Q. Please provide copies of reports or other documentation that describe the latest condition of the following assets and any work completed to date addressing the following issues:

a. Bay d'Espoir penstocks;

b. Hinds Lake rotor resistance;

c. Granite Canal control system;

d. Upper Salmon rotor rim cracking;

e. Hinds Lake bearing coolers;

f. Cat Arm spherical control valves;

g. Hardwoods combustion can failures;

h. Hardwoods bellows failures/cracking;

i. Holyrood boiler tube issue, variable frequency drive issues, air flow limitations, hydraulic fluid issues;

j. Stephenville vibration issues;

k. Hardwoods combustion can failures;

l. Hardwoods bellows cracking issue;

m. All Holyrood boiler tube failure studies;

n. All "Quarterly Report on Performance of Generating Units" reports; and

o. Exploits frazil ice issues.

A. The reports referenced below provide an overview of the latest condition of the asset(s) and any work completed to date.

a. Bay d'Espoir Penstocks:

- PUB-NLH-020, Attachment 1: "Final Report for BDE Penstock #1 Condition Assessment," Hatch, Revision 1, January 29, 2016;

- PUB-NLH-020, Attachment 2: "Crack Investigation and Repair Report Penstock No. 1 Bay d'Espoir Hydroelectric Development," Kleinschmidt, June 2016;

- PUB-NLH-020, Attachment 3: "Root Cause Analysis Report for Bay d'Espoir Penstock No. 1 Refurbishment," Hatch, Revision B, February 24, 2017;

- PUB-NLH-020, Attachment 4: "Final Report for Bay d'Espoir Penstock No. 1 Stress Analyses," Hatch, Revision 0, March 29, 2017;

- PUB-NLH-020, Attachment 5: "Final Report for Repair and Failure Investigation," Hatch, Revision 2, May 17, 2018;

- PUB-NLH-020, Attachment 6: "Penstock No. 3 Inspection and Evaluation Bay d'Espoir Hydroelectric Development," Kleinschmidt, December 2017; and

- PUB-NLH-020, Attachment 7: "Penstock No. 3 Weld Refurbishment," Hatch, Revision 0, June 21, 2018.

b. Hinds Lake Rotor Resistance:

- PUB-NLH-020, Attachment 8: "Hinds Lake GS Field Pole Field Report," VOITH, August 24, 2018.

c. Granite Canal Control System:

- There are no formal reports on this issue.

- Hydro has experienced control system malfunctions when remotely starting/stopping the unit. Hydro has engaged the control system original equipment manufacturer and Hydro's Engineering Services department to assess the issues and work to determine root cause and next steps to improve reliability of the system. This assessment is ongoing and findings are expected in 2019.

d. Upper Salmon Rotor Rim Key Cracking:

- There are no formal reports on this issue.

- This generator has experienced fretting corrosion in recent years, indicating movement between the rotor spider and rotor rim. Due to the floating rim design of this unit, some movement is expected; however, more than desirable movement between the spider and rim can cause cracking of the rotor rim key welds. In 2017, the frequency of cracked rotor rim welds increased. If a weld were to crack, a key has the potential to move fully out of its slot and fall between the rotor poles and the generator stator, which could result in equipment damage and subsequent failure. To address this risk, in consultation with the original equipment manufacturer, Hydro increased the frequency of visual inspection and repair of welds in 2017 and 2018 until the planned refurbishment work was completed in 2018. During the planned outage in 2018, Hydro replaced the rotor rim keys and has continued to complete regular inspection of new keys through the anticipated wear-in period for the new keys.

e. Hinds Lake Bearing Coolers:

- There are no formal reports on this issue.

- In 2017, Hydro experienced leaks in the cooling system at the plant. Subsequent testing of the coolers revealed that three of the six coolers were leaking. These coolers were repaired, an external cooler was purchased as a mitigation, and a full set of replacement coolers were ordered for installation during the 2018 planned outage. These six coolers have since been replaced.

f. Cat Arm Spherical Valve Controls:

- There are no formal reports on this issue.

- The potential for spherical valves to malfunction during unit trips was identified, with particular concern to events where the plant is not staffed during the trip event. There was potential for flooding in the lower levels of the plant. This revealed the need for capital investment to mitigate the risk so a project was proposed to replace the spherical valve controls on both units in the plant. This proposed project was approved and the spherical valve controls on both units in Cat Arm were upgraded during the 2018 planned maintenance outage.

g. Hardwoods Combustion Can Failures:

- During the discussions between representatives of Liberty and Hydro regarding the review of the Reliability and Resource Adequacy Study, the Parties agreed reports regarding this asset are not necessary for the review at this time.

h. Hardwoods Bellows Failures/Cracking:

- During the discussions between representatives of Liberty and Hydro regarding the review of the Reliability and Resource Adequacy Study, the Parties agreed reports regarding this asset are not necessary for the review at this time.

i. Holyrood Boiler Tube Issue, Variable Frequency Drive Issues, Air Flow Limitations, Hydraulic Fluid Issues:

- Holyrood Boiler Tube Issues:

  - PUB-NLH-020, Attachment 9: "Holyrood TGS Boiler Tube Thinning Assessment," Amec Foster Wheeler, August 8, 2016;

  - PUB-NLH-020, Attachment 10: "Thermal Study –Superheater and Reheater Metal," B&W, July 5, 2016;

  - PUB-NLH-020, Attachment 11: "In Situ Metallographic Examination of Reheat Tubes; Holyrood Generating Station Unit #3," Wayland Engineering Ltd., August 7, 2016;

- PUB-NLH-020, Attachment 12: "NOTIS® Inspection of Superheater Tubes for: Newfoundland and Labrador Hydro Holyrood Generating Station, Unit 3," B&W, September 2016;

- PUB-NLH-020, Attachment 13: "Holyrood TGS Boiler Tube Thinning Assessment (October 2016 Update)," Amec Foster Wheeler, October 19, 2016;

- PUB-NLH-020, Attachment 14: "Analysis of Newfoundland and Labrador Hydro Holyrood Unit 3 Boiler Tubes," Kinectrics, November 21, 2016;

- PUB-NLH-020, Attachment 15: "Holyrood Thermal Generating Station Unit 3 Boiler Tube Life and De-Rate Analysis Summary," Amec Foster Wheeler, January 3, 2017;

- PUB-NLH-020, Attachment 16: "Unit 3 2017 Boiler Tube Inspection – Preliminary Assessment of Results," Amec Foster Wheeler, September 6, 2017;

- PUB-NLH-020, Attachment 17: "Metallurgical Evaluation of Boiler Waterwall Tube #84 Holyrood Thermal Generating Station - Unit 1," rpc, April 3, 2017;

- PUB-NLH-020, Attachment 18: "DWD & Corrosion Evaluation of Boiler Tubes,"[1] rpc, November 1, 2017;

- PUB-NLH-020, Attachment 19: DWD Analysis of Boiler Tube Sample – Unit 3, Wayland Engineering Ltd. January 7, 2019;

[1] Unit #1 and Unit #2 Waterwall DWD 2017.

- PUB-NLH-020, Attachment 20: "Condition Assessment of Furnace Tubes for Holyrood Thermal Generating Station, Unit 2," B&W, June 2018; and Newfoundland and Labrador Hydro.

- PUB-NLH-020, Attachment 21: "NOTIS® Inspection of Superheater Tubes for: Newfoundland and Labrador Hydro Holyrood Generating Station, Unit 3," B&W, September 2018.

- Variable Frequency Drive Issues:

  - PUB-NLH-020, Attachment 22: "NL Hydro – Nalcor, Holyrood Plant," Siemens, July 6–7, 2016.

- Air Flow Limitations:

  - PUB-NLH-020, Attachment 23: "Site Visit Report,"[2] B&W, October 2016;

  - PUB-NLH-020, Attachment 24: "Holyrood Generating Station Boiler Performance Investigation Recap," B&W, June 30, 2017;

  - PUB-NLH-020, Attachment 25: "Field Service Report,"[3] Howden, December 2017;

  - PUB-NLH-020, Attachment 26: "Performance Study Unit Capacity Limitations," B&W, Revision 04, June 20, 2018; and

[2] Load Limit Operations Review.
[3] High pressure drop issue through air heaters on both Units 1 and 2.

  - PUB-NLH-020, Attachment 27: "Holyrood Generating Station Units Performance Review November 2017 to April 2018," JEM Consulting Ltd., June 13, 2018.

- Hydraulic Fluid Issues

  - PUB-NLH-020, Attachment 28: "Document Package Service/Maintenance on Unit #1," Pennecon, March 4, 2019; and

  - PUB-NLH-020, Attachment 29: "Document Package Service/Maintenance on Unit #2," Pennecon, March 4, 2019.

j. Stephenville Vibration Issues:

- During the discussions between representatives of Liberty and Hydro regarding the review of the Reliability and Resource Adequacy Study, the Parties agreed reports regarding this asset are not necessary for the review at this time.

k. Hardwoods Combustion Can Failures:

- During the discussions between representatives of Liberty and Hydro regarding the review of the Reliability and Resource Adequacy Study, the Parties agreed reports regarding this asset are not necessary for the review at this time.

l. Hardwoods Bellows Cracking Issue

- During the discussions between representatives of Liberty and Hydro regarding the review of the Reliability and Resource Adequacy Study, the Parties agreed reports regarding this asset are not necessary for the review at this time.

m. All Holyrood Boiler Tube Failure Studies:

- PUB-NLH-020, Attachment 30: Unit 1 and Unit 2 Summary of Reheat Repairs 2016, B&W;

- PUB-NLH-020, Attachment 31: Unit 2 Primary Superheater Tube Failure Summary, B&W, 2016;

- PUB-NLH-020, Attachment 32: “LTSH Tube Failure Review at Newfoundland & Labrador Hydro Holyrood Thermal Generating Station Unit #2,” Alstom Canada Inc., November 26, 2014;

- PUB-NLH-020, Attachment 33: “Failure Analysis of Waterwall Tube #114 Holyrood G.S Unit #2,” Wayland Engineering Ltd., June 28, 2018; and

- PUB-NLH-020, Attachment 34: “Failure Analysis of Waterwall Tube Holyrood G.S. Unit #3”, Wayland Engineering Ltd., February 1, 2019).

n. All Quarterly Reports on Performance of Generating Units:

- Please refer to Hydro’s response to PUB-NLH-015.

o. Exploits Frazil Ice Issue and Reports:

- PUB-NLH-020, Attachment 35: “Draft Report for Grand Falls Generating Station 2013 Freeze-up Event,” Hatch, Revision A, February 14, 2014.

HATCH

Newfoundland and Labrador Hydro

Final Report

For

BDE Penstock #1 Condition Assessment

H349209-00000-200-230-0001
Rev. 1
January 29, 2016

Newfoundland and Labrador Hydro

Final Report

For

BDE Penstock #1 Condition Assessment

H349209-00000-200-230-0001
Rev. 1
January 29, 2016

HATCH

Newfoundland and Labrador Hydro
BDE Penstock #1 Condition Assessment
H349209

Final Report

BDE Penstock #1 Condition Assessment

H349209-00000-200-230-0001

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 2016

REGISTERED PROFESSIONAL ENGINEER
J.E. SNOOK
SIGNATURE
Jan 29/16
DATE
NEWFOUNDLAND & LABRADOR

2016-01-29	1	Final	M. Pyne	J. Tucker	J. Snook
DATE	REV.	STATUS	PREPARED BY	CHECKED BY	APPROVED BY

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1. Introduction

In April 2015, Hatch was engaged by Newfoundland and Labrador Hydro (NL Hydro) to perform a condition assessment of Penstock #1 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. Penstock #1 is connected to generating Units #1 and #2.

The purpose of the condition assessment was to inspect all critical areas of the penstock from a mechanical and structural perspective, including the surface coatings, penetrations, instrumentation, scroll case, and primary structural welds. Where necessary, UT was performed to accentuate visual inspection. The inspection was internal only as the penstock is below grade.

Hatch engaged Tacten to perform the inspection. See Appendix A for Tacten's inspection report. Site inspections were performed during the week of May 4, 2015 to May 8, 2015 by James Callanan, Ben Daniels and Wolfgang Holtzmann of Tacten. Michael Pyne of Hatch was on site during the inspection. NL Hydro provided a confined space attendant during the inspection. The inspection was primarily visual with ultrasonic thickness (UT) readings at various locations. Tacten's inspection report and on-site photos were used to develop the final condition assessment report.

In addition to the site inspections, Hatch performed the following activities for the condition assessment:

- Review of existing drawings as provided by NL Hydro. The drawings were primarily used to determine component thickness and in developing a familiarity with the penstock for the site visits.

2. Penstock Description

The penstock for Units #1 and #2 is a welded steel penstock approximately 17ft in diameter. The penstock is approximately 3,800 ft long with a slopes varying between 0°-19°. Access to the upstream end of the penstock was made by repelling down from the top of the intake structure and via the access hatch near Surge Tank #1. The exit point was through the hatch near Surge Tank #1 and the access hatch in the scroll case to the powerhouse. The penstock profile and UT locations are provided in Appendix B.

3. Penstock Inspection

3.1 Intake Area

The penstock access ladder, found in the intake structure, was not used to access the penstock. The ladder showed signs of corrosion and has significant build up along the fall arrest system. This buildup impedes any use of the existing system and makes rappelling or the use of a tripod the only means of access currently. The condition of the ladder can be seen in Figure 3-1.

Figure 3-1: General Condition of Ladder from Headgate to Bottom of Penstock, Corrosion Present

There was leakage from the headgate and there appears to be a portion of missing concrete on the bottom left hand side.

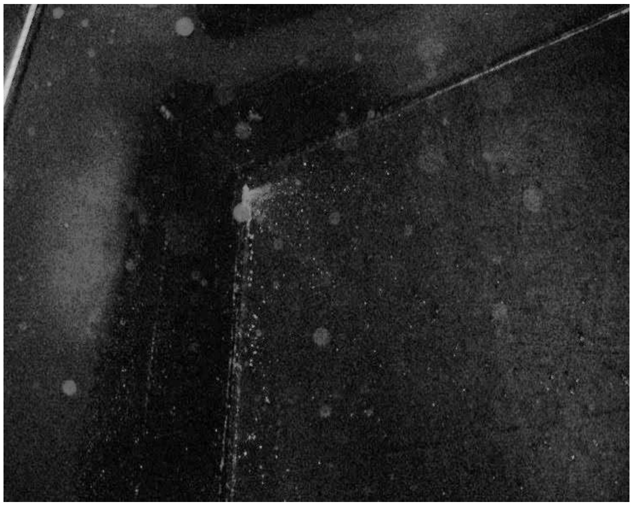

Figure 3-2: Top Left - Facing Headgate, Water Flow Present

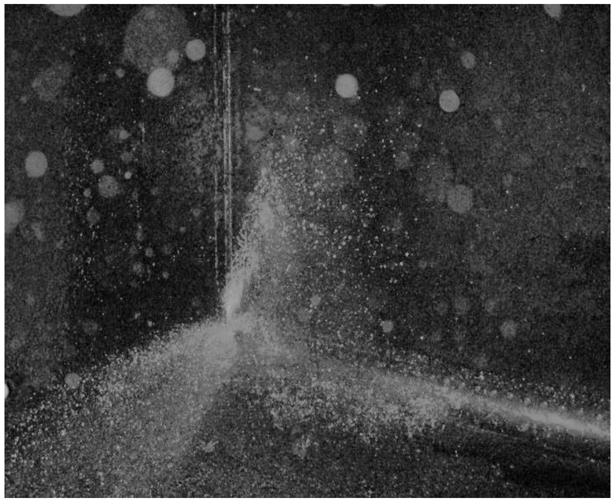

Figure 3-3: Bottom Left - Facing Headgate, Water Flow Present

Figure 3-4: Bottom Right - Facing Headgate, Water Flow Present

3.2 Interior Penstock Inspection

The penstock structure and welds were found to be in good condition and there were no visible signs of pitting corrosion or other deterioration in the steel; however the coatings showed failure throughout (see Tacten report). The structure and welded connections have been protected by a buildup of sludge along the length of the penstock. This sludge buildup has reached a critical mass and now falls off in large sections under its own weight, this leaves the bare steel unprotected from corrosion. The old coating can be seen on the backside of fallen sludge sections as shown in Figure 3-8.

Ultrasonic thickness (UT) readings were taken in 4 locations using a 5 point pattern at the 8 o'clock and 4 o'clock positions in cans: 1a, 2a, 5a, and 10a. These locations are indicated on the penstock profile in Appendix B.

The UT results indicate minor discrepancies from the drawings provided.

This discrepancy in the UT readings and the reference drawings can be explained by any number of factors including, but not limited to:

1. Inaccurate UT readings

To ensure UT readings were as accurate as possible, readings were taken at various locations. Since all readings were consistent, it is unlikely that the inaccuracy of UT readings is a strong contributing factor.

2. Loss of material due to corrosion

There is little indication of corrosion on the inside of the penstock. However, it was not possible to visually verify the condition of the exterior without excavation.

3. Constructed with thicker plate

Penstock section 10A could have been constructed with 1 3/4" thick plate deviating from the construction drawings.

Figure 3-5: General Conditions of Welds throughout Penstock – Connections at 1a

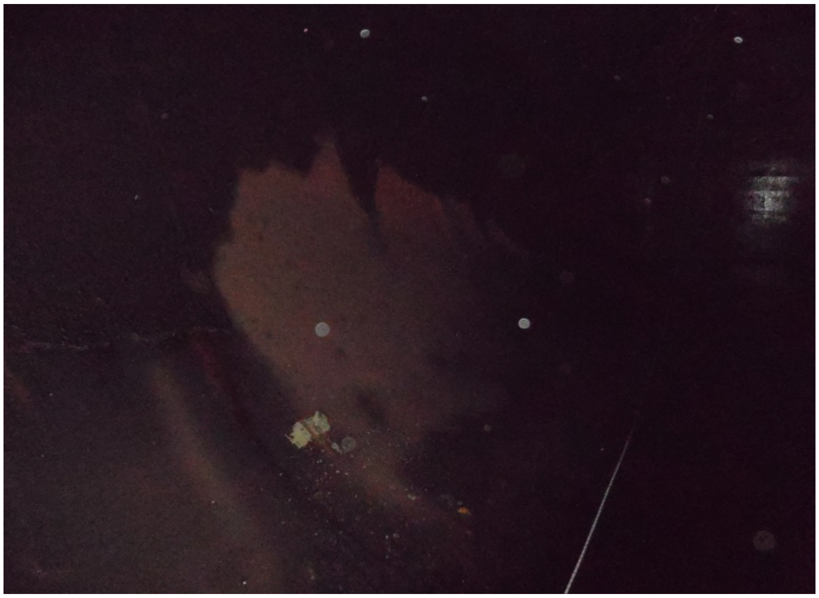

Figure 3-6: General Conditions of Coating throughout Penstock (a)

Figure 3-7: General Conditions of Coating throughout Penstock (b)

Figure 3-8: General Conditions of Coating throughout Penstock (c)

3.3 Penstock Penetrations

Penstock penetrations were all found to be in good condition. The access hatch located at the surge tank is below grade and it was noted that loose rocks in this area could fall into the penstock. Loose rocks should be removed before future work and inspections as it presents a safety risk and could allow rocks into the penstock which could cause damage.

Figure 3-9: General Conditions of Penetrations – Access Hatch Bottom of Surge Tank

Figure 3-10: General Conditions of Penetrations – Can 8a

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3.4 Flow Meters

The penstock flow meters appear to be in good condition and remain firmly connected.

Figure 3-11: General Condition of Flow Meter Sensors in Can 9a (a)

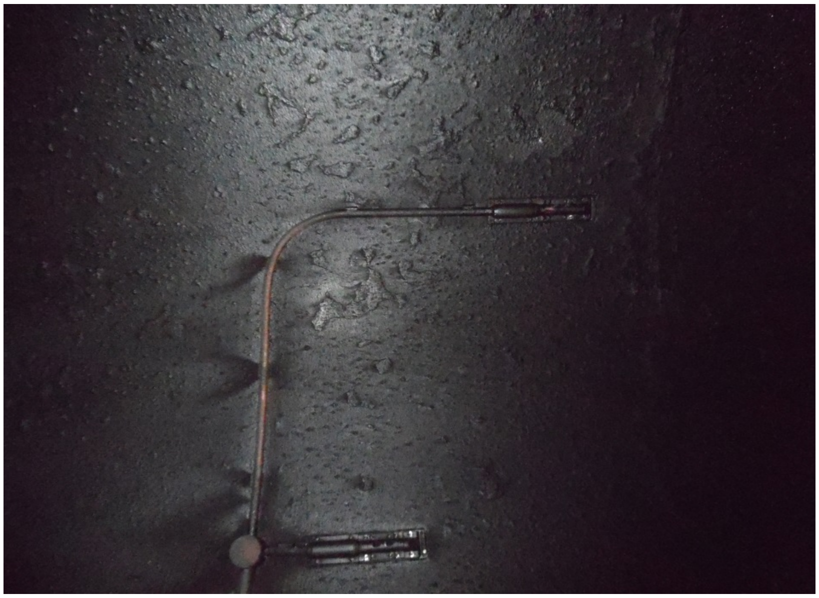

Figure 3-12: General Condition of Flow Meter Sensors in Can 9a (b)

3.5 Scroll Case Inspection

The scroll case was in excellent condition. The steel plate was coated and some of the coating has been damaged. From the photographs it is believed that the damaged coating is due to erosion from debris in the water.

Figure 3-13: General Condition of Scroll Casing (a)

Figure 3-14: General Condition of Scroll Casing (b)

Figure 3-15: General Conditions of Penetrations – Scroll Case (a)

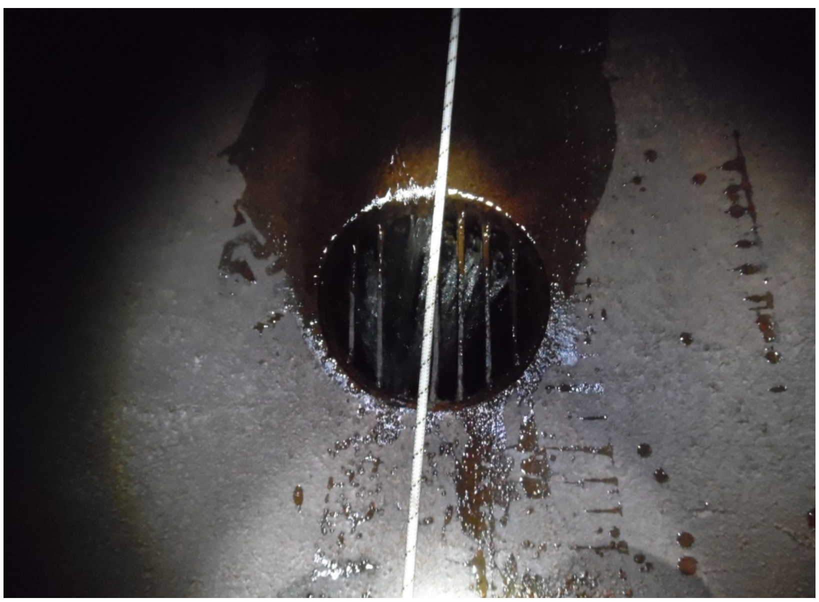

Figure 3-16: General Conditions of Penetrations – Scroll Case (b)

Figure 3-17: General Conditions of Penetrations – Exit Hatch in Scroll Case

4. Summary of Recommendations

4.1 Recommendations

1. There appears to be damage to the concrete on the bottom left hand side of the headgate. This extra leakage from the headgate will cause difficulties for containing debris and recoating. A system/procedure should be developed to allow the penstock to be sealed, drained and allow proper containment of debris
2. The penstock, scroll case, components, and penetrations are in excellent condition. A cost benefit analysis should be completed but as a minimum the internal coating system should be repaired/reinstated as indicated in Section 4.2
3. It is recommended that during the execution of future interior work, additional UT readings be taken for the remaining sections to determine the plate thickness. If the actual plate thickness deviates from the reference drawings, a code compliance check is recommended.
4. Loose rocks around the surge tank access hatch should be removed before future work and inspections. These rocks pose a safety hazard and cause damage to the turbine.
5. Currently the fall arrest system at the intake structure is unusable. The ladder does exhibit surface corrosion but does not appear to have any structural deficiencies. It is recommended that the fall arrest system be removed as it currently only impedes using the ladder.

4.2 NACE Inspector Recommendations

1. It would appear that the penstock interior has a protective coating applied (see Figure 3-8) and this coating has failed throughout the penstock. This coating was probably intended to provide protection from corrosion and erosion. Assuming this coating was part of the original design philosophy the penstock should be recoated. The internal surface should be water blasted or wet abrasive blasted if there is not a suitable profile present after cleaning for proper application of the protective coating system. A moisture cure coating would be appropriate for the application environment and anticipated high humidity during surface preparation and coating operations. Wasser MioZinc 100 and 2 coats of MC Tar would be suitable for this surface preparation and service environment.

5. Cost Estimate

Preliminary (+30/-20%) cost estimates were prepared for the recommendations outlined in Section 4. A 25% contingency is included. All cost estimates exclude owners cost, such as procurement and construction management.

The cost estimates for the surface preparation, coating and containment for the interior and of Penstock #1 are presented in Table 5-1.

Table 5-1: Coating and Coating Inspection Cost

	Direct Cost	Contingency (25%)	Total Cost
Surface preparation and painting, including containment	2,500,000	625,000	3,125,000

Appendix A
Surge Tank Inspection Report (Tacten)

INSPECTION OF SURGE TANK AND PENSTOCK #1

Bay d'Espoir Generating Station

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1.0 Introduction

Tacten industrial Inc. mobilized to Bay d'Espoir on May 3, 2015 to complete an inspection on surge tank and penstock for unit #1. Using rope access, it included a visual inspection on the internal & external condition of tank and internal condition of the penstock. Additionally ultrasonic thickness measurements were performed at various locations of the tank and penstock as well as adhesion testing on the tank.

1.1 Inspection Summary

The external visual inspection was performed on surge tank #1, concentrating on the checkered portion of the tank shell, tank riser, tank top, 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.

The internal inspection of the penstock included the shell, weld seems, penetrations and scroll case.

Ultrasonic inspection was carried out on the tank top, tank shell, legs, leg connections and penstock.

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. The first balcony around the tank had gate at the ladder access point. The hot water system was in overall good condition with the exception of several connection points where there are insulation bags or damaged cladding potentially allowing water ingress leading from the control shed to the base of the legs.

The tank top had coating breakdown and corrosion. The swivel ladder and hatch opening for the tank were all operational.

The cathodic protection system is damaged and the wiring is severed.

The exterior of the surge tank had minor coating breakdown and showed signs of minor corrosion. 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. There is also breakdown in the silicone seals at leg penetrations and riser to bowl connection (cladding).

The coating on the interior of the penstock is beyond end of life, there is no bond to the substrate any longer. The penstock is however getting some protection from corrosion from a thick layer of sludge. When the sludge is removed the coating is removed at the same time revealing bright shiny metal with no signs of active corrosion. It was noted throughout the penstock that the sludge has reached the point where it is heavy enough to fall off in sheets.

The exterior coating of the surge tank is in poor shape and the topcoat on the legs is peeling down to primer. Adhesion testing revealed a poor bond between the topcoat and the primer. The primer however has a good bond to the substrate and is protecting the legs from corrosion. On the tank itself the coating has general cracking over the entire surface, this is likely due to age through UV breakdown. Adhesion testing results in this area revealed acceptable results on some areas of the tank where the cracking was less prominent.

Coating System	Red Coating	White Coating	Primer Coating	Grey Coating
Adhesion Result (Psi)	330	200	1420	Failed

The interior coatings of the surge tank are fair to good condition, there are large areas of coating breakdown from the water line down in to the bowl to riser connection. Above the water line the coating is in good condition. Adhesion testing results on the inside of the tank indicated acceptable results for spot repair and over coating on the interior of the tank and riser.

The cathodic protection system is in a state of disrepair with broken and missing pieces, tangled ropes and wires and would likely be ineffective in its current state. All components should be pulled from the interior of the tank to prevent the pieces from migrating through the turbine.

2.0 External Inspection Results

2.1 Ladder System

Overall the ladder system was in good condition, coating breakdown and minor corrosion was present.

General condition of ladder, coating breakdown present.

General condition of ladder, coating breakdown present.

General condition of ladder brackets.

General condition of ladder on tank portion of the tower.

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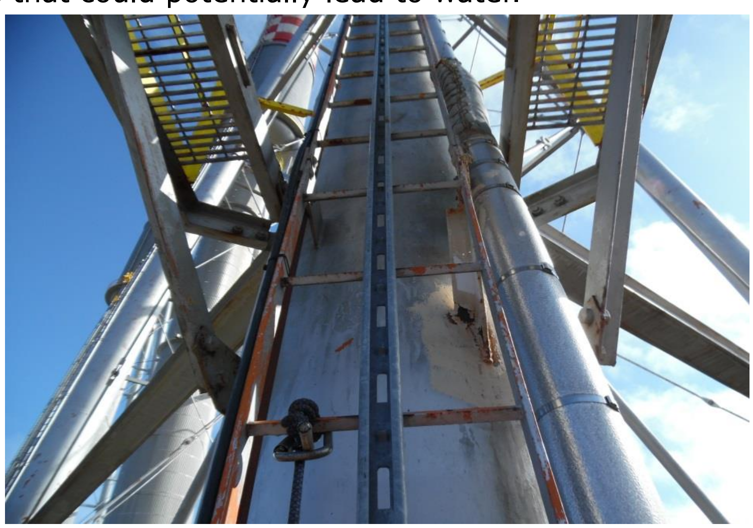
2.2 Hot Water Heating System

The system was in overall good condition with the exception of connection points # 3, 5, 8, 11, 13, 15, 18, 19, 21 where there are insulation bags or damaged cladding potentially allowing water ingress leading from the control shed to the base of the legs.

Sample photo showing insulation and cladding not reinstated.

Following three photographs show insulation bags or damaged areas that could potentially lead to water.



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2.3 Rest Area

The rest area is in good condition, minor coating breakdown.

Photo of bottom brackets.

General Condition of rest area from above.

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2.4 First Balcony

Missing barrier door and coating breakdown.

General condition of balcony and rails, coating breakdown.

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General condition of balcony and rails, coating breakdown.

General condition of 4 turnbuckles on balcony, coating breakdown and slightly bent.

General condition of cladding on 1st balcony level.

Silicone breakdown (360 degrees), potential water ingress between bowl and riser connection

2.5 Second Balcony

Coating breakdown on balcony and railings

Coating breakdown on balcony and railings

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Lower hinge missing on balcony gate

General condition of all 4 leg connection points, possible water ingress, silicone failing.

General condition of all 4 leg connection points, possible water ingress, silicone failing.

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2.6 Tank Top

General condition of ladder and ladder connections.

General condition of ladder and ladder connections.

Condition of tank roof/ladder and hatchway.

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2.7 Riser Exterior

Exterior cladding of riser is in good condition. Banding Missing #6 in first connection, 2nd connection #4, 3rd connection #1 is loose and hanging.

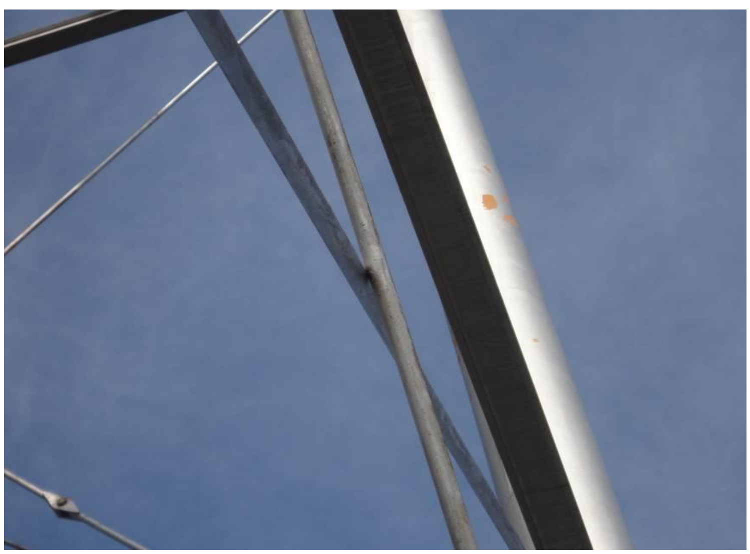
General condition of connection points to riser.

General condition of cladding on riser.

2.8 Legs and Cross braces

General condition of connections into legs. Minor coating breakdown.

General condition of cross braces on the surge tank.



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3.0 Internal Inspection Results

3.1 Tank Top

General condition of underside of tank roof. Coating breakdown.

General condition of underside of tank roof. Coating breakdown.

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3.2 Tank Shell

General condition of tank top before water line. Minor coating breakdown and minor corrosion present on welds.

General condition of tank top before water line. Minor coating breakdown and minor corrosion present on welds.

General condition below the water line.

General condition of the bowl.

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3.3 Riser

General view of cathodic protection system from top of riser.

General condition of riser cross braces and coatings inside of riser.
Bent and missing bolts.

General condition of coatings inside of riser.

Base of riser’s connection to penstock.

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Base of riser’s connection to penstock.

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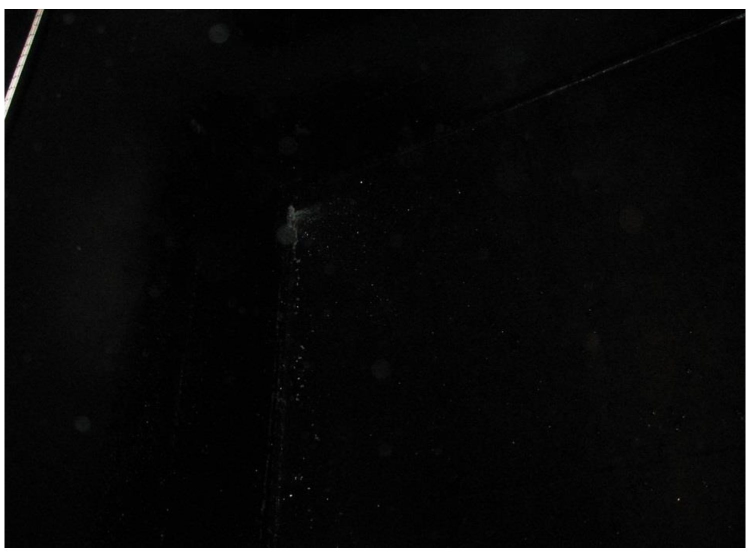
4.0 Penstock

General condition of ladder leading from head gate to bottom of penstock, corrosion present.

Facing the head gate, Top left, bottom left and bottom right water flow is present.



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Facing the head gate, Top left, bottom left and bottom right water flow is present.

Facing the head gate, Top left, bottom left and bottom right water flow is present.

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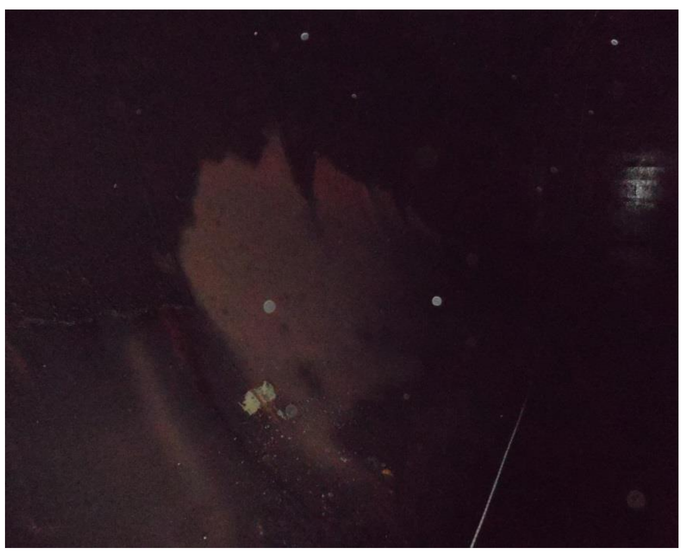
Weld connections at 1a.

General condition of coating throughout the penstock.



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General condition of coating throughout the penstock.

General condition of coating throughout the penstock.

Access hatch at bottom of surge tank.

Penetration in Can 8a.

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Penetration in the scroll case.

Penetration in the scroll case.

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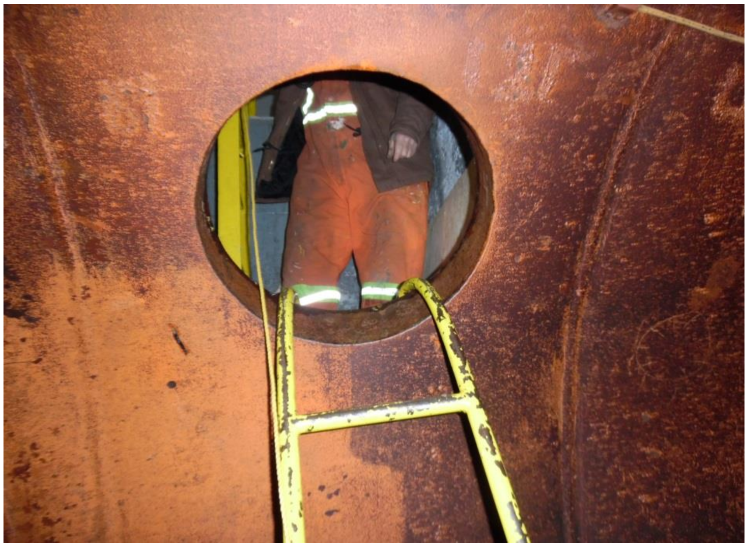
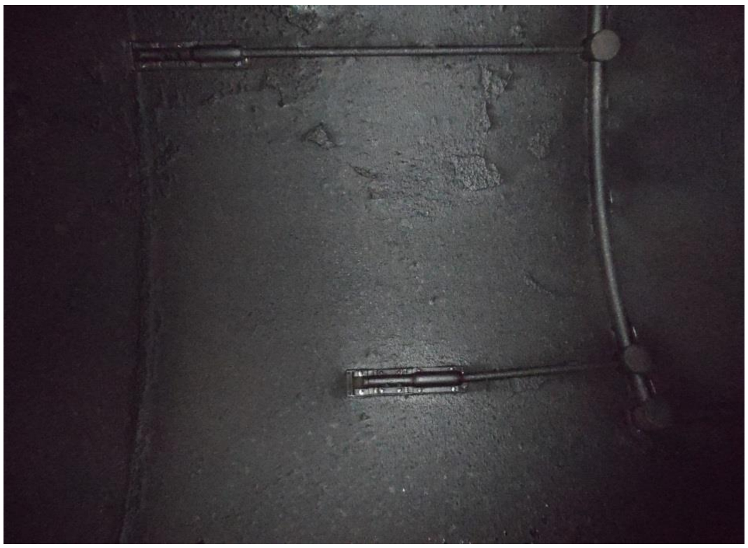
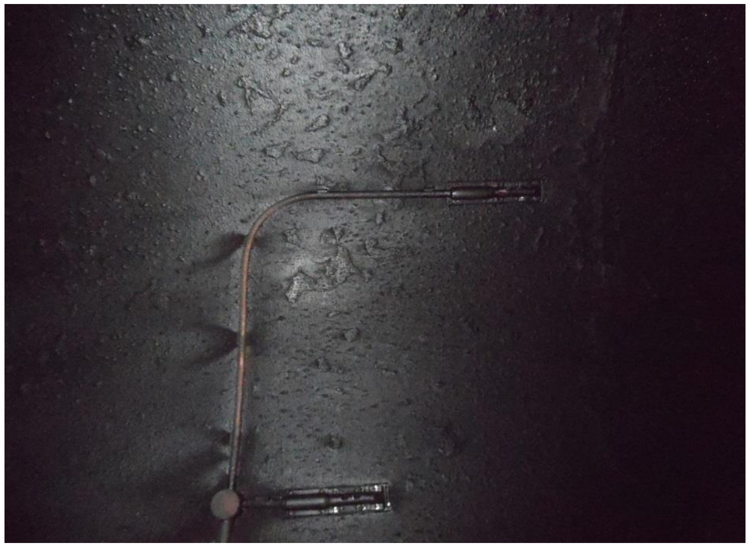
Exit hatch in scroll case.



General condition of flow meter sensors in Can 9a.



General condition of flow meter sensors in Can 9a.



General condition of scroll casing.

General condition of scroll casing.

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5.0 Ultrasonic Thickness Gauging

Calibration Block CS: #09-1266
Probe: KBA560 #01YC278
Ultrasonic Machine: Krautkramer DMS2 #12544

5.1 Tank Shell UT Results

Description: Readings were recorded as per below sketch on the following page

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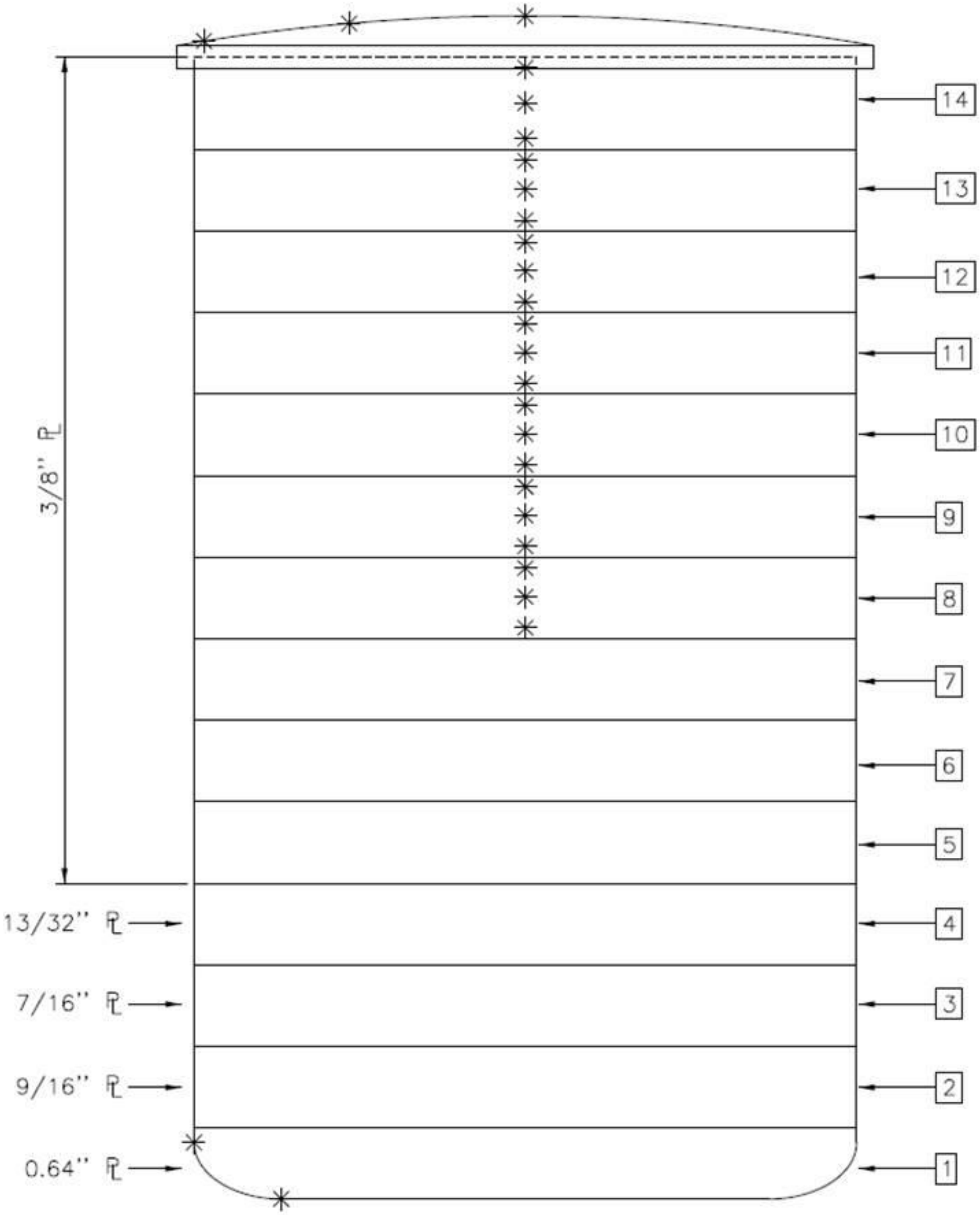

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Shell Course #	Top	Middle	Bottom	Average	Drawing Nominal	Percent Difference
Roof	0.280	0.280	0.265	0.270		
	0.280	0.280				
	0.260	0.275	0.270			
	0.240	0.280	0.260			
	0.280	0.275	0.260			
14	0.379	0.397	0.350	0.366	0.375	-2.524
	0.366	0.370	0.347			
	0.372	0.388	0.350			
	0.367	0.368	0.347			
	0.372	0.365	0.345			
13	0.335	0.357	0.359	0.350	0.375	-6.631
	0.345	0.351	0.346			
	0.351	0.357	0.354			
	0.347	0.353	0.357			
	0.343	0.356	0.341			
12	0.346	0.355	0.348	0.348	0.375	-7.147
	0.350	0.347	0.332			
	0.355	0.370	0.333			
	0.352	0.348	0.359			
	0.351	0.342	0.335			
11	0.373	0.367	0.338	0.348	0.375	-7.218
	0.330	0.349	0.339			
	0.350	0.348	0.344			
	0.346	0.351	0.339			
	0.342	0.363	0.340			
10	0.333	0.341	0.332	0.340	0.375	-9.351
	0.339	0.337	0.334			
	0.353	0.359	0.326			
	0.346	0.353	0.327			
	0.348	0.341	0.330			
9	0.340	0.343	0.361	0.355	0.375	-5.262
	0.341	0.365	0.348			
	0.343	0.380	0.370			
	0.339	0.360	0.361			
	0.343	0.370	0.365			
8	0.353	0.355		0.352	0.375	-6.267
	0.342	0.352				
	0.340	0.359				
	0.349	0.361				
	0.351	0.353				
1	0.732	0.758		0.722	0.640	12.813
	0.754	0.704				
	0.758					
	0.700					
	0.648					

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5.2 Leg 1 UT Results

Can #	Reading	Average	Drawing Nominal	Percent Difference
1	0.637	0.636	0.640	-0.594
	0.637			
	0.640			
	0.632			
	0.635			
2	0.538	0.539	0.550	-2.073
	0.534			
	0.538			
	0.539			
	0.544			
3	0.540	0.545	0.550	-0.982
	0.543			
	0.550			
	0.550			
	0.540			
4	0.585	0.590	0.600	-1.633
	0.596			
	0.590			
	0.585			
	0.595			
5	0.570	0.572	0.600	-0.982
	0.573			
	0.572			
6	0.580	0.579	0.600	-3.444
	0.578			
	0.580			
7	0.575	0.575	0.600	-4.167
	0.570			
	0.580			
8	0.605	0.603	0.600	0.556
	0.602			
	0.603			
9	0.601	0.601	0.600	0.111
	0.600			
	0.601			
10	0.640	0.648	0.640	1.302
	0.654			
	0.651			

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Can #	Reading	Average	Drawing Nominal	Percent Difference
11	0.651	0.654	0.640	2.135
	0.650			
	0.660			
12	0.658	0.660	0.680	-2.892
	0.653			
	0.670			
13	0.653	0.653	0.680	-4.020
	0.653			
	0.652			
14	0.650	0.644	0.680	-5.245
	0.643			
	0.640			
15	0.647	0.645	0.680	-5.147
	0.645			
	0.643			
16	0.652	0.654	0.680	-3.873
	0.653			
	0.656			
17	0.690	0.696	0.680	2.402
	0.700			
	0.699			
18	0.698	0.694	0.680	2.108
	0.690			
	0.695			
19	0.704	0.707	0.680	3.971
	0.708			
	0.709			
20	0.680	0.678	0.680	-0.245
	0.675			
	0.680			
21	0.685	0.687	0.720	-4.583
	0.690			
	0.686			
22	0.710	0.717	0.720	-0.463
	0.720			
	0.720			
23	0.870	0.871	0.880	-1.061
	0.870			
	0.872			
24	0.850	0.851	0.880	-3.295
	0.855			
	0.848			
25	0.955	0.953	0.880	8.295
	0.953			
	0.951			

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5.3 Leg Connection UT Results

Leg 1 is the ladder leg then going counter clockwise.

These readings were taken in a 5 point reading above and below the welds at the leg connections to the surge tank.

Leg 1	0.696	0.681	0.681	0.698	0.678
Leg 2	0.682	0.674	0.681	0.7	0.697
Leg 3	0.682	0.702	0.68	0.678	0.699
Leg 4	0.679	0.685	0.672	0.669	0.69

5.4 Penstock UT Results

The readings in the penstock were taken in a 5 point pattern at the 8 o'clock and 4 o'clock.

12 o'clock being the penstock roof looking towards the powerhouse) in the following areas:

1A					
8 o'clock	0.51	0.504	0.493	0.451	0.503
4 o'clock	0.514	0.521	0.512	0.517	0.496
2A					
8 o'clock	0.419	0.461	0.422	0.412	0.422
4 o'clock	0.437	0.42	0.405	0.435	0.413
5A					
8 o'clock	0.544	0.584	0.565	0.57	0.57
4 o'clock	0.59	0.583	0.55	0.564	0.57
10A					
8 o'clock	1.756	1.758	1.769	1.77	1.781
4 o'clock	1.773	1.775	1.781	1.774	1.781

6.0 Recommendations

Penstock - The penstock should be water blasted or wet abrasive blasted if there is not a suitable profile present after cleaning for proper application of the protective coating system. A moisture cure coating would be appropriate for the application environment and anticipated high humidity during surface preparation and coating operations. Wasser MioZinc 100 and 2 coats of MC Tar would be suitable for this surface preparation and service environment.

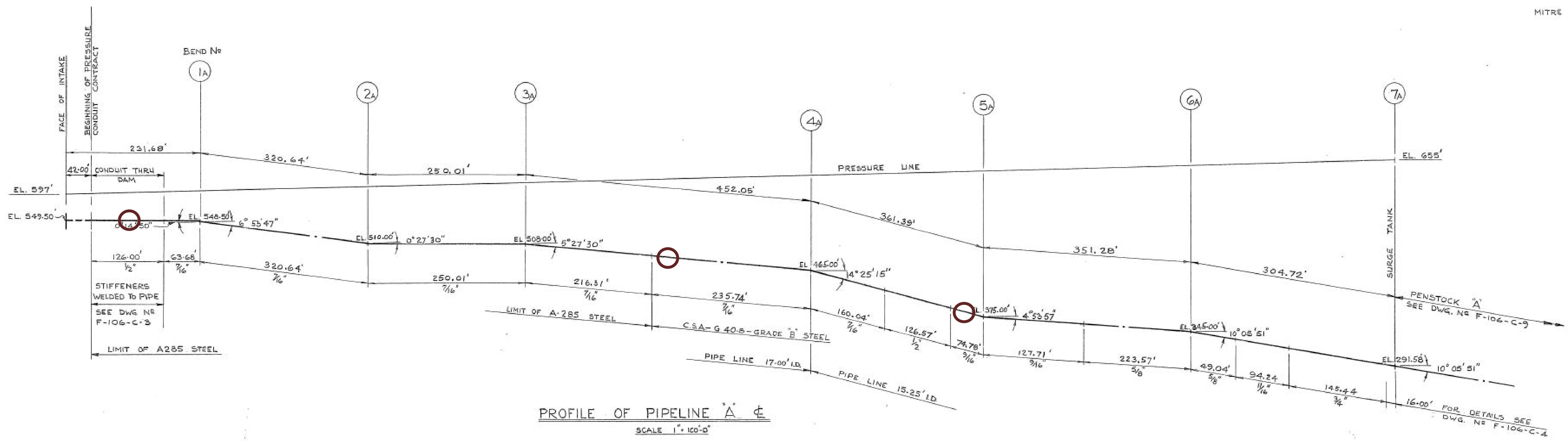
Tank Interior - The interior of the surge tank should be wet abrasive blasted, sweep blasting the entire surface and blasting those areas that require it to bare metal A moisture cure coating would be appropriate for the application environment and anticipated high humidity during surface preparation and coating operations. Wasser MioZinc 100 applied to all bare metal areas and weld seams and 2 coats of MC Tar would be suitable for this surface preparation and service environment.

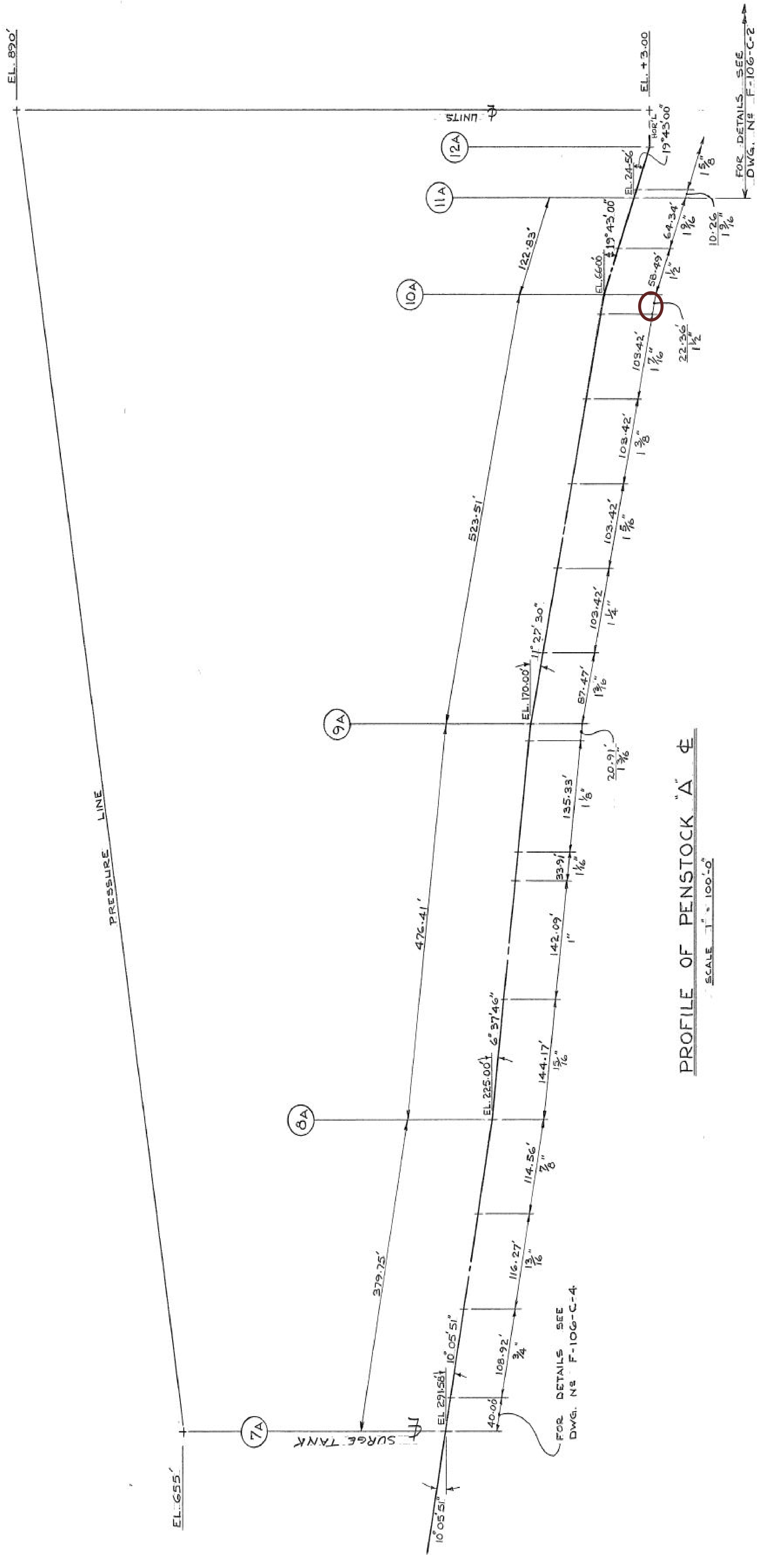
Tank exterior - The legs, beams and bracing should be prepared by high pressure water jetting @5000psi to remove all grey paint that is not tightly adhered (Adhesion of 250 psi or greater). All areas that show signs of corrosion or failure of the primer coat should be prepared to SSPC-SP2 and SSPC-SP 3 and primed accordingly. The moisture cure system is advantageous here as well as it is suited for the surface preparation and service environment Wasser MioZinc 100, MioMastic 100, MC Luster would be appropriate for exterior service.

The tank landings, ladders and roof should be prepared by high pressure water jetting @5000psi to remove all cracking paint that is not tightly adhered (Adhesion of 250 psi or greater). All areas that show signs of corrosion or failure of the primer coat should be prepared to SSPC-SP2 and SSPC-SP 3 and primed accordingly. The moisture cure system is advantageous here as well as it is suited for the surface preparation and service environment Wasser MioZinc 100, MioMastic 100, MC Luster would be appropriate for exterior service.

Other suitable coating systems exist, however this is the system that was used on surge tank #3 and proved to be beneficial to the schedule based on its characteristics.

Appendix B
Penstock UT Map


PROFILE OF PIPELINE "A" ℄
SCALE 1" = 100'-0"
BEND No
FACE OF INTAKE
BEGINNING OF PRESSURE CONDUIT CONTRACT
CONDUIT THRU DAM
EL. 597'
EL. 549.50
PRESSURE LINE
EL. 655'
SURGE TANK
PENSTOCK "A" SEE DWG. No F-106-C-9
STIFFENERS WELDED TO PIPE
SEE DWG. No F-106-C-3
LIMIT OF A285 STEEL
LIMIT OF A-285 STEEL
C.S.A-G 40.8-GRADE "B" STEEL
PIPE LINE 17.00' I.D.
PIPE LINE 15.25' I.D.
FOR DETAILS SEE DWG. No F-106-C-4
MITRE



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CRACK INVESTIGATION AND REPAIR REPORT

PENSTOCK NO.1
BAY D'ESPOIR HYDROELECTRIC DEVELOPMENT

Prepared for:

Newfoundland and Labrador Hydro
St. John's, Newfoundland and Labrador

Prepared by:

Kleinschmidt

Ontario, Canada
www.KleinschmidtGroup.com

June 2016

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CRACK INVESTIGATION AND REPAIR REPORT

PENSTOCK NO.1 AT BAY D'ESPOIR HYDROELECTRIC DEVELOPMENT

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CRACK INVESTIGATION AND REPAIR REPORT

PENSTOCK NO.1 AT BAY D'ESPOIR HYDROELECTRIC DEVELOPMENT

1.0 BACKGROUND

This report is intended to summarize the site inspection and repair recommendations of a crack that developed in Penstock No.1 at the Bat d'Espoir hydroelectric development owned and operated by Newfoundland and Labrador Hydro (NL Hydro).

On May 21, 2016 water was observed flowing down the hill next to Penstock No.1. NL Hydro investigated and found a two foot long crack on the left side of the 17 foot diameter penstock about 260 meters downstream of the intake. It was estimated that the flow from the crack was about 50L/second and was eroding the soil next to the penstock. Following the discovery the intake was closed and the penstock dewatered to prevent further crack development, stop the leak, and facilitate further investigation inside and outside of the pipe.

Kleinschmidt was retained on May 27, traveled to the area on May 28, and completed a site investigation on the May 29. Notes from that site visit are presented in Section 2 of this report with photos in Appendix B.

2.0 SITE INSPECTION

On May 29, 2016, Christopher M. Vella, P.E., S.E., P.Eng, arrived on site to visually inspect the penstock and crack. Photographs taken during the inspection are in Appendix B of this report. Mr. Vella made the following observations:

- The crack was located at Station 0+260 as measured from the intake (Photo 1) and was measured to be 24.5 inches long from what could be seen visually (Photo 3). Per Drawing F-106-C-7, this location approximately corresponds to Bend No. 3A.
- The crack was observed to be in the base material (penstock plating) and not through the weld material (Photo 2). This cracked area is in what is considered the heat effected zone where the welding process heats the base material enough to alter the properties without melting it. This zone tends to be more brittle than the original base material.
- Rust/corrosion was noted in the crack and was too mature to have developed since the leakage was first observed on May 21 (Photo 5). This indicates that a portion of the crack was initiated prior to the May 21 incident. The rust was light enough that it is likely less than 5 years old but certainly more than a few months.
- Tacten personnel in the pipe recorded video of the crack and the crack appears longer in the video than it does outside of the pipe. The crack could not be reached inside the pipe to measure and verify the length. It was recommended that non-destructive testing (NDT) be performed to verify crack length. (*This was done and results are in Appendix D*).
- Inside measurements were taken to determine if the pipe is out-of-round. Measurements were taken ten feet upstream of the crack and ten feet downstream of the crack. Vertical measurements were taken from the 6 to 12 o'clock positions, and measurements from the 2 to 8 o'clock positions and from the 4 to 10 o'clock positions were taken. Horizontal (3 to 6 o'clock) measurements could not be obtained due to the height of this area and reach limitations.
  - Measurements 10' upstream:
    - 16'-9" (vertical)
    - 17'-2" (4 to 10 o'clock)
    - 16'-11" (8 to 2 o'clock)
  - Measurements 10' downstream:
    - 16'-10" (vertical)
    - 17'-2" (4 to 10 o'clock)
    - 16'-11" (8 to 2 o'clock)

- The out-of-round measurements show the pipe is "squished" by as much as 3" vertically which is less than 2% of the diameter. This is amount is not a concern, would not have caused the crack, and is common for buried large diameter penstocks with high diameter to thickness ratios. Proper compaction and material of the bedding from the invert to the spring line is critical to help support and maintain shape so degradation over time of the bedding material can result in some ovalization of the pipe.

- Ultrasonic thickness readings were taken of the plate around the crack. The average of the readings is 0.422 inches which compares to 0.4375 inches as specified on the drawings. The difference (0.015" or 1/64 th) is minor and within the manufactured tolerance of the plate. This would not have been a direct cause of the failure.

- A section of the backfill/side material on the left side (from point of view looking downstream) of the penstock was slumped several feet vertically for about 40 meters upstream and 40 meters downstream of the crack location (Photos 1 and 8). The most likely cause is saturation of the material which has a high fines content and is susceptible to slope instability due to saturation. Because a penstock leak can cause saturation of the material and lead to slope failure of this kind it is reasonable to assume that a penstock leak may have caused this slope failure and the corrosion in the crack indicates the crack initiated many months before being observed. Because the saturation would not normally go upstream very far, it was recommended that the material upstream of the crack and above the bedding material be pulled out of the way to allow for visual inspection of the penstock upstream of the crack to insure there are no other cracks that may have cause saturation of the fill material in this area.

- The exterior of the penstock was walked along its length to look for possible other areas of settlement, slumps and wet spots. Nothing was found to be concerning or that might indicate other leakage areas.

- The first drain well downstream of the crack location had less than 1 gal/min of flow as visually estimated from looking down from the top. The concrete trough at the bottom was visible and there was no significant build-up of sediment.

- The next drainage well located immediately upstream of the surge tank was half full of water and the bottom could not be seen. It was recommended that this be pumped out and the drainage pipe cleaned to restore flow.

- The site review included discussions about and review of the filling procedure used. The procedure is well thought out with good control, monitoring, and checks in place to ensure the pipe is not overstressed. We found no fault with the filling procedure.

2.1 Probable Cause

The failure was likely initiated by a local defect in the material or weld. Because of its location in the heat effected zone at the interface of the weld and base materials it seems like the initial cause might be incomplete fusion. This could be caused by a variety of reasons such as:

1. Incompatibility between the base and weld materials. Unlikely if no other problem areas have been observed at this point in the penstocks life.
2. Improper welding procedure. This id also unlikely if no other problem areas observed.
3. Location specific welder error (e.g. the slag wasn't properly cleaned in this area, or a crater crack). This seems most likely.

Several cycles of dewatering and watering and thermal changes over the years would have caused the crack to initiate at the defect and further loading cycles to increase the size, even if only by a very small amount (<mm). Dewatering the penstock in the spring allows the pipe to warm up and then filling the pipe with cold spring water would result in some of the greatest thermal variance the pipe would see and could cause an existing crack to propagate.

There are no guarantees that there are no other defects or active leaks in the penstock, however, there are no other areas on the penstock that show signs of slumping or to be excessively wet (as may be indicated by vegetation associated with wet areas). There was no significant signs of settlement or misalignment of the penstock and the penstock is not excessively out-of-round. The squish is to the degree that could be expected for a pipe this size so is not a concern.

It is my opinion that once the crack is fixed, and no other cracks are found upstream of the current crack, it is my opinion that the penstock will be safe to fill and operate.

2.2 NEXT STEPS IDENTIFIED FOLLOWING INSPECTION

The following steps were provided to NL Hydro on May 30 and the status of the step as of this report has been noted:

1. Push the penstock plate back into position as best practicable. Using the excavator as an anchor point to push from, place an I-beam (or similar) against the bulge in the penstock, heat the plate area with a torch, and then apply pressure using a jack pushing off the excavator. Insure flush connections between the jack and beam and excavator in order to avoid slipping and sudden load release. This will be difficult because of the pipe slope. Bolt connections when possible between pieces to safeguard against flying parts in the event of a slip is advised for worker safety. (*This step has been completed*)

2. Hydro to work with Tacten to weld in tabs and setup staging inside the penstock in preparation for welding. (*This step has been completed*)

3. Remove exterior coating for at least 6 inches above and below the crack to facilitate testing and welding. Clean area inside penstock for welding. (*This step has been completed*)

4. Once penstock plate is in position the plate/weld should be tested to verify the length of the crack. Shear wave (or angled beam) testing is the preferred method to determine the length of the crack because it is better suited to find deep defects compared to magnetic particle testing. (*This step has been completed and it was found that the crack was 29.5 inches long. NDT results are in Appendix D*)

5. Once the weld testing is complete and the length of crack has been verified by Tacten and confirmed by Kleinschmidt the crack can be cleaned and prepared for welding by grinding out the crack to clean surfaces with an opening large enough to allow for welding access/penetration. (*This step has been completed. Note that preparing the weld surfaces and angles would have been completed after Step 7 below*)

6. Kleinschmidt to complete stress analysis to confirm weld and plate sizing and determine the need for backfill before Friday. Kleinschmidt to advise if backfill required to satisfy allowable stresses and structural integrity of the penstock when full of water. (*This step has been completed. On Thursday June 2 Kleinschmidt advised that the soil backfill was not required for the structural integrity of the penstock in this location*)

7. Kleinschmidt to advise on go for weld and discuss procedure with Tacten welder to complete weld repair of crack. (*Kleinschmidt provided weld procedure and green light for weld on Thursday June 2. A discussion with welder was not had and determined not required for this relatively standard full penetration weld. Kleinschmidt did confirm procedure/intent with Lev Kearley of NL Hydro on Thursday evening. Preparation and*

welding started Thursday night and was completed early Friday. Tests of the new weld are attached in Appendix E)

8. The Devoe Bar Rust 236 is an adequate protective coating for the exterior of the penstock to be applied after welding is complete and the area cleaned. (*Complete*)

9. Pump out drain monitoring well located just upstream of the surge tank and attempt to clear blockage. (*This has been completed*)

10. Monitor flow in drain monitoring wells prior to filling the penstock and then monitor daily following filling for 4 days than weekly for a month. If flow in the wells increase than penstock leakage is likely and volume and turbidity should be assessed. (*Preparation has started for this*)

3.0 ANALYSIS

Stress analysis calculations were performed on the penstock to confirm proper plate sizing for conditions to rule out design error, and to determine need for backfill in area when watered up. The internal pressure or hoop stress was calculated at the crack location for both normal pond and maximum pond (flood) elevations. Buckling of the penstock was also analyzed using external loads on the pipe, mainly soil and snow. The analysis is included in Appendix C.

3.1 INTERNAL PRESSURE

A normal pond elevation of 182.6m (599.08ft) and a flood pond elevation of 184.2m (604.3ft) were used in the hoop stress analysis. The crack location roughly corresponded to Bend No. 3A on Drawing F-106-C-7, which is at approximately El. 508.00ft. Also on the same drawing, the steel type was noted as ASTM A285. A285 Grade C steel was assumed as it is typically used for this large size pipe. A penstock wall thickness of 0.42in was used throughout the analysis based on ultrasonic thickness measurements taken during the field inspection.

The allowable stress intensity is based on the steel yield and ultimate strength values and was calculated as 20 ksi (138 MPa). Both the hoop stress due to normal pond loading and due to flood loading, 14.75 ksi and 15.60 ksi respectively, were less than the allowable stress intensity.

3.2 EXTERNAL PRESSURE

The penstock was analyzed for buckling due to external loads applied to the top 120 degrees of the pipe. The analysis was very conservative as it included the dead weight of the whole shell and the dead load of the water inside. The snow load calculated was approximately 130 psf (6224 Pa). The depth of soil cover on the penstock used was 2ft (0.6m). Another conservative value applied to the top of the penstock was a live load of 100 plf. No vehicular loading was used in the analysis. Also, because the penstock is buried, wind and earthquake were not used in the analysis.

Typical load combinations were calculated and the one producing the maximum load was used. The maximum pressure calculated due to shell dead load, water dead load, soil cover, live load, and snow load was 9.68 psi (66.7kPa). The allowable buckling pressure was calculated as 13.4 psi (92.4kPa).

3.3 CONCLUSION

The stress analysis calculations showed the penstock is adequate as is with calculated stresses well below allowable. Also, because the crack has not opened to a large gap, the suggested weld repair would be a complete joint penetration groove weld as it develops the strength of base material and would satisfy the stress requirements. Leaving the top of the penstock unburied for 30ft +/- will have no ill effect on the penstock's performance.

4.0 RECOMMENDATION AND PROCEDURE

Based on site observations and the analysis discussed on Section 3 above we recommended a complete joint penetration groove weld as the preferred repair as it develops the strength of base material and would satisfy the stress requirements. A plate that would lap over the area and be welded on was also considered and ruled out as unnecessary and potentially requiring more effort to shape the plate to get flush contact around the edges. It would also leave the crack open and able to corrode as getting a good coating in the crack would be very difficult. The proper way would be to remove the crack and close the opening with weld as is being recommended.

4.1 RECOMMENDED REPAIR

Based upon the available information the crack appears to be location specific and is not indicative of a general incompatibility of the existing penstock's weld and base material. Therefore, we recommend weld repair of this specific crack with the following procedure.

1. Remove all existing cracking:
    a. Remove the existing crack by either grinding or carbon air arc gouging.
    b. Magnetic Particle (MT) test the cleaned area, particularly the crack ends to confirm that there is no residual cracking.
    c. If additional cracking is discovered, remove crack and extend removal at least 200mm (8 inches) into sound metal beyond the crack's end.
    d. Retest entire repair area by MT and repeat steps 1.c and 1.d if necessary.
    e. All Non-Destructive Testing (NDT) shall be performed by personnel currently certified to CAN/CGSB-48.9712-2014 Level II or higher for the specific technique being used.
    f. All NDT testing shall conform to the American Society of Mechanical Engineers (ASME) Pressure Vessel and procedures and acceptance criteria.
    g. All MT testing shall be in accordance with ASTM E709-15 Standard Guide for Magnetic Particle Testing.
2. Welding Procedure:
    a. Per the *Profile of Pipeline "A" CL* on Newfoundland Drawing F-106-C-7, the penstock's base material appears to be ASTM A285 steel in the area of the crack (around Bend Number 3A). The material composition of this pressure vessel plate steel (assumed Grade C) is 0.28% Carbon (C), 0.20-0.35% Copper (Cu) by heat

analysis, 0.18-0.37% Copper (Cu) by product analysis, 0.9% Manganese (Mn) by heat analysis, 0.98% Manganese (Mn) by product analysis, 0.035% Phosphorus (P), and 0.035% Sulphur (S).

b. The penstock's shell shall be welded with a full penetration groove weld in accordance with a welding procedure that complies with either the ASME Section IX Welding and Brazing Qualification, or CSA Standard W59-13 Welded steel construction (metal arc welding).

c. It is anticipated that most of the welding shall be performed downhand from the exterior of the penstock shell. The procedure shall include backgouging of the back underside of the root pass.

3. Repair Execution:

   a. All welding shall be performed by personnel currently certified to either ASME Section IX or CSA Standard W47.1 Fusion Welding of Steel Company Certification for the approved welding procedure to be used.

   b. After the underside of the root pass is backgouged, the repair weld shall be MT tested before placing the cover pass(es).

   c. After completion of all the welding the repair shall be either MT or Ultrasonic Tested (UT). All UT testing shall comply with the procedures in ASTM E1962-14 Standard Practice for Ultrasonic Surface Testing Using Electromagnetic Acoustic Transducer and acceptance criteria in ASME Section V Nondestructive Examination.

4.2 FOLLOW-UP

It is recommended that the penstock be inspected in two years with specific attention paid to reviewing the deterioration of the internal coating system and to inspecting the repaired area. If the penstock is scheduled to be dewatered on either side of two years than that would be an acceptable time to inspect the penstock to avoid excessive down time if no outages are planned in exactly two years.

Based only on the Hatch penstock report (January 2016) and on site observations it is recommended that the interior of the penstock be recoated within ten to fifteen years. The interior coating system is failing and light surface rust was noted. A typical practical approach to determining a recoating timeline would be to clearly mark a few spots where the existing coating has delaminated and monitor these exact locations to see how quickly corrosion, particularly surface pitting, develops. If you visually inspect and UT measure thicknesses at identical monitoring spots once every year or two for 3 to 5 years you should have a realistic determination of the rate of corrosion. Pitting development is particularly troublesome because it: 1) obviously decreases the base metal's strength, and 2) the pits will have thinner coating thicknesses around the edges that shorten a coating's service life. The interior should be cleaned and coated prior to significant corrosion and pitting development. We have seen the interior of uncoated 100 year old penstocks very smooth (e.g. PacifiCorp Pioneer penstock in 2014), and newer ones heavily pitted. (e.g. Enel Pyrites new unit at only 11 years old in 2006). A big difference we've noticed is if the penstock is buried or above ground.

Steel corrosion generally requires oxygen, and as the steel surface rusts it prevents oxygen from penetrating deeper. But if the surface rust is disturbed, such as when an above grade penstock expands and contracts the surface rust delaminates from the substrate allowing oxygen to penetrate deeper and continue substrate corrosion. Buried penstocks are a more stable environment and therefore generally display less corrosion and surface pitting. Also conditions such as the water quality (e.g. low chloride), the type of soil burying the penstock, and galvanic potential between mating materials (e.g. weld filler and base steel) can have a significant effect. Based on past performance of similar penstocks it would take several decades for the corrosion to degrade the penstock shell to the point that the structural integrity would start to become compromised based purely on section loss; however, to maintain safety factors, to avoid localized stresses that pitting could develop, to ensure longevity of a new coating system and a long service life for the penstock, it is advised that the penstock be recoated in less than ten years. At this time it is understood that Penstock No. 2 will be inspected this summer. Because this author has not been in either Penstock No. 1 or Penstock No. 2, it is recommended that the inspector make specific observations and recommendations in their report regarding the coating system of Penstock No. 2 and should mark a few locations for future testing to observe rate of deterioration.

We can provide a coating specification if required.

5.0 PENSTOCK INSPECTIONS

Newfoundland Hydro asked what would be a typical inspection frequency and what would be part of a typical penstock inspection.

5.1 INSPECTION FREQUENCY

There is no set industry standard that recommends all penstocks should be inspected at a set frequency. Our experience has been that a penstocks inspection frequency should be determined on a case by case bases after considering several factors which include:

- Age of penstock
- Type of penstock
- Coating system
- Support system
- Buried or unburied
- Water quality and sediment load
- Frequency of load rejections
- Hazard Class
- Access issues
- Criticality of facility to power production

A penstock should have an exterior inspection by the owner every 1 to 5 years depending on the factors listed above. If at a manned facility a walk of the exterior by operations staff monthly is not unusual and at least annually is common practice for all penstock types. In general, a newer steel penstock (less than 30 years old) would be inspected at least every five years by the owner and have a full internal inspection by a qualified engineer about every ten years, planned around outages, and generally would concentrate on interior and exterior coating, settlement and movement of penstock and supports, shape, and condition of penetrations. Future frequency of inspections would be dependent on the findings of the previous inspections and would be largely dependent on how well the coating system is holding up and if any structural concerns were developing. Specific non-destructive testing of welds would not typically be included unless an observation and recommendation from the inspector required it. An older steel penstock (more than 30 years as this is the life expectancy of some coating systems) with no significant issues but with coating system deterioration should have an internally inspection every five years by a qualified engineer to track the rate of coating deterioration and corrosion development such that a timeline can be developed for recoating or patching. An older steel penstock with known issues (thinning sections, patches, significant corrosion, leaks, settlement, etc.) should be inspected at least annually by the owner and two to five years by a qualified engineer who would be involved in recommending repairs and a timeline based on degree and type of issues. Selective non-destructive testing of welds would be expected to start every five years or when recommended by the inspector.

An old wood stave penstock (there are no new ones) in good condition should have an exterior inspection annually by the owner with five year inspections by a qualified engineer experienced with wood stave penstocks. A wood stave penstock with known issues (significant leaks, patches, rotting wood, significantly corroded banding) should be inspected at least semi-annually by the owner as this type of penstock can develop issues quickly in harsh environments and this will facilitate repairs that can become an annual maintenance item. Inspection by a qualified engineer may be required bi-annually or annually depending on the amount and rate of deterioration.

A new fiberglass penstock would be expected to go 10 to 15 years before its first internal inspection and another ten before its second. Future frequency of inspections would be dependent on the findings of the previous inspections and would be largely dependent on if any structural concerns were developing (ovaling, settlement, leaks, UV related deterioration, hairline cracking).

These are general timelines based on our experience and more specific timelines would require knowledge of the penstocks. With the appropriate information (material, buried or unburied, support type, age, drawings, coating info, and inspection reports) we could perform a simple desk top study to provide preliminary recommendations for inspection frequency for specific penstocks that could be refined as penstocks are inspected and the condition and rate of deterioration is assessed.

Inspections are generally carried out by experienced and qualified engineers that may be staff engineers or consultants. Independent or third party inspections of penstocks is not widely required by regulation in the industry at this time but often done by owners looking for an independent review or without qualified staff. The Federal Energy Regulatory Commission

(FERC) in the United States is currently developing guidelines for penstock inspections but these have not yet been released. The CDA Guidelines do not address penstock inspections in any significant detail.

5.2 Inspection Scope

I have provided here a summary of what a typical steel penstock inspection scope should include but the scope is typically tailored for each site. I have left out means and methods as that would add significant detail and could be a report on its own for all the various aspects.

1. Document review – Review of available documents is important to understand the penstock prior to performing the inspection. Documents that we would normally ask for include:

    a. Design and Construction history review including drawings, design criteria, design calculations, foundation information, and maintenance records.

    b. Operational History review such as steady state conditions, operating records, reservoir rule curves, headwater and tailwater rating curves, transient flow conditions, load acceptance and rejection tests, and wicket gate opening/closing times.

    c. Previous inspection reports

2. Exterior Inspection – A walk down of the exterior of the penstock buried or unburied preferably when the pipe is at operational pressures. For buried penstocks you're looking for slumps or sloughing of sloped material next to penstock, for wet areas, significant depressions, settlement, and holes. A penstock would need to be deep (more than twice its diameter from crown), in a rock tunnel, or overgrown to consider not walking the exterior. For exposed penstocks you should take wall/shell thickness readings with UT gage at representative locations (at least every time the pipe changes thickness, material, or coating). An inspection should check alignment, settlement and condition of supports, sagging of penstock between supports, out-of-roundness, and condition of coating with paint thickness measurements if applicable. Condition of ring girders and saddle supports should be reviewed along with all joints. Welded, riveted, and bolted joints,

seams and connections should be visually inspected. All penetrations should be inspected including vent pipes, stand pipes, piezometers, surge tank entrance, and valves. Thrust blocks should be reviewed for condition and movement/settlement. The surge tank should also be inspected but this may be separated from the penstock as this can be a significant effort on its own.

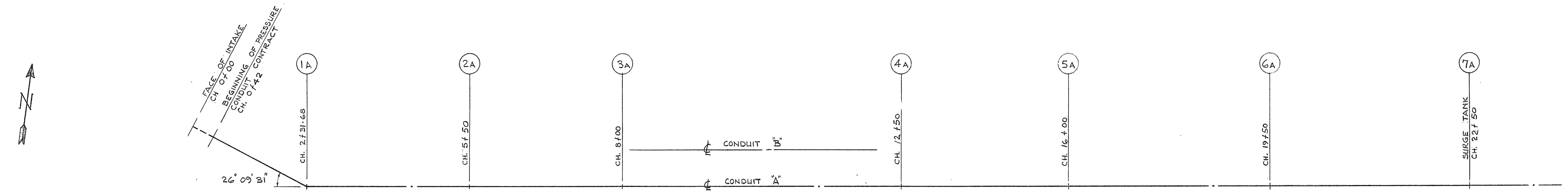
3. Interior Inspection – A dewatered inspection of a penstock is the best way to check for corrosion, erosion, and cavitation, the condition of coating, and a good way to measure out-of-roundness but understand that the degree of out-of-roundness will be more when dewatered than when at operational pressures. The coating and the wall thickness should be measured at representative intervals at the invert, crown and spring line and a few places of corrosion should be marked for future inspections such that rate of deterioration can be assessed. Organic growth should also be commented on (thickness, type, is it affecting the coating). It is expected that all personnel safety requirements will be followed (confined space, safe work plan, Rescue Plan, fall arrest, etc)

4. Stress analysis – if an analysis is not available then consider analyzing the penstock for current operating conditions, wicket gate closure times, and with current shell thickness.

5. Report – a detailed report of all observations based on the above scope with specific recommendations with timelines for mitigation, repairs, coatings, and follow-up inspections if required.

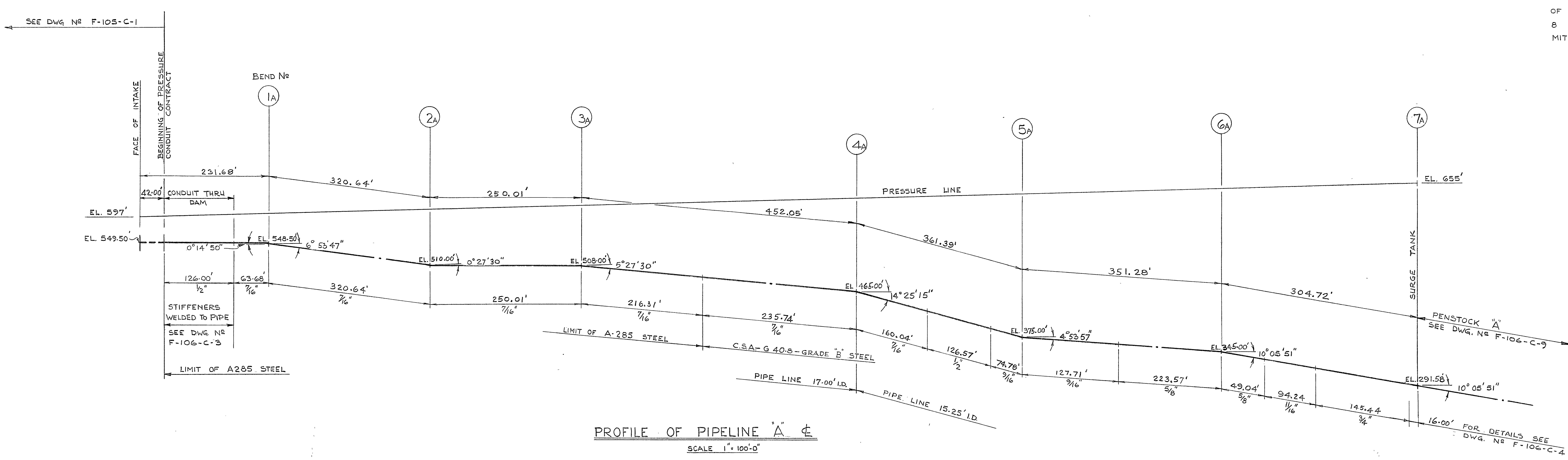
APPENDIX A

FIGURES



PLAN OF PIPELINE "A" ℄

SCALE 1" = 100'-0



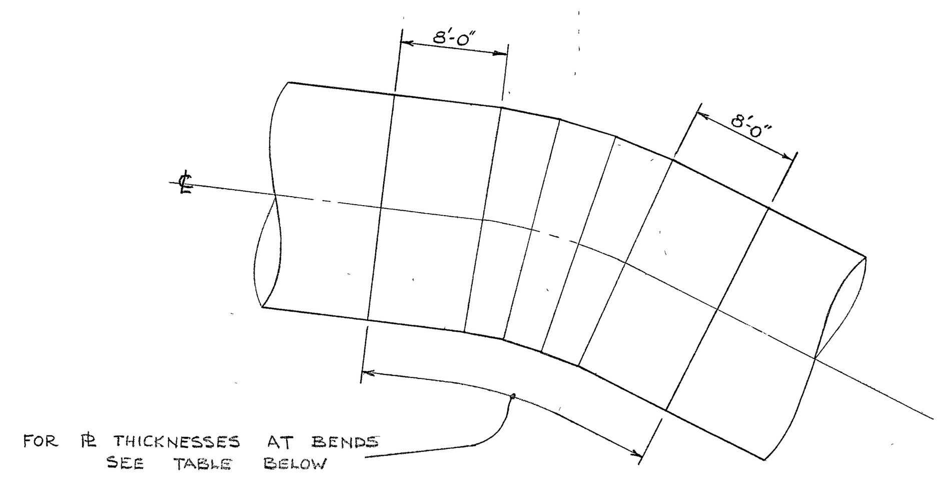
PROFILE OF PIPELINE "A" ℄

SCALE 1" = 100'-0"

NOTES

1. THE PRESSURE CONDUITS SHALL BE CALLED "A" AND "B". CONDUIT "A" IS SOUTH OF CONDUIT "B" AND SHALL BE COMPLETED IN 1966. CONDUIT "A" CONSISTS OF PIPELINE "A" AND PENSTOCK "A".

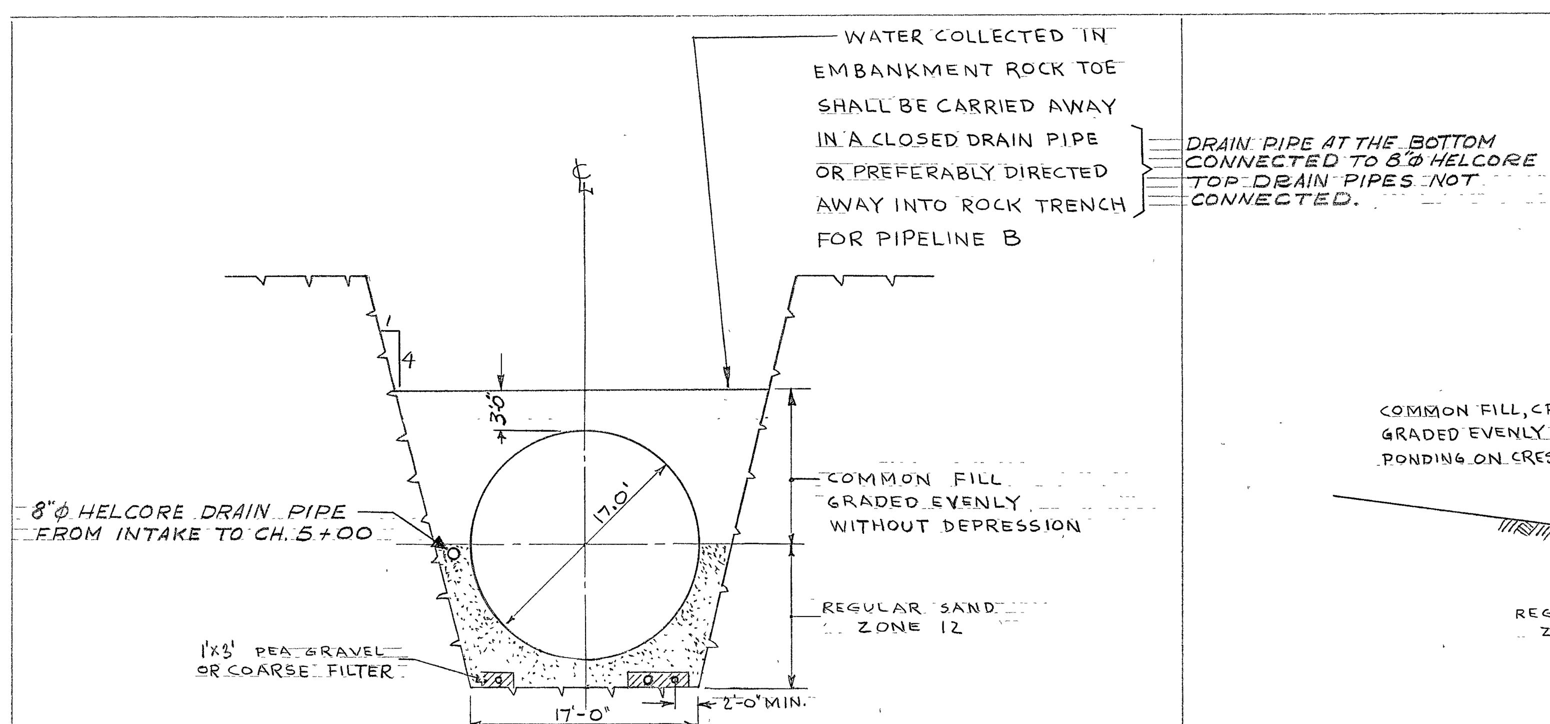
2. THE PIPELINE SHALL BE DESIGNED IN ACCORDANCE WITH SPECIFICATION Nº M-3116 EXCEPT FOR BENDS WHERE 1/8" SHALL BE ADDED TO PLATE THICKNESSES CALCULATED TO RESIST HOOP TENSION PLUS THE EFFECTS OF THE TORUS SHAPE OF BENDS. THIS EXTRA THICKNESS OF 1/8" SHALL EXTEND OVER THE BENDS AND AT LEAST 8 FEET UPSTREAM AND DOWNSTREAM OF THE LAST MITRE JOINT.



TYPICAL BEND

SCALE 1" = 10'-0"

SEE SPEC. M-3116

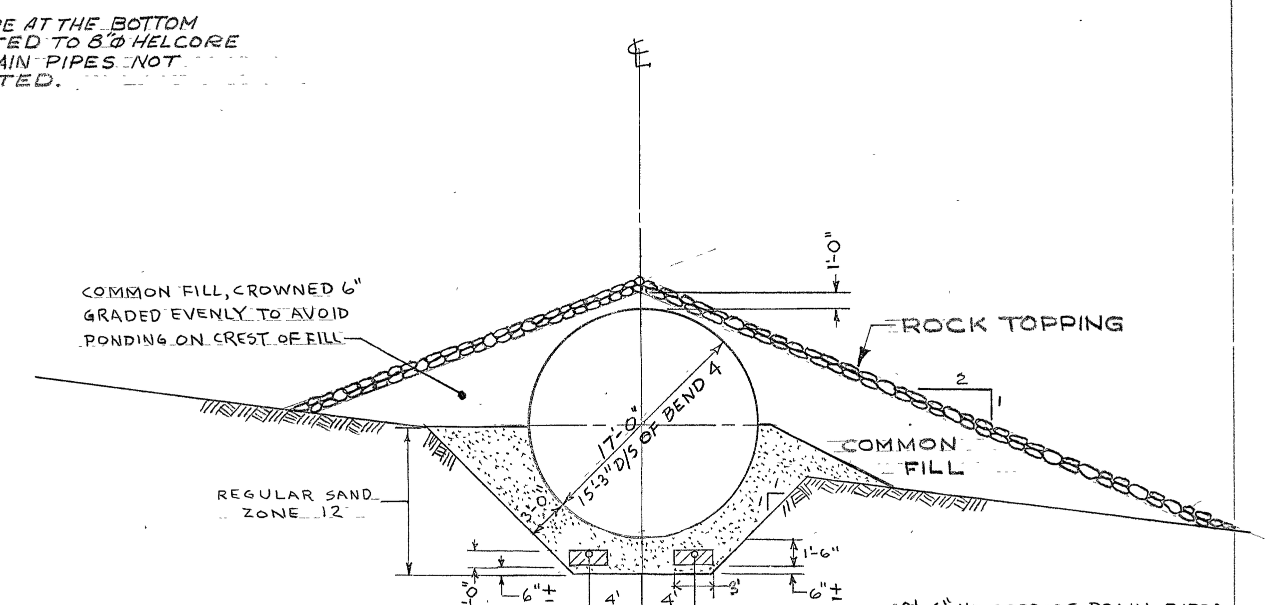


2—6" NO-CORRODE DRAIN PIPES NEAR TOP OF LAYER WITH DRAIN HOLES FACING DOWN

1—8" HELCOR PIPE FROM INTAKE BOX DRAIN

4 TYPICAL SECTION UPSTREAM OF BEND 7A IN ROCK CUT

SCALE 1" = 1'-0"



2—6" NO-CORRODE DRAIN PIPES, INSIDE COARSE FILTER OR PEA GRAVEL HOLES FACING DOWN

DRAIN PIPES PLUGGED AT UPPER ENDS NEAR THE CROSS DRAINS.

4 TYPICAL SECTION UPSTREAM OF BEND 7A IN EARTH TRENCH

SCALE 1" = 1'-0"

PERVIOUS LAYER ZONE 12 MATERIAL AND FILTER MUST BE SEALED WITH IMPERVIOUS FILL IMMEDIATELY DOWNSTREAM OF EACH CROSS DRAIN TO PREVENT SEEPAGE WATER FROM BY-PASSING THE CROSS DRAINS.

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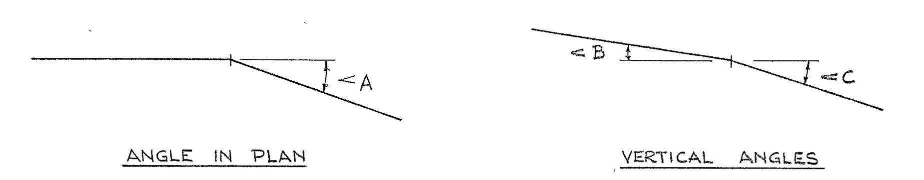
ANGLES & ℙ THICKNESSES AT BENDS

BEND	<A	<B	<C	TRUE ANGLE	ℙ THICKNESS
1 A	26° 09' 31"	0° 14' 50"	6° 53' 47"	26° 55' 34"	7/16"
2 A	——	6° 53' 47"	0° 27' 30"	6° 26' 17"	1/2"
3 A	——	0° 27' 30"	5° 27' 30"	5° 00' 00"	1/2"
4 A	——	5° 27' 30"	14° 25' 15"	8° 57' 45"	9/16
5 A	——	14° 25' 15"	4° 53' 57"	9° 31' 18"	3/4"
6 A	——	4° 53' 57"	10° 05' 51"	5° 11' 54"	13/16
7 A	——	10° 05' 51"	10° 05' 51"	0° 00' 00"	



ANGLE IN PLAN

VERTICAL ANGLES

REFERENCE DRAWINGS

F-106-C-3 CONDUITS THROUGH DAM
F-106-C-4 SURGE TANK-DETAILS OF TEES
F-106-C-5 " " -GENERAL LAYOUT & DETAILS
F-106-C-6 PRESSURE CONDUITS-CLEARING
F-106-C-8 " " -EXCAVATION & DRAINAGE
F-106-C-9 " " -PENSTOCK A
F-106-C-10 " " -PENSTOCK B

OTHER REFERENCES

1. SPECIFICATION No. M-3116

NO.	DATE	LOCATION	DESCRIPTION	MADE BY	APPR'D
5	2-6-68		AS BUILT, FROM FIELD INFORMATION	A.B.	JHM
4	5 JAN '67		2 TYP. SECTIONS CHANGED, ONE REMOVED	A.R.	
3	9 DEC '66	1,2,3,4	3 TYPICAL SECTIONS ADDED	A.R.	JHM
2	20 SEP '65		REVISED PROFILE & PLATE THICKNESSES	A.R.	
1	AUG '65		EL. @ BEND 4 CORRECTED, MINOR REVISIONS	J.P.	JHM

REVISIONS

APPROVED FOR CONSTRUCTION
JUL 16 1965
APPROVED BY:
MANAGER ENGINEERING

DESIGNED R. MacD.
DRAWN J.P.
CHECKED
RECOMMENDED JH Maier P.Eng

TRANS'N | ELECT'L | CIVIL JHM
PASSED

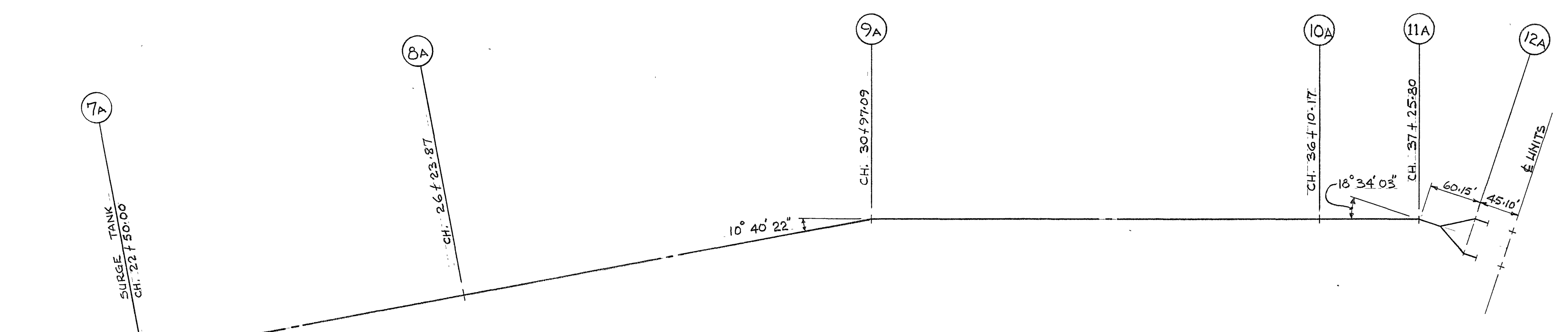
NEWFOUNDLAND AND LABRADOR POWER COMMISSION

BAY D'ESPOIR DEVELOPMENT

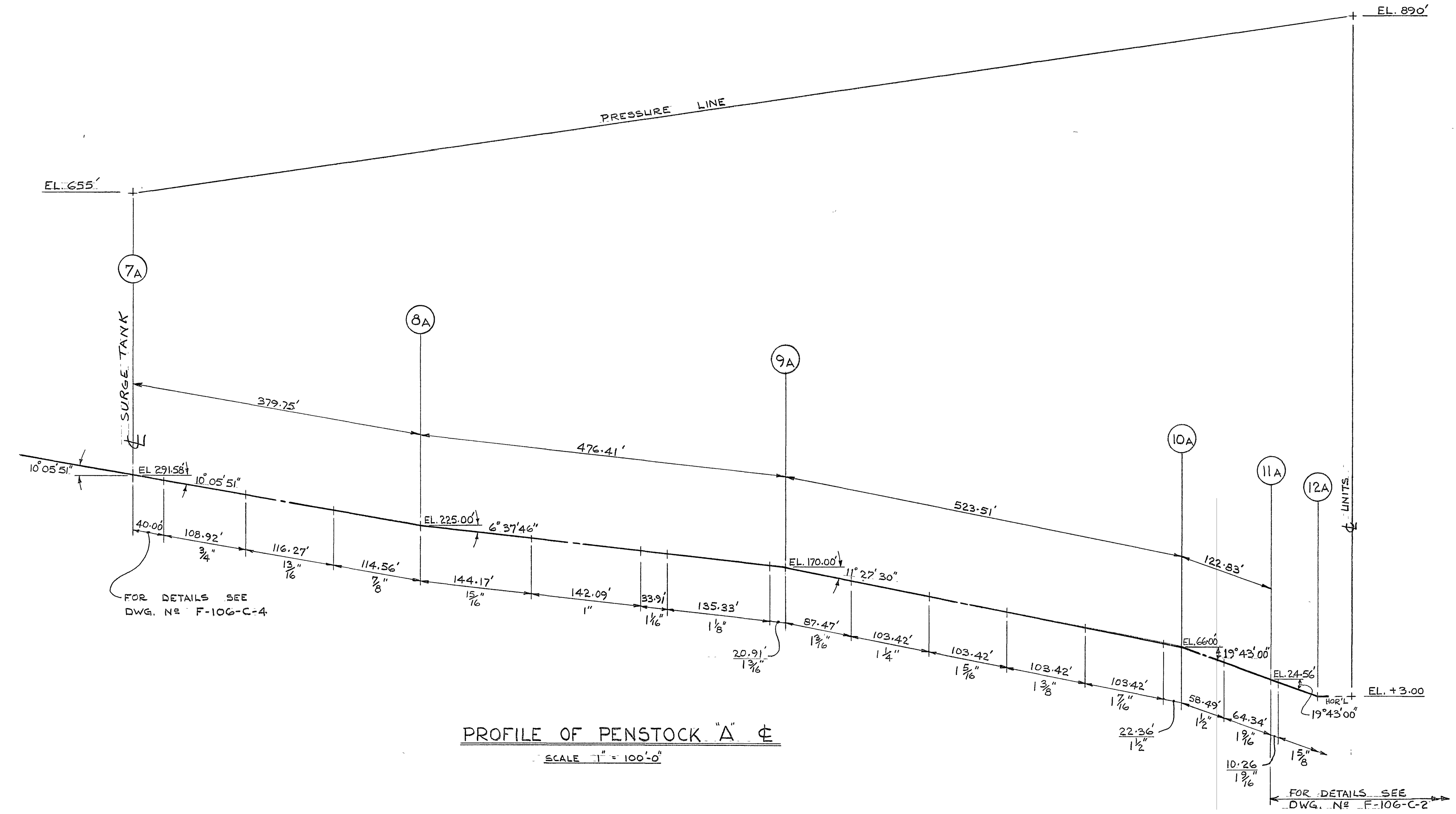
ENGINEERING AND DESIGN BY
SHAWMONT ENGINEERING NEWFOUNDLAND LIMITED
MONTREAL, QUEBEC

PRESSURE CONDUITS
PLAN & PROFILE PIPELINE "A"

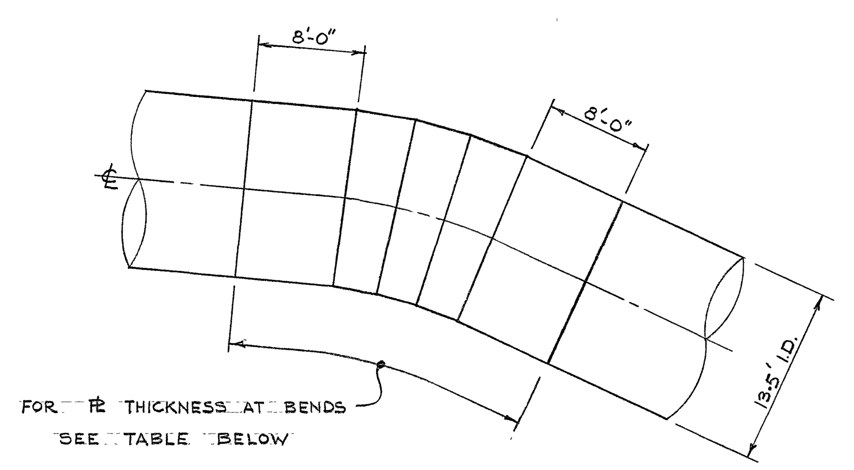
CONTRACT	SCALE	FILE NO.	DATE	DWG. NO.	REVISION
	NOTED	PD - 11	JULY 16, 1965	F-106-C-7	5



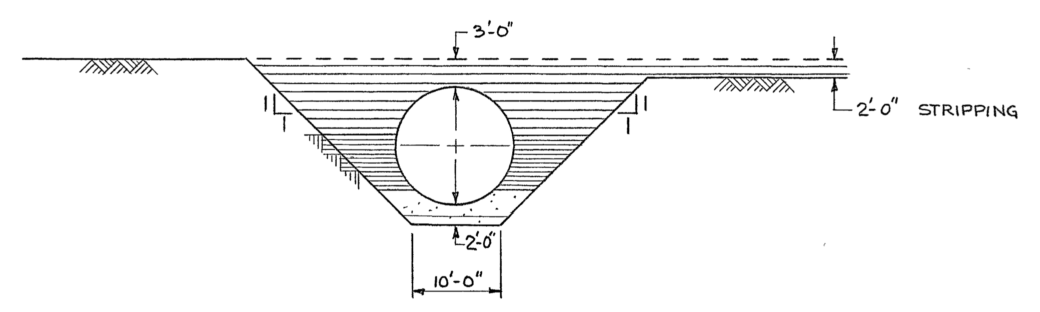
PLAN PENSTOCK 'A'
SCALE 1" = 100'-0"



PROFILE OF PENSTOCK 'A' ℄
SCALE 1" = 100'-0"



TYPICAL BEND
SCALE 1" = 10'-0"



TYPICAL CROSS SECTION (9A) TO (11A)
SCALE 1" = 15'-0"

BEND	< A	< B	< C	TRUE ANGLE	℘ THICKNESS
7 A	——	10° 05' 51"	10° 05' 51"	0° 00' 00"	——
8 A	——	10° 05' 51"	6° 37' 46"	3° 28' 05"	1 1/8"
9 A	10° 40' 22"	6° 37' 46"	11° 27' 30"	11° 35' 25"	1 3/8"
10 A	——	11° 27' 30"	19° 43' 00"	8° 15' 30"	1 3/4"
11 A	18° 34' 03"	19° 43' 00"	19° 43' 00"	17° 28' 12"	1 7/8"

ANGLES & ℘ THICKNESS AT BENDS

ANGLE IN PLAN

VERTICAL ANGLES

NOTES

1. THE PENSTOCK SHALL BE DESIGNED IN ACCORDANCE WITH SPECIFICATION Nº M-3116 EXCEPT FOR BENDS WHERE 1/8" SHALL BE ADDED TO PLATE THICKNESSES CALCULATED TO RESIST HOOP TENSION AND THE EFFECTS OF THE TORUS SHAPE OF BENDS. THIS EXTRA THICKNESS OF 1/8" SHALL EXTEND OVER THE BENDS AND AT LEAST 8 FEET UPSTREAM AND DOWNSTREAM OF THE LAST MITRE JOINT.
2. THE INTERNAL DIAMETER OF THE PENSTOCK IS 13'-6".
3. STEEL SHALL BE C.S.A. G40-8 GRADE 'B'.
4. FOR TYPICAL CROSS SECTION FROM (7A) TO (9A) SEE DWG. Nº F-106-C-7.

REFERENCE DRAWINGS

1. F-106-C-2 PRESSURE CONDUITS - LAYOUT & DETAILS OF BIFURCATION.
2. F-106-C-4 SURGE TANKS - DETAILS OF TEES.
3. F-106-C-5 SURGE TANKS - GENERAL LAYOUT & DETAILS.
4. F-106-C-6 PRESSURE CONDUITS - CLEARING.
5. F-106-C-7 PRESSURE CONDUITS - PLAN & PROFILE PIPE LINE 'A'.

OTHER REFERENCES

1. SPECIFICATION Nº M-3116

ASSOCIATION OF PROFESSIONAL ENGINEERS PROVINCE OF NEWFOUNDLAND
W. E. BONNELL
LICENCE TO PRACTICE

APPROVED FOR CONSTRUCTION
SEP 22 1965
APPROVED BY:
MANAGER ENGINEERING

NO.	DATE	LOCATION	DESCRIPTION	MADE BY	APPR'D
3	SEPT 2/66		PLAN & PROFILE REVISED	J.P.	

REVISIONS

TRANS'N | ELECT'L | CIVIL
PASSED

DESIGNED: R. MAC D.
DRAWN: J.P.
CHECKED: A.P. K.
RECOMMENDED: P. Eng.

NEWFOUNDLAND AND LABRADOR POWER COMMISSION
BAY D'ESPOIR DEVELOPMENT
ENGINEERING AND DESIGN BY
SHAWMONT ENGINEERING NEWFOUNDLAND LIMITED
MONTREAL, QUEBEC

PRESSURE CONDUITS
PLAN & PROFILE PENSTOCK 'A'

CONTRACT	SCALE	FILE NO.	DATE	DWG. NO.	REVISION
	NOTED	PD-11	SEPT. 21, 1965	F-106-C-9	3

	BEND	∠A	∠B	∠C	TRUE ANGLE	PL THICKNESS
SURGE TANK TEE	7B	—	10°05'51"	10°05'51"	0°00'00"	—
	8B	—	10°05'51"	6°54'24"	3°11'27"	1 1/16"
	9B	5°54'17"	6°54'24"	11°25'17"	10°47'16"	1 1/16"
	10B	—	11°25'17"	19°33'02"	8°05'45"	1 3/4"
	11B	13°20.05"	13°38'02"	19°43'00"	18°11'49"	1 7/8

OCT 25 1966

This approval of interpretation of the work to be done does not relieve the seller of responsibility for accuracy of details.

FILE 2-13


ELEVATION of PENSTOCK 'A'
PLAN VIEW
GENERAL NOTES:
FIELD NOTE:
HORTON STEEL WORKS, LIMITED
SHAWMONT ENGINEERING NEWFOUNDLAND LIMITED
APPROVED
MAY 6 1966
This approval of interpretation of the work to be done does not relieve the seller of responsibility for accuracy of details.
FILE 2-13
10830


APPROVED
SHAWMONT ENGINEERING NEWFOUNDLAND LIMITED
This approval of interpretation of the work to be done does not relieve the seller of responsibility for accuracy of details.
24"ϕ MANHOLE DETAILS
HORTON STEEL WORKS, LIMITED
FORT ERIE ONT.
DETAIL "A"
DETAIL "B"
NOZZLE
TYPICAL ASSEMBLY
MATERIAL SPECS:
USAGE OF PENSTOCK CUTOUT
PLAN OF M.H. COVER
ELEV. OF COVER
HINGE PIN
PUSH-OFF BOLT
FIELD NOTES:- NO.1
RECEIVED
SHAWMONT NEWFOUNDLAND
12 X
FILE COPY
NEWFOUNDLAND AND LABRADOR POWER COMMISSION
68H038H03

APPENDIX B

INSPECTION PHOTOGRAPHS

PHOTO 1 – LOOKING DOWNSTREAM FROM THE INTAKE AREA AT THE DAMAGED AREA OF PENSTOCK NO.1

PHOTO 2 – CRACK IN PENSTOCK PLATE ALONG LONGITUDINAL WELD

PHOTO 3 – MEASURING VISIBLE LENGTH

PHOTO 4 – USING STRAIGHT BAR TO HIGHLIGHT BULGE IN PENSTOCK PLATE

PHOTO 5 – CLOSE-UP OF CRACK. NOTE CORROSION IN CRACK THAT APPEARS OLDER THAN ONE WEEK.

PHOTO 6 – LOOKING UPSTREAM ALONG CRACK LOCATION WITH BACKFILL REMOVED

PHOTO 7 – LOOKING UPSTREAM FOR SIDE VIEW OF CRACK AND BULGE

PHOTO 8 – LOOKING AT THE LEFT SIDE OF THE PENSTOCK IN AREA OF CRACK. NOTE SLUMPED BACKFILL

APPENDIX C

PENSTOCK STRESS CALCULATIONS

Kleinschmidt

P.O. Box 650
141 Main St.
Pittsfield, Maine 04967
Telephone: 207.487.3328
www.KleinschmidtUSA.com

Designed By: LLC
Date: 6/1/16
Checked By: CMV
Date: 6/2/16
Job Number: 2670003.00

Project: Bay d'Espoir Penstock

Task: Penstock Calculations - Crack Weld

Objective:

Based on an site visit by CMV regarding a logintudinal crack in the base material following a longitudinal weld:
- *Design crack weld repair*
- *Check buried pipe condition*

References:

1. ASCE No. 79, 2nd Ed. 2012
2. AWWA M11, 4th Ed.
3. AISC Design Guide 15 Historic Shapes and Specifications
4. Structural Design in Metals, 2nd Ed. 1957
5. AISC Steel Construction Manual - 14th Ed.
6. AISI - Buried Steel Penstocks - Steel Plate Engineering Data - Vol. 4, 2nd Ed. 1998
7. ASCE 7-10
8. Bureau of Reclamation, "Welded Steel Penstocks" Engineering Monograph No. 3, 1977
9. Hydroelectric Handbook, 2nd ed., 1950
10. Obsolete Canadian Steel Grades 1935-1971
11. Drawings from client

Assumptions and Inputs:

$\gamma_w := \mathbf{62.4}\text{pcf}$ — *Unit weight of water*

$\gamma_s := \mathbf{490}\text{pcf}$ — *Unit weight of steel*

$E_{steel} := \mathbf{29000}\text{ksi}$ — *MOE of steel*

$\mu := \mathbf{0.3}$ — *Poisson's ratio of steel*

$$\alpha := \frac{0.00065\cdot\Delta°F^{-1}}{100} = 6.50\times10^{-6}\cdot\Delta°F^{-1}$$ *Coefficient of thermal expansion for steel*

$L_{pen} := 3800\text{ft}$ — *Total length of penstock*

$D_i := 17\text{ft}$ — *Diameter of penstock*

$r_i := \frac{D_i}{\mathbf{2}} = 8.5\,\text{ft}$ — *Radius of penstock*

$NP := 182.6\cdot m \quad NP = 599.08\,\text{ft}$ — *Normal Pond Elevation*

$CE := 508.0\cdot ft$ — *Elevation of Penstock crack location (around 3A per client)*

$P_{crack} := (NP - CE)\cdot\gamma_w$ — *Normal Pressure at crack* — $P_{crack} = 39.47\,\text{psi}$

$FP := 184.2\cdot m \quad FP = 604.33\,\text{ft}$ — *Flood Elevation*

$P_{flood} := (FP - CE)\cdot\gamma_w$ — *Pressure due to flood load at crack* — $P_{flood} = 41.74\,\text{psi}$

Pipe Vintage and Joint Type :

The penstock is welded plate steel ASTM A285 changing to G40.8 Grade B after crack location, 1965+/-. Do not know grade of A285 Steel. Assume Grade C.

1965 Welded:

Use Reference 10 and ASTM.

$F_{u\_1965} := 55 \cdot ksi$ — *Assumed tensile strength of steel pipe ASTM A285 Gr.C*

$F_{y\_1965} := 30 \cdot ksi$ — *Assumed yield strength of steel pipe ASTM A285 Gr.C*

$$S_{A\_1965} := \min\left(\frac{F_{u\_1965}}{2.4}, \frac{F_{y\_1965}}{1.5}\right) = 20.0 \cdot ksi$$ *Allowable stress intensity (R1, 3.5.3)*

Check Thickness (R1, Eqns 4-1 through 4-4):

$\boxed{t_{wall} := 0.42in}$ — *Penstock thickness*

$\boxed{P_{design} := P_{crack}}$ — *Maximum (design) internal pressure at crack*

$P_{design} = 39.47\ psi$

$E := 0.65$ — *Joint Efficiency (welded) - (R1, Table 3-3, "Single Welded butt joints with backing bars")*

$$t_{min\_\sigma} := \frac{P_{design} \cdot r_i}{E \cdot S_{A\_1965}} = 0.31 \cdot in$$ *Minimum required thickness based on max internal pressure (R1, Eqn 4-1)*

$check_{min\_t} := if\left(t_{wall} \geq max\left(t_{min\_\sigma}\right), "OK", "No\ Good"\right)$ — $check_{min\_t} = "OK"$

Check Internal Pressure:

$$\sigma_p := \frac{P_{design} \cdot r_i}{E \cdot t_{wall}} = 14.75 \cdot ksi$$ *Stress applied*

$S_{A\_1965} = 20.00 \cdot ksi$ — *Allowable stress*

$check_{Stress} := if\left(S_{A\_1965} \geq \sigma_p, "OK", "No\ Good"\right)$ — $check_{Stress} = "OK"$

$$\sigma_f := \frac{P_{flood} \cdot r_i}{E \cdot t_{wall}} = 15.60 \cdot ksi$$ *Stress due to flood*

$check_{StressF} := if\left(S_{A\_1965} \geq \sigma_f, "OK", "No\ Good"\right)$ — $check_{StressF} = "OK"$

Allowable Transient Pressure:

$$R_p := \frac{D_i + t_{wall}}{2} = 102.21 \cdot in$$ *Radius of the middle surface of the pipe shell*

$$P_t := \frac{S_{A\_1965} \cdot E \cdot t_{wall}}{R_p} = 53.42\ psi$$ *Max transient pressure allowed*

Weld suggestions for crack:

Prequalified Welded Joints, Complete-Joint-Penetration Groove Welds, Table 8-2, R5

1. Single-V-groove weld with backer bar.
2 Single-bevel-groove weld with backer bar.

Check Buckling - Buried Pipe Condition:

ASD Load Combinations & Factors (R7, 2.4.1):

Dead = D, Live = L, Roof live = Lr, Snow = S, Rain = R, Wind = W, Earthquake = EQ

Load Combinations:

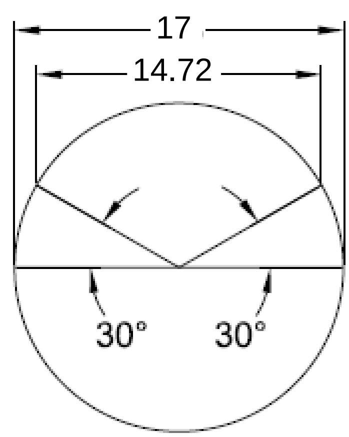
LC1 = D
LC2 = D + L
LC3 = D + (Lr or S or R)
LC4 = D + 0.75L + 0.75(Lr or S or R)
LC5 = D ± (0.6W or 0.7EQ)
LC6 = D + 0.75(0.6W or 0.7EQ) + 0.75L + 0.75(Lr or S or R)
LC7 = 0.6D ± (0.6W or 0.7EQ)

Live Load:

$LL := \mathbf{100} plf$ — *Assumed live load of workers walking on the penstock*

Wind Load & Earthquake Load:
Will not control, buried. Not applicable.

Snow and/or Ice Load (R7, Chapter 7):



$p_g := \mathbf{120} psf$ — *Ground snow load (assume 120psf)*

$I := \mathbf{1.0}$ — *Importance factor (R7, Table 1.5-2, Risk Cat. II)*

$C_t := \mathbf{1.2}$ — *Thermal factor (R7, Table 7-3, Unheated, Open Air)*

$C_e := \mathbf{0.9}$ — *Exposure factor (R7, Table 7-2, Fully Exposed, Terrain Cat. B)*

$C_s := \mathbf{1.0}$ — *Roof slope factor conservatively assumed for area above 30 deg as shown (R7, Fig. 7-2)*

$p_s := C_s \cdot C_e \cdot C_t \cdot I \cdot p_g = 129.6 \cdot psf$ — *Design snow pressure*

$\boxed{w_{snow} := p_s \cdot (14.72 ft) = 1907.7 \cdot plf}$ — *Design snow load*

Properties:

$\boxed{t_{wall} = 0.420 \cdot in}$ — *Penstock wall thickness*

$D_i = 17.00\ ft$ — *Inner diameter of penstock*

$D_o := D_i + 2 \cdot t_{wall} = 17.07\ ft$ — *Outer diameter of penstock*

$$A_s := \frac{\pi \cdot \left(D_o^{\ 2} - D_i^{\ 2}\right)}{4} = 1.873 \cdot ft^2$$ *Area of penstock steel*

$A_w := \frac{\pi \cdot D_i^2}{4} = 227.0 \cdot ft^2$ *Cross sectional area of flow*

$w_s := \gamma_s \cdot A_s = 917.8 \cdot plf$ *Weight of penstock steel*

$w_w := \gamma_w \cdot A_w = 14163.6 \cdot plf$ *Weight of water*

$\boxed{DL1 := w_s = 918 \cdot plf}$ *Steel penstock dead load*

$\boxed{DL2 := w_w = 14164 \cdot plf}$ *Water dead load (Full pipe)*

$S_x := \frac{\pi \cdot \left(D_o^4 - D_i^4\right)}{32 \cdot D_o} = 13756 \cdot in^3$ *Section modulus of penstock*

$I_x := \frac{\pi \cdot \left(D_o^4 - D_i^4\right)}{64} = 1408903 \cdot in^4$ *Moment of inertia of penstock*

$\boxed{w_{LC3} := (DL1 + DL2) + w_{snow} = 16989 \cdot plf}$ *Uniform load (Load Combination 3)* *(CONTROLS)*

$w_{LC4} := (DL1 + DL2) + 0.75 \cdot LL + 0.75 \cdot w_{snow} = 16587.16 \cdot plf$ *Uniform load (Load Combination 6)*

$q_{DL} := \frac{w_{LC3}}{14.72 \cdot ft} = 8.01\ psi$ *Max pressure due to LC 3 - assuming spread over 120º top area, conservative*

Check External Loads on Penstock :

- Assume 2 feet of soil cover
- Assume no vehicular live loading

$\gamma_{soil} := \mathbf{120} pcf$ *Unit weight of soil*

$t_{wall} = 0.420 \cdot in$ *Wall thicknes (New penstock section)*

$ID := D_i = 17.00\ ft$ *Inner diameter of penstock*

$A_s := \frac{\pi \left[\left(ID + 2 \cdot t_{wall}\right)^2 - ID^2 \right]}{4} = 269.73 \cdot in^2$ *Cross-section area of steel penstock*

$S_x := \frac{\pi \left[\left(ID + 2 \cdot t_{wall}\right)^4 - ID^4 \right]}{32 \cdot \left(ID + 2 \cdot t_{wall}\right)} = 13756 \cdot in^3$ *Section Modulus*

$I_x := \frac{t_{wall}^3}{12} = 0.0741 \cdot \frac{in^4}{ft}$ *MOI of Steel Penstock (per unit length)*

$EI := E_{steel} \cdot I_x = 14.92 \cdot \frac{kip \cdot ft^2}{ft}$ *Pipe wall stiffness (per unit length)*

$h_{min} := \mathbf{2} ft$ *Minimum amount of soil cover above penstock*

Determine Allowable Buckling Pressure for Soil Dead Load (per R2, Chapter 6):

$FS_{buck} := \mathbf{2.0}$ — *Bucking factor of safety*

$H := \dfrac{h_{min}}{ft} = 2.00$ — *Height of fill above penstock*

$B' := \dfrac{1}{1 + 4 \cdot e^{(-0.065 \cdot H)}} = 0.22$ — *Empirical coefficient of elastic support*

$R_w := 1.0$ — *Water buoyancy factor*

If coarse-grained soil WITH fines is assumed:

$E' := \mathbf{1200} psi$ — *Modulus of soil reaction (R2, Table 6-1)*
*(Coarse-grained soil **with fines**, **2ft cover**, 9**5%** relative compaction)*

Table 6-1 Values* of modulus of soil reaction, *E'* (psi) based on depth of cover, type of soil, and relative compaction

			Standard AASHTO relative compaction‡							
	Depth of Cover		85%		90%		95%		100%	
Type of Soil†	*ft*	*(m)*	*psi*	*(kPa)*	*psi*	*(kPa)*	*psi*	*(kPa)*	*psi*	*(kPa)*
Fine-grained soils with less than 25% sand content (CL, ML, CL-ML)	2–5	(0.06–1.5)	500	(3,450)	700	(4,830)	1,000	(6,895)	1,500	(10,340)
	5–10	(1.5–3.1)	600	(4,140)	1,000	(6,895)	1,400	(9,655)	2,000	(13,790)
	10–15	(3.1–4.6)	700	(4,830)	1,200	(8,275)	1,600	(11,030)	2,300	(15,860)
	15–20	(4.6–6.1)	800	(5,520)	1,300	(8,965)	1,800	(12,410)	2,600	(17,930)
Coarse-grained soils with fines (SM, SC)	2–5	(0.06–1.5)	600	(4,140)	1,000	(6,895)	1,200	(8,275)	1,900	(13,100)
	5–10	(1.5–3.1)	900	(6,205)	1,400	(9,655)	1,800	(12,410)	2,700	(18,615)
	10–15	(3.1–4.6)	1,000	(6,895)	1,500	(10,340)	2,100	(14,480)	3,200	(22,065)
	15–20	(4.6–6.1)	1,100	(7,585)	1,600	(11,030)	2,400	(16,545)	3,700	(25,510)
Coarse-grained soils with little or no fines (SP, SM, GP, GW)	2–5	(0.06–1.5)	700	(4,830)	1,000	(6,895)	1,600	(11,030)	2,500	(17,235)
	5–10	(1.5–3.1)	1,000	(6,895)	1,500	(10,340)	2,200	(15,170)	3,300	(22,750)
	10–15	(3.1–4.6)	1,050	(7,240)	1,600	(11,030)	2,400	(16,545)	3,600	(24,820)
	15–20	(4.6–6.1)	1,100	(7,585)	1,700	(11,720)	2,500	(17,235)	3,800	(26,200)

$q_a := \left(32 \cdot R_w \cdot B' \cdot E' \cdot \dfrac{EI}{ID^3}\right)^{0.5} = 13.4\,psi$ — *Allowable Buckling pressure (R2, eqn 6-7)*

Check Allowable Buckling Pressure Due to Maximum Soil Dead Load:

$q_{soil} := h_{min} \cdot \gamma_{soil} = 1.67\,psi$ — *Maximum soil pressure on top of penstock*

$FS_{buck} = 2.00$ — *Required buckling factor of safety*

$check_{buckling} := if(q_{soil} \cdot FS_{buck} \le q_a, \text{"OK"}, \text{"No Good"})$ $\quad check_{buckling} = \text{"OK"}$

Computed buckling factor of safety: $\boxed{FS := \dfrac{q_a}{q_{soil}} = 8.04}$

Check Allowable Buckling Pressure Due to Maximum Soil Dead Load + Dead, Live, Snow:

$q_{DL} := \dfrac{w_{LC3}}{14.72 \cdot ft} = 8.01\,psi$ — *Max pressure do to LC 3 Dead + Live + Snow*

$$\text{check}_{\text{buckling2}} := \text{if}\left[\left(q_{soil} + q_{DL}\right)\cdot FS_{buck} \le q_a, \text{"OK"}, \text{"No Good"}\right]$$

$$\text{check}_{\text{buckling}} = \text{"OK"}$$

Computed buckling factor of safety:

$$FS := \frac{q_a}{q_{soil} + q_{DL}} = 1.38$$

SUMMARY *- Use CJP Groove Weld for weld repair. Penstock OK for buckling in buired condition. Also, unburied section (10-30ft long), top 120º +/- OK for this length and size of pipe.*

APPENDIX D

WELD TESTS

Acuren Group Inc.
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Phone: 709.753.2100
Fax: 709.753.7011

NDT, Inspection and Engineering

ACUREN

NONDESTRUCTIVE EXAMINATION

TO: **NEWFOUNDLAND HYDRO**
BAY D'ESPOIR NL

PAGE: **1 OF 1**

DATE: **MAY 31/2016**
ACUREN JOB #: **183-16-10TAC003-0005**
REPORT #: **UT-MT053116-001 R0**
PO: **NA** WO: **NA**

ATTENTION: **KARL INKPEN** WORK LOCATION: **BAY D'ESPOIR NL**
PROJECT: **PENSTOCK #1**
ITEM(S) EXAMINED: **SEE BELOW**

PART #: **SEE BELOW** MATERIAL: **CARBON STEEL** THICKNESS: **BELOW**
SCOPE: **PERFORM UT AS PER CLIENT REQUEST.**
TYPE OF INSPECTION: **Ultrasonic**

TEST DETAILS:

ACCEPTANCE STANDARD: **CLIENT INFO** REVISION: **N/A**
PROCEDURE/TECHNIQUE: **CAN-UT-14P002** REVISION: **06**

TYPE: **Flaw Detection** METHOD: **Contact**
INSTRUMENT: **Olympus** MODEL: **Epoch XT** S/N: **131476205** CAL DUE: **JUNE 19 16**
CAL. BLOCK: **IIW** S/N: **4875** CABLE-TYPE: **COAXIAL** LENGTH: **6'**
CAL. BLOCK: S/N: COUPLANT: **SONOTECH UTX**

Probe & Technique Details:

	Test Angle (°)	Probe Type	Crystal Size	Freq. (MHz)	Serial Number	Damping Ω	Test From	Reference Reflector	Transfer Value	Reference dB	Reference % FSH	Scan dB	Range
1	**0**	**OLYMP.**	**½"**	**2.25**	**16040**	**NA**	**A**	**SBW**	**NA**	**45**	**40-60**	**+14**	**125mm**
2	**70**	**OLYMP.**	**½"**	**2.25**	**15263**	**NA**	**A/B**	**1.5mmSBW**	**NA**	**45**	**40-60**	**+14**	**125mm**

TEST SURFACE CONDITION: **As Welded** TEST SURFACE TEMPERATURE: **0°C to 50°C**

RESULTS:
Shear wave ultrasound inspection was carried out on the areas either side of the crack found in penstock #1 to determine overall length. The crack was determined to have a length of 29.5" long and starts 1.5" from the closest downstream circ weld. The crack follows the toe of the weld and on either end turns up into the parent material of the penstock (as seen in picture) A Magnetic particle inspection was also carried out see attached MT report.

CLIENT REPRESENTATIVE: N/A
TECHNICIAN:

MIKE TRICKETT
1st Technician
CGSB II Reg. #14179

2nd Technician

REVIEWER: Jason Matthews 05/31/16

(Generated Using: CAN-QUA-02F007 R02 - 12/15/2015)

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NDT, Inspection and Engineering

Acuren: An ISO 9001 certified company

NONDESTRUCTIVE EXAMINATION

TO: NEWFOUNDLAND HYDRO
BAY D'ESPOIR NL

PAGE: 1 OF 1

DATE: MAY 31/2016
ACUREN JOB #: 183-16-10TAC003-0005
REPORT #: MT-MT053116-001 R0
PO: N/A WO: NA

ATTENTION: KARL INKPEN
WORK LOCATION: BAY D'ESPOIR NL
PROJECT: PENSTOCK #1
ITEM(S) EXAMINED: SEE BELOW

PART #: See below MATERIAL: Carbon steel THICKNESS: .437"
SCOPE: NDE as per client request
TYPE OF INSPECTION: Magnetic Particle

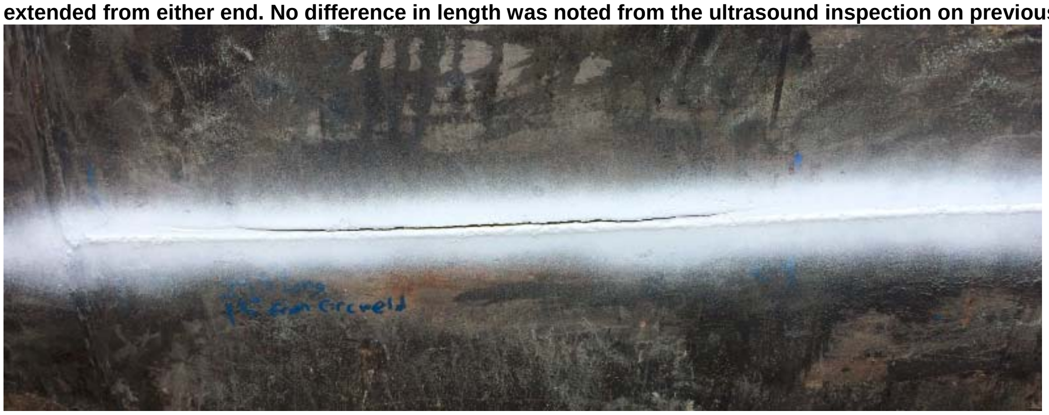
TEST DETAILS:

ACCEPTANCE STANDARD: CLIENT INFO — REVISION: N/A
PROCEDURE/TECHNIQUE: CAN-MT-14P001 — REVISION: R11 /2015

TYPE: Wet Visible	METHOD: Yoke
PARTICLE BRAND: Magnaflux PRODUCT NO.: 7HF	CURRENT: AC MT INSTRUMENT: Parker B-300
PARTICLE COLOUR: Black	MT INSTRUMENT S/N: 23490 CAL DUE: Oct 4 16
SUSPENSION: Oil	LIFT CHECK BEFORE USE: Yes LIFT WEIGHT S/N: 12846
CONTRAST PAINT: Magnaflux PRODUCT NO.: WCP2	LIGHTING EQUIPMENT: Flashlight
MAG TIME (SECONDS): 15 DEMAG REQUIRED?: No	BLACKLIGHT MAKE: N/A S/N: N/A
TECHNIQUE DEMONSTRATED OVER A PAINTED SURFACE?: N/A	LIGHT METER S/N: 150803637 CAL DUE: Oct 6 16
	LIGHT INTENSITY: Output > 100 fc
TEST SURFACE CONDITION: As Welded	TEST SURFACE TEMPERATURE: Oil -20°C to 50°C

RESULTS:

Magnetic particle inspection was carried out in the area on either side of the crack found in penstock #1 to ensure no surface cracks extended from either end. No difference in length was noted from the ultrasound inspection on previous report.



CLIENT REPRESENTATIVE: N/A

TECHNICIAN: Mike Trickett
1st Technician
CGSB II
CGSB Reg. #14179

2nd Technician

REVIEWER: Jane Matthews 05/31/16

(Generated Using: CAN-QUA-02F007 R02 - 12/15/2015)

APPENDIX E

MT WELD INSPECTION REPORTS FOR NEW WELD

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NDT, Inspection and Engineering

ACUREN

NONDESTRUCTIVE EXAMINATION

TO: NEWFOUNDLAND HYDRO
BAY D'ESPOIR NL

PAGE: 1 OF 1

DATE: MAY 31/2016
ACUREN JOB #: 183-16-10TAC003-0005
REPORT #: MT-MT053116-002 R0
PO: NA   WO: NA
WORK LOCATION: BAY D'ESPOIR NL

ATTENTION: KARL INKPEN
PROJECT: PENSTOCK #1
ITEM(S) EXAMINED: SEE BELOW

PART #: See below   MATERIAL: Carbon steel   THICKNESS: .437"
SCOPE: NDE as per client request
TYPE OF INSPECTION: Magnetic Particle

TEST DETAILS:

ACCEPTANCE STANDARD: CLIENT INFO   REVISION: N/A
PROCEDURE/TECHNIQUE: CAN-MT-14P001   REVISION: R11 /2015

TYPE: Wet Visible	METHOD: Yoke
PARTICLE BRAND: Magnaflux PRODUCT NO.: 7HF	CURRENT: AC MT INSTRUMENT: Parker B-300
PARTICLE COLOUR: Black	MT INSTRUMENT S/N: 23490 CAL DUE: Oct 4 16
SUSPENSION: Oil	LIFT CHECK BEFORE USE: Yes LIFT WEIGHT S/N: 12846
CONTRAST PAINT: Magnaflux PRODUCT NO.: WCP2	LIGHTING EQUIPMENT: Flashlight
MAG TIME (SECONDS): 15 DEMAG REQUIRED?: No	BLACKLIGHT MAKE: N/A S/N: N/A
TECHNIQUE DEMONSTRATED OVER A PAINTED SURFACE?: N/A	LIGHT METER S/N: 150803637 CAL DUE: Oct 6 16
	LIGHT INTENSITY: Output > 100 fc
TEST SURFACE CONDITION: As Welded	TEST SURFACE TEMPERATURE: Oil -20°C to 50°C

RESULTS:

Magnetic particle inspection was carried out on the inside of the penstock after a scaffold was erected. The inspection was done on the bottom side of the weld that was inspected earlier today after one of the welders noticed a sharp edge on the toe of the weld opposite the crack. The sharp edge was caused by the parent material being eroded away leaving an edge of weld metal this continues on intermittently approx. 6" upstream from the crack on the other side of the weld from the crack.

CLIENT REPRESENTATIVE: N/A
TECHNICIAN: Mike Trickett
Mike Trickett
1st Technician
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2nd Technician

REVIEWER: Jane Matthews
06/03/16

(Generated Using: CAN-QUA-02F007 R02 - 12/15/2015)

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NONDESTRUCTIVE EXAMINATION

TO: **NEWFOUNDLAND HYDRO**
BAY D'ESPOIR NL

PAGE: **1 OF 2**

DATE: **JUNE 2/2016**
ACUREN JOB #: **183-16-10TAC003-0005**
REPORT #: **MT-MT060216-001**
PO: NA   WO: **NA**

ATTENTION: **KARL INKPEN**   WORK LOCATION: **BAY D'ESPOIR NL**
PROJECT: **PENSTOCK #1**
ITEM(S) EXAMINED: **SEE BELOW**

PART #: **See below**   MATERIAL: **Carbon steel**   THICKNESS: **.437"**
SCOPE: **NDE as per client request**
TYPE OF INSPECTION: **Magnetic Particle**

TEST DETAILS:

ACCEPTANCE STANDARD: **ASME SEC VIII**   REVISION: **2015**
PROCEDURE/TECHNIQUE: **CAN-MT-14P001**   REVISION: **R11 /2015**

TYPE: **Wet Visible**	METHOD: **Yoke**
PARTICLE BRAND: **Magnaflux** PRODUCT NO.: **7HF**	CURRENT: **AC** MT INSTRUMENT: **Parker B-300**
PARTICLE COLOUR: **Black**	MT INSTRUMENT S/N: **23490** CAL DUE: **Oct 4 16**
SUSPENSION: **Oil**	LIFT CHECK BEFORE USE: **Yes** LIFT WEIGHT S/N: **12846**
CONTRAST PAINT: **Magnaflux** PRODUCT NO.: **WCP2**	LIGHTING EQUIPMENT: **Flashlight**
MAG TIME (SECONDS): **15** DEMAG REQUIRED?: **No**	BLACKLIGHT MAKE: **N/A** S/N: **N/A**
TECHNIQUE DEMONSTRATED OVER A PAINTED SURFACE?: **N/A**	LIGHT METER S/N: **150803637** CAL DUE: **Oct 6 16**
	LIGHT INTENSITY: Output **> 100 fc**
TEST SURFACE CONDITION: As Welded	TEST SURFACE TEMPERATURE: Oil -20°C to 50°C

RESULTS:

MT was performed on items listed below at the time of inspection no rejectable indications were found.

MT was performed on the excavated area on the crack in penstock #1. The ends of the crack were ground out until indication was fully removed.

Down Stream end of cracked area after MT   **Up Stream end of cracked area after MT**

CLIENT REPRESENTATIVE: N/A
TECHNICIAN: [signature]
Mike Trickett
1st Technician
CGSB II
CGSB Reg. #14179

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REVIEWER: Jane Matthews
06/03/16

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NDT, Inspection and Engineering

NONDESTRUCTIVE EXAMINATION

To: **NEWFOUNDLAND HYDRO**
BAY D'ESPOIR NL

Page: **2 OF 2**

Date: **JUNE 2/2016**
Acuren Job #: **183-16-10TAC003-0005**
Report #: **MT-MT060216-001**
PO: NA WO: **NA**
Work Location: **BAY D'ESPOIR NL**

Attention: **KARL INKPEN**
Project: **PENSTOCK #1**
Item(s) Examined: **SEE BELOW**

RESULTS:

After root was welded and cleaned up MT was performed, no rejectable indications were found.

