow chart for determining the coefficient which provides the appropriate mass for the rock armour. For this design the stability coefficient is assumed to have an allowable damage of 2 – 5% (original design was 10-15%). Damage is based on the percent volume of displaced armour material. The mass of the rock armour will vary depending on the allowable damage in the design. The lower the damage factor the greater the mass of rock armour required.

A study by Tournier et al in 1996 reported when using the Hudson Formula that uniformly sized and uniformly graded armour performs better then randomly placed rock armour. They reported that armour that is not uniformly graded will have weak points where the armour mass is not consistent with the designed armour. Should information provided by this study be utilized in the design it may result in additional wastage during blasting and additional time for sorting and placement.

5.2 Baird and Hall Method

Instead of designing the requirements of shoreline protection based on an equation, Baird and Hall (1984) designed a method which utilizes locally available material. Therefore, this design method is unique to each location. The approach is as follows:

i) Determine the characteristics (e.g. friction angle, unit weight, degree of weathering or fracturing, etc.) of the locally available material;

ii) Define the range of the locally available rock armour mass;

iii) Determine the mass restriction between the smaller core material and rock armour; and,

iv) Evaluate different dimensions (slope angle, width of bench, and thickness of armour layer) of the shoreline protection.

In the application of this method, the rock armour reshapes itself with wave action over time, which creates a more natural embankment.

Typically, there is a larger volume of material used in this method, than in the Hudson Formula design because the rock armour size can be much smaller. Therefore, it minimized waste rock at the quarry. This can reduce construction costs and time.

This design method has been used all over the world, including in Newfoundland. For example, in 1984, the Department of Public Works of Canada applied this method in Codroy, Newfoundland. The design was for a 6.8 m wave height and was reported to have rock armour of 0.5 to 4.0 tonnes. A review of this construction was conducted in 1986. Although no wave height data were recorded, the designed wave height was assumed to have been reached on more than one occasion and the slope was reported to have performed exceptionally.

While this method has many advantages over the Hudson Formula, it does lack the science and engineering behind its design. Therefore it will require an ongoing monitoring program to determine its effectiveness, and may require regular ongoing maintenance or substantial overbuild during initial construction to increase its service life.

6.0 APPLICATION OF DESIGN METHODS

The Baird and Hall method was developed for areas where typically the local quarry material produced is unsuitable for the Hudson Formula. For this study area, the properties of the nearby quarry allows for either method to be used. It was noted during the initial construction that minimal wastage was observed while producing the 8 tonne stones.

In determining the feasibility of which method to proceed with, preliminary assumptions were made. The Hudson Formula design assumes the rehabilitated slope angle is 3H:1V and for the Baird and Hall it is 5H:1V (typical). The Hudson Formula allows for a lower percentage of damage and decreases the stone size from that of the original design. It also extends the toe of the embankment further out, thereby reducing the assumed negative effects of the bedrock outcrop. In order to construct a 5H:1V slope in accordance with Baird and Hall the toe of the embankment

would extend past the bedrock outcrop and possibly into deep water requiring an unknown quantity of material.

The Hudson Formula design was therefore determined to be the most suitable for this application.

6.1 Perfered Option – Rebuild Eroded Area between Station 0+190 and 0+280

During the literature review, it was noted that the Hudson formula has success in the design phase over the majority of the constructed embankment.

6.1.1 Design Criteria and Recommendations:

Some modifications are required in the area of concern and are recommended below:

- Reduce the slope below the previous bench location to 3H:1V using filter material and armour stone to extend the embankment past the partially submerged outcrop. The original design was 2H:1V;
- Design for a significant wave height of 4.3 m. The original design was 4.2 m;
- Assume the wave will have a breaking action. The original design was for a non-breaking wave;
- Rock armour should be three (3) layers thick. The original design was two (2) layers thick;
- Rock armour should be uniformly graded and sized;
- Rock armour should be a minimum of 6.5 tonnes. The original design was 10.5 tonnes. Note that the armour stone is smaller than the original design due to the additional layer and the flatter slope; and,
- Rock armour should be anchored into bedrock where applicable (above low water level)

The construction process will be similar to the 2005 reconstruction

6.1.2 Preliminary Cost Estimate

A Class D (±30%) estimate for this work is **$700,000.00** (HST extra). Refer to the cost estimate in Appendix C for more detail. All estimates were determined by assumptions of the topography offshore. The amount of material and cost of the construction are subject to change following surveys of the area.

7.0 RECOMMENDATIONS

AMEC recommends a field investigation to further assess the embankment between stations 0+190 and 0+280 and near shore bathymetry, to assist with the detailed design to rehabilitate the shoreline protection. AMEC recommends the following to to be completed prior to going to tender and construction:

- Conduct a field investigation;
  - Conduct bathymetry soundings of the near shore area of the area of erosion;
  - Conduct underwater photography where/if needed;
  - Conduct survey of the area of erosion; and,
  - Assess current quarry condition.
- Review/revise wave data using new findings from the field investigation; and,
- Prepare a design brief based on new findings, including construction drawings, technical specifications, and quantities/cost estimate (±10%).

An estimate for this work is included in the Class D cost estimate in Appendix C.

8.0 CLOSURE

This report was prepared for the exclusive use of Newfoundland and Labrador Hydro for specific application to the project study area. The study was conducted in accordance with the work plan developed for this site and verbal requests from Hydro. The limitations of this report are stated in Appendix E.

Yours truly,

AMEC Environment & Infrastructure
A Division of AMEC Americas Limited

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Robert Moroney, PhD, PEng

Reviewed by:

Kevin Penney, MScEng, PEng.

9.0 REFERENCES

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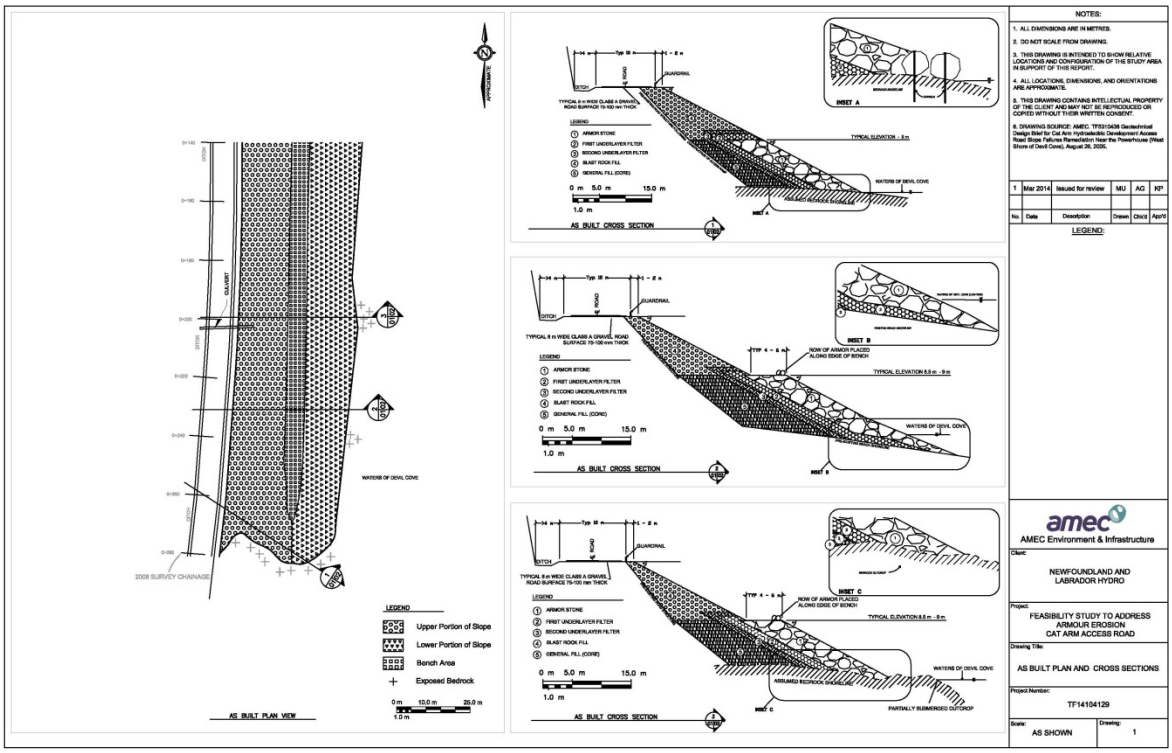
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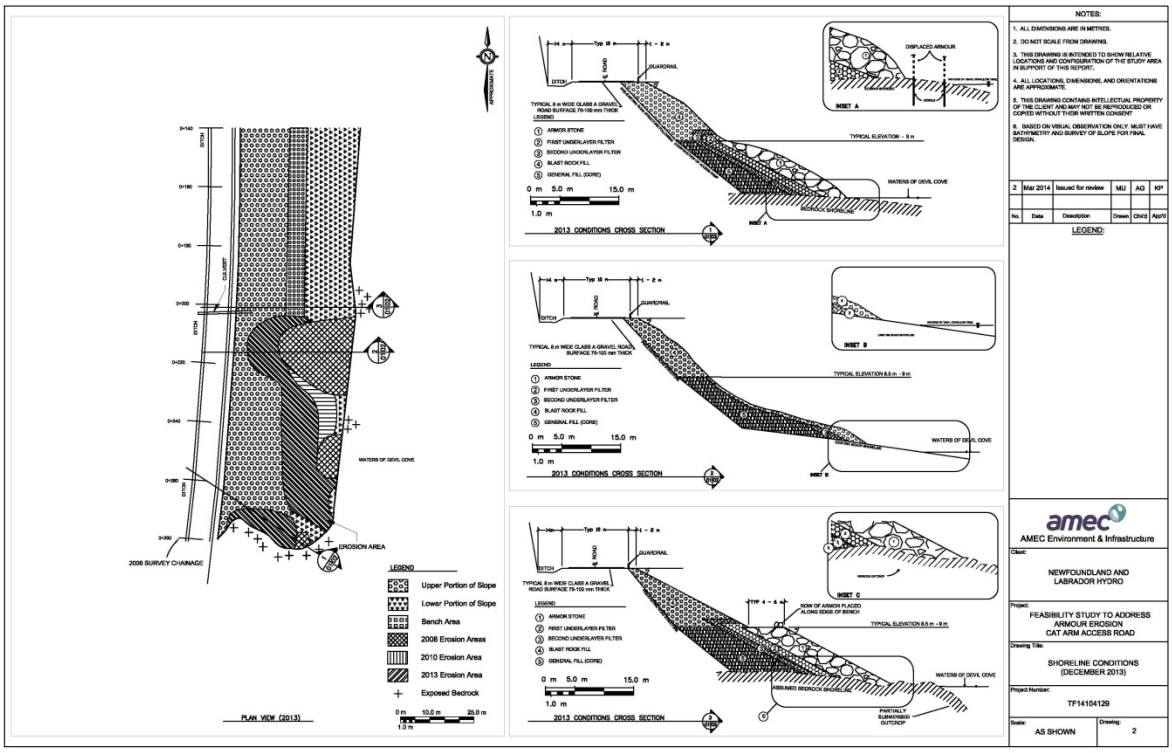
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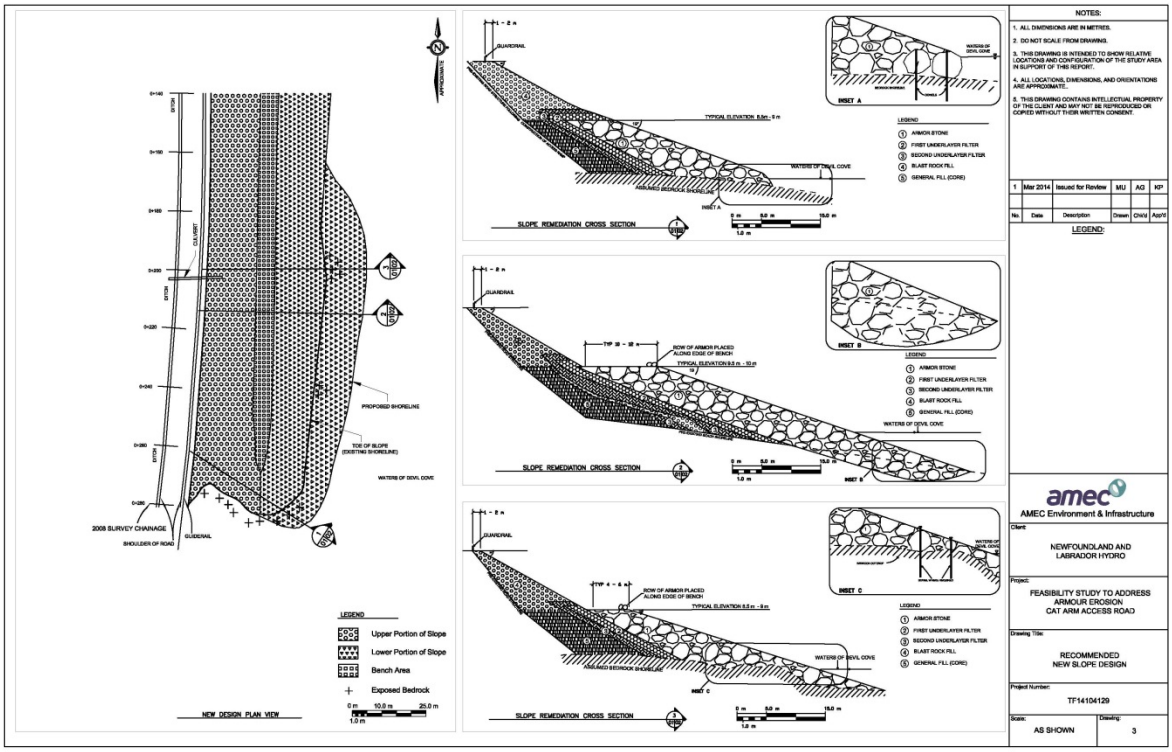
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APPENDIX A: DRAWINGS

ISO 9001:2008 Quality Management System (St. John's, NL)


NOTES:
1. ALL DIMENSIONS ARE IN METRES.
2. DO NOT SCALE FROM DRAWING.
3. THIS DRAWING IS INTENDED TO SHOW RELATIVE LOCATIONS AND CONFIGURATION OF THE STUDY AREA IN SUPPORT OF THIS REPORT.
4. ALL LOCATIONS, DIMENSIONS, AND ORIENTATIONS ARE APPROXIMATE.
5. THIS DRAWING CONTAINS INTELLECTUAL PROPERTY OF THE CLIENT AND MAY NOT BE REPRODUCED OR COPIED WITHOUT THEIR WRITTEN CONSENT.
6. DRAWING SOURCE: AMEC. TF0310436 Geotechnical Design Brief for Cat Arm Hydroelectric Development Access Road: Slope Failures Remediation Near the Powerhouse (West Shore of Devil Cove), August 26, 2005.
1 Mar 2014 Issued for review MU AG KP
No. Date Description Drawn Chk'd App'd
LEGEND:
AMEC Environment & Infrastructure
Client: NEWFOUNDLAND AND LABRADOR HYDRO
Project: FEASIBILITY STUDY TO ADDRESS ARMOUR EROSION CAT ARM ACCESS ROAD
Drawing Title: AS BUILT PLAN AND CROSS SECTIONS
Project Number: TF14104129
Scale: AS SHOWN
Drawing: 1
AS BUILT PLAN VIEW
2008 SURVEY CHAINAGE
WATERS OF DEVIL COVE
LEGEND
Upper Portion of Slope
Lower Portion of Slope
Bench Area
Exposed Bedrock
AS BUILT CROSS SECTION
INSET A
INSET B
INSET C
TYPICAL ELEVATION - 9 m
TYPICAL ELEVATION 8.6 m - 9 m
NOM OF ARMOUR PLACED ALONG EDGE OF BENCH
ASSUMED BEDROCK SHOULDER
PARTIALLY SUBMERGED OUTCROP


NOTES:
1. ALL DIMENSIONS ARE IN METRES.
2. DO NOT SCALE FROM DRAWING.
3. THIS DRAWING IS INTENDED TO SHOW RELATIVE LOCATIONS AND CONFIGURATION OF THE STUDY AREA IN SUPPORT OF THIS REPORT.
4. ALL LOCATIONS, DIMENSIONS, AND ORIENTATIONS ARE APPROXIMATE.
5. THIS DRAWING CONTAINS INTELLECTUAL PROPERTY OF THE CLIENT AND MAY NOT BE REPRODUCED OR COPIED WITHOUT THEIR WRITTEN CONSENT.
6. BASED ON VISUAL OBSERVATION ONLY. MUST HAVE BATHYMETRY AND SURVEY OF SLOPE FOR FINAL DESIGN.
2 Mar 2014 Issued for review MU AG KP
No. Date Description Drawn Chk'd App'd
LEGEND:
AMEC Environment & Infrastructure
Client: NEWFOUNDLAND AND LABRADOR HYDRO
Project: FEASIBILITY STUDY TO ADDRESS ARMOUR EROSION CAT ARM ACCESS ROAD
Drawing Title: SHORELINE CONDITIONS (DECEMBER 2013)
Project Number: TF14104129
Scale: AS SHOWN
Drawing: 2
PLAN VIEW (2013)
2008 SURVEY CHAINAGE
EROSION AREA
WATERS OF DEVIL COVE
LEGEND
Upper Portion of Slope
Lower Portion of Slope
Bench Area
2008 Erosion Areas
2010 Erosion Area
2013 Erosion Area
Exposed Bedrock
2013 CONDITIONS CROSS SECTION
INSET A
INSET B
INSET C
DISPLACED ARMOUR
TYPICAL ELEVATION - 9 m
TYPICAL ELEVATION 8.6 m - 9 m
NOM OF ARMOUR PLACED ALONG EDGE OF BENCH
ASSUMED BEDROCK SHOULDER
PARTIALLY SUBMERGED OUTCROP


NOTES:
1. ALL DIMENSIONS ARE IN METRES.
2. DO NOT SCALE FROM DRAWING.
3. THIS DRAWING IS INTENDED TO SHOW RELATIVE LOCATIONS AND CONFIGURATION OF THE STUDY AREA IN SUPPORT OF THIS REPORT.
4. ALL LOCATIONS, DIMENSIONS, AND ORIENTATIONS ARE APPROXIMATE.
5. THIS DRAWING CONTAINS INTELLECTUAL PROPERTY OF THE CLIENT AND MAY NOT BE REPRODUCED OR COPIED WITHOUT THEIR WRITTEN CONSENT.
1 Mar 2014 Issued for Review MU AG KP
No. Date Description Drawn Chkd App'd
LEGEND:
amec
AMEC Environment & Infrastructure
Client:
NEWFOUNDLAND AND LABRADOR HYDRO
Project:
FEASIBILITY STUDY TO ADDRESS ARMOUR EROSION CAT ARM ACCESS ROAD
Drawing Title:
RECOMMENDED NEW SLOPE DESIGN
Project Number:
TF14104129
Scale:
AS SHOWN
Drawing:
3
NEW DESIGN PLAN VIEW
SLOPE REMEDIATION CROSS SECTION
SLOPE REMEDIATION CROSS SECTION
SLOPE REMEDIATION CROSS SECTION
LEGEND
Upper Portion of Slope
Lower Portion of Slope
Bench Area
Exposed Bedrock
PROPOSED SHORELINE
TOE OF SLOPE (EXISTING SHORELINE)
WATERS OF DEVIL COVE
2008 SURVEY CHAINAGE
SHOULDER OF ROAD
GUIDERAIL
CLASSIFY
INSET A
INSET B
INSET C
ROW OF ARMOR PLACED ALONG EDGE OF BENCH
TYPICAL ELEVATION 8.0 m - 9 m
ARMOR STONE
FIRST UNDERLAYER FILTER
SECOND UNDERLAYER FILTER
BLAST ROCK FILL
GENERAL FILL (CORE)

APPENDIX B: PHOTOGRAPHS

ISO 9001:2008 Quality Management System (St. John's, NL)

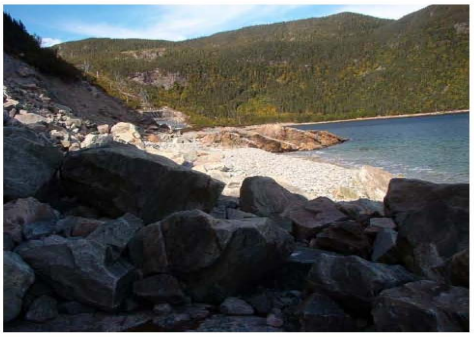


Photo 1 – Area 1 at the time of the September 2004 slope investigation

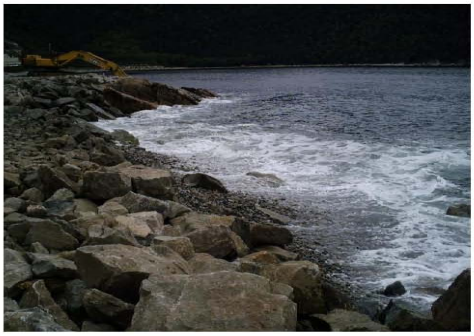


Photo 2 – Area 1 at start of embankment construction (September 2005)

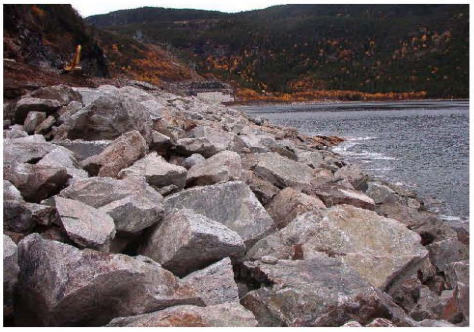


Photo 3 – Construction of lower slope of embankment in Area 1 during 2005 construction (October 2005)



Photo 4 – Erosion in Area 1 at time of October 2008 investigation



Photo 5 – Area 2 at the time of the Sept 2004 slope investigation



Photo 6 – Area 2 at start of embankment reconstruction (Sept 2005)



Photo 7 – Construction of lower slope of embankment in Area 2 during 2005 construction (October 2005)



Photo 8 – Erosion in Area 2 at time of October 2008 investigation



Photo 9 – Area 3 at the time of the Sept 2004 slope investigation



Photo 10 – Placement of anchored armour during 2005 construction



Photo 11 – Displaced armour in Area 3 showing drill hole of previous anchor location (October 2008)



Photo 12 – Overview of Area 3 showing displaced armour at time of the October 2008 site investigation



Photo 13 –Areas 1 and 2 as seen from edge of road, April 2010



Photo 14 – Exposed core material along shoreline, April 2010



Photo 15 – Ovierview of areas 1 and 2 looking South April 2010



Photo 16 – Debris trail from 2013 rock fall



Photo 17 – Boulder from 2013 rock fall resting on shoreline (2013)



Photo 18 – Overview of shoreline erosion (2013)

APPENDIX C: COST ESTIMATES

ISO 9001:2008 Quality Management System (St. John's, NL)

Cost Estimate 1- Rebuild Eroded Area Between Station 0+190 and 0+280
TF14104129

Table 1- Construction Costs

Contractor Expenses				
Material	**Unit**	**Quantity**	**Rate**	**Total**
Mob/demob	Ls	1	$25,000.00	$ 25,000.00
Project Setup (office, sanitary facilities, signage, etc)	Ls	1	$5,000.00	$ 5,000.00
Shoreline Access plus Removal and Reinstall Guide Rail	Ls	1	$10,000.00	$ 10,000.00
Quarry Preparation and Rehabilitation	Ls	1	$25,000.00	$ 25,000.00
Quarry Blasting Operations	m^3	12000	$10.00	$ 120,000.00
Armour Stone - Transportation	m^3	8500	$15.00	$ 127,500.00
Armour Stone - Placement	m^3	8500	$12.00	$ 102,000.00
Filter Stone - Transportation	m^3	2000	$10.00	$ 20,000.00
Filter Stone - Placement	m^3	2000	$7.00	$ 14,000.00
Blast Rock Fill - Transportation	m^3	1500	$10.00	$ 15,000.00
Blast Rock Fill - Placement	m^3	1500	$7.00	$ 10,500.00
Project Cleanup	Ls	1	$10,000.00	$ 10,000.00
Anchors/dowels	est	1	$40,000.00	$ 40,000.00
Contingency	est	1	$76,000.00	$ 76,000.00
			SUB TOTAL	**$ 600,000.00**
Engineering and Construction Monitoring Services				
Activity	**Unit**	**Quantity**	**Rate**	**Total**
Site Investigation and Survey	est	1	$ 20,000.00	$ 20,000.00
Design Brief	est	1	$ 15,000.00	$ 15,000.00
Construction Drawings and Tender Preparation	est	1	$ 9,000.00	$ 9,000.00
Tender and Contract Reward	est	1	$ 8,000.00	$ 8,000.00
Construction Monitoring (assumes 3 weeks)	week	3	$ 14,000.00	$ 42,000.00
As built and Completion Report	est	1	$ 6,000.00	$ 6,000.00
			SUB TOTAL	**$ 100,000.00**
Total				**$ 700,000.00**

Notes:

1. HST Extra
2. Quantities are estimated based on avaliable survey data and conceptual data
3. Rates are inclusive of all equipment and personnel required to carry out the specified work
4. Accomidations and living expenses inclusive of unit costs

APPENDIX D: FEASIBILITY MATRIX

ISO 9001:2008 Quality Management System (St. John's, NL)

Feasibility	Local Availability[1]		Constructability[2]		Environmental[3]		Visual[4]		Viability[5]		Cost[2]		Rank Total
	Risk	score	Risk	score	Risk	score	Risk	score	Serviceability[6]	score	Fiscal Impact	score	
Status quo	-	-	-	-	-	-	-	-	-	-	-	-	-
Regular Upkeep	Requires scheduled monitoring and maintenance	0	Road and embankment maintenance, relatively basic clean up and maintenance	0	No effect	0	No effect	0	Ongoing	3	low	1	4
Rock Armour	Local rock source	0	Production of armour stone in nearby quarry haulage, placement and shaping on site.	2	Environmental protection measures have to be applied to the rock source site and the armour construction site. In cases armour stone has enhanced the aquatic habitat.	2	Minor alteration to the embankment slope.	2	Medium to long term	2	moderate	2	10
Gabions	Materials available locally	0	Assemble and fill gabion and fit to place.	3	Low probability	1	Can be constructed to represent various settings and can be used with short root vegetation or grasses.	1	Medium to long term	4	moderate	2	11
Cribs	Materials available locally	1	Simple construction of tiered timber members. Anchored to the ground by the backfill. Backfill should be carefully places to avoid loss of fines and subsequent subsidence.	2	Low probability	1	Can be constructed of locally sourced natural timbers. Various forms of short root vegetation can be used in conjunction with this construction.	1	Medium to long term	4	moderate	2	11
Concrete Armour	These units need to be shipped to site or manufactured in a local concrete plant. Producing locally is onerous, requiring purchase of specialised moulds and equipment.	5	Once on site, units are placed with long reach claw with relative ease	4	The modular units can be placed with minimal effort; craned to place. Typical environmental risk and protections will be required to be reviewed and developed.	3	The units are irregular manmade objects which knit together to provide a robust structure. Visual intrusion in this case is deemed minimal	4	Long term	5	Very high	4	25
Breakwaters	Local rock source	1	Production of armour stone in nearby quarry haulage, placement and shaping on site. May require marine vessel support.	5	Will require marine and aquatic review, consultation, planning etc	5	Major transformation of the naturally undisturbed seabed and seascape.	5	Medium to long term	5	High to very high	4	25

APPENDIX E: LIMITATIONS

ISO 9001:2008 Quality Management System (St. John's, NL)

Amec Foster Wheeler Environment & Infrastructure
a Division of Amec Foster Wheeler Americas Limited

LIMITATIONS

Amec Foster Wheeler Environment and Infrastructure, a division of Amec Foster Wheeler Americas Limited, prepared this Feasibility Study exclusively for Nalcor Energy. Amec Foster Wheeler prepared the Feasibility Study in accordance with the Standard Terms and Conditions made part of its contract with Nalcor Energy. The information contained herein in no way reflects on the environmental aspects of the project, unless specifically stated.

The Feasibility Study and any design criteria presented herein are based on information provided to Amec Foster Wheeler by Nalcor Energy, and on published technical reports. All relevant assumptions are listed in the Study. Amec Foster Wheeler did not conduct intrusive field investigations, and actual conditions may be different than those anticipated at the time this Study was prepared.

Amec Foster Wheeler accepts no responsibility for damages of any kind occasioned by or attributed to i) Nalcor Energy's use of the Feasibility Study for any purpose other than that for which it was originally intended, or ii) any use of the Feasibility Study by a third party for any purpose whatsoever. Any reliance on or decision based thereon by a third party is the sole responsibility of such third party.

Amec Foster Wheeler prepared this Feasibility Study in accordance with accepted industry practice, and with the same degree of care and diligence typically employed by consultants performing similar work in this geographic location. No other warranty is expressed or implied.

A REPORT TO

THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

	Electrical
	Mechanical
	Civil
	Protection & Control
	Transmission & Distribution
	Telecontrol
	System Planning

Upgrade Circuit Breakers

Various Sites

July 2015

newfoundland labrador hydro
a nalcor energy company

SUMMARY

This proposal is for the refurbishment and replacement of 66/69 kV, 138 kV and 230 kV circuit breakers. This report presents the methodology used for determining when a circuit breaker will be refurbished or replaced for air blast, SF_6, and oil circuit breakers.

Hydro has 193 circuit breakers in service that are rated at 66 kV or higher. A number of these circuit breakers have a service life that is nearing or in some instances exceeding the point where a refurbishment or replacement should be completed. This proposal presents an upgrade plan developed by Hydro for these circuit breakers based on service age, condition and duration since their last refurbishment.

Following the events of January 2014, Hydro developed a plan to accelerate the replacement of air blast circuit breakers. The plan, submitted to and approved by the Public Utilities Board in 2014, will see all the current in-service air blast circuit breakers replaced by 2020. The plan also included details on, overhauls of SF_6 circuit breakers completed at approximately mid-life and replaced at or near age 40, and all oil circuit breakers replaced prior to 2025 to ensure compliance with federal environmental legislation and the removal of polychlorinated biphenyls (PCBs) contaminated bushings.

This project proposes to perform the identified and predicted circuit breaker upgrade work scheduled through 2020 over a multi-year period.

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1 INTRODUCTION

The circuit breaker is a critical component of the power system. Located in a terminal station, each circuit breaker performs switching actions to complete, maintain, and interrupt current flow under normal or fault conditions. The reliable operation of a circuit breaker through its fast response and complete interruption of current flow is essential for the protection and stability of the power system.

1.1 Purpose of the Project

Hydro's circuit breaker upgrading project is required to refurbish or replace most of Hydro's circuit breakers on the Island Interconnected System. The majority of circuit breakers within Hydro's system have been operational for more than 30 years, with a significant number in the late stages or beyond their normal lifecycle (typically estimated between 40 to 55 years depending on circuit breaker type). The probability of failure for a circuit breaker increases with age, and thus cost effective refurbishment and/or replacement, where appropriate, is critical.

1.2 Current State

Hydro has 193 circuit breakers rated at voltages of 66 kV and higher. As shown in Figure 1, 25% of Hydro's circuit breakers are between 31 and 40 years of age and 35% are greater than 41 years of age.

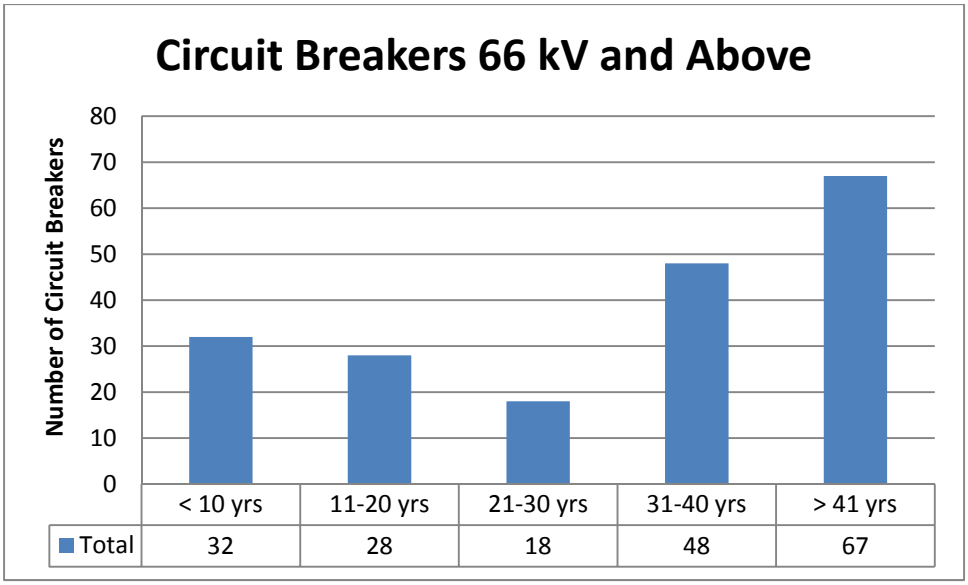


Figure 1: Age Distribution of 66 kV and Above Circuit Breakers

The three high voltage levels of circuit breakers utilized by Hydro are 66/69 kV, 138 kV and 230 kV. Figure 2 shows the age distribution of circuit breakers by voltage class.

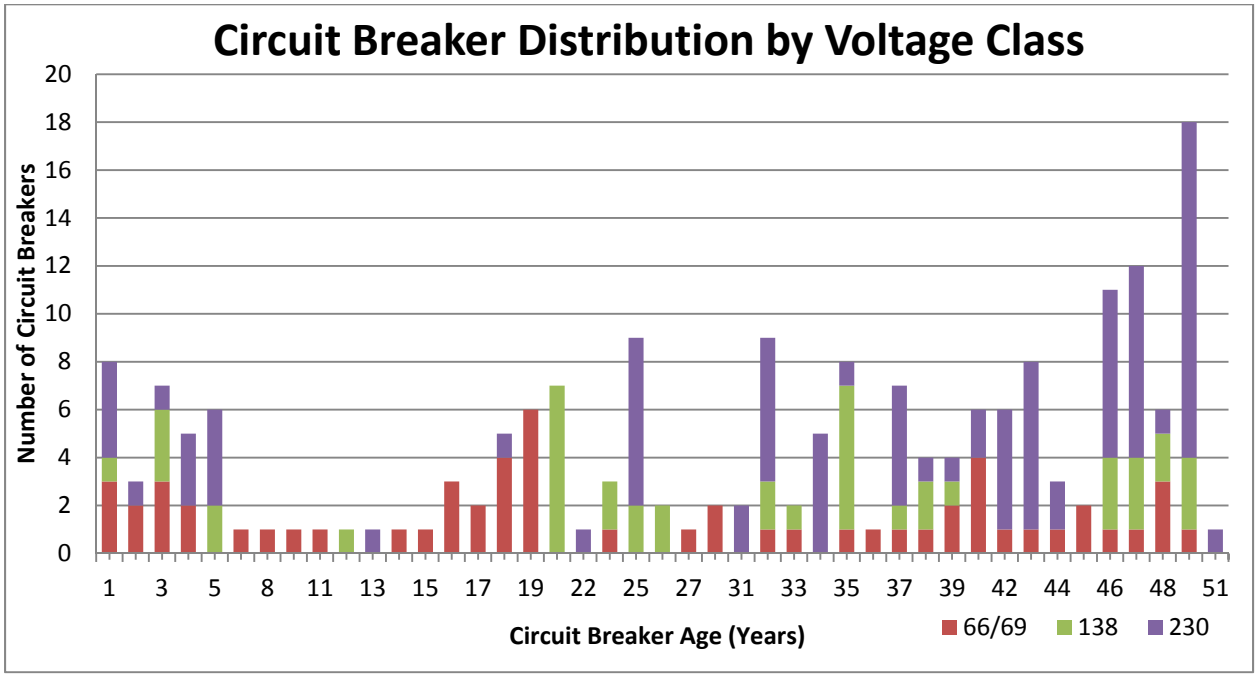


Figure 2: Circuit Breaker Distribution by Age and Voltage Class

Currently, Hydro maintains three different types of circuit breakers:

1. Air blast circuit breakers (ABCBs);
2. Oil circuit breakers (OCBs); and
3. Sulphur hexafluoride (SF_6) circuit breakers.

The current distribution of breakers by location, type and by voltage is attached as Appendix A. The SF_6 circuit breaker is the newest design.

Each type of circuit breaker has unique operating characteristics:

- **ABCBs** offer features such as fast response and automatic reclosing. They are widely used where repeated operation is essential.
- Unlike ABCBs, which extinguish the current arc created inside the circuit breaker with air as its medium, **OCBs** extinguish the arc using insulating oil.
- **SF_6 circuit breakers** use SF_6 gas, which has a higher density than air allowing SF_6 to be a highly reliable dielectric for extinguishing the current arc created during switching. The trend in the utility industry is towards the SF_6 circuit breakers because of the superiority of the new technology, availability and its operating characteristics. It is the primary type of circuit breaker available on the market today.

Figure 3 shows photos of the three types of circuit breakers.



Figure 3: Circuit Breakers - ABCB (left), OCB (middle) and SF_6 (right)

The circuit breaker is comprised of two major components:

- the interrupting device which includes the stationary contact, moving contact, arc quenching medium; and
- the insulating material along with the operating mechanism.

Air blast, oil and SF_6 circuit breakers are very different in design and construction and, as such, their refurbishment varies with each type:

- For ABCBs, both the interrupting device and operating mechanism require a mid-life refurbishment of seals, O-rings, and lubrication.
- OCBs will be replaced and not refurbished under this upgrading project due to environmental legislation for polychlorinated biphenyls (PCBs) that are contained in the OCB's bushings. This is described in more detail below.
- SF_6 circuit breakers typically require an operating mechanism refurbishment at mid-life as the interrupter is a sealed unit.

2 PROJECT DESCRIPTION

With the circuit breaker being a critical and high-cost capital asset, Hydro has been working to maximize the life of its in-service units. In recent years, Hydro has been replacing aging circuit breakers, upgrading ABCBs, refurbishing operating mechanisms associated with SF_6 circuit breakers, and dealing with the phase out of bushings containing PCBs, such as those associated with OCBs.

To bring forward a consolidated and coordinated care program for circuit breakers, Hydro developed its first long term plan in 2011 (with updates up to and including 2015). This plan contains the following elements:

- Refurbishment of certain types (DCF, DCVF and DLF) of ABCBs (this work is already well underway);
- SF_6 operating mechanism refurbishment;
- OCB replacements to replace aging assets and comply with environmental legislation (deals with possible PCB bushings);
- SF_6 circuit breaker replacements; and
- ABCB replacements.

The 2011 plan had timeframes that balanced reliable operation with financial impacts, and considered constructability, as well as system outage constraints, for a large quantity of aged circuit breakers that all require either refurbishment or replacement. It was decided to extend the service life of ABCBs to at least 50 years, refurbish SF_6 circuit breakers to maintain a life of 40 years and replace oil circuit breakers to ensure compliance with Environment Canada regulations.

Because of recent outage incidents on the Island Interconnected System in 2013 and 2014 (for which the failure of ABCBs was a factor), Hydro has reviewed its ABCB replacement plan in particular, and has accelerated this program. The accelerated program was outlined to the Board in the report, *Report to the Board of Commissioners of Public Utilities Related to Air Blast*

Circuit Breakers, filed in the proceeding, *Investigation and Hearing into Supply Issues and Power Outages on the Island Interconnected System* on August 1, 2014.

Historically, Hydro has applied to the Board for regulatory approval for a two-year period (one year for procurement, one year of work) in respect of circuit breaker refurbishment or replacement. Seeking annual regulatory approval for a long-term plan is not efficient and thus this proposal will address the critical areas noted above by outlining the work plan for each type of circuit breaker, commencing from approval by the Board until conclusion of the accelerated program for ABCB replacement in 2020.

2.1 Air Blast Circuit Breakers

Until 2014, Hydro had an on-going program to replace all ABCBs with SF_6 circuit breakers by 2031 and an overhaul program, which typically occurred at the 35 to 40 year period of the service lifecycle. Previously, the replacement of ABCBs would be considered after 50 years of service and ten to 15 years after refurbishment. Although the performance of ABCB has historically been reasonable, Hydro experienced significant events in January 2013 and January 2014 that involved ABCBs. As a consequence, Hydro now plans to initiate a program to carry out the replacement of ABCBs on an accelerated schedule to have all of these types of breakers replaced by the end of 2020.

The strategy and details of this accelerated ABCB replacement plan is outlined in this proposal and is largely based on the report “Accelerated Air Blast Circuit Breaker Replacement Program”, completed by AMEC Americas Limited on July 30, 2014 (the "AMEC Report"). The AMEC Report was part of the August 1, 2014 filing *Report to the Board of Commissioners of Public Utilities Related to Air Blast Circuit Breakers* in the proceeding *Investigation and Hearing into Supply Issues and Power Outages on the Island Interconnected System*. It is also attached to this report as Appendix B.

Rather than a two-phased approach as recommended by AMEC, Hydro has entered into an arrangement with a supplier for a single, continuous contract for the duration of the accelerated program. The benefits of this arrangement are described in more detail in Section 3.2.7.

2.2 Oil Circuit Breakers

OCBs will not be refurbished and are scheduled for replacement prior to 2025 as required by Environment Canada regulations. The existing OCBs have sealed bushings with an unknown quantity of PCB concentration, but based on the date of manufacture, these bushings could potentially have PCBs greater than 500 mg/kg.[1]

2.2 Sulfur Hexafluoride (SF_6) Circuit Breakers

The refurbishment of SF_6 circuit breakers will typically be scheduled after 20 years of service. With the development of the upgrading program, a number of the existing SF_6 circuit breakers have already reached a service life greater than 20 years. SF_6 circuit breakers in this category have been given a priority for refurbishment. The remaining SF_6 circuit breakers are planned to be refurbished at or near the 20-year service life period. This approach has been taken to help balance financial costs and operational risk while minimizing the number of customer outages and ensuring constructability in terms of available resources, physical workspace, etc. The plan for replacement will be after 40 years of service. Some SF_6 circuit breakers will require replacement before the 40-year service life period based upon their condition and operational history, which is further outlined below.

There are currently no refurbishments planned for the 66/69 kV voltage level SF_6 circuit breakers in the time frame covered by this proposal. Replacements will occur based on condition assessments, or at the currently scheduled year, whichever is first.

[1] See Hydro's response to NP-NLH-064 as provided in Hydro's 2015 Capital Budget Application (http://pub.nl.ca/applications/NLH2015Capital/files/rfi/NP-NLH-064.pdf).

The main objective for this overall upgrading plan is to develop and execute a strategic approach for all existing circuit breakers. This approach supports the corporate asset management philosophy, complies with current legislation and plans to minimize customer outages.

2.3 Station Upgrades

The replacement of the circuit breakers outlined within this project will also require the completion of upgrades and replacements to aging infrastructure associated with the breakers.

These upgrades include the following:

- The replacement of cable trenches used to protect the power and control cables required to control and monitor the breakers; and
- Upgrades to the AC station services, DC station services, and annunciator panels for those stations requiring the replacement of several breakers. The upgrades are required to accommodate the additional loads and to allow monitoring associated with the new replacement breakers, which will be SF_6 circuit breakers, and are required for stations in Bay d'Espoir, Buchans, Massey Drive, Stony Brook, Stephenville, Sunnyside, and Western Avalon.

3 JUSTIFICATION

Hydro is seeking to justify this project based on system reliability, environmental requirements, safety, vendor recommendations and cost. The decision to refurbish/replace has been carefully considered, taking into account the age of the asset, system criticality and timing.