Root Area MT

The weld was then filled and caped on the outside of penstock. The backing bar was then removed from the inside of the penstock and the root was cleaned and final cap was welded.

Cap on inside

Cap on outside

Client Representative: N/A

Technician: Mike Trickett
1st Technician
CGSB II
CGSB Reg. #14179

2nd Technician

Reviewer: 06/03/16

(Generated Using: CAN-QUA-02F007 R02 - 12/15/2015)

HATCH

Newfoundland and Labrador Hydro

Root Cause Analysis Report

For

Bay d'Espoir Penstock No. 1 Refurbishment

H352666-00000-220-066-0002
Rev. B
February 24, 2017

Newfoundland and Labrador Hydro

Root Cause Analysis Report

For

Bay d'Espoir Penstock No. 1 Refurbishment

H352666-00000-220-066-0002
Rev. B
February 24, 2017

Report

Root Cause Analysis Report

H352666-00000-220-066-0002

2017-02-24	B	Client Review	M. Pyne	D. French	G. Saunders
DATE	REV.	STATUS	PREPARED BY	CHECKED BY	APPROVED BY

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1. Introduction

Hydro engaged Hatch on September 22, 2016 to investigate the condition of some of the welded joints on Penstock No. 1. In September of 2016, Penstock No. 1 experienced a failure to one of the longitudinal welded joints. The joint was repaired, but further inspection by Hydro indicated there were problems with other longitudinal joints.

Upon completion of the inspection plan developed by Hatch, it was confirmed that the majority of the longitudinal weld joints from the intake down to Section 117 (Refer to Appendix H), approximately 450 m of penstock seams, had experienced a significant amount of weld metal loss.

As a result of the recent repairs to the welded joints and the amount of weld metal loss to the longitudinal seams, Hydro requested Hatch complete a Root Cause Analysis (RCA) on the problem.

The purpose of the RCA is to, where possible, identify any design, metallurgical, operational and environmental factors that either separately or collectively caused the corrosion issues, which have been found through inspection, in the longitudinal weld joints and resulted in the failure of the longitudinal joints.

Incidents and improvement opportunities may arise anywhere in an organization and can vary a great deal in nature, severity or impact, or underlying causes. Despite the large range of issues and conditions, the same basic process is applicable to any improvement/problem solving initiative. The RCA is a multi-step process, and generally involves the following:

- Data Collection
- Defining the factors
- Root Cause Identification
- Recommendations

2. Data Collection

The following data was collected to determine the factors that caused and/or accelerated the failures:

1. Drawings of Penstock No.1.
2. Material properties were identified from the drawings and samples from the penstock shell plate and welds were tested.
3. Kleinchmidt Crack Investigation and Repair Report Penstock No. 1 Bay d'Espoir Hydroelectric Development, June 2016.
4. Bay d'Espoir Pressure Conduit #1 Inspection Report 1987.
5. Water and Organic growth samples were collected and tested.
6. Discussions with engineering and operations personnel.
7. Internal inspections of penstock and welding seams.
8. External inspections of backfill.

3. Failure Factors

3.1 Construction Methods

Penstock No.1 is constructed from a series of cans that vary in length depending on location, but in general the cans are approximately 9’ long. Each can consists of two rolled steel plates that are welded together longitudinally. This form of assembly requires two longitudinal welded joints.

The penstock varies in diameter from 17’ to 15’ 3”, and the thickness varies depending on the location. The penstock is also constructed of two grades of steel, ASTM 285 Gr. C steel from the intake up to and including section 16, and CSA G40.8 Gr. B. for the remainder.

During the era in which Penstock No. 1 was constructed, plate rolling was generally completed utilizing a three roll single pinch point roll. When rolling plates with this type of roll the start and end of each plate will be flat. Figure 3-1 shows an exaggerated peaking (in red) compared to the desired tubular structure (in blue).

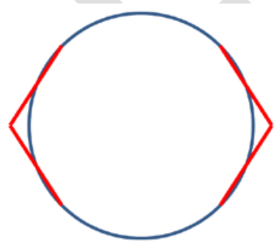


Figure 3-1: Peaking (Red) As Welded (Blue)

Difficulties with lining up the longitudinal seams are evident when examining the internals of the penstock and seeing evidence of extensive dogging of the joints to bring the longitudinal seams together. The flat spots and induced stress from fitting the straight ends increase the residual stress at the joints. Below is an image of the longitudinal seam that failed in September. Large amounts of peaking were observed at the initial crack location, see Figure 3-2, and this would mean the weld was resisting significant residual stresses to maintain a round shape at the seam. The increased stress also makes the longitudinal joints more susceptible to material loss as they become sensitized to corrosion.

Figure 3-2: Longitudinal Weld Failure Showing Peaking

3.2 Internal Coating

The existing internal coating is original to the penstock and was specified as a two coat system manufactured by The Standard Manufacturing Company of Newfoundland. The primer coat consisted of 5 mils dry film thickness (DFT) of Matflint #7-Primer and the finish coat was 6 mils dry film thickness of Matflint #7-Black Coal Tar Epoxy (Bay d'Espoir Pressure Conduit #1 Inspection Report 1987).

After a review of a previous inspection report, it is evident that initial coating deterioration occurred prior to 1987 and the deterioration has steadily progressed since then. In the report it also mentions that failure of the coating initiated at the welds. This inspection also completed a review of the interior surface and noted no excessive damage at this time.

Visual inspection of the penstock interior surface indicated some of the coating to be present; however, a physical inspection showed there was no bond between the coating and the steel, as the coating was easily lifted off by scraping the surface. Visual inspection of all exposed surfaces showed varying signs pitting corrosion which is typical for a penstock of this age.

At the time of construction (1960's), Coal Tar Epoxies were being utilized as one of the industry standards for penstocks internal protection coatings on penstocks (Centre for Energy Advancement through technological Innovation (CEATI) Technology Review Hydro-Electric Coating Strategies for Corrosion Prevention). Penstock guidelines and best practices commonly reference internal coatings per AWWA C203 Standard for Coal-tar Protection Coatings and Linings (Steel Penstocks 2012 (2nd Edition)).

In general coal tar epoxy coatings have a lifespan of 10-20 years depending on the service. For internal penstock coating in particular CEATI estimates the expected life for this particular system to be on average 15 years. The coating on penstock No. 1 has been in place since the original installation and has exceeded the standard life expectancy.

Failure modes for Coal Tar Epoxy coating systems are typically as outlined below. However, due to lack of available information from the original fabrication/construction we cannot determine if either of these contributed to the coating failure:

1. Insufficient surface preparation. Surface preparation needs to be completed on the entire internal surface including welds. In other industries we have seen instances where welds were insufficiently prepped which leads to localized coating failure along weld seems. This localized failure allows the spread by water getting behind the coating and "lifting" the coating and therefore progressing the failure outward from the welds.
2. Insufficient curing time/environment. Coal tar epoxies are typically high DFT (approximately 10-14 mils) systems built up in multiple coats. Typical DFT of a single coat should not exceed 3-4 mils. Thicker coats should be avoided as it causes increased curing times and possible curing issues. It is possible that the system was applied in two thick coats, leading to improper curing.

3. As coal tar epoxies age, they become brittle and crack. This embrittlement and cracking allows localized failures which eventually lead to moisture penetrating the system and ultimately system failure. This embrittlement and cracking would be exacerbated by any dimensional changes from increasing/decreasing ovality. The penstock tends to flatten during extended periods of being de-watered (the degree of which is directly related to the exterior backfill support), but rounds out after re-pressurizing.

3.3 Organic Growth

The internal surface of Penstock No. 1 has a layer of organic growth, approximately 50 mm thick, extending from the intake to Section 117. The layer of organic growth reduces in thickness as you progress downstream towards the powerhouse. When inspecting the penstock in the scroll case area the organic growth was not present and corrosion was substantially reduced with no signs of accelerated pitting of the weld metal or Heat Affected Zone (HAZ).

To assess the possibility of microbiologically influenced corrosion (MIC) a series of organic samples were taken and sent for testing. The following organic tests were performed by Acuren, Mississauga, Ontario.

- Low Nutrient Bacteria (LNB)
- Iron-Related Bacteria (IRB)
- Anaerobic Bacteria (ANA)
- Acid-Producing Bacteria (APB)
- Sulfate-Reducing Bacteria (SRB)

In general, MIC testing is completed on wetted specimens; this allows standard testing to be completed. Final readings of testing indicate the following:

- Negative readings for IRB and SRB
- Weak Positive readings for LNB, ANA and APB

Based on these findings it would appear that the organic growth provides an environment more susceptible to corrosion and allows ions to flow more freely.

3.4 Water Analysis

Water testing data was collected from 1965, 1980, 1988, 1992, 1993, 1994, 1995, 1996 and 2016. Testing between 1965 and 2016 yielded similar Langelier saturation index (LSI) results. However, the most recent water test indicates a change water chemistry. We recommend additional testing to confirm these results.

The available data from 1965-2016 was used to compute the LSI, which is used to quantify the corrosive behavior of a specific water source. This calculation takes the PH, alkalinity, Total Dissolved Solids (TDS), temperature and calcium all into account rather than strictly depending on the PH value.

The LSI ranks water corrosion potential on a scale typically between -5 to 4, -5 being highly corrosive and 4 having a high likely hood of scale buildup. When applying the LSI to the Bay d'Espoir water samples the following values were obtained:

Table 3-1: LSI Vs Water Sample Year

Year	LSI	Year	LSI
1965	-4.77	1994	-5.72
1980	-6.57	1995	-5.69
1988	-5.02	1996	-4.75
1992	-5.71	-	-
1993	-5.65	2016	-3.9

These values would indicate that the water flowing through the penstock would be considered highly corrosive. Refer to Appendix E for further information on samples and the LSI index.

3.5 Base Metal and Weld Analysis

Throughout the upper section of the penstock it was noted that longitudinal seams were experiencing extensive pitting, material loss and well defined notches along the heat affected zone (HAZ) of the welds. This excess material loss and notching contributes to high stresses, crack initiation and propagation. Refer to Figure 3-3 and Figure 3-4 for images of the notching, excessive pitting, and material loss.

Figure 3-3: Longitudinal Seams in Penstock No.1 Section 16

Figure 3-4: Longitudinal Seams in Penstock No.1 Section 16

To assess the metallurgy, mechanical and chemical properties of the parent metal and weld metal, a series of non-destructive and destructive testing was carried out.

The following non-destructive testing (NDT) was performed by TEAM Industrial Services, St. John's, NL, to aid the RCA investigation:

- Radiographic Examination

The following destructive testing was performed by Cambridge Materials Testing Limited, Cambridge, Ontario, to aid the RCA investigation:

- Microetch Evaluation
- Macroetch Evaluation
- Vickers Hardness Traverse
- Transverse Weld Tensile
- Weld Metal Chemical Analysis Test
- Base Metal Chemical Analysis Test

The following destructive testing was performed by Acuren, Mississauga, Ontario, to aid the RCA investigation:

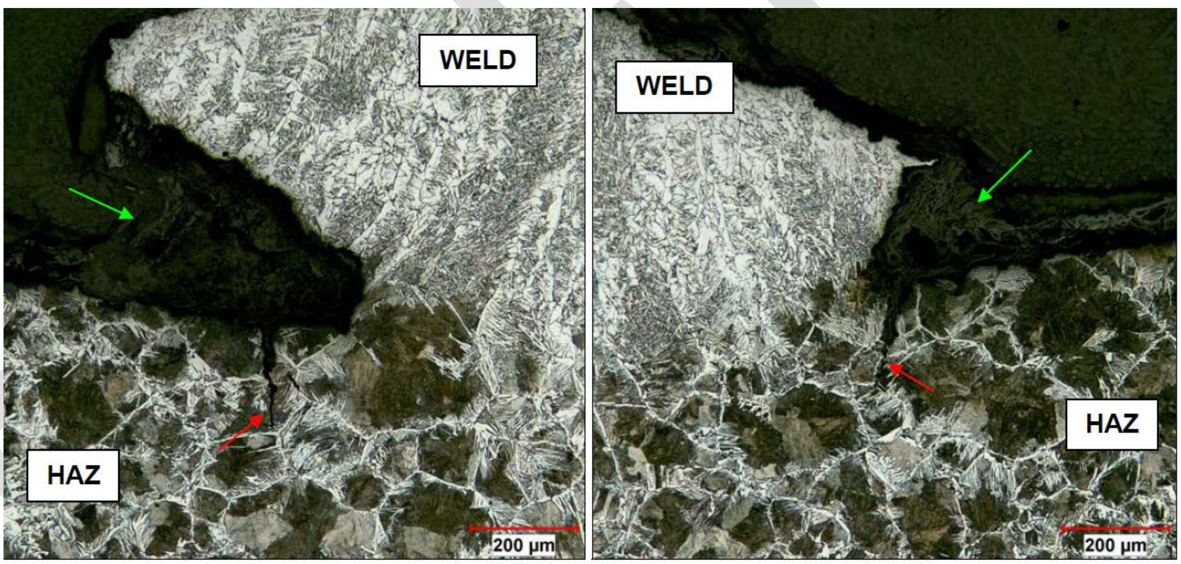
- Potential Difference Measurements (Weld/Base Metal Galvanic Testing)

The above tests were completed for three separate coupons:

1. Longitudinal seam between ASTM 285 Gr. C (Coupon #1 Section 16)
2. Circumferential seam between CSA G40.8 Gr. B (Coupon #2 Section 17)
3. Circumferential seam between ASTM 285 Gr. C (Coupon #3 Section 8)

Detailed results of the testing can be found in Appendix A, B & C. The Vickers Hardness test, weld tensile test, and chemical analysis are all consistent with the base metals listed on the design drawings and shield metal arc (SMAW) E4918 welding consumables.

As indicated in the attached reports, both the weld metal and parent metal are high in Sulphur. High amounts of Sulphur, by itself, can produce porosity in the weld metal and heat affected zones, primarily at the surface. Surface porosity is one of the main contributors to pitting corrosion. The presence of pitting corrosion would accelerate the effects of preferential corrosion and stress corrosion cracking.



Specimen examined at 100X, photos shown at approximately 85X
Etched in 2% Nital

Figure 3-5: Coupon #1 Micro of HAZ Transgranular Cracks

The macroetch and microetch of coupon #1 (longitudinal) show surface pitting and advanced stages of preferential corrosion with cracks initiated from the cavities and are progressing through the HAZ.

The macroetch and microetch of coupon #2 & 3 (circumferential) show surface pitting and preliminary stages of preferential corrosion without any cracks.

The results of the Weld/Base Metal Galvanic Testing generally indicate that a galvanic cell between the weld metal and base metal is present and the weld metal, in particular the heat affected zone(HAZ), was more susceptible to corrosion than the base metal.

3.6 Weld Seam Stresses

Penstock pressure from the static head or dynamic head causes a stress in the penstock shell. These stresses are longitudinal and hoop stress. The hoop stress is twice as high as the longitudinal and is the stress found in the longitudinal joints. As a result, virtually all failures in penstocks or pressure piping where there is a crack or split in a seam occurs in the longitudinal direction.

3.6.1 Stress in Longitudinal Joints

Longitudinal seams are more susceptible to failure due to higher stresses.

The stress in longitudinal weld seams is known as the hoop stress. The hoop stress (σ_h) is dependent upon the pressure (P), diameter (D) and wall thickness (t).

$$\sigma_h = \frac{PD}{2t}$$

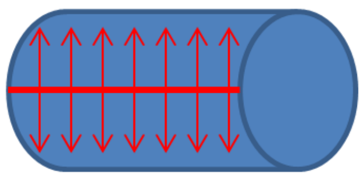


Figure 3-6: Hoop Stress Pulls Longitudinal Seams Apart

3.6.2 Stress in Circumferential Joints

Circumferential seams are less susceptible to failure due to lower stresses.

The stress in circumferential weld seams is known as the longitudinal stress. The longitudinal stress (σ_L) is dependent upon the pressure (P), diameter (D) and wall thickness (t).

$$\sigma_L = \frac{PD}{4t}$$

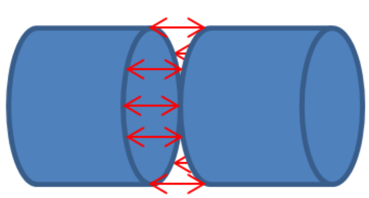


Figure 3-7: Longitudinal Stress Pulls Circumferential Seams Apart

3.7 Backfill

When reviewing the backfill requirements of Penstock No. 1 it was noted that there is a difference between the design specification and the design drawings. The specification states the penstocks be covered with soil to a minimum depth of three feet. The surrounding fill is part of the conduit construction, and serves to keep the pipe in shape when it is unwatered, to prevent collapse due to the pressure in the pipe falling below atmospheric, and by insulating, to prevent excessive thermal stresses.

The construction drawing shows a detail that has cover thicknesses in multiple locations below one foot. Construction drawing detail below:

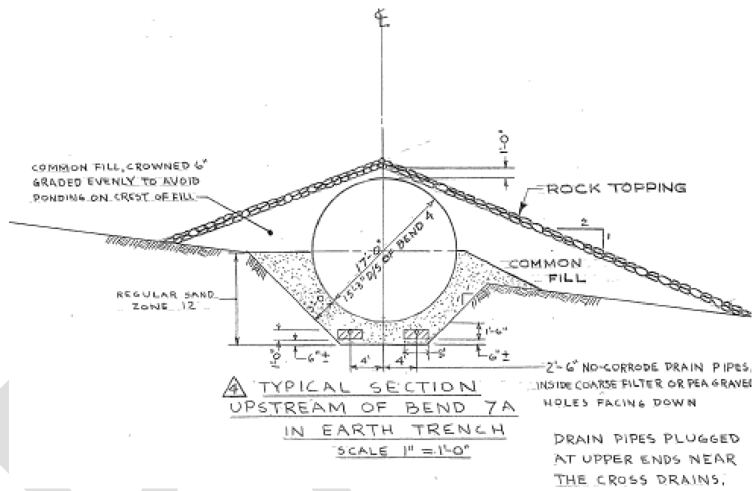


Figure 3-8: Design Drawing Half Trench

Current reference material shows typical half trench buried penstock cover details (Buried Steel Penstocks – Steel Plate Engineering Data –Volume 4) of two feet minimum of cover and can be seen below:

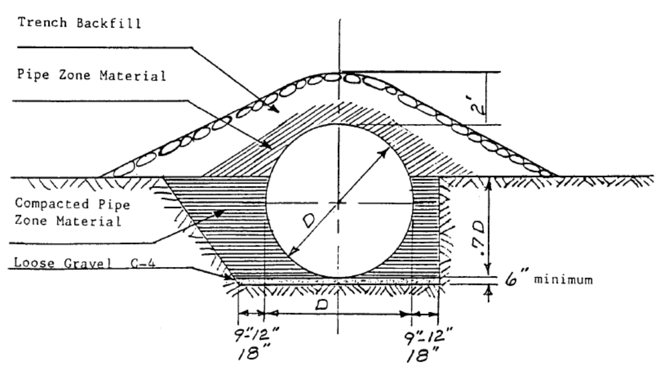


Figure 3-9: Typical Half Trench

When analyzing the backfill it was determined that backfill is structurally integral to the penstock and provides needed support along the center line. In the area where the penstock cracks occurred, the depth of backfill is less than 2 feet and some sliding and sloughing has occurred. This has been shown to increase the stress level by approximately 100% in the area of longitudinal welds locations. Refer to the finite element stress analysis completed for the backfilling of the excavated areas in Appendix G.

4. Heat Affected Zone Corrosion Contributing Factors

The results of the testing included in the preceding sections indicate that the longitudinal seams, from the intake downstream to Section 117, experienced weld metal loss, primarily in the Heat Affected Zone, attributed to "Preferential Heat Affected Zone Corrosion".

The problem arises from the fact that weld metal compositions (which are normally optimized for mechanical properties) tend to be slightly anodic to the parent steel, this issue arises across all welded structures. Therefore, the weld metal corrodes at a higher rate than the base metal.

The preferential corrosive attack of weldments can occur for a number of reasons:

1. Differences in composition between the weld metal and the base metal can generate a potential difference in certain environments, thus setting up a galvanic cell, leading to corrosion.
2. Differences in as-welded microstructure could make the weld metal sufficiently different from and even less corrosion resistant than the base metal.
3. Microstructural differences between the base metal and as-welded heat affected zones can lead to localized attack of the HAZ.
4. Preferential corrosion is more prone to occur when the weld metal is exposed to aqueous environments that are fairly high in conductivity, and can occur at pH values below approximately 7 to 8. Historical data indicates pH levels as low as 5.2. In addition, the MIC's in the organic growth, and the sulfur content in the base metal and weld metal could accelerate pitting corrosion.
5. Due to the construction methods of the penstock, the longitudinal seams would have inherent residual stresses that would be intensified by the heating and cooling of the welding process. High residual stresses can contribute to another phenomenon known as "Stress Corrosion Cracking" which would exacerbate the preferential corrosion and contribute to the reasons why the longitudinal seams experienced a more accelerated corrosion rate than the circumferential seams. Due to the construction methods, the circumferential weld seems would experience lower residual stresses.

5. Identification of Root Cause

Although the method or tool used to conduct RCA varies, the principle is the same regardless of the tool used. Methods and tools should be selected in accordance with the particular problem requirements. In this case, an Events and Casual Factor Analysis was completed. A Casual Factor Summary Table (see below) was generated to organize the information by the defining factors, their primary effects and their contribution to the Root Cause Mapping.

Table 5-1: Root Cause Summary (Corrosion)

Defining Factor	Primary Effect	Root Cause Mapping
Construction Methods	1. High residual stresses	1. High residual stresses combined with exposure to harsh environments lead to stress corrosion cracking.
Internal Coating	1. Failure of coating	1. Exposure to harsh environment.
Organic Growth	1. Generates microbiologically influenced corrosion	1. Presence of MIC amplifies harsh environment
Water Analysis	1. Low Langelier Saturation Index numbers	1. Harsh environment
Base Metal and Weld Metal Analysis	1. High Sulphur in base metal and weld metal. 2. Galvanic couple between heat affected zone and base metal	1. High susceptibility to porosity and pitting corrosion when exposed to harsh environment. 2. Heat Affected Zone acts sacrificially to base metal and weld metal when exposed to harsh environment.
Weld Seam Stresses	1. High operating stresses in longitudinal seams	1. Increases sensitivity to corrosion when exposed to harsh environment.
Backfill	1. Insufficient backfill and sloughing leads to high stresses.	1. Increases sensitivity to corrosion when exposed to harsh environment.

In this case, the analysis links the “exposure to the harsh environment” as a path through the Root Cause Mapping to all of the casual factors. The primary effect that leads to the “exposure to the harsh environment” is the failure of the internal coating system.

Table 5-2: Casual Factor Summary Table (Cracking)

Defining Factor	Primary Effect	Root Cause Mapping
Corrosion (Table 5-1)	1. Material loss 2. Notching along heat affected zone	1. Reduced thickness of longitudinal seams below critical values. 2. Intensified stresses along longitudinal weld seams.
Weld Seam Stresses	1. High operating stresses in longitudinal seams	1. Reached critical stress due to insufficient material and notching which lead to failure.
Backfill	1. Insufficient backfill and sloughing leads to high stresses.	1. Reached critical stress due to insufficient material and notching which lead to failure.

The Casual Factor Summary Table links reaching the critical stress to the material loss and notching.

6. Conclusions

6.1 Penstock Corrosion

The interior of the penstock was originally coated with a coal tar epoxy that protected the interior surface. The coating has exceeded the normal service life of this type of product and no longer protects the interior surface of the steel penstock.

In general, the entire interior of the penstock is no longer protected from corrosion by a coating system, the corrosion attack is primarily focused on the longitudinal weld seams in the weld and heat affected zones. Based on our analysis, in our opinion the penstock is experiencing stress corrosion cracking.

Stress corrosion cracking requires two main contributing factors:

1. Harsh environment

The water flowing through the penstock has a low PH and a low LSI making it a harsh environment. Further to this an MIC generating organic growth has attached itself to the interior surface which also adds to the harshness of the environment.

2. High stresses

The high stresses in the longitudinal weld seams causes stress corrosion sensitization. This can be broken down into three factors:

- High residual stresses in longitudinal joints from fabrication
- Insufficient/sloughing backfill
- Longitudinal joints have higher stresses due to hoop stress

These factors have made the longitudinal seams the primary point for corrosion attack in the penstock.

Further corrosion accelerants were found during the investigation:

- The metallurgy also contributed to the susceptibly to corrosion. After completing a chemical analysis, it was determined that the weld metal and base metal were both high in Sulphur. This high Sulphur can increase pitting corrosion and exacerbate stress corrosion cracking.
- Galvanic testing also indicated a galvanic couple that caused pitting corrosion in the heat affected zones.

Each of these factors could cause or accelerate the corrosion when the weld metal and base metal were exposed to a harsh environment.

6.2 Penstock Cracks

The probable cause of the failure of the longitudinal seam was a function of the general corroded condition of the welds and the location of the joint.

The failed joint occurred in the highest pressure area of the largest diameter portion of the penstock and in an area with the least amount of backfill. As a general rule the diameter to thickness ratio is usually less than 400 for handling thin shell cans. The ratio for these sections of the penstock exceed 400 thus it would require more care when fabricated to keep round during installation.

The existing backfill in the area of the cracked joints provided insufficient cover due to local sloughing/sliding of the fill material. With a high stress concentration along the weld seam due to corrosion, a reduced thickness of metal and the high pressure stress due to hydraulic head and lack of backfill support, the metal reached a critical stress and failed.

7. Recommendations

The objective of root cause analysis is to identify the underlying cause(s) that led to the problem so that these root cause(s) can be eliminated. By treating the root cause(s) and not just the symptoms, future occurrences can be prevented.

Since the major contributing factor to the corrosion of the welds is “exposure to the harsh environment”, and its root cause is “failure of the internal coating system”, the primary recommendation is to reinstate the coating system.

The original design of the penstock included a coal tar epoxy coating. In our opinion, due to the corrosive nature of the water, organic growth and identified corrosion problems the entire length of the penstock should be coated with a suitable corrosion resistant system. The recommended timeline for this work is within the next 5 years.

Other mitigating alternatives were considered, such as cathodic protection, and treating the water to raise the PH and minimize the organic growth. However, attaching anodes to the interior of a penstock creates a hazard to the turbine equipment and the volume of water flowing through the penstock makes water treatment impractical.

Based on a preliminary review of the design of the penstock and backfill interaction, we have determined the backfill is integral to the structural integrity of the penstock. Hatch determined through analysis that even small excavated areas are required to be reinstated prior to watering up the penstock. Visual inspection of the backfill in the area where the re-welding and crack repairs occurred indicated there is a possible interrelationship between the location of the cracks and the condition of the backfill. Hydro is currently having an assessment of the backfill design completed to confirm the required backfill cross section. Further recommendations will be detailed in this report.

Based on the findings of the Analysis, we recommend Hydro implement inspection procedures that check the functional quality of any internal coatings system to ensure there is sufficient adhesion of the coating to the steel and there is no underside corrosion occurring. This may require inspection procedures that are in accordance with the National Association of Corrosion Engineer (NACE) and removal of some of the coating in areas of high stress.

8. References

1. ASCE Steel Penstocks 2012, Manuals and Reports on Engineering Practice No. 79.
2. CEATI Technology Review Hydro-Electric Coating Strategies for Corrosion Prevention.
3. ASME OM SG 3.
4. Buried Steel Penstocks Steel Plate Engineering Data Volume 4.
5. PLP-131-020-0004 Hatch Root Cause Analysis Method.

Appendix A
Weld Coupon #1 Test Report

1. Introduction

As part of the Root Cause Analysis (RCA) investigation a coupon measuring approximately 460 mm x 460 mm (18” x 18”) was removed from Section 16 (A285 Gr C Material) of BDE Penstock #1. The coupon incorporated a portion of one of the longitudinal weld seams that was partially repaired by Hydro’s personnel, but did not include the repaired section.

2. Required Tests

The following non-destructive testing was performed by TEAM Industrial Services, St. John’s, NL, to aid the RCA investigation:

- Radiographic Examination

The following destructive testing was performed by Cambridge Materials Testing Limited, Cambridge, Ontario, to aid the RCA investigation:

- Macroetch Evaluation
- Vickers Hardness Traverse
- Microetch Evaluation
- Transverse Weld Tensile
- Weld Metal Chemical Analysis Test
- Base Metal Chemical Analysis Test
- Coating System Asbestos and Quantitation Test

3. Test Results

Radiographic Examination

The radiographic examination showed no rejectable defects. Porosity was detected, but was in the range of acceptable limits.

Macroetch Evaluation

A Photomacroetch of the weld was prepared from two different sections of the coupon etched in 2% Nital. A stereo microscope was then used to examine the samples for general comments on weld imperfections.

- Both sections showed a profile consistent with “Preferential Heat Affected Zone Corrosion”.
- Both sections exhibited cracks propagating from the toes of the weld.

- One section exhibited porosity on the face of the weld.

Microstructural Examination

The two sections used in the previous Vickers hardness traverse were re-prepared according to ASTM E3-11 for microstructural examination. The specimens were etched in 2% Nital and examined using an optical microscope at various magnifications. The examination was performed at and near the fusion line locations on either side of the weld, where cracks were observed in the macroexamination.

- Microstructure examination showed ferrite and pearlite in both specimens.
- Both specimens displayed a relatively coarse grain HAZ on either side of the FL locations.
- Both specimens displayed a more refined structured HAZ consisting of fairly uniform mixture of pearlite and ferrite on the FL+1mm locations.
- Viewing at a higher magnification, cavities can be seen at both weld toes. Both cavities were filled with corrosion product.
- Transgranular cracking was present within the corrosion cavities. Both cracks were propagating through the HAZ.

Vickers Hardness Traverse

Both macroetch sections were re-polished according to ASTM E3-11 and subjected to a Vickers Hardness Traverse. The Vickers Hardness readings were performed according to ASTM E92-16 using a 10kgf test force and indentations were measured at 100x magnification.

- Hardness values for the weld metal ranged from 169 to 198
- Hardness values for the HAZ ranged from 143 to 173
- Hardness values for the Base material ranged from 139 to 151

Hardness values are within the range of normal expected values for this type of material and E4918 (E7018) welding consumables.

Transverse Weld Tensile

- Ultimate Tensile Strength (UTS) of base metal = 69.5 ksi (480MPa)

The tensile specimen fractured in the base metal indicating the UTS of the weld metal meets the requirements of being higher than the UTS of the base metal.

Weld Metal Chemical Analysis

The chemistry indicated on the attached report is consistent with an E4918 (E7018) electrode.

The sulphur content is below the maximum allowable of 0.035% (CSA W48, Table 1); however, according to Lincoln and Air Liquide specification sheets, the normal level of sulphur in the deposited weld metal for standard SMAW electrodes is 0.008% to 0.013% with E4918 (E7018) normally around 0.011%. Thus, even though the sulphur content is below the maximum allowable, it is 2X the normal percentage.

Base Metal Chemical Analysis

The base metal chemistry is consistent with ASTM A285 Gr C material.

Coating System Asbestos and Quantitation Test

Coating system was identified as a Coal Tar Epoxy.

No presence of asbestos was detected in the coating system.

Attachment A
Test Results

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Report For:	TEAM Industrial Services (NFLD) 41 Sagona Avenue MOUNT PEARL, Newfoundland A1N 4P9	**Laboratory #:** **Report Date:** **Received Date:**	**739108-16** October 27, 2016 October 17, 2016
Attention:	Keith Gowan	**Customer P.O.#:**	
Specimen:	For Hatch Limited, "Penstock" Weld Pipe Coupon		

MACROETCH EVALUATION TEST REPORT

Two random transverse sections were cut from the submitted weld coupon and prepared according to ASTM E3-11. The sections were arbitrarily labelled Section 1 and Section 2 by CMTL. The sections were etched in 2% Nital and then examined using a stereo microscope for general comments on weld imperfections.

RESULTS

Section 1: Examination of the specimen showed that the weld had discontinuities at both toes and porosity on the face on one side of the weld (refer to Figure 2). At higher magnification, the discontinuities at the toes of the weld were revealed to be cracks propagating along the fusion line of the weld (refer to Figure 3). The weld appeared to have no undercut or inclusions, and there was complete penetration and complete fusion observed throughout the weld.

Section 2: Examination of the specimen showed that the weld had discontinuities at both toes on one side of the weld (refer to Figure 4). At higher magnification, the discontinuities at the toes of the weld were revealed to be cracks propagating along the fusion line of the weld (refer to Figure 5). The weld appeared to have no porosity, undercut or inclusions, and there was complete penetration and complete fusion observed throughout the weld.

Cambridge Materials Testing Limited

Per Randi Lee
Randi Lee *Quality Assurance*

Per Dan Bielby
Dan Bielby *Technician*

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VICKERS HARDNESS TRAVERSE TEST REPORT

The macroetch sections were then re-polished according to ASTM E3-11 and subjected to a Vickers hardness traverse (refer to Figure 1). The Vickers hardness readings were performed according to ASTM E92-16 using a 10kgf test force. Indentations were measured at 100X magnification.

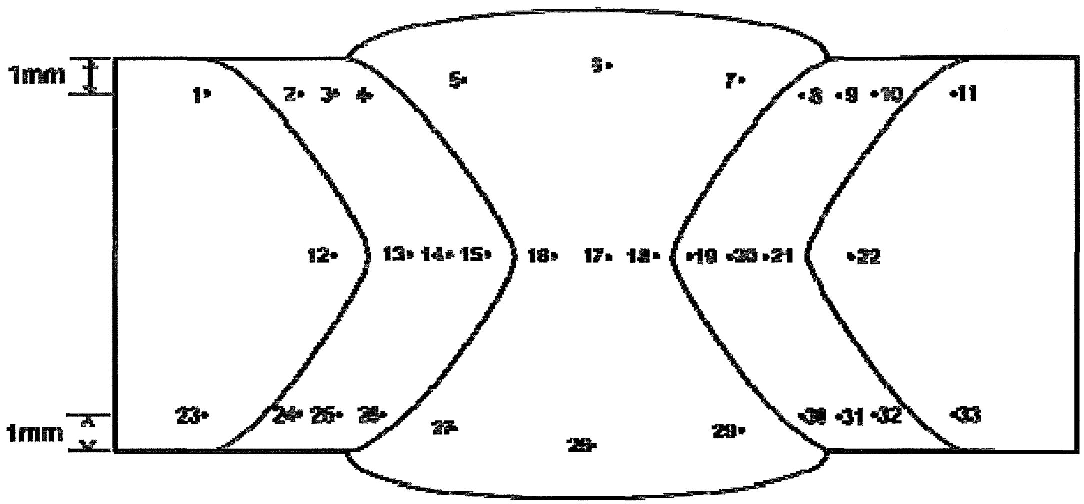

Figure 1: Schematic drawing showing the Vickers hardness indentation locations.

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RESULTS

Traverse Pass	Location	Indent	Section 1 Hardness (HV 10kgf)	Section 2 Hardness (HV 10kgf)
Top Cap Pass	Base Material	1	143	144
	HAZ	**2**	**158**	**162**
		3	**169**	**154**
		4	**171**	**158**
	Weld	5	183	181
		6	190	193
		7	180	188
	HAZ	**8**	**161**	**173**
		9	**156**	**160**
		10	**151**	**158**
	Base Material	11	144	146
Mid-Thickness Pass	Base Material	12	146	149
	HAZ	**13**	**149**	**166**
		14	**149**	**161**
		15	**160**	**160**
	Weld	16	169	171
		17	172	186
		18	173	181
	HAZ	**19**	**144**	**169**
		20	**144**	**143**
		21	**146**	**147**
	Base Material	22	139	139
Bottom Cap Pass	Base Material	23	150	151
	HAZ	**24**	**167**	**163**
		25	**163**	**154**
		26	**162**	**161**
	Weld	27	198	187
		28	198	198
		29	196	197
	HAZ	**30**	**154**	**160**
		31	**155**	**167**
		32	**161**	**167**
	Base Material	33	142	147

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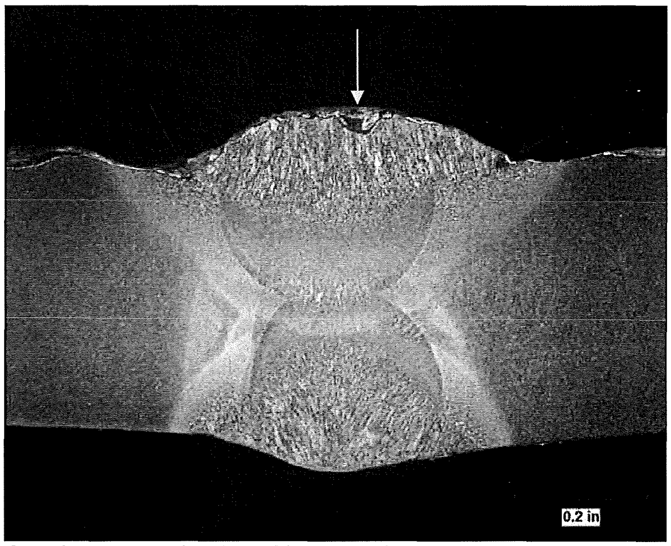

Specimen examined at 4X, photo shown at approximately 4X
Etched in 2% Nital

Figure 2: Photomacrograph of the Section 1, which had discontinuities at both toes (red arrows) and porosity (yellow arrow) on the face on one side of the weld.

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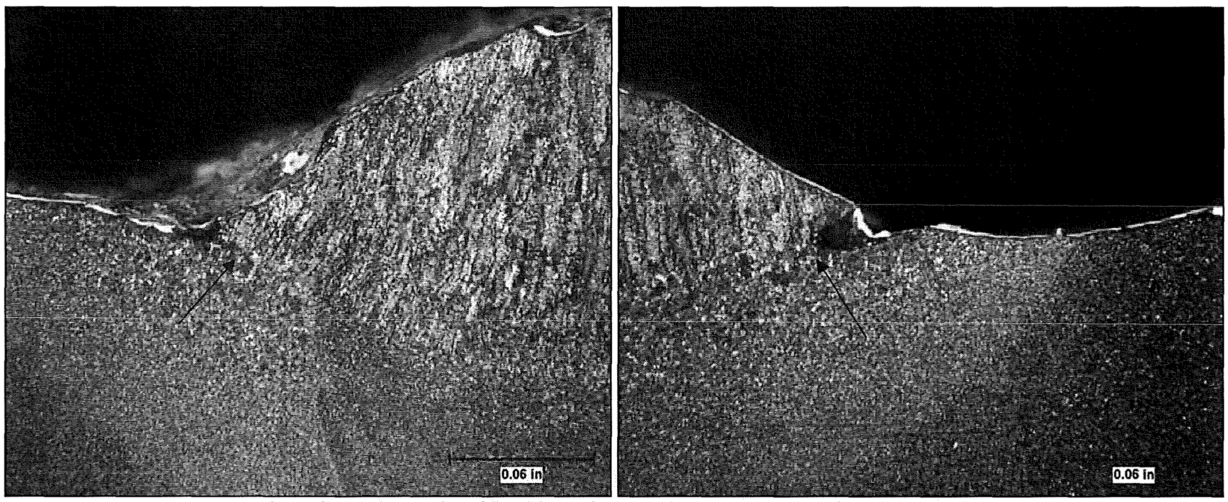

Specimen examined at 16X, photos shown at approximately 15X
Etched in 2% Nital

Figure 3: Photomacrographs of the Section 1. The discontinuities at the toes of the weld were revealed to be cracks propagating along the fusion line of the weld (red arrows).

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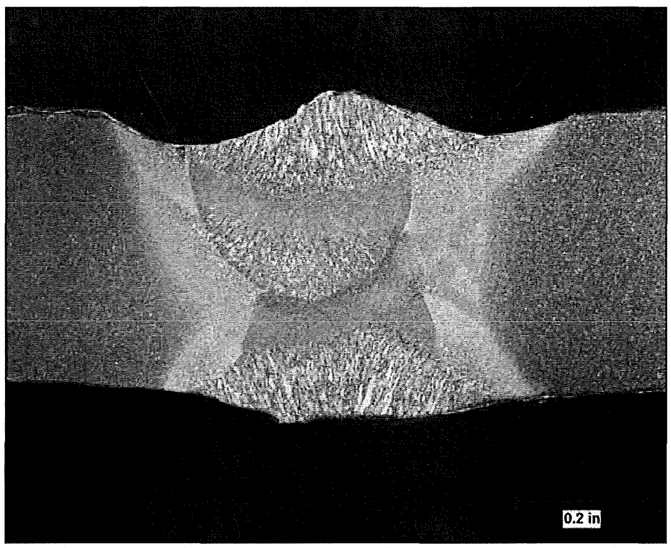

Specimen examined at 4X, photo shown at approximately 4X
Etched in 2% Nital

Figure 4: Photomacrograph of the Section 2, which had discontinuities at both toes (red arrows) on one side of the weld.

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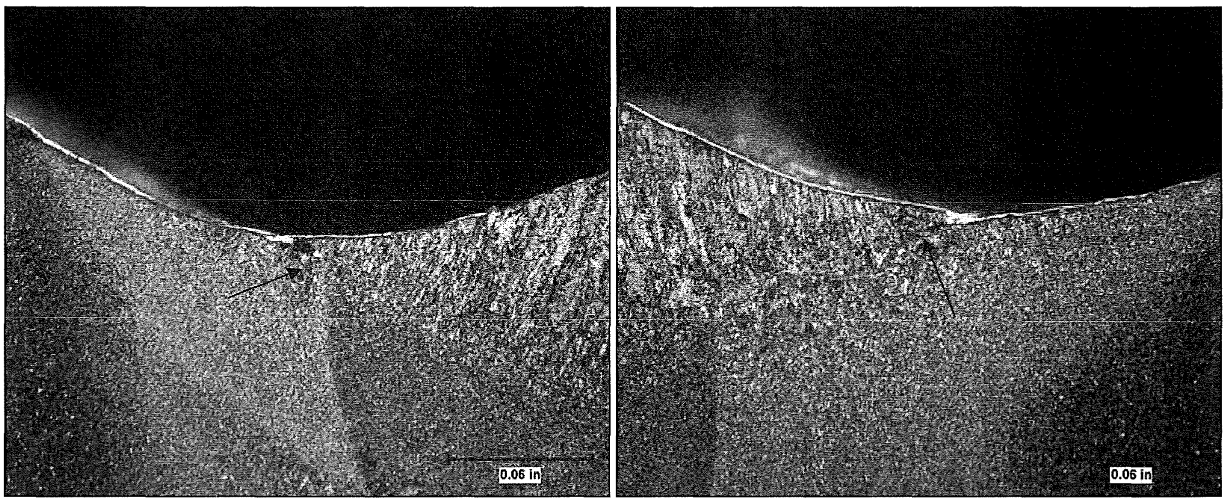
Lab # 739108-16



Specimen examined at 16X, photos shown at approximately 15X
Etched in 2% Nital

Figure 5: Photomacrographs of the Section 2. The discontinuities at the toes of the weld were revealed to be cracks propagating along the fusion line of the weld (red arrows).

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Report For:	TEAM Industrial Services (NFLD) 41 Sagona Avenue MOUNT PEARL, Newfoundland A1N 4P9	**Laboratory #:** **Report Date:** **Received Date:**	**742906-16 (Revised)** December 16, 2016 December 6, 2016
Attention:	Keith Gowan	**Customer P.O.#:**	
Specimen:	For Hatch Limited, "Penstock" Weld Pipe Coupon		

METALLURGICAL TEST REPORT

Two weld coupon specimens, previously subjected to macroscopic examination (CMTL Lab #739108-16), were further sectioned, then mounted and prepared for microscopic examination in accordance with ASTM E3-11. The specimens were etched in 2% Nital and examined using an optical microscope. Examinations were performed at and near fusion line locations on either side of the weld, where the cracks were observed during the previous macroscopic examination. These locations were labelled as "FL" and "FL +1" as instructed by the customer.

RESULTS

Section 1: Examination of the weld coupon specimen at the "FL" locations revealed transgranular cracks propagating through the HAZ of the weld from cavities located at both toes on the face of the weld (refer to Figure 1). Both cavities were filled with corrosion product, indicating the cavities may have formed due to pitting corrosion. The HAZ microstructure at the toe of the weld consisted of relatively coarse-grained pearlite with intergranular ferrite. The weld microstructure consisted of columnar ferrite and pearlite. At the "FL +1" locations, the HAZ microstructure was a heterogeneous mixture of ferrite and pearlite, with a more refined grain size (refer to Figure 2).

Section 2: Examination of the weld coupon specimen at the "FL" locations revealed transgranular cracks propagating through the HAZ of the weld from a cavity located at one toe on the face of the weld, and from an overlap at the other toe on the face of the weld (refer to Figure 3). The cavity was filled with corrosion product, indicating it may have formed due to pitting corrosion. An inclusion was observed within the overlap. The HAZ microstructure at the toe of the weld consisted of relatively coarse-grained pearlite with intergranular ferrite. The weld microstructure consisted of columnar ferrite and pearlite. At the "FL +1" locations, the HAZ microstructure was a heterogeneous mixture of ferrite and pearlite, with a more refined grain size (refer to Figure 4).

Cambridge Materials Testing Limited

Per Randi Lee
Randi Lee — *Quality Assurance*

Per Dan Bielby
Dan Bielby — *Technician*

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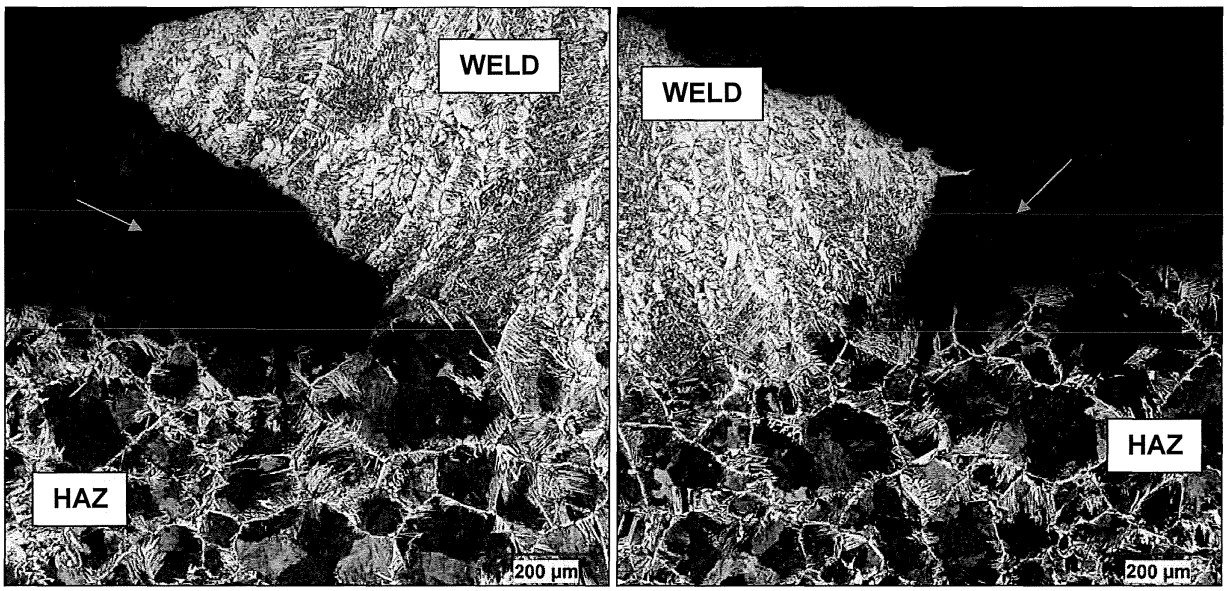

Specimen examined at 100X, photos shown at approximately 85X
Etched in 2% Nital

Figure 1: Photomicrographs of the Section 1 weld coupon at the "FL" locations. Transgranular cracks (red arrows) propagated through the HAZ of the weld from cavities located at the both toes on the face of the weld. Both cavities were filled with corrosion product (green arrows). The HAZ microstructure at the toe of the weld consisted of relatively coarse-grained pearlite with intergranular ferrite. The weld microstructure consisted of columnar ferrite and pearlite.

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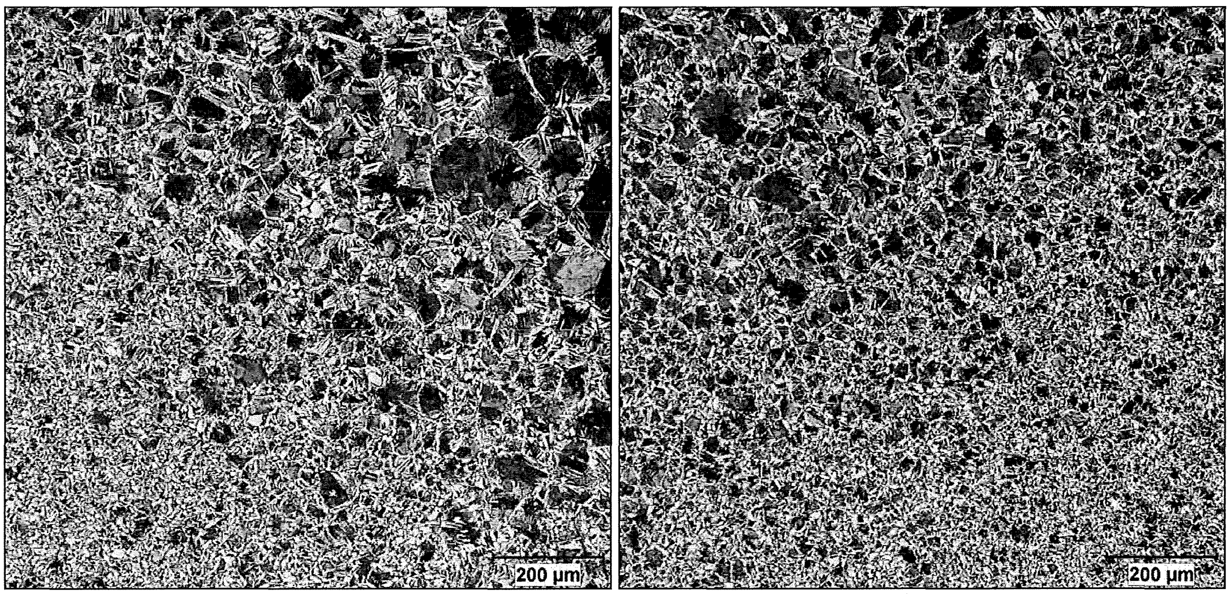

Specimen examined at 100X, photos shown at approximately 85X
Etched in 2% Nital

Figure 2: Photomicrographs of the Section 1 weld coupon at the "FL +1" locations, where the HAZ microstructure was a heterogeneous mixture of ferrite and pearlite, with a more refined grain size.

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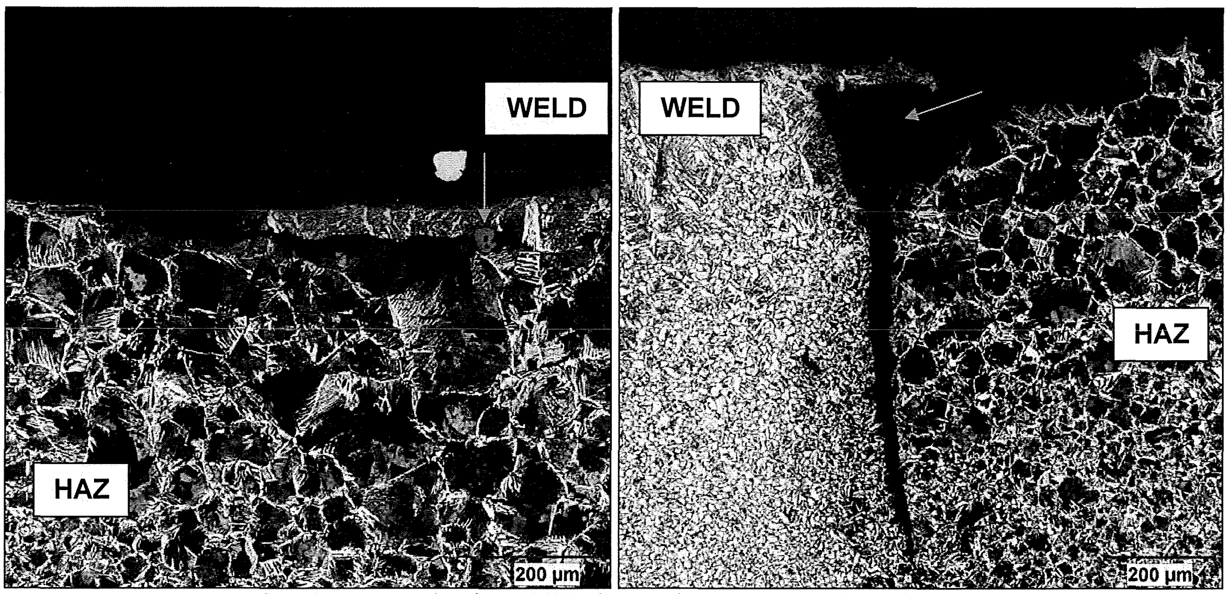

Specimen examined at 100X, photos shown at approximately 85X
Etched in 2% Nital

Figure 3: Photomicrographs of the Section 2 weld coupon at the "FL" locations. Transgranular cracks (red arrows) propagated through the HAZ of the weld from a cavity located at one toe on the face of the weld (right), and from an overlap at the other toe on the face of the weld (left). The cavity was filled with corrosion product (green arrow, right). An inclusion was observed within the overlap (green arrow, left). The HAZ microstructure at the toe of the weld consisted of relatively coarse-grained pearlite with intergranular ferrite. The weld microstructure consisted of columnar ferrite and pearlite.

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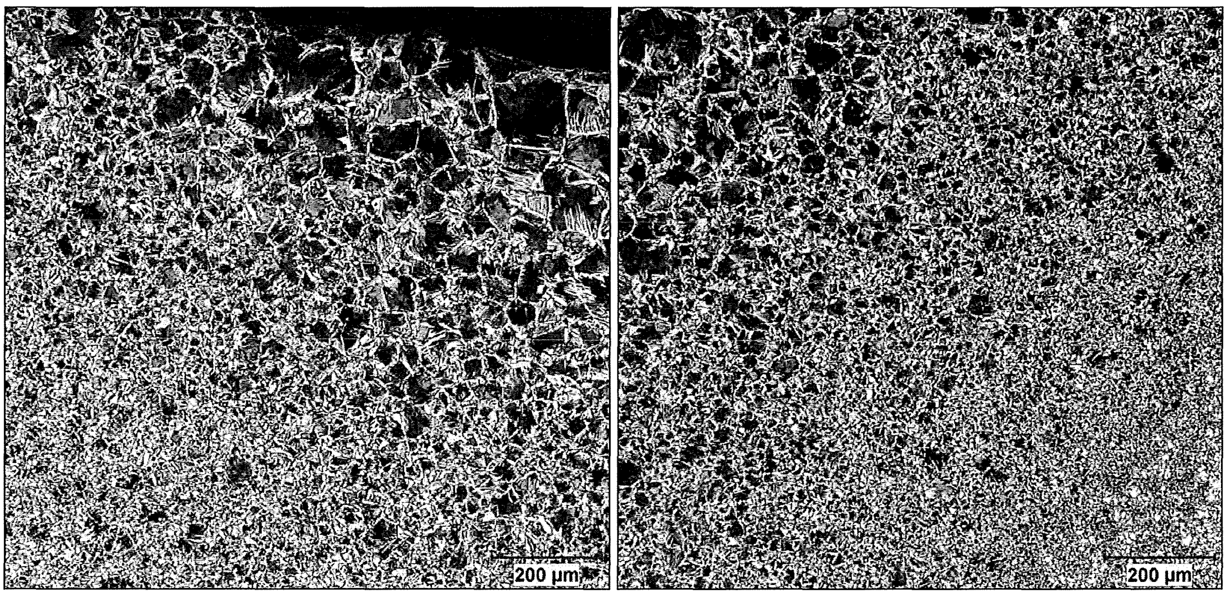

Specimen examined at 100X, photos shown at approximately 85X
Etched in 2% Nital

Figure 4: Photomicrographs of the Section 2 weld coupon at the “FL +1” locations, where the HAZ microstructure was a heterogeneous mixture of ferrite and pearlite, with a more refined grain size.

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Report for: TEAM Industrial Services (NFLD)
41 Sagona Avenue
MOUNT PEARL, Newfoundland
A1N 4P9

Laboratory No. 739111-16

Report Date: October 21, 2016
Received Date: October 17, 2016

Attention: Keith Gowan

Specimen: For Hatch Limited, "Penstock" Weld Pipe Coupon

TRANSVERSE WELD TENSILE REPORT

	RESULT	
Specimen Width:	0.745	in.
Specimen Thickness:	0.370	in.
Cross Sectional Area:	0.276	in^2
Maximum Load:	19,152	lbf
Ultimate Tensile Strength:	69,500	psi

The tensile specimen fractured in the base metal in a ductile manner.

Testing performed according to ASME Boiler and Pressure Vessel Code Section IX (2015 Edition).

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Per Randi Lee
Randi Lee — *Quality Assurance*

Per Matthew Liska
Matthew Liska — *Technician*

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Report for: TEAM Industrial Services (NFLD)
41 Sagona Avenue
MOUNT PEARL, Newfoundland
A1N 4P9

Laboratory No. 739110–16

Report Date: October 21, 2016
Received Date: October 17, 2016

Attention: Keith Gowan

Specimen: For Hatch Limited, "Penstock" Weld Pipe Coupon

CHEMICAL ANALYSIS TEST REPORT

Total Carbon	0.073	%	Silicon	0.52	%
Manganese	0.69	%	Titanium	0.02	%
Phosphorus	0.015	%	Vanadium	0.01	%
Sulphur	0.021	%			

Chemistry was performed on the weld metal.

Chemical analysis performed according to ASTM E1019-11, ASTM E1097-12 (modified) and ASTM E1479-99(2011).

Cambridge Materials Testing Limited

Per Randi Lee
Randi Lee *Quality Assurance*

Per Brittany DeGraaf
Brittany DeGraaf *Technician*

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Report for: TEAM Industrial Services (NFLD)
41 Sagona Avenue
MOUNT PEARL, Newfoundland
A1N 4P9

Laboratory No. 739109-16

Report Date: October 21, 2016
Received Date: October 17, 2016

Attention: Keith Gowan

Specimen: For Hatch Limited, "Penstock" Weld Pipe Coupon

CHEMICAL ANALYSIS TEST REPORT

Total Carbon	0.21	%
Manganese	0.52	%
Phosphorus	< 0.010	%
Sulphur	0.020	%
Silicon	0.07	%

The above analysis satisfies the chemical composition limits of UNS grade G10200 (1020) and G10230 (1023) steel.

Chemical analysis performed according to ASTM E1019-11, ASTM E1097-12 (modified) and ASTM E1479-99(2011).

Cambridge Materials Testing Limited

Per Randi Lee
Randi Lee *Quality Assurance*

Per Brittany DeGraaf
Brittany DeGraaf *Technician*

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Report For: TEAM Industrial Services (NFLD)
41 Sagona Avenue
MOUNT PEARL, Newfoundland
A1N 4P9

Laboratory #: **739812-16**

Report Date: October 26, 2016
Received Date: October 25, 2016

Attention: Keith Gowan

Customer P.O.#:

Specimen: For Hatch Limited, Paint (Coal Tar Epoxy) from ID Surface of a "Penstock" Weld Pipe Coupon

TEST REPORT

One pipe section with paint was received for identification and quantitation of asbestos, if present, along with the identification, where possible, of other materials. The paint was removed from the pipe and milled to a powder for purposes of analysis in accordance with EPA/600/R-93/116 (July 1993) using both stereomicroscope and polarized light microscopy. The paint sample was analyzed to evaluate the morphology, colour, refractive index, extinction, sign of elongation, birefringence, and dispersion staining colour characteristics of fibrous matter.

RESULTS

SAMPLE DESCRIPTION	% COMPOSITION (VISUAL AREA ESTIMATION)	
	Asbestos	Other
Homogenous, black, hard, flakey, non-friable	None	Matrix: 100%

Notes: 1. No fibrous matter was identified within the paint material.
2. Testing performed at the CMTL Mississauga location.

Cambridge Materials Testing Limited

Per Jill Cook
Jill Cook *Quality Assurance*

Per
Technician

Appendix B
Weld Coupon #2 Test Report

1. Introduction

As part of the Root Cause Analysis (RCA) investigation a coupon measuring approximately 460 mm x 460 mm (18” x 18”) was removed from section XX (CSA 40.8 Gr B material, Coupon #2) of BDE Penstock #1. The coupon incorporated a portion of one of the circumferential weld seams.

2. Required Tests

The following non-destructive testing was performed by TEAM Industrial Services, St. John’s, NL, to aid the RCA investigation:

- Radiographic Examination

The following destructive testing was performed by Cambridge Materials Testing Limited, Cambridge, Ontario, to aid the RCA investigation:

- Macroetch Evaluation
- Vickers Hardness Traverse
- Microetch Evaluation
- Transverse Weld Tensile
- Weld Metal Chemical Analysis Test
- Base Metal Chemical Analysis Test

3. Test Results

Radiographic Examination

The radiographic examination showed no rejectable defects. Porosity was detected, but was in the range of acceptable limits.

Macroetch Evaluation

A Photomacroetch of the weld was prepared from two different sections of the coupon etched in 2% Nital. A stereo microscope was then used to examine the samples for general comments on weld imperfections.

- Both sections showed the weld had pitting along the inside diameter surface within the HAZ (at the weld toes).
- No cracks or inclusions were exhibited in either of the sections.
- Both sections showed there was complete penetration and complete fusion was observed throughout the weld.

Vickers Hardness Traverse

Both macroetch sections were re-polished according to ASTM E3-11 and subjected to a Vickers Hardness Traverse. The Vickers Hardness readings were performed according to ASTM E92-16 using a 10kgf test force and indentations were measured at 100x magnification.

- Hardness values for the weld metal ranged from 170 to 214
- Hardness values for the HAZ ranged from 168 to 214
- Hardness values for the Base material ranged from 174 to 185

Hardness values are within the range of normal expected values for this type of material and E4918 (E7018) welding consumables.

Microstructural Examination

The two sections used in the previous Vickers hardness traverse were re-prepared according to ASTM E3-11 for microstructural examination. The specimens were etched in 2% Nital and examined using an optical microscope at various magnifications. The examination was performed at and near the fusion line on either side of the weld and labeled “FL” and “FL+1mm” as instructed by the customer.

- Microstructure examination showed ferrite and pearlite in both specimens.
- Both specimens displayed a relatively coarse grain HAZ on either side of the FL locations.
- Both specimens displayed a more refined structured HAZ consisting of fairly uniform mixture of pearlite and ferrite on the FL+1mm locations.
- Some sulphide inclusions were found dispersed throughout the material at higher magnification.

Transverse Weld Tensile

- Ultimate Tensile Strength (UTS) of weld metal = 84.5 ksi (582.6 MPa)

The tensile specimen fractured in the weld zone in a ductile manner. Even though this test failed in the weld metal, the UTS of the weld metal is significantly higher than the normal UTS of the base metal.

Weld Metal Chemical Analysis

The chemistry indicated on the attached report is consistent with an E4918 (E7018) electrode.

The sulphur content is below the maximum allowable of 0.035% (CSA W48, Table 1); however, according to Lincoln and Air Liquide specification sheets, the normal level of sulphur in the deposited weld metal for standard SMAW electrodes is 0.008% to 0.013% with

E4918 (E7018) normally around 0.011%. Thus, even though the sulphur content is below the maximum allowable at 0.018%, it is still above normal levels.

Total Carbon, Manganese, Phosphorus, Sulphur, and Silicon values are all within specifications.

Base Metal Chemical Analysis

The base metal chemistry is consistent with CSA 40.8 Gr B material.

Total Carbon, Manganese, Phosphorus, Sulphur, and Silicon values are all within composition specifications for UNS grade G15240 (1524) steel.

Attachment A
Test Results

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Report for: TEAM Industrial Services (NFLD)
41 Sagona Avenue
MOUNT PEARL, Newfoundland
A1N 4P9

Laboratory No. 744803–17

Report Date: January 13, 2017
Received Date: January 09, 2017

Attention: Cyril Pretty

Specimen: For Hatch Limited, "Penstock" Weld Pipe Coupon, Sample #2 - Circumferential Weld, Material: CSA 40.8 Gr. B

CHEMICAL ANALYSIS TEST REPORT

Total Carbon	0.21	%
Manganese	1.44	%
Phosphorus	0.010	%
Sulphur	0.020	%
Silicon	0.26	%

Chemistry was performed on the base metal.

The above analysis satisfies the chemical composition limits of UNS grade G15240 (1524) steel.

Chemical analysis performed according to ASTM E1019-11, ASTM E1097-12 (modified) and ASTM E1479-99(2011).

Cambridge Materials Testing Limited

Per Randi Lee
Randi Lee — *Quality Assurance*

Per Brittany DeGraaf
Brittany DeGraaf — *Technician*

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Report for: TEAM Industrial Services (NFLD)
41 Sagona Avenue
MOUNT PEARL, Newfoundland
A1N 4P9

Laboratory No. 744805-17

Report Date: January 13, 2017
Received Date: January 09, 2017

Attention: Cyril Pretty

Specimen: For Hatch Limited, "Penstock" Weld Pipe Coupon, Sample #2 - Circumferential Weld, Material: CSA 40.8 Gr. B

TRANSVERSE WELD TENSILE REPORT

	RESULT	
Specimen Width:	0.748	in.
Specimen Thickness:	0.345	in.
Cross Sectional Area:	0.258	in^2
Maximum Load:	21,842	lbf
Ultimate Tensile Strength:	84,500	psi

The tensile specimen fractured in the weld zone in a ductile manner.

Testing performed according to ASME Boiler and Pressure Vessel Code Section IX (2015 Edition).

Cambridge Materials Testing Limited

Per Randi Lee
Randi Lee *Quality Assurance*

Per Matthew Liska
Matthew Liska *Technician*

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Report for: TEAM Industrial Services (NFLD)
41 Sagona Avenue
MOUNT PEARL, Newfoundland
A1N 4P9

Laboratory No. 744804–17

Report Date: January 13, 2017
Received Date: January 09, 2017

Attention: Cyril Pretty

Specimen: For Hatch Limited, "Penstock" Weld Pipe Coupon, Sample #2 - Circumferential Weld, Material: CSA 40.8 Gr. B

CHEMICAL ANALYSIS TEST REPORT

Total Carbon	0.14	%
Manganese	1.60	%
Phosphorus	0.015	%
Sulphur	0.018	%
Silicon	0.39	%

Chemistry was performed on the weld metal.

Chemical analysis performed according to ASTM E1019-11, ASTM E1097-12 (modified) and ASTM E1479-99(2011).

Cambridge Materials Testing Limited

Per Randi Lee
Randi Lee *Quality Assurance*

Per Brittany DeGraaf
Brittany DeGraaf *Technician*

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Report For:	TEAM Industrial Services (NFLD) 41 Sagona Avenue MOUNT PEARL, Newfoundland A1N 4P9	**Laboratory #:** **Report Date:** **Received Date:**	**744802-17** January 13, 2017 January 9, 2017
Attention:	Cyril Pretty	**Customer P.O.#:**	
Specimen:	For Hatch Limited, "Penstock" Weld Pipe Coupon, Sample #2 Circumferential Weld Material: CSA 40.8 Gr. B		

METALLURGICAL TEST REPORT

Two random transverse sections were cut from the submitted weld coupon and prepared according to ASTM E3-11. The sections were arbitrarily labelled Section 1 and Section 2 by CMTL and subjected to a macroetch evaluation, microstructural examination and Vickers hardness traverse.

MACROETCH EVALUATION

The sections were etched in 2% Nital and then examined using a stereo microscope for general comments on weld imperfections.

RESULTS

Section 1: Examination of the specimen showed that the weld had pitting along the inside diameter surface within the HAZ (at the weld toes) (refer to Figure 2). The weld appeared to have no cracks or inclusions, and there was complete penetration and complete fusion observed throughout the weld.

Section 2: Examination of the specimen showed that the weld had pitting along the inside diameter surface within the HAZ (at the weld toes) (refer to Figure 3). The weld appeared to have no cracks or inclusions, and there was complete penetration and complete fusion observed throughout the weld.

Cambridge Materials Testing Limited

Per Randi Lee
Randi Lee *Quality Assurance*

Per HollySteele
Holly Steele *Technician*

Cambridge materials testing limited

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TEAM Industrial Services (NFLD)
Lab # 744802-17

VICKERS HARDNESS TRAVERSE

The macroetch sections were then re-polished according to ASTM E3-11 and subjected to a Vickers hardness traverse (refer to Figure 1). The Vickers hardness readings were performed according to ASTM E92-16 using a 10kgf test force. Indentations were measured at 100X magnification.

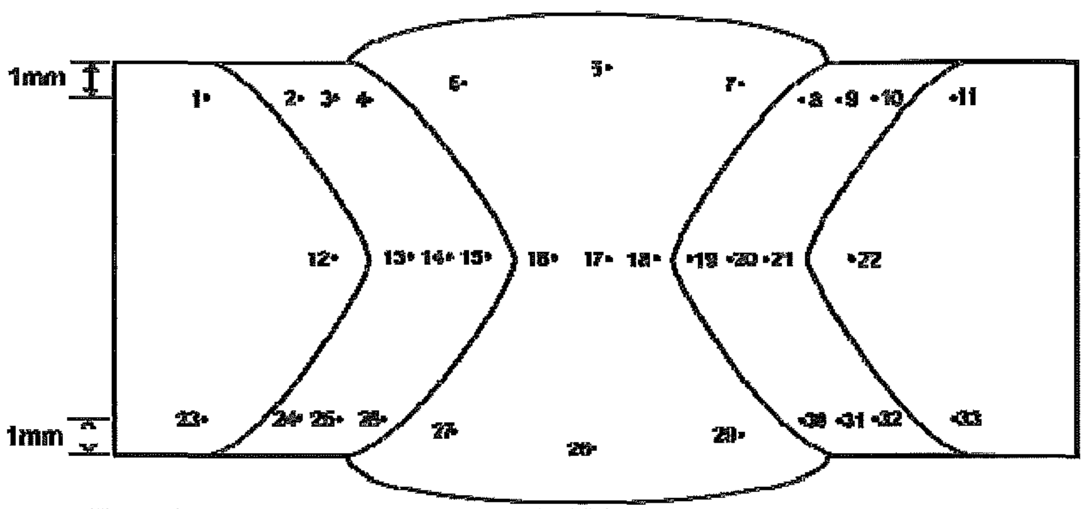

Figure 1: Schematic drawing showing the Vickers hardness indentation locations.

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TEAM Industrial Services (NFLD)
Lab # 744802-17

RESULTS

Traverse Pass	Location	Indent	Section 1 Hardness (HV 10kgf)	Section 2 Hardness (HV 10kgf)
Top Cap Pass	Base Material	1	181	181
	HAZ	**2**	**171**	**168**
		3	**181**	**180**
		4	**184**	**193**
	Weld	5	170	176
		6	173	177
		7	178	175
	HAZ	**8**	**185**	**188**
		9	**183**	**190**
		10	**182**	**176**
	Base Material	11	185	183
Mid-Thickness Pass	Base Material	12	179	185
	HAZ	**13**	**184**	**193**
		14	**192**	**197**
		15	**203**	**212**
	Weld	16	188	197
		17	199	196
		18	195	199
	HAZ	**19**	**209**	**207**
		20	**201**	**196**
		21	**190**	**195**
	Base Material	22	184	184
Bottom Cap Pass	Base Material	23	174	176
	HAZ	**24**	**185**	**187**
		25	**196**	**194**
		26	**214**	**209**
	Weld	27	214	192
		28	198	197
		29	207	195
	HAZ	**30**	**214**	**210**
		31	**209**	**198**
		32	**193**	**188**
	Base Material	33	178	177

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TEAM Industrial Services (NFLD)
Lab # 744802-17

MICROSTRUCTURAL EXAMINATION

The sections used for the Vickers hardness traverse were re-prepared according to ASTM E3-11 for microstructural examination. The specimens were etched in 2% Nital and examined using an optical microscope at various magnifications. Examinations were performed at and near the fusion line on either side of the weld, the weld was arbitrarily labelled "Side A" and "Side B" by CMTL for identification purposes. These locations were labelled as "FL" and "FL+1mm" as instructed by the customer.

RESULTS

Section 1: Examination of the etched specimen revealed a microstructure consisting of ferrite and pearlite. A relatively coarse grain HAZ was observed on either side of the weld at the "FL" locations (refer to Figure 4 and Figure 5). At the "FL+1mm" locations, the HAZ showed a more refined structure consisting of a fairly uniform mixture of ferrite and pearlite. At a higher magnification some sulphide inclusions were observed dispersed throughout the material (refer to Figure 6).

Section 2: Examination of the etched specimen revealed a microstructure consisting of ferrite and pearlite. A relatively coarse grain HAZ was observed on either side of the weld at the "FL" locations (refer to Figure 7 and Figure 8). At the "FL+1mm" locations, the HAZ showed a more refined structure consisting of a fairly uniform mixture of ferrite and pearlite. At a higher magnification some sulphide inclusions were observed dispersed throughout the material (refer to Figure 9).

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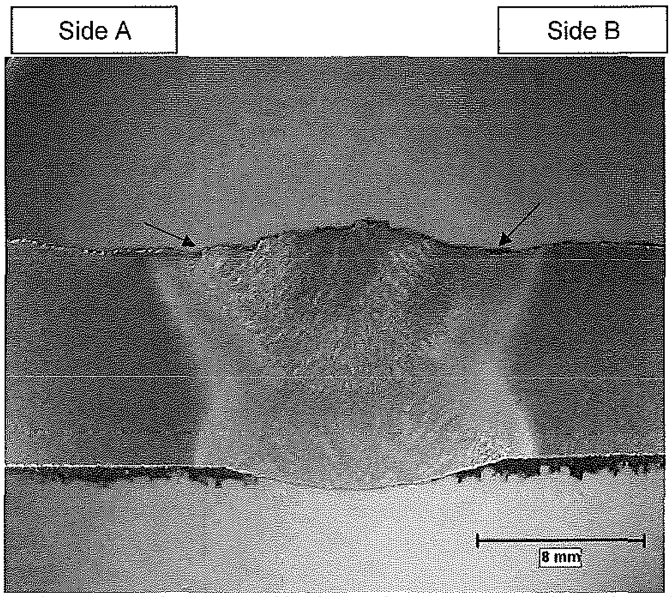
TEAM Industrial Services (NFLD)
Lab # 744802-17



Specimen examined at 3.2X, photo shown at approximately 3.2X
Etched in 2% Nital

Figure 2: Photomacrograph of the Section 1, showing the pitting along the surface within the HAZ/at the weld toes along the inside diameter.

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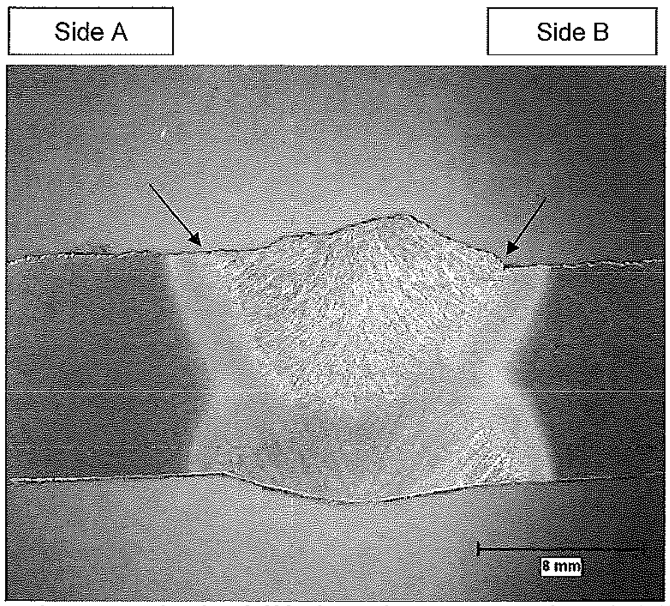
Lab # 744802-17



Specimen examined at 3.2X, photo shown at approximately 3.2X
Etched in 2% Nital

Figure 3: Photomacrograph of the Section 2, showing the pitting along the surface within the HAZ/at the weld toes along the inside diameter.

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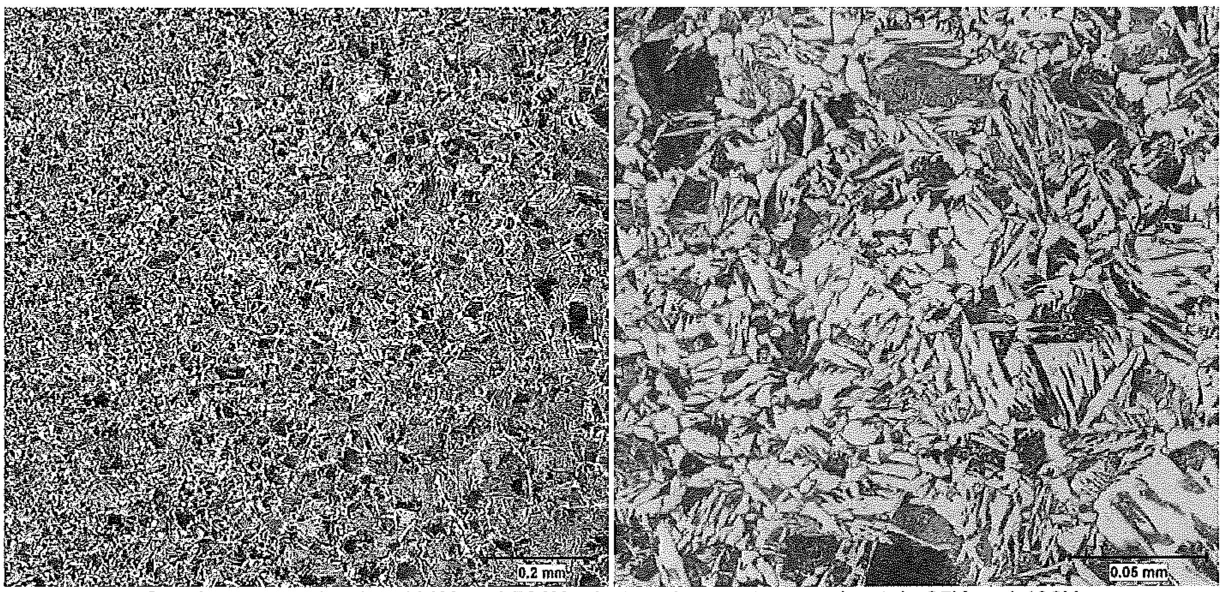

Specimen examined at 100X and 500X, photos shown at approximately 85X and 428X
Etched in 2% Nital

Figure 4: Photomicrographs of the Section 1 “Side A” weld coupon at the “FL” location, where a relatively coarse grain HAZ of ferrite and pearlite was observed.

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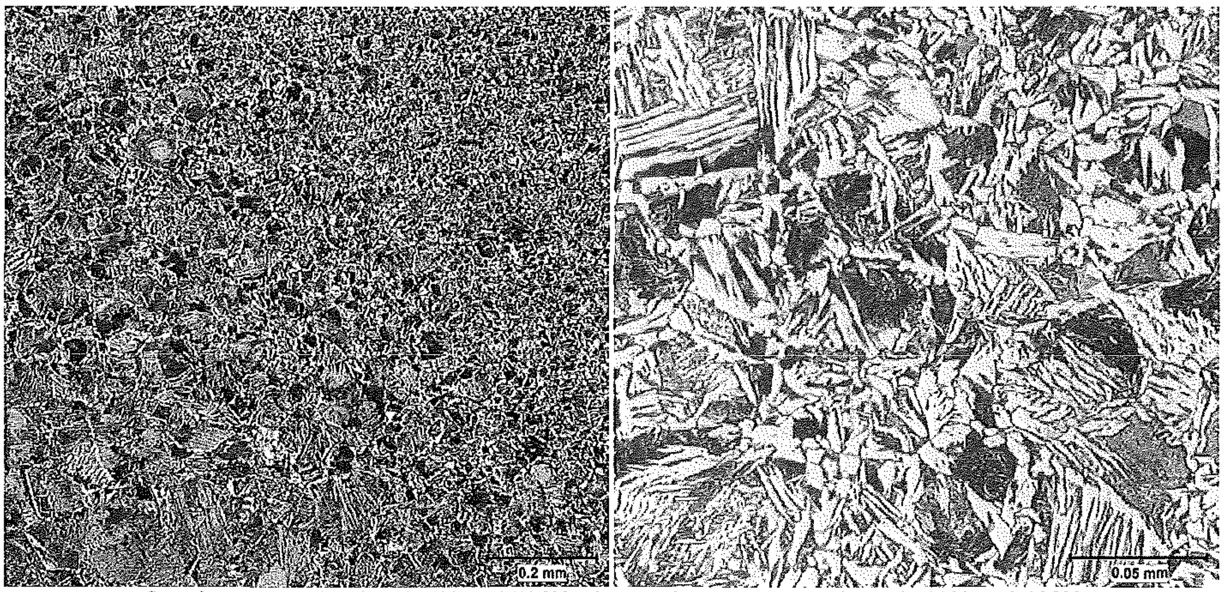
TEAM Industrial Services (NFLD)
Lab # 744802-17



Specimen examined at 100X and 500X, photos shown at approximately 85X and 428X
Etched in 2% Nital

Figure 5: Photomicrographs of the Section 1 "Side B" weld coupon at the "FL" location, where a relatively coarse grain HAZ of ferrite and pearlite was observed.

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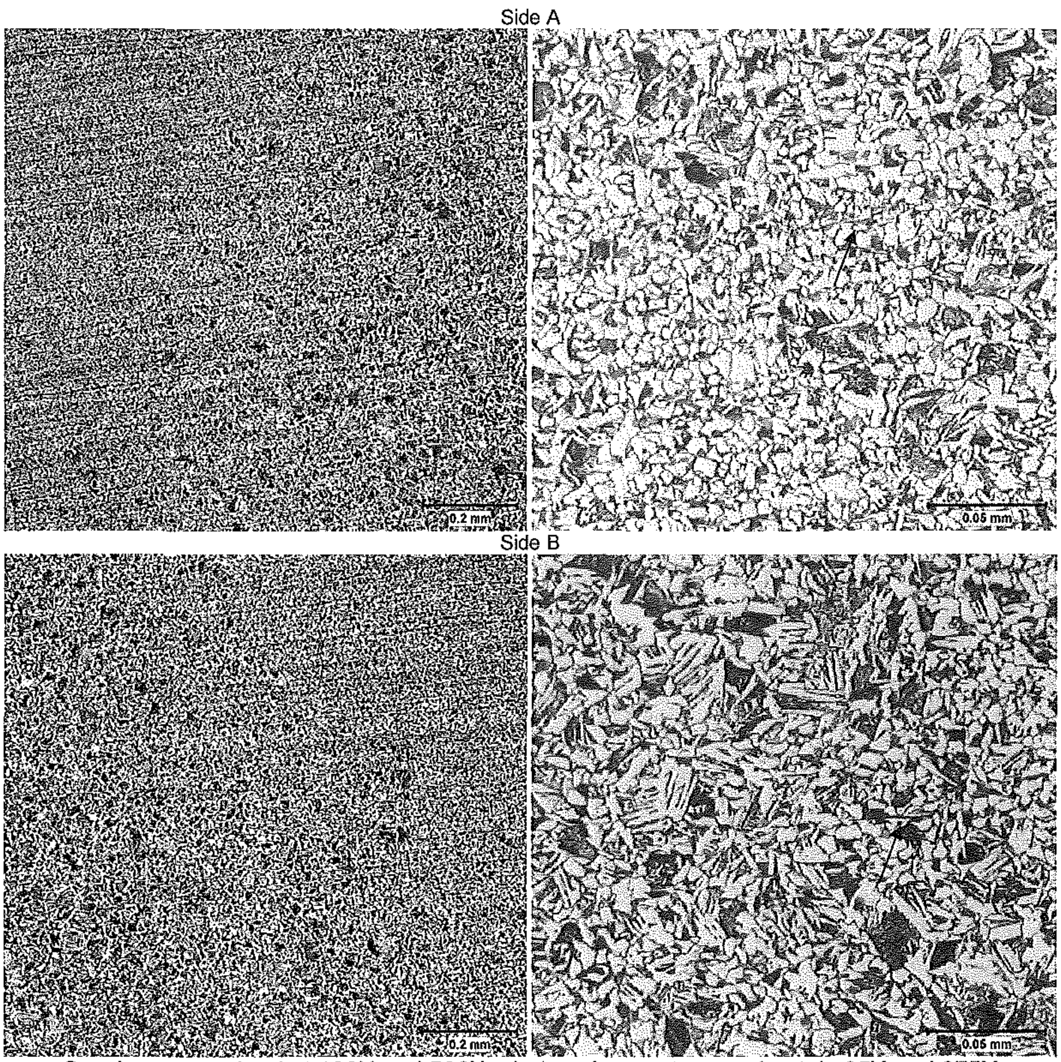

Specimen examined at 100X and 500X, photos shown at approximately 85X and 375X
Etched in 2% Nital

Figure 6: Photomicrographs of the Section 1 "Side A" and "Side B" weld coupon at the "FL +1" locations; where the HAZ microstructure showed a fairly uniform mixture of ferrite and pearlite, with a more refined grain size. At a higher magnification some sulphide inclusions were observed (refer to red arrows).

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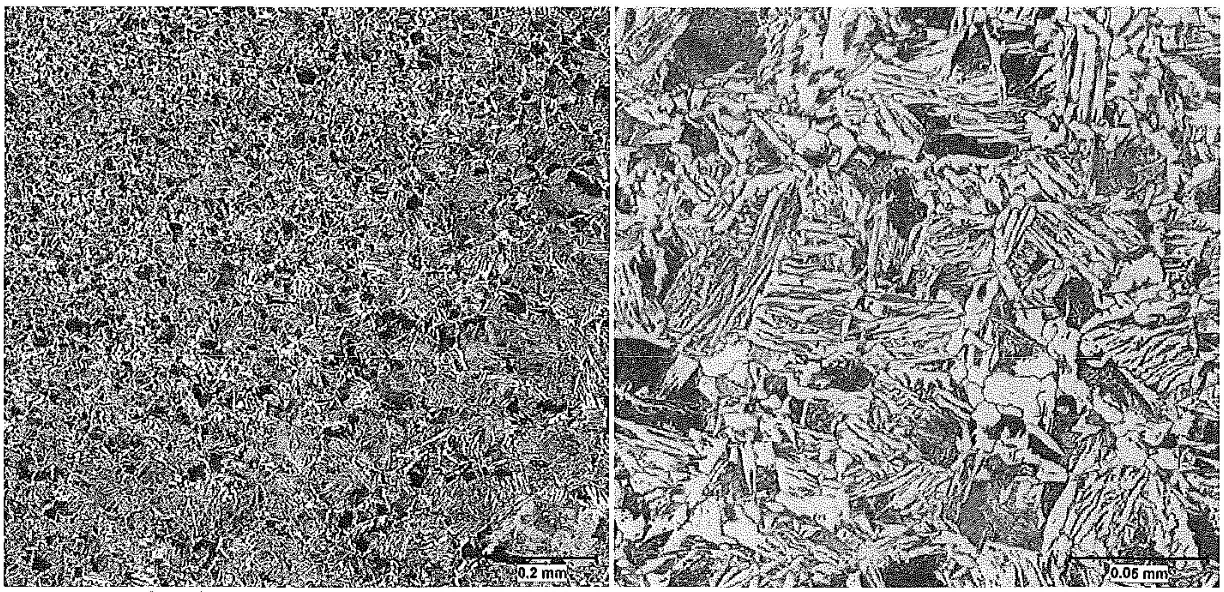

Specimen examined at 100X and 500X, photos shown at approximately 85X and 428X
Etched in 2% Nital

Figure 7: Photomicrographs of the Section 2 "Side A" weld coupon at the "FL" location, where a relatively coarse grain HAZ of ferrite and pearlite was observed.

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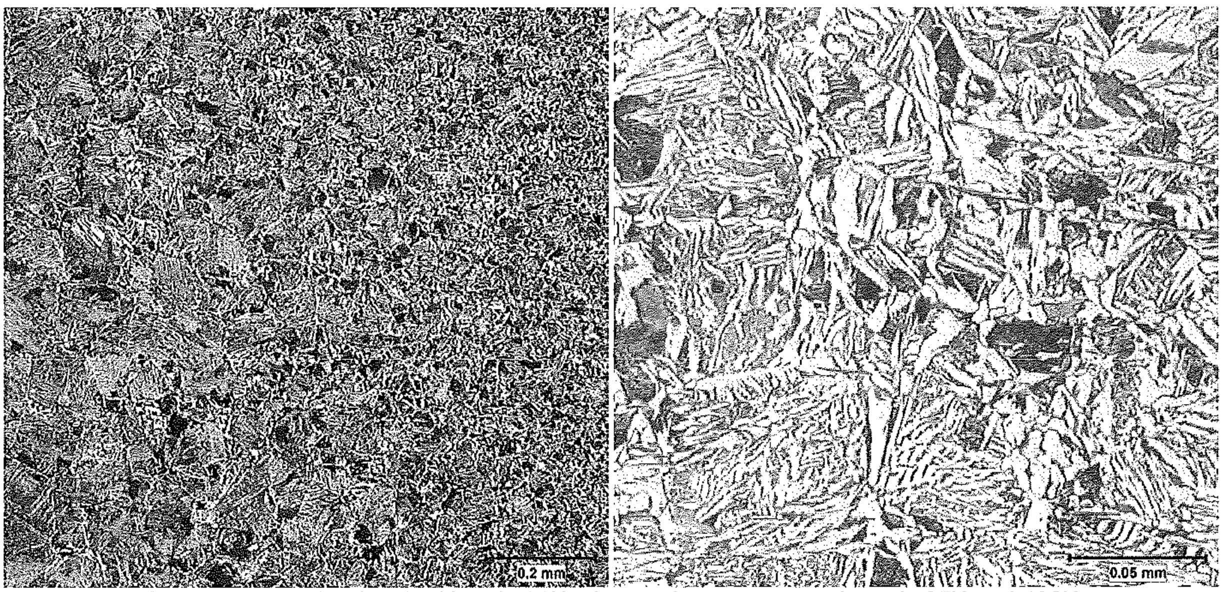

Specimen examined at 100X and 500X, photos shown at approximately 85X and 428X
Etched in 2% Nital

Figure 8: Photomicrographs of the Section 2 "Side B" weld coupon at the "FL" location, where a relatively coarse grain HAZ of ferrite and pearlite was observed.

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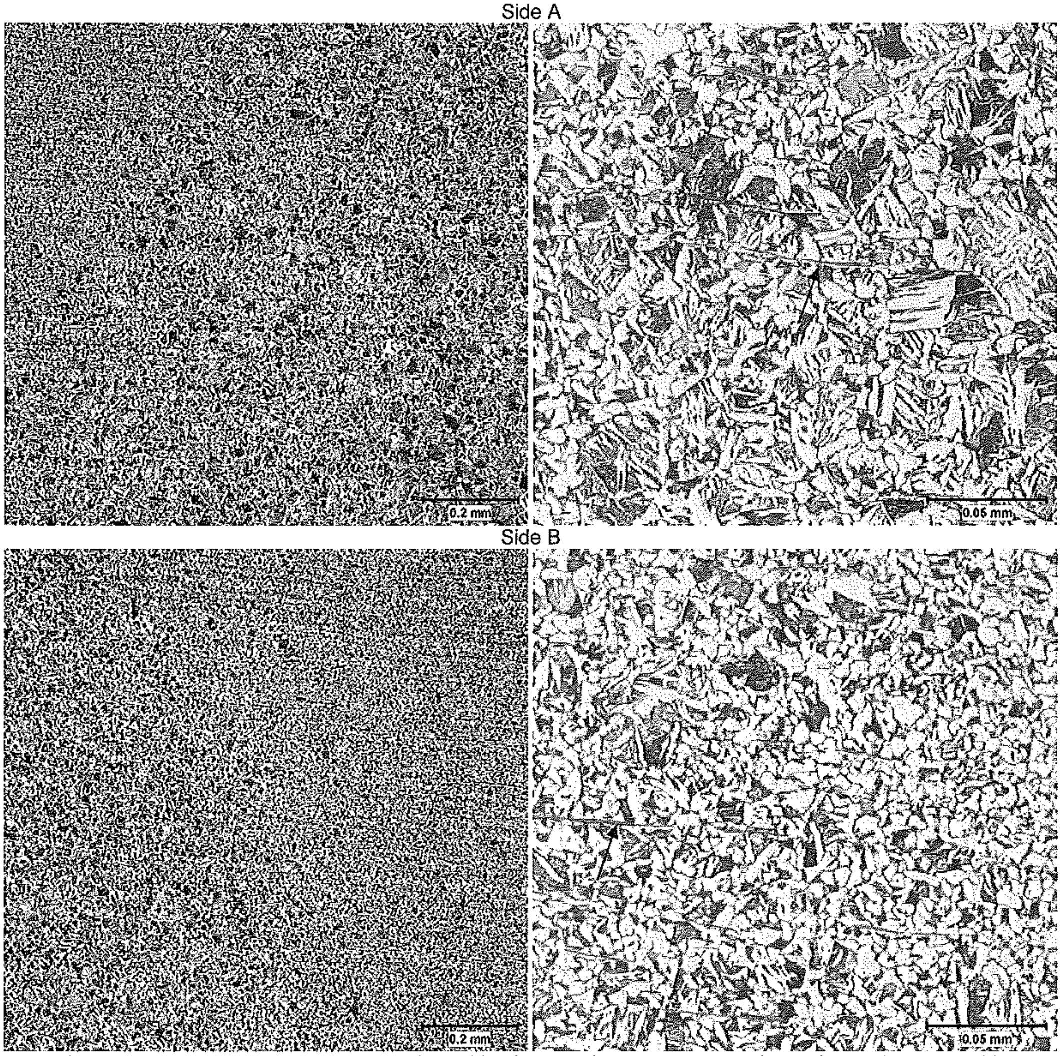
Side A



Specimen examined at 100X and 500X, photos shown at approximately 85X and 375X
Etched in 2% Nital

Figure 9: Photomicrographs of the Section 2 "Side A" and "Side B" weld coupon at the "FL +1" locations; where the HAZ microstructure showed a fairly uniform mixture of ferrite and pearlite, with a more refined grain size. At a higher magnification some sulphide inclusions were observed (refer to red arrows).

Appendix C
Weld Coupon #3 Test Report

1. Introduction

As part of the Root Cause Analysis (RCA) investigation a coupon measuring approximately 460 mm x 460 mm (18" x 18") was removed from section XX (A285 Gr C section, Coupon #3) of BDE Penstock #1. The coupon incorporated a portion of one of the circumferential weld seams.

2. Required Tests

The following non-destructive testing was performed by TEAM Industrial Services, St. John's, NL, to aid the RCA investigation:

- Radiographic Examination

The following destructive testing was performed by Cambridge Materials Testing Limited, Cambridge, Ontario, to aid the RCA investigation:

- Macroetch Evaluation
- Vickers Hardness Traverse
- Microetch Evaluation
- Transverse Weld Tensile
- Weld Metal Chemical Analysis Test
- Base Metal Chemical Analysis Test

3. Test Results

Radiographic Examination

The radiographic examination showed no rejectable defects.

Macroetch Evaluation

A Photomacroetch of the weld was prepared from two different sections of the coupon etched in 2% Nital. A stereo microscope was then used to examine the samples for general comments on weld imperfections.

- Both sections showed the weld had pitting along the inside diameter surface within the HAZ (at the weld toes).
- No cracks or inclusions were exhibited in either of the sections.
- Both sections showed there was complete penetration and complete fusion was observed throughout the weld.

Microstructural Examination

A Photomacroetch of the weld was prepared from two different sections of the coupon etched in 2% Nital. A stereo microscope was then used to examine the samples for general comments on weld imperfections.

- Microstructure examination showed ferrite and pearlite in both specimens.
- Both specimens displayed a relatively coarse grain HAZ on either side of the FL locations.
- Both specimens displayed a more refined structured HAZ consisting of fairly uniform mixture of pearlite and ferrite on the FL+1mm locations.
- Some sulphide inclusions were found dispersed throughout the material at higher magnification.

Vickers Hardness Traverse

Both macroetch sections were re-polished according to ASTM E3-11 and subjected to a Vickers Hardness Traverse. The Vickers Hardness readings were performed according to ASTM E92-16 using a 10kgf test force and indentations were measured at 100x magnification.

- Hardness values for the weld metal ranged from 153 to 181
- Hardness values for the HAZ ranged from 121 to 158
- Hardness values for the Base material ranged from 130 to 158

Hardness values are within the range of normal expected values for this type of material and E4918 (E7018) welding consumables.

Microstructural Examination

The two sections used in the previous Vickers hardness traverse were re-prepared according to ASTM E3-11 for microstructural examination. The specimens were etched in 2% Nital and examined using an optical microscope at various magnifications. The examination was performed at and near the fusion line on either side of the weld, arbitrarily named “Side A” and ”Side B” for CMTL identification purposes. These locations were labeled “FL” and “FL+1mm” as instructed by the customer.

- Microstructure examination showed ferrite and pearlite in both specimens.
- Both specimens displayed a relatively coarse grain HAZ on either side of the FL locations; with “Side A” having more ferrite observed and “Side B” having more pearlite with a more distinct coarse grain HAZ.
- Both specimens displayed a more refined structured HAZ consisting of fairly uniform mixture of pearlite and ferrite on the FL+1mm locations.

- Some sulphide inclusions were found dispersed throughout the material at higher magnification.

Transverse Weld Tensile

- Ultimate Tensile Strength (UTS) of weld metal = 63.5 ksi (437.8 MPa)
- The tensile specimen fractured in the weld zone in a ductile manner. Even though this test failed in the weld metal, the UTS of the weld metal is significantly higher than the normal UTS of the base metal.

Weld Metal Chemical Analysis

The chemistry indicated on the attached report is consistent with an E4918 (E7018) electrode.

The sulphur content is below the maximum allowable of 0.035% (CSA W48, Table 1); however, according to Lincoln and Air Liquide specification sheets, the normal level of sulphur in the deposited weld metal for standard SMAW electrodes is 0.008% to 0.013% with E4918 (E7018) normally around 0.011%. Thus, even though the sulphur content is below the maximum allowable at 0.023%, it is still above normal levels.

Total Carbon, Manganese, Phosphorus, Sulphur, and Silicon values are all within specifications.

Base Metal Chemical Analysis

Chemical Analysis is similar to the chemical composition limits of ASTM A285 Grade C steel, with the exception of Sulphur.

Attachment A
Test Results

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Report For:	TEAM Industrial Services (NFLD) 41 Sagona Avenue MOUNT PEARL, Newfoundland A1N 4P9	**Laboratory #:** **Report Date:** **Received Date:**	**743344-16 (Revised)** January 4, 2017 December 12, 2016
Attention:	Cyril Pretty	**Customer P.O.#:**	
Specimen:	For Hatch Limited, "Penstock" Weld Pipe Coupon, Sample #3 Circumferential Seam Material: ASTM A285 Gr. C		

METALLURGICAL TEST REPORT

Two random transverse sections were cut from the submitted weld coupon and prepared according to ASTM E3-11. The sections were arbitrarily labelled Section 1 and Section 2 by CMTL and subjected to a macroetch evaluation, microstructural examination and Vickers hardness traverse.

MACROETCH EVALUATION

The sections were etched in 2% Nital and then examined using a stereo microscope for general comments on weld imperfections.

RESULTS

Section 1: Examination of the specimen showed that the weld had pitting along the surface within the HAZ (at the weld toes) (refer to Figure 2). The weld appeared to have no cracks or inclusions, and there was complete penetration and complete fusion observed throughout the weld.

Section 2: Examination of the specimen showed that the weld had pitting along the surface within the HAZ (at the weld toes) (refer to Figure 3). The weld appeared to have no cracks or inclusions, and there was complete penetration and complete fusion observed throughout the weld.

Cambridge Materials Testing Limited

Per Randi Lee
Randi Lee *Quality Assurance*

Per Holly Steele
Holly Steele *Technician*

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TEAM Industrial Services (NFLD)
Lab # 743344-16 (Revised)

VICKERS HARDNESS TRAVERSE

The macroetch sections were then re-polished according to ASTM E3-11 and subjected to a Vickers hardness traverse (refer to Figure 1). The Vickers hardness readings were performed according to ASTM E92-16 using a 10kgf test force. Indentations were measured at 100X magnification.

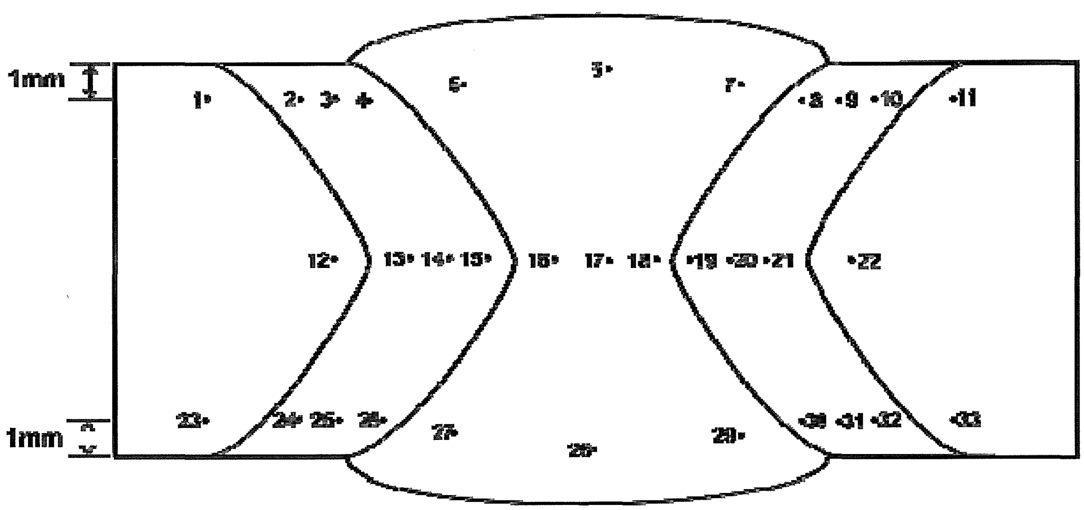

Figure 1: Schematic drawing showing the Vickers hardness indentation locations.

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RESULTS

Traverse Pass	Location	Indent	Section 1 Hardness (HV 10kgf)	Section 2 Hardness (HV 10kgf)
Top Cap Pass	Base Material	1	136	158
	HAZ	**2**	**133**	**155**
		3	**140**	**156**
		4	**136**	**158**
	Weld	5	164	161
		6	156	163
		7	166	180
	HAZ	**8**	**136**	**138**
		9	**138**	**136**
		10	**129**	**126**
	Base Material	11	134	141
Mid-Thickness Pass	Base Material	12	134	138
	HAZ	**13**	**133**	**147**
		14	**138**	**141**
		15	**139**	**142**
	Weld	16	154	153
		17	164	157
		18	161	160
	HAZ	**19**	**137**	**140**
		20	**137**	**138**
		21	**137**	**133**
	Base Material	22	134	131
Bottom Cap Pass	Base Material	23	133	138
	HAZ	**24**	**132**	**126**
		25	**135**	**139**
		26	**139**	**141**
	Weld	27	174	175
		28	181	174
		29	170	171
	HAZ	**30**	**143**	**141**
		31	**140**	**141**
		32	**121**	**143**
	Base Material	33	130	147

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Lab # 743344-16 (Revised)

MICROSTRUCTURAL EXAMINATION

The sections used for the Vickers hardness traverse were re-prepared according to ASTM E3-11 for microstructural examination. The specimens were etched in 2% Nital and examined using an optical microscope at various magnifications. Examinations were performed at and near the fusion line on either side of the weld, the weld was arbitrarily labelled “Side A” and “Side B” by CMTL for identification purposes. These locations were labelled as “FL” and “FL+1mm” as instructed by the customer.

RESULTS

Section 1: Examination of the etched specimen revealed a microstructure consisting of ferrite and pearlite. A relatively coarse grain HAZ was observed on either side of the weld at the “FL” locations; with Side A having more ferrite observed and Side B having more pearlite with a more distinct coarse grain HAZ (refer to Figure 4 and Figure 5). At the “FL+1mm” locations, the HAZ showed a more refined structure consisting of a fairly uniform mixture of ferrite and pearlite. At a higher magnification some sulphide inclusions were observed dispersed throughout the material (refer to Figure 6).

Section 2: Examination of the etched specimen revealed a microstructure consisting of ferrite and pearlite. A relatively coarse grain HAZ was observed on either side of the weld at the “FL” locations; with Side A having more ferrite observed and Side B having more pearlite with a more distinct coarse grain HAZ (refer to Figure 7 and Figure 8). At the “FL+1mm” locations, the HAZ showed a more refined structure consisting of a fairly uniform mixture of ferrite and pearlite. At a higher magnification some sulphide inclusions were observed dispersed throughout the material (refer to Figure 9).

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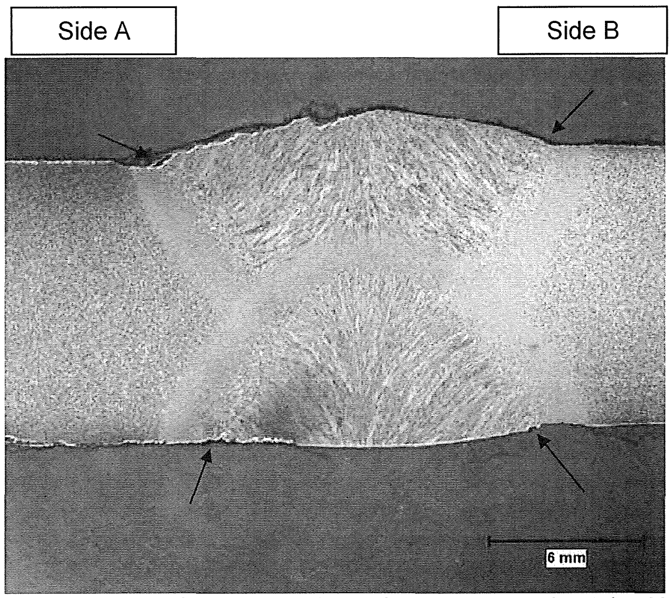
Lab # 743344-16 (Revised)



Specimen examined at 4X, photo shown at approximately 4X
Etched in 2% Nital

Figure 2: Photomacrograph of the Section 1, showing the pitting along the surface within the HAZ/at the weld toes.

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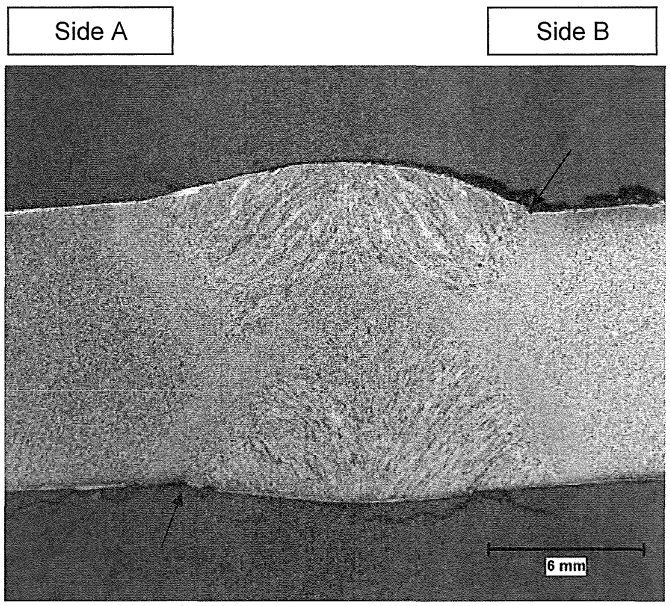

Specimen examined at 4X, photo shown at approximately 4X
Etched in 2% Nital

Figure 3: Photomacrograph of the Section 2, showing the pitting along the surface within the HAZ/at the weld toes.

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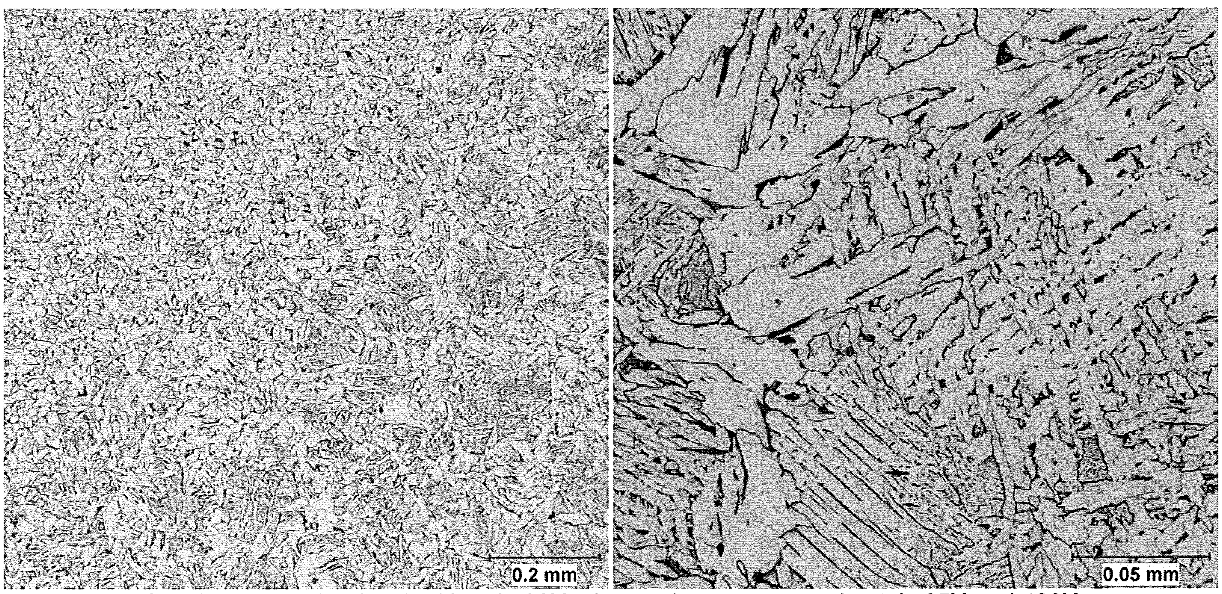

Specimen examined at 100X and 500X, photos shown at approximately 85X and 428X
Etched in 2% Nital

Figure 4: Photomicrographs of the Section 1 "Side A" weld coupon at the "FL" location, where a relatively coarse grain HAZ of ferrite and some pearlite was observed.

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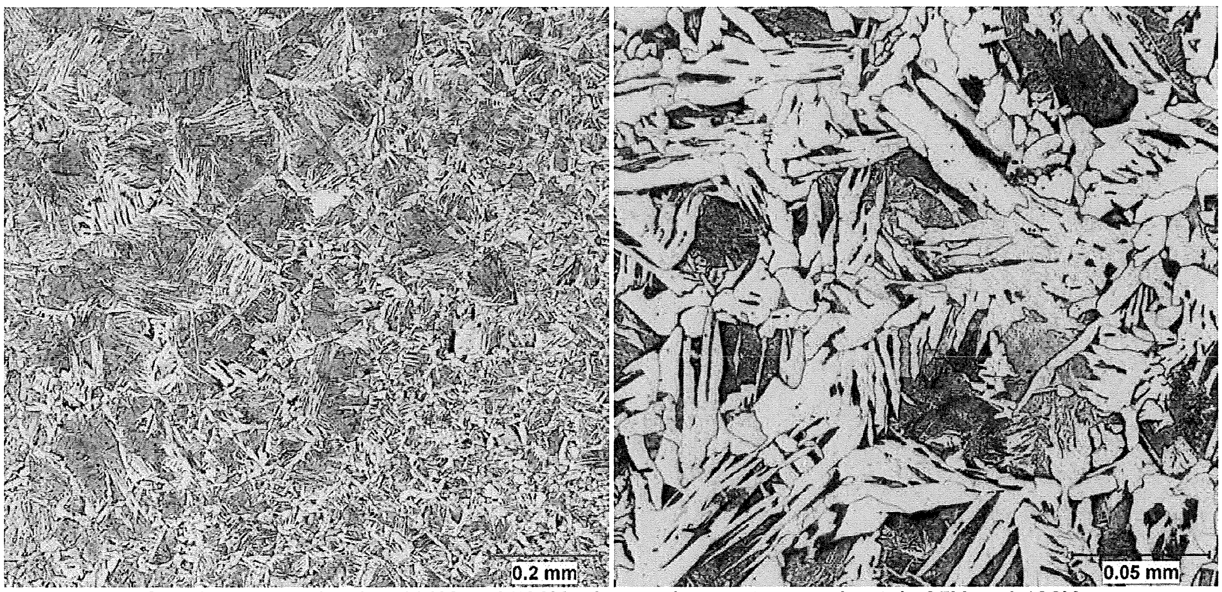

Specimen examined at 100X and 500X, photos shown at approximately 85X and 428X
Etched in 2% Nital

Figure 5: Photomicrographs of the Section 1 “Side B” weld coupon at the “FL” location, where a relatively coarse grain HAZ of ferrite and pearlite was observed.

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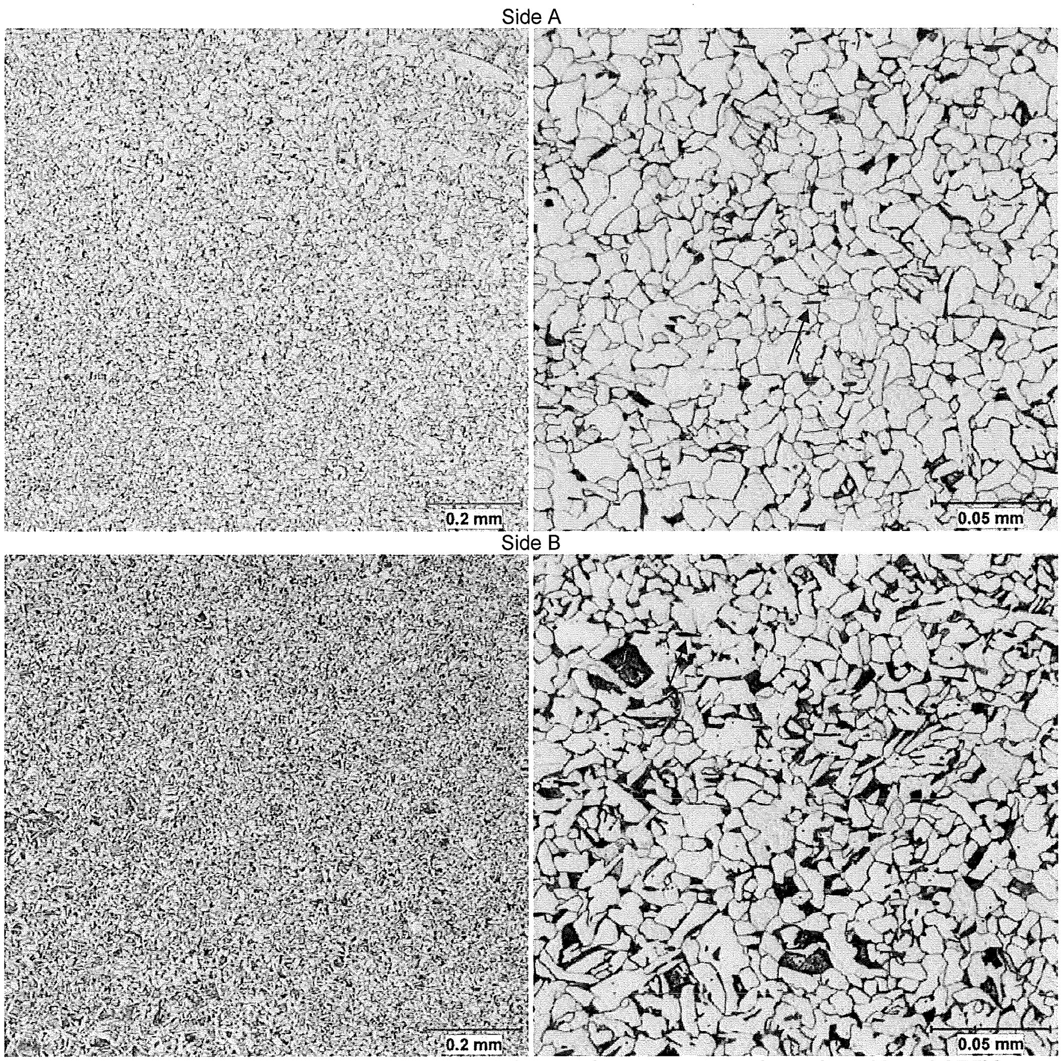

Specimen examined at 100X and 500X, photos shown at approximately 85X and 375X
Etched in 2% Nital

Figure 6: Photomicrographs of the Section 1 “Side A” and “Side B” weld coupon at the “FL +1” locations; where the HAZ microstructure showed a fairly uniform mixture of ferrite and pearlite, with a more refined grain size. At a higher magnification some sulphide inclusions were observed (refer to red arrows).

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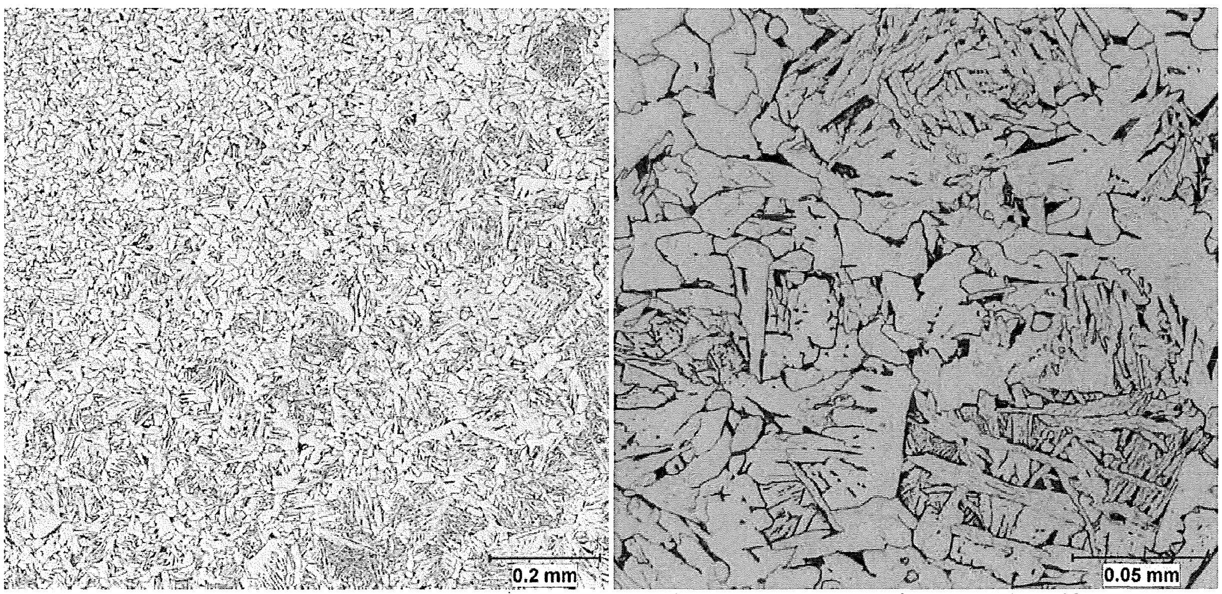

Specimen examined at 100X and 500X, photos shown at approximately 85X and 428X
Etched in 2% Nital

Figure 7: Photomicrographs of the Section 2 “Side A” weld coupon at the “FL” location, where a relatively coarse grain HAZ of ferrite and some pearlite was observed.

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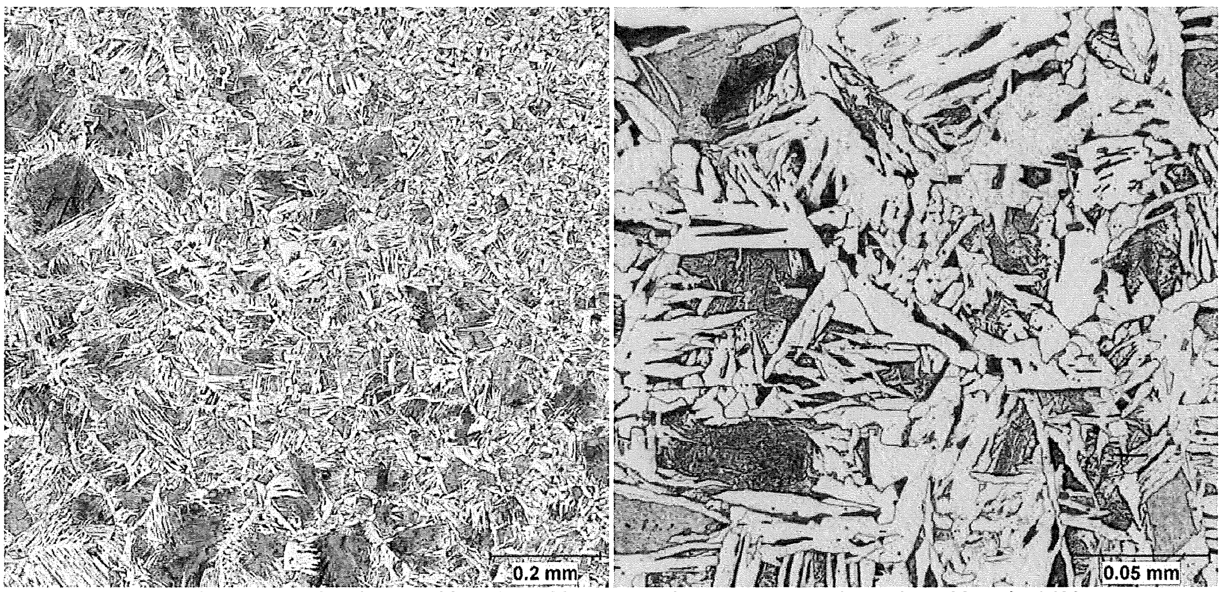

Specimen examined at 100X and 500X, photos shown at approximately 85X and 428X
Etched in 2% Nital

Figure 8: Photomicrographs of the Section 2 “Side B” weld coupon at the “FL” location, where a relatively coarse grain HAZ of ferrite and pearlite was observed.

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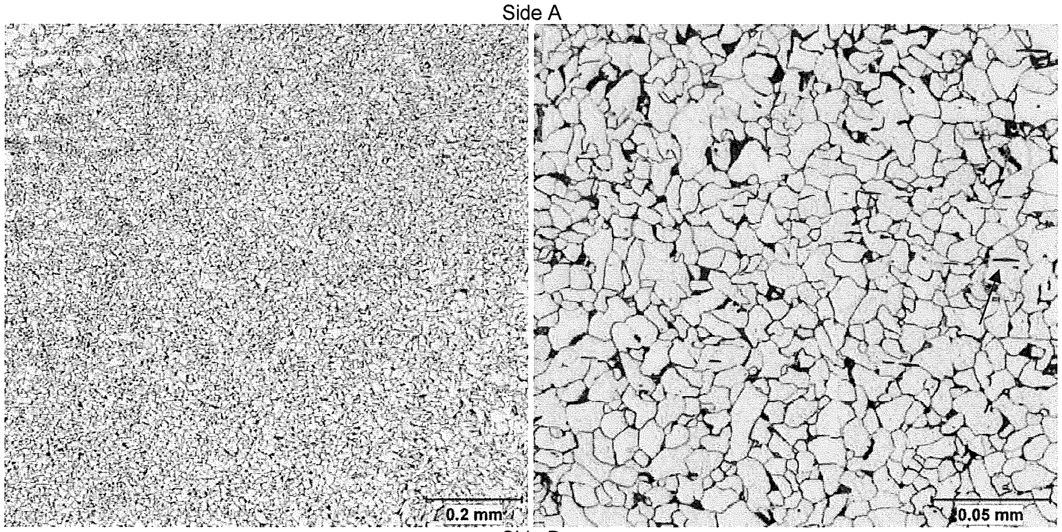
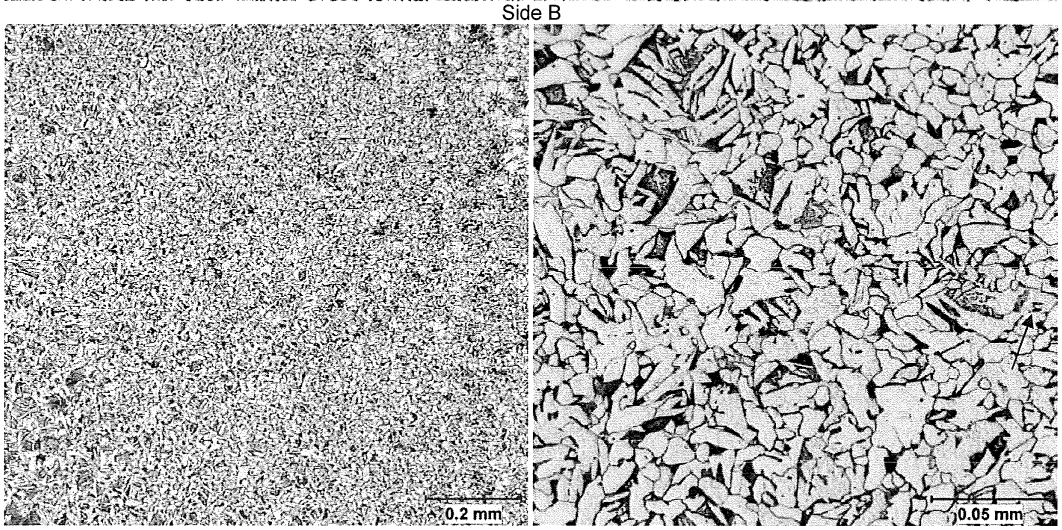
Side A



Side B



Specimen examined at 100X and 500X, photos shown at approximately 85X and 375X
Etched in 2% Nital

Figure 9: Photomicrographs of the Section 2 “Side A” and “Side B” weld coupon at the “FL +1” locations; where the HAZ microstructure showed a fairly uniform mixture of ferrite and pearlite, with a more refined grain size. At a higher magnification some sulphide inclusions were observed (refer to red arrows).

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Report for: TEAM Industrial Services (NFLD)
41 Sagona Avenue
MOUNT PEARL, Newfoundland
A1N 4P9

Laboratory No. 743345–16

Report Date: December 21, 2016
Received Date: December 12, 2016

Attention: Cyril Pretty

Specimen: For Hatch Limited, "Penstock" Weld Pipe Coupon, Sample #3 - Circumferential Seam, Material: ASTM A285 Gr. C

CHEMICAL ANALYSIS TEST REPORT

Total Carbon	0.098	%
Manganese	0.63	%
Phosphorus	0.010	%
Sulphur	0.032	%
Silicon	0.22	%

The above analysis is similar to the chemical composition limits of ASTM A285/A285M-12 Grade C steel, with the exception of Sulphur.

Chemical analysis performed according to ASTM E1019-11, ASTM E1097-12 (modified) and ASTM E1479-99(2011).

Cambridge Materials Testing Limited

Per Randi Lee
Randi Lee *Quality Assurance*

Per Brittany DeGraaf
Brittany DeGraaf *Technician*

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Report for: TEAM Industrial Services (NFLD)
41 Sagona Avenue
MOUNT PEARL, Newfoundland
A1N 4P9

Laboratory No. 743346–16

Report Date: December 21, 2016
Received Date: December 12, 2016

Attention: Cyril Pretty

Specimen: For Hatch Limited, "Penstock" Weld Pipe Coupon, Sample #3 - Circumferential Seam, Material: ASTM A285 Gr. C

CHEMICAL ANALYSIS TEST REPORT

Total Carbon	0.091	%
Manganese	1.18	%
Phosphorus	0.015	%
Sulphur	0.023	%
Silicon	0.30	%

Chemistry was performed on the weld metal.

Chemical analysis performed according to ASTM E1019-11, ASTM E1097-12 (modified) and ASTM E1479-99(2011).

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Per Randi Lee
Randi Lee — *Quality Assurance*

Per Brittany DeGraaf
Brittany DeGraaf — *Technician*

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Report for: TEAM Industrial Services (NFLD)
41 Sagona Avenue
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A1N 4P9

Laboratory No. 743347-16

Report Date: December 20, 2016
Received Date: December 12, 2016

Attention: Cyril Pretty

Specimen: For Hatch Limited, "Penstock" Weld Pipe Coupon, Sample #3 - Circumferential Seam, Material: ASTM A285 Gr. C

TRANSVERSE WELD TENSILE REPORT

	RESULT	
Specimen Width:	0.748	in.
Specimen Thickness:	0.377	in.
Cross Sectional Area:	0.282	in^2
Maximum Load:	17,880	lbf
Ultimate Tensile Strength:	63,500	psi

The tensile specimen fractured in the base metal in a ductile manner.

Testing performed according to ASME Boiler and Pressure Vessel Code Section IX (2015 Edition).

Cambridge Materials Testing Limited

Per Randi Lee
Randi Lee — *Quality Assurance*

Per Matthew Liska
Matthew Liska — *Technician*

Appendix D
Bay d'Espoir Pressure Conduit #1
Inspection Report 1987

HYDRO

BAY D'ESPOIR

PRESSURE CONDUIT #1

INSPECTION REPORT

NEWFOUNDLAND AND LABRADOR HYDRO

HYDRO

GENERATION & TRANSMISSION OPERATIONS
Engineering Services (Mech.)

BAY D'ESPOIR

PRESSURE CONDUIT #1

INSPECTION REPORT

Prepared by: Wayne Rice
Kevin J. Dawson

Date: September 9, 1987

HYDRO

INTRODUCTION

On September 2, 1987, Engineering Services personnel conducted an internal inspection of the #1 pressure conduit at the Bay D'Espoir Generating Station. This was the first such inspection of the conduit since it was placed in service in 1967. In general, the conduit appeared to be in excellent condition. No weld cracking, wall thinning or bulging was observed. This report contains details of the inspection procedure, details of the inspection process, which involved visual and ultrasonic methods, used and a listing of the inspection results.

DESCRIPTION OF PRESSURE CONDUIT

The #1 pressure conduit at BDE is an all-welded steel pipe approximately 3837 feet long and consists of three major sections. Between the intake structure and the surge tank the conduit is made up of approx. 1250 feet of 17' - 0" diameter ASTM A-285 Grade B carbon steel pipe and approx. 1000 feet of 15' - 3" diameter CSA Standard G-40.8 steel pipe . This section is known as "Pipeline A". From the surge tank to a point about 80 ft. upstream of the centre line of the units, the conduit consists of approx. 1476 feet of CSA Standard G-40.8 steel pipe. This section is known as "Penstock A". At this point the conduit bifurcates into two 9' - 6" diameter pipes, which are reduced to 7' - 3" diameter pipe and terminate at a spherical valve. There are no expansion joints. The thickness of the steel pipe varies from 7/16 inch to 1 5/8 inch depending on the location. The interior of the pressure conduit is coated with one coat of Matflint No. 7 -primer and one coat of Matflint No.7-black to achieve a total dry film thickness of 11 mils. Full details of the conduit layout, distances, grades and the coating specification can be found in appendix 1.

HYDRO

INSPECTION PROCEDURE

- PROCEDURE

The inspection procedure was as follows. Access to the conduit was gained through the unit scroll case. It should be noted that the original plan was to conduct the inspection at three locations by entering the conduit at the intake, through a manhole adjacent to the surge tank and through the unit scroll case . Due to the unavailability of a rope ladder (required to enter from the intake) and the rusted condition of the manhole cover bolting, it was decided that it would be faster to enter the conduit through the unit and to walk from the unit to the intake with the inspection being carried out on the return trip. The inspection was primarily visual. Each weld was inspected, the general condition of the conduit plating and coating observed and random thickness measurements taken.

- EQUIPMENT

DM-2 Thickness meter and couplant
Flashlights (One per person plus a spare)
Camera
Rain Suits, hard hats, rubber boots and gloves

- SAFETY

The decay of vegetation and animal matter within conduits of this type can produce pockets of methane gas. A substantial air flow, probably due to the venting effect of the surge tank, was observed at the scroll case. Due to this, gas measurements were not considered to be required, however, this decision should be re-assessed each time the conduit is entered. It is also recommended that a radio be carried. None were available for this inspection. The slope in most of the conduit is not extremely steep and therefor it was not necessary to have ropes laid down to aid travel. However, caution was exercised while walking especially on the steeper slope sections. Again, this should be assessed on a case by case basis.

HYDRO

INSPECTION RESULTS

- VISUAL

Inspection of the intake gate revealed only minor leaks around its perimeter, the largest being at the bottom right hand corner. Water seepage was observed at the intake concrete to steel transition section of the conduit. The location of this leakage is indicated on dwg. F 105 C-2 in Appendix 1. In light of the present problems being experienced with the intake dyke, this leakage should be monitored. When the conduit is under pressure, the leakage flow is reversed and blockage of the box drains could allow a build-up of water within the dyke. This information has been passed to Bob Barnes and to Mr John Young of ACRES.

In the conduit itself, all section welds were visually inspected with no damage being found. The conduit plating was also inspected. Throughout the length of the complete conduit there is a heavy build-up of what appears to be rust/organic, magnetic material approx. .200 inch to .300 inch thick. This buildup has sheared off in a sheet fashion at numerous locations, especially adjacent to section welds and by as much as 25% in the following areas: (Ref. Drawing F-106-C-11, Appendix 1).

1. Section 3A - 250.01'
2. Near the lower end of section 8A below the surge tank.

In general, in areas where the heavy build-up has been dislodged only a thin layer of surface corrosion is apparent. The underlying metal appears to be in excellent condition however there appears to be no Matflint coating. It is suspected that the Matflint coating failed and thus allowed water to react with the metal which in turn produced the rust build-up. The black colour of the water side of the build-up suggests that the residue of the Matflint coating is, in fact, the top layer of the deposit. Photographs of the build-up can be found in Appendix 2. A laboratory analysis of the deposit is in progress.

HYDRO

- ULTRASONIC INSPECTION

Random pipe wall thicknesses were recorded at twelve locations along the penstock. These are listed in Table 1, with their locations and corresponding values from drawing F-106-C-11. The approximate locations of these readings are also shown on F-106-C-11, Appendix 1.

TABLE 1

THICKNESS READING NO.	LOCATION	MEASURED THICKNESS (in)	SPECIFIED THICKNESS (in) DWG. F-106-C-11
1	Sect. 1A, 12 welds from start of penstock.	0.540	0.500
2	Sect. 2A, Weld #20	0.462	0.438
3	Sect. 2A, Weld #30	0.462	0.438
4	Sect 3A, Weld #22	0.438	0.438
5	Sect 4A, Weld #42	0.490	0.438
6	Sect 7A-8A, Weld #20	0.725	0.750
7	Sect 7A-8A, Weld #65	0.880	0.813
8	Sect 9A, 3 Welds Upstream of start of 11° Sect 10A	1.167	1.188
9	Sect 10A, Weld #12	1.293	1.250
10	Sect 10A, Weld #24	1.330	1.313
11	Sect 10A, Weld #38	1.393	1.375
12	Sect 10A, Weld #48	1.490	1.438

HYDRO

APPENDIX I

C5 - PROTECTIVE COATING

C5.1 PREPARATION

The internal surface of the conduit, and the external surface of the conduit within six inches of field welds shall be given a coat of boiled linseed oil or an equal temporary coating to protect them during transit and storage.

The external surface of the conduit which will be bonded to concrete after embedment shall be cleaned by power wire brushing in accordance with Specification SSPC-P53-52T and shall then be given one coat of cement-latex milk prior to shipment. The cement-latex milk shall consist of ten parts Portland Cement (by weight), five parts water, and one part of modified latex emulsion.

All other areas of the external surface of the pipe shall be protected by cleaning and prime coating in the Contractor's shop, followed by finishing coats applied in the field and/or shop.

Necessary safety precautions shall be taken to avoid fire, explosion or danger to human health. All paints shall be applied under dry conditions, when the temperature is not below 55°F and the surface to be painted is devoid of moisture condensation.

(a) Cleaning

Heavy deposits of oil or grease shall be removed by wiping or scrubbing the surface with rags or brushes wetted with solvent. The final wiping shall be done with clean solvents and clean rags or brushes.

(b) Blast Cleaning

All surfaces shall be given a "grey" or "commercial" blast cleaning in accordance with Canadian Government Specification Board Spec. 31-GP-404 latest revision.

(c) Post-Blast Cleaning

After dry-blast cleaning, the surface shall be dusted off or blown off with compressed air, free of detrimental oil and water. If wet-blasted, the surface shall be cleaned by rinsing with fresh water to which sufficient corrosion inhibitor has been added to prevent rusting. This treatment shall be supplemented by brushing, if necessary, to remove any residue.

C5.2 APPLICATION

(a) First Prime Coat

The blast-cleaned surface shall be primed within 8 hours unless other precautions are taken to prevent rusting before application of prime coat. The primer used shall be Crown Diamond Phenix Epoxy Red Lead Primer No. 100. It can be applied only by brush or roller. When applied at the rate of 450-500 square feet per gallon, it will leave a minimum dry film thickness of one mil. These limits must be adhered to and are subject to approval after completion. Care should be taken to avoid any unnecessary damage after painting.

(b) Second Coat of Primer

After all work has been completed, a second coat of the specified primer shall be applied by brush, roller or spray at a rate of 450-500 square feet per gallon resulting in a minimum dry film thickness of one mil. These limits must be adhered to. A minimum period of 24 hours drying time is required before application of the second primer coat.

(c) Finishing Coat

When the priming coats are thoroughly dry, the pipe shall be given one coat of Hilson No. 330 Mastic or equal, containing asbestos fibres. This shall be applied at a minimum rate of 5 gallons per 100 square feet. The temperature must be above 40°F during this application.

Immediately following the application of this coating, and before it dries, the pipe shall be wrapped with a layer of 7 - 1/2 oz jute hessian embedded in the mastic. This jute shall be wrapped so as to have a minimum overlap between turns of three inches.

A second coat of Hilson No. 330 Mastic compound consisting of 2 gallons per 100 square feet shall then be applied over the jute. Each gallon of this coating shall be cut back with one quart of a suitable petroleum solvent.

(C5. 2) (c) Finishing Coat (Cont'd)

The priming coats must be applied in the Contractor's shop but the emulsion and jute hessian protective coatings may be applied in the shop or on Site, at the Contractor's option, provided that a continuous prime coat exists before the bitumastic compound is applied. The Hilson compound must be thoroughly dry before the pipe is moved.

C5. 3 APPLICATION OF INTERIOR COATING

(a) Prime Coat

The blast-cleaned surface (prepared as per Clause C5. 1) shall be primed within 8 hours to prevent rusting. The first coat shall be a Matflint No. 7 primer, applied by brush only at a rate of 260 square feet per gallon. The dry film thickness shall not be less than 5 mils. Care should be taken that no areas are skipped, that pin-holes are avoided and uniformity of the prime coat is assured.