3.1 Refurbishment or Replacement

This proposal is required to refurbish or replace aging circuit breakers Hydro has in service. The data from Figure 1 highlight the following:

- The average age of the entire circuit breaker population is well past the estimated circuit breaker midlife of 20 years and is approaching the manufacturers' specified design end-of-service life of 40 years.
- Sixty-seven circuit breakers are in the range of 41 to 51 years old. This does not include breakers planned for replacement in 2015.
- To maintain the circuit breaker asset below a 40-year lifecycle period would require a large short term financial capital cost to replace the 67 circuit breakers mentioned above and the numerous quantities of circuit breakers annually that would continue to reach this benchmark over the coming several years. This approach is not feasible and as a result, an alternate plan for rehabilitation was considered, taking into consideration reliability, safety and environmental concerns.
- Up until the events in January of 2013 and 2014, ABCBs had, in general, proven to be reliable circuit breakers over their service life. However, Hydro has decided to have all ABCBs replaced by 2020, regardless of age. SF_6 circuit breakers will typically be replaced after 40 years of service and all OCBs will be replaced by 2025.

3.1.1 Air Blast Circuit Breaker Refurbishments/Replacements

Since 1999, refurbishments have been completed on ABCBs. The ABCB replacement plan, shown in Appendix C, includes the updated accelerated ABCB replacement plan.

As noted in Appendix C, refurbishment of some ABCBs will be done with a short turn around for

replacement. Other planned refurbishments of ABCBs will be cancelled in favour of replacement. Refurbishments of some ABCBs were not cancelled as it was determined that a refurbishment would allow for some flexibility in the specific date of replacement while ensuring continued reliability of the asset. As noted in Appendix C, a few ABCBs refurbishments were cancelled where it was felt that it was safe and cost effective to do so with an accelerated replacement schedule.

3.1.2 Oil Circuit Breakers Replacements

There has been no major refurbishment work performed with OCBs. Hydro's intention is to replace these breakers by 2025 to ensure Hydro is compliant with the latest PCB regulations (see discussion below). At the end of this proposed project, the current plan reflects that five OCBs will remain for replacement, and will be addressed in a future capital budget proposal. The replacement plan for OCBs is included in Appendix D of this report.

Typically, older OCBs will be given a priority to be replaced first followed by OCBs with known problems such as high contact resistance or poor electrical testing results.

3.1.3 SF_6 Circuit Breaker Refurbishments/Replacements

In 2004, Hydro adopted a philosophy of refurbishing operating mechanisms associated with 230 kV and 138 kV SF_6 circuit breakers. By the end of 2015, 29 SF_6 circuit breakers will have been refurbished. The plan is to complete three to five refurbishments per year for a total of 45 circuit breakers refurbished by the end of 2019. This proposal will also see four SF_6 circuit breakers replaced by the end of 2020. See Appendix E for a complete listing of SF_6 circuit breakers with their planned refurbished and replacement dates.

3.2 Operating Experience

3.2.1 Reliability Performance

As previously noted, the majority of circuit breakers (all types) within Hydro's system have been operational for more than 30 years with a significant number in the late stages of, or beyond

their normal lifecycle (typically estimated between 40 to 55 years depending on circuit breaker type). The probability of failure for a circuit breaker increases with age and plans regarding refurbishment or replacement are therefore required.

In determining how well an asset is performing, Hydro compares the asset against the national average of performance for that type of asset. This national average is based on a combination of data collected by the Canadian Electricity Association (CEA), and includes: forced outages, frequency of failure, and the availability of the asset. Table 1 lists the performance data for each criterion. The listed data are the performance averages for Hydro's circuit breaker assets over the previous five years for 138 kV and 230 kV circuit breakers in comparison to the national average of 138 kV and 230 kV circuit breakers. The comparison uses the performance data from the latest CEA five-year average data collected between 2008 through 2012.

Table 1 shows Hydro has experienced 28 forced outages due to problems with its circuit breakers over the last five years.

Table 1: Circuit Breaker Performance (All Types)

	Number of Outages	Frequency (Per a) [1]	Unavailability (%) [2]
Hydro 230 kV Circuit Breakers (all types) (2009-2013)	20	0.054	0.033
CEA 230 kV Circuit Breakers (all types) (2009-2013)	1380	0.142	0.517
Hydro 138 kV Circuit Breakers (all types) (2009-2013)	8	0.039	0.000
CEA 138 kV Circuit Breakers (all types) (2009-2013)	1680	0.0996	0.454

[1] Frequency (Per a) is the number of failures per year.
[2] Unavailability is the percent of time per year the unit is unavailable.

As the above table demonstrates, Hydro's breaker performance exceeds CEA performance generally. The above data would therefore suggest that Hydro's current long-term refurbishment/replacement plans remain in place. However, because of the recent supply issues and power outages on the Island Interconnected System involving ABCBs, Hydro has

reviewed its ABCB replacement plan and has accelerated the replacement of these breakers within this program.

With respect to SF_6 circuit breakers, Hydro and CEA data shows this type of circuit breaker to be a reliable option. The CEA tracks two categories of SF_6 circuit breakers: live tank and dead tank breakers. A live tank breaker has the main breaker tank energized at the operating voltage level. A dead tank breaker has the main breaker tank not energized. Hydro has both categories in its circuit breaker fleet. Table 2 shows that Hydro has had very few forced outages of either category of SF_6 circuit breaker (a total of four) during the period 2009 to 2013.

Table 2: Circuit Breaker Performance (SF_6 Circuit Breakers)

Live Tank	**Number of Outages**	**Frequency (Per a)**	**Unavailability (%)**
Hydro 230 kV Circuit Breakers (SF_6 live tank) (2009-2013)	1	0.013	0.000
CEA 230 kV Circuit Breakers (SF_6 live tank) (2009-2013)	122	0.050	4.050
Hydro 138 kV Circuit Breakers (SF_6 live tank) (2009-2013)	2	0.0274	0.000
CEA 138 kV Circuit Breakers (SF_6 live tank) (2009-2013)	163	0.0335	1.179

Dead Tank	**Number of Outages**	**Frequency (PER a)**	**Unavailability (%)**
Hydro 230 kV Circuit Breakers (2009-2013)	0	0.000	0.000
CEA 230 kV Circuit Breakers (2009-2013)	155	0.071	0.885
Hydro 138 kV Circuit Breakers (2009-2013)	1	0.0244	0.000
CEA 138 kV Circuit Breakers (2009-2013)	88	0.0426	3.319

3.2.2 Circuit Breaker Replacement and Upgrades

Table 3 provides a recent history of the circuit breaker replacement and upgrade work.

Table 3: Historical Information

Year	Capital Budget ($000)	Actual Expenditures ($000)	Units	Cost per Unit ($000)	Comments
2014	3,695	1,572	11	143	• Two replacements • Nine overhauls
2013	2,785	2,421	16	151	• Four replacements • Purchased one breaker (not installed) • Installed platforms for six breakers • Five overhauls • Purchased materials for one overhaul
2012	1,677	1,288	10	129	• Three replacements • Purchased one breaker (not installed) • Three overhauls • Purchased materials for three overhauls
2011	780	757	2	379	• Replacement of two 69 kV breakers (St. Anthony)
2011	631	646	1	646	• Replacement of one 230 kV breaker (Sunnyside)
2011	334	297	11	27	• Five overhauls • Purchased materials for six overhauls
2010	342	501	6	83.5	• Four overhauls • replacement of one 138 kV breaker (Bottom Brook) • replaced one phase of B1B11 in Holyrood

3.2.3 Maintenance History

The five-year maintenance history for all circuit breakers is shown in Table 4.

Table 4: Circuit Breaker Maintenance Costs (Total)

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2014	585.4	140.4	725.8
2013	81.5	344.4	425.9
2012	72.5	196.6	269.1
2011	61.8	160.3	222.1
2010	50.3	64.5	114.8

With ABCBs, Hydro has experienced problems with air leaks and valves sticking, resulting in increased maintenance costs and circuit breaker unavailability. Such problems have mainly been a result of deteriorating seals and O-rings. The problems experienced by Hydro are common in the utility industry and owners of these types of ABCBs have addressed the problems through similar upgrading programs.

The two main problems experienced with SF_6 circuit breakers have been leaking SF_6 gas and operating mechanisms that malfunction. The operating mechanism is a mechanical device that is spring charged and engages the circuit breaker's contacts. If an operating mechanism malfunctions, the operation of the circuit breaker is unavailable. In addition, with the air operated type of SF_6 circuit breakers there has been corrosion of air receiver tanks. Some examples of SF_6 circuit breaker replacements due to maintenance conditions include:

- Breaker B3L50 at Bottom Brook was replaced in 2010 due to gas leaks that were reoccurring and could not be repaired.
- Breaker L51T2 at Howley was replaced in 2009 due to severe corrosion of the air receiver associated with the SF_6 circuit breaker that is air operated.
- Breakers B1T1 and B1L57 at St. Anthony were replaced in 2011 and 2012 due to gas leaks that were reoccurring and could not be repaired.
- Breaker B1L22 at the Springdale Terminal Station was replaced in 2013 due to internal damage.

Without the current refurbishment/replacement plan, annual maintenance costs are anticipated to grow due to the increasing age of the assets.

3.2.4 Environmental Performance: Oil Circuit Breakers

The replacement of OCBs is being done to ensure that the environmental issues associated with the use of PCB material in oil circuit breaker bushings are addressed. The use of PCB material in OCB bushings has presented an environmental issue that has led to the development of a plan for its removal and safe disposal. Prior to the mid-1980s, the manufacturers of bushings used insulating oil that contained PCBs of varying concentration. The latest federal *PCB Regulations* (SOR/2008-273) provided an end of use date for different concentrations of PCBs. Section 16(1) provided that the end of use for equipment containing PCBs in a concentration of 500 mg/kg or more was December 31, 2009; and for equipment containing PCBs in a concentration of at least 50 mg/kg but less than 500 mg/kg is December 31, 2025. The regulations also gave utilities an option to apply for an extension until 2014 to have all sealed equipment containing PCBs greater than 500 mg/kg removed. Hydro, like other CEA members, has a significant amount of sealed equipment with unknown levels of PCBs. As a result, Hydro applied for an extension in 2010 and this was granted until December 31, 2014.

However, due to the large volume of sealed equipment with unknown PCB levels, CEA members (including Hydro) pursued a regulatory amendment to allow the use of bushings and instrument transformers with PCB concentrations of 500 mg/kg and greater until December 2025. In April 2014, the amended *PCB Regulations* were released and the new regulations came into force on January 1, 2015. This allows Hydro to continue with its current plan to have OCB bushings removed by 2025.

This aspect of this proposed project is a continuation of Hydro's current plan for the removal and safe disposal of PCB contaminated equipment prior to the federally mandated deadline of December 2025.

3.2.5 Industry Experience

Many utilities in North America are in a similar position as Hydro with infrastructure that is nearing the end of its serviceable life. Replacement of aging circuit breakers with SF_6 circuit

breakers is common practice and in fact, one of the limited options available to utilities for circuit breakers of higher voltages. Hydro has developed a plan to find the most economic and reliable solution to refurbish and replace aging circuit breakers.

3.2.6 Vendor Recommendations

ABB, the OEM for the ABCBs, had advised that a refurbishment of this type of circuit breaker would extend the service life of an ABCB by approximately 15 years. In theory, this would allow ABCBs to have an anticipated useful service life of at least 50 years. Hydro had initially planned to refurbish the remaining ABCBs and schedule their replacement ten to 15 years after this refurbishment to a service life of 50 years minimum. This plan was amended in 2014 to accelerate replacement, based on Hydro's own experience and that of others in the Canadian electrical industry. The plan to refurbish all ABCBs remains in effect; however, accelerated replacement will happen for several ABCBs before the 50-year service life is reached.

The majority of the vendors for SF_6 circuit breakers suggest that 40 years is a suitable end of service life period provided a refurbishment is completed near the mid-life of the circuit breaker.

3.2.7 Maintenance or Support Arrangements

For SF_6 refurbishments, Hydro is using ABB to assist with the refurbishment of the ABB 230 kV ELF (air-operated type) SF_6 circuit breakers and Siemens Canada Ltd. to direct the work associated with the refurbishment of Siemens 230 kV 3AQ1 SF_6 circuit breakers.

Hydro has established a partnership agreement with an OEM (Original Equipment Manufacturer) for the supply and installation of circuit breaker replacements for the majority of breakers scheduled to be replaced between 2015 and 2020. The finalization of this arrangement is contingent on Board approval. Benefits of agreement include the following:

- The contractor is required to meet the terms and conditions of the contract on an annual basis and the award of the following years' scope of work is subject to the

contractor's performance in the previous year. Yearly purchase orders will be issued and subject to mutual agreement between the parties as to various terms.

- Hydro is entitled to terminate the contract at any time with notice, subject to payment for work/orders in process or already completed.
- Prices are as quoted and any escalation of costs over time and exchange rates are subject to defined formulas. This approach provides for cost certainly and predictability over the term of the contract.

3.2.8 Anticipated Useful Life

For the replacement of SF_6 circuit breakers, 40 years will be the trigger point. Until the recent system events, ABCBs were typically replaced ten to 15 years after refurbishment and after the circuit breaker had been in service for 50 years. However, the new accelerated plan, which focuses on maintaining reliability, will now replace some ABCB prior to the above criteria to eliminate the risk of failures.

The failure and lack of availability of circuit breakers is anticipated if the plan to refurbish and replace this equipment is not continued.

3.3 Development of Alternatives

The purpose of this project is to maintain a fleet of 66/69 kV, 138 kV and 230 kV circuit breakers that are reliable, cost effective, and are more environmental friendly. The three possible alternatives to achieve this goal are:

1. Replacement of all circuit breakers at the age of 40 years;
2. Refurbishment of failed circuit breakers as they occur; and
3. Replacement and refurbishment of circuit breakers in a planned strategic approach to balance financial and human resources while minimizing outages.

3.4 Evaluation of Alternatives

1. **Replacement of all circuit breakers at the age of 40 years**. This alternative would require approximately 60 circuit breakers to be replaced immediately, which would result in significant costs. Further, such a plan would require a significant number or duration of system outages that are not feasible. As a result, Hydro will not pursue this alternative.
2. **Refurbish failed circuit breakers as they occur.** This approach is reactive and not prudent to maintain system reliability when the asset is critical in the provision of continuous power. With a planned approach, the refurbishment and replacement of circuit breakers can be scheduled at an appropriate period for completion. Hydro does not plan to pursue this alternative.
3. **Replacement and refurbishment of circuit breakers in a planned, strategic approach.** This is the preferred alternative as it balances the financial costs, resource requirements and system outages.

In reviewing Alternative #3 further, the following is noted with respect to each type of circuit breaker in Hydro's system.

- The options to consider for **ABCBs** consist of (i) refurbishment or (ii) replacement. Replacement for all ABCBs was originally planned to be completed by 2031. However, due to the problems experienced with ABCBs in the past two years, an accelerated alternative is being pursued is to replace all ABCBs by 2020.
- Due to PCB regulations, **OCBs** will be replaced versus being refurbished. Regulatory requirements preclude examination of alternatives.
- In considering the options for the **SF_6 circuit breakers,** it is noted that the refurbishment cost of a 230 kV SF_6 circuit breaker is one-seventh the cost of replacement (and one-third the cost of replacing a 138 kV circuit breaker). The system outage requirement for a refurbishment is typically one week versus a four to five week outage for a replacement. The refurbishment entails the restoration of seals and wearing parts in the operating mechanism to achieve an anticipated service life of 40 years.

The refurbishment of some types of circuit breakers does not meet any criterion that is cost effective, for instance, the cost to refurbish 66/69 kV SF_6 circuit breakers. Therefore, Hydro has not included the refurbishment of this type of circuit breaker in this proposal. As previously noted, replacement of this type of circuit breaker is the more cost effective solution.

In summary, Hydro will pursue Alternative #3 using a two-tiered approach involving both refurbishments and replacements, as appropriate. This approach will help minimize system outages and provide for a more considered approach to circuit breaker upgrades, both financially and in the use of Hydro and other resources.

4 PROJECT EXECUTION

This proposal is seeking approval of this multi-year plan to refurbish and replace circuit breakers. Hydro plans to use a combination of refurbishments and replacements for air blast, SF_6 and oil circuit breakers. The plan will see all existing in-service ABCBs replaced by 2020, all OCBs being replaced prior to 2025, and all existing in-service 138 kV and 230 kV SF_6 circuit breakers refurbished at mid-life and replaced at or near the 40 year lifecycle period. This project is for the years 2016 to 2020 of the plan.

For SF_6 circuit breakers, there will be two to five refurbishments completed annually between the years 2016 and 2020. The replacement of SF_6 circuit breakers is not scheduled to begin until 2019 unless a circuit breaker's condition warrants an earlier replacement.

The replacement of the circuit breakers outlined within this project will also require the completion of upgrades and replacements to aging infrastructure associated with the breakers. These upgrades include the replacement of cable trenches and upgrades to the AC station services, DC station services, and annunciator panels for several stations.

A listing of all planned refurbishments and replacements are outlined in Appendices C, D and E. Table 5 summarizes the budget for this work. In the infrequent circumstance that the priority of a given breaker replacement changes, individual breakers may be replaced in a year other than that in the current plan.

4.1 Budget Estimate

Table 5: Project Budget Estimate

Project Cost ($ x 1,000):	2016	2017	2018	2019	2020	TOTAL
Material Supply	100.0	100.0	100.0	100.0	100.0	500.0
Labour	2,061.7	2,494.9	3,259.7	3,220.7	2,741.3	13,778.2
Consultant	211.6	423.3	824.4	784.4	634.9	2,878.6
Contract Work	3,519.5	5,927.5	8,261.6	7,912.7	6,552.4	32,173.8
Other Direct Costs	87.0	139.2	204.4	204.4	178.3	813.4
Interest and Escalation	391.2	815.4	1,493.5	1,802.9	1,799.1	6,302.1
Contingency	598.0	908.5	1,265.0	1,222.2	1,020.7	5,014.4
TOTAL	**6,969.1**	**10,808.7**	**15,408.6**	**15,247.3**	**13,026.8**	**61,460.4**

The capital expenditures for this project noted above do not include the replacement of the circuit breakers indicated in the Appendix C, D and E as requiring replacement for "NL/NS Link" or "LCP". It should also be noted that this budget includes station services upgrades, as noted above, as well as replacement/refurbishment costs for all three types of circuit breakers (ABCBs, OCBs and SF_6).

4.2 Project Schedule

The anticipated project schedule is shown in Table 5.

Table 5: Project Schedule

Activity		Start Date	End Date
Planning	Initial Planning / Scheduling	January 2016	February 2016
Design / Procurement 2016	Equipment Ordering Tendering	January 2016	March 2016
Construction 2016	Equipment Installations / Overhauls	May 2016	October 2016
Commissioning 2016	Installations in service	May 2016	November 2016
Design / Procurement 2017	Equipment Ordering Tendering	January 2017	February 2017
Construction 2017	Equipment Installations / Overhauls	April 2017	October 2017
Commissioning 2017	Installations in service	April 2017	November 2017
Design / Procurement 2018	Equipment Ordering Tendering	January 2018	February 2018
Construction 2018	Equipment Installations / Overhauls	April 2018	October 2018

Activity		Start Date	End Date
Commissioning 2018	Installations in service	April 2018	November 2018
Design / Procurement 2019	Equipment Ordering Tendering	January 2019	February 2019
Construction 2019	Equipment Installations / Overhauls	April 2019	October 2019
Commissioning 2019	Installations in service	April 2019	November 2019
Design / Procurement 2020	Equipment Ordering Tendering	January 2020	February 2020
Construction 2020	Equipment Installations / Overhauls	April 2020	October 2020
Commissioning 2020	Installations in service	April 2020	November 2020
Closeout	Project Completion/Close Out	December 2020	December 2020

4.3 Standardization of Circuit Breakers

Standardization on a single type of SF_6 circuit breaker within the Island Interconnected System in the short term can bring about the following benefits:

- Reduced engineering and procurement costs associated with dealing with multiple types of breakers;
- Decrease review time and effort in drawings and approvals;
- Training can be focused (and likely increased) as less time will be required to familiarize staff with multiple types of circuit breakers on the system. Staff will become more familiar with (and specialized in) the SF_6 circuit breaker, simply by virtue of it being the majority type on the system;
- Fewer spare parts will be required to be maintained for each site; and
- Asset management will be simplified generally as a result of having to manage a majority of one type of circuit breaker throughout the system.

Although there are potential risks with using a single type of equipment throughout the system, Hydro has carefully evaluated, and chosen to standardize on, the SF_6 circuit breaker due to its market penetration and wide use by other utilities.

4.4 A Multi-year Project Approach

As previously noted, Hydro is applying to the Board for approval of this project until 2020, as opposed to an annual application process, as was included in the 2015 Capital Budget Application, with respect to circuit breaker replacement/refurbishment. The cost savings of executing a single five-year contract versus annual two-year contracts are shown in Table 6.

Table 6: Two-Year Versus Five-Year Contract

Alternative Comparison Cumulative Net Present Value To The Year 2015		
Alternatives	**Cumulative Net Present Value (CPW)**	**CPW Difference between Alternative and the Least Cost Alternative**
Single Five-Year Contract	$28,037	0
Annual Two-Year Contract	$222,391	$194,354

There are several benefits to taking a multi-year approach to this project:

- Hydro will be able to develop a long-term relationship with a single supplier (subject to certain terms as previously noted), thereby reducing contractor ramp-up time and costs for refurbishment and/or replacement of circuit breakers.
- Hydro will be able to benefit from the standardization of circuit breakers, which reduces training, engineering, and the need for critical spares, as outlined in section 4.3.
- Hydro will be able to benefit from greater cost certainty and cost control mechanisms through a long-term written arrangement with a single supplier.
- It is estimated that the Cumulative Present Worth of the avoided costs associated with using a multi-year approach versus a single year approach is 194K, as shown in Table 6. These estimated savings would include the avoided costs of the annual contract preparation and tendering process, which would normally be charged to the project on a yearly basis. Additional avoided costs not charged to the project (and thereby not quantifiable here) would include: preparation of annual regulatory filings and costs relating the engagement of purchasing staff in the tendering process. These additional avoided costs would be borne by Hydro in the normal course, but could be avoided with less frequent regulatory filings required for a long-term project of this type.

Hydro is required to report to the Board when expenditures differ from approved amounts by prescribed amounts. If expenditures differ from this project according to the triggers set in the Capital Budget Application Guidelines, Hydro will report on this project to the Board as part of its regular capital expenditure and carryover reporting on capital projects. As with all multi-year projects, Hydro will comply with the Board's *Capital Budget Application Guidelines,* in particular with respect to multi-year expenditures.

APPENDIX A:
Hydro Circuit Breakers on the Island Interconnected System

Hydro Circuit Breakers (by Location/Voltage/Type)

		Air Blast	Oil	SF6	Grand Total
BBK TS	66/69		1		**1**
	138			3	**3**
	230	4			**4**
BBK TS Total		**4**	**1**	**3**	**8**
BCV TS	138			2	**2**
BCV TS Total				**2**	**2**
BDE TS	66/69		1	1	**2**
	230	13		5	**18**
BDE TS Total		**13**	**1**	**6**	**20**
BHL TS	66/69		2		**2**
	138			1	**1**
BHL TS Total			**2**	**1**	**3**
BUC TS	66/69			3	**3**
	230	4		1	**5**
BUC TS Total		**4**		**4**	**8**
BWT TS	138			1	**1**
BWT TS Total				**1**	**1**
CAT TS	230			2	**2**
CAT TS Total				**2**	**2**
CBC TS	230			5	**5**
CBC TS Total				**5**	**5**
CBF TS	66/69		1	1	**2**
CBF TS Total			**1**	**1**	**2**
CFLTS	230	4		1	**5**
CFLTS Total		**4**		**1**	**5**
CHD TS	66/69		1		**1**
CHD TS Total			**1**		**1**
DHR TS	66/69		1		**1**
DHR TS Total			**1**		**1**
DLK TS	66/69		1	2	**3**
	138			4	**4**
	230			2	**2**
DLK TS Total			**1**	**8**	**9**
DLS TS	66/69			1	**1**
DLS TS Total				**1**	**1**
HBY TS	66/69			1	**1**
HBY TS Total				**1**	**1**
HLY TS	66/69			1	**1**
	138			4	**4**
HLY TS Total				**5**	**5**

		Air Blast	Oil	SF6	Grand Total
HRD TS	66/69		2	3	**5**
	138		1		**1**
	230	6		6	**12**
HRD TS Total		**6**	**3**	**9**	**18**
HVY TS	138		1		**1**
HVY TS Total			**1**		**1**
HWD TS	66/69		4	5	**9**
	230	1		3	**4**
HWD TS Total		**1**	**4**	**8**	**13**
IRV TS	138			3	**3**
IRV TS Total				**3**	**3**
MDR TS	66/69		1	2	**3**
	230	2		1	**3**
MDR TS Total		**2**	**1**	**3**	**6**
MFATS3	138			2	**2**
MFATS3 Total				**2**	**2**
OPD TS	66/69		2	4	**6**
	230	2			**2**
OPD TS Total		**2**	**2**	**4**	**8**
PBN TS	66/69			3	**3**
	138			1	**1**
PBN TS Total				**4**	**4**
PPT TS	138			4	**4**
PPT TS Total				**4**	**4**
RBK TS	66/69			1	**1**
RBK TS Total				**1**	**1**
RWC TS	66/69			1	**1**
RWC TS Total				**1**	**1**
SOK TS	138			1	**1**
SOK TS Total				**1**	**1**
SPL TS	138		1	1	**2**
SPL TS Total			**1**	**1**	**2**
SSD TS	138	5		2	**7**
	230	3		2	**5**
SSD TS Total		**8**		**4**	**12**
STA TS	66/69			6	**6**
STA TS Total				**6**	**6**
STB TS	138	6			**6**
	230	6		1	**7**
STB TS Total		**12**		**1**	**13**
SVL TS	66/69		3		**3**
	230			1	**1**
SVL TS Total			**3**	**1**	**4**

		Air Blast	Oil	SF6	Grand Total
USL TS	230			2	**2**
USL TS Total				**2**	**2**
VBN TS	230			2	**2**
VBN TS Total				**2**	**2**
WAV TS	66/69		2		**2**
	138		1		**1**
	230	6		3	**9**
WAV TS Total		**6**	**3**	**3**	**12**
WDL TS	66/69			1	**1**
WDL TS Total				**1**	**1**
WTS TS	230	3			**3**
WTS TS Total		**3**			**3**
Grand Total		**65**	**26**	**102**	**193**

APPENDIX B:
Report of AMEC Americas Limited

NEWFOUNDLAND AND LABRADOR HYDRO

Accelerated Air Blast Circuit Breaker Replacement Program

July 30, 2014

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Accelerated Air Blast Breaker Replacement Program 14

1) Executive Summary

Newfoundland and Labrador Hydro (Hydro) has an on-going program to replace circuit breakers at the end of the asset's useful life. This includes replacing all 63 air blast circuit breakers with SF6 circuit breakers by 2031. Although historically the performance of air blast circuit breakers has been reasonable, Hydro has experienced two significant outage incidents in the last two years in which the failure of air blast circuit breakers was a significant contributing factor. As a consequence Hydro now plans to initiate a program to carry out the replacement on an accelerated schedule. This document provides a strategic plan for accomplishing this.

The accelerated air blast circuit breaker replacement program is designed to be implemented in two three-year phases with the first installation of breakers in 2015. A partnership arrangement would be established between Hydro and an external contractor for each phase for the supply and installation of breakers. Breakers purchased under the current replacement program would be installed in 2014 but beginning in 2015 the existing program would be merged into the accelerated program.

The overall program scheduled to be completed by 2020 provides a significant reduction in the time required to replace all air blast circuit breakers while maintaining safety, ensuring reliability and maximizing the use of available resources.

2) Introduction

Hydro plans to initiate a program to replace all air blast circuit breakers on an accelerated schedule. There are a total of 63 air blast circuit breakers on the Hydro system. Although historically the performance of these breakers has been reasonable, Hydro has experienced two significant outage incidents in the last two years in which the failure of air blast circuit breakers was a significant contributing factor.

During the next few years there are a number of activities already in progress which will result in the replacement of a number of these breakers. The activities include the LCP program at Holyrood, Bay D'Espoir and Hardwoods, the NL/NS link at Bottom Brook, breaker replacement associated with the transformer repairs at Sunnyside and the program currently underway to replace breakers at end-of-life. The accelerated replacement program will be carried out in addition to these other programs but must consider the overall impact of all activities on the system and resources. Close coordination with these other programs is required.

3) Background

In July 2012 Hydro submitted an *Upgrade Circuit Breaker* plan to the Board of Commissioners of Public Utilities (PUB) as part of its 2013 capital plan. The plan contained two components. One was to refurbish and replace aging air blast and SF6 circuit breakers to ensure system reliability. The other was to comply with legislation to remove PCB contaminated bushings on oil circuit breakers by replacing the oil circuit breakers with new SF6 circuit breakers.

No changes are anticipated for either the oil circuit breaker replacement program or the SF6 refurbishment and replacement program

The July 2012 plan for air blast circuit breakers had been to overhaul these breakers at about 40 years of service and replace them at the useful end of the asset life between 50 and 55 years of service. Replacement breakers would be SF6 type breakers and the replacement program would be completed by 2031. This meant that four to five overhauls would be completed per year and about three replacements per year. The report indicated that the experience in Newfoundland and from other utilities was that overhauls were effective in maintaining the reliability of air blast circuit breakers and extending their lifecycle.

In January 2013 and January 2014 Hydro experienced major system outages. In both incidents air blast circuit breakers failed to operate properly. During the PUB investigation into the January 2014 power outages its consultant, the Liberty Consulting Group, made a number of recommendations regarding air blast circuit breakers. These recommendations included exercising breakers, catching up on overdue maintenance, reducing the preventive maintenance cycle from 6 years to 4 years and periodically operating breakers from protection. Furthermore, the PUB in its May 15th Interim Report has requested that Hydro file a report on August 1st on the acceleration of the replacement of air blast circuit breakers.

This Accelerated Air Blast Breaker Replacement program has been independently developed for Hydro to address the recent experience with the decreased reliability of air blast circuit breakers and the recommendations of the Liberty Consulting Group. Factors considered in the development of the program include the criticality of the circuit breaker to system reliability, the age of the breaker and time since its last overhaul, the optimal use of resources through selection of the number work sites and avoiding delays in removal of air systems. Data for the development of the program was obtained from Hydro's Breaker 20 Year Plan dated Mar 26, 2014 and revisions to it up to July 3, 2014.

4) Program Goal and Scope

The overall program goal is to replace all air blast circuit breakers on an accelerated schedule in order to eliminate reliability issues associated with failure of air blast circuit breakers. This requires a balanced approach that replaces the breakers on a timely basis but maintains reliability of the power system during the work required to replace them. A six (6) year project schedule has been chosen that would begin in 2015. A partnership arrangement would be established between Hydro and an external contractor. Initially, Hydro would prepare and issue tender documents, evaluate bids and award the contract. The external contractor would supply and install the breakers. During the contract execution, Hydro would disconnect existing breaker, review and approve drawings including protection and control, provide outage coordination and on-site supervision, and oversee commissioning.

The scope of the contract would include:

- Removal of existing breaker and foundation
- Construction of a new foundation for the circuit breaker structure
- Supply and installation of new breaker
- Installation of new protection equipment and control cables
- Commissioning of new breaker

The accelerated air blast circuit breaker replacement program is designed to be implemented in two three-year phases. For each phase, a multi-year contract (3 years) will be issued for supply and installation of breakers. The contract will contain specific numbers of breakers to be supplied and installed each year. The contract should also contain an option to supply and install additional breakers on an incremental basis by year that allows for flexibility to adapt to changing system conditions. By breaking the contract into two phases Hydro can ensure a competitive and competent supplier is used throughout while still benefitting from the economies resulting from large orders and dealing with one (either through a successful re-bid or a contract extension) or two suppliers.

5) Schedule

Due to the time required to procure circuit breakers it is not practical to implement an accelerated breaker replacement plan in the field prior to 2015. In 2014 the procurement process would be put in place that incorporates and replaces the existing Upgrade Circuit Breaker project to have the necessary breakers and services available in 2015. Current activities will ensure that a number of air blast circuit breakers get replaced in 2014. This also enables time to properly analyze the requirements, prepare a plan and put in place a contract for the accelerated replacement of circuit breakers beginning in 2015.

The plan requires that a tender be prepared and issued in the fall of 2014 for the first phase of the program to secure a contractor for the years 2015-2017. Breakers required for installation in 2015 need to be delivered in the spring of 2015. Installation would then take place during the construction season of April – October. Subsequent years 2016 and 2017 would follow a similar schedule. Preparation for Phase 2 would take place during the summer/fall of 2017. At that time either the existing contract could be extended for an additional 3 years or a new contract awarded in time to continue the replacement program without interruption.

It is important that a thorough review of the specific breakers to be replaced be conducted on an annual basis. This review should include all affected departments including system operations (ECC), regional operations and maintenance, engineering, plant operations as required and protection and control. The first review should take place in the fall to finalize the list for the following year. A preliminary schedule and resource requirements should be looked at. With this if there are resource issues then there is still time to address them. Three months prior to the beginning of the construction season the outage schedule needs to be finalized. During the construction season final scheduling and approval of outages would be done in accordance with Hydro procedures.

6) Risk

The accelerated air blast circuit breaker replacement program contains significant but manageable risks. During the years 2015 and 2016 there are 12 air blast circuit breakers being replaced each year. This is in addition to oil circuit breaker replacements (5 and 4 respectively), overhauls and preventive maintenance. This represents a significant risk to schedule and resource availability. However, in both 2015 and 2016 there are other breaker replacement programs already active such as LCP that would mitigate the risk somewhat. Coordination of the work by Hydro and the contractor / partner is critical to the success of this program.

7) General

The overall plan for accelerated circuit breaker replacement needs to meet the following criteria:

- ***Safety*** of personnel and equipment must be a priority at all times. Hence any plan that incorporates external resources needs to ensure that all safety requirements of Hydro are met or exceeded.
- ***Reliability*** of power system is continuously maintained. Although the outages incurred to install new breakers will impact the ability of the power system to respond to disturbances the overall plan should not create undue risks. It is imperative that the plan be coordinated with system operations.
- The replacement of the circuit breakers should consider ***effective use of resources*** including technical capabilities and capacity of available labour, equipment and materials as well as be ***economic***.
- ***Timely***. Accelerating the replacement of circuit breakers will reduce the potential for further outages caused by failures of air blast circuit breakers.

A number of factors were used to select and prioritize the breaker replacements. These included the criticality of the breaker to system reliability, the age of the breaker and time since its last overhaul, optimizing use of resources through selection of the number work sites and avoiding delays in removal of air systems. Locations where the breakers were critical to system reliability or where breakers with known problems existed were given the highest priority. For continuity and efficient use of resources, the number of work locations was constrained and once a Terminal Station was started replacements continued at that location until completed. This also ensured that the air systems could be removed on a timely basis. Coordination with other on-going breaker replacement programs was an important consideration due to the impact on both resources and reliability of the system. The age and the time of the last overhaul were used to guide the replacement when other more critical factors had been satisfied.

During **Phase 1** of the accelerated program from 2015 – 2017 a total of 18 air blast circuit breakers will be replaced. These are in addition to those being done under other programs currently in progress. By the end of 2017 a total of 34 breakers (all 230 kV) at 7 locations will have been replaced. This will also enable the associated air systems at 5 of these locations to be de-commissioned. At Sunnyside, the portion of the air system used to supply the 230 kV breakers can also be de-commissioned. The air systems which are an integral component required for the reliable operation of air blast circuit breakers require a significant amount of maintenance

In the years 2014 – 2016 other programs are in place that will result in replacement of air blast circuit breakers. The LCP program will result in ten (10) 230 kV breaker replacements at Holyrood and Bay D'Espoir. Two breakers (1 – 230 kV, 1 – 138 kV) are scheduled to be replaced in 2014 at Sunnyside in conjunction with the transformer T1 replacement. The NL/NS link requires that all four (4) 230 kV breakers at Bottom Brook be replaced in 2016.These are to be replaced by Emera and at this time are treated separately from the accelerated breaker program. In addition, the Upgrade Circuit Breakers project has air blast circuit breakers scheduled for replacement in 2015 and 2016 but these breakers have been included in the accelerated program beginning in 2015. For efficiency, consideration should also be given to incorporating the Emera work within the accelerated program.

During **Phase 2** of the accelerated program from 2018 – 2020 the remaining 29 air blast circuit breakers will be replaced (18 – 230 kV, 11 – 138 kV) at five locations. The air systems at these locations will also be de-commissioned. All 138 kV breaker replacements are scheduled to occur during Phase 2 because the 138 kV system is less critical to the overall reliability of the

electrical grid and resultant outages tend to be more localized. Moreover, from a project perspective the initial procurement need not address 138 kV breakers.

The following table provides a summary of the complete air blast breaker replacement programs. A more detailed description of the replacement program by location is included in Section 9 and Appendix 1 contains a complete list of all breakers to be replaced.

Air Blast Circuit Breaker Replacement

		Phase 1			Phase 2			
Description	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**Total**
Accelerated Program		9	4	5	11	10	8	47
LCP	3	3	4					10
NL/NS Link			4					4
Other	2							2
Total	5	12	12	5	11	10	8	63

8) Circuit Breaker Planned Maintenance and Overhauls

On June 2, 2014 Hydro filed a report with the PUB on work required on air blast circuit breakers. In it Hydro identified that 40 breaker Preventive Maintenance (PMs) were due to be completed by the end of 2015. The schedule would be to complete 23 in 2014 (14 planned, nine overdue) and 17 in 2015 (eight planned, nine overdue). In 2016 and beyond the PMs would return to nine or ten per year and decrease over time.

The PM program for air blast circuit breakers has not been reviewed as part of this study. It is anticipated, however, that all overdue work will still be completed by the end of 2015 and the number of scheduled PMs for air blast circuit breakers should decrease rapidly between 2016 and 2019 with no PMs required in 2020. Although the PM program for air blast breakers will decrease and then end by 2019, the PM program for SF6 breakers will correspondingly increase as new SF6 breakers are added.

Hydro also had plans for overhauls of existing breakers at about 40 years. The current plan is to complete overhauls in 2014 and 2015. Beyond 2015 the circuit breaker replacement program would eliminate the need for overhauls of air blast circuit breakers.

This overhaul program for air blast breaker was briefly reviewed to determine if any opportunities existed for eliminating some overhauls by advancing the schedule for breaker replacement. It was noted that Hydro had advanced a couple of breakers, one at Bay D'Espoir (B1B10) and another at Sunnyside (L100L109). Given the aggressive schedule for breaker replacement and the desire to replace the most critical breakers first, no further opportunities were identified. Moreover, completion of the overhauls in 2014 and 2015 will be beneficial to the accelerated breaker replacement program by providing some added flexibility in the scheduling of breakers in the latter years of the program.

Air blast circuit breakers that have been scheduled for an overhaul have been identified in the detailed description of the breaker replacement program by location contained in Section 9.

Appendix 1 also includes the date of the last overhaul for all breakers in the replacement program.

It is recommended that Hydro retain some breakers and/or breaker parts from those recently removed from service to be used as spares until the completion of the breaker replacement program. The inventory kept should be comparable to what is used for a breaker overhaul since maintenance personnel are familiar with the overhaul procedure.

9) Breaker Replacement Program by Location

There are currently 63 air blast circuit breakers at 10 locations still in service. A plan for each site follows. Programs that are already in place such as the LCP program are included to provide a complete picture of the activity level by year and location. Consideration has been given to reliability, efficient use of resources, and a balancing of the effort by year. A specific breaker replacement schedule is included. However, there is flexibility in the overall schedule that would allow for some swapping of breaker replacements while still achieving the same overall results.

a) Holyrood

Holyrood contains nine (9) 230 kV air blast circuit breakers. All of these breakers will be replaced between 2014 and 2016 as part of the LCP program. This program will be operated separately from the accelerated program but the numbers will be tracked. No changes to this program are anticipated.

Breaker replacement schedule[1]:
2014 – B2B11, B1B11, B1L17[2]
2015 – B2L42[3], B3L18, B3B13
2016 – B12L42, B12L17, B12B15

Notes
1. All breakers replaced as part of the LCP program.
2. Breaker failed in Jan 2014
3. Breaker scheduled for overhaul in 2014

b) Bay D'Espoir

Bay D'Espoir Terminal Station contains thirteen (13) 230 kV air blast circuit breakers. This generating station is critical to the reliability of the integrated island electrical system. During phase 1 eleven (11) of the breakers will be replaced.

There are 6 generator unit breakers that need to be replaced. These breakers are operated frequently as the hydro units are brought on and off line. The concern with these breakers is not with failure to having them exercised but rather with wear and tear due to the number of operations. Hydro has identified these breakers as the most critical to the system driven by the fact they are generator breakers without an alternate route to get power to the grid. Due to on-going work at other locations such as Sunnyside, Holyrood and Oxen Pond and the challenge of attempting to schedule outages for all generator breakers in one year, these breakers have

been scheduled to be replaced in 2015 and 2016. This will also mitigate risks associated with having the hydro plant available for energy, peak demand and reserve.

From a risk perspective, if a generator breaker fails before it is replaced then the consequence is the loss of that generator until it can be repaired or replaced. For a hydro unit the risk is primarily loss of capacity and/or reserve in times when total supply is limited such as during peak load conditions. To mitigate this it is recommended that a plan be developed to rapidly deal with the failure of one of these breakers. This could include keeping a spare breaker or key parts set aside specifically for these locations. It is also recommended that a PM be performed in 2015 on the three breakers that are not scheduled for replacement until 2016.

The remaining seven breakers are part of the ring bus. The outage required to remove any one breaker will not impact the output of the plant or the delivery of energy to the system via the connecting transmission lines. However, the system will be at risk and tripping of any of the transmission lines at Bay D'Espoir may result in the loss of additional transmission lines or unit generation. Each outage will need to be carefully planned and the generation levels at Bay D'Espoir may need to be adjusted to ensure the overall system reliability is maintained. Given the complications and risks associated with replacing these breakers, the number of breakers scheduled in any one year has been limited to three. The result is that the outages for these breakers are spread over the four years to minimize system related reliability risks. One of the breakers B4B5 will be replaced in 2016 as part of the LCP program.

From a risk perspective, if a ring breaker fails before it is replaced then the consequence is that other breakers will operate to isolate the failed breaker. The most common failure mode occurs when a breaker is commanded to operate such as for a fault but fails to do so. The impact on the system is less predictable because of the numerous potential configurations and load levels but could be severe.

The air system will be de-commissioned in 2018 at the end of the breaker replacements.

Breaker replacement schedule:
2015 – B1T2, B2T3, B2T4, B1B2
2016 – B1T1, B3T5, B3T6, B4B5[1]
2017 – B3B4, B6B10, B2B3
2018 – B5B6, B1B10[2]

Notes:
1. Breaker to be replaced as part of LCP program
2. Breaker scheduled for overhaul in 2014. Advanced from 2016.

c) Sunnyside

Sunnyside Terminal Station contains four (4) 230 kV and six (6) 138 kV air blast circuit breakers. Sunnyside occupies a critical location in the Newfoundland electrical grid connecting the large generation supply of Bay D'Espoir to the major load area of the Avalon peninsula. Therefore, maintaining the integrity of the 230 kV ring bus at Sunnyside is crucial to the reliability of the grid. In the major outage of January 2014, tie transformer T1 failed and the 230 kV air blast circuit breaker B1L03 failed to operate. Work will be carried out in 2014 to replace

the tie transformer, 138 kV breaker B2T1 which was damaged during the transformer fire and breaker B1L03.

During Phase 1 the remaining 230 kV breakers are scheduled to be replaced over a two year period. This will ensure that this critical location will be upgraded with new equipment by the end of 2016.