(b) Finishing Coat

When the prime coat is thoroughly dry, the pipe shall be given one coat of Matflint No. 7 - black, applied by brush or roller at a rate of 260 square feet per gallon giving a dry film thickness of not less than 6 mils. If brush is used the finishing strokes shall be made in the direction of flow of water in pipes. The temperature must be above 50°F during this application.

C5. 4 PROVISION FOR CANCELLATION

The work described under Clause C5. 3 above may be cancelled, at any time, at the sole discretion of the Owner. In the event of the Owner exercising such a perogative no payment shall be made under this item.

February 11, 1965.

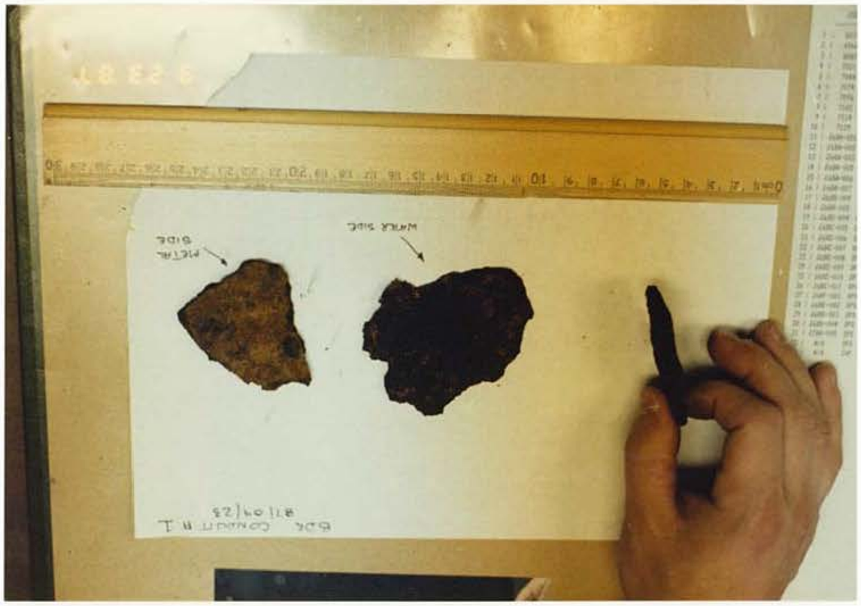
DRWING #'s F-105-C-2
"INTAKES No.1 & No.2"
CONCRETE DETAILS.

F-106-C-11
"PRESSURE CONDUITS"
LAYOUT & LOCATION DATA.

HYDRO

APPENDIX 2

PHOTOGRAPHS OF
#1 PRESSURE CONDUIT
INTERIOR COATING.



Appendix E
Water Chemistry Reports

ACUREN

Laboratory Report

Client	
Hatch 370 Torbray Road Bally Rou Place, Suite E200 St. John's, NF A1A 3W8	Laboratory Report

Attention	*Client's Order Number*	*Date*	*Report Number*
Michael Pyne	N/A	Jan. 18, 2017	128-17-10HAT004-0001 Rev. 0

Client's Material /Product Description	*Date Sample Received*	*Material / Product Specification*
Quantity: 3 Water samples	Dec. 28, 2017	-----

1. Analysis for pH*

	UNITS	SAMPLE #1	SAMPLE #2	SAMPLE #3
pH	pH	7.67	7.52	7.42

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CERT #3977.01 & 3977.04

2. Total Metals Analysis by ICPMS*

Metals	UNITS	SAMPLE #1	SAMPLE #2	SAMPLE #3	RDL
Total Aluminum (Al)	mg/L	0.053	0.050	0.049	0.0050
Total Antimony (Sb)	mg/L	<0.00050	<0.00050	<0.00050	0.00050
Total Arsenic (As)	mg/L	<0.0010	<0.0010	<0.0010	0.0010
Total Barium (Ba)	mg/L	<0.0020	<0.0020	<0.0020	0.0020
Total Beryllium (Be)	mg/L	<0.00050	<0.00050	<0.00050	0.00050
Total Bismuth (Bi)	mg/L	<0.0010	<0.0010	<0.0010	0.0010
Total Boron (B)	mg/L	<0.010	<0.010	<0.010	0.010
Total Cadmium (Cd)	mg/L	<0.00010	<0.00010	<0.00010	0.00010
Total Calcium (Ca)	mg/L	1.1	1.1	1.0	0.20
Total Chromium (Cr)	mg/L	<0.0050	<0.0050	<0.0050	0.0050
Total Cobalt (Co)	mg/L	<0.00050	<0.00050	<0.00050	0.00050

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Laboratory Report

Total Copper (Cu)	mg/L	<0.0010	<0.0010	<0.0010	0.0010
Total Iron (Fe)	mg/L	<0.10	<0.10	<0.10	0.10
Total Lead (Pb)	mg/L	<0.00050	<0.00050	<0.00050	0.00050
Total Lithium (Li)	mg/L	<0.0050	<0.0050	<0.0050	0.0050
Total Magnesium (Mg)	mg/L	0.35	0.35	0.34	0.050
Total Manganese (Mn)	mg/L	<0.0020	<0.0020	<0.0020	0.0020
Total Molybdenum (Mo)	mg/L	<0.00050	<0.00050	<0.00050	0.00050
Total Nickel (Ni)	mg/L	<0.0010	<0.0010	<0.0010	0.0010
Total Potassium (K)	mg/L	<0.20	<0.20	<0.20	0.20
Total Selenium (Se)	mg/L	<0.0020	<0.0020	<0.0020	0.0020
Total Silicon (Si)	mg/L	0.47	0.46	0.46	0.050
Total Silver (Ag)	mg/L	<0.00010	<0.00010	<0.00010	0.00010
Total Sodium (Na)	mg/L	1.5	1.4	1.4	0.10
Total Strontium (Sr)	mg/L	0.0053	0.0047	0.0043	0.0010
Total Tellurium (Te)	mg/L	<0.0010	<0.0010	<0.0010	0.0010
Total Thallium (Tl)	mg/L	<0.000050	<0.000050	<0.000050	0.000050
Total Tin (Sn)	mg/L	<0.0010	<0.0010	<0.0010	0.0010
Total Titanium (Ti)	mg/L	<0.0050	<0.0050	<0.0050	0.0050
Total Tungsten (W)	mg/L	<0.0010	<0.0010	<0.0010	0.0010
Total Uranium (U)	mg/L	<0.00010	<0.00010	<0.00010	0.00010
Total Vanadium (V)	mg/L	<0.00050	<0.00050	<0.00050	0.00050
Total Zinc (Zn)	mg/L	<0.0050	<0.0050	<0.0050	0.0050
Total Zirconium (Zr)	mg/L	<0.0010	<0.0010	<0.0010	0.0010

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RDL – Reportable Detection Limit

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Laboratory Report

Jennifer Pollock, EIT
Metallurgist

Dr. Erhan Ulvan, Ph.D, P.Eng
Manager - Central Region Engineering and Laboratory

The Client Representative who receives this report is responsible for verifying that any acceptance standards listed in the report are correct, and promptly notifying Acuren of any issues with this report and/or the work summarized herein. The owner is responsible for notifying Acuren in writing if they would like their samples returned or placed into storage (at their cost) otherwise, all samples/specimens associated with this report will be disposed of 60 days after the report date.

NOTES:

A) Any tests subcontracted to an approved subcontractor are highlighted above (*)

B) Levels of Services :Regular Service: 3 to 5 business days; Next Day Service: 8 to 16 business hours; Same Day Service: within 8 business hours; Super Rush: Work will commence immediately regardless of the time and will continue until it is completed

C) The Client will be notified if completion of test will exceed the time specified as a result of the volume of work or the complexity of the test

D) The Client should specify the standards used for testing/comparison purpose. We have a comprehensive library and online subscription of commonly used standards, however, we may ask the client to supply the standards if not common or the Client requests to purchase standard(s) on his behalf.

E) Please provide all the necessary information/documents (MSDS) pertaining to any Toxic / Dangerous materials prior to their arrival in the Laboratory.

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1988

TABLE I

ANALYSIS OF BAY D'ESPOIR WATER

Parameter	Concentration (ppm except as noted)
pH	5.59
Conductivity (umhos/cm)	28.5
TDS	11.4
Alkalinity (ppm $CaCo_3$)	2.5
Fluoride	<0.1
Chloride	3.0
Nitrite	<0.1
Bromide	<0.1
Nitrate	0.04
Phosphate	<0.1
Sulphite	<0.1
Sulphate	2.6
Cobalt	<0.01
Zinc	1.2
Cadmium	<0.02
Boron	<0.02
Bismuth	<0.2
Phosphorus	<0.5
Beryllium	<0.002
Silicon	0.62
Iron	0.12
Manganese	0.02
Calcium	16
Magnesium	0.54
Copper	<0.01
Aluminum	<0.15
Vanadium	<0.01

Form WAF-3 1M 2/78
WATER ANALYSIS FACILITY
Department of Chemistry (C-411)
Memorial University of Newfoundla

ANALYTICAL RESULTS

Submitted by: John Noel - Hydro   Phone: Date: Nov. 14 1980

Address: Bill to: Approved: (authorized representative)

User's sample code: Baie d'Espoir #4

Water analysis code: 3844

Date complete: 19   Signed:

	Parameter	Value	Units		Parameter	Value	Units
1.	Alkalinity	2	mg/L $CaCO_3$	12.	Calcium	0.94	mg/L
2.	Acidity		mg/L $CaCO_3$	13.	Magnesium	0.38	mg/L
3.	Apparent colour		TCU	14.	Manganese	< 0.01	mg/L
4.	Hardness	4.09	mg/L $CaCO_3$	15.	Iron	0.10	mg/L
5.	Kjeldahl nitrogen		mg/L N	16.	Copper		mg/L
6.	Nitrate	0.044	mg/L N	17.	Zinc		mg/L
7.	pH	5.19	units	18.	Cadmium		mg/L
.	Total phosphorus	0.016	mg/L PO_4		Lead		mg/L
.	Specific conductance	20	micromhos/cm		Sodium		mg/L
.	Turbidity		NTU		Potassium		mg/L
	Chemical oxygen demand		mg/L COD		silicate	0.328	mg/L
	Fluoride	0.023	mg/L F		nitrite	< 0.005	mg/L
	Chloride	9	mg/L Cl		Bicarb. Alkalinity	2	mg/L
	Biochemical Oxygen demand		mL/L		Carb. Alkalinity	< 1	mg/L
	Dissolved oxygen		mL/L		Tot. Suspended Solids	< 5	mg/L
	Ortho phosphate	< 0.005	mg/L PO_4		Tot. Dissolved solids	31	mg/L

COMMENTS:

*Canadian "Drinking Water Standards" upper limit or recommended range.

J. T. DONALD & CO. LIMITED
CONSULTANTS
CHEMICAL AND ENGINEERING SERVICES
MARKET RESEARCH · ANALYSTS · ASSAYERS
ESTABLISHED 1880

TELEPHONE 937-...581
1181 GUY STREET
MONTREAL 25, CANADA

REPORT OF ANALYSIS

Shawmont Engineering Newfoundland Ltd.,
1010 Beaver Hall Hill,
Montreal, Que.

Attn: Mr. A. Bonnell

LABORATORY NO. 1382
DATE RECEIVED Mar. , 1965
SAMPLE OF Water

MARKED

	Parts per Million
Suspended Matter	0.2
Total Iron (Fe)	0.1
Turbidity	0
Analysis of Filtered Sample	
Total Solids on Evaporation	25.8
Silica (SiO_2)	1.4
Calcium (Ca)	1.6
Magnesium (Mg)	0.5
Alkalies as Sodium (Na) Calc.	1.6
Sulphate (SO_4)	0.7
Chloride (Cl)	1.7
Bicarbonate (HCO_3)	7.9
Carbon Dioxide (CO_2)	[illegible]
Colour	5?.0
pH	6.1
Total Hardness as $CaCO_3$	6.0
Carbonate Hardness as $CaCO_3$	6.0
Non-Carbonate Hardness as $CaCO_3$	Nil
Carbonate Alkalinity as $CaCO_3$	Nil
Bicarbonate Alkalinity as $CaCO_3$	6.5
Hypothetical Combination	
Calcium Bicarbonate $Ca(HCO_3)_2$	6.5
Magnesium Bicarbonate $Mg(HCO_3)_2$	3.0
Sodium Bicarbonate $NaHCO_3$	0.7
Sodium Sulphate Na_2SO_4	1.0
Sodium Chloride NaCl	2.8
Silica SiO_2	1.4
Iron Oxide Fe_2O_3	0.1

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TABLE 3.2A

WATER ANALYSIS REPORT SUMMARY

PARAMETER	UNIT OF MEASURE	CDWQG STANDARD		BAY D'ESPOIR POWERHOUSE NO. 1				
		MAC[1]	AO[2]	OCT.92	NOV.93	NOV.94	MAY 95	MAY 96
Alkalinity	mg/L $CaCO_3$			3.66	3.3	—	—	—
Apparent Color	TCU[3]		≤15	33	48	32	31	33
Hardness (requires Ca,Mg)	mg/L $CaCO_3$		80–100	2.7	3.2	2.6	3.1	3.4
Kjeldahl Nitrogen	mg/L N			0.18	0.10	0.24	0.10	0.10
Nitrate (+nitrite)	mg/L N	45		0.061	0.035	0.060	0.067	0.0043
pH	Units		6.5–8.5	6.21	6.19	6.28	6.18	7.04
Total Phosphorus	mg/L PO_4			<0.02	<0.02	—	—	—
Specific Conductance	µmhos/cm			18.0	14.9	20.2	18.3	15.3
Turbidity	NTU[4]	1.0	5.0[5]	1.05	2.30	0.29	0.44	0.33
Chemical Oxygen Demand	mg/L COD			12	11	10	—	11
Calcium	mg/L Ca			0.62	0.73	0.53	0.72	0.84
Magnesium	mg/L Mg			0.28	0.33	0.31	0.31	0.32
Manganese	mg/L Mn		≤0.05	<0.005	<0.005	—	0.02	<0.005
Iron	mg/L Fe		≤0.30	0.04	0.05	0.08	0.07	0.06
Copper	mg/L Cu		≤1.0	0.19	0.16	0.09	0.06	0.08
Zinc	mg/L Zn		≤5.0	<0.005	<0.005	<0.005	<0.005	<0.005
Cadmium	mg/L Cd	0.005		<0.005	<0.005	—	—	—
Lead	mg/L Pb	0.010		0.004	0.003	<0.001	0.002	<0.001
Chloride	mg/L Cl		≤250	1.7	1.5	4.1	2.6	1.9
Sodium	mg/L Na		≤200	1.54	1.14	—	—	—
Potassium	mg/L K			0.22	0.18	—	—	—
Ammonia	mg/L N			<0.02	<0.02	—	—	—
Dissolved Oxygen	mg/L O			—	—	—	<0.05	—
Fluoride	mg/L F	1.5		0.08	<0.05	<0.05	—	<0.05
Sulfate	mg/L SO_4		≤500	2.1	1.1	1.7	3.7	2.2
Total Dissolved Solids	mg/L		≤500	12	10	16	15	13
Total Suspended Solids	mg/L			<4	<4	<4	<4	<4
Total Organic Carbon	mg/L C			3.7	—	3.8	3.9	4.1
Mercury	mg/L Hg	0.001		—	<0.00005	—	—	—

[1] MAC Maximum Acceptable Concentration
[2] AO Aesthetic Objective
[3] TCU True Color Units
[4] NTU Nephelometric Turbidity Units
[5] At point of consumption

Appendix F
Acuren Test Reports

ACUREN Laboratory Report

Client	Laboratory Report		
Hatch 370 Torbray Road Bally Rou Place, Suite E200 St. John's, NF A1A 3W8			

Attention	*Client's Order Number*	*Date*	*Report Number*
Michael Pyne	RFA	February 7, 2017	128-17-10HAT004-0001 Rev. 0

Client's Material /Product Description	*Date Sample Received*	*Material / Product Specification*
Quantity: 3 Weld Samples, 3 Water samples, and 2 Algae Samples	December 28, 2017	-----

1. Galvanic Test

Figure 1 illustrates the as-received samples. In Sample 1, the weld is along the longitudinal direction of the tank, while in Samples 2 and 3, the weld is along the circumferential direction of the tank. Table 1 lists the chemical composition of the base metal and the electrode used for the welding process.

Figure 1. Low magnification morphology of HAZ-Metal couple sample 1.

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Laboratory Report

Table 1. Base metal and electrode used for welding process

Sample #	1	2	3
Base Metal	ASTM 285-C	CSA G40.8-B	ASTM 285-C
Welding Electrode	E7018	E7018	E7018

Coupons of approximately 10×10 mm^2 were cut from the fusion zone (weld), heat affected zone (HAZ), and base metal (BM) of all the samples listed in Table 1. Please be advised that as the HAZ was very narrow with a ">" shape on one side and a "<" on the other side, we took utmost care to extract sample from that specific zone, however there is a slight chance that the extracted part would not be completely from one single region (i.e. HAZ, weld, base metal). Sample was then grinded with 600 grit sandpaper, washed with soap and rinsed with deionized water and 99.9% ethanol.
Corrosion tests were carried out at ambient temperature for one hour in an acidic solution with a pH of 6.25 prepared by nitric acid (HNO_3) diluted in deionized water (DI). Each test was repeated twice as per ASTM G71 – 81 (2014). Table 2 lists the results of galvanic tests for all three samples. Corrosion rate is reported in mpy.

Table 2. Galvanic corrosion rate of all samples

Sample #			1	2	3
WELD/HAZ	Test 1	Corrosion Rate (mpy)	1.20	0.09	0.97
		Corroded Part	WELD	Both	HAZ
	Test 2	Corrosion Rate (mpy)	0.51	0.09	0.23
		Corroded Part	WELD	Both	Both
WELD/BM	Test 1	Corrosion Rate (mpy)	0.18	0.05	0.37
		Corroded Part	Both	Both	Both
	Test 2	Corrosion Rate (mpy)	0.51	0.18	1.70
		Corroded Part	BM	Both	Weld
HAZ/BM	Test 1	Corrosion Rate (mpy)	0.28	0.05	0.83
		Corroded Part	Both	Both	HAZ
	Test 2	Corrosion Rate (mpy)	1.24	0.09	1.43
		Corroded Part	BM	Both	Both

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Visual Examinations

Figures 2 to 10 present low magnification morphology of samples after galvanic testing. It should be noted that almost all of the corroded samples show pitting corrosion as well.

Sample 1:

Figure 2 shows that for HAZ/BM couple, both of them were corroded in test 1, while BM was protected in test 2 and there is no sign of pitting corrosion. Figure 3 depicts that both parts were corroded in test 1 for WELD/BM couple, but BM was protected in test 2. As

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shown in Figure 4, HAZ was protected in both tests against the WELD. Based on the observations, it can be suggested that the weld has the least corrosion resistance in the galvanic setup and BM shows the best corrosion resistance.

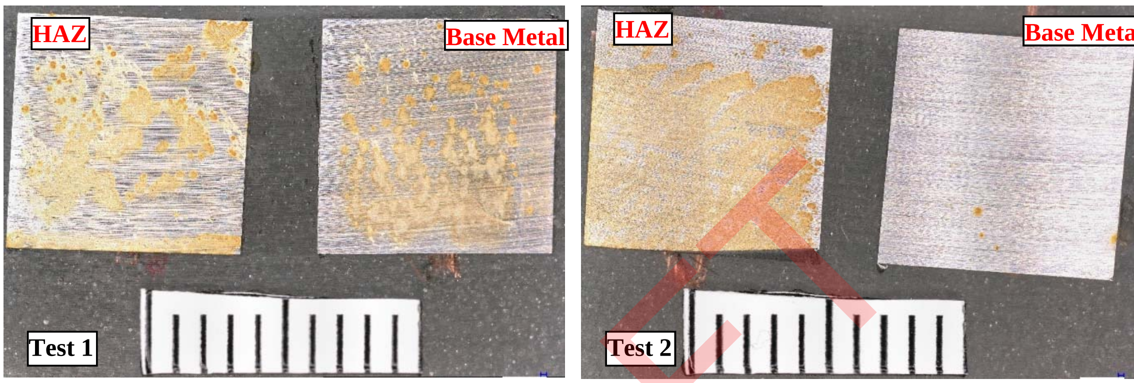

Figure 2. Low magnification morphology of HAZ/BM couple Sample 1.

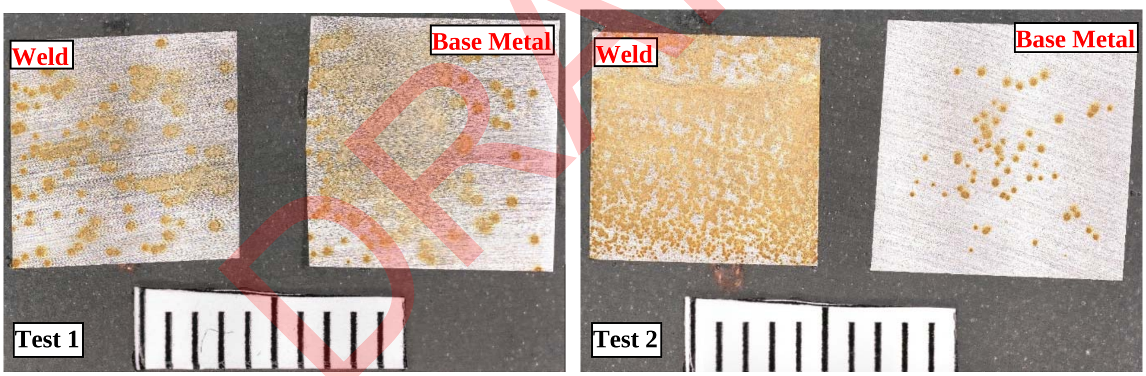

Figure 3. Low magnification morphology of WELD/BM couple Sample 1.

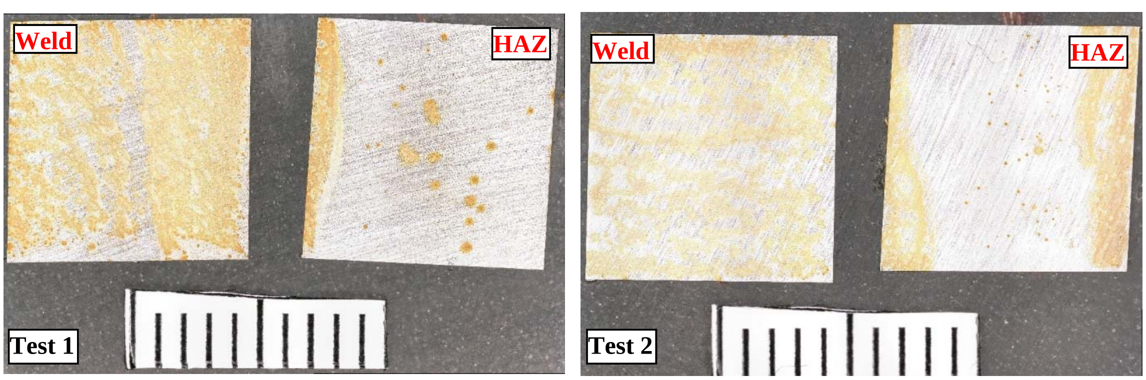

Figure 4. Low magnification morphology of WELD/HAZ couple Sample 1.

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Sample 2:

Figure 5 suggests that both HAZ and BM were corroded in both tests. For WELD/BM couple, both parts were corroded in both tests as shown in Figure 6. Figure 7 depicts that both WELD and HAZ regions were corroded in both tests. In total, it appears that none of the three regions is protected against one another, and pitting corrosion is a major feature on the surfaces of all samples.

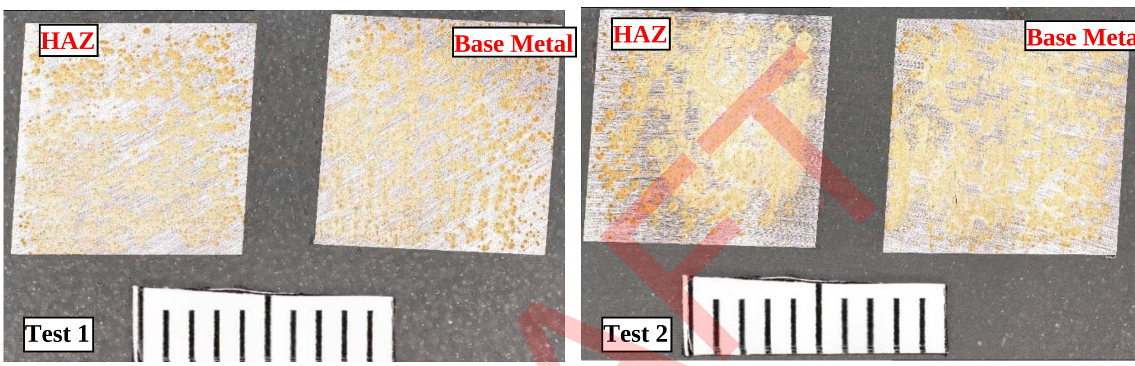

Figure 5. Low magnification morphology of HAZ-Metal couple Sample 2.

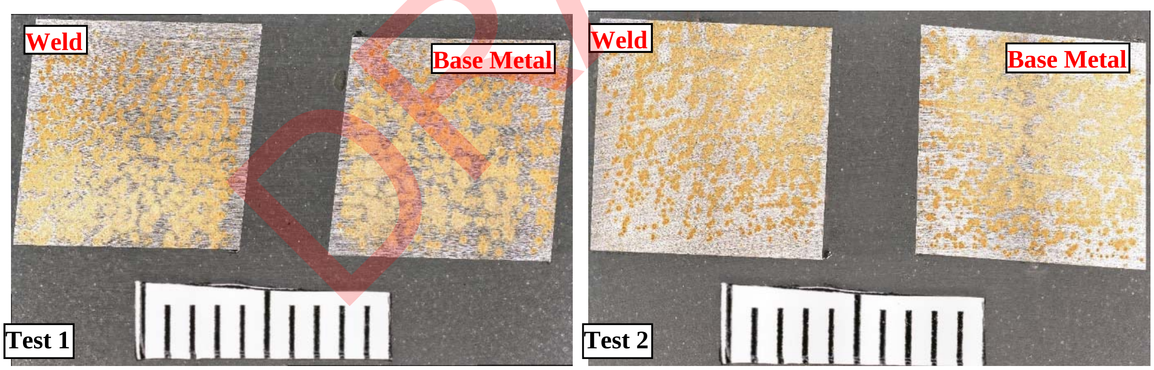

Figure 6. Low magnification morphology of Weld-Metal couple Sample 2.

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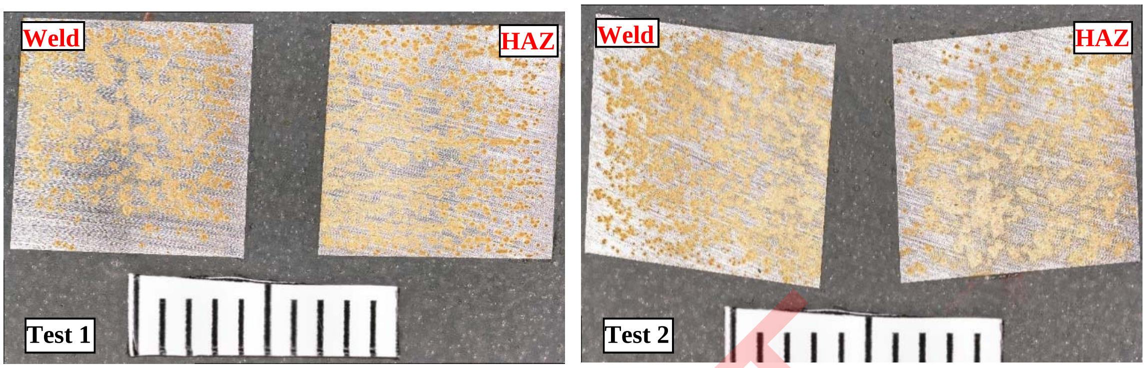

Figure 7. Low magnification morphology of Weld-HAZ couple Sample 2.

Sample 3:

From Figure 8, it appears that HAZ was protected against BM in HAZ/BM galvanic couple. As for WELD/BM couple (Figure 9), both parts were corroded in test 1. In the second test, WELD is corroded, while BM is slightly corroded. As shown in Figure 10, in WELD/HAZ couple, the first test shows HAZ is corroded and WELD is protected, while in the second test, Weld is also corroded similar to HAZ.

In General, it seems that apart from general corrosion of different parts of the weld joint, there is a possibility that HAZ could suffers from galvanic corrosion against WELD.

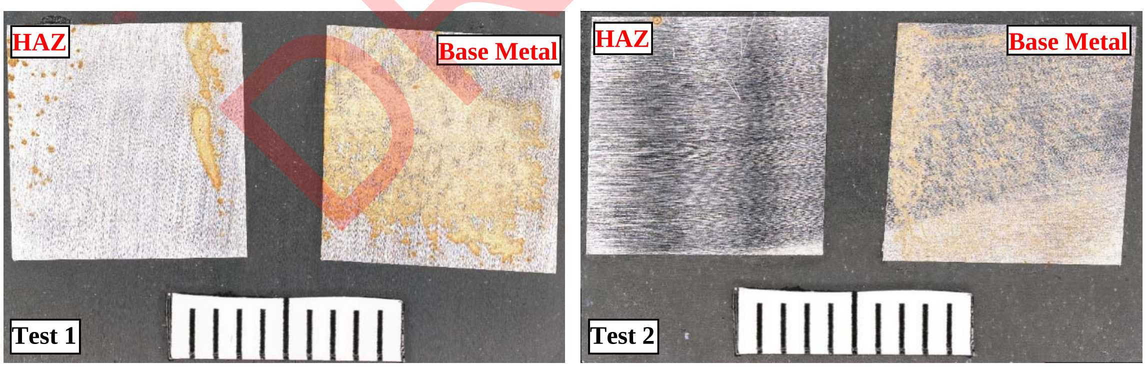

Figure 8. Low magnification morphology of HAZ-Metal couple Sample 3.

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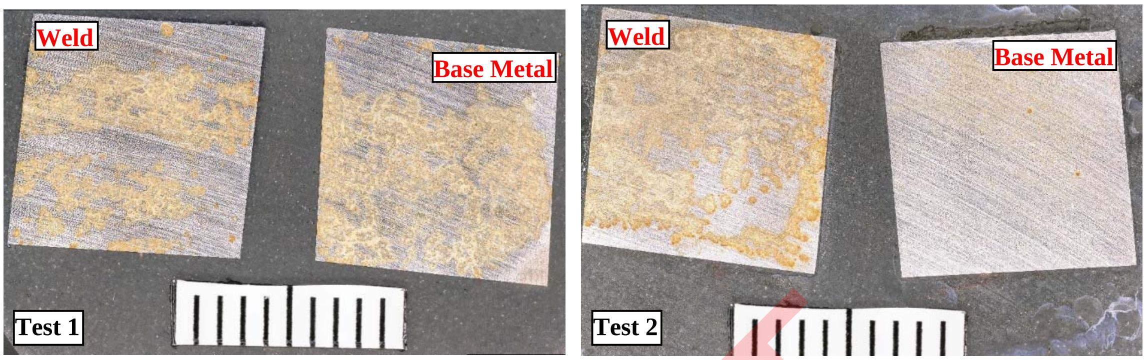

Figure 9. Low magnification morphology of Weld-Metal couple Sample 3.

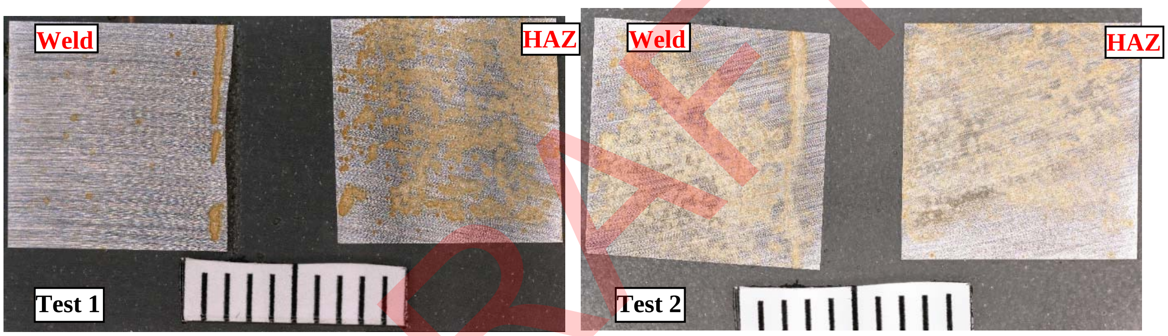

Figure 10. Low magnification morphology of Weld-HAZ couple Sample 3.

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Reference Samples:

As it can be observed in Figure 11, samples show no significant corrosion after on hour of exposure to similar solution used for galvanic test. This indicates the severity of galvanic corrosion for this design.

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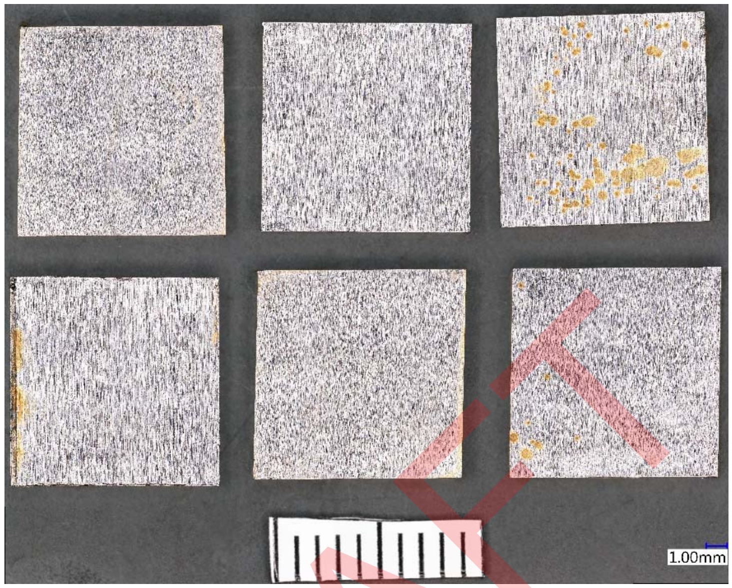

Figure 11. Low magnification morphology of all reference samples after normal corrosion.

2. Water Analysis*

	Units	Sample #1	Sample #2	Sample #3	RDL
pH	pH	7.67	7.52	7.42	N/A
Total Dissolved Solids	mg/L	22	22	14	10
Alkalinity (Total as $CaCO_3$)	mg/L	4.3	2.2	2.1	1.0

RDL – Reportable Detection Limit

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3. Total Metals Analysis by ICPMS of Water Samples*

Metals	Units	Sample #1	Sample #2	Sample #3	RDL
Total Aluminum (Al)	mg/L	0.053	0.050	0.049	0.0050
Total Antimony (Sb)	mg/L	<0.00050	<0.00050	<0.00050	0.00050
Total Arsenic (As)	mg/L	<0.0010	<0.0010	<0.0010	0.0010
Total Barium (Ba)	mg/L	<0.0020	<0.0020	<0.0020	0.0020
Total Beryllium (Be)	mg/L	<0.00050	<0.00050	<0.00050	0.00050
Total Bismuth (Bi)	mg/L	<0.0010	<0.0010	<0.0010	0.0010
Total Boron (B)	mg/L	<0.010	<0.010	<0.010	0.010

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Total Cadmium (Cd)	mg/L	<0.00010	<0.00010	<0.00010	0.00010
Total Calcium (Ca)	mg/L	1.1	1.1	1.0	0.20
Total Chromium (Cr)	mg/L	<0.0050	<0.0050	<0.0050	0.0050
Total Cobalt (Co)	mg/L	<0.00050	<0.00050	<0.00050	0.00050
Total Copper (Cu)	mg/L	<0.0010	<0.0010	<0.0010	0.0010
Total Iron (Fe)	mg/L	<0.10	<0.10	<0.10	0.10
Total Lead (Pb)	mg/L	<0.00050	<0.00050	<0.00050	0.00050
Total Lithium (Li)	mg/L	<0.0050	<0.0050	<0.0050	0.0050
Total Magnesium (Mg)	mg/L	0.35	0.35	0.34	0.050
Total Manganese (Mn)	mg/L	<0.0020	<0.0020	<0.0020	0.0020
Total Molybdenum (Mo)	mg/L	<0.00050	<0.00050	<0.00050	0.00050
Total Nickel (Ni)	mg/L	<0.0010	<0.0010	<0.0010	0.0010
Total Potassium (K)	mg/L	<0.20	<0.20	<0.20	0.20
Total Selenium (Se)	mg/L	<0.0020	<0.0020	<0.0020	0.0020
Total Silicon (Si)	mg/L	0.47	0.46	0.46	0.050
Total Silver (Ag)	mg/L	<0.00010	<0.00010	<0.00010	0.00010
Total Sodium (Na)	mg/L	1.5	1.4	1.4	0.10
Total Strontium (Sr)	mg/L	0.0053	0.0047	0.0043	0.0010
Total Tellurium (Te)	mg/L	<0.0010	<0.0010	<0.0010	0.0010
Total Thallium (Tl)	mg/L	<0.000050	<0.000050	<0.000050	0.000050
Total Tin (Sn)	mg/L	<0.0010	<0.0010	<0.0010	0.0010
Total Titanium (Ti)	mg/L	<0.0050	<0.0050	<0.0050	0.0050
Total Tungsten (W)	mg/L	<0.0010	<0.0010	<0.0010	0.0010
Total Uranium (U)	mg/L	<0.00010	<0.00010	<0.00010	0.00010
Total Vanadium (V)	mg/L	<0.00050	<0.00050	<0.00050	0.00050
Total Zinc (Zn)	mg/L	<0.0050	<0.0050	<0.0050	0.0050
Total Zirconium (Zr)	mg/L	<0.0010	<0.0010	<0.0010	0.0010

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4. Microbiological Corrosion of Algae Samples

	Viable bacteria in samples after 15 days (Range per mL)	
	Sample 1	Sample 2
Low Nutrient Bacteria (LNB)	Weak Positive (~1 to 10)	Mild Positive (~10 to 100)
Iron-Related Bacteria (IRB)	Negative	Negative
Anaerobic Bacteria (ANA)	Weak Positive (~1 to 10)	Weak Positive (~1 to 10)
Acid-Producing Bacteria (APB)	Weak Positive (~1 to 10)	Negative
Sulfate-Reducing Bacteria (SRB)	Negative	Negative

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NOTES:

A) Any tests subcontracted to an approved subcontractor are highlighted above (*)

B) Levels of Services :Regular Service: 3 to 5 business days; Next Day Service: 8 to 16 business hours; Same Day Service: within 8 business hours; Super Rush: Work will commence immediately regardless of the time and will continue until it is completed

C) The Client will be notified if completion of test will exceed the time specified as a result of the volume of work or the complexity of the test

D) The Client should specify the standards used for testing/comparison purpose. We have a comprehensive library and online subscription of commonly used standards, however, we may ask the client to supply the standards if not common or the Client requests to purchase standard(s) on his behalf.

E) Please provide all the necessary information/documents (MSDS) pertaining to any Toxic / Dangerous materials prior to their arrival in the Laboratory.

Appendix G
Backfill Calculations

Nalcor Energy - Bay d'Espoir Penstock 1 - Fill time and soil cover influence

Calculation Cover Sheet

Client:	Nalcor Energy		
Project Title:	Bay d'Espoir Penstock 1 weld repairs		
Discipline:	Mechanical/Civil		
Calculation No:	H352666-00000-240-202-0002	**File No:**	**Number of Sheets:** 27
Description:	This calculation checks penstock fill time. This calculation checks the influence of soil cover at the top half of the penstock on the stresses in the 17 ft diameter sections		
Category of calculation verification required *tick box*	☑ 1 ☐ 2 ☐ 3 ☐ 4		
Prepared by:	Oleg Belashov O.Belashov	**Date:**	28Nov 2016
Print Name >	(Responsible Engineer)		
Preliminary Review by:		**Date:**	28Nov 2016
Print Name >	Michael Pyne		
Can the calculation now be released for work?	☑ Yes ☐ No	**To the Client?**	☑ Yes ☐ No
Checked by: by:		**Date:**	28Nov 2016
Print Name >	Michael Pyne		
Reviewed by:		**Date:**	
Print Name >			
Approved by:		**Date:**	
Print Name >			
General Notes:	Internal Rev A-01		

Revisions

Rev.	Date	Prepared by	Checked by	Approved by	Description
A	28Nov 2016	O. Belashov OB	M. Pyne	G.Saunders	

Superseded by Calculation No. **Date:**

Reason voided:

Calculation Descriptions and Assumptions

1. This calculation etimates the penstock fill time.
2. This calculation checks the influence of soil cover at the top half of the penstock on the stresses in the 17 ft diameter sections.
3. The soil on the top of the penstock does not provide any radial restrain for the pipe and is modeled as external pressure applied on top half of the pipe
4. The soil underneath the penstock is modeled as elastic support with the subgrade reaction modulus of soil Ks= $11\frac{\mathrm{MPa}}{\mathrm{m}} = 40.52\cdot\frac{\mathrm{lbf}}{\mathrm{in}^3}$
5. Penstock thickness at 17 ft diameter sections is 0.422in according to Ref 7
6. Open channel flow Mannings's Equation is used to determine the cross section area inside the penstock available for air to escape.
7. 100% welded joint efficiency, subject to 100% UT or RT

References

1. Applied Fluid Dynamics Handbook; Robert D.Blevins; 1984
2. ASCE Manuals and Reports on Engineering Practice No. 79, Second edition
3. ASTM A285 2012
4. F-105-C-2
5. F-106-C-7
6. F-106-C-11
7. PENSTOCK NO.1 BAY D'ESPOIR HYDROELECTRICDEVELOPMENTCRACK; INVESTIGATION ANDREPAIR REPORT; by Kleinschmidt; June 2016

1) Filling time and pipe area available for air to escape

Input parameters

$EL_{HWL} := 593ft$ Head pond water elevation, Ref 4

$EL_{sill} := 541ft$ Intake gate sill elevation, Ref 4

$w_g := 17ft$ Intake gate clear width

$EL_{ST} := 291.58ft$ Surge tank bottom elevation

$D_{ST} := 13ft + 6in$ Assumed surge tank inlet pipe diameter, no info on the surge tank is available

$n := 13$ Number of penstock sections

$i := 0 .. n - 1$

Penstock geometry, Ref 6

$i + 1 =$	Section length $L_i :=$	Section diameter $D_i :=$
1	231.68ft	17ft + 0in
2	320.64ft	17ft + 0in
3	250.01ft	17ft + 0in
4	452.05ft	17ft + 0in
5	361.39ft	15ft + 3in
6	351.28ft	15ft + 3in
7	304.72ft	15ft + 3in
8	379.75ft	13ft + 6in
9	476.41ft	13ft + 6in
10	523.51ft	13ft + 6in
11	122.83ft	13ft + 6in
12	63.89ft	13ft + 6in
13	45.10ft	13ft + 6in

$G_o := 0.5in, 1in .. 6in$ Range of intake gate openings for consideration

Filling time as function of gate opening

$\sum L = 1184 \cdot m$ Total penstock length

$H := EL_{HWL} - EL_{sill} = 52 \cdot ft$ Head on the intake gate sill

$V_p := \sum_i \left[\frac{\pi \cdot (D_i)^2}{4} \cdot L_i\right] = 19856\,m^3$ Penstock volume

$L_{ST} := EL_{HWL} - EL_{ST} = 301.42 \cdot ft$ Surge tank pipe to be filled

$V_{ST} := \frac{\pi \cdot D_{ST}^{\ 2}}{4} \cdot L_{ST} = 1222\,m^3$ Surge tank pipe volume

$V_{tot} := V_p + V_{ST} = 21078\,m^3$ Total volume to be filled, excluding spiral case since no info is provided.

$Q_g(G_o) := \frac{0.61}{\left(1 + 0.61 \cdot \frac{G_o}{H}\right)^{0.5}} \cdot w_g \cdot G_o \cdot \sqrt{(2 \cdot g \cdot H)}$ Flow rate in volume/time units as function of intake gate opening, Ref 1

$t(G_o) := \frac{V_{tot}}{Q_g(G_o)}$ Filling time as function of gate opening

Pipe cross section area available for air to escape as function of gate opening

The calculation is performed using open channel flow Manning's Equation

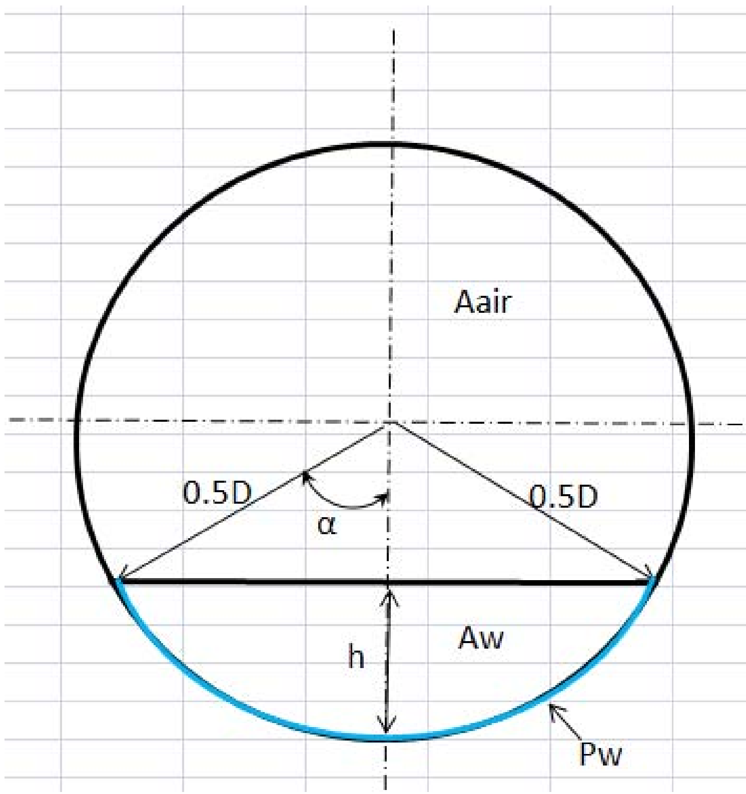


Figure 1: Open channel flow in the penstock

$S_p := \tan(0.25deg)$ Penstock slope, Manning's Equation works with very small pipe slope but the slope cannot be zero

$n := 0.012$ Manning's roughness coefficient for steel pipe

$D_{min} := \min(D) = 13.5 \cdot ft$ Min diameter in the penstock

$A_p := \frac{\pi \cdot D_{min}^2}{4} = 13.3\,m^2$ Penstock cross section area at the minimum diameter

$\alpha(h) := \operatorname{acos}\left(\frac{0.5 \cdot D_{min} - h}{0.5 \cdot D_{min}}\right)$ α (Figure 1) as function of h

$A_w(h) := \frac{D_{min}^2}{4} \cdot (\alpha(h) - \sin(\alpha(h)) \cdot \cos(\alpha(h)))$ Flow area as function of h

$P_w(h) := \alpha(h) \cdot D_{min}$ Wetted perimeter

$R_h(h) := \frac{A_w(h)}{P_w(h)}$ Hydraulic radius

$AR(h) := A_w(h) \cdot R_h(h)^{\frac{2}{3}}$ $A \cdot R^{\frac{2}{3}}$ term from Manning's equation

$Q_p(h) := \frac{ft^3}{s} \cdot \left[\left(\frac{1.49}{n} \right) \cdot \left(\frac{1}{ft^2} \cdot \frac{1}{ft^{\frac{2}{3}}} \right) \cdot AR(h) \cdot \sqrt{S_p} \right]$ Manning's equation for volume flow in open channel

$h := 1m$ Initial guess for solver

Given

$Q_p(h) = Q$

$h(Q) := (\mathrm{Find}(h))$ Solve for h (Figure 1)

$h(G_o) := h(Q_g(G_o))$ Express h as function of gate opening

$A_{air}(G_o) := 1 - \frac{A_w(h(G_o))}{A_p}$ Area available for air to escape in % of total pipe area as function of intake gate opening

Summary

Gate opening $\frac{G_o}{in} =$	Flow rate $\frac{Q_g(G_o)}{\frac{m^3}{s}} =$	Fill time $\frac{t(G_o)}{hr} =$	Flow area height $\frac{h(G_o)}{m} =$	Flow area $\frac{A_w(h(G_o))}{m^2} =$	Air area $\frac{A_{air}(G_o)}{\%} =$
0.5	0.71	8.27	0.28	0.40	97.00
1.0	1.41	4.14	0.39	0.65	95.14
1.5	2.12	2.76	0.48	0.86	93.55
2.0	2.83	2.07	0.55	1.05	92.11
2.5	3.53	1.66	0.61	1.23	90.78
3.0	4.24	1.38	0.67	1.39	89.52
3.5	4.95	1.18	0.72	1.55	88.32
4.0	5.65	1.04	0.77	1.71	87.17
4.5	6.36	0.92	0.81	1.85	86.06
5.0	7.06	0.83	0.85	2.00	84.99
5.5	7.76	0.75	0.90	2.14	83.94
6.0	8.47	0.69	0.93	2.27	82.92

$A_p = 13.3\,m^2$

There is plenty of room for air to escape for all the considered intake gate openings

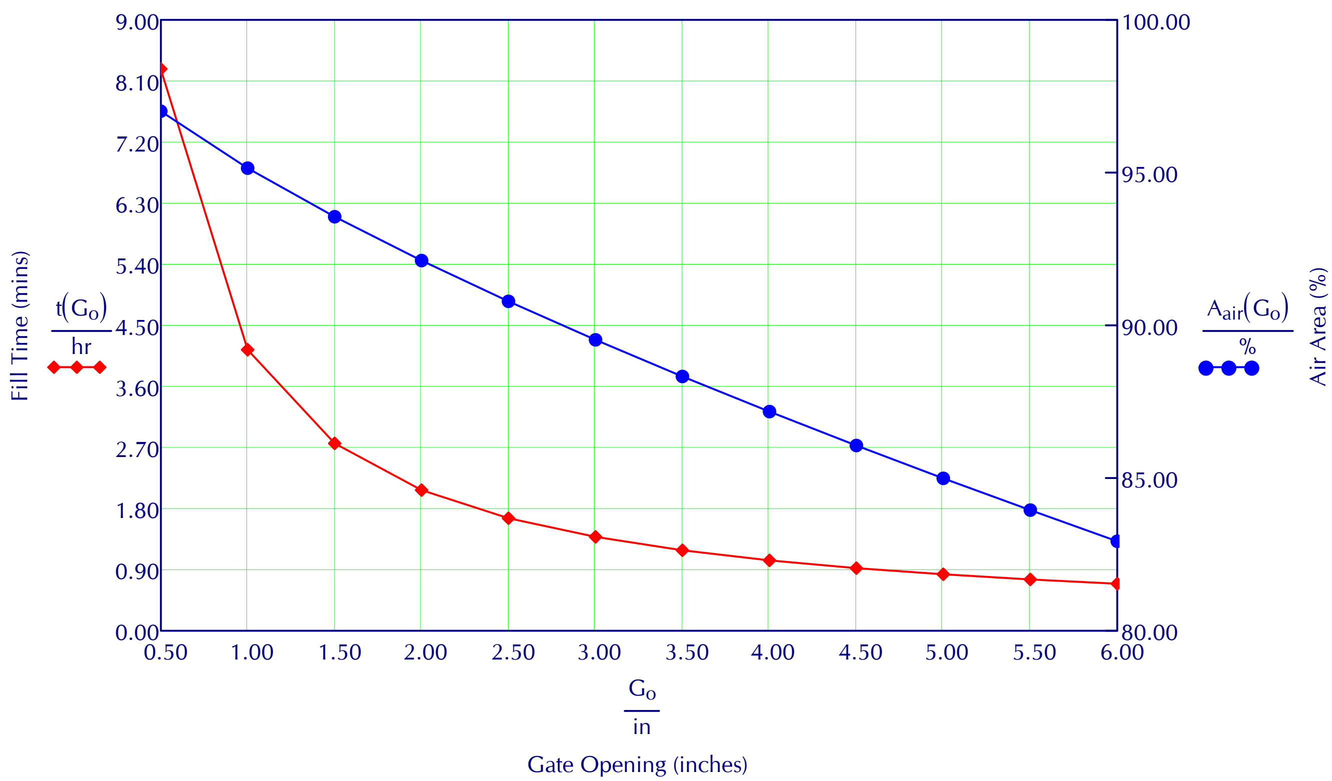


Figure 2: Fill Time and Air Area as Function of Gate Opening

2) Finite Element Analyses of excavation

FE model description

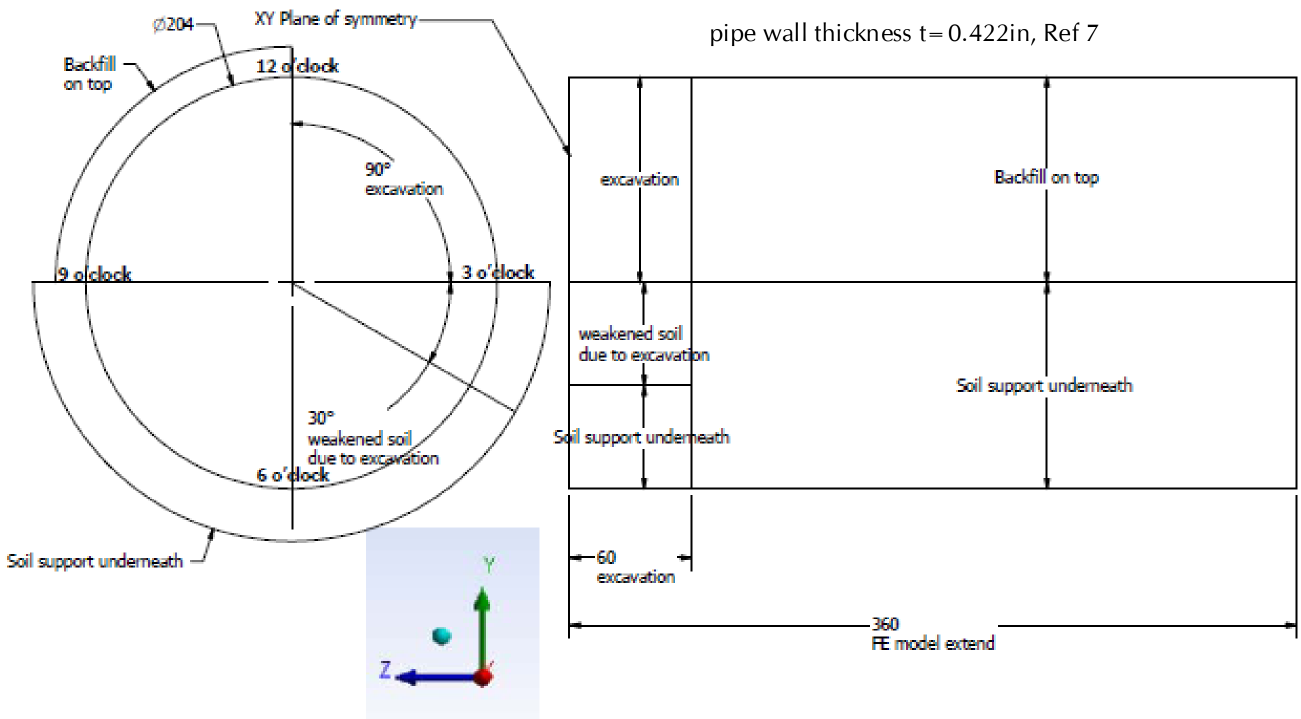


Figure 3: Finite element model dimensions, inches. 60ft long pipe with soil support at the bottom half. Top soil pressure on the top half. Excavation extend from 12 to 3 o'clock 10 ft long. 30deg from 3 o'clock 10 ft long is considered weakened soil (very low Ks value) and is assumed to be part of the excavation. Middle of the excavation is a plane of symmetry thus only half of 60 ft pipe was modeled

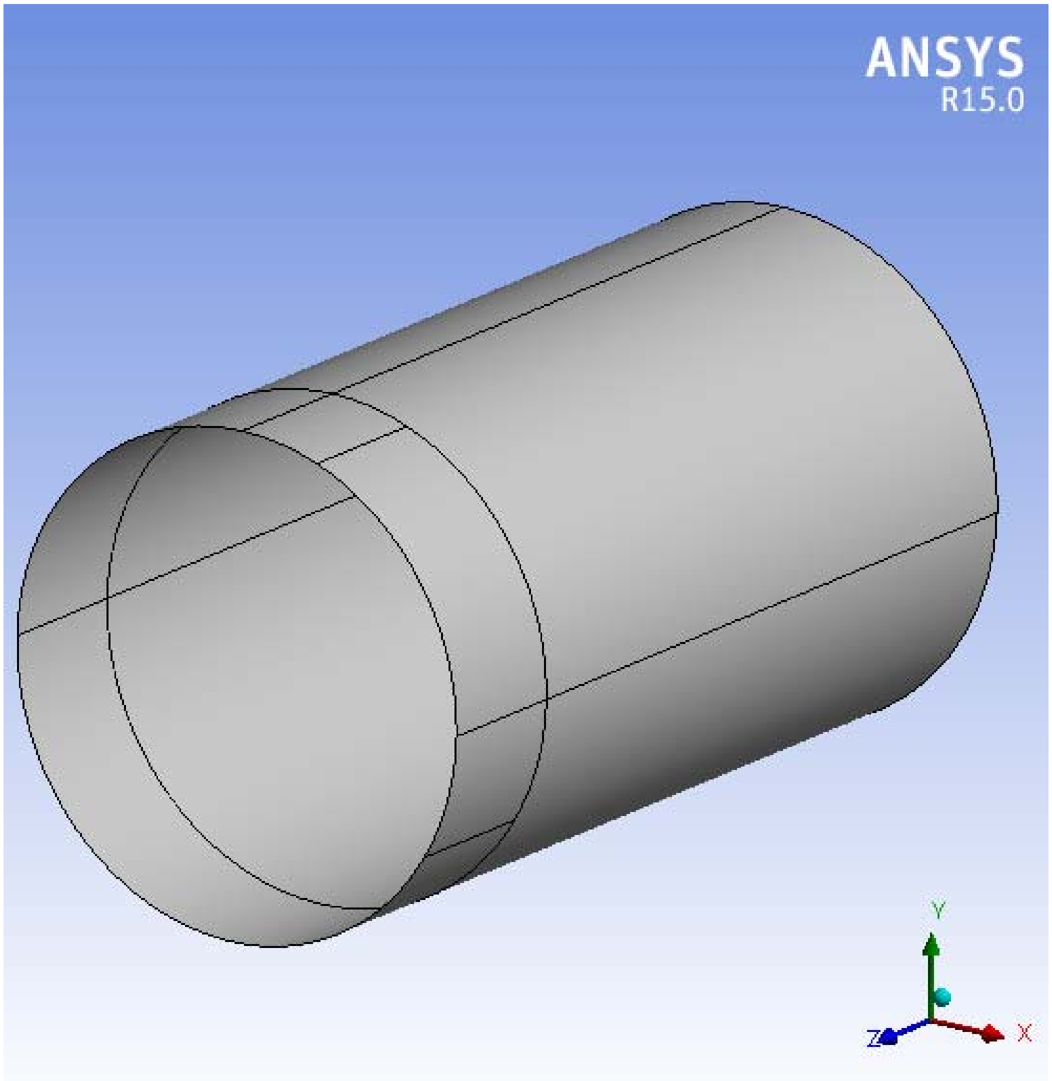


Figure 4: Finite element model. Ansys R15.0 software was used.

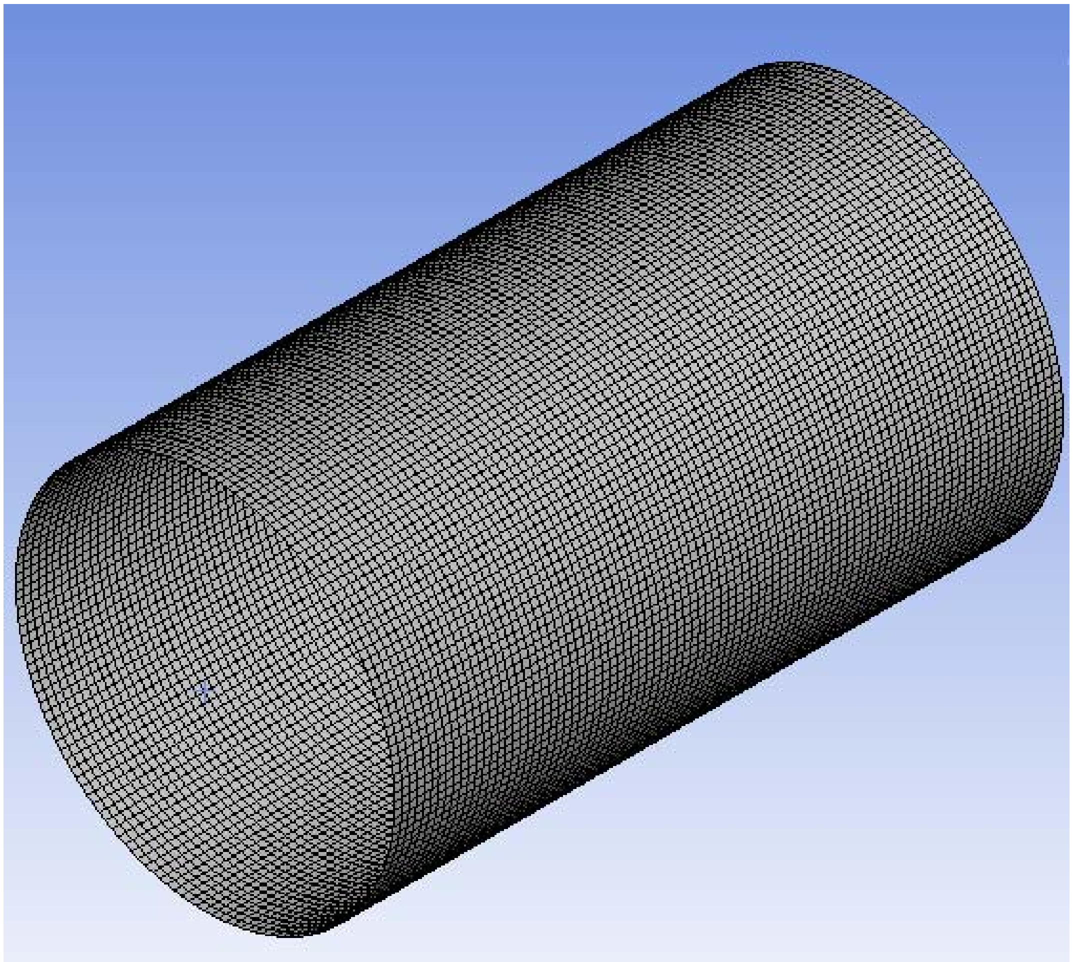
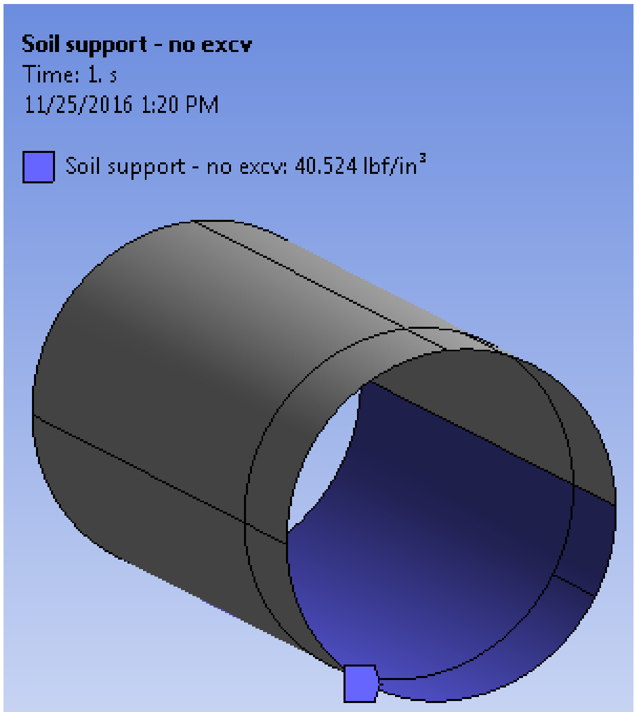
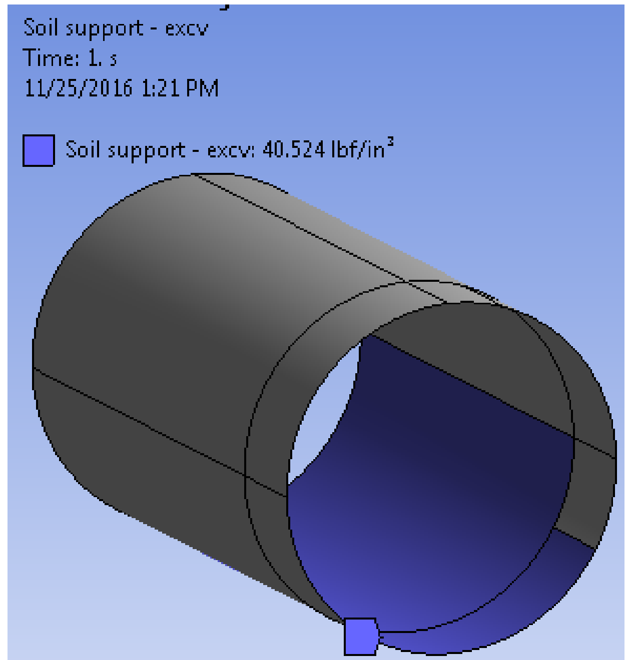


Figure 5: Finite element mesh. The model was meshed with 4-node SHELL181 elements. E = 200GPa, v = 0.3, ρ = 7850kg/m^3

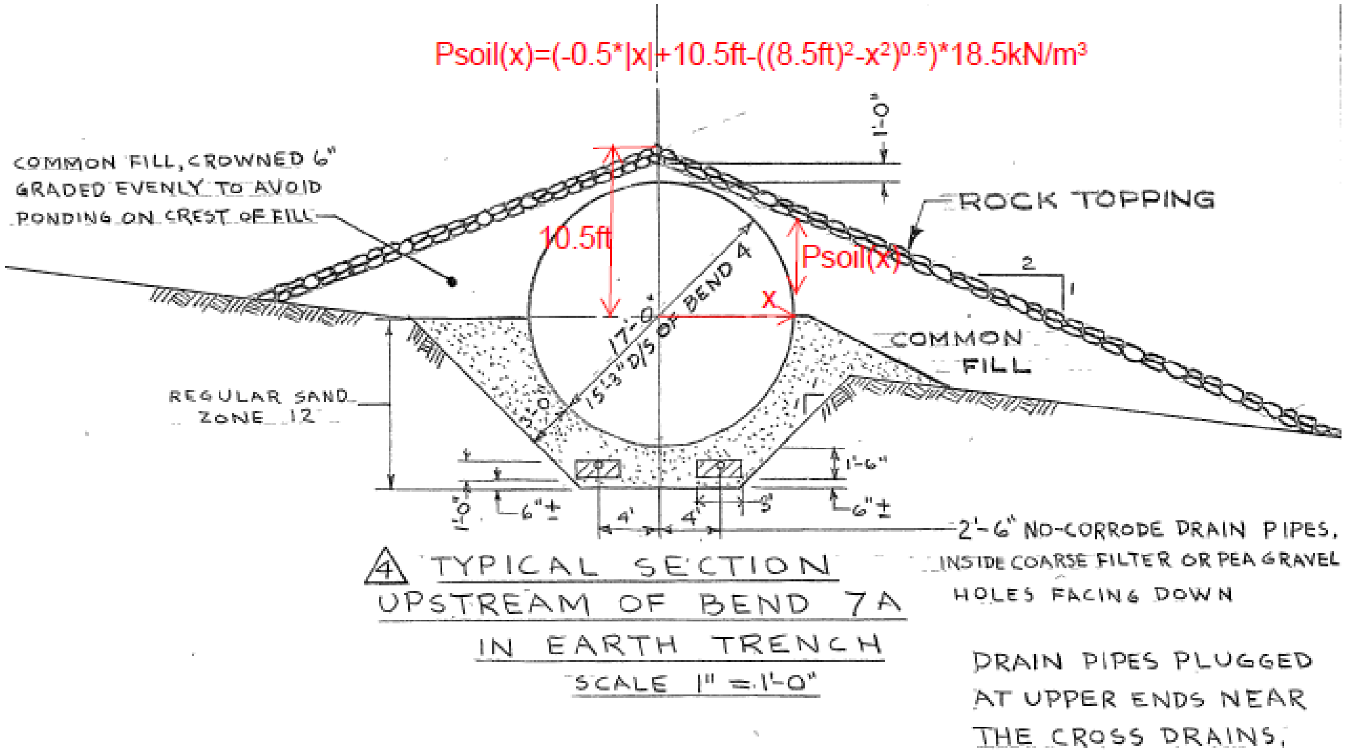


No excavation



With excavation

Figure 6: Subgrade reaction modulus of soil $Ks = 11\frac{MPa}{m} = 40.52\cdot\frac{lbf}{in^3}$ was applied at the bottom half.



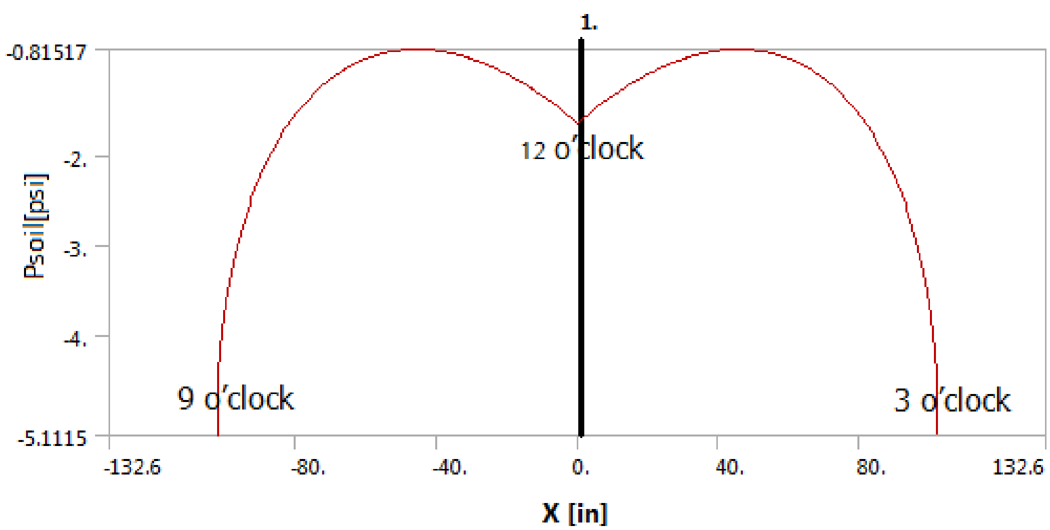
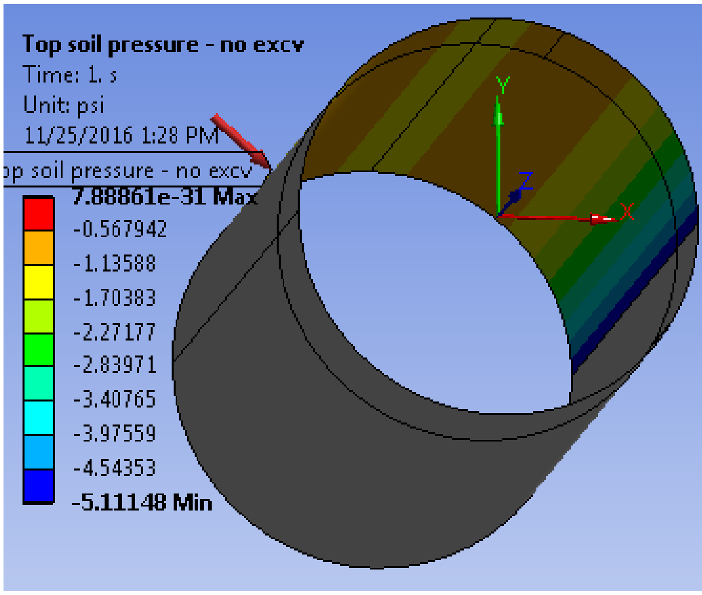
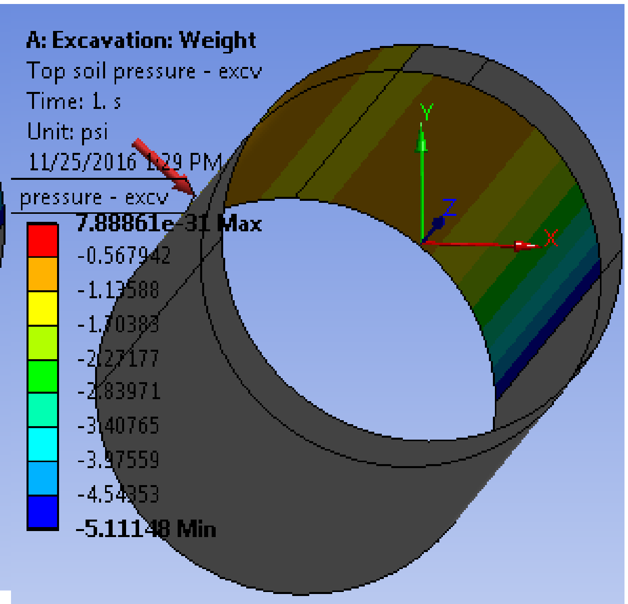


Figure 7:Pressure from the soil on top of pipe. The soil density was assumed at $18.5 \frac{kN}{m^3} = 0.0682 \cdot \frac{lbf}{in^3}$.



No excavation



With excavation

Figure 8:Pressure from the soil on top of pipe applied as external pressure.

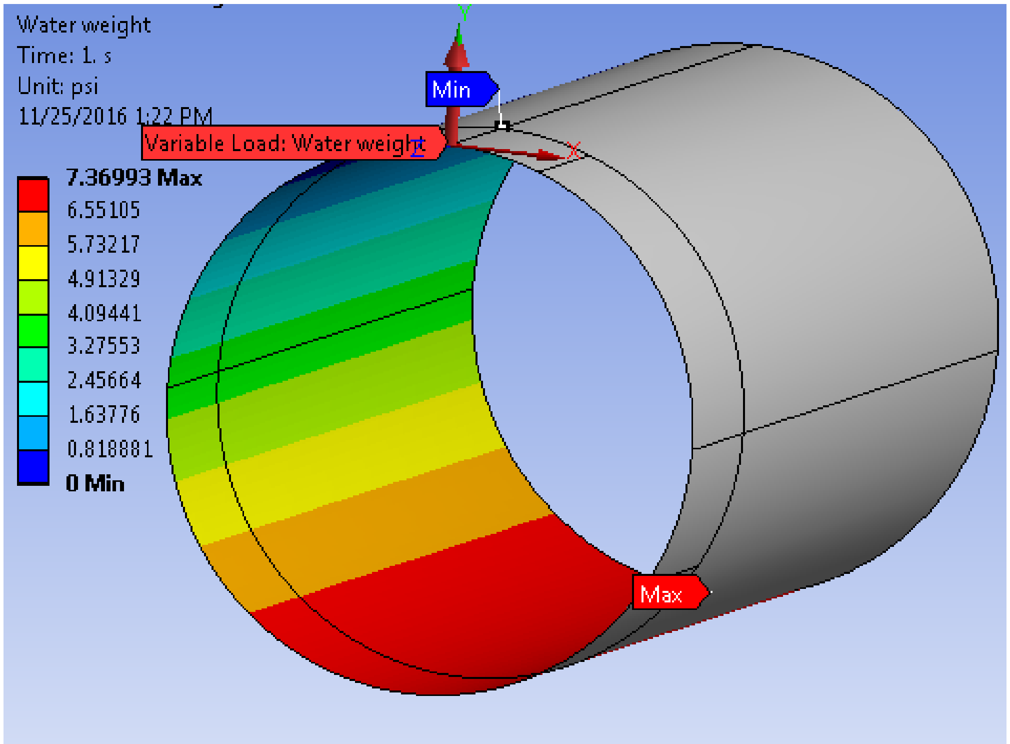


Figure 9: Water weight applied as hydrostatic internal pressure with 0 psi at the top of the pipe

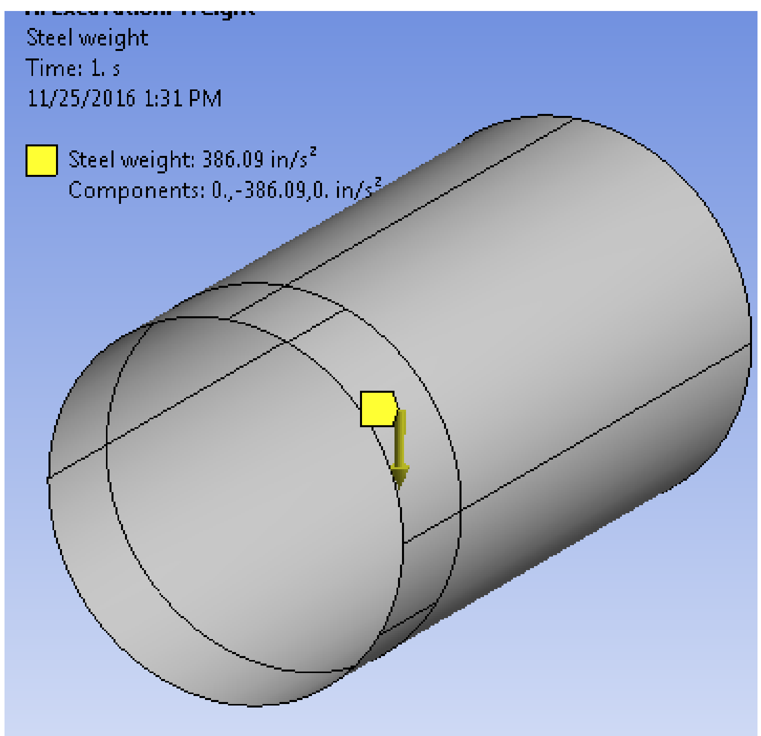


Figure 10: Steel weight

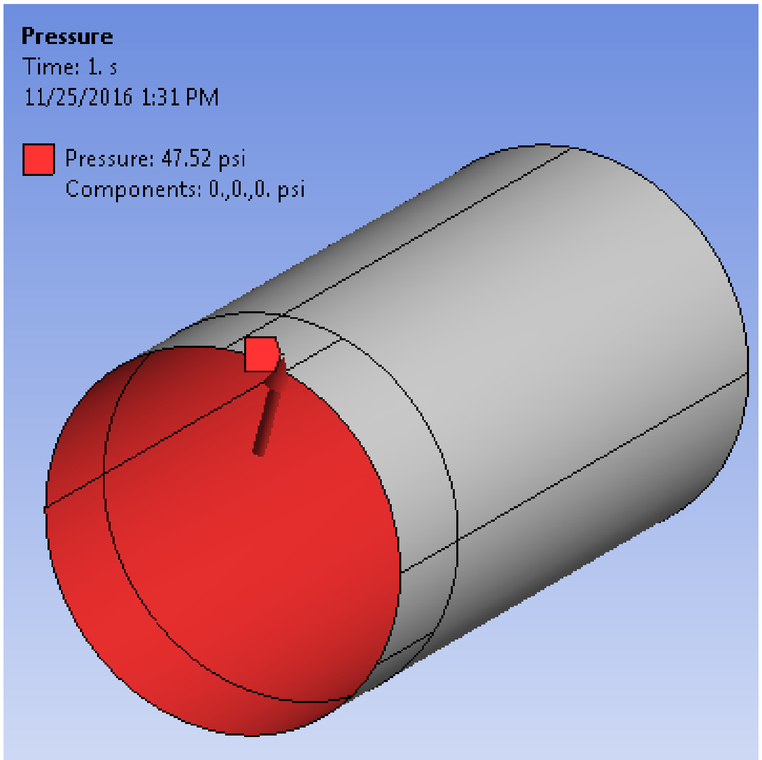


Figure 11: Internal pressure 47.52 psi including pressure surge from pressure line of Ref 5.

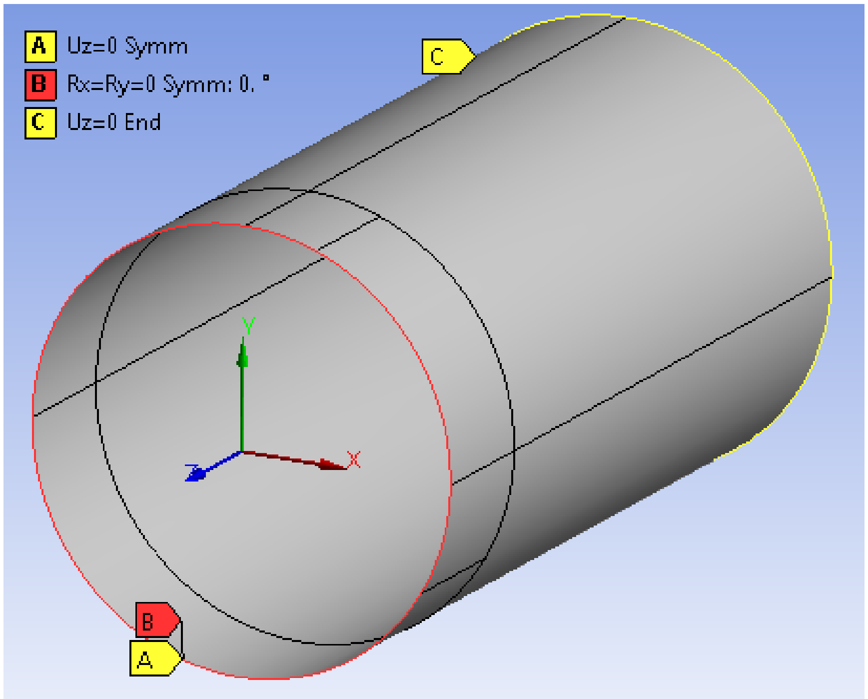


Figure 12: Constrains: Uz = Rx = Ry = 0 at the XY symmetry plane. Uz = 0 at the end.

Results

Three loading scenarios were considered:
LS1 = Water Weight + Steel Weight + Internal Pressure. No soil on top of the penstock, no excavation
LS2 = Water Weight + Steel Weight + Top Soil Weight + Internal Pressure. No excavation
LS3 = Water Weight + Steel Weight + Top Soil Weight + Internal Pressure. With excavation

$F_{uA285} := 55ksi$ Tensile stress $F_{uA285} = 379 \cdot MPa$ Assume Grade C, Ref 3

$F_{yA285} := 30ksi$ Yield stress $F_{yA285} = 207 \cdot MPa$

$Si_{A285} := \min\left(\frac{F_{uA285}}{2.4}, \frac{F_{yA285}}{1.5}\right) = 20000 \cdot psi$ Basic allowable stress intensity according to Ref 2 for continuous plate

$Sa_{pA285} := 1.0 \cdot Si_{A285} = 20000 \cdot psi$ Allowable for primary general membrane stress. Ref 2, for continuous plate

$Sa_{lA285l} := 1.5 \cdot Si_{A285} = 30000 \cdot psi$ Allowable for local membrane stress + pramary bending. Ref 2, for continuous plate

$Sa_{QA285} := \min\left(3 \cdot Si_{A285}, F_{uA285}\right) = 55000 \cdot psi$ Allowable for secondary stress = Local membrane stress + local shell bending. Ref1, for continuous plate

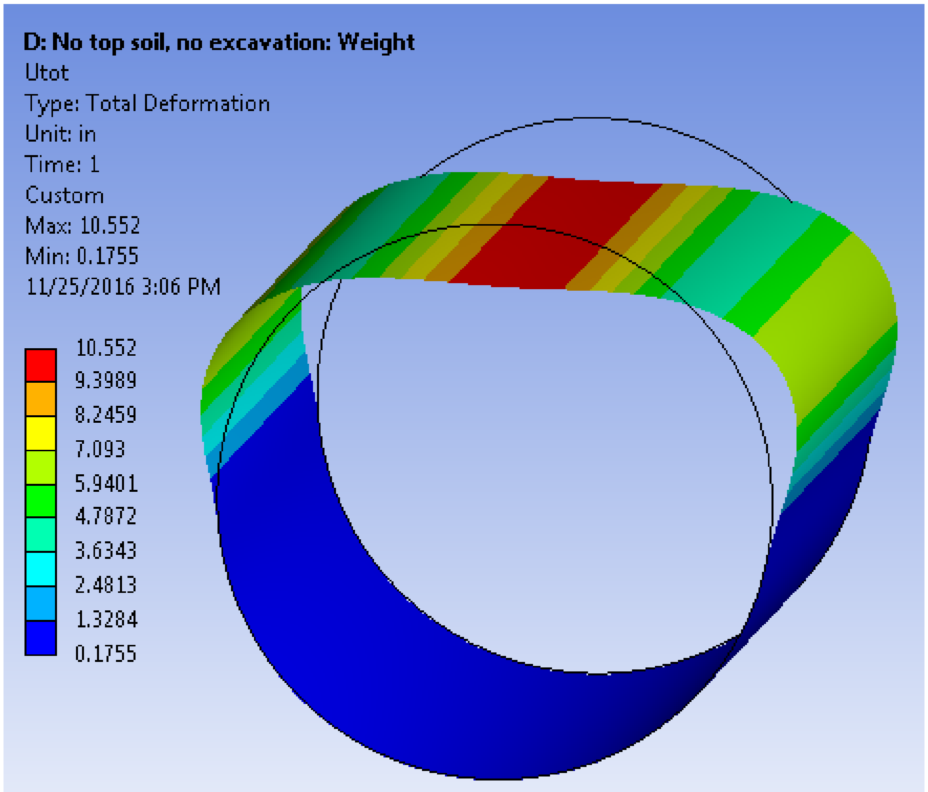


Figure 13: Deformation due LS1 without Internal Pressure.

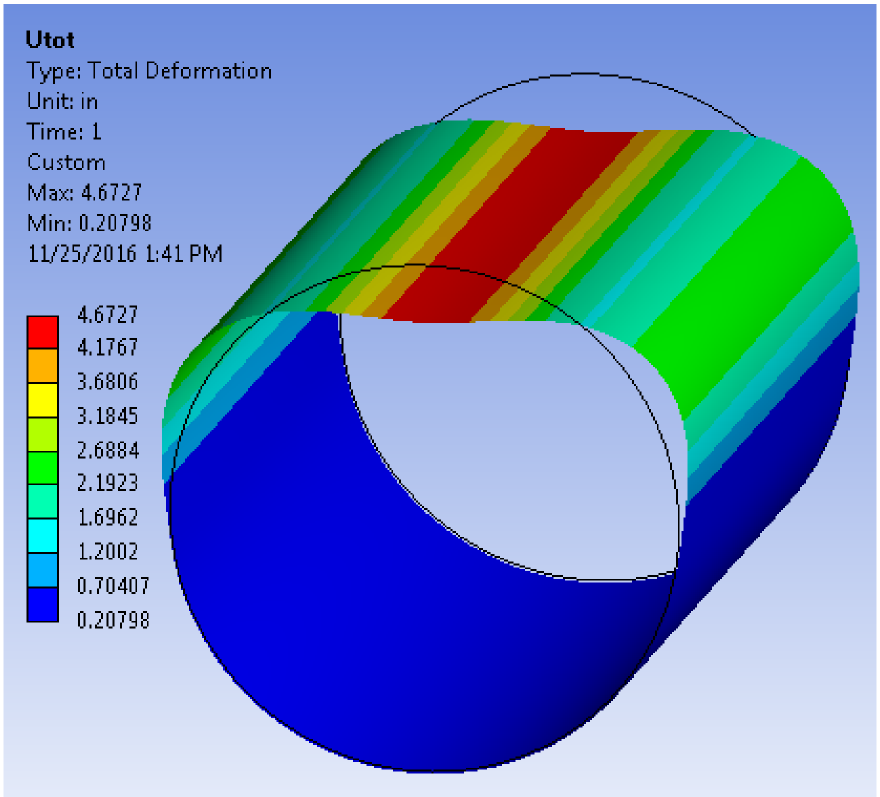


Figure 14: Deformation due LS2 without Internal Pressure.

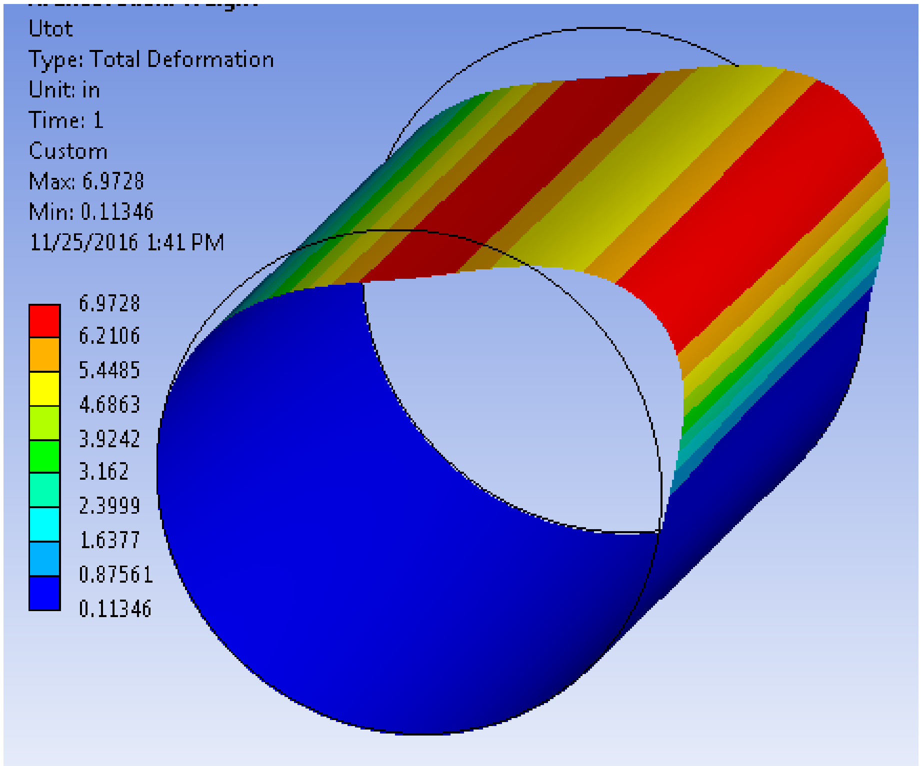


Figure 15: Deformation due LS3 without Internal Pressure.

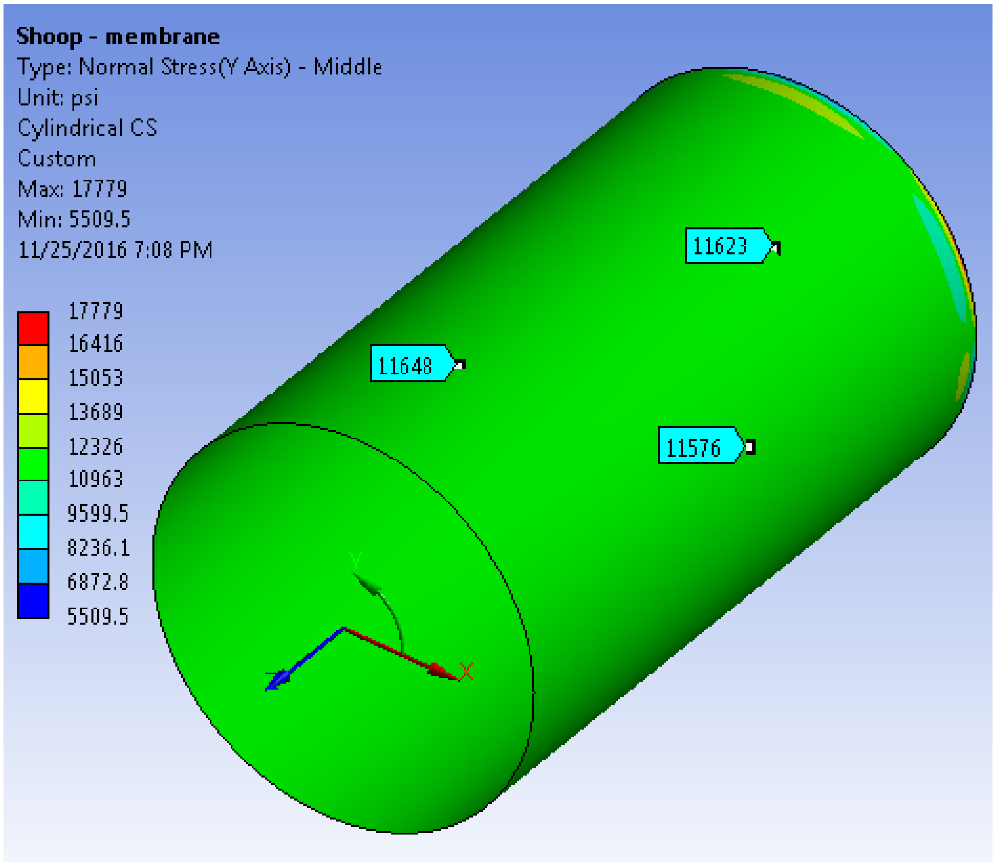


Figure 16: LS1 - Membrane hoop stress. Allowable for continuous plate $Sa_{pA285} = 20000 \cdot psi$. Ignore minor spikes at the boundary. No overstress.

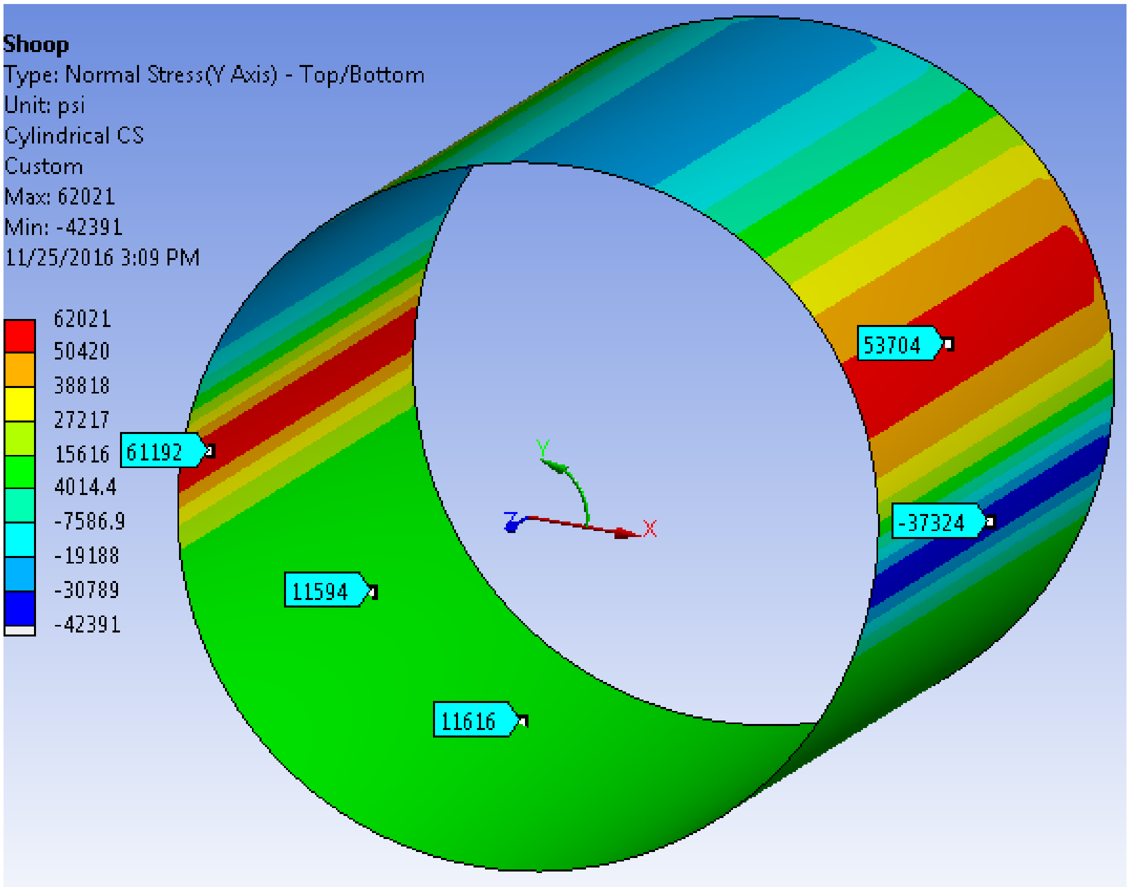


Figure 17: LS1 - Total hoop stress. Allowable for continuous plate $Sa_{IA285I} = 30000 \cdot psi$. 100% overstress, more if longitudinal welded joint efficiency at 3 and 9 o'clock is taken into account.

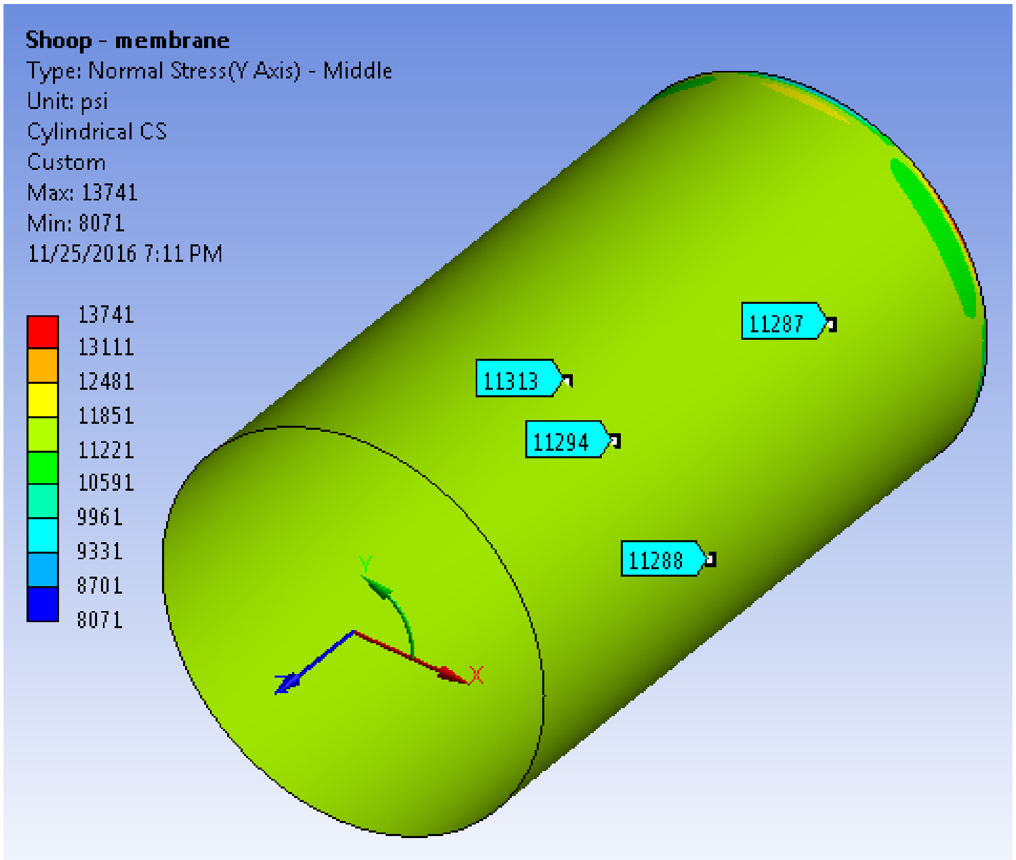


Figure 18: LS2 - Membrane hoop stress. Allowable for continuous plate $Sa_{pA285} = 20000 \cdot psi$. Ignore minor spikes at the boundary. No overstress.

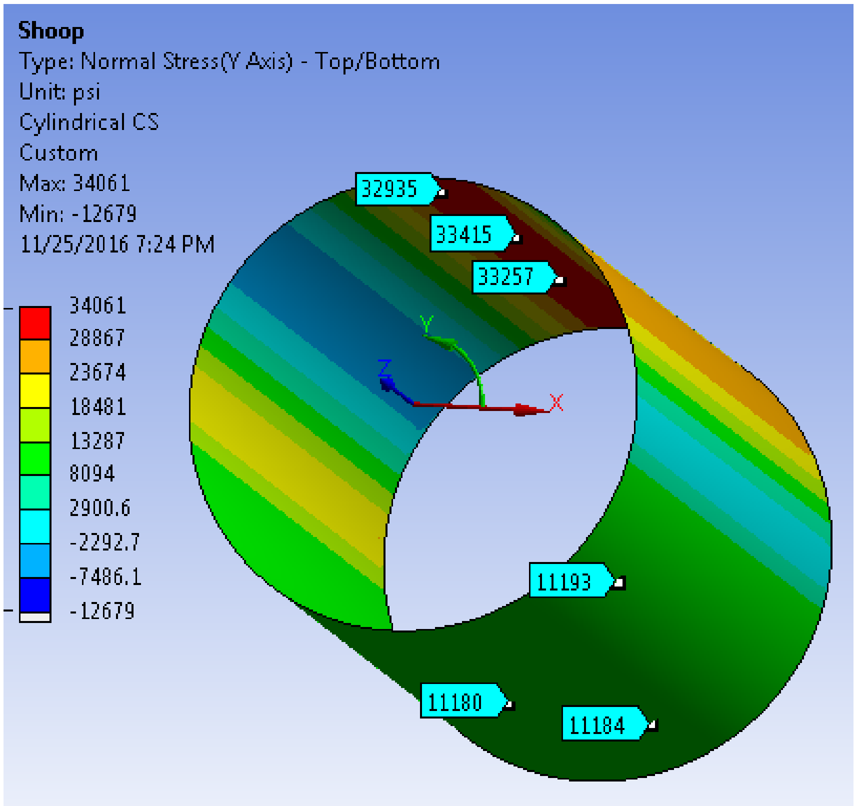


Figure 19: LS2 - Total hoop stress. Allowable for continuous plate $Sa_{|A285|} = 30000 \cdot psi$. 12% overstress.

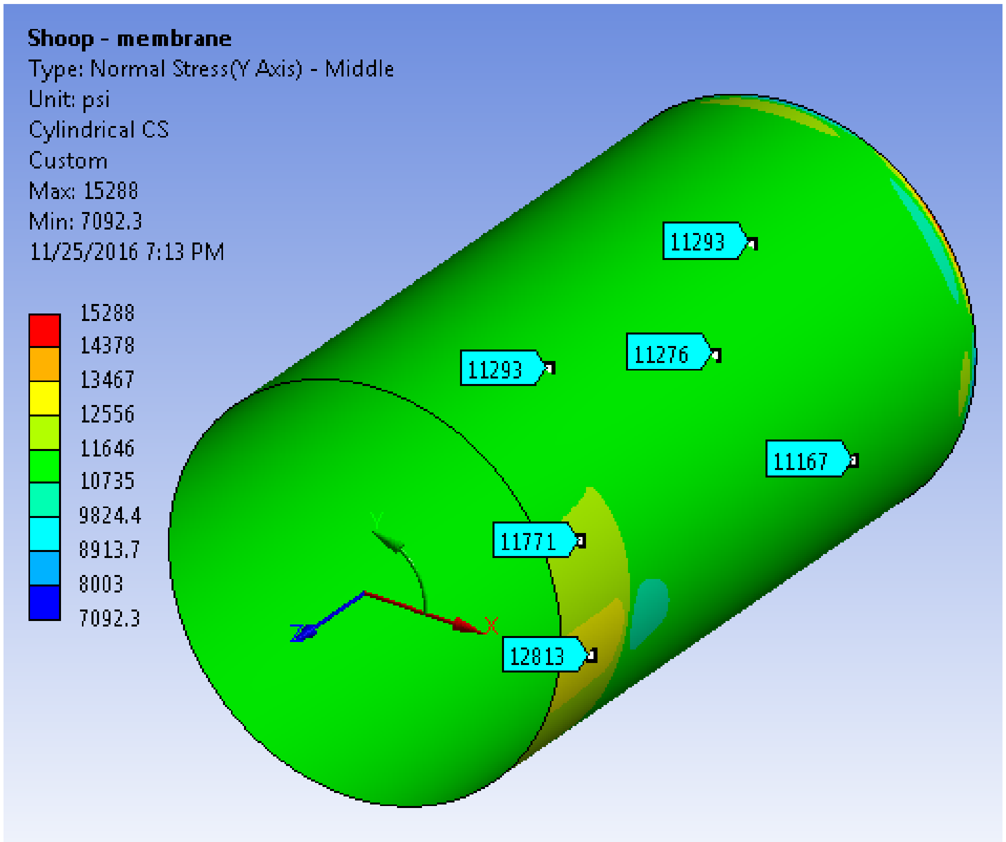


Figure 20: LS3 - Membrane hoop stress. Allowable for continuous plate $Sa_{pA285} = 20000 \cdot psi$. Ignore minor spikes at the boundary. No overstress.

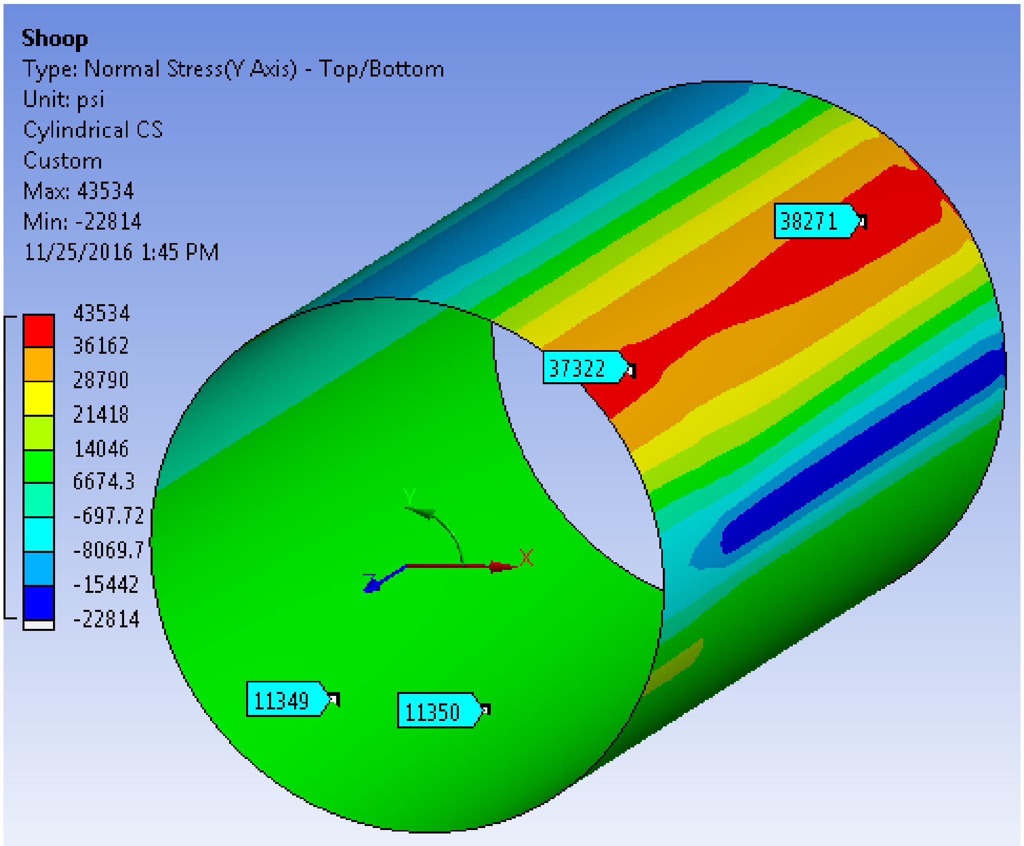


Figure 21: LS3 - Total hoop stress. Allowable for continuous plate $Sa_{|A285|} = 30000 \cdot psi$. 45% overstress, more if longitudinal welded joint efficiency at 3 o'clock is taken into account.

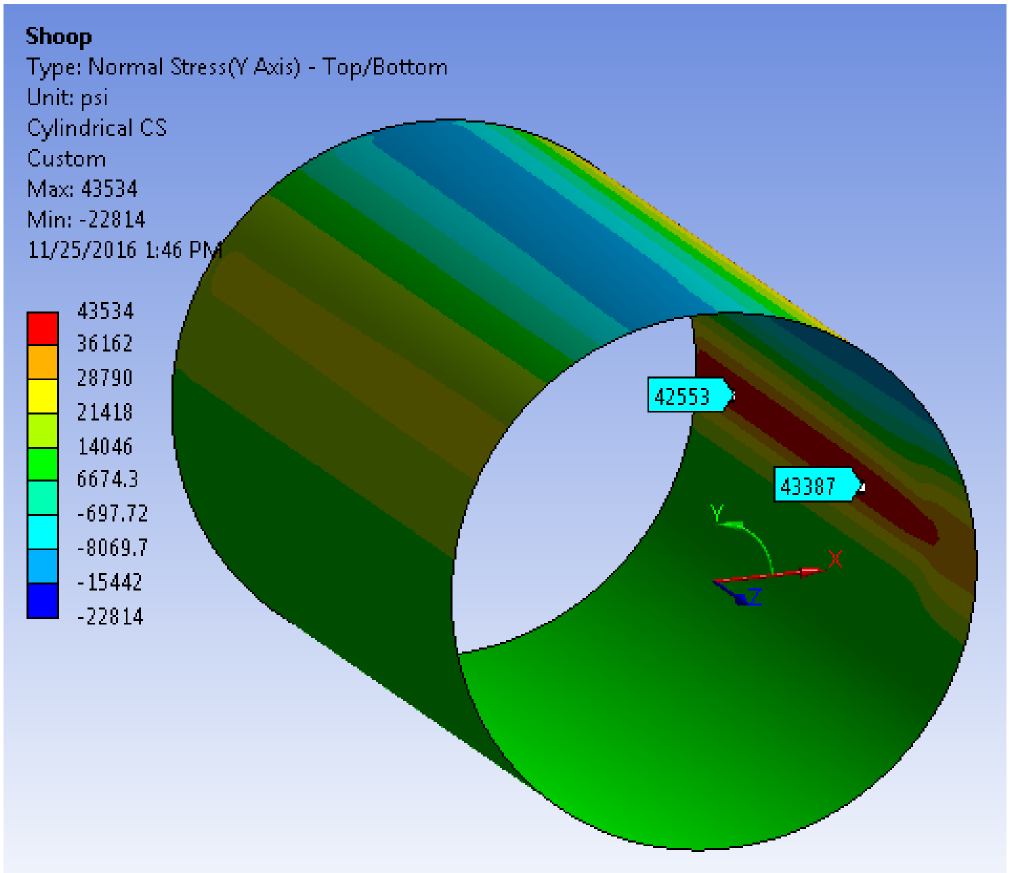
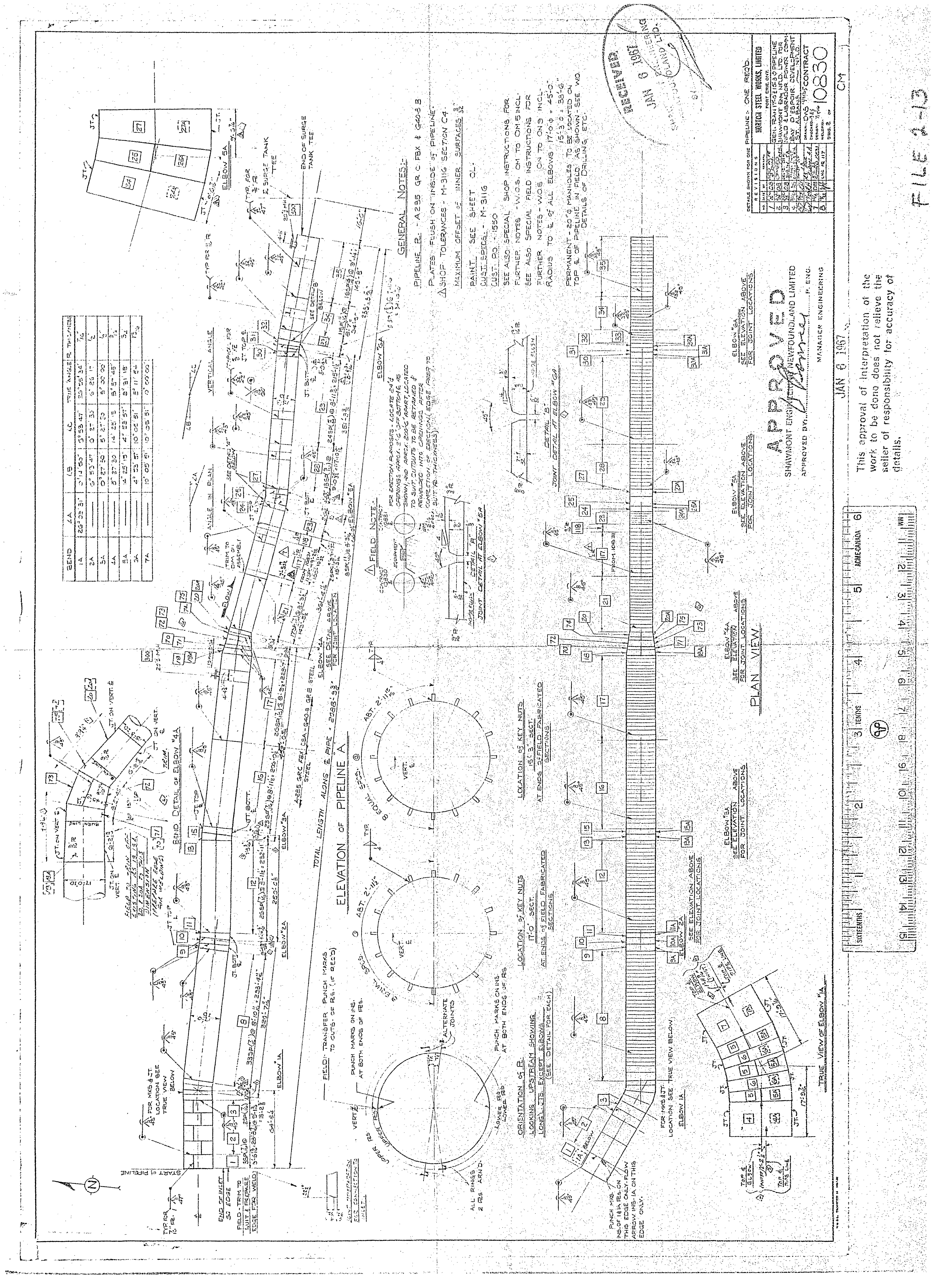


Figure 22: LS3 - Total hoop stress. Allowable for continuous plate $Sa_{|A285|} = 30000 \cdot psi$. 45% overstress, more if longitudinal welded joint efficiency at 3 o'clock is taken into account.

Conclusions and recommendations

Soil cover on top of the penstock plays an important role in reducing the stresses caused by the water + steel weight.
Excavation causes 100% hoop stress increase (from 22,000psi to 43,500 psi) at 3 o'clock.
It is recommended to restore the excavated sections to their original state (as per Ref 5) prior to filling the penstock.
It is recommended to construct a more comprehensive FE model taking into account soil-steel frictions to study the influence of the soil cover at the top half of the pipe on the stresses in the 17ft diameter penstock sections.

Appendix H
NL Hydro Drawing No. 10830-2 Penstock No.1 Intake to Surge Tank


ELEVATION of PIPELINE A
PLAN VIEW
GENERAL NOTES:-
APPROVED
SHAWMONT ENGINEERING NEWFOUNDLAND LIMITED
JAN 6 1967
This approval of interpretation of the work to be done does not relieve the seller of responsibility for accuracy of details.
TRUE VIEW OF ELBOW #1A
BEND DETAIL OF ELBOW #4A
10830

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HATCH

Newfoundland and Labrador Hydro

Final Report

For

Bay d'Espoir Penstock No. 1 Stress Analyses

H352666-00000-240-230-0002
Rev. 0
March 29, 2017

Newfoundland and Labrador Hydro

Final Report

For

Bay d'Espoir Penstock No. 1 Stress Analyses

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HATCH

Bay d'Espoir Penstock No. 1 Stress Analyses

H352666-00000-240-230-0002

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PEG Newfoundland and Labrador
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REGISTERED PROFESSIONAL ENGINEER
PEG Newfoundland and Labrador
GREGORY SAUNDERS
SIGNATURE
March 29, 2017
DATE
NEWFOUNDLAND & LABRADOR
MIRC 01626

			O.Belashov		
2017-03-29	0	Final	O. Belashov	G.Qu	G. Saunders
DATE	REV.	STATUS	PREPARED BY	CHECKED BY	APPROVED BY

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1. Introduction

On May 21, 2016, Newfoundland and Labrador Hydro (Hydro) discovered a leak coming from a 2 ft crack in a longitudinal seam in Bay d'Espoir Penstock No. 1. Hydro subsequently closed the intake and dewatered Penstock No. 1 as a mitigative measure – i.e., to prevent further crack propagation and soil erosion.

Hydro retained an engineering consultant on May 27, 2016 to perform a site investigation and prepare a repair procedure. This repair was completed, and an internal inspection was completed by TACTEN in conjunction with Kleinschmidt Associates. They stated the cause of the failure was thermal stress induced due to watering up. The penstock was pressurized after the crack was re-welded and inspected, and put back into service.

On September 14, 2016, a second crack in a longitudinal seam was observed in the penstock and was located approximately 15 ft upstream from the previous crack. Upon discovery, Hydro closed the intake and dewatered the penstock to prevent further crack propagation and soil erosion.

Hydro then engaged Hatch on September 22, 2016 to complete an assessment of the welds to determine the cause of the failures. Upon discovering a corrosion problem with the longitudinal welds Hatch provided recommendations on what should be done to refurbish these welds so the penstock could be put back in service. Additionally, Hydro requested Hatch complete a stress analysis on the section of penstock that experienced the cracking to determine the highly stressed areas and to provide recommendations that would reduce these stresses to acceptable limits.

Also due to the alignment of Penstock No. 1 it has several direction changes between the intake structure and surge tank. Hatch recommended the displacement at the largest vertical change in direction, Bend No. 4A, be analyzed to determine if there could be movement at this location due to lack of thrust restraints. Refer to conduit A in appendix A for location of bend relative to intake and surge tank.

The following study calculates stresses in the Bay d'Espoir Penstock No. 1 using finite element methods. There are four objectives in the study: 1) determine the stresses with the current configuration 2) investigate the influence of common fill (backfill) on the penstock stresses; 3) investigate stability of the common fill; and 4) compute displacements at Bend 4A Ref [1].

2. Finite Element Models

Four finite element models were built in ANSYS Workbench R17.1. All section views are taken facing downstream.

- Model 1 – 2D model of a typical 17-ft diameter penstock section in a half trench with no backfill on top (Figure 1). The model represents an extreme case for the exposed penstock.
- Model 2 – 2D model of a typical 17-ft diameter penstock section in a half trench with original backfill configuration on top (Figure 2, Figure 5).
- Model 3 – 2D model of a typical 17-ft diameter penstock section in a half trench with proposed backfill configuration on top (Figure 3, Figure 6).
- Model 4 - 3D model of the bend\reducer at Bend 4A with proposed backfill (Figure 4, Figure 7). The model is used to estimate displacements at the bend.

The wall thickness for all four models was taken from Ref [1] where t=0.422 in. for t_{nom}=7/16 in. The wall thickness at the bend was assumed to have the same corrosion allowance as the 7/16 in. section of penstock where t=0.547 in. for t_{nom}=9/16 in.

The load combinations listed in Table 1 were considered.

Table 1 Load Combinations

Model	Loading Scenario	Self Weight	Water Weight	Rock Fill Weight	Snow Weight	Design Pressure
Model 1	LC1	X	X			
	LC2	X	X			X
Model 2	LC1	X	X			
	LC2	X	X			X
Model 3	LC1	X	X	X		
	LC2	X	X	X		X
	LC3	X	X	X	X	
	LC4	X	X	X	X	X
Model 4	LC2	X	X			X

Penstock Loads:

Self Weight – applied as gravitational acceleration of 32.2 ft/s^2 on all components in the model (Figure 10, Figure 18).

Water Weight – applied as hydrostatic pressure on the penstock internal surface with 0 psi at the top and 7.34 psi at the bottom (Figure 11).

Rock Fill Weight – applied as 0.3095 psi uniform pressure on the external surfaces of the backfill (Figure 13). The 0.3095 psi pressure corresponds to the rock fill being 6 in. high with 89 lb/ft^3 density.

Snow Weight – applied as 0.45 psi uniform pressure on the top surface of the backfill (Figure 14). It has been observed that when uniform pressure is applied on all external surfaces of the backfill it actually reduces the hoop stress in the penstock. Therefore only half of snow load (129.6 psf=0.9 psi) calculated in Ref [1] was applied on the top surface of the backfill as it is unlikely that a full snow load will be present only on the top with nothing on the sides of the penstock.

Design Pressure – 59 psi, corresponding to the load rejection pressure, was applied at the internal surface (Figure 12): this pressure occurs during load rejection at the circumferential joint between the section fabricated using ASTM A285 and the section fabricated using CSA G40.8. The pressure magnitude was derived from the pressure line specified in Ref [5] with a head pond water level of 597 ft and surge tank water level of 655 ft. The joint elevation is 487.42 ft and the pressure line elevation is 623.17 ft at the joint resulting in (623.17 ft - 487.42 ft)*62.428 lb/ft^3=59 psi.

The 2D models were meshed with 8-node PLANE183 (Figure 8, Figure 9). Five such elements were placed throughout the shell thickness to adequately capture shell bending. The bedding and backfill in the 3D model (Figure 17) was meshed with 8-node SOLID185 while 4-node SHELL181 elements were used to mesh the penstock.

For Model 2, 3, and 4 a frictional contact with 0.1944 (Interface Friction Angle 11 °) friction coefficients was assigned between the penstock outer surface and the backfill (Figure 16, Figure 21). For Models 1, 2, 3, and 4, the frictional contact with 0.2679 (Interface Friction Angle 15°) friction coefficient was assigned between the penstock outer surface and bedding (Figure 21).

Models were constrained as shown in Figure 15 and Figure 20. Both the penstock ends in Model 4 have not been constrained meaning that the gravitational force, friction, and backfill shear strength (however small it may be) are supporting the penstock.

The material properties of steel (penstock) assuming linear elastic material are

- Elastic modulus 29,000,000 psi
- Poisson ratio 0.3

- Density 490 lb/ft^3.

The material properties of compacted sand (bedding) assuming a linear elastic material are

- Elastic modulus 3191 psi
- Poisson ratio 0.33
- Density 127 lb/ft^3.

The material properties of common fill (backfill) assuming an elasto-plastic material (Mohr-Coulomb material model) is:

- Elastic modulus 1015 psi
- Poisson ratio 0.33
- Density 102 lb./ft^3
- Internal friction angle 26°
- Cohesion 0.07252 psi
- Dilation angle 5°.

The material properties for the common fill conservatively reflect the expected quality of the material.

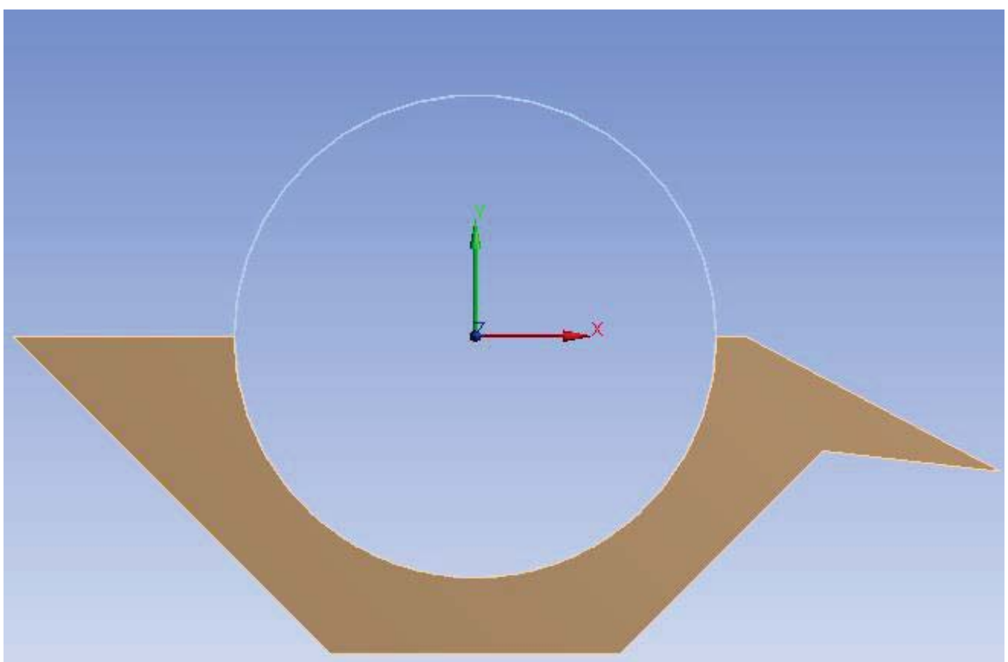


Figure 1 Model 1 – 2D Plane Strain - No Backfill

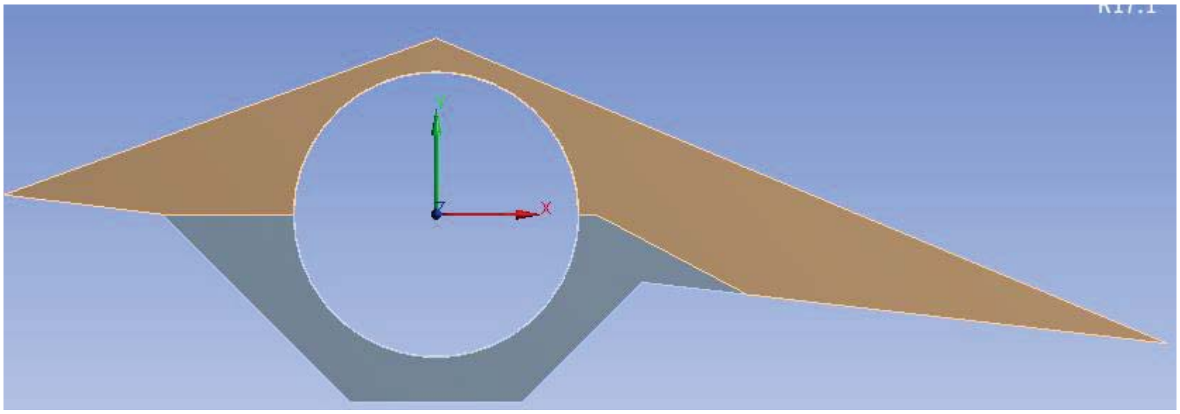


Figure 2 Model 2 – 2D Plane Strain – Original Backfill Configuration

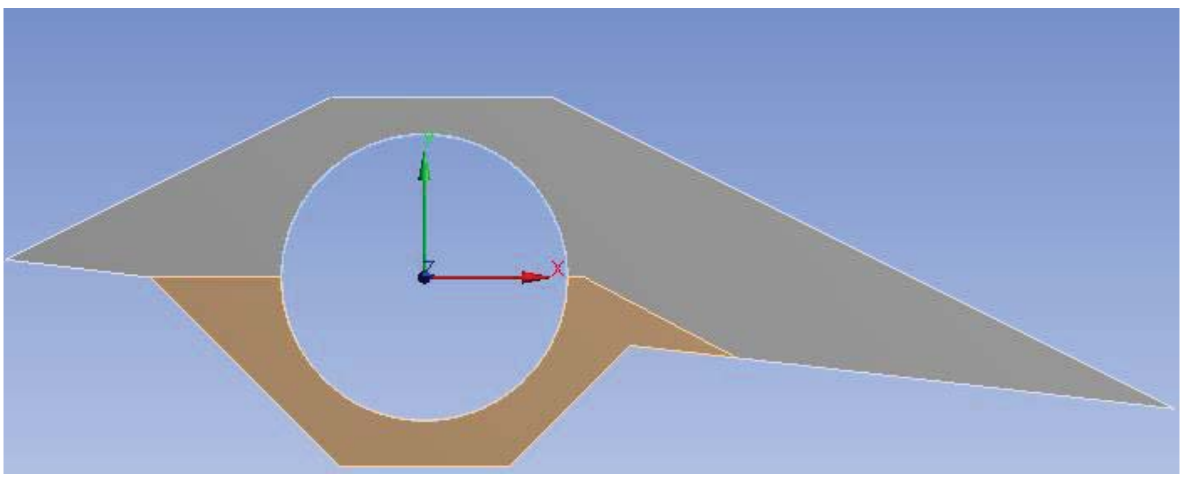


Figure 3 Model 3 – 2D Plane Strain - Proposed Backfill Configuration

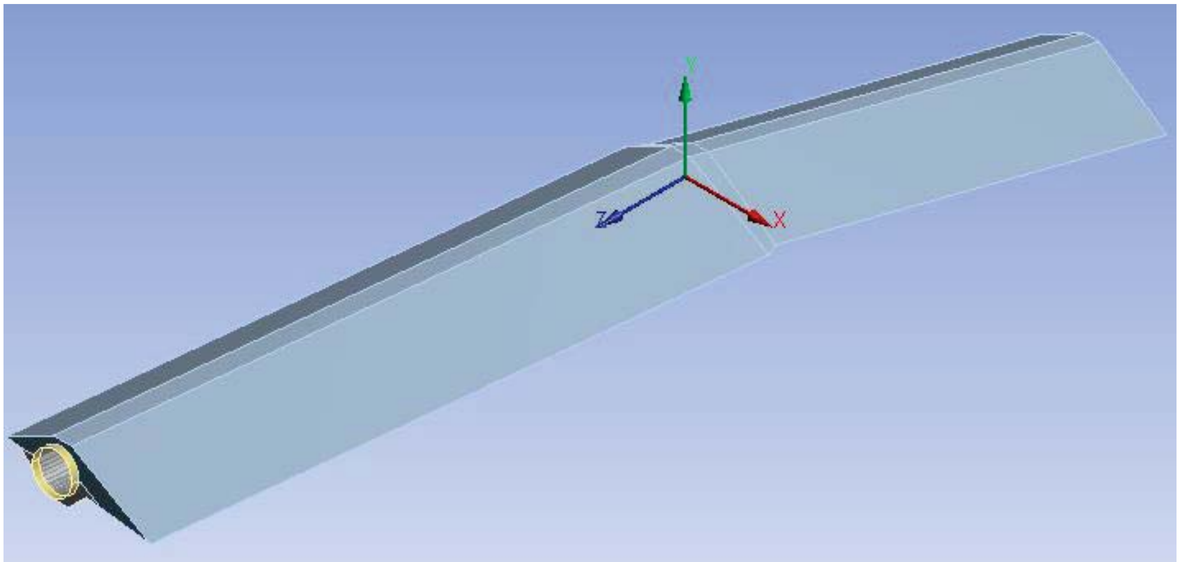


Figure 4 Model 4 – 3D Model of Bend 4A with Proposed Backfill Configuration

It was conservatively assumed that the half trench configuration extents all the way along the 15.3-ft penstock.

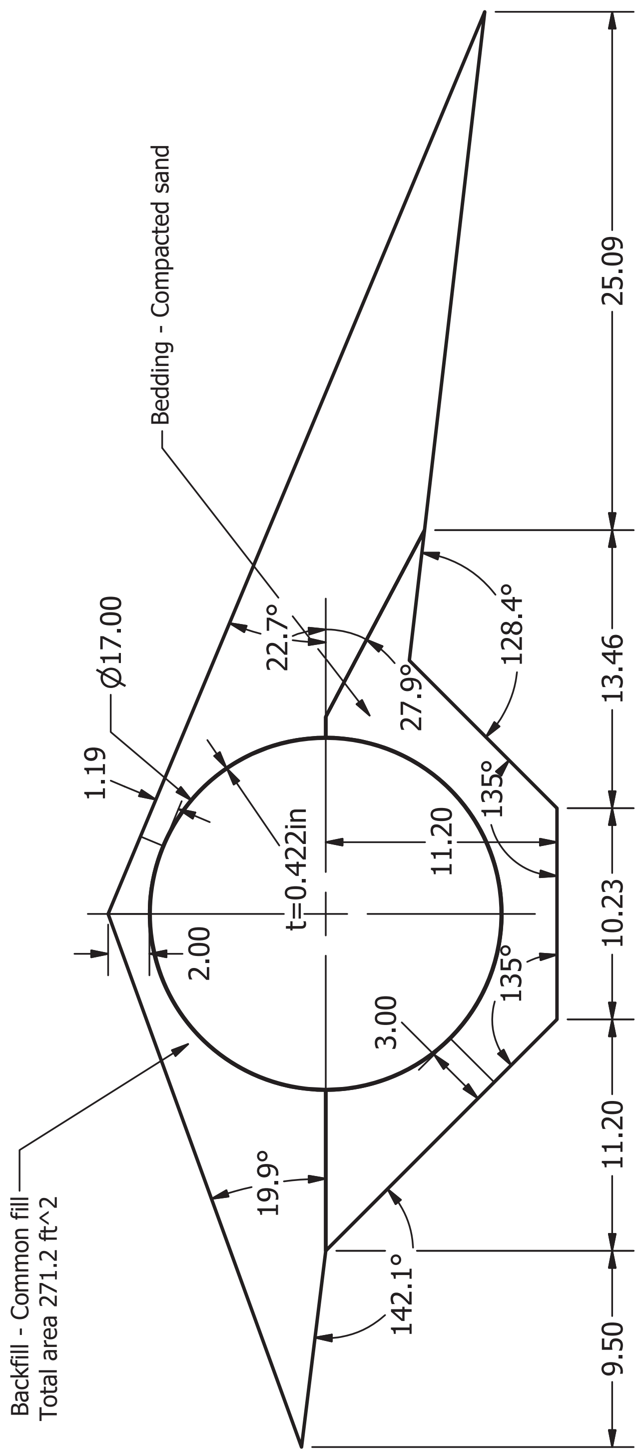


Figure 5 Model 2: Bay d'Espoir - Penstock 1 - 2D model - Original backfill configuration for half trench sections
All dimensions ft
The geometry is scaled from F-106-C-7

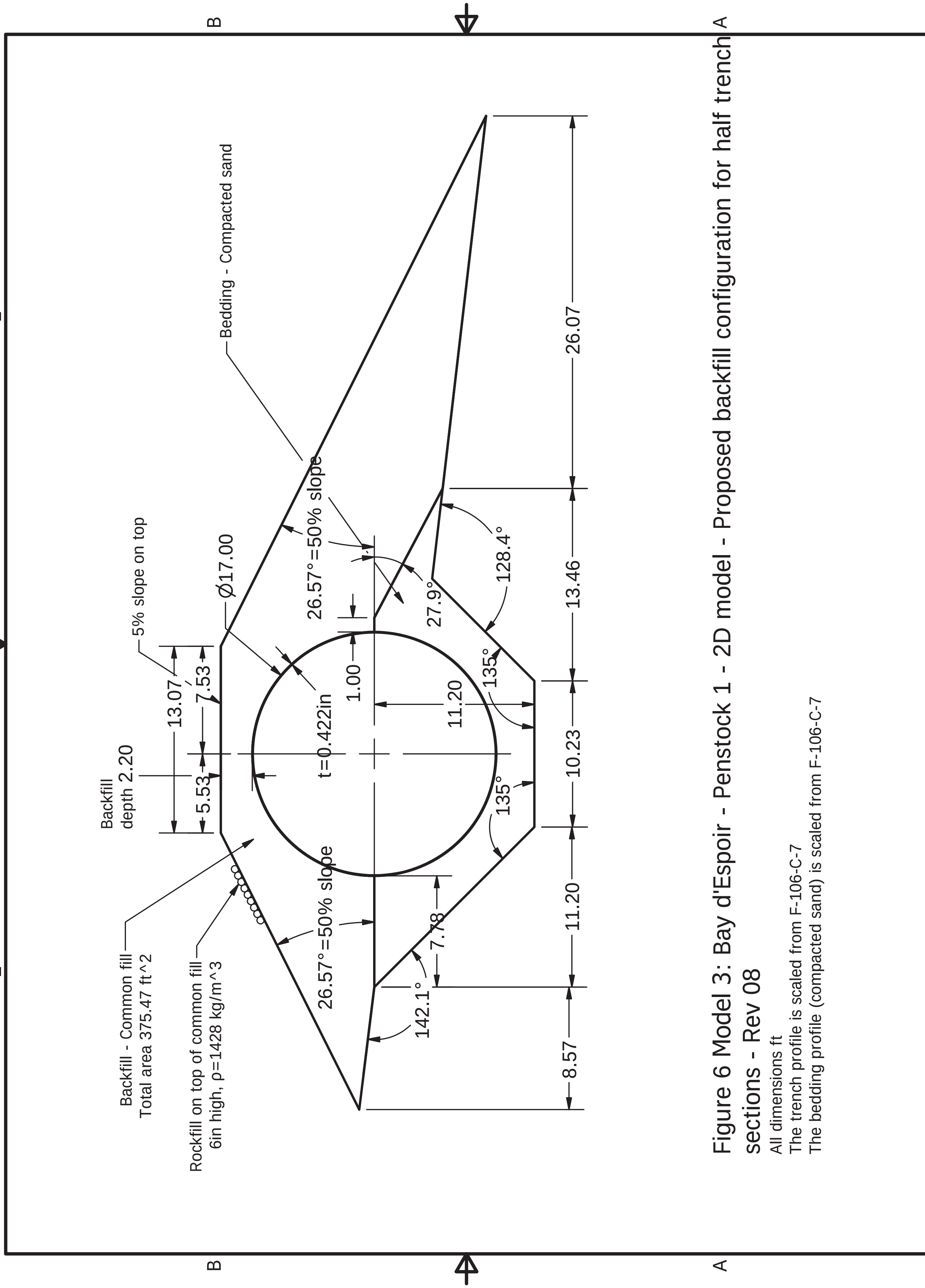


Figure 6 Model 3: Bay d'Espoir - Penstock 1 - 2D model - Proposed backfill configuration for half trench sections - Rev 08

All dimensions ft
The trench profile is scaled from F-106-C-7
The bedding profile (compacted sand) is scaled from F-106-C-7

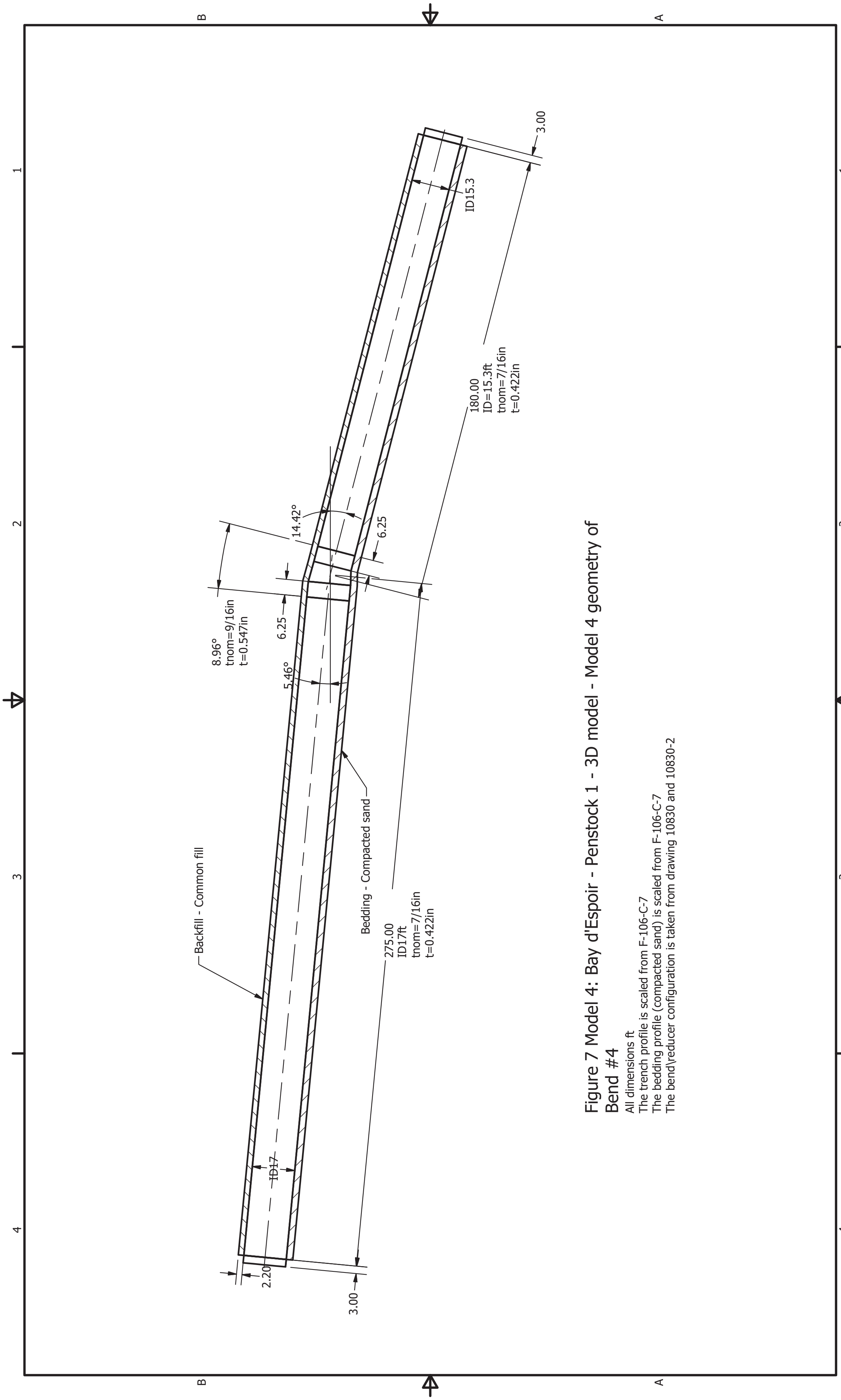


Figure 7 Model 4: Bay d'Espoir - Penstock 1 - 3D model - Model 4 geometry of Bend #4

All dimensions ft
The trench profile is scaled from F-106-C-7
The bedding profile (compacted sand) is scaled from F-106-C-7
The bend\reducer configuration is taken from drawing 10830 and 10830-2

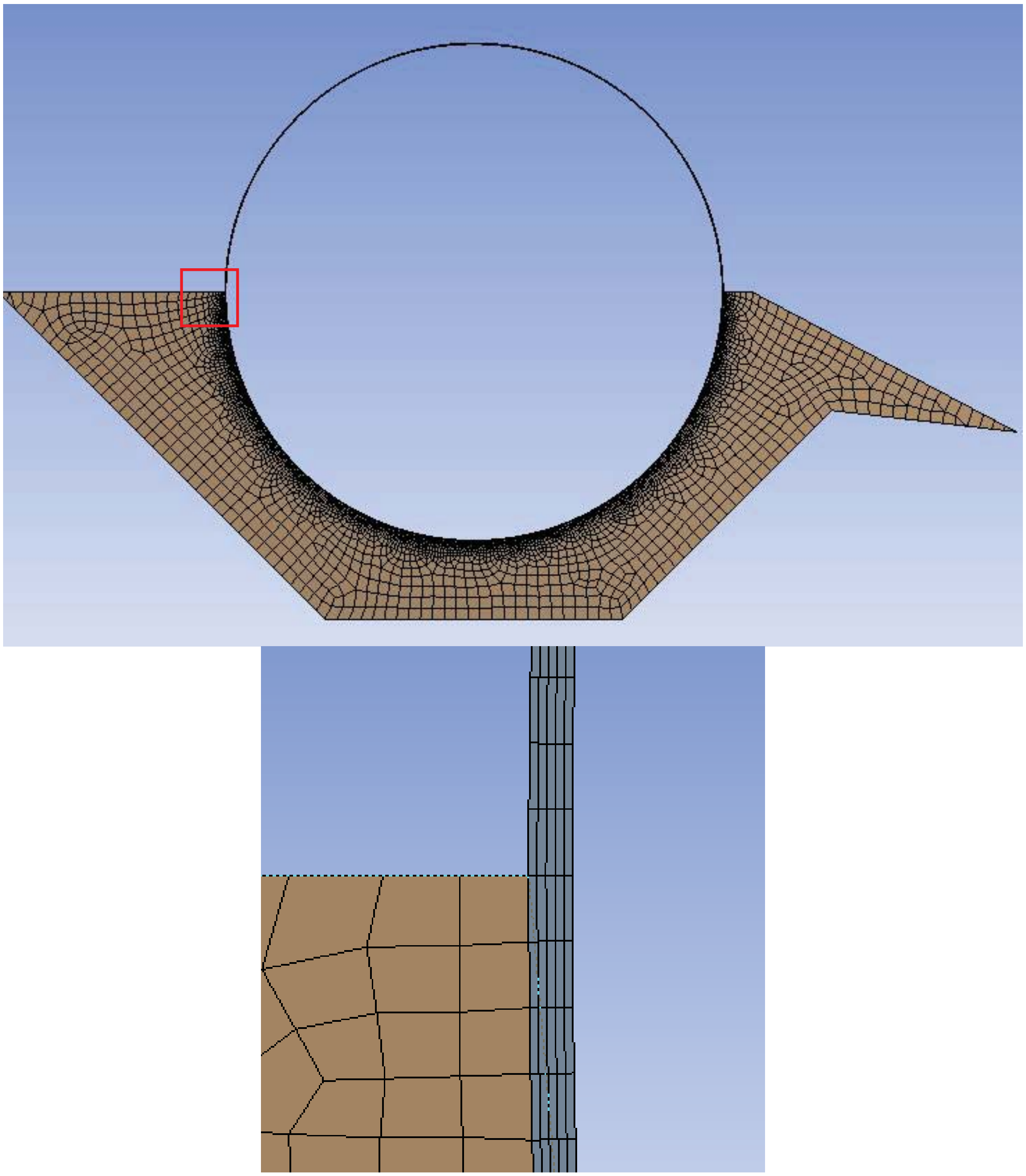


Figure 8 Model 1 – Finite Element Mesh

Five 8-node PLANE183 elements were used and were placed throughout the shell thickness to adequately capture shell bending.

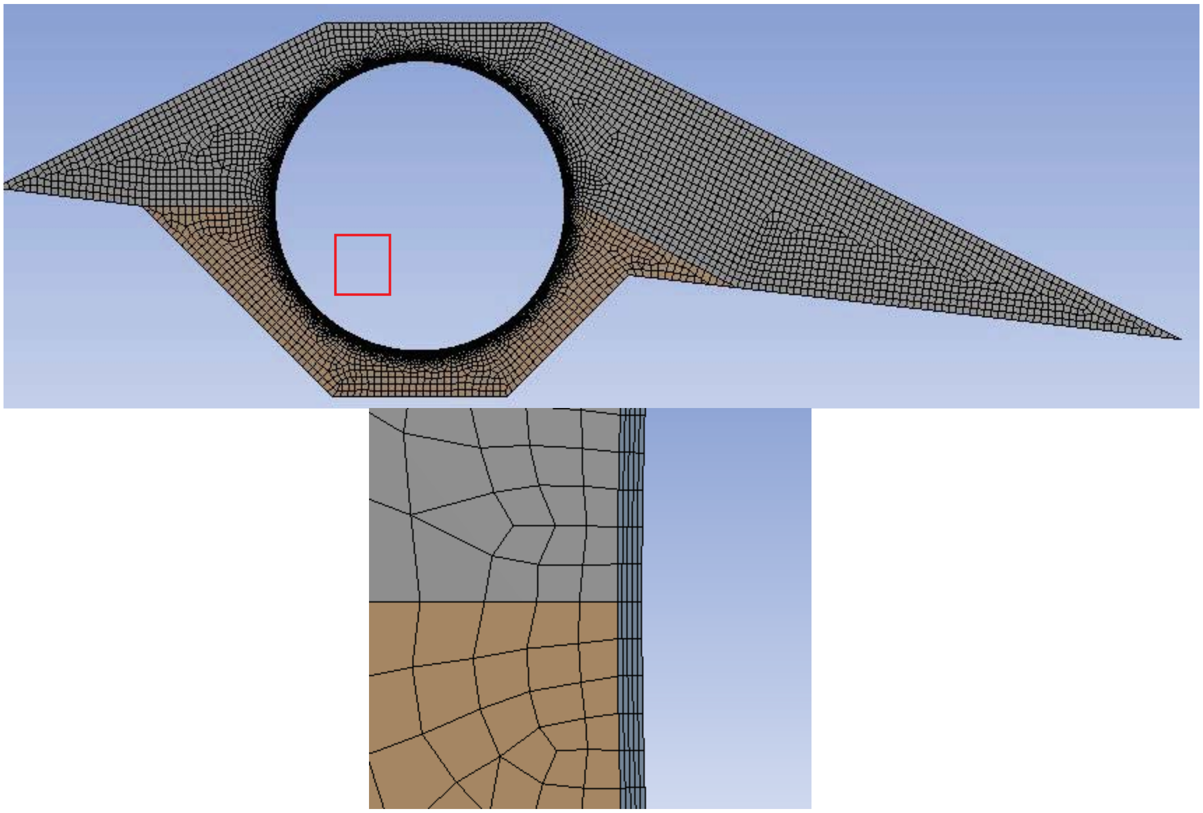


Figure 9 Model 2 and Mode 3 – Finite Element Mesh

Five 8-node PLANE183 elements were used and were placed throughout the shell thickness to adequately capture shell bending.

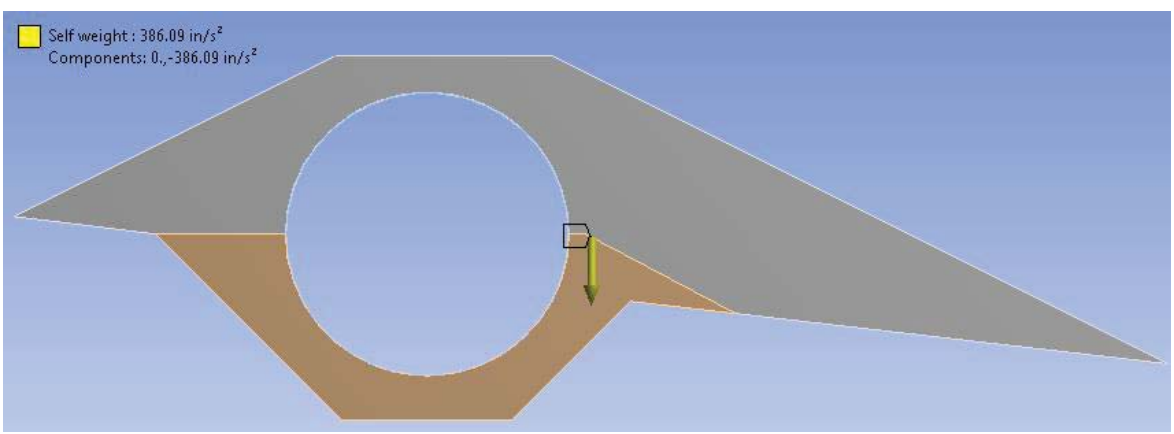


Figure 10 Model 1, 2, and 3 – Self Weight

Gravitational acceleration was applied on all model components.

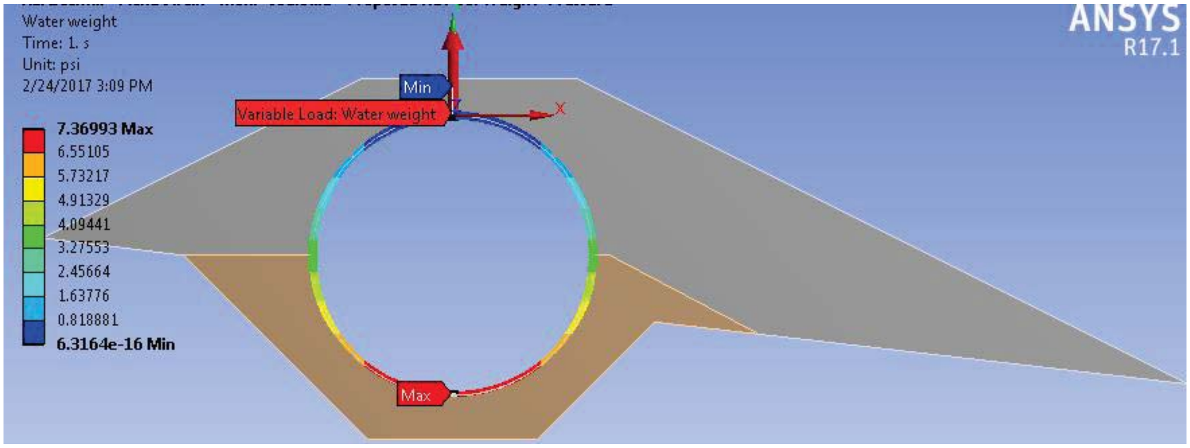


Figure 11 Model 1, 2, and 3 – Water Weight

Water weight was applied as hydrostatic pressure on the penstock internal surface with 0 psi at the top and 7.34 psi at the bottom.

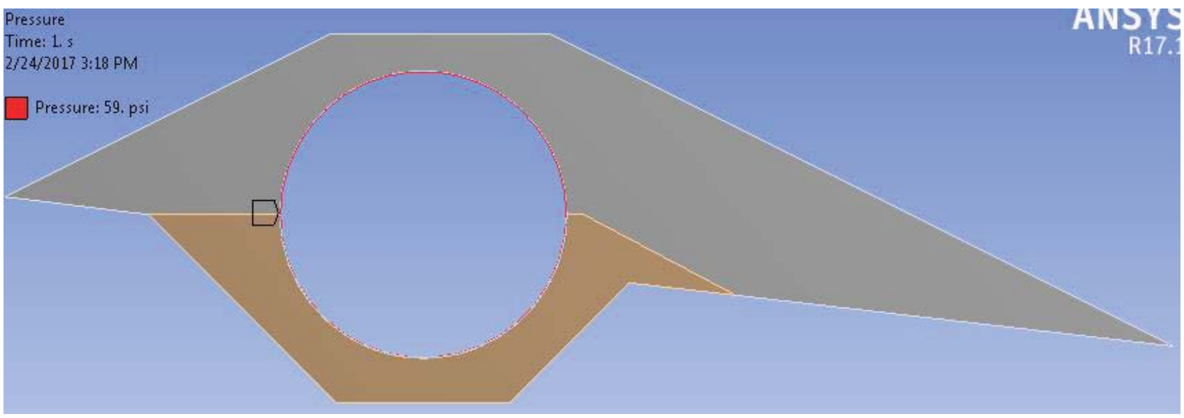


Figure 12 Model 1, 2, and 3 – Design Pressure

Corresponding to the load rejection pressure, 59 psi was applied at the internal surface. During load rejection at the circumferential joint between the penstock sections made of ASTM A285 and CSA G40.8, 59 psi occurs.

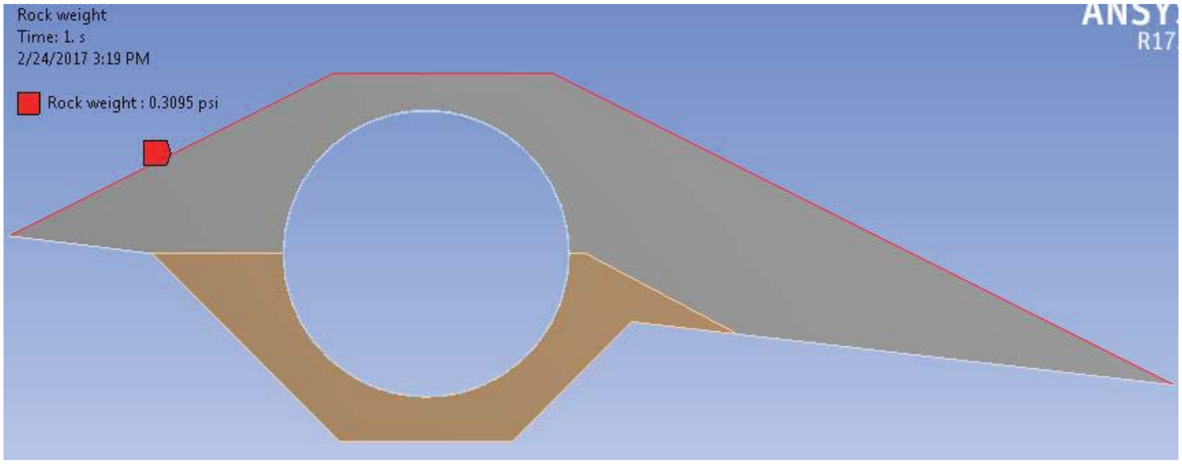


Figure 13 Model 3 – Rock Fill Weight

Rock fill weight was applied as 0.3095 psi uniform pressure on the external surfaces of the backfill.

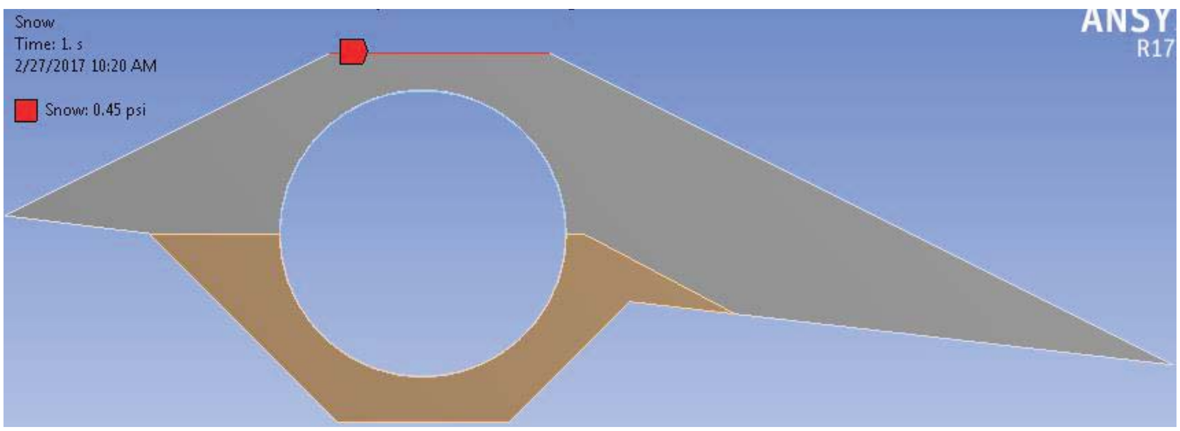


Figure 14 Model 3 – Snow Weight

Snow weight was applied as 0.45 psi uniform pressure on the top surface of the backfill.

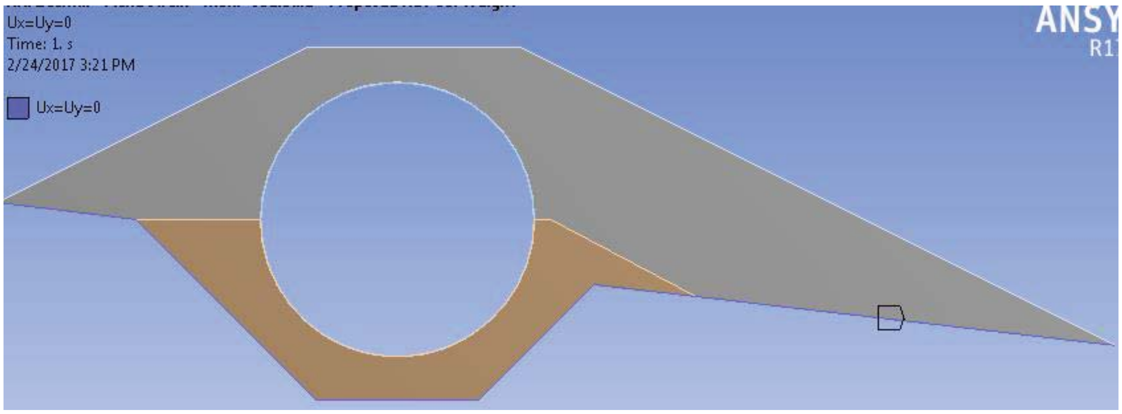


Figure 15 Model 1, 2, and 3 – Constrains

Both degrees of freedom Ux=Uy=0 were constrained at the bottom surfaces of the bedding and backfill.

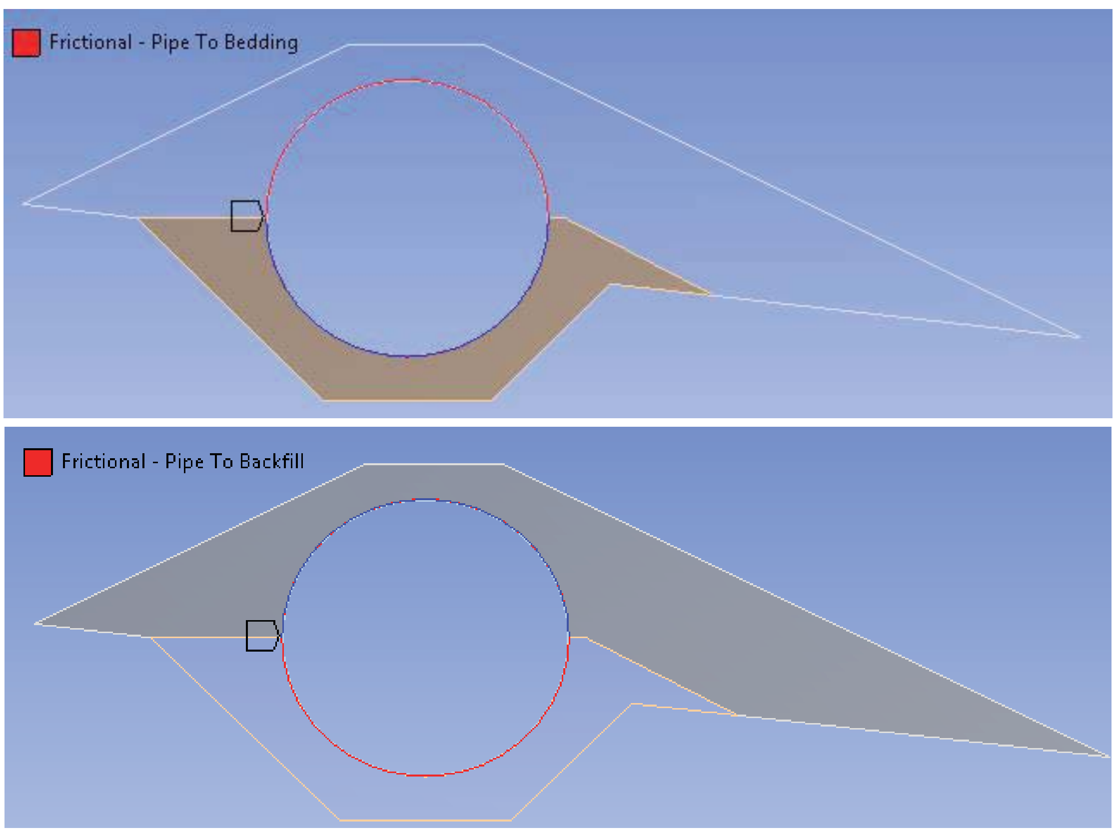


Figure 16 Model 1, 2, and 3 – Contacts

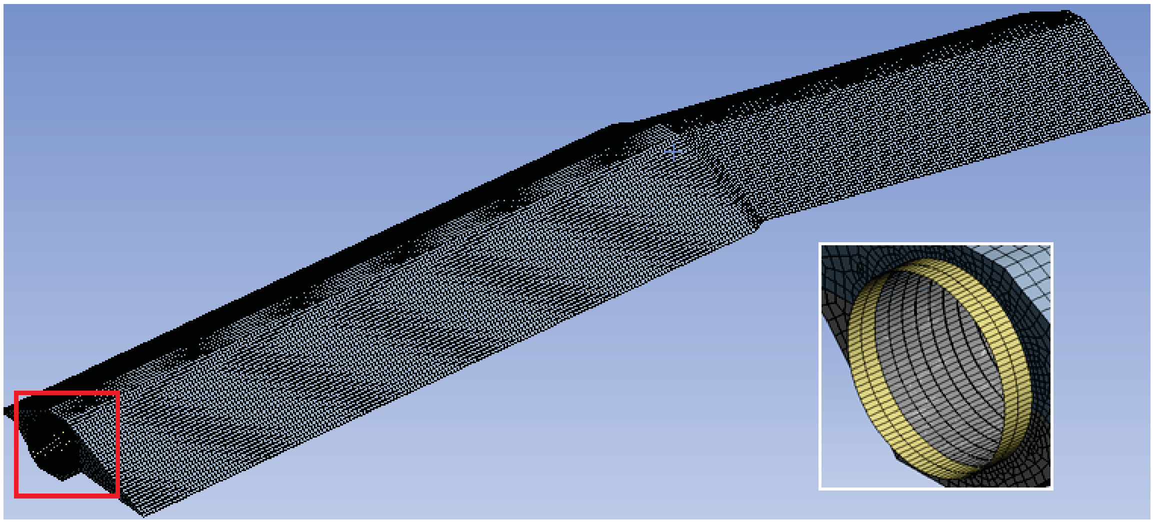


Figure 17 Model 4 – Finite Element Mesh

To mesh the bedding and backfill, 8-node SOLID185 elements were used and 4-node SHELL181 elements were used to mesh the penstock.

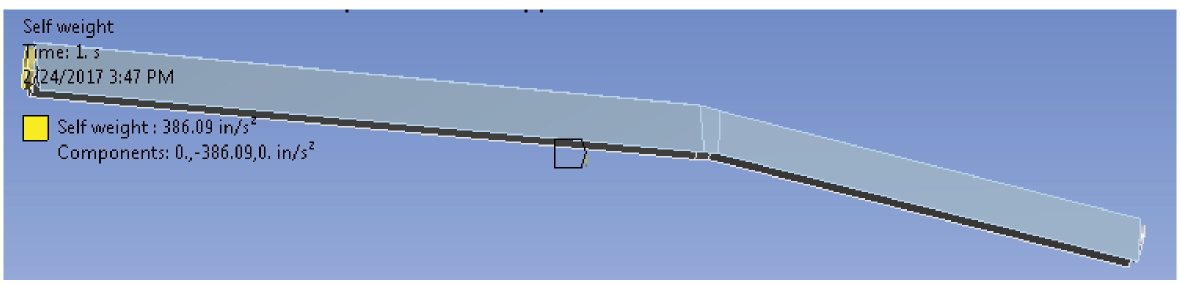


Figure 18 Model 4 – Self Weight

Gravitational acceleration was applied on all model components.

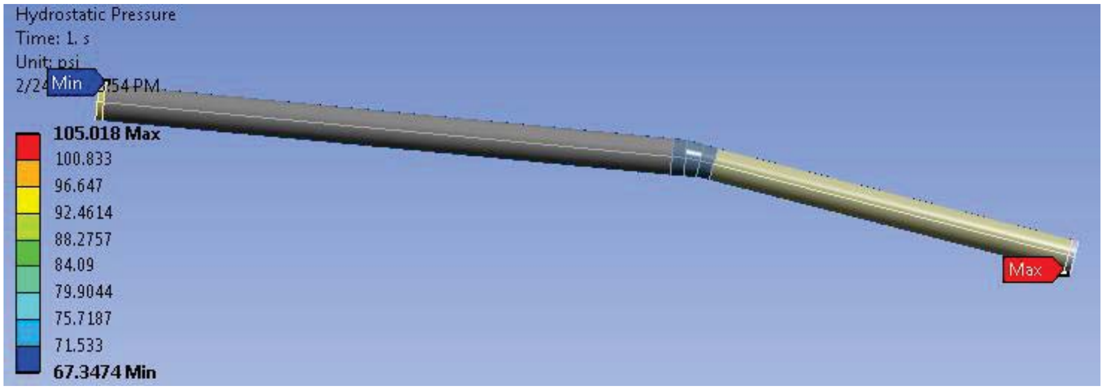


Figure 19 Model 4 – Hydrostatic Pressure

Hydrostatic pressure corresponding to the load rejection pressure was applied on the penstock internal surfaces. The load represents both the design pressure and water weight.

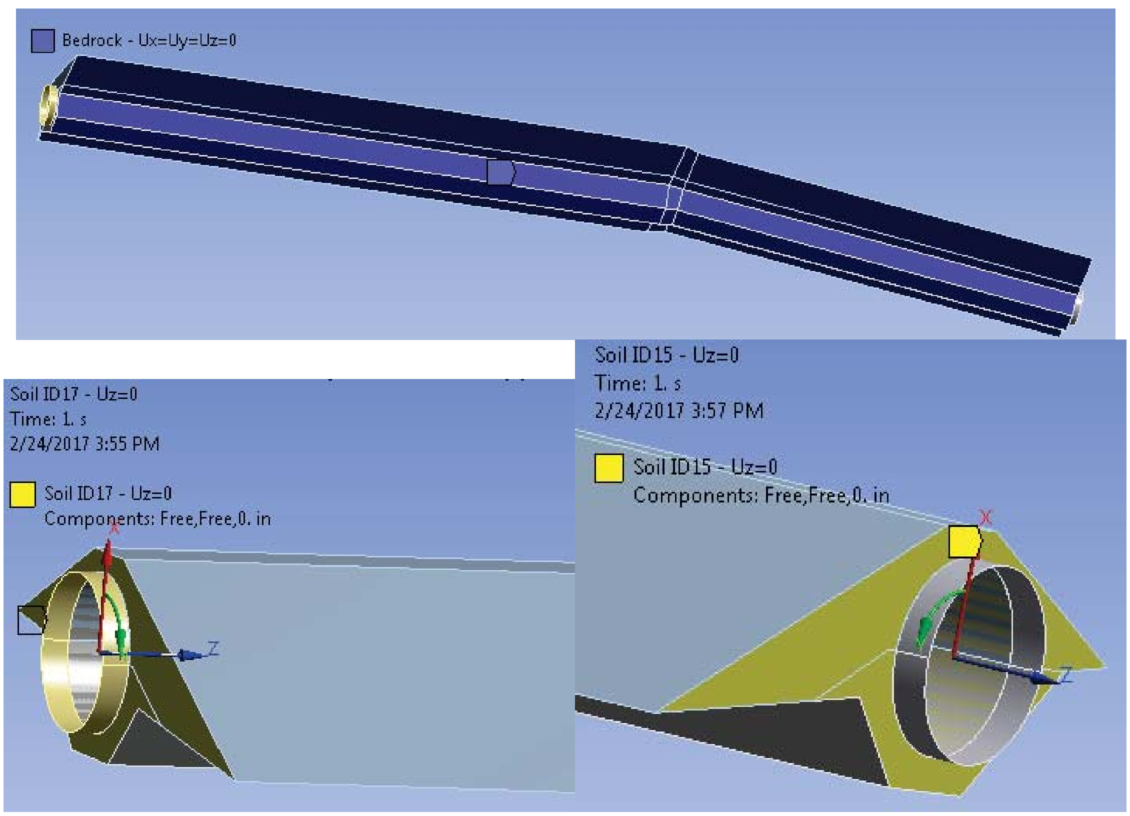


Figure 20 Model 4 – Constrains

All three degrees of freedom Ux=Uy=Uz=0 were constrained at the bottom surfaces of the bedding and backfill. Both bedding and backfill were constrained in the normal direction (Uzn=0) at both ends of the model. Both penstock ends were left free.

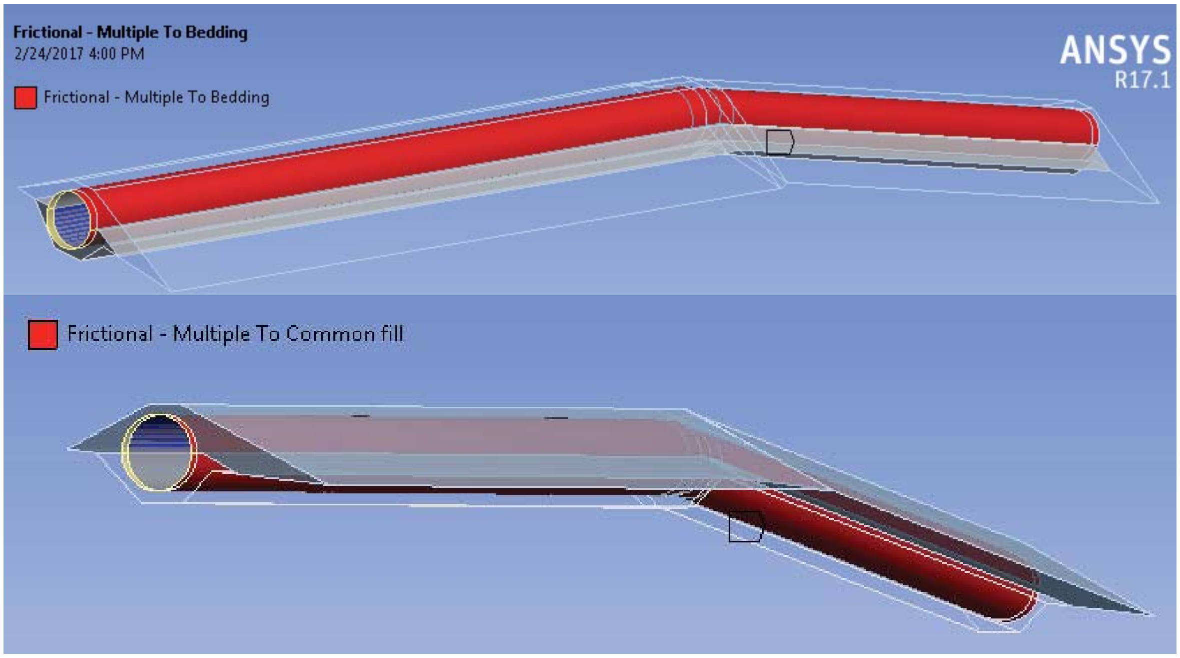


Figure 21 Model 4 – Contacts

Frictional contact with 0.1944 (Interface Friction Angle 11°) friction coefficient was assigned between the penstock outer surface and the backfill.

Frictional contact with 0.2679 (Interface Friction Angle 15°) friction coefficient was assigned between the penstock outer surface and the bedding.

3. Results

Material properties for ASTM A285 Grade C: Tensile stress TS=55ksi; Yield stress YS=30ksi. According to Ref [6] the longitudinal welds are likely double-welded butt joints. There is no information available to determine the joint efficiency (η) so to be conservative in this analysis it is assumed to be the lowest value commonly used 0.7. This value comes from the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code (B&PV) for welded joints with no radiographic inspection. The allowable stresses are calculated in accordance with the ASME standard method Si=min(TS/2.4, YS/1.5)*η=14,000 psi. Allowable stress for primary membrane is Pm=1.0*Si=14,000 psi. Allowable stress for Local Primary Membrane plus Primary Bending is [2] Pl+Pb=1.5Si=21,000 psi.

The primary membrane (hoop) stress based on a 59.0 psi design pressure is (59 psi*17 ft)/(2*0.422 in.) =14,261 psi resulting in 14,261/14,000=1.02 demand/capacity ratio with 2% overstress. The hoop stress resulting from the combination of local shell bending and primary membrane stress can be compared with Pl+Pb=21,000 psi. The results for deformation and hoop stress (Figure 23 to Figure 38) are summarized in Table 2. It can be clearly seen that the backfill provides lateral support to the penstock and is critical for the penstock structural integrity.

Penstocks typically have allowable deflections of 5% of the diameter (approximately 10 in for the analyzed section of penstock No. 1)

Table 2 Result Summary for Model 1, 2 and 3

Model	Load Combination	Penstock Deformation [in]	Penstock Hoop Stress [psi] Absolute Value	Allowable	Demand Capacity Ratio*	Back Fill Plastic Zone
Model 1	LC1	9.10	56,495	21,000	**2.69**	N/A
	LC2	8.97	71,039	21,000	**3.38**	
Model 2	LC1	3.23	16,580	21,000	0.79	Large extent of the plastic zone, the back fill is prone to slumping
	LC2	2.58	28,755	21,000	**1.37**	
Model 3	LC1	0.98	6,597	21,000	0.31	The extent of the plastic zone is localized, the back fill is stable
	LC2	0.88	19,490	21,000	0.93	
	LC3	1.27	7,052	21,000	0.34	
	LC4	1.18	21,174	21,000	**1.01**	

* Demand/Capacity ratio greater than 1.0 means overstress.

The results from model 1 show the penstock will be significantly overstressed for both load combinations in the absence of backfill.

The results from model 2 show the penstock will be overstressed for load combination 2 (self-weight, water weight and internal pressure). However, the backfill is prone to localized failures and these areas will behave more like model 1.

The results from model 3 show the penstock will be slightly overstressed for load combination 2 (self-weight, water weight and internal pressure). However, the backfill will be less prone to failures and the stresses should remain consistent.

The backfill slope stability was assessed using the ANSYS model.

- For the original backfill configuration (Figure 5), the backfill slope has a potential risk of instability. Figure 39 and Figure 40 shows the equivalent plastic strain plots from Model 2, where the blue color represents the soil remaining elastic, and the other colors indicate that the soil is in plastic state (prone to large deformation if a continuous zone is formed) . As shown, the thin soil cover is prone to be negatively impacted by deformation of the penstock. At the north slope, the upper and the relatively lower plastic zones are getting close to forming a continuous zone. Additional negative external impacts (excessive penstock vibration, rainfall and etc.) could have triggered the instability during the penstock design life. This identified potential instability mode is consistent with the observed slope failure at the site, which occurred at the north side of penstock.

Figure 22 – Backfill Slope Failure

- With the proposed backfill configuration (Figure 6), the backfill slope stability condition is significantly improved. As shown in Figure 41 to Figure 44, the thicker cover soil provides better lateral support to the penstock and the plastic soil zone is confined in a local area, indicating that the backfill is stable.

The intent of the 3D model (Model 4) is to calculate the displacements at Bend 4A. The penstock in the model is restrained only by gravitational forces resulting from water, steel, and backfill weight as well as the friction between the soil and steel. The results (Figure 45 and Figure 49) show that the bend does not get separated from the bedding (contact gap is zero). The displacements at the bend are small (in the order of 0.06 in. excluding radial deformation) and are not a concern.

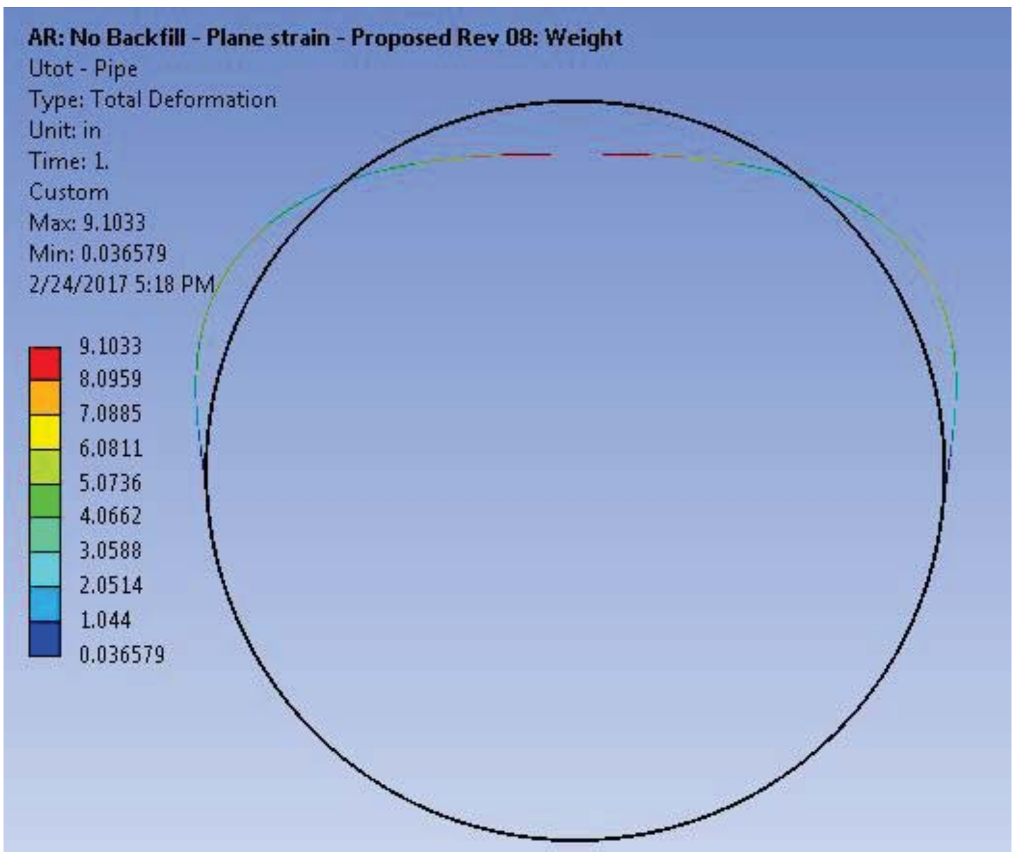


Figure 23 Model 1, LC1 – Penstock Total Deformation

Maximum deformation of 9.1 in. occurs at the top of the penstock.

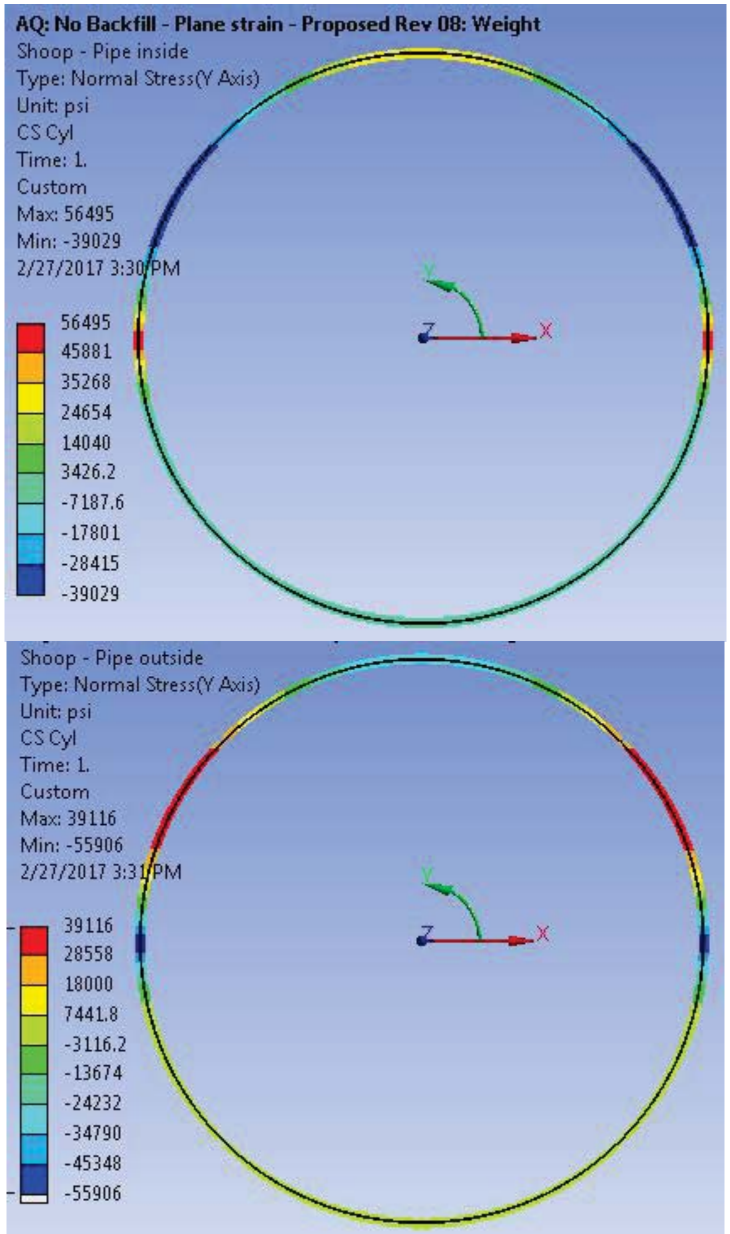


Figure 24 Model 1, LC1 – Penstock Hoop Stress: Inside Surface (upper) - Outside Surface (lower)

Stresses are indicated as tension (positive values) and compression (negative values) which represents hoop stress resulting from shell bending. Areas where hoop stress exceeds a magnitude of 21,000 psi (allowable stress) is considered to be in a state of overstress. For the internal wall this correlates to areas shown in yellow through red and light green through dark blue. For the external wall this correlates to areas shown in orange through red and light green through dark blue.

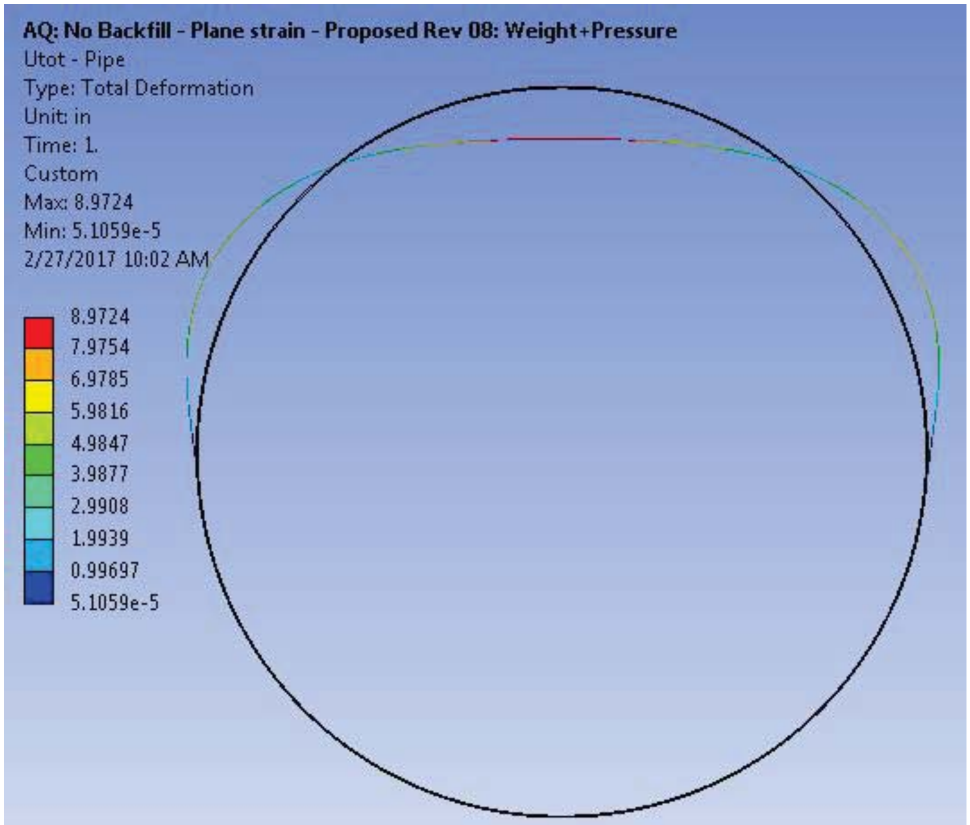


Figure 25 Model 1, LC2 – Penstock Total Deformation

Max deformation of 8.97 in. occurs at the top of the penstock.

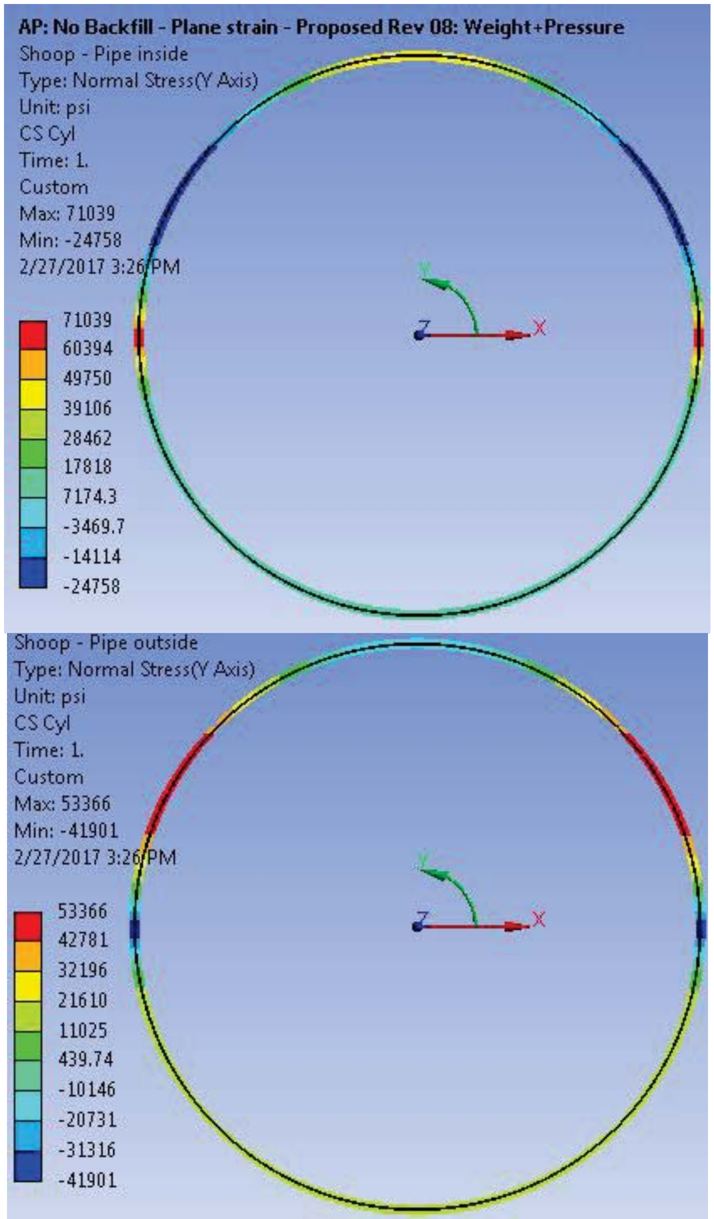


Figure 26 Model 1, LC2 – Penstock Hoop Stress: Inside Surface (upper) - Outside Surface (lower)

Stresses are indicated as tension (positive values) and compression (negative values) which represents hoop stress resulting from shell bending. Areas where hoop stress exceeds a magnitude of 21,000 psi (allowable stress) is considered to be in a state of overstress. For the internal wall this correlates to areas shown in light green through red and dark blue. For the external wall this correlates to areas shown in yellow through red and blue through dark blue.

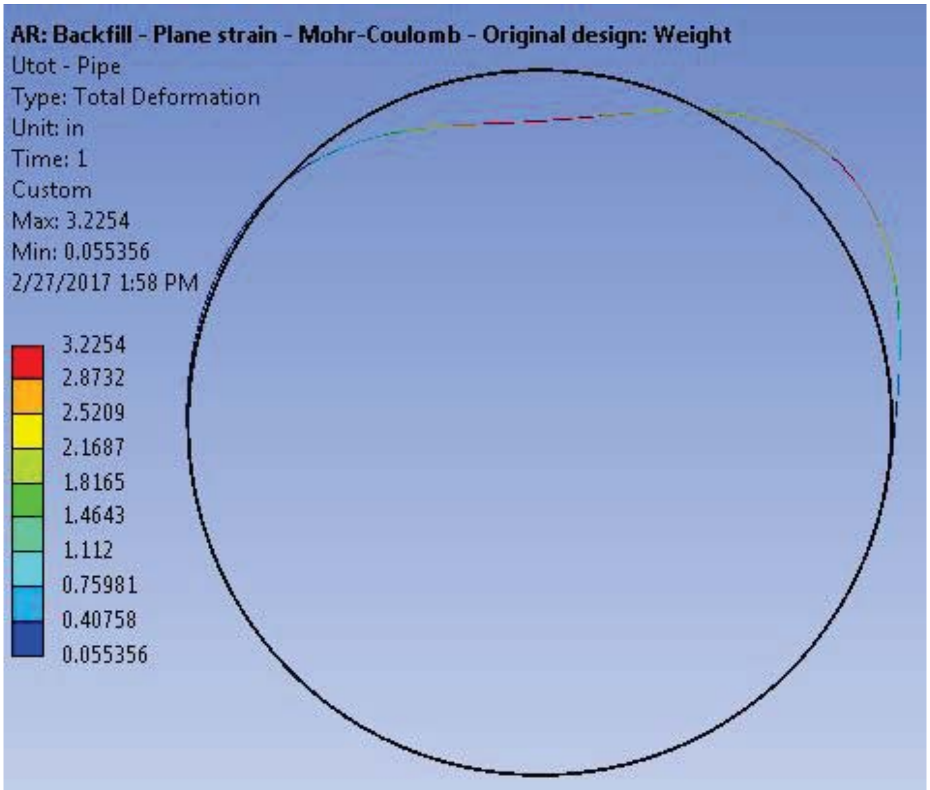


Figure 27 Model 2, LC1 – Penstock Total Deformation

Maximum deformation of 3.23 in. occurs at the top of the penstock, 2.90 in. occurs at 2 o'clock.

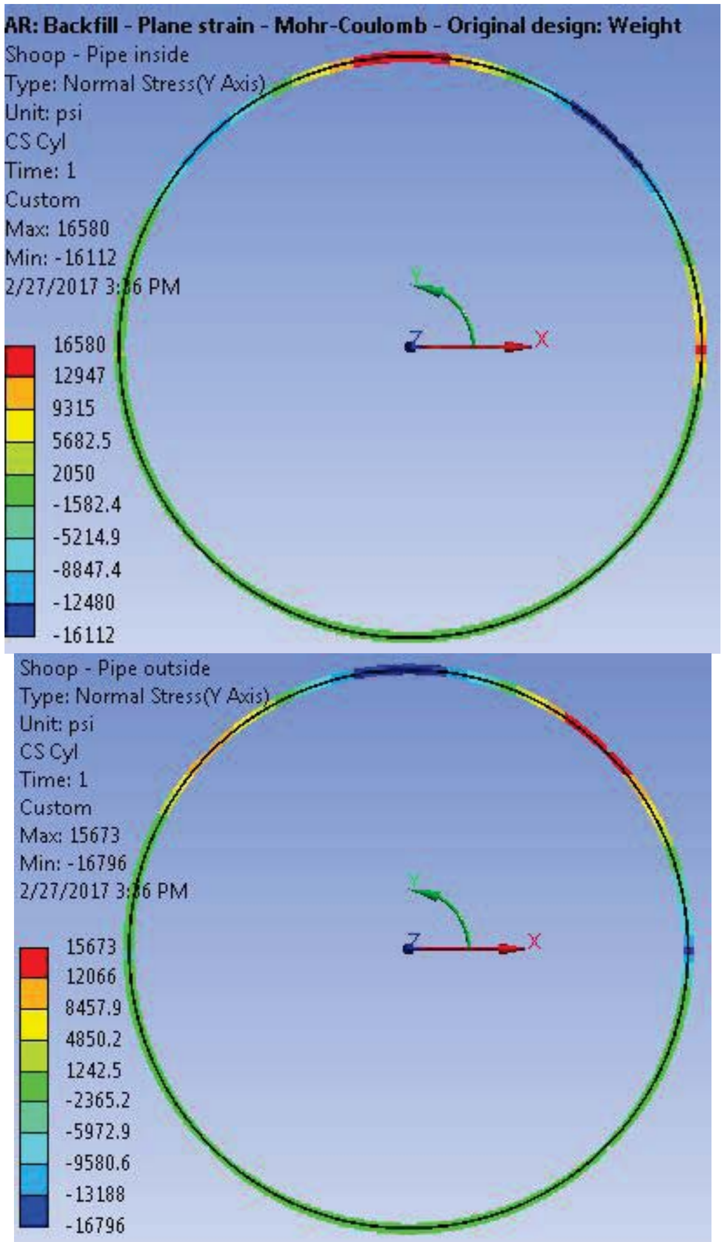


Figure 28 Model 2, LC1 – Penstock Hoop Stress: Inside Surface (upper) - Outside Surface (lower)

Stresses are indicated as tension (positive values) and compression (negative values) which represents hoop stress resulting from shell bending. Areas where hoop stress exceeds a magnitude of 21,000 psi (allowable stress) is considered to be in a state of overstress. For the internal wall there is no overstress for this case. For the external wall there is no overstress for this case.

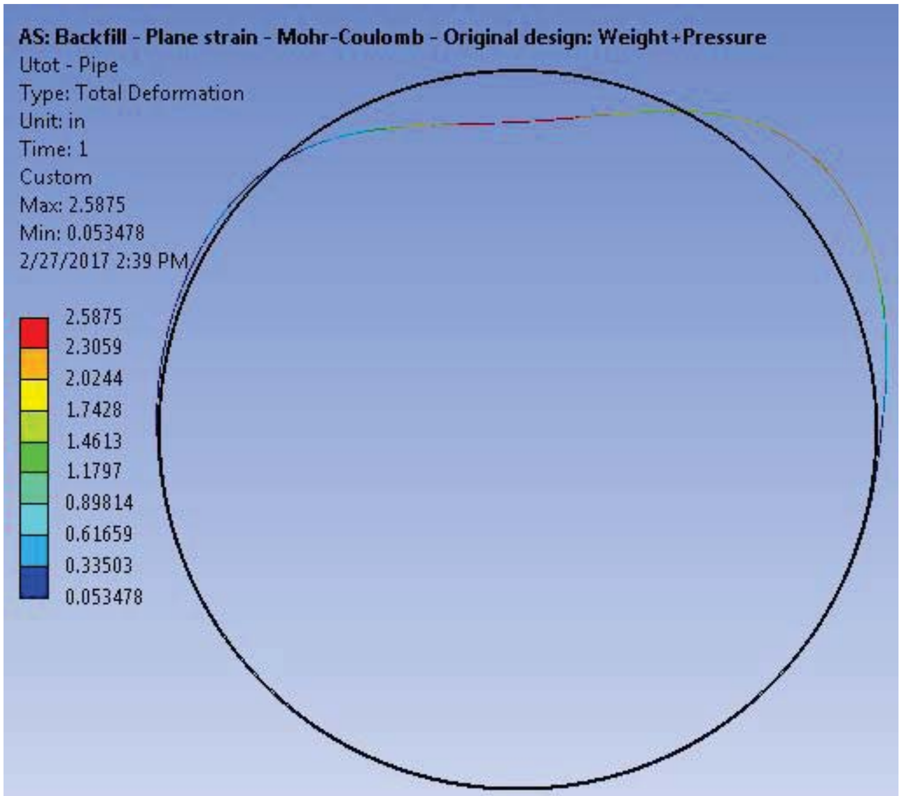


Figure 29 Model 2, LC2 – Penstock Total Deformation

Maximum deformation of 2.58 in. occurs at the top of the penstock, 2.3 in. occurs at 2 o'clock.

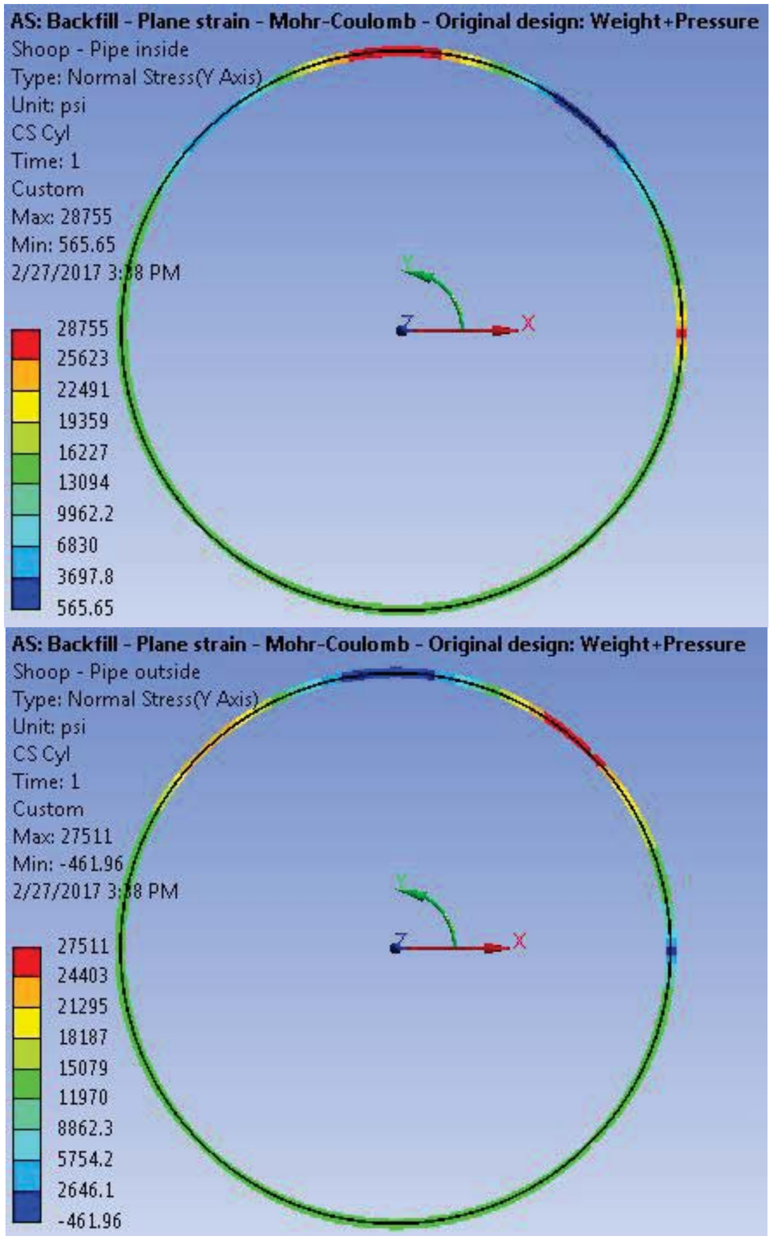


Figure 30 Model 2, LC2 – Penstock Hoop Stress: Inside Surface (upper) - Outside Surface (lower)

Stresses are indicated as tension (positive values) and compression (negative values) which represents hoop stress resulting from shell bending. Areas where hoop stress exceeds a magnitude of 21,000 psi (allowable stress) is considered to be in a state of overstress. For the internal wall this correlates to areas shown in yellow through red. For the external wall this correlates to areas shown in orange through red.

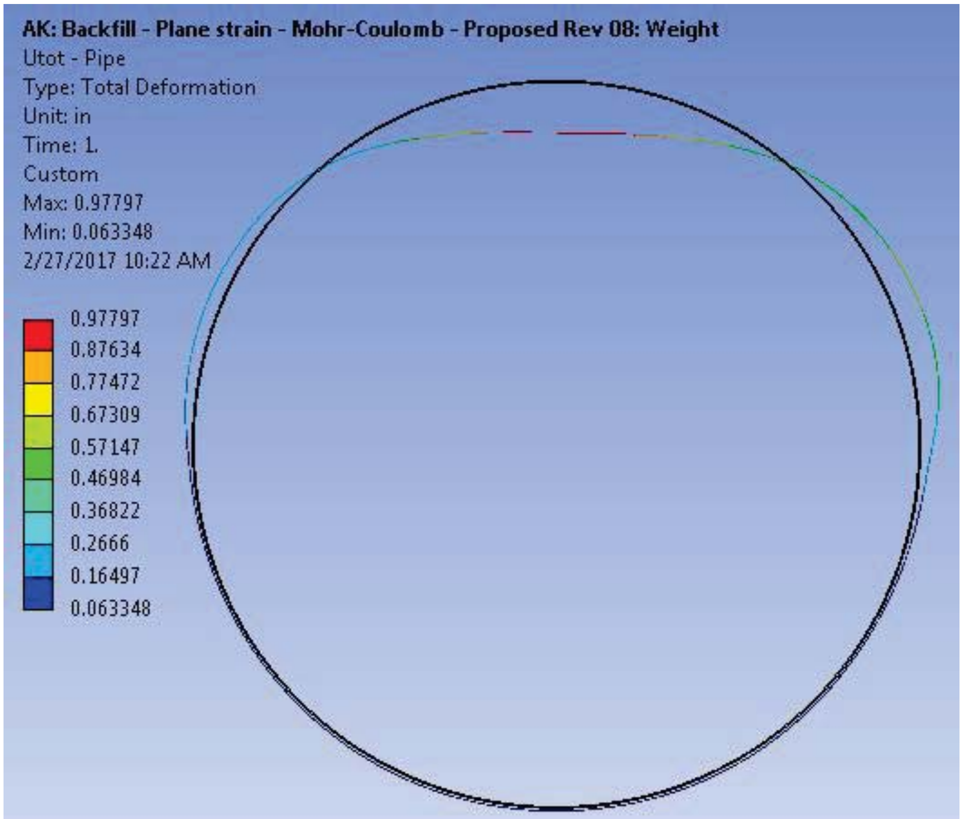


Figure 31 Model 3, LC1 – Penstock Total Deformation

Maximum deformation of 0.98 in. occurs at the top of the penstock.

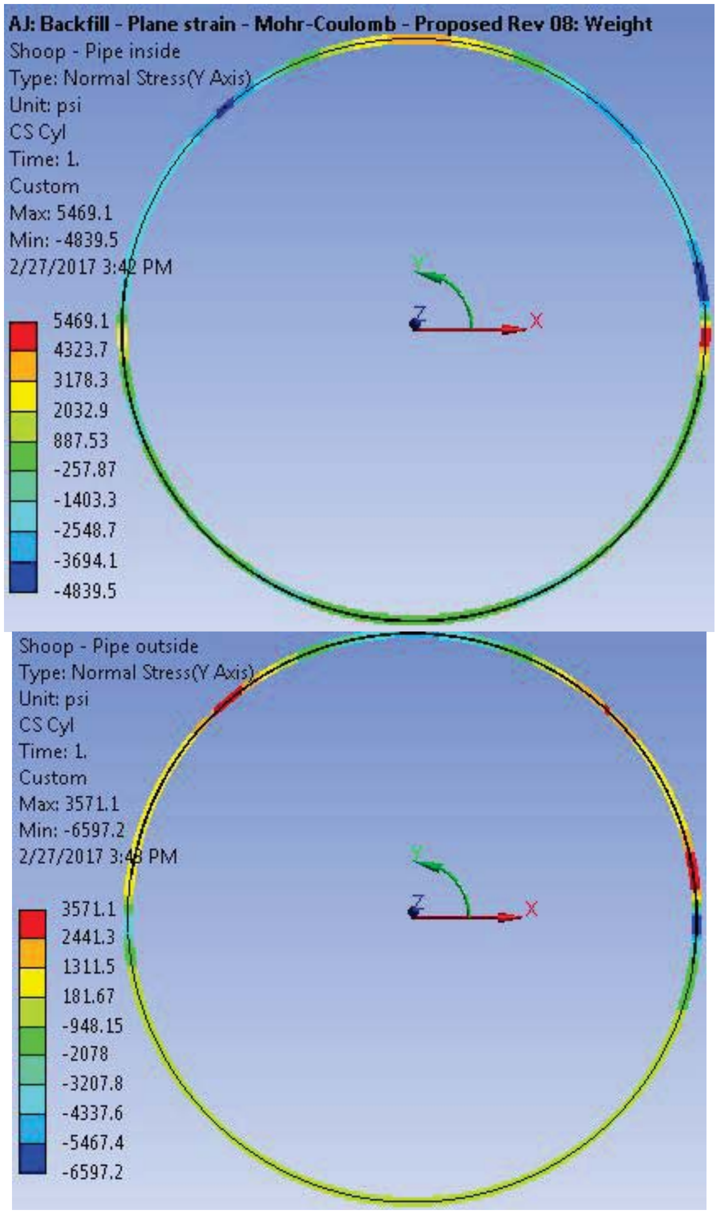


Figure 32 Model 3, LC1 – Penstock Hoop Stress: Inside Surface (upper) - Outside Surface (lower)

Stresses are indicated as tension (positive values) and compression (negative values) which represents hoop stress resulting from shell bending. Areas where hoop stress exceeds a magnitude of 21,000 psi (allowable stress) is considered to be in a state of overstress. For the internal wall there is no overstress for this case. For the external wall there is no overstress for this case.

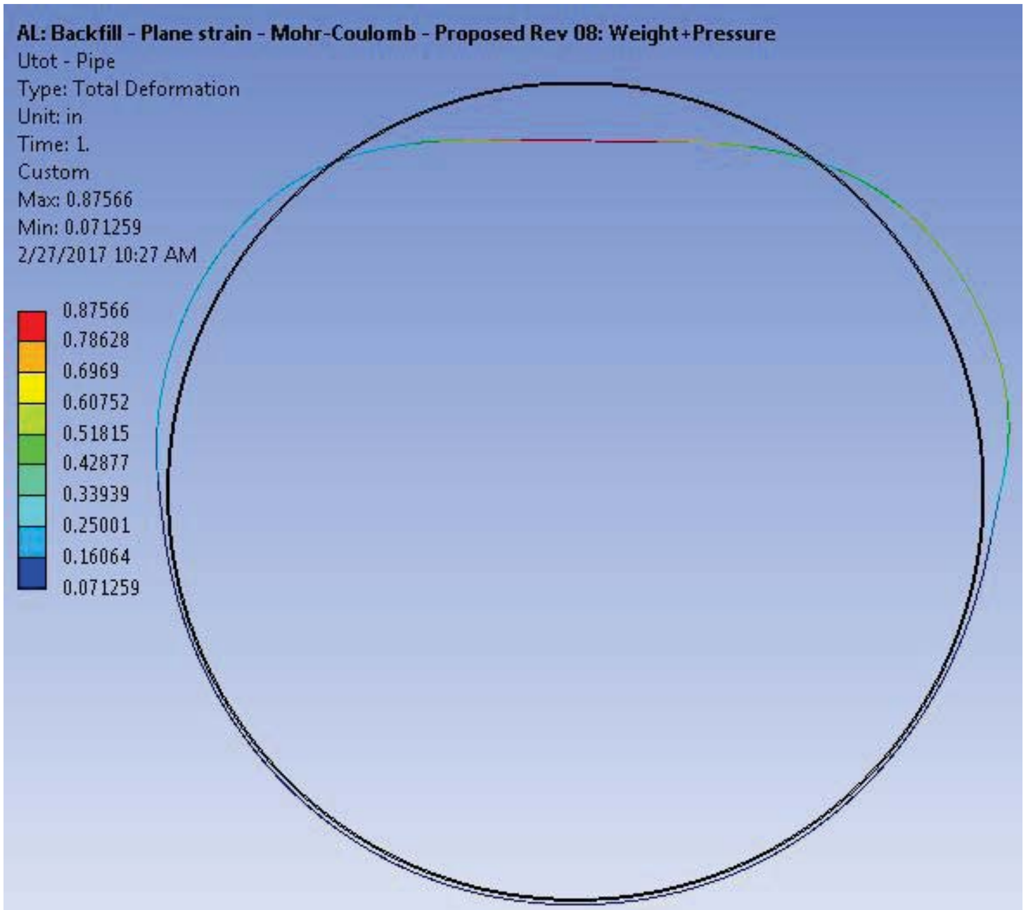


Figure 33 Model 3, LC2 – Penstock Total Deformation

Max deformation of 0.88 in. occurs at the top of the penstock.

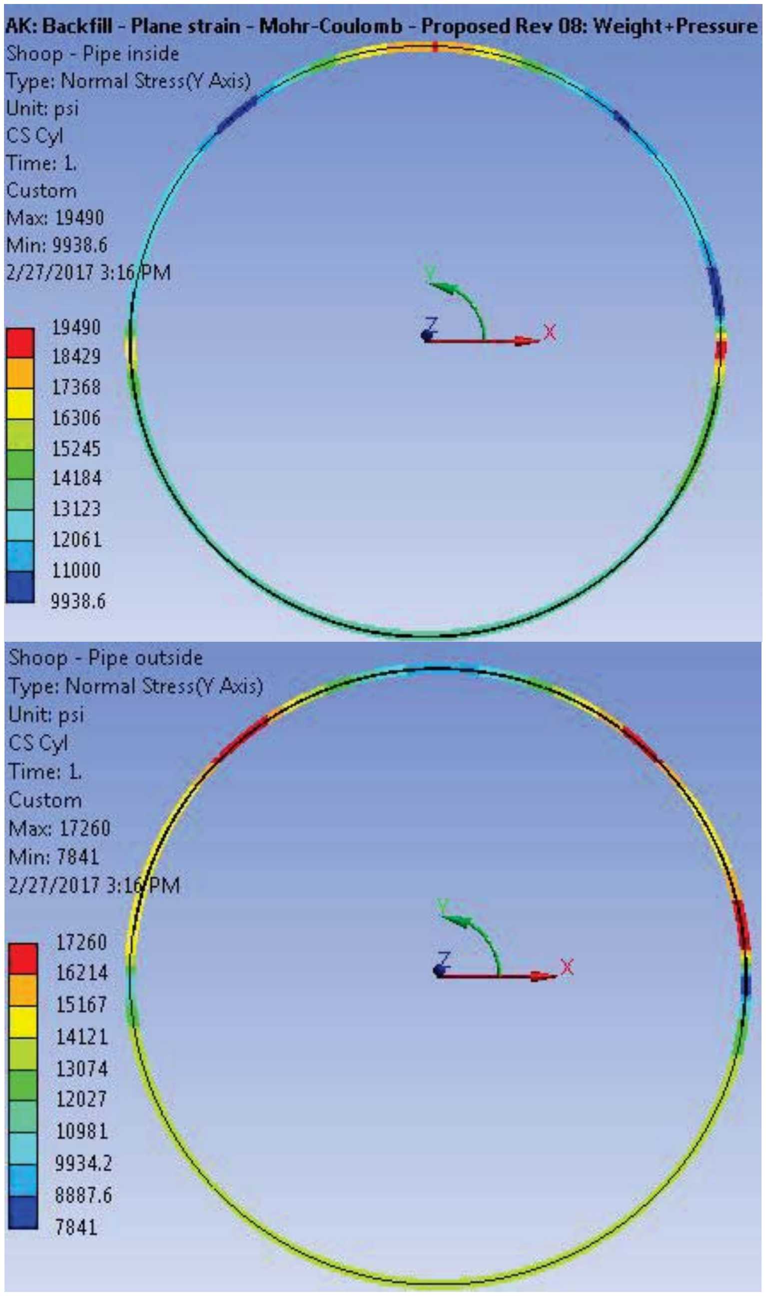


Figure 34 Model 3, LC2 – Penstock Hoop Stress: Inside Surface (upper) - Outside Surface (lower)

Stresses are indicated as tension (positive values) and compression (negative values) which represents hoop stress resulting from shell bending. Areas where hoop stress exceeds a magnitude of 21,000 psi (allowable stress) is considered to be in a state of overstress. For the internal wall there is no overstress for this case. For the external wall there is no overstress for this case.

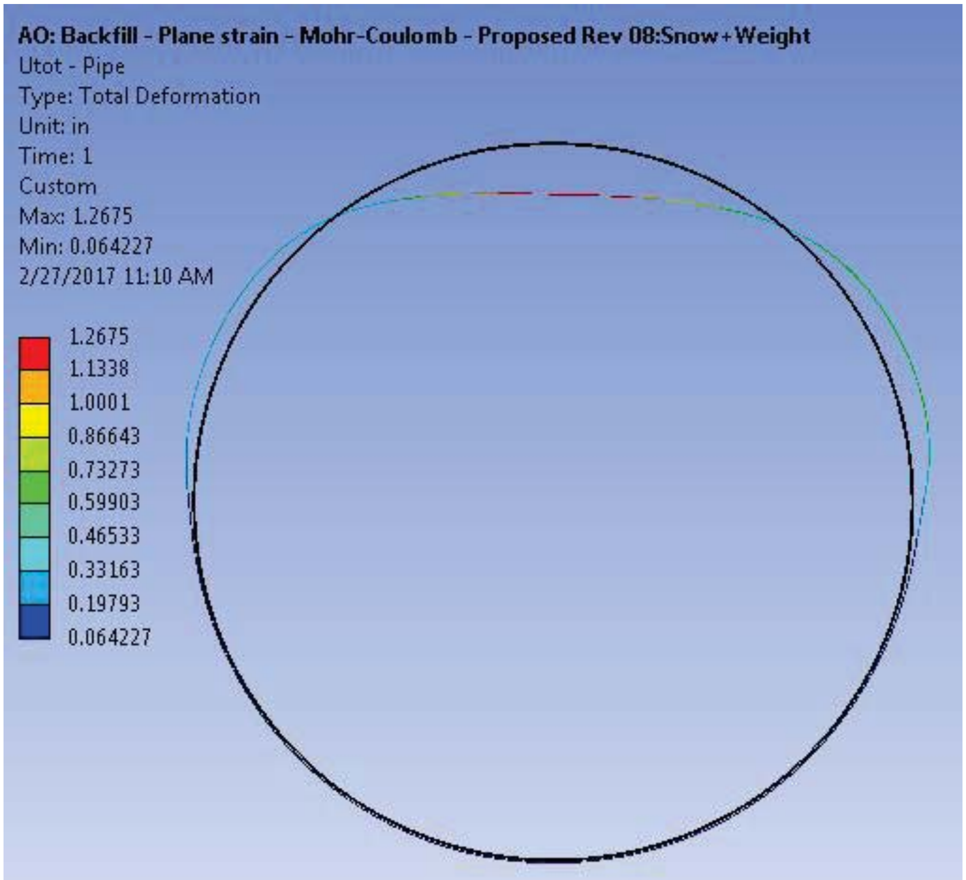


Figure 35 Model 3, LC3 – Penstock Total Deformation

Maximum deformation of 1.27 in. occurs at the top of the penstock.

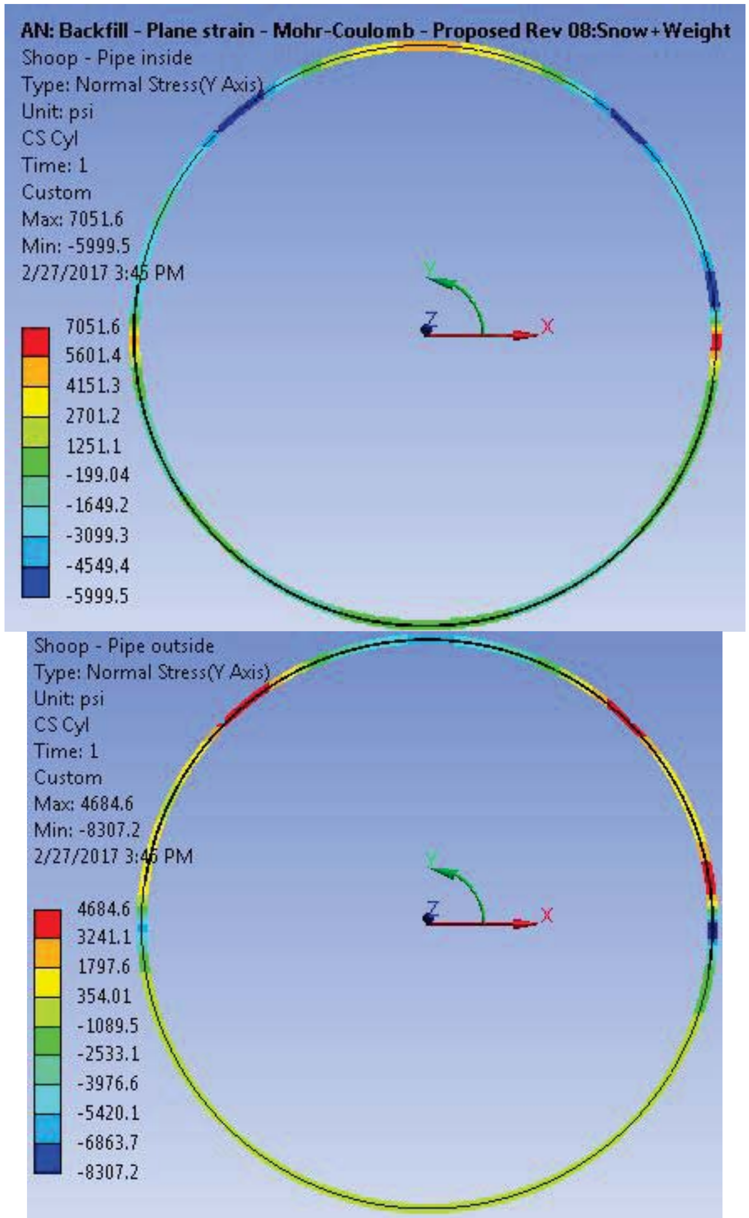


Figure 36 Model 3, LC3 – Penstock Hoop Stress: Inside Surface (upper) - Outside Surface (lower)

Stresses are indicated as tension (positive values) and compression (negative values) which represents hoop stress resulting from shell bending. Areas where hoop stress exceeds a magnitude of 21,000 psi (allowable stress) is considered to be in a state of overstress. For the internal wall there is no overstress for this case. For the external wall there is no overstress for this case.

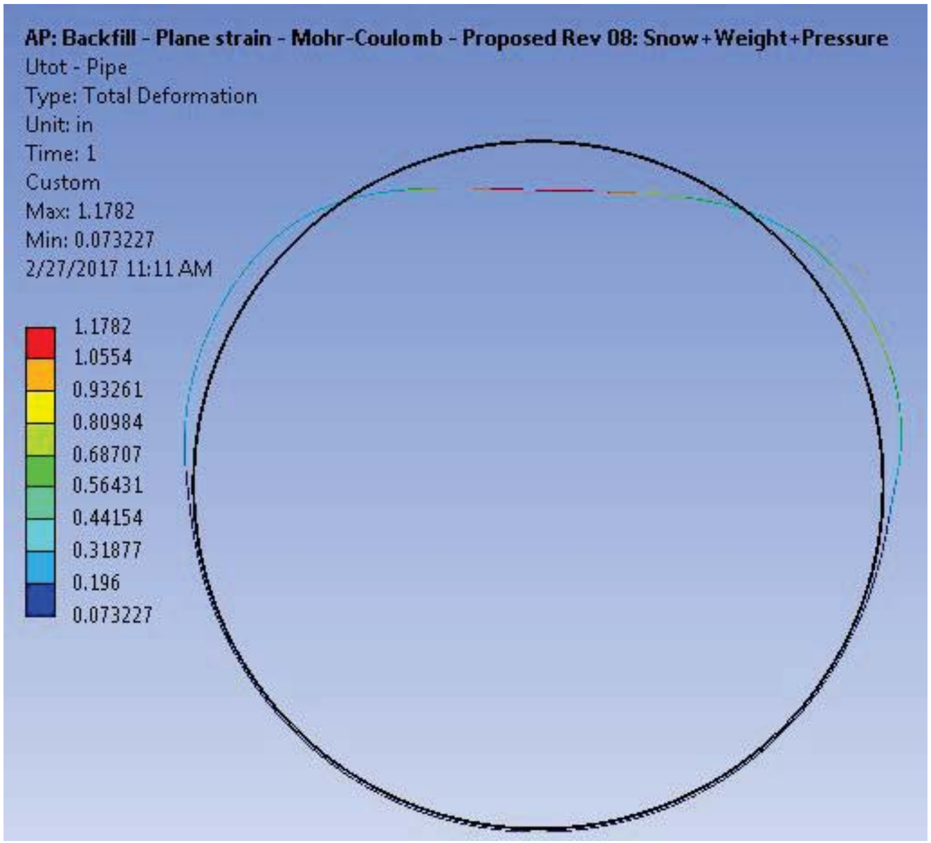
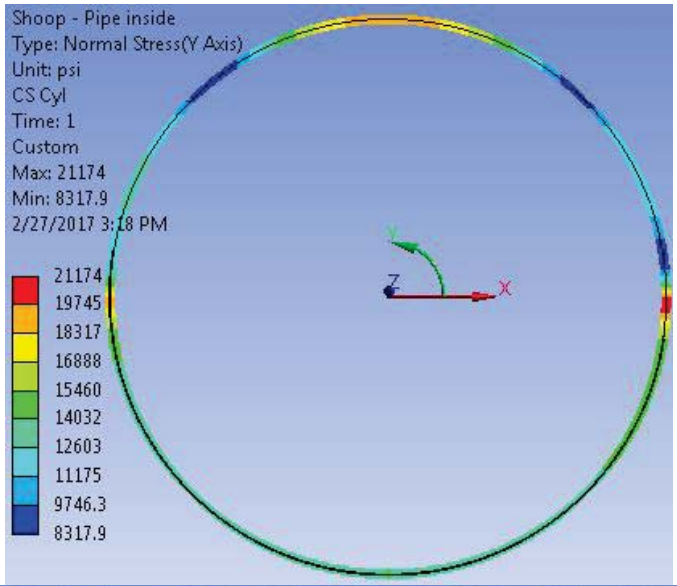


Figure 37 Model 3, LC4 – Penstock Total Deformation

Maximum deformation of 1.18 in. occurs at the top of the penstock.



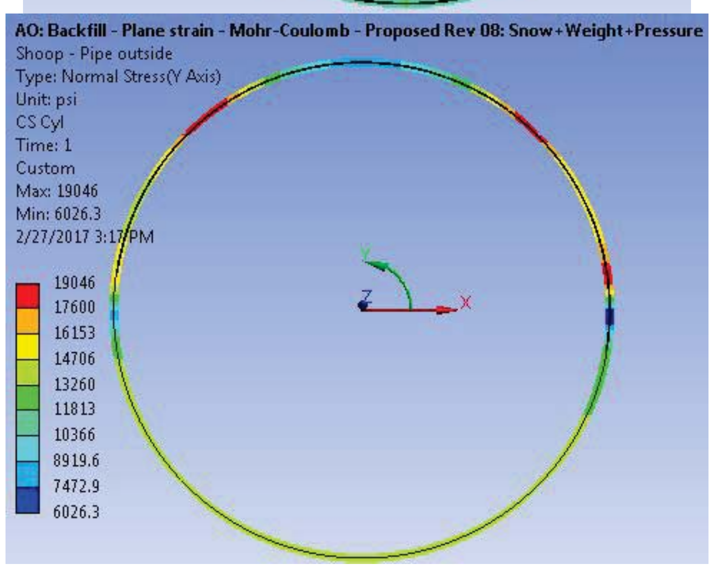


Figure 38 Model 3, LC4 – Penstock Hoop Stress: Inside Surface (upper) - Outside Surface (lower)

Stresses are indicated as tension (positive values) and compression (negative values) which represents hoop stress resulting from shell bending. Areas where hoop stress exceeds a magnitude of 21,000 psi (allowable stress) is considered to be in a state of overstress. For the internal wall this correlates to areas shown in red. For the external wall there is no overstress for this case.

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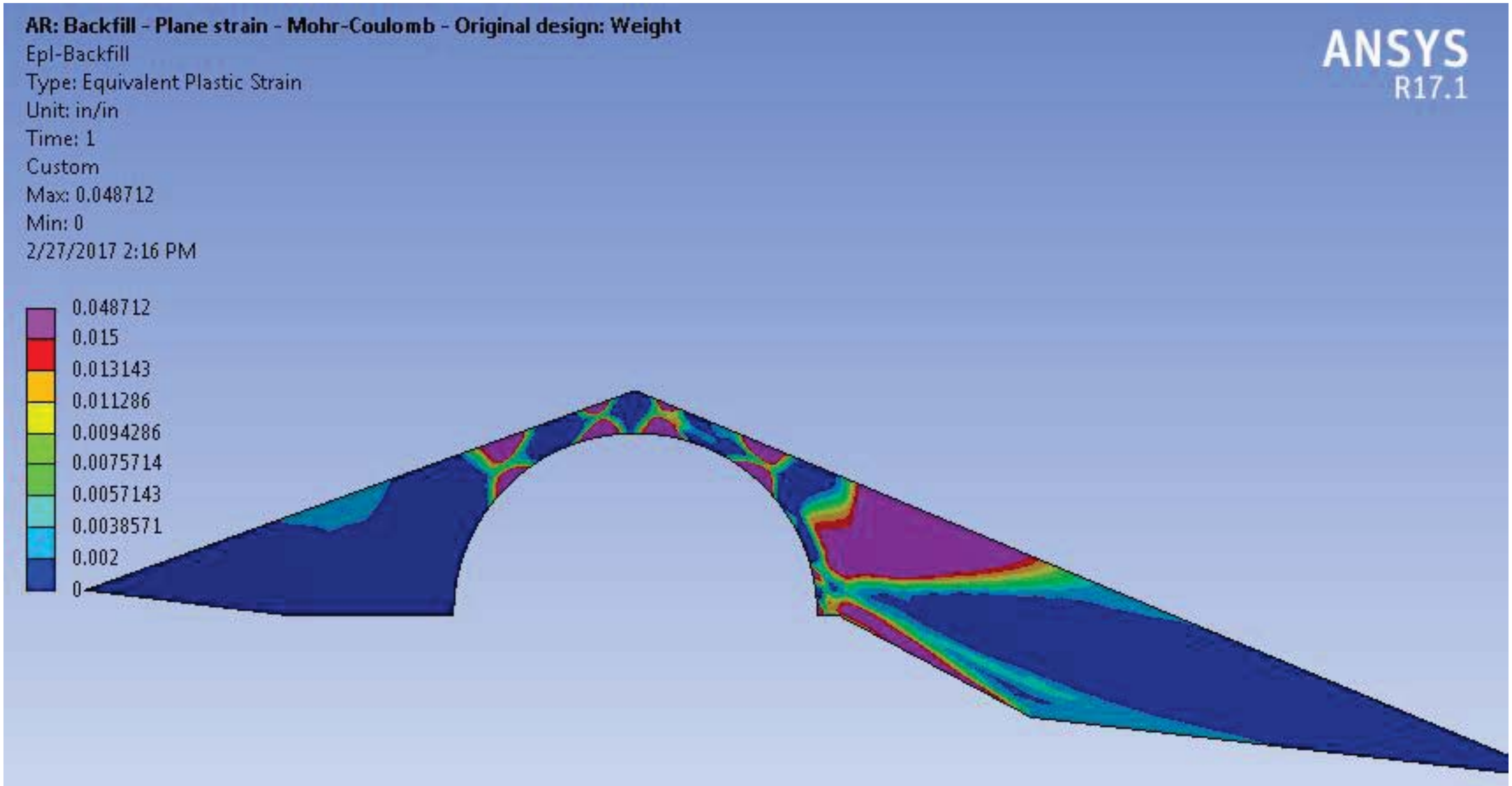


Figure 39 Model 2, LC1 – Equivalent Plastic Strain in Backfill

The large extent of the plastic zone (from 12 to 3 o'clock) indicates that the original design has a potential risk of slope instability (sloughing).

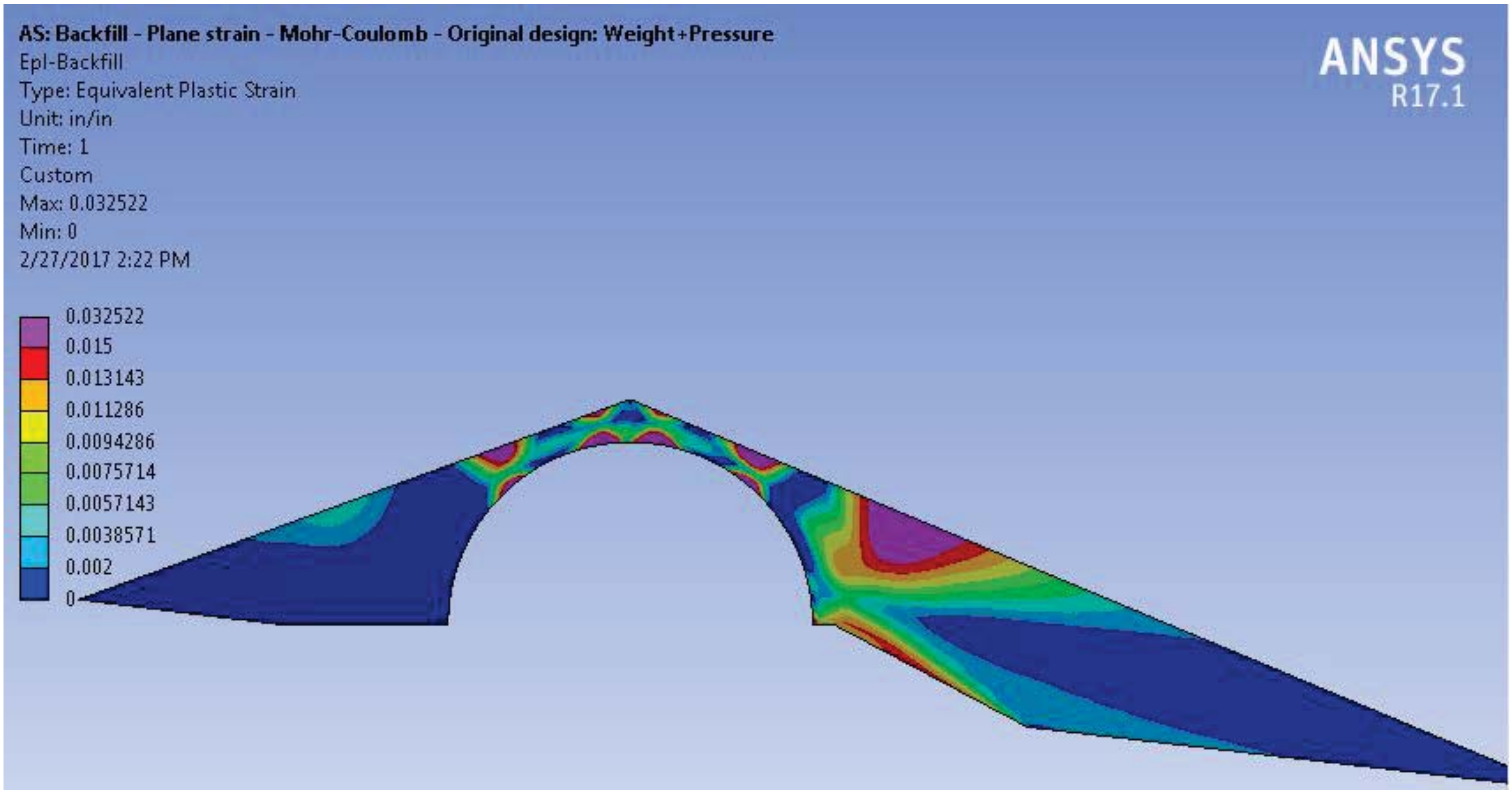


Figure 40 Model 2, LC1 – Equivalent Plastic Strain in Backfill

The large extent of the plastic zone (from 12 to 3 o'clock) indicates that the original design has a potential risk of slope instability (sloughing).

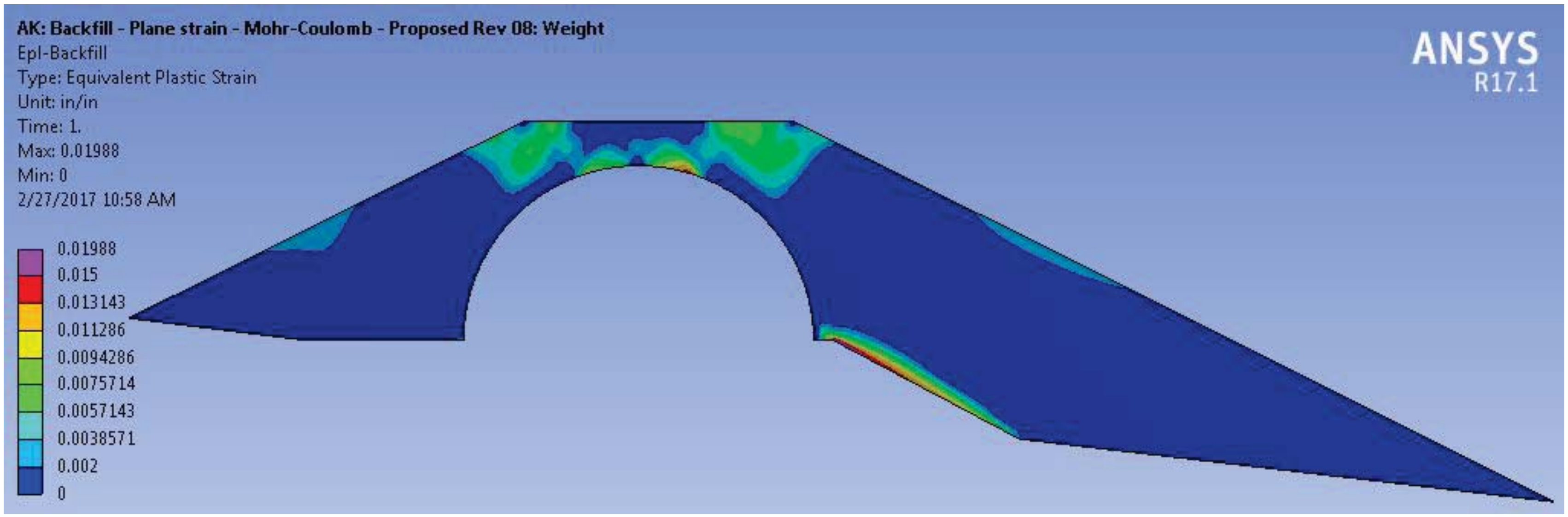


Figure 41 Model 3, LC1 – Equivalent Plastic Strain in Backfill

The extent of the plastic zone is localized, the backfill is stable.

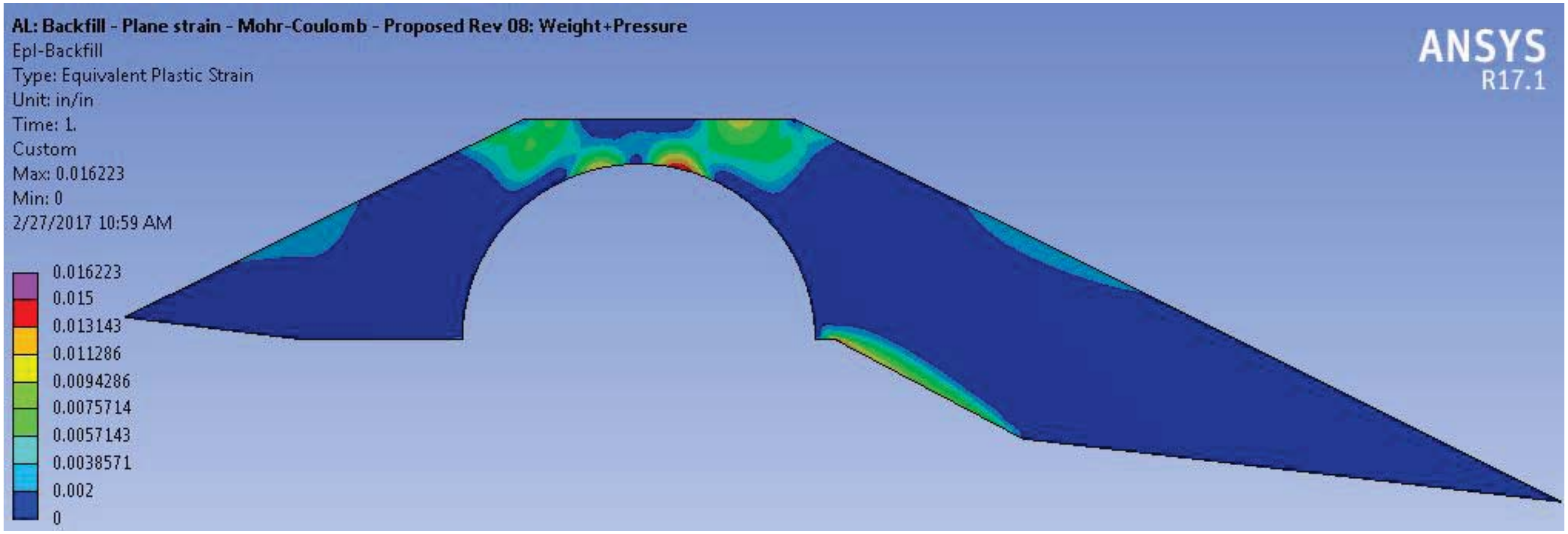


Figure 42 Model 3, LC2 – Equivalent Plastic Strain in Backfill

The extent of the plastic zone is localized, the backfill is stable.

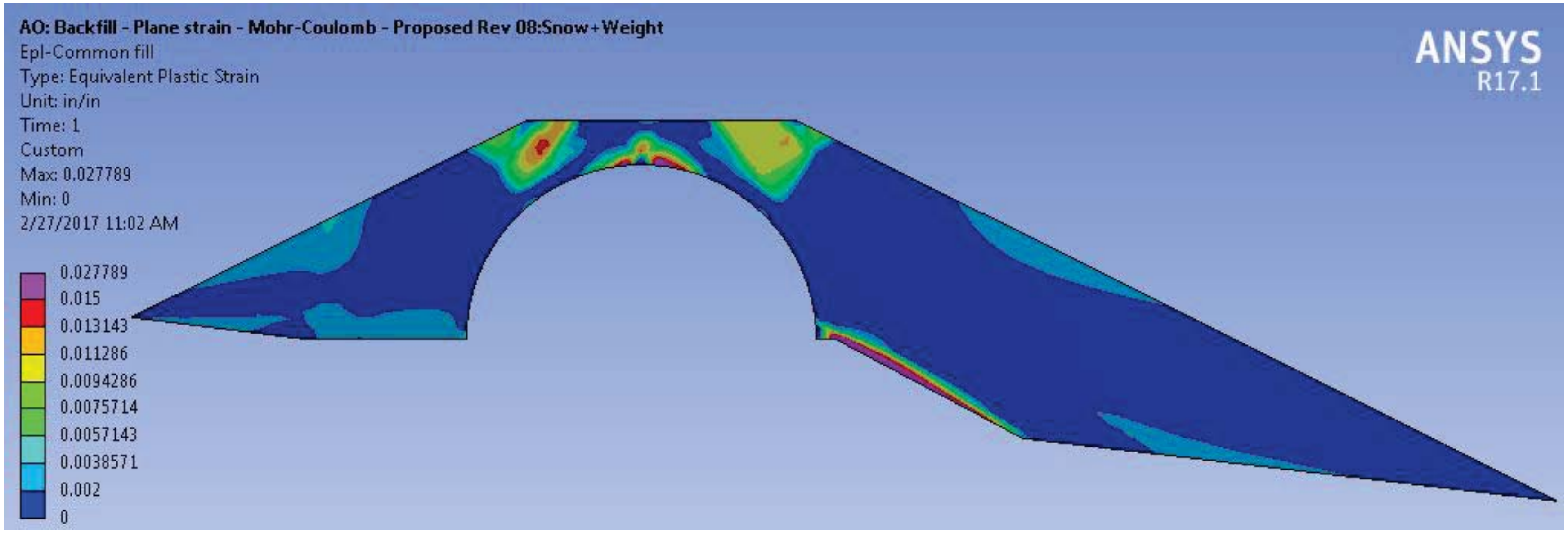


Figure 43 Model 3, LC3 – Equivalent Plastic Strain in Backfill

The extent of the plastic zone is localized, the backfill is stable.

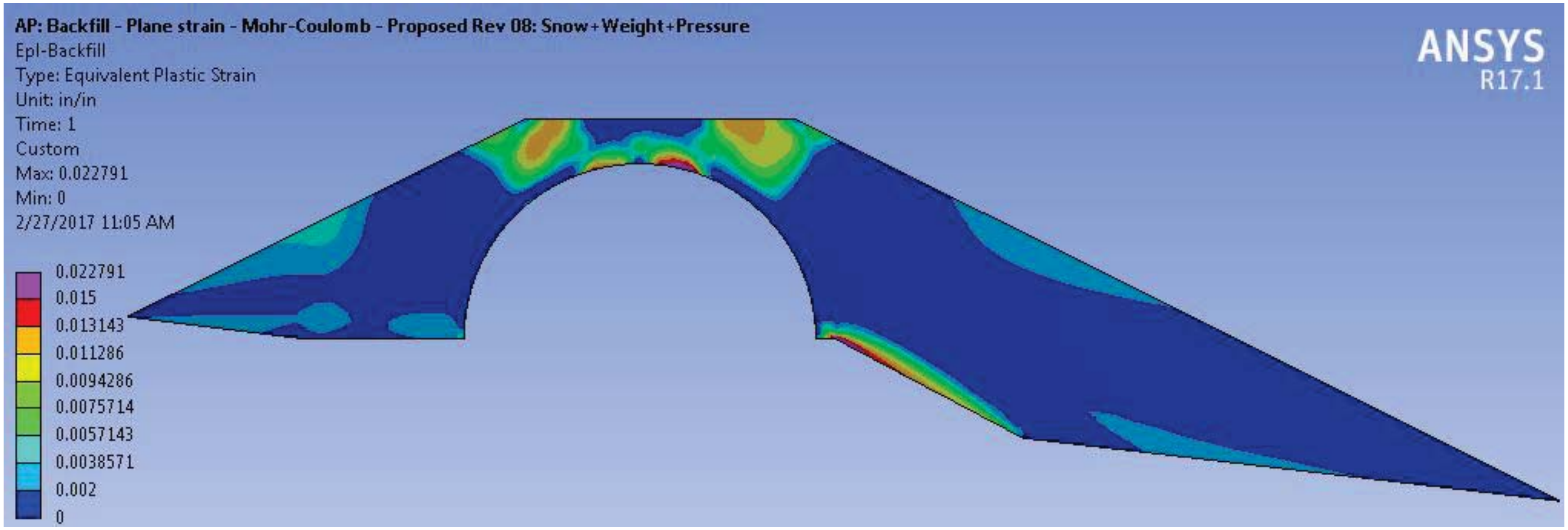


Figure 44 Model 3, LC4 – Equivalent Plastic Strain in Backfill

The extent of the plastic zone is localized, the backfill is stable.

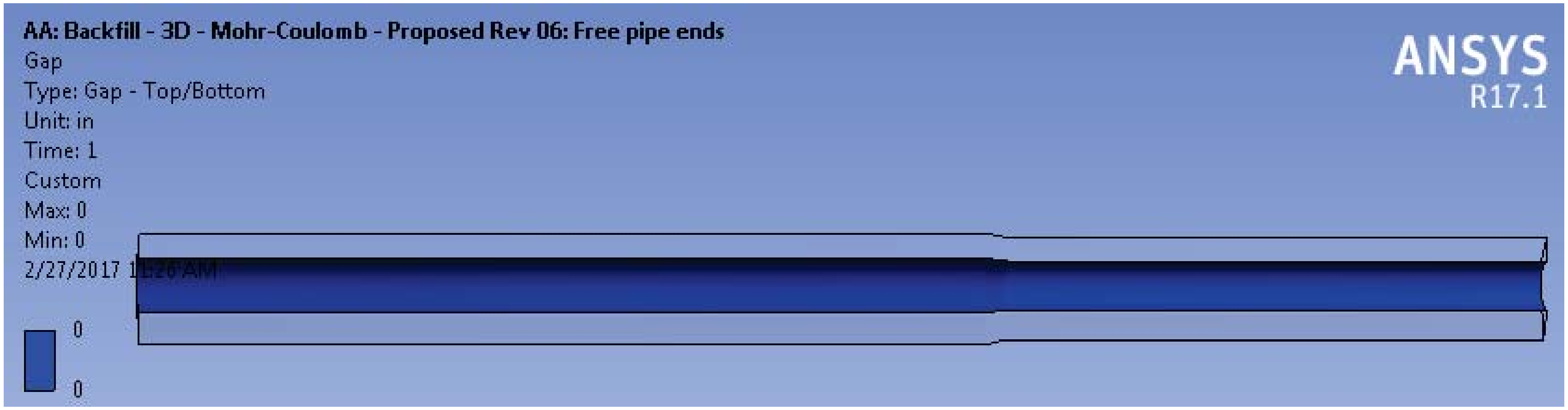


Figure 45 Model 4, LC2 – Gap between the Penstock and Bedding

The gap is 0 in. all along the interface; the bend is not expected to rise.

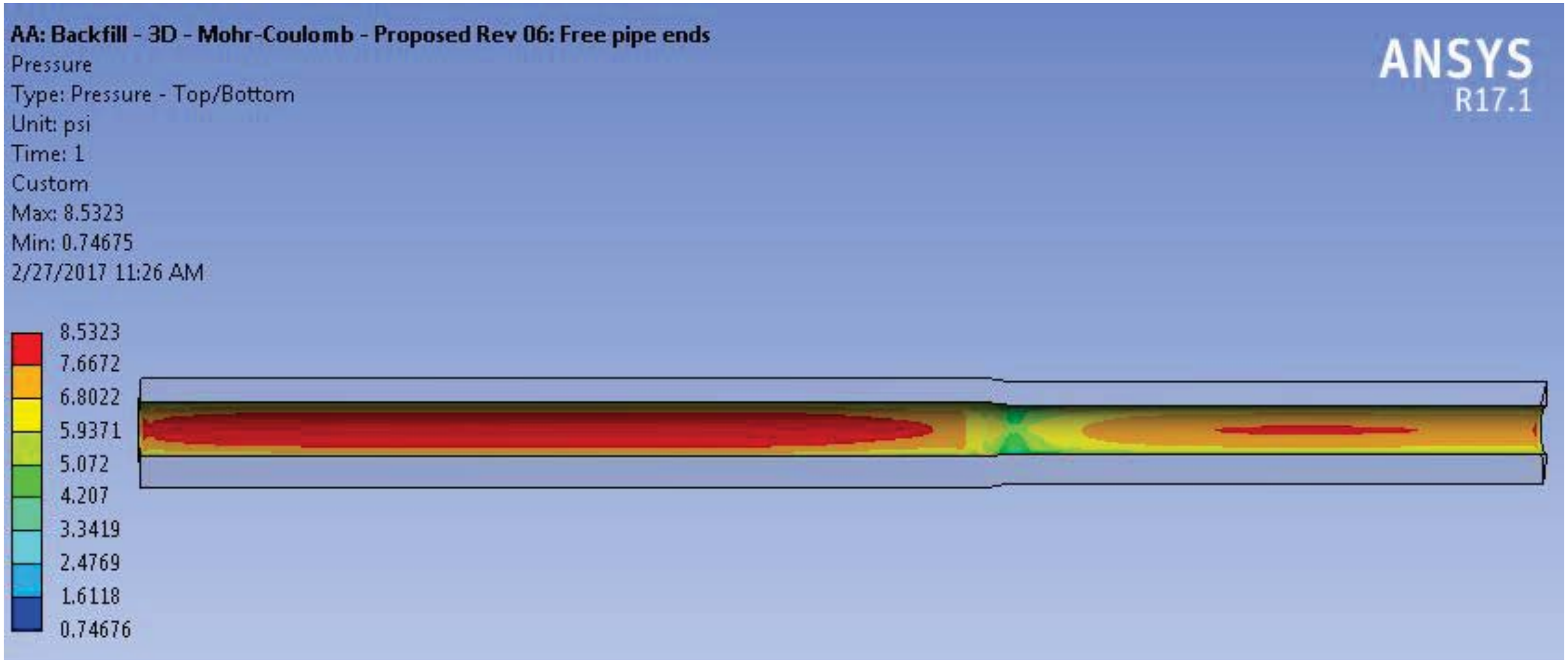


Figure 46 Model 4, LC2 – Contact Pressure between the Penstock and Bedding

The pressure is above 0 psi all along the interface; the bend is not expected to rise.

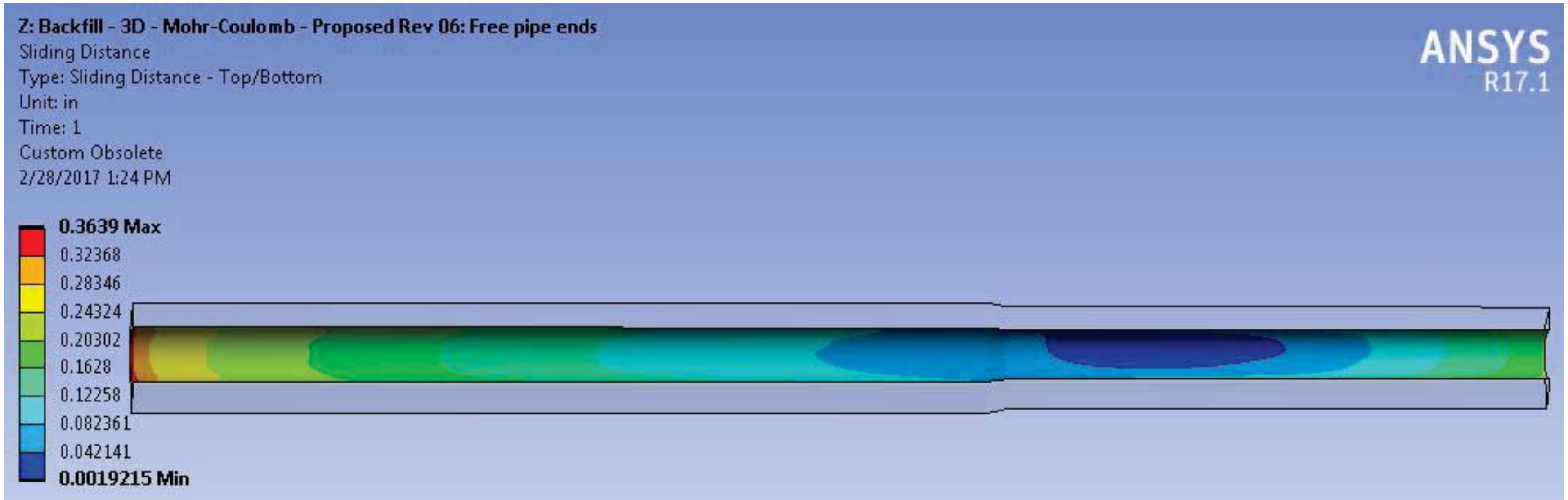


Figure 47 Model 4, LC2 – Sliding Distance between the Penstock and Bedding

The penstock in the model is not constrained at the ends and is expected to undergo contraction in axial direction upon application of internal pressure. The model predicts sliding at the bend of 0.05 in.

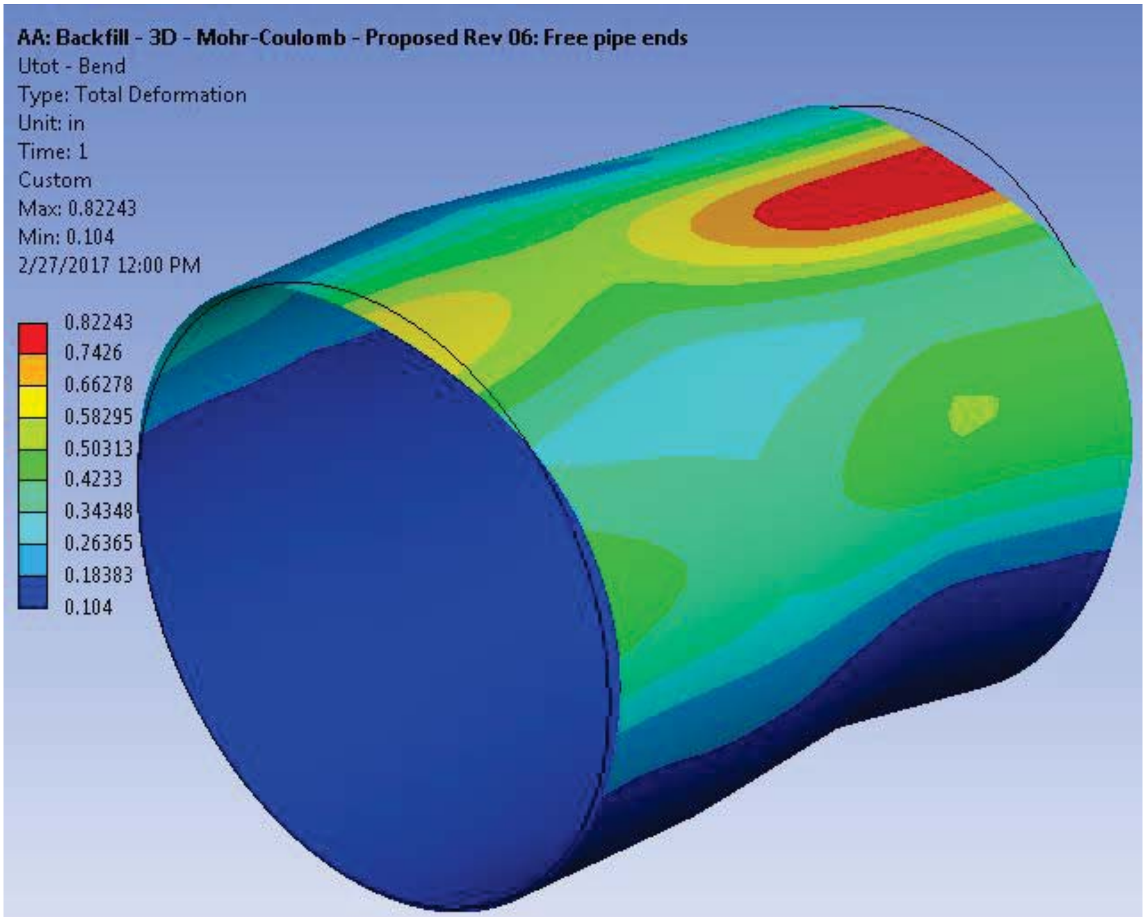


Figure 48 Model 4, LC2 – Total Deformation in Bend 4A

The deformation is mostly radial. The deformation is consistent with 2D models.

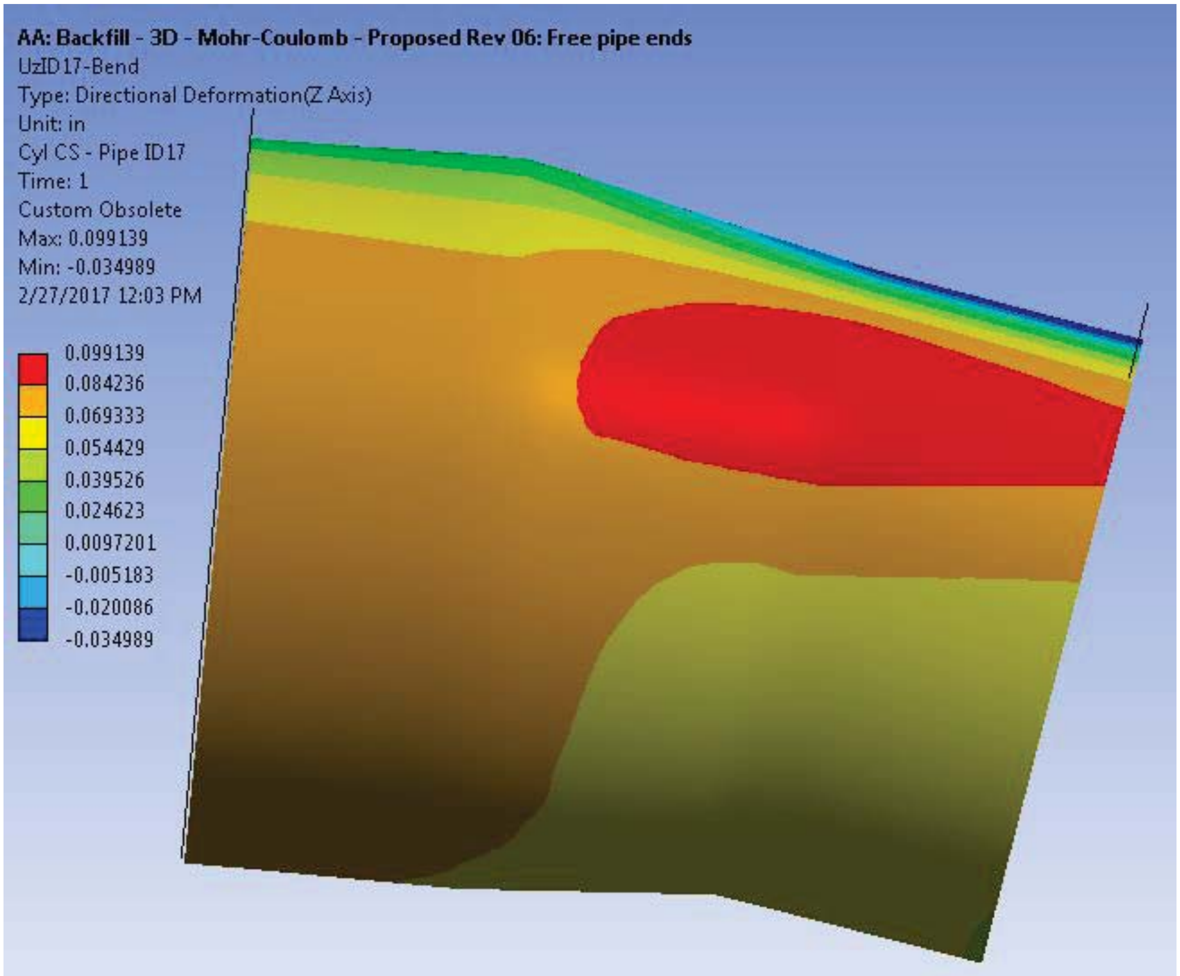


Figure 49 Model 4, LC2 – Directional (Along the 17-ft Diameter Penstock Section Centerline) Displacement of Bend 4A

The bend displacement is very small.

4. Conclusions

Based on the findings of this study the following is concluded:

- The backfill at the half trench penstock sections of 17-ft diameter penstock provides lateral support to the penstock and is essential for the penstock structural integrity.
- Any discontinuity of the backfill at the half trench sections containing the 17-ft diameter penstock may cause overstress in the penstock.
- The original backfill configuration (Figure 5) at the half trench sections has potential risk of slope instability (sloughing/sliding).
- The 17-ft diameter ASTM A285 penstock is 37% overstressed with the current half trench backfill configuration assuming the backfill is intact. The overstress is likely greater than 37% given the present open cracking and slumping of the backfill reported in Ref [1].
- A short section of 17-ft diameter ASTM A285 penstock, upstream of the circumferential joint with CSA G40.8 penstock, is 2% overstressed with respect to the allowable primary membrane (hoop) stress recommended in Ref [2] and this holds true regardless of the backfill condition or configuration. In our opinion this amount of overstress is not considered significant and required no remediation.
- With the proposed backfill configuration, the displacements at Bend 4A are small and not a concern.

5. Recommendations

Based on the findings of this study we recommend the following:

- Due to the criticality of the backfill to the integrity of the penstock, we recommend reinstatement of any sloughing/sliding backfill to its original profile in this construction season. The backfill material should be sloped/shaped such that it is not susceptible to surface erosion. This should be considered as a temporary mitigation, to reduce excessive stresses in the penstock.
- For the permanent refurbishment, place the backfill as per the configuration proposed in Figure 6. The following steps are required:
  - Dewater the penstock
  - Remove the organics/erosion protection layer along the half trench sections of 7/16-in thick 17-ft diameter penstock
  - The common fill material shall be placed in stages on each side of the penstock to avoid overstress in the penstock
  - Place a 6-in. thick layer of erosion protection material (the removed erosion protection material may be re-used).
- Materials to be used in construction
  - Backfill: expected to be sourced from a local borrow area and shall be free from excessive moisture, organics, and debris, as approved by a geotechnical engineer.
  - Erosion Protection Material: 2-in. clear stone or equivalent as approved by a geotechnical engineer.

6. References

[1] Crack Investigation And Repair Report; Penstock No.1 Bay d'Espoir Hydroelectric Development; Kleinschmidt; June 2016.

[2] ASCE Manuals and Reports on Engineering Practice No. 79, Second edition.

[3] ASTM A285 2012.

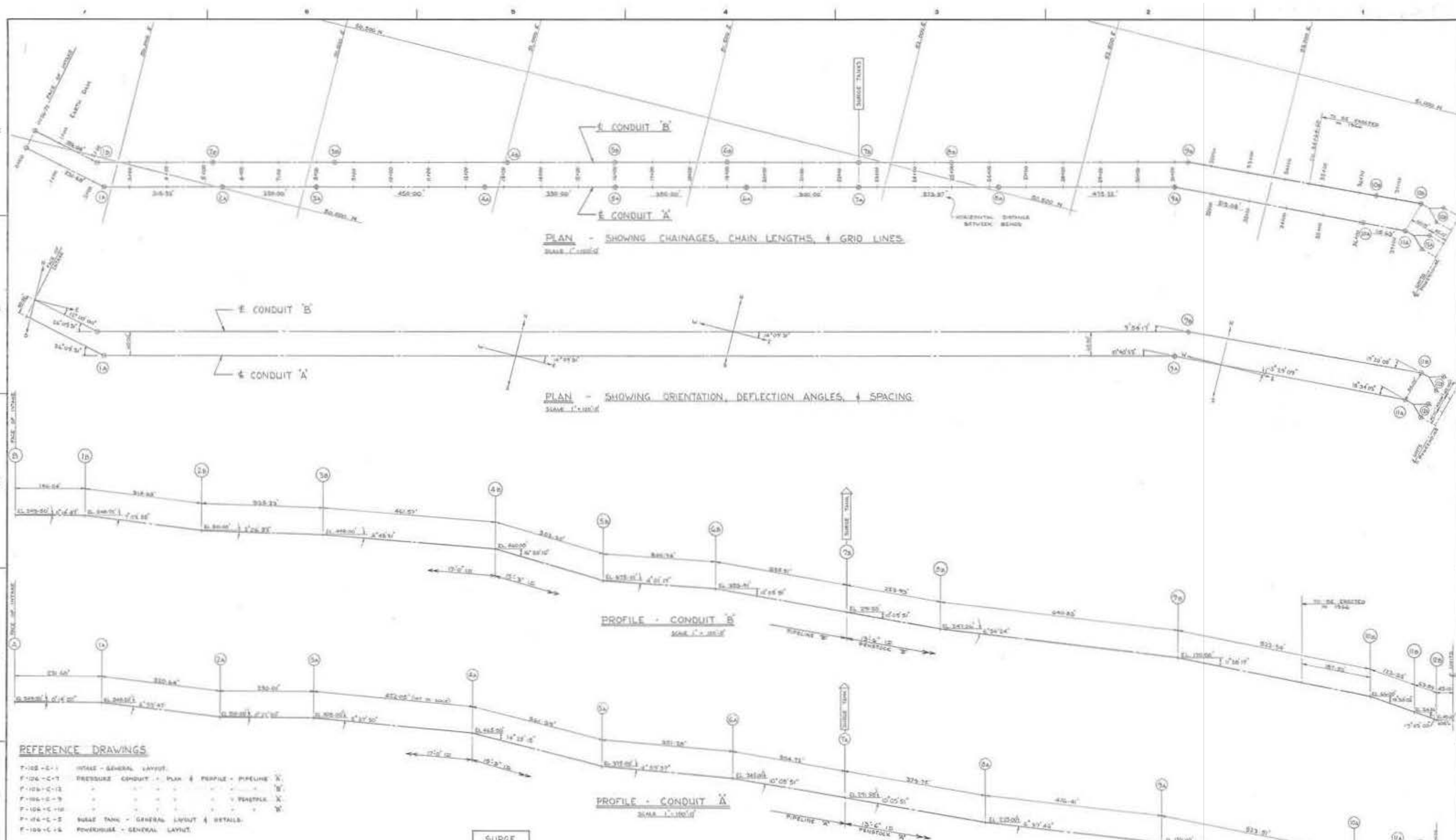
[4] CISC; Obsolete Canadian Structural Steel Grades; 1935 – 1971.

[5] Drawing F-106-C-7.

[6] Drawing 10830.

[7] Drawing 10830-2.

Appendix A
Pressure Conduits Layout and Location Data



REFERENCE DRAWINGS

								SURGE TANKS						
PIPE	DATA	INTAKE	BEND 1	BEND 2	BEND 3	BEND 4	BEND 5	BEND 6	BEND 7	BEND 8	BEND 9	BEND 10	BEND 11	BEND 12	℄ OF UNITS
A	CHAINAGE	0+00·00	2+31·68	5+50·00	8+00·00	12+50·00	16+00·00	19+50·00	22+50·00	26+23·87	30+97·09	34+10·17	37+25·80	37+85·95	38+31·05
A	NORTHING	49,975·55	49,927·38						50,421·08		50,628·28		50,666·51		
A	EASTING	49,754·80	49,981·42						51,938·45		52,759·79		53,387·34		
B	CHAINAGE	0+26·72	2+12·74	5+25·00	8+50·00	13+10·00	16+00·00	19+00·00	22+50·00	25+00·00	31+36·18	36+48·67	37+64·83	38+24·98	38+70·08
B	NORTHING	50,024·46	49,985·18								50,700·98		50,747·42		
B	EASTING	49,765·20	49,947·17								52,782·26		53,409·20		

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NEWFOUNDLAND AND LABRADOR POWER COMMISSION
BAY D'ESPOIR DEVELOPMENT
SHAWMONT ENGINEERING NEWFOUNDLAND LIMITED
PRESSURE CONDUITS
LAYOUT & LOCATION DATA
F-106-C-11

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Newfoundland and Labrador Hydro

Final Report

For

Repair and Failure Investigation

H356043-00000-240-230-0003
Rev. 2
May 17, 2018

Newfoundland and Labrador Hydro

Final Report

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Newfoundland and Labrador Hydro Bay d'Espoir Penstock No. 1 Refurbishment - 2017 H356043	Engineering Report Mechanical Engineering Refurbishment and Failure Investigation Final Report

Refurbishment and Failure Investigation Final Report

H356043-00000-240-230-0003

REGISTERED PROFESSIONAL ENGINEER
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PROFESSIONAL ENGINEERS AND GEOSCIENTISTS
MICHAEL A. J. PYNE
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2018-05-17
DATE
NEWFOUNDLAND & LABRADOR

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To practice Professional Engineering in Newfoundland and Labrador.
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DATE	REV.	STATUS	PREPARED BY	CHECKED BY	APPROVED BY

HATCH

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1. Executive Summary

A third rupture of Penstock No. 1 at Bay d'Espoir (BDE) occurred on November 4, 2017. The rupture occurred in the form of a 2' long crack just below the crack that was refurbished 14 months earlier (September 2016) in Can 35.

The May 2016 crack occurred in the can adjacent to the 2017 rupture. This crack also occurred at the longitudinal weld on the north side of the penstock. All three ruptures occurred in the upper circumferential section of the penstock.

A metallurgical analysis of the failed section confirmed that the latest rupture in Can 35 initiated at the toe of the 2016 refurbished weld and then propagated into the parent plate material in an orientation parallel to the weld. Extensive material tests did not indicate any defects in plate material or the welds.

During the original refurbishment in September 2016 on Penstock No.1, defects found in many longitudinal seams on the inside led to the refurbishment of 346 internal weld seams (approximately 1,500' of the total 3,900' length), in the upper portion of the penstock. All refurbished cans were inspected visually and with magnetic particle examination, prior to return to service.

During the refurbishment of the latest penstock rupture in November 2017, the majority of the longitudinal welds inside the penstock, from the intake to the surge tank were re-inspected. The 2017 NDT extended beyond the examination completed in 2016 and utilized the same inspection method. Of the 346 weld seams refurbished in 2016, 27 exhibited defects – plus the two seams in the ruptured portion of the penstock – resulting in 29 weld seams (8.4%) completed in 2016 requiring rework. Additionally, two new seams with cracks were discovered beyond the 2016 refurbished cans, for a total of 31 seams requiring refurbishment in 2017. All defects or cracks found during this inspection were refurbished, reinforced and inspected.

To assist in determining the root cause of the penstock ruptures, strain gauges and pressure transducers were installed. The instrumentation was monitored during filling of the refurbished penstock, during a planned part-load rejection test of Unit No. 2 and during normal operations for six weeks after the load rejection test. Hatch has carried out a detailed analysis of all measured data, a finite-element (FE) analysis of the penstock geometry interaction with the backfill and a fatigue analysis.

The investigations to-date indicate that the latest rupture was most likely caused by a combination of the following factors:

1. High residual stress due to fitting and re-welding of the ruptured seam in 2016.
2. High localized bending stresses at the longitudinal joint.
3. Fatigue caused by high-cycle low-amplitude stresses due to pressure fluctuations in the penstock transmitted from the turbine.
4. Sloughing of the soil/backfill.

Hatch believes that the risk of failure of the refurbished Penstock No. 1 from now until the next inspection (summer 2018) is low.

Several alternatives for a long-term solution to achieve safe and reliable operation of the penstock were examined.

Penstock No. 1, Unit No. 1 and Unit No. 2 operation may be continued with the following considerations:

- Operation of the units in the rough zones should be limited to that absolutely necessary. Additionally, transitioning through the rough zone should be as quickly as practical; there is no limit on the maximum load that the units can be operated at.
- Walk the penstock once a day and after unusual pressure transients, such as load rejections, and monitor regularly by camera for evidence of leaks.
- Internal inspection of Penstock No. 1 during the summer of 2018 and determine inspection frequency based on findings.

Penstock No. 1 remedial work:

- Backfill and re-coating operations should be postponed until completion and evaluation of inspection summer 2018.

Inspection of Penstock No. 2 and Penstock No. 3 is also recommended since they are of similar design and vintage as Penstock No. 1. While previous inspections of these penstocks have been completed, they have not been focused on the recently determined sources of the Penstock No. 1 failures.

2. Introduction

Hydro engaged Hatch's engineering services in response to a rupture in Penstock No. 1 at the Bay d'Espoir (BDE) hydroelectric generating station on November 4, 2017.

Hatch designed a solution and mobilized to oversee inspection and refurbishment work. A test program was prepared to monitor pressure and stresses in the rupture area of the penstock. The penstock was placed back in service on December 8, 2017.

The instrumentation installed on the penstock for the commissioning tests on December 8, 2017 continued to collect data after the tests until February 20, 2018 when the data acquisition system was returned to the National Research Council. The measurements taken over a six-week period showed insignificant change, indicating that the penstock rehabilitation remains stable.

This final report presents results of the site inspection, refurbishment design and execution, testing, finite element (FE) analysis and interpretation of the test measurements, as well as a fatigue analysis. Several alternatives for a long-term solution were examined at a preliminary level, and recommendations provided. The recommendations include considerations for inspection and evaluation of Penstock No. 2 and Penstock No. 3.

3. Background

The BDE main powerhouse consists of six generating units fed from three penstocks. Penstock No.1 feeds Units No. 1 and No. 2, Penstock No. 2 feeds Units No. 3 and No. 4 and Penstock No. 3 feeds Units No. 5 and No. 6. Each penstock bifurcates near the powerhouse to feed water to two separate units through two spherical valves. Units No.1 and No. 2 along with Penstock No. 1 were built in 1967. Penstocks No. 2 and No. 3 were built in 1968 and 1969, respectively, and, based on project As Built Drawings, were thought to have identical designs to Penstock No. 1. However, two differences have been discovered during refurbishment, analysis, and investigation.

1. Penstock No. 1 design and as-built backfill depth on top (1 ft) is less than as-built backfill depth on Penstock No.2 (2 ft) and Penstock No. 3 (2 ft). This may cause Penstock No.1 to undergo larger deformation than the other penstocks during dewatering.
2. In 2016, during inspection, external stiffening rings were discovered in the upper sections of Penstock No. 2. As these rings are not shown on design drawings or specifications, it is hypothesized that they may have been installed as construction and lifting aids for handling. It is unknown if Penstock No. 3 was also built with external ribs (none shown on design drawings).

Penstock No. 1 is approximately 3,900 feet long and is constructed from a series of carbon steel cans that vary in length depending on location, but in general the cans are approximately 9’ long with shorter mitered cans to form bends. Each can consist of two rolled semi-cylindrical steel plates welded together longitudinally. There are no circumferential stiffener rings except in areas such as bends and concrete embedded sections. The penstock is supported on a prepared granular bedding and covered with backfill.

The penstock diameter varies from 17’ near the intake to 13’6” near the powerhouse, and the wall thickness varies from 7/16” near the intake to 1-7/16” near the powerhouse. The upper 1100 feet of the penstock steel conforms to ASTM A285 Gr. C and the remainder CSA G40.8 Gr. B. Cracks in longitudinal welds have been discovered in both sections. However, all the ruptures have occurred in the sections constructed of ASTM A285 Gr. C. All cracking in the CSA G40.8 section have occurred in the sections fabricated with 7/16” plates.

The penstock sections are subject to varying internal pressure starting from 43.5’ of water (18.8 psi or 130 kPa) near the intake to 590’ (255.7 psi or 1,763 kPa) at the powerhouse under static hydraulic conditions.

During the era (1965-1966) in which Penstock No. 1 was constructed, plate rolling was generally accomplished utilizing a three-roll single pinch point roll. When rolling plates with this type of roller, the start and end of each plate will be flat (unless other techniques are used such as pre-bending or by cutting off the flat section). This causes the cross-section of cans at the longitudinal weld seams to appear as a cone rather than a circular arc, which is termed as “peaking” for the purpose of discussion in this report. The level of peaking is characterized by the radial gap between the longitudinal joint and the theoretical circular arc. Peaking (10 to 30 mm) was noted on all Cans inspected. Peaking is not normal in the fabrication of penstock shells today due to better plate rolling techniques. This discontinuity in the circular geometry at the longitudinal seam induces localized bending stresses under internal pressure (confirmed by FE modeling).

On May 21, 2016 BDE Penstock No. 1 was found to have a leak from a two-foot (600 mm) long rupture along a longitudinal weld seam in Can 34. The crack was repaired and the penstock was put back into service. On September 14, 2016 Penstock No. 1 experienced another longitudinal seam rupture in Can 35, approximately 16’ (5 m) upstream from the previous rupture in the adjacent can. Newfoundland and Labrador Hydro repaired this rupture. Hatch was then engaged on September 22, 2016, to assess the penstock, at which time it was discovered that significant amounts of interior weld in the upper section of the penstock showed weld erosion and deterioration with partial depth cracking.

Upon completion of inspections in September 2016, it was confirmed that the majority of longitudinal weld joints from the intake down to Section 117 (Dwg.10830, approximately 3000’ of weld length), had experienced a significant amount of weld metal loss due to corrosion. A total of three hundred and forty-six (346) longitudinal seam welds (3114’) in this section of the penstock were refurbished by gouging out the old weld from the inside, rewelding and inspection before the penstock was put back in service.

Hatch provided a refurbishment method and construction assistance during work. The penstock was put back into service on November 30, 2016.