During Phase 2, the remaining air blast circuit breakers, all at 138 kV, will be replaced.

Breaker replacement schedule:
2014 – B1L03[1], B2T1[2]
2015 – B1L02, L06L07[3]
2016 – L02L07
2017
2018 – B3T4, B2L12[3], L19L100[3]
2019 – L109T4[4], L100L109[5]

Notes

1. Breaker failed to operate Jan 2014. New breaker purchased for Hardwoods moved to Sunnyside
2. Breaker damaged during transformer fire.
3. Breaker scheduled for overhaul in 2014
4. Breaker scheduled for overhaul in 2015
5. Breaker scheduled for overhaul in 2014. Advanced to 2014 due to condition assessment.

d) Hardwoods

One (1) 230 kV air blast circuit breaker remains in service at Hardwoods Terminal Station. Early replacement will allow for the air system to be de-commissioned. It was scheduled for replacement in 2014 but has been swapped with a breaker at Sunnyside. It has been re-scheduled to 2015.

Breaker replacement schedule:
2015 – B1L01[1]

Notes:

1. Purchased in 2013, scheduled for installation in 2014 but moved to Sunnyside.

e) Oxen Pond

Oxen Pond Terminal Station contains two (2) 230 kV air blast circuit breakers. To coordinate with transformer upgrade / tie breaker design one breaker will be installed in 2014 and placed in service in 2015. The other breaker will be scheduled for 2016 to complete the station and enable the air system to be de-commissioned.

Breaker replacement schedule:
2014/15 – B1L18[1]
2015 – B1L36

Notes:

1. Breaker to be installed in 2014 but commissioned in 2015. Therefore it is not included in accelerated replacement program.

f) Bottom Brook

All four (4) 230 kV breakers at Bottom Brook Terminal Station are air blast circuit breakers. These breakers are scheduled for replacement by Emera in 2016 for the NL/NS link. The breakers are configured in a ring bus arrangement and Bottom Brook supplies the southwestern part of NL. The removal from service of each breaker will need to be carefully planned. Although treated separately, the replacement of breakers at Bottom Brook will need to be coordinated with the accelerated breaker replacement program. Hydro should explore the possibility of managing this work under the accelerated program. When complete the air system can be de-commissioned.

Breaker replacement schedule[1]:
2016 – B1B11, B1L09, L09L33, L11L33

Notes:

1. All breakers to be replaced by Emera as part of NL/NS link

g) Massey Drive

Massey Drive Terminal Station contains two (2) 230 kV air blast circuit breakers. They are scheduled for replacement in 2017. This schedule needs to be reviewed prior to initiating the work to replace the breakers at Bottom Brook. If transmission line TL211 can be removed from service then one breaker at Massey Drive and two at Bottom brook can be replaced simultaneously under the same outage.

Breaker replacement schedule:
2017 – B1L28, B5L11

h) Stony Brook

Stony Brook Terminal station contains six (6) 230 kV air blast breakers and six (6) 138 kV air blast breakers. The replacement program is included in Phase 2. Four breakers are scheduled per year with a mixture of 230 kV and 138 kV breakers each year. Most of the 138 kV breakers will require a line or transformer outage for the duration of the replacement work. Work on this station has been delayed until Phase 2 because all 230 kV breakers have been overhauled since 2008 and should be reliable. Some of the 138 kV breakers are scheduled for an overhaul in the next couple of years. Due to the large number of breakers to be replaced and the requirement for outages for the 138 kV work, the scheduling of this work will require extra discussion and be carefully planned to ensure reliability and to minimize outage times. The air system can be de-commissioned in 2020.

Breaker replacement schedule:
2018 – B2L04, L05L31, B3L130, B3T2
2019 – B1L31, L05L35, B1L32, B1L35
2020 – B3L22[1], B3L133[2], B3T1[2], B3L10[2]

Notes:
1. Breaker scheduled for overhaul in 2014
2. Breaker scheduled for overhaul in 2015

i) Western Avalon

Western Avalon contains six (6) 230 kV air blast circuit breakers. These are all scheduled for replacement in Phase 2.The primary reason is that all six breakers will have been overhauled between 2005 and 2014. Two breakers per year are scheduled for replacement. This assumes that all breakers continue to perform well regardless of model. If issues arise with a particular model (e.g. B1L03 is an older model type DCVF), then adjustments may need to be made in the schedule. This can be done during the annual review process.

Breaker replacement schedule:
2018 – B1L17, B1L37
2019 – B1L08, L03L17
2020 – L01L03[1], B1B3[2]

Notes:
1. Breaker scheduled for overhaul in 2014
2. Breaker scheduled for overhaul in 2015

j) Buchans

Buchans Terminal station contains four (4) 230 kV breakers. These breakers are scheduled for replacement over a two year period in 2019 – 2020 at the end of Phase 2. With overhauls recently completed or scheduled for the current year the reliability of the station should be good. Hence, the installation of replacement breakers can be delayed. The breakers are configured in a ring bus configuration that enables the removal of one breaker at a time without causing any outages. The air system can be de-commissioned in 2020.

Breaker replacement schedule:
2019 – L05L33, B1L05[1]
2020 – L28L32[1], B1L28[1]

Notes:
1. Breaker scheduled for overhaul in 2014

10) Conclusions and Recommendations

This report provides a plan for the implementation of an accelerated air blast circuit breaker program. During the current year, 2014, previously scheduled work to replace breakers, undertake breaker overhauls and perform preventive maintenance will occur. In addition preparation work for the accelerated program should begin in 2014 with tender preparation, selection of a partner/contractor and ordering the first set of breakers. Installation of the air blast circuit breakers would then take place over a 6-year period between 2015 and 2020. At the end

of 2020 all 63 air blast circuit breakers that were on the Hydro system at the beginning of 2014 would be replaced.

This report includes a discussion of the many factors affecting the replacement of the air blast circuit breakers and provides a summary by year and location of each breaker to be replaced. Some of the key recommendations contained in the report are repeated below.

R1. Implement the accelerated air blast circuit breaker replacement program in two phases. The actual implementation may be done through separate contracts or a single contract with extension. This will minimize spares as well as ensure efficiencies in the implementation.

R2. Coordinate the accelerated air blast circuit breaker replacement programs with other breaker replacement programs including LCP and NL/NS link.

R3. Review the plan annually to ensure the specific breakers selected are the most appropriate for replacement and to address any scheduling and resource issues.

R4. Maintain a set of spares from recently replaced breakers to have available in case of premature failure of a still-in-service air blast circuit breaker.

APPENDIX 1

ACCELERATED AIR BLAST BREAKER REPLACEMENT PROGRAM

Location	NLH ID	Year Built	Oper Volt (kV)	Overhaul Year	Replacement Year	Age at Replacement	Criticality
HRD TS	B1B11	1974	230	-	2014	40	B
HRD TS	B1L17	1973	230	2014	2014	41	B
HRD TS	B2B11	1974	230	-	2014	40	B
SSD TS	B1L03	1966	230	2002	2014	48	B
SSD TS	B2T1	1969	138	-	2014	45	C
BDE TS1	B1B2	1966	230	2004	2015	49	B
BDE TS1	B1T2	1966	230	1999	2015	49	A
BDE TS1	B2T3	1966	230	2000	2015	49	A
BDE TS1	B2T4	1968	230	2000	2015	47	A
HRD TS	B2L42	1973	230	2014	2015	42	B
HRD TS	B3B13	1978	230	-	2015	37	B
HRD TS	B3L18	1978	230	-	2015	37	B
HWD TS	B1L01	1972	230	NA	2015	43	B
OPD TS	B1L18	1969	230	2008	2015	46	B
OPD TS	B1L36	1969	230	2008	2015	46	B
SSD TS	B1L02	1966	230	2003	2015	49	B
SSD TS	L06L07	1968	230	2014	2015	47	B
BBK TS	B1L09	1971	230	-	2016	45	C
BBK TS	B1L11	1971	230	-	2016	45	C
BBK TS	L09L33	1973	230	-	2016	43	C

BBK TS	L11L33	1978	230	-	2016	38	C
BDE TS1	B1T1	1966	230	2002	2016	50	A
BDE TS1	B3T5	1969	230	2000	2016	47	A
BDE TS1	B3T6	1966	230	2001	2016	50	A
BDE TS1	B4B5	1964	230	2003	2016	52	B
HRD TS	B12B15	1978	230	-	2016	38	B
HRD TS	B12L17	1973	230	-	2016	43	B
HRD TS	B12L42	1978	230	-	2016	38	B
SSD TS	L02L07	1966	230	2002	2016	50	B
BDE TS1	B2B3	1968	230	2006	2017	49	B
BDE TS1	B3B4	1972	230	2005	2017	45	B
BDE TS1	B6B10	1968	230	2005	2017	49	B
MDR TS	B1L28	1966	230	2007	2017	51	C
MDR TS	B5L11	1967	230	2006	2017	50	C
BDE TS1	B1B10	1975	230	2014	2018	43	B
BDE TS1	B5B6	1968	230	2007	2018	50	B
SSD TS	B2L12	1966	138	2014	2018	52	D
SSD TS	B3T4	1966	138	2012	2018	52	C
SSD TS	L19L100	1966	138	2014	2018	52	D
STB TS	B2L04	1966	230	2011	2018	52	C
STB TS	B3L130	1968	138	2012	2018	50	D
STB TS	B3T2	1969	138	2012	2018	49	C
STB TS	L05L31	1969	230	2008	2018	49	C
WAV TS	B1L17	1969	230	2009	2018	49	B

WAV TS	B1L37	1968	230	2005	2018	50	B
BUC TS	B1L05	1973	230	2014	2019	46	C
BUC TS	L05L33	1973	230	2013	2019	46	C
SSD TS	L100L109	1968	138	2014	2019	51	D
SSD TS	L109T4	1968	138	2015	2019	51	C
STB TS	B1L31	1966	230	2008	2019	53	C
STB TS	B1L32	1968	230	2009	2019	51	C
STB TS	B1L35	1966	230	2010	2019	53	C
STB TS	L05L35	1966	230	2009	2019	53	C
WAV TS	B1L08	1968	230	2010	2019	51	B
WAV TS	L03L17	1969	230	2009	2019	50	B
BUC TS	B1L28	1975	230	2014	2020	45	C
BUC TS	L28L32	1972	230	2014	2020	48	C
STB TS	B3L10	1977	138	2015	2020	43	D
STB TS	B3L133	1969	138	2015	2020	51	D
STB TS	B3L22	1967	138	2014	2020	53	D
STB TS	B3T1	1969	138	2015	2020	51	C
WAV TS	B1B3	1977	230	2015	2020	43	B
WAV TS	L01L03	1969	230	2014	2020	51	B

APPENDIX C:
Air Blast Circuit Breakers Refurbishment/Replacement Plan

LOCATION	NLH ID	MFG	TYPE	MODEL	YEAR BUILT	OPER VOLT (kV)	CURRENT AGE	OVERHAUL YEAR	REPLACEMENT YEAR	AGE AT REPLACEMENT
HWD TS	B1L01	Brown Boveri	Air Blast	DLF 245 nc2	1972	230	43	NA	2015	43
BDE TS1	B1T2	Brown Boveri	Air Blast	DCVF 245 mc6	1966	230	49	1999	2015	49
BDE TS1	B2T4	Brown Boveri	Air Blast	DCVF 245 mc6	1968	230	47	2000	2015	47
OPD TS	B1L18	Brown Boveri	Air Blast	DCVF 245 mc6	1969	230	46	2008	2015	46
HRD TS	B2L42	Brown Boveri	Air Blast	DLF 245 nc2	1973	230	42	2014	2015	42
BDE TS1	B2T3	Brown Boveri	Air Blast	DCVF 245 mc6	1966	230	49	2000	2015	49
HRD TS	B3L18	Brown Boveri	Air Blast	DLF 245 nc2	1978	230	37	-	2015	37
HRD TS	B3B13	Brown Boveri	Air Blast	DLF 245 nc2	1978	230	37	-	2015	37
SSD TS	B1L02	Brown Boveri	Air Blast	DCVF 245 mc6	1966	230	49	2003	2015	49
OPD TS	B1L36	Brown Boveri	Air Blast	DCVF 245 mc6	1969	230	46	2008	2015	46
BDE TS1	B1B2	Brown Boveri	Air Blast	DCVF 245 mc6	1966	230	49	2004	2015	49
SSD TS	L06L07	Brown Boveri	Air Blast	DCVF 245 mc6	1968	230	47	2014	2015	47
BDE TS1	B3T6	Brown Boveri	Air Blast	DCVF 245 mc6	1966	230	49	2001	2016	50

LOCATION	NLH ID	MFG	TYPE	MODEL	YEAR BUILT	OPER VOLT (kV)	CURRENT AGE	OVERHAUL YEAR	REPLACEMENT YEAR	AGE AT REPLACEMENT
BDE TS1	B3T5	Brown Boveri	Air Blast	DCVF 245 mc6	1969	230	46	2000	2016	47
HRD TS	B12L42	Brown Boveri	Air Blast	DLF 245 nc2	1978	230	37	-	2016	38
HRD TS	B12L17	Brown Boveri	Air Blast	DLF 245 nc2	1973	230	42	-	2016	43
BDE TS1	B1T1	Brown Boveri	Air Blast	DCVF 245 mc6	1966	230	49	2002	2016	50
SSD TS	L02L07	Brown Boveri	Air Blast	DCVF 245 mc6	1966	230	49	2002	2016	50
BDE TS1	B4B5	Brown Boveri	Air Blast	DCVF 245 mc6	1964	230	51	2003	2016	52
BBK TS	B1L11	Brown Boveri	Air Blast	DLF 245 nc2	1971	230	44	-	2016	45
BBK TS	B1L09	Brown Boveri	Air Blast	DLF 245 nc2	1971	230	44	-	2016	45
BBK TS	L09L33	Brown Boveri	Air Blast	DLF 245 nc2	1973	230	42	-	2016	43
BBK TS	L11L33	Brown Boveri	Air Blast	DLF 245 nc2	1978	230	37	-	2016	38
HRD TS	B4B12	Brown Boveri	Air Blast	DLF 245 nc2	1978	230	37	-	2016	38
MDR TS	B5L11	Brown Boveri	Air Blast	DCVF 245 mc6	1967	230	48	2006	2017	50
BDE TS1	B6B10	Brown Boveri	Air Blast	DCVF 245 mc6	1968	230	47	2005	2017	49
BDE TS1	B2B3	Brown Boveri	Air Blast	DCVF 245 mc6	1968	230	47	2006	2017	49
MDR TS	B1L28	Brown Boveri	Air Blast	DCVF 245 mc6	1966	230	49	2007	2017	51
BDE TS1	B3B4	Brown Boveri	Air Blast	DCVF 245 mc6	1972	230	43	2005	2017	45
CFLTS	230-13	Brown Boveri	Air Blast	DLF 245 nc4	1976	230	39	-	2017	41

LOCATION	NLH ID	MFG	TYPE	MODEL	YEAR BUILT	OPER VOLT (kV)	CURRENT AGE	OVERHAUL YEAR	REPLACEMENT YEAR	AGE AT REPLACEMENT
CFLTS	230-22	Brown Boveri	Air Blast	DLF 245 nc4	1972	230	43	-	2017	45
CFLTS	230-23	Brown Boveri	Air Blast	DLF 245 nc4	1972	230	43	-	2017	
CFLTS	230-24	Brown Boveri	Air Blast	DLF 245 nc4	1972	230	43	-	2017	
WAV TS	B1L37	Brown Boveri	Air Blast	DCVF 245 mc6	1968	230	47	2015	2018	50
BDE TS1	B5B6	Brown Boveri	Air Blast	DCVF 245 mc6	1968	230	47	2007	2018	50
WAV TS	B1L17	Brown Boveri	Air Blast	DCVF 245 mc6	1969	230	46	2009	2018	49
STB TS	B2L04	Brown Boveri	Air Blast	DCVF 245 mc6	1966	230	49	2011	2018	52
STB TS	L05L31	Brown Boveri	Air Blast	DCF 245 mc6	1969	230	46	2008	2018	49
SSD TS	B3T4	Brown Boveri	Air Blast	DCF 170 mc4	1966	138	49	2012	2018	52
STB TS	B3L130	Brown Boveri	Air Blast	DCF 170 mc4	1968	138	47	2012	2018	50
STB TS	B3T2	Brown Boveri	Air Blast	DCF 170 mc4	1969	138	46	2012	2018	49
BDE TS1	B1B10	Brown Boveri	Air Blast	DCVF 245 mc6	1975	230	40	2014	2018	43
SSD TS	B2L12	Brown Boveri	Air Blast	DCF 170 mc4	1966	138	49	2014	2018	52
SSD TS	L19L100	Brown Boveri	Air Blast	DCF 170 mc4	1966	138	49	2014	2018	52
WTSTS	230-3	Brown Boveri	Air Blast	DLF 245 nc4	1966	230	49	-	2018	

LOCATION	NLH ID	MFG	TYPE	MODEL	YEAR BUILT	OPER VOLT (kV)	CURRENT AGE	OVERHAUL YEAR	REPLACEMENT YEAR	AGE AT REPLACEMENT
WTSTS	230-4	Brown Boveri	Air Blast	DLF 245 nc4	1966	230	49	-	2018	
WAV TS	B1L08	Brown Boveri	Air Blast	DCVF 245 mc6	1968	230	47	2010	2019	51
STB TS	B1L31	Brown Boveri	Air Blast	DCVF 245 mc6	1966	230	49	2008	2019	53
STB TS	L05L35	Brown Boveri	Air Blast	DCVF 245 mc6	1966	230	49	2009	2019	53
STB TS	B1L32	Brown Boveri	Air Blast	DCVF 245 mc6	1968	230	47	2009	2019	51
WAV TS	L03L17	Brown Boveri	Air Blast	DCVF 245 mc6	1969	230	46	2009	2019	50
SSD TS	L109T4	Brown Boveri	Air Blast	DCF 170 mc4	1968	138	47	2015	2019	51
STB TS	B1L35	Brown Boveri	Air Blast	DCF 245 mc6	1966	230	49	2010	2019	53
SSD TS	L100L109	Brown Boveri	Air Blast	DCF 170 mc4	1968	138	47	2014	2019	51
BUC TS	L05L33	Brown Boveri	Air Blast	DLF 245 nc2	1973	230	42	2013	2019	46
BUC TS	B1L05	Brown Boveri	Air Blast	DLF 245 nc2	1973	230	42	2015	2019	46
WTSTS	230-2	Brown Boveri	Air Blast	DLF 245 nc4	1972	230	43	-	2019	47
WAV TS	L01L03	Brown Boveri	Air Blast	DCVF 245 mc6	1969	230	46	2014	2020	51

LOCATION	NLH ID	MFG	TYPE	MODEL	YEAR BUILT	OPER VOLT (kV)	CURRENT AGE	OVERHAUL YEAR	REPLACEMENT YEAR	AGE AT REPLACEMENT
STB TS	B3L133	Brown Boveri	Air Blast	DCF 170 mc4	1969	138	46	2015	2020	51
STB TS	B3T1	Brown Boveri	Air Blast	DCF 170 mc4	1969	138	46	2015	2020	51
STB TS	B3L22	Brown Boveri	Air Blast	DCF 170 mc4	1967	138	48	2014	2020	53
BUC TS	L28L32	Brown Boveri	Air Blast	DLF 245 nc2	1972	230	43	2014	2020	48
BUC TS	B1L28	Brown Boveri	Air Blast	DLF 245 nc2	1975	230	40	2014	2020	45
WAV TS	B1B3	Brown Boveri	Air Blast	DLF 245 nc4	1977	230	38	2015	2020	43
STB TS	B3L10	Brown Boveri	Air Blast	DLF 145 nc2	1977	138	38	2015	2020	43

APPENDIX D:
Oil Circuit Breaker Replacement Plan

LOCATION	NLH ID	MFG	TYPE	MODEL	YEAR BUILT	OPER VOLT (kV)	CURRENT AGE	OVERHAUL YEAR	REPLACEMENT YEAR	AGE AT REPLACEMENT
CHD TS	B1L27	CGE	Oil	KSO-69-1500	1970	66	45	NA	2014	44
SPL TS	B1L23	CGE	Oil	KSO-138-1500	1967	138	48	NA	2015	48
BHL TS	L27T1	CGE	Oil	KSO-69-1500	1967	66	48	NA	2015	48
CBF TS	152T	CGE	Oil	KSO-69-1500	1966	66	49	NA	2015	49
BBK TS	L400T2	CGE	Oil	KSO-69-1500	1967	66	48	NA	2015	48
WAV TS	B2T1	CGE	Oil	KSO-69-1500	1967	66	48	NA	2015	48
BHL TS	L26L27	CGE	Oil	KSO	1968	66	47	NA	2015	47
DHR TS	B1L27	CGE	Oil	KSO-69-1500	1970	66	45	NA	2016	46
HWD TS	B7B8	CGE	Oil	FKP	1971	66	44	NA	2016	45
HWD TS	B7T1	CGE	Oil	FKP	1972	66	43	NA	2016	44
HWD TS	B7T5	CGE	Oil	FKP	1976	66	39	NA	2016	40
HVY TS	13-1	CGE	Oil	KSO-138-2500	1976	138	39	NA	2017	41
HRD TS	B7L2	CGE	Oil	KSO-69-1500	1969	66	46	NA	2017	48
WAV TS	B2T2	CGE	Oil	FKP	1973	66	42	NA	2017	44
WAV TS	B4L64	CGE	Oil	KSO	1977	138	38	NA	2018	41
SVL TS	B2L405	CGE	Oil	FKP	1975	66	40	NA	2018	43
SVL TS	L405T4	CGE	Oil	FKP	1975	66	40	NA	2018	43
HRD TS	B8L39	CGE	Oil	KSO-138-5000	1978	138	37	NA	2019	41
BDE TS2	B13T11	CGE	Oil	FKP	1976	66	39	NA	2019	43
MDR TS	B3T3	CGE	Oil	FKP	1975	66	40	NA	2019	44
SVL TS	B2T3	CGE	Oil	FKP	1975	66	40	NA	2020	45
DLK TS	B2T1	CGE	Oil	FKP	1980	66	35	NA	2021	41
OPD TS	B2B5	CGE	Oil	FKP	1977	66	38	NA	2021	44

LOCATION	NLH ID	MFG	TYPE	MODEL	YEAR BUILT	OPER VOLT (kV)	CURRENT AGE	OVERHAUL YEAR	REPLACEMENT YEAR	AGE AT REPLACEMENT
HWD TS	B8T3	ASEA	Min. Oil	HLC 72.5/2000	1986	66	29	NA	2022	36
HRD TS	B6L3	CGE	Oil	FKP	1978	66	37	NA	2022	44
OPD TS	B2T2	ASEA	Min. Oil	HLC 72.5/2000	1986	66	29	NA	2023	37

APPENDIX E:
SF_6 Circuit Breaker Refurbishment/Replacement Plan

LOCATION	NLH ID	MFG	TYPE	MODEL	YEAR BUILT	OPER VOLT (kV)	CURRENT AGE	OVERHAUL YEAR	REPLACEMENT YEAR	AGE AT REPLACEMENT
BDE TS2	B9L34	Brown Boveri	SF6	ELF 245 n2s	1981	230	34	2004	2020	39
HWD TS	B2L42	Brown Boveri	SF6	ELF 245 n2s	1981	230	34	2005	2020	39
WAV TS	L01L37	Siemens	SF6	3AQ1	1990	230	25	2005	2030	40
BUCTS	L32L33	Brown Boveri	SF6	ELF 245 n2s	1980	230	35	2006	2020	40
HRD TS	B12L18	Brown Boveri	SF6	ELF 245 n2s	1981	230	34	2006	2021	40
USLTS	L34T1	Brown Boveri	SF6	ELF 245 nc2s	1981	230	34	2006	2021	40
HRD TS	B12T10	Siemens	SF6	3AQ1	1990	230	25	2006	2031	41
HRD TS	B13B15	Brown Boveri	SF6	ELF 245 n2s	1981	230	34	2007	2021	40
BDE TS2	B11L06	Siemens	SF6	3AQ1	1990	230	25	2007	2030	40
BDE TS2	B10B11	Siemens	SF6	3AQ1	1990	230	25	2009	2030	40
CAT TS	L47T1	Mitsubishi Electric Corp.	SF6	200-SFMT-40A	1984	230	31	2010	2024	40
CAT TS	L47T2	Mitsubishi Electric Corp.	SF6	200-SFMT-40A	1984	230	31	2010	2024	40
BDE TS2	B9B10	Siemens	SF6	3AQ1	1990	230	25	2011	2030	40
STB TS	L04L32	Siemens	SF6	3AQ1	1990	230	25	2011	2031	41
BDE TS2	L06L34	Siemens	SF6	3AQ1	1990	230	25	2011	2031	41
HWD TS	B1B2	Sprecher Energie	SF6	BHG 114	1993	230	22	2011	2034	41
DLK TS	B1L39	Brown Boveri	SF6	ELF 145 nls	1980	138	35	2013	2021	41
DLK TS	B1L45	Brown Boveri	SF6	ELF 145 nls	1980	138	35	2013	2022	42
HLY TS	B1L24	Brown Boveri	SF6	ELF 145 nls	1980	138	35	2013	2022	42
HLY TS	B1L43	Brown Boveri	SF6	ELF 145 nls	1980	138	35	2013	2022	42
HLY TS	B1L45	Brown Boveri	SF6	ELF 145 nls	1980	138	35	2014	2023	43
DLK TS	L39T2	Sprecher & Schuh	SF6	HGF 112/1C	1983	138	32	2015	2023	40
IRV TS	B1L363	Brown Boveri	SF6	ELF 145 nls	1980	138	35	2015	2023	43
MDR TS	B1L48	Sprecher & Schuh	SF6	HGF 114/1A	1983	230	32	2015	2024	41

LOCATION	NLH ID	MFG	TYPE	MODEL	YEAR BUILT	OPER VOLT (kV)	CURRENT AGE	OVERHAUL YEAR	REPLACEMENT YEAR	AGE AT REPLACEMENT
DLK TS	B3L47	Sprecher & Schuh	SF6	HGF 114/1A	1983	230	32	2015	2024	41
DLK TS	L45T2	Sprecher & Schuh	SF6	HGF 112/1C	1983	138	32	2015	2024	41
DLK TS	B3L48	Sprecher & Schuh	SF6	HGF 114/1A	1983	230	32	2015	2025	42
SVL TS	B1L09	S & C Electric	Circuit Switcher	Mark III	1983	230	32	2015	2025	42
WAV TS	B1T1	S & C Electric	Circuit Switcher	Mark III	1983	230	32	2015	2025	42
HLY TS	B1T2	Siemens	SF6	3 AR 1	1982	138	33	2016	2025	43
WAV TS	B1T2	S & C Electric	Circuit Switcher	Mark III	1983	230	32	2016	2026	43
BBK TS	L14L50	S & C	Circuit Switcher	Model 2030	1989	138	26	2016	2029	40
IRV TS	B1L24	ASEA	SF6	HPL145/20C1	1992	138	23	2016	2032	40
IRV TS	B1L23	ASEA	SF6	HPL145/20C1	1992	138	23	2016	2032	40
BHL TS	B1L59	ASEA Brown Boveri Inc.	SF6	HPL 145/20Cl	1990	138	25	2017	2029	39
SSD TS	B3L19	Asea Brown Boveri	SF6	HPL 145/20C1	1990	138	25	2017	2029	39
BWT TS	L60T1	S & C	Circuit Switcher	Model 2030	1989	138	26	2017	2029	40
BCV TS	B1L56	AEG	SF6	DT145-F1	1995	138	20	2017	2035	40
BCV TS	B1R1	AEG	SF6	DT145-F1	1995	138	20	2018	2035	40
PBN TS	B1L41	AEG	SF6	DT145-F1	1995	138	20	2018	2035	40
PPT TS	B1L41	AEG	SF6	DT145-F1	1995	138	20	2018	2035	40
PPT TS	L41R1	AEG	SF6	DT145-F1	1995	138	20	2018	2035	40
PPT TS	L41R2	AEG	SF6	DT145-F1	1995	138	20	2018	2035	40
PPT TS	B1L44	AEG	SF6	DT145-F1	1995	138	20	2019	2036	41
CBC TS	B1B2	GEC Alstom	SF6	HGF 114/1A	1997	230	18	2019	2037	40

LOCATION	NLH ID	MFG	TYPE	MODEL	YEAR BUILT	OPER VOLT (kV)	CURRENT AGE	OVERHAUL YEAR	REPLACEMENT YEAR	AGE AT REPLACEMENT
USL TS	L34L63	Alstom	SF6	HGF 1014IPO	2002	230	13	2022	2042	40
SOK TS	L22T1	Siemens	SF6	CPV2-145-25-1	2003	138	12	2023	2043	40
SPL TS	B1L22	Hyosung	SF6	HCSP-144B	2010	138	5	2030	2050	40
CBCTS	B1C1	Areva T&D Inc.	SF6	DT1-245 F3	2010	230	5	2030	2050	40
CBCTS	B1C2	Areva T&D Inc.	SF6	DT1-245 F3	2010	230	5	2030	2050	40
CBCTS	B2C3	Areva T&D Inc.	SF6	DT1-245 F3	2010	230	5	2030	2050	40
CBCTS	B2C4	Areva T&D Inc.	SF6	DT1-245 F3	2010	230	5	2030	2050	40
BBKTS	B3L50	Areva	SF6	DT1-145-FK	2010	138	5	2030	2050	40
VBNTS	B1T1	Areva T&D Inc.	SF6	DT1-245 F3	2011	230	4	2031	2051	40
VBNTS	B1T2	Areva T&D Inc.	SF6	DT1-245 F3	2011	230	4	2031	2051	40
SSD TS	L03L06	Areva T&D Inc.	SF6	DT1-245 F3	2011	230	4	2032	2052	41
BBK TS	B2L14	Areva T&D Inc.	SF6	DT1-145	2012	138	3	2032	2052	40
MFATS3	B1T1	Alstom	SF6	DT1- 145	2012	138	3	2032	2052	40
MFATS3	B1L1302	Alstom	SF6	DT1- 145	2012	138	3	2032	2052	40
CFLTS	230-21	Alstom	SF6	GL314X	2012	230	3	2032	2052	40
HWD TS	B1L36	Areva T&D Inc.	SF6	DT1-245 F3	2013	230	2	2033	2053	40
BDE TS2	B13L20	Alstom	SF6	DT1- 72.5	2013	66	2	N/A	2053	40
NA	B7L38	Alstom	SF6	DT1- 72.5	2013	66	2	N/A	2053	40
NA	B1L29	Mitsubishi Electric Corp.	SF6	70-SFMT-32F-B	2014	66	1	N/A	2054	40
NA	B2T1	Siemens	SF6	SPS2-145-2--2	2014	138	1	2034	2054	40
SSD TS	B1L03	Mitsubishi Electric Corp.	SF6	200-SFMT-40-GHE IPO	2014	230	1	2034	2054	40
HRD TS	B1B11	Siemens	SF6	SPS2-IP0-253-31.5-2	2014	230	1	2034	2054	40
HRD TS	B1L17	Siemens	SF6	SPS2-IP0-253-31.5-2	2014	230	1	2034	2054	40
HRD TS	B2B11	Siemens	SF6	SPS2-IP0-253-31.5-2	2014	230	1	2034	2054	40
OPD TS	B5C1	Brown Boveri	SF6	ELF 72.5 n1rsv	1979	69	36	NA	2019	40

LOCATION	NLH ID	MFG	TYPE	MODEL	YEAR BUILT	OPER VOLT (kV)	CURRENT AGE	OVERHAUL YEAR	REPLACEMENT YEAR	AGE AT REPLACEMENT
DLKTS	B2L25	Westinghouse	SF6	690SP2500	1982	69	33	NA	2022	40
STA TS	B1L61	Westinghouse	SF6	690SP2500	1983	69	32	NA	2023	40
RWC TS	B1L57	Siemens	SF6	SP 72.5-23	1988	69	27	NA	2028	40
HWD TS	B8B9	Siemens	SF6	SP 72.5-23-3	1992	69	23	NA	2032	40
DLK TS	B2L26	Siemens	SF6	SPS-72.5-23-1	1996	66	19	NA	2036	40
HRD TS	B7T5	AEG	SF6	DT1-72F1	1996	69	19	NA	2037	41
HRD TS	B6T10	AEG	SF6	DT1-72F1	1996	69	19	NA	2037	41
STA TS	B1C1	AEG	SF6	DT1-72F1	1996	69	19	NA	2037	41
STA TS	B1C2	AEG	SF6	DT1-72F1	1996	69	19	NA	2037	41
BUC TS	B2T1	GEC Alstom	SF6	DT1-72.5 F1	1997	69	18	NA	2038	41
BUC TS	B2L80	GEC Alstom Canada	SF6	DT1-72F1	1997	69	18	NA	2038	41
MDR TS	B4T1	GEC Alstom/ Cogenel AEG	SF6	DT1 72.5 F1	1997	69	18	NA	2038	41
STA TS	B1C3	AEG	SF6	DT1-72F1	1996	69	19	NA	2038	42
PBN TS	B2T1	GEC Alstom Canada	SF6	DT1-72F1	1997	69	18	NA	2039	42
PBN TS	B2L21	GEC Alstom	SF6	DT1-72.5 F1	1998	69	17	NA	2039	41
RBK TS	L53T1	GEC-Alstom	SF6	DT1-72.5-1M	1998	69	17	NA	2039	41
HWD TS	B8C2	Siemens	SF6	FA220	1999	69	16	NA	2040	41
HWD TS	B8T4	Siemens	SF6	SPS2	1999	69	16	NA	2040	41
OPD TS	B2C2	Siemens	SF6	FA220	1999	69	16	NA	2040	41
CBF TS	252T	Alstom	SF6	DT1-72F1	2001	69	14	NA	2041	40
PBN TS	B2L62	Alstom AEG	SF6	DT1-72.5 F1	2000	69	15	NA	2041	41
HWD TS	B7T2	Alstrom	SF6	DT1-72.5 F1	2004	69	11	NA	2044	40
BUC TS	B2L64	Areva T&D Inc.	SF6	DT-72.5 F1	2005	69	10	NA	2045	40
HWD TS	B7C1	Areva	SF6	DT1-72.5 F1	2007	69	8	NA	2047	40
HLY TS	L51T2	Areva	SF6	DT1-72.5 F1 FK	2009	69	6	NA	2049	40
STA TS	B1T1	Alstom	SF6	DT1-72.5 F1	2011	69	4	NA	2051	40

LOCATION	NLH ID	MFG	TYPE	MODEL	YEAR BUILT	OPER VOLT (kV)	CURRENT AGE	OVERHAUL YEAR	REPLACEMENT YEAR	AGE AT REPLACEMENT
HBY TS	B1L21	Alstom	SF6	DT1-72.5 F1	2011	66	4	NA	2051	40
DLS TS	B1L15	Areva T&D Inc.	SF6	DT1-72.5	2012	69	3	NA	2052	40
MDR TS	B2T2	Areva T&D Inc.	SF6	DT1-72.5	2012	69	3	NA	2052	40
STA TS	B1L57	Areva T&D Inc.	SF6	DT1-72.5	2012	69	3	NA	2052	40
OPD TS	B2T1	ABB	SF6	72 PM 31-30 (FSA-2)	2014	66	1	NA	2054	40
OPD TS	B5T3	ABB	SF6	72 PM 31-30 (FSA-2)	2014	66	1	NA	2054	40

A REPORT TO
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Soldiers Pond to Hardwoods Corridor Upgrade

July 2015

newfoundland labrador hydro
a nalcor energy company

SUMMARY

An investigation has been performed with regard to a capacity increase in Hydro's transmission system in the corridor between Soldiers Pond Terminal Station (SOP) and Hardwoods Terminal Station (HWD). The analysis consists of a technical and economic The section of 230 kV transmission line TL201 between SOP and HWD will be renamed TL266.review of alternatives to select a solution that will reliably meet long term load growth requirements while adhering to System Planning Criteria.

Following completion of the Lower Churchill Project, there will be significant power flows between SOP and terminal stations in St. John's. The increased power flows will result in violations to System Planning Criteria as transmission lines will be overloaded under contingency conditions. A capital project is therefore proposed to increase the capacity of this corridor.

Technical and economic reviews of the alternatives have been performed. The economic analysis indicated that the least-cost alternatives include the thermal uprating of TL266 [1]. From a technical perspective, this alternative was determined in the analysis to result in significant reliability concerns. In contrast, a new transmission line would be constructed to industry standard with steel towers and designed to withstand a fifty-year CSA wind and ice load. It is strongly recommended that the significant capital investment required in the transmission line corridor be consistent with these standards.

Based on the analysis summarized in this report, the preferred alternative involves the replacement of the existing 230 kV transmission line between SOP and HWD. This solution, at a capital cost of $26.56 M and constructed over 2.5 years, would help to ensure a reliable long term supply for the St. John's Region.

[1] The section of 230 kV transmission line TL201 between SOP and HWD will be renamed TL266.

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1 INTRODUCTION

An investigation has been performed with regard to a capacity increase in Hydro's transmission system in the corridor between Soldiers Pond Terminal Station (SOP) and Hardwoods Terminal Station (HWD). The analysis consists of a technical and economic review of alternatives to select a solution that will reliably meet long term load growth requirements while adhering to System Planning Criteria.

1.1 Existing 230 kV Transmission System on the Avalon Peninsula

The 230 kV transmission network on the Avalon Peninsula is illustrated in Figure 1. The system allows for power delivery to load centres at HWD, Oxen Pond Termination Station (OPD) in St. John's, at Holyrood Terminal Station (HRD), at Western Avalon Terminal Station (WAV) near Chapel Arm, and at Voisey's Bay Nickel Terminal Station (VBN) near Long Harbour.

Hydro's sources of supply for the Avalon Peninsula include 230 kV transmission lines as well as thermal and hydroelectric generation. Transmission lines TL203 and TL237 allow for power delivery to WAV from hydroelectric sources in the western and central regions of the Island Interconnected Transmission System. Hydro operates generation on the Avalon Peninsula including three steam turbines[2], a combustion turbine[3] and black start diesels[4] at the Holyrood Thermal Generating Station (HTGS) and a combustion turbine[5] at HWD. Additional sources of supply on the Avalon Peninsula include hydroelectric generation owned by Newfoundland Power, wind turbines located at Fermeuse, and standby diesel generation owned by Vale at VBN.

[2] Holyrood units are rated for 170 MW, 170 MW and 150 MW, respectively.
[3] The Holyrood Combustion Turbine is rated for 123.5 MW.
[4] The Holyrood Black Start Diesels are currently available for 10 MW. It should be noted that these units have been installed as a temporary means of black starting the HTGS. These units are not considered for long term system planning analysis.
[5] The HWD Gas Turbine is available for 50 MW.

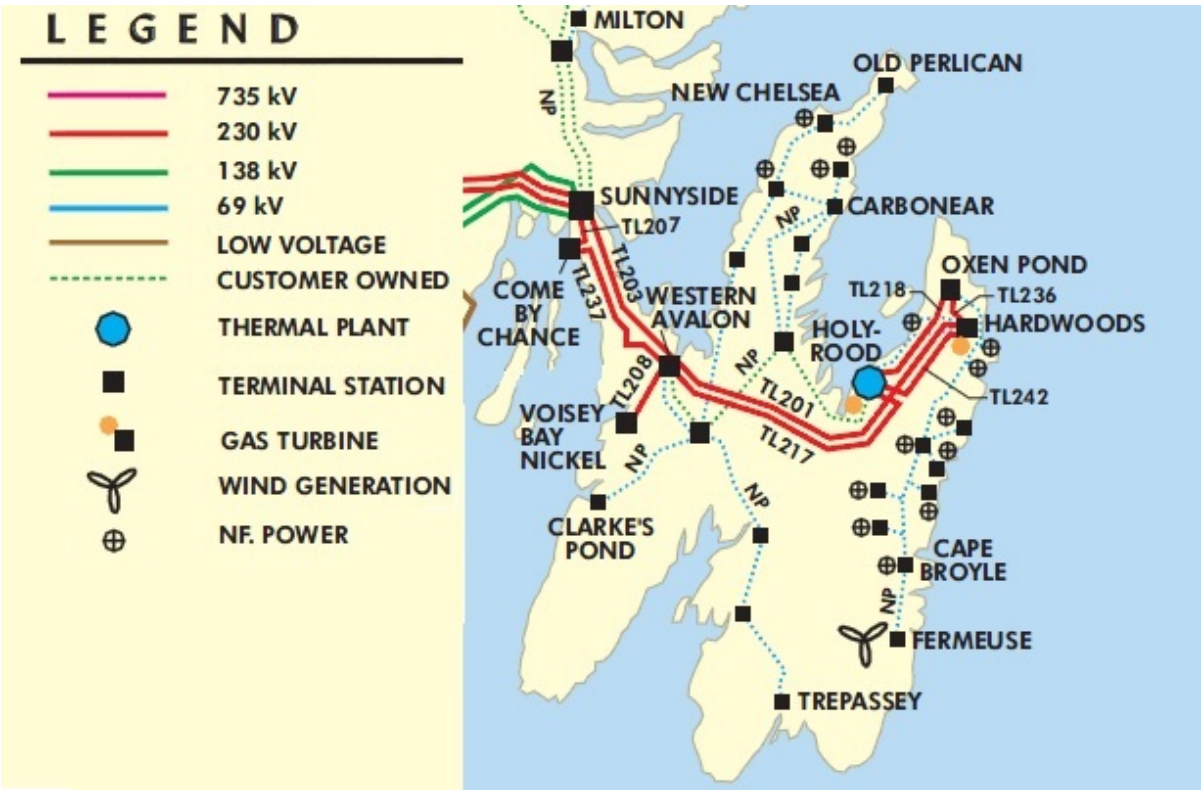


Figure 1 - Avalon Peninsula Transmission Map

230 kV transmission lines on the Avalon Peninsula are summarized in Table 1. The table contains details including year of constructions, line length, construction type, and rating. Hydro's basis for the development of transmission line ratings is provided in Appendix A. Further detail relating to historical and existing transmission line designs and ratings are provided in the detailed study provided in Appendix B.

Table 1: Avalon Peninsula 230 kV Transmission Line Summary

TL	Length (km)	From	To	Year Built	Construction Type	Rating (MVA)		
						30 C	15 C	0 C
201	80.7	Western Avalon	Hardwoods	1966	H-Frame Wood	175.5	260	322
203	44.5	Western Avalon	Sunnyside	1965	H-Frame Wood	261.7	308	347
207	6.5	Sunnyside	Come By Chance	2001	Guyed V Steel	341.8	402	454
208	15.8	Western Avalon	Voisey's Bay Nickel	1968	Guyed V Steel	199.3	298	370
217	76.7	Western Avalon	Holyrood	2002	Guyed V Steel	341.8	402	454
218	37.3	Holyrood	Oxen Pond	2002	H-Frame Wood	199.3	298	370
236	10.3	Hardwoods	Oxen Pond	2002	Steel Tower	355.8	412	460
237	45.0	Western Avalon	Come-By-Chance	2001	Guyed V Steel	355.8	412	460
242	27.2	Holyrood	Hardwoods	2002	Steel	355.8	412	460

1.2 Future 230 kV Transmission System on the Avalon Peninsula

The Lower Churchill Project (LCP) will include the addition of infrastructure on the Avalon Peninsula including a new 230 kV terminal station, SOP. This station will be the southern terminus of the Labrador-Island Link (LIL), a 900 MW, 1100 km HVdc transmission system that will allow for the delivery of power from Muskrat Falls to the Island Interconnected Transmission System. SOP will include high voltage ac equipment, HVdc converters, filter banks, as well as three high-inertia synchronous condensers.