A third rupture was discovered on November 4, 2017. This rupture was on the same can just below the rupture that was last repaired (September 2016). Hydro immediately engaged the services of Hatch to assist in the inspection, rehabilitation and assessment of the penstock.

The root cause analysis conducted by Hatch in 2016 concluded that the 2016 failures occurred most likely due to stress corrosion cracking resulting from the presence of high stresses at the corroded longitudinal welds and the corrosive environment resulting from the loss of internal penstock coating. The report also attributed the higher stresses to insufficient backfill on top of the penstock and high residual stresses induced during penstock fabrication.

4. Inspection

The latest penstock rupture on November 4, 2017 was inspected visually (Figure 1-1). The entire length of the affected can around the crack was cut and shipped to a metallurgical laboratory for metallurgical analysis and material testing (Figure 4-1). The majority of longitudinal welds on the interior of the penstock from the intake to the surge tank (2272' or 690 m) were inspected visually, by magnetic particle, and using laser survey. Laser survey of the interior of the penstock was used to determine the interior shape of the penstock and confirm the level of peaking present. Cracks or defects were discovered on twenty-nine (29) longitudinal welds out of 430 seams inspected. Twenty-seven (27) of these were on 2016 refurbished weld seams and two (2) were on original weld seams. Including the 2 longitudinal weld seams from the ruptured portion of the penstock makes the total 31 repaired seams. A detailed inspection chart is shown on the following page that shows the 2016 repair/refurbishment, 2017 repair/refurbishment, cleared cans, cans that exhibited new defects, and cans that exhibited extensive cracking in 2016. The backfill and settlement monitoring posts over the same length of penstock were surveyed and the data is presented.

None of the circumferential welds were inspected as no cracks were found in 2016 and these joints only have half the stress due to internal pressure as compared to the longitudinal joints.

Hatch investigated if there was any loss of support at the bottom of the failed cans and adjacent area by drilling through 3" couplings welded to the bottom of the penstock at four different longitudinal locations. The visual examination of the bedding below the penstock, and the laser survey of the penstock invert and external settlement monitoring posts showed insignificant bedding loss.

The penstock between the surge tank and the powerhouse was not inspected as no cracks were found in this section in 2016. The plate in these sections is thicker and the penstock diameter is smaller. Additionally, no significant weld seam corrosion was found during the 2016 inspections. Absence of peaking at the longitudinal welds in the penstock downstream of the surge tank should be confirmed at the next inspection.

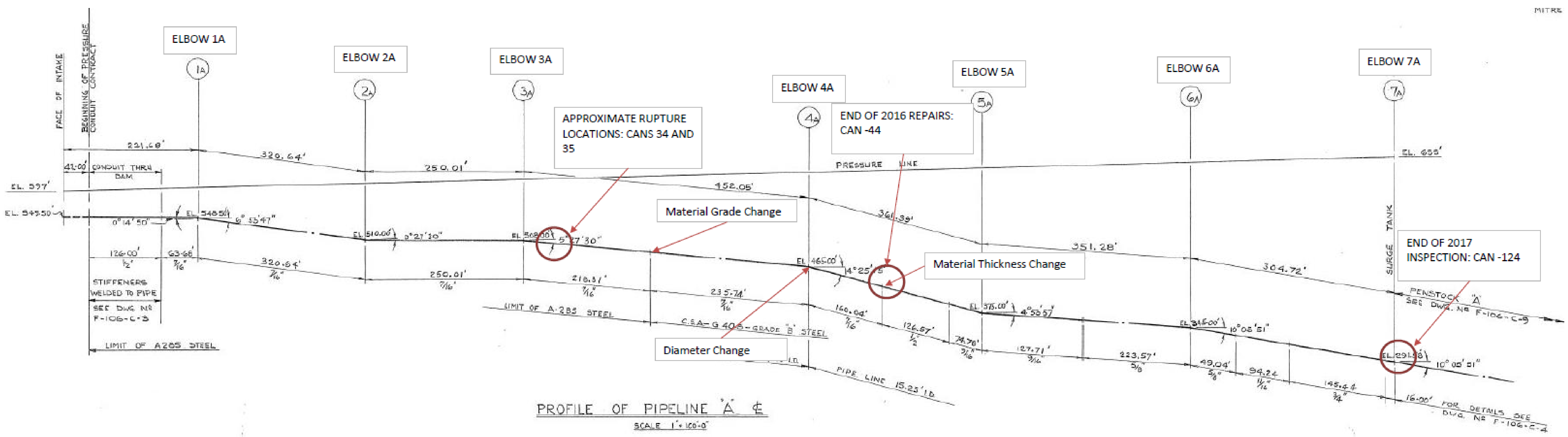
Figure 4-1: Close-up View of the Rupture in Can 35 (in the Laboratory for Material Tests)

PENSTOCK NO. 1 INSPECTION TRACKER

Inspection Legend	
(green)	REPAIRED 2016, CLEAN 2017
(yellow)	REPAIRED 2016 REPAIRED 2017
(orange)	CRACKING BEYOND 6MM 2016, REPAIRED 2017
(red)	RUPTURES
(blue)	NOT INSPECTED 2016 BUT INSPECTED 2017 CLEAN
(grey)	UNTOUCHED
(purple)	NOT INSPECTED 2016, REPAIRED 2017

Points of Interest	
MT	Material Thickness Change
MH	Manhole Location
MC	Material Grade Change
RD	Reducer Cans
XA	Bend Cans

Figure 4-2: Inspection Tracker



Bay d'Espoir Penstock No.1- Profile from Intake (left) to Surge Tank

Figure 4-3: Penstock Profile

5. 2017 Refurbishment

Hatch designed the refurbishment of the ruptured penstock can. It involved removal of a 2' wide 9' long longitudinal strip of the penstock can with the crack in the middle (Figure 4-1) and inserting a 1/2" thick pre-rolled (8'6" radius) plate (CSA G40.21 350WT-CAT 4, which is superior to existing) and welding it in place according to the procedure provided by Hatch. For safety, the longitudinal weld in Can 34, repaired originally in May 2016, was also removed and replaced by inserting another 1/2" thick pre-rolled plate. To reinforce the new refurbished area and the one from May 2016, spliced reinforcing plates (8'6" radius, 1/2" thick) were welded on the exterior of cans 33, 34, 35 and 36 (see Hatch drawing 352666-D-M-0001.1, rev B).

For the 29 longitudinal seams in other cans with defects or cracks, existing weld metal was removed from inside of the penstock and rewelded. Prior to the installation of the reinforcing plates the excess weld reinforcement on the longitudinal welds was ground flush to reduce the stress concentration at the welds and allowing the reinforcing plates to sit tighter to the existing plate surface. In each case a 22" wide 9' long rolled patch plate (8'6" radius, 1/2" thick) was welded in place on the inside of the refurbished longitudinal welds, as shown schematically in Figure 5-1 below. Figure 5-1 also shows peaking at the weld.

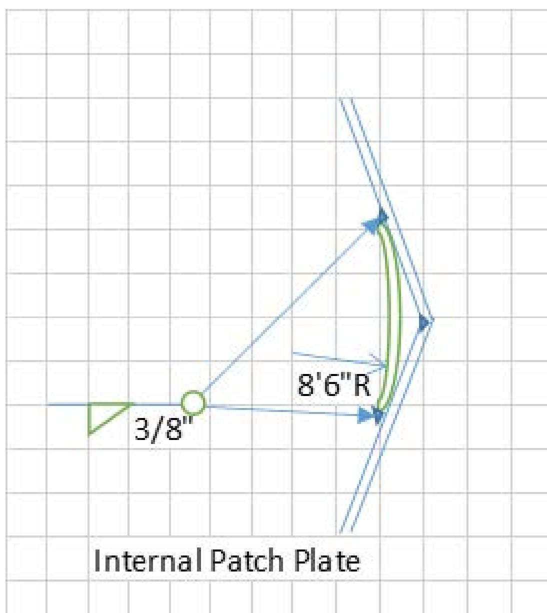


Figure 5-1: Refurbishment of Internal Longitudinal Seams

Table 5-1 shows the statistics of the longitudinal weld inspection and refurbishment.

There were 346 weld seams refurbished in 2016. The 2017 weld inspection showed defects in 8.38% of the welds refurbished in 2016, and the majority of these defects occurred on the north side of the penstock. All ruptures to date have occurred on the north side.

Table 5-1: Longitudinal Weld Statistics

Item	Description	Number	Units
1	2017 Internal Longitudinal Seams Repaired/Refurbished	31	Count
2	2016 Internal Longitudinal Seams with Defects	29	Count
3	2017 Welds Showing Defects from Original Construction	2	Count
4	2017 South Internal Seams Repaired/Refurbished	10	Count
5	2017 North Internal Seams Repaired/Refurbished	21	Count
6	2016 Total Seams Repaired/Refurbished	346	Count
7	2016 Total South Seams Repaired/Refurbished	173	Count
8	2016 Total North Seams Repaired/Refurbished	173	Count
9	Approximate Seam Total (Intake to Powerhouse)	870	Count
10	Seams Inspected 2017	430	Count
11	Approximate Total Longitudinal Seam Length	7830	ft
12	Approximate Visual (VT) and Magnetic Particle (MT) Length 2017	3870	ft
13	Approximate Seam Repair/Refurbishment Length 2017	279	ft
14	Approximate Seam Repair/Refurbishment Length 2016	3114	ft
15	2017 Defects Vs Inspection	7.21	%
16	2017 Inspection Percentage	49.43	%
17	2017 South Internal Defects vs Total	32.26	%
18	2017 North Internal Defects vs Total	67.74	%
19	2017 Defects on 2016 Welds	8.38	%
20	Approximate 2016 Repair/Refurbishment Vs Total Penstock	39.77	%
21	Approximate 2017 Repair/Refurbishment Vs Total Penstock	3.56	%

6. Testing

To investigate the cause of penstock cracking, Hatch developed a test program to monitor pressure and stresses in the penstock during penstock filling and operation. The penstock was instrumented with strain gauges on the inside and outside adjacent to the penstock failures and at a randomly selected location about 280’ (85m) upstream from the last rupture location. Backfill was partially removed at the randomly selected location to expose the external surface of the penstock for applying the strain gauges.

A data acquisition system was installed to record measurements of strains and pressure in the penstock at the test locations. Hydro Operations also recorded unit operating parameters and penstock pressure at the powerhouse.

Data was recorded for the following milestones:

- base measurement with strain gauges installed but no backfill replaced
- after backfilling penstock to the original design profile
- after completing the backfill to the geometry recommended by Hatch
- when water reached the bottom and top of test locations during penstock filling
- penstock full of water at intake forebay level
- during Unit No. 2 start up and speed-no-load
- during Unit No. 2 rough zone operation
- Unit No. 2- 40 MW load rejection
- Unit No. 1 start up
- Unit No. 1 and No. 2 in rough zone
- Unit No. 1 and No. 2 operating at 70 MW.

The steel in this region of the penstock has a yield strength of 206 MPa, and an ultimate tensile strength of 380 MPa. Design is generally performed to keep stress in the steel below the yield strength, as strains or deflections below this point are elastic and the material returns to its original condition when loading is removed. Tensile rupture should not develop in a material until the stress exceeds the ultimate tensile strength, however, plastic or permanent (non-recoverable) deformations develop in a material once the stress level has exceeded the yield strength. Additionally, material with stresses above the yield strength generally deflects more rapidly as additional load is applied. Stresses above the yield strength of a material likely indicates that the material is operating beyond the intended design values, but do not necessarily mean structural failure is imminent.

Strain gauge measurements on the inside of the penstock adjacent to the longitudinal weld seam indicated high stresses are present (280 MPa) with penstock under normal pressure, which are above the yield strength but still below the ultimate tensile strength. In addition to the high localized stress, cyclic (alternating) stresses of the order of ±15 MPa (2.2 ksi) and ±7 MPa (1 ksi) were measured by the strain gauges adjacent to the longitudinal welds during load rejection and rough zone operation, respectively. Stresses adjacent to the weld seams were also determined analytically by the finite element model of the penstock, with results also showing high stresses similar to those measured by the strain gauges in the field.

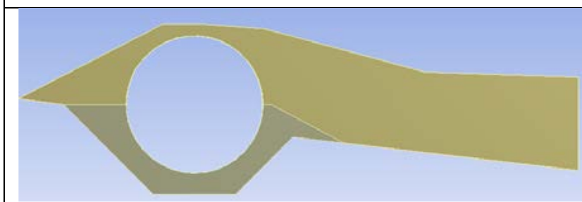
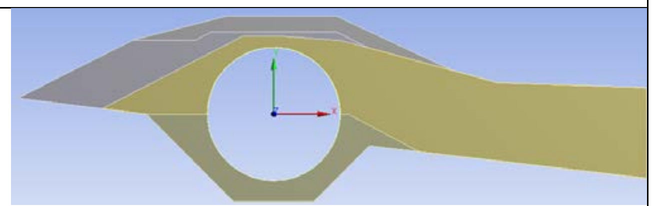
A spectral analysis of the measured stresses showed that a few frequencies were predominant in the measurements of internal pressure as well as strains. Further detailed analysis of the data measured shows the penstock is subject to cyclic stresses of lower amplitude and frequency during other events as discussed in Section 8.4.

7. Numerical Analysis

A two-dimensional finite-element (FE) model of the steel shell with the abnormal peaking at the longitudinal weld seam and the surrounding backfill was analyzed using the commercially available software ANSYS. The behavior of the backfill was modeled using large deflection non-linear characteristics of the soil.

The results of the FE analysis are shown graphically in Figures 7-1 to 7-4 (see also Appendix C for enlarged view) and the principal conclusions are:

- The geometrical discontinuity due to peaking at the longitudinal weld seam creates very high localized bending stresses.
- The unsymmetrical as-built backfill creates unsymmetrical backfill loads resulting in large deflection of the empty shell and higher stresses during penstock filling (σ_0-red line and σ_1-blue line in Figure 7-1); however, the stresses in penstock under full pressure are not impacted in the same manner by the unsymmetrical backfill (σ_2-black line in Figure 7-1).
- Additional backfill recommended by Hatch creates uniform support of the shell and reduces overall stresses with penstock empty and during filling (σ_0-red line and σ_1-blue line in Figure 7-2 vs Figure 7-1); however, there is only a small reduction in stresses with penstock under full pressure (σ_2-black line Figure 7-2 vs Figure 7-1). Also, increasing the backfill more than that recommended by Hatch (>2') has no incremental benefit in reducing the stresses in the penstock shell when empty, filling or under full pressure.
- Additional backfill beyond the 2 ft cover recommended by Hatch, does not reduce the high local bending stresses in the vicinity of the longitudinal weld seam (30^o position in Figure 7-2Figure 7-2 vs Figure 7-1) under internal pressure.
- Figure 7-4 shows that when the penstock is empty and filling with no internal pressure (t=1) the maximum bending stress reduces from 250 MPa to 150 MPa if the backfill is symmetrical relative to the as-is unsymmetrical backfill. However, with internal pressure applied, the maximum bending stress at the weld seam reverses to about 650 MPa and the backfill has little or no impact on the amplitude. However, variations in pressure (30 to 45 psi) increases the maximum bending stress from 450 MPa to 650 MPa. It is concluded from this analysis that improving the backfill significantly reduces circumferential bending stress during de-watering/watering up and when the penstock is empty but has insignificant effect on a pressurized penstock. This information was extracted from a theoretical linear elastic model. This allows a comparison of stresses only as the material thickness remains constant and the material does not self-relieve stresses that exceed yield. In reality, material strain hardening takes place progressively in ductile materials once the stresses exceed the yield stress of the material. It is likely that these stresses are lower in the penstock as at the location of high stress the material permanently deforms which reduces the localized stress.

FE Model Looking downstream-Backfill-original	FE Model-Recommended Backfil
	
Legend: 0=empty penstock (soil + steel weight); 1=filled with water (soil + steel + water weight) 2= pressurized (soil + steel +water weight + 38.21 psi internal pressure	

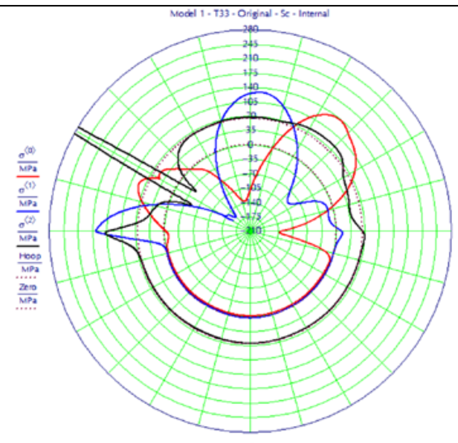
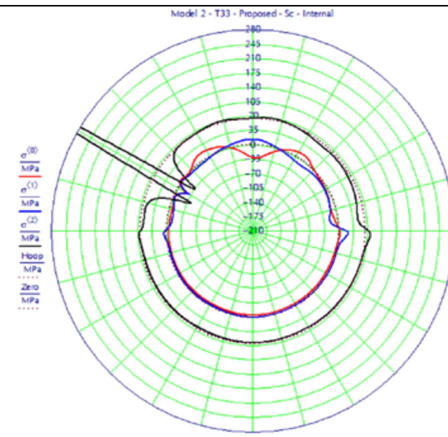
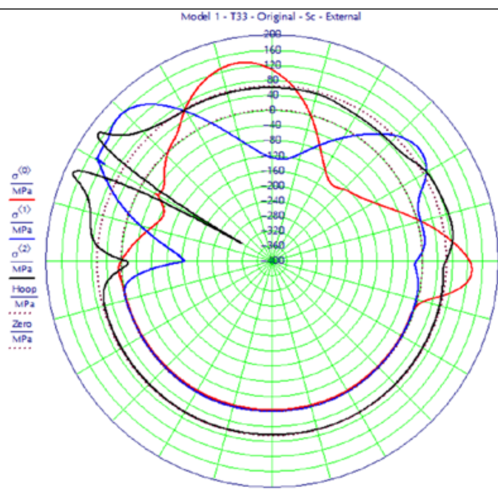
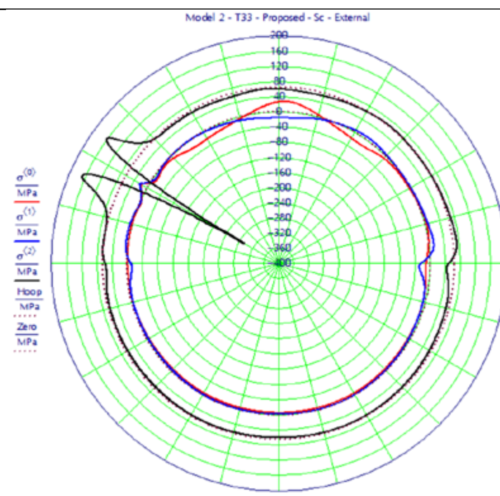

	
	

Figure 7-1: Circumferential Stresses - As is Backfill - (looking downstream)	**Figure 7-2: Circumferential Stresses - Additional Backfill by Hatch**

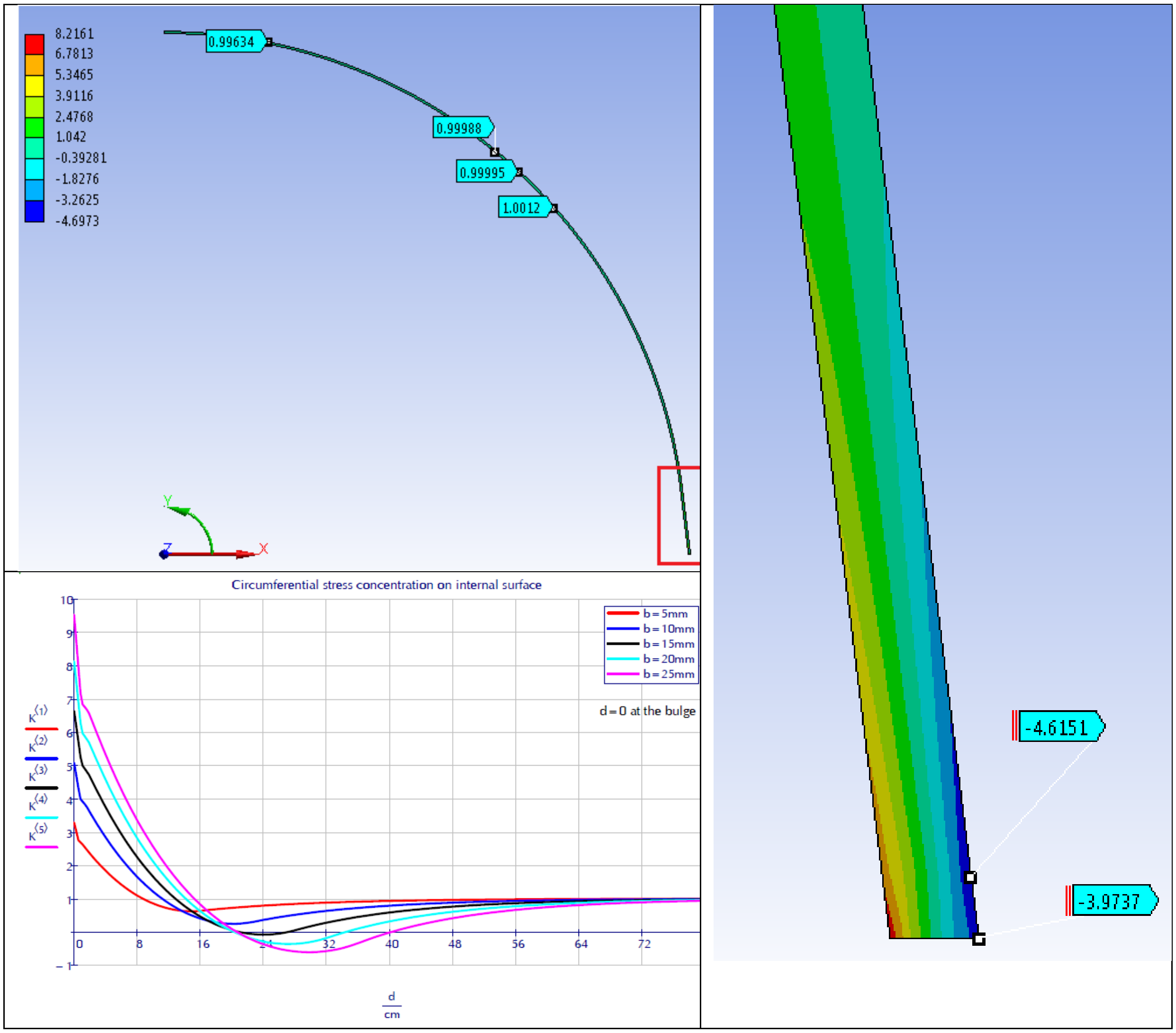
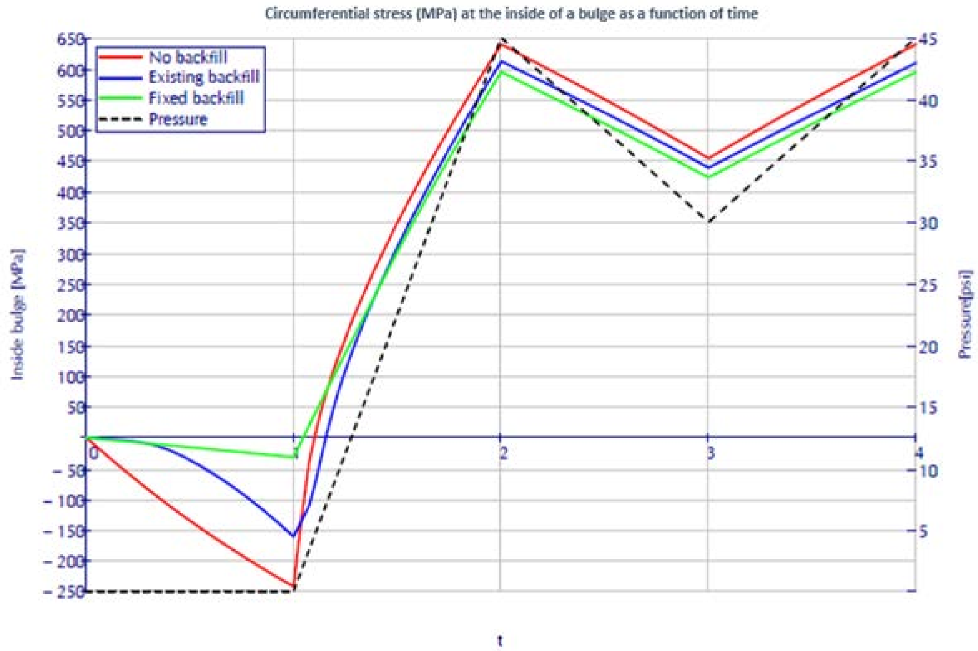


Figure 7-3: Influence of Non-Circular Geometry at Longitudinal Welds Under Pressure



Water weight = hydrostatic pressure gradient with 0psi at the top and 7.4psi at the bottom applied at the internal surface

Pressure = a constant pressure applied at the internal surface

t=1 : Water weight + Backfill weight + 0psi

t=2 : Water weight + Backfill weight +45 psi

t=3 : Water weight + Backfill weight +30 psi

t=4 : Water weight + Backfill weight +45 psi

Figure 7-4: Linear Variation of Maximum Bending Stress at the Weld with Pressure and Change in Backfill

8. Failure Analysis

8.1 Metallurgical Analysis

The penstock shell strip containing the latest rupture was shipped to Atlantic Metallurgical Consulting and Wayland Engineering for metallurgical analysis and material testing. These samples yielded similar material properties to those determined in the 2016 metallurgical analysis completed by Cambridge Materials Testing. The shell material for the penstock was confirmed to be compliant with 1982 chemical requirements for ASTM A 285 Grade C. Additionally, the chemical compositions from both 2016 and 2017 tests noted the presence of higher than normal sulphur content (0.032%) within the shell material by todays standards (0.025%). The AMC report is included in Appendix E.

Initial visual inspection of the fracture surface showed (Figure 4-1) that the crack was approximately 43 inches long and propagated along the toe of the weld for a large portion of the seam and veered into the base metal along one end. During sample removal, the crack continued to propagate parallel to the weld. This would indicate large residual stresses being present within the weld joint. Figure 8-1 maps out different areas of a weld cross section for clarity with regards to the metallurgical summary.

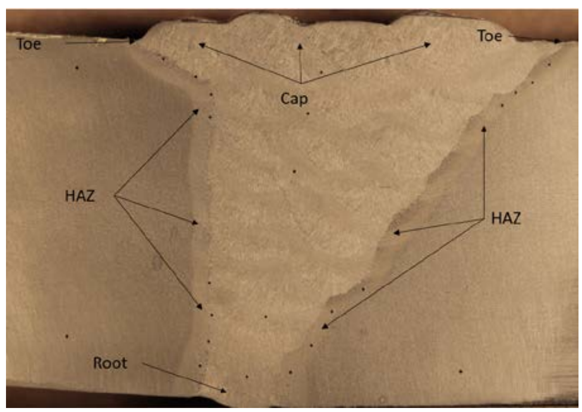


Figure 8-1: Weld Nomenclature

Macroscopic examination of numerous cross-sectional samples showed no evidence of appreciable weld defects or anomalies (porosity, lack of fusion, incomplete penetration). Several macro samples had additional hardness readings completed. The hardness values ranged from 151-164 Hv10 for the base metal, 175-183 Hv10 for the weld metal, and 175-182 Hv10 in the area close to the cracks. The Hv10 hardness test is the Vickers diamond indenter method with 10 kg load on the indenter. Additionally, the microstructures were pearlitic (which is a ductile crystalline structure) in nature and showed no signs of a martensitic (which is a brittle crystalline structure) structure. These results indicate there was no formation of hard phases (that could cause brittleness or accelerated corrosion), that can be caused by rapid cooling after welding. These results generally indicate that the original welds were well executed.

Two different types of cracks were discovered through macro examination and are shown in Figure 8-2. The primary cracks (through thickness) generally propagate from the toe of the weld through the heat affected zone (HAZ). All observed crack micro examinations had pearlitic structures which is a desirable trait and would indicate that the cracks were not caused by brittle structures. There is evidence of bending and high tensile loading when analyzing the micro photographs. Several of the samples had secondary cracking (interplanar) present. The secondary cracks appear to follow sulphide inclusions that are present within the base material and can likely be attributed to the presence of said inclusions. It seems unlikely the secondary cracking is the primary cause of the rupture but could have accelerated the failure.

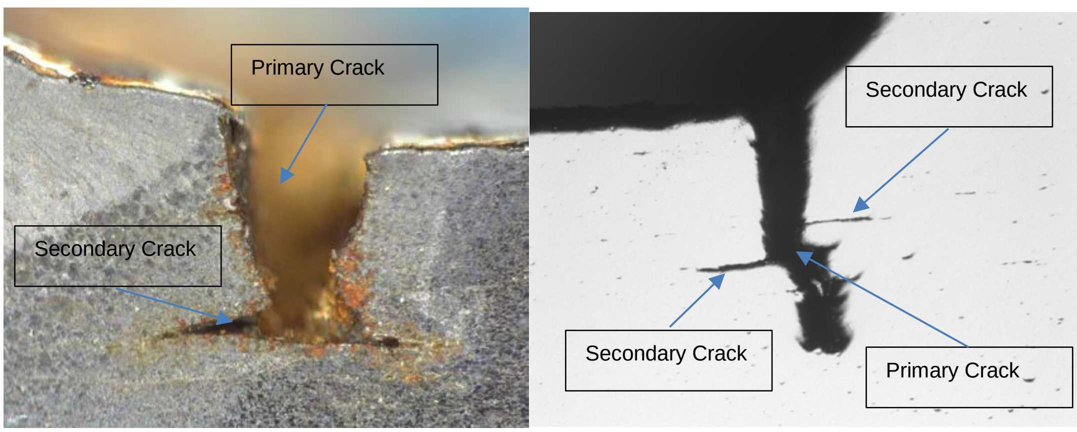


Figure 8-2: Primary Cracks (Vertical) and Secondary Cracks (Horizontal)

Further to the visual, macro, micro and chemical analysis, a set of mechanical testing was completed. The testing consisted of tensile testing for the base metal and the weld metal. The tensile samples failed within the base metal and were also ductile in nature (similar to the results determined in the 2016 investigation). The tensile test in Figure 8-3 shows an extensive reduction in area and significant cupping which is typical of a ductile failure. This testing is further evidence that brittle fracture was not involved and that the material and weld metal is ductile, which is preferred practice for design of steel structures.

Figure 8-3: Ductile Failure Tensile Tests Penstock No. 1

8.2 Analysis of Test Data

The following is a summary of key observations from the analysis of the test data. Since the strain gauges were installed with no backfill at the gauge locations but the penstock was already under stress from backfill on adjacent sections, the measurements do not represent accurately the stresses due to the backfill in other sections of the penstock. Similarly, the gauges do not measure residual stress already in the material at the time of gauge installation. The same is not true with the changes in measurements due to internal pressure. It may be observed in Figure 7-1 that the stresses due to backfill (σ_0-red line) are substantially lower than stresses under pressure (σ_2-black line). This would imply that measured stresses may actually be slightly lower than true values. However, this does not affect the measurements of alternating stresses from pressure fluctuations, which appear to be the more likely cause of metal fatigue contributing to penstock rupture.

The principal stresses calculated based on the strain measurements at Can 65 show an observable increase in stress from the static internal pressure of (38 psi) of the fully watered up penstock, when compared to the principal stresses observed when the water level reaches only to the top of Can 65. These stresses vary slightly with unit operating (lower dynamic pressure).

The following are some observations from the recorded measurements:

- As would be expected, the maximum stresses occur when the penstock is under dynamic pressure and subject to a load rejection. The highest measured stress was on the inside in the vicinity of the longitudinal weld seams in Can 65. Stresses in the order of 280 MPa [above the yield strength of 30 ksi (206 MPa) but below the ultimate tensile strength of 55 ksi (380 MPa)] were measured in the ASTM A285 Gr. C section with the penstock full and during a load rejection. The measured values suggest that the operational stresses were 25% less than the ultimate strength and 37% above the yield strength of ASTM A285 Gr. C. The high stress is attributed to the penstock peaking at the longitudinal weld caused by the lack of rolling radius of the two mating edges.

- A load rejection results in pressure rise of 10% at the powerhouse (259 psi+26 psi). The corresponding pressure waves up the penstock cause fluctuations in pressure at Can 33 of the order of ±17%(±6.8 psi) in the area where the rupture occurred (Figure 8-4). The corresponding fluctuation in the maximum stress is 280 ± 25 MPa during load rejection (Figure 8-5). Load rejection occurs between 1500 and 3500 seconds and the peak was at approximately 2700 seconds.
- The fluctuations in maximum stress during rough zone operation are of the order of ±7 MPa (1.0) ksi) and ±5 MPa (0.7 ksi) with two units and one unit in the rough zone, respectively (Figures 8-5 and 8-6). This is interesting as it was not anticipated that the rough zone operations would result in significant stress fluctuations in the penstock. Rough zone occurs from approximately 4500 seconds onward.

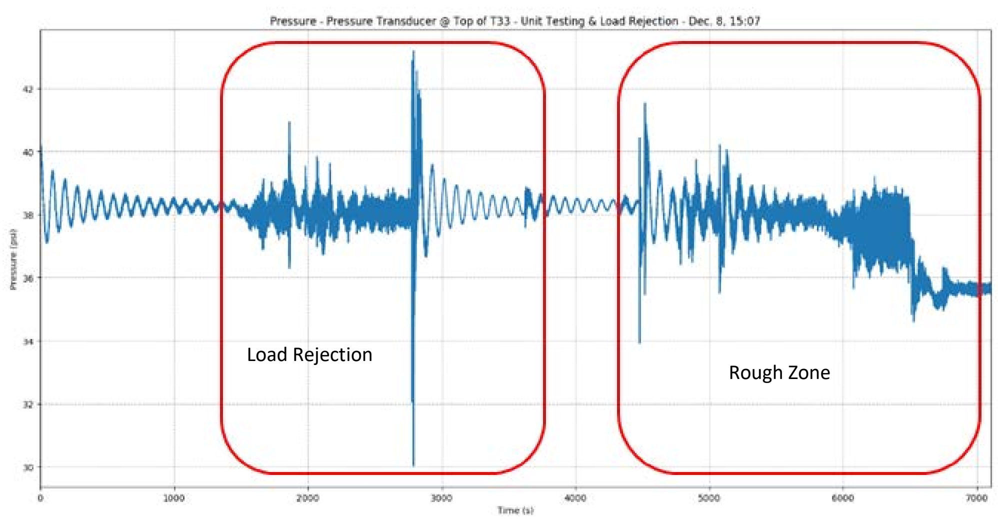


Figure 8-4: Pressure Measurement in Penstock at Can 33 during Rough Zone and Load Rejection

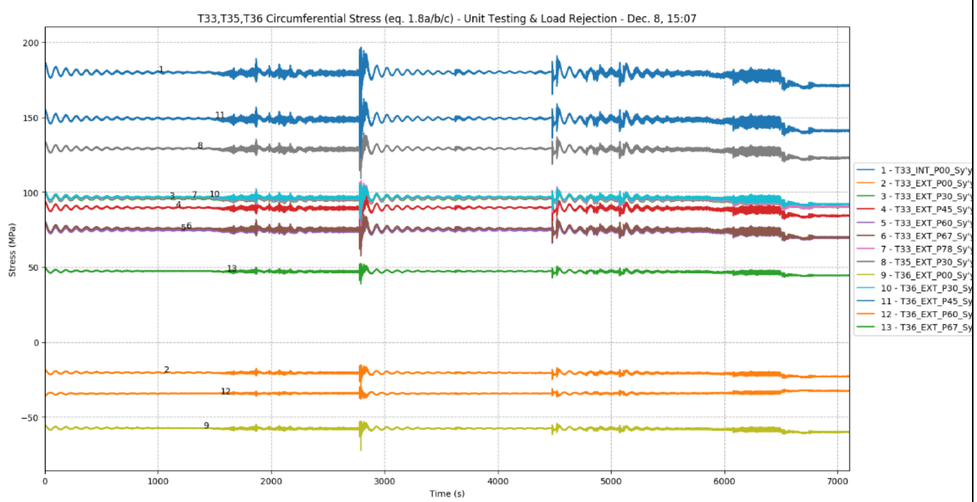


Figure 8-5: Circumferential Stresses in Penstock at Can 33 - Rough Zone and Load Rejection

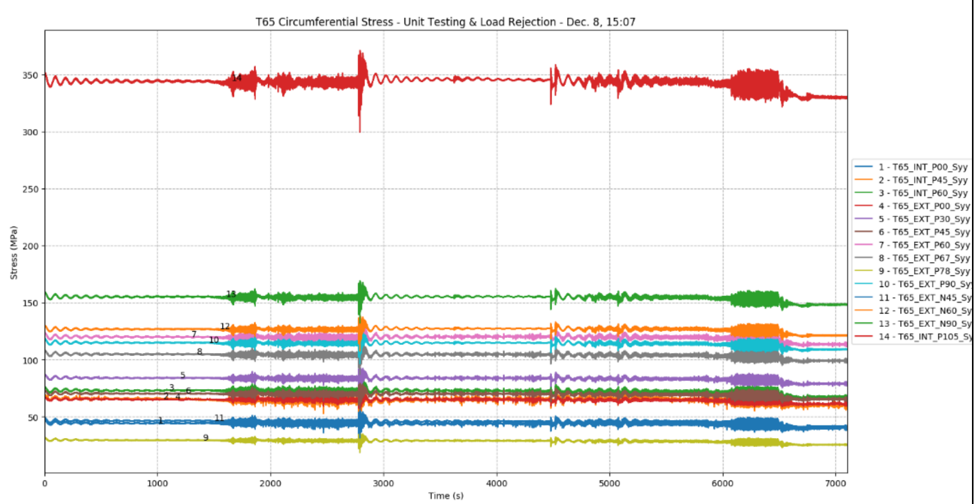


Figure 8-6: Circumferential Stresses in Penstock at Can 65 - Rough Zone and Load Rejection

8.3 Operational History

Newfoundland and Labrador Hydro provided the last five years of operational data to Hatch for analysis. The operational data provided shows decreasing amounts of starts/stops for each unit over the five years analyzed, and high hourly time spent within the rough zone (between 25 to 40 MW based on the measured test results). In general, eliminating unnecessary starts/stops is a common recommendation to increase the life of a hydraulic turbine. However, in this instance operating the units at low loads to meet the power demand resulted in these units spending an increased amount of time operating in the rough zone. The amount of time spent within the rough zone over the last five years is shown in Figure 8-7, and the number of annual starts/stops is shown in Figure 8-8.

Analyzing the data and approximating the total hydraulic rough zone time shows that over the last five years Penstock No. 1 averaged more than 400 hours in the hydraulic rough zone per year, with a peak of over 800 hours in 2014. Tt should be noted that 2016 and 2017 had significant down time for repairs and the duration of rough zone operation was reduced as a result.

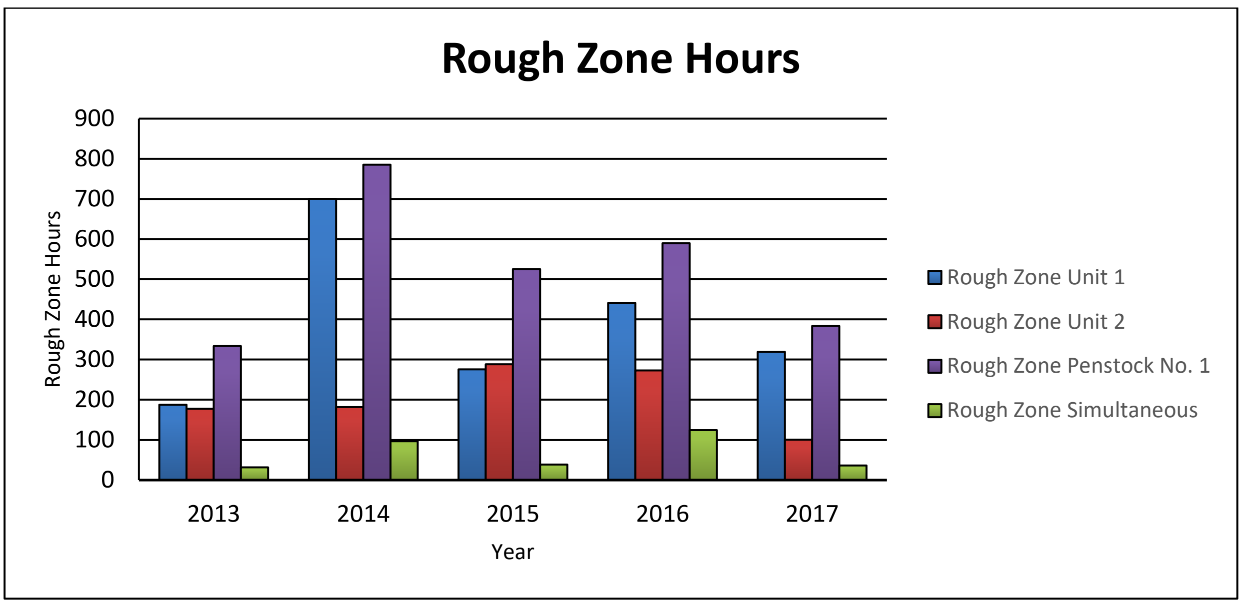


Figure 8-7: Rough Zone Trends

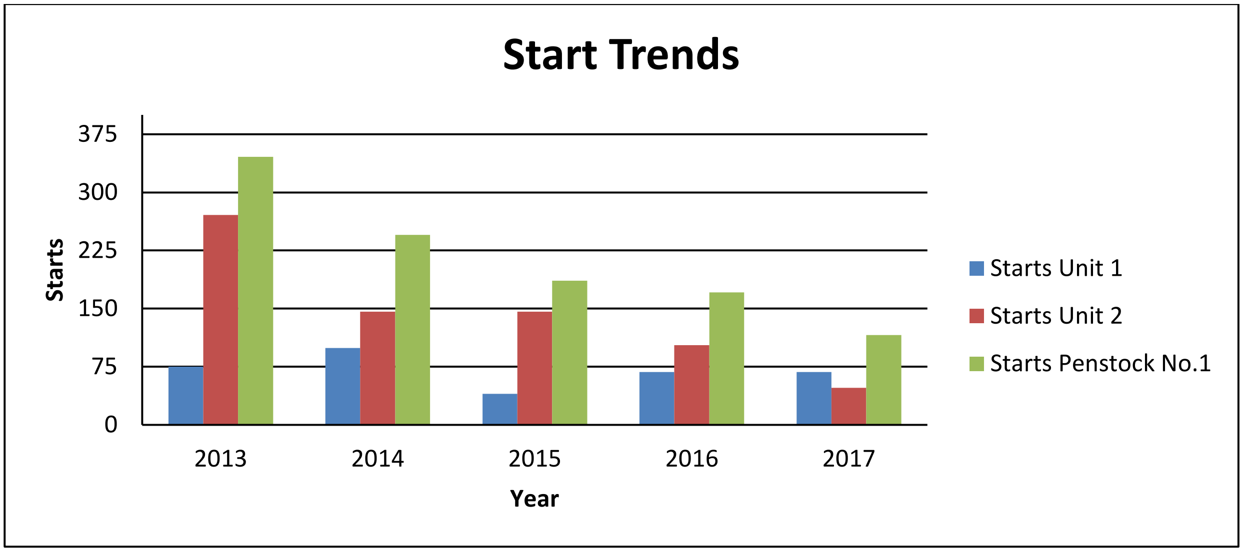


Figure 8-8: Start Trends

8.4 Fatigue Analysis

A comprehensive elastic fatigue analysis was carried out using the measured strains inside the penstock by the gauge closest to the longitudinal weld. The procedure prescribed in Section VIII Division 2 of the ASME Boiler and Pressure Vessel Code (Annex 3F) was used.

The maximum stress in the weld was calculated by extrapolating the measurements by the strain gauge and a factor (1.42) determined from finite element analysis. The contribution to fatigue by the various modes of operations and associated cyclic stress and number of cycles is summarized in Table 8-1 below.

Table 8-1: Fatigue Assessment – Total Cycle Damage (No Environmental Factor)

Zone	Fatigue Damage, D
Spherical Valve Opening	0.0025
2 Unit Rough Zone	0.1606
1 Unit Rough Zone	0.4512
Spherical Valve Closing	0.0036
Load Rejection	0.0024
Wicket Gate Opening	0.0258
Wicket Gate Closing	0.0433
Normal Operation	0.2428
Sum	**0.9322**

Note: A cumulative Fatigue Damage value of 1.00 indicates the design life has been reached.

The above table used a lifetime of cycles (~50 years) for all zones, except the rough zones. The lifetime of cycles used estimated frequencies of event cycles (i.e., number of times the spherical valve is closed in a given year) representative of the Bay d'Espoir facility. As the only available data for rough zone operation was from 2013-2017 these five years of rough zone data was used, and no rough zone operation was applied to the remaining 45 years of the penstock lifetime.

ASME BPVC VIII.2 notes an environmental modification factor should be applied to this calculation to account for fluid environment, loading frequency, temperature, and material variables, however, a factor for this specific application is not provided. ASME nuclear codes make reference to the environmental factor and these codes can be considered for general reference, but do not directly relate to penstock design. For example, NUREG/CR-6815 ANL-02/39 provides an environmental factor of 1.74 for carbon steels with temperatures less than 150°C. NUREG/CR-6815 also defines a factor of 4 for "moderate or acceptable environmental effects". As the internal penstock environment is known to be corrosive it seems highly likely that the inclusion of the environmental factor will result in a fatigue damage factor greater than 1.00, indicating that the design life has been reached.

Additionally, this analysis does not consider the fact that the penstock has undergone stresses exceeding the elastic limit of the material. This would increase the damage factor as well.

While several assumptions were required in this analysis, the results show that metal fatigue near the longitudinal seam is a large contributing factor of the most recent failure of Penstock No. 1.

A FE elastic perfectly plastic model was used to determine the plastic strain induced in the penstock at the peaking region from the first pressurization and each consecutive de-water and water up (de-pressurization to re-pressurization). The model used a pressure range of 0 psi (uniform pressure) to 45 psi (maximum pressure during high level head pond and load rejection). The elastic perfectly plastic model does not account for strain hardening which is conservative in nature as strain hardening would increase the yield stress upon each successive cycle until failure. The penstock material is able to withstand approximately 15% plastic strain induced before failure. Upon the first pressurization, the penstock has an induced strain of approximately 1.5%. Once plastic strain is induced, each successive cycle only adds a small additional amount of plastic strain until the point of failure. This amounts to approximately 100 dewatering cycles for design backfill geometry, or approximately 580 dewatering cycles for updated backfill geometry, before a failure point is reached.

8.5 Probable Cause of Failure

The strain gauge measurements have confirmed the presence of very high stresses (greater than Yield Strength) in the vicinity of the penstock longitudinal welds on the inside. It is not uncommon for ductile materials to redistribute high localized stress by yielding locally. A failure in such circumstances can result from fatigue due to cyclic loading. The cyclic stresses measured during rough zone operations are most likely to have contributed significantly to fatigue failure. This is interesting as it was not anticipated that the rough zone operations would result in significant stress fluctuations in the penstock.

Based on recent discussions, we understand the September 2016 repair was carried out by forcing the split plates together in order to close the gap to allow it to be welded together. This would have caused very high residual stresses in the parent material and the weld. The combination of the residual stress, the high localized stresses due to internal pressure and newly discovered cycling loading from rough zone operation are likely to have resulted in the November 4, 2017 failure. The failure occurred within 14 months of the original 2016 failure so corrosion would not have played a role this time.

Although the magnitude of stress range due to load rejection is higher (2 to 3 times) than that due to rough zone operation, the number of high stress cycles at each load rejection is less than 10, whereas the rough zone operation involves many more cycles (hundreds of thousands to upwards of millions each year).

It is unlikely that a repeat failure such as that occurred at Can 35, 14 months after the previous failure, can occur prior to any inspections during the summer of 2018. This conclusion is based on the following:

- The residual stresses introduced by the method of repairing the failure in Sept 2016 are absent in the current refurbishment.
- The reinforcing plate welded over the refurbished weld seam in 2017 shares the pressure load and reduces stress in the refurbished weld by nearly 50%.
- The high localized stress due to peaking at the original longitudinal weld in Cans 34 and 35 does not exist as the peaking is not there anymore; a new plate was inserted which blends well with the radius of the penstock shell.
- The 29 cans with weld defects were refurbished and have a reinforcing plate to reduce the localized stress due to peaking geometry. It is noted that not all longitudinal welds were refurbished and a majority of them still exhibit peaking from original fabrication along with the accompanying high localized stress. However, with no previous signs of cracking in these longitudinal seams it is not anticipated there will be problems over the next 6 months.
- With the discovery of rough zone impact on the penstock, the number of alternating load cycles while operating in the rough zone is expected to be reduced significantly as operation in the rough zone will be reduced significantly to suit these new findings.

Fatigue analysis indicates that a combination of alternating stresses in the penstock measured during rough zone operation combined with the operation of the spherical valves, wicket gate opening and closing, and operation of the units outside the rough zone have contributed to significant fatigue of the penstock. Amongst these the highest contribution is from rough zone operation (61%), followed by operation outside the rough zone (21%). It should be noted that the latter (normal operation outside the rough zone) is accumulated over the 50-year life-time.

9. Risk Assessment

This section examines the risk of penstock failure during the 2018 year.

	Description of Risk	Mitigation	Risk Ranking	Consequences	Actions
1	Cracks develop at the location of previous repairs	Peaking geometry causing high local stresses has been removed. An overlapping patch plate has been welded to cover the longitudinal welds and thus share the load due to internal pressure. All welds have been inspected by magnetic particle examination (MT).	Low	Failure resulting in Units No.1 and No. 2 being unavailable for power generation	None
2	Cracks develop at other longitudinal welds in the upper section of the penstock.	All welds were MT inspected. Defects were removed and refurbished by welding followed by MT. A 22' wide patch plate was welded on top of each refurbished longitudinal weld on the inside to reduce high local bending stresses caused by peaking geometry.	Low	Failure resulting in Units 1 and 2 being unavailable for generation	Inspect Penstock No. 1 during the 2018 summer and determine future inspection frequency.
3	Accelerated growth of cracks in longitudinal welds due to cyclic Loading	It is recommended that Units No. 1 and No. 2 are operated in the rough zone no longer than necessary during load ramp up and shut-downs	Low	Failure resulting in Units No. 1 and No. 2 being unavailable for generation	Do not operate in the rough zone
4	Other sources of transient pressure due to unknown events such as malfunction of spherical valve operation	Investigate spherical valve operation; measure pressure at the valve and in the penstock during valve closing, closed and opening. Remove any potential of hunting in the seal controls which may cause pressure transients	Low	Failure resulting in Units No. 1 and No. 2 being unavailable for generation	No unknown events have been observed during this study, recommend continued monitoring of pressure data.
5	Adequacy of backfill support for the penstock	Backfill has been added on top and the backfill profile on the penstock has been upgraded to reduce risk of sloughing or unsymmetrical loading on the penstock	Very Low	High stresses in the penstock due to longitudinal bending	None in 2018
6	Penstock failure resulting in loss of bedding due to erosion by release of water	Based on the lower pressures and history of previous ruptures, the failed section of the penstock exhibits "Leak before catastrophic failure" characteristics. Therefore, monitoring can reduce consequences of failure. It is recommended that the penstock	Low	High stresses in the penstock due to longitudinal bending could result in a massive failure	Daily inspection; install camera for monitoring; investigate source of any observed leaks.

	Description of Risk	Mitigation	Risk Ranking	Consequences	Actions
		be inspected visually every day for water leakage. Cameras should be used to give the plant operator a view of the upper reaches of the penstock. Installation of an infra-red camera should be explored.			
7	Damage caused by Load Rejection	The penstock was commissioned and tested for one-unit load rejection. Theoretically, a simultaneous two-unit load rejection could double the range of pressure cycles and hence the localized stresses near the longitudinal welds. It is recommended that a visual inspection of the penstock be carried out after each load rejection (one or both units).	Very Low	Premature penstock failure causing unavailability of the units	Visually inspect penstock after each load rejection,

10. Long-Term Solutions for Penstock No. 1

The refurbishment of Penstock No. 1 in November 2017 was carried out with the primary purpose of reinstating it into service at the earliest possible date while ensuring penstock rupture would not occur during the winter months. The investigation into the cause of recent failures discussed in this report leads to the conclusion that there is a structural concern with Penstock No.1; the original fabricated deviation from the circular geometry at the longitudinal welds. ASME BPVC VIII.1 states the permissible out-of-roundness of cylindrical shells shall not have a cross sectional difference exceeding 1% between the maximum and minimum diameter (1% of 17' diameter equals ~50.8 mm; measurements of peaking is upwards of 60 mm on the diameter), therefore the penstock is not within the permissible limits. This combined with the pressure fluctuations resulting from turbine operation, the corrosiveness of the water and the age have all contributed to the recent ruptures. While the penstock may last several more years before the next failure, long-term solutions should be examined.

Table 10-1 is a preliminary list of possible long-term solutions with advantages and disadvantages of each.

The scope of this study and time constraints do not permit an analysis or discussion of these alternatives at this time. The identification of a long-term solution requires further study.

Table 10-1: Long Term Solution Matrix

Item Number	Description	Advantages	Disadvantages
1	Replace entire penstock (or portions of penstock) with new penstock run parallel to existing structure.	1. Low risk of failure 2. New penstock can be constructed to meet current standards 3. Existing penstock can remain in operation until final tie ins	1. High cost 2. Large amount of civil work required 3. Encroaching on Penstock No. 2 backfill and cover is likely 4. Heavy machinery, lifting activities, and excavation around two operational penstocks. 5. High likelihood of weather delays 6. High likelihood of requiring rock blasting.
2	Replace sections of penstock in phases in-situ	1. Low risk of failure 2. New penstock can be constructed to meet current standards 3. Construction can be phased 4. Not disturbing Penstock No. 2	1. High cost 2. Multiple outages required 3. Cost of removal of existing penstock will be incurred 4. High likelihood of weather delays
3	Install internal weld seam reinforcing similar to work completed in 2017 on Cans 34 and 35.	1. Lower risk of failure 2. Construction can be phased 3. Work is all internal and weather delays would be minimal 4. Not disturbing Penstock No. 2	1. High cost 2. Multiple outages required 3. Work is confined space 4. Extensive scaffolding requirement 5. Possible flow disturbances caused by plates protruding into flow contributing to head loss 6. Long-term effectiveness not predictable
4	Install external weld seam reinforcing similar to the refurbishment completed in 2017 on Cans 33 through 36.	1. Low risk of failure 2. Construction can be phased	1. High cost 2. Requires removal and reinstatement of backfill for exterior shell access. 3. High likelihood of weather delays 4. Long-term effectiveness not predictable
5	Form around penstock and encase in concrete	1. Low risk of failure 2. Construction can be phased 3. No outages required 4. Not disturbing Penstock No. 2	1. High cost 2. High likelihood of weather delays 3. Corrosion due to moisture between steel and encasement could lead to premature failure
6	Install external stiffener rings	1. Low risk of failure 2. Construction can be phased	1. High cost 2. Requires removal and reinstatement of backfill for exterior shell access. 3. Extensive excavation and shoring requirements to install full 360 degree stiffeners. 4. High likelihood of weather delays. 5. Due to extensive excavation requirements there is a possibility of encroaching on Penstock No. 2. 6. Existing material is prone to sloughing which presents a large safety risk to personnel working inside extensive trenches. 7. Requires multiple outages 8. Does not eliminate the stress intensification at the bulge except in the vicinity of the stiffener rings
7	Install internal stiffener rings	1. Low risk of failure 2. Construction can be phased 3. Work is all internal and weather delays would be minimal 4. Not disturbing Penstock No. 2	1. High cost 2. Multiple outages required 3. Work is confined space 4. Extensive scaffolding requirements 5. Increased head loss due to flow disturbances caused by rings protruding into flow. 6. Does not eliminate the stress intensification at the bulge except in the vicinity of the stiffener rings 7. Potential output reduction
8	Install new steel liner inside existing penstock	1. Low risk of failure 2. Construction can be phased 3. Work is all internal and weather delays would be minimal 4. Not disturbing Penstock No. 2	1. High cost 2. Multiple outages required 3. Work is confined space 4. Extensive scaffolding requirements. 5. Risk of corrosion due to moisture trapped between the two shells. 6. No access for full penetration welds of circumferential joints. 7. Higher head loss due to reduced cross-section

Item Number	Description	Advantages	Disadvantages
9	Install Fiberglass liner	1. Low risk of failure 2. Construction can be phased 3. Work is all internal and weather delays would be minimal 4. Not disturbing Penstock No. 2	1. High cost 2. Multiple outages required 3. Work is confined space 4. Extensive scaffolding requirements
10	Install concrete liner	1. Low risk of failure 2. Construction can be phased 3. Work is all internal and weather delays would be minimal 4. Not disturbing Penstock No. 2	1. High cost 2. Multiple outages required 3. Work is confined space 4. Extensive scaffolding requirements 5. Possibility of concrete becoming dislodging during operation and migrating into the turbine 6. Higher head loss due to reduced X-section.
11	Cut top off of existing penstock and install new penstock inside	1. Low risk of failure 2. New penstock can be constructed to meet current standards 3. Construction can be phased 4. Not disturbing Penstock No. 2 5. Reduced excavation costs	1. High cost 2. Multiple outages required 3. Cost of removal of existing penstock material will be incurred 4. High likelihood of weather delays 5. The material of the lower half of the old penstock has corroded and has been subjected to cyclic loading which could shorten its life.
12	Increase inspection frequency (once per year) and keep existing penstock in service	1. Medium risk of failure 2. No capital cost incurred 3. Existing penstock can remain in operation	1. Increased operational cost 2. Possibility of failures occurring in heating season 3. Units not available for production during inspection outages.
13	Cut out a section of the shell plate around each longitudinal seam and weld in place a rolled plate section, similar to the manner in which the 2017 refurbishment was carried out but without any external reinforcing plates	1. Lower risk of failure 2. The stress concentration at the longitudinal weld due to non-circular geometry is reduced significantly. 3. Construction can be phased 4. Not disturbing Penstock No. 2	1. Labor intensive with higher cost 2. Multiple outages required 3. Cost of removal of existing penstock material and backfill will be incurred 4. High likelihood of weather delays 5. Longevity of the solution is not predictable.
14	Combination of Alternatives (12) and (13): Inspect the penstock annually and if defects continue to show up, remove section of plate with the longitudinal weld and weld in place a new inserted rolled plate	1. Medium risk of failure 2. Moderate capital cost incurred to allow deferment of high capital requirement for total replacement 3. Existing penstock can remain in operation	1. Increased operational cost 2. Reduced possibility of failures occurring in heating season 3. Units not available for production during inspection outages.
15	Installation of Unit number 8 on Penstock No.4 and utilizing Penstock No.1 as back up and repair on an as needed basis	1. Lower risk of failure 2. Operational time of failure prone penstock is greatly reduced. 3. Construction can be phased 4. Not disturbing Penstock No. 2 5. Allows reserve capacity for more maintenance flexibility which is required for aging assets.	1. High cost 2. Large amount of civil work required 3. Heavy machinery, lifting activities, and excavation around one operational penstock. 4. High likelihood of weather delays 5. Higher head loss = less output

11. Penstock No. 2 and No. 3

Penstock No. 2 was built to the same design and specifications as Penstock No. 1 and was constructed a year later. External rings on Penstock 2 were discovered during inspection in 2016. However, these rings are not detailed on any drawings, nor mentioned in any historical information, and therefore the reason for them is not understood. Under similar operating conditions and depending on their design, a penstock with external rings would be expected to last longer. NDT of internal longitudinal welds in 2016 showed significantly fewer defects as compared to Penstock No.1.

Penstock No. 3 which is a similar design was built a couple of years later than Penstock No.2. However, the drawings show a symmetrical and improved backfill design. These drawings, and those for the other two penstocks, do not show any external reinforcing rings.

Considering the similarity in the design and operating conditions of the three penstocks and the recent ruptures in Penstock No. 1, it is prudent to have a comprehensive inspection and assessment program for Penstocks No. 2 and 3. This should include measurement of any deviations from circularity of the penstock profiles at the longitudinal welds. This can be performed by laser survey similar to Penstock No. 1 as completed in 2017. Backfill should be removed at a few locations to ascertain the size and spacing of any external stiffener rings. NDT of the longitudinal seams and shell thickness measurements should be carried out inside the penstock. Since all 6 of the BDE units are known to suffer from instability due to draft tube surges, instrumentation should be installed to determine the pressure variations in the penstock during start, stops and regular operation.

12. Conclusions

Visual inspection of the November 4, 2017 failure and metallurgical examination of the material indicates that the failure originated at the toe of the previous repair weld and progressed through the parent material. Metallurgical testing completed by Atlantic Metallurgical Consulting and Wayland Engineering concluded the material in the penstock met the criteria for the specifications on the design drawings and there were no brittle microstructures induced by the welding process. No metallurgical contribution can be attributed to the rupture. This failure was most likely caused by a combination of the following factors:

- High residual stress due to re-welding of the failed seam in 2016 under high load that was used to bring the two edges of the ruptured joint together.
- Highly localized bending stresses due to the original construction geometry (peaking) at the longitudinal weld seam under internal pressure (measured and verified by FE modeling).
- Fatigue caused by high cycle low amplitude stresses due to extended operation in the rough zone.
- Fatigue caused by high cycle low amplitude stresses due to pressure fluctuations during normal operation over the 50-year life-time.

Hatch believes that the risk of failure of Penstock No. 1 from now until the next inspection, which will take place in the summer of 2018, is relatively low. Based on the observation in November 2017 that showed defects appear in 8% of the longitudinal welds refurbished the previous year, it is possible that similar cracks may begin to form but is unlikely they will progress to a critical depth to cause a rupture within this timeframe. However, it should be noted that very high stresses were measured in the vicinity of the longitudinal welds under normal pressure and that the penstock has accumulated damage over its life time in other areas not detectable by the inspections carried out.

Backfill has only a marginal improvement of stresses for a pressurized penstock but significantly reduces the circumferential bending stresses when de-watering, empty, and watering up the penstock.

13. Recommendations

The following recommendations have been already implemented.

- Refurbish the section of the failed penstock (Can 34) by removing the entire segment with the crack, insert a new ½" thick plate and weld in place followed by MT. Install a reinforcing overlap plate over the ruptures in Cans 34 and 35.
- MT all longitudinal welds between the intake and the surge tank on the inside. Remove defects, reweld and MT. Install a 22" wide patch plate over the refurbished weld on the inside to reduce the localized bending stress due to the peaking at the weld.
- Add backfill to make it symmetrical and prevent sloughing over the penstock where this has not already been completed.
- Install strain gauges and pressure transducers in the vicinity of the failed areas (Cans 34 and 35) of the penstock and monitor during commissioning and periodically thereafter (unusual events such as load rejections until February 2018.
- Operation of the units in the rough zones has been limited to that necessary to ramp up and down through the rough zone.
- Walk the penstock once a day and after unusual pressure transients, such as load rejections, for evidence of leaks and regularly observe the area by camera.
- Develop alternatives for long-term mitigation.

It is recommended that Penstock No.1 which serves Unit No. 1 and No. 2 operation may be continued with the following considerations:

- Continued operation of the units in the rough zones should be limited to that necessary to ramp up and down through the rough zone.
- Continue to walk the penstock once a day and after unusual pressure transients, such as load rejections, for evidence of leaks and regularly observe the area by camera.
- Verify integrity of existing strain gauge signals by testing continuity. Purchase a data acquisition system capable of receiving data from the existing instrumentation. Continue to monitor the remaining strain gauges and pressure transducer periodically.
- Further develop alternatives for long-term mitigation.
- Inspect Penstock No. 1 during the summer of 2018. Inspection procedure should be as follows:
    - Inspect interior welds on new plates welded into penstock using visual and magnetic particle. Welds need to be cleaned prior to inspection.

- Inspect 5 additional cans upstream and downstream of the ruptured area (Cans 34-36) visually and with magnetic particle. Once complete, inspect every 10th can upstream of the rupture area to the intake and similarly downstream to the surge tank. If defects are found in welds, increased inspection frequency may be recommended.
- Inspect the penstock downstream of the surge tank by laser scanning for out of roundness at the longitudinal welds present in the upper reaches of the penstock.

Penstock No. 2 should be inspected at the next available outage as follows:

- Inspect welds on every 10th can between the intake and the surge tank with visual and with magnetic particle. Prior to inspection, welds need to be cleaned. If defects are found in welds, increased inspection frequency may be recommended.
- Complete internal laser survey to check ovality and peaking.
- Install a pressure transducer to determine if pressure variations similar to Penstock No. 1 exist.

Penstock No. 3 should be inspected at the next available outage as follows:

- Inspect welds on every 10th can between the intake and the surge tank with visual and with magnetic particle. Prior to inspection, welds need to be cleaned. If defects are found in welds, increased inspection frequency may be recommended.
- Complete shell thickness measurements.
- Complete laser survey to check ovality and peaking.
- Install a pressure transducer to determine if pressure variations similar to Penstock No. 1 exist.
- Depending on findings, testing to determine mechanical and chemical properties of penstock material may be recommended.

Planned backfill and future re-coating operations for Penstock 1 should be postponed. Based on findings from planned inspections, if no further deterioration of the welds is discovered, replacement of the penstock would likely be unnecessary in the short term. Backfill and re-coating would then be required for long term operation if the penstock, or sections of it, are not replaced. If further deterioration is encountered, the long-term solutions should be revisited.

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PENSTOCK NO. 3
INSPECTION AND EVALUATION

BAY D'ESPOIR HYDROELECTRIC DEVELOPMENT

Prepared for:

Newfoundland and Labrador Hydro
St. John's, Newfoundland and Labrador

Prepared by:

Kleinschmidt

Halifax, Nova Scotia
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December 2017

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LIST OF ABBREVIATIONS

ASCE	AMERICAN SOCIETY OF CIVIL ENGINEERS
ASME	AMERICAN SOCIETY OF MECHANICAL ENGINEERS
CH	CHAINAGE (IN METERS)
CMS	CUBIC METERS PER SECOND
FU	ULTIMATE TENSILE STRESS
FY	YIELD STRESS
GWH	GIGAWATT HOURS
KPA	KILO-PASCALS
KLEINSCHMIDT	KLEINSCHMIDT ASSOCIATES
MW	MEGAWATTS
NL HYDRO	NEWFOUNDLAND AND LABRADOR HYDRO
SPRAT	SOCIETY OF PROFESSIONAL ROPE ACCESS TECHNICIANS
STA	STATION (IN FEET)
TRR	TECHNICAL ROPE AND RESCUE
UT	ULTRASONIC THICKNESS

PENSTOCK NO. 3
INSPECTION AND EVALUATION

BAY D'ESPOIR HYDROELECTRIC DEVELOPMENT

EXECUTIVE SUMMARY

Newfoundland and Labrador Hydro (NL Hydro) contracted with Kleinschmidt in February 2017 to inspect and evaluate the condition of Penstock No. 3 at the Bay d'Espoir Hydroelectric Development. In 2016, cracking was identified in Penstock No. 1 due to weld degradation and Kleinschmidt was contracted to assist with the weld repair design. Penstock No. 3 was installed in 1968, a year after the No. 1 and No. 2 penstocks, with similar plate materials, thicknesses, and weld procedures. After the cracking found in Penstock No. 1 raised concerns about the weld integrity of Penstock No. 3 as well, NL Hydro elected to have Kleinschmidt complete a detailed inspection and evaluation in 2017. NL Hydro also inspected Penstock No. 2 following Kleinschmidt's inspection of Penstock No. 3 and found some weld corrosion similar to Penstock No.1 which they have repaired in a similar manner. The main focus of the inspection was to assess the integrity of the welds and to complete steel thickness measurements to evaluate potential life extension of the penstock and appurtenances.

A detailed interior inspection was completed that included an up close visual and sounding inspection of representative welds and the collection of thickness measurements using ultrasonic non-destructive testing methods (NDT) by Kleinschmidt engineers. A structural evaluation was also completed using current design codes and the thickness data collected during the inspection.

Welds were inspected along length of the penstock but with more frequent intervals where the cracking was found in Penstock No. 1. The welds were cleaned with a hammer, wire brush then clean cloth to a clean finish for visual inspection and then sounded with a hammer. The weld edges, shape and size of the bead, level of corrosion and proneness to chipping were noted for each weld that was inspected. The condition of the weld and visual condition prior to cleaning was also noted by the engineers to compare visually with other welds that were not cleaned.

No significant deficiencies were noted with any welds inspected. The longitudinal welds in the flat section of Penstock No. 3 (approximately STA 5+00 (CH 151.5) to STA 8+00 (CH 242.4)) were the poorest and corresponds to the area of the crack in Penstock No. 1. Beads were nominally flat with the surrounding base material with similar corrosion. There was no indication of cracking and weld edges were smooth transitions from the base material. These welds were generally in fair condition and in better condition than that seen from photos of Penstock No. 1 in the same geographic area.

Measurements of the penstock shell thickness indicate minimal loss of material thickness. Some mild to moderate pitting was noted with organic material buildup on the interior. Assuming similar rates of material loss, the penstock should have significant service life remaining. The coating was in fair condition.

The structural evaluation showed stress ratios for a combined static and dynamic internal pressures peak at 1.10. This indicates that the penstock does not meet present day design criteria for new penstock design. However, when the hoop stress is compared to the plate yield stress the minimum factor of safety is 1.36, acceptable for late 1960 steel pipe.

This approximately 50-year-old penstock, however, has shown little loss of thickness from the original plate thicknesses. We therefore anticipate that the penstock has an additional 80 years of useful service life (est. 2097) provided that the penstock interior coating is replaced before the steel begins to significantly deteriorate and is adequately maintained and monitored. In addition to recoating the penstock in 10 to 15 years, Kleinschmidt recommends continued monitoring of the exterior of the penstock for signs of leakage and detailed inspection of the interior in five year intervals until the penstock is recoated.

PENSTOCK NO. 3
INSPECTION AND EVALUATION
BAY D'ESPOIR HYDROELECTRIC DEVELOPMENT

1.0 INTRODUCTION

Newfoundland and Labrador Hydro (NL Hydro) contracted with Kleinschmidt in February 2017 to inspect and evaluate the condition of Penstock No. 3 at the Bay d'Espoir Hydroelectric Development.

In 2016, cracking was identified in Penstock No. 1 due to weld degradation and Kleinschmidt was contracted to assist with the weld repair design. Later in 2016, Kleinschmidt performed a full inspection and evaluation of Penstock No. 2 as it is the same age, 1967, and construction as Penstock No. 1. Penstock No. 2 was found to be in good condition with only minor maintenance and repair items identified to ensure that the penstock continued to operate as required.

Penstock No. 3 was installed in 1968, a year after the No. 1 and No. 2 penstocks, with similar plate materials, thicknesses, and weld procedures. After the cracking found in Penstock No. 1 raised concerns about the weld integrity of Penstock No. 3 as well, NL Hydro elected to have Kleinschmidt complete a detailed inspection and evaluation in 2017. The main focus of the inspection was to assess the integrity of the welds and to complete steel thickness measurements to evaluate potential life extension of the penstock and appurtenances.

This report presents our evaluation of the capacity of the penstock in its current condition, provides recommendations for inspection procedures in the future, and estimates the remaining service life.

2.0 PROJECT DESCRIPTION

NL Hydro owns and operates the Bay d'Espoir Hydroelectric Development in Bay d'Espoir Newfoundland, Canada. The Project went into service in 1967 and is supplied by Jeddore Lake. The tailrace feeds a canal leading to the tidal waters of Bay d'Espoir and the Atlantic Ocean. The plant has a hydraulic head of approximately 176 meters (577 feet) and seven generating units with a total capacity of 604 megawatts (MW). The development comprises two intake structures, feeding four penstocks into two powerhouses where seven units operate with a total annual generation of approximately 2,650 gigawatt hours (GWh). Penstocks No. 1, No. 2, and No. 3 have surge towers approximately 727 meters (2400 feet) upstream of the powerhouse. The first phase of the project construction involved the installation of the main intake structure and a four-unit powerhouse with Penstocks No. 1 and No. 2 connecting the two. The second phase consisted of installing Penstock No. 3, along with two additional units in the powerhouse, and a separate intake structure and powerhouse for Unit No. 7, connected by Penstock No. 4 in 1970. Penstock No. 3 supplies Units No. 5 and No. 6. The rated flow across all seven units is 397 cubic meters per second (m^3/s) (14,020 cubic feet per second (cfs)).

Penstock No. 3 is buried along its entire length from the intake to the powerhouse. There are three large manholes located on the crown of the penstock; (1) approximately halfway between the powerhouse and surge tower, (2) at the surge tower, and (3) halfway between the intake and the surge tower.

Appendix A includes the original 1968 profile drawings of the penstock including original plate thicknesses. The penstock steel plate thicknesses range from 7/16 inches at the intake to 1 5/8 inches at the bifurcation upstream of the powerhouse (plate thicknesses are expressed in inches because the original design was based on inches matching the drawings provided). The penstock is constructed of A285, G40.88 and HSB 50 steel. The penstock is 17.0 feet in diameter until STA 12+41 (CH 376.2), then 15.25 feet in diameter between STA 12+41 (CH 376.2) and STA 27+50 (CH 833.3) where it then reduces to 13.5 feet in diameter for the remaining 1581 feet (479.1 meters) to the bifurcation. The welds are generally double V groove full penetration welds. The penstock slope varies from approximately 0 degrees to 20 degrees just upstream of the bifurcation.

The penstock is buried along its entire length. It has three manholes along its length along with access at the intake and scroll case. A majority of the penstock has a cover of two feet (0.61 meter) (minimum) of clayey soil and one foot (0.30 meter) of riprap. The penstock is deeply buried as it crosses under the switchyard and goes into the powerhouse. The penstock has drainage long its length with several weirs where the drainage daylights to the ditches and wells for inspection and monitoring.

3.0 INSPECTION

Christopher Vella, P.E., and Keenan Goslin, P.E., of Kleinschmidt inspected the interior and exterior, of Penstock No. 3 on April 25 and April 26, 2017, with the assistance of personnel from Technical Rope & Rescue and NL Hydro. NL Hydro personnel assisted with safety procedures and site access and answered questions about the history, operation, and maintenance of the station.

Kleinschmidt's inspection consisted of measuring shell thicknesses, identifying any pitting or cracking, and an overall general condition assessment of the interior of the shell. The exterior of the buried penstock was examined for signs of leakage. Appendix C Table 1includes our key field observations in the notes.

3.1 WORKING CONDITIONS

Kleinschmidt's inspection team entered the penstock at the intake structure of Penstock No. 3 each day. TRR assisted with confined space entrance and rigging for fall restraint. The penstock has varying slopes with two steep sections. The penstock slopes range from less than a degree to a 20 degree slope upstream of the powerhouse as noted in Appendix A. The grade levels out as the penstock enters the powerhouse. Ropes were used to access the steep portions of the penstock upstream of the surge tank and upstream of the bifurcation. A few inches of water was at the invert of the penstock and intake due to leakage of the headgate. Leakage was mainly at the top corners of the gate and left seal approximately halfway up the gate as seen in Photo 1 (Appendix B). The penstock surfaces were generally dry otherwise.

The exterior of the penstock was inspected on April 26, 2017. The ground surface was generally rock covered with steep slopes in many areas and short vegetation. Several areas still had snow cover. Deeply buried sections under the dam and switchyard were not inspected from the exterior.

All stationing measured during Kleinschmidt's field inspection is based on the beginning of the pressure conduit acting as STA 0+00 (STA 1+38 (CH 41.8) on the Appendix A drawings) with stationing measured in feet. All downstream field stationing was then measured on the penstock inclined length rather than the horizontal stationing on the drawings. The field stationing has been converted to match the drawing horizontal chainage for this report. The field data is still included in Appendices C and E. The field stationing for the penstock did not match the reference drawings exactly, but plate thicknesses reported for each location should be comparible to measured values due to the selection of measurement locations. For the purpose of this report, all stationing is reported to match the Appendix A reference drawing with stationing in feet and the metric equivalent given in meters.

3.2 INTERIOR INSPECTION

The interior of the penstocks were inspected on April 25, 2017, and April 26, 2017. All stationing measured during Kleinschmidt's inspection is based on a start point at the upstream end of the steel conduit, STA 1+38 (CH 41.8) as noted in the reference drawings included as Appendix A. The penstock was inspected from this upstream end of the conduit to the bifurcation, STA 38+29 (CH 1160.3), just upstream from the scroll case. Field stationing for the lower penstock inspection was measured with respect to the centerline of the surge tower (STA 22+50 (CH 681.8)) continuing downstream towards the powerhouse and then compiled and aligned with the section of penstock upstream of the surge tank for data tabulation and reporting.

Penstock thickness readings were recorded from the interior at various locations. Shell thickness measurements were taken with a Panametrics Model 45MG Ultrasonic thickness gage. A dual element transducer, Panametrics Model D790, was used and the readings were taken in the "standard" mode. In "standard" mode the paint thickness does not affect the steel thickness readings if the paint thickness is below 1/64 (0.0156) inch (15.6 mils). The gage was calibrated before the field measurements to an accuracy of 0.001 inch. Due to the fact that both the field measurements and Appendix A drawings give shell thicknesses in inches, this evaluation did so as well. Metric equivalents are given in parenthesis.

Thickness readings were recorded from the interior of the penstock generally near the invert of the penstock, typically near 5 o'clock, 6 o'clock and 7 o'clock based on an orientation looking downstream. All references to penstock left and right are also oriented looking downstream. Table C-1 and Table C-2 in Appendix C summarizes the average shell thickness readings and stresses respectively for each section of penstock. A summary of this data is provided in Table 4-1.

The following sections describe the interior shell, joint condition and presents our observations of dents.

3.2.1 Interior Surface, Coating and Joint Condition

Penstock No. 3 is fabricated from 30 different plate sizes ranging from 7/16 to 1 5/8 inches. Inspection thickness readings were taken at 17 of these plates, ranging from 11 millimeters (7/16-inch) to 33.1 millimeters (1.303-inch). Many of these sections exhibited little to no appreciable material loss with thickness readings averaging more than 0.95% greater than the listed original plate thickness. There are a few localized exceptions where 29 readings are less than the design plate thickness. These are all at areas of pitting corrosion and overall readings for the station were still above the design thickness.

The interior of the penstock is generally in good condition with some scattered moderate corrosion and pitting with tubercles and growth. The majority of thickness measurements were taken within these pits and many readings read at or just slightly above the original thicknesses marked on the drawings. Pitting was minor however and detailed pit measurements were not taken. This is expected of steel construction from this era when steel plate was frequently rolled out slightly thicker than called for in the design to account for fabrication tolerances. There was no need for grinding the steel, we were able to obtain thickness readings by scraping off the other layer of water silt/debris build up and rust turbicles.

There was evidence of localized delamination throughout the penstock and at the bifurcation (Photo 5, Photo 28 and Photo 29). At STA 1+93 (CH 58.5), the coating begins to deteriorate and is more pronounced on the left from invert to about two-thirds of the diameter. At STA 2+64 (CH 80) there is fresh coating loss and at STA 4+77 (CH 144.5) there is a patch on the ceiling. The amount of delamination may be due to temperature and weather conditions during application (if field applied) and potential scour at changes of elevation of the penstock.

The welded joints were in fair condition and did not have any apparent visible cracks or excessive deterioration (see Photos 9 thru 22). The inspection of the welds in Penstock No. 3 was in greater detail than the visual inspection of suspect joints conducted in 2016 of Penstock No. 2 in that more locations were inspected and an impact hammer was used to test the weld strength. Welds in Penstock No. 3 were cleaned with a scraper and wire brush and then wiped clean. An initial visual inspection of the height of the bead, condition of the bead in regards to pitting, corrosion or cracking, was conducted. The weld was also impacted with a geoligists hammer to assess the integrity of the weld joints. The shape of the bead was assessed and its continuity with the base material. The welds upstream of the surge tank were inspected twice as frequent at the request of NL Hydro. The welds were manually exposed and hammered to test for weld integrity. The welds in this area were noted to be in worse condition when compared to welds downstream of the surge tank. Corrosion of the welds was fair to good for all. These welds did not display the conditions found in Penstock No. 1.

At 15+50 (CH 469.7) the weld bead of the horizontal weld was noted not to be as high as the rest of the welds. At STA 18+18 (CH 550.9), the weld was in very good condition. Ovalization measurements of the penstock were taken at STA 23+66 (CH 717.0) with a vertical measurement of 13 feet 7 inches (4.12m) and horizontal measurement of 13 feet 4 inches (4.04m). Ovalization was noted visually along the remaining length of penstock with no noticeable ovalization of the cross section.

3.2.2 Appurtenances

Penstock appurtenances include vents, valves, access ports, manholes, and other components of the penstock other than supports. Bay d'Espoir's Penstock No. 3 has three large manholes and a bifurcation wye at the powerhouse.

The manholes were in fair condition with moderate corrosion of the interior surface of the manhole. The bottom plate was missing, Photo 23, at the unopened manhole approximately midway between the intake and surge tank (approximately STA 12+22 (CH 370.3)). The manhole at the surge tank was at approximately STA 22+20 (CH 672.7) and the opened manhole in the lower section was approximately at STA 33+10 (1003.0).

Drainage pipes and culverts were noted to be in fair condition and a broken culvert was noted downstream of the surge tank. A monitoring weir was identified with flow through the weir. Flow was not estimated in the field as it was apparent that a majority of the flow was due to snow melt. Drainage is shown along the length of the penstock in Drawing F2106-C-1 (Appendix A); however, the termination of the drainage plumbing and weirs are not shown.

The headgate and intake structure were in good condition with only minor leakage of the headgate apparent along the right side and bottom left corner of the headgate when looking upstream (Photo 3 and Photo 4).

3.2.3 SURGE TANK

The surge tank welds were visually inspected from the invert of the penstock. Emphasis was given to the areas where welds were cracked at the base of the surge tank for Penstock No. 2. Close up inspection of cleaned welds was not possible without the construction of scaffolding; however, no signs of distressed welds were noticeable from the base of the penstock.

3.3 EXTERIOR INSPECTION

Kleinschmidt began the exterior inspection at the intake and moved downstream. The penstock is buried along its entire length with rock fill over each of the penstocks as seen in Photo 1. Kleinschmidt observed the exterior ground surface for signs of leakage while walking the length of the penstock. Signs of leakage that were looked for include sloughing of the ground over the penstock and other depressions mainly. Neither of these conditions were found along the length of the penstock that appear recent indicating leakage is unlikely or not significant.

The weather was sunny, cool and snow was present in areas surrounding the penstock.

NL Hydro personnel excavated holes in designated areas around the crown of the penstock to expose the steel. Typical exterior shell conditions can be seen in Photo 2. The coating was examined and steel thickness measurements were taken at the exterior locations. The depth of cover varied from several inches to over several feet. The location of the holes was estimated from the drawings and is shown in Appendix A. Drainage for the penstock is important to maintain support for the penstock and should be repaired. Excessive ground water can erode support for the penstock and potential increase the potential of failures. Drainage also gives a method to monitor potential leakage. The broken culvert appears to have separated at joint. The culvert is shown in Photo 30.

4.0 EVALUATION

The purpose of the evaluation is to assess the condition of the penstock and its suitability for continued operation and to identify repairs or maintenance that may be required to ensure its safe operation. Based on Kleinschmidt's experience and judgment the four potential ways that the penstock could fail are (1) bursting due to excessive internal pressure or loss of shell thickness, (2) general buckling due to external pressure, (3) local buckling leading to tensile cracking or general buckling, and (4) local weld failure due to improper weld procedures during construction.

4.1 LOADING CONDITIONS AND ALLOWABLE STRESSES

The loading conditions and allowable stresses were determined from the criteria presented in the American Society of Civil Engineers (ASCE) Manuals and Reports on Engineering Practice No. 79 Steel Penstocks, 2nd Edition. The allowable primary stress intensity is the lesser of the material yield stress (F_y) divided by 1.5 or of the ultimate tensile stress (F_u) divided by 2.4. A summary of assumed yield stress, ultimate tensile stress, and allowable stress intensity for each section of penstock can be found in Appendix D. The allowable steel stress used in this analysis was 17,000 pounds per square inch (psi) for ASTM A285 and 24,000 pounds per square inch (psi) was used for CSA G40.8 Grade B. The yield strength of HSB 50 was assumed to be 50,000 psi; however, no reference was located for this value. No ultimate tensile strength was assumed so that allowable stresses in the evaluation were based on the yield strength criteria for HSB 50 steel (33,333 psi).

The welded seams are not as strong as the original base material; these strength reductions are designated as "joint efficiency, E" and are included in the penstock stress tables in Appendix C. A joint efficiency of 70% was assumed for all welded joints per Table 3-3 of ASCE No. 79.

Load cases considered include:

- stresses in the penstock under normal operating conditions;
- stresses in the penstock under flood conditions;
- transient stresses in the penstock during a load rejection at normal pond elevations;
- external surcharge loads in a dewatered condition

4.2 Shell Stresses Induced by Internal Pressure

Table 4-1 summarizes the statistical analysis of our steel-shell thickness data and internal pressure steel stress analysis results. See Appendix C for detailed thickness data and stress calculations. Average thickness and a 97.5% confidence interval (CI) were calculated for each station. The 97.5% CI is the average thickness minus 1.96 times the standard deviation of the thickness readings; it is considered the minimum thickness likely in the penstock and conservatively accounts for thicknesses less than the average thickness (ASCE 1995).

The maximum hoop stress in the penstock shell is due to internal static and dynamic water pressures. The stress ratio is the maximum hoop stress divided by the allowable steel stress. A hoop stress ratio less than 1.0 indicates that the penstock meets industry-standard factors of safety as designated in *ASCE Engineering Practice No. 79, Steel Penstocks* (2012).

Normal pond or Full Supply Level (FSL) and dynamic water hammer pressures were determined based on elevations given in the Appendix A drawings. Normal pond static pressures were based on an elevation of 597 feet (182m) at the intake. Transient pressures were taken with a peak dynamic or transient head elevation of 890 feet (271m) at the powerhouse and linearly reducing to 660 (201m) feet at the surge tower and then matching the FSL of 597 feet (182m) at the intake.

However, these ratios are based on current industry guidelines for new design. When the hoop stress is compared to the plate yield stress, also shown in Table 4-1, the minimum factor of safety is 1.36, acceptable for late 1960 steel pipe.

TABLE 4-1 SUMMARY OF THICKNESS DATA AND STRESSES DUE TO INTERNAL PRESSURE

STATION (ft.)	MAX JOINT STRESS[1,3] (psi)	DYNAMIC HOOP STRESS INCREASE[1,3] (psi)	TOTAL WATER HAMMER STRESS[1,3] (psi)	ALLOWABLE STRESS (psi)	STRESS RATIO[1,2,3]	FACTOR OF SAFETY AGAINST YIELD
1+47	5,439	404	5,843	17,000	0.34	4.28
3+44	6,941	1,308	8,248	17,000	0.49	3.03
5+46	9,594	2,020	11,614	17,000	0.68	2.15
8+38	13,913	3,252	17,165	17,000	1.01	1.46
11+68	17,565	4,463	22,028	24,000	0.92	1.63
15+50	16,644	4,130	20,774	24,000	0.87	1.73
18+18	20,819	4,284	25,102	24,000	1.05	1.43
19+48	20,426	4,219	24,645	24,000	1.03	1.46
20+38	23,992	4,905	28,897	33,333	0.87	1.73
21+38	22,001	4,432	26,434	24,000	1.10	1.36
22+80	24,110	4,681	28,792	33,333	0.86	1.74
23+66	24,953	6,000	30,954	33,333	0.93	1.62
25+20	24,453	6,860	31,313	33,333	0.94	1.60
26+74	23,421	7,467	30,888	33,333	0.93	1.62
28+30	23,321	8,408	31,729	33,333	0.95	1.58
29+85	22,465	9,054	31,519	33,333	0.95	1.59
31+54	22,786	10,068	32,854	33,333	0.99	1.52
33+19	21,702	9,908	31,610	33,333	0.95	1.58
34+75	22,904	10,504	33,408	33,333	1.00	1.50
36+19	21,559	9,887	31,446	33,333	0.94	1.59
36+19	22,521	10,199	32,720	33,333	0.98	1.53
37+44	22,618	10,136	32,754	33,333	0.98	1.53
38+63	23,095	10,527	33,622	33,333	1.01	1.49

[1] Joint efficiency of 0.7 included
[2] Total stress / Allowable stress
[3] Uses 97.5% confidence thickness
[4] SF = Fy/Total stress

4.3 GENERAL BUCKLING INDUCED BY EXTERNAL LOADS

General shell buckling occurs when an external pressure implodes the penstock shell along its longitudinal axis. The penstock was analyzed for buckling due to external loads applied to the top 120 degrees of the pipe. Per the National Building Code of Canada, the snow load calculated is 103 psf and the depth of soil cover on the penstock was assumed to be 3 feet. Conservatively, an additional live load of 100 psf was used for analysis to account for potential off road vehicle loads or equipment. The snow and live load combination uses a reduced snow and live load of 75 percent of each.

Three external loading combinations were considered in the analysis of the penstock. Load combinations include the following:

1. DL (water and steel) + internal vacuum pressure
2. DL (water and steel) + snow load
3. DL (water and steel) + combination snow (75%) and live load (75%).

Notes:

- No vehicular loading was used in the analysis where it does not pass under roadways and, because of the rough rock cover, could not be driven over.
- The penstock is buried therefore wind and earthquake were not used in the analysis.
- Similar to Penstock 2, the penstock appears to be located in cohesive fine grained soil above the local ground water table with drainage piping provided underneath the penstock. External water pressure on the dewatered penstock is not considered an applicable loading condition as there is adequate drainage.

The maximum pressure calculated for the 13.5-foot-diameter pipe due to shell dead load, soil cover, live load, and snow load was 4.35 psi. This is less than the allowable buckling pressure of 13.7 psi.

4.3.1 Surcharge Load Analysis

A surcharge load analysis was completed for the shallow buried sections of penstock with 100 pounds per square foot external live load with the snow load combination. See Table 4-2.

Table 4-2 Summary of Surcharge Load Analysis

Penstock Diameter (ft)	Allowable External Pressure (psi)	Snow Load (psi)	Snow + 100 psf Live Load (psi)
13.5	13.72	4.01	4.36
15.25	9.10	3.93	4.27
17	4.83	3.79	4.13

There were no vehicular surcharge analysis conducted for the shallowly buried penstock as there is no location for traffic to cross the penstock. Where vehicular traffic can cross the penstock, additional analyses were not completed due to the depth of the buried penstock at these locations (intake and switchyard) as well as the results of the analysis for similar conditions in Penstock No. 2 that was completed by Kleinschmidt in 2016. The analysis for Penstock No. 2 showed the soil pressures due to an HS-20 truck load per AASHTO Standard Specifications (AWWA 2004), which is a 72,000-pound, three-axle truck with axles spaced at 14 feet from the front axle to middle axle then variable from 14 feet to 28 feet to the rear axle was approximately 5 times less than the allowable buckling loads at that location. For this section of the penstock, live loads have minimal increase in soil pressures to the penstock given the depth of overburden.

4.3.2 Subatmospheric Internal Penstock Pressure Analysis

Subatmospheric internal pressure can occur if the penstock is dewatered quickly without adequate venting downstream of a headgate or as the result of a negative transient wave pressure. Evaluating negative internal pressures due to transient pressures was outside the scope of this project and no detailed hydrodynamic model was created, but the likelihood of occurrence of subatmospheric pressure is minimal, and allowable buckling pressures are greater than potential negative pressures due to transient waves at startup. Vent capacity was evaluated according the *Hydroelectric Handbook*, Section 31 – Air Inlets (Creager and Justin 1950), assuming that water is stopped due to a headgate closing and that the full flow of the penstock is stopped all at once at the intake. Based on this calculation the required vent area is approximately 0.29 square meters (3.07 square feet), which is well below the area provided by the approximately 5.1-square-meter (55-square-foot) existing openings.

4.4 Local Buckling and Stresses

Local buckling occurs when a point load causes a small area of the shell to be stressed beyond its material buckling stress limits, and it becomes permanently deformed. Boulders and rocks could be a source of point loads but no serious deformations were noted in the inspection. The penstock is continuously supported by the soil so it is unlikely there are excessive local buckling stresses in the penstock.

4.5 LOCAL WELD CONDITIONS

As noted in Section 1.0, NL Hydro discovered a 0.6-meter-long (2-foot-long) crack in Penstock No. 1 in May 2016. Kleinschmidt responded and assisted with the design of the crack repair, *Crack Investigation and Repair Report – Penstock No. 1 Bay d'Espoir Hydroelectric Development* (June 2016). Kleinschmidt's investigation theorized that the crack, which occurred near a weld, was caused by an improper weld procedure during construction that resulted in incomplete fusion. After repairing the crack NL Hydro rewatered the penstock A second crack then opened in the Penstock No. 1 in September 2016. This crack led to a detailed weld investigation that has found many other microscopic cracks in the welds. In addition, Penstock No. 2 was inspected in 2016 and Penstock No. 3 in 2017. Additional evaluation was not completed by Kleinschmidt of the welds beyond the up close visual inspection discussed in Section 3.2.1.

5.0 CONCLUSIONS

Based on our inspection findings and evaluation, the existing steel penstock has significant remaining service life. No cracks were found in this penstock and the coating was in fair condition.

5.1 SHELL CONDITION AND THICKNESS

Measurements of the penstock shell thickness indicate minimal loss of material thickness. Some mild to moderate pitting was noted with organic material buildup on the interior. Assuming similar rates of material loss, the penstock should have significant service life remaining.

5.2 INTERNAL PRESSURE STRENGTH

Stress ratios for a combined static and dynamic internal pressures peak at 1.10 (Table 4-1). This indicates that the penstock does not meet present day design criteria for new penstock design. However, when the hoop stress is compared to the plate yield stress the minimum factor of safety is 1.36, acceptable for late 1960 steel pipe.

5.3 REMAINING SERVICE LIFE

The expected service life for a steel penstock is typically at least 80 years (ASCE 2012). This approximately 50-year-old penstock, however, has shown little loss of thickness from the original plate thicknesses. We therefore anticipate that the penstock has an additional 80 years of useful service life (est. 2097) provided that the penstock interior coating is replaced before the steel begins to significantly deteriorate and other recommendations discussed in Section 6.0 are completed.

6.0 RECOMMENDATIONS

The penstock is good condition and we have just a few recommendations. These recommendations include recoating the interior of the penstock, monitoring of the exterior for signs of leakage, and continued inspections of the interior.

6.1 COATING

We recommend recoating the interior of the penstock in 10-15 years. Areas where the coating was intact were in very good condition whereas areas with delaminated coating showed greater corrosion. At this stage, Kleinschmidt is unable to estimate the rate of corrosions for the exposed steel. We do not know how long it has been exposed in each area and there is no standard rate of corrosion as there are many variables; the specific properties and components of the steel, the acidic properties of the water, silt amounts in the water, the acidity and corrosiveness of the surrounding solids, and the penstock also has organic build-up along the pipe which can either contribute to accelerated corrosion on bare steel or help build a protective barrier. The estimated rate of corrosion can be better estimated after the next detailed inspection if thicknesses are taken in the same locations with similar methods. Until then, stress ratios are high enough that it would be prudent to plan for a recoating to reduce loss of material thickness and extend the service life of the penstock. A quality field applied penstock coating can last 20-40 years or more. If the penstock is recoated prior to significant steel deterioration every 20-40 years, NL Hydro can anticipate extending the life of the penstock nominally another 80 years. The coating will not prevent the eventual corrosion of the shell from the exterior. The exterior is currently coated but it is difficult to tell its condition.

6.2 MONITOR EXTERIOR

Kleinschmidt also recommends repairing culvert damage described previously as well as continuing to monitor the exterior of the penstocks for signs of leakage. Drain pipes should also be monitored at times with consistent weather conditions.

6.3 Interior Inspections

6.3.1 General Evaluation

Kleinschmidt recommends that NL Hydro conducts an internal inspection in 2022 and 2027. These two inspections, spaced at a 5-year interval, should take thickness readings and vertical diameters at each station noted in Kleinschmidt's inspection report.

Due to the larger material loss noted in the exterior thickness measurements at the crown, we recommend taking additional readings during the next inspection to get a more accurate measurement of material loss.

These inspections should give a good indication as to the rate of coating delamination, and shell deterioration. If the current condition of the penstock remains essentially unchanged over the next 10 years, Kleinschmidt would recommend continuing to inspect the coating condition visually every 5 years until it is replaced. As for the detailed inspection of thicknesses and vertical diameters, after the two 5-year detailed inspections have established the trending deterioration, regardless if the coating has been replaced or not, the detailed inspections can be extended to a 10-year interval which is more typical of industry standard for penstock inspections unless changing conditions warrant returning to a 5-year interval.

7.0 REFERENCES

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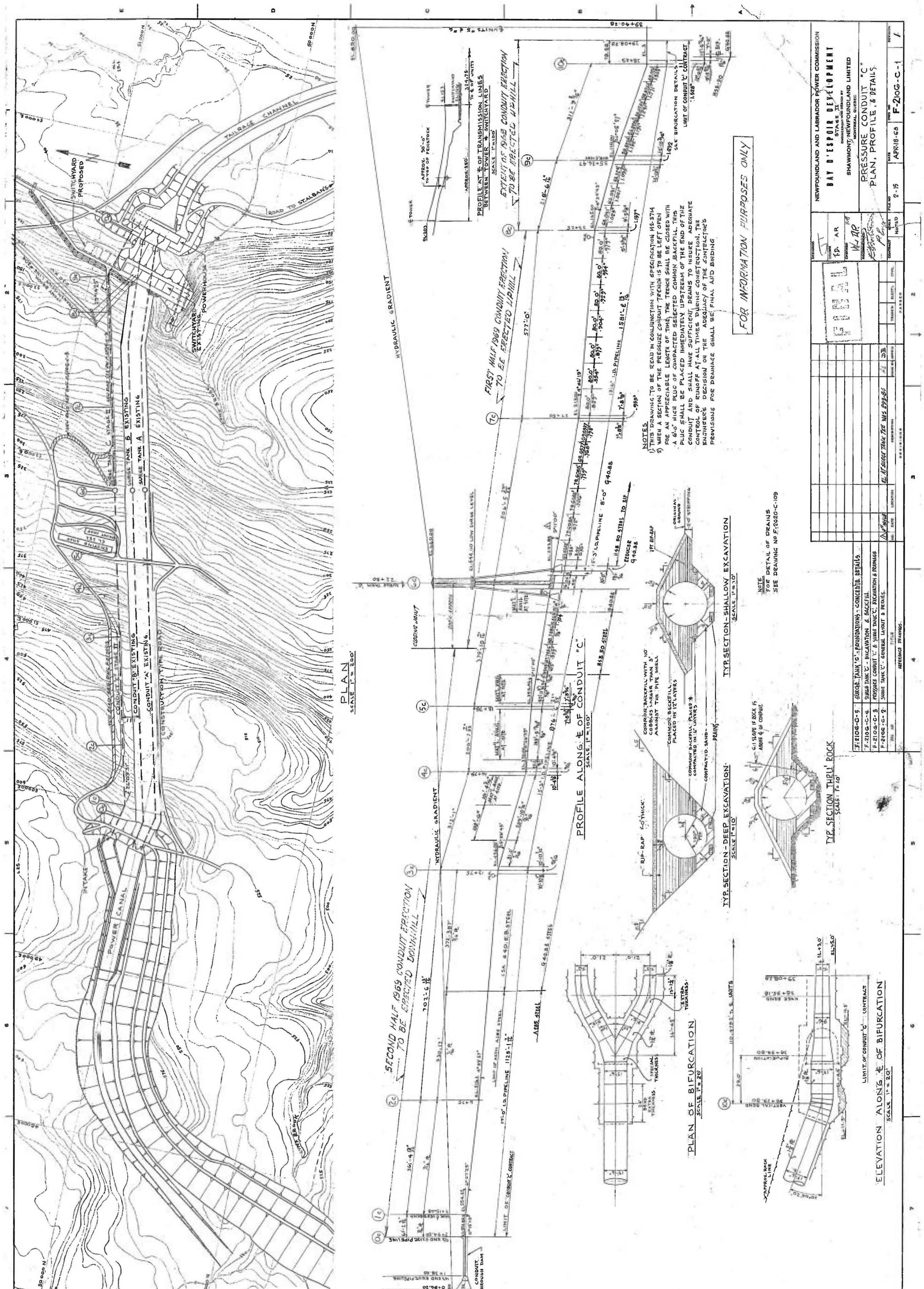
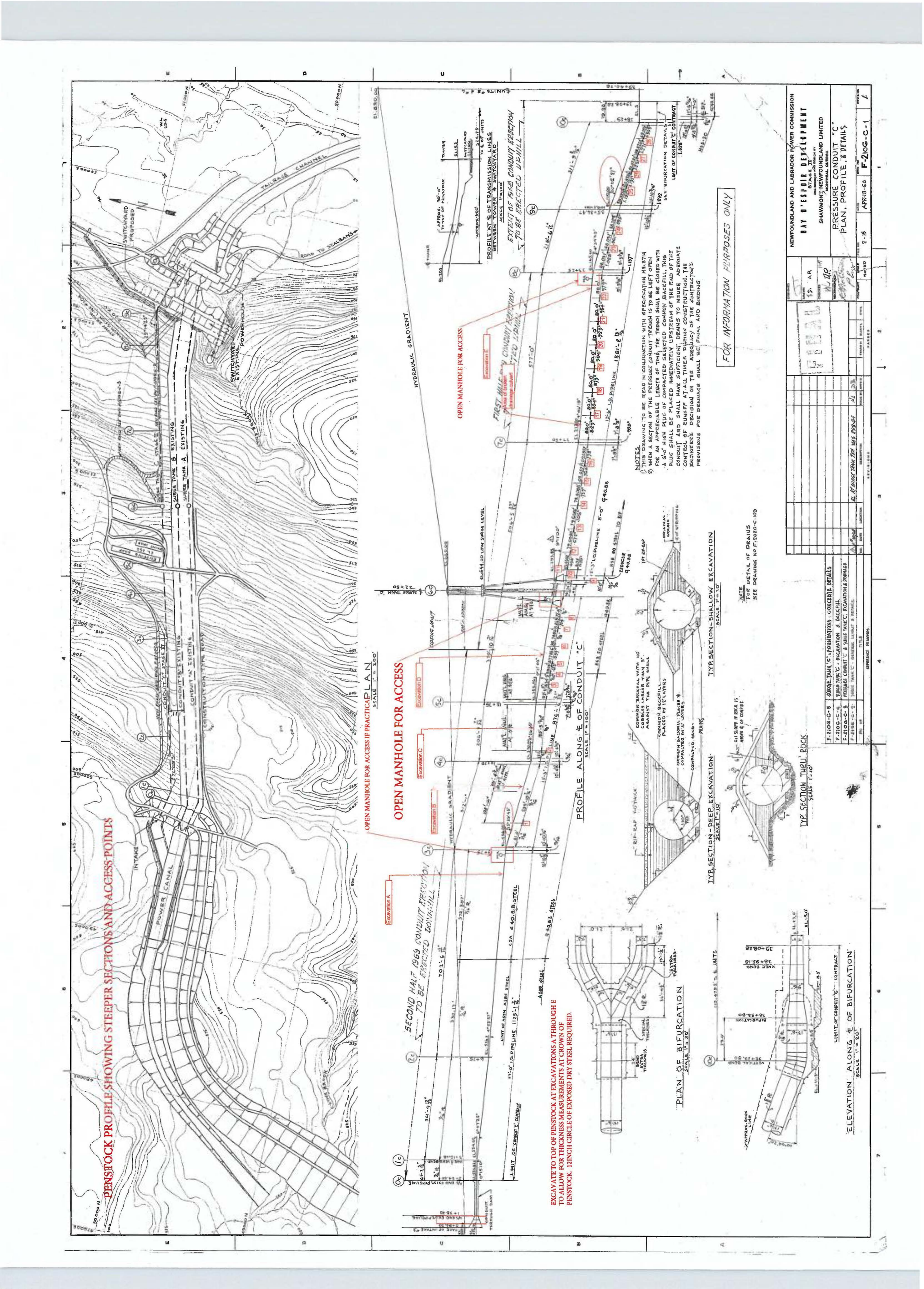
APPENDIX A

PENSTOCK LAYOUT DRAWINGS


NEWFOUNDLAND AND LABRADOR POWER COMMISSION
BAY D'ESPOIR DEVELOPMENT
PRESSURE CONDUIT "C"
PLAN, PROFILE, & DETAILS
F-2106-C-1
FOR INFORMATION PURPOSES ONLY
PLAN
PROFILE ALONG ℄ OF CONDUIT 'C'
PLAN OF BIFURCATION
ELEVATION ALONG ℄ OF BIFURCATION
TYP. SECTION-SHALLOW EXCAVATION
TYP. SECTION-DEEP EXCAVATION
TYP. SECTION THRU' ROCK
POWER CANAL
INTAKE
TAILRACE CHANNEL
NOTES


PENSTOCK PROFILE SHOWING STEEPER SECTIONS AND ACCESS POINTS
OPEN MANHOLE FOR ACCESS
OPEN MANHOLE FOR ACCESS IF PRACTICAL
EXCAVATE TO TOP OF PENSTOCK AT EXCAVATIONS A THROUGH E TO ALLOW FOR THICKNESS MEASUREMENTS AT CROWN OF PENSTOCK. 12INCH CIRCLE OF EXPOSED DRY STEEL REQUIRED.
PLAN
PROFILE ALONG ℄ OF CONDUIT "C"
FOR INFORMATION PURPOSES ONLY
NEWFOUNDLAND AND LABRADOR POWER COMMISSION
BAY D'ESPOIR DEVELOPMENT
PRESSURE CONDUIT "C"
PLAN, PROFILE, & DETAILS
F-2106-C-1

APPENDIX B

PHOTOGRAPHS

Photo 1 - Penstock Exterior below intake

Photo 2 - Typical exterior condition near manhole

Photo 3 - Leakage from Headgate

Photo 4 - Leakage from top of headgate

Photo 5 - Typical penstock condition with areas of missing coating

Photo 6 - Typical penstock condition with minor pitting

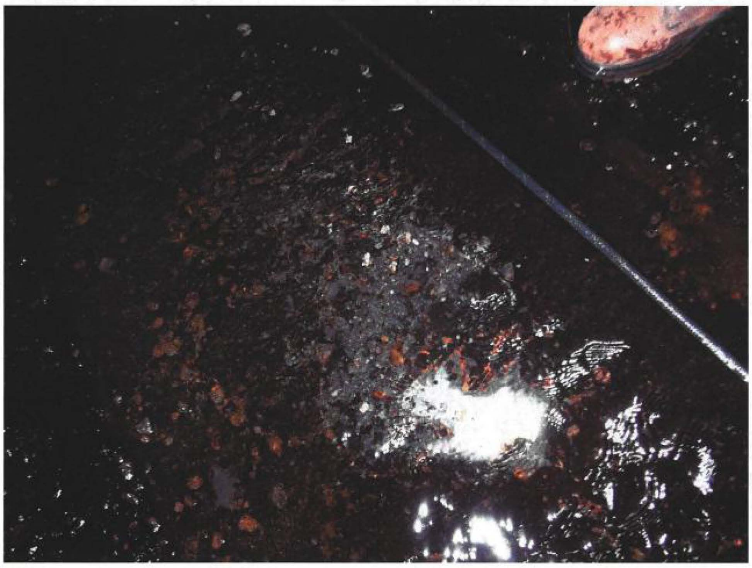


Photo 7 - Typical invert condition with water flowing and organic buildup

Photo 8 – Longitudinal welds with narrow spacing and continuous seams through sections

Photo 9 - Weld with minor pitting (238 feet downstream of intake)

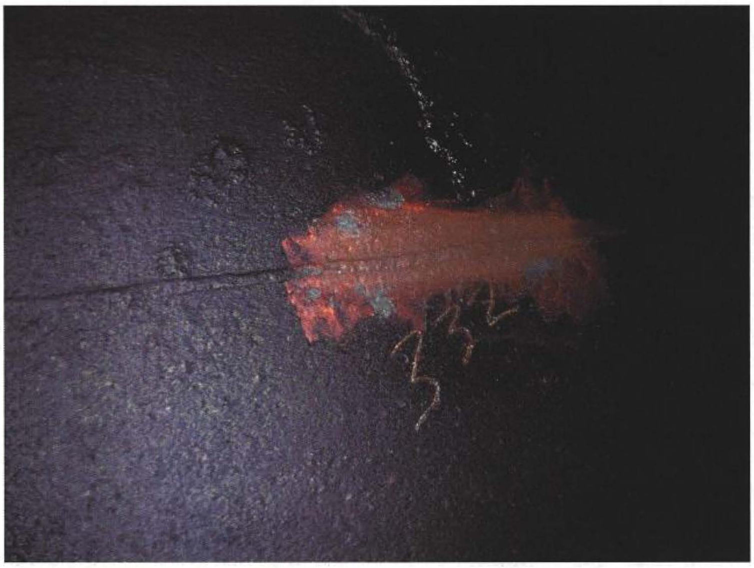


Photo 10 - Weld in fair condition with minor pitting (332 feet downstream of intake)

Photo 11 - Weld in fair condition but flatter than welds upstream (408 feet downstream of intake)

Photo 12 - Weld in fair condition but flatter than welds upstream (566 feet downstream of intake)

Photo 13 - Weld in fair condition, flat (671 feet downstream of intake)

Photo 14 - Weld in fair condition, flat (700 feet downstream of intake)

Photo 15 - Weld in good condition (820 feet downstream of intake)

Photo 16 - Longitudinal weld in good condition (950 feet downstream of intake)

Photo 17 - Longitudinal weld in good condition (1680 feet downstream of intake)

Photo 18 - Longitudinal weld in good condition (1810 feet downstream of intake)

Photo 19 - Longitudinal weld in good condition (1900 feet downstream of intake)

Photo 20 - Longitudinal weld in good condition (2050 feet downstream of intake)

Photo 21 - Longitudinal weld in good condition (705 feet downstream of surge tank)

Photo 22 - Longitudinal weld in good condition (1039 feet downstream of surge tank)

Photo 23 - Missing manhole plate midway between intake and surge tank

Photo 24 - Front edge of bifercation

Photo 25 - Typical coating condition (1195 feet downstream of surge tank)

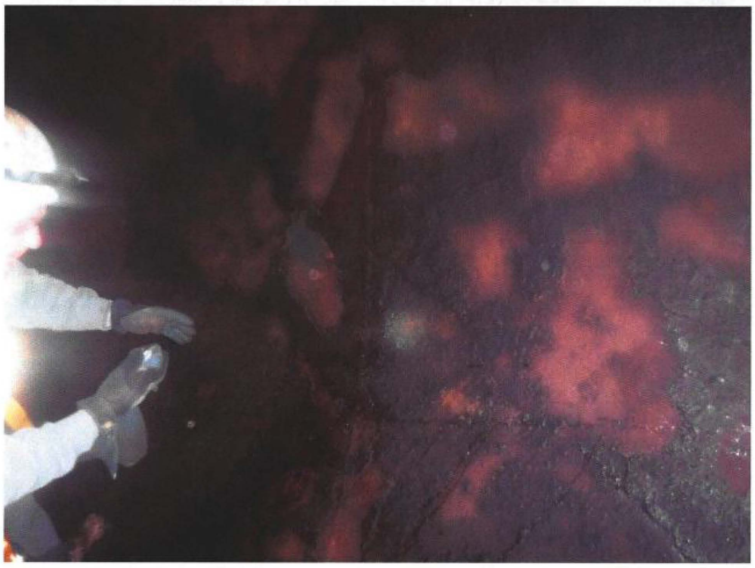


Photo 26 - Missing coating in bifurcation

Photo 27 - Coating flaked off sitting on penstock invert (various locations in penstock)

Photo 28 - Delaminated layers (coating likely) in bifurcation upstream of scroll case

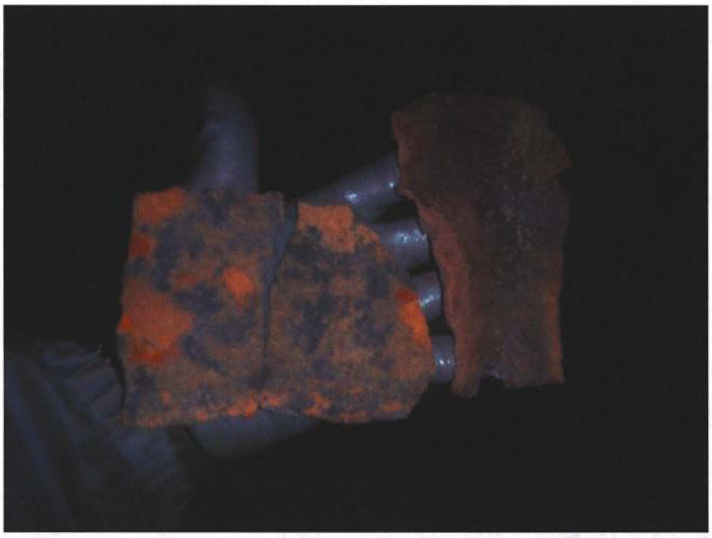


Photo 29 - Delaminated layers in scroll case

Photo 30 - Damaged culvert

APPENDIX C

THICKNESS DATA AND STRESS CALCULATIONS

C-1 THICKNESS MEASUREMENTS AND STRESSES (FSL)
C-2 WATER HAMMER (DYNAMIC) STRESSES

TABLE 1 - Full Supply Level (FSL)
PENSTOCK THICKNESS MEASURMENTS AND STRESSES

Unit weight of water=	62.4	pcf
Normal pond EL=	597	feet
Joint Efficiency=	0.7	(per Penstock #2 assessment & ASCE 79)
$D_{ds\ surge}$ OD=	13.61	feet
D_1 OD=	17.07	feet
D_2 OD=	15.34	feet

Location (STA)[5]		Radius (feet)	Reading Number	Thickness Reading (in)	Avg. Thickness (in)	Plate Thickness (in)	%Change in Material	97.5% Confidence Interval	C.L. EL. (ft)	Allowable Steel Stress (psi)	Base Material		At Joints		Notes
											Stress (psi)[1]	Stress Ratio[2]	Stress (psi)[3]	Stress Ratio[4]	
INTERIOR															
From Upstream End of Conduit Through Dam							0.95%								
P3-I	1+47	8.53	1	0.4890	0.490	0.4375	11.8%	0.4858	555.32	17000	3807.6	0.22	5439.4	0.32	
P3-I			2	0.4930		0.4375	12.7%								
P3-I			3	0.4890		0.4375	11.8%								
P3-I	1+93														Coating begins to deteriorate;more pronounced on left from invert to about 2/3 diameter. Invert rough with pitting and build-up (tubercles and growth); minor pitts
P3-I	2+51														Photo 38 and 39; horizontal weld seam in good condition; slight pitting in areas without coating
P3-I	3+44	8.53	4	0.4160	0.417	0.4375	-4.9%	0.4155	551.51	17000	4858.4	0.29	6940.6	0.41	Weld inspection and UT measurement 04:30; light pitting
P3-I			5	0.4170		0.4375	-4.7%								
P3-I			6	0.4170		0.4375	-4.7%								
P3-I	4+73														Photos 50-55 patch on ceiling
P3-I	5+46	8.53	7	0.4440	0.445	0.4375	1.5%	0.4430	529.96	17000	6715.5	0.40	9593.6	0.56	Coating loss from dewatering with patches on invert, Photo 58. Welds in good condition
P3-I			8	0.4460		0.4375	1.9%								
P3-I			9	0.4450		0.4375	1.7%								
P3-I	7+02														Photo 64 horizontal weld inspection 04:00
P3-I	7+41														Coating loss from dewatering on bottom
P3-I	8+38	8.53	10	0.4350	0.436	0.4375	-0.6%	0.4318	502.24	17000	9739.2	0.57	13913.1	0.82	
P3-I			11	0.4390		0.4375	0.3%								
P3-I			12	0.4350		0.4375	-0.6%								
P3-I	11+68	8.53	13	0.4510	0.452	0.4375	3.1%	0.4437	474.06	24000	12295.5	0.51	17565.0	0.73	change to Grade 40.8 B. See photos 75-79
P3-I			14	0.4480		0.4375	2.4%								
P3-I			15	0.4560		0.4375	4.2%								
P3-I	**12+52**														Manhole - no bottom plate
P3-E	13+13	8.53	73	0.4190	0.418	0.4375	-4.2%	0.4147	457.59	24000	14919.9	0.62	21314.1	0.89	
P3-E			74	0.4160		0.4375	-4.9%								
P3-E			75	0.4180		0.4375	-4.5%								
P3-I	15+50	7.67	16	0.5710	0.571	0.5625	1.5%	0.5695	430.68	24000	11651.0	0.49	16644.2	0.69	
P3-I			17	0.5710		0.5625	1.5%								
P3-I			18	0.5700		0.5625	1.3%								
P3-E	16+00	7.67	76	0.6920	0.687	0.5625	23.0%	0.6747	417.91	24000	10590.0	0.44	15128.6	0.63	
P3-E			77	0.688		0.5625	22.3%								
P3-E			78	0.68		0.5625	20.9%								
P3-E	17+75	7.67	79	0.603	0.593	0.6250	-3.5%	0.5743	373.23	24000	15545.3	0.65	22207.6	0.93	
P3-E			80	0.592		0.6250	-5.3%								
P3-E			81	0.584		0.6250	-6.6%								
P3-I	18+18	7.67	19	0.6440	0.646	0.625	3.0%	0.6427	362.25	24000	14573.2	0.61	20818.8	0.87	
P3-I			20	0.6460		0.625	3.4%								
P3-I			21	0.6470		0.625	3.5%								
P3-I	19+48	7.67	22	0.7030	0.702	0.6875	2.3%	0.7001	346.11	24000	14298.2	0.60	20425.9	0.85	
P3-I			23	0.7030		0.6875	2.3%								
P3-I			24	0.7010		0.6875	2.0%								
P3-E	20+10	7.67	82	0.539	0.540	0.5990	-10.0%	0.5381	333.00	33333	19568.8	0.59	27955.4	0.84	
P3-E			83	0.541		0.5990	-9.7%								
P3-E			84	0.541		0.5990	-9.7%								
P3-I	20+38	7.67	25	0.6480	0.644	0.625	3.7%	0.6302	331.74	33333	16794.3	0.50	23991.9	0.72	HSB 50 Steel
P3-I			26	0.6360		0.625	1.8%								
P3-I			27	0.6490		0.625	3.8%								
P3-I	21+38	7.67	28	0.7570	0.757	0.75	0.9%	0.7492	307.81	24000	15400.9	0.64	22001.3	0.92	
P3-I			29	0.7610		0.75	1.5%								
P3-I			30	0.7530		0.75	0.4%								
	22+20														Manhole
P3-I	23+66	6.81	31	0.6700	0.673	0.672	-0.3%	0.6645	280.11	33333	16877.3	0.51	24110.5	0.72	Horizontal weld inspection good condition
P3-I			32	0.6710		0.672	-0.1%								
P3-I			33	0.6780		0.672	0.9%								
P3-I	25+20	6.81	34	0.7000	0.704	0.706	-0.8%	0.6918	255.53	33333	17467.3	0.52	24953.3	0.75	Horizontal weld in fair condition
P3-I			35	0.7010		0.706	-0.7%								
P3-I			36	0.7080		0.706	0.3%								
P3-I			37	0.7140		0.706	1.1%								
P3-I			38	0.6990		0.706	-1.0%								
P3-I	26+74	6.81	39	0.7730	0.771	0.768	0.7%	0.7568	230.95	33333	17116.9	0.51	24452.8	0.73	
P3-I			40	0.7630		0.768	-0.7%								
P3-I			41	0.7800		0.768	1.6%								
P3-I			42	0.7680		0.768	0.0%								
P3-I	28+30	6.81	43	0.8410	0.840	0.829	1.4%	0.8367	209.38	33333	16394.7	0.49	23421.1	0.70	
P3-I			44	0.8400		0.829	1.3%								
P3-I			45	0.8380		0.829	1.1%								

Location (STA)[5]		Radius (feet)	Reading Number	Thickness Reading (in)	Avg. Thickness (in)	Plate Thickness (in)	%Change in Material	97.5% Confidence Interval	C.L. EL. (ft)	Allowable Steel Stress (psi)	Base Material		At Joints		Notes
											Stress (psi)[1]	Stress Ratio[2]	Stress (psi)[3]	Stress Ratio[4]	
P3-I	29+85	6.81	46	0.8700	0.869	0.879	-1.0%	0.8682	196.49	33333	16325.0	0.49	23321.4	0.70	Moved u/s to catch horizontal weld
P3-I			47	0.8690		0.879	-1.1%								
P3-I			48	0.8690		0.879	-1.1%								
P3-I	31+54	6.81	49	0.9440	0.940	0.929	1.6%	0.9329	182.43	33333	15725.5	0.47	22465.1	0.67	
P3-I			50	0.9370		0.929	0.9%								
P3-I			51	0.9390		0.929	1.1%								
P3-E	33+10	6.81	85	0.992	0.993	0.9790	1.3%	0.9886	168.70	33333	15331.6	0.46	21902.3	0.66	At lower manhole
P3-E			86	0.991		0.9790	1.2%								
P3-E			87	0.995		0.9790	1.6%								
P3-I	33+19	6.81	52	0.9620	0.958	0.979	-1.7%	0.9502	168.70	33333	15950.2	0.48	22786.1	0.68	Just upstream of manhole
P3-I			53	0.9550		0.979	-2.5%								
P3-I			54	0.9560		0.979	-2.3%								
P3-I	34+75	6.81	55	1.0800	1.087	1.095	-1.4%	1.0717	136.93	33333	15191.7	0.46	21702.4	0.65	Large horizontal weld
P3-I			56	1.0950		1.095	0.0%								
P3-I			57	1.0850		1.095	-0.9%								
P3-I	36+19	6.81	58	1.1360	1.135	1.152	-1.4%	1.1029	97.32	33333	16032.8	0.48	22904.0	0.69	Good wave forms
P3-I			59	1.1340		1.152	-1.6%								
P3-I			60	1.1350		1.152	-1.5%								
P3-I	36+19	6.81	61	1.1940	1.191	1.152	3.6%	1.1717	97.32	33333	15091.5	0.45	21559.2	0.65	Rough spot poor wave forms
P3-I			62	1.1870		1.152	3.0%								
P3-I			63	1.1910		1.152	3.4%								
P3-I	37+44	6.81	64	1.2250	1.223	1.231	-0.5%	1.2178	54.48	33333	15764.7	0.47	22521.1	0.68	
P3-I			65	1.2240		1.231	-0.6%								
P3-I			66	1.2200		1.231	-0.9%								
P3-I	38+63	6.81	67	1.3110	1.309	1.303	0.6%	1.3037	13.70	33333	15832.7	0.47	22618.2	0.68	
P3-I			68	1.3060		1.303	0.2%								
P3-I			69	1.3090		1.303	0.5%								
P3-I	39+33	6.81	70	1.3060	1.304	1.303	0.2%	1.3003	3.00	33333	16166.4	0.48	23094.9	0.69	Bifurcation
P3-I			71	1.3050		1.303	0.2%								
P3-I			72	1.3020		1.303	-0.1%								

Notes:

Stress

[1] Hoop stress = $Pr/t_{97.5}$

[2] Hoop stress / S_A

[3] Hoop stress / 0.7 $_{joint\ efficiency}$

[4] Joint stress / S_A

[5] Location

E - Exterior Measurement at Crown

I - Interior Measurement

P3 - Penstock No. 3 at Bay D'Espoir

TABLE 2 - Full Supply Level (FSL) + Surge 30%
PENSTOCK THICKNESS MEASURMENTS AND STRESSES

Unit weight of water=	62.4
Normal pond EL=	597
Joint Efficiency=	0.7
$D_{ds\ surge}$ OD=	13.61
D_1 OD=	17.07
D_2 OD=	15.34
Hydraulic Gradient at Units	890.00
Hydraulic Gradient at Surge Tank	660.00

Location		Radius (feet)	Avg. Thickness (in)	Plate Thickness (in)	%Change in Material	97.5% Confidence Interval	C.L. EL. (ft)	Allowable Steel Stress (psi)	Base Material Stress (psi)[1]	Base Material Stress Ratio[2]	At Joints Stress (psi)[3]	At Joints Stress Ratio[4]
P3-I	1+47	8.50	0.490	N/A	N/A	0.4858	555.32	17,000	4090.2	0.24	5843.2	0.34
P3-I	3+44	8.50	0.417	0.4375	-4.8%	0.4155	551.51	17,000	5773.9	0.34	8248.5	0.49
P3-I	5+46	8.50	0.445	0.4375	1.7%	0.4430	529.96	17,000	8129.7	0.48	11613.8	0.68
P3-I	8+38	8.50	0.436	0.4375	-0.3%	0.4318	502.24	17,000	12015.5	0.71	17165.0	1.01
P3-I	11+68	8.50	0.452	0.4375	3.2%	0.4437	474.06	24,000	15419.5	0.64	22027.9	0.92
P3-I	15+50	7.63	0.571	0.5625	1.5%	0.5695	430.68	24,000	14541.8	0.61	20774.1	0.87
P3-I	18+18	7.63	0.646	0.625	3.3%	0.6427	362.25	24,000	17571.7	0.73	25102.5	1.05
P3-I	19+48	7.63	0.702	0.6875	2.2%	0.7001	346.11	24,000	17251.3	0.72	24644.8	1.03
P3-I	20+38	7.63	0.644	0.625	3.1%	0.6302	331.74	33,333	20228.1	0.61	28897.3	0.87
P3-I	21+38	7.63	0.757	0.75	0.9%	0.7492	307.81	24,000	18503.7	0.77	26433.8	1.10
P3-I	22+80											
P3-I	23+66	6.75	0.673	0.672	0.1%	0.6645	280.11	33,333	20154.3	0.60	28791.8	0.86
P3-I	25+20	6.75	0.704	0.706	-0.2%	0.6918	255.53	33,333	21667.7	0.65	30953.8	0.93
P3-I	26+74	6.75	0.771	0.768	0.4%	0.7568	230.95	33,333	21919.2	0.66	31313.2	0.94
P3-I	28+30	6.75	0.840	0.829	1.3%	0.8367	209.38	33,333	21621.6	0.65	30887.9	0.93
P3-I	29+85	6.75	0.869	0.879	-1.1%	0.8682	196.49	33,333	22210.4	0.67	31729.1	0.95
P3-I	31+54	6.75	0.940	0.929	1.2%	0.9329	182.43	33,333	22063.4	0.66	31519.2	0.95
P3-I	33+19	6.75	0.958	0.979	-2.2%	0.9502	168.70	33,333	22997.8	0.69	32854.0	0.99
P3-I	34+75	6.75	1.087	1.095	-0.8%	1.0717	136.93	33,333	22127.3	0.66	31610.4	0.95
P3-I	36+19	6.75	1.135	1.152	-1.5%	1.1029	97.32	33,333	23385.5	0.70	33407.8	1.00
P3-I	36+19	6.75	1.191	1.152	3.4%	1.1717	97.32	33,333	22012.4	0.66	31446.3	0.94
P3-I	37+44	6.75	1.223	1.231	-0.6%	1.2178	54.48	33,333	22903.7	0.69	32719.6	0.98
P3-I	38+63	6.75	1.309	1.303	0.4%	1.3037	13.70	33,333	22928.1	0.69	32754.5	0.98
P3-I	39+33	6.75	1.304	1.303	0.1%	1.3003	3.00	33,333	23535.6	0.71	33622.3	1.01

APPENDIX D

PENSTOCK EVALUATION CALCULATIONS

Allowable pressures (kPa)/External Pressures (kPa) Reference # 3, 5 and 8

Diameter 13.5 feet								
				Unit Weight of Water=	62.4 pcf			
Height of water above conduit=	0 feet	Live load:	100 psf	P_v=	0			
Height of rip rap above conduit=	1 feet	Snow load:	103 psf	Rip Rap Unit Weight=	150 lb/ft^3			
Height of fill above conduit=	2 feet			Fill Unit Weight=	120 lb/ft^3			
Total Height of Soil=	3 feet			(soil load) W_c=	5308.2 lb/ft			
OD Conduit Diameter=	13.5 feet	ID:	13.6 feet	(live load) W_l=	1361.1 lb/ft	100 psf per foot section		
	Assume well drained =							
Buoyancy Factor R_w=	1 1			W_s=	1406 lb/ft			
B_prime=	0.2330			W_{steel}=	1160 lb/ft			
(coarse grain soils with fines) E_prime=	600 psi			Density steel=	490 pcf			
E=	30000000 psi							
b=	1			External pressure with vacuum=	3.30 psi	Ratio Q/q_a=	0.240344185	
t=	0.665 inches			External pressure with snow load=	4.01 psi	Ratio Q/q_a=	0.292575354	
I=	0.0245 $inches^4$			External pressure with snow and live=	4.36 psi	Ratio Q/q_a=	0.317447224	
FS=	2							
q_a=	13.72 psi							

Allowable pressures (kPa)/External Pressures (kPa)

Diameter 15.25 feet							
				Unit Weight of Water=	62.4 pcf		
Height of water above conduit=	0 feet	Live load:	100 psf	P_v=	0		
Height of rip rap above conduit=	1 feet	Snow load:	103 psf	Rip Rap Unit Weight=	150 lb/ft^3		
Height of fill above conduit=	2 feet			Fill Unit Weight=	120 lb/ft^3		
Total Height of Soil=	3 feet			(soil load) W_c=	5984.5 lb/ft		
OD Conduit Diameter=	15.25 feet	ID:	15.34 feet	(live load) W_l=	1534.5 lb/ft		
	Assume well drained =						
Buoyancy Factor R_w=	1 1			W_s=	1584.8 lb/ft		
B_prime=	0.233028			W_{steel}=	1121.0 lb/ft		
(coarse grain soils with fines) E_prime=	600 psi			Density steel=	490 pcf		
E=	30000000 psi						
b=	1			External pressure with vacuum=	3.21 psi	Ratio Q/q_a=	0.353327334
t=	0.570 inches			External pressure with snow load=	3.93 psi	Ratio Q/q_a=	0.432132618
I=	0.0154 $inches^4$			External pressure with snow and live=	4.27 psi	Ratio Q/q_a=	0.469658772
FS=	2						
q_a=	9.10 psi						

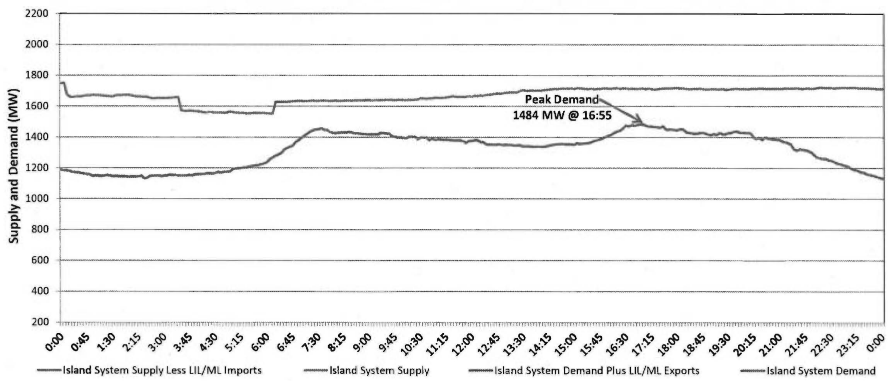
Allowable pressures (kPa)/External Pressures (kPa)

Diameter 17 feet					
				Unit Weight of Water=	62.4 pcf
Height of water above conduit=	0 feet	Live load:	100 psf	P_v=	0
Height of rip rap above conduit=	1 feet	Snow load:	103 psf	Rip Rap Unit Weight=	150 lb/ft^3
Height of fill above conduit=	2 feet			Fill Unit Weight=	120 lb/ft^3

Total Height of Soil=	3	feet			(soil load) W_c=	6657	lb/ft			
OD Conduit Diameter=	17	feet	ID:	17 feet	(live load) W_l=	1707	lb/ft	100 psf per foot section		
		Assume well drained =								
Buoyancy Factor R_w=	1	1			W_s=	1762.9	lb/ft			
B_prime=	0.2330				W_{steel}=	909.8	lb/ft			
(coarse grain soils with fines) E_prime=	600	psi			Density steel=	490	pcf			
E=	30000000	psi								
b=	1				External pressure with vacuum=	3.08	psi		Ratio Q/q_a=	0.636796962
t=	0.416	inches			External pressure with snow load=	3.79	psi		Ratio Q/q_a=	0.785156082
I=	0.0060	$inches^4$			External pressure with snow and live=	4.13	psi		Ratio Q/q_a=	0.855802958
FS=	2									
q_a=	4.83	psi								

Newfoundland Labrador Hydro (NLH)
Supply and Demand Status Report Filed Friday, December 07, 2018

Section 1
Island Interconnected System Supply, Demand & Exports
Actual 24 Hour System Performance For Thursday, December 06, 2018



Supply Notes For December 06, 2018 [1,2]

A As of 1635 hours, November 28, 2018, Holyrood Unit 1 available at 160 MW (170 MW).
B As of 0756 hours, November 30, 2018, Hardwoods Gas Turbine unavailable due to planned outage 25 MW (50 MW).
C As of 2001 hours, November 30, 2018, Holyrood Unit 2 unavailable due to planned outage (170 MW).
D At 0110 hours, December 06, 2018, Hinds Lake Unit unavailable due to planned outage (75 MW).
E At 0330 hours, December 06, 2018, Upper Salmon Unit unavailable (84 MW).
F At 0615 hours, December 06, 2018, Hinds Lake Unit available (75 MW).

Section 2
Island Interconnected Supply and Demand

Fri, Dec 07, 2018	Island System Outlook[3]			Seven-Day Forecast	Temperature (°C) Morning	Temperature (°C) Evening	Island System Daily Peak Demand (MW) Forecast	Island System Daily Peak Demand (MW) Adjusted[7]
Available Island System Supply:[5]		**1,700**	**MW**	Friday, December 07, 2018	-2	-4	**1,470**	**1,367**
NLH Island Generation:[4]		1,380	MW	Saturday, December 08, 2018	-5	-1	1,420	1,318
NLH Island Power Purchases:[6]		125	MW	Sunday, December 09, 2018	-5	-3	1,445	1,342
Other Island Generation:		195	MW	Monday, December 10, 2018	-5	-4	1,450	1,347
ML/LIL Imports:		-	MW	Tuesday, December 11, 2018	-2	-6	1,500	1,397
Current St. John's Temperature & Windchill:	-2 °C	-10	°C	Wednesday, December 12, 2018	-6	-4	1,460	1,357
7-Day Island Peak Demand Forecast:		**1,540**	MW	Thursday, December 13, 2018	-7	-10	1,540	1,436

Supply Notes For December 07, 2018 [3]

Notes:
1. Generation outages for running and corrective maintenance are included. These are not unusual for power system operations. They generally do not impact customer supply. The power system operators schedule outages to system equipment whenever possible to coincide with periods when customer demands are low and sufficient supply reserves are available. However, from time to time equipment outages are necessary and reserves may be impacted.
2. Due to the Island system having no synchronous connections to the larger North American grid, when there is a sudden loss of large generating units there may be a requirement for some customer's load to be interrupted for short periods to bring generation output equal to customer demand. This automatic action of power system protection, referred to as under frequency load shedding (UFLS), is necessary to ensure the integrity and reliability of system equipment. Under frequency events have typically occurred 5 to 8 times per year on the Island Interconnected System and the resultant customer load interruptions are generally less than 30 minutes. With the activation of the Maritime Link frequency controller during the winter of 2018, UFLS events have occurred less frequently.
3. As of 0800 Hours.
4. Gross output including station service at Holyrood (24.5 MW) and improved NLH hydraulic output due to water levels (35 MW).
5. Gross output from all Island sources (including Note 4).
6. NLH Island Power Purchases include: CBPP Co-Gen, Nalcor Exploits, Rattle Brook, Star Lake, Wind Generation and capacity assistance (when applicable).
7. Adjusted for curtailable load, market activities and the impact of voltage reduction when applicable.

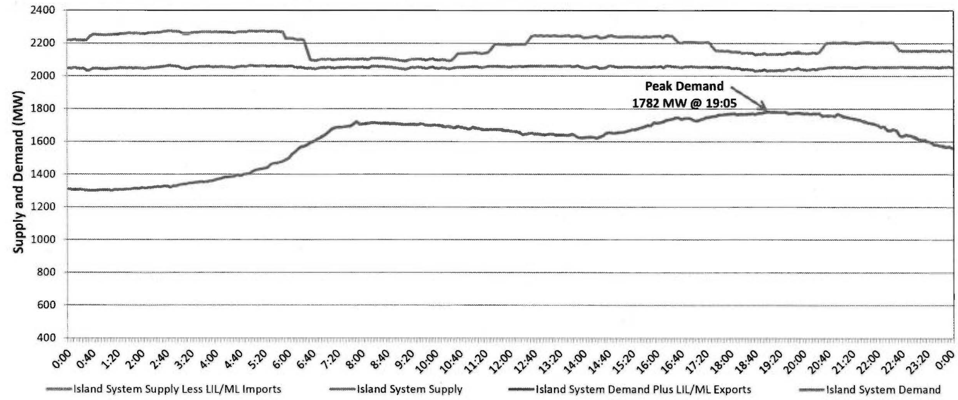
Section 3
Island Peak Demand Information
Previous Day Actual Peak and Current Day Forecast Peak

Thu, Dec 06, 2018	Actual Island Peak Demand[8]	16:55	1,484 MW
Fri, Dec 07, 2018	Forecast Island Peak Demand		1,470 MW

Notes: 8. Island Demand / LIL / ML Exports (where applicable) is supplied by NLH generation and purchases, plus generation owned and operated by Newfoundland Power and Corner Brook Pulp & Paper (Deer Lake Power, DLP).

Newfoundland Labrador Hydro (NLH)
Supply and Demand Status Report Filed Thursday, February 21, 2019 (Revised, February 22, 2019)

Section 1
Island Interconnected System Supply, Demand & Exports
Actual 24 Hour System Performance For Wednesday, February 20, 2019



Supply Notes For February 20, 2019 [1,2]

Section 2
Island Interconnected Supply and Demand

Thu, Feb 21, 2019	Island System Outlook[3]		
Available Island System Supply:[5]		1,995	MW
NLH Island Generation:[4]		1,640	MW
NLH Island Power Purchases:[6]		125	MW
Other Island Generation:		205	MW
ML/LIL Imports:		25	MW
Current St. John's Temperature & Windchill:	-16 °C	-28	°C
7-Day Island Peak Demand Forecast:		1,775	MW

Seven-Day Forecast	Temperature (°C) Morning	Temperature (°C) Evening	Island System Daily Peak Demand (MW) Forecast	Island System Daily Peak Demand (MW) Adjusted[7]
Thursday, February 21, 2019	-16	-12	1,775	1,668
Friday, February 22, 2019	-13	-11	1,730	1,624
Saturday, February 23, 2019	-14	-13	1,625	1,520
Sunday, February 24, 2019	-13	-10	1,555	1,451
Monday, February 25, 2019	-9	-3	1,535	1,431
Tuesday, February 26, 2019	-1	-2	1,425	1,323
Wednesday, February 27, 2019	-6	-9	1,560	1,456

Supply Notes For February 21, 2019 [3]

A At 0639 hours, February 21, 2019, Hardwoods Gas Turbine unavailable (50 MW).
B At 0708 hours, February 21, 2019, St. Anthony Diesel Plant available at 7.7 MW (9.7 MW).