SOP is located near the intersection of transmission lines that interconnect WAV, HRD, HWD, and OPD. The establishment of this station will result in the reconfiguration of 230 kV transmission lines as per the following list and as illustrated in Figure 2.

- TL201 – Western Avalon to Soldiers Pond.
- TL217 – Western Avalon to Soldiers Pond.
- TL242 – Soldiers Pond to Hardwoods.
- TL265 – Soldiers Pond to Holyrood (eastern portion of old TL217).
- TL266 – Soldiers Pond to Hardwoods (eastern portion of old TL201).
- TL268 – Soldiers Pond to Holyrood (western portion of old TL242).

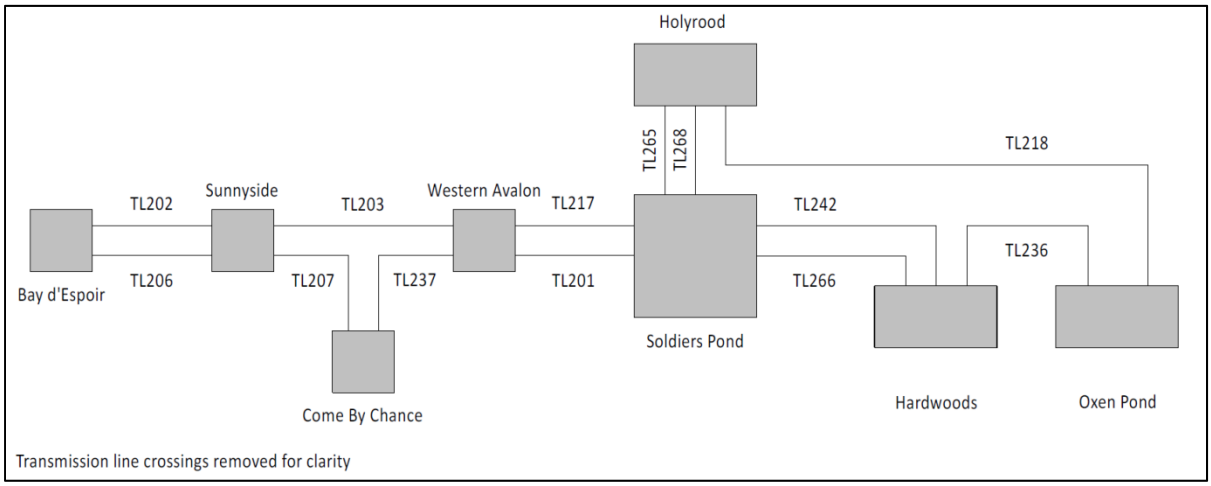


Figure 2: Avalon 230 kV Transmission System – End of 2017

It is noted that TL218 will not be connected at Soldiers Pond. Rather, this line will bypass the station and serve as an interconnection between HRD and OPD, as per the existing configuration. The configuration of this transmission line is further discussed in Section 3.3.

It should also be noted that a new 230 kV transmission line (TL267) will be constructed between Bay d'Espoir Terminal Station (BDE) and WAV.

Most system additions described in this section are expected to be in service by the end of 2017. The exception is TL267, which will be completed by mid-2018.

1.3 The SOP-HWD Corridor

Following completion of the Lower Churchill Project, there will be significant power flows between SOP (the largest source of supply within the Island Interconnected Transmission System) and terminal stations in St. John's (the largest load centre within the Island Interconnected Transmission System). Prior to the establishment of SOP, transmission lines TL242 and TL218 will be heavily loaded due to significant power flows from HRD to St. John's. This is further discussed in Section 3.8. As SOP is established and lines are interconnected, TL242 and TL266 will become the primary corridor for power delivery to St. John's.

The increased power flows will result in violations to System Planning Criteria as transmission lines will be overloaded under contingency conditions. This is discussed in Section 2.2. A capital project is therefore proposed to increase the capacity of this corridor.

A series of alternatives have been investigated. These include:

1. Thermal uprating of TL266;
2. Replacement of existing TL266 wood pole construction with new 230 kV transmission line steel tower construction; and
3. Reconfiguration of TL218.

This report contains technical and economic evaluations of these alternatives. The preferred alternative is identified and a statement of scope, cost estimate, and construction schedule are provided.

2 JUSTIFICATION

This section includes descriptions of Hydro's System Planning Criteria and an analysis of the SOP-HWD corridor. Discussions of system reliability and forecasted customer growth are also provided.

2.1 System Planning Criteria

Hydro's 230 kV transmission system is subject to the following System Planning Criteria:

Bulk Transmission Planning Criteria

- Hydro's bulk transmission is planned to be capable of sustaining the single contingency loss of any transmission element without loss of system stability.
- In the event a transmission element is out of service, power flow in all other elements of the power system should be at or below normal rating.
- The Hydro system is planned to be able to sustain a successful single pole reclose for a line to ground fault based on the premise that all system generation is available.

Transformer Capacity

- Transformer additions at all major terminal stations (i.e. two or more transformers per voltage class) are planned on the basis of being able to withstand the loss of the largest unit.
- For single transformer stations there is a back-up plan in place which utilizes Hydro's and/or Newfoundland Power's mobile equipment to restore service.

Operating Voltages

- For normal operations, the system is planned on the basis that all voltages be maintained between 95% and 105%.
- For contingency or emergency situations 90% to 110% is considered acceptable.

2.2 Analysis of the SOP-HWD Corridor

As discussed in Section 1.3, the SOP-HWD corridor will serve as a primary link between the largest source of supply and the largest load centres in the Island Interconnected Transmission System. A load flow plot of the Avalon Peninsula for the 2018 Peak Load Case[6] is illustrated in Figure 3. Displayed system loads are in accordance with the load forecast presented in Section 2.4.

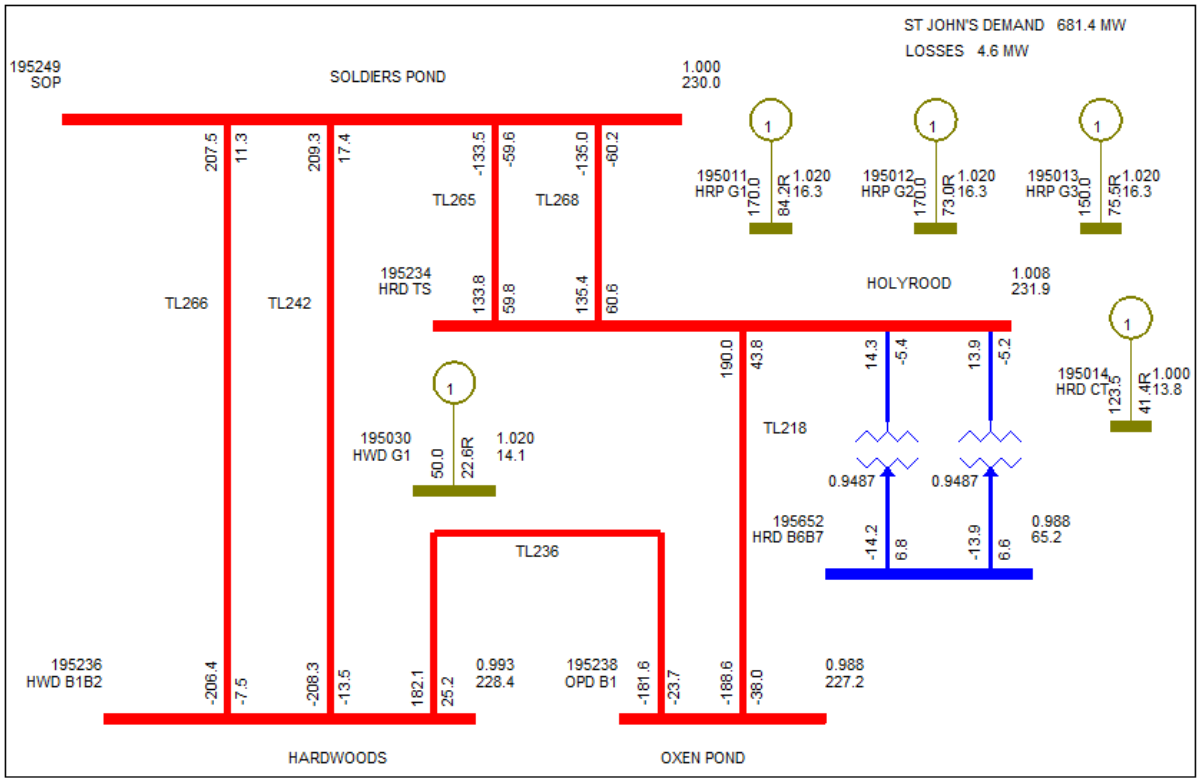


Figure 3: Load Flow Plot – 2018 Peak Case[7]

The load flow plot presents the real and reactive power flows (to the left and right of transmission system elements, respectively). Positive values indicate a net power flow leaving a bus; negative values indicate net power flow entering a bus. Red lines indicate 230

[6] The 2018 Peak Load Case would occur in January of 2018.

[7] In this case it is noted that three Holyrood units, the Holyrood Combustion Turbine, and the Hardwoods Gas Turbine are online at rated capacity. It is assumed that all three Holyrood Units will be available for generation during the winter of 2017/2018. During the following winters, Holyrood units will operate in standby mode and will be available for active power generation as required. Active power generation from Holyrood units will cease when the Labrador Island Link is fully commissioned.

kV transmission system elements; blue lines indicate 66 kV elements. Low voltage elements (less than 66 kV) are coloured green. Bus voltages are provided in per unit and in kV. “St. John’s Demand” indicates the total power demand of the St. John’s region at OPD, HWD, and HRD delivery points. “Losses” represent the total losses for transmission lines shown in the load flow plots.

As indicated by the sum of active power flows on transmission lines TL242 and TL266, over 400 MW will be transmitted in the SOP-HWD corridor in this scenario.

Figure 4 provides an illustration of the 230 kV transmission system in the case of an outage to TL242 (between SOP and HWD) over peak. As indicated, TL266 (which was originally the eastern portion of TL201 and constructed in 1966) will be overloaded in this scenario. As noted in Table 1, TL201 has a rating of 322 MW at an ambient temperature of 0 degrees. At the forecasted peak 400 MW, the transmission system cannot withstand the loss of TL242.This is a violation to System Planning Criteria, as defined in the previous section, and an increase in capacity is required.

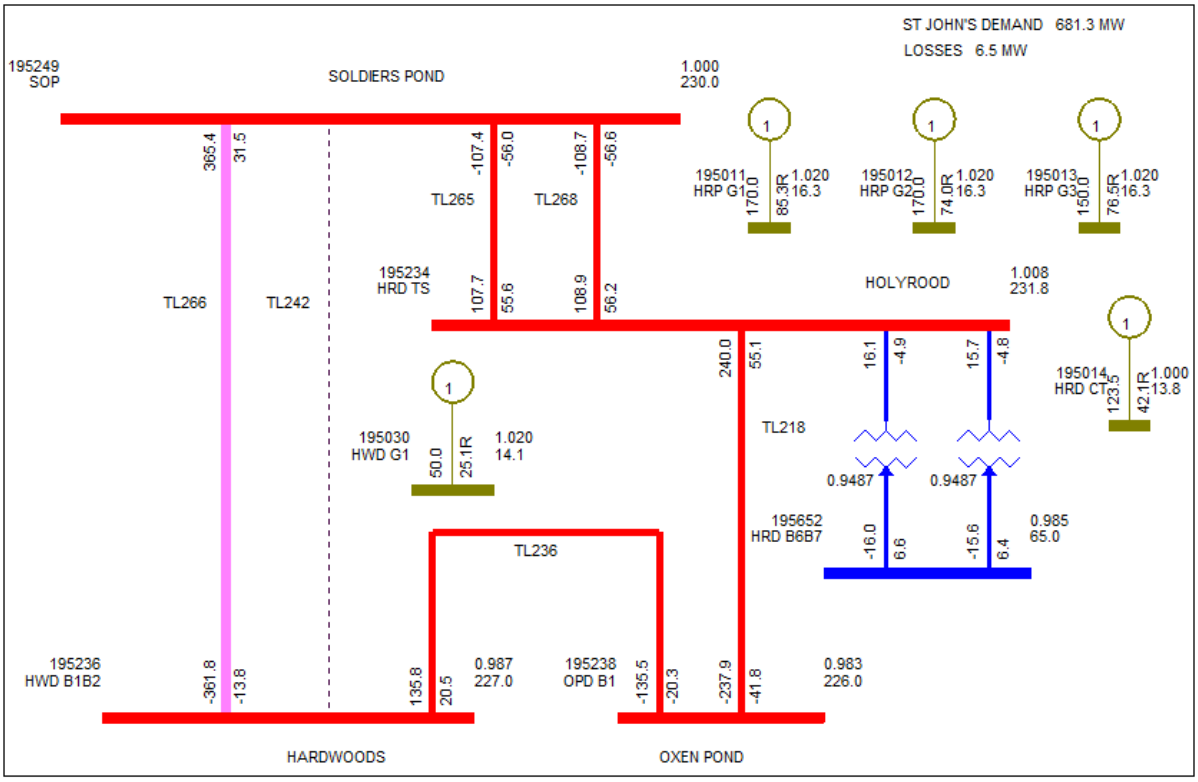


Figure 4: Load Flow Plot – 2018 Peak Case – TL242 Outage

A discussion of alternatives for increasing capacity in the corridor is provided in Section 3.

2.3 Reliability Performance

2.3.1 Outage Statistics

Outage statistics for 230 kV transmission lines that currently run through the SOP-HWD corridor are provided in Table 2. It should be noted that statistics are not available specifically for the line sections between SOP and HWD because these lines currently extend beyond that corridor. The table also includes statistics for all NLH and CEA 230 kV transmission lines. As indicated, TL242 has the best reliability performance of the three transmission lines in the corridor.

Table 2: Transmission Line Forced Outage Statistics (2009-2013) – Five Year Average

	Number of Outages	Frequency (per a)	Unavailability (%)	Frequency (per 100 km a)
TL201[8]	33	3.30	0.023	8.148
TL218[9]	6	0.60	0.067	3.158
TL242	2	0.20	0.001	1.481
NLH 230 kV (2009-2013)	75	0.07	0.270	0.950
CEA 230 kV (2009-2013)	734	0.147	0.201	0.437

- Outage Frequency (per component year) is the number of forced outages divided by the number of component-years.
- Unavailability (%) is the product of the outage frequency and average outage duration, in years.
- Outage Frequency (per 100 kilometer-years) is the number of forced outages divided by the number of kilometre-years, divided by 100.

Outage statistics for power delivery to the St. John's Region as well as NLH and CEA data are provided in Table 3.

[8] As discussed in Section 1.2, TL201 will be split at SOP into TL201 (WAV-SOP) and TL266 (SOP-HWD).
[9] It is noted that TL218 does not terminate at SOP or HWD, but rather shares a common corridor with TL242 and TL266 over a distance of 16 km.

Table 3: Delivery Point Outage Statistics

Delivery Point	T-SAIFI	T-SAIDI
Hardwoods (2010-2014)	1.20	30.40
Oxen Pond (2010-2014)	1.20	56.80
Central Region (2010-2014)	0.82	100.49
Hydro System (2010-2014)	2.34	160.93
CEA (2009-2013)	0.78	74.16

2.3.2 Maintenance History

Maintenance costs associated with transmission lines TL201, TL218 and TL242 are provided in Table 4, Table 5, and Table 6, respectively. For wood pole lines (TL201 and TL218), corrective maintenance (CM) costs and capital (wood pole line management - WPLM) costs are provided. For steel transmission line TL242, CM costs and preventative maintenance (PM) costs are provided.

Table 4: Maintenance History – TL201

YEAR	CAPITAL (WPLM)	CM
2014	$ 762,108[10]	$ 59,159
2013	$ 134,020	$ 664
2012	$ -	$ 2,678
2011	$ -	$ 4,501
2010	$ -	$ 950
TOTAL	**$ 896,128**	**$ 67,954**

[10] Includes insulator replacements.

Table 5: Maintenance History – TL218

YEAR	CAPITAL (WPLM)	CM
2014	$ 52,242	$ 11,305
2013	$ -	$ 4,269
2012	$ -	$ 8,819
2011	$ -	$ 39,454
2010	$ 908	$ 8,374
TOTAL	**$ 53,151**	**$ 72,223**

Table 6: Maintenance History – TL242

YEAR	PM	CM
2014	$ 7,916	$ -
2013	$ 5,574	$ 3,358
2012	$ 1,627	$ -
2011	$ 3,580	$ -
2010	$ 2,500	$ 1,241
TOTAL	**$ 21,199**	**$ 4,599**

2.4 Forecast Customer Growth

A forecast of purchased power requirements for Newfoundland Power's St. Johns Region is provided in Table 7. Load profile and load duration curves are provided in Figure 5 and Figure 6, respectively.

Table 7: Purchased Power Requirements Forecast for Newfoundland Power St. John's Region (2015)

	Purchase Location		
	Oxen Pond	Hardwoods	Holyrood
	MW	MW	MW
2015	323.4	288.6	40.3
2016	326.3	291.1	40.7
2017	332.5	296.6	41.5
2018	336.8	300.5	42.1
2019	341.2	304.4	42.6
2020	345.6	308.3	43.1
2021	349.9	312.2	43.7
2022	354.3	316.0	44.2
2023	358.6	319.9	44.8
2024	363.0	323.8	45.3
2025	367.3	327.7	45.9
2026	372.2	332.0	46.5
2027	378.6	337.8	47.3
2028	384.6	343.1	48.0
2029	388.9	346.9	48.6
2030	394.3	351.7	49.2
2031	399.7	356.6	49.9
2032	404.8	361.1	50.5
2033	410.0	365.7	51.2
2034	415.1	370.3	51.8
2035	420.3	375.0	52.5
2036	425.5	379.6	53.1
2037	430.7	384.2	53.8
2038	435.9	388.9	54.4
2039	441.1	393.5	55.1
2040	446.3	398.1	55.7
2041	451.4	402.7	56.4
2042	456.6	407.4	57.0
2043	461.8	412.0	57.7
2044	467.0	416.6	58.3
2045	472.2	421.2	59.0
2046	477.4	425.9	59.6
2047	482.5	430.5	60.2
2048	487.7	435.1	60.9
2049	492.9	439.7	61.5
2050	498.1	444.4	62.2

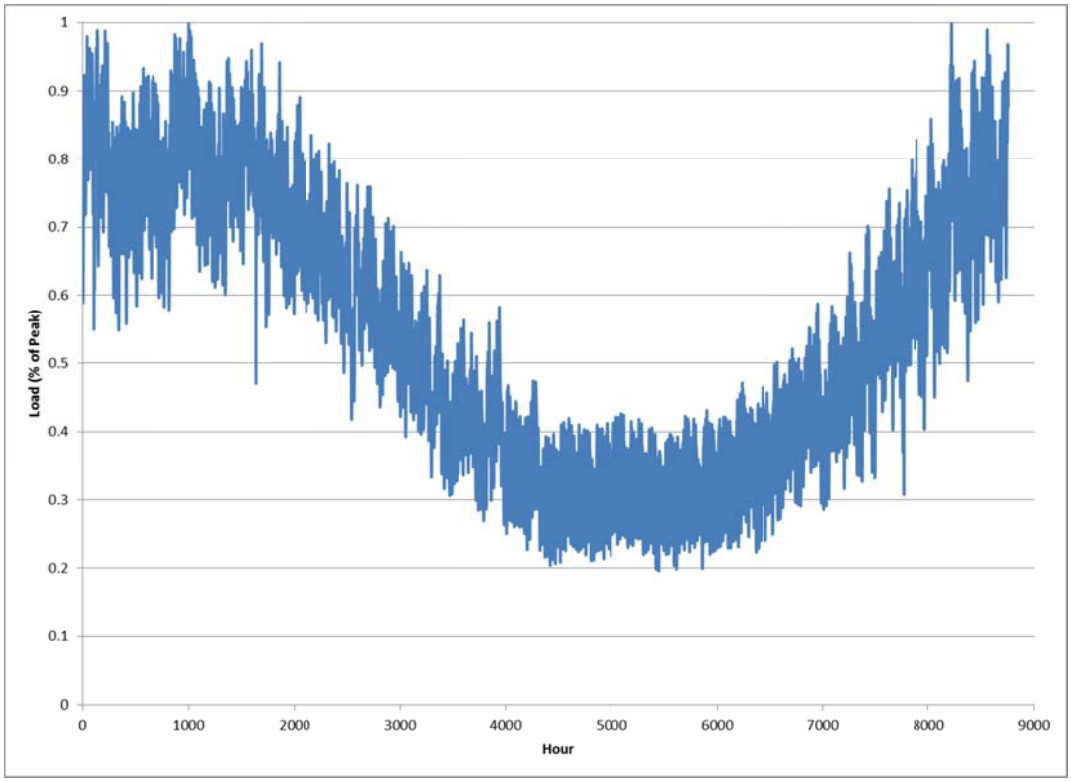


Figure 5: St. John's Region Load Profile

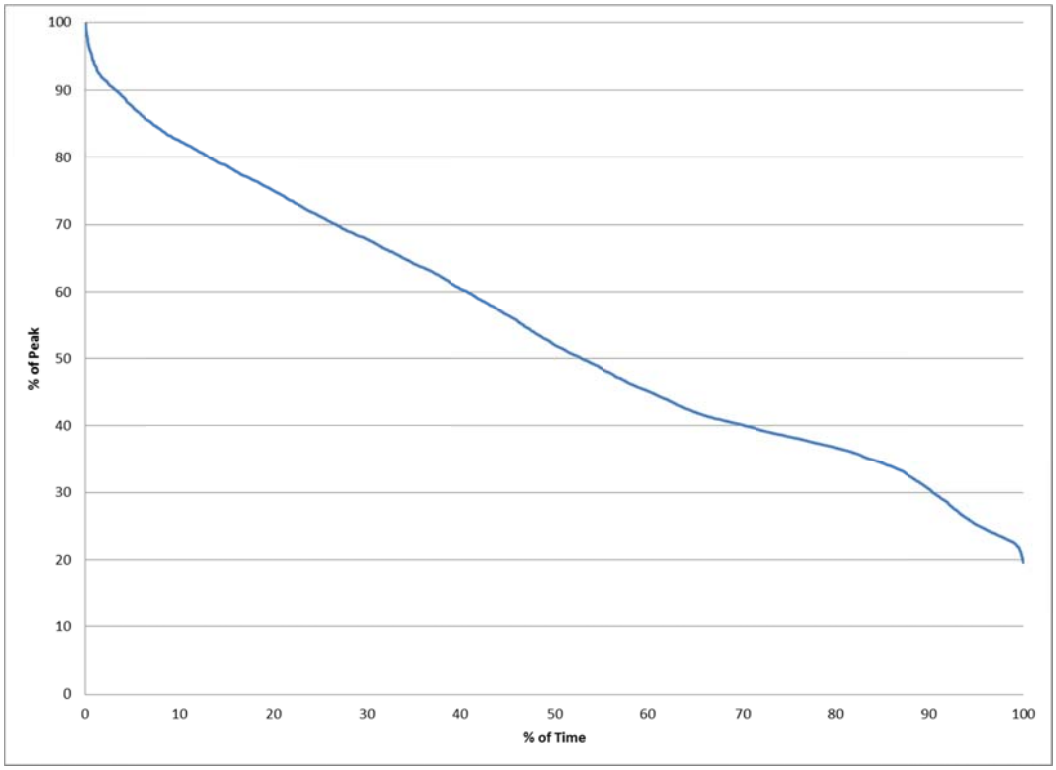


Figure 6: St John's Region Load Duration Curve

3 DEVELOPMENT OF ALTERNATIVES

A series of alternatives have been investigated for increasing the capacity in the SOP-HWD corridor. These include:

1. Thermal uprating of TL266;
2. Replacement of existing TL266 wood pole construction with new 230 kV transmission line steel tower construction; and
3. Reconfiguration of TL218.

These alternatives are summarized in the sections below and an economic evaluation of alternatives is provided in Section 3.4.

3.1 Thermal uprating of TL266

An alternative for the reinforcement of the SOP-HWD corridor involves the thermal uprating of TL266. This transmission line, originally constructed in 1966, has a wood pole construction. TL266 is comprised of 636 kcmil (Grosbeak) and 795 kcmil (Drake) ACSR[11] conductors. The capacity of TL266 is limited by the sections of Grosbeak conductor, which provide a winter rating (0^0C ambient temperature) of 322 MVA at an operating temperature of 50^0C.

As discussed in the detailed transmission line design analysis provided in Appendix B, TL266 can be reconductored with a low-sag Drake ACSS[12] conductor, designed to operate at temperatures exceeding 105^0C. The conductor has an ampacity of 1480 A, which is equivalent to 589.6 MVA at 230 kV. This conductor is the only viable alternative that can be installed on existing transmission structures that has sufficient ampacity to meet loading requirements. Further details relating to ACSS conductor are provided in Appendix B.

At this rating, the capacity of SOP-HWD corridor meets all System Planning Criteria for the

[11] ACSR = aluminum conductor, steel reinforced.
[12] ACSS = aluminum conductor, steel supported.

2018 peak load case. This is illustrated in in the load flow plot presented in Figure 7 where TL242 is out of service.

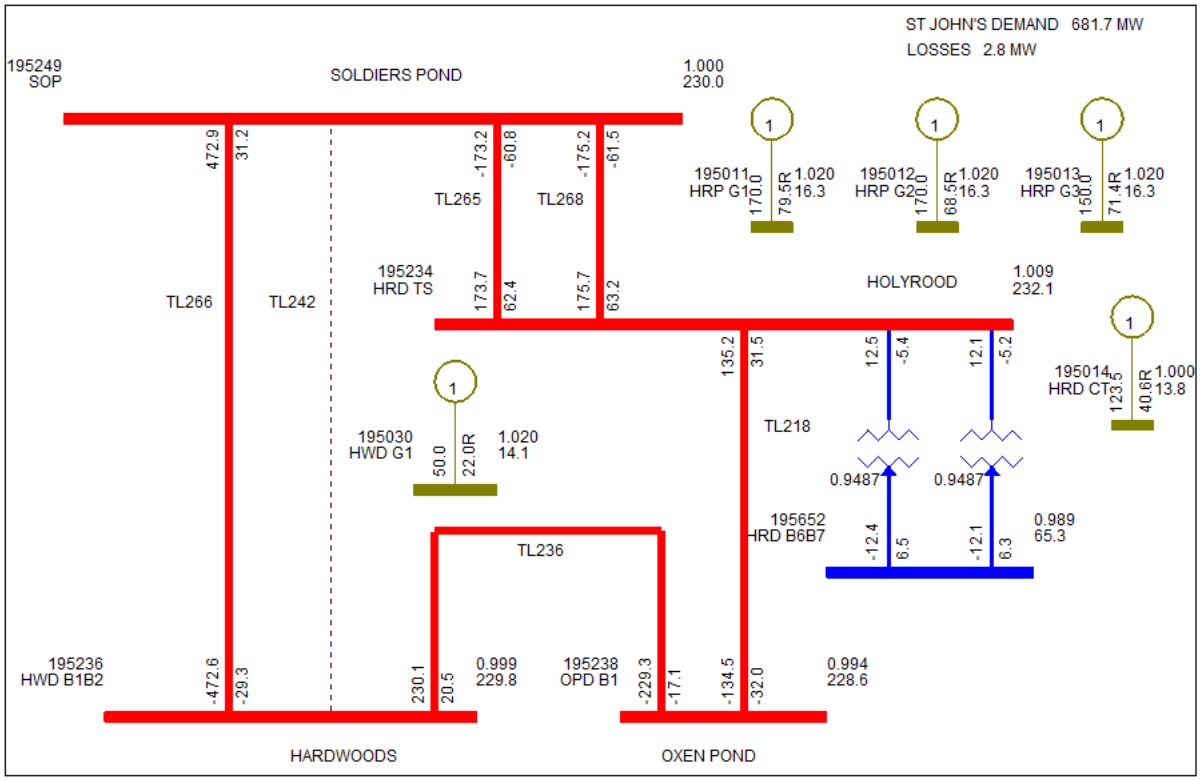


Figure 7: Load Flow Plot – 2018 Peak Case – TL242 Outage with TL266 Thermal Uprating

With a 795 ACSS conductor, the rating of TL266 would exceed that of TL242. TL242 has a steel construction and has an 804 AACSR/TW[13] conductor with an ampacity of 1153 A, which is equivalent to 459.6 MVA at 230 kV. The worst-case contingency in the SOP-HWD corridor is therefore found in the scenario where TL266 is out of service. This is illustrated in the load flow plot presented in Figure 8. This figure indicates that further system reinforcement would be required in 2025 to meet the 2026 peak load.

[13] AACSR/TW = aluminum alloy conductor, steel reinforced, trapezoidal wire.

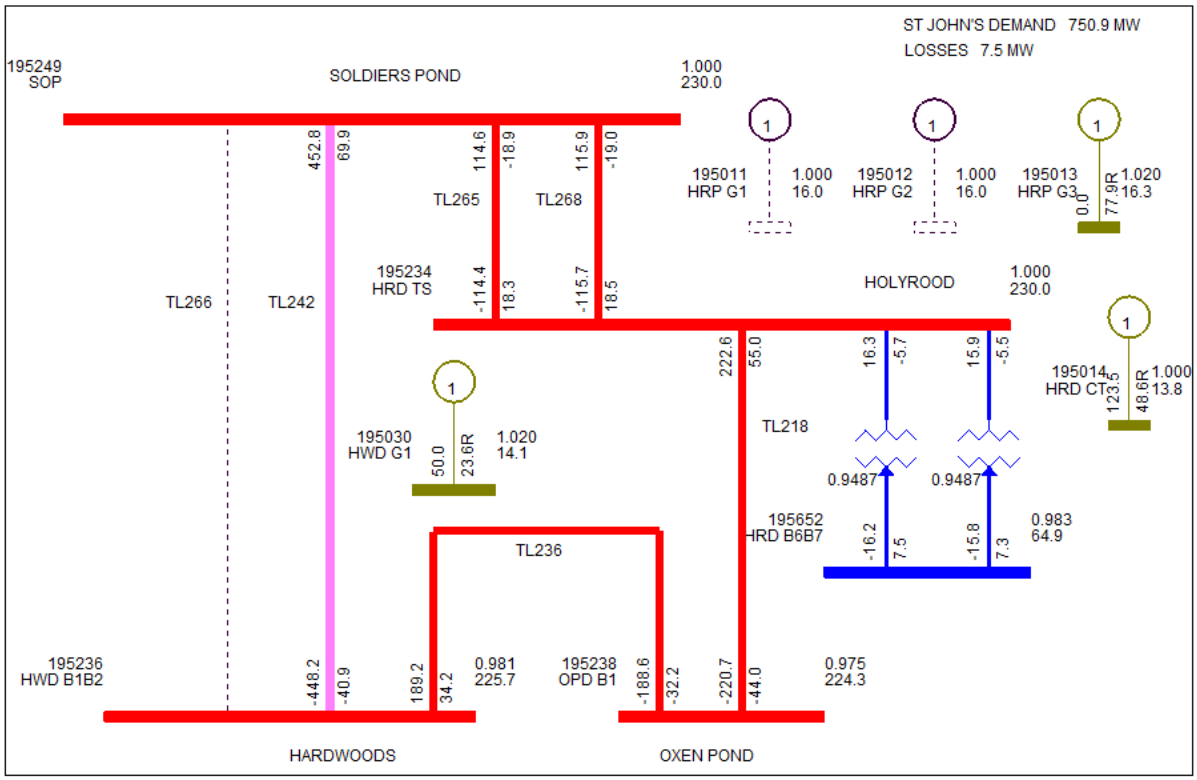


Figure 8: Load Flow Plot – 2026 Peak Case – TL242 Overload

In 2025, options for system reinforcements could include the construction of a new transmission line in the SOP-HWD corridor, or the thermal uprating of TL242 with 804 ACSS/TW conductor. These alternatives are discussed in Section 3.6.

As discussed in Appendix B, the wood pole construction of TL266 will reach end of life in 2030. A transmission line rebuild is therefore a required component of this alternative.

3.1.1 Reliability Considerations for Using Existing TL266

The thermal uprating of TL266 as described in previous section ensures compliance with System Planning Criteria. Thermal uprating is performed such that the loss of a single system element does not result the overloading of another. It must be noted, however, that the thermal uprating of the transmission line only provides an increase in ampacity and does not result in any improvement in reliability or robustness due to structural or hardware weaknesses. Further analysis was therefore performed to assess the risk associated with transmission line icing events that have the potential to cause damage to

multiple transmission lines.

As discussed in the detailed study presented in Appendix B, TL266 is designed to withstand a 25.4 mm ice load. The return period for this design ice load is somewhere between three to five years (20% to 33% annual failure probability). TL218 is designed to withstand a 38 mm ice load. The return period for this design ice load is somewhere between seven to ten years (10% to 14% annual failure probability). This is in contrast to TL242 which, like other transmission lines that were reinforced during upgrades on the Avalon Peninsula in the early 2000s, is designed to withstand a 66 mm ice load. This represents a one in fifty-year icing event (2% annual failure probability). Avalon Peninsula transmission line upgrades are further discussed in Appendix B.

Consideration must therefore be given to an icing event that exceeds 38 mm. Such an event would have the potential to damage to both TL266 and TL218 as they share a common corridor. The probability of such an event occurring in a given year would range from 10% to 14%. The duration of the outage to the transmission lines would be a function of the extent of the damaged sustained. For the purposes of this investigation, outage durations ranging from one to seven days are considered. The range of these durations is deemed to be a sufficiently wide so as to provide a reasonable reflection of the range of repair times for transmission lines TL266 and T218 following a significant icing event.

Based on the probabilities and outage durations described above, the unavailability due to a 38 mm (or greater) icing event would range from 0.027% to 0.268%.

As illustrated in Figure 9, a maximum total load of approximately 528 MW can be supported at OPD, HWD, and HRD delivery points in a scenario involving the loss of TL266 and TL218. In 2018 the peak demand for the St. John's region is approximately 680 MW, indicating that approximately 77% of peak load can be supported in the event of a failure to TL266 and

TL218 during peak load conditions[14].

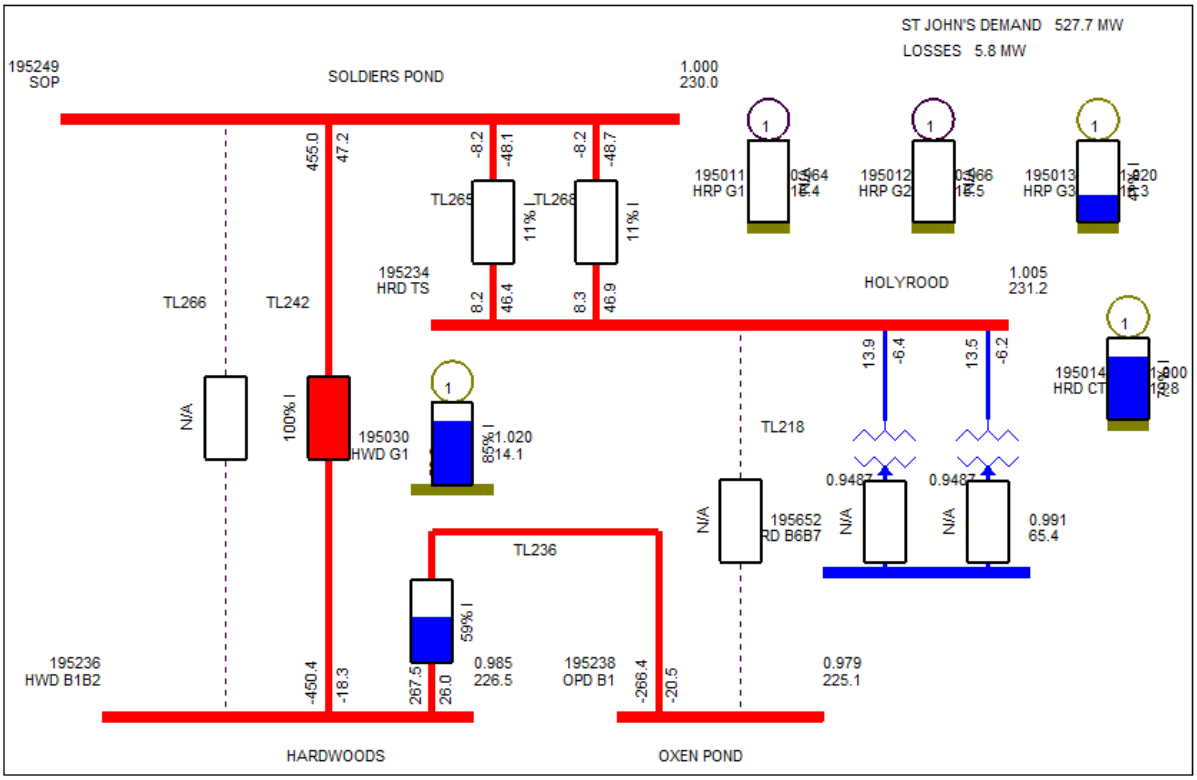


Figure 9: TL266 and TL218 Outage Scenario

As per the load duration curve presented in Section 2.4, the exposure for unserved energy represents approximately 16% of the year. This equates to approximately two months. It is also noted that the exposure increases proportionately with load growth in the St. John's area. By 2025, the peak demand for the St. John's region will reach approximately 740 MW, indicating 71% of peak load can be supported in the event of a failure to TL266 and TL218. The exposure for unserved energy in St. John's reaches approximately 25% of the year, or three months, by this time.

An economic evaluation of this alternative is provided in Section 3.4.1.

[14] It is assumed that the HWD Gas Turbine is available for 50 MW. Delivery to load over Newfoundland Power lines at Holyrood are as determined in load flow analysis.

3.2 Replacement with a New 230 kV Transmission Line

Another alternative for the reinforcement for the SOP-HWD corridor involves the replacement of TL266 with a new 230 kV transmission line. Consideration was given to the construction of this new transmission line with 795 kcmil (Drake) ACSR and 1191.5 kcmil (Grackle) conductors[15]. Other conductors, including 1379 All Aluminum Alloy Conductor (AAAC) and 795 ACSS were given preliminary consideration for this investigation, as discussed in Appendix B. These conductors would provide comparable ampacities to the 1192.5 Grackle conductor, but were not included as part of the detailed analysis due to higher capital costs.

It is noted that the new transmission line would be constructed with steel towers. As discussed in Appendix B, wood pole construction alternatives were considered, but were excluded as capital costs would exceed those of steel towers.

With a Drake conductor, the new transmission line would have a maximum operating temperature of 85^0C, providing an ampacity of 1200 A. This is equivalent to 478.0 MVA at 230 kV. With a Grackle conductor, the new transmission line would have a maximum operating temperature of 85^0C, providing an ampacity of 1500 A. This is equivalent to 597.6 MVA at 230 kV. Each of these alternatives would effectively increase the capacity of the SOP-HWD corridor, allowing TL266 to be removed from service. In such a configuration, System Planning Criteria would be met for the 2018 peak load case, as illustrated in the load flow plot presented in Figure 10 .

[15] Discussion of conductor optimization is provided in Section 3.6.

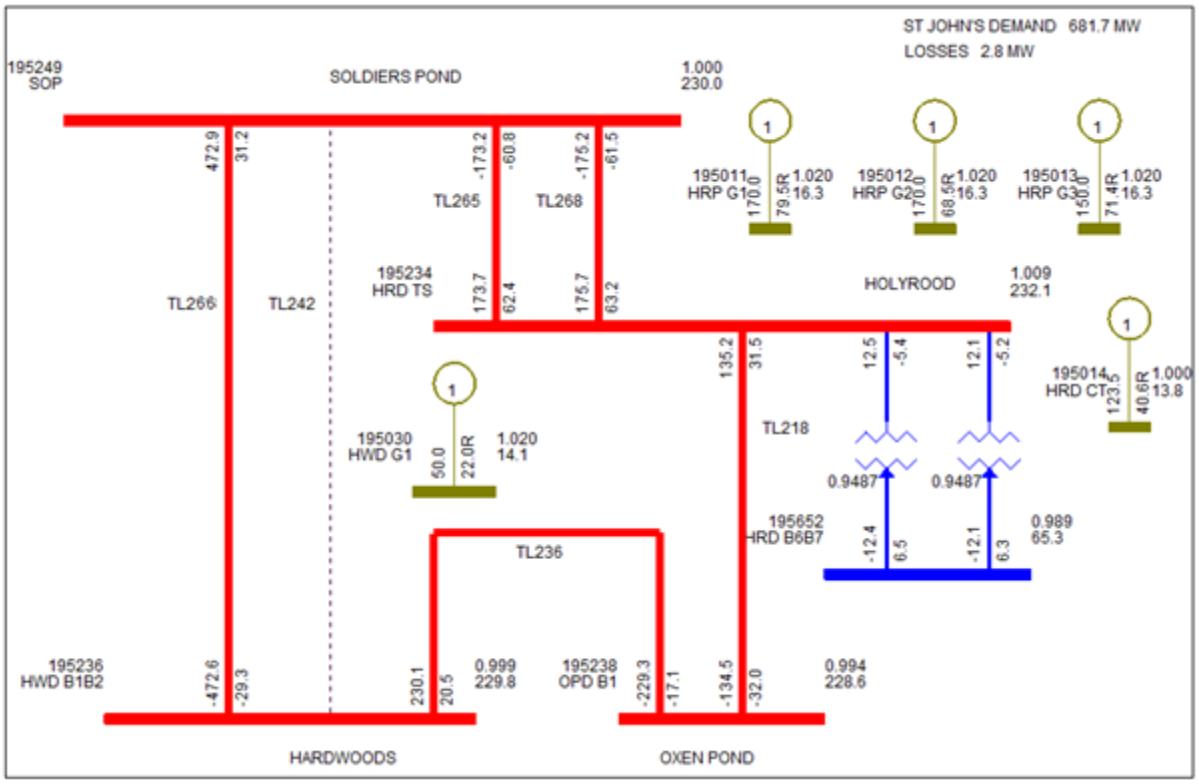


Figure 10: Load Flow Plot – 2018 Peak Case – TL242 Outage with New TL

It is noted that the thermal rating of the new transmission line would exceed that of TL242. The worst-case contingency in the SOP-HWD corridor is therefore found in the scenario where the new transmission line is out of service. Analysis indicated that additional capacity would be required in the SOP to HWD corridor in 2025 to meet System Planning Criteria in 2026. This is illustrated in the load flow plot presented in Figure 12.

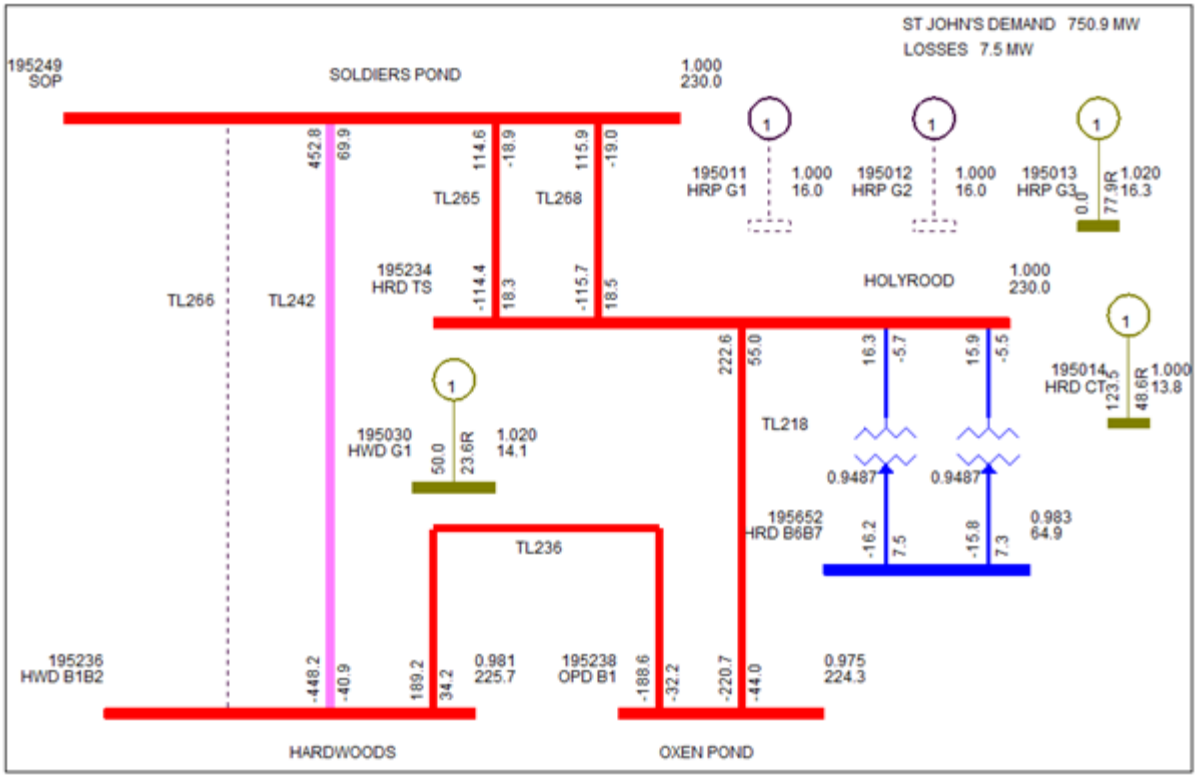


Figure 11: Load Flow Plot – 2026 Peak Case – TL242 Overload

In 2025, options for system reinforcements could include the construction of a new transmission line or the thermal uprating of TL242 with 804 ACSS/TW conductors. An economic review of capacity upgrades to ensure compliance with System Planning Criteria in 2026 and beyond is presented in Section 3.6.

3.2.1 Reliability Considerations for the Replacement of TL266 with a New Transmission Line

It is noted that the new transmission line would be constructed with steel towers and designed to withstand a 50-year CSA wind and ice load (2% annual exceedance probability). This is in compliance with industry standards.

Based on a 2% probability and the outage durations described in Section 3.1.1, the expected unavailability for the steel lines would range from 0.005% to 0.038%.

Further discussion of the design and reliability of the steel transmission lines is provided in Appendix B.

3.3 Reconfiguration of TL218

As discussed in Section 1.2, TL218 interconnects HRD and OPD and bypasses SOP. For the purposes of this investigation, consideration was given to the reconfiguration of TL218 such that it is interconnected at SOP, as illustrated in Figure 12. This alternative would allow for power flows over TL266 and TL242 to be shared with TL218 and would therefore allow for the deferral of transmission line reinforcements in the SOP-HWD corridor.

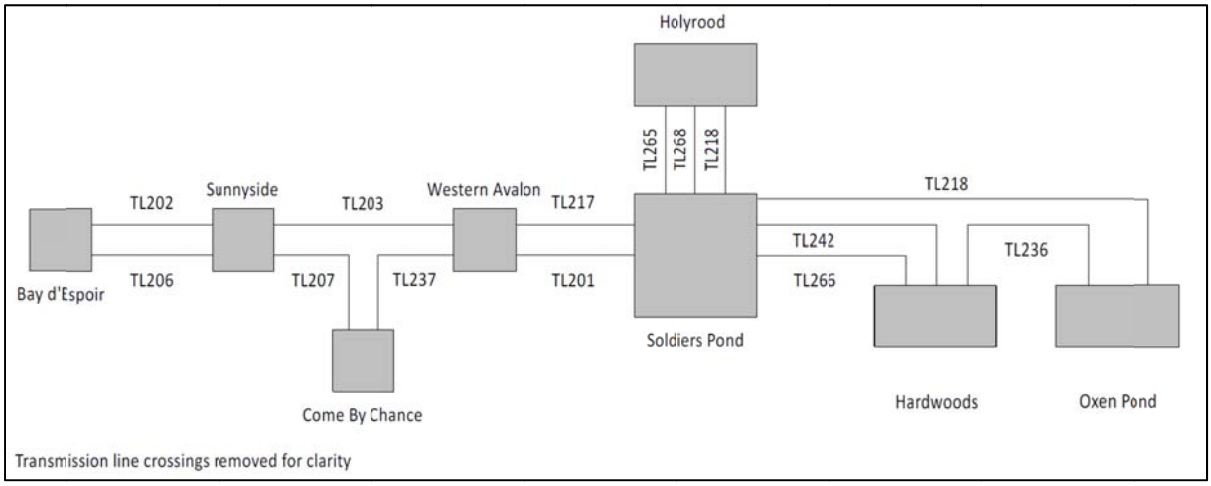


Figure 12: Avalon 230 kV Transmission System - End of 2017 – Reconfiguration of TL218

A review of this configuration indicates that additional capital costs would be required prior to 2018. Additional circuit breakers and protection and control systems would be installed at SOP to accommodate the interconnection two new line terminations. It should also be noted that two 1.6 km lengths of TL218 must be rebuilt to include overhead ground wire at the site of interconnection with SOP. This requirement is to ensure compliance with Hydro's Transmission Line Design Criteria which specify that overhead ground wire be installed over a minimum distance of 1.6 km from a terminal station to provide lightning protection.

As illustrated in Figure 13, the reconfiguration of TL218 would allow for the deferral of the thermal uprating of TL266 to 2022 as the line would be overloaded under contingency in 2023.

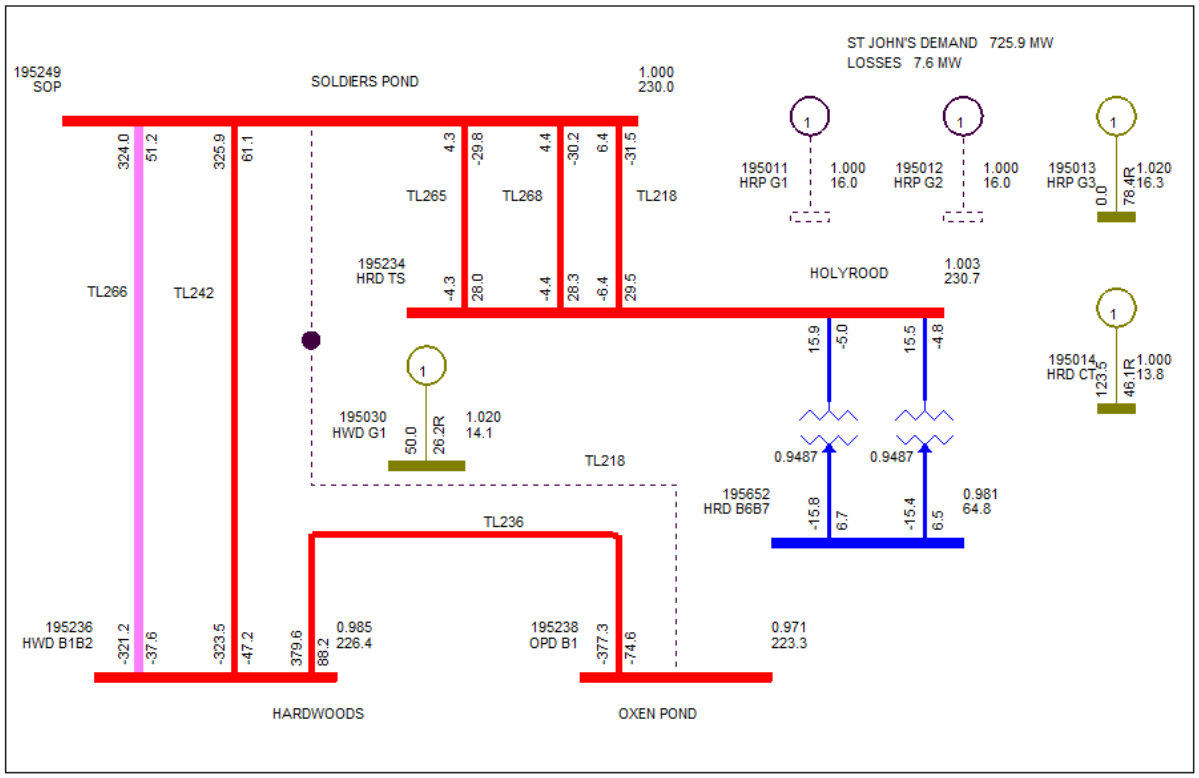


Figure 13: Configuration with TL218 Tied in SOP – TL266 Overload in 2023

It is also noted that this alternative requires the advancement of a thermal upgrade to TL218. As illustrated in Figure 14, if TL218 is interconnected at SOP, the transmission line section between HWD and OPD must be thermally uprated prior to 2024.

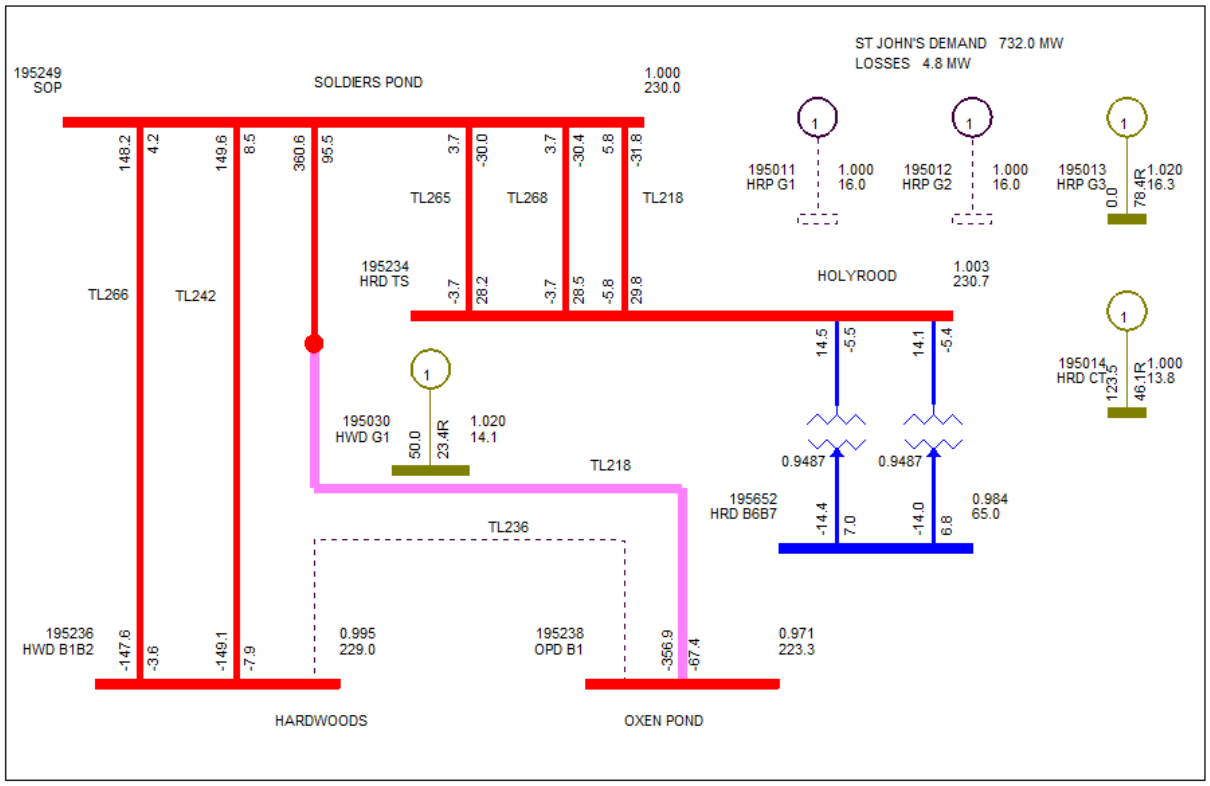


Figure 14: Configuration with TL218 Tied in SOP – TL218 Overload in 2024

As illustrated in Figure 15, if TL218 is not reconfigured (as is the case for the other alternatives), this line section does not need to be uprated until 2032.

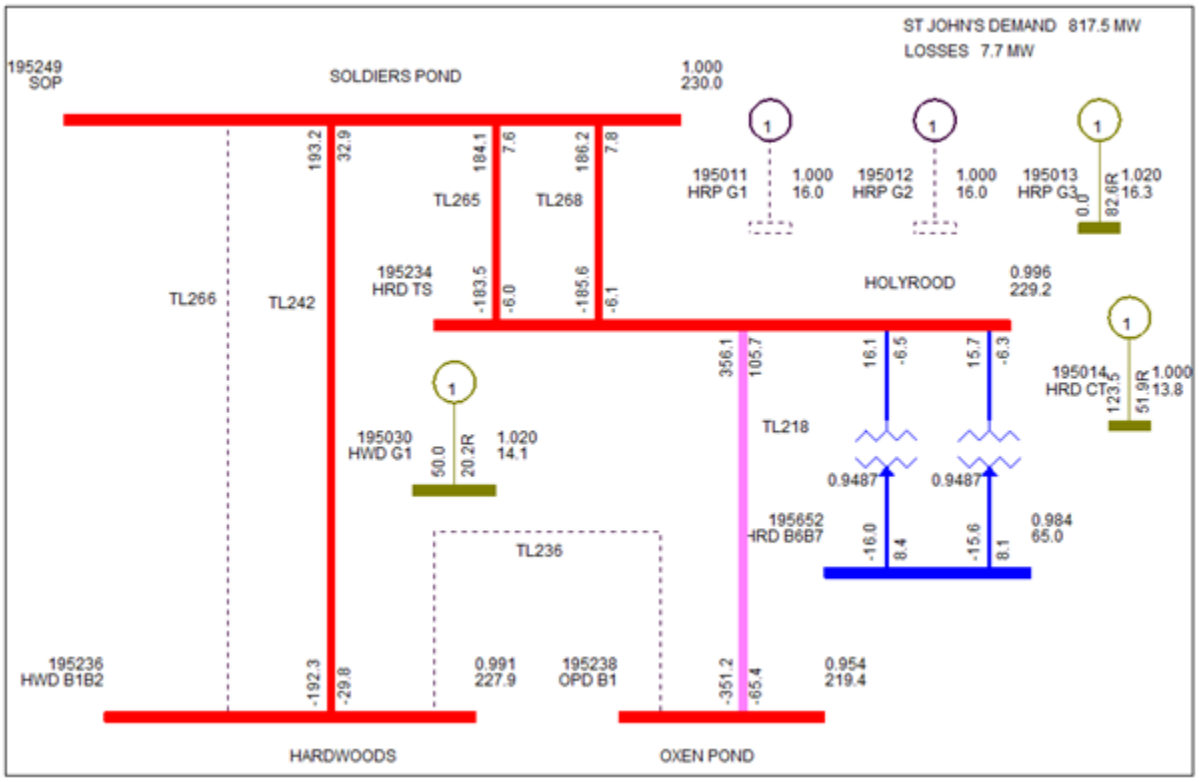


Figure 15: Configuration with TL218 Bypassing SOP – TL218 Overload in 2032

With the TL218 reconfiguration, TL242 must be thermally uprated in 2047 to avoid thermal overload under contingency in 2048. This case is illustrated in Figure 16.

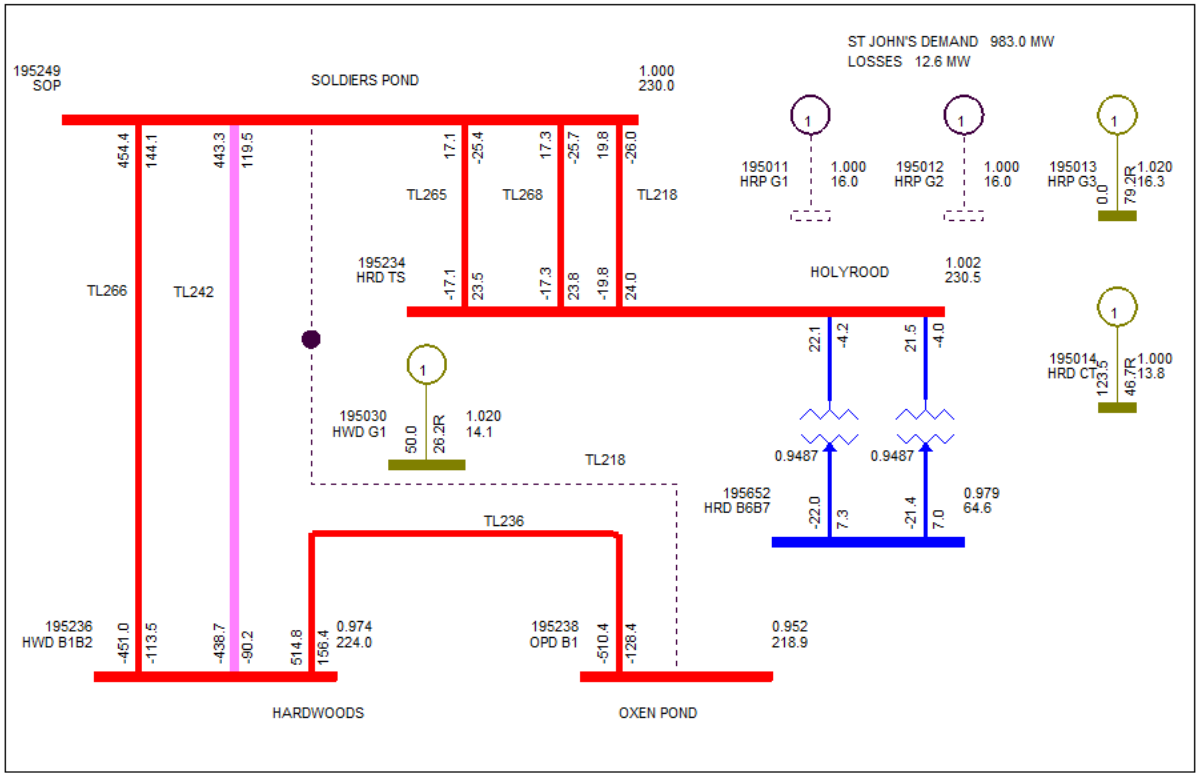


Figure 16: Configuration with TL218 Bypassing SOP – TL242 Overload in 2048

An economic review of this alternative is provided in 3.4.1.

3.3.1 Reliability Considerations for the Reconfiguration of TL218

It is noted that with the reconfiguration of TL218, the unavailability of the transmission lines due to severe icing events would be the same as for the case involving the thermal uprating of TL266, as discussed in Section 3.1.1.

3.4 Economic Evaluation of Alternatives

As discussed in the previous section, the following alternatives have been investigated for increasing the capacity in the SOP-HWD corridor:

1. Thermal uprating of TL266;

2. Replacement of existing TL266 wood pole construction with new 230 kV transmission line steel tower construction; and
3. Reconfiguration of TL218.

3.4.1 Comparison of Alternatives

The comparison of lifecycle costs for the alternatives was made for a forty-year study period on the basis of the following considerations:

- Capital cost;
- Operating and maintenance cost; and
- Cost of losses.

Details relating to each of these considerations are summarized in Appendix C. Explanations of the parameters are provided in Appendix B.

The results of the economic evaluation are summarized in Table 8. As noted, the lifecycle cost preference is for the thermal uprating of TL266 and is approximately $4.0 M. However, as discussed in Section 3.1.1, the thermal uprating of TL266 only provides an increase in ampacity and does not result in any improvement in reliability or robustness.

Table 8: Economic Comparison of Alternatives

SOP-HWD Transmission Corridor Analysis		
Alternative Comparison ***Cumulative Net Present Value*** ***To The Year*** **2015**		
Alternatives	**Cumulative Net Present Value (CPW)**	**CPW Difference between Alternative and the Least Cost Alternative**
TL266 Uprating	33,988,477	0
New TL	37,973,997	3,985,519
TL218 Reconfiguration	44,084,179	10,095,702

3.5 Selection of the Preferred Alternative

On the basis of the technical and economic review of alternatives presented in the previous sections, the preferred alternative is the replacement of TL266 with a new transmission line between SOP and HWD.

The economic analysis presented in the previous section indicates that the lifecycle cost difference between the thermal uprating of TL266 and replacement with a new transmission line is approximately $4.0 M. From a technical perspective, an alternative involving the thermal uprating of TL266 presents significant reliability concerns. This alternative does not result in any improvement in reliability or robustness. As a result, icing conditions could result in outages that present a serious impact to customers, as discussed in Section 3.1.1. In contrast, a new transmission line would be constructed to industry standard with steel towers and designed to withstand a fifty-year CSA wind and ice load. It is strongly recommended that the significant capital investment required in the transmission line corridor be consistent with these standards. The reliability improvement associated with this alternative outweighs the difference in lifecycle cost.

3.6 Conductor Optimization and Future Capacity Planning of the SOP-HWD Corridor

As discussed in the previous section, the replacement of TL266 with a new transmission line is the preferred alternative for the SOP-HWD corridor. An economic analysis was therefore undertaken to perform conductor optimization and to identify an optimal program for the addition of capacity for the study period. The analysis considered combinations of corridor upgrades to determine the optimal plan for increasing capacity. Corridor capacity upgrade alternatives are listed in Table 9.

Table 9: Corridor Upgrade Alternatives

Year	Corridor Upgrade Options
2017	Replacement of TL266 with new TL with 795 kcmil Drake Conductor **or** Replacement of TL266 with new TL with 1192.5 kcmil Grackle Conductor
2025	Thermal uprating of TL242 with 804 kcmil ACSS conductor **or** Construction of new TL with 795 kcmil Drake Conductor **or** Construction of new TL with 1192.5 kcmil Grackle Conductor
Beyond 2025	Other reinforcements, as required, depending on previous upgrades.

Load flow analysis was performed to determine the timing of corridor upgrades. Lifecycle costs considerations defined in Section 3.4.1 were then used to perform the economic evaluation.

The results of the analysis are summarized in Table 10. As noted the least-cost plan for the corridor would involve the following upgrades:

1. Replacement of TL266 with a new transmission line with 1192.5 kcmil Grackle Conductor prior to 2018;
2. Thermal Uprating of TL242 with 804 kcmil ACSS conductor in 2025; and
3. Construction of a new transmission line with 795 kcmil Drake Conductor in 2044.[16]

[16] The use of 1192.5 kcmil Grackle conductor may also be considered for a new transmission line in 2044. For the purposes of this investigation, a 795 kcmil Drake conductor was selected as a least cost alternative to meet load requirements for the study period. However, a future conductor optimization study would be required to confirm conductor selection.

Table 10: Economic Comparison of Alternatives – Conductor and Future Capacity Options

SOP-HWD Transmission Corridor Analysis **Alternative Comparison** ***Cumulative Net Present Value*** ***To The Year*** **2015**		
Alternatives	**Cumulative Net Present Value (CPW)**	**CPW Difference between Alternative and the Least Cost Alternative**
New TL Grackle, TL242 ACSS 2025, New TL Drake 2044	30,851,296	0
New TL Drake, TL242 ACSS 2025, New TL Drake 2028	37,031,742	6,180,446
New TL Grackle, New TL Grackle 2025	38,348,921	7,497,625
New TL Grackle, New TL Drake 2025	38,413,989	7,562,693
New TL Drake, New TL Grackle 2025	38,629,225	7,777,930
New TL Drake, New TL Drake 2025	38,645,274	7,793,979

3.7 Scope of Preferred Alternative

The proposed SOP to HWD corridor upgrade consists of the replacement of TL266 with a new 230 kV transmission line, 16 km in length. Construction of the transmission line is to be completed prior to 2018. A conductor size of 1192.5 kcmil, 54/19, ACSR, “Grackle” with an 85 ˚C conductor temperature rating is specified.

The transmission line shall have overhead ground wire (OHGW) over its full length for lightning protection. The line shall incorporate an optical fibre for protection and communication needs.

The transmission line shall be terminated at SOP and HWD in place of TL266. Existing TL266 structures shall be decommissioned following the completion of this project.

3.8 Consideration of the Proposed Project as Part of the LCP Scope

It is noted that this project does not fall within the scope of the LCP although the justification for this project is due to increased power flows in the corridor between SOP and HWD following the establishment of SOP. Analysis indicates, however, that if SOP were not established, other transmission line upgrades would be required to meet load growth in the St. John's Region.

A detailed long term analysis of supply to the St. John's Region without the LCP is beyond the scope of this investigation. However, it is noted that if SOP were not established, transmission lines TL242 and TL218 would be heavily loaded due to significant power flows from HRD to St. John's. These lines would represent the primary corridor between source and load, just as TL242 and TL266 would provide the primary path for power flow from SOP, as described previously in this report.

Preliminary analysis indicates that upgrades to TL218 would be required in the 2018-2019 timeframe if SOP were not established. This requirement is driven by violations to System Planning Criteria, where an outage to TL242 (between HRD and HWD) over peak would result in an overload of TL218. As discussed in Section 3.3, as SOP is established, TL218 does not require thermal uprating until 2032.

Given the load growth forecasted as per Section 2.4, other future transmission line reinforcements between HRD and terminal stations in St. John's would undoubtedly be required if SOP were not established.

On this basis, the justification for transmission line reinforcement is to meet load growth in the St. John's Region. While establishment of SOP results in the advancement of reinforcement in the corridor between SOP and HWD, other transmission line modifications are deferred.

4 CONCLUSION

An investigation has been performed relating to an increase of capacity in Hydro's transmission system in the corridor between SOP and HWD. The analysis consisted of a technical and economic review of alternatives to select a solution that will reliably meet long term load growth requirements while adhering to System Planning Criteria.

Based on the analysis summarized in this report, the preferred alternative involves in the construction of a new 230 kV transmission line. This solution, at a capital cost of $26.56 M, is the preferred alternative that meets all technical requirements. This project, constructed over a 2.5 years, will help to ensure a reliable long term supply for the St. John's Region.

5 BUDGET ESTIMATE

A budget estimate for the project is provided in Table 11. As noted, the total project cost is estimated to be $26.56 M.

Table 11: Project Budget Estimate

Project Cost: *($ x1,000)*	**2016**	**2017**	**2018**	**Total**
Material Supply	520.0	4,616.0	0.0	5,136.0
Labour	936.0	1,616.5	291.0	2,843.5
Consultant	1,000.0	0.0	0.0	1,000.0
Contract Work	600.0	9,226.0	0.0	9,826.0
Other Direct Costs	444.0	403.0	72.0	919.0
Interest and Escalation	199.0	1,628.3	1,064.2	2,891.5
Contingency	0.0	0.0	3,944.9	3,944.9
TOTAL	**3,699.0**	**17,489.8**	**5,372.1**	**26,560.9**

6 PROJECT SCHEDULE

The project schedule is provided in Table 12. The proposed project work would be completed over 2.5 years with engineering, surveying, brush removal, and procurement being completed in the first year; construction in the second year; and project closeout activities in 2018.

Table 12: Project Schedule

Activity		Start Date	End Date
Engineering	Engineering Design and Planning	Jan 2016	Apr. 2017
Properties/ Surveys	Property Acquisition, Surveying and Staking	Jan 2016	Apr. 2017
Clearing	Brush Removal and Clearing along Right of Way	Sept. 2016	Oct. 2016
Procurement	Procurement of Material and Hardware	Dec. 2016	June 2017
Construction	Transmission Line Construction	May 2017	Nov. 2017
Closeout	Project Closeout	Dec. 2017	June 2018

APPENDIX A

HYDRO'S BASIS FOR TRANSMISSION LINE RATINGS

The Hydro transmission line conductor ratings are calculated using IEEE Std 738 "IEEE Standard for Calculating the Current-Temperature of Bare Overhead Conductors". The ruling ground clearance (sag) curve for many of Hydro's transmission lines constructed in the 1960s and 1970s was the 50°C "hot" conductor sag curve as the meteorological loading conditions considered ice thicknesses of between 0.5 to 1.5 inches of radial ice for the ice load sag curve. Consequently, the majority of Hydro transmission line conductor ratings are based upon a maximum conductor temperature of 50°C. Operating experience revealed larger ice load conditions for 230 kV transmission lines on the Avalon Peninsula.

The rebuild of steel tower 230 kV transmission lines on the Avalon Peninsula between 1999 and 2002 utilized a larger radial ice thickness, which, in turn, became the ruling ground clearance sag curve for these transmission lines. Calculations utilizing the sag – tension programs revealed that the equivalent "hot" conductor sag curve for the rebuilt transmission lines limited the maximum conductor temperature to 80°C.

Hydro calculates three transmission line conductor ratings for three separate ambient air temperatures at maximum conductor temperature. These three conductor ratings are:

- Rate A (30°C ambient temperature) for summer operation;
- Rate B (15°C ambient temperature) for spring/fall operation; and
- Rate C (0°C ambient temperature) for winter operation.

In its use of IEEE Std 738, Hydro sets the 1 line latitude at 49° N, the elevation above sea level at 0 feet, the solar absorptivity at 0.5, emissivity at 0.5, local solar time at 11 am, and assumes a clear atmosphere given the lack of heavy industry near transmission line routes. With respect to wind speed, Hydro assumes a 2 ft/sec wind to account for sheltered spans and wind directions parallel to the conductor.

APPENDIX B

ASSESSMENT OF VARIOUS LIFE CYCLE COST PARAMETERS IN INCREASING AMPACITY OF EXISTING TL 201 LINE

Assessment of Various Life Cycle Cost Parameters in Increasing Ampacity of Existing TL 201 Line

Prepared by
Asim Haldar
(With assistance from Alex Byrne)
Date: June 2015

Abstract

This report presents the various cost parameters that are needed in carrying out a life cycle cost analysis (LCCA) to compare a number of options with particular reference to uprating/upgrading versus building a new line. The options considered are: (a) uprating of existing TL 266 (old TL 201), (b) uprating of TL 242 and (c) building a new 230 kV line (TL 272). The scope of this work is to provide the cost parameters to the System Planning department (SPD) and SPD will finally perform the cost benefit analysis to select the "best option" for increasing the ampacity of the line system between Soldiers Pond (SOP) and Hardwoods (HWD) terminal stations.

The option of building a new transmission line considers both steel and wood pole line constructions. However, the direct cost estimate of wood pole line is higher than the steel line and therefore, this option will not be considered in the LCC analysis. The cost parameters include direct and indirect costs, annualized maintenance and the future failure costs.

Executive Summary

The study presents a systematic methodology in assessing the various cost parameters that are required to do a life cycle cost analysis (LCCA) with particular reference to selecting a number of options to increase the ampacity requirement of the existing line system between Soldiers Pond (SOP) and Hardwoods (HWD) terminal stations. Current system configuration consists of two wood pole lines and a steel line, all at 230 kV level although one of the wood pole lines is not directly connected between the two stations but is in the same right of way (ROW).

As it was identified that the arrangement of the conductor system in these lines is not sufficient enough for adequate power transfer capacity considering the future time horizon (2017-2050). As such, this study was initiated to provide cost parameters in the evaluation of a number of options for a system uprate/upgrade of the existing 230 kV line system or building a new line at 230 kV level or a combination of both. The final analysis in selecting an optimum option, considering cost and reliability, and the justification are beyond the scope of this investigation.

The present study only concentrates on the estimation of various cost parameters and the design basis of uprating/upgrading of the existing line system and to consider an option of building a new line in the existing ROW. The existing line uprating is based on the original Hydro's design loads while the design basis for the new line is based on CSA design standard (2010). The service life for the uprating of existing wood pole line is assumed to be 15 years (expected residual life), for TL 242 as 30 years while a 50 year service life is considered for the new line.

A single HTLS (High Temperature Low Sag) conductor option is considered for existing TL 201 and TL 242 line uprating. However, a number of conductor options are considered for the proposed new line (TL 272).

Finally, the study report presents the capital cost estimates of two line configurations (steel and hybrid wood pole lines) considering a number of conductor options. The report also presents

the annualized maintenance cost and the cost of failures for both steel and the hybrid wood pole lines. For the uprating of the existing wood pole line, the maintenance cost is estimated under the WPLM program at a periodic time interval and is also included in the cost estimates. These cost estimate data will be used by the planning department as input data in the cost-benefit analysis in selecting a “best option” for increasing the ampacity of the line system.

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List of Symbols

W = estimated weight of the tower

c = empirical constant and is obtained from the tower weight calibration

K = a parameter determined from phase spacing

l = effective height where the resultant of all loads acts

H = sum of all horizontal loads due to wind, line angle tension etc.

V = sum of all vertical loads including the ice weight on tower

L = sum of all longitudinal loads (differential ice, broken conductor etc.)

1.0 Introduction

1.1 Background

Newfoundland and Labrador Hydro operates transmission lines at 230 kV level between Sunnyside and St. John's (Figure 1). These lines are located on the Avalon Peninsula, eastern part of Newfoundland, which is characterized by a maritime regional climate and is affected by almost all low pressure systems that cross North America. Additionally, the region is also affected by maritime systems passing along the eastern seaboard.



Figure 1-1: Study Area

Since their commissioning, the 1960's vintage lines have experienced severe ice loadings almost every year. Several large ice accumulations have been observed and since 1965, there were at least four (4) major line failures on the peninsula. These failures occurred in 1970, 1984, 1988 and 1994 respectively. In 1990, one span in TL 217 (a 230 kV line from Western Avalon to Holyrood) had severe icing and the conductor came very close to the ground and had a severe burn mark. Figures 1-2 and 1-3 depict the observed glaze icing which caused line failures in 1984 and 1994 respectively.



Figure 1-2: Ice Sample from Conductor (1984 Storm)

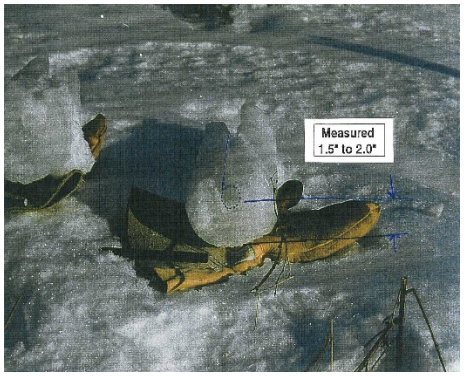


Figure 1-3: Ice Sample from Guy Wire (1984 Storm)

Based on a number of line failures that were encountered on the Avalon Peninsula and the significant outages experienced until mid-1990's, Hydro undertook an in depth failure investigation study (Haldar, 1996) and concluded that the observed failure rate based on many events over a 30-year operational life of these lines could be modeled with an annual rate of 0.1 for the entire Avalon region. This information was used later to revise the original design ice load used in 1960's and is documented in [Haldar, 1996, Avalon Study Report]. All 230 kV steel lines on the Avalon Peninsula were upgraded to withstand significantly higher ice loads based on the recommendations of this study. The major part of the upgrading work was to re-conductor the existing steel lines with a specially designed extra high strength AACSR conductor (Aluminum Alloy Conductor Steel Reinforced, 804kcmil size) and the installation of a number of suspension towers and newly designed dead end towers to provide adequate structural

capacity. The upgrading work of 129 km of 230 kV line system was completed in 2003. Figure 1-4 depicts the transmission line system layout on the Avalon Peninsula before the upgrading work. Figure 1-5 depicts the transmission line system layout on the Avalon Peninsula after the upgrading work was completed in 2003. In general, the layout for these lines varies from flat to extremely rough and hilly terrain.

Transmission lines TL 203, TL 201 & TL 218 consist of H-framed wood pole structures while TL 207/237, TL 217 and TL 242 use lattice steel towers such as guyed V as suspension structures and self-supported towers as heavy angle and dead end structures (Figure 1-4) as part of this upgrading process.

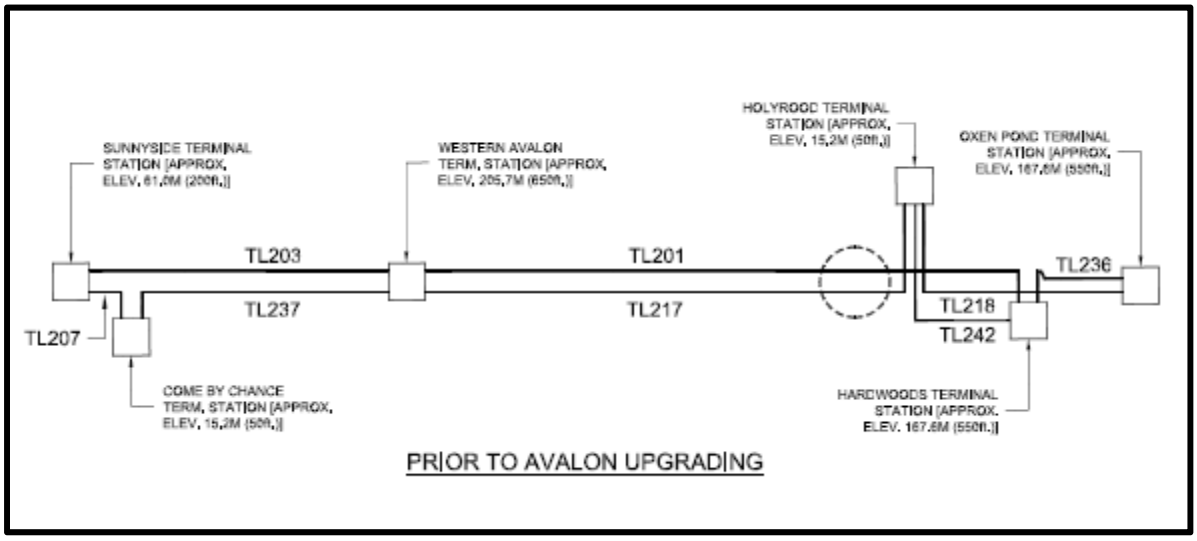


Figure 1-4: Line Layout Diagram before Avalon Upgrade

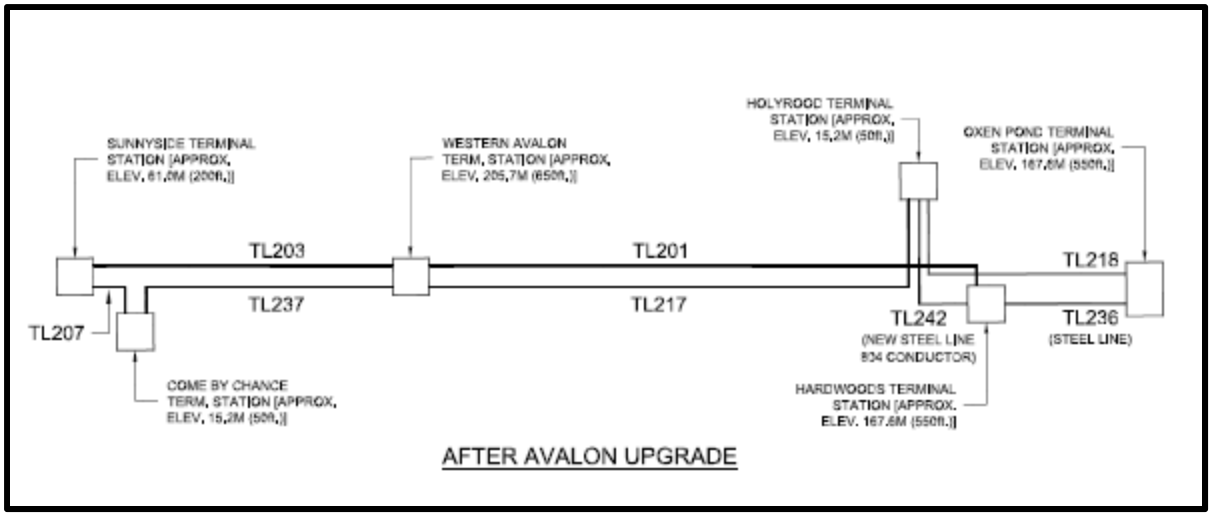


Figure 1-5: Line Layout Diagram after Avalon Upgrade

TL 218, the original steel line from Holyrood plant to Hardwood terminal station was upgraded with 804 conductor and renamed as TL 242. TL 242, the original wood pole line from Holyrood plant to Hardwoods terminal station was terminated outside Hardwoods terminal station on a single dead end structure (1431kcmil conductor up to this point) and the line then continues to traverse towards the Oxen Pond terminal station and was renamed as TL 218 after the Avalon upgrading work. The reason for terminating the line outside Hardwood terminal station was to provide increased reliability of the transmission line system.

1.2 HVDC Line

Nalcor Energy is at present building a ± 350 kV HVDC transmission line for transporting 900 MW electricity from Labrador to the Island of Newfoundland. The line traverses from the Muskrat Falls terminal station (near the power generating site Muskrat Falls, a site located 25 km west of Happy Valley-Goose Bay, Labrador) to the Strait of Belle Isle through underwater HVDC cables and passes under the Strait to the Island of Newfoundland. From the Strait, the proposed ± 350 kV HVDC transmission line route follows the western coast of the Great Northern Peninsula, crosses the Long Range Mountains (LRM), traverses further to the south of Grand Falls and terminates at Soldiers Pond converter station near St. John's. The proposed line route is shown in Figure 1-6.

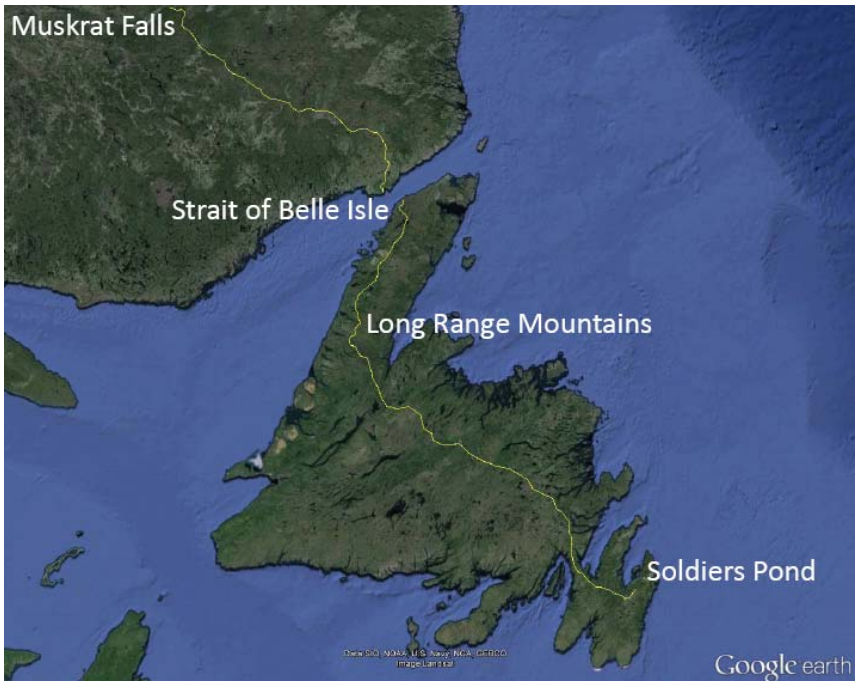


Figure 1-6: Proposed HVDC Line Route Showing Soldiers Pond Station

The HVDC line will terminate at the Soldiers Pond Convertor station and the bulk ac power after conversion will be distributed through the Hydro's existing transmission network system towards easterly and westerly directions. To transport this power through existing corridors, Hydro requires increased power transfer capacity than what is currently available in these lines because of thermal limitations (ampacity issue). The existing TL 201 is a 50-year old wood pole line, well maintained and mostly uses a 636 26/7 ACSR conductor ("Grossbeak") between SOP and HWD terminal stations. The use of this conductor restricts its additional power transfer capacity because of thermal limitation. Once the Soldiers Pond terminal station is built and the lines are terminated as shown in Figure 1-7, the existing TL 201 line between Soldiers Pond and Hardwoods Terminal stations (Renamed as TL 266) will require additional power transfer capacity (ampacity) to support the electrical requirement of the HVDC infrastructure.