Notes:
1. Generation outages for running and corrective maintenance are included. These are not unusual for power system operations. They generally do not impact customer supply. The power system operators schedule outages to system equipment whenever possible to coincide with periods when customer demands are low and sufficient supply reserves are available. However, from time to time equipment outages are necessary and reserves may be impacted.
2. Due to the Island system having no synchronous connections to the larger North American grid, when there is a sudden loss of large generating units there may be a requirement for some customer's load to be interrupted for short periods to bring generation output equal to customer demand. This automatic action of power system protection, referred to as under frequency load shedding (UFLS), is necessary to ensure the integrity and reliability of system equipment. Under frequency events have typically occurred 5 to 8 times per year on the Island Interconnected System and the resultant customer load interruptions are generally less than 30 minutes. With the activation of the Maritime Link frequency controller during the winter of 2018, UFLS events have occurred less frequently.
3. As of 0800 Hours.
4. Gross output including station service at Holyrood (24.5 MW) and improved NLH hydraulic output due to water levels (35 MW).
5. Gross output from all Island sources (including Note 4).
6. NLH Island Power Purchases include: CBPP Co-Gen, Nalcor Exploits, Rattle Brook, Star Lake, Wind Generation and capacity assistance (when applicable).
7. Adjusted for curtailable load, market activities and the impact of voltage reduction when applicable.

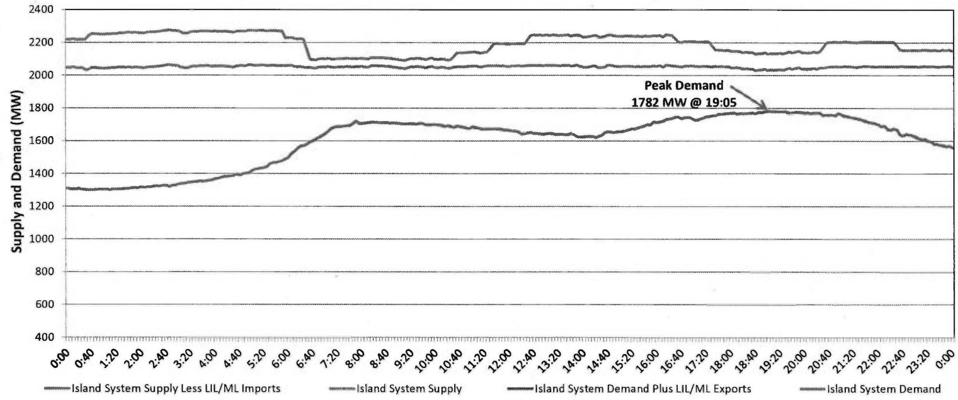
Section 3
Island Peak Demand Information
Previous Day Actual Peak and Current Day Forecast Peak

Wed, Feb 20, 2019	Actual Island Peak Demand[8]	19:05	1,782	MW
Thu, Feb 21, 2019	Forecast Island Peak Demand		1,775	MW

Notes: 8. Island Demand / LIL / ML Exports (where applicable) is supplied by NLH generation and purchases, plus generation owned and operated by Newfoundland Power and Corner Brook Pulp & Paper (Deer Lake Power, DLP).

Newfoundland Labrador Hydro (NLH)
Supply and Demand Status Report Filed Thursday, February 21, 2019 (Revised, February 22, 2019)

Section 1
Island Interconnected System Supply, Demand & Exports
Actual 24 Hour System Performance For Wednesday, February 20, 2019



Supply Notes For February 20, 2019 [1,2]

Section 2
Island Interconnected Supply and Demand

Thu, Feb 21, 2019	Island System Outlook[3]			Seven-Day Forecast	Temperature (°C) Morning	Temperature (°C) Evening	Island System Daily Peak Demand (MW) Forecast	Island System Daily Peak Demand (MW) Adjusted[7]
Available Island System Supply:[5]		1,995	MW	Thursday, February 21, 2019	-16	-12	1,775	1,668
NLH Island Generation:[4]		1,640	MW	Friday, February 22, 2019	-13	-11	1,730	1,624
NLH Island Power Purchases:[6]		125	MW	Saturday, February 23, 2019	-14	-13	1,625	1,520
Other Island Generation:		205	MW	Sunday, February 24, 2019	-13	-10	1,555	1,451
ML/LIL Imports:		25	MW	Monday, February 25, 2019	-9	-3	1,535	1,431
Current St. John's Temperature & Windchill:	-16 °C	-28	°C	Tuesday, February 26, 2019	-1	-2	1,425	1,323
7-Day Island Peak Demand Forecast:		1,775	MW	Wednesday, February 27, 2019	-6	-9	1,560	1,456

Supply Notes For February 21, 2019 [3]

A At 0639 hours, February 21, 2019, Hardwoods Gas Turbine unavailable (50 MW).
B At 0708 hours, February 21, 2019, St. Anthony Diesel Plant available at 7.7 MW (9.7 MW).

Notes:
1. Generation outages for running and corrective maintenance are included. These are not unusual for power system operations. They generally do not impact customer supply. The power system operators schedule outages to system equipment whenever possible to coincide with periods when customer demands are low and sufficient supply reserves are available. However, from time to time equipment outages are necessary and reserves may be impacted.
2. Due to the Island system having no synchronous connections to the larger North American grid, when there is a sudden loss of large generating units there may be a requirement for some customer's load to be interrupted for short periods to bring generation output equal to customer demand. This automatic action of power system protection, referred to as under frequency load shedding (UFLS), is necessary to ensure the integrity and reliability of system equipment. Under frequency events have typically occurred 5 to 8 times per year on the Island Interconnected System and the resultant customer load interruptions are generally less than 30 minutes. With the activation of the Maritime Link frequency controller during the winter of 2018, UFLS events have occurred less frequently.
3. As of 0800 Hours.
4. Gross output including station service at Holyrood (24.5 MW) and improved NLH hydraulic output due to water levels (35 MW).
5. Gross output from all Island sources (including Note 4).
6. NLH Island Power Purchases include: CBPP Co-Gen, Nalcor Exploits, Rattle Brook, Star Lake, Wind Generation and capacity assistance (when applicable).
7. Adjusted for curtailable load, market activities and the impact of voltage reduction when applicable.

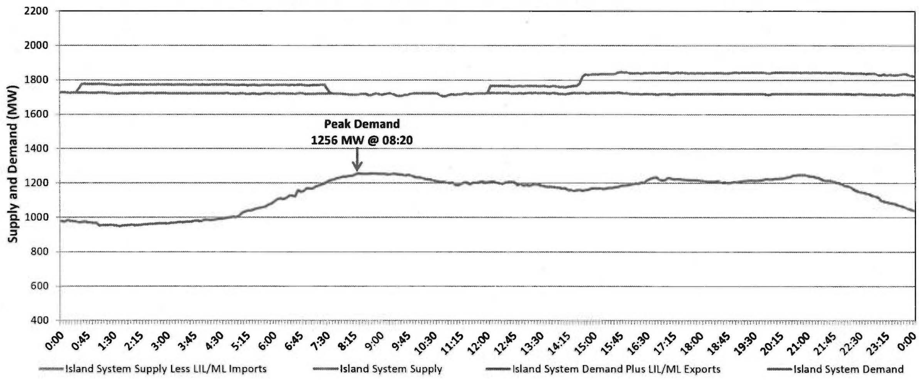
Section 3
Island Peak Demand Information
Previous Day Actual Peak and Current Day Forecast Peak

Wed, Feb 20, 2019	Actual Island Peak Demand[8]	19:05	1,782 MW
Thu, Feb 21, 2019	Forecast Island Peak Demand		1,775 MW

Notes: 8. Island Demand / LIL / ML Exports (where applicable) is supplied by NLH generation and purchases, plus generation owned and operated by Newfoundland Power and Corner Brook Pulp & Paper (Deer Lake Power, DLP).

Newfoundland Labrador Hydro (NLH)
Supply and Demand Status Report Filed Wednesday, May 01, 2019

Section 1
Island Interconnected System Supply, Demand & Exports
Actual 24 Hour System Performance For Tuesday, April 30, 2019



Supply Notes For April 30, 2019 [1,2]

A As of 0000 hours, April 01, 2019, Holyrood Unit 3 unavailable due to planned outage (150 MW).
B As of 1134 hours, April 12, 2019, Holyrood Unit 2 unavailable (170 MW).
C As of 0900 hours, April 23, 2019, St. Anthony Diesel Plant unavailable due to planned outage 7.7 MW (9.7 MW).
D As of 1833 hours, April 27, 2019, Hardwoods Gas Turbine available at 25 MW (50 MW).

Section 2
Island Interconnected Supply and Demand

Wed, May 01, 2019	Island System Outlook[3]			Seven-Day Forecast	Temperature (°C)		Island System Daily Peak Demand (MW)	
					Morning	Evening	Forecast	Adjusted[7]
Available Island System Supply:[5]		1,700	MW	Wednesday, May 01, 2019	0	3	1,275	1,275
NLH Island Generation:[4]		1,340	MW	Thursday, May 02, 2019	1	2	1,240	1,240
NLH Island Power Purchases:[6]		150	MW	Friday, May 03, 2019	2	2	1,230	1,230
Other Island Generation:		210	MW	Saturday, May 04, 2019	2	2	1,115	1,115
ML/LIL Imports:		-	MW	Sunday, May 05, 2019	2	3	1,035	1,035
Current St. John's Temperature & Windchill:	-1 °C	-9	°C	Monday, May 06, 2019	3	4	1,075	1,075
7-Day Island Peak Demand Forecast:		1,275	MW	Tuesday, May 07, 2019	6	2	1,030	1,030

Supply Notes For May 01, 2019 [3]

Notes:
1. Generation outages for running and corrective maintenance are included. These are not unusual for power system operations. They generally do not impact customer supply. The power system operators schedule outages to system equipment whenever possible to coincide with periods when customer demands are low and sufficient supply reserves are available. However, from time to time equipment outages are necessary and reserves may be impacted.
2. Due to the Island system having no synchronous connections to the larger North American grid, when there is a sudden loss of large generating units there may be a requirement for some customer's load to be interrupted for short periods to bring generation output equal to customer demand. This automatic action of power system protection, referred to as under frequency load shedding (UFLS), is necessary to ensure the integrity and reliability of system equipment. Under frequency events have typically occurred 5 to 8 times per year on the Island Interconnected System and the resultant customer load interruptions are generally less than 30 minutes. With the activation of the Maritime Link frequency controller during the winter of 2018, UFLS events have occurred less frequently.
3. As of 0800 Hours.
4. Gross output including station service at Holyrood (24.5 MW) and improved NLH hydraulic output due to water levels (35 MW).
5. Gross output from all Island sources (including Note 4).
6. NLH Island Power Purchases include: CBPP Co-Gen, Nalcor Exploits, Rattle Brook, Star Lake, Wind Generation and capacity assistance (when applicable).
7. Adjusted for curtailable load, market activities and the impact of voltage reduction when applicable.

Section 3
Island Peak Demand Information
Previous Day Actual Peak and Current Day Forecast Peak

Tue, Apr 30, 2019	Actual Island Peak Demand[8]	08:20	1,256	MW
Wed, May 01, 2019	Forecast Island Peak Demand		1,275	MW

Notes: 8. Island Demand / LIL / ML Exports (where applicable) is supplied by NLH generation and purchases, plus generation owned and operated by Newfoundland Power and Corner Brook Pulp & Paper (Deer Lake Power, DLP).

newfoundland labrador
hydro
a nalcor energy company

Hydro Place. 500 Columbus Drive.
P.O. Box 12400. St. John's. NL
Canada A1B 4K7
t. 709.737.1400 f. 709.737.1800
www.nlh.nl.ca

April 10, 2019

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

Attention: **Ms. Cheryl Blundon**
Director of Corporate Services & Board Secretary

Dear Ms. Blundon:

Re: Newfoundland and Labrador Hydro's Capacity Assistance Agreements with Vale Newfoundland and Labrador Limited

Background

Newfoundland and Labrador Hydro ("Hydro") presently has three capacity assistance agreements in place with industrial customers; one with Corner Brook Pulp and Paper Limited ("CBPP") and two with Vale Newfoundland and Labrador Limited ("Vale").

The Board of Commissioners of Public Utilities (the "Board") approved a 6 MW Load Curtailment Agreement with Vale in Board Order No. P.U. 44(2018). In that Order, Hydro was directed to file a report with the Board no later than April 15 of the year following each winter period. The report is to include the dates, times, duration, and system conditions under which capacity assistance was requested, provided, and capacity and variable payments made.

The Board approved the revised capacity assistance agreement with CBPP in Board Order No. P.U. 40(2018). The report detailing the use of that agreement is required by May 30, 2019.

Hydro also has an agreement with Vale for the provision of up to 8 MW of capacity assistance from Vale's diesel generating facilities. This agreement was provided to the Board on November 18, 2018 for information purposes.[1]

In accordance with Board direction, this letter summarizes the details and costs associated with Hydro's use of the capacity assistance agreements for the four month winter period of December 1, 2018 to March 31, 2019.

Capacity Assistance Operating Experience Summary

During the winter of 2018–2019, Hydro did not make any requests to Vale to utilize the load curtailment under either the 6 MW Load Curtailment Agreement, or make a request for capacity assistance from their standby diesel generation. Therefore, there were no expenditures for curtailed energy at the Energy Curtailed Rate.[2] The total fixed fee (capacity) paid to Vale, as required under the agreements, is shown in Table 1.

---

[1] As this agreement is for supply of capacity and energy to Hydro and does not affect the Industrial Service Agreements approved by the Board, Hydro did not seek a Board Order with respect to this agreement.
[2] "Energy Curtailed Rate" means $0.20 per kWh of energy curtailed.

Table 1: Fixed Fee Charges under Vale Agreements

Agreement	No. of Assistance Requests	Demand Capacity Fee $/kW/yr.[3]	Capacity (kW)	Paid Under The Agreement ($)
Capacity Assistance	0	28	7,560	211,680
Load Curtailment	0	28	6,000	168,000
2018-2019 Total	**0**		**13,560**	**379,680**

Please contact the undersigned should you have any questions.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

Shirley A. Walsh
Senior Legal Counsel, Regulatory
SAW/sk

cc: Gerard Hayes, Newfoundland Power Inc.
Paul Coxworthy, Stewart McKelvey
Denis Fleming, Cox & Palmer
Dennis Browne, Q.C., Browne Fitzgerald Morgan & Avis
Sheryl Nisenbaum, Praxair Canada Inc.

ecc: Larry Bartlett, Teck Resources Ltd.
Dean A. Porter, Poole Althouse

[3] "Demand Curtailment Fee" calculated at $7 per kW/month, for the agreement duration of four months.

Project Memo

H357358

June 21, 2018

To: D. Drake

From: G. Saunders, P.Eng.

cc: G. Randell

Newfoundland and Labrador Hydro
Penstock No. 3 Weld Refurbishment

Minor Weld Indications in Penstock 3

1. Introduction

Penstock No. 3 was de-watered May 2018 for a limited scope weld inspection and condition assessment. Stemming from the weld inspection, several regions of the penstock were found to be corroded with cracks in the heat affected zones (HAZ) requiring refurbishment prior to the penstock being returned to service. The regions of the penstock and associated activities are presented in Table 1-1 below.

Table 1-1: Penstock 3 Activities by Region

Region	Cans 1 - 180	Cans 181 - 199	Cans 200 - 230	Cans 231 - 296	Cans 297 - 350	Cans 351 - 400
Inspection Frequency*	64% +	21% +	100%	19% +	100%	10% +
Refurbishment Frequency**	85% +	0%	48% +	0%	48% +	0%
Steel Grade(s)***	ASTM A285 & CSA G40.8	CSA G40.8	OX522-D & CSA G40.8	OX522-D & CSA G40.8	OX522-D	OX522-D
Activity	Condition Assessment & Weld Refurbishment	Condition Assessment	Condition Assessment & Weld Refurbishment	Condition Assessment	Condition Assessment & Weld Refurbishment	Condition Assessment
Notes	*Inspection refers to Visual Examination and Magnetic Particle Examination. **Refurbishment extents were determined by inspection results and penstock condition. ***Steel grades noted to be verified by laboratory testing.					

2. Minor Weld Indications in Condition Assessment

During condition assessment activities, minor weld indications/defects were discovered on two cans downstream of the Surge Tank, Can 239 and Can 362, and pitting corrosion was observed in multiple locations. However, the general condition of the longitudinal weld seams from the Surge Tank to the Powerhouse shows far less preferential weld corrosion and better existing weld profile.

Downstream of the Surge Tank, Can 239 (reducer of 15'-3" diameter to 13'-6", plate thickness ~20.64 mm) was inspected and found to be in better condition than that upstream of the Surge Tank; however, there were scattered linear indications detected. These shallow indications had a depth of 2-3 mm, ranging in length from 25-100 mm. Given the thickness of the plate in this area, this metal loss is substantially less than that observed upstream of the Surge Tank. Samples of indications from Can 239 are shown in Figure 2-1 below.

Figure 2-1: Can 239

Downstream of elbow No. 8C, Can 362 was noted to also have scattered shallow linear indications of length 25-75 mm, shown in Figure 2-2 below. This weld seam is in better relative condition with minor pitting.

Figure 2-2: Can 362

Figure 2-3 shows Can 389 as a general representation of weld quality in the area, with better relative condition and no detectable indications, showing some pitting corrosion (uniformly distributed between the base metal and weld metal).

Figure 2-3: Can 389

3. Weld Condition in Refurbished Areas

For comparison, Figure 3-1 and 3-2 show portions of the longitudinal seams of the 17' diameter penstock section upstream of the Surge Tank, closer to the intake. This section of the penstock has a plate thickness of approximately 11mm. During the weld refurbishment works the cracking in this section was determined to have an average 4-5 mm depth, which corresponds to 36-45% of the plate thickness. One seam (Can 116) was noted to have cracking to a depth of approximately 8mm (72.7% of the plate thickness). The condition of these longitudinal weld seams show significant corrosion of the welds in the form of pitting and preferential corrosion of the weld metal and heat affected zone (HAZ). With the loss of weld metal, the weld to base metal interface has a notch with a depth of approximately 2-3 mm and visible cracking in this area.

Figure 3-1: Can 29

Figure 3-2: Can 55

4. Summary and Recommendations

Pitting corrosion and shallow indications were observed during the condition assessment in several regions of the penstock where the welds were not fully refurbished. It is expected that the minor indications observed provide a representative sampling of the inspected areas, and that other such minor indications are probable in areas which were not fully inspected. It is Hatch's opinion these defects do not present a substantial risk of failure within the next several years and that emergency repairs for these two areas are not warranted at this time. Understanding that a penstock refurbishment project is planned for execution in the next three years, these sections should be inspected annually until this refurbishment is completed. Any further deterioration of these welds should be carefully investigated to determine if immediate weld refurbishment is required.

G. Saunders, P.Eng.
General Manager, St. John's Office

MP:smb

newfoundland labrador hydro a nalcor energy company

BAY D'ESPOIR
PENSTOCK 3 INSPECTION TRACKER

Date: June 21, 2018

INTAKE

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
North			I, F	I, F	I, F	I, F	I, F	I, F	I, F								I, F	I, F	I, F		I, F		I, F		NI
CAN #	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
South						I, F	I, F	I, F		I, F	I, F	I, F	I, F	I, F	I, F							I, F			

	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50
North				I, F	I, F	I, F	I, F		I, F				I, F		I, F				I, F	I, F	I, F	I, F	I, F		I, F
CAN #	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50
South	I, F	I, F						I, F		I, F			I, F		I, F										I, F

ASTM A285 11mm Plate (cans 1–50)

Doorsheet #1 Location (north)

Doorsheet #2 Location (north)

	51	52	53	54	55	56	57	58	59	60	61	62	63	64	65	66	67	68	69	70	71	72	73	74	75	76	77
North									I, F	I, P					I, F					I, F					I, F		
CAN #	51	52	53	54	55	56	57	58	59	60	61	62	63	64	65	66	67	68	69	70	71	72	73	74	75	76	77
South					I, F					I, F		I, F	I, F	I, F	NI	I, F	I, P	I, F	I, F	I, P	I, F	I, F	I, F	I, F	I, F	I, F	I, F

	78	79	80	81	82	83	84	85	86	87	88	89	90	91	92	93	94	95	96	97	98	99	100	101	102	103
North			I, P				I, F											I, F	I, F	I, F	I, F	I, F	I, F	I, F		
CAN #	78	79	80	81	82	83	84	85	86	87	88	89	90	91	92	93	94	95	96	97	98	99	100	101	102	103
South		I, F	I, P	I, F	I, P	I, F	I, F	I, F	I, F	I, F	I, F	I, F	I, F	I, F	I, P	NI	NI	I, P	I, F	I, P	I, F	I, F	I, F	NI	NI	I, F

ASTM A285 11mm Plate (cans 51–94) | G40.8B 11mm Plate (cans 95–103)

Approx. Manway #1 Location

Elbow #3C

	104	105	106	107	108	109	110	111	112	113	114	115	116	117	118	119	120	121	122	123	124	125	126	127	128	129	130
North			I, F	I, F	I, F	I, P	I, F	I, F					I, F	I, F	I, P	I, P	I, F						I, F	I, F	I, F	NI	I, F
CAN #	104	105	106	107	108	109	110	111	112	113	114	115	116	117	118	119	120	121	122	123	124	125	126	127	128	129	130
South	I, F	I, F	I, F	I, F	I, P	I, P	I, F	I, P	I, P	I, F	I, F	NI	I, F	NI	NI	I, P	NI	NI	I, P	NI	I, P	I, P	I, F	I, P	I, P	I, P	I, F

	131	132A	132B	133	134	135	136	137	138	139	140	141	142	143	144	145	146	147	148	149	150	151	152	153	154	155
North	NI	I, F	I, F	NI	NI	I, P	I, P	I, F	I, F	I, F	I, F	NI	NI	I, F	I, P	NI	NI	I, P	NI	I, P	NI	I, P	NI	I, P	NI	I, F
CAN #	131	132A	132B	133	134	135	136	137	138	139	140	141	142	143	144	145	146	147	148	149	150	151	152	153	154	155
South	NI	NI	I, F	NI	NI	NI	I, P	NI	NI	I, F	I, P	NI	NI	NI	I, P	NI	NI	NI	I, P	NI	NI	NI	NI	NI	I, P	I, P

G40.8B 11mm Plate (cans 104–131) | G40.8B, 14.3mm THK (cans 132A–134) | G40.8B, Can 136/137=11mm THK, 138 to 156=14.3mm THK (cans 135–155)

Elbow #4C

Doorsheet #3 Location (south)

	156	157	158	159	160	161	162	163	164	165	166	167	168	169	170	171	172	173	174	175	176	177	178	179	180	181
North	I, P	I, P	NI	I, P	I, P	I, F	NI	I, F	I, F	I, F	NI	NI	NI	NI	NI	I, F	NI	NI	I, P	I, P	NI	NI	NI	NI	NI	NI
CAN #	156	157	158	159	160	161	162	163	164	165	166	167	168	169	170	171	172	173	174	175	176	177	178	179	180	181
South	NI	I, P	I, P	NI	NI	NI	NI	NI	NI	I, P	I, P	NI	I, F	NI	I, F	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	

	182	183	184	185	186	187	188	189	190	191	192	193	194	195	196	197	198	199	200	201	202	203	204	205	206	207	208
North	NI	NI	NI	NI							NI								NI	NI	NI	NI	NI	I, P	NI	NI	NI
CAN #	182	183	184	185	186	187	188	189	190	191	192	193	194	195	196	197	198	199	200	201	202	203	204	205	206	207	208
South											NI				NI				NI	NI	NI	NI	NI	I, F	I, F	NI	I, F

G40.8B, 14.3mm THK (cans 156–164) | G40.8B, 19.05mm THK (cans 165–168) | G40.8B, 15.875mm THK (cans 169–193) | G40.8B, 15.875mm to 17.4625mm THK (cans 194–205) | OX522-D (cans 206–208)

Coupon taken (north)

Approx. Manway #2 Location

Reducer

	209	210	211	212	213	214	215	216	217	218	219	220	221	222	223	224	225	226	227	228	229	230	231	232	233	234
North	I, F	I, F	I, F	I, F	I, F	I, F	I, F	I, F	I, F	I, F	I, F	NI	I, F	I, F	NI	NI	NI	NI	NI	NI	NI	NI				NI
CAN #	209	210	211	212	213	214	215	216	217	218	219	220	221	222	223	224	225	226	227	228	229	230	231	232	233	234
South	I, P	I, P	I, P	I, P	NI	I, F	I, F	NI	I, F	NI	I, F	I, P	NI	I, F	I, P	I, F	I, P	NI	NI	NI	NI	NI	NI	NI		

OX522-D, 15.875mm to 16.59mm THK (cans 209–224) | G40.8B, 19.05mm THK (cans 225–234)

SURGE TANK

	235	236	237	238	239	240	241	242	243	244	245	246	247	248	249	250	251	252	253	254	255	256	257	258	259
North	NI			NI	I, P	NI							NI								NI				
CAN #	235	236	237	238	239	240	241	242	243	244	245	246	247	248	249	250	251	252	253	254	255	256	257	258	259
South				NI								NI										NI			

Doorsheet #4 Location (north)

Elbow #7C

	260	261	262	263	264	265	266	267	268	269	270	271	272	273	274	275	276	277	278	279	280	281	282	283	284	285
North						NI				NI							NI					NI				
CAN #	260	261	262	263	264	265	266	267	268	269	270	271	272	273	274	275	276	277	278	279	280	281	282	283	284	285
South							NI									NI										

	286	287	288	289	290	291	292	293	294	295	296	297	298	299	300	301	302	303	304	305	306	307	308	309	310	311	312
North	NI					NI		NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	I, F	I, F	I, F	I, F	NI	NI	NI	I, P	NI	I, F
CAN #	286	287	288	289	290	291	292	293	294	295	296	297	298	299	300	301	302	303	304	305	306	307	308	309	310	311	312
South	NI									NI		NI	NI	NI	NI	NI	I, P	NI	NI	NI	NI	I, P	I, F	I, P	I, P	NI	NI

Coupon taken (north)

Approx. Manway #3 Location

	313	314	315	316	317	318	319	320	321	322	323	324	325	326	327	328	329	330	331	332	333	334	335	336	337	338
North	I, F	I, F	I, F	I, F	I, F	NI	I, F	I, F	I, F	NI	I, F	NI	NI	I, F	I, P	NI	I, P	I, P	I, F	I, P	I, P	NI	I, F	NI	NI	I, P
CAN #	313	314	315	316	317	318	319	320	321	322	323	324	325	326	327	328	329	330	331	332	333	334	335	336	337	338
South	I, F	I, F	I, F	I, F	I, F	I, F	I, P	I, F	I, F	NI	NI	NI	NI	I, F	I, P	I, P	I, P	I, F	NI	I, P	NI	I, P	I, P	I, P	I, P	NI

	339	340	341	342	343	344	345	346	347	348	349	350	351	352	353	354	355	356	357	358	359	360	361	362	363	364	365
North	NI	I, F	NI	I, F	NI	NI	NI	NI	NI	NI	NI	NI		NI	NI			NI		NI				I, P			
CAN #	339	340	341	342	343	344	345	346	347	348	349	350	351	352	353	354	355	356	357	358	359	360	361	362	363	364	365
South	NI	I, P	NI	I, P	NI	NI	NI	NI	NI	NI	NI	NI									NI						

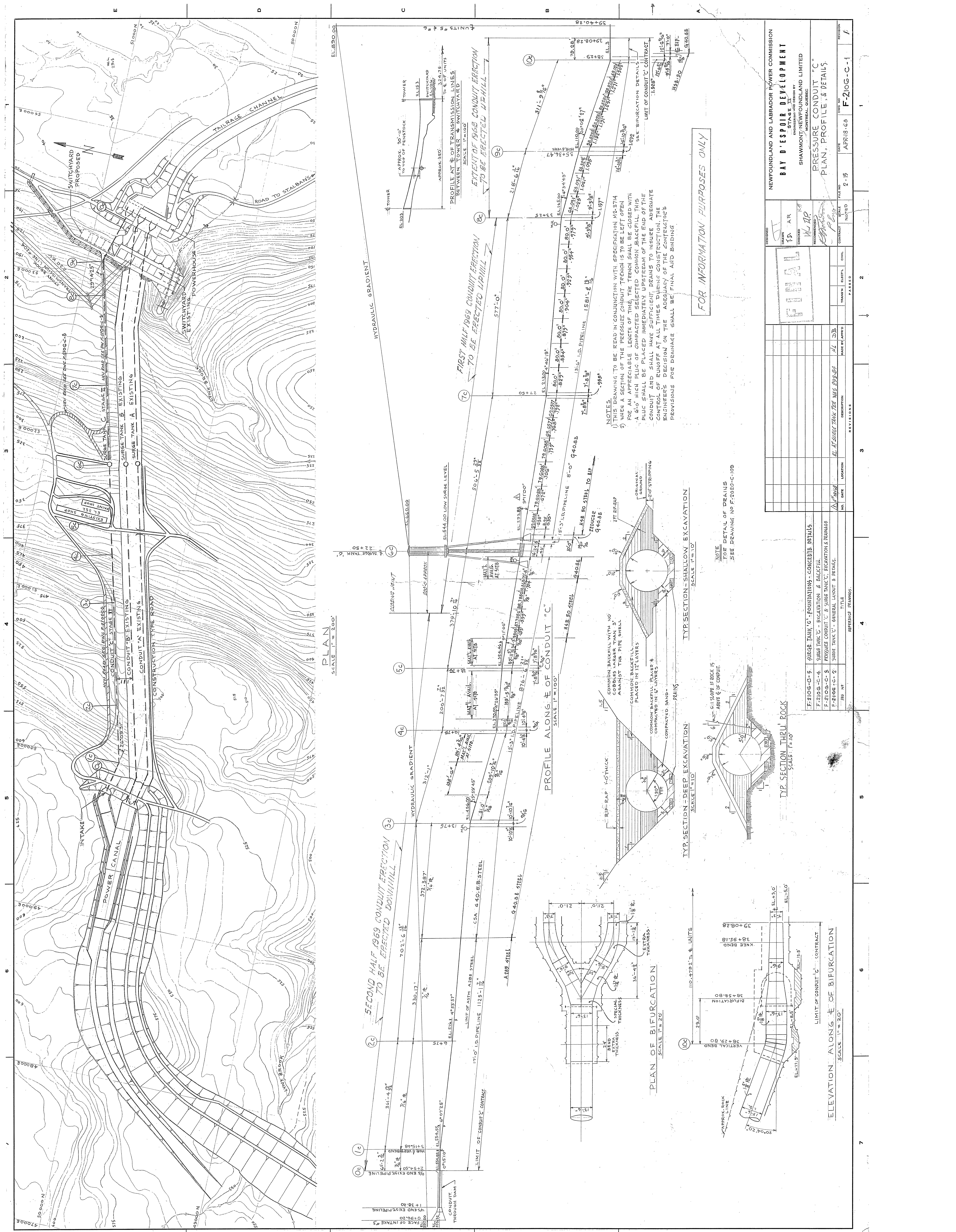
Elbow #8C

Elbow #9C

	366	367	368	369	370	371	372	373	374	375	376	377	378	379	380	381	382	383
North							NI											
CAN #	366	367	368	369	370	371	372	373	374	375	376	377	378	379	380	381	382	383
South	NI														NI			

	384	385	386	387	388	389	390	391	392	393	394	395	396	397	398	399	400
North						NI										NI	
CAN #	384	385	386	387	388	389	390	391	392	393	394	395	396	397	398	399	400
South																	

Elbow #10C


NEWFOUNDLAND AND LABRADOR POWER COMMISSION
BAY D'ESPOIR DEVELOPMENT
STAGE II
SHAWMONT/NEWFOUNDLAND LIMITED
PRESSURE CONDUIT "C"
PLAN, PROFILE, & DETAILS
F-210G-C-1
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PLAN
PROFILE ALONG ℄ OF CONDUIT "C"
PLAN OF BIFURCATION
ELEVATION ALONG ℄ OF BIFURCATION
TYP. SECTION - DEEP EXCAVATION
TYP. SECTION - SHALLOW EXCAVATION
TYP. SECTION THRU' ROCK

VOITH

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Nalcor

Hinds Lake GS

Field Pole Field Report

DRAFT

TABLE OF CONTENTS

TRIP REPORT: June – July 2018

AUTHOR: G. Floreani

TO: Nalcor – Rodney Willcott, Brent Peddle, John Oliveira

Copy: Justine Falardo, Ron Rochon, Jamie Latreille

SUBJECT: Hitachi VWWG Rotor Field Winding (20Pole)

COMMENT: All test results and activities were recorded by Nalcor`s Engineer and can be used in conjunction with this report. The Engineering log is at shown at the bottom of this report

OVERVIEW: Nalcor was undergoing a planned outage at their Hinds lake VWWG. Scope of the outage was but not limited to dismantling the generator, removal of the rotor and Co2 blast cleaning the Field Winding (RE: improve past Insulation Resistance (IR) and low Polarization Index (PI)

On July 3 2018 at Nalcor`s request Voith Hydro Mississauga dispatched Mr. Jamie Latreille an experienced and qualified Field Representative. Voith Hydro also packaged and shipped some necessary supplies, tooling and test equipment.

The plan at site was to hoard the rotor in the erection bay, install heaters and industrial de-humidifiers and attempt to remove moisture from the field windings that may have been absorbed from the Co2 blasting.

Please note it was very humid in the power station.

During the moisture removal process other Field winding components collector leads/bus, standoffs, collector rings, brush rigging were either disconnected / dismantled isolated and tested. Any component found damaged was repaired and cleaned.

Next was to disconnect the Field Windings in half (pole 1&2 and 10&11) then in quarters (5&6 and 15&16) and so on to get to a point where a possible field coil change out using Qty. 2 spare field coils stored at site.

With the work that was diligently undertaken by staff the IR did improve in some sections but not all.

The reading are well below the recommended IEEE 43-2013 Standard.

The Field Coil insulation is likely deteriorated to a point where possible carbon conductive material may be absorbed in the insulation and is tracking to ground. (making it near to impossible to clean/clear the tracking to ground with poles in situ.)

It was at this time frame where a decision was made to reassemble the unit put in back in operation and monitor the IR to see if IR improves or maintains pre assembly readings.

- On August 3rd Nalcor reported the Hinds Lake Hitachi generator has run for 2 days.
  The IR results taken was 241 K-Ohms

- On Aug. 7th Nalcor reported the Hinds Lake Hitachi generator has run for 7 days.
  The IR results taken was 231 K-Ohms (protection metering is showing a ground fault condition)

  Rodney Willcott will discuss with Nalcor operations people if a unit shutdown could be scheduled in order to verify IR readings.

  Nalcor will keep Voith Hydro informed of any progress

RECOMMENDATIONS:

- Based on the vigorous rehabilitation work completed by Nalcor personal Voith feels the field pole insulation life has come to its end and strongly recommends the Field Coils be removed and sent out for re-insulation c/w new connectors and pole fixation hardware as necessary.

- Voith Hydro is available upon request to Price this work.

All test results and activities were recorded by Nalcor`s Engineer at site and can be used in conjunction with this report. The Engineering log is attached at the end of this report

Regards
Glen Floreani

Jamie Latreille Voith Hydro
Daily Log

July 3-18
- Travel to Deer Lake

July 4-18
- Fall Arrest

July 5-18
- Fall Arrest

July 6-18
- Rotor inspection

July 7-18
- Rotor work and testing

July 8-18
- Disconnect field coil connections 10 & 11

July 9-18
- Rotor work and testing

July 10-18
- Disconnect field coil connections 5 & 6

July 11-18
- Rotor work and testing

July 12-18
- Disconnect field coil connections 15 & 16

July 13-18
- Rotor work and testing

July 14-18
- Rotor work assembly and testing

July 15-18
- Rotor work assembly and testing

July 16-18
- Rotor work assembly and testing

July 17-18
- Travel home

Nalcor Summary Engineering Logs reports

Nalcor Summary reports

HINDS LAKE ROTOR DIAGNOTICS AND REPAIR

ENGINEERING REPORT - July 7th, 2018

John Oliveira, P. Eng.

newfoundland labrador hydro
a nalcor energy company

The rotor was cleaned throughout the week of July 2nd to July 6th. Cleaning was done through dry ice jetting. Megger testing resulted in 0.6MΩ prior to cleaning. During and after cleaning, repeated testing resulted in in 0MΩ.

From the end of day of July 6th to the morning of July 7th, the rotor was left in plastic tarp housing overnight with a 130 pints/day dehumidifier and a 10HP fan to remove humidity

Megger testing of leads against steel core resulted 0.

Removed brackets from the leads and placed insulation between leads and core. Megger resulted 0.

Figure 1 – Leads with brackets removed and additional insulation placed beneath them

Leads were tested again with a Polarization Index instrument, which is more precise. The result was 43kΩ.

The group decided to start separating the pole connections to identify in which half of the rotor the path to ground is. The separation was done at the mid-point of the field coils, between poles 10 and 11, where it has been separated before in the early 90s. The adjoining pole coils were protected with wet blankets, and the top of the plastic tarp housing will be removed to allow welding fumes to escape.

HINDS LAKE ROTOR DIAGNOTICS AND REPAIR

ENGINEERING REPORT - July 10th, 2018

John Oliveira, P. Eng.

newfoundland labrador hydro
a nalcor energy company

As per Voith's engineering orientation, the rotor enclosure was left with the top open, and the fan and the dehumidifier on. At 8:30 am, the readings with Voith's Megger were:

- 1-10: 410 kΩ;
- 11-20: 735 kΩ;
- Rotor temperature: 26C; Humidity = 45%

Corrected to 40C (See IEEE Std. 43-2013), they are:

	July 9th corrected to 40C (kΩ)[1]	*July 10th corrected to 40C (kΩ)*
Poles 1-10:	367	357
Poles 11-20:	626	624

We attributed the slightly inferior readings to the increased humidity. We also verified the previous day's discrepancy in the readings with the Ohmmeter. The cause was that the Megger was connected to the 1-10 poles, and thus, the ohmmeter was capturing the Megger's own resistance.

We followed with a Pole Drop Test on each half. The results were:

Pole	Voltage Drop (V)	Pole	Voltage Drop (V)
1	9.99	11	10.13
2	12.36	12	12.24
3	12.42	13	12.38
4	12.32	14	12.23
5	12.41	15	12.38
6	12.27	16	12.3
7	12.38	17	12.43
8	12.26	18	12.31
9	12.42	19	12.57
10	10.05	20	10.18
Total (V)	118.88		119.15
Supply (V)	119.9		119.9
Difference (V)	**1.02**		**0.75**

[1] These are the Voith's Megger readings from the beginning of July 9th, corrected to 40C

HINDS LAKE ROTOR DIAGNOTICS AND REPAIR

ENGINEERING REPORT - July 11th, 2018

John Oliveira, P. Eng.

At 8:30 am, the Megger readings stayed constant. The results are:

	Readings as taken (MΩ)	*Readings corrected to 40C (MΩ)*
Poles 1-5:	1.42	1.21
Poles 6-10:	0.5	0.425
Poles 11-20:	0.736	0.623

Rotor Temperature: 26.1 C; Humidity: 43%

As soon as the Megger reading was completed, the work on breaking the 15-16 connection started.

The connection was broken at 11:00 am, and a Megger reading on the newly split quarters ensued, with the following results:

Figure 1 - Connection broken between poles 15 and 16

	Readings as taken (MΩ)	*Readings corrected to 40C (MΩ)*
Poles 11-15:	6.02	5.12
Poles 16-20:	0.824	0.70

Rotor Temperature: 25.9 C; Humidity: 51%

We ran the results through Voith's engineering, and during that meeting, we considered the hypothesis that the saddle brackets (which secure the poles' jumpers) has sharp corners, and that the insulation in

HINDS LAKE ROTOR DIAGNOTICS AND REPAIR

ENGINEERING REPORT - July 12th, 2018

John Oliveira, P. Eng.

newfoundland labrador hydro
a nalcor energy company

This report is partly based off field notes and the events related to me, when I arrived at site at 2:00 p.m.

As discussed in the previous day's report, removing the brackets from the pole jumpers helped increase the insulation resistance measurements. The initial Megger readings at 8:30 am, with all the top brackets removed were:

	Readings as taken (MΩ)	*Readings corrected to 40C (MΩ)*
Poles 1-5:	1.42	1.21
Poles 6-10:	1.25	1.06
Poles 11-15:	6.16	5.24
Poles 20-16:	0.891	0.76

Rotor Temperature: 24.1 C; Humidity: 72%

To test how effective cleaning the leading edges would be (as described in July 11th's report), the bottom of the leading edge of poles 20-16 was cleaned, but no improvement in the insulation resistance reading was verified. No exposed cooper was verified there, either.

We proceeded with the removal of the brackets on the air gap-side (bottom) connections. The results stayed constant, except for the 20-16 quarter, which rose up to 1.0MΩ (0.85MΩ corrected to 40C). The connection between the 15-16 poles was remade temporarily to assert the overall insulation resistance of the 1-20 half. The result was 936 kΩ (0.79MΩ corrected to 40C).

Figure 1 - Jumper with all insulation stripped. Added rubber insulation between copper and studs.

HINDS LAKE ROTOR DIAGNOTICS AND REPAIR

ENGINEERING REPORT - July 13th, 2018

John Oliveira, P. Eng.

newfoundland labrador hydro
a nalcor energy company

At 8:30 in the morning, all the broken connections were temporarily re-established, and the whole rotor measured. The results were:

	Readings as taken (MΩ)	*Readings corrected to 40C (MΩ)*
Full rotor	0.401	0.321

Rotor Temperature: 21.4 C; Humidity: 53%

As we had a meeting scheduled with the hydro generation management group for 1:00 p.m., we proceeded with more detailed cleaning. One person was assigned to each low-reading quarter, while one electrician started preparing the removed jumper brackets to be put back in place by cleaning them and laying the first insulating tape layers.

At noon, with roughly half the rotor cleaned, we measured the Insulation Resistance of the full rotor (connected through temporary connections) and then each quadrant. The results are as follows:

	Readings as taken (MΩ)	*Readings corrected to 40C (MΩ)*
Full rotor	0.449	0.359
Poles 1-5	1.78	1.424
Poles 6-10	1.46	1.168
Poles 11-15	6.08	4.864
Poles 16-20	1.23	0.984

Rotor Temperature: 21.4 C; Humidity: 53%

At the 1:00 pm meeting with the improved cleaning results, we decided on the following course of action:

1. Cleaning will proceed through today and tomorrow;
2. With three quarters having similar readings, and seeing similar improvement with cleaning, we do not believe the low insulation resistance readings would be caused by a faulty pole. No further connections will be broken.
3. Preparations will start to put the rotor back into service. The connection will be remade throughout the weekend.
4. We will keep monitoring the insulation resistance as work proceeds on bringing the rotor back together.
5. Two more dehumidifiers will be installed around the rotor, and the housing enclosed with tarp to reduce the moisture as much as possible.

Only one electrician remained cleaning the rotor for the first part of the afternoon. Three-hand cleaning resumed at 3:00 p.m. At 3:30 pm another set of insulation resistance measurement was made, with no significant change.

HINDS LAKE ROTOR DIAGNOTICS AND REPAIR

ENGINEERING REPORT - July 14th, 2018

John Oliveira, P. Eng.

newfoundland labrador hydro
a nalcor energy company

At 8:30 in the morning, we measured the insulation resistance, and the readings didn't vary from yesterday, as expected:

	Readings as taken (MΩ)	*Readings corrected to 40C (MΩ)*
Poles 1-5	1.71	1.368
Poles 6-10	1.48	1.184
Poles 11-15	6.41	5.128
Poles 16-20	1.22	0.976

Rotor Temperature: 21.4 C; Humidity: 49%

Work started in reconnecting the quarters to bring the unit back into service. The leads were cleaned and painted with red Glyptal paint:

Figure 1 - Leads painted with red Glyptal paint

The brackets for the connection jumpers have been thoroughly cleaned and grinded. They then received the first layer of insulating tape.

Please note that the rotor enclosure was open, and most of the plastic removed. The rotor will be enclosed with tarp overnight, and three dehumidifiers will be left running to bring the humidity down.

HINDS LAKE ROTOR DIAGNOTICS AND REPAIR

ENGINEERING REPORT - July 9th, 2018

July 9th, 2018

newfoundland labrador hydro a nalcor energy company

The heaters were left overnight with a higher setting, which brought the rotor temperature up. We went back to using the Megger tester as the resistance is now high enough to be read by it. At 8:40 am, the readings were:

- Poles 1-10: 530 kΩ;
- Poles 11-20: 803 kΩ
- Top of rotor temperature: 34C; bottom of rotor temperature: 28C; humidity: 36%

As there was an apparent reduction in resistance from the day before, the readings were re-done with Voith's megger. The results were:

- Poles 1-10: 408 kΩ;
- Poles 11-20: 696 kΩ;

Despite the reduction with Voith's Megger, the original findings of the day (with Hydro's megger) were not reduced from the day before. As per *IEEE Std. 43 - Recommended Practice for Testing Insulation Resistance of Electric Machinery*, measurements at different temperatures need to be corrected to 40C. The standard provides the formula for insulation resistance temperature correction. Therefore, we have:

	July 8th corrected to 40C (kΩ)	*July 9th corrected to 40C (kΩ)*
Poles 1-10:	428	477
Poles 11-20:	728	722

Even with the apparent reduction addressed, the insulation resistance is still not high enough that we feel comfortable bringing the rotor back to service. And as Voith's instrument was yielding more conservative results, we decided to carry subsequent measurements with it.

We agreed that further cleaning would yield diminishing returns and would not

Voith's engineering recommended that the top fins be removed so the leads can also be removed. This way, we will be able to make sure that the low resistances we are reading are caused by the poles, and not the leads. Working on removing the top fins started at 12:30 pm, and will progress through the afternoon. After the leads are removed, another Megger testing will be done. At 3:00 pm, a conference call with Voith's engineering will be held.

A quick reading with the multimeter's ohmmeter measuring the resistance from a point of exposed copper to ground has noted the following:

- Poles 1-10 Ohmmeter reading: 0.048 *MΩ*
- Poles 11-20 Ohmmeter reading: 2.2 *MΩ*

HINDS LAKE ROTOR DIAGNOTICS AND REPAIR

ENGINEERING REPORT - July 9th, 2018

July 9th, 2018

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Amec Foster Wheeler reference: AM212/015/000001 R01
Security Class: Amec Foster Wheeler Confidential

August 8, 2016

Mr. Nelson Seymour
Nalcor Energy
PO Box 12400
Hydro Place, 500 Columbus Drive
St. John's, NL
A1B 4K7

Dear Mr. Seymour,

RE: HOLYROOD TGS BOILER TUBE THINNING ASSESSMENT

Nalcor has a need to potentially operate the three generating units at Holyrood TGS to 2021 with a high degree of reliability. A risk assessment conducted by Nalcor has identified boiler tube failures due to tube thinning as a reliability risk and has proposed de-rating the units as a means of mitigating this risk over the remaining operating period. Amec Foster Wheeler Nuclear Canada has been engaged to review the technical basis for this de-rate assessment, and to apply alternative assessment methods to maximise unit load capability while maintaining acceptable reliability. The initial Nalcor assessment was provided as a basis [1].

Following this review, Amec Foster Wheeler concurs with the overall approach taken in the original Nalcor de-rate technical basis. However, there were issues with the process for establishing the normal and emergency operating loads that created uncertainty in the outcomes and assessment of continued reliability.

Using design and operational data provided by Nalcor [2][3] (also tabulated in Appendix 1), ASME [4] code calculations were revisited while also exploring alternative assessment methods. Amec Foster Wheeler recommends a fitness-for-service approach be taken using B&W Plant Service Bulletin PSB-26 [5] for water-touched components and API 579-1/ASME FFS-1 [6] creep rupture calculations for steam-touched components. From the analysis, it is concluded that with planned replacements completed there is a low risk of boiler tube failures due to wall thinning on Units 1 and 2, operating at current pressures, with no de-rate, to 2021.

Amec Foster Wheeler
4th Floor, 700 University Avenue
Toronto, Ontario, Canada. M5G 1X6
Tel: (416) 592-7000 Fax: (416) 592-8284
www.amecfw.com

The assessment for Unit 3 has concluded there is a high risk of tube failures due to wall thinning within the next year. A 10% de-rate in operating pressure is recommended in addition to monitoring and tube replacement.

If it is assumed that there is a linear relationship between operating pressure and unit load for load ranges being considered, the target loads for Units 1 and 2 are 175 MW (gross), and 135MW (gross) for Unit 3. Additional recommendations are provided below.

It needs to be noted that the above assessment is based on calculations conducted with the current ASME code allowable stress values and therefore represents a variance from the registered design. Concurrence from the boiler and pressure vessel jurisdictional authority is recommended. These conclusions also consider only boiler tube wall thinning, and do not address other potential reliability risks.

1.0 BACKGROUND

Holyrood TGS consists of three oil-fired conventional steam cycle generating units. The units have a maximum output rating of 175 MW for Units 1 and 2, and 150 MW for Unit 3. Units 1 and 2 (Stage 1) were commissioned in 1969/70, and Unit 3 (Stage 2) was commissioned in 1979. Units 1 and 2 were uprated in 1987 with modifications. Unit 3 has not been uprated but the material changes have been made and the reheater surface was modified (tubes removed) in 2001 to improve boiler performance.

The boiler tubing on all three units has experienced various forms of degradation that presents a reliability risk. The primary concerns were oil ash corrosion in the high temperature sections of the tubing and fireside corrosion and erosion in the low temperature tubing. A change in fuel is considered to have mitigated the impact of these degradation mechanisms. Pad-weld repairs or replacement of tube sections have been completed in all three units to address tube failures. Wall thickness surveys are also being conducted annually to monitor tube wall loss.

2.0 ASSESSMENT METHOD

The original assessment consisted of a re-calculation of design pressure for the lowest measured wall thickness observed over the period of 2010 to 2016, using ASME BPVC Section I rules (para PG-27.2.1) [4]. The original ASME minimum wall thickness was used to back-calculate the allowable stress. Where the original ASME minimum wall thickness was not available the supplied wall thickness was used.

The assessment was based on ASME code of construction allowable stresses (1968 for Units 1 and 2, and 1977 for Unit 3), and assumed uniform wall thickness. No other tube failure mechanisms were considered. In addition, adoption of the analysis results assumed no further wall thickness reductions over the remaining operating period.

The original assessment identified a new design pressure for each inspection location where the lowest measured thickness was less than the original ASME wall thickness. A revised load was estimated for locations where the new allowable pressure was less than the original operating pressure. The revised load reflected the percentage reduction in pressure adjusted for

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measurement at the turbine stop valve, assuming a linear relationship between steam pressure and unit load.

In the original assessment the average load for the target sections of tubing was identified as the Emergency Maximum Load. The Normal Maximum Load was based on the Emergency Maximum reduced by a further 10 MW to derive a target operating load.

Following the original assessment, Nalcor contracted Babcock & Wilcox (B&W) to evaluate the Unit 3 boiler superheater, reheater, and economizer tube metal temperatures. B&W generated ASME wall thickness and temperature maps for each tube length in the Unit 3 boiler, for an equivalent fuel and using the code of construction allowable stress values. The results of this study were documented in a report [3]. This action was undertaken to address potentially significant limitations in the original work where supplied wall thicknesses were used as the minimum. Note that the results presented in this letter are based on the materials and temperatures stated in the Revision 02 of this B&W report. If significant changes are made to this evaluation, or if any undocumented field modifications are identified, the analysis presented here should be revisited and revised if necessary.

The present analysis considers four alternative methods for evaluating Maximum Allowable Working Pressure (MAWP) as listed below. For Unit 3, the B&W analysis was used to identify tube metal temperatures and materials. The B&W analysis considered the impact of the reheater surface removal in 2001. For Units 1 and 2, the post up-rate conditions were used [2].

1) Application of the B&W Plant Service Bulletin PSB-26 [5]

   This bulletin provides guidance on limits for boiler tube wall loss tolerance based on supplied wall thickness, and takes advantage of manufacturing tolerances and design tolerances. For tubes satisfying this criteria, no change in operating pressure will be proposed.

2) Application of the current (2015) ASME code (Section I, PG-27.2.1) [4]

   The allowable stresses for ASME materials was increased in 1999 by reducing the factor of safety. This increase in allowable stress permits an increase in the allowable pressure for a given tube wall thickness. The MAWP is derived for each section for the lowest measured wall thickness using the same method applied in the initial analysis. The margin (difference) between the calculated MAWP and original operating pressure, and the margins for incremental pressure reductions are provided.

3) Application of the current (2015) ASME code (Section I, Appendix A, para A-317.2.1) [4]

   In addition to the increases in allowable stress in the current code, Appendix A, para A-317 provides a non-mandatory alternative for calculating wall thickness for boiler tubes and piping that further reduces the required tube wall thickness for a given pressure. Calculations similar to the method described above were completed to determine MAWP.

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4) Assessment of Tubing Operating in Creep Range (API 579-1/ASME FFS-1) [6]

For high temperature components, the creep life evaluation methods identified in API 579-1/ASME FFS-1 were applied. These methods are used for fitness-for-service assessments and are accepted in the National Board Inspection Code (NBIC) [7]. These evaluations result in estimated total life in operating hours for a given wall thickness, operating pressure, material, and temperature.

Assumptions

For the purpose of this wall thinning failure risk assessment, the following assumptions were applied. If any of these assumptions change, this assessment should be revisited.

- The station is required to operate in a manner consistent with current operations until 2021 in terms of cycles, hours, and operating temperatures.
- Over the next five years, the units will accumulate approximately 35,000 operating hours each (~80% operating factor per year).
- Currently, Unit 1 has approximately 193,000 total operating hours, Unit 2 has approximately 186,000 total operating hours, and Unit 3 has approximately 149,000 total operating hours.
- Wall thickness is uniform around the circumference and there is no further wall thinning.
- All tubing has been in-service since unit commissioning without accommodation for replaced tubing.
- The lowest wall thickness is representative of the tube bank for the respective area.
- Data supplied by the boiler manufacturer is correct; materials, minimum and supplied tube dimensions and temperatures.
- Allowable stresses and methods from the 2015 versions of the ASME Boiler and Pressure Vessel Code, Section I are applicable.
- Creep life calculations using lower bound Larson-Miller Parameter material properties are applicable.
- The set pressures for the closest upstream safety valves are taken as the maximum expected operating pressure for a given region.

3.0 RESULTS

The outcomes for the fitness-for-service methods described above are summarized in Table 1 and all analysis results are presented in detail in Appendix 1. These results provide a snapshot of current condition based on the inspection results and design documentation available at the time of this assessment.

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Note that for Units 1 and 2, results in Appendix 1 are presented for the reheater section being replaced in 2016. Appendix 1 also presents the results for the boiler floor tubes on Unit 3 that are planned to be restored in 2016. Discussion of these tubes are excluded from the comments below.

Acceptance Criteria

The following acceptance criteria were applied when evaluating the analysis results:

- B&W Plant Service Bulletin PSB-26: Current measured thickness greater than criteria is considered acceptable.
- ASME Code: Safety valve set pressure less than the code calculated MAWP using current tube wall thicknesses is considered acceptable.
- Creep Rupture: Calculated minimum creep life greater than 2x desired total life (projected total operating hours at 2021) is considered acceptable.
  - Unit 1 target: 456,000 hours
  - Unit 2 target: 442,000 hours
  - Unit 3 target: 368,000 hours
  - Tubes with calculated minimum creep life between the current number of operating hours and target number of operating hours are considered marginal and at medium risk of failure. Tubes with current operating hours exceeding the calculated minimum creep life are considered to be at high risk of failure.

3.1 Waterwall and Economiser Tubing

The waterwall and economiser tubing in all three units pass the PSB-26 criteria. This result indicates current operating pressures should not challenge the integrity of these tubes.

In Units 1 and 2, integrity of the economiser overhead bends at the 5th floor, and the Unit 3 economiser 6th floor lower tube wall bends are challenging ASME minimum wall thickness. Additionally, the waterwall upper rear tubes in Unit 2 were also found to be challenging ASME minimum wall thickness. However, these tubes currently still satisfy the PSB-26 criteria and are not anticipated to challenge creep life before end of operations. It is concluded these sections of tubing in all three units represents a low risk of failure due to tube wall thinning. Greater attention is required at these locations going forward to confirm and monitor wall thickness.

3.2 Superheater and Reheater Tubing

The steam tubing was assessed against the PSB-26 criteria, current ASME BPVC Section I (2015) code requirements, and evaluated for creep rupture life in accordance with API 579-1/ASME FFS-1.

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- Unit 1

  The steam tubing in Unit 1 does not satisfy the PSB-26 criteria in all cases, but satisfies all ASME Section I criteria using the current code and original operating pressure. Therefore the risk of tube failure due to thinning is considered low.

- Unit 2

  The limiting location for Unit 2 is the primary superheater 8th floor bend. This location fails both the PSB-26 criteria and the current code ASME requirements at original operating pressure. The lower bound creep rupture life at the assumed operating pressure is approximately 2.6 million hours. The major factors leading to this result are extensive wall loss and a material (SA-210 A1) operating at the upper end of the acceptable range.

  The results indicate this section of the primary superheater would require dropping operating pressure by approximately 10% to satisfy the current ASME code criteria. However, since the creep rupture life is shown to be extensive, it is concluded that the boiler can be operated for an additional five years at full operating pressure with low risk of tube failure due to thinning. Re-inspection of the area can confirm wall thickness, and replacement can be considered if the most severe damage is localised.

- Unit 3

  The Unit 3 steam tubing fails to satisfy the PSB-26 criteria and the ASME code requirements in several locations within the secondary superheater and reheater sections. Additional metallurgical concerns have also been identified with respect to the use of SA-213 T11 and T2 in the primary superheater.

  The limiting locations are in the 9th floor cavity in the reheater. With only 64% remaining wall thickness, the 9th floor overhead reheater bends do not satisfy the PSB-26 criteria for steam tubing, do not meet the current ASME code requirements at full pressure (or with a 20% pressure de-rate), and do not meet the remaining creep life criteria. Creep life exhaustion is also predicted for the SA-213 T11 tubing below feet. Although there may be some life remaining before creep rupture based on available inspection results (currently no evidence of creep damage), it should be noted that predicted creep life is on the same order of magnitude as the reheater tubing that failed in Unit 1 earlier in 2016. To provide additional assurance in the short-term (1 year), a 10% pressure de-rate is recommended until additional targeted inspections/repairs can be conducted.

  The main issue with the 9th floor cavity reheater tubes, in addition to wall thinning, is predicted metal temperatures at the upper limits of the allowable range. In this temperature range the ASME allowable stresses begin to drop significantly. Creep life is also highly dependent on temperature. This is illustrated where, although passing the PSB-26 thickness criteria, the SA-213 T11 spans are now challenging predicted creep life.

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Similarly, high predicted metal temperatures at the 10th floor primary superheater tubes are challenging predicted creep life, although still satisfying the PSB-26 criteria for wall thickness. This concern of elevated metal temperatures has also been identified in the B&W study [3]. Longer-term operation without mitigation (either through tube replacement or measures to decrease local temperatures) represents a reliability risk.

The Unit 3 reheater tubing at the 9th floor overhead south side bends and the 9th floor reheater T11 tubing below feet present a high risk of tube failure if mitigating action is not taken. The compromised primary superheating tubes should also be closely monitored. A 10% de-rate will provide additional assurance in the short-term (1 year), but selective, or bulk replacement of these tubes should be considered at the earliest opportunity followed by annual monitoring and replacement to ensure longer-term reliability.

4.0 SUMMARY AND RECOMMENDATIONS

The methods applied in the initial assessment by Nalcor for assessing boiler tube reliability associated with tube wall thinning are consistent with industry practice. Reductions in pressure for boiler component integrity management is common but acceptance from the local jurisdictional authority is typically required when operating outside of the original design configuration. Operating parameter changes to be applied over an extended period are consistent with direction in NBIC Section 3.4.1 "Re-Rating". The action can address the need to de-rate for integrity management, redefine ASME limitations using a more recent code, or up-rating.

The revised analysis completed by Amec Foster Wheeler presents options for establishing a load limit for the remaining operating period (2016 to 2021) that would mitigate boiler tube reliability concerns due to tube wall thinning.

The results of the analysis indicate that Nalcor has two options:

- Base the target loads on the 2015 ASME BPVC Section I Code para. A-317.2.1 requirements.
- Base the target loads on the B&W PSB-26 for water-touched tubing where the failure mechanism is controlled by overload, and based on creep rupture where failure is controlled by creep life (steam-touched tubing).

The first option is more consistent with the re-rate alteration process. The second approach is a fitness-for-service case. Margins on safety for the ASME case are based on limits on allowable stress. In the fitness-for-service case, the margins are based on extended life well in-excess of the requirements for creep, and manufacturing and design margins for PSB-26. It is also noted that PSB-26 is consistent with the recommended practice for erosion corrosion (FAC) in ASME B31.1 Appendix IV.

To support extended life, Amec Foster Wheeler recommends adoption of the fitness-for-service approach.

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Through application of the PSB-26 criteria and predicted remaining creep life calculations, the analysis performed using currently available data suggests that Units 1 and 2 can continue to operate at full pressure with low risk of boiler tube failures due to wall thinning, to 2021. Target loads can therefore be maintained at 175 MW (gross). This conclusion assumes minimal future wall loss, with ongoing monitoring and repair.

For Unit 3, creep life is exhausted for the 9th floor cavity reheater tubing, where predicted creep life values are now in the same order of magnitude as the reheater tubing that required replacement on Units 1 and 2. Creep life is also being challenged for tubing in the primary superheater (10th floor). A 10% de-rate will provide additional assurance for reliable operation in the short-term, but corrective action is recommended at the earliest opportunity (within 1 year) to avoid tube failures. Assuming a linear relationship between pressure and load, a target load of 135 MW (gross) is recommended.

A summary of the tubes challenging ASME minimum allowable wall thickness and/or creep life, with recommended actions (for 1- and 5-year time horizons) assuming adoption of the fitness-for-service approach, is provided in Table 1 below.

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Table 1: Recommendations for Boiler Tubes of Concern

Unit	Appendix 1 Row #	Compromised Tube Location	Fitness-for-Service Evaluation Criteria at 100% Operating Pressure[1]: B&W PSB-26	Fitness-for-Service Evaluation Criteria at 100% Operating Pressure[1]: Creep Life (Larson-Miller Parameter)	Immediate Action(s) (1 Year of Continued Operation): Recommended Action	Immediate Action(s) (1 Year of Continued Operation): Recommended Unit De-Rate	Longer-Term Action(s) (5 Years of Continued Operation): Recommended Action	Longer-Term Action(s) (5 Years of Continued Operation): Recommended Unit De-Rate
1	21	Economizer, 5th Floor, Overhead (Bends)	**PASS**	*EXTENSIVE REMAINING LIFE*	Continue monitoring tube wall thinning.	None Required	Continue monitoring tube wall thinning.	None Required
2	8	Primary Superheater, 8th Floor (Bends)	*FAIL*	**EXTENSIVE REMAINING LIFE**	Continue monitoring tube wall thinning.	None Required	Continue monitoring tube wall thinning.	None Required
	22	Water Wall Upper Rear Tubes	**PASS**	*EXTENSIVE REMAINING LIFE*				
	23	Economizer, 5th Floor, Overhead (Bends)	**PASS**	*EXTENSIVE REMAINING LIFE*				
3	1, 2	Economizer Tubes, 6th Floor, Lower Tube Wall (North and South Bends)	**PASS**	*EXTENSIVE REMAINING LIFE*	Identify a suitable wall thickness for each zone and conduct inspection and selective replacement at the earliest opportunity (within 1 year).	10% (15 MW) (risk of creep rupture may be reduced, but not eliminated with a reduced operating pressure)	Proactively replace tubing at or near end of creep life at the earliest opportunity, placing priority on the highest-risk tubing. Continue monitoring tube wall thinning on other tubing.	10% (15 MW) (risk of creep rupture may be reduced, but not eliminated with a reduced operating pressure) Re-assess based on inspection and replacement results.
	16, 17	**Low Temperature Superheater, 10th Floor, Below Feet (Boiler Side) (Bends and Tubes)**	*PASS*	**MARGINAL – MEDIUM RISK**				
	18	**Low Temperature Superheater, 10th Floor, Below Feet (Economizer Side) (Bends)**	*PASS*	**HIGH RISK**				
	19	**Low Temperature Superheater, 10th Floor, Below Feet (Economizer Side) (Tubes)**	*PASS*	**MARGINAL – MEDIUM RISK**				
	20	High Temperature Superheater, 8th Floor, Overhead (Bends)	*FAIL*	**EXTENSIVE REMAINING LIFE**				
	25, 26	High Temperature Superheater, 8.5 Floor, Below Feet (Tubes and Bends)	*PASS*	**EXTENSIVE REMAINING LIFE**				
	29	**Reheater Tubes, 9th Floor, Overhead (Bends)**	*FAIL*	**HIGH RISK**				
	30	**Reheater Tubes, 9th Floor, Overhead (Tubes)**	*FAIL*	**MARGINAL – MEDIUM RISK**				
	31	**Reheater Tubes, 9th Floor, Below Feet (Tubes, SA-213 T11)**	*PASS*	**HIGH RISK**				
	32	**Reheater Tubes, 9th Floor, Below Feet (Tubes, SA-213 T22)**	*PASS*	**MARGINAL – MEDIUM RISK**				

[1]Most relevant evaluation criteria for a given tube (based on metal temperatures) are **bold**.

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<u>Recommendations</u>

The following recommendations are provided to support Nalcor in optimising load capability and mitigate the outage risk associated with boiler tube wall thinning:

1. It is recommended a fitness-for-service approach be applied to manage boiler tube integrity related to tube wall thinning. Limits for water-touched tubes should be based on the PSB-26 criteria, and for the steam-touched (high-temperature) tubes, based on predicted creep rupture life.

2. The results of this analysis should be reviewed with the local jurisdictional authority to assess regulatory requirements associated with implementation. It is expected that this discussion will confirm the feasibility of adopting the fitness-for-service approach.

3. It is recommended additional tube replacements be completed in the Unit 3 primary superheater and reheater at the earliest opportunity. The creep life analysis has determined that the primary superheater tubing on the 10th floor (below feet) and reheater tubing in the 9th floor cavity are approaching end of life. Creep life is predicted to be in the same order of magnitude as the reheater tubing in Units 1 and 2 that required replacement in 2016. A 10% (15 MW) de-rate is recommended in the interim period in order to regain margin and reduce the risk of creep rupture.

4. An assessment should be performed to determine minimum acceptable wall thickness for compromised areas to support inspection and selective replacement.

5. Conduct follow-up inspections in 2016 to confirm materials and wall thickness in limiting locations (extent of damage).

6. Continue with annual boiler tube wall thickness surveys to monitor damage accumulation rates and locations. If there is evidence of additional wall thinning, the re-rating needs to be revisited. The cause(s) of tube thinning on Unit 3 should be investigated and mitigated where possible in order to reduce the risk of early tube failure.

7. Other failure mechanisms beyond wall thinning, such as fatigue cracking, are outside this scope of this thickness-based analysis. Fatigue failures are due to pressure/temperature cycles, therefore it is recommended that stops/starts and load cycling be limited when possible.

8. Use of pressure for control of generator output is recommended over load control, due to potential non-linearity in the translation between the pressure and load at higher pressure reductions (i.e. >10%). Additionally, if a long-term de-rate is applied, a boiler performance assessment is recommended to evaluate other impacts.

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REFERENCES

[1] Correspondence, "Holyrood TGS Condition Re-Rate Assessment Review", AmecFW File No. AM212/011/000001 R00, 2016-04-27.

[2] Report, "Uprating Holyrood Units 1 and 2 from 150 MW to 175 MW", File No. TIS 8536, 1990-10-01.

[3] Report, "Thermal Study – Superheater and Reheater Metal" B&W File No. TP900932 R02, 2016-07-05.

[4] ASME Boiler and Pressure Vessel Code Section I, 2015-07-01.

[5] B&W Plant Service Bulletin, "Tube Thickness Evaluation Repair or Replacement Guide", B&W File No. PSB-26, 1994-06-01.

[6] API 579-1/ASME FFS-1, "Fitness for Service", 2007-06-05.

[7] National Board Inspection Code (NBIC), Part 3 "Repairs and Alterations", NB-23 (2015).

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APPENDIX 1

Analysis Results

Unit 1																													
#	Inspection Location	Physical Properties					B&W Plant Service Bulletin PSB-26					MAWP (ASME BPVC Section I, PG-27.2.1)							MAWP (ASME BPVC Section I, A-317.2.1)							Larson-Miller at 100% Operating Pressure		Larson-Miller at 90% Operating Pressure	
		Lowest Measured Wall Thickness (inch)	Assumed 100% Operating Pressure (psi)	Material	Temp. (°F)	Tube OD (inches)	PSB-26 Requirement (t = specified wall)	Percent Remaining from Original	Required Wall (inches)	Margin at Design Pressure (inches)	Criteria Satisfied?	MAWP (psi)	Max. Operating Pressure Margin (psi)	Margin with 2% pressure reduction (psi)	Margin with 5% pressure reduction (psi)	Margin with 10% pressure reduction (psi)	Margin with 15% pressure reduction (psi)	Margin with 20% pressure reduction (psi)	MAWP (psi)	Max. Operating Pressure Margin (psi)	Margin with 2% pressure reduction (psi)	Margin with 5% pressure reduction (psi)	Margin with 10% pressure reduction (psi)	Margin with 15% pressure reduction (psi)	Margin with 20% pressure reduction (psi)	Minimum Predicted Life (hours)	*Mean Predicted Life (hours)*	Minimum Predicted Life (hours)	*Mean Predicted Life (hours)*
1	Water Wall Tubes at Buners	0.204	2205	SA210A1	701	2.5	70%t	102%	0.140	0.064	**YES**	**2580**	**375**	*419*	*485*	*595*	*705*	*816*	**2770**	**565**	*609*	*675*	*786*	*896*	*1006*	**1.00E+08**	*8.83E+08*	*2.51E+08*	*2.02E+09*
2	Economizer, 8th Floor, Below Feet	0.202	2205	SA192	704	2	70%t	101%	0.140	0.062	**YES**	**2605**	**400**	*444*	*510*	*620*	*730*	*841*	**2767**	**562**	*606*	*673*	*783*	*893*	*1003*	**9.05E+07**	*1.76E+08*	*2.07E+08*	*3.95E+08*
3	Boiler Floor Tubes	0.174	-	-	-	-	70%t	87%	0.140	0.034	**YES**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Primary Superheater, 10th Floor, Below Feet	0.206	2055	SA213T11	914	2	85%t	114%	0.153	0.053	**YES**	**2694**	**639**	*680*	*741*	*844*	*947*	*1050*	**2859**	**804**	*846*	*907*	*1010*	*1113*	*1215*	**2.05E+06**	*1.28E+07*	*3.24E+06*	*2.03E+07*
5	Primary Superheater, 9th Floor, Overhead	0.19	2055	SA210A1	768	2	85%t	106%	0.153	0.037	**YES**	**2415**	**360**	*401*	*463*	*565*	*668*	*771*	**2572**	**517**	*559*	*620*	*723*	*826*	*928*	**2.02E+07**	*1.31E+08*	*4.48E+07*	*2.72E+08*
6	Primary Superheater, 9th Floor, Below Feet	0.183	2055	SA210A1	732	2	85%t	111%	0.140	0.043	**YES**	**2639**	**584**	*625*	*687*	*790*	*892*	*995*	**2817**	**762**	*803*	*864*	*967*	*1070*	*1173*	**9.68E+07**	*6.85E+08*	*2.22E+08*	*1.46E+09*
7	Primary Superheater, 8th Floor (Bend)	0.153	2055	SA210A1	732	2	85%t	93%	0.140	0.013	**YES**	**2146**	**91**	*132*	*194*	*297*	*400*	*502*	**2314**	**259**	*300*	*362*	*465*	*567*	*670*	**1.87E+07**	*1.56E+08*	*4.59E+07*	*3.49E+08*
8	Primary Superheater, 8th Floor (Tube)	0.173	2055	SA210A1	732	2	85%t	105%	0.140	0.033	**YES**	**2473**	**418**	*459*	*521*	*624*	*726*	*829*	**2647**	**592**	*633*	*695*	*798*	*900*	*1003*	**5.84E+07**	*4.33E+08*	*1.37E+08*	*9.38E+08*
9	Secondary Superheater, 7th Floor, Overhead	0.192	2055	SA213TP321H	993	2	85%t	116%	0.140	0.052	**YES**	**3249**	**1194**	*1235*	*1297*	*1400*	*1502*	*1605*	**3460**	**1405**	*1446*	*1507*	*1610*	*1713*	*1816*	**1.83E+07**	*2.42E+08*	*3.46E+07*	*4.60E+08*
10	Secondary Superheater, 7th Floor, Below Feet	0.215	2055	SA213T22	975	2	85%t	83%	0.221	-0.006	**NO**	**2147**	**92**	*133*	*195*	*298*	*400*	*503*	**2275**	**220**	*262*	*323*	*426*	*529*	*631*	**8.43E+05**	*3.79E+06*	*1.65E+06*	*7.26E+06*
11	Secondary Superheater, 8th Floor, Below Feet	0.197	2055	SA213TP347H	1160	2	85%t	82%	0.204	-0.007	**NO**	**2059**	**4**	*45*	*107*	*209*	*312*	*415*	**2190**	**135**	*176*	*237*	*340*	*443*	*546*	**8.06E+05**	*2.27E+06*	*1.34E+06*	*3.77E+06*
12	Secondary Superheater, 6th Floor (Overhead from Scaffold)	0.193	2055	SA213T22	959	2	85%t	81%	0.202	-0.009	**NO**	**2074**	**19**	*60*	*122*	*224*	*327*	*430*	**2208**	**153**	*194*	*256*	*358*	*461*	*564*	**7.58E+05**	*3.49E+06*	*1.49E+06*	*6.83E+06*
13	*Reheater, 8th Floor, Overhead*[2]	*0.061*	*532*	*SA213TP304H*	*1186*	*2.125*	*85%t*	*41%*	*0.126*	*-0.065*	*NO*	***318***	*-214*	*-203*	*-187*	*-161*	*-134*	*-108*	***387***	*-145*	*-134*	*-118*	*-92*	*-65*	*-38*	*1.23E+05*	*1.10E+06*	*2.26E+05*	*2.02E+06*
14	Reheater, 9th Floor, Below Feet (North Bend)	0.14	532	SA213T22	1060	2.125	85%t	95%	0.126	0.014	**YES**	**690**	**158**	*168*	*184*	*211*	*238*	*264*	**752**	**220**	*230*	*246*	*273*	*299*	*326*	**2.82E+06**	*7.46E+06*	*4.48E+06*	*1.08E+07*
15	Reheater, 9th Floor, Below Feet (North Bend)	0.182	532	SA213T22	1060	2.125	85%t	123%	0.126	0.056	**YES**	**933**	**401**	*412*	*428*	*455*	*481*	*508*	**1000**	**468**	*478*	*494*	*521*	*547*	*574*	**8.79E+06**	*1.86E+07*	*1.21E+07*	*2.41E+07*
16	Reheater, 9th Floor, Below Feet (South Section of Tube)	0.214	532	SA213T9	1100	2.125	85%t	105%	0.173	0.041	**YES**	**699**	**167**	*177*	*193*	*220*	*246*	*273*	**742**	**210**	*221*	*237*	*263*	*290*	*317*	**2.56E+06**	*1.71E+07*	*4.17E+06*	*2.78E+07*

[2] Tubes to be replaced in 2016.

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APPENDIX 1

Analysis Results

Unit 1																													
#	Inspection Location	Physical Properties					B&W Plant Service Bulletin PSB-26					MAWP (ASME BPVC Section I, PG-27.2.1)							MAWP (ASME BPVC Section I, A-317.2.1)							Larson-Miller at 100% Operating Pressure		Larson-Miller at 90% Operating Pressure	
		Lowest Measured Wall Thickness (inch)	Assumed 100% Operating Pressure (psi)	Material	Temp. (°F)	Tube OD (inches)	PSB-26 Requirement (t = specified wall)	Percent Remaining from Original	Required Wall (inches)	Margin at Design Pressure (inches)	Criteria Satisfied?	MAWP (psi)	Max. Operating Pressure Margin (psi)	Margin with 2% pressure reduction (psi)	Margin with 5% pressure reduction (psi)	Margin with 10% pressure reduction (psi)	Margin with 15% pressure reduction (psi)	Margin with 20% pressure reduction (psi)	MAWP (psi)	Max. Operating Pressure Margin (psi)	Margin with 2% pressure reduction (psi)	Margin with 5% pressure reduction (psi)	Margin with 10% pressure reduction (psi)	Margin with 15% pressure reduction (psi)	Margin with 20% pressure reduction (psi)	Minimum Predicted Life (hours)	*Mean Predicted Life (hours)*	Minimum Predicted Life (hours)	*Mean Predicted Life (hours)*
17	Reheater, 9th Floor, Below Feet (North Section of Tube)	0.154	532	SA213T22	1060	2.125	85%t	104%	0.126	0.028	**YES**	**770**	**238**	*248*	*264*	*291*	*318*	*344*	**833**	**301**	*312*	*328*	*354*	*381*	*407*	**4.43E+06**	*1.08E+07*	*6.71E+06*	*1.50E+07*
18	Reheater, 9th Floor, Overhead	0.165	532	SA213T22	1060	2.5	85%t	111%	0.126	0.039	**YES**	**691**	**159**	*170*	*186*	*212*	*239*	*266*	**753**	**221**	*232*	*248*	*274*	*301*	*328*	**2.84E+06**	*7.51E+06*	*4.52E+06*	*1.09E+07*
19	Reheater, 10th Floor, Below Feet	0.137	532	SA209T1	700	2.5	85%t	102%	0.114	0.023	**YES**	**1646**	**1114**	*1124*	*1140*	*1167*	*1193*	*1220*	**1823**	**1291**	*1301*	*1317*	*1344*	*1370*	*1397*	**1.68E+12**	*5.78E+12*	*2.73E+12*	*9.40E+12*
20	Water Wall Knee Region	0.211	2205	SA210A1	701	2.5	70%t	106%	0.140	0.071	**YES**	**2682**	**477**	*521*	*587*	*697*	*808*	*918*	**2875**	**670**	*714*	*780*	*890*	*1000*	*1111*	**1.39E+08**	*1.18E+09*	*3.44E+08*	*2.68E+09*
21	Economizer, 5th Floor, Overhead (Bend)	0.143	2205	SA192	704	2	70%t	72%	0.140	0.003	**YES**	**1747**	-458	-414	-347	-237	-127	-17	**1893**	-312	-268	-202	-92	**18**	*129*	**3.42E+06**	*7.41E+06*	*8.95E+06*	*1.87E+07*
22	Economizer, 5th Floor, Overhead (Tube)	0.183	2205	SA192	704	2	70%t	92%	0.140	0.043	**YES**	**2323**	**118**	*162*	*228*	*338*	*448*	*559*	**2479**	**274**	*318*	*384*	*494*	*605*	*715*	**3.69E+07**	*7.36E+07*	*8.71E+07*	*1.70E+08*

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APPENDIX 1

Analysis Results

Unit 2																													
#	Inspection Location	Physical Properties					B&W Plant Service Bulletin PSB-26					MAWP (ASME BPVC Section I, PG-27.2.1)							MAWP (ASME BPVC Section I, A-317.2.1)							Larson-Miller at 100% Operating Pressure		Larson-Miller at 90% Operating Pressure	
		Lowest Measured Wall Thickness (inch)	Assumed 100% Operating Pressure (psi)	Material	Temp. (°F)	Tube OD (inches)	PSB-26 Requirement (t = specified wall)	Percent Remaining from Original	Required Wall (inches)	Margin at Design Pressure (inches)	Criteria Satisfied?	MAWP (psi)	Max. Operating Pressure Margin (psi)	Margin with 2% pressure reduction (psi)	Margin with 5% pressure reduction (psi)	Margin with 10% pressure reduction (psi)	Margin with 15% pressure reduction (psi)	Margin with 20% pressure reduction (psi)	MAWP (psi)	Max. Operating Pressure Margin (psi)	Margin with 2% pressure reduction (psi)	Margin with 5% pressure reduction (psi)	Margin with 10% pressure reduction (psi)	Margin with 15% pressure reduction (psi)	Margin with 20% pressure reduction (psi)	Minimum Predicted Life (hours)	*Mean Predicted Life (hours)*	Minimum Predicted Life (hours)	*Mean Predicted Life (hours)*
1	Water Wall Tubes at Buners	0.171	2205	SA210A1	701	2.5	70%t	86%	0.140	0.031	**YES**	**2105**	-100	-56	**10**	*120*	*231*	*341*	**2287**	**82**	*126*	*192*	*303*	*413*	*523*	**1.68E+07**	*1.81E+08*	*4.57E+07*	*4.39E+08*
2	Economizer, 8th Floor, Below Feet	0.209	2205	SA192	704	2	70%t	105%	0.140	0.069	**YES**	**2710**	**505**	*549*	*615*	*726*	*836*	*946*	**2875**	**670**	*714*	*781*	*891*	*1001*	*1111*	**1.23E+08**	*2.37E+08*	*2.77E+08*	*5.25E+08*
3	Boiler Floor Tubes	0.177	-	-	-	-	70%t	89%	0.140	0.037	**YES**	**-**	-	-	-	-	-	-	**-**	-	-	-	-	-	-	-	-	-	-
4	Primary Superheater, 10th Floor, Below Feet (Bend)	0.163	2055	SA213T11	914	2	85%t	91%	0.153	0.010	**YES**	**2054**	-1	**40**	*101*	*204*	*307*	*410*	**2206**	**151**	*192*	*253*	*356*	*459*	*562*	**6.61E+05**	*4.08E+06*	*1.05E+06*	*6.49E+06*
5	Primary Superheater, 10th Floor, Below Feet (Tube)	0.188	2055	SA213T11	914	2	85%t	104%	0.153	0.035	**YES**	**2422**	**367**	*408*	*470*	*573*	*675*	*778*	**2582**	**527**	*568*	*629*	*732*	*835*	*938*	**1.31E+06**	*8.16E+06*	*2.07E+06*	*1.30E+07*
6	Primary Superheater, 9th Floor, Overhead	0.191	2055	SA210A1	768	2	85%t	106%	0.153	0.038	**YES**	**2430**	**375**	*416*	*477*	*580*	*683*	*786*	**2588**	**533**	*574*	*635*	*738*	*841*	*944*	**2.12E+07**	*1.37E+08*	*4.68E+07*	*2.83E+08*
7	Primary Superheater, 9th Floor, Below Feet	0.182	2055	SA210A1	732	2	85%t	110%	0.140	0.042	**YES**	**2623**	**568**	*609*	*670*	*773*	*876*	*979*	**2800**	**745**	*786*	*847*	*950*	*1053*	*1156*	**9.22E+07**	*6.55E+08*	*2.12E+08*	*1.40E+09*
8	Primary Superheater, 8th Floor (Bend)	0.125	2055	SA210A1	732	2	85%t	76%	0.140	-0.015	**NO**	**1700**	-355	-313	-252	-149	-46	**56**	**1861**	-194	-153	-91	**11**	*114*	*217*	**2.56E+06**	*2.68E+07*	*6.86E+06*	*6.39E+07*
9	Primary Superheater, 8th Floor (Tube)	0.179	2055	SA210A1	732	2	85%t	108%	0.140	0.039	**YES**	**2573**	**518**	*559*	*620*	*723*	*826*	*929*	**2749**	**694**	*735*	*796*	*899*	*1002*	*1105*	**7.94E+07**	*5.72E+08*	*1.84E+08*	*1.23E+09*
10	Secondary Superheater, 7th Floor, Overhead	0.192	2055	SA213TP321H	993	2	85%t	116%	0.140	0.052	**YES**	**3249**	**1194**	*1235*	*1297*	*1400*	*1502*	*1605*	**3460**	**1405**	*1446*	*1507*	*1610*	*1713*	*1816*	**1.83E+07**	*2.42E+08*	*3.46E+07*	*4.60E+08*
11	Secondary Superheater, 7th Floor, Below Feet	0.22	2055	SA213T22	975	2	85%t	85%	0.221	-0.001	**NO**	**2206**	**151**	*192*	*253*	*356*	*459*	*562*	**2336**	**281**	*322*	*383*	*486*	*589*	*692*	**9.95E+05**	*4.46E+06*	*1.94E+06*	*8.51E+06*
12	Secondary Superheater, 8th Floor, Below Feet	0.192	2055	SA213TP347H	1160	2	85%t	80%	0.204	-0.012	**NO**	**1998**	-57	-16	**46**	*149*	*251*	*354*	**2128**	**73**	*114*	*175*	*278*	*381*	*484*	**7.01E+05**	*1.98E+06*	*1.17E+06*	*3.28E+06*
13	Secondary Superheater, 6th Floor (Overhead from Scaffold)	0.213	2055	SA213T22	959	2	85%t	89%	0.202	0.011	**YES**	**2326**	**271**	*312*	*374*	*477*	*579*	*682*	**2466**	**411**	*452*	*514*	*617*	*719*	*822*	**1.54E+06**	*7.07E+06*	*3.04E+06*	*1.37E+07*
14	*Reheater, 8th Floor, Overhead*[3]	*0.05*	*525*	*SA213TP304H*	*1186*	*2.125*	*85%t*	*34%*	*0.126*	*-0.076*	*NO*	***247***	*-278*	*-267*	*-252*	*-225*	*-199*	*-173*	***316***	*-209*	*-199*	*-183*	*-157*	*-131*	*-104*	*4.03E+04*	*3.61E+05*	*7.45E+04*	*6.66E+05*
15	Reheater, 9th Floor, Below Feet (South Bend)	0.206	525	SA213T9	1100	2.125	85%t	101%	0.173	0.033	**YES**	**668**	**143**	*154*	*170*	*196*	*222*	*248*	**711**	**186**	*197*	*212*	*239*	*265*	*291*	**2.24E+06**	*1.50E+07*	*3.64E+06*	*2.43E+07*
16	Reheater, 9th Floor, Below Feet (South Bend)	0.202	525	SA213T9	1100	2.125	85%t	100%	0.173	0.029	**YES**	**653**	**128**	*139*	*154*	*181*	*207*	*233*	**696**	**171**	*181*	*197*	*223*	*250*	*276*	**2.02E+06**	*1.35E+07*	*3.29E+06*	*2.19E+07*
17	Reheater, 9th Floor, Below Feet (South Section of Tube)	0.225	525	SA213T9	1100	2.125	85%t	111%	0.173	0.052	**YES**	**741**	**216**	*226*	*242*	*268*	*294*	*321*	**785**	**260**	*271*	*287*	*313*	*339*	*365*	**3.53E+06**	*2.36E+07*	*5.75E+06*	*3.82E+07*

[3] Tubes to be replaced in 2016.

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APPENDIX 1
Analysis Results

Unit 2																													
		Physical Properties					B&W Plant Service Bulletin PSB-26					MAWP (ASME BPVC Section I, PG-27.2.1)							MAWP (ASME BPVC Section I, A-317.2.1)							Larson-Miller at 100% Operating Pressure		Larson-Miller at 90% Operating Pressure	
#	Inspection Location	Lowest Measured Wall Thickness (inch)	Assumed 100% Operating Pressure (psi)	Material	Temp. (°F)	Tube OD (inches)	PSB-26 Requirement (t = specified wall)	Percent Remaining from Original	Required Wall (inches)	Margin at Design Pressure (inches)	Criteria Satisfied?	MAWP (psi)	Max. Operating Pressure Margin (psi)	Margin with 2% pressure reduction (psi)	Margin with 5% pressure reduction (psi)	Margin with 10% pressure reduction (psi)	Margin with 15% pressure reduction (psi)	Margin with 20% pressure reduction (psi)	MAWP (psi)	Max. Operating Pressure Margin (psi)	Margin with 2% pressure reduction (psi)	Margin with 5% pressure reduction (psi)	Margin with 10% pressure reduction (psi)	Margin with 15% pressure reduction (psi)	Margin with 20% pressure reduction (psi)	Minimum Predicted Life (hours)	*Mean Predicted Life (hours)*	Minimum Predicted Life (hours)	*Mean Predicted Life (hours)*
18	Reheater, 9th Floor, Below Feet (North Section of Tube)	0.17	525	SA213T22	1060	2.125	85%t	115%	0.126	0.044	**YES**	**863**	**338**	*348*	*364*	*390*	*416*	*443*	**928**	**403**	*413*	*429*	*455*	*481*	*508*	**7.10E+06**	*1.57E+07*	*1.01E+07*	*2.08E+07*
19	Reheater, 9th Floor, Overhead	0.169	525	SA213T22	1060	2.5	85%t	114%	0.126	0.043	**YES**	**711**	**186**	*196*	*212*	*238*	*264*	*291*	**773**	**248**	*258*	*274*	*300*	*327*	*353*	**3.39E+06**	*8.67E+06*	*5.29E+06*	*1.24E+07*
20	Reheater, 10th Floor, Below Feet	0.133	525	SA209T1	700	2.5	85%t	99%	0.114	0.019	**YES**	**1590**	**1065**	*1076*	*1091*	*1118*	*1144*	*1170*	**1766**	**1241**	*1252*	*1267*	*1294*	*1320*	*1346*	**1.55E+12**	*5.31E+12*	*2.51E+12*	*8.65E+12*
21	Water Wall Knee Region	0.216	2205	SA210A1	701	2.5	70%t	108%	0.140	0.076	**YES**	**2756**	**551**	*595*	*661*	*771*	*881*	*992*	**2950**	**745**	*789*	*855*	*965*	*1075*	*1186*	**1.74E+08**	*1.45E+09*	*4.27E+08*	*3.25E+09*
22	Water Wall Upper Rear Tubes	0.15	2205	SA210A1	701	2.5	70%t	75%	0.140	0.010	**YES**	**1810**	-395	-351	-285	-175	-64	**46**	**1988**	-217	-173	-107	**3**	*113*	*224*	**4.08E+06**	*5.24E+07*	*1.19E+07*	*1.34E+08*
23	Economizer, 5th Floor, Overhead (Bend)	0.155	2205	SA192	704	2	70%t	78%	0.140	0.015	**YES**	**1917**	-288	-244	-177	-67	**43**	*153*	**2065**	-140	-95	*-29*	**81**	*191*	*301*	**7.62E+06**	*1.60E+07*	*1.92E+07*	*3.92E+07*
24	Economizer, 5th Floor, Overhead (Tube)	0.188	2205	SA192	704	2	70%t	94%	0.140	0.048	**YES**	**2396**	**191**	*235*	*302*	*412*	*522*	*632*	**2554**	**349**	*393*	*459*	*570*	*680*	*790*	**4.72E+07**	*9.36E+07*	*1.10E+08*	*2.14E+08*

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APPENDIX 1

Analysis Results

Unit 3																													
#	Inspection Location	Physical Properties					B&W Plant Service Bulletin PSB-26					MAWP (ASME BPVC Section I, PG-27.2.1)							MAWP (ASME BPVC Section I, A-317.2.1)							Larson-Miller at 100% Operating Pressure		Larson-Miller at 90% Operating Pressure	
		Lowest Measured Wall Thickness (inch)	Assumed 100% Operating Pressure (psi)	Material	Temp. (°F)	Tube OD (inches)	PSB-26 Requirement (t = specified wall)	Percent Remaining from Original	Required Wall (inches)	Margin at Design Pressure (inches)	Criteria Satisfied?	MAWP (psi)	Max. Operating Pressure Margin (psi)	Margin with 2% pressure reduction (psi)	Margin with 5% pressure reduction (psi)	Margin with 10% pressure reduction (psi)	Margin with 15% pressure reduction (psi)	Margin with 20% pressure reduction (psi)	MAWP (psi)	Max. Operating Pressure Margin (psi)	Margin with 2% pressure reduction (psi)	Margin with 5% pressure reduction (psi)	Margin with 10% pressure reduction (psi)	Margin with 15% pressure reduction (psi)	Margin with 20% pressure reduction (psi)	Minimum Predicted Life (hours)	*Mean Predicted Life (hours)*	Minimum Predicted Life (hours)	*Mean Predicted Life (hours)*
1	Economizer Tubes, 6th Floor, Lower Tube Wall (South Bend)	0.153	2200	SA210A1	700	2.5	70%t	75%	0.142	0.011	YES	1858	-342	-298	-232	-122	-12	98	2037	-163	-119	-53	57	167	277	5.49E+06	6.85E+07	1.58E+07	1.73E+08
2	Economizer Tubes, 6th Floor, Lower Tube Wall (North Bend)	0.155	2200	SA210A1	700	2.5	70%t	76%	0.142	0.013	YES	1886	-314	-270	-204	-94	16	126	2065	-135	-91	-25	85	195	305	6.33E+06	7.76E+07	1.81E+07	1.95E+08
3	Economizer Tubes, 6th Floor, Lower Tube Wall (Tube)	0.189	2200	SA210A1	700	2.5	70%t	93%	0.142	0.047	YES	2370	170	214	280	390	500	610	2557	357	401	467	577	687	797	5.06E+07	4.85E+08	1.31E+08	1.13E+09
4	Economizer Tubes, 8th Floor, Lower (Under Sootblower)	0.178	2200	SA210A1	700	2.5	70%t	88%	0.142	0.036	YES	2212	12	56	122	232	342	452	2396	196	240	306	416	526	636	2.75E+07	2.83E+08	7.33E+07	6.74E+08
5	Economizer Tubes, 8th Floor, Lower (North Bend)	0.218	2200	SA210A1	700	2.5	70%t	107%	0.142	0.076	YES	2794	594	638	704	814	924	1034	2990	790	834	900	1010	1120	1230	2.05E+08	1.69E+09	5.01E+08	3.79E+09
6	Economizer Tubes, 8th Floor, Lower (North Bend)	0.186	2200	SA210A1	700	2.5	70%t	92%	0.142	0.044	YES	2327	127	171	237	347	457	567	2513	313	357	423	533	643	753	4.31E+07	4.20E+08	1.13E+08	9.89E+08
7	Economizer Tubes, 8th Floor, Upper (South Bend)	0.171	2200	SA210A1	700	2.5	70%t	84%	0.142	0.029	YES	2112	-88	-44	22	132	242	352	2295	95	139	205	315	425	535	1.81E+07	1.96E+08	4.93E+07	4.74E+08
8	Economizer Tubes, 8th Floor, Upper (Tube)	0.178	2200	SA210A1	700	2.5	70%t	88%	0.142	0.036	YES	2212	12	56	122	232	342	452	2396	196	240	306	416	526	636	2.75E+07	2.83E+08	7.33E+07	6.74E+08
9	Economizer Tubes, 8th Floor, Upper (North Bend)	0.178	2200	SA210A1	700	2.5	70%t	88%	0.142	0.036	YES	2212	12	56	122	232	342	452	2396	196	240	306	416	526	636	2.75E+07	2.83E+08	7.33E+07	6.74E+08
10	Low Temperature Superheater, 8th Floor, Overhead (Bend)	0.180	2010	SA210A1	696	2.5	85%t	89%	0.173	0.007	YES	2258	248	288	348	449	549	650	2444	434	474	535	635	736	836	8.91E+07	8.29E+08	2.29E+08	1.92E+09
11	Low Temperature Superheater, 8th Floor, Overhead (Tube)	0.194	2010	SA210A1	696	2.5	85%t	96%	0.173	0.021	YES	2461	451	491	552	652	753	853	2651	641	681	742	842	943	1043	1.85E+08	1.59E+09	4.60E+08	3.61E+09
12	Low Temperature Superheater, 9th Floor, Below Feet (Bend)	0.179	2010	SA210A1	741	2.5	85%t	88%	0.173	0.006	YES	1922	-88	-48	12	113	213	314	2081	71	112	172	272	373	473	7.58E+06	6.52E+07	1.88E+07	1.47E+08
13	Low Temperature Superheater, 9th Floor, Below Feet (Tube)	0.216	2010	SA210A1	741	2.5	85%t	106%	0.173	0.043	YES	2387	377	417	477	578	678	779	2555	545	585	645	746	846	947	4.29E+07	3.08E+08	9.91E+07	6.60E+08
14	Low Temperature Superheater, 9th Floor, Overhead (Bend)	0.170	2010	SA209T1A	766	2.5	85%t	84%	0.173	-0.003	NO	2184	174	214	274	375	475	576	2374	364	404	465	565	666	766	2.75E+08	8.72E+08	4.37E+08	1.37E+09

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APPENDIX 1
Analysis Results

Unit 3																													
#	Inspection Location	Physical Properties					B&W Plant Service Bulletin PSB-26					MAWP (ASME BPVC Section I, PG-27.2.1)							MAWP (ASME BPVC Section I, A-317.2.1)							Larson-Miller at 100% Operating Pressure		Larson-Miller at 90% Operating Pressure	
		Lowest Measured Wall Thickness (inch)	Assumed 100% Operating Pressure (psi)	Material	Temp. (°F)	Tube OD (inches)	PSB-26 Requirement (t = specified wall)	Percent Remaining from Original	Required Wall (inches)	Margin at Design Pressure (inches)	Criteria Satisfied?	MAWP (psi)	Max. Operating Pressure Margin (psi)	Margin with 2% pressure reduction (psi)	Margin with 5% pressure reduction (psi)	Margin with 10% pressure reduction (psi)	Margin with 15% pressure reduction (psi)	Margin with 20% pressure reduction (psi)	MAWP (psi)	Max. Operating Pressure Margin (psi)	Margin with 2% pressure reduction (psi)	Margin with 5% pressure reduction (psi)	Margin with 10% pressure reduction (psi)	Margin with 15% pressure reduction (psi)	Margin with 20% pressure reduction (psi)	Minimum Predicted Life (hours)	*Mean Predicted Life (hours)*	Minimum Predicted Life (hours)	*Mean Predicted Life (hours)*
15	Low Temperature Superheater, 9th Floor, Overhead (Tube)	0.210	2010	SA209T1A	756	2.5	85%t	103%	0.173	0.037	YES	2803	793	833	894	994	1095	1195	3005	995	1035	1096	1196	1297	1397	1.30E+09	4.09E+09	2.05E+09	6.45E+09
16	Low Temperature Superheater, 10th Floor, Below Feet (Boiler Side) (Bend)	0.374	2010	SA213T11	1019	2.5	85%t	95%	0.335	0.039	YES	1860	-150	-110	-49	51	152	252	1956	-54	-14	47	147	248	348	1.74E+05	9.75E+05	2.66E+05	1.50E+06
17	Low Temperature Superheater, 10th Floor, Below Feet (Boiler Side) (Tube)	0.430	2010	SA213T11	1019	2.5	85%t	109%	0.335	0.095	YES	2206	196	236	297	397	498	598	2320	310	350	410	511	611	712	3.46E+05	1.96E+06	5.30E+05	3.01E+06
18	Low Temperature Superheater, 10th Floor, Below Feet (Economizer Side) (Bend)	0.310	2010	SA213T2	993	2.5	85%t	92%	0.287	0.023	YES	1719	-291	-251	-191	-90	10	111	1813	-197	-157	-96	4	105	205	1.12E+05	2.95E+05	1.64E+05	4.33E+05
19	Low Temperature Superheater, 10th Floor, Below Feet (Economizer Side) (Tube)	0.347	2010	SA213T2	993	2.5	85%t	103%	0.287	0.060	YES	1965	-45	-4	56	156	257	357	2069	59	99	159	260	360	461	1.81E+05	4.77E+05	2.64E+05	7.01E+05
20	High Temperature Superheater, 8th Floor, Overhead (Bend)	0.216	2010	SA209T1A	941	2.25	85%t	66%	0.278	-0.062	NO	1840	-170	-130	-69	31	132	232	1959	-51	-11	50	150	251	351	3.23E+05	8.75E+05	4.79E+05	1.30E+06
21	High Temperature Superheater, 8th Floor, Overhead (Tube)	0.228	2010	SA209T1A	941	2.25	85%t	70%	0.278	-0.050	NO	1959	-51	-10	50	150	251	351	2081	71	112	172	272	373	473	4.05E+05	1.10E+06	6.00E+05	1.63E+06
22	High Temperature Superheater, 8th Floor, Below Feet	0.221	2010	SA209T1A	905	2.25	85%t	78%	0.242	-0.021	NO	2704	694	734	794	895	995	1096	2876	866	906	967	1067	1168	1268	1.68E+06	4.66E+06	2.51E+06	7.00E+06
23	High Temperature Superheater, 8.5 Floor, Overhead (Bend)	0.275	2010	SA213T22	1037	2	85%t	84%	0.278	-0.003	NO	1924	-86	-46	14	115	215	316	2025	15	56	116	216	317	417	4.52E+05	1.76E+06	8.40E+05	3.09E+06
24	High Temperature Superheater, 8.5 Floor, Overhead (Tube)	0.283	2010	SA213T22	1034	2	85%t	87%	0.278	0.005	YES	2035	25	65	125	226	326	427	2141	131	171	232	332	433	533	6.23E+05	2.39E+06	1.15E+06	4.17E+06
25	High Temperature Superheater, 8.5 Floor, Below Feet (Bend)	0.279	2010	SA213T22	1021	2.25	85%t	98%	0.242	0.037	YES	1900	-110	-70	-9	91	192	292	2005	-5	35	95	196	296	397	4.12E+05	1.70E+06	7.80E+05	3.10E+06

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		Lowest Measured Wall Thickness (inch)	Assumed 100% Operating Pressure (psi)	Material	Temp. (°F)	Tube OD (inches)	PSB-26 Requirement (t = specified wall)	Percent Remaining from Original	Required Wall (inches)	Margin at Design Pressure (inches)	Criteria Satisfied?	MAWP (psi)	Max. Operating Pressure Margin (psi)	Margin with 2% pressure reduction (psi)	Margin with 5% pressure reduction (psi)	Margin with 10% pressure reduction (psi)	Margin with 15% pressure reduction (psi)	Margin with 20% pressure reduction (psi)	MAWP (psi)	Max. Operating Pressure Margin (psi)	Margin with 2% pressure reduction (psi)	Margin with 5% pressure reduction (psi)	Margin with 10% pressure reduction (psi)	Margin with 15% pressure reduction (psi)	Margin with 20% pressure reduction (psi)	Minimum Predicted Life (hours)	*Mean Predicted Life (hours)*	Minimum Predicted Life (hours)	*Mean Predicted Life (hours)*
26	High Temperature Superheater, 8.5 Floor, Below Feet (Tube)	0.275	2010	SA213T22	1021	2.25	85%t	96%	0.242	0.033	**YES**	**1868**	-142	-102	-41	**59**	*160*	*260*	**1972**	-38	**2**	*62*	*163*	*263*	*364*	**3.72E+05**	*1.54E+06*	*7.06E+05*	*2.82E+06*
27	Reheater Tubes, 7th Floor, Top of Scaffold (Bend)	0.113	600	SA213TP347H	1017	2.25	85%t	76%	0.126	-0.013	**NO**	**1547**	**947**	*959*	*977*	*1007*	*1037*	*1067*	**1729**	**1129**	*1141*	*1159*	*1189*	*1219*	*1249*	**1.22E+09**	*3.76E+09*	*2.13E+09*	*6.55E+09*
28	Reheater Tubes, 7th Floor, Top of Scaffold (Tube)	0.129	600	SA213TP347H	1017	2.25	85%t	87%	0.126	0.003	**YES**	**1804**	**1204**	*1216*	*1234*	*1264*	*1294*	*1324*	**1989**	**1389**	*1401*	*1419*	*1449*	*1479*	*1509*	**2.56E+09**	*7.87E+09*	*4.47E+09*	*1.37E+10*
29	Reheater Tubes, 9th Floor, Overhead (Bend)	0.116	600	SA213T22	1107	2.25	85%t	64%	0.153	-0.037	**NO**	**352**	-248	-236	-218	-188	-158	-128	**392**	-208	-196	-178	-148	-118	-88	**6.53E+04**	*2.24E+05*	**1.16E+05**	*3.71E+05*
30	Reheater Tubes, 9th Floor, Overhead (Tube)	0.140	600	SA213T22	1107	2.25	85%t	78%	0.153	-0.013	**NO**	**437**	-163	-151	-133	-103	-73	-43	**479**	-121	-109	-91	-61	-31	-1	**1.89E+05**	*5.65E+05*	**3.19E+05**	*8.73E+05*
31	Reheater Tubes, 9th Floor, Below Feet (SA-213 T11)	0.161	600	SA213T11	1063	2.5	85%t	89%	0.153	0.008	**YES**	**484**	-116	-104	-86	-56	-26	**4**	**529**	-71	-59	-41	-11	**19**	*49*	**9.06E+04**	*4.89E+05*	**1.37E+05**	*7.42E+05*
32	Reheater Tubes, 9th Floor, Below Feet (SA-213 T22)	0.160	600	SA213T22	1098	2.5	85%t	89%	0.153	0.007	**YES**	**486**	-114	-102	-84	-54	-24	**6**	**531**	-69	-57	-39	-9	**21**	*51*	**3.09E+05**	*9.06E+05*	**5.16E+05**	*1.39E+06*
33	Boiler Roof Tubes (Boiler Side)	0.188	-	-	-	-	70%t	78%	0.168	0.020	**YES**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
34	Water Wall Knee Region	0.213	-	-	-	-	70%t	101%	0.147	0.066	**YES**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
35	*Boiler Floor Tubes*[4]	*0.110*	-	-	-	-	*70%t*	*52%*	*0.147*	*-0.037*	*NO*	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
36	Water Wall at Buners (Elevation 1)	0.169	-	-	-	-	70%t	80%	0.147	0.022	**YES**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
37	Water Wall at Buners (Elevation 2)	0.199	-	-	-	-	70%t	95%	0.147	0.052	**YES**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
38	Water Wall at Buners (Elevation 3)	0.191	-	-	-	-	70%t	91%	0.147	0.044	**YES**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

[4] Tubes to be restored in 2016.

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Thermal Power Department
Technical Services

Engineering Study Report

Customer:	**Newfoundland and Labrador Hydro** **Holyrood Unit #3**
Subject:	**Thermal Study – Superheater and Reheater Metal**
Ref No:	TP9000932 R0 July 5/16
Prepared By:	Tony Chen, P. Eng Principal Performance Engineer
Reviewed By:	Gary Westerveld, P. Eng Technical Services
Date:	July 5, 2016

BABCOCK & WILCOX
PROJECT SERVICES

July 6, 2016

Project: TP9000932
Originator: BWC

TABLE OF CONTENTS

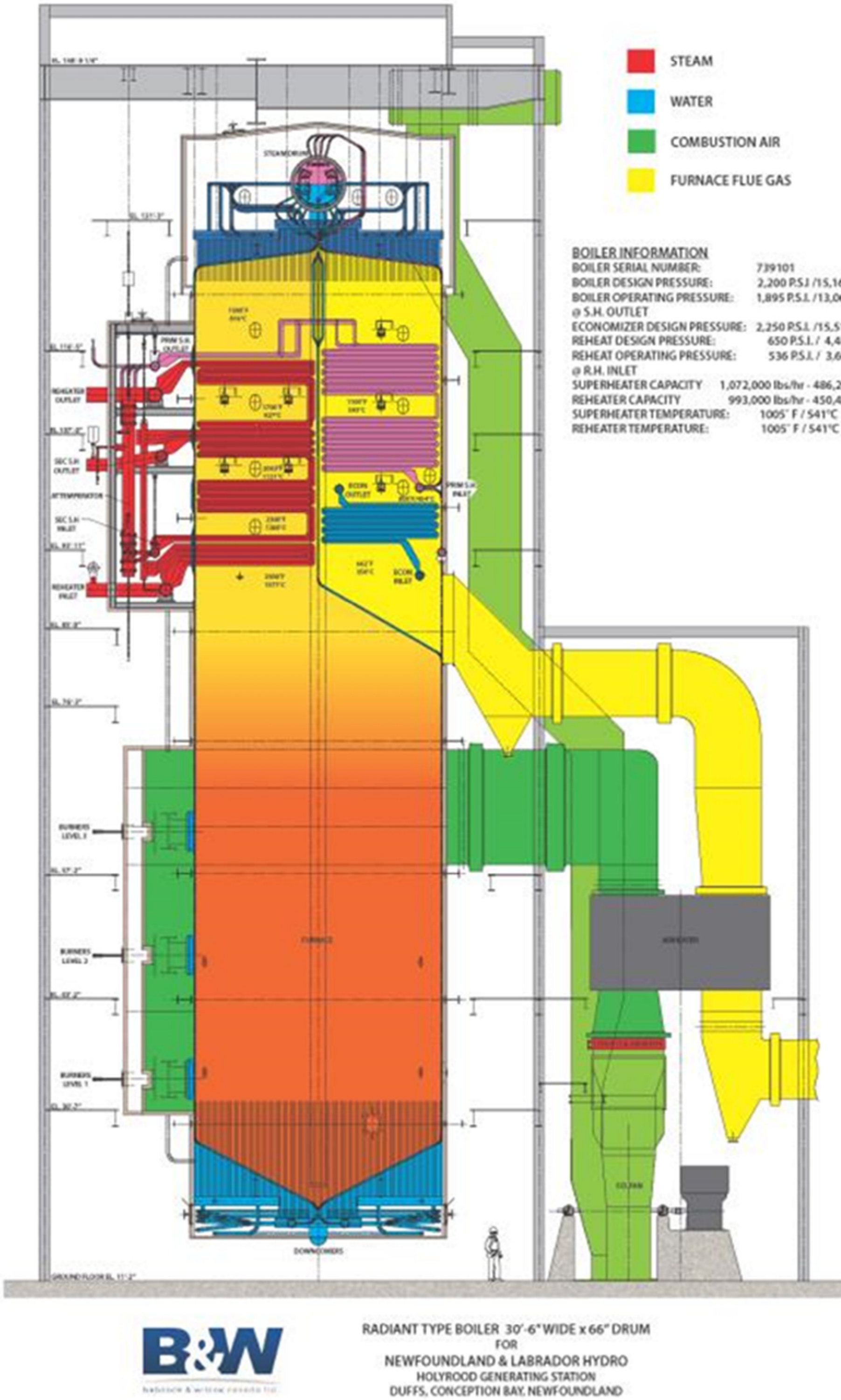
1 INTRODUCTION

Newfoundland and Labrador Hydro (NLH) have contracted Babcock & Wilcox PGG Canada to conduct an engineering study to evaluate the superheater and reheater tube metals for their Holyrood Unit # 3.

The boiler was originally designed, manufactured, erected and put in service in the late 1970's (B&W Contract Number 122-7391). The boiler is a typical "Radiant" type unit with horizontal superheater, reheater, and economizer. Bunker "C" oil has been used as the main fuel up to now. The original boiler has an MCR (Maximum Continuous Rating) main steam flow of 960,600 lb/hr at 1005 ^{o}F and 1,890 psig with a reheat flow of 865,700 lb/hr at 1005 ^{o}F and 471 psig. Boiler and superheater design pressure is 2,200 psig. Reheater design pressure is 650 psig. The original electrical power output rating was 150 MWe.

The reheater modification has been made to the original boiler by Alstom in 2001. As a result, the surface area of the reheater was reduced by 2,318 square feet.

This study rebuilt a thermal performance model to calculate the superheater and reheater design temperatures and the associated ASME minimum thickness requirements. Six (6) boiler loads and one fuel were analyzed per the original performance data sheet. The results are presented in a series of data sheets in the report.



Boiler Sideview

2 EXECUTIVE SUMMARY

Babcock & Wilcox Canada has carried out an engineering study to evaluate the superheater and reheater tube metals for Newfoundland and Labrador Hydro (NLH) on their Holyrood Unit # 3.

Table 4.1 to 4.6 summarized the predicted results that outline the row by row tube design temperatures and the associated ASME minimum thickness requirements.

A review of predicted performance data after the reheater modification indicates that several tube metal temperatures exceed the original maximum allowable temperature for the given tube material and thickness. The tube rows in question are as follows:

Bank	Tube Index	Load Conditions
Reheater	RH14b	THO/VWO, Normal
Prim. SH	PSH3	THO/VWO, Normal
Prim. SH	PSH2, PH4, PSH5, PSH6, PSH7	THO/VWO

The predicted primary superheater outlet header and the attemperator/piping also exceed the original design metal temperatures. These components should be monitored and inspected when possible.

3 STUDY APPROACH

3.1 Scope of Study

The following activities have been completed:

1. B&W utilized proprietary computer modeling programs to calculate boiler thermal performance for the Holyrood Unit#3 boiler for the original turbine heat balance load conditions and fuel.

2. B&W's design method has been established to determine the maximum temperature any given tube may be exposed to for a set of operating conditions. Two principal factors which are assumed to occur simultaneously contribute to localize the most severe conditions as compared to average performance, namely maximum steam temperature and maximum absorption rate. The maximum steam temperature and maximum absorption rate are effected by the following:

   - Unbalanced steam flow
   - Elevated flue gas temperature
   - Unbalanced flue gas temperature
   - Unequal reception of radiation
   - Unbalanced flue gas flow

   The superheater and reheater design criteria are conservatively set with the methods described above. Determination of actual operating conditions requires performance testing, additional instrumentation, and recalibration of existing plant instrumentation along with detailed thermal performance cleanliness study (Kf study). This additional work is not warranted to simply establish design conditions and thus has not been included in this study.

3. B&W has completed a summary report including data sheets that outline the row by row tube design temperatures and the associated ASME minimum thickness requirements.

3.2 Basis of Study

The basis for any boiler performance analysis is the determination of fuel, air, and flue gas flows within the unit across the load range.

3.2.1 Fuel

This study was based on following fuel analysis:

Oil Analysis		
O2	0.30	% by wt.
N2	0.60	% by wt.
S	2.30	% by wt.
H2O	10.80	% by wt.
C	85.80	% by wt.
H2O	0.10	% by wt.
ASH	0.10	% by wt.
Total	100.00	% by wt.
HHV	18,450	BTU/lb

3.2.2 Heat and Mass Balance Calculations

B&W Single Heat and Material Balance Program – P08475 was used to calculate flue gas flow, combustion air flow, furnace heat absorption and **F**urnace **E**xit **G**as **T**emperature (**FEGT**), and boiler thermal efficiency based on the following inputs:

- Steam and water conditions required to calculate boiler output;
- Fuel ultimate analysis;
- Excess air requirement for burners;
- Air heater uncorrected gas outlet temperature and air inlet temperature.

Tables 3.1 lists six (6) operating conditions that was evaluated in this study.

Table 3.1: Operating Conditions

Item	VWO (Vlv Wide Open)	THO (Top Htrr Out of Service)	MCR (Normal)	75% MCR (Normal)	50% MCR (Normal)	25% MCR (Normal)
Design Fuel	Buncker C Oil	Buncker C Oil	Buncker C Oil	Buncker C Oil	Buncker C Oil	Buncker C Oil
No. of Burner in Service	9	9	9	6	6	3
FLOW RATES: (Lbs/Hr)						
Steam Flow Lvg. Sec. Superheater	1,072,200	1,020,900	960,600	696,600	476,500	264,500
Steam Flow Lvg. Rehetaer	963,700	993,000	865,700	631,600	435,200	242,500
Aux. Steam From Prim SH. Outlet	30,000	30,000	30,000	30,000	30,000	30,000
Cont. Blowdown	10,700	10,200	9,600	7,000	4,800	2,600
PRESSURES: (Psig)						
Steam at Sec. SH Outlet	1,910	1,900	1,890	1,855	1,834	1,821
Steam at Reheater Inlet	542	558	487	351	238	127
Drum Operating Pressure	2,050	2,027	2,002	1,914	1,862	1,830
Boiler Design Pressure	2,200	2,200	2,200	2,200	2,200	2,200
Reaheater Design Pressure	650	650	650	650	650	650
TEMPERATURES: (Deg. F)						
Leaving Sec. SH	1,005	1,005	1,005	1,005	965	900
Leaving Reheater	1,005	1,005	1,005	1,005	965	900
Enter Reheater	704	713	683	638	637	655
Enter Economizer	476	412	464	433	400	352
SH, RH Spray Water	290	290	290	270	250	220
Combustion Air Enter Unit	80	80	80	80	80	80

3.2.3 Tube Bank Heat Transfer and Metallurgy Calculations

Heat transfer in each section of convection passes that include superheater, reheater, and economizer was then calculated using B&W Convective Heat Transfer Performance Program – P00140 with the combination of flue gas flow, FEGT, and steam flow calculated by program P08475.

P00140 also calculated superheater and reheater tube metal temperatures to be used in ASME code tube material selection and thickness calculations. The program utilises both analytical and empirical correlations of heat transfer and fluid mechanics that have been developed and refined by B&W over many years.

Design tube metal temperatures are calculated by the program based on combining the worst case expected flue gas temperatures with the minimum expected steam flow to a given tube. Margins on gas temperature are included for variations in furnace cleanliness as well as flue gas flow and temperature. Variations can be expected both on the bulk FEGT and local unbalances in FEGT. B&W's experience has shown that the calculated bulk flue gas temperature leaving the furnace is accurate within a range of + 100 ^{o}F to - 50 ^{o}F. These extremes are referred to as 'T+100' and 'T-50'. Additional unbalances are added for side to side (i.e. local) variations in FEGT and flue gas flow.

On the steam side, unbalances in tube-to-tube steam flow caused by supply header arrangements and tube-to-tube geometry variations within a tube bank are considered. The mean tube metal temperature (based on flue gas and steam side unbalances) is calculated at the end of each tube row (in the direction of steam flow). This temperature is used with the design pressure to calculate the required thickness and material. All ASME code tube thickness calculations are based on the 1977 ASME Section 1 allowable stresses for existing materials. This boiler was originally designed to these allowable.

4 SUMMARY OF RESULTS

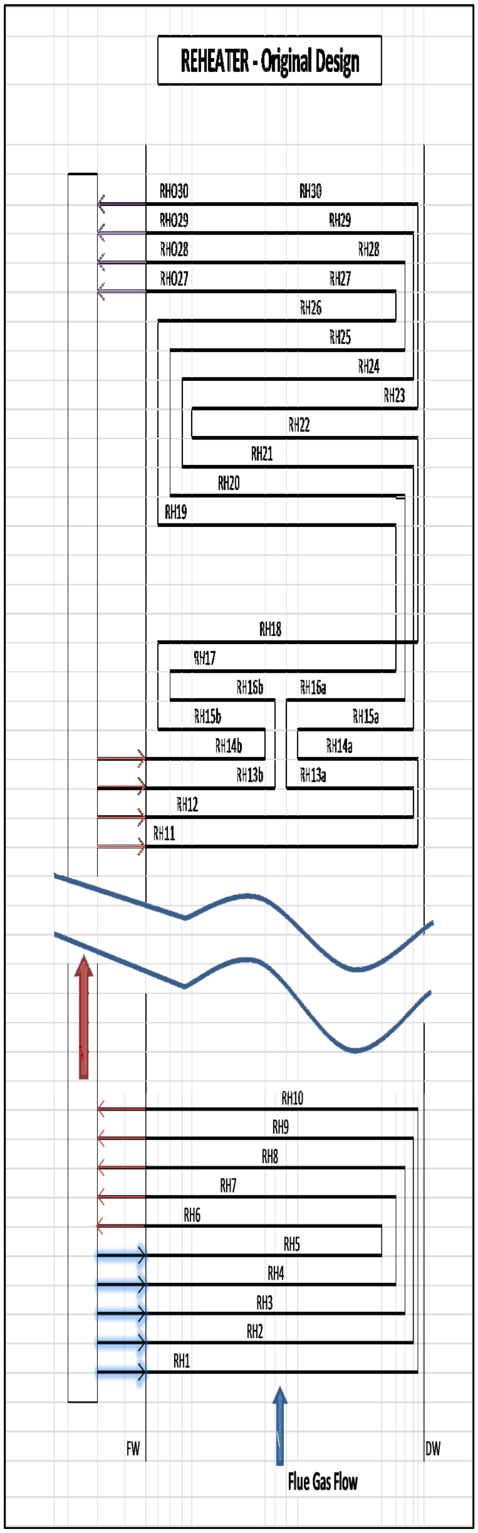
4.1 Original Unit

Table4.1 to 4.3 lists the tube metal temperatures and ASME code required minimum thickness for the reheater, secondary superheater, and primary superheater with the original design surface. The original installed tube thickness and materials were also listed in these tables.

These calculations were based on two (2) conditions as follows:

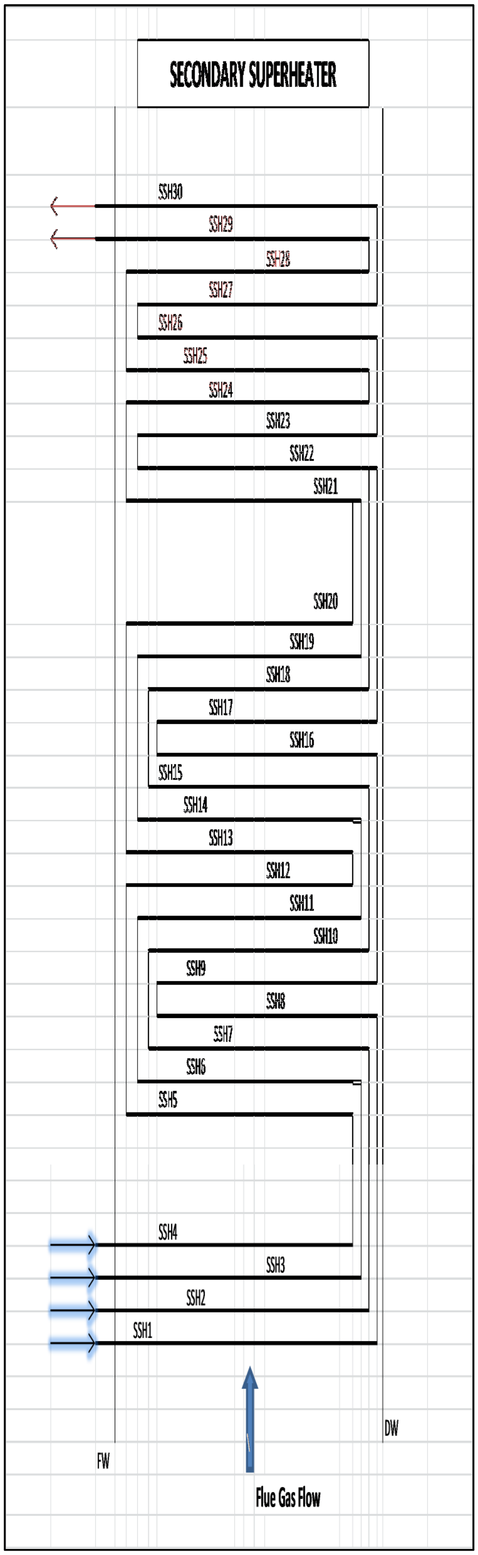
1. Valve Wide Open (**VWO**) or Top Heater Out of Services (**THO**)
2. Normal Operating Conditions (100%, 75%, 50%, and 25%MCR)

Table 4.1 Reheater Tube Metal Temperature and Required Minimum Thickness (Original Unit)



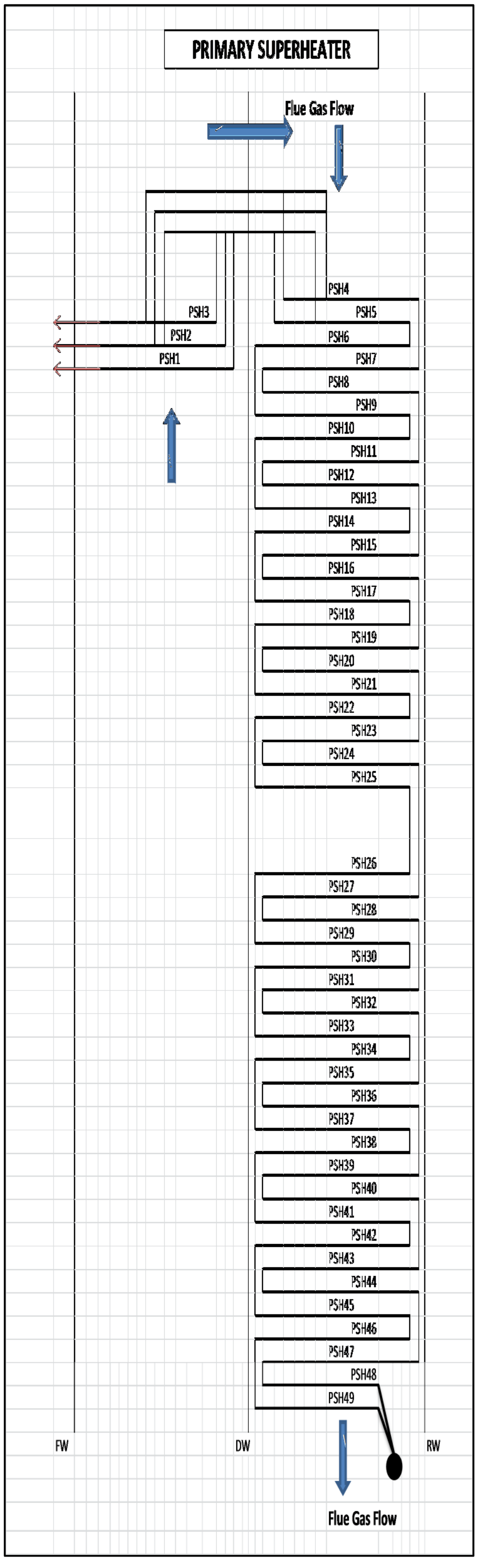
Reheater				VWO/THO - Original			Normal - Original		
ROW NO.	Tube OD (inch)	Installed Tube Materials	Installed Tube MW (inch)	Req'd MW (inch)	T_{AVE} (°F)	T_{SPOT} (°F)	Req'd MW (inch)	T_{AVE} (°F)	T_{SPOT} (°F)
RHO 30	2.25	SA213T5	0.252	0.225	1101	1109	0.219	1097	1103
RHO 29	2.25	SA213T5	0.252	0.225	1102	1110	0.219	1097	1104
RHO 28	2.25	SA213T5	0.252	0.232	1104	1113	0.225	1100	1107
RHO 27	2.25	SA213T5	0.252	0.230	1108	1117	0.232	1104	1112
RH 30	2.25	SA213T22	0.180	0.173	1102	1108	0.170	1098	1103
RH 29	2.25	SA213T22	0.180	0.177	1103	1109	0.173	1099	1104
RH 28	2.25	SA213T22	0.180	0.177	1106	1112	0.173	1102	1107
RH 27	2.25	SA213T22	0.188	0.181	1110	1116	0.177	1106	1111
RH 26	2.25	SA213T22	0.188	0.154	1081	1087	0.152	1079	1083
RH 25	2.25	SA213T22	0.180	0.154	1080	1086	0.152	1077	1082
RH 24	2.25	SA213T22	0.180	0.160	1086	1093	0.154	1083	1088
RH 23	2.25	SA213T22	0.180	0.160	1088	1094	0.157	1084	1090
RH 22	2.25	SA213T22	0.180	0.133	1054	1060	0.131	1051	1057
RH 21	2.25	SA213T22	0.180	0.135	1056	1062	0.133	1053	1059
RH 20	2.25	SA213T22	0.180	0.144	1068	1075	0.142	1065	1071
RH 19	2.25	SA213T22	0.180	0.173	1101	1111	0.170	1099	1105
RH 18	2.50	SA213T22	0.188	0.181	1092	1103	0.178	1089	1096
RH 17	2.50	SA213T22	0.180	0.141	1045	1053	0.139	1042	1048
RH 16b	2.50	SA213T11	0.180	0.127	998	1005	0.125	997	1002
RH 15b	2.50	SA213T11	0.180	0.130	1000	1007	0.127	998	1004
RH 14b	2.50	SA213T11	0.180	0.106	979	986	0.105	978	984
RH 13b	2.50	SA213T11	0.180	0.108	982	989	0.106	981	986
RH 16a	2.50	SA213T22	0.180	0.144	1047	1054	0.141	1044	1050
RH 15a	2.50	SA213T22	0.180	0.146	1050	1058	0.144	1047	1053
RH 14a	2.50	SA213T11	0.180	0.160	1029	1037	0.157	1026	1033
RH 13a	2.50	SA213T22	0.180	0.130	1030	1038	0.129	1028	1034
RH 12	2.50	SA213T11	0.180	0.125	997	1004	0.125	997	1002
RH 11	2.50	SA213T11	0.180	0.130	1001	1008	0.130	1001	1008
RH 10	2.50	SA213T22	0.148	0.121	1016	1028	0.124	1020	1031
RH 9	2.50	SA213T22	0.148	0.116	1006	1019	0.118	1010	1021
RH 8	2.50	SA213T11	0.148	0.132	1003	1016	0.136	1007	1018
RH 7	2.50	SA213T11	0.148	0.132	1003	1015	0.136	1007	1018
RH 6	2.50	SA213T11	0.148	0.134	1004	1016	0.138	1008	1019
RH 5	2.25	SA213T11	0.148	0.068	910	923	0.068	913	924
RH 4	2.25	SA213T11	0.148	0.069	914	927	0.069	917	929
RH 3	2.25	SA213T11	0.148	0.070	919	933	0.070	923	934
RH 2	2.25	SA213T22	0.148	0.077	954	971	0.078	956	971
RH 1	2.25	SA213T22	0.148	0.109	1014	1036	0.110	1017	1036

Table 4.2 Sec. SH Tube Metal Temperature and Required Minimum Thickness (Original Unit)



SEC. SUPERHEATER				VWO/THO - Original			Normal - Original		
ROW NO.	Tube OD (inch)	Installed Tube Materials	Installed Tube MW (inch)	Req'd MW (inch)	T_{AVE} (°F)	T_{SPOT} (°F)	Req'd MW (inch)	T_{AVE} (°F)	T_{SPOT} (°F)
SSH 30	2.00	SA213T22	0.387	0.365	1071	1096	0.354	1065	1085
SSH 29	2.00	SA213T22	0.398	0.396	1089	1116	0.383	1082	1104
SSH 28	2.00	SA213T22	0.387	0.365	1072	1097	0.354	1067	1088
SSH 27	2.00	SA213T22	0.387	0.339	1056	1080	0.334	1052	1072
SSH 26	2.00	SA213T22	0.327	0.308	1038	1059	0.304	1035	1054
SSH 25	2.00	SA213T22	0.335	0.335	1054	1080	0.334	1053	1073
SSH 24	2.00	SA213T22	0.327	0.308	1037	1059	0.304	1035	1054
SSH 23	2.00	SA213T22	0.327	0.282	1021	1041	0.282	1020	1037
SSH 22	2.00	SA213T22	0.327	0.263	1004	1022	0.263	1004	1019
SSH 21	2.00	SA213T22	0.327	0.304	1034	1063	0.300	1033	1058
SSH 20	2.25	SA213T22	0.328	0.321	1022	1053	0.317	1021	1048
SSH 19	2.25	SA213T22	0.328	0.296	1005	1028	0.296	1004	1025
SSH 18	2.25	SA213T2	0.335	0.335	995	1029	0.335	995	1025
SSH 17	2.25	SA213T2	0.332	0.332	991	1029	0.332	991	1025
SSH 16	2.25	SA213T2	0.285	0.278	975	997	0.278	975	995
SSH 15	2.25	SA213T2	0.285	0.284	977	1000	0.281	976	997
SSH 14	2.25	SA213T2	0.288	0.287	979	1003	0.288	979	999
SSH 13	2.25	SA213T2	0.294	0.294	981	1012	0.310	981	1008
SSH 12	2.25	SA213T2	0.285	0.250	960	981	0.250	960	979
SSH 11	2.25	SA213T2	0.288	0.241	954	974	0.241	954	972
SSH 10	2.25	SA213T2	0.285	0.239	953	973	0.239	953	971
SSH 9	2.25	SA213T2	0.285	0.239	953	973	0.239	953	971
SSH 8	2.25	SA209T1a	0.257	0.215	924	942	0.215	924	940
SSH 7	2.25	SA209T1a	0.257	0.220	926	945	0.220	926	943
SSH 6	2.25	SA209T1a	0.257	0.225	929	949	0.225	929	947
SSH 5	2.25	SA209T1a	0.260	0.260	944	973	0.260	944	974
SSH 4	2.25	SA209T1a	0.257	0.199	916	936	0.202	916	935
SSH 3	2.25	SA209T1a	0.257	0.182	903	920	0.182	903	919
SSH 2	2.25	SA209T1a	0.257	0.182	903	920	0.182	903	919
SSH 1	2.25	SA209T1a	0.257	0.182	904	921	0.184	904	919

Table 4.3 Prim. SH Tube Metal Temperature and Required Minimum Thickness (Original Unit)



PRIM. SUPERHEATER				VWO/THO - Original			Normal - Original		
ROW NO.	Tube OD (inch)	Installed Tube Materials	Installed Tube MW (inch)	Req'd MW (inch)	T_{AVE} (°F)	T_{SPOT} (°F)	Req'd MW (inch)	T_{AVE} (°F)	T_{SPOT} (°F)
PSH 1	2.50	SA213T11	0.394	0.283	972	983	0.211	908	915
PSH 2	2.50	SA213T11	0.394	0.302	981	993	0.217	916	924
PSH 3	2.50	SA213T11	0.394	0.380	1005	1026	0.233	940	951
PSH 4	2.50	SA213T2	0.338	0.329	982	1001	0.230	918	930
PSH 5	2.50	SA209T1a	0.338	0.312	952	965	0.198	892	899
PSH 6	2.50	SA209T1a	0.254	0.246	927	937	0.194	868	875
PSH 7	2.50	SA209T1a	0.254	0.238	924	933	0.193	865	872
PSH 8	2.50	SA209T1a	0.254	0.203	903	910	0.190	847	853
PSH 9	2.50	SA209T1a	0.254	0.201	902	909	0.190	846	853
PSH 10	2.50	SA209T1a	0.203	0.195	881	889	0.188	828	835
PSH 11	2.50	SA209T1a	0.203	0.195	878	885	0.188	826	832
PSH 12	2.50	SA209T1a	0.203	0.190	852	859	0.185	804	810
PSH 13	2.50	SA209T1a	0.203	0.190	852	858	0.185	804	809
PSH 14	2.50	SA209T1a	0.203	0.188	833	839	0.185	789	794
PSH 15	2.50	SA209T1a	0.203	0.188	831	836	0.185	786	791
PSH 16	2.50	SA209T1a	0.203	0.186	813	819	0.184	772	777
PSH 17	2.50	SA209T1a	0.203	0.186	813	818	0.184	772	777
PSH 18	2.50	SA209T1a	0.203	0.185	796	802	0.184	758	763
PSH 19	2.50	SA209T1a	0.203	0.185	793	799	0.184	756	761
PSH 20	2.50	SA209T1a	0.203	0.185	778	784	0.184	744	749
PSH 21	2.50	SA209T1a	0.203	0.185	778	783	0.184	744	749
PSH 22	2.50	SA209T1a	0.203	0.184	764	769	0.184	733	738
PSH 23	2.50	SA209T1a	0.203	0.184	761	766	0.184	731	735
PSH 24	2.50	SA209T1a	0.203	0.184	748	753	0.184	721	726
PSH 25	2.50	SA209T1a	0.203	0.184	754	759	0.184	725	730
PSH 26	2.50	SA210A1	0.210	0.204	739	744	0.195	714	718
PSH 27	2.50	SA210A1	0.210	0.201	732	736	0.195	714	718
PSH 28	2.50	SA210A1	0.210	0.198	722	726	0.194	709	712
PSH 29	2.50	SA210A1	0.210	0.198	722	726	0.192	702	705
PSH 30	2.50	SA210A1	0.210	0.195	713	717	0.190	701	704
PSH 31	2.50	SA210A1	0.210	0.194	712	716	0.190	695	697
PSH 32	2.50	SA210A1	0.210	0.192	704	707	0.190	695	698
PSH 33	2.50	SA210A1	0.210	0.192	703	707	0.190	695	698
PSH 34	2.50	SA210A1	0.210	0.190	696	699	0.190	695	698
PSH 35	2.50	SA210A1	0.210	0.190	695	698	0.190	695	699
PSH 36	2.50	SA210A1	0.210	0.190	695	698	0.190	695	698
PSH 37	2.50	SA210A1	0.210	0.190	695	698	0.190	695	698
PSH 38	2.50	SA210A1	0.210	0.190	695	698	0.190	695	698
PSH 39	2.50	SA210A1	0.210	0.190	695	698	0.190	695	698
PSH 40	2.50	SA210A1	0.210	0.190	695	698	0.190	695	698
PSH 41	2.50	SA210A1	0.210	0.190	695	698	0.190	695	698
PSH 42	2.50	SA210A1	0.210	0.190	695	698	0.190	695	698
PSH 43	2.50	SA210A1	0.210	0.190	695	698	0.190	695	698
PSH 44	2.50	SA210A1	0.210	0.190	695	698	0.190	695	698
PSH 45	2.50	SA210A1	0.210	0.190	695	698	0.190	695	698
PSH 46	2.50	SA210A1	0.210	0.190	695	698	0.190	695	698
PSH 47	2.50	SA210A1	0.210	0.190	695	698	0.190	695	698
PSH 48	2.50	SA210A1	0.210	0.190	695	698	0.190	695	698
PSH 49	2.50	SA210A1	0.210	0.190	695	698	0.190	695	698

4.2 Current Unit – After the Reheater Modification

The reheater modification has been made to the original boiler by Alstom in 2001. The surface area of the reheater was reduced by 2,318 square feet. Thus the heat absorption on the superheater would be significantly increased. As a result, a higher metal temperature would be expected on the superheater tubes, especially the primary superheater outlet tubes.

Figures 4.1 to 4.3 illustrate the tube metal temperature behavior for the reheater, secondary superheater, and primary superheater. A review of predicted performance data after the reheater modification indicates that several tube metal temperatures exceed the original maximum allowable temperature for the given tube material and thickness. The tube rows in question are as follows:

Bank	Tube Index	Load Conditions
Reheater	RH14b	THO/VWO, Normal
Prim. SH	PSH3	THO/VWO, Normal
Prim. SH	PSH2, PH4, PSH5, PSH6, PSH7	THO/VWO

The predicted primary superheater outlet header and the attemperator/piping also exceed the original design metal temperatures.