A number of options that can be considered in increasing the thermal limit of TL 201 are discussed in details in the next section. Some of these options could be (1) re-conductor the line with a larger diameter conductor (2) re-conductor plus add mid-span structures (3) re-conductor with "High Temperature Low Sag" (HTLS) conductor (4) add equipment to provide

series compensation support and (5) build a new line.

This study primarily focusses on evaluating the various parameters of assessing life cycle cost (LCC) assessment with respect to thermal uprating of TL 201 either re-conductoring the existing line with a conductor of higher ampacity without increasing significant structural loads or building a new line with a larger diameter conductor at 230 kV level in the existing ROW. This study will provide a number of input parameters with respect to LCC that will be required to do a proper cost benefit analysis to choose a specific option; **The LCC analysis is beyond the scope of this investigation.**

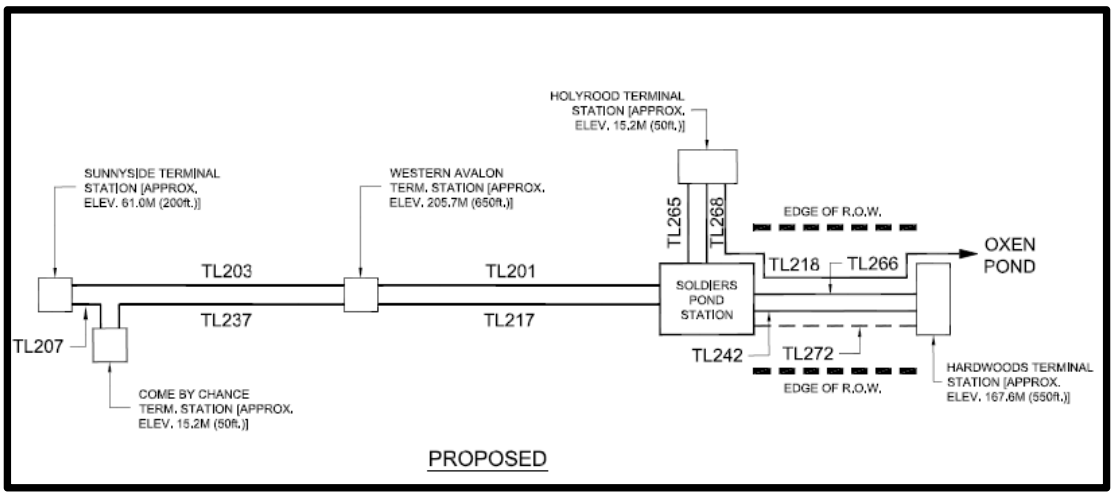


Figure 1-7: Proposed Layout of the Lines between Soldiers Pond and Hardwoods Terminal Stations

1.3 Objective of this Study

The primary objective of this study is to consider two main options to provide increased capacity for the existing line system between Soldiers Pond and Hardwoods Terminal Stations. The options are to either uprate the existing TL 201 (new name TL 266) or build a new line in the existing ROW between these two terminal stations. The purpose of this study is to provide various cost elements of a Life Cycle Cost (LCC) analysis which will be used as primary input data to a "Planning model" in evaluating various options and selecting the most cost effective option for uprating/upgrading of the existing lines or building a new line in the existing ROW.

1.4 Layout of the Report

Section 1 provides a brief background of this project initiative and provides some historical information on the recent upgrading work that was done on the steel line system on the Avalon Peninsula. It also provides the objective and the primary focus of this study.

Section 2 presents an overview on ampacity improvement process.

Section 3 presents the scope and the detailed breakdown of the tasks that were asked by the System Planning department (SPD).

Section 4 presents the basic methodology that is normally followed in developing the Life Cycle Cost Analysis (LCCA) model and the identification of various cost parameters.

Section 5 presents a brief description of the existing ROW, line system and the challenges that the T & D department faces in building the new line in the existing ROW.

Section 6 presents an overview of the design philosophy, both for the existing and new lines and the validation of sag and tension data for a number of selected conductors.

Section 7 presents the methodology used for the existing line, TL 201 and the issues and

challenges.

Section 8 presents the cost models for two line configurations (1) Hybrid line and (2) Steel Line. For a hybrid line, suspension structures are designed as two pole H-framed x-braced and knee braced while the dead end structures are designed as steel towers to provide adequate line tension capacity.

Section 9 presents the various cost elements that are required for a Life Cycle Cost Analysis.

Section 10 presents the schedule for uprating and /or building a new line.

Section 11 presents the summary and conclusions.

Section 12 presents the references.

2.0 Transmission Capacity (Ampacity) Improvement Uprating/Upgrading

The conductor temperature increases as the power is transported through the cable. It is important to know the thermal limit of the conductor to ensure that the conductor can withstand the rise in the temperature without losing its strength. The thermal limit of the cable is normally limited by two constraints (1) conductor strength with reference to the material characteristic and (2) constraints on ground clearance. Until the 1990's, most overhead lines used ACSR conductors (Aluminum Conductor Steel Reinforced) where the temperature rise in the steel was not an issue because it can withstand up to 200°C without damage; however the thermal limit of regular aluminum is limited to 80°C because the aluminum loses its strength due to annealing (softening of aluminum strand thus losing the strength). Therefore, a continuous operation of ACSR at such a high temperature can cause permanent damage to the conductor.

To increase the thermal ratings of the existing line (ampacity), a number of options can be considered. These are:

- Increase of the allowable temperature provided the existing ground clearance does not violate the standard. For example, assuming that the existing line was designed to operate at a temperature of 50 °C, increasing the temperature to 90 °C will provide an increase in the ampacity. If the line does not provide adequate ground clearances, then the attachment points can be raised or the tension can be increased or both.

- Consider dynamic thermal rating of the line where the rating can be increased as the wind speed exceeds 0.6m/sec. This can be achieved easily by installing wind sensors at selected locations along the line route and remotely accessing the data from the control center. This is not suitable for continuous operation but can provide some limited increase in the capacity when the line is operated successfully at some percentage of the annual operating time.
- Consider replacing the conductor with a larger one or use a conductor that can operate continuously at 100 °C or above as long as the clearance criteria can be met if it is an existing line. Larger diameter conductors provides increased aluminum area and

ampacity but also increases the structural loads on suspension and strain structures and this normally will require some additional reinforcement or replacement of existing structures. For example, if the tension is increased significantly on the strain tower, then one may have to significantly reinforce or replace the complete structure. This can be avoided by using an equivalent diameter HTLS (High Temperature Low Sag) conductor where the conductor can be operated continuously above 100°C while maintaining a stable tension and creep characteristics.

2.1 Conductor Types Considered for the Study

ACSR, ACAR and AAAC (All Aluminum Alloy Conductor) conductors normally use 1350-H19 hardened aluminum or aluminum alloy wires 6201-T81. If the temperature for ACSR, ACAR, or AAAC conductor exceeds 100 °C at an exposure time of 30 minutes or more, it can result in a permanent and significant loss of strength due to annealing (loss of strength). Due to the size and shape of the conductor, destructive testing, such as tensile testing, will most likely be required to identify the presence of annealing and/or over aging.

2.1.1 ACSR

The ACSR conductor has been in Hydro's system since mid-1960's. It normally comprises of outside aluminum strands (normally in two or three layers) with an internal core supported by high strength steel (795 26/7 strands "Drake: conductor or extra high strength steel (804 AACSR with EHSS, recent use in Avalon Upgrade). Normally, the conductor can be used up to 80 °C for safe operation without loss of strength in aluminum due to annealing. Typically, the load distribution between aluminum and steel core is 1:1. For example, in a DRAKE conductor, steel core typically supports 56% of load while the aluminum supports 44% of the total load. If elevated temperature operation reduces the strength of the aluminum wires by 20%, the overall strength of the conductor will be reduced by 9%. Since the degradation of the aluminum wires only partially impacts the overall conductor strength, conductor temperature in excess of the annealing temperature of aluminum can be applied to ACSR such that the maximum loss of overall strength of the conductor is limited to 10% (Heritage MAAC Group, 2010).

2.1.2 AAAC

AAAC conductor is composed of 1350-0 aluminum on the outside layers supported by high strength aluminum in the inner core to provide improved strength. The conductor is recommended for continuous operation up to 80 °C and an emergency operation for a limited number of hours. The conductor has been used in Hydro's system in early 1980's and has performed satisfactorily at 230 kV voltage level.

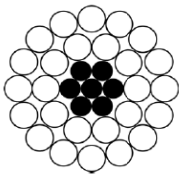
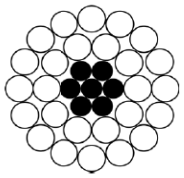
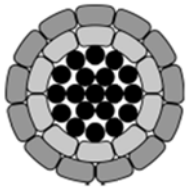
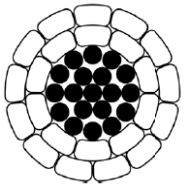
2.1.3 ACSS

ACSS (Aluminium Conductor Steel Supported) conductors which use 1350-0 aluminum in the fully annealed condition and will not have its strength dramatically affected by the increased temperature. The rated strength of ACSS conductors is primarily the strength of the steel core plus the small strength contribution of the annealed aluminum wires. (MAAC Group, 2010).

Since the aluminum wires are already annealed, application of high temperature will not further reduce the strength of the wires or the overall conductor. In the case of ACSS conductors, the maximum temperature is limited by the temperature susceptibility of the protective coating of the steel core wires and temperature capability of dead-ends, splices, and other fittings. Typically the steel core wires of ACSS conductors use a zinc - 5% aluminum-mischmetal alloy coating (Galfan) instead of conventional galvanizing to permit operation up to 250°C.

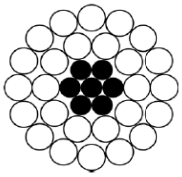
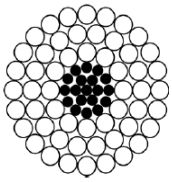
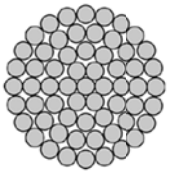
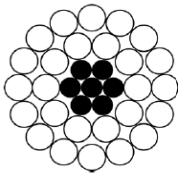
2.2 Conductor Characteristics

Table 2-1: Conductor Characteristics (Mechanical and Electrical) for Existing Lines (TL 201 & TL 242)

Conductor Types	Drake[(1)] (Existing, part of the Line TL 201)	Drake ACSS (Proposed for Uprating)	804 kcmil (Existing, TL 242)	804 kcmil ACSS (Proposed for Uprating)
				
Stranding	26/7	26/7	13/10/19	23/19
Overall Diameter (in.)	1.107	1.108	1.108	1.108
Self-Weight (lb/ft.)	1.091	1.091	1.484	1.483
UTS (kips)	31024	32600	63621	63846
dc Resistance @ 20 °C (Ω/kft)	0.02185	0.02066	0.02292	0.01996

(1) most of TL 201 has 636kcmil conductor; however part of the line also has 795 "Drake"; 636kcmil is not included in this Table

Table 2-2: Conductors Proposed for New Lines - Characteristics (Mechanical and Electrical)

Conductor Types	Drake	Grackle	AAAC	Drake ACSS
				
Stranding	26/7	54/19	61	26/7
Overall Diameter (in.)	1.107	1.337	1.354	1.108
Self-Weight (lb/ft.)	1.091	1.531	1.298	1.091
UTS (kips)	31024	42489	47884	32600
dc Resistance @ 20^0 C (Ω/kft)	0.02185	0.01463	0.01454	0.02066

2.3 Conductor Ampacity Characteristics

Table 2-3: Conductor Ampacity for Existing Line TL 201

Ampacity Versus Temperature				
Drake ACSR 26/7	Conductor Temperature			
	75 °C	85 °C	95 °C	105 °C
Summer@30 °C	841 A	940 A	N/A	N/A
Winter @0 °C	1142 A	1200 A	N/A	N/A

Ampacity Versus Temperature				
795 ACSS-MA5 26/7	Conductor Temperature			
	75 °C	85 °C	95 °C	105 °C
Summer@30 °C	863 A	960 A	1040 A	1120 A
Winter @0 °C	1171 A	1240 A	1300 A	1360 A

Table 2-4: Conductor Ampacity for Existing Line TL 242

Ampacity Versus Temperature				
804 AACSR	**Conductor Temperature**			
23/19 EHSS	75 °C	85 °C	95 °C	105 °C
Summer@30 °C	833 A	930 A	N/A	N/A
Winter @0 °C	1107 A	1200 A	N/A	N/A

Ampacity Versus Temperature				
804 ACSS-TW	**Conductor Temperature**			
23/19 EHSS	75 °C	85 °C	95 °C	105 °C
Summer@30 °C	880 A	980 A	1070 A	1160 A
Winter @0 °C	1194 A	1260 A	1320 A	1380 A

Table 2-5: Conductor Ampacities for New Lines

Ampacity Versus Temperature				
Drake ACSR	**Conductor Temperature**			
26/7	75^0 C	85^0 C	95^0 C	**105^0 C**
Summer@30^0 C	841 A	940 A	N/A	N/A
Winter @0^0 C	1142 A	1200 A	N/A	N/A

Ampacity Versus Temperature				
Grackle ACSR	**Conductor Temperature**			
54/19	75^0 C	85^0 C	95^0 C	105^0 C
Summer@30^0 C	1055 A	1180 A	N/A	N/A
Winter @0^0 C	1432 A	1500 A	N/A	N/A

Ampacity Versus Temperature				
1379 AAAC	**Conductor Temperature**			
61 strands	75^0 C	85^0 C	95^0 C	105^0 C
Summer@30^0 C	1086 A	1220 A	N/A	N/A
Winter @0^0 C	1482 A	1570 A	N/A	N/A

Ampacity Versus Temperature				
795 ACSS-MA5	**Conductor Temperature**			
26/7	75^0 C	85^0 C	95^0 C	105^0 C
Summer@30^0 C	863 A	960 A	1040 A	1120 A
Winter @0^0 C	1171 A	1240 A	1300 A	1360 A

3.0 Scope

The scope of the work includes primarily three options. These are:

Option A: Develop cost estimate of TL 266 line for uprating/upgrading work with a 795 ACSS conductor (HTLS). This option to consider only reconductoring and some limited structural upgrading work such as replacing knee brace arrangement with steel x-arm as required basis (Class 3 level estimate).

Option B: Develop cost estimate of TL 242 line for uprating/upgrading work with an 804 ACSS conductor (HTLS). This option to consider only reconductoring (Class 3 level estimate).

Option C: Develop cost estimates for building a new line parallel to existing TL 266 and TL 242. This option should consider a number of conductor options and also two line configurations (1) steel and (2) wood pole line constructions.

a. Construction of a new line (HWD-SOP) using 795 ACSR conductor;
b. Construction of new line (HWD-SOP) using 1192 ACSR conductor;
c. Construction of new line (HWD-SOP) using 1379 AAAC conductor; and
d. Construction of new line (HWD-SOP) using 795 ACSS conductor.

The above cost estimates are developed assuming that the new transmission line shall be shielded over the whole length and include one overhead ground wire (OHGW) and one optical ground wire (OPGW). This requirement is driven by protection requirements and the sensitivity of lightning strikes near SOP.

4.0 Methodology

The purpose of this study is to determine the optimum design return period of a typical HV line by balancing the initial line cost against the present value of all future losses (failure costs, outage costs, conductor losses, etc.). It is well known that the overestimation of the design wind and ice loads will significantly affect the initial design cost of a line, while the underestimation of these loads would certainly impose "future" failure costs which, in some instances, could be quite significant. A typical line failure for a very small event in Newfoundland could cost $500,000 dollars just to replace the damaged transmission line sections (Avalon Study report, 1995), not including the customer interruption costs (commercial and business) and losses.

4.1 Simple Cost Equation

A methodology is developed based on a probabilistic system model and the mathematical expression is presented below.

$$C_T = C_I + PVC\,(C_M + Damage\ Cost + Cost\ of\ Losses) \quad [4.1]$$

$$Damage\ Cost = P_f\,C_f + Outage\ Cost \quad [4.2]$$

4.1.1 Total Life Cycle Cost, C_T

The total life cycle cost is based on the initial capital cost of the line designed for a specific return period, T, and the present value of all future maintenance and failure costs.

4.1.2 Initial Capital Cost, C_I

This cost includes the costs of all line materials, construction, engineering, survey and any property acquisition, commissioning etc. The failure rate λ is directly related to return period, **T**.

4.1.3 Cost of Maintenance, C_M

The cost of line maintenance refers to maintaining the asset during the service life of the line.

This will normally include inspection of line by ground patrol, climbing, helicopter usage and any costs associated with preventive maintenance

4.1.4 Damage Cost

The damage cost has two components. (1) Tangible cost and (2) intangible cost. The tangible portion of damage cost normally includes the expected replacement cost of the line after a failure and the cost of expected energy not supplied during an outage.

4.1.5 Failure Cost

This cost primarily includes the replacement cost of the line section that failed during an extreme event. This cost can be estimated reasonably based on past data. This cost is estimated based on the annual probability of failure (P_f) and the consequence of a failure.

4.1.6 Outage Cost

This cost can vary widely depending on the consequence of the failure on the system, customer distributions and hence the composite customer damage function (CCDF) normally expressed in $/KWh (described in Section 6.0 of CEATI report Project 3347).

4.1.7 Intangible Cost

Intangible costs could be the increase in the future insurance premium, societal cost, loss of company's reputation due to power outages, etc. which are difficult to quantify (Billiton and Allan, 1987). Intangible costs are not included in this analysis.

4.1.8 Cost of Conductor Losses

Depending on the size of the conductor considered in the study, one needs to account for the economic value of the power losses (MW/unit length of line) during the service of the line. This is normally done as annualized cost ($) discounted over a fixed service life of the line (normally 50 years).

Figure 4.1 depicts the graphical representation of equation 4.1. The initial line cost will increase as the reliability increases while the cost of failures will decrease with increasing line reliability. It is expected that an optimum region can be found by balancing these two costs. Figure 4.2 presents the flow diagram for developing various cost components.

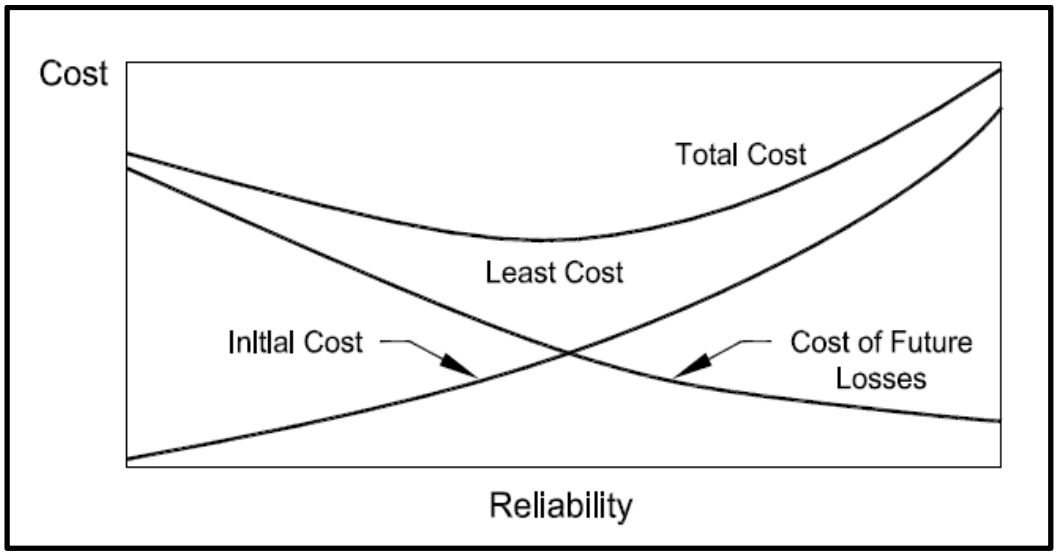


Figure 4-1: Optimum Cost Risk Diagram

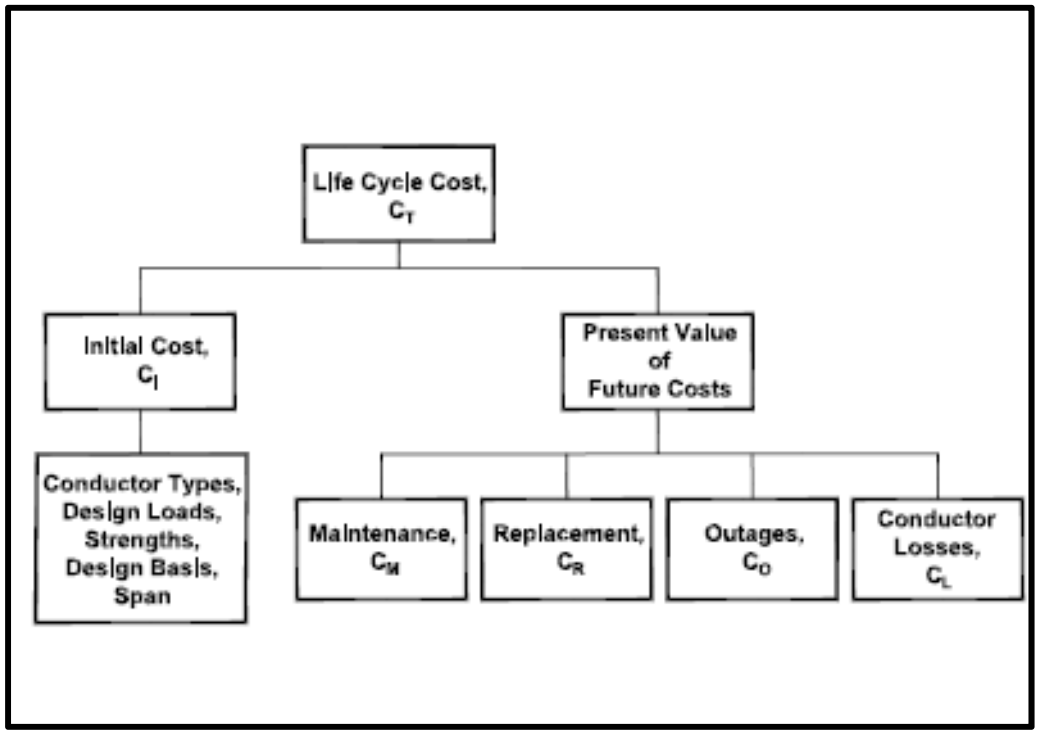


Figure 4-2: Flow Diagram for Developing Life Cycle Cost (LCC) Models

5.0 Routing and Challenges

The existing transmission line route between SOP and HWD stations is shown in Figure 5-1. By staying on the left side of the route (exterior) all the way from Hardwoods to Soldiers Pond Terminal Station (Figure 5-3,looking towards SOP), a number of large crossings over water bodies will be avoided and this will remove the requirement of dead end structures for crossings. Also, it will be easier to get into the Hardwoods station because the new line does not have to cross the existing lines. The only disadvantage for this routing is that Hydro has to acquire a small section of the private land near the Hardwoods station in order to get TL 272 on the right side of the station looking towards the station. Figure 5-2 shows a typical cross section of the ROW where three lines are shown side by side (looking towards the HWD station).

T & D has already initiated the process to acquire this extra piece of ROW. However, if this not feasible and is not acquired within the project schedule, then the only option will be to cross the existing lines at several locations and the line to traverse on the right side of the existing ROW. In this case, Hydro does not have to acquire the land but a number of crossings will be required at multiple locations and this additional cost should be included in the cost estimate. In addition, the cost of crossing the large water bodies at multiple locations would need to be included.



Figure 5-1: Overall Line Route and ROW between Soldiers Pond and Hardwoods Terminal Stations

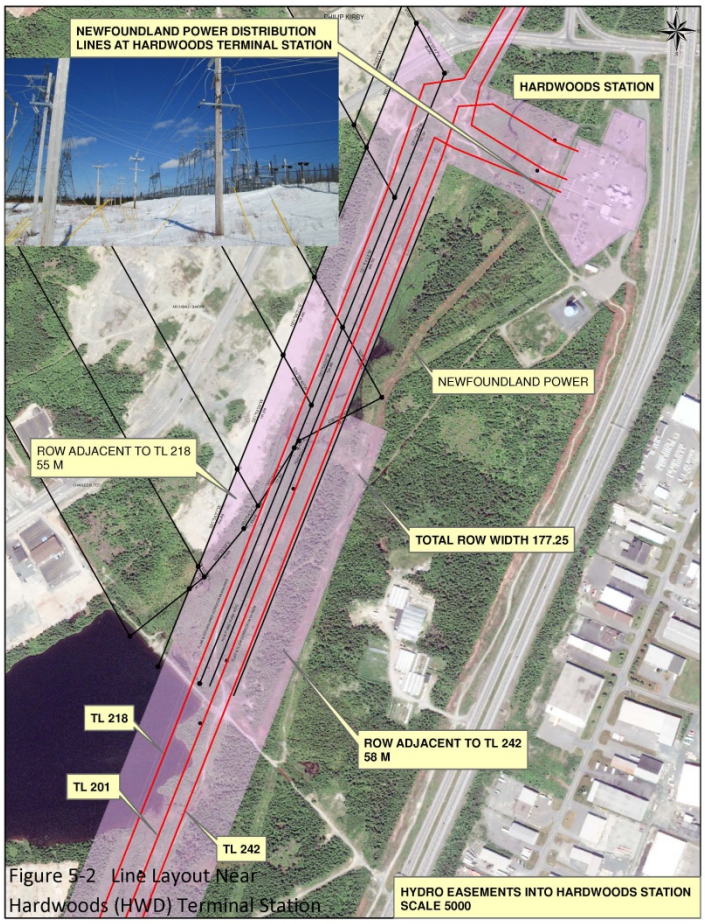


Figure 5-2: Line Layout near Hardwoods (HWD) Terminal Station

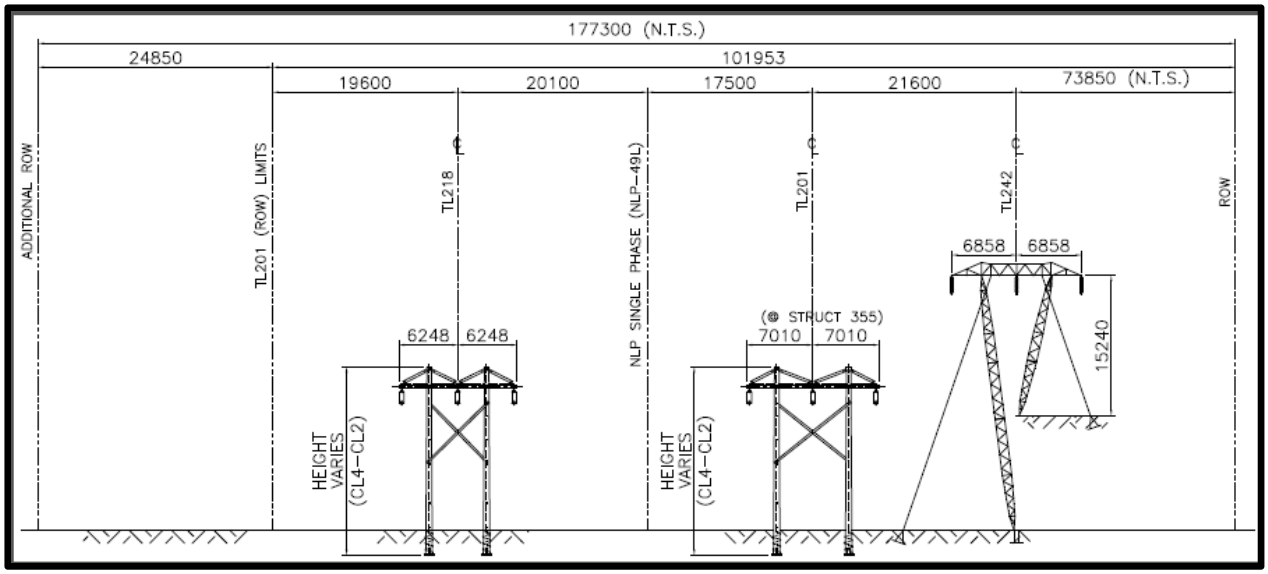


Figure 5-3: Line Configurations - TL 218, TL 201 & TL 242 in the Existing ROW

Figures 5-3 and 5-4 present the enlarged view near the HWD and SOP stations respectively. Figure 5-5 presents a photograph that was taken during the site visit on April 1, 2015. It shows clearly that Weir's shed is built on our existing ROW without Hydro's permission and this shed needs to be moved because of the safety issue.

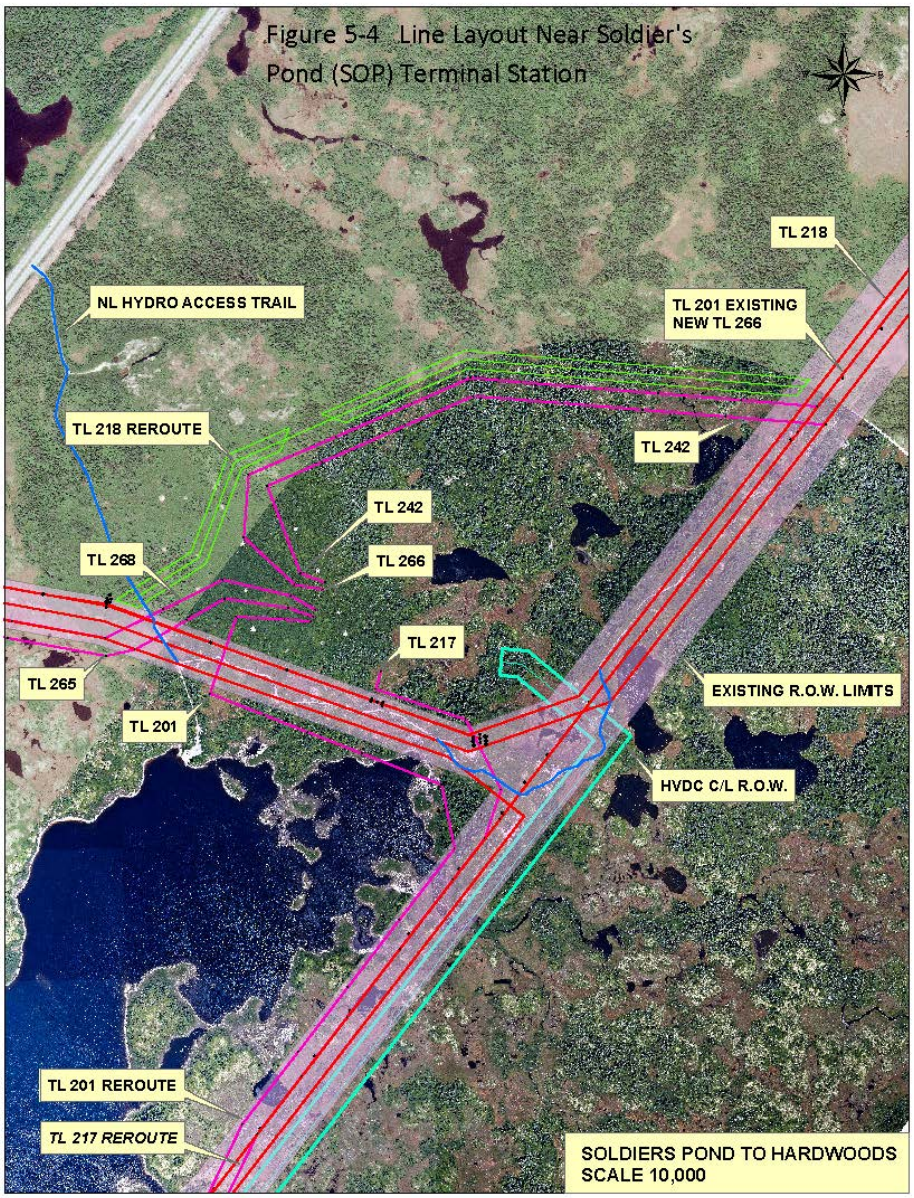


Figure 5-4: Line Layout near Soldiers Pond (SOP) Terminal Station

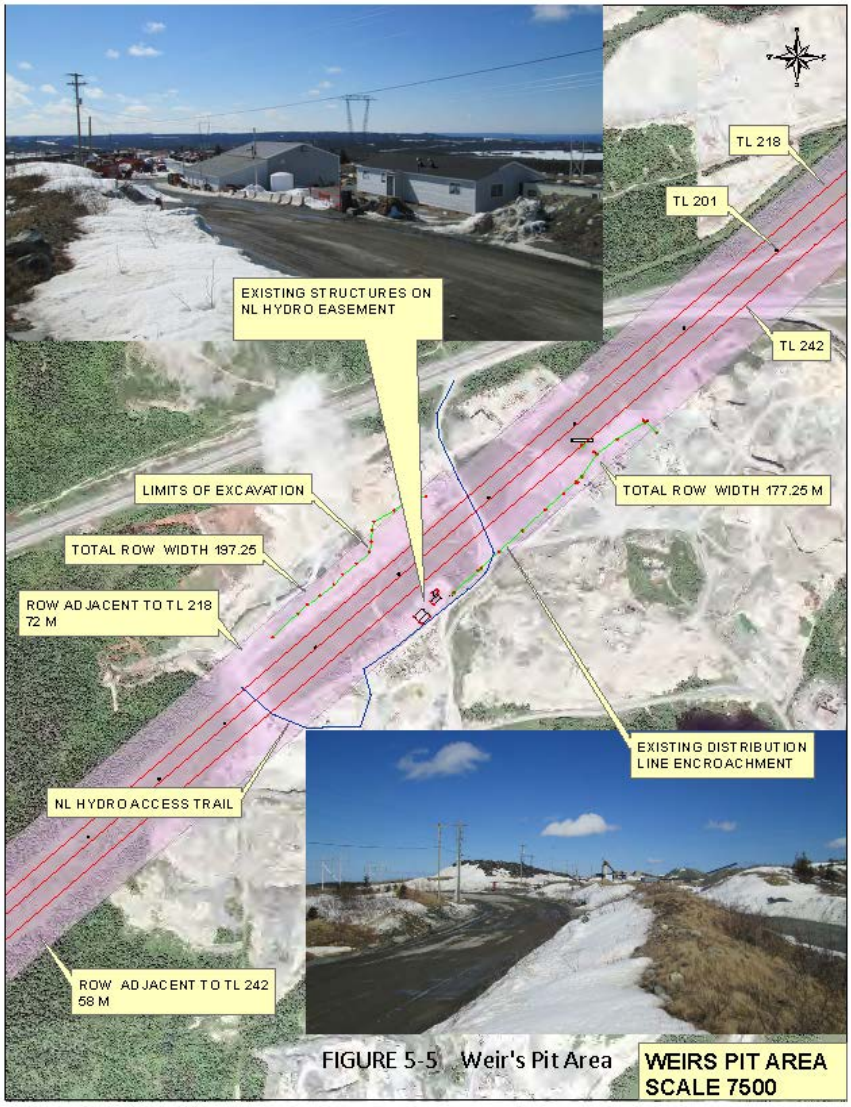


Figure 5-5: Weir's Pit Area

6.0 Design Basis

Overhead lines are normally designed for two types of loads (1) Normal Loads and (2) Security Loads. During the operation of the asset, normal loads, sometimes called probabilistic climatological loads such as ice, wind and combined wind and ice loads, are expected to occur within the service life (t_L). These loads are often quantified in terms of a single return period value (T-year). It is expected that the line and its components survive the effects of these normal loads without any failure within the expected service life of the asset. Should the line system fail, the line is also designed to limit (contain) the extent of the failure zone and therefore, security based design loads (containment loads) are also considered in the design process. The objective here is to minimize loss of the components' effects to avoid a major cascade failure. Besides these loads, lines are also designed for regular maintenance and construction loads.

At a high level, a line primarily consists of two main systems. These are (1) Wire System and (2) Support System. The support system can be further broken down to include (1) tangent support subsystem and (2) dead end support subsystem. Figure 6-1 presents a typical wood pole line system. These two primary systems are marked in Figure 6-1. Figure 6-2 shows a breakdown of a typical line system and components in a fault tree diagram format.

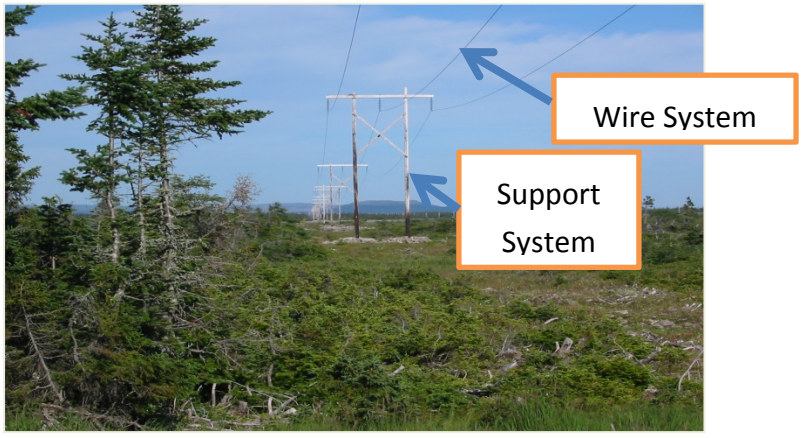


Figure 6-1: A Typical Wood Pole H-Frame Line System

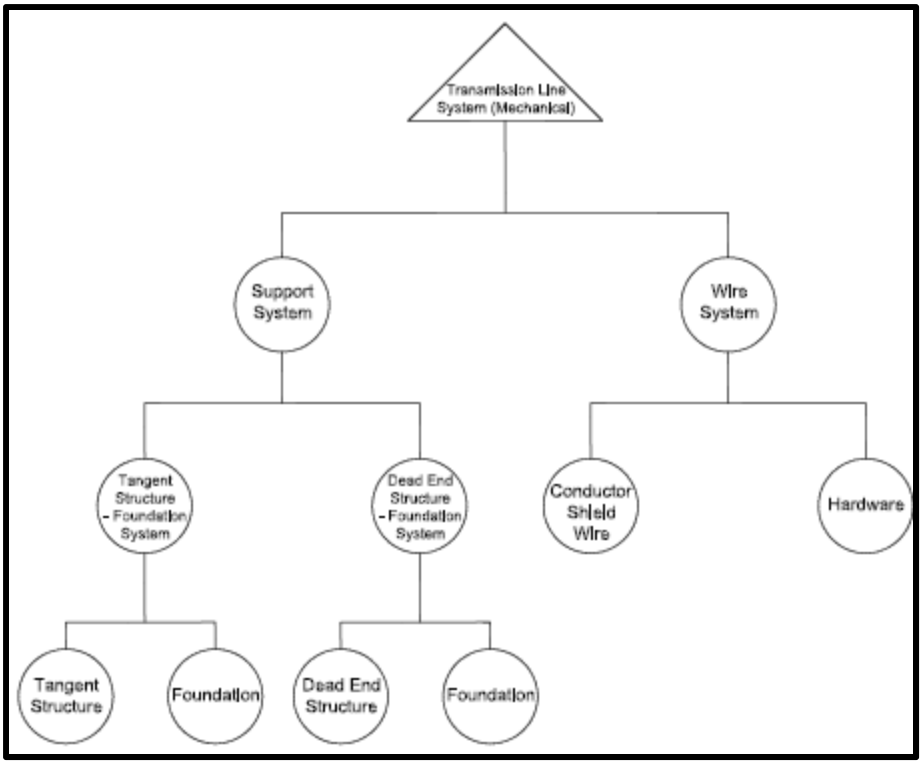


Figure 6-2: Fault Tree Diagram of a line System

6.1 Line Design Philosophies

In industry, two types of overhead line design approaches are normally used. These are: (1) Allowable Stress Design (ASD) and (2) Reliability Based Design (RBD). Under RBD approach, Load and Resistance Factored Design (LRFD) and Semi-Probabilistic Design following IEC 60826 or ASCE 74 are normally used. Each of these design approaches are described briefly.

6.1.1 Allowable Stress Design (ASD)

Design of overhead line components in North America is often based on deterministic assumptions where the load effects on a line component and the capacity are both defined in terms of single values. The loads are defined as nominal loads and the capacity with appropriate factors of safety. The nominal capacity is predicted based on code given formulae or numerical models.

6.1.2 Reliability Based Design (RBD)

Although the ASD approach has served the utility industry reasonably well, increasingly, utilities' design practices are moving towards a reliability based design (RBD) methodology in order to quantify the line reliability in a predictable manner. Reliability based design is based on the assumption that the strength as well as the effects of loads on the line or its components (such as structure, conductor, insulator etc.) are random variables and can be defined fully by their respective probability distributions (normally lognormal or Gumbel Type 1 distribution).

The basic concept in reliability based design is that the design procedure explicitly considers that the line components (structure, conductor etc.) can fail within its expected service life. Thus the development of a RBD procedure begins with the mathematical theory of probability which takes into account the interference of stress (effects of all the possible combination of loads) and the strength (resistance). Failure probability is often computed in terms of a reliability index beta (β), Figure 6.3 depicts the stress strength interference diagram where the overlap region presents a measure of the failure probability. The objective is to make sure that the two diagrams are separated further apart to minimize the failure probability (higher beta value).

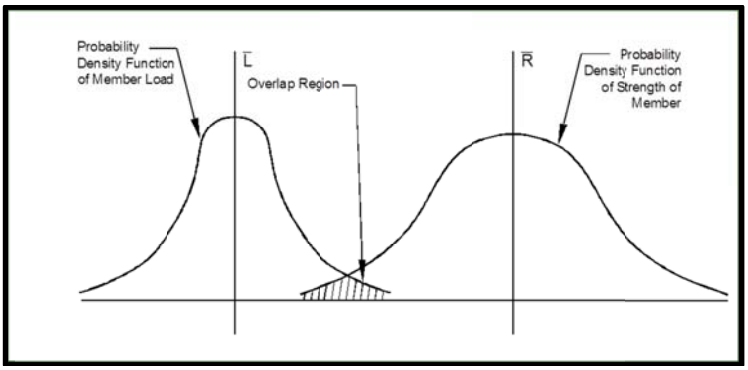


Figure 6-3: Stress-Strength Interference Diagram

In structural reliability analysis, this overlap can be measured in terms of a "beta value" (β), which is directly related to the failure probability (Melchers, 1996). For example, a β value of 1.282 represents 10% failure probability while a β value of 1.645 implies 5% failure

probability. The higher β value indicates a lower failure probability. Once the failure probability is assessed under a specific loading scenario, the risk can be calculated by simply multiplying the failure probability by the consequences of the failure expressed in dollars.

$$\Phi R_n = \Upsilon Q_T \quad [6\text{-}1]$$

Φ, the strength factor for wood pole structure is considered as 0.5 and for steel tower is assumed to be 0.9; R_n represents the nominal capacity for steel tower and components while for wood pole bending it is the expected capacity based on mean fibre strength

6.2 Design Load

6.2.1 Existing Lines TL 201 and TL 242

TL 201 was built in 1966 and it is a 50 year old wood pole line. The line is being maintained currently under the WPLM program and the expected residual life of this line is estimated as 15 years (WPLM report, 2012). The original design wind and ice loads for this line was based on CSA (Canadian Standards Association, mid 60's) heavy load in [Haldar, 1996] and was 12.5 mm glaze ice combined with 117-km/hr wind. Upon review of the pertinent information available at the time, two basic load conditions evolved**:** Normal Zone with 25.4 mm radial glaze ice and Ice Zone with 38 mm radial glaze ice. The ice zone was used for a small section of the line system on the Avalon Peninsula. The factor of safety for this wood pole line was used as 2.0.

The transmission line TL 242 is a steel construction and was upgraded as part of Avalon upgrading work in 1998-2003. The line uses an extra high strength 804kcmil trapezoidal AACSR conductor and can withstand a 66 mm radial glaze ice loading. The line is well maintained and is in good condition.

Table 6-1 presents the design loads that were used for TL 201 in mid 1960's and the current uprating proposal did not revise the loading because the expected residual life is only for 15 years.

Table 6-1: Design Load for Existing TL 201 Line (For Uprating Option)

DESIGN LOAD	Ice (radial mm)	Ice (radial in.)	Wind (Pa)	Wind (psf.)	Temperature (deg. F)
Extreme Ice	25.4	1.0	0	0	0
Extreme Ice[(1)]	38.0	1.5	0	0	0
Extreme Wind (Hydro) with GF	0	0	861.8	18	0
Wind & Ice (hydro) - Traditional	12.5	0.5	383.0	8	0

[(1)]Note – For TL 218, Line from Holyrood to Hardwoods is designed for 38mm ice

6.2.2 Existing Line Sag Validation

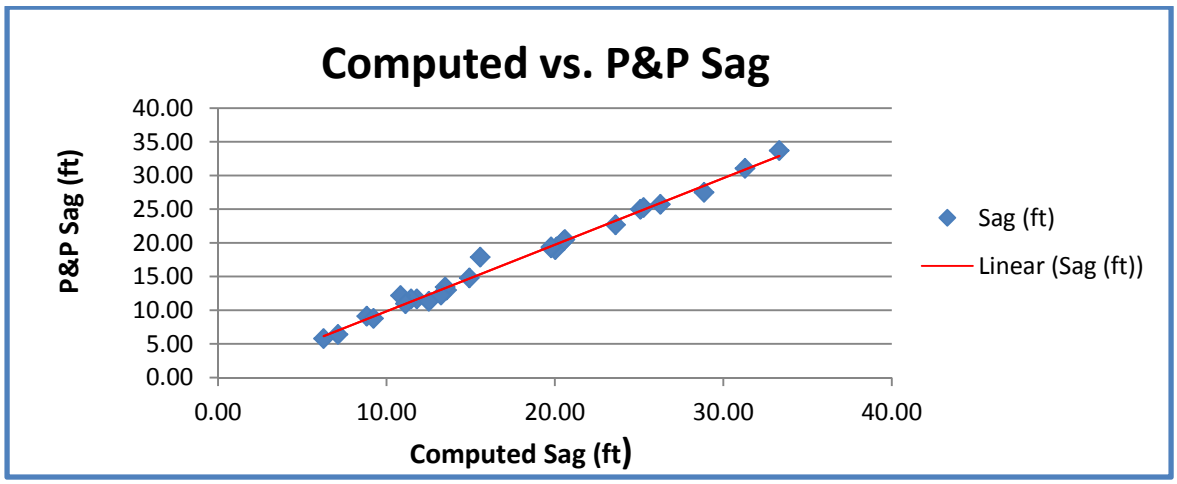


Figure 6-4: Comparison of Computed sags versus sags Depicted in P&P (TL 201)

Since the TL 201 plan and profile information is 50 years old, it was decided to validate some of the sag information to make sure that there is a correct picture of the wind and weight span distributions between SOP and HWD Terminal Stations. To do this validation, computed sags are compared with those presented in the plan and profile (P & P) for various spans and a comparison plot is presented in Figure 6-4. The comparison is well within the acceptable limit. However it was observed in some instances that the span marked between the two structures did not always match with the actual measured sag (using a scale).

Next, the sags for a selected number of spans at the field were measured and this information at various temperature levels (-1°C to 9°C) was compared with the plan and profile (P & P) sag. In one instance, it was found that the measured sag was significantly higher compared to plan and profile sag and the further investigation showed that the measured span in the field was also significantly higher compared to the span marked on the plan and profile. This indicates that a full survey work needs to be done before any uprating work in TL 201 can be undertaken to ensure that the correct sag-tension information can be realized.

6.2.3 Existing Line Sag Validation (Field Measurements)

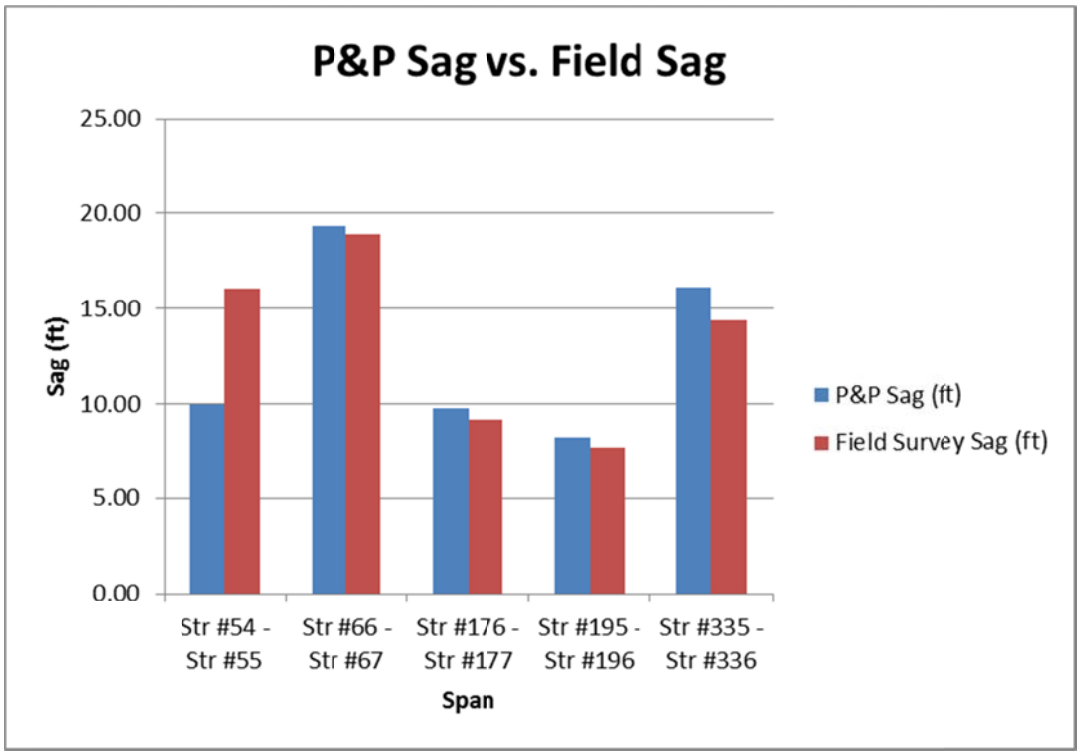


Figure 6-5: Comparison of Computed sags versus Measured Sags in the Field (TL201)

For the design of the new line in the existing ROW, the loading was developed following IEC 60826/CSA C22.3 (2010). The tension limit for each load case is based on acceptable practice and is in line with Hydro's internal design criteria. Table 6-2 presents the design information.

Table 6-2: Design Load Cases for New Line (TL 272)

DESIGN CSA LOAD	Ice (radial mm)	Ice (radial in.)	Wind (Pa)	Wind (psf.)	Temperature (deg. C)	Temperature (deg. F)	Tension Limit (%)
Extreme Ice	61.0	2.4	0	0	0	0	
Extreme Wind (Hydro) with GF	0	0	861.8	18	0	0	50 (Final)
Wind and Ice (High Ice Low Wind)	61.0	2.4	191.5	4	0	0	70 (Final)
Wind and Ice (Low Ice High Wind)	38.6	1.52	383.0	8	0	0	60 (Final)
Wind & Ice (hydro) - Traditional	19.1	0.75	383.0	8	0	0	50(Final)
Galloping Load	12.7	0.5	100.0	2	0	0	
Cold	0	0	0	0	0	0	33.3 (Initial)
Extreme Cold (-50 deg. F)	0	0	0	0	-45.6	-50	50 (Initial)
Everyday 40F	0	0	0	0	4.5	40	20 (Final)
Everyday EDT with 4psf wind (swing)	0	0	0	0	4.5	40	
120F (existing hot curve)	0	0	0	0	50	120	-
167F (proposed hot for reqd. Ampacity	0	0	0	0	75	167	-

6.2.4 New Line Sag Validation

To ensure the accuracy of the sag-tension output from the commercial program some limited validation of the sag outputs was done by comparing information from a line that has used a similar 1379 AAAC conductor. The results of the comparison for two spans are shown in Table 6-3.

Table 6-3: Comparison of Sag with CAT ARM Line for similar Loading Agenda

	SPAN = 837 FT		SPAN = 700 FT	
Loading Condition	**Initial Sag (ft)**	**Final Sag (ft)**	**Initial Sag (ft)**	**Final Sag (ft)**
Extreme Ice	33.37	33.42	23.21	23.24
Combined Wind & Ice	26.94	28.49	18.77	18.09
Bare @ 40^0 F	17.65	21.33	7.63	10.82
	SPAN = 837 FT		**SPAN = 700 FT**	
	Initial Sag (ft)	**Final Sag (ft)**	**Initial Sag (ft)**	**Final Sag (ft)**
Extreme Ice	33.8	33.8	25.7	25.7
Combined Wind & Ice	25	27.9	18.8	20.9
Bare @ 40^0 F	13.3	21.1	9.55	15.2

6.2.5 New Line Conductor Sag

Figure 6-7 presents the sags for extreme ice loads for various ruling spans

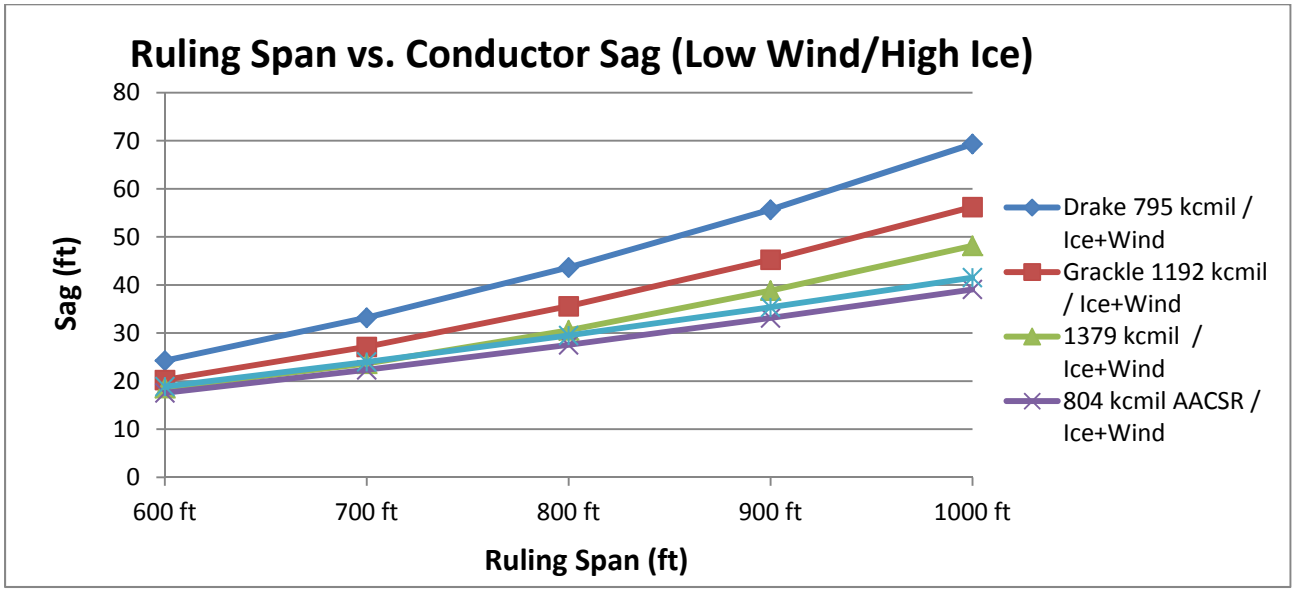


Figure 6-6: Simulated Sags from PLSCADD Runs

6.2.6 New Line Conductor Sag

Figure 6-8 presents the sags for various ruling spans at 175^0 F.

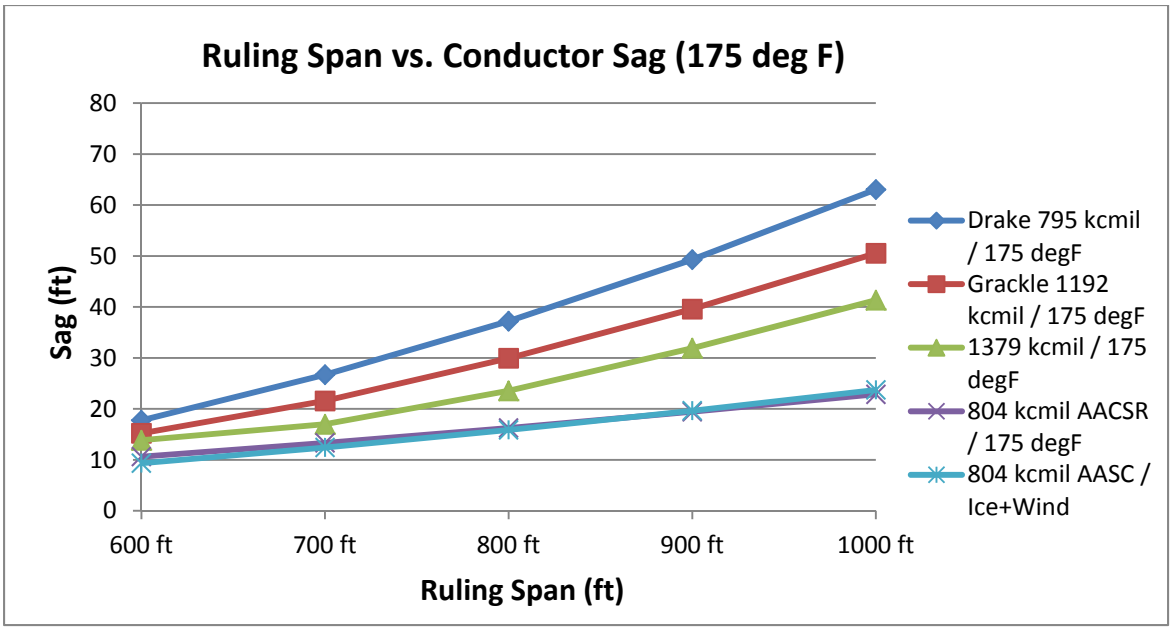


Figure 6-8: Simulated Sags from PLSCADD Runs

6.2.7 New OHGW & OPGW Sag Runs

Figure 6-9 presents the sags for various ruling spans for wind and ice loads**.**

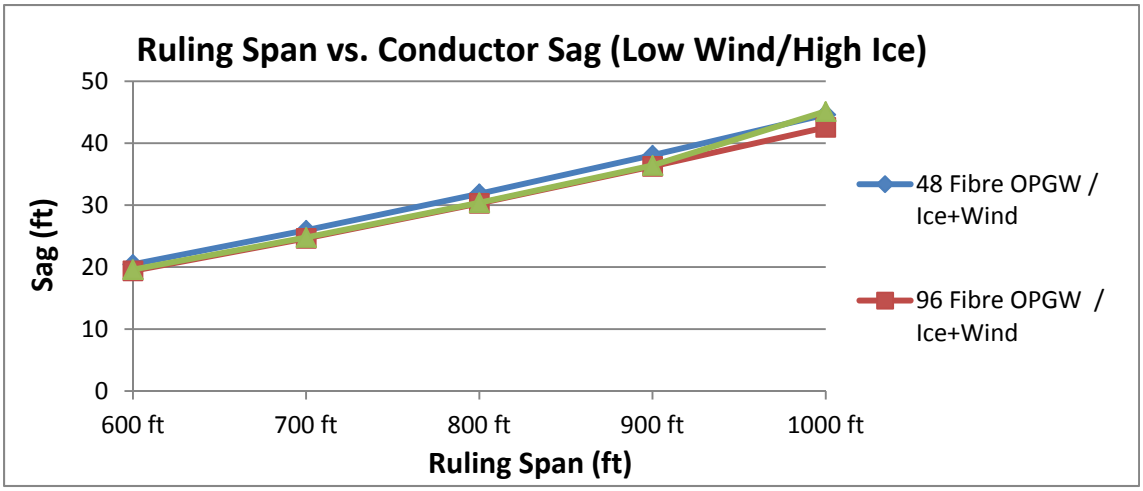


Figure 6-9: Simulated Sags from PLSCADD Runs

6.2.8 Comparison of Sag for ACSR and ACSS Conductors

Figure 6-10 compares the sag at two temperature levels for ACSR and ACSS conductors.

Although ACSR conductor has a much larger diameter compared to ACSS, the ampacity in

general is higher compared to ACSS. However, ACSR conductor is limited to operation at 85°C and therefore can only provide ampacity up to 1500A. However ACSS can be operated at much higher temperature (up to 200°C.) and it is shown that at 130°C. It has the same ampacity as shown for ACSR yet with a much lower sag, lower structural loads (because diameter is smaller). So this ACSS can be considered as an alternative to conventional ACSR conductor if the ampacity is a significant issue.

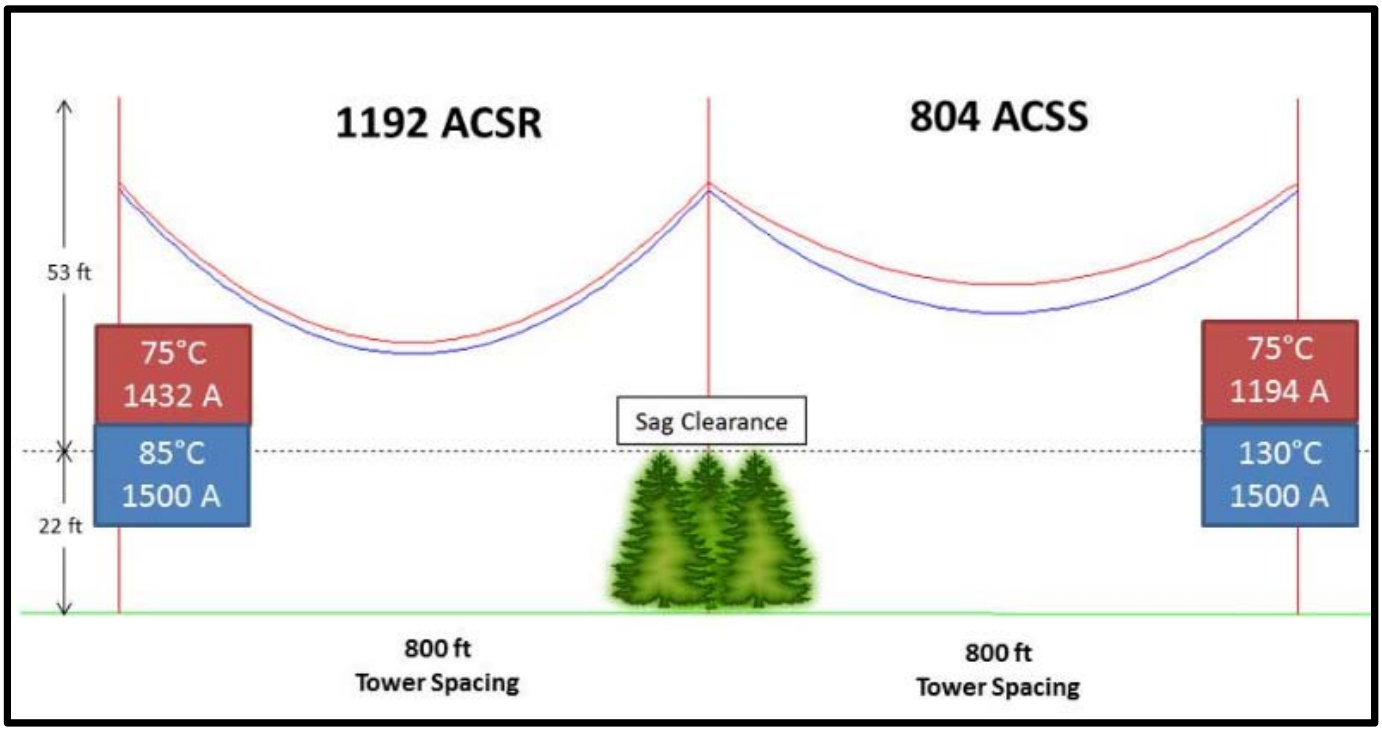


Figure 6-10: Comparison of Sags for ACSR and ACSS Conductors

7.0 Cost Model for Existing Line Uprating

In developing the cost model for the existing line TL 201, the current Plan and Profile information and the conductor profile information are first reviewed. In this assessment process, a typical ruling span is selected and the sag and tension information for the original design loads (Table 6-1) are verified against the P & P information as well as against some limited field information. The results of this assessment confirmed that the distribution of weight and wind spans are well within the acceptable design limits of the existing structures.

The conductor 795 ACSS (equivalent diameter to Drake) was selected to meet the ampacity requirement of this study. Next, a design assessment is made to see how the conductor could be installed without violating the criteria for existing ground clearance as well as the existing structural capacity of the tangent and dead end structures. The conductor is larger than the existing 636 kcmil "Grosbeak" conductor. It is expected that the structural loads will be increased to some extent in vertical and transverse directions. The review of the original structural design indicated that most structures in this line have more than adequate factor of safety under original vertical and transverse loadings and therefore, the increase in structural loads will have minimum impact on most of these structures. In some instances where the structural capacity in vertical direction is exceeded, the mitigation measure would be to use steel X-arm by replacing the existing knee brace arrangement.

In a 2012 report to the Board of Commissioners of Public Utilities (the Board), Hydro provided a critical review of the WPLM program and indicated that the expected remaining life of the wood pole plant life asset on the Avalon Peninsula (TL 201, TL 203) would be 15 years. So far, the existing line has been maintained well under WPLM program and it is expected that this program to continue and on-going inspection and any replacement of pole, X-brace or any other line components that may arise from the inspection will happen at selected time points of this asset's life. For this exercise, it is assumed that specific inspection will happen in 2020 and 2025 respectively. The cost of this inspection and any

replacement of line components are included in the cost estimate and are presented in Section 9.0.

For TL 242, an 804 ACSS conductor equivalent to the existing 804kcmil conductor with respect to size and strength is considered for the uprating work. Therefore, the scope of the work will be to take the existing conductor down and re-conductor the line with an ACSS conductor by matching the existing sag of TL 242. The structural loading in this case will not change and the cost for this exercise is also presented in Section 9.0. Figures 7-1 and 7-2 present the distributions of span and weight spans as per the Plan & Profile information.

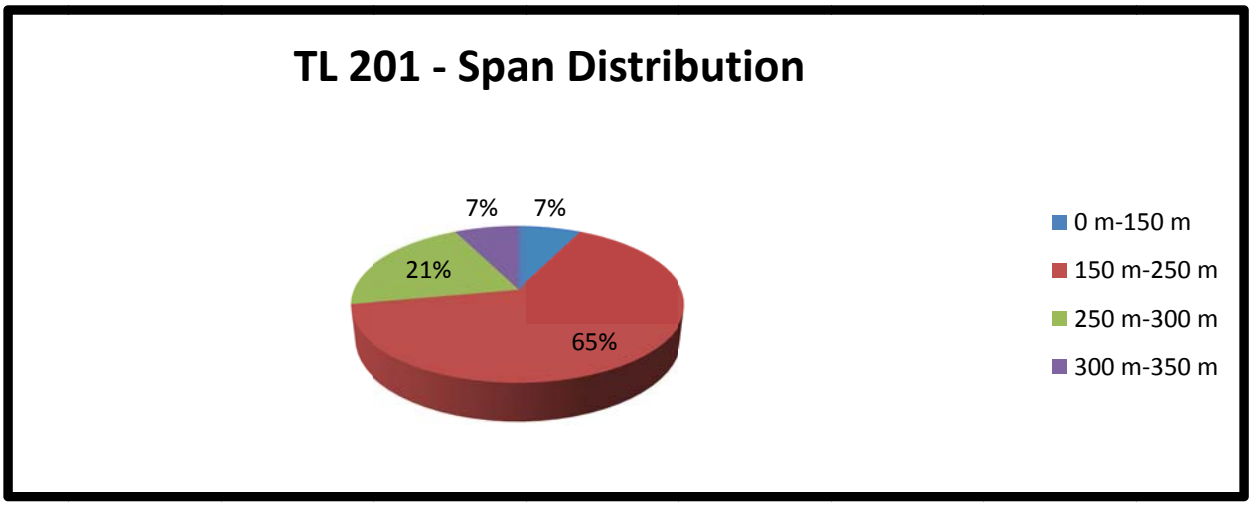


Figure 7-1: Distribution of Spans in Existing TL 201 Line

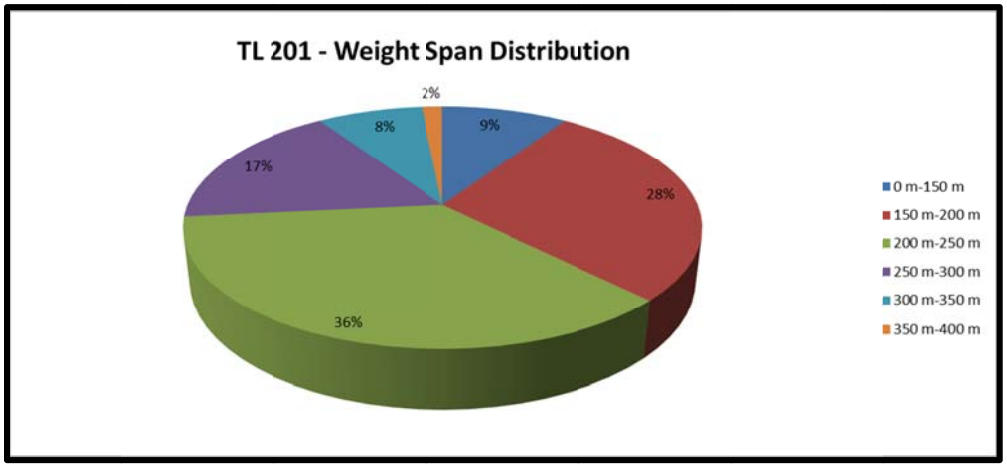


Figure 7-2: Distribution of Weight Spans in Existing TL 201 Line

8.0 Cost Model for New Line

In developing the cost model for the proposed new line, two types of line configurations (wood and steel) and four different conductor types are considered in this study. The methodology is broken down in two parts.

In the first part, the determination of basic ruling span for a fixed structure height for various configurations and conductor types are estimated. These are primarily done using the sag data, allowable ground clearance, insulator length etc. The calculation requires the input data for conductor type, diameter, self-weight and the initial tension for a typical ruling span that will be compatible with the structure type selected. Once the ruling span is determined, wind and weight spans are estimated using historical information.

In the second part, structural capacity is used to determine the allowable wind and weight spans. Once these are determined, ruling spans are calculated for two line configurations. For wood pole structure, capacity criteria include knee-brace strength, pole buckling and pole bending. For steel tower, the spans are calculated based on bridge capacity as well as the mast capacity. Final ruling spans are determined based on the minimum of all these spans determined under each conductor type. Tables 8.1 and 8.2 present the allowable spans based on structural capacity criteria.

Table 8-1: Allowable Span for H-Frame Structure

Conductor Types	Ruling Span (Feet)
Drake	474.00
Grackle	450.00
AAAC	440.00
ACSS-TW	465.00

Table 8-2: Allowable Span for Steel Tower

Conductor Types	Ruling Span (Feet)
Drake	885.00
Grackle	815.00
AAAC	825.00
ACSS-TW	860.00

8.1 Empirical Model for Tower Weight

An empirical model to estimate the weights for suspension and strain towers are presented considering the phase loads using the above spans The effect of the conductor tension on the strain structure under extreme wind and ice loads is also considered. The foundation weights are estimated based on the structure weights using historical information. This type of information is specific to each structure type and is presented under three separate sub-sections.

8.1.1 Tower Weight Model

The tower weight W is estimated based on an empirical formula as:

$$W = cKl(H^{0.65} + V^{0.5} + L^{0.65})$$

[8.1]

Where

c = empirical constant and is obtained from the tower weight calibration

K = a parameter determined from phase spacing

l = effective height where the resultant of all loads acts

H = sum of all horizontal loads due to wind, line angle tension etc.

V = sum of all vertical loads including the ice weight on tower

L = sum of all longitudinal loads (differential ice, broken conductor etc.)

The empirical model is based on a self–supported tower configuration. For guyed tower, an appropriate adjustment factor is applied to take into account the tower flexibility and the reduction in guyed tower weight compared to self-supported tower.

8.1.2 Suspension Tower Weight

A suspension tower is subjected to wind and ice loads and these loads typically act at the conductor and shield wire attachment points. Figure 8.1 presents a typical loading diagram on a guyed-V suspension tower.

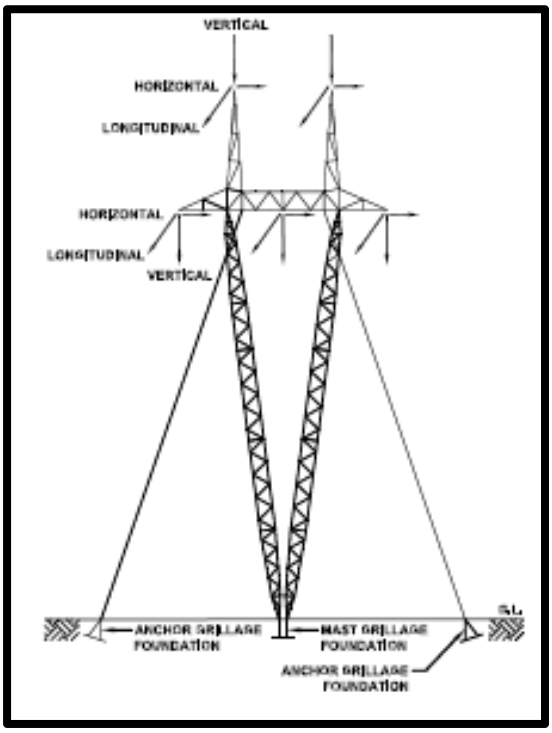


Figure 8-1: Forces on a Typical Guyed-V Suspension Tower

Table 8-3: Estimated Guyed-V Tower and Foundation Weights for four Conductor Types

Conductor Type	Suspension Tower Weight (lbs.)	Foundation Weight (lbs.)
Drake	7,100	1,553
Grackle	5,847	1,553
AAAC	5,624	1,553
ACSS-TW	5,624	1,553

8.1.3 Dead End Tower Weight

A heavy angle dead end or a full tangent dead end tower is subjected not only to wind and ice loads on conductors, shield wires, etc. but also a vector component of the cable tension loads because of the line alignment. Figure 8.2 presents a typical loading diagram on the strain tower, Dead end tower weights are calculated based on a set of towers of the same family designed for Hydro's steel line system during the Avalon upgrading project (Haldar, 1996) and the weight is estimated based on this data. The advantage of using standard Hydro tower will reduce the engineering time for additional design work and improve the schedule.

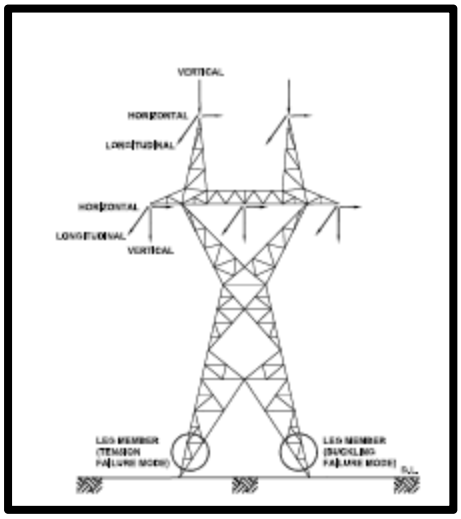


Figure 8-2: Forces on a Typical Dead End Tower

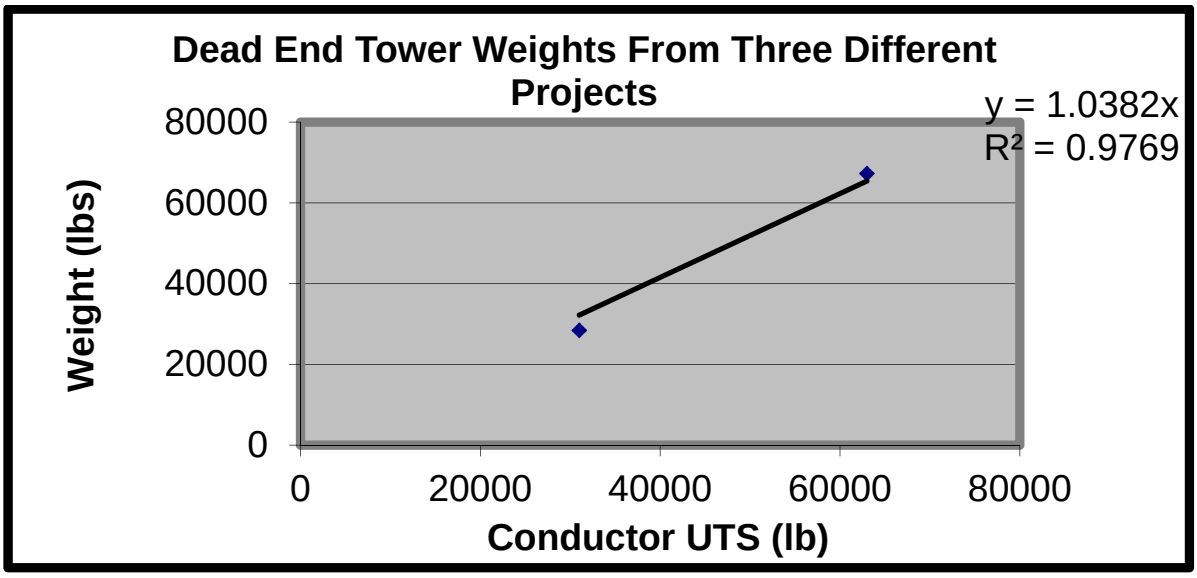


Figure 8-3: Dead End Tower Weight Model

Following the weight estimation, the cost of the structure is developed from the basic structural weight and using the cost value per unit weight developed from a number of quotations that were specifically sought for this study. Similarly the conductor cost as well as the overhead ground wire and the optical ground wire cost per circuit kilometer are also assessed and used to develop the initial capital cost. The line cost estimation includes the direct material and installation costs of structures/towers and conductors. Once the line length is known, the number of structures is estimated based on the allowable design span length. Finally the other costs such as survey, engineering design, property acquisition, project management, field management and the commissioning are also included.

Table 8-4: Estimated Dead-end Tower and Foundation Weights for four Conductor Types

Conductor Type	Dead-end Tower Weight (lbs.)	Foundation Weight (lbs.)
Drake	48,446	25,802
Grackle	70,243	37,278
AAAC	67,249	37,278
ACSS-TW	67,249	37,278

The following sections present the details of the line cost and various components. For all major line components, quotations were sought from the suppliers, contractors and a detailed spreadsheet was developed to estimate the line costs for various options.

Table 8-5: Suspension Tower Cost for Four Conductor Types

Conductor Type	Tower Material and Installation Cost($)
Drake	$67,317
Grackle	$59,438
AAAC	$59,104
ACSS-TW	$59,104

Table 8-6: Dead End Tower Costs for Four Conductor Types

Conductor Type	Tower Material and Installation Cost($)
Drake	$374,330
Grackle	$482,609
AAAC	$478,117
ACSS-TW	$478,117.80

Table 8-7: Conductor–Material plus Installation Costs

Conductor Type	Conductor Material ($/CCT)	Installation Cost($/CCT)
Drake	$20,181	$75,000
Grackle	$26,922	$78,000
AAAC	$32,280	$88,000
ACSS-TW	$36,177	$100,000

Table 8-8: OPGW/OHGW–Material plus Installation Costs

Ground Wire Type	Material ($/CCT)	Installation Cost($/CCT)
OPGW	$9,761	$17,000
OHGW	$4,000	$12,000

8.2 Line Cost Model (Equation 4.1 in Section 4.0)

Once the costs for each tower type (suspension and strain towers) and the conductor are known, the total line cost can be obtained as the sum of all suspension tower costs, two dead end tower costs and the conductor cost. The number of suspension towers is calculated based on the line length and the tower spacing (span length).

The cost of all tower types including the foundations and the conductor for the entire line system is expressed in the following form:

$$C_I = \sum_{1}^{N} CS_i + \sum_{1}^{2} CD_i + (\text{Cost of Conductor/OPGW/OHGW materials and Installation}) \quad [8.2]$$

Where

C_I = initial material and installation costs of the line for a return period, T for a specific conductor/OPGW/OHGW type, N = number of suspension towers in the line segment

CS_i = unit cost of a typical suspension tower, i CD_i = unit cost of a typical strain tower,

The total cost of the line can be obtained by adding the cost for each segment.

8.2.1 New Steel Line

Table 8-9: Line Costs (Direct-Material plus Installation Costs)

Conductor	Suspension Tower Cost	Dead End Tower Cost	Conductor +OHGW/OPGW Cost	Miscellaneous Cost	Direct Costs (Tower +Conductor+ OPGW/OHGW)
Drake	$3,500,530	$6,952,366	$2,481,026	$500,000	$13,433,923
Grackle	$3,387,995	$7,818,604	$2,646,623	$500,000	$14,353,224
AAAC	$3,309,833	$7,782,667	$2,907,709	$500,000	$14,500,210
ACSS-TW	$3,132,520	$7,782,667	$3,177,958	$500,000	$14,593,146

Direct cost shown in Table 8.9 is further updated with costs for line survey, engineering design and ROW acquisition. These costs are independent of the return period based load values.

8.2.2 New Hybrid Line Cost

Table 8-10: Tangent H-Frame Structure Cost for Four Conductor Types

Conductor Type	Tangent Structure Material and Installation Cost ($)
Drake	$39,402
Grackle	$39,402
AAAC	$39,402
ACSS-TW	$39,402

Table 8-11: Dead End Tower Costs for Four Conductor Types

Conductor Type	Tower Material and Installation Cost($)
Drake	$374,330
Grackle	$482,609
AAAC	$478,117
ACSS-TW	$478,117

Table 8-12: Line Costs (Direct-Material plus Installation Costs)

Conductor Type	Suspension Structure Cost	Dead End Tower Cost	Conductor +OHGW/OPGW Cost	Direct Costs (Tower +Conductor+ OPGW/OHGW)
Drake	$4,176,657	$6,952,366	$2,481,026	$13,610,051
Grackle	$4,728,291	$8,278,532	$2,646,623	$15,653,448
AAAC	$4,846,499	$8,278,532	$2,907,709	$16,032,741
ACSS-TW	$4,570,682	$8,278,532	$3,177,958	$16,027,173

Direct cost shown in Table 8.12 is further updated with fixed costs for line survey, engineering design and ROW acquisition. These costs are independent of the return period based load values.

8.2.3 Existing TL 201 Line Uprating Cost

Table 8-13: Line Cost TL 266 Uprating (Direct-Material plus Installation Costs)

Conductor Type	Direct Costs (Structure +Conductor)
ACSS	$ 3,908,645

8.2.4 Existing TL 242 Line Uprating Cost

Table 8-14: Line Cost TL 242 Uprating (Direct-Material plus Installation Costs)

Conductor Type	Direct Costs (Structure +Conductor)
ACSS	$ 3,593,688

9.0 Elements of Life Cycle Cost (LCC) Estimates (Existing Lines and New Line with a Number of Conductor Options)

The various elements that are required to develop the life cycle cost estimates for a number of conductor options considered are presented following the terms in equation (4.1). The first term in equation (4-1) represents the initial capital cost of either uprating the existing line or building a new line between Soldiers Pond and Hardwoods terminal stations. The uprating work involves primarily re-conductoring TL 201 either with a 795 "Drake" or a 795 ACSS conductor. The uprating work also involves re-conductoring TL 242 either with an 804 ACSS conductor. On the other hand, construction of a new line involves studying various options with a number of conductors and developing cost estimates for these options. These conductors are: (a) 795 "Drake", (b) 1192 "Grackle" (c) 1379 "AAAC" and (d) 795 ACSS (EHSS)

A number of conductor options have been considered in this study and the initial capital costs for uprating the existing lines or building a new line are summarized below. The next sections present the annual cost of maintenance for steel line, maintenance cost of wood pole line at selected time periods (conditioned based wood pole management) and the expected annual cost of losses due to line failure. The cost of outage is not included because the assumption is based on N-1 criterion, implying that the customer will not see any service interruption should a line fails. The expected cost of conductor losses should be included in the final LCC analysis and will be done by the System Planning department.

9.1 Initial Line Cost

The initial cost development part is broken down in several components. These costs are (1) material (2) construction (3) engineering (4) survey & property acquisition (5) project management (6) field management (7) commissioning (operation) and (8) any contingency. Material cost includes procurement cost for all materials for uprating existing TL 201 line and building a new line with a number of conductor options. Construction cost includes installation of structures/towers, foundations, conductor and OHGW. Figures 9.1 and 9.2

present the initial capital costs for the new line considering wood and steel constructions. Figures 9.3 and 9.4 present the initial capital cost for the uprating of TL 201 and TL 242.