Table 4.4 to 4.6 lists the tube metal temperatures and ASME code required minimum thickness for the reheater, secondary superheater, and primary superheater for the current unit.

Figure 4.1 Reheater Metal Temperatures

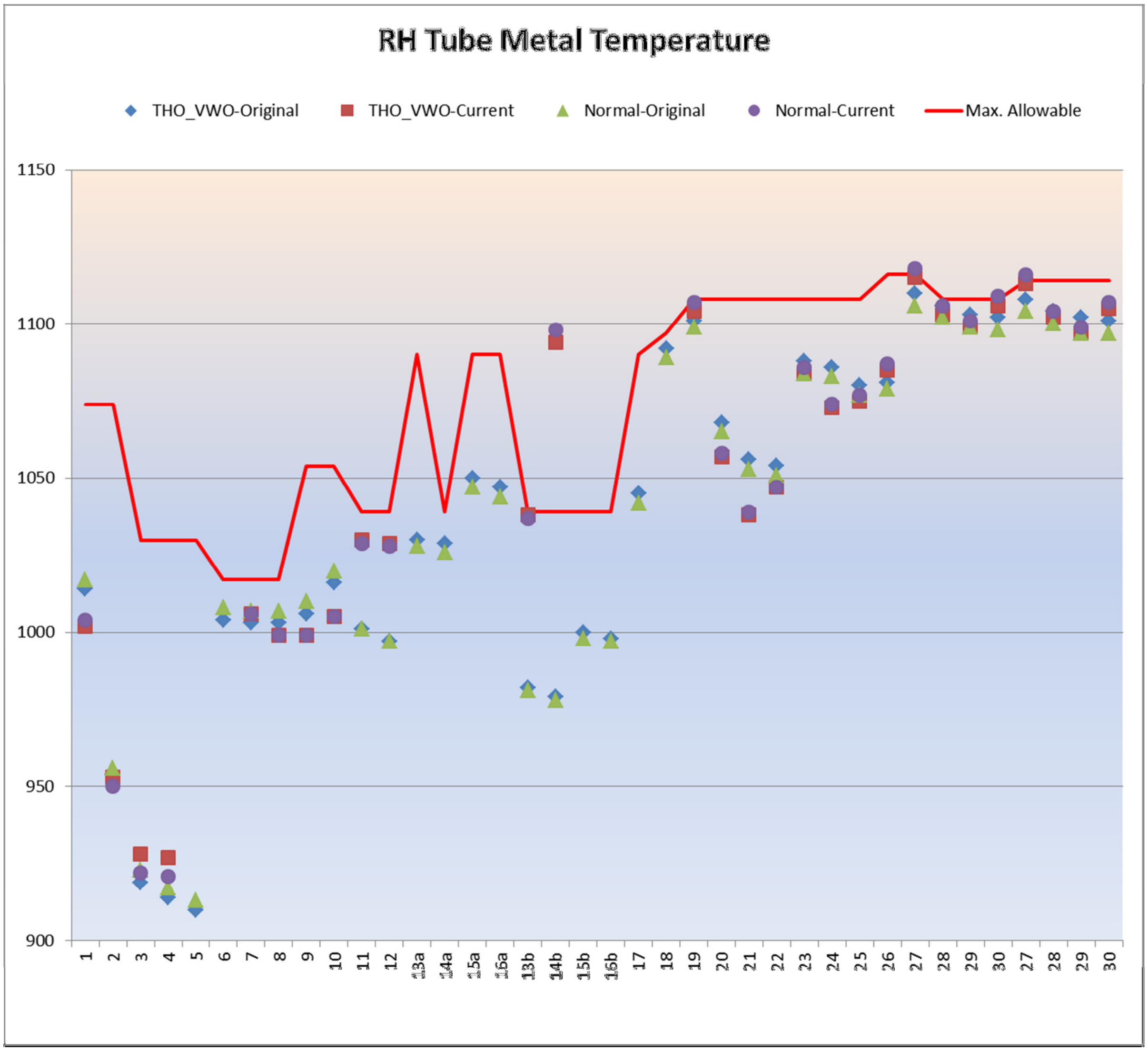


Figure 4.2 Secondary Superheater Metal Temperatures

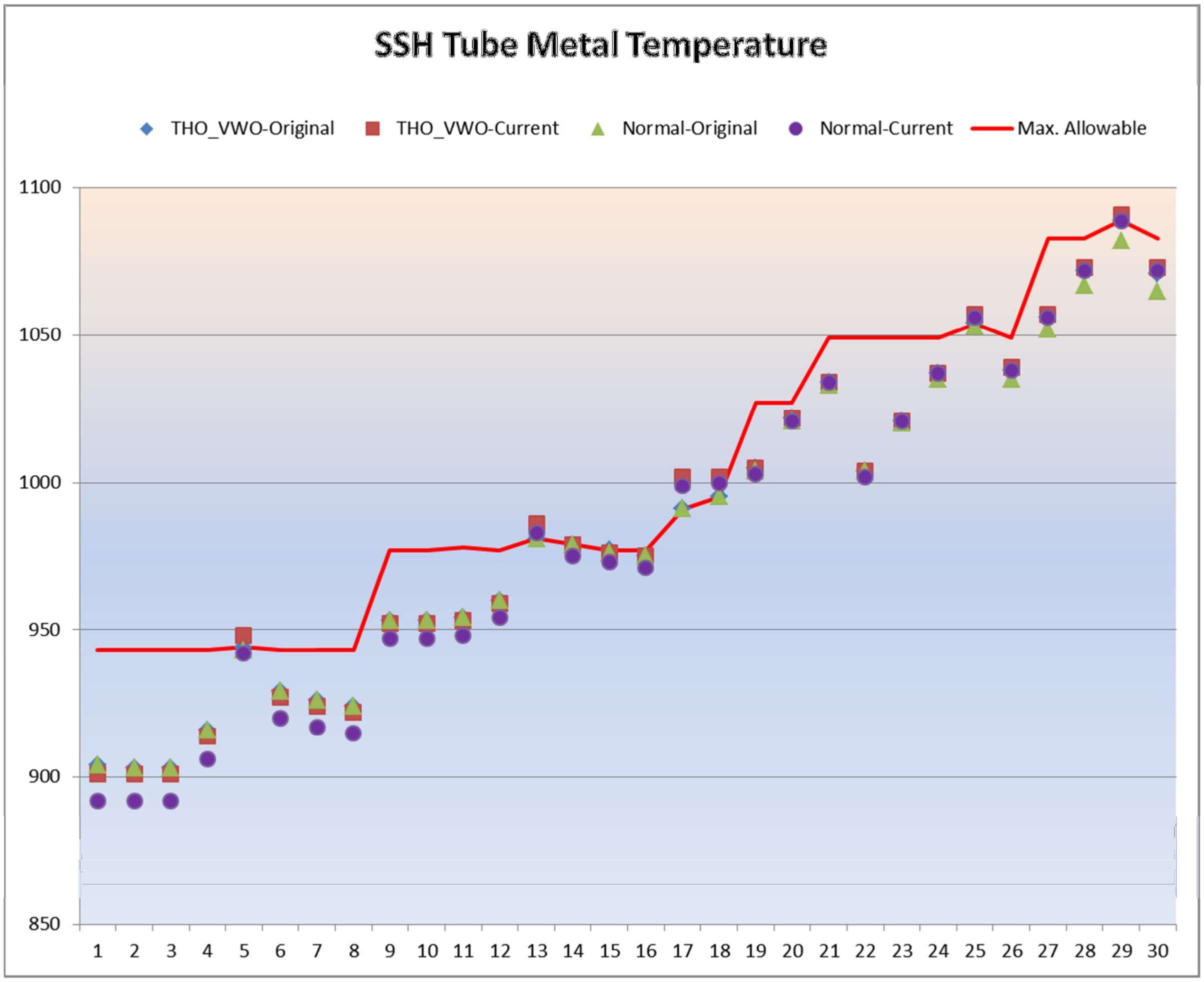


Figure 4.3 Primary Superheater Metal Temperatures

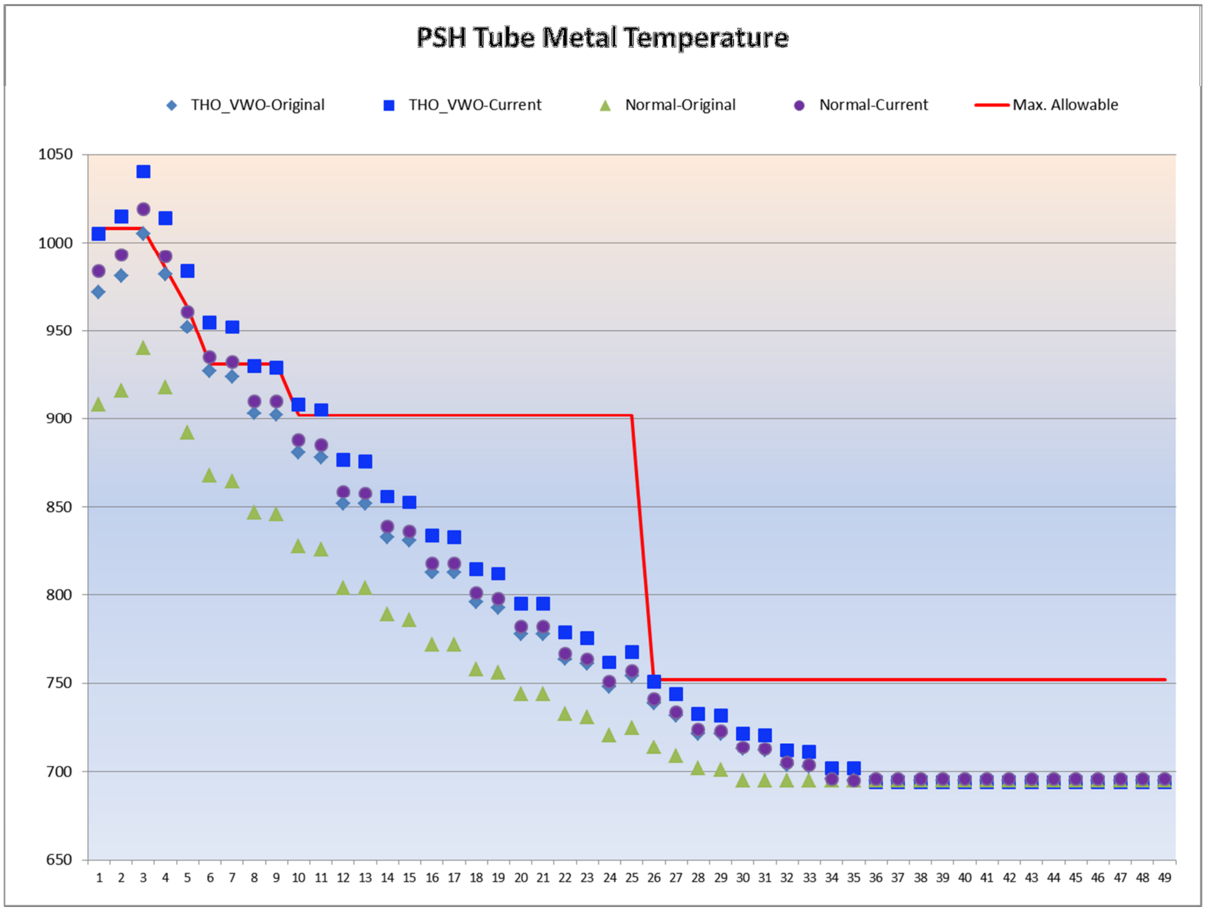
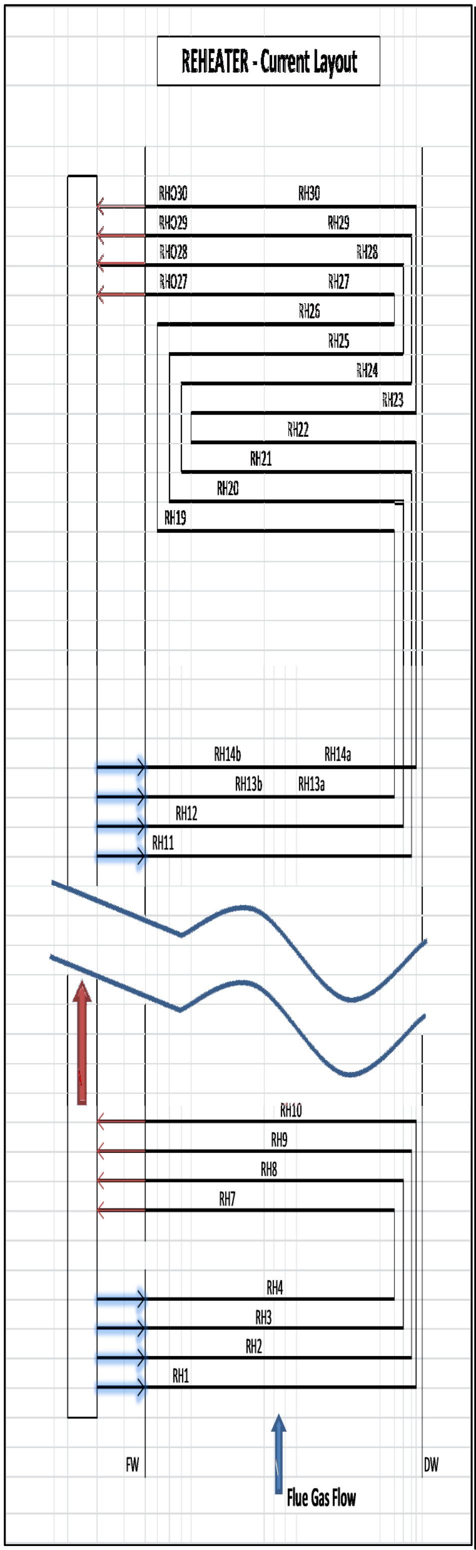
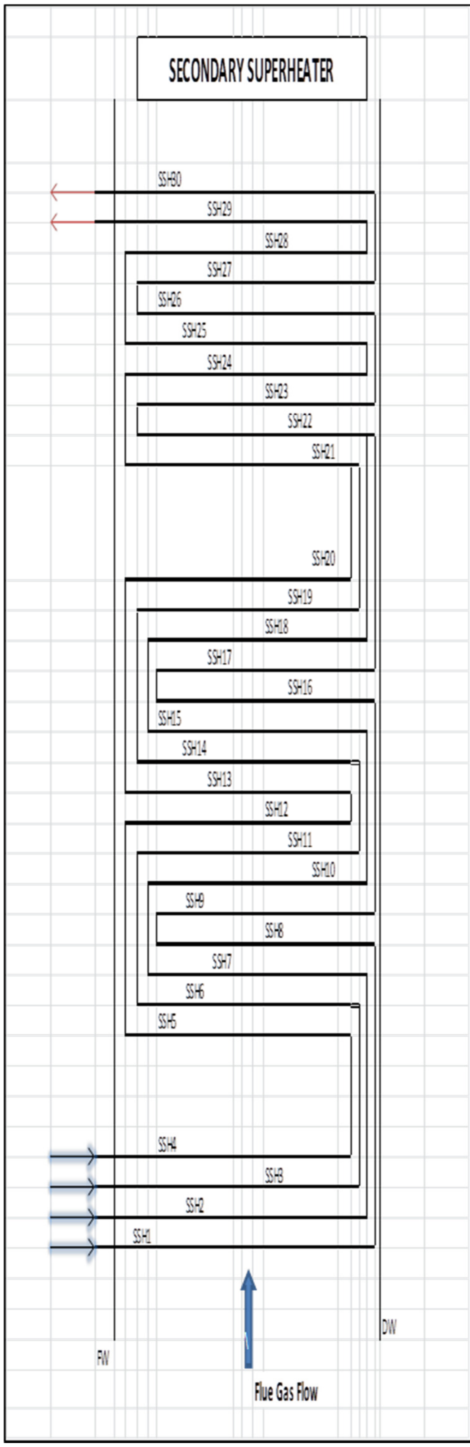


Table 4.4 Reheater Tube Metal Temperature and Required Minimum Thickness (Current Unit)



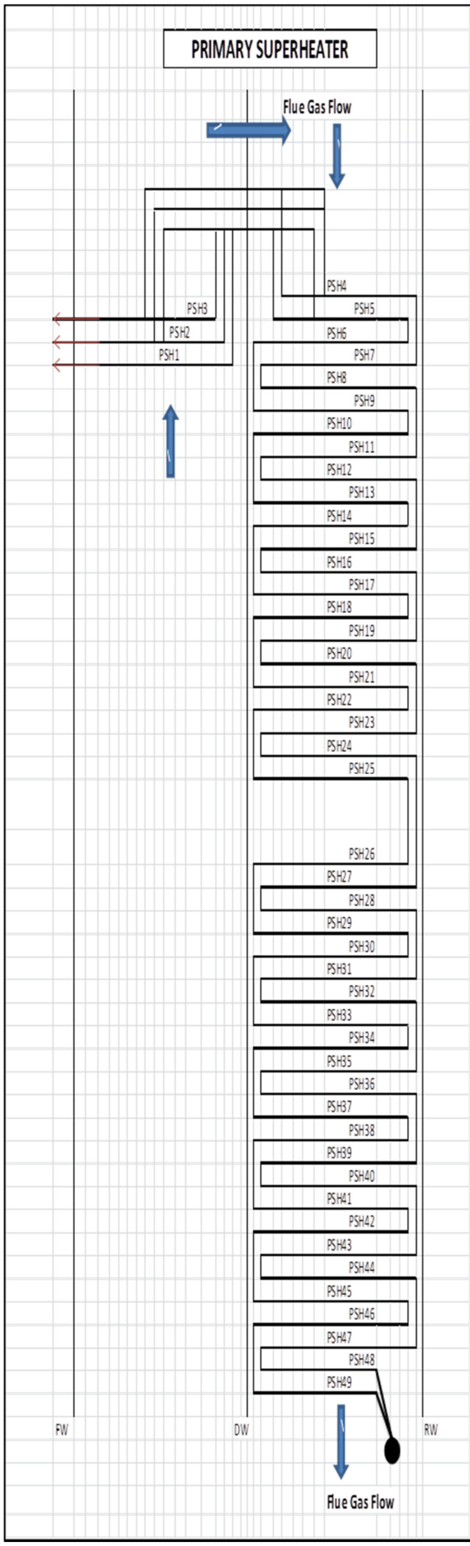
REHEATER			VWO/THO - Current			Normal - Current		
ROW NO.	Installed Tube OD (inch)	REQ'D Tube Materials	REQ'D MW (inch)	T_{AVE} (°F)	T_{SPOT} (°F)	Req'd MW (inch)	T_{AVE} (°F)	T_{SPOT} (°F)
RHO 30	2.25	SA213T5	0.232	1105	1114	0.238	1107	1116
RHO 29	2.25	SA213T5	0.219	1097	1106	0.225	1099	1107
RHO 28	2.25	SA213T5	0.225	1102	1111	0.232	1104	1113
RHO 27	2.25	SA213T5	0.246	1113	1123	0.253	1116	1126
RH 30	2.25	SA213T22	0.177	1106	1113	0.180	1109	1115
RH 29	2.25	SA213T22	0.173	1099	1105	0.173	1101	1107
RH 28	2.25	SA213T22	0.177	1103	1110	0.177	1106	1112
RH 27	2.25	SA213T22	0.188	1115	1122	0.188	1118	1125
RH 26	2.25	SA213T22	0.157	1085	1091	0.160	1087	1093
RH 25	2.25	SA213T22	0.149	1075	1081	0.152	1077	1082
RH 24	2.25	SA213T22	0.147	1073	1079	0.149	1074	1080
RH 23	2.25	SA213T22	0.157	1084	1090	0.160	1086	1092
RH 22	2.25	SA213T22	0.129	1047	1053	0.129	1047	1053
RH 21	2.25	SA213T22	0.157	1038	1045	0.124	1039	1045
RH 20	2.25	SA213T22	0.135	1057	1064	0.137	1058	1064
RH 19	2.25	SA213T22	0.177	1104	1115	0.180	1107	1117
RH 18	Removed							
RH 17								
RH 16b								
RH 15b								
RH 14b	2.50	SA213T5	0.237	1094	1110	0.243	1095	1110
RH 13b	2.50	SA213T11	0.175	1038	1046	0.172	1037	1045
RH 16a	Removed							
RH 15a								
RH 14a	connect to 14b							
RH 13a	connect to 13b							
RH 12	2.50	SA213T11	0.160	1029	1036	0.157	1028	1034
RH 11	2.50	SA213T11	0.163	1030	1038	0.160	1029	1036
RH 10	2.50	SA213T22	0.116	1005	1018	0.116	1005	1018
RH 9	2.50	SA213T22	0.112	999	1013	0.112	999	1011
RH 8	2.50	SA213T11	0.129	999	1012	0.129	999	1011
RH 7	2.50	SA213T11	0.136	1006	1019	0.136	1006	1018
RH 6	Removed							
RH 5								
RH 4	2.25	SA213T11	0.071	927	942	0.070	921	934
RH 3	2.25	SA213T11	0.072	928	942	0.070	922	935
RH 2	2.25	SA213T22	0.077	953	970	0.076	950	966
RH 1	2.25	SA213T22	0.103	1002	1023	0.104	1004	1024

Table 4.5 Sec. SH Tube Metal Temperature and Required Minimum Thickness (Current Unit)



SEC. SUPERHEATER			VWO/THO - Current			Normal - Current		
ROW NO.	Tube OD (inch)	Tube Materials	Req'd MW (inch)	T_{AVE} (°F)	T_{SPOT} (°F)	Req'd MW (inch)	T_{AVE} (°F)	T_{SPOT} (°F)
SSH 30	2.00	SA213T22	0.365	1073	1098	0.365	1072	1095
SSH 29	2.00	SA213T22	0.403	1091	1119	0.396	1089	1115
SSH 28	2.00	SA213T22	0.365	1073	1099	0.365	1072	1096
SSH 27	2.00	SA213T22	0.339	1057	1082	0.339	1056	1078
SSH 26	2.00	SA213T22	0.312	1039	1061	0.308	1038	1058
SSH 25	2.00	SA213T22	0.339	1057	1082	0.335	1056	1079
SSH 24	2.00	SA213T22	0.308	1037	1060	0.308	1037	1058
SSH 23	2.00	SA213T22	0.282	1021	1046	0.282	1021	1038
SSH 22	2.00	SA213T22	0.263	1004	1025	0.261	1002	1019
SSH 21	2.00	SA213T22	0.304	1034	1065	0.304	1034	1062
SSH 20	2.25	SA213T22	0.321	1022	1054	0.317	1021	1050
SSH 19	2.25	SA213T22	0.296	1005	1029	0.293	1003	1026
SSH 18	2.25	SA213T11	0.337	1002	1030	0.333	1000	1026
SSH 17	2.25	SA213T11	0.337	1002	1030	0.329	1000	1026
SSH 16	2.25	SA213T2	0.278	975	998	0.272	971	992
SSH 15	2.25	SA213T2	0.281	976	1000	0.275	973	994
SSH 14	2.25	SA213T11	0.272	979	1002	0.278	975	997
SSH 13	2.25	SA213T11	0.290	987	1011	0.294	981	1007
SSH 12	2.25	SA213T2	0.250	959	980	0.241	954	973
SSH 11	2.25	SA213T2	0.239	953	973	0.233	948	967
SSH 10	2.25	SA213T2	0.237	952	972	0.231	947	965
SSH 9	2.25	SA213T2	0.237	952	973	0.231	947	966
SSH 8	2.25	SA209T1a	0.211	922	940	0.199	915	931
SSH 7	2.25	SA209T1a	0.215	924	943	0.204	917	934
SSH 6	2.25	SA209T1a	0.221	927	947	0.208	920	938
SSH 5	2.25	SA209T1a	0.233	948	972	0.254	942	967
SSH 4	2.25	SA209T1a	0.198	914	935	0.185	906	924
SSH 3	2.25	SA209T1a	0.179	901	918	0.178	892	908
SSH 2	2.25	SA209T1a	0.180	901	918	0.178	892	908
SSH 1	2.25	SA209T1a	0.180	901	919	0.178	892	909

Table 4.6 Prim. SH Tube Metal Temperature and Required Minimum Thickness (Current Unit)



PRIM. SUPERHEATER			VWO/THO - Current			Normal - Current		
ROW NO.	Tube OD (inch)	Tube Materials	Req'd MW (inch)	T_{AVE} (°F)	T_{SPOT} (°F)	Req'd MW (inch)	T_{AVE} (°F)	T_{SPOT} (°F)
PSH 1	2.50	SA213T22	0.333	1015	1021	0.312	984	995
PSH 2	2.50	SA213T22	0.348	1017	1032	0.344	993	1007
PSH 3	2.50	SA213T22	0.400	1044	1068	0.353	1022	1041
PSH 4	2.50	SA213T22	0.348	1014	1040	0.340	993	1012
PSH 5	2.50	SA213T2	0.333	984	999	0.333	961	975
PSH 6	2.50	SA213T2	0.272	957	968	0.263	935	945
PSH 7	2.50	SA213T2	0.268	954	965	0.254	932	942
PSH 8	2.50	SA209T1a	0.252	930	940	0.214	910	918
PSH 9	2.50	SA209T1a	0.250	929	939	0.212	910	917
PSH 10	2.50	SA209T1a	0.211	908	916	0.196	888	895
PSH 11	2.50	SA209T1a	0.205	905	912	0.192	885	892
PSH 12	2.50	SA209T1a	0.195	877	884	0.192	859	865
PSH 13	2.50	SA209T1a	0.195	876	883	0.190	858	864
PSH 14	2.50	SA209T1a	0.192	856	863	0.189	839	845
PSH 15	2.50	SA209T1a	0.190	853	859	0.189	836	842
PSH 16	2.50	SA209T1a	0.188	834	840	0.187	818	824
PSH 17	2.50	SA209T1a	0.188	833	839	0.187	818	823
PSH 18	2.50	SA209T1a	0.186	815	821	0.185	801	806
PSH 19	2.50	SA209T1a	0.186	812	818	0.185	798	803
PSH 20	2.50	SA209T1a	0.185	795	801	0.185	782	787
PSH 21	2.50	SA209T1a	0.185	795	801	0.185	782	787
PSH 22	2.50	SA209T1a	0.185	779	785	0.184	767	772
PSH 23	2.50	SA209T1a	0.185	776	782	0.184	764	769
PSH 24	2.50	SA209T1a	0.184	762	767	0.184	751	756
PSH 25	2.50	SA209T1a	0.184	768	774	0.184	757	762
PSH 26	2.50	SA210A1	0.208	751	757	0.204	741	746
PSH 27	2.50	SA210A1	0.205	744	748	0.203	734	738
PSH 28	2.50	SA210A1	0.201	733	737	0.199	724	728
PSH 29	2.50	SA210A1	0.201	732	736	0.198	723	727
PSH 30	2.50	SA210A1	0.198	722	726	0.195	714	718
PSH 31	2.50	SA210A1	0.198	721	725	0.195	713	717
PSH 32	2.50	SA210A1	0.194	712	715	0.192	705	708
PSH 33	2.50	SA210A1	0.194	711	715	0.192	704	708
PSH 34	2.50	SA210A1	0.192	702	706	0.190	696	700
PSH 35	2.50	SA210A1	0.192	702	705	0.190	695	699
PSH 36	2.50	SA210A1	0.190	694	697	0.190	696	699
PSH 37	2.50	SA210A1	0.190	694	697	0.190	696	699
PSH 38	2.50	SA210A1	0.190	694	697	0.190	696	699
PSH 39	2.50	SA210A1	0.190	694	697	0.190	696	699
PSH 40	2.50	SA210A1	0.190	694	697	0.190	696	699
PSH 41	2.50	SA210A1	0.190	694	697	0.190	696	699
PSH 42	2.50	SA210A1	0.190	694	697	0.190	696	699
PSH 43	2.50	SA210A1	0.190	694	697	0.190	696	699
PSH 44	2.50	SA210A1	0.190	694	697	0.190	696	699
PSH 45	2.50	SA210A1	0.190	694	697	0.190	696	699
PSH 46	2.50	SA210A1	0.190	694	697	0.190	696	699
PSH 47	2.50	SA210A1	0.190	694	697	0.190	696	699
PSH 48	2.50	SA210A1	0.190	694	697	0.190	696	699
PSH 49	2.50	SA210A1	0.190	694	697	0.190	696	699

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B&W warrants that advice and consultation services and engineering studies will be performed in a manner consistent with generally accepted industry standards and practices. The sole remedy is that any portion of the services furnished to Purchaser which is shown not to have been so performed shall be corrected or re-performed to the standards in effect at the time of original performance at B&W expense; provided all necessary information and access requested by B&W is given to substantiate such claim, and further provided that such non-conformance is detected by Purchaser within ninety (90) days following completion of that portion of the services, and B&W is immediately notified in writing.

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End of Report

WAYLAND ENGINEERING LTD.

IN SITU METALLOGRAPHIC EXAMINATION OF REHEAT TUBES; HOLYROOD GENERATING STATION UNIT #3

AUGUST 2016

Prepared for: Newfoundland and Labrador Hydro
Holyrood Generating Station
1 Duff's Road
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Prepared by:

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DATE Aug 7/16
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Report No: DE1606-A
Date: August 7, 2016

1.0 INTRODUCTION

Wayland Engineering Ltd. was asked by Newfoundland and Labrador Hydro (Hydro) to perform in-situ metallography on select reheat tubes in Unit #3 at the Holyrood Generating Station during the summer 2016 scheduled shutdown. Calculations performed by a third party predicted that tubes in the reheat section may be past their mean life in terms of creep [1]. Inspection was performed at select locations to determine the current tube condition. In situ metallography was included as part of this inspection process.

Design operating temperature and pressure for these reheat tubes is 1005^{O}F and 650psig, respectively. The tubes are 2.25” diameter X 0.180” nominal wall thickness and are specified as an ASTM-A213 T22 alloy. All tubes are reported to be original to the unit, so they have been operating approximately 156,000 hours [1].

2.0 RESULTS

The main objective of this procedure was to determine the existing microstructural condition of the reheat tubes; particularly if there was any microscopic evidence of permanent damage such as creep. Replication was performed at four locations as determined by a Hydro consultant [2]. The locations chosen were on the bottom, or flue gas side, of the lower row of tubes in the reheat section. Four tubes were identified as being representative of those exposed to highest possible temperatures. These were on the bends of tubes #1, #19, #43, & #60 at the south side of the boiler. Flue gas deposit had been previously removed from these areas to facilitate ultrasonic thickness readings.

A standard replication procedure, as per ASTM E1351, was followed to obtain the replicas for the metallographic examination. This involved removing any remaining scale/oxide layer followed by progressively polishing the area to a scratch free finish. An appropriate etchant was then applied to the prepared surface to reveal the microstructure. Acetate tape replicas were obtained and prepared for microscopic examination. Representative microstructures were photographed for inclusion in this report.

The microstructures of all four reheat tubes consisted of spherical carbide particles in a matrix of ferrite grains, Figures 1 to 4. Although there was complete spheroidization and migration of the carbides, the outline of some original pearlite colonies could still be identified. The carbide particles have begun to migrate towards the ferrite grain boundaries. There was no visible evidence of any appreciable creep damage (such as cracks, micro-fissures or void linkage) at any of the four locations examined.

3.0 DISCUSSION/CONCLUSIONS

The results of this metallographic examination show similar microstructures at four reheat tube bends of Unit #3. The microstructures all consisted of spherical carbide particles in a matrix of ferrite grains. Outlines of some original pearlite colonies could still be identified. The original microstructure of these components is not known. Assuming that the original microstructures consisted of unresolved pearlite and ferrite grains, these tubes show evidence of some microstructural transformation. However, the degree of transformation is not unexpected after 156,000 hours of service at these temperatures.

There was no visible evidence of any appreciable creep damage (such as cracks, micro-fissures or void linkage) at any of the four reheat tube locations examined.

References:

[1] E-mail from J. Curtis, NL Hydro, August 9, 2016.
[2] Conversation Between C. Taweel, WEL, & S. Lingley, B & W. August 4, 2016.

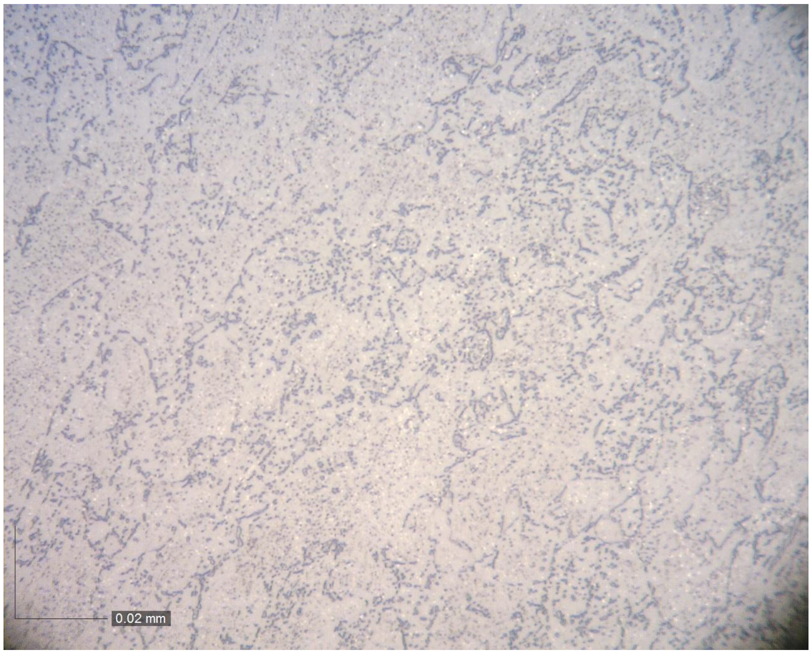

Figure 1: Representative Microstructure of Lower Reheat Tube #1 from the East at Lower West Side of Bend at South End. Microstructure Consists of Spherical Carbide Particles Fairly Evenly Distributed Throughout a Matrix of Ferrite Grains. Some Carbides Have Begun to Migrate to the Ferrite Grain Boundaries.

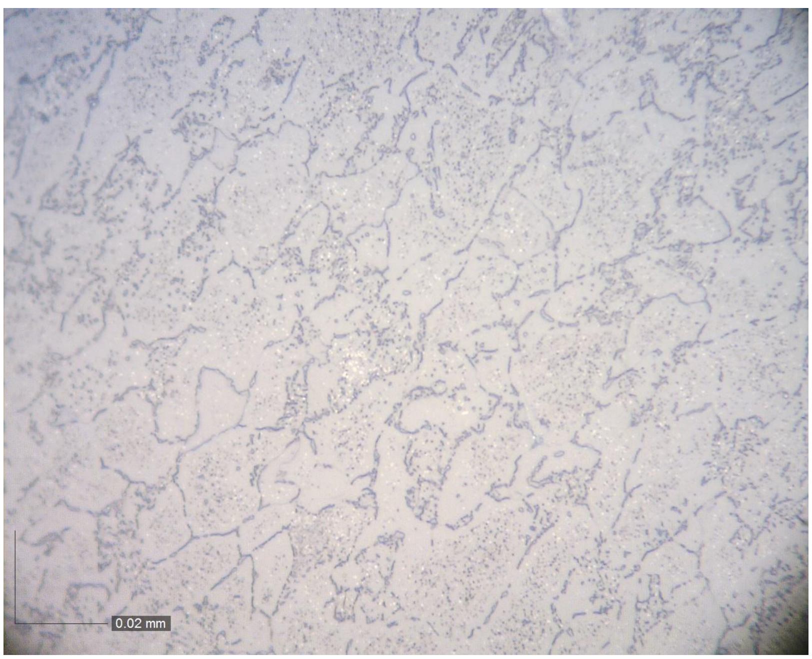

Figure 2: Representative Microstructure of Lower Reheat Tube #19 from the East at Bottom of Bend at South End. Microstructure Consists of Spherical Carbide Particles Fairly Evenly Distributed Throughout a Matrix of Ferrite Grains. Some Carbides Have Begun to Migrate to the Ferrite Grain Boundaries.

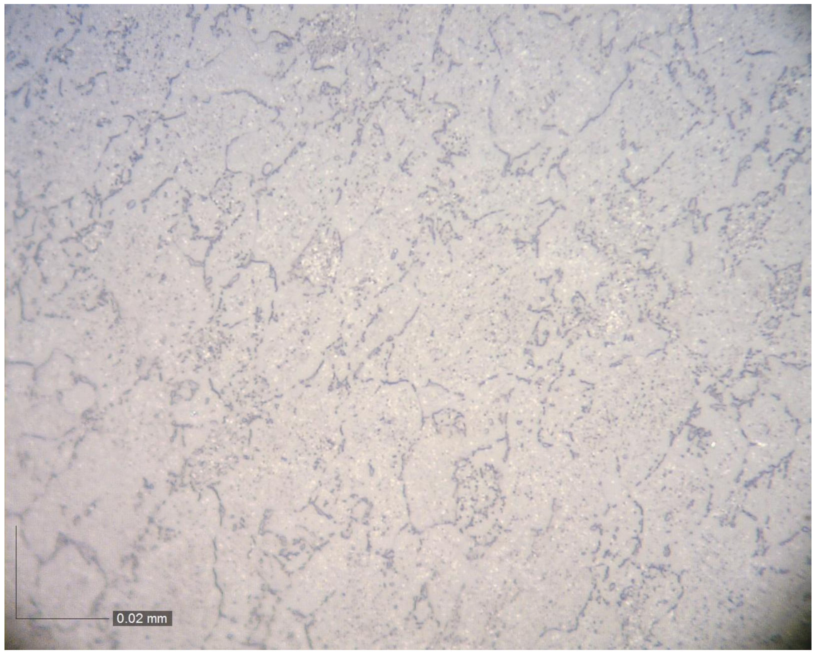

Figure 3: Representative Microstructure of Lower Reheat Tube #43 from the East at Bottom of Bend at South End. Microstructure Consists of Spherical Carbide Particles Fairly Evenly Distributed Throughout a Matrix of Ferrite Grains. Some Carbides Have Begun to Migrate to the Ferrite Grain Boundaries.

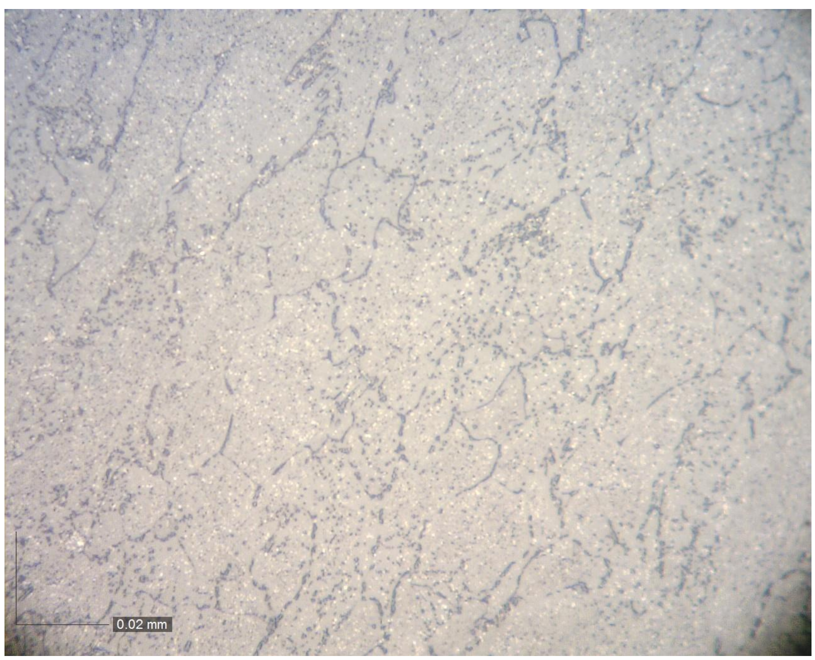

Figure 4: Representative Microstructure of Lower Reheat Tube #60 from the East at Lower East Side of Bend at South End. Microstructure Consists of Spherical Carbide Particles Fairly Evenly Distributed Throughout a Matrix of Ferrite Grains. Again, Some Carbides Have Begun to Migrate to the Ferrite Grain Boundaries.

NOTIS® INSPECTION OF SUPERHEATER TUBES

For:

NEWFOUNDLAND AND LABRADOR HYDRO

Holyrood Generating Station, Unit 3

September 2016 Outage

B&W Project Number: BA9254020
B&W Original Contract: 122-7391

By:

MT Gilkinson – Project Coordinator
The Babcock & Wilcox Company
Field Engineering Services

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CONTENTS

Inspection Summary

This report documents the results of a nondestructive remaining tube life exam performed at Newfoundland and Labrador Hydro's Holyrood Generating Station, Unit 3. On September 29th, 2016, The Babcock & Wilcox Company (B&W) performed an inspection utilizing the Nondestructive Oxide Thickness Inspection Service (NOTIS®) to measure the internal oxide thickness and tube wall thickness at a total of ninety (90) locations on the reheat and primary superheaters of this unit. This data is utilized along with B&W databases for steam oxidation kinetics and creep-rupture properties of tube steels to generate remaining life estimates for the tubes. The pertinent results of this inspection are summarized by component and follow:

Reheat Superheater Outlet Header – Tube Stubs

Testing on the reheat superheater included a total of seventy-eight (78) locations in tube rows 14 and 19. The original tube size and specifications for tube row 14 are 2.500 inch OD X 0.180 inch MW (minimum specified wall), SA-213 grade T11 (1¼CR-½Mo). The original tube size and specifications for tube row 14 are 2.250 inch OD X 0.180 inch MW (minimum specified wall), SA-213 grade T22 (2¼CR-1Mo). The tube rows 15 through 18 were removed from the bank in 2001 as part of a reheater modification. There currently are no tube rows between the inspected rows 14 and 19; however, the numbering was kept to maintain consistency with previous records.

Of the eighty (78) tubes inspected, two (2) tubes had an estimated remaining creep-life less than 200,000 hours. Pendant 35, Row 19 had a remaining life of 190,000 hours and Pendant 52, Row 19 had the minimum remaining life calculated of 180,000 hours.

Sixteen (16) tubes, or approximately 89% of the tubes inspected in Row 19, have a measured wall thickness below original tube specification. One (1) of the tubes measured below B&W's suggested repair or replacement of steam-cooled tubes with a wall thickness at or below 0.153", or 85% of original specified tube wall; however, an additional seven (7) tubes are within 0.010" of the recommended repair or replacement value. Pendant 32 was the most significantly reduced tube wall measuring 0.152", or approximately 84% of original 0.180" specified wall. No tubes in Row 14 had a measured wall below original tube specification. The lowest recorded wall thickness in Row 14 was 0.186", or approximately 103% of original specified wall. Tube Row 19 was inspected on the leading edge where wall thinning is more prevalent, while Row 14 was inspected on the trailing edge where wall thinning is less anticipated.

Eighteen (18) total tubes were inspected in Row 19 and had an average oxide thickness of 0.014". The highest measured oxide in Row 19 was 0.019" and was identified on Pendant 48. All sixty (60) pendants were inspected in Row 14 and the average oxide recorded was 0.006". The maximum oxide measured in Row 14 was 0.008" and was identified on Pendants 18 and 29.

Primary Superheater Outlet Header – Tube Stubs

Testing on the primary superheater included a total of twelve (12) locations in tube row 4 (leading edge tube on the economizer side of the convection pass). The original tube size and specifications are 2.250 inch OD X 0.338 inch MW (minimum specified wall), SA-213 grade T2 (½CR-½Mo).

All tubes were found to have good remaining creep lives (200,000 hours). No tubes measured below B&W's suggested repair or replacement of steam-cooled tubes with a wall thickness below 85% of original specified tube wall. Pendant 63 was the most significantly reduced tube and measured 0.349", or approximately 103% of original 0.338 inch specified wall thickness. All twelve (12) tubes had a measured oxide thickness of 0.006".

Recommendations

While all inspected tubes have good remaining creep-life estimations, tubes with a wall thickness at or below 85% of their original specified tube wall should be considered for repair or replacement in the near future. Such tubes may not be tolerant of temperature excursions, continued wall loss, mechanical overloading, or other stresses. One (1) such tube was identified during this inspection and an additional seven (7) are within 0.010", all located on Row 19 of the reheat superheater. A copy of B&W's Plant Service Bulletin 26; Tube Thickness Evaluation Repair or Replacement Guideline is included for reference in Appendix C.

The remaining creep-life calculations and tube metal temperatures are based on the data collected during the current outage; however, the change in heating surface (removal of tube rows in the reheat superheater) will affect the accuracy of estimations. Without oxide measurements at the time of the reheater alteration we are unable to establish how much of the oxide developed prior to and after the changes to the bank were made. Re-inspection will allow refinement of future oxide growth predictions and can improve remaining creep-life estimations.

B&W suggests re-inspection after three (3) years of additional unit operation with the NOTIS® system on the reheat superheater. Furthermore, we would suggest expanding the scope to include additional locations on the reheater. We recommend re-inspection of the primary superheater after seven (7) years of additional unit operation.

Notes on the Color Plots Provided in Appendices A and B

Contained in Appendices A and B are graphical outputs and tabulated inspection data. Single elevation plots of wall thickness versus element, oxide thickness versus element, a full component plot of tube remaining life, and a remaining life versus element plot are provided for each of the inspected tube rows.

The information included in the Appendices is presented in the following order:

1. Inspection Information Sheet

2. Drawing of Test Locations

3. Graphical Presentations
   - Full Component Plot
   - Remaining Life Graphs (by tube row)
   - Oxide Thickness Graphs (by tube row)
   - Tube Wall Thickness Graphs (by tube row)

4. Tabular Data

Unit Information

Customer: Newfoundland and Labrador Hydro Contract: 122-7391

Station & Unit: Holyrood, Unit #3 Location: Holyrood, NL

Steam Capacity, lbs/hr: Main Steam 1,072,200 Hot Reheat 963,700

Outlet Temperature, °F: Main Steam 1,005 Hot Reheat 1,005

Operating Pres., psig: Superheater 1,895 Reheater 471

Design Pressure, psig: Superheater 2,200 Reheater 650

Start-Up Date: Late 1970's

NOTIS® General Inspection Information

Date(s) of Inspection: September 29th, 2016

Surface Preparation by: Boilermakers Method: Flap Wheel Quality: OK

Approximate Hours in Service at Time of Inspection: 152,000

Appendix Ref.	Component	Number of Inspected Elements	Number of Inspected Tube Rows	Number of Locations Tested	Largest Measured Oxide, Inches
A	Reheat Superheater	18 60	1 1	78	0.019"
B	Primary Superheater	12	1	12	0.006"

Total Number of Inspected Locations: 90

Introduction and Background

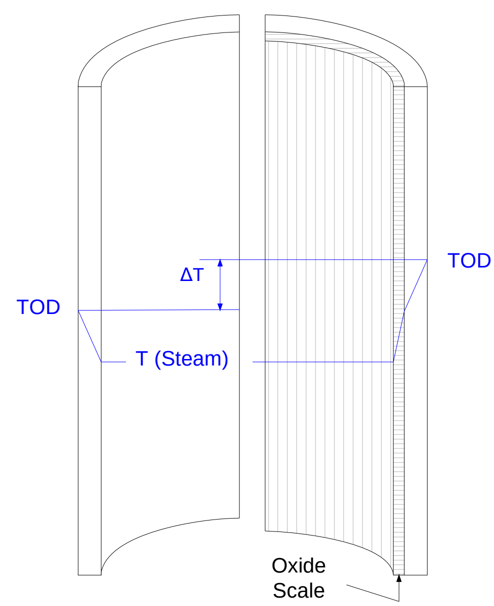
Steam carrying superheater and reheater tubes operating above 900°F (482°C) are subject to failure by creep-rupture. Creep is the process by which metal, when exposed to high temperature and sustained stress, gradually deforms over time. If the applied (hoop) stress due to internal steam pressure and the temperature of operation of a tube are known, the expected creep life can be estimated from tabulated creep data.

When a tube enters service, the metal in contact with the internal steam begins to form a layer of oxide scale known as magnetite (Fe_3O_4). As the tube's service life progresses, the inside diameter (ID) oxide gradually grows in thickness at a rate that is dependent on temperature. This scale acts as a barrier to heat transfer from gas side to steam side and causes an increase in tube metal temperature as depicted in Figure A. Therefore, metal temperature and oxide scale growth are interrelated. Oxide growth is dependent on metal temperature which, in turn, increases as a function of oxide thickness. The magnitude of the increase in metal temperature can range from 1° to 2°F (½ to 1°C) per 0.001 inch (0.025 mm) of scale. This increase in temperature can greatly affect a tube's creep life.

Knowing the thickness of a tube's internal oxide scale makes it possible to estimate the average operating temperature it has experienced in service. Once the average temperature of the tube is determined, the calculation of remaining creep life for use in assessing the general condition of the superheater is possible. In the past, such measurements were obtained by removing tube samples for laboratory examination. This method is costly and time-consuming and gives data for only a few locations. To address these problems, B&W developed NOTIS® (Nondestructive Oxide Thickness Inspection Service). NOTIS® is a patented (U.S. No. 4,669,310) ultrasonic inspection system that nondestructively measures the thickness of a tube's internal oxide and eliminates the need for costly tube sample removal. Although this technique is similar to standard ultrasonic wall thickness tests, this system provides the high resolution needed to detect and measure the ID scale.

Tube wall thickness measurements also provide valuable information needed for the condition assessment of the superheater. Wall thinning due to wastage from such mechanisms as corrosion or erosion must be considered in any remaining life analysis. Wall loss will result in increased stresses in the thinned areas that in turn reduce creep-rupture life. NOTIS® incorporates both ultrasonic wall thickness and oxide thickness measurements in evaluating the condition of the superheater tube. These two measurements are made concurrently for each tube inspected.

Superheater Tube Temperature Profile



0.001" (0.025 mm) scale = 2 °F (1°C) increase in TOD (typical)
For oxide thickness of 0.010 to 0.030" (0.25 to 0.76 mm)
ΔT = 20 to 60°F (11 to 33°C)

Figure A: Schematic illustrating internal oxide scale build-up and its subsequent affect on tube metal temperature.

The NOTIS® technique has distinct advantages over tube sample removal. Many tubes may be assessed with NOTIS® in a short time during a scheduled outage. Decisions regarding future replacement of superheater tubing can be based upon a larger, more representative sampling. ♦

Tube Identification

NOTIS® can be used to measure the oxide and wall thicknesses of a large number of tubes. To avoid confusion, proper identification of each tube is necessary. B&W utilizes a standard numbering scheme that eliminates the possibility of mixing-up data. Typically, many oxide thickness measurements are taken in the same plane lying normal to the tubes (i.e., the same elevation). This plane is called the plane of inspection. The intersection of the superheater with the plane of inspection is a grid like that shown in Figure B. A set of coordinates are assigned to each tube within the grid. The abscissa of the subject tube is the element number counted from the unit's left hand sidewall. The ordinate of the subject tube is the depth of the tube into the element; normally this is counted from front to rear (or from bottom to top for horizontal tubes). Each tube location is, therefore, described by these two coordinates. Figure B shows an example of this numbering system. Oxide and wall thickness measurements are assigned the same coordinates as the tube on which they are taken. The precise location of a thickness measurement is described by attaching an elevation to the tube coordinates. This is especially important when the same tube is inspected at two different inspection planes. ♦

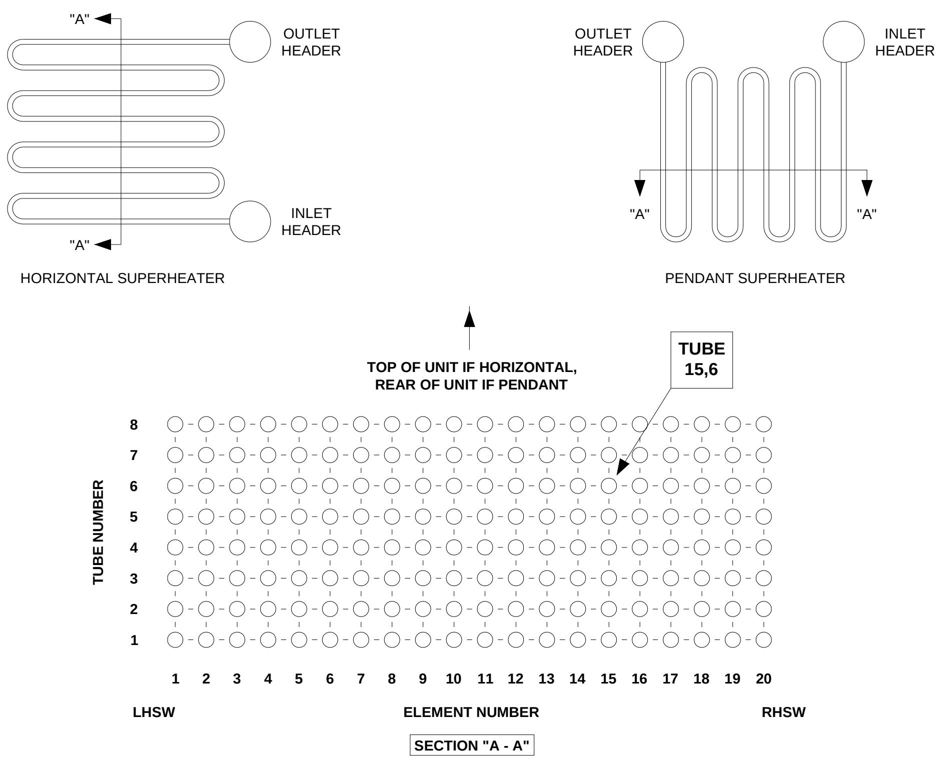


Figure B: Diagrams illustrating the standard numbering system used for NOTIS® inspections.

The NOTIS® System

Basic Theory

The NOTIS® system is able to measure the thickness of iron oxide scale that forms on the inside surface of steam cooled boiler tubes. This thickness measurement is performed using a patented ultrasonic method developed by B&W. A transducer is coupled to a tube's prepared outside diameter (OD) surface and a short pulse of ultrasound is directed into the tube. The reflections from the metal-oxide interface and the oxide-air interface are displayed on the NOTIS® equipment. The time the sound takes to travel between these interfaces, and from the tube's OD surface to the metal-oxide interface, are measured. Oxide and wall thicknesses are then calculated using equations that correlate the time measurements to thicknesses. •

Accuracy and Resolution

NOTIS® provides a resolution of 0.001 inch (0.025 mm) and accuracy of ±0.002 inch (0.05 mm), in the measurement of internal oxides of 0.004 inch (0.10 mm) or greater. These figures are predicated upon the tube OD surface being properly prepared. It should be noted that internal oxide scales less than 0.004 inch (0.10 mm) have only a slight effect on heat transfer and therefore on overall tube creep remaining life. •

Oxide Measurement Capabilities

At elevated temperatures, both the external and internal surfaces of boiler tubes slowly oxidize. The external scale, exposed to combustion gases, is normally removed by a variety of mechanisms whereas the internal scale usually remains intact. Typically, the scale formed on the inner surface is multi-layered and is normally characterized by two separate oxide layers, an iron-rich inner layer and an oxygen-rich outer layer. The oxygen-rich layer generally contains numerous pores or voids. The NOTIS® system can differentiate the small responses (interface signals) between these inner and outer oxide layers. Photomicrographs of these iron-rich and oxide-rich layers are shown in Figure C on the following page. Since the ultrasonic signals from the tube ID-to-oxide scale interface and oxide scale-to-air interface are much greater than those from the iron-rich and oxygen-rich scale layers, a tightly adhering porous oxide layer does not affect the accuracy of the NOTIS® system.

If the iron-rich and/or oxygen-rich oxide layers become disbonded, the NOTIS® system will only measure the oxide thickness to the separation. This situation, indicative of exfoliation, is readily identifiable by the NOTIS® operator due to the abrupt variations in oxide thickness measurements.

Exfoliation is the flaking of scale particles from the internal oxide layer. This condition is undesirable because accumulations of these flakes can become entrapped in lower tube bends, resulting in reduced steam flow, elevated tube temperatures, and reduced tube creep life. Exfoliated scale particles can also cause solid particle erosion when they are entrained in the steam flow and carried to the turbine.

The NOTIS® operator can identify tubes with possible exfoliation. During the inspection, exfoliation is suggested when the amount of scale detected varies in a step fashion within the region on the tube being inspected. For example, a tube may have a 0.010 inch (0.25 mm) thick oxide in an exfoliated area immediately adjacent to a 0.020 inch (0.51 mm) oxide measurement. The irregular disbonding of the oxide scale can produce marked differences in thickness data in the same tube. If an area is found during the inspection where exfoliation is suspected, the largest oxide measured for that tube is recorded and the area is noted as having possible exfoliation.

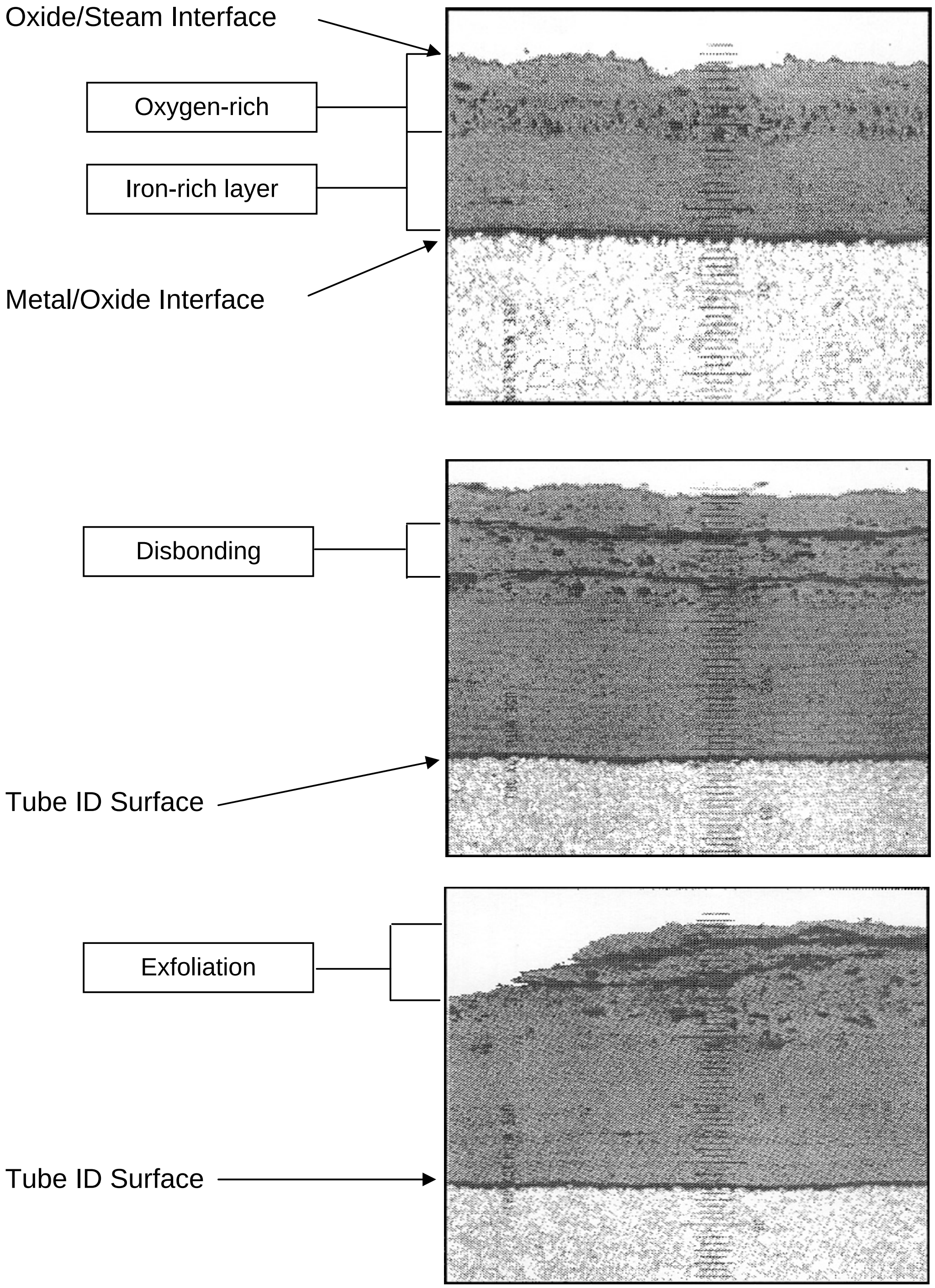


Figure C: Photomicrographs of transverse cross-sections through three (3) tube samples displaying various internal oxide conditions.

The occurrence of exfoliation may also be indicated by the oxide scale thicknesses measured in adjacent tubes within the same row. A thin measured oxide in a tube next to others having thick oxide scales may suggest exfoliation. If exfoliation is suggested by contrast to adjacent tubes, this may also be noted in the report on the inspection data sheets. ♦

Life Prediction Methodology

Basic Theory - The LMP

The prediction of tube creep life is made possible by creep rupture laboratory studies. Laboratory creep specimens, similar to cylindrical tensile test specimens, are machined from various steels. Specimens are then heated to a known temperature (**T**), pulled uniaxially at a known stress (**S**) and the time (**t**) to failure measured. By testing various combinations of stress and temperature, the creep-rupture properties for a selected material can be quantified.

There are numerous ways to present or illustrate a material's creep-rupture properties. One method is to plot laboratory test data using the Larson-Miller Parameter (LMP). The LMP is a function relating **T**emperature and **t**ime. This parameter is defined as:

$$LMP = [\mathbf{T} \times (20 + \log \mathbf{t})]$$

where, **T** is the temperature of the test specimen in degrees Rankine [(degrees F + 459.67), or (degrees C + 273.15) X 1.8)], and **t** is the time (in hours) the material is at this temperature. Every tube in service has an associated LMP number that increases as time continues. This LMP data can be related to stress as illustrated in Figure D. This relationship between stress and LMP is used to predict a most probable time to creep rupture failure. Given two of the three factors affecting creep rupture, i.e., temperature and stress (calculated hoop stress of tube), the third factor, time, can be determined from the LMP creep life plots. These factors are utilized by the NOTIS® program to estimate the total expected creep rupture life of a tube in service. The remaining life of the tube is the total life expectancy less the time spent in service.

ASTM has compiled and published creep-rupture data from several sources, including B&W. This data, which uses the LMP to plot creep-rupture curves of LMP versus stress, may be found in the ASTM Data Series publications. There is, unfortunately, a large amount of scatter in LMP values contained in the ASTM data.

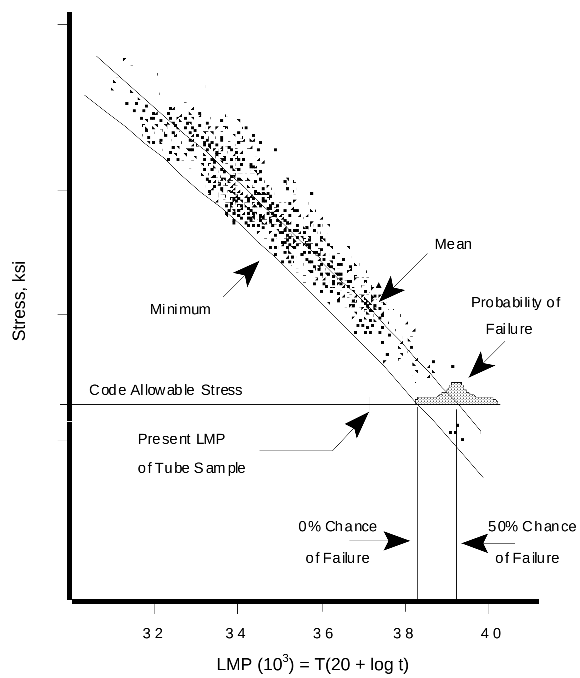


Figure D: Stress vs. LMP plot illustrating the statistical distribution of failures for a specific classification of tubing.

Since at a given stress there is a large variation in the LMP, an absolute time to failure cannot be predicted for a single tube. Instead, a statistical distribution of failures among a large number of similar tubes must be considered.

Among a large sampling of like tubes, the number of failures versus LMP number will follow a normal or bell-shaped curve as shown in Figure D. Failures are less likely at first when the tube LMP approximates the minimum of the LMP scatter. The failure rate will rise to a peak when the tube LMP equals the mean of the LMP data scatter and then finally drop off again. For a single tube, the probability of failure follows a similar distribution curve. •

Creep Life Fraction Analysis

To evaluate the ever changing stress and temperature conditions normally experienced by a superheater or reheater tube, creep life fractions are used. A creep life fraction is the ratio (t/t_f) of time the tube spends at a specific stress and temperature (t), to the time that it would take to cause creep rupture failure at these conditions (t_f). In general, the life fraction method is a way of assessing the relative amount of damage to a tube at a certain set of conditions.

Robinson's Rule of life fractions states that if the applied stress and temperature conditions vary, the sum of the life fractions (or damage) associated with each set of conditions should equal 1 at failure. Robinson's Rule is expressed as follows:

$$(t/t_f)_1 + (t/t_f)_2 + ... + (t/t_f)_n = 1 \text{ at failure}$$

where the subscripts 1 through n indicate each condition of stress and temperature.

Example

Part I:

A tube operates at a hoop stress of 5,000 psi (34.5 MPa) and a temperature of 1050°F (565.56°C). What is the predicted time to failure?

Using these parameters and the Stress-LMP curve in Figure D, the effective minimum LMP at failure is 38,100.

From the LMP equation the expected time to failure (t_f) can be calculated.

LMP	=	$[°F + 459.67] \times [20 + \log t_f]$	or	$[(°C + 273.15) \times 1.8] \times [20 + \log t_f]$
38,100	=	$[1050 + 459.67] \times [20 + \log t_f]$	or	$[(565.56 + 273.15) \times 1.8 \times [20 + \log t_f]$
38,100	=	$[1509.67] \times [20 + \log t_f]$	or	$[1509.67] \times [20 + \log t_f]$
25.237	=	$20 + \log t_f$		
$\log t_f$	=	5.237		
t_f	=	172,584 hours		

Thus, this tube would be expected to have a life of approximately 172,584 hours at these operating parameters. If this tube has operated for 100,000 hours at these parameters, what life fraction has been used up?

The creep life fraction expended is:

Life fraction expended = $f_{(expended)}$ = t/t_f = $100{,}000 \div 172{,}584$ = 0.57943

The creep life fraction remaining is:

Life fraction remaining = $f_{(remaining)}$ = $1 - f_{(expended)}$ = 1 - 0.57943 = 0.42057

$t_{(remaining)} = f_{(remaining)} \times (t_f)$
$t_{(remaining)} = 0.42057 \times 172{,}584 = 72{,}584$ hours

Therefore, this tube has used up approximately 58% of its predicted life (172,584 hours) and is expected to last 72,584 hours if service is continued at these operating parameters.

Part II:

Assume that after operating at 1050°F (565.56°C) for 100,000 hours, this same tube now increases in temperature to 1065°F (573.89°C). The LMP equation is used to calculate t_f at 1065°F (573.89°C) as follows:

LMP	=	$[°F + 459.67] \times [20 + \log t_f]$	or	$[(°C + 273.15) \times 1.8] \times [20 + \log t_f]$
38,100	=	$[1065 + 459.67] \times [20 + \log t_f]$	or	$[(573.89 + 273.15) \times 1.8 \times [20 + \log t_f]$
38,100	=	$[1524.67] \times [20 + \log t_f]$	or	$[1524.67] \times [20 + \log t_f]$
24.989	=	$20 + \log t_f$		
$\log t_f$	=	4.989		
t_f	=	97,499 hours		

Thus, a new tube operating at 1065°F (573.89°C) would have an expected life of 97,499 hours. Recall from Part I, however, that the tube in this example has already used up 58% of its life at 1050°F (565.56°C) giving it a remaining life fraction of 0.42057. Robinson's Rule can now be applied to determine the time this tube can be in service at the higher temperature (1065°F / 573.89°C) after experiencing 100,000 hours operation at 1050°F (565.56°C).

Robinson's Rule: Sum of the life fractions is equal to unity, or one (1), at failure.

$(t/t_f)_{1050} + (t/t_f)_{1065} = 1$
$(100{,}000 \div 172{,}584) + (t \div 97{,}499) = 1$
$t \div 97{,}499 = 0.42057$
$t = 41{,}005$ hours

For the two sets of conditions presented in this example, the combined total life would be 141,005 hours, not the 172,584 hours predicted by the first set of conditions only. This illustrates the effect rising tube metal temperature has on tube life.

In service, superheater and reheater tubes are subjected to varying combinations of stress and temperature. Computer technology is required to calculate and sum the many life fractions needed to predict time to failure. The NOTIS® program performs such a computer analysis. •

Basis of the Remaining Life Analysis

The following assumptions are used for the analysis:

- Creep-rupture is the primary failure mode.
- Tube wastage, or wall thinning rates, are constant with time (i.e., wall thickness is a linear function of time). Wall thinning will continue in the future at the same rate as in the past.
- The original tube wall thickness prior to service is greater than the specified wall thickness. The manufacturer's tube wall tolerance is assumed.
- At time zero, ID oxide thickness is equal to zero.
- The steam side oxide forms an insulating barrier which increases the tube metal temperature with time.
- Steam temperature within the tube remains constant with time.
- The unit will operate in the future much as it has in the past.
- The tube will not suffer a short-term overheat as a result of starvation or pluggage.
- B&W has separated its own LMP data from the ASTM compilation and has fitted a single (minimum) curve to it. This data is used in the remaining creep life calculations.
- For tubes suspected of having exfoliation of the internal scale, the largest oxide measurement obtained from the tube is used for the remaining life analysis. •

• Analysis Procedure

- The past and future life of the tube is broken into specific intervals of time.
  - An oxide growth rate is determined for the tube based on the present oxide thickness, as measured by NOTIS®, and the time in service. The initial oxide thickness is assumed to be zero. Once a mathematical function describing oxide thickness with time and temperature is defined, the oxide thickness in each analysis interval is known. The tube metal temperature in each interval, considering the insulating property of the oxide, is calculated.
  - A linear wall thinning rate is determined for the tube based on the present tube wall thickness measured by NOTIS®, the assumed original tube wall thickness, and the service time of the tube. Once a function describing wall thickness with time is defined, the wall thickness in each analysis interval is known. A hoop stress is calculated using the ASME Boiler Code Section I tube formula in each interval.
- The creep life fraction used in each interval is determined.
  - Given the stress, the LMP of failure may be determined from the creep database.
  - Given the temperature and the LMP of failure, the time (t_f) a new tube would last at each set of conditions is determined.
  - The interval creep life fraction used is t/t_f.

The life fractions are summed over the analysis intervals until the total is 1, at which time failure by creep is possible. The remaining life is obtained by subtracting the tube service time from this total life. •

Accuracy of Creep Life Prediction

Life fraction analysis is the most accurate and widely accepted method for estimating tube lives. Although this method is straight-forward and well documented, it is not exact.

The major problem influencing accuracy is the scatter inherent in material properties. Tubes with the same material classification will possess different creep-rupture properties as illustrated in Figure D. Thus, at a given level of stress and temperature, failure times will vary significantly from tube to tube. Additionally, during service, short excursions to higher temperatures can tend to lower the actual remaining life fraction.

Pin-pointing the exact time to creep-rupture failure for a tube is virtually impossible. Therefore, a range of most probable expected lives is presented. As discussed and illustrated in the Presentation of Results section of this report, each inspected tube is placed into a band of expected remaining life. The range of these bands takes into account the shortcomings of the life fraction analysis as well as the accuracy of the actual operating parameters for the unit. In effect, these bands are confidence limits.

Although remaining life estimates should be viewed qualitatively rather than absolutely, much useful information can be realized. Decisions regarding repair or replacement of critical locations can be made based on the findings. Re-inspection intervals can also be based on the remaining life estimates of critical locations. •

NOTIS® Re-inspection Intervals

A NOTIS® re-inspection period will often be recommended. The benefit of a re-inspection is two-fold. First, it is set so that worsening conditions can be tracked, thus minimizing the possibility of forced downtime due to creep-rupture failures. Secondly, re-inspection is used for fine tuning life predictions. Comparisons can be made between expected and actual internal oxide growth and projected wall thinning rates. The re-inspection will increase the confidence level of subsequent life predictions and ultimately provide more accurate estimates. ♦

Presentation of Results

There are a variety of formats in which the inspection results can be displayed. Babcock & Wilcox utilizes both numerical and graphical outputs. The results of all locations inspected with the NOTIS® system are provided in tabular form on inspection data sheets contained in the appendices. The results are also illustrated by means of graphical representation, again contained in the appendices.

Standard graphical output is displayed in a form referred to as a full component plot, similar to that shown in Figure E on the following page. A full component plot is organized such that remaining lives are put into pre-selected ranges and plotted, using a number/color code. An underline on the number/color code indicates possible exfoliation of the internal oxide.

Babcock & Wilcox

Newfoundland and Labrador Hydro
Holyrood Generating Station, Unit 3

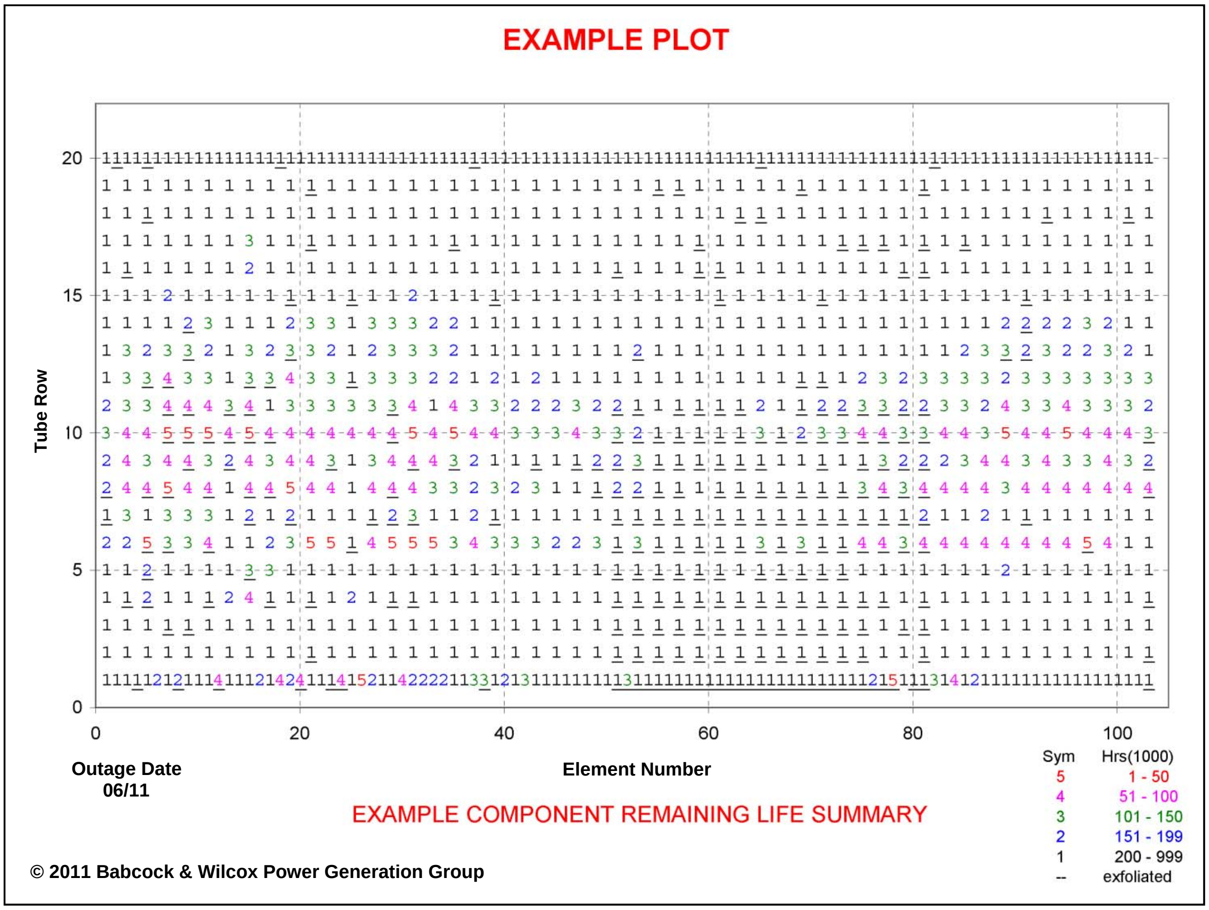


Figure E: Example of a Full Component Plot displaying the remaining lives of the tubes at a single plane of inspection.

STANDARD NUMBER/COLOR CODES & REMAINING USEFUL CREEP LIFE:		
Symbol	**Remaining Life Range, Hours**	**Comments**
5	**0 – 50,000**	**Tubes nearing end of life (< 6 Years RUL*)**
4	**51,000 – 100,000**	**Reduced remaining lives (6 to 11 Years RUL*)**
3	**101,000 – 150,000**	**Long remaining lives (11 to 17 Years RUL*)**
2	**151,000 – 199,000**	**Long remaining lives (17 to 23 Years RUL*)**
1	**=> 200,000**	**Longest remaining lives (=> 23 Years RUL*)**

*** RUL = Remaining Useful Life – Ranges Based on 8,760 Operating Hrs. / Year (100% Availability)**

Additional graphs that supplement the full component plot are also provided when deemed useful. These plots (or graphs) can show unit trends or problems and include:

- Single elevation plots of wall thickness versus element - Generally provided for all inspected tube rows. Within a single tube row, wall thickness can be an indicator of relative temperature exposure and gas flow unbalance. These graphs are helpful in detecting areas of severe wall loss.

- Single elevation plots of oxide thickness versus element - Generally provided for all inspected tube rows. Within a single row, oxide thickness is an indicator of relative temperature exposure. These graphs are helpful in determining gas temperature unbalance in the unit. Data points represented by an ◆ indicate possible exfoliation of the internal oxide.

- Single elevation plots of remaining life versus element – Provided for appropriate tube rows. Unlike the full component plots which place remaining lives into ranges, these graphs indicate the actual calculated numbers. ♦

Interpretation of Results

Careful examination of the oxide thickness, wall thickness, and remaining life provided in the data sheets and graphs can reveal much about the operation of the unit. B&W has inspected many units with NOTIS® and correlated certain patterns observed in the data with known unit operation. Some examples follow.

- Within a single tube row, oxide thickness is an indication of relative temperature exposure. In opposed wall fired units, gas temperatures will be lower at the sidewalls and peak toward the centerline and/or quarter points of the unit. In tangentially fired units, gas temperature peaks usually occur near the sidewalls. Within a tube row, oxide thickness tends to follow furnace gas temperature, so localized peaks on single elevation oxide plots can be an indication of gas temperature unbalance across the boiler. Other reasons for locally high oxides, which indicate elevated metal temperatures, can indicate the presence of a steam flow obstruction or imbalance in the circuit.

- Depending upon the circumstances, wall thickness data may indicate the occurrence of certain phenomena. If all tubes that exhibit reduced wall thickness are in the same area of the component, this is a strong indication of erosion or ash corrosion. If elevated oxide readings are found in the same area, this region may be running hotter due to higher gas velocity and temperature. Higher gas temperatures, and the insulating effects of the thicker oxides, would promote ash corrosion which can account for thinner walls. Thinner walls in tubes on either side of a soot blower cavity, regardless of the location from sidewall to sidewall, may be the result of soot blower erosion.

- Remaining life estimates are an effective way of combining a tube's wall and oxide thickness into a relative measure of creep damage. Remaining life decreases with increasing oxide thickness (temperature) and wall loss (stress). Hence, remaining life graphs will reflect the above mentioned phenomena.

- Although NOTIS® provides much useful information, it is not absolute. The NOTIS® remaining life analysis provides a relative assessment of the inspected component's condition. While the data collected with the NOTIS® system is quite accurate, the results should be viewed on a qualitative rather than an absolute basis. ♦

APPENDIX A

Reheat Superheater

Babcock & Wilcox

Newfoundland and Labrador Hydro
Holyrood Generating Station, Unit 3

NOTIS® Component Inspection Information

Component: Reheat Superheater

Elements Inspected (Numbered from Left Hand Side Wall)

1-60 (Row 14)
1, 8, 9, 12 13, 14, 24, 28, 32, 35, 37, 40, 41, 44, 48, 52 & 60 (Row 19)

Total Number of Inspected Elements 60

Tube Rows Inspected (Numbered Front to Rear)

Rows: 14 & 19

Total Number of Inspected Locations 78

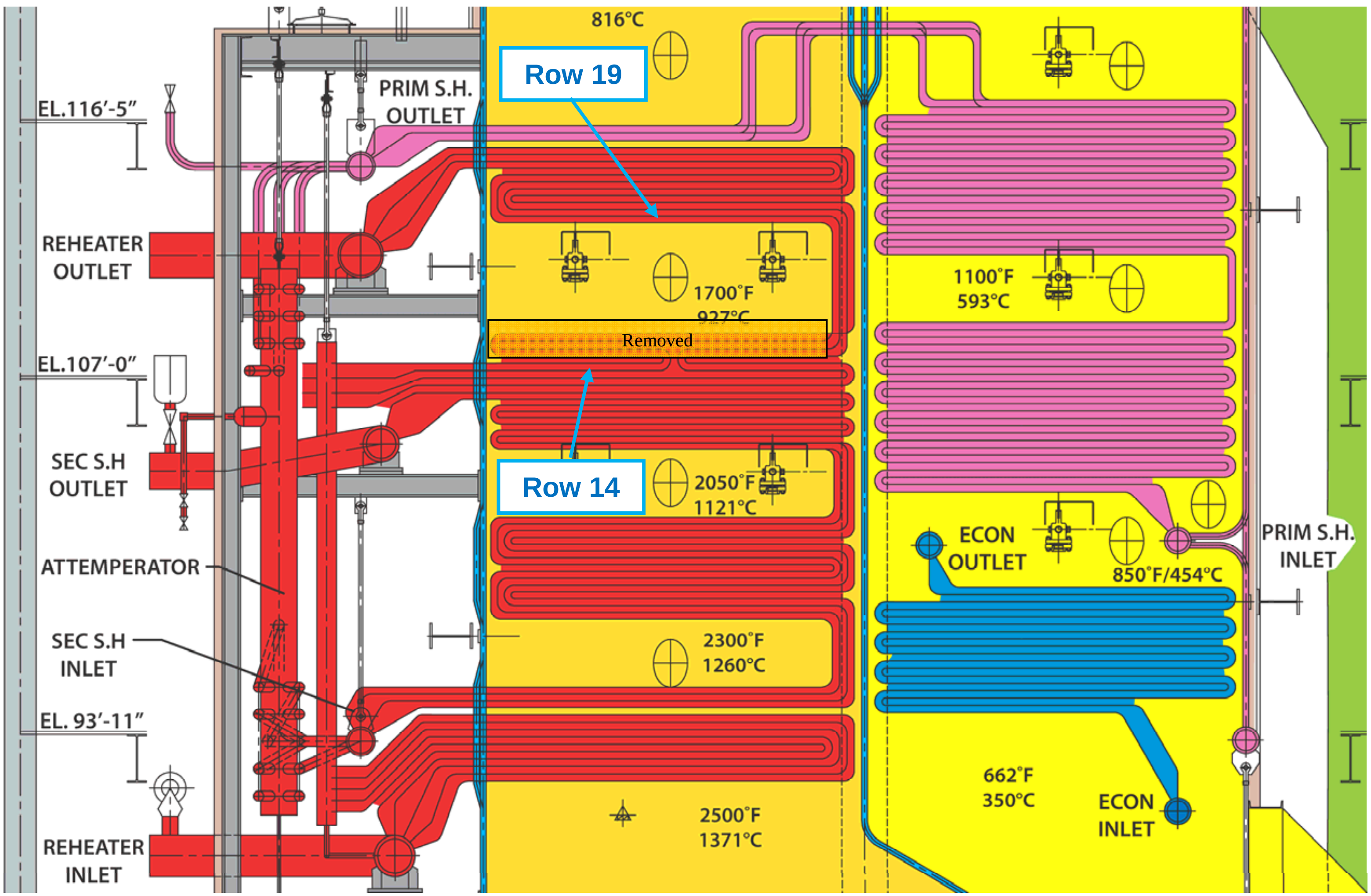
Minimum Measured Wall Thickness 0.152"
Largest Measured Oxide Thickness 0.019"

Notes:

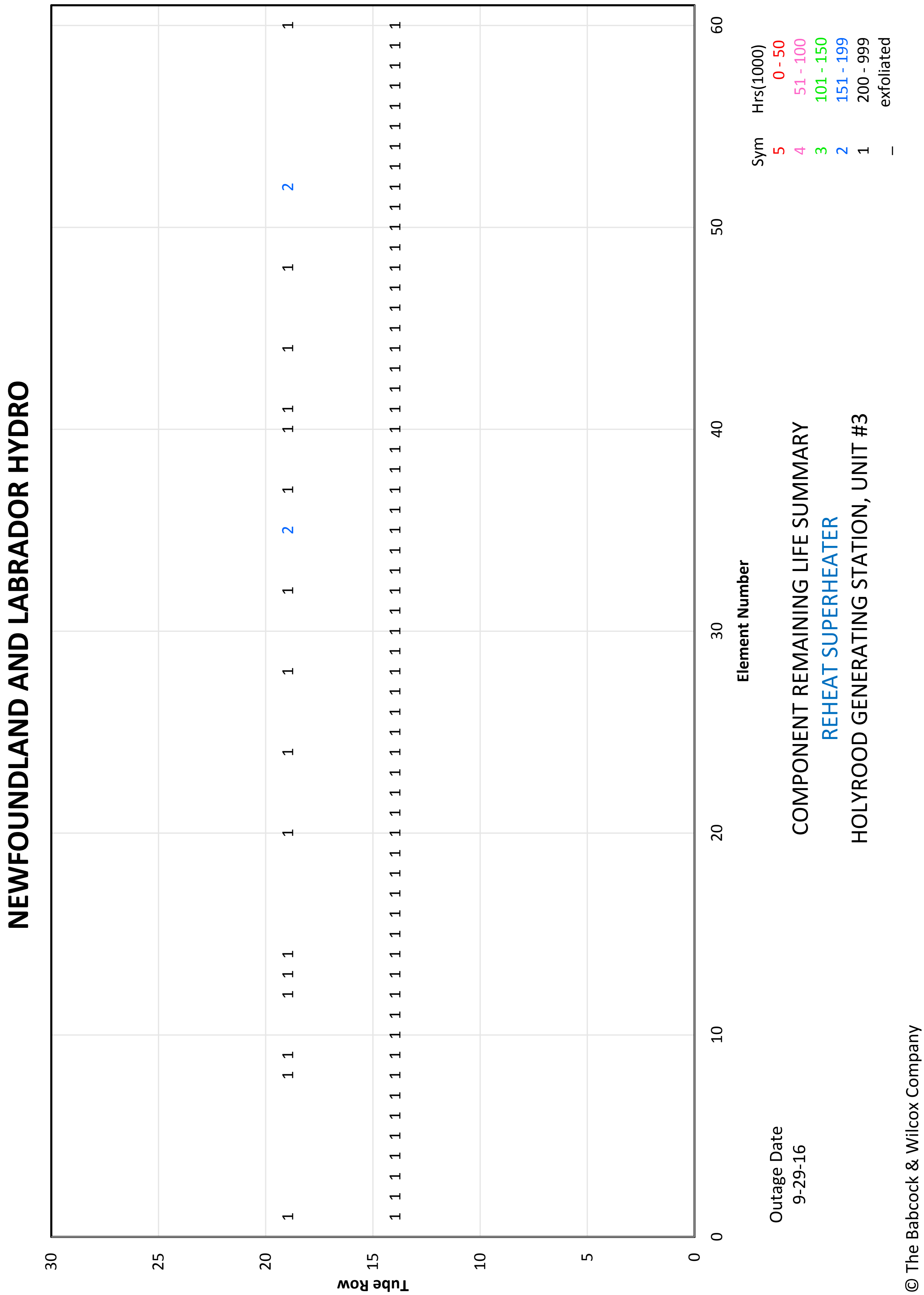
Original Tube Specifications:

Tube Row 14: 2.500" OD X 0.180" Wall, SA-213 Grade T11
Tube Row 19: 2.250" OD X 0.180" Wall, SA-213 Grade T22

Reheat Superheater NOTIS Test Locations

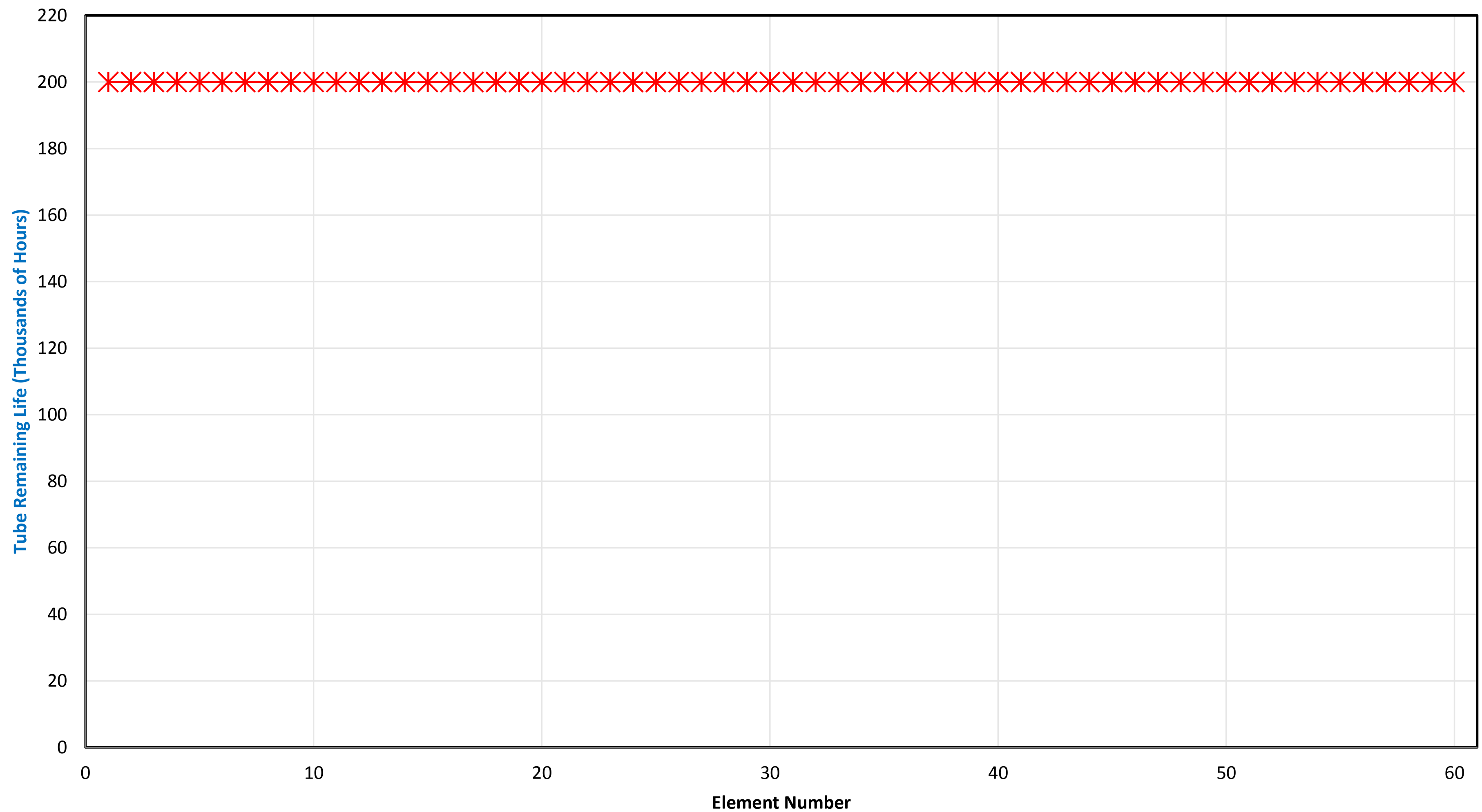


Full Component Plot


NEWFOUNDLAND AND LABRADOR HYDRO
Tube Row
Element Number
Sym Hrs(1000)
5 0 - 50
4 51 - 100
3 101 - 150
2 151 - 199
1 200 - 999
– exfoliated
Outage Date
9-29-16
COMPONENT REMAINING LIFE SUMMARY
REHEAT SUPERHEATER
HOLYROOD GENERATING STATION, UNIT #3
© The Babcock & Wilcox Company

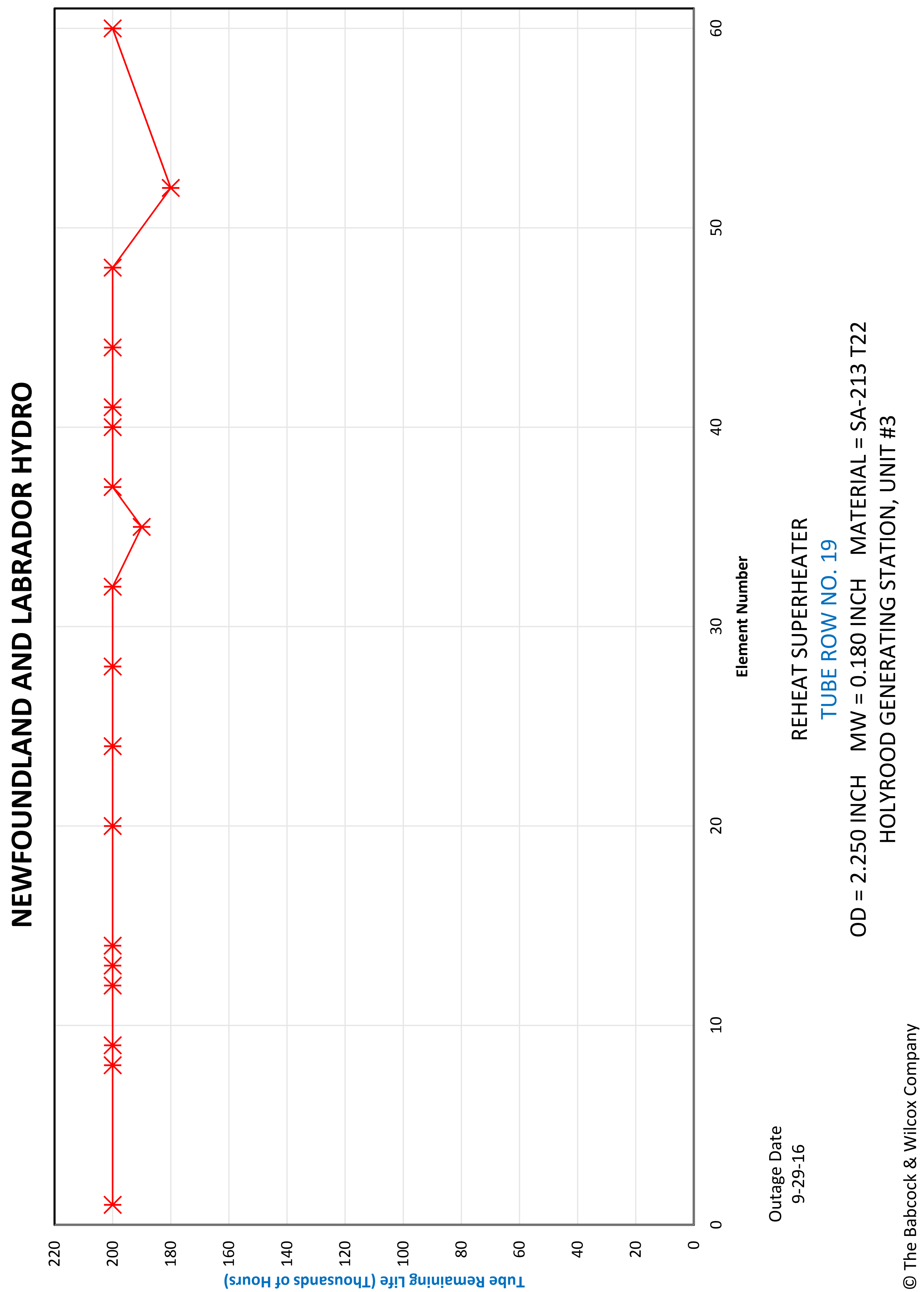
Remaining Life Graphs
(By Tube Row)

NEWFOUNDLAND AND LABRADOR HYDRO



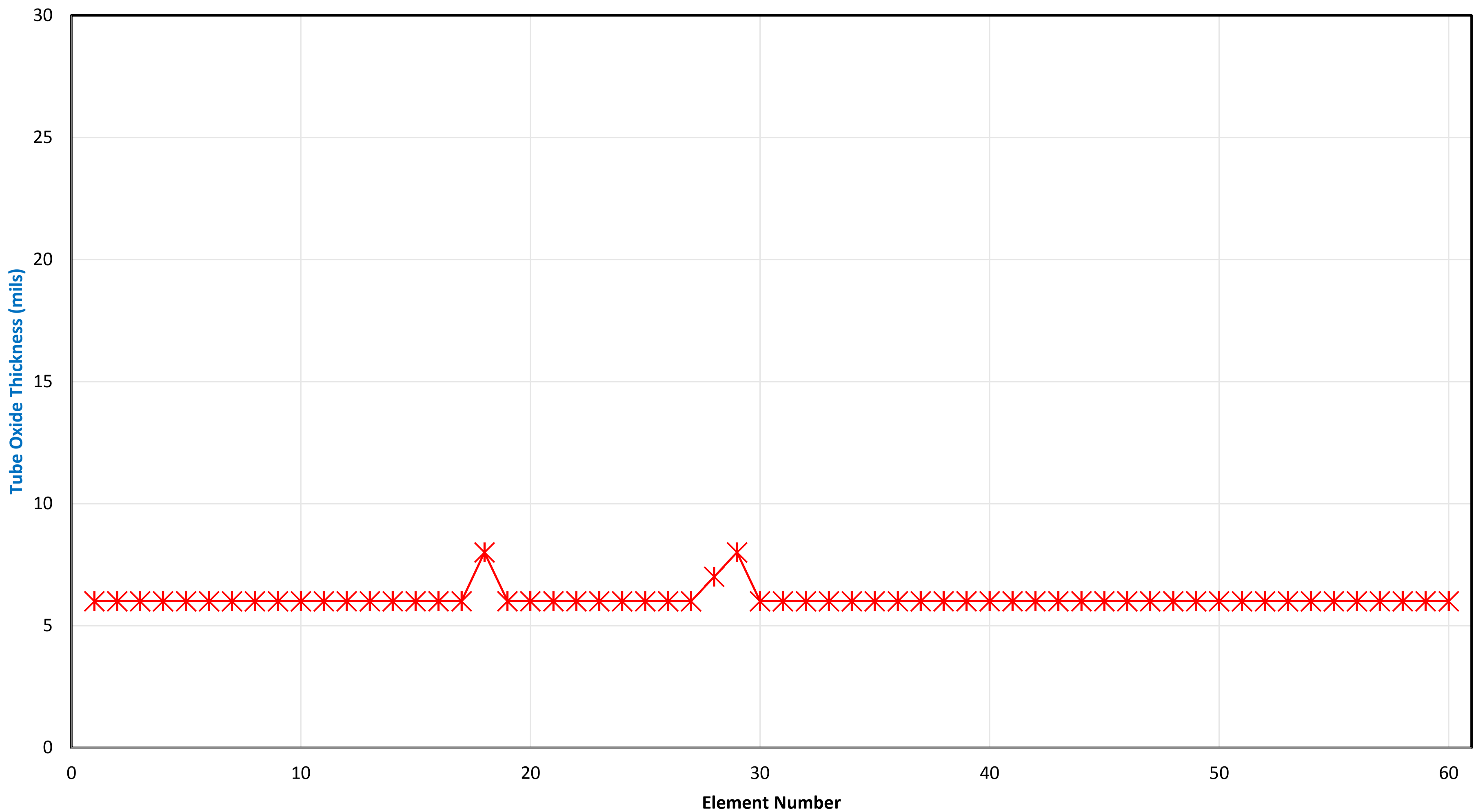
Outage Date
9-29-16

REHEAT SUPERHEATER
TUBE ROW NO. 14
OD = 2.500 INCH   MW = 0.180 INCH   MATERIAL = SA-213 T11
HOLYROOD GENERATING STATION, UNIT #3


NEWFOUNDLAND AND LABRADOR HYDRO
Tube Remaining Life (Thousands of Hours)
0
20
40
60
80
100
120
140
160
180
200
220
Element Number
0
10
20
30
40
50
60
Outage Date
9-29-16
REHEAT SUPERHEATER
TUBE ROW NO. 19
OD = 2.250 INCH MW = 0.180 INCH MATERIAL = SA-213 T22
HOLYROOD GENERATING STATION, UNIT #3
© The Babcock & Wilcox Company

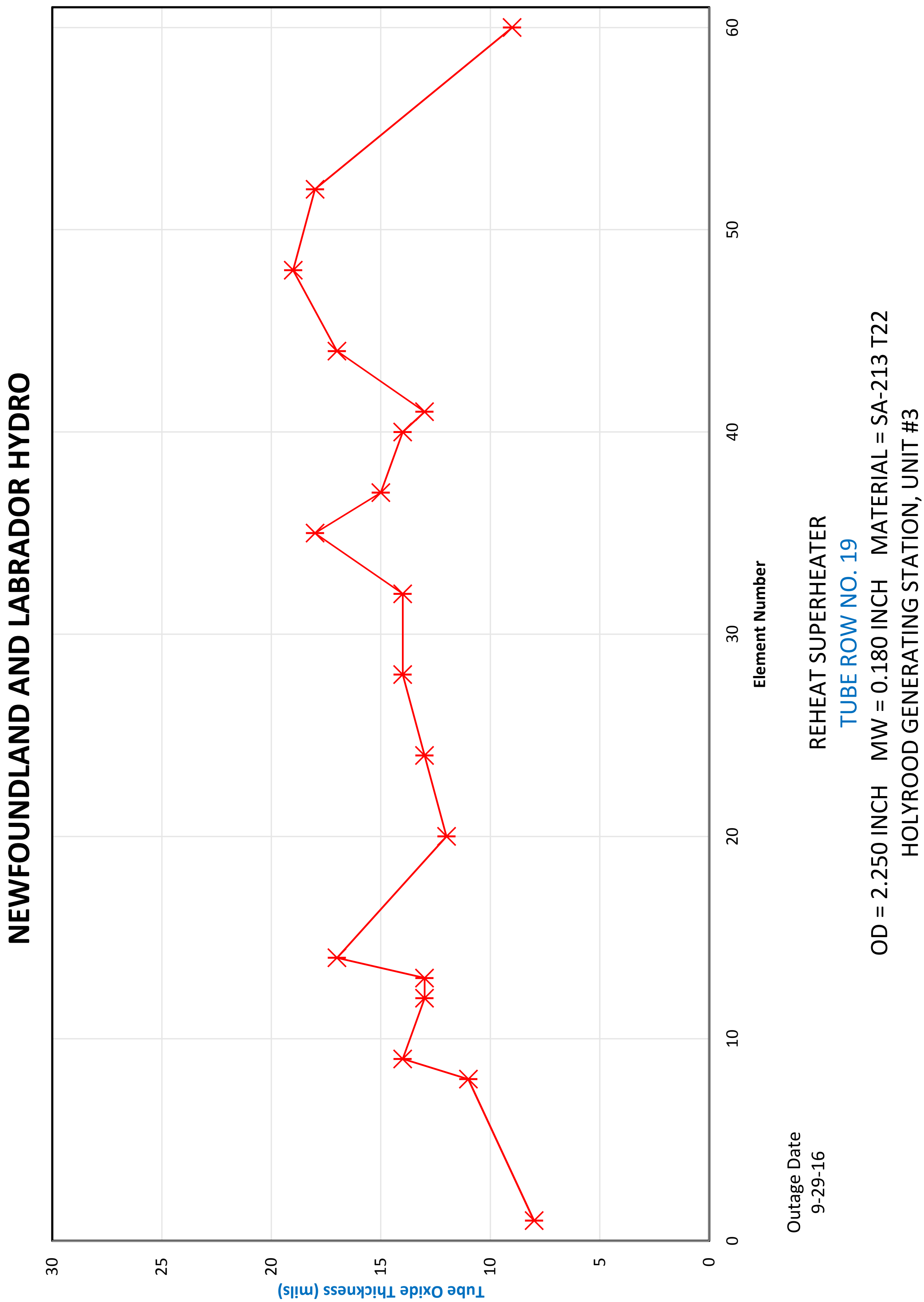
Oxide Thickness Graphs
(By Tube Row)

NEWFOUNDLAND AND LABRADOR HYDRO



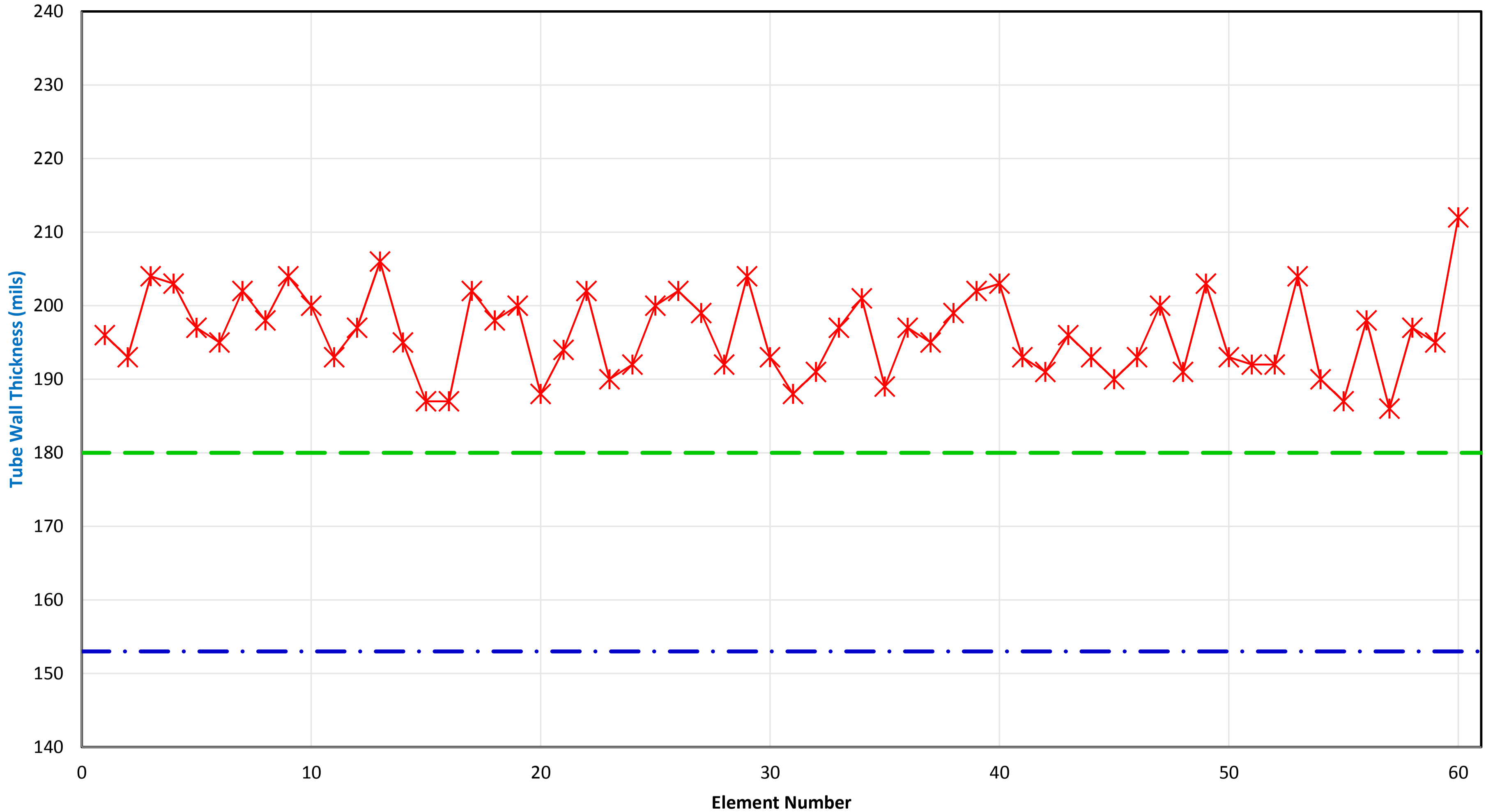
Outage Date
9-29-16

REHEAT SUPERHEATER
TUBE ROW NO. 14
OD = 2.500 INCH MW = 0.180 INCH MATERIAL = SA-213 T11
HOLYROOD, UNIT #3


NEWFOUNDLAND AND LABRADOR HYDRO
Tube Oxide Thickness (mils)
0
5
10
15
20
25
30
Element Number
0
10
20
30
40
50
60
Outage Date
9-29-16
REHEAT SUPERHEATER
TUBE ROW NO. 19
OD = 2.250 INCH MW = 0.180 INCH MATERIAL = SA-213 T22
HOLYROOD GENERATING STATION, UNIT #3

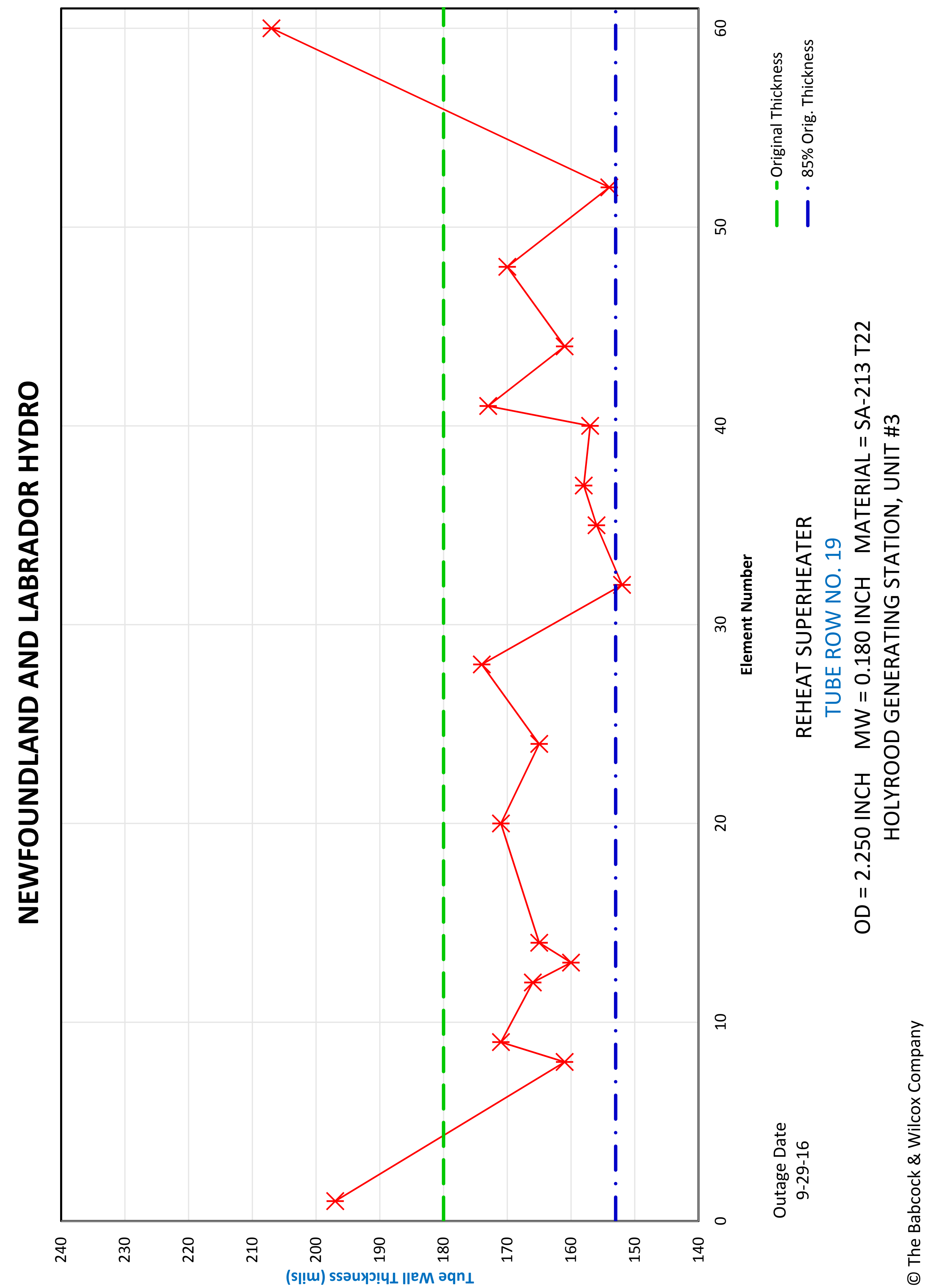
Tube Wall Thickness Graphs
(By Tube Row)

NEWFOUNDLAND AND LABRADOR HYDRO



Outage Date
9-29-16

REHEAT SUPERHEATER
TUBE ROW NO. 14
OD = 2.500 INCH MW = 0.180 INCH MATERIAL = SA-213 T11
HOLYROOD GENERATING STATION, UNIT #3


NEWFOUNDLAND AND LABRADOR HYDRO
Tube Wall Thickness (mils)
240
230
220
210
200
190
180
170
160
150
140
0
10
20
30
40
50
60
Element Number
Original Thickness
85% Orig. Thickness
Outage Date
9-29-16
REHEAT SUPERHEATER
TUBE ROW NO. 19
OD = 2.250 INCH MW = 0.180 INCH MATERIAL = SA-213 T22
HOLYROOD GENERATING STATION, UNIT #3
© The Babcock & Wilcox Company

Tabular Data

NONDESTRUCTIVE TUBE REMAINING LIFE PREDICTIONS: NOTIS

CUSTOMER NAME: NEWFOUNDLAND & LABRADOR HYDRO - HOLYROOD GENERATING STATION - UNIT #3
COMPONENT NAME: REHEAT SUPERHEATER
OUTLET PRESSURE: 471 P.S.I.G.
OPERATING TIME: 152,000 HOURS
DATE OF TESTING: 9-29-16

ELEMENT	TUBE NUMBER	ALLOY CODE	SPEC. WALL in.	SPEC. DIAM. in.	MEAS. WALL in.	MEAS. I.D. OX. in.	NOTES	REMAINING LIFE hrs.	O.D. TEMP. °F	MEAN TEMP. °F
1	19	5	0.180	2.250	0.197	0.008		200,000	991	979
8	19	5	0.180	2.250	0.161 *	0.011		200,000	1021	1009
9	19	5	0.180	2.250	0.171 *	0.014		200,000	1041	1029
12	19	5	0.180	2.250	0.166 *	0.013		200,000	1035	1023
13	19	5	0.180	2.250	0.160 *	0.013		200,000	1035	1023
14	19	5	0.180	2.250	0.165 *	0.017		200,000	1055	1043
20	19	5	0.180	2.250	0.171 *	0.012		200,000	1029	1017
24	19	5	0.180	2.250	0.165 *	0.013		200,000	1035	1023
28	19	5	0.180	2.250	0.174 *	0.014		200,000	1041	1029
32	19	5	0.180	2.250	0.152 **	0.014		200,000	1041	1029
35	19	5	0.180	2.250	0.156 *	0.018		190,000	1059	1047
37	19	5	0.180	2.250	0.158 *	0.015		200,000	1046	1034
40	19	5	0.180	2.250	0.157 *	0.014		200,000	1041	1029
41	19	5	0.180	2.250	0.173 *	0.013		200,000	1035	1023
44	19	5	0.180	2.250	0.161 *	0.017		200,000	1055	1043
48	19	5	0.180	2.250	0.170 *	0.019		200,000	1063	1051
52	19	5	0.180	2.250	0.154 *	0.018		180,000	1059	1047
60	19	5	0.180	2.250	0.207	0.009		200,000	1003	991
1	14	4	0.180	2.500	0.196	0.006		200,000	966	954
2	14	4	0.180	2.500	0.193	0.006		200,000	966	954
3	14	4	0.180	2.500	0.204	0.006		200,000	966	954
4	14	4	0.180	2.500	0.203	0.006		200,000	966	954
5	14	4	0.180	2.500	0.197	0.006		200,000	966	954
6	14	4	0.180	2.500	0.195	0.006		200,000	966	954
7	14	4	0.180	2.500	0.202	0.006		200,000	966	954
8	14	4	0.180	2.500	0.198	0.006		200,000	966	954
9	14	4	0.180	2.500	0.204	0.006		200,000	966	954
10	14	4	0.180	2.500	0.200	0.006		200,000	966	954
11	14	4	0.180	2.500	0.193	0.006		200,000	966	954
12	14	4	0.180	2.500	0.197	0.006		200,000	966	954
13	14	4	0.180	2.500	0.206	0.006		200,000	966	954
14	14	4	0.180	2.500	0.195	0.006		200,000	966	954
15	14	4	0.180	2.500	0.187	0.006		200,000	966	954
16	14	4	0.180	2.500	0.187	0.006		200,000	966	954
17	14	4	0.180	2.500	0.202	0.006		200,000	966	954
18	14	4	0.180	2.500	0.198	0.008		200,000	991	979
19	14	4	0.180	2.500	0.200	0.006		200,000	966	954
20	14	4	0.180	2.500	0.188	0.006		200,000	966	954
21	14	4	0.180	2.500	0.194	0.006		200,000	966	954
22	14	4	0.180	2.500	0.202	0.006		200,000	966	954
23	14	4	0.180	2.500	0.190	0.006		200,000	966	954
24	14	4	0.180	2.500	0.192	0.006		200,000	966	954
25	14	4	0.180	2.500	0.200	0.006		200,000	966	954
26	14	4	0.180	2.500	0.202	0.006		200,000	966	954
27	14	4	0.180	2.500	0.199	0.006		200,000	966	954
28	14	4	0.180	2.500	0.192	0.007		200,000	978	966
29	14	4	0.180	2.500	0.204	0.008		200,000	991	979
30	14	4	0.180	2.500	0.193	0.006		200,000	966	954
31	14	4	0.180	2.500	0.188	0.006		200,000	966	954
32	14	4	0.180	2.500	0.191	0.006		200,000	966	954
33	14	4	0.180	2.500	0.197	0.006		200,000	966	954
34	14	4	0.180	2.500	0.201	0.006		200,000	966	954
35	14	4	0.180	2.500	0.189	0.006		200,000	966	954
36	14	4	0.180	2.500	0.197	0.006		200,000	966	954
37	14	4	0.180	2.500	0.195	0.006		200,000	966	954
38	14	4	0.180	2.500	0.199	0.006		200,000	966	954
39	14	4	0.180	2.500	0.202	0.006		200,000	966	954
40	14	4	0.180	2.500	0.203	0.006		200,000	966	954
41	14	4	0.180	2.500	0.193	0.006		200,000	966	954
42	14	4	0.180	2.500	0.191	0.006		200,000	966	954
43	14	4	0.180	2.500	0.196	0.006		200,000	966	954
44	14	4	0.180	2.500	0.193	0.006		200,000	966	954
45	14	4	0.180	2.500	0.190	0.006		200,000	966	954

NONDESTRUCTIVE TUBE REMAINING LIFE PREDICTIONS: NOTIS

CUSTOMER NAME: NEWFOUNDLAND & LABRADOR HYDRO - HOLYROOD GENERATING STATION - UNIT #3
COMPONENT NAME: REHEAT SUPERHEATER
OUTLET PRESSURE: 471 P.S.I.G.
OPERATING TIME: 152,000 HOURS
DATE OF TESTING: 9-29-16

ELEMENT	TUBE NUMBER	ALLOY CODE	SPEC. WALL in.	SPEC. DIAM. in.	MEAS. WALL in.	MEAS. I.D. OX. in.	NOTES	REMAINING LIFE hrs.	O.D. TEMP. °F	MEAN TEMP. °F
46	14	4	0.180	2.500	0.193	0.006		200,000	966	954
47	14	4	0.180	2.500	0.200	0.006		200,000	966	954
48	14	4	0.180	2.500	0.191	0.006		200,000	966	954
49	14	4	0.180	2.500	0.203	0.006		200,000	966	954
50	14	4	0.180	2.500	0.193	0.006		200,000	966	954
51	14	4	0.180	2.500	0.192	0.006		200,000	966	954
52	14	4	0.180	2.500	0.192	0.006		200,000	966	954
53	14	4	0.180	2.500	0.204	0.006		200,000	966	954
54	14	4	0.180	2.500	0.190	0.006		200,000	966	954
55	14	4	0.180	2.500	0.187	0.006		200,000	966	954
56	14	4	0.180	2.500	0.198	0.006		200,000	966	954
57	14	4	0.180	2.500	0.186	0.006		200,000	966	954
58	14	4	0.180	2.500	0.197	0.006		200,000	966	954
59	14	4	0.180	2.500	0.195	0.006		200,000	966	954
60	14	4	0.180	2.500	0.212	0.006		200,000	966	954

ALLOY CODES

Alloy Code 4 = ASME SA-213 Grade T11
Alloy Code 5 = ASME SA-213 Grade T22

NOTES

* Thickness Below Original Specified Tube Wall

** Thickness is 85% of Original Specified Tube Wall or Less

NOTES ON TUBE AND ELEMENT NUMBERING

Elements are numbered from Left Hand Side Wall to Right Hand Side Wall.

Tube rows are numbered from bottom to top in the reheater, or in the direction of flow.

Tube rows 5, 6, 15, 16, 17 and 18 were previously removed from the reheater; however, the tube rows are included in the total tube row count.

APPENDIX B

Primary Superheater

NOTIS® Component Inspection Information

Component: Primary Superheater

Elements Inspected (Numbered from Left Hand Side Wall)

7, 14, 21, 28, 35, 42, 49, 56, 63, 70, 77 & 84

Total Number of Inspected Elements 12

Tube Rows Inspected (Numbered Front to Rear)

Row: 4 (Leading Edge on Economizer side of the Convection Pass)

Total Number of Inspected Locations 12

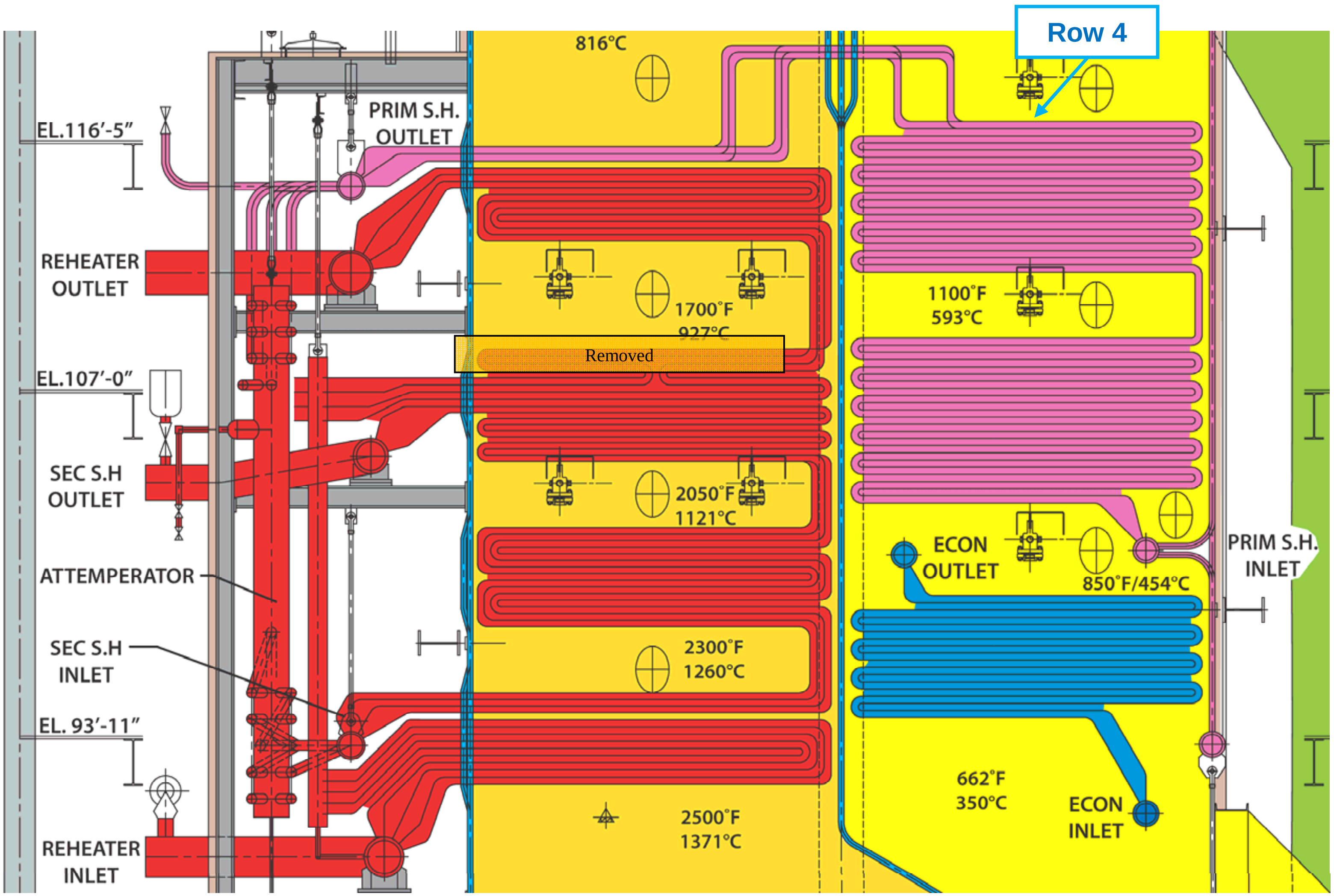
Minimum Measured Wall Thickness 0.349"
Largest Measured Oxide Thickness 0.006"

Notes:

Original Tube Specifications:

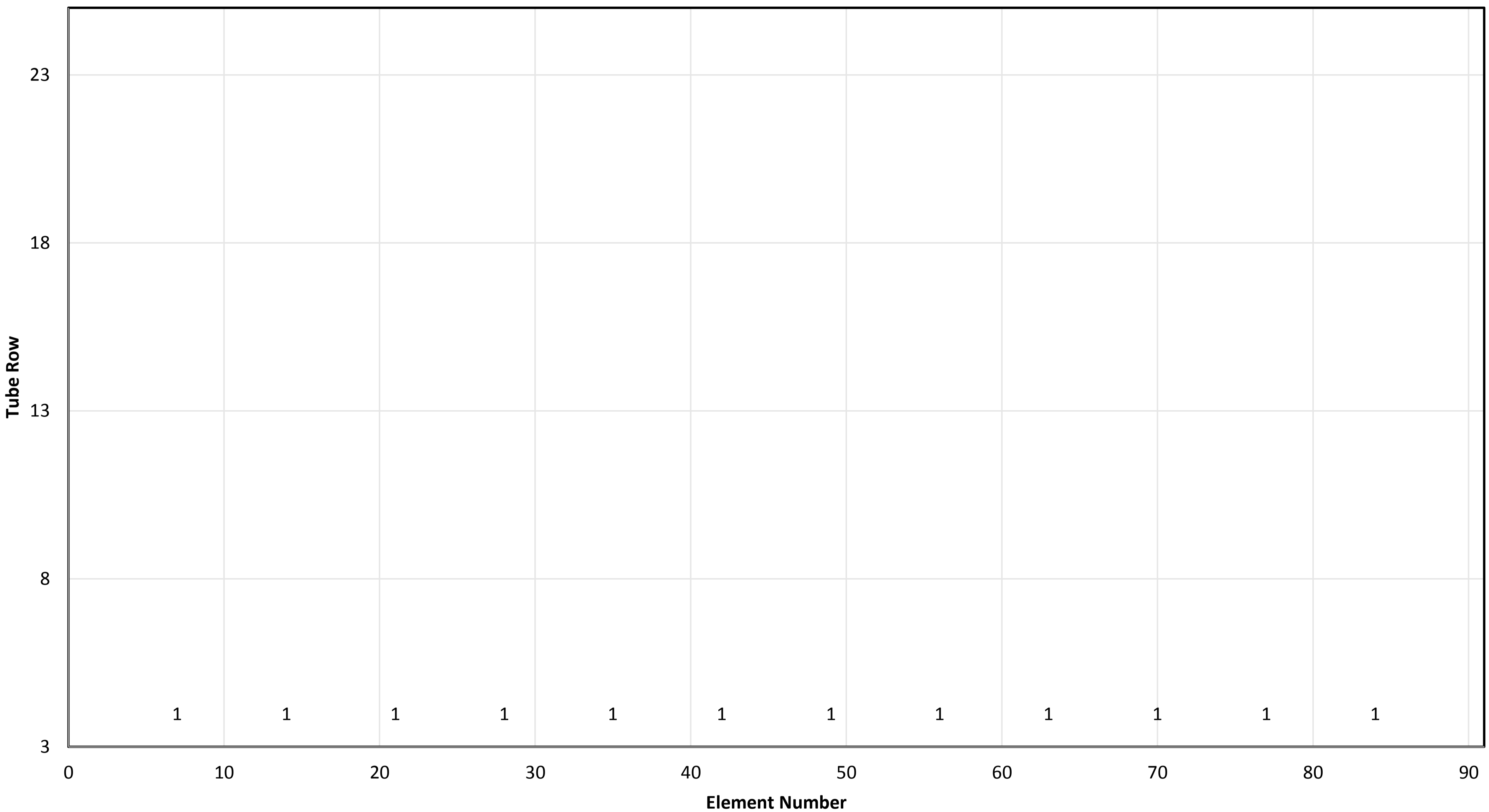
Tube Row 4: 2.250" OD X 0.338" Wall, SA-213 Grade T2

Primary Superheater NOTIS Test Locations



Full Component Plot

NEWFOUNDLAND AND LABRADOR HYDRO

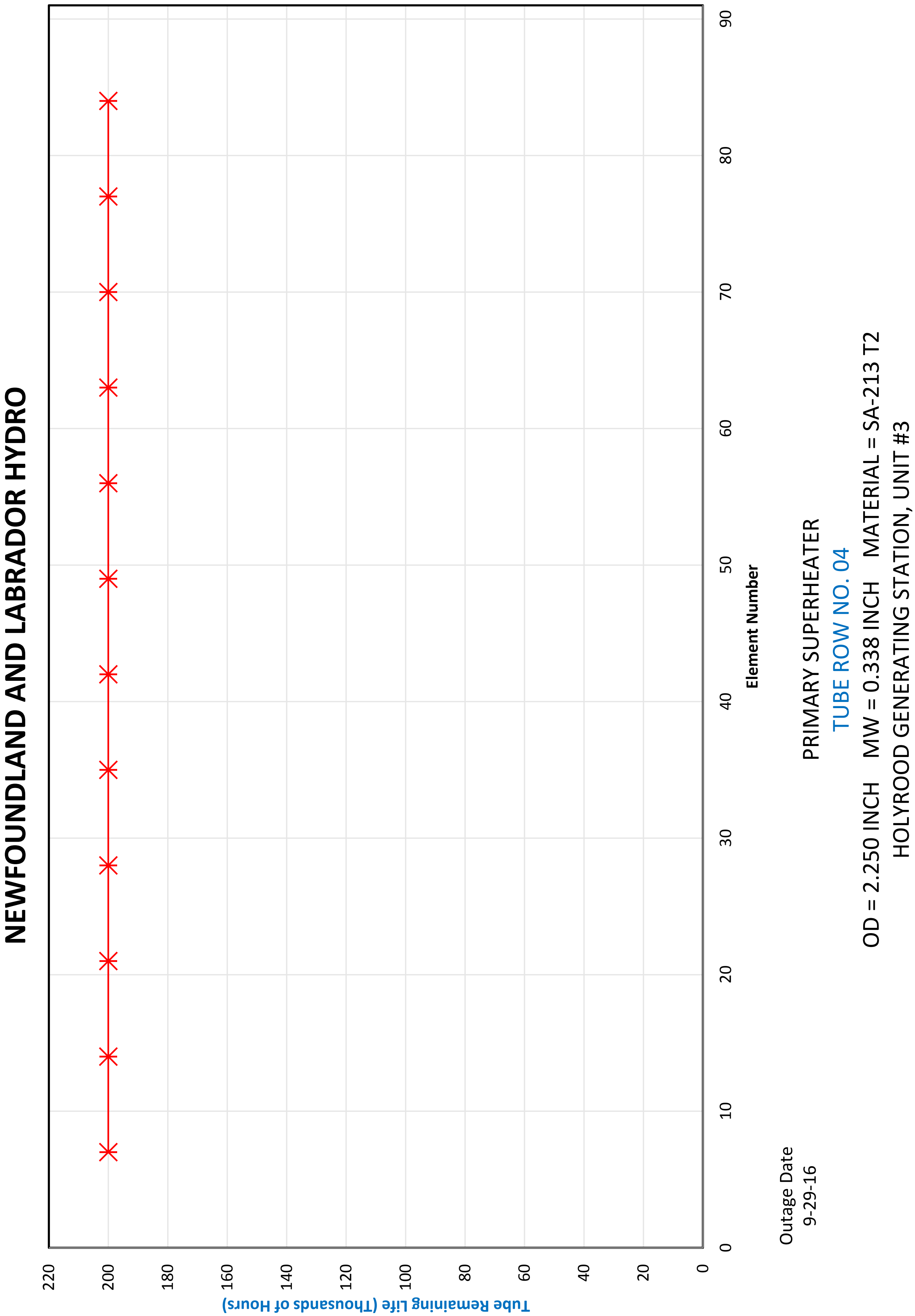


Outage Date
9-29-16

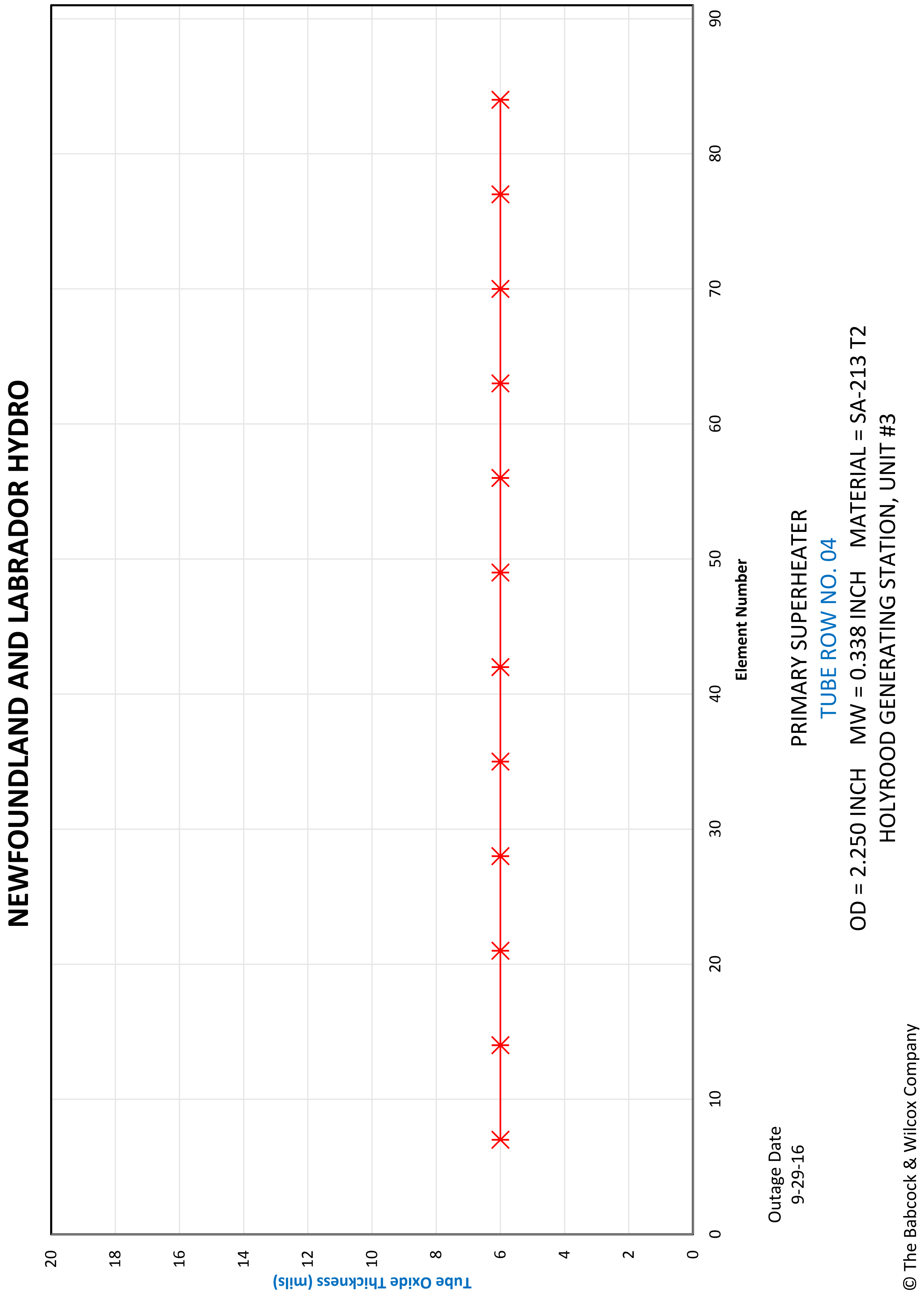
COMPONENT REMAINING LIFE SUMMARY
PRIMARY SUPERHEATER
HOLYROOD GENERATING STATION, UNIT #3

Sym	Hrs(1000)
5	0 - 50
4	51 - 100
3	101 - 150
2	151 - 199
1	200 - 999
_	exfoliated

Remaining Life Graphs
(By Tube Row)


NEWFOUNDLAND AND LABRADOR HYDRO
Tube Remaining Life (Thousands of Hours)
0
20
40
60
80
100
120
140
160
180
200
220
0
10
20
30
40
50
60
70
80
90
Element Number
Outage Date
9-29-16
PRIMARY SUPERHEATER
TUBE ROW NO. 04
OD = 2.250 INCH MW = 0.338 INCH MATERIAL = SA-213 T2
HOLYROOD GENERATING STATION, UNIT #3

Oxide Thickness Graphs
(By Tube Row)


NEWFOUNDLAND AND LABRADOR HYDRO
Tube Oxide Thickness (mils)
0
2
4
6
8
10
12
14
16
18
20
0
10
20
30
40
50
60
70
80
90
Element Number
Outage Date
9-29-16
PRIMARY SUPERHEATER
TUBE ROW NO. 04
OD = 2.250 INCH MW = 0.338 INCH MATERIAL = SA-213 T2
HOLYROOD GENERATING STATION, UNIT #3
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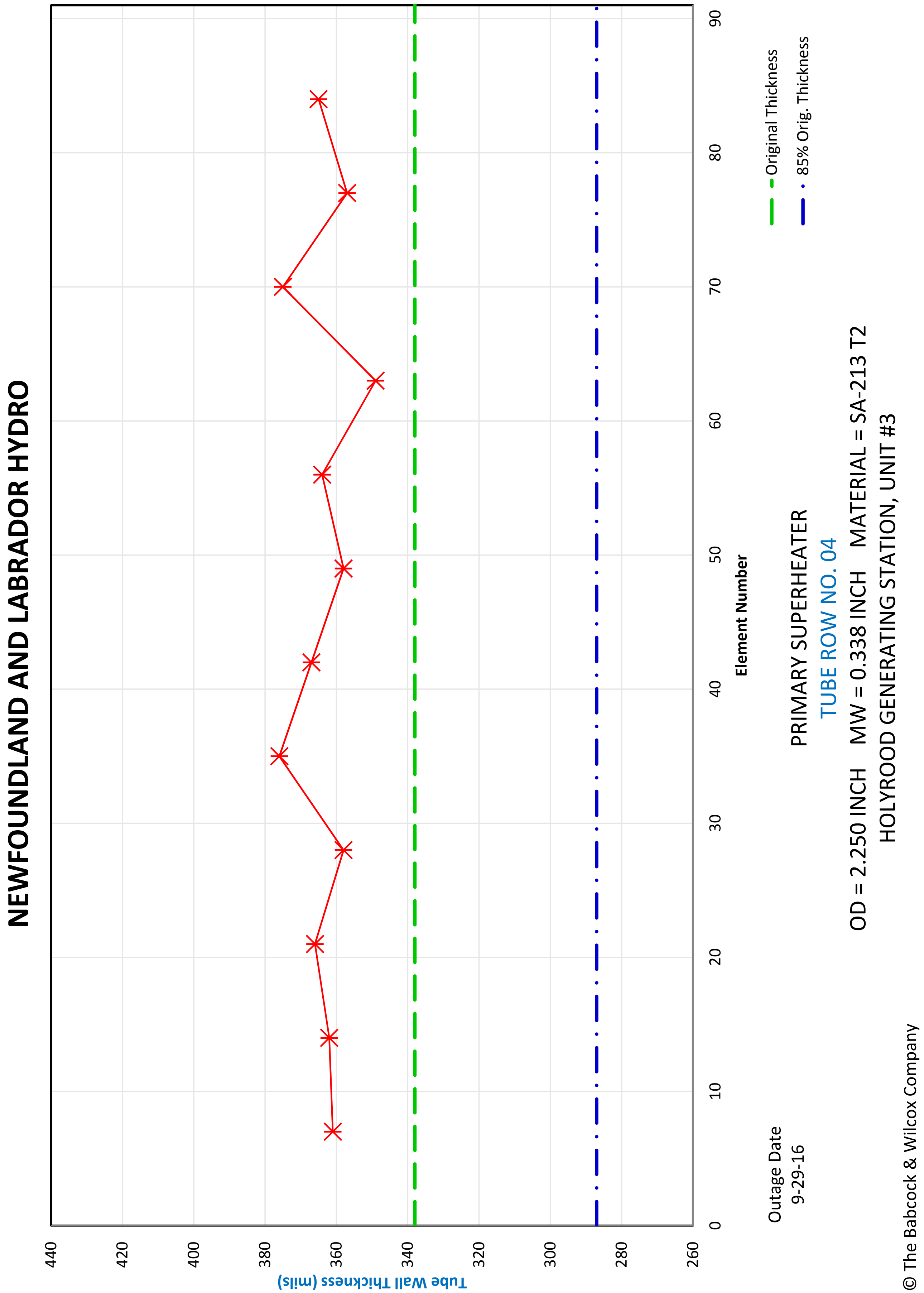
Tube Wall Thickness Graphs
(By Tube Row)


NEWFOUNDLAND AND LABRADOR HYDRO
Tube Wall Thickness (mils)
440
420
400
380
360
340
320
300
280
260
0
10
20
30
40
50
60
70
80
90
Element Number
Original Thickness
85% Orig. Thickness
Outage Date
9-29-16
PRIMARY SUPERHEATER
TUBE ROW NO. 04
OD = 2.250 INCH MW = 0.338 INCH MATERIAL = SA-213 T2
HOLYROOD GENERATING STATION, UNIT #3
© The Babcock & Wilcox Company

Tabular Data

NONDESTRUCTIVE TUBE REMAINING LIFE PREDICTIONS: NOTIS

CUSTOMER NAME: NEWFOUNDLAND & LABRADOR HYDRO - HOLYROOD GENERATING STATION - UNIT #3
COMPONENT NAME: PRIMARY SUPERHEATER
OUTLET PRESSURE: 1,895 P.S.I.G.
OPERATING TIME: 152,000 HOURS
DATE OF TESTING: 9-29-16

ELEMENT	TUBE NUMBER	ALLOY CODE	SPEC. WALL in.	SPEC. DIAM. in.	MEAS. WALL in.	MEAS. I.D. OX. in.	NOTES	REMAINING LIFE hrs.	O.D. TEMP. °F	MEAN TEMP. °F
7	4	3	0.338	2.250	0.361	0.006		200,000	959	944
14	4	3	0.338	2.250	0.362	0.006		200,000	959	944
21	4	3	0.338	2.250	0.366	0.006		200,000	959	944
28	4	3	0.338	2.250	0.358	0.006		200,000	959	944
35	4	3	0.338	2.250	0.376	0.006		200,000	959	944
42	4	3	0.338	2.250	0.367	0.006		200,000	959	944
49	4	3	0.338	2.250	0.358	0.006		200,000	959	944
56	4	3	0.338	2.250	0.364	0.006		200,000	959	944
63	4	3	0.338	2.250	0.349	0.006		200,000	959	944
70	4	3	0.338	2.250	0.375	0.006		200,000	959	944
77	4	3	0.338	2.250	0.357	0.006		200,000	959	944
84	4	3	0.338	2.250	0.365	0.006		200,000	959	944

ALLOY CODES

Alloy Code 3 = ASME SA-213 Grade T2

NOTES

NOTES ON TUBE AND ELEMENT NUMBERING

Elements are numbered from Left Hand Side Wall to Right Hand Side Wall.