9.1.1 New Line (H-Frame Wood Pole Structure, Hybrid Line)

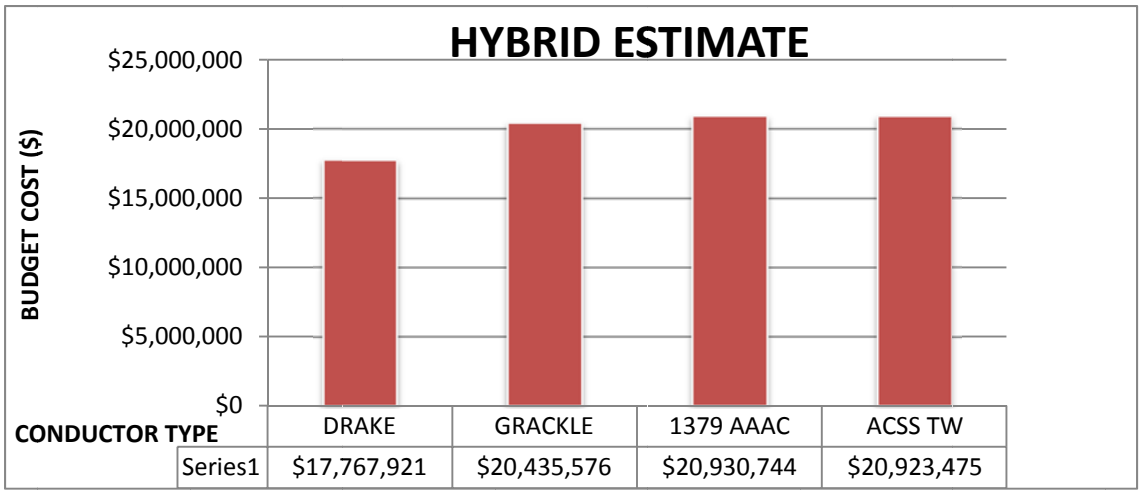


Figure 9-1: Comparison of Initial Capital Cost for Various Conductor Options

9.1.2 New Line (Guyed V Steel Tower Construction)

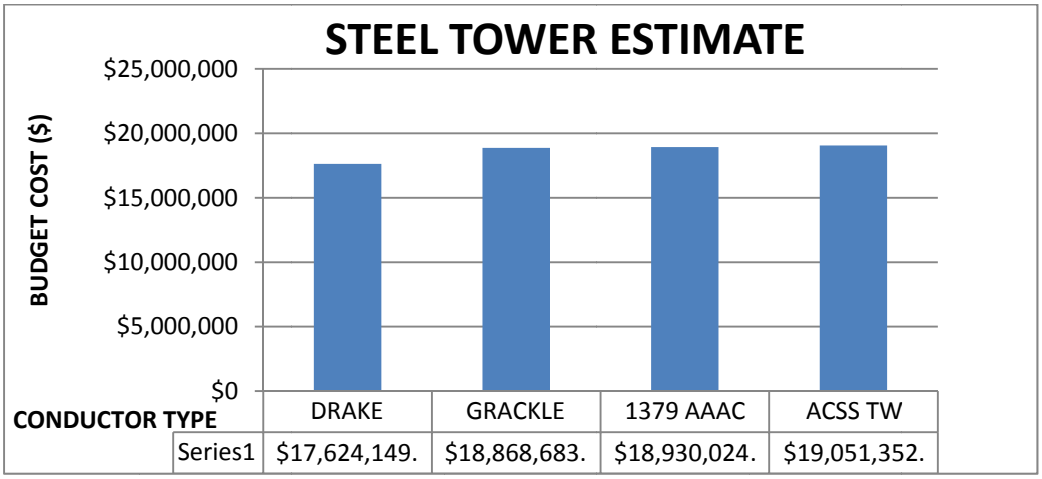


Figure 9-2: Comparison of Initial Capital Cost for Various Conductor Options

9.1.3 Existing Line TL 201 (Wood Pole Structure, Uprating Costs)

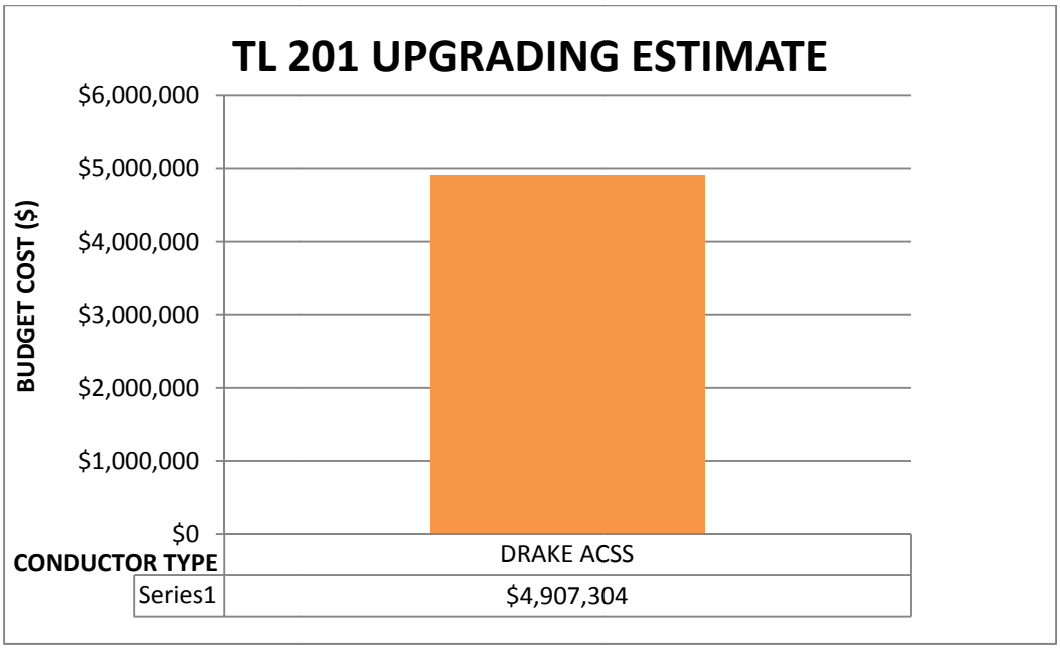


Figure 9-3: Initial Capital Cost for Uprating TL 201 with Two Types of Conductors

9.1.4 Existing Line TL 242 (Steel Line, Uprating Cost)

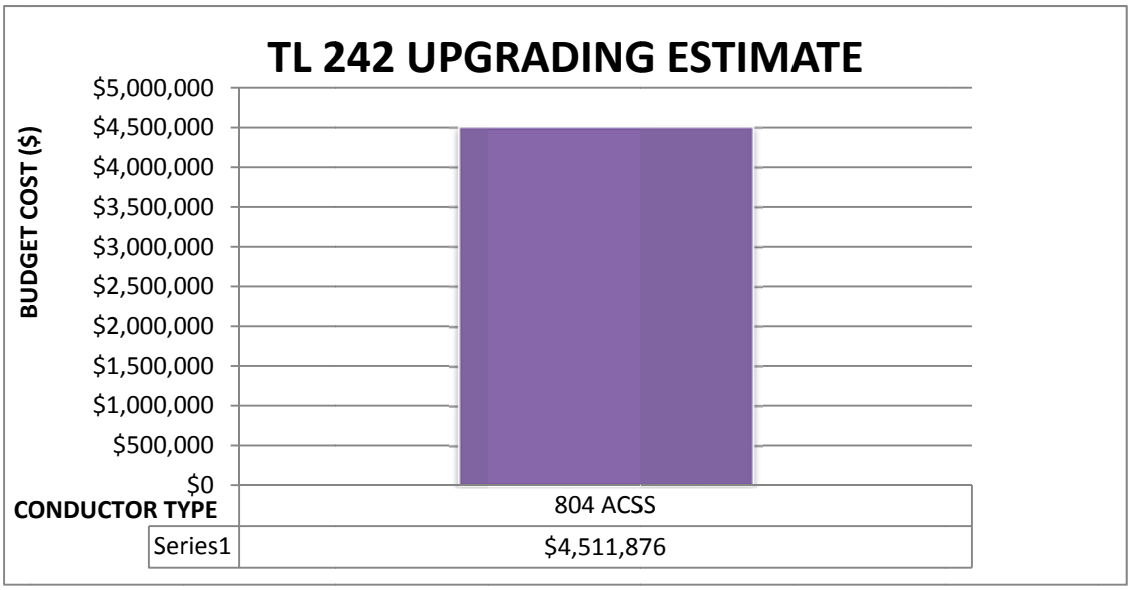


Figure 9-4: Initial Capital Cost for Uprating of TL 242

9.2 Cost of Maintenance

Following equation (4-1), the cost of maintenance for the existing line as well as for the new line that may be built in the future are developed from the historical information that Hydro has incurred over the years. For example, the maintenance cost for the wood pole line (existing as well as the new line) is derived from the WPLM database (Marshall, 2015). For steel line maintenance cost, the annualized cost data is also derived from the historical database (Lush, 2015). These costs are summarized in Table 9.1 on an annualized basis for steel line and for new wood pole line, at a periodic interval of 10 years. For new lines, the maintenance starts at the year when the line is 20 years old. For steel line, the criterion is that the 20% of line is inspected per year (full line inspected in 5 year). For wood pole line, the inspection and the replacement of defected pole starts at 2037, 2047, 2057 and 2067 assuming the line is commissioned in 2017. This follows the current WPLM philosophy (10 year interval of inspection). However, for existing TL 201 line, it is assumed that the interval of inspection and any refurbishment to occur will be at a 5 year interval. Table 9-1 also shows the expected service life of these line assets.

Table 9-1: Maintenance Cost Data for Steel Lines

Assets	Service Life (Years)	Maintenance Cost ($)
Existing TL 242	30	$8000
New Steel Line	50	$8000

Table 9-2: Maintenance Cost of Wood Pole Lines @ Selected time periods

Assets	Service Life (Years)	Maintenance Cost ($)
Existing TL 201	15	$180K @ 2020 $198K @ 2025
New Wood Pole Line	50	$578K @ 2037 $1,147M @ 2047 $1,880M @ 2057 $2,880M @ 2067

9.3 Cost of Failure

The cost of failure is estimated based on a line failure happening during the expected service life of the line. For a new line designed with a certain return period, the expected cost of failure is:

Expected Cost = $P_f * C_f$ [9-2]

Where P_f is the annual probability of failure = 0.02 for a 50-year return period, and C_f is the cost of failure assumed to be $1M based on historical information. The annualized cost in this case will be $20,000. For the two existing lines, the same approach was used but the service life was reduced.

Table 9-3: Annual Cost of Failure

Assets	Service Life (Years)	Cost of Failure ($) of Line Assets
Existing TL 201	15	$166,000(1)
	15	$333,000(2)
	15	$500,000(3)
Existing TL 242	30	$20,000
New Wood Pole Line	50	$20,000
New Steel Line	50	$2,0000

(1) The failure cost for old TL 201 is significantly higher because RP is one in three years (25mm ice) compared to 1 in 50 year; Items (2) and (3) are based on damage costs of $1.0M and $1.5M respectively

9.4 Cost of Outage

For this study it is assumed that the line failure will not cause a customer outage and therefore, this cost is not considered. However, should one chose to include this cost the methodology is well established and is given in (Haldar et al 2012, CEATI Project 3347).

9.5 Cost of Conductor Losses

The present value of the conductor losses needs to be included in the LCC analysis. It has been agreed that the System Planning department will conduct a load flow study and determine the loss value and add this cost to the LCC cost given in this report.

10.0 Schedules

Table 10-1: New Steel Transmission Line TL 272 - Project Schedule

Activity		Start Date	End Date
Engineering	Engineering Design and Planning	Jan 2016	Apr. 2017
Properties/ Surveys	Property Acquisition, Surveying and Staking	Jan 2016	Apr. 2017
Clearing	Brush Removal and Clearing along Right of Way	Sept. 2016	Oct. 2016
Procurement	Procurement of Material and Hardware	Dec. 2016	June 2017
Construction	Transmission Line Construction	May 2017	Nov. 2017
Closeout	Project Closeout	Dec. 2017	June 2018

Table 10-2: TL 201 Drake ACSS Upgrading - Project Schedule

Activity		Start Date	End Date
Planning	Engineering Design and Planning	Jan. 2016	Aug. 2016
Surveying	Surveying and Staking	May 2016	Aug. 2016
Procurement	Procurement of Material and Hardware	March 2016	Aug. 2016
Construction	Conductor Re-stringing	Sept. 2016 April 2017 Sept 2017	Oct. 2016 May 2017 Oct. 2017
Closeout	Project Closeout	Nov. 2017	Dec. 2017

Table 10-3: TL 242 804 ACSS Upgrading - Project Schedule

Activity		Start Date	End Date
Planning	Engineering Design and Planning	Jan. 2016	Aug. 2016
Surveying	Surveying and Staking	May 2016	Aug. 2016
Procurement	Procurement of Material and Hardware	March 2016	Aug. 2016
Construction	Conductor Re-stringing	Sept. 2016 April 2017 Sept 2017	Oct. 2016 May 2017 Oct. 2017
Closeout	Project Closeout	Nov. 2017	Dec. 2017

11.0 Summary and Conclusions

The study presents the cost estimates of various options considered in increasing the power transfer capacity of existing transmission line system between the proposed SOP and HWD terminal stations. This includes uprating/upgrading work on existing TL 266 and TL 242 lines and developing design basis and cost estimates for building a new line in the existing ROW. For the new line both steel and wood pole constructions with a number of conductor options are considered. For the existing lines TL 266 and TL 242, only one HTLS conductor type is considered.

The cost estimates data include initial capital cost, annualized maintenance cost and the cost of failure. For the wood pole line TL 266, the residual life is estimated as 15 years and the maintenance cost at three specific time points are estimated and included in the cost estimates. Service life of TL 242 is assumed to be 30 years.

The cost estimate data developed in this study will be used by the System Planning department to carry out a detailed cost-benefit analysis in order to select a “best option” that will balance the total life cycle cost against the benefit derived from each option.

12.0 References

Stratton, Paul 2015 Personal Communication on Discount and CPI rates

Baker, Gordon, 2015 Personal Communication on Conductor Ratings and Sag Runs

Marshall, Andre 2015 Data from WPLM database

Lush, Kenny 2015 Inspection Maintenance Cost Data for Steel Line (TL 205)

PUB Report 2012 Executive Summary Report on the Review of WPLM program

Haldar et al 2013 Optimum Design Return Period of Overhead Lines Considering Line Failure Costs –A Guide for Utility Engineers CEATI **Project**: T073700-3347 (confidential report)

Haldar, Asim 1996 Reliability of Transmission Line System on the Avalon Peninsula, Prepared as Hydro Report

APPENDIX C

DETAILS OF ECONOMIC EVALUATION

Table 13: Capital Project Costs

Project	Capital Cost
Construction of New TL - Drake Conductor	$ 24,865,100
Construction of New TL - Grackle Conductor	$ 26,560,900
Thermal Uprating of TL266 - Drake ACSS Conductor	$ 6,442,900
Thermal Uprating of TL242 - 804 ACSS Conductor	$ 5,993,000
Addition of Circuit Breakers at SOP and HWD	$ 3,886,806

Table 14: TL266 Wood Pole Line Management Costs

Year	WPLM Cost
2020	$ 180,000
2025	$ 198,000
2030	$ 218,000

Table 15: SOP-HWD 230 kV Steel Tower Maintenance Costs

Annual Maintenance Cost
$ 8,000

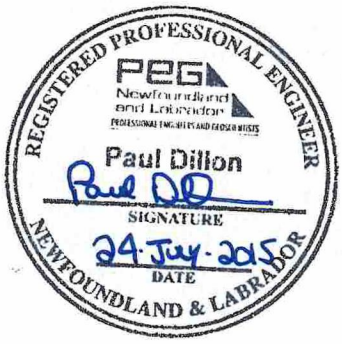
Table 16: Evaluation of Losses[17]

Year	Energy $/MWh	Capacity $/KW-Yr
2018	$40.07	$95.52
2019	$41.20	$94.96
2020	$42.45	$103.36
2021	$44.81	$106.63
2022	$47.17	$110.02
2023	$49.64	$113.50
2024	$51.86	$117.10
2025	$53.91	$120.82
2026	$56.04	$120.34
2027	$58.24	$119.87
2028	$60.53	$119.40
2029	$62.90	$118.93
2030	$65.36	$118.46
2031	$68.55	$115.73
2032	$71.88	$113.05
2033	$75.36	$110.44
2034	$78.99	$107.89
2035	$82.79	$105.39
2036	$84.01	$107.50
2037	$85.27	$109.65

[17] Based on marginal costs developed using PIRA forecast from January, 2015.

Year	Energy $/MWh	Capacity $/KW-Yr
2038	$86.57	$111.84
2039	$87.90	$114.08
2040	$89.28	$116.36
2041	$90.69	$118.69
2042	$92.15	$121.06
2043	$93.65	$123.48
2044	$95.19	$125.95
2045	$96.77	$128.47
2046	$98.40	$131.04
2047	$100.07	$133.66
2048	$101.79	$136.34
2049	$103.55	$139.06
2050	$105.37	$141.84
2051	$107.23	$144.68
2052	$109.14	$147.57
2053	$111.11	$150.53
2054	$113.12	$153.54
2055	$115.19	$156.61

A REPORT TO
THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES



Electrical
Mechanical
Civil
Protection & Control
Transmission & Distribution
Telecontrol
System Planning

Distribution Upgrades 2016

Various Sites

July 2015

newfoundland labrador hydro
a nalcor energy company

SUMMARY

This proposal consists of nine individual distribution upgrade projects located in various Hydro distribution systems. A brief description of each project is as follows:

1. Central Interconnected
    a. Farewell Head. Replace poles, insulators, and conductor;
    b. King's Point. Replace poles, insulators, and conductor;
    c. Coney Arm. Upgrade Recloser CA1-R2 – Replace recloser;
    d. Grandy Brook. Upgrade Recloser GB1-R1 – Replace recloser; and
    e. Bay d'Espoir. Upgrade Distribution Structure. Replace conductor transformers, and transformer structure.
2. Northern Interconnected
    a. Sally's Cove. Replace poles, insulators, and conductor.
3. Northern Isolated
    a. L'Anse au Loup. Replace poles, insulators, and conductor.
4. Labrador Interconnected
    a. Happy Valley. Replace poles, insulators, and conductor.
5. Labrador Isolated
    a. Paradise River. Replace poles, insulators, conductor, and transformers.

These projects are all justified based on the fact that the line components being replaced have exceeded their expected life and are in a deteriorated condition. This creates a reliability issue for customers and a safety issue for workers. Approximately 90% of poles to be replaced are Blackjack poles which are treated with creosote. Ground water contamination from the presence of the creosote coating on the surface of Blackjack poles is environmentally undesirable. Failure to replace these line components will negatively affect the safe and reliable supply of electricity to Hydro's customers.

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1 INTRODUCTION

Hydro provides service to residents in select rural communities within the province through the use of distribution systems. The distribution systems typically consist of a substation coupled with a wood pole distribution line that supplies power from the station to service drops throughout the community. This project proposal includes distribution lines located in the distribution systems of Farewell Head, King's Point, Coney Arm, Grandy Brook, Bay d'Espoir, Sally's Cove, L'Anse au Loup, Happy Valley and Paradise River that have been identified as requiring upgrades to the existing infrastructure. The Farewell Head, King's Point, Coney Arm, Grandy Brook, and Bay d'Espoir distribution systems are a part of the Island Interconnected System. The Sally's Cove distribution system is a part of the Northern Interconnected system. The L'Anse au Loup distribution system is a part of the Northern Isolated system. The Happy Valley distribution system is a part of the Labrador Interconnected System. Finally, the Paradise River distribution system is a part of the Labrador Isolated System.

The distribution lines referred to in this report were originally constructed over 40 years ago. A high percentage of line components were installed at the time of original construction and have exceeded their economic lives of 37 years. In addition, as a result of standardized inspection and testing procedures, it has become evident that line components are deteriorated and have remaining life spans of only one to five years before failure occurs. The majority of the line components identified for replacement are obsolete.

If the identified components are not replaced in the near future, failure is a possibility. Failure of such components will have a negative effect on the safety and reliability performance of the line. The failure of a line may also result in unplanned power outages to customers at a time when required repairs may be hampered by severe weather conditions.

2 PROJECT DESCRIPTION

This project is required to replace distribution line components on the following distribution systems:

1. Central Interconnected
    - Farewell Head. Upgrade Distribution System;
        - Replace distribution structures, cribs and transformers.
    - King's Point. Upgrade Distribution System;
        - Replace distribution structures, anchors and downguys.
    - Coney Arm. Replace Recloser CA1-R2;
    - Grandy Brook. Replace Recloser GB1-R1; and
    - Bay d'Espoir. Upgrade Distribution Structure.
        - Install section of new underground distribution line as well as pad mounted transformers.

2. Northern Interconnected
    - Sally's Cove.
        - Replace distribution structures, anchors and downguys.

3. Northern Isolated
    - L'Anse au Loup.
        - Replace distribution structures and reroute section of line.

4. Labrador Interconnected
    - Happy Valley.
        - Replace distribution structures and reconductor a section of line.

5. Labrador Isolated
    - Paradise River.
        - Replace distribution structures, extend single phase to three phase, and install conductor.

3 JUSTIFICATION

The distribution lines referred to in this report were originally constructed over 40 years ago. The line components, still in operation, were installed at the time of original construction and have exceeded their life expectancy. In accordance with Hydro's standardized inspection and grading system, (See 3.2.5 Industry Experience) the line components have been found to be in "B" (one to five years of remaining life) or "C" (less than one year of remaining life) condition. The deterioration of the components planned for replacement creates a risk of line component failure. These line components also pose a safety issue, specifically with deteriorated poles being a danger to work on or around. In addition, the potential of porcelain cutouts breaking during operation poses a risk of electrical contact and a risk of falling objects to people working on these structures. An environmental issue also exists with blackjack poles (see Figure 1). Ground water contamination due to the presence of the creosote coating on the surface of the pole is environmentally undesirable.

The distribution lines referred to in this report were originally constructed over 40 years ago. A high percentage of line components were installed at the time of original construction and have exceeded their economic lives of 37 years. In addition, as a result of standardized inspection and testing procedures, it has become evident that line components are deteriorated and have remaining life spans of only one to five years before widespread failure occurs. The majority of the line components identified for replacement are obsolete.

If the identified components are not replaced in the near future, failure is a possibility. Failure of such components will have a negative effect on the safety and reliability performance of the line. The failure of a line may also result in unplanned power outages to customers at a time when required repairs may be hampered by severe weather conditions.

3.1 Existing System

Farewell Head – Feeders in this area to be addressed are three phase and vary from about 3 km long to about 40 km long.

King's Point – Feeders in this area to be addressed are single and three phase, and vary from about 7 km long to about 46 km long.

Coney Arm – The feeder in this area to be addressed is three phase and is about 14 km long.

Grandy Brook – Feeders in this area to be addressed are three phase and vary from about 2 km long to about 53 km long.

Bay d'Espoir – Feeders in this area to be addressed are three phase and vary from about 17 km long to about 47km long.

Sally's Cove – The feeder in this area to be addressed is single phase and is about 7 km long.

L'Anse au Loup – Feeders in this area to be addressed are three phase and vary from about 35 km long to about 51 km long.

Happy Valley – Feeders in this area to be addressed are three phase and vary from about 5 km long to about 37 km long.

Paradise River – The feeder in this area to be addressed in three phase and is about 2 km long.

Following are summary tables of major work or upgrades performed on these lines in recent years.

Some systems have had no major work and/or upgrades in certain years.

Table 1: Farewell Head Major Work or Upgrades

Year	Major Work/Upgrade ($000)	Comments
2014	78.5	Insulator Replacements
2012	83.8	Reinsulate/Refurbish Lines
2011	62.8	Reinsulate/Refurbish Lines
2010	57.6	Submarine Cable Testing

Table 2: King's Point Major Work or Upgrades

Year	Major Work/Upgrade ($000)	Comments
2014	38.8	Pole Replacements
2012	18.0	Porcelain Cutout Replacements
2011	6.5	Transformer Upgrades
2010	2.8	Transformer Installations

Table 3: Coney Arm Major Work or Upgrades

Year	Major Work/Upgrade ($000)	Comments
2014	0.3	Line Reroute
2013	1.0	Line Reroute
2010	21.3	Transformer Installations

Table 4: Grandy Brook Major Work or Upgrades

Year	Major Work/Upgrade ($000)	Comments
2014	13.0	Crossarm Replacements
2013	92.2	Transformer Upgrades
2011	27.9	Replace Transformers and Clean Oil Spill
2010	9.3	Replace Transformers

Table 5: Bay d'Espoir Major Work or Upgrades

Year	Major Work/Upgrade ($000)	Comments
2014	54.5	Switching for Contractor
2013	46.9	Replace Porcelain Cutouts
2012	53.4	Replace Poles, Insulators, Conductor and Transformers
2010	29.1	Transformer Replacements/Relocations

Table 6: Sally's Cove Major Work or Upgrades

Year	Major Work/Upgrade ($000)	Comments
2014	3.0	Replace Poles, Insulators and Transformers
2012	3.2	Replace Poles, Insulators and Transformers
2011	0.8	Pole Replacements
2010	1.5	Transformer Replacements

Table 7: L'Anse au Loup Major Work or Upgrades

Year	Major Work/Upgrade ($000)	Comments
2013	35.0	Transformer Replacements
2012	20.4	Install and Commission Voltage Regulator and Replace Porcelain Cutouts
2011	28.5	Transformer Replacements
2010	12.4	Transformer Replacements

Table 8: Happy Valley Major Work or Upgrades

Year	Major Work/Upgrade ($000)	Comments
2014	103.6	Pole and Transformer Replacements
2013	130.7	Replace Poles, Transformers, and Cutouts
2012	40.8	Line Upgrades (Poles, Hardware, Conductor)
2011	41.6	New Line Extension

Table 9: Paradise River Major Work or Upgrades

Year	Major Work/Upgrade ($000)	Comments
2014	3.4	Pole Replacements
2010	24.8	Supply and Install Transformer Storage Ramp

3.2 Operating Experience

Farewell Head

- Communities serviced include Skinner's Cove, Change Islands, Fogo, Shoal Bay, Barr'd Island, Joe Batt's Arm, Sandy Cove, Tilting, Seldom, Little Seldom, and Stag Harbour. The total number of customers in the communities serviced is 1,780.

King's Point

- Communities serviced include King's Point, Rattling Brook, Silverdale, Jackson's

Cove, Langdown Cove, Nicky's Nose Cove, and Harry's Harbour. The total number of customers in the communities serviced is 636.

Coney Arm

- The line for upgrade is providing service to Hydro facilities only.

Grandy Brook

- Communities serviced include Burgeo and La Poile. The total number of customers in the communities serviced is 917.

Bay d'Espoir

- Communities serviced include St. Veronica, St. Joseph's Cove, Head of Bay d'Espoir, Milltown, Morrisville, St. Alban's, and Man-Of-War Cove. The total number of customers in the communities serviced is 1301.

Sally's Cove

- The line for upgrade provides service to approximately 32 customers in the communities of Sally's Cove and Green Point.

L'Anse au Loup

- Communities serviced include L'Anse au Loup, L'Anse Amour, English Point, Buckle's Point, Forteau, L'Anse au Clair, L'Anse au Diable, West St. Modeste, Pinware, and Red Bay. The total number of customers in the communities serviced is 998.

Happy Valley

- Communities serviced include Happy Valley, Goose Bay, North West River, Sheshatshiu, and Mud Lake. The total number of customers in the communities serviced is 5098.

Paradise River

- Line planned for upgrade provides service to approximately 37 customers in the community of Paradise River.

3.2.1 Reliability Performance

Hydro tracks all distribution system outages using industry standard indexes, SAIFI and SAIDI which are explained as follows:

SAIDI- indicates the System Average Interruption Duration Index for customers served per year, or the average length of time a customer is without power in the respective distribution system per year.

SAIFI - is the System Average Interruption Frequency Index per year which indicates the average of sustained interruptions per customer served per year or the average number of power outages a customer has experienced in the respective distribution system per year.

Table 10 lists the 2010 to 2014 SAIFI and SAIDI data for each line, 2010 to 2014 corporate values, and the latest CEA five year average (2009 to 2013) for comparison.

3.2.1.1 Outage Statistics

Table 10: Outage Statistics - SAIFI SAIDI Data

Five Year Averages (2010 to 2014)				
Location	**All Causes**		**Defective Equipment**	
	SAIFI	**SAIDI**	**SAIFI**	**SAIDI**
Farewell Head Line 1	2.14	9.73	0.40	3.71
Farewell Head Line 3	2.03	5.17	0.60	0.16
Farewell Head Line 4	5.78	22.76	3.14	11.30
Farewell Head Line 5	6.38	23.99	2.21	8.22
Farewell Head Line 6	7.16	25.76	3.81	11.98
King's Point Line 1	1.83	8.21	0.01	0.01
King's Point Line 2	1.90	5.73	0.00	0.00
Coney Arm Line 1	0.00	0.00	0.00	0.00
Grandy Brook Line 1	1.56	2.98	0.01	0.03
Bay d'Espoir Line 1	2.56	6.38	0.75	2.49
Sally's Cove Line 1	0.83	1.63	0.00	0.00
L'Anse au Loup Line 1	8.56	10.13	0.46	0.51
L'Anse au Loup Line 2	8.18	9.62	0.93	1.50
Happy Valley Line 16	1.75	2.10	0.29	0.32
Paradise River Line 1	9.41	4.72	0.00	0.00
Hydro Corporate	5.25	13.78	0.55	1.28
CEA (2009 – 2013)	2.94	9.83	0.42	1.10

Although the reliability performance for some of the lines is better than the Hydro average, inspections have determined there are components that are deteriorated and require replacement to avoid in-service failure and unplanned outages. The work should be conducted proactively to avoid a major failure of the line resulting in an extended outage to customers.

3.2.2 Legislative or Regulatory Requirements

There are no legislative or regulatory requirements associated with this project.

3.2.3 Safety Performance

The following safety issues have been identified:

- The poles to be replaced are deteriorated and pose a risk to the safety of operations

personnel who may be performing climbing activities to conduct regular inspections or maintenance work. The majority of the poles identified as deteriorated are blackjack poles that are no longer commonly used in the utility industry. Industry experience shows that it is common for blackjack poles to deteriorate from the inside out as a result of the thick layer of tar/creosote on the surface of the pole. The deterioration experienced on the inside of the pole causes a major reduction in strength of the structure. Utility lines constructed using blackjack poles may appear acceptable by visual inspection but the actual strength of the structure may be significantly reduced causing an increased risk of failure.

- Porcelain cutouts have experienced numerous failures while being operated. Damaged cutouts may result in equipment becoming energized and pose an electrical contact risk for operation crews. Due to these safety concerns, the porcelain cutouts no longer comply with current Hydro standards and are in the process of being replaced with new polymer cutouts.

3.2.4 Environmental Performance

The following environmental issues have been identified:

The "Policy for Use of Creosote Treated Wood In and Near Fresh Water" as set by the Department of Environment and Conservation has determined that blackjack poles (see Figure 1) are environmentally unacceptable due to the threat of ground/water contamination from the presence of the creosote coating on the surface of the pole.

Approximately 90% of the poles due to be replaced are blackjack poles. Penta and CCA pole treatments are longer lasting and less damaging to fresh water supplies than creosote treatment. These pole treatments are also economical to purchase and have been for the past 30 years. Approximately 70% of the blackjack poles in Hydro's Distribution System were installed before these new pole treatments became available and economical. For this

reason, through the process of attrition, blackjack poles are being removed from Hydro's Distribution System.



Figure 1: Example Blackjack Wood Pole Structure

3.2.5 Industry Experience

Using a standardized inspection/grading system within the utility industry, the line components proposed for replacement have been identified as being at or close to the end of their useful lives. It has also been recognized that some of the existing line components are no longer a standard used by Hydro for line applications; this increases the level of difficulty in material procurement for repair.

Hydro performs inspections on all distribution line components classifying them using the following standardized grading system:

- Grade "A" Condition: More than five years of life remaining;
- Grade "B" Condition: One to five years of life remaining; and
- Grade "C" Condition: Less than one year of life remaining.

3.2.6 Vendor Recommendations

There are no specific vendor recommendations for these projects.

3.2.7 Maintenance or Support Arrangements

A visual inspection of distribution feeders is performed every eight years to evaluate the condition of the line. This inspection is completed by Hydro personnel and any corrective maintenance required is reported, scheduled and completed. The inspection schedule is determined through a reliability centered maintenance program initiated by Hydro and is dependent on a variety of factors including geographical location, line age, and customer usage. Inspection schedules may vary between lines depending on the existing circumstances. The deteriorated poles identified on each of these lines were classified as "B" or "C" condition during the last inspection in 2014 and are scheduled to be replaced in 2016. Prior to the 2014 inspection these lines were inspected in 2008 and, at that time, the poles were classified as "B" condition.

3.2.8 Maintenance History

The five-year maintenance histories for the distribution lines in this report are shown in the following tables.

Table 11: Farewell Head L1 Five-Year Maintenance History

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2014	0.7	33.1	33.8
2013	28.3	43.9	72.2
2012	0.2	0.1	0.3
2011	0.4	29.1	29.5
2010	10.3	3.8	14.1

Table 12: Farewell Head L3 Five-Year Maintenance History

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2014	0.0	1.2	1.2
2013	5.4	0.0	5.4
2012	0.7	0.0	0.7
2011	0.0	0.6	0.6
2010	0.0	3.2	3.2

Table 13: Farewell Head L4 Five-Year Maintenance History

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2014	6.7	29.2	35.9
2013	0.0	1.2	1.2
2012	0.0	0.2	0.2
2011	0.0	0.2	0.2
2010	2.6	5.8	8.4

Table 14: Farewell Head L5 Five-Year Maintenance History

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2014	12.8	49.5	62.3
2013	0.0	7.1	7.1
2012	0.0	6.0	6.0
2011	7.4	9.7	17.1
2010	4.2	7.2	11.4

Table 15: Farewell Head L6 Five-Year Maintenance History

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2014	0.0	34.0	34.0
2013	0.0	10.7	10.7
2012	17.5	7.3	24.8
2011	1.7	8.2	9.9
2010	11.1	4.3	15.4

Table 16: King's Point L1 Five-Year Maintenance History

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2014	15.0	16.8	31.8
2013	0.4	6.0	6.4
2012	0.0	1.6	1.6
2011	0.0	3.5	3.5
2010	0.0	0.4	0.4

Table 17: King's Point L2 Five-Year Maintenance History

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2014	2.5	9.3	11.8
2013	0.0	1.9	1.9
2012	0.0	3.2	3.2
2011	0.0	0.3	0.3
2010	0.0	0.5	0.5

Table 18: Coney Arm L1 Five-Year Maintenance History

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2014	0.0	0.1	0.1
2013	0.0	0.5	0.5
2012	0.0	0.8	0.8
2011	0.0	3.5	3.5
2010	0.0	0.5	0.5

Table 19: Grandy Brook L1 Five-Year Maintenance History

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2014	0.0	7.3	7.3
2013	9.4	10.5	19.9
2012	0.0	1.1	1.1
2011	0.0	1.6	1.6
2010	0.0	1.4	1.4

Table 20: Bay d'Espoir L1 Five-Year Maintenance History

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2014	0.2	26.7	26.9
2013	0.0	28.6	28.6
2012	0.0	10.1	10.1
2011	0.0	9.6	9.6
2010	0.0	42.4	42.4

Table 21: Sally's Cove L1 Five-Year Maintenance History

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2014	0.1	0.1	0.2
2013	0.1	0.5	0.6
2012	0.2	0.3	0.5
2011	0.3	1.4	1.7
2010	0.0	1.4	1.4

Table 22: L'Anse au Loup L1 Five-Year Maintenance History

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2014	5.5	13.6	19.1
2013	1.3	9.8	11.1
2012	4.9	5.7	10.6
2011	2.0	2.1	4.1
2010	0.7	7.4	8.1

Table 23: L'Anse au Loup L2 Five-Year Maintenance History

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2014	4.7	8.4	13.1
2013	6.2	10.9	17.1
2012	5.3	13.5	18.8
2011	6.9	16.0	22.9
2010	0.4	9.4	9.8

Table 24: Happy Valley L16 Five-Year Maintenance History

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2014	0.9	21.6	22.5
2013	0.0	25.2	25.2
2012	6.7	28.1	34.8
2011	0.0	64.3	64.3
2010	0.0	30.4	30.4

Table 25: Paradise River L1 Five-Year Maintenance History

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2014	0.0	0.9	0.9
2013	0.0	1.2	1.2
2012	0.0	0.0	0.0
2011	0.0	2.4	2.4
2010	0.5	1.0	1.5

3.2.9 Historical Information

A distribution line upgrade consists of one or more of the following; pole replacements, insulator replacements, conductor replacements, structure framing, transformer replacements, and service attachment transfers. A line could cover several kilometers or only a few. Because of the variety in line lengths and equipment, unit costs for a particular job are not available. Table 26 lists budgeted and actual costs for distribution upgrades in the last five years as well the amounts budgeted for 2015.

Table 26: Historical Information

Year	Project Description	Budget ($000)	Actuals ($000)
2015B	Upgrade Distribution Feeder – Line 1, 3, 4, 6 and 7 Bottom Waters (Year 1 of 2)	42.7	
	Pole Replacements – Pinsent's Arm and Labrador City	593.4	
	Insulator Replacements – Farewell Head	500.0	
	Relocate Voltage Regulators – Hawke's Bay	166.4	
	Install Second Distribution Feeder - Nain	1050.3	
	Upgrade Distribution Feeder - Line 1 Nain (Year 2 of 2)	261.0	
	Upgrade Distribution Feeder - Line 1 Daniel's Hr. (Year 2 of 2)	877.8	
	Upgrade Distribution Feeder - Line 1 and 2 Main Brook (Year 2 of 2)	837.1	
	Upgrade Distribution Feeder - Line 1 Plum Point (Year 2 of 2)	1,440.9	
	Upgrade Distribution Feeder - Line 1 Hampden (Year 2 of 2)	733.2	
2014	Upgrade Distribution Feeder - Line 1 Nain (Year 1 of 2)	43.0	10.0
	Upgrade Distribution Feeder – Happy Valley (Year 1 of 2)	64.3	26.6
	Upgrade Distribution Feeder - Line 1 Daniel's Hr. (Year 1 of 2)	69.7	14.9
	Upgrade Distribution Feeder - Line 1 and 2 Main Brook (Year 1 of 2)	64.3	104.7
	Upgrade Distribution Feeder - Line 1 Plum Point (Year 1 of 2)	75.3	6.4
	Upgrade Distribution Feeder - Line 1 Hampden (Year 1 of 2)	53.6	30.5
	Upgrade Distribution Feeder - Line 1 McCallum	359.1	320.1
	Upgrade Distribution Feeder - Line 1, 2, 4 and 5 Barachoix	583.7	553.8
	Upgrade Distribution Feeder - Line 1 Bay d'Espoir	692.6	632.3
	Upgrade Distribution Feeder - Line 1 Conne River	494.2	443.2
	Upgrade Distribution Feeder - Line 1 St. Lewis (Year 2 of 2)	908.1	740.5
	Upgrade Distribution Feeder - Line 1 and 3 Roddickton (Year 2 of 2)	1,259.5	1,366.7
	Upgrade Distribution System - Charlottetown (Year 2 of 2)	365.0	269.2
	Upgrade Distribution System - South Brook (Year 2 of 2)	975.8	846.2
	Upgrade Distribution Feeder - Line 1 Grey River (Year 2 of 2)	487.1	410.8
2013	Upgrade Distribution Feeder - Line 1 St. Lewis (Year 1 of 2)	76.9	23.3
	Upgrade Distribution Feeder - Line 1 and 3 Roddickton (Year 1 of 2)	98.4	106.5
	Upgrade Distribution System - Charlottetown (Year 1 of 2)	27.8	22.8
	Upgrade Distribution System - South Brook (Year 1 of 2)	76.3	108.5
	Upgrade Distribution Feeder - Line 1 Grey River (Year 1 of 2)	32.5	111.9
	Upgrade Distribution Feeder - Line 1 Cow Head	665.6	658.4
	Upgrade Distribution Feeder - Line 1 St. Brendan's	330.2	310.7
	Upgrade Distribution Feeder - Line 1 Holyrood	632.4	372.1
	Upgrade Distribution Feeder - Line 11 Wabush	400.8	513.2
	Upgrade Distribution Voltage - Line 6 St. Anthony	641.9	648.6
	Upgrade Distribution Feeder - Line 6 Farewell Head	961.9	980.0
	Upgrade Distribution Feeder - Line 5 Farewell Head	1,110.1	1,184.9
	Upgrade Distribution Feeder - Line 2 Plum Point (Year 2 of 2)	1,110.5	1,276.2

Year	Project Description	Budget ($000)	Actuals ($000)
2012	Upgrade Distribution Feeder - Line 1 Bay d'Espoir	856.6	896.9
	Upgrade Distribution Feeder - Line 2 Bay d'Espoir	952.9	811.2
	Upgrade Distribution Feeder - Line 1 Francois	440.9	650.4
	Upgrade Distribution Feeder - Line 1 Parson's Pond	381.9	344.7
	Upgrade Distribution Feeder - Line 2 Plum Point (Year 1 of 2)	50.4	33.2
	Upgrade Distribution Feeder - Line 7 Happy Valley	1,260.1	1,163.6
	Upgrade Distribution Feeder - Line 2 Glenburnie (Year 3 of 4)	2,114.6	1,895.0
	Reconfigure Feeders – Wabush	55.4	55.4
	Upgrade Distribution Feeder - Line 1 Rigolet (Year 2 of 2)	725.7	658.5
	Upgrade Distribution Feeder - Line 1 Makkovik (Year 2 of 2) - (Materials ordered in 2011)	799.5	612.6
2011	Replace Poles – Westport	256.4	279.3
	Replace Poles - Grandy Brook	286.4	312.4
	Replace Poles - Farewell Head	339.6	393.9
	Upgrade Distribution Feeder - Line 1 Rigolet (Year 1of 2)	72.0	10.5
	Upgrade Distribution Feeder - Line 1 Francois	440.9	116.0
	Upgrade Distribution Feeder - Line 8 Happy Valley	553.5	488.2
	Upgrade Distribution Feeder - Line 4 Roddickton (Year 2 of 2)	902.6	1,106.2
	Upgrade Distribution Feeder - Line 1 Makkovik (Year 2 of 2)	742.4	137.3
	Upgrade Distribution Feeder - Line 2 Glenburnie (Year 2 of 4)	578.2	527.8
2010	Replace Poles - English Harbour West	274.8	249.8
	Replace Poles - Line 1 Fleur De Lys	269.2	246.9
	Replace Poles – Barachoix	273.3	256.1
	Upgrade Distribution System - Line 1 Makkovik (Year 1 of 2)	57.1	25.1
	Upgrade Distribution System - Line 4 Roddickton (Year 1 of 2)	160.6	98.4
	Upgrade Distribution System - Line 2 Glenburnie (Year 1 of 4)	267.3	134.8
	Upgrade Distribution System - Line 4 Happy Valley	265.3	251.6

3.2.10 Anticipated Useful Life

The service life of a distribution line structure is generally broken down as follows:

Poles - 37 years

Transformers - 30 years

Conductors - 55 years

3.3 Forecast Customer Growth

There is no significant load growth on these systems for the next five years that is anticipated to have an impact on this project.

3.4 Development of Alternatives

Three alternatives were considered. Constructing an entirely new distribution line and retiring the existing line (Alternative 1), allowing the existing line components to remain in service until failure (Alternative 2), replacing deteriorated line components and utilizing existing non-deteriorated line components (Alternative 3).

Alternative 1

The construction of an entire new line would not benefit from existing line components that are still operable such as poles, conductor, insulators, and cross arms. This requires spending which is unnecessary for the continuation of safe, reliable, and least-cost electricity.

Alternative 2

Allowing existing line components to remain in service until failure is not viable as it negatively affects the reliability of electrical service provided to Hydro's customers. Also, a safety issue would exist for Hydro employees and local citizens who are near a deteriorated pole when it fails. Because failing poles also cause energized electrical conductors to fall to the ground, a risk of electrical shock or electrocution exists. Due to the safety hazards, Hydro does not allow distribution line components to remain in service until failure.

Alternative 3

This alternative is the most efficient and economical of the three alternatives. Replacing deteriorated line components removes the chance of outages due to deteriorated line components, while utilizing existing non-deteriorated line components means Hydro doesn't incur the cost to replace line components before end of life.

3.5 Evaluation of Alternatives

There are no viable alternatives to replacing the deteriorated components.

3.5.1 Energy Efficiency Benefits

There are no energy efficiency benefits that can be attributed to this project.

3.5.2 Economic Analysis

A net present value calculation was not performed in this instance as there are no viable alternatives to upgrading the lines.

This project will have no effect on the levelized cost of electricity since no new generation source is involved.

A cost benefit analysis calculation was not performed in this instance as there are no quantifiable benefits.

4 CONCLUSION

This project is required to ensure that a reliable energy supply is available for the customers serviced by each of the lines referenced in this report. Since the existing lines are over the age of 40 and various components of these lines are deteriorated, these items have exceeded their service lives and are recommended for replacement.

4.1 Budget Estimate

The budget estimate for this project is shown in Table 27.

Table 27: 2016 Distribution Systems Upgrades Budget Estimate

Project Cost: *($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	90.0	1,400.0	0.0	1,490.0
Labour	180.0	1,060.0	0.0	1,240.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	2,350.0	0.0	2,350.0
Other Direct Costs	0.0	0.0	0.0	0.0
Interest and Escalation	15.6	524.3	0.0	539.9
Contingency	0.0	1,016.0	0.0	1,016.0
TOTAL	**285.6**	**6,350.3**	**0.0**	**6,635.9**

4.2 Project Schedule

The anticipated project schedule is shown in Table 28.

Table 28: 2016 Distribution Systems Upgrades Project Schedule

Activity		**Start Date**	**End Date**
Planning	Resource Planning	January 2016	January 2016
Design	Assessment Completed	September 2014	November 2014
Procurement	Materials Ordered	January 2017	March 2017
Construction	Monitor Construction Activities	May 2017	October 2017
Commissioning	Inspection Preformed by Local Operations Crews	August 2017	September 2017
Closeout	Project Closeout	September 2017	November 2017