Tube rows are numbered in the direction of flow. Rows 1 - 3 are from bottom to top on the boiler side and Rows 4-49 are top to

APPENDIX C

B&W Plant Service Bulletin 26; Tube Thickness Evaluation Repair or Replacement Guideline

babcock & wilcox power generation group

Plant Service Bulletin

Tube Thickness Evaluation Repair or Replacement Guideline

Purpose

This bulletin was written to assist customers in evaluating existing boiler tube wall thicknesses and defining when repair or replacement is recommended.

Background

Experience has shown that many tubes do not necessarily fail when operating at thicknesses below the minimum wall calculated, according to the ASME Code. However, operation in this manner encroaches on the ASME Code design margin. A tube that is below minimum wall thickness may or may not be tolerant of temperature excursions, thermal cycling, mechanical loading or other stresses.

Cognizant of this, some operators have elected to take a practical approach, based on actual operating experience, to determine when to repair or replace thinned tubes. A practical minimum wall thickness criterion can be established through a record-keeping process to track the wall thickness of various boiler tubes over time, and to relate tube failure history of those tubes to tube thicknesses. This is an effective method for locating troubled areas before they lead to forced outages. With this method, the decision to take action for thinned tubes is based on a percentage of the original wall thickness (t) of the tubes.

Table 1
Guidelines for Tube Repair/Replacement

Location	Actual Tube Wall Thickness Relative to Percent Specified Wall Thickness, t	Course of Action
1. Furnace Support Tubes and Economizer Stringer Support Tubes	Tubes equal to or greater than 85% t	Monitor thickness
	Tubes less than 85% t	Restore tube wall thickness or replace tube *
2. Economizer, Furnace Wall and Other Water-Cooled Tubes	Tubes equal to or greater than 70% t	Monitor thickness
	Tube less than 70% t	Restore tube wall thickness or replace tube*
3. Superheater, Reheater and Other Steam-Cooled Tubes	Tubes equal to or greater than 85% t	Monitor thickness
	Tubes less than 85% t	Restore tube wall thickness or replace tube*

* It is difficult to restore the wall thickness for tubes below 0.090 inch due to possible weld burn-through and distortion. On Kraft recovery boilers, refuse boilers, and boilers operating below 1000 psig, the tubes should be replaced when below the ASME minimum wall thickness.

Because high-temperature (steam-cooled) tubes usually fail by creep rupture, and water-cooled tubes usually operate below the creep-rupture regime, a different set of evaluation criteria is required for each of these two types of tubes. Furnace tubes of once-through boilers operate at high temperatures and therefore, are classified as steam-cooled tubes when evaluating tube thickness. A guideline for determining what course of action to take is shown in Table 1.

Many factors were used and taken into consideration for establishing the usable thickness guideline. One of these factors is the need to avoid material yielding as the tube thins in service.

The decision to repair or replace tubing that is under the original specified minimum wall thickness should be evaluated by the operating company and discussed with the local jurisdiction and/or insurance carrier. This evaluation should consider the following:

1. History of previous failure of similar tubes
2. Wastage rate
3. Susceptibility to temperature excursion
4. Thermal cycling
5. Mechanical loading
6. Scheduling of outages of sufficient length to replace tubes
7. Risk of injury to personnel from primary failure or subsequent reactions

Recommendations

Customers should develop a program for their individual boilers using this as a guide to collect the specific information needed for reliable maintenance planning.

When replacing short tube segments, it is recommended that replacement tubing be the same OD, thickness and material specification as the original. When replacing large sections, an engineering review should be made to determine the advisability of upgrading to the latest design criteria or to apply other design changes that may eliminate existing problems. Arbitrarily increasing the tube wall thickness or alloy grade is not recommended, as it may lead to additional problems.

All boiler tubes may be replaced without weld restriction provided a qualified welding procedure is employed, together with a welding filler metal that is appropriate for the alloy content, tensile strength and service temperature of the tubing.

ALL REPAIRS MUST BE ACCEPTABLE TO THE GOVERNING CODE JURISDICTION AND/OR INSURANCE CARRIER.

Support

If you elect to follow the above guidelines, The Babcock & Wilcox Company (B&W) can assist in developing the specific information needed for an individual unit. Contact your regional B&W Field Engineering Services office if you have any questions or need assistance.

babcock & wilcox power generation group

While others may use the Babcock name, we are the original Babcock & Wilcox with experience in engineering, constructing and servicing steam generating systems since 1867. Insist on us by name.

For more information, or a complete listing of our sales and service offices, call 1-800-BABCOCK (222-2625), send an e-mail to info@babcock.com or access our Web site at www.babcock.com.

PSB-26 1MU3L

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Amec Foster Wheeler Reference:	AM212/015/000002 R00
Security Class:	Amec Foster Wheeler Confidential
Recipient's Reference:	N/A

October 19, 2016

Nelson Seymour
Nalcor Energy
PO Box 12400
Hydro Place, 500 Columbus Drive
St. John's, NL
A1B 4K7

Re: Holyrood TGS Boiler Tube Thinning Assessment (October 2016 Update)

Dear Mr Seymour,

Nalcor has a need to potentially operate the three generating units at Holyrood TGS to 2021 with a high degree of reliability. A risk assessment conducted by Nalcor has identified boiler tube failures due to tube thinning as a reliability risk and has proposed de-rating the units as a means of mitigating this risk over the remaining operating period. Amec Foster Wheeler Nuclear Canada had been engaged to review the technical basis for this de-rate assessment, and to apply alternative assessment methods to maximise unit load capability while maintaining acceptable reliability.

In August 2016, Amec Foster Wheeler completed this assessment [R-1] with a recommendation to de-rate Unit 3 operating pressure by 10% in order to mitigate the risk of tube failures. The main determinant for this recommendation was a reduced margin in creep life as a result of tube thinning and elevated temperatures around the 9th floor cavity reheater tubes and bends, and the low temperature superheater tubes and bends at the 10th floor. The temperature data used for these calculations is documented in a metal temperature study that was performed by Babcock & Wilcox (B&W) [R-2] in July 2016, where concerns around elevated tube temperatures are also documented.

In order to refine the temperature data used as an input into the creep life calculations, B&W performed NOTIS testing on the highest-risk tubing to calculate effective metal temperatures during an outage in September 2016 [R-3]. Additional UT wall thickness data were also obtained [R-4], and tube samples were removed for metallurgical analysis. The following were the target locations:

- Low Temperature Superheater, 10th Floor, Below Feet (Economizer Side)
- Reheater Tubes, 9th Floor, Overhead (SA-213 T22)
- Reheater Tubes, 9th Floor, Below Feet (SA-213 T11)

NOTIS is a B&W tool for using UT techniques to measure the tube ID oxide scale, which is then used to estimate effective metal temperature based on scale growth kinetics. Metallurgical analyses to confirm the ID scale thickness (from NOTIS), to confirm tube material, and to assess potential wall thinning mechanisms were performed on these tube samples. The B&W results from these inspections were provided to Amec Foster Wheeler.

Using the supplied data, the creep life calculations were repeated using the refined (lower) temperatures determined by B&W through the NOTIS testing. Rows 16-19 and 29-32 in the attached table reflect the results of the updated calculations for the reheater and low temperature superheater tubing. The calculated OD temperatures were conservatively used for these calculations, and the wall thickness values were refreshed with the lowest measured values where applicable. The temperatures on the boiler side of the 10^{th} floor low temperature superheater tubing were assumed to drop by the same amount as the economizer side. The bends are assumed to operate at the same temperature as the tubes.

As illustrated in the attached table, creep life in the limiting tubes is not expected to be challenged when calculated using the NOTIS-derived effective metal temperatures. However, calculated creep life is still marginally below the acceptable limit defined in [R-1] in a couple of cases (see rows 20 and 29 in attached table). On this basis, the recommendation for a 10% de-rate can be removed for the short term, with additional targeted tube inspections and replacements (if required) recommended to be performed in 2017. This recommendation is contingent on the finalization and documentation of the B&W NOTIS results, and is subject to change if these results are revised.

Yours truly,

David McNabb, P. Eng.
Manager, Inspection and Maintenance Engineering
Amec Foster Wheeler

References

[R-1] Correspondence, "Holyrood TGS Boiler Tube Thinning Assessment", AmecFW File No. AM212/015/000001 R01, 2016-08-08.

[R-2] Report, "Thermal Study – Superheater and Reheater Metal" B&W File No. TP900932 R02, 2016-07-05.

[R-3] Email from John Adams to David McNabb, "Fw: NOTIS Data", AmecFW File No. AM212/RE/001 R00, 2016-10-12.

[R-4] Email from John Adams to David McNabb, "Fw: 2016 U#3 Primary Superheater & Reheater UT Data", AmecFW File No. AM212/RE/002 R00, 2016-10-12.

Unit 3

#	Inspection Location	Physical Properties					B&W Plant Service Bulletin PSB-26					MAWP (ASME BPVC Section I, PG-27.2.1)							MAWP (ASME BPVC Section I, A-317.2.1)							Larson-Miller at 100% Operating Pressure	
		Lowest Measured Wall Thickness (inch)	Assumed 100% Operating Pressure (psi)	Material	Temp. (ºF)	Tube OD (inches)	PSB-26 Requirement (t = specified wall)	Percent Remaining from Original	Required Wall (inches)	Margin at Design Pressure (inches)	Criteria Satisfied?	MAWP (psi)	Max. Operating Pressure Margin (psi)	Margin with 2% pressure reduction (psi)	Margin with 5% pressure reduction (psi)	Margin with 10% pressure reduction (psi)	Margin with 15% pressure reduction (psi)	Margin with 20% pressure reduction (psi)	MAWP (psi)	Max. Operating Pressure Margin (psi)	Margin with 2% pressure reduction (psi)	Margin with 5% pressure reduction (psi)	Margin with 10% pressure reduction (psi)	Margin with 15% pressure reduction (psi)	Margin with 20% pressure reduction (psi)	Minimum Predicted Life (hours)	*Mean Predicted Life (hours)*
1	Economizer Tubes, 6th Floor, Lower Tube Wall (South Bend)	0.153	2200	SA210A1	700	2.5	70%t	75%	0.142	0.011	YES	1858	-342	-298	-232	-122	-12	98	2037	-163	-119	-53	57	167	277	5.49E+06	6.85E+07
2	Economizer Tubes, 6th Floor, Lower Tube Wall (North Bend)	0.155	2200	SA210A1	700	2.5	70%t	76%	0.142	0.013	YES	1886	-314	-270	-204	-94	16	126	2065	-135	-91	-25	85	195	305	6.33E+06	7.76E+07
3	Economizer Tubes, 6th Floor, Lower Tube Wall (Tube)	0.189	2200	SA210A1	700	2.5	70%t	93%	0.142	0.047	YES	2370	170	214	280	390	500	610	2557	357	401	467	577	687	797	5.06E+07	4.85E+08
4	Economizer Tubes, 8th Floor, Lower (Under Sootblower)	0.178	2200	SA210A1	700	2.5	70%t	88%	0.142	0.036	YES	2212	12	56	122	232	342	452	2396	196	240	306	416	526	636	2.75E+07	2.83E+08
5	Economizer Tubes, 8th Floor, Lower (North Bend)	0.218	2200	SA210A1	700	2.5	70%t	107%	0.142	0.076	YES	2794	594	638	704	814	924	1034	2990	790	834	900	1010	1120	1230	2.05E+08	1.69E+09
6	Economizer Tubes, 8th Floor, Lower (North Bend)	0.186	2200	SA210A1	700	2.5	70%t	92%	0.142	0.044	YES	2327	127	171	237	347	457	567	2513	313	357	423	533	643	753	4.31E+07	4.20E+08
7	Economizer Tubes, 8th Floor, Upper (South Bend)	0.171	2200	SA210A1	700	2.5	70%t	84%	0.142	0.029	YES	2112	-88	-44	22	132	242	352	2295	95	139	205	315	425	535	1.81E+07	1.96E+08
8	Economizer Tubes, 8th Floor, Upper (Tube)	0.178	2200	SA210A1	700	2.5	70%t	88%	0.142	0.036	YES	2212	12	56	122	232	342	452	2396	196	240	306	416	526	636	2.75E+07	2.83E+08
9	Economizer Tubes, 8th Floor, Upper (North Bend)	0.178	2200	SA210A1	700	2.5	70%t	88%	0.142	0.036	YES	2212	12	56	122	232	342	452	2396	196	240	306	416	526	636	2.75E+07	2.83E+08
10	Low Temperature Superheater, 8th Floor, Overhead (Bend)	0.180	2010	SA210A1	696	2.5	85%t	89%	0.173	0.007	YES	2258	248	288	348	449	549	650	2444	434	474	535	635	736	836	8.91E+07	8.29E+08
11	Low Temperature Superheater, 8th Floor, Overhead (Tube)	0.194	2010	SA210A1	696	2.5	85%t	96%	0.173	0.021	YES	2461	451	491	552	652	753	853	2651	641	681	742	842	943	1043	1.85E+08	1.59E+09
12	Low Temperature Superheater, 9th Floor, Below Feet (Bend)	0.179	2010	SA210A1	741	2.5	85%t	88%	0.173	0.006	YES	1922	-88	-48	12	113	213	314	2081	71	112	172	272	373	473	7.58E+06	6.52E+07
13	Low Temperature Superheater, 9th Floor, Below Feet (Tube)	0.216	2010	SA210A1	741	2.5	85%t	106%	0.173	0.043	YES	2387	377	417	477	578	678	779	2555	545	585	645	746	846	947	4.29E+07	3.08E+08
14	Low Temperature Superheater, 9th Floor, Overhead (Bend)	0.170	2010	SA209T1A	766	2.5	85%t	84%	0.173	-0.003	NO	2184	174	214	274	375	475	576	2374	364	404	465	565	666	766	2.75E+08	8.72E+08
15	Low Temperature Superheater, 9th Floor, Overhead (Tube)	0.210	2010	SA209T1A	756	2.5	85%t	103%	0.173	0.037	YES	2803	793	833	894	994	1095	1195	3005	995	1035	1096	1196	1297	1397	1.30E+09	4.09E+09
16	Low Temperature Superheater, 10th Floor, Below Feet (Boiler Side) (Bend)[1]	0.374	2010	SA213T11	985	2.5	85%t	95%	0.335	0.039	YES	2434	424	464	525	625	726	826	2560	550	590	650	751	851	952	6.84E+05	3.99E+06
17	Low Temperature Superheater, 10th Floor, Below Feet (Boiler Side) (Tube)[2]	0.430	2010	SA213T11	985	2.5	85%t	109%	0.335	0.095	YES	2887	877	917	977	1078	1178	1279	3035	1025	1066	1126	1226	1327	1427	1.38E+06	8.13E+06
18	Low Temperature Superheater, 10th Floor, Below Feet (Economizer Side) (Bend)[3]	0.310	2010	SA213T2	959	2.5	85%t	92%	0.287	0.023	YES	2325	315	355	415	516	616	717	2453	443	483	543	644	744	845	4.47E+05	1.20E+06
19	Low Temperature Superheater, 10th Floor, Below Feet (Economizer Side) (Tube)[4]	0.306	2010	SA213T2	959	2.5	85%t	91%	0.287	0.019	YES	2289	279	320	380	480	581	681	2416	406	447	507	607	708	808	4.23E+05	1.14E+06
20	High Temperature Superheater, 8th Floor, Overhead (Bend)	0.216	2010	SA209T1A	941	2.25	85%t	66%	0.278	-0.062	NO	1840	-170	-130	-69	31	132	232	1959	-51	-11	50	150	251	351	3.23E+05	8.75E+05
21	High Temperature Superheater, 8th Floor, Overhead (Tube)	0.228	2010	SA209T1A	941	2.25	85%t	70%	0.278	-0.050	NO	1959	-51	-10	50	150	251	351	2081	71	112	172	272	373	473	4.05E+05	1.10E+06
22	High Temperature Superheater, 8th Floor, Below Feet	0.221	2010	SA209T1A	905	2.25	85%t	78%	0.242	-0.021	NO	2704	694	734	794	895	995	1096	2876	866	906	967	1067	1168	1268	1.68E+06	4.66E+06
23	High Temperature Superheater, 8.5 Floor, Overhead (Bend)	0.275	2010	SA213T22	1037	2	85%t	84%	0.278	-0.003	NO	1924	-86	-46	14	115	215	316	2025	15	56	116	216	317	417	4.52E+05	1.76E+06
24	High Temperature Superheater, 8.5 Floor, Overhead (Tube)	0.283	2010	SA213T22	1034	2	85%t	87%	0.278	0.005	YES	2035	25	65	125	226	326	427	2141	131	171	232	332	433	533	6.23E+05	2.39E+06
25	High Temperature Superheater, 8.5 Floor, Below Feet (Bend)	0.279	2010	SA213T22	1021	2.25	85%t	98%	0.242	0.037	YES	1900	-110	-70	-9	91	192	292	2005	-5	35	95	196	296	397	4.12E+05	1.70E+06
26	High Temperature Superheater, 8.5 Floor, Below Feet (Tube)	0.275	2010	SA213T22	1021	2.25	85%t	96%	0.242	0.033	YES	1868	-142	-102	-41	59	160	260	1972	-38	2	62	163	263	364	3.72E+05	1.54E+06
27	Reheater Tubes, 7th Floor, Top of Scaffold (Bend)	0.113	600	SA213TP347H	1017	2.25	85%t	76%	0.126	-0.013	NO	1547	947	959	977	1007	1037	1067	1729	1129	1141	1159	1189	1219	1249	1.22E+09	3.76E+09
28	Reheater Tubes, 7th Floor, Top of Scaffold (Tube)	0.129	600	SA213TP347H	1017	2.25	85%t	87%	0.126	0.003	YES	1804	1204	1216	1234	1264	1294	1324	1989	1389	1401	1419	1449	1479	1509	2.56E+09	7.87E+09
29	Reheater Tubes, 9th Floor, Overhead (Bend)[5]	0.116	600	SA213T22	1063	2.25	85%t	64%	0.153	-0.037	NO	508	-92	-80	-62	-32	-2	+8	56Ű	-33	-21	-3	+Ű	57	87	ḱ.ǥ0 +05	1.21E+06

[1] Revised effective metal temperatures based on NOTIS data collected in Q3-2016 used in revised MAWP and Larson-Miller calculations.
[2] Revised effective metal temperatures based on NOTIS data collected in Q3-2016 used in revised MAWP and Larson-Miller calculations.
[3] Revised effective metal temperatures based on NOTIS data collected in Q3-2016 used in revised MAWP and Larson-Miller calculations.
[4] Revised effective metal temperatures based on NOTIS data, and lowest measured wall thickness data collected in Q3-2016 inspection campaign used in revised MAWP and Larson-Miller calculations.
[5] Revised effective metal temperatures based on NOTIS data collected in Q3-2016 used in revised MAWP and Larson-Miller calculations.

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#	Inspection Location	Physical Properties					B&W Plant Service Bulletin PSB-26					MAWP (ASME BPVC Section I, PG-27.2.1)							MAWP (ASME BPVC Section I, A-317.2.1)							Larson-Miller at 100% Operating Pressure	
		Lowest Measured Wall Thickness (inch)	Assumed 100% Operating Pressure (psi)	Material	Temp. (°F)	Tube OD (inches)	PSB-26 Requirement (t = specified wall)	Percent Remaining from Original	Required Wall (inches)	Margin at Design Pressure (inches)	Criteria Satisfied?	MAWP (psi)	Max. Operating Pressure Margin (psi)	Margin with 2% pressure reduction (psi)	Margin with 5% pressure reduction (psi)	Margin with 10% pressure reduction (psi)	Margin with 15% pressure reduction (psi)	Margin with 20% pressure reduction (psi)	MAWP (psi)	Max. Operating Pressure Margin (psi)	Margin with 2% pressure reduction (psi)	Margin with 5% pressure reduction (psi)	Margin with 10% pressure reduction (psi)	Margin with 15% pressure reduction (psi)	Margin with 20% pressure reduction (psi)	Minimum Predicted Life (hours)	*Mean Predicted Life (hours)*
30	Reheater Tubes, 9th Floor, Overhead (Tube)[6]	0.140	600	SA213T22	1063	2.25	85%t	78%	0.153	-0.013	**NO**	6ḱ⁺	ḱ⁺	*44*	*62*	*92*	*122*	*152*	69⁺	9⁺	*104*	*122*	*152*	*182*	*212*	.0⁺ +06	*3.14E+06*
31	Reheater Tubes, 9th Floor, Below Feet (SA-213 T11)[7]	0.161	600	SA213T11	991	2.5	85%t	89%	0.153	0.008	**YES**	86ᵹ	⁺6ᵹ	*276*	*294*	*324*	*354*	*384*	9ᵹḱ	ḱᵹḱ	*355*	*373*	*403*	*433*	*463*	.5Ű +06	*9.20E+06*
32	Reheater Tubes, 9th Floor, Below Feet (SA-213 T22)[8]	0.160	600	SA213T22	991	2.5	85%t	89%	0.153	0.007	**YES**	066	ᵹ66	*478*	*496*	*526*	*556*	*586*	65	565	*577*	*595*	*625*	*655*	*685*	⁺.ḱᵹ +0Ű	*7.44E+07*
33	Boiler Roof Tubes (Boiler Side)	0.188	-	-	-	-	70%t	78%	0.168	0.020	**YES**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
34	Water Wall Knee Region	0.213	-	-	-	-	70%t	101%	0.147	0.066	**YES**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
35	*Boiler Floor Tubes[9]*	*0.110*	-	-	-	-	*70%t*	*52%*	*0.147*	*-0.037*	*NO*	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
36	Water Wall at Buners (Elevation 1)	0.169	-	-	-	-	70%t	80%	0.147	0.022	**YES**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
37	Water Wall at Buners (Elevation 2)	0.199	-	-	-	-	70%t	95%	0.147	0.052	**YES**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
38	Water Wall at Buners (Elevation 3)	0.191	-	-	-	-	70%t	91%	0.147	0.044	**YES**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

[6] Revised effective metal temperatures based on NOTIS data collected in Q3-2016 used in revised MAWP and Larson-Miller calculations.
[7] Revised effective metal temperatures based on NOTIS data collected in Q3-2016 used in revised MAWP and Larson-Miller calculations.
[8] Revised effective metal temperatures based on NOTIS data collected in Q3-2016 used in revised MAWP and Larson-Miller calculations.
[9] Tubes to be restored in 2016.

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ANALYSIS OF NEWFOUNDLAND & LABRADOR HYDRO HOLYROOD UNIT 3 BOILER TUBES

Kinectrics Report: K-700390-RA-001-R00

Babcock & Wilcox Power Generation Group Canada
Purchase Order No.: TPX289603 Amendment No.:2

November 21, 2016

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ANALYSIS OF NEWFOUNDLAND & LABRADOR HYDRO HOLYROOD UNIT 3 BOILER TUBES

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SUMMARY

Metallurgical temperature estimates for 1-1/4Cr-1/2Mo (T11) and 2-1/4Cr-1Mo (T22) reheater tubes, and one 1/2Cr-1/2Mo (T2) primary superheater tube, recently removed Holyrood Unit 3, revealed that they were operating below design conditions. The temperature estimates were based on 1) examinations of the ID surface oxide and 2) the hardness of the tube alloy. The residual creep lives of the three tubes were then predicted using analytical methods, historically developed by Ontario Hydro Research Division and its derivatives. Based on the observed rates of tube wall thinning and the estimated metal operating temperatures, the risk of creep failures in these tubes is considered to be 'low'; all three have significant (i.e., >10 years) residual creep life under the historical Unit 3 boiler operating conditions.

Keywords: Holyrood, Unit 3, Superheater, Reheater, Oxide, Creep Rupture Life

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To: Shaun Lingley
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ANALYSIS OF NEWFOUNDLAND & LABRADOR HYDRO HOLYROOD UNIT 3 BOILER TUBES

1.0 CONCLUSIONS

As a result of the metallurgical investigation and analysis of the primary superheater and reheater tube sections from Holyrood Unit 3, the following conclusions were reached:

1. The primary superheater (PSH) tube No. 64 from platen 48 was manufactured from SA213-T2 alloy (½Cr-½Mo). Based on measurements of the maximum ID oxide thickness, the tube metal temperature was estimated to be in the range of 453ºC to 490ºC (847ºF to 914ºF). For comparison, the tube metal temperature estimates based on tube alloy hardness measurements were in the range of 476ºC to 501ºC (888ºF to 933ºF). Using the I.S.O. parametric approach, measured wall thinning rate, the maximum estimated temperature, and design pressure, the residual creep rupture life of this tube was conservatively estimated to be 63,000 h.
2. The reheater (RH) tube No. 49 from platen 22 was manufactured from SA213-T22 alloy (2¼Cr-1Mo). Based on measurements of the maximum ID oxide thickness, the tube metal temperature was estimated to be in the range of 522ºC to 555ºC (972ºF to 1030ºF). For comparison, the tube metal temperature estimates based on tube alloy hardness measurements were in the range of 582ºC to 600ºC (1080ºF to 1113ºF). Using the I.S.O. parametric approach, measured wall thinning rate, the maximum estimated temperature, and design pressure, the residual creep rupture life of this tube was conservatively estimated to be 102,000 h.
3. One side of the reheater tube No. 44 from platen 34 was manufactured from SA213-11 alloy (1¼Cr-½Mo). (The other side, not examined in this project, was reported to be SA213-T22 alloy). Based on measurements of the ID oxide, the tube metal temperature was estimated to be in the range of 489ºC to 505ºC (911ºF to 941ºF). For comparison, the tube metal temperature estimates based on tube alloy hardness measurements were in the range of 472ºC to 481ºC (882ºF to 898ºF). Using the I.S.O. parametric approach, measured wall thinning rate, the maximum estimated temperature, and design pressure, the residual creep rupture life of this tube was conservatively estimated to be 670,000 h.
4. The ID oxide- and hardness-based metallurgical temperature estimates indicate that the Holyrood reheater and primary superheater tubes have been operating below the design conditions.
5. The tube OD deposits comprised mixed sulphates, ($MeSO_4$), where Me = Fe, Na, Ca, and K (major phase) and minor amounts of aluminum phosphate ($AlPO_4$). Primary superheater tube No. 64 experienced negligible (≤1%) wall thinning, whilst reheater tube No. 44 from platen 34 experienced only minor oil ash corrosion of the tube OD surfaces (i.e., up to 5% wall thinning). The maximum metal temperature estimates of these two tubes were well below the critical temperature range in which oil ash corrosion takes place (593ºC to 704ºC or 1100ºF to 1300ºF).
6. In contrast, reheater tube No. 49 from platen 22 experienced mild oil ash corrosion of the tube OD surface (up to 18% wall thinning). The maximum metal

temperature estimates of this tube were at the lower end of the critical temperature range in which oil ash corrosion takes place.

7. Minor concentrations (1-2 wt%) of vanadium were detected in the oil ash deposits, but this was accompanied by 1-2 wt% magnesium. Molten slag complexes containing vanadium, sodium, and sulphur have the potential to cause accelerated high temperature corrosion, but this damage can be mitigated by the addition of magnesium compounds to the fuel to promote the formation of high melting magnesium vanadate complexes.
8. In addition to general wall thinning associated with ID oxidation and OD oil ash corrosion, the three PSH and RH tubes displayed general microstructural aging (carbide coarsening) that is considered normal for Cr-Mo alloy boiler tubes after 153,000 hours of service. Aside from these features, no other boiler tube material damage mechanisms (e.g., creep, fatigue, erosion) were identified on any of the examined sections.

2.0 INTRODUCTION

In October 2016, the Holyrood Thermal Generating Station conducted ultrasonic (UT) measurements on selected reheater and primary superheater tubes of the Unit 3 boiler to determine the tube wall thickness and ID oxide thickness [1,2]. At the same time, tube samples were removed for metallurgical assessment and residual life estimation. The three (3) tube sections, identified in Table 1, were forwarded to Kinectrics for detailed examination.

The three tube samples were subjected to wall thickness measurements, microstructural examination, and chemical analysis. Tube metal temperatures were estimated using two methods and residual life estimates were made using variations of a basic technique based on wall thinning measurements.

Holyrood TGS burns low sulphur (0.7%) No. 6 heavy fuel oil that is delivered by tankers to an adjacent marine terminal. Unit 3 was commissioned in 1980 and, at the time of this outage, had accumulated approximately 157,000 boiler firing hours. Design data provided by Babcock & Wilcox for the three tubes examined in this report are presented in Table 1 [1-3]. It was reported that only the water circuit and economizer tubes had been chemically cleaned in the Unit 3 boiler; no superheater or reheater tubes have ever been chemically cleaned [3]. In addition, none of the tube sections examined in this report have been previously replaced.

3.0 EXAMINATIONS

The metallurgical investigation and analysis of the tube sections comprised the following activities:

1. Visual and stereoscopic examinations,
2. Chemical analysis of tube alloys,
3. Chemical analysis of OD oil ash deposits and scales,
4. Tube sectioning for removal of metallurgical specimens,
5. Removal of ash deposits and visual examination of tube OD metallic surfaces

6. Microstructural examination of polished cross-section specimens using optical and scanning electron microscopes for evaluation of tube wall thickness, ID oxide thickness, and carbide distribution,
7. ID oxide- and hardness-based estimates of tube metal temperatures, and
8. Estimates of residual creep life using analytical methods historically developed by Ontario Hydro Research Division (OHRD) and its derivatives.

All work was performed in accordance with the ISO 9001 procedures of Kinectrics Inc.

4.0 RESULTS

4.1 Chemical Analysis

Samples of the tube alloys were submitted for chemical analysis by inductively-coupled plasma mass spectroscopy (ICP-MS) for metals and LECO combustion for carbon and sulphur. The results, presented in Table 2, confirmed the reported composition of the tube alloys indicated in Table 1.

4.2 Visual and Macroscopic Examination

As-received photographs of the three tube sections submitted for metallurgical analysis are presented in Figures 1 to 4. Each tube section was approximately 12 inches long. The tube labelling information is summarized in Table 1. The orientation of the tubes (i.e., top/bottom, east/west) was not marked on any of the tubes. Note that PSH tube sample K-700390-TUBE-0001 was not labelled correctly. The correct identification information for this tube sample is presented in Table 1 [3].

The tube cross sections (cut ends) did not reveal any localized areas of severe wall thinning. All three tubes were covered in thick oil ash deposits. The deposits were thickest on reheater tube No. 49, and thinnest for primary superheater tube No. 64. The deposits were generally thicker on one side of each reheater tube and thinnest on the opposite side. In contrast, the deposits on the superheater tube did not display as great of a variation in thickness. Typically, fuel ash deposits on boiler tubes are heaviest on the inlet sides of boiler tubes and thinnest on the outlet sides. For the purpose of this analysis, the side of each tube that displayed the thickest deposits (inlet side) was labelled as 0º.

Visual examination of the coal ash deposit revealed at least three distinct layers: a hard and porous top layer, pink and yellow in colour, a dark gray inner layer adjacent to the base metal, and an intermediate layer tightly adhered to both the top and bottom layers and dull gray in colour. As indicated in Figures 5 to 7, a more complete removal of the oil ash deposits was accomplished for one half of each submitted tube section by carefully grit blasting the tube OD surfaces down to the bare metal. The exposed tube surfaces were then visually examined. All three tube OD surfaces were macroscopically rough, but no pitting, holes, flat spots, deformation (e.g., blisters), grooves, or cracks were observed on any of the cleaned sections.

Prior to grit blasting, samples of the oil ash deposits were removed using a chisel as much as practicable and submitted for chemical analysis by inductively-coupled plasma mass spectroscopy (ICP-MS) and X-ray diffraction (XRD). The analysis results are presented in Tables 3 and 4. The tube OD deposits comprised mixed sulphates, ($MeSO_4$), where Me = Fe, Na, Ca, and K (major phase) and aluminum phosphate ($AlPO_4$ – minor phase). Trace amounts of silica/quartz (SiO_2) and hematite (Fe_2O_3) were also detected.

4.3 Examination of Tube Cross Sections

Prior to grit blasting the OD surfaces, cross-sections were cut out of the middle of each tube sample. For RH tube sample K-700390-TUBE-0003, the ring cross-section was taken from the SA213-T11 side of the weld. These specimens were mounted, polished, and examined by optical and scanning electron microscopy. Figures 8 to 10 display overall images of the mounted and polished cross-section specimens.

Measurements of tube wall thickness based on the measurements of Figures 8 to 10 are presented in Table 5. Wall thinning rates, *K*, were calculated according to the following equation:

$$K = \frac{W_{\max} - W_{\min}}{W_{\max} \times t} \qquad (1)$$

where *t*, the time in service was taken as 153,000 h and W_{max} was taken as the minimum wall thickness (MWT), Table 1. As shown, the wall thinning rates range from ~6.5 x 10^{-8}/h to ~1.2 x 10^{-6}/h. The wall thinning rates for the two RH tubes were approximately 5x to 18x higher than the rate for the PSH tube. The maximum tube wall wastage or wall-thinning (18%), was associated with RH tube No. 49.

4.3.2 Steam Side Oxide

Total steam side oxide thickness measurements were made at four circumferential positions, spaced 90º apart, Table 6. Generally the ID oxide thickness was greater for the two RH tubes, compared to the PSH tube. Figures 11 to 13 provide representative examples of the duplex oxide layer microstructure observed for each of the three tubes.

Representative optical micrographs of the oil ash deposits on each of the three tube sections are presented in Figures 14 to 16. These images reveal the multi-layered nature of the OD surface deposits.

Figures 17 to 19 are SEM images illustrating the general microstructure of the RH and PSH tube alloys. All three tubes displayed carbide coarsening both within the grains and at the alloy grain boundaries; very little evidence of the original pearlitic microstructure remained in these specimens. There was no evidence of creep void formation.

4.4 Tube Alloy Hardness Measurements

Vickers micro hardness measurements were obtained from the tube ID, mid-wall, and OD positions at four circumferential positions spaced 90º apart. The results of these hardness measurements are presented in Table 7.

5.0 DISCUSSION

5.1 Tube Metal Temperature Estimations

The creep life of high temperature components is critically dependent on local metal temperature. For boiler tubes, local metal temperatures can vary considerably from top-to-bottom, from one platen to another, and are not expected to remain constant throughout the life of the plant, due to load fluctuations and other factors such as steam-side oxide scale growth during operation. Analysis methods have been historically developed by the former Ontario Hydro Research Division and its derivatives, and others, to estimate the "equivalent" or "mean" metal temperatures and associated residual creep lives by quantitative evaluation of in material property changes after long term service-exposure [4-14]. These temperature estimation models are essentially time-temperature correlations, in various parametric forms, which require a knowledge of certain material-specific calibration constants for practical application. When the calibration constants and exposure time (i.e., boiler fired hours) are known, the equivalent metal temperature can be estimated, based on changes in material properties, such as steam-side oxide thickness and residual metal strength (hardness).

5.1.1 Steam Side Oxide Thickness-Based Estimates

Various quantitative expressions exist to estimate tube metal temperature from steam-side oxide thickness [4-14] for low Cr (Cr<3%) alloy steels. No particular technique has proven to be more accurate than the rest [7] though the techniques proposed by Laborelec [4,10] and Aptec [5] have been favoured in the former Ontario Hydro Research Division and its derivatives [9-11]. In this assessment, the Laborelec expression for tube metal temperature was employed.

As per the Laborelec technique, tube metal temperature is estimated by the following basic equation:

$$T(^{o}C) = \frac{A}{B + \log t - 2\log(0.42x)} \tag{2}$$

where *t* is the operating hours, *x* is the steam-side oxide thickness in mm, and *A* and *B* are model constants. The best fit model constants for 1Cr-1/2Mo and 2-¼Cr-1Mo steels are as indicated in the table below [10].

Material	**A**	**B**
<u>1% Cr 0.5% Mo</u>		
T≤585ºC	7380	2.23
T>585ºC	48333	49.877
<u>2.25% Cr 0.5% Mo</u>		
T≤595ºC	7380	1.98
T>595ºC	48333	49.2

On the basis of 153,000 boiler firing hours [3], and the respective oxide thickness measurements obtained at the various locations identified in Table 6, corresponding estimates of the tube metal temperature were calculated using Equation (2) and the results are presented in Table 8. One of the uncertainties with this method of temperature estimation is the difficulty in ensuring that the examined oxide layer is intact at the measurement location. Care was taken during the specimen cutting and polishing operations to minimize possible damage to the oxide layer. In addition, multiple measurements were taken at each analysis location and averaged to reduce the possibility that localized oxide damage could skew the results. In Table 8, temperature estimates are reported for both the average and maximum oxide thickness at each location.

5.1.2 Tube Alloy Hardness-Based Estimates

An alternative approach for estimating tube metal temperatures is to correlate "mean" metal operating temperatures with hardness changes, which occur primarily as a result of carbide precipitation and growth (microstructural coarsening) [7,14]. One such correlation for low alloy steels makes use of the Larson-Miller parameter, *P*:

$$Hardness(HV) = 961.7 - 2.0669 \times 10^{-2} P \tag{3}$$

where

$$P = T(20 + \log t) \tag{4}$$

In these expressions, hardness is measured using the Vickers scale, *t* is service time in hours, and *T* is absolute temperature, in degrees Rankine, ºR (ºR = ºF + 460). As indicated in Figure 20, the constants in Equation (3) are primarily dependent on the initial pre-service hardness of the tube alloy, [14]. The constants used in equation (3) correspond to 2¼Cr – 1Mo steel. The corresponding expression for 1Cr-1/2Mo or 1 ¼ Cr-1Mo steels is:

$$Hardness(HV) = 595.453 - 1.2603 \times 10^{-2} P \tag{5}$$

As shown in Table 8, solving equations (3) to (5) for the Holyrood boiler tubes yielded a range of temperatures from 476ºC to 501ºC (888ºF to 933ºF) for the primary superheater tube No. 64; 582ºC to 600ºC (1080ºF to 1113ºF) for reheater tube No. 49; and 472ºC to 481ºC (882ºF to 898ºF) for reheater tube No. 44.

Given the possible errors involved in measurement, and the inherent variability in temperature prediction from one model to another, the estimates based on metal hardness were considered to be in reasonable agreement with the values calculated on the basis of steam-side oxide thickness. The ID oxide- and hardness-based metallurgical temperature estimates shown in Table 8 indicate that the Holyrood reheater and primary superheater tubes have been operating below the design conditions, Table 1.

5.2 Remaining Life Calculations

The established method for residual creep life prediction of steam tubing, developed by OHRD [13], involves the relationship.

$$t_{rn} = \frac{1}{K}\left[1 - \left\{K(n-1)t_{ro} + 1\right\}^{\frac{1}{1-n}}\right] \qquad (6)$$

where t_{rn} = service life
K = wall thinning rate
n = creep stress-rate index (taken as 4)
t_{ro} = creep life in absence of wall thinning

5.2.1 The t_{ro} Term

To determine t_{rn} using this equation, it is necessary to obtain a value for t_{ro}. As noted in [13], the most valid method would be to conduct an accelerated creep rupture test on the actual tube material to determine t_{rn} and hence obtain t_{ro}. In the absence of actual creep rupture test data for the material of interest, an alternative approach involves the use of published data for the tube alloy. In each case, the maximum estimated temperatures from Table 8 were used and the stress was the mean diameter hoop stress, i.e.:

$$\sigma = \frac{PDm}{2w} \qquad (7)$$

Where P = pressure, Dm = mean diameter and w = wall thickness. For the Holyrood tubes, values for P were conservatively taken as the design pressures listed in Table 1 (not the operating pressures) and Dm was determined from the nominal O.D. of the tubes and the MWT values listed in Table 1. The hoop stress values thus determined are listed in Table 9.

5.2.2 Larsen-Miller Approach

The Larsen-Miller parameter is given by the equation:

$$LMP = T(20 + \log t_r) \times 10^{-3} \qquad (8)$$

Where t_r is the creep rupture life, T the temperature in ºR and the LMP value is stress-dependent. A representative Larsen-Miller plot for 2-1/4Cr-1Mo (T22) steel is given in Figure 21.

5.2.3 I.S.O. Parametric Approach

In the I.S.O. representation, creep rupture life t_R is given by the expression [10,11]:

$$P(\sigma) = \frac{\log t_R - A}{(T - B)^n} \tag{9}$$

Where T is the temperature in ºC, A and B are material constants and σ is the stress in MPa. The graphical relationship between σ and $P(\sigma)$ is approximated by:

$$P = K_1 + K_2\sigma + K_3\sigma^2 + K_4 4\sigma^3 \tag{10}$$

The values of A, B, and K for 1Cr-1/2Mo and 2-¼Cr-1Mo steels are given in Table 10 [10].

Using the Larsen-Miller and I.S.O. methods, t_{ro} values were determined for the three Holyrood boiler tube samples and the results are presented in Table 11. In general, the I.S.O. derived t_{ro} values are lower than those from the Larsen-Miller method, in some cases by nearly two orders of magnitude. This observation is consistent with the trends previously reported by OHRD and its derivatives when comparing these two methods of creep life estimation [10].

Using Equation (5), t_{rn} values were determined using both sets of t_{ro} values from Table 11. The residual lives are then t_{nr} – 153,000 h; the results are given in Table 12. Clearly, the I.S.O.-derived t_{ro} values lead to somewhat lower predicted lives, though the difference is only significant at short remaining lives. This too, is consistent with the trends previously reported by OHRD and its derivatives when comparing these two methods of creep life estimation [10]. Note that there is some conservatism built into the remaining life estimates given in Table 12 because (1) the boiler design pressures were used, which are higher than the actual operating pressures and (2) the maximum tube metal temperature estimates were used from Table 8. Finally, it should be remembered that the estimated residual creep rupture lives correspond to the historical operating conditions for the Holyrood Unit 3 boiler (i.e., average tube metal operating temperatures, pressures, and wall thinning rates). Any future changes in boiler operating conditions may result in actual tube creep rupture lives that are different from those given in Table 12.

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Table 1 – Identification of Holyrood Unit 3 Boiler Tube Samples

Kinectrics Tube ID	K-700390-TUBE-0001	K-700390-TUBE-0002	K-700390-TUBE-0003
Location	PSH 10th Floor	Reheat 9th Floor	Reheat 9th Floor
Description	Down Pass Top Tube	-	Below feet
Tube No.	64	49	44
Platen No.	48	22	34
Reported Material	SA213-T2 (½Cr-½Mo)	SA213-T22 (2¼Cr-1Mo)	SA213-T11/T22 (Weld) (1¼Cr-½ Mo / 2¼Cr-1Mo)
M.W.T. (Inches)	0.338	0.180	0.180
OD (Inches)	2-½	2-¼	2-½
Tube Design Temperatures and Pressures [3]			
Design Pressure (psig)	2200	650	650
Operating Pressure (psig)	1895	536	536
Unbalanced Conditions. Max Tube Temp. O.D.	560ºC 1040ºF	602ºC 1115ºF	578ºC 1073ºF
Balanced Conditions – T. Av. Norm.	533ºC 993 ºF	596ºC 1104 ºF	572ºC 1061 ºF

Table 2 – Chemical Analysis Results (wt%) for Unit 3 Boiler Tube Alloys

Element	Tube 1	SA213-T2	Tube 2	SA213-T22	Tube 3	SA213-T11
Iron	Bal	Bal	Bal	Bal	Bal	Bal
Carbon	0.17	0.10 - 0.20	0.15	0.15 max.	0.15	0.15 max.
Chromium	0.64	0.50 - 0.81	2.04	1.90 - 2.60	1.16	1.00 - 1.50
Molybdenum	0.536	0.44 - 0.65	0.911	0.87 - 1.13	0.493	0.44 - 0.65
Manganese	0.39	0.30 - 0.61	0.373	0.30 - 0.60	0.452	0.30 - 0.60
Silicon (as Si)	0.207	0.10 - 0.30	0.403	0.50 max.	0.804	0.50 - 1.00
Sulphur	0.035	0.045 max.	0.22	0.030 max.	0.21	0.030 max.
Phosphorus	0.0257	0.045 max.	0.0885	0.030 max.	0.0251	0.030 max.
Nickel	0.096	-	0.076	-	0.05	-
Copper	0.166	-	0.0658	-	0.063	-
Aluminum	0.024	-	0.095	-	0.052	-
Antimony	0.018	-	0.037	-	0.024	-
Titanium	0.0004	-	0.0007	-	0.003	-
Niobium	<0.005	-	<0.005	-	<0.005	-
Bismuth	<0.003	-	<0.003	-	<0.003	-
Arsenic	<0.001	-	<0.001	-	<0.001	-
Cerium	<0.001	-	<0.001	-	<0.001	-
Zirconium	<0.0005	-	<0.0005	-	<0.0005	-
Lead	<0.0005	-	<0.0005	-	<0.0005	-
Boron	<0.0003	-	<0.0003	-	<0.0003	-
Silver	<0.0003	-	<0.0003	-	<0.0003	-
Zinc	<0.0001	-	<0.0001	-	<0.0001	-
Tantalum	0.013	-	0.012	-	0.012	-
Tungsten	0.021	-	0.02	-	0.023	-
Cobalt	0.008	-	0.009	-	0.006	-
Tin	0.01	-	0.003	-	0.004	-
Vanadium	0.002	-	0.024	-	0.011	-

Table 3 – Chemical Analysis Results (wt%) for Unit 3 Boiler Tube OD Deposits

Analyte	Tube 0001		Tube 0002		Tube 0003	
	ppm	wt%	ppm	wt%	ppm	wt%
Sulphur	153000	30.19%	131000	26.22%	150000	31.00%
Iron	77000	15.19%	37100	7.43%	47800	9.88%
Calcium	54000	10.66%	34900	6.99%	59700	12.34%
Sodium	50600	9.98%	111000	22.22%	64600	13.35%
Potassium	30900	6.10%	36300	7.27%	34700	7.17%
Zinc	29500	5.82%	27500	5.50%	20300	4.19%
Phosphorus	29500	5.82%	25700	5.14%	21400	4.42%
Silicon (as Si)	27100	5.35%	41200	8.25%	30700	6.34%
Aluminum	15500	3.06%	27600	5.52%	22000	4.55%
Vanadium	9230	1.82%	6940	1.39%	6440	1.33%
Magnesium	7540	1.49%	5640	1.13%	7560	1.56%
Barium	6820	1.35%	2560	0.51%	6430	1.33%
Nickel	6690	1.32%	3270	0.65%	3480	0.72%
Lead	1950	0.38%	1920	0.38%	1690	0.35%
Copper	1850	0.37%	2510	0.50%	2270	0.47%
Strontium	837	0.17%	689	0.14%	1030	0.21%
Chromium	835	0.16%	798	0.16%	718	0.15%
Manganese	789	0.16%	497	0.10%	726	0.15%
Arsenic	788	0.16%	547	0.11%	520	0.11%
Titanium	729	0.14%	752	0.15%	730	0.15%
Bismuth	491	0.10%	398	0.08%	305	0.06%
Molybdenum	465	0.09%	170	0.03%	337	0.07%
Cobalt	261	0.05%	153	0.03%	172	0.04%
Cadmium	116	0.02%	102	0.02%	89.9	0.02%
Tin	93.6	0.02%	85.6	0.02%	51.2	0.01%
Tungsten	51.2	0.01%	15.5	0.00%	19.9	0.00%
Antimony	36.3	0.01%	64.8	0.01%	39.4	0.01%
Zirconium	34.3	0.01%	51.4	0.01%	49.1	0.01%
Boron	29.4	0.01%	17.1	0.00%	17.6	0.00%
Lithium	24.6	0.00%	57	0.01%	27.9	0.01%
Silver	21.6	0.00%	14.9	0.00%	7.98	0.00%
Cesium	3.83	0.00%	1.58	0.00%	2.37	0.00%
Thallium	2.89	0.00%	0.369	0.00%	1.32	0.00%
Selenium	2.4	0.00%	1.19	0.00%	1.4	0.00%
Beryllium	1.37	0.00%	2.77	0.00%	1.41	0.00%
Thorium	1.14	0.00%	1.02	0.00%	1.68	0.00%
Uranium	1.03	0.00%	1.09	0.00%	0.806	0.00%
Mercury	<0.05	-	<0.05	-	<0.05	-
Total Metals	506795	100.00%	499560	100.00%	483920	100.00%

Table 4 – X-Ray Diffraction Analysis Results for Unit 3 Boiler Tube OD Deposits

Kinectrics Tube ID	K-700390-TUBE-0001	K-700390-TUBE-0002	K-700390-TUBE-0003
Major Phases	Anhydrite ($CaSO_4$)	Anhydrite ($CaSO_4$)	Anhydrite ($CaSO_4$)
Minor Phases	Berlinite ($AlPO_4$)	Berlinite ($AlPO_4$)	Berlinite ($AlPO_4$)
Trace		Cristobalite (SiO_2) Quartz (SiO_2)	Cristobalite (SiO_2) Quartz (SiO_2) Hematite (Fe_2O_3)

Table 5 – Measurements of Wall Thinning for Reheater and Primary Superheater Tubes from Holyrood TGS Unit 3

Tube ID	MWT	Circumferential Position	Wall Thickness (mm)							Wall Thinning	Wall Thinning Rate (hrs-1)
			1	2	3	Min	Max	Avg	Wastage (Max.)		
K-700390-TUBE-0001 PSH Tube No. 64 Material: SA213-T2	8.59	0°	8.67	8.67	8.78	8.67	8.78	8.71	-0.08	-1%	-6.46E-08
		90°	8.67	8.67	8.78	8.67	8.78	8.71	-0.08	-1%	-6.46E-08
		180°	8.50	8.52	8.67	8.50	8.67	8.56	0.09	1%	6.49E-08
		270°	8.77	8.87	8.84	8.77	8.87	8.83	-0.18	-2%	-1.41E-07
		All Locations				**8.50**	**8.87**	**8.70**	**0.09**	**1%**	**6.49E-08**
K-700390-TUBE-0002 RH Tube No. 49 Material: SA213-T22	4.57	0°	3.99	4.21	4.30	3.99	4.30	4.17	0.58	13%	8.32E-07
		90°	4.11	3.96	3.75	3.75	4.11	3.94	0.82	18%	1.18E-06
		180°	4.42	4.18	3.88	3.88	4.42	4.16	0.69	15%	9.89E-07
		270°	4.40	4.43	4.51	4.40	4.51	4.45	0.17	4%	2.46E-07
		All Locations				**3.75**	**4.51**	**4.18**	**0.82**	**18%**	**1.18E-06**
K-700390-TUBE-0003 RH Tube No. 44 Material: SA213-T11	4.57	0°	4.45	4.51	4.50	4.45	4.51	4.49	0.12	3%	1.74E-07
		90°	4.34	4.46	4.52	4.34	4.52	4.44	0.23	5%	3.32E-07
		180°	4.68	4.54	4.45	4.45	4.68	4.56	0.12	3%	1.74E-07
		270°	4.36	4.43	4.46	4.36	4.46	4.42	0.21	5%	3.03E-07
		All Locations				**4.34**	**4.68**	**4.48**	**0.23**	**5%**	**3.32E-07**

Wall Thinning (WT,%) $$WT(\%) = \frac{W_{orig} - W_{min}}{W_{orig}}$$

Wall Thinning Rate (K, hr^{-1}) $$K = \frac{W_{orig} - W_{min}}{W_{orig} \times t(hrs)}$$

Table 6 – Steam-Side Oxide Thickness Results for Reheater and Primary Superheater Tubes from Holyrood TGS Unit 3

Tube ID	Circumferential Position	Oxide Thickness (µm)											
		1	2	3	4	5	6	7	8	9	10	Max	Avg
K-700390-TUBE-0001	0º	88.4	85.6	64.3	87.0	37.4	49.9	66.6	49.9	-	-	88.4	66.1
PSH Tube No. 64	90º	63.9	75.2	62.4	80.9	88.0	118.7	-	-	-	-	118.7	81.5
Material: SA213-T2	180º	86.3	150.4	90.1	75.7	77.6	76.7	156.6	108.3	79.0	-	156.6	100.1
0.64Cr-0.54Mo	270º	146.6	133.9	123.0	132.0	89.9	78.0	65.7	73.3	64.3	-	146.6	100.7
K-700390-TUBE-0002	0º	75.8	85.8	128.7	218.8	181.5	197.7	268.6	279.5	-	-	279.5	179.6
RH Tube No. 49	90º	215.7	209.5	222.3	218.5	225.1	222.8	190.2	199.2	200.3	-	225.1	211.5
Material: SA213-T22	180º	176.9	182.6	181.6	183.5	176.2	183.1	172.8	174.6	179.3	-	183.5	179.0
2.0Cr-0.9Mo	270º	195.4	193.5	207.6	201.5	192.9	237.7	231.3	229.5	-	-	237.7	211.2
K-700390-TUBE-0003	0º	166.2	151.9	145.7	149.9	148.0	155.6	162.2	157.5	173.6	-	173.6	156.7
RH Tube No. 44	90º	105.5	118.7	170.5	146.7	162.3	155.6	141.4	139.6	189.9	-	189.9	147.8
Material: SA213-T11	180º	53.0	79.5	187.9	184.6	179.0	144.3	145.8	149.6	-	-	187.9	140.5
1.2Cr-0.5Mo	270º	146.1	177.4	153.2	147.7	219.9	112.1	178.3	123.9	149.5	128.2	219.9	153.6

Table 7 – Vickers Microhardness Measurements (DPH) for Reheater and Primary Superheater Tubes from Holyrood TGS Unit 3

Tube ID	Circumferential Position	Wall Position	Vicker Hardness (DPH)					
			1	2	3	4	5	Avg
K-700390-TUBE-0001 PSH Tube No. 64 Material: SA213-T2	0	ID	156	158	160	155	156	157
		Mid	157	160	155	162	157	158
		OD	152	154	168	161	165	160
	90	ID	154	157	151	149	155	153
		Mid	155	150	155	152	156	154
		OD	152	158	151	153	154	154
	180	ID	164	160	157	158	158	159
		Mid	155	156	159	154	155	156
		OD	170	169	167	159	173	168
	270	ID	164	160	156	166	166	162
		Mid	156	159	150	156	151	154
		OD	168	165	169	165	169	167
K-700390-TUBE-0002 RH Tube No. 49 Material: SA213-T22	0	ID	153	157	155	161	154	156
		Mid	151	145	145	145	149	147
		OD	167	164	158	158	153	160
	90	ID	151	161	155	150	151	154
		Mid	148	147	145	149	152	148
		OD	154	151	152	154	150	152
	180	ID	147	146	147	144	144	146
		Mid	146	150	151	146	151	149
		OD	151	150	149	150	151	150
	270	ID	151	150	150	152	155	152
		Mid	145	143	140	143	144	143
		OD	150	155	147	146	154	150
K-700390-TUBE-0003 RH Tube No. 44 Material: SA213-T11	0	ID	167	169	168	166	177	169
		Mid	174	167	164	169	165	168
		OD	167	174	168	170	170	170
	90	ID	169	170	165	164	165	167
		Mid	160	164	164	169	165	164
		OD	164	170	167	163	168	166
	180	ID	163	166	166	165	167	165
		Mid	166	170	163	163	167	166
		OD	165	165	169	164	169	166
	270	ID	168	161	167	163	170	166
		Mid	168	165	161	163	167	165
		OD	165	168	171	169	167	168

Table 8 – Estimates of Tube Metal Temperature for Reheater and Primary Superheater Tubes from Holyrood TGS Unit 3

Tube	Oxide Technique	Hardness Technique
K-700390-TUBE-0001 PSH Tube No. 64 Material: SA213-T2 0.64Cr-0.54Mo	Based on Avg. Oxide Thickness: 435ºC to 461ºC (816ºF to 862ºF) Based on Max. Oxide Thickness: 453ºC to 490ºC (847ºF to 914ºF)	476ºC to 501ºC (888ºF to 933ºF)
K-700390-TUBE-0002 RH Tube No. 49 Material: SA213-T22 2.0Cr-0.9Mo	Based on Avg. Oxide Thickness: 520ºC to 533ºC (968ºF to 991ºF) Based on Max. Oxide Thickness: 522ºC to 555ºC (972ºF to 1030ºF)	582ºC to 600ºC (1080ºF to 1113ºF)
K-700390-TUBE-0003 RH Tube No. 44 Material: SA213-T11 1.2Cr-0.5Mo	Based on Avg. Oxide Thickness: 474ºC to 482ºC (886ºF to 899ºF) Based on Max. Oxide Thickness: 489ºC to 505ºC (911ºF to 941ºF)	472ºC to 481ºC (882ºF to 898ºF)

Table 9 – Mean Diameter Hoop Stresses

Tube Sample	Stress (MPa)	Stress (psi)
K-700390-TUBE-0001 PSH Tube No. 64 Material: SA213-T2 0.64Cr-0.54Mo	48.5	7036
K-700390-TUBE-0002 RH Tube No. 49 Material: SA213-T22 2.0Cr-0.9Mo	25.8	3738
K-700390-TUBE-0003 RH Tube No. 44 Material: SA213-T11 1.2Cr-0.5Mo	28.9	4189

Table 10 – Relevant I.S.O. Constants [10]

Steel	Temperature Range, ºC	Constants						
		A	B	n	K1	K2	K3	K4
1Cr1/2Mo	480 – 600	13.29	227	1.0	-1.96×10^{-2}	-1.77×10^{-4}	-1.47×10^{-6}	-5.68×10^{-9}
2-1/4Cr1Mo	450 - 600	13.36	227	1.0	-1.58×10^{-2}	-2.62×10^{-4}	-2.28×10^{-6}	-9.18×10^{-9}

Table 11 – Comparison of Calculated t_{ro} Values Based on Maximum Estimated Tube Temperatures

Tube Sample	Larson-Miller (h)	I.S.O. (h)
K-700390-TUBE-0001 PSH Tube No. 64 Material: SA213-T2 0.64Cr-0.54Mo	$2.7x10^7$	$2.2x10^5$
K-700390-TUBE-0002 RH Tube No. 49 Material: SA213-T22 2.0Cr-0.9Mo	$5.8x10^5$	$5.4x10^5$
K-700390-TUBE-0003 RH Tube No. 44 Material: SA213-T11 1.2Cr-0.5Mo	$3.6x10^8$	$1.6x10^6$

Table 12 – Comparison of Boiler Tube Residual Life Predictions (hours)

Tube Sample	Larson-Miller	I.S.O.
K-700390-TUBE-0001 PSH Tube No. 64 Material: SA213-T2 0.64Cr-0.54Mo	6,900,000	63,000
K-700390-TUBE-0002 RH Tube No. 49 Material: SA213-T22 2.0Cr-0.9Mo	111,000	102,000
K-700390-TUBE-0003 RH Tube No. 44 Material: SA213-T11 1.2Cr-0.5Mo	2,400,000	670,000

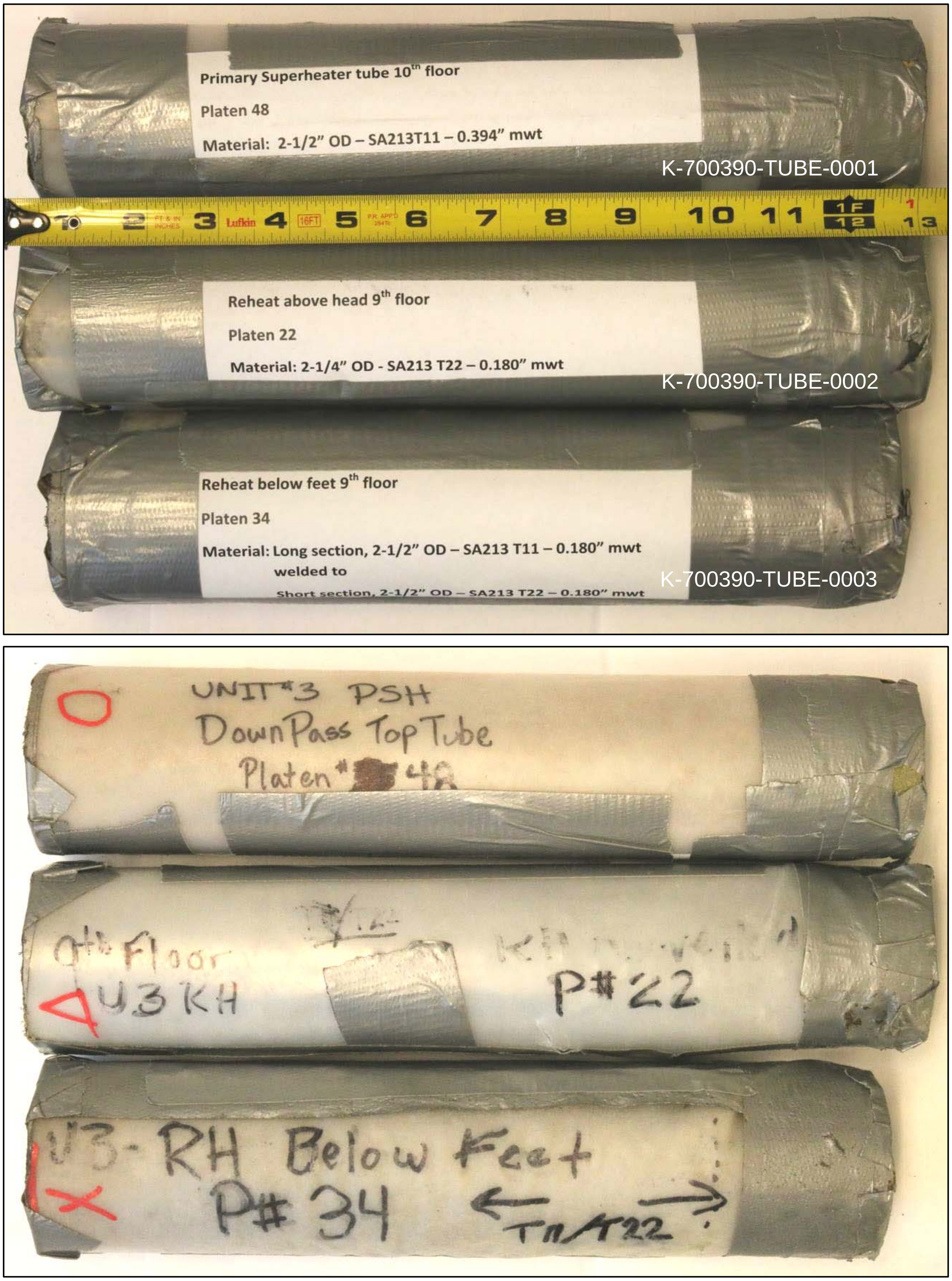


Figure 1. As-received photographs of three N&LP Holyrood Unit 3 boiler tube samples.

Figure 2. Photographs of PSH tube sample K-700390-TUBE-0001. The dashed line indicates the top of the tube.

Figure 3. Photographs of RH tube sample K-700390-TUBE-0002. The dashed line indicates the bottom of the tube.

Figure 4. Photographs of RH tube sample K-700390-TUBE-0003. The dashed line indicates the bottom of the tube.

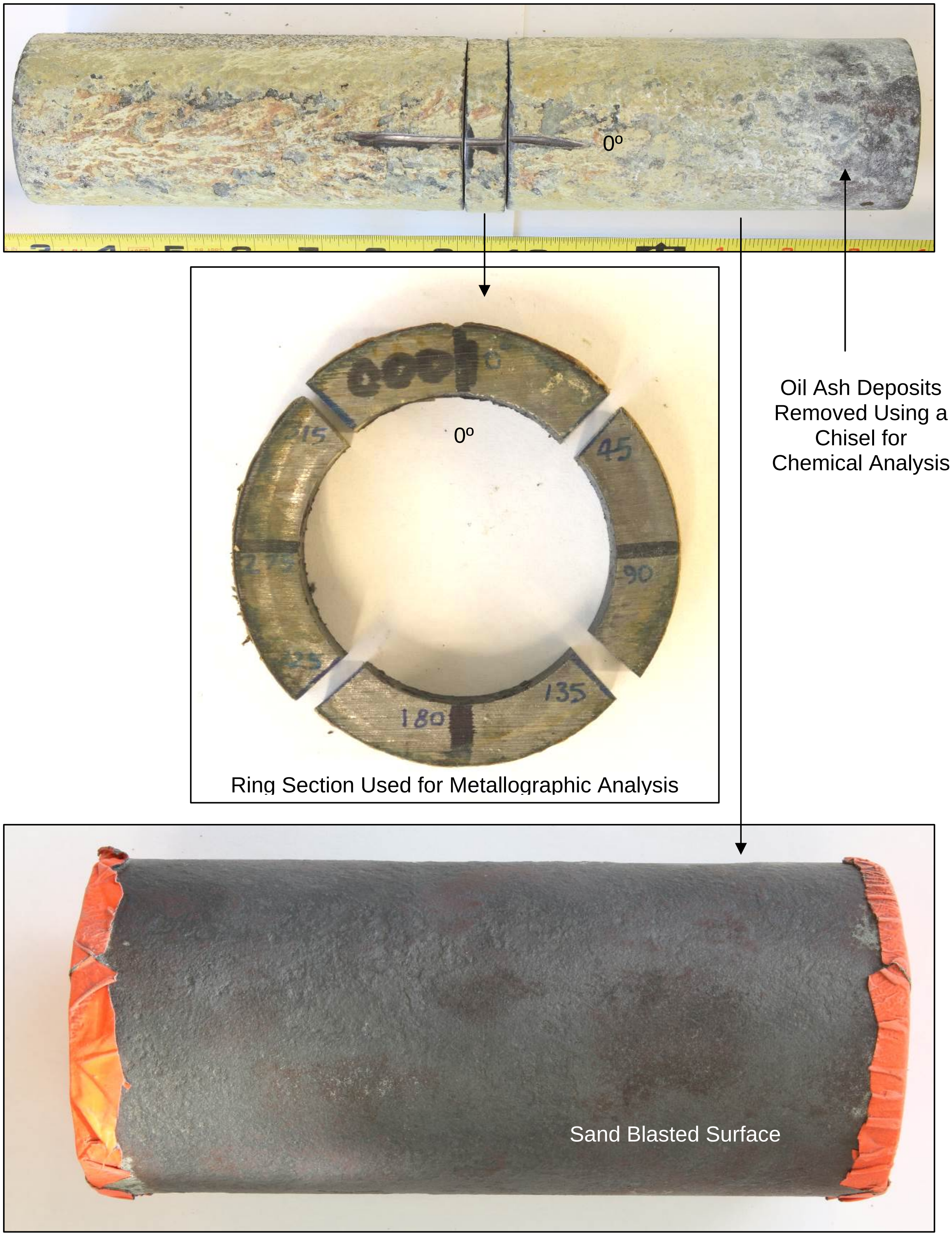


Figure 5. Cutting plan for tube sample K-700390-TUBE-0001. For this sample, 0º is at the top of the tube.

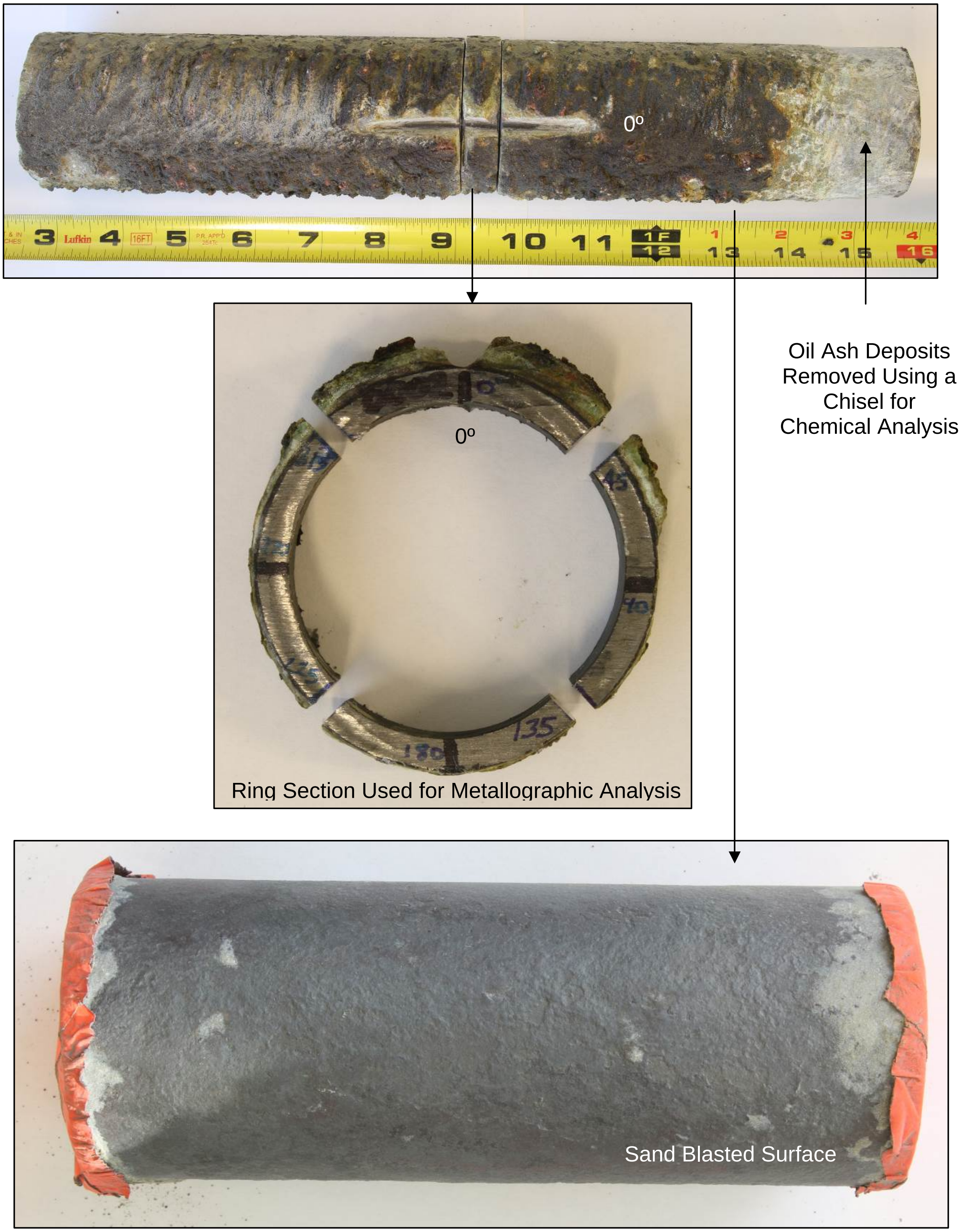


Figure 6. Cutting plan for tube sample K-700390-TUBE-0002. For this sample, 0º is at the bottom of the tube.

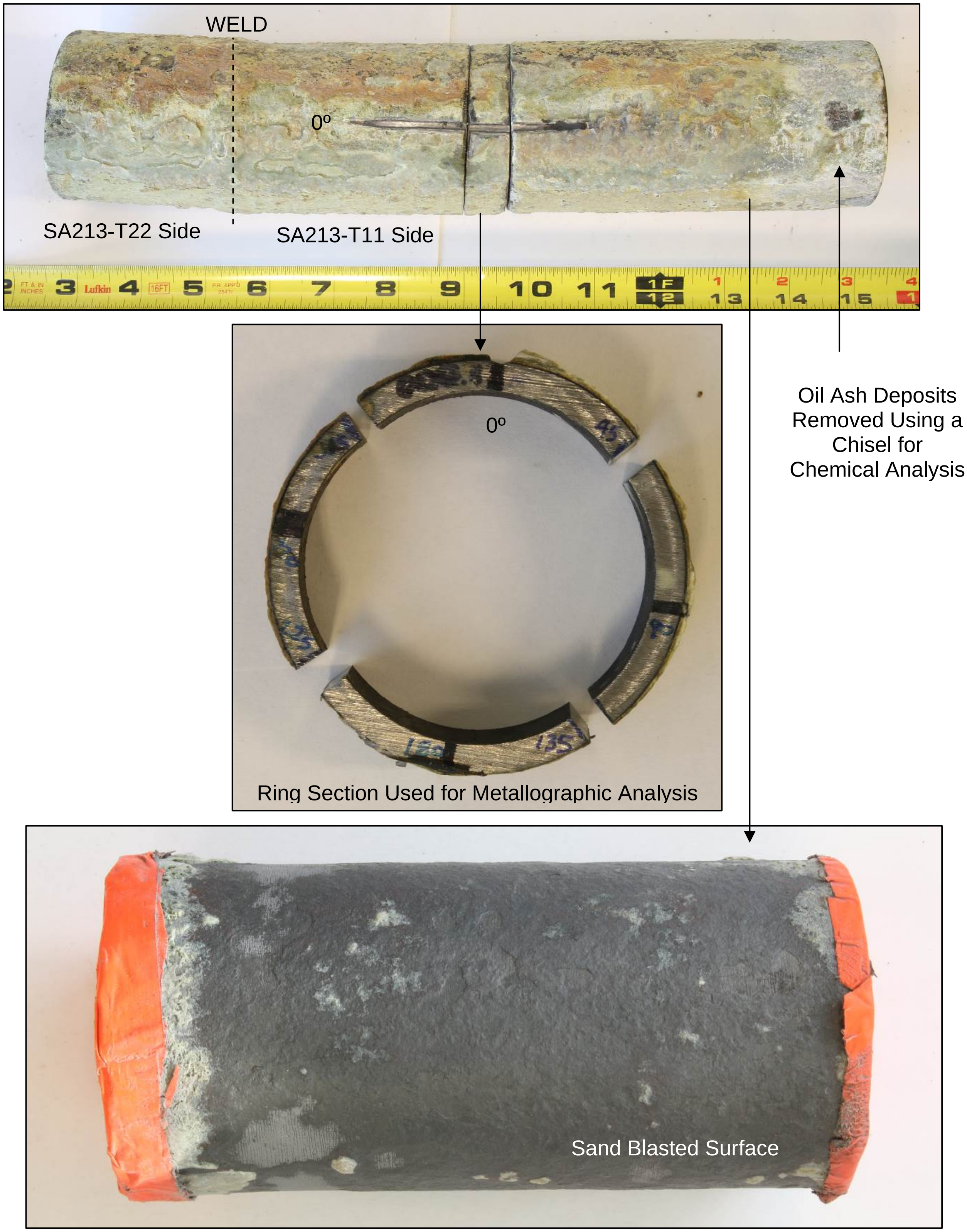


Figure 7. Cutting plan for tube sample K-700390-TUBE-0003. For this sample, 0º is at the bottom of the tube.

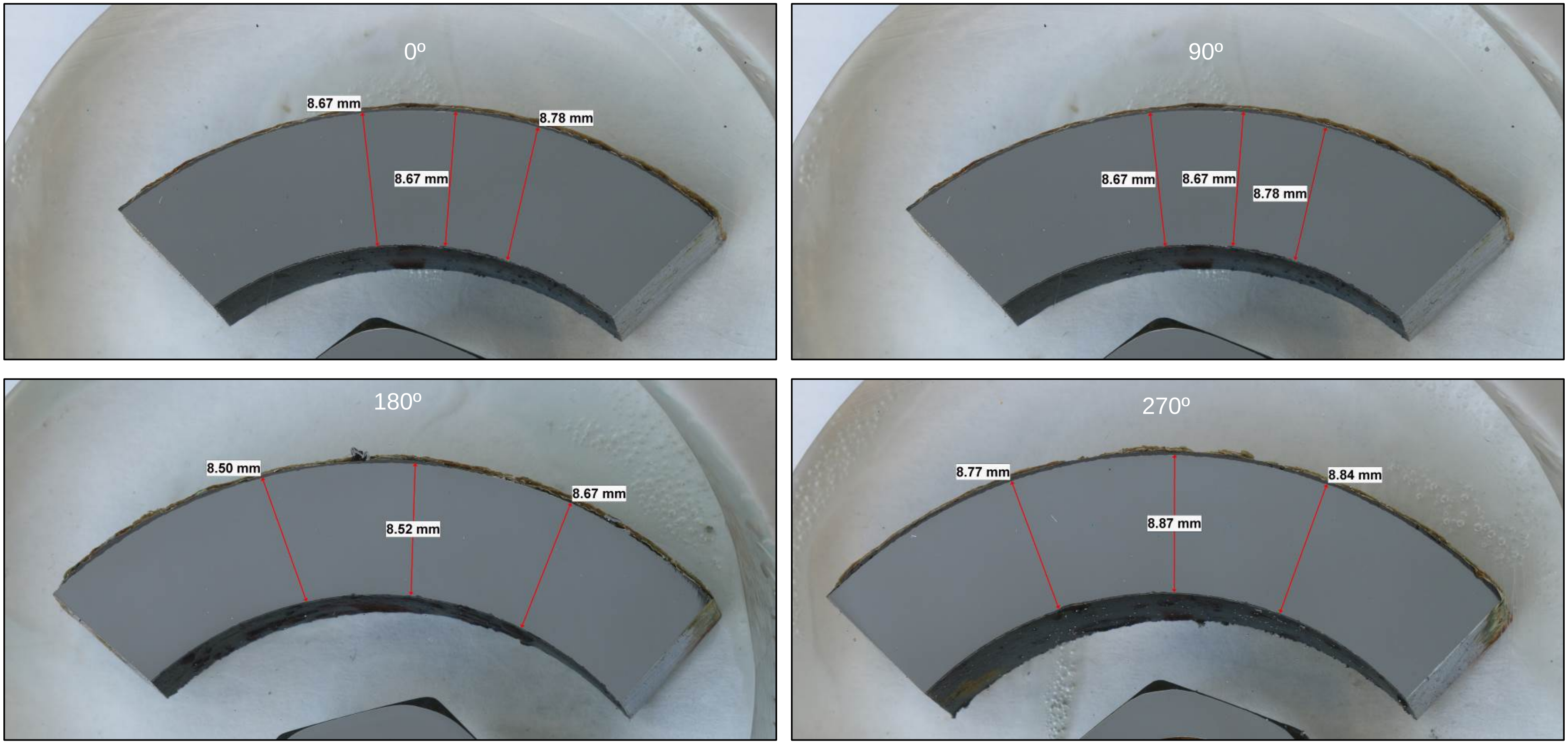


Figure 8. Polished cross-section specimens from K-700390-TUBE-0001.

Figure 9. Polished cross-section specimens from K-700390-TUBE-0002.

Figure 10. Polished cross-section specimens from K-700390-TUBE-0003.

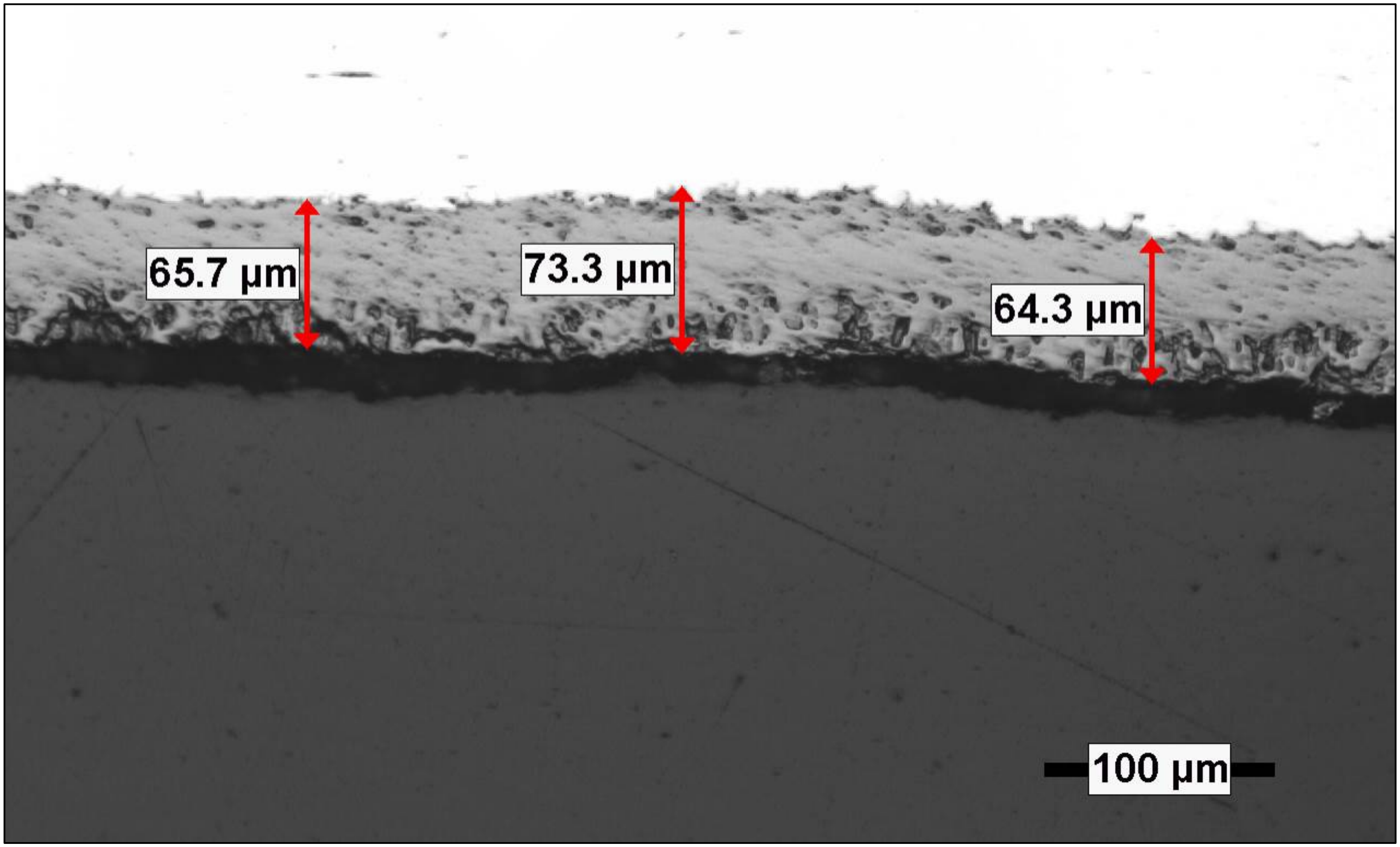


Figure 11. Representative optical micrograph of the ID oxide layer on K-700390-TUBE-0001 at 270º.

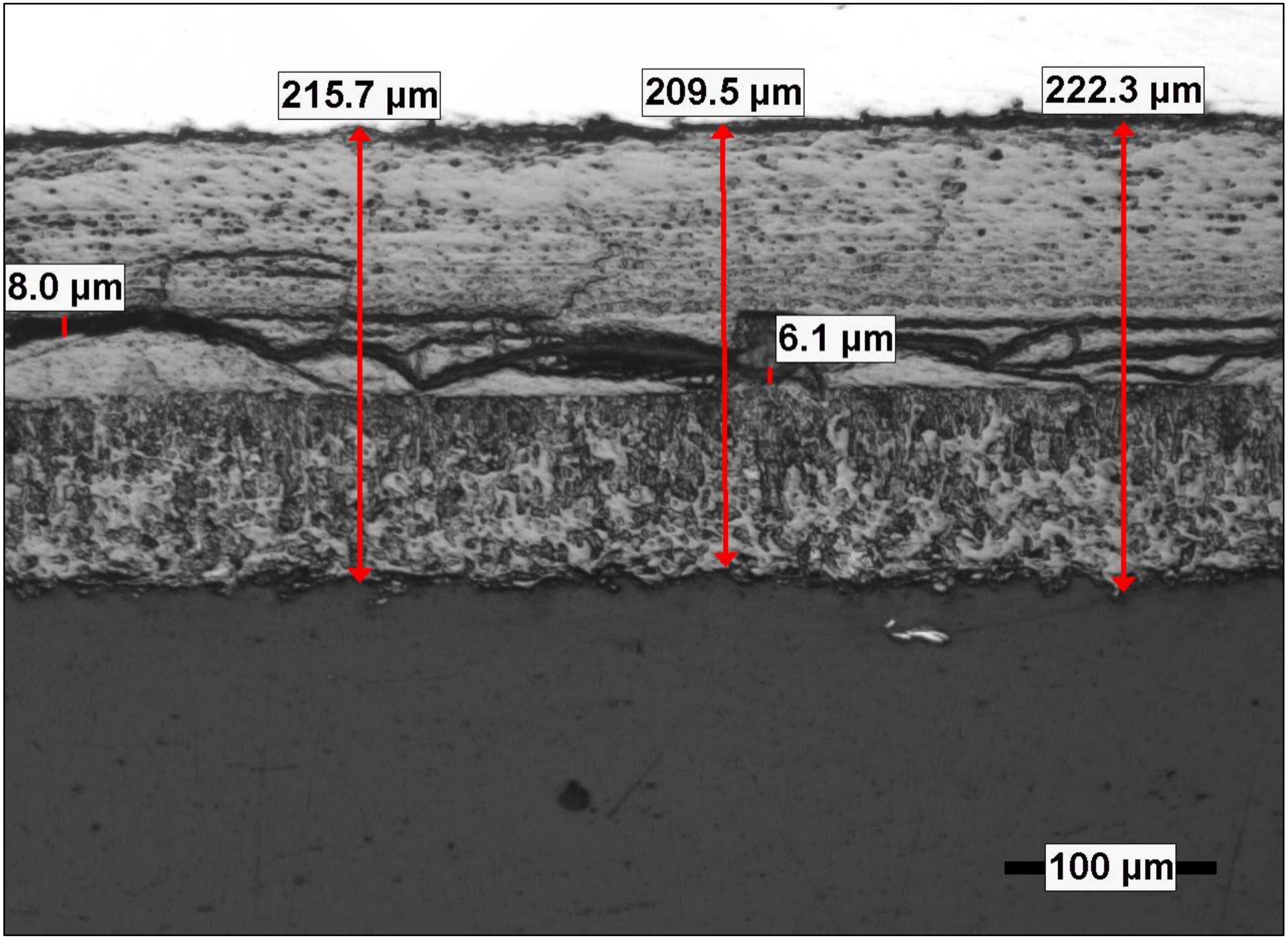


Figure 12. Representative optical micrograph of the ID oxide layer on K-700390-TUBE-0002 at 90º.

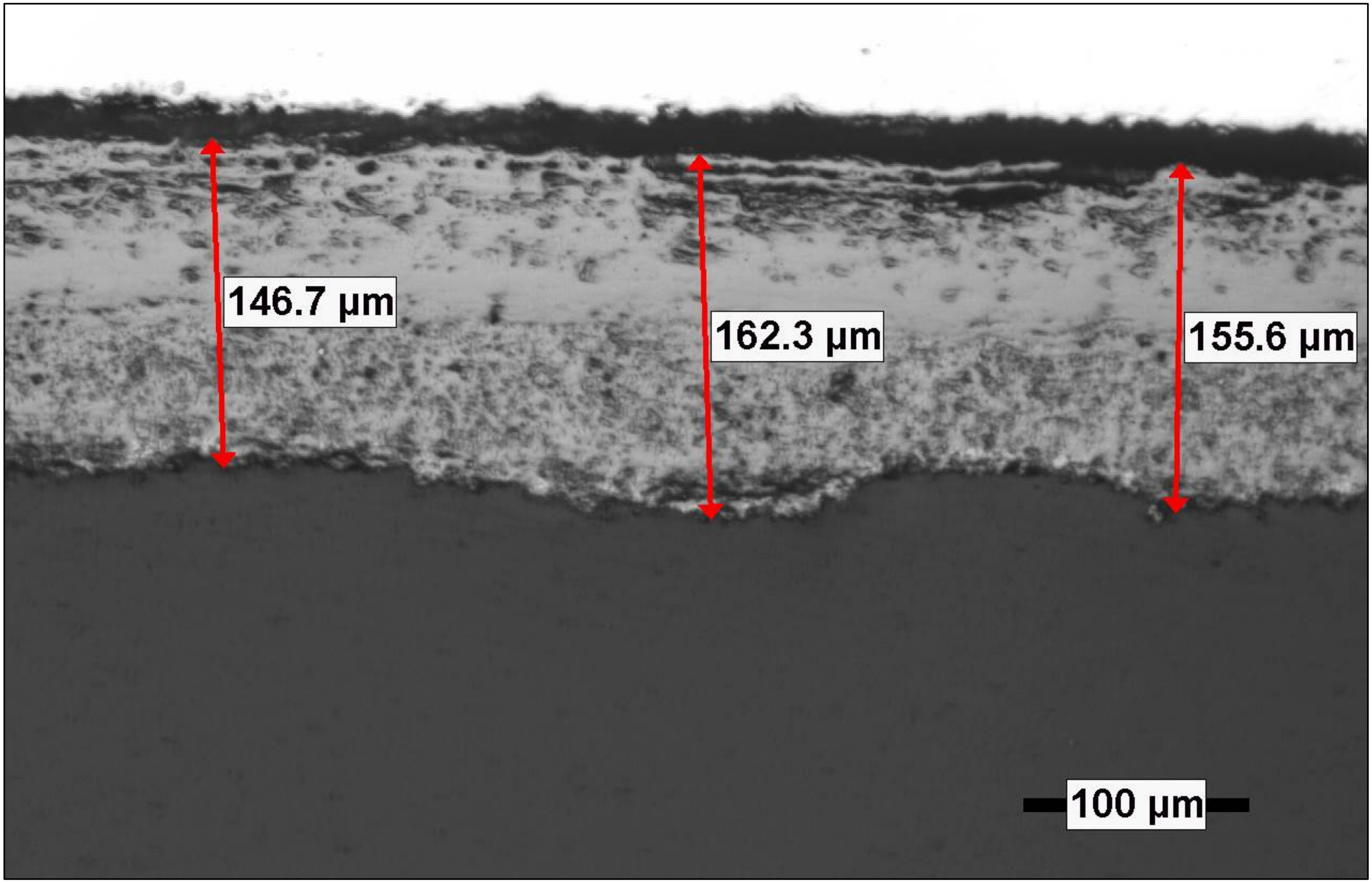


Figure 13. Representative optical micrograph of the ID oxide layer on K-700390-TUBE-0003 at 90º.

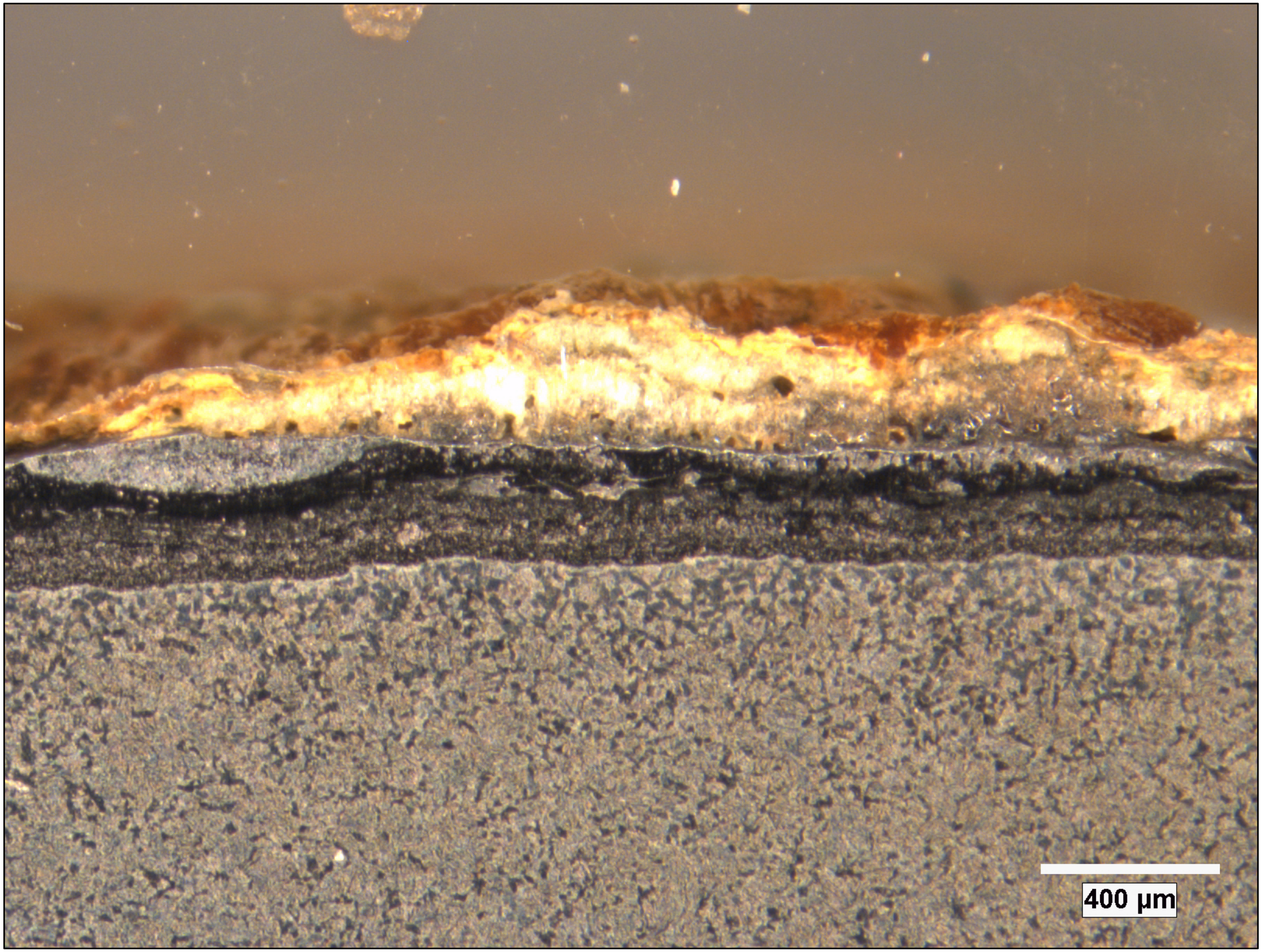


Figure 14. Optical micrograph of the OD oil ash deposit layer on K-700390-TUBE-0001 at 180º.

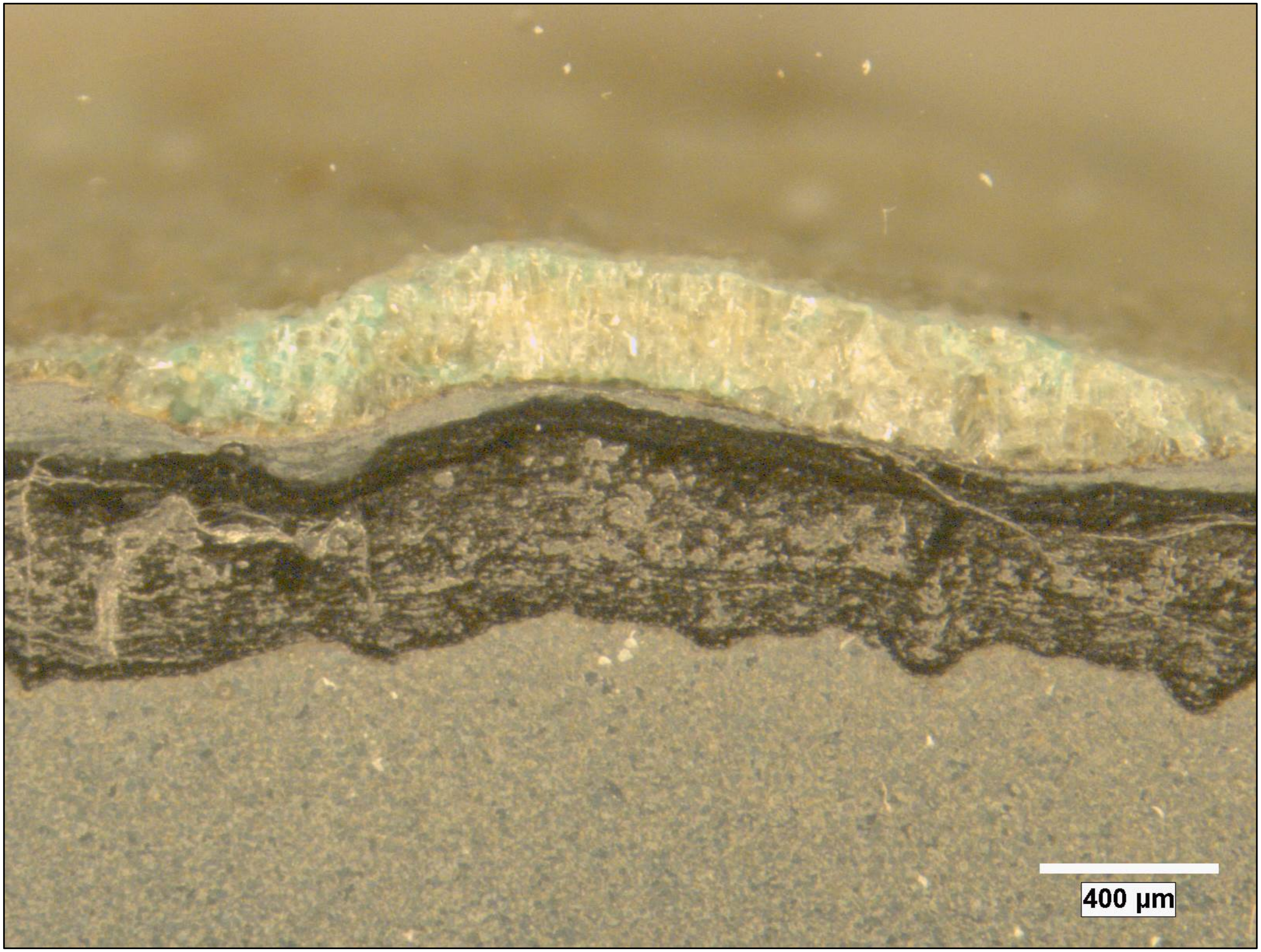


Figure 15. Optical micrograph of the OD oil ash deposit layer on K-700390-TUBE-0002 at 180º.

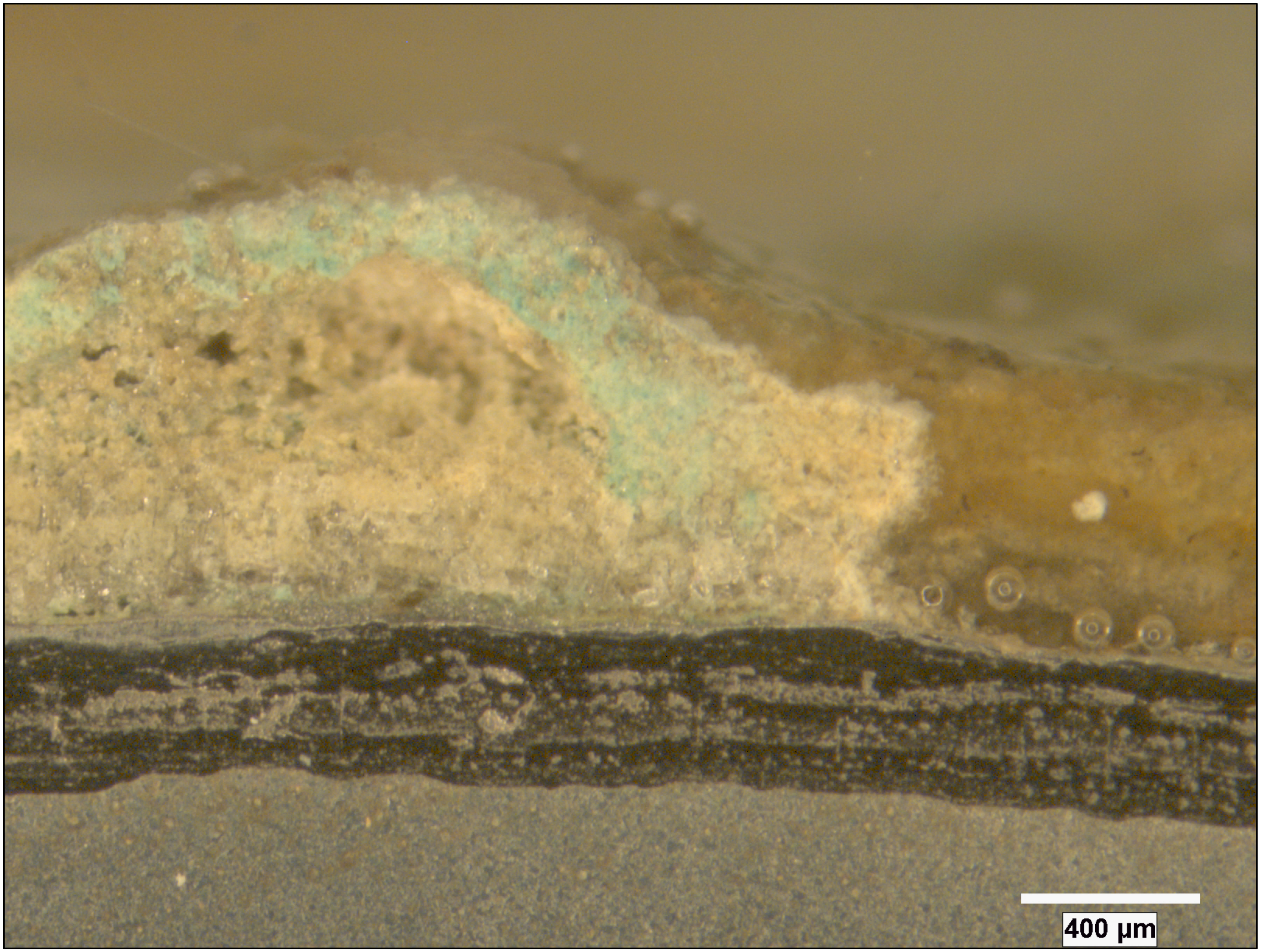


Figure 16. Optical micrograph of the OD oil ash deposit layer on K-700390-TUBE-0003 at 180º.

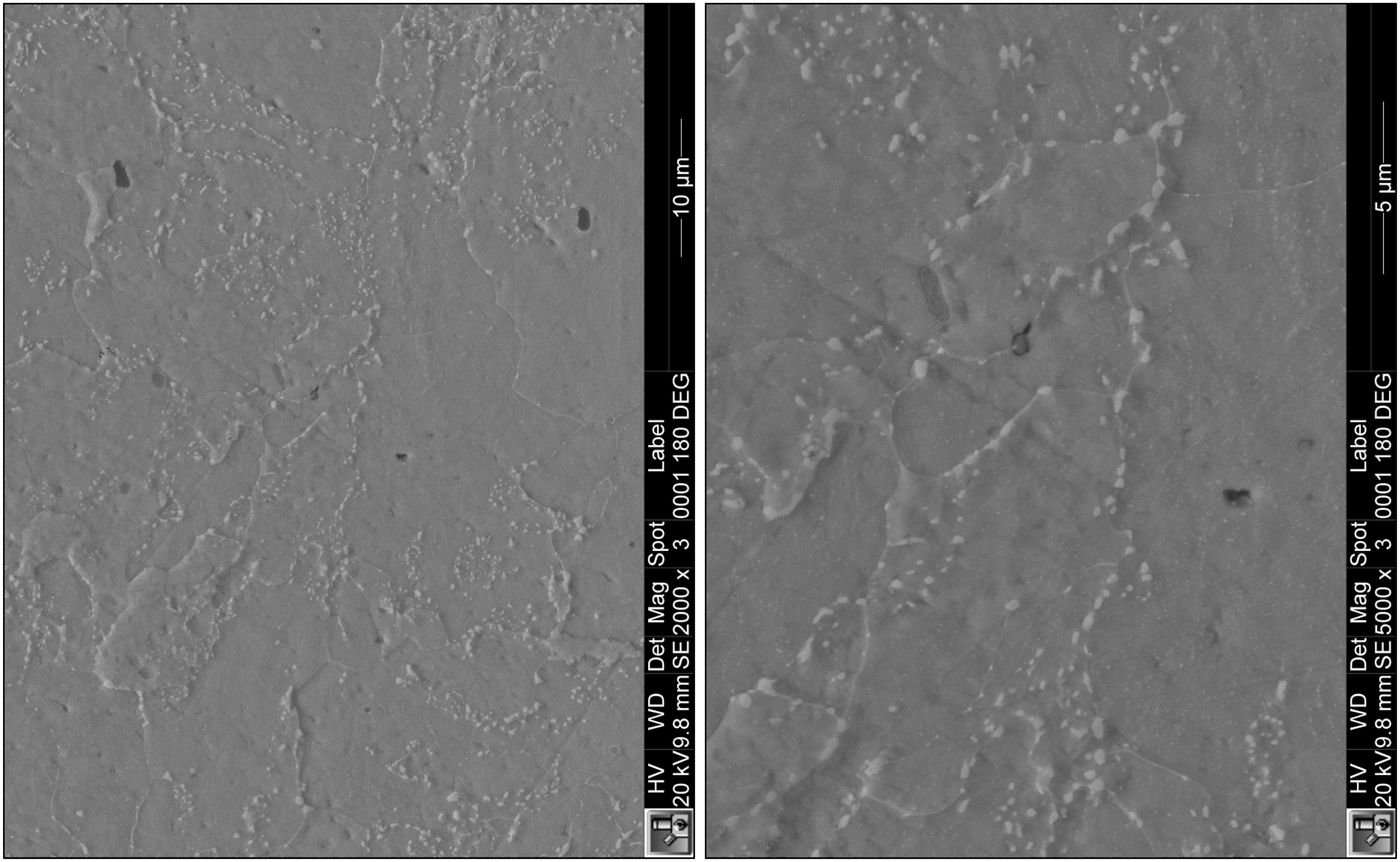
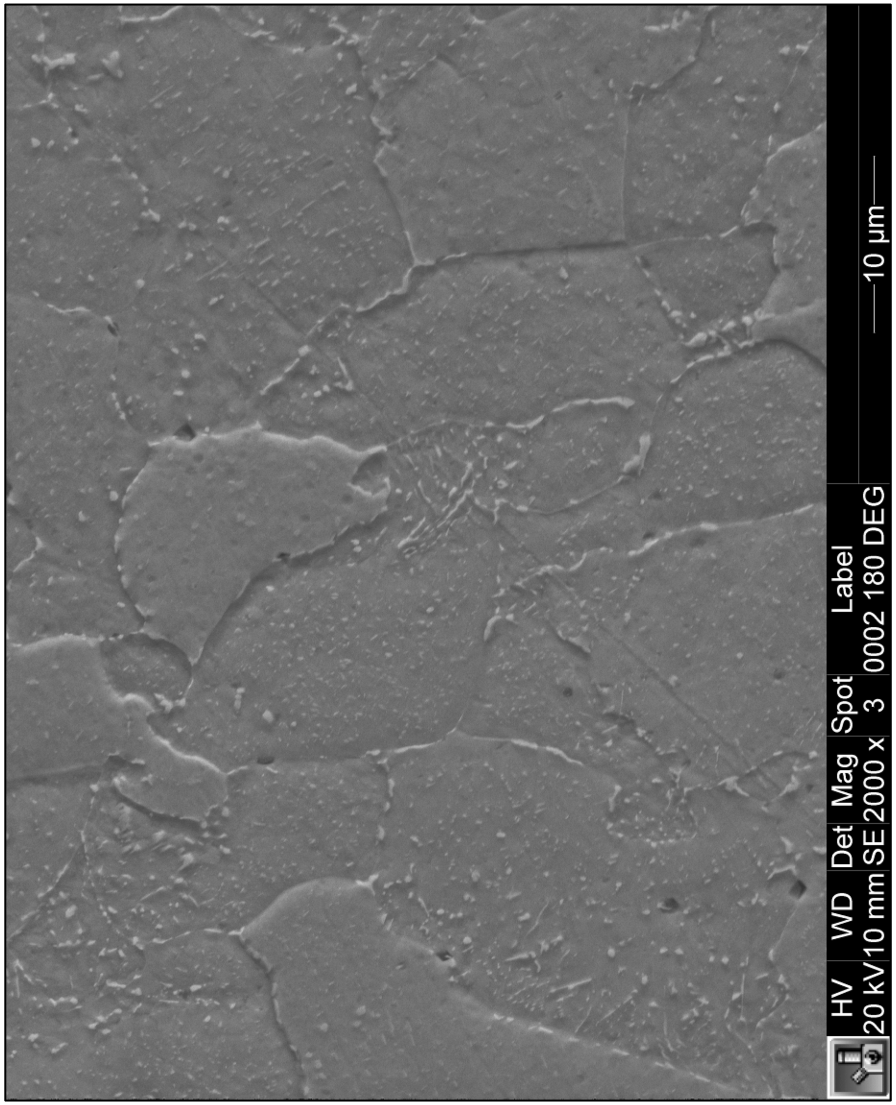


Figure 17. SEM micrographs of the SA213-T2 tube alloy microstructure of sample K-700390-TUBE-0001 at 180º.



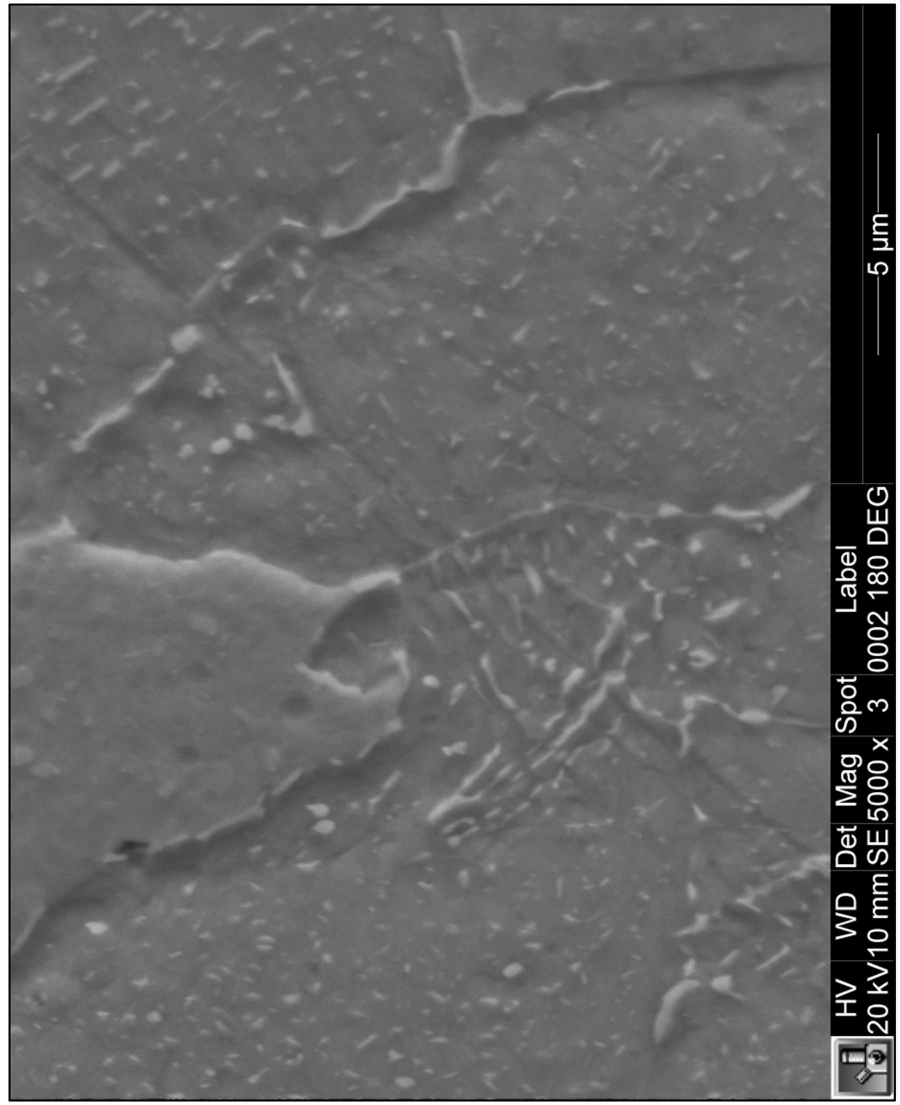
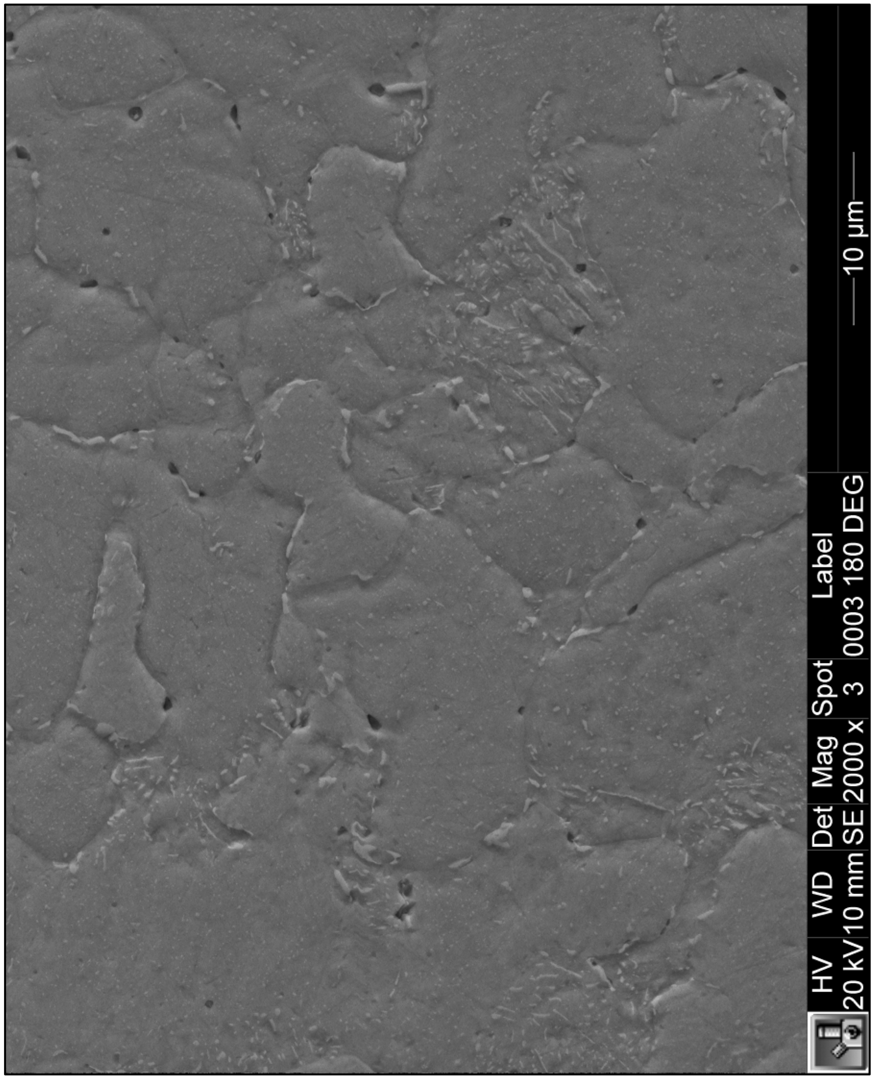


Figure 18. SEM micrographs of the SA213-T22 tube alloy microstructure of sample K-700390-TUBE-0002 at 180º.



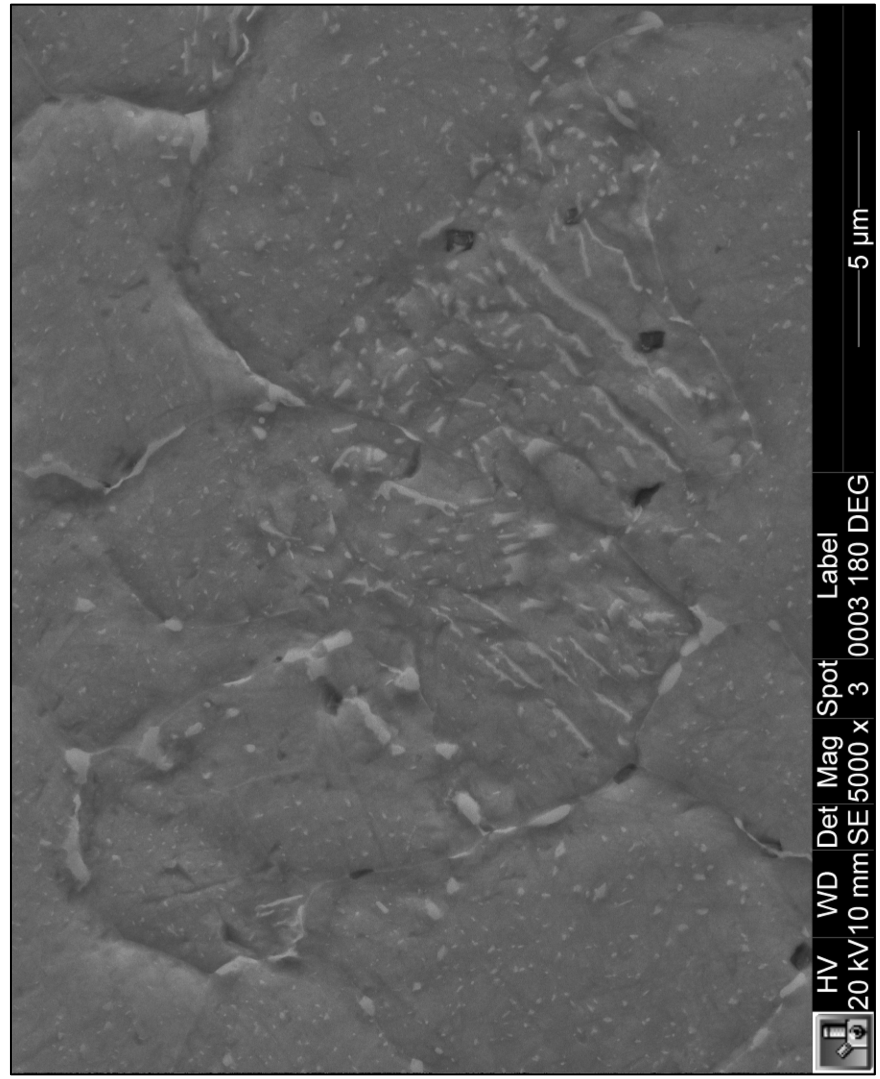


Figure 19. SEM micrographs of the SA213-T11 tube alloy microstructure of sample K-700390-TUBE-0003 at 180º.

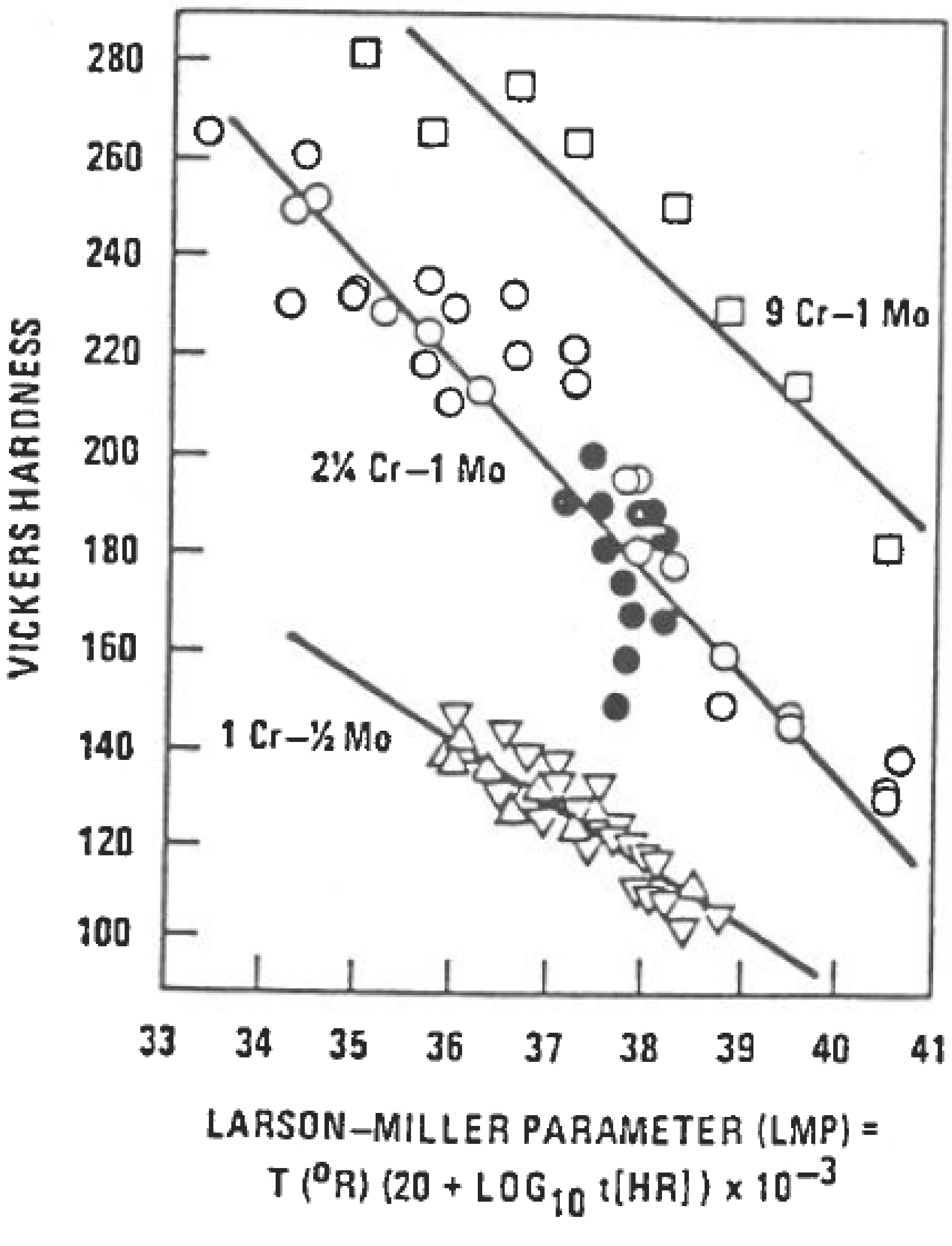


Figure 20. Correlations between hardness and the Larson-Miller parameter for 1Cr-1/2Mo, 21/4Cr-1Mo, and 9Cr-1Mo steels. [14]

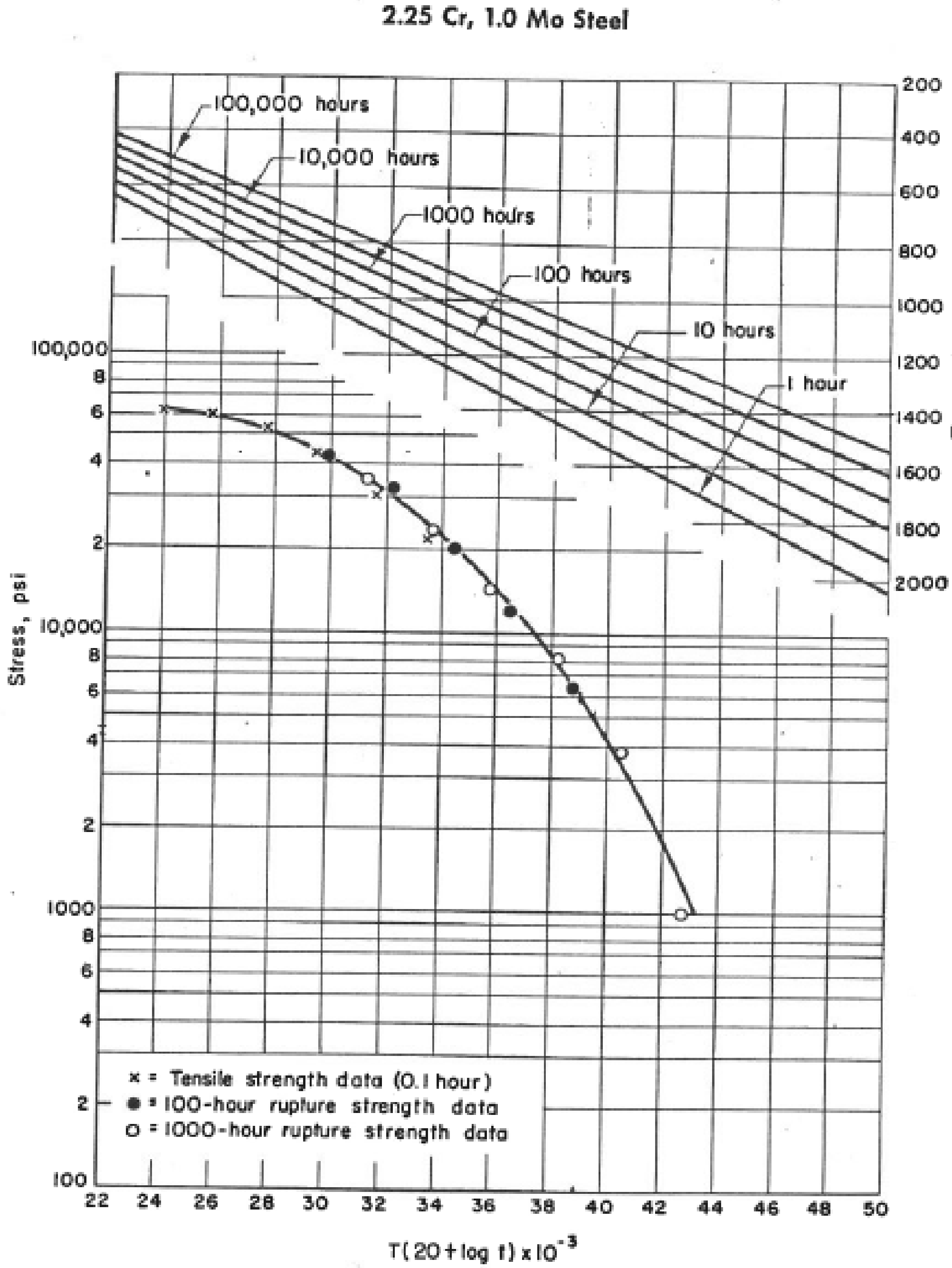


Figure 21. Variation of Larson-Miller stress rupture parameter for 2-1/4Cr-1Mo (T22) steel [10].

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January 3, 2017

Nelson Seymour
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Hydro Place, 500 Columbus Drive
St. John's, NL
A1B 4K7

Re: Holyrood Thermal Generating Station Unit 3 Boiler Tube Life and De-Rate Analysis Summary

Dear Mr. Seymour,

1.0 EXECUTIVE SUMMARY

In 2016, several assessments, inspections, and tests were conducted on the Unit 3 boiler tubing to assess the need for a de-rate of the boiler. This letter serves to summarize and discuss the various data collected in 2016 and provide recommendations.

In August 2016, a boiler tube life assessment was conducted for Units 1, 2, and 3. This assessment used design temperatures to provide remaining life estimates. A 10% de-rate to mitigate tube failures was recommended for Unit 3 only.

During the September 2016 Unit 3 outage, wall thickness measurements by Ultrasonic Testing (UT) and Babcock and Wilcox's (B&W) Non-destructive Oxide Thickness Inspection Service (NOTIS®) were conducted on high-risk areas of the boiler, identified by the previous assessment. Three tubes were also removed for metallurgical analysis. The inspection and test data was consistent and provided tube temperature estimates based on steam-side scale thickness measurements (below design temperatures). Metallurgical examination also confirmed a wall thinning degradation mechanism in localized areas of reheater tubes due to fireside corrosion.

Boiler life estimates were re-assessed with refined temperatures and concluded that boiler tube creep life is not expected to be challenged. On this basis, a de-rate of the Unit 3 boiler is not required. The risk of a significant unit outage during the 2016/2017 winter season due to creep rupture is considered to be low. Tube life estimates for each boiler region are shown in Appendix A.

Targeted tube inspections and replacements are recommended for localized areas where creep life is marginally below acceptable limits. An inspection plan, including recommended inspection locations, techniques, and acceptance criteria is provided in Appendix B.

2.0 BACKGROUND

Newfoundland and Labrador Hydro (NL Hydro) has a need to potentially operate the three generating units at Holyrood TGS to 2021 with a high degree of reliability. A risk assessment conducted by NL Hydro has identified boiler tube failures due to tube thinning as a reliability risk and has proposed de-rating the units as a means of mitigating this risk over the remaining operating period. Amec Foster Wheeler Nuclear Canada has been engaged to review the technical basis for this de-rate assessment, and to apply alternative assessment methods to maximise unit load capability while maintaining acceptable reliability.

In August 2016, Amec Foster Wheeler completed its initial assessment for Units 1, 2, and 3 [R-1]. While it was concluded that a de-rate was not needed for Units 1 and 2, a recommendation was made to de-rate Unit 3 operating pressure by 10% in order to mitigate the risk of tube failures. The main determinant for this recommendation was a reduced margin in creep life as a result of tube thinning and elevated temperatures around the 9th floor cavity reheater tubes and bends, and the low temperature superheater tubes and bends at the 10th floor. The temperature data used for these calculations is documented in a metal temperature study that was performed by Babcock & Wilcox (B&W) [R-2] in July 2016, where concerns around elevated tube temperatures are also documented.

In September 2016, Unit 3 was brought down for an outage. Inspections of the boiler were conducted. In order to refine the temperature data used as an input into the creep life calculations, B&W performed Non-destructive Oxide Thickness Inspection Service (NOTIS) testing on the highest-risk tubing to calculate effective metal temperatures [R-3][R-4]. Additional UT wall thickness data was also obtained [R-5], and tube samples were removed for metallurgical analysis. The following areas were inspected:

- Low Temperature Superheater, 10th Floor, Below Feet (Economizer Side)
- Reheater Tubes, 9th Floor, Overhead (SA-213 T22)
- Reheater Tubes, 9th Floor, Below Feet (SA-213 T11)

In October 2016, Amec Foster Wheeler re-examined the de-rate assessment using preliminary[1] effective metal temperatures determined by B&W through NOTIS testing [R-6]. Creep life calculations were then repeated using the refined (lower) temperatures and found that creep life in the limiting tubes was not expected to be challenged. However, calculated creep life was still found to be marginally below the acceptable limit defined in [R-6] in two regions of the boiler. On this basis, the recommendation was made to remove the requirement of a 10% de-rate for the short term, with additional targeted tube inspections and replacements (if required) recommended to be performed in 2017. Finalized boiler tube life estimates are shown in Appendix A. Note that only the three areas identified above used refined temperatures, all other estimates are based on design temperatures.

In November 2016, Kinectrics completed their metallurgical assessment of removed boiler tubes [R-7]. The report findings were generally consistent with the B&W NOTIS findings that the boiler tubes were operating below estimated design temperatures. The residual creep lives of the three tubes (one superheater and two reheater tubes) were then predicted using analytical methods, and the risk of creep failures was found to be 'low'; all three had significant (i.e., >10 years) residual creep life under the historical Unit 3 boiler operating conditions.

[1] Note the finalized NOTIS data was later confirmed to be identical to the preliminary data.

3.0 DISCUSSION

The below discussion seeks to compare the various sources of information, discuss the findings as they pertain to the degradation observed in HTGS reheater and superheater tubes, and provide recommendations for future inspections.

3.1 Wall Thickness Measurements

There are four sources of wall thickness data discussed in this report:

- pre-September 2016 ultrasonic thickness (UT) measurements [R-1]
- September 2016 outage:
    - NOTIS measurements [R-4]
    - UT measurements, along the axial length of the tubes [R-5]
    - metallographic measurements on removed tubes, removed mid-span [R-7]

The September 2016 inspection outage campaign provided significant wall thickness data in areas of the boiler deemed as high-risk in the initial assessment [R-1]. A comparison of wall thickness measurements from selected *straight tube sections* is shown in Table 1. A comparison of wall thickness measurements from selected *bends* is shown in Table 2. Values below the original specified wall thicknesses are highlighted in red.

Wall thicknesses were measured from different tubes and at different axial locations, thus the results are not directly comparable. However the following general trends were observed:

- Measurements are generally consistent between the three methods (NOTIS, UT, metallography).
- Low Temperature Superheater tubes, in the straight sections, did not show significant thinning by any of the three inspection methods. Two of twelve data points from the metallurgical examination were just below (1% wall loss or less) the original specified minimum wall thickness (MWT). All other thickness data collected by NOTIS and UT was above the MWT. Measurements by UT along the length of the tubes showed a slight decreasing trend in wall thickness towards the north bend.
- Low Temperature Superheater tubes, at the extrados of the north bend, showed evidence of thinning from the UT inspection data. Eight of the twelve tube bends inspected by UT (tubes # 7, 14, 28, 35, 42, 49, 70, and 77) exhibited wall thicknesses lower than the MWT, up to a maximum of 9% wall loss.
- Reheater tubes (9th floor, overhead, Row 19), in the straight sections, showed evidence of thinning in the data obtained from all three inspection techniques. Although the UT data, taken along the length of selected tubes, found only two readings below MWT (tube #40, south end), NOTIS data taken on the straight section near the south bend found sixteen of the eighteen tubes inspected below the MWT, up to a maximum of 16% wall loss.
- Reheater tubes (9th floor, overhead, Row 19), at the extrados of the south bend, showed evidence of thinning from the UT inspection data. Seven of the nine tube bends inspected by UT (tubes #8, 12, 16, 20, 32, 36, 40) exhibited wall thicknesses lower than the MWT, up to a maximum of 17% wall loss and a slight decreasing trend in wall thickness towards the south bend.
- Reheater tubes (9th floor, below feet, Row 14), in the straight sections, showed minor evidence of thinning at selected locations in the data obtained from UT inspection and

metallography. Two of the twelve tubes inspected by UT exhibited wall thicknesses lower than the original wall thickness (tubes # 12 and 28), up to a maximum of 4% wall loss and a slight decreasing trend in wall thickness towards the north bend. Eleven of twelve data points from the metallurgical analysis were just below the original wall thickness, up to a maximum of 5% wall loss. NOTIS inspection of all sixty tubes in this row did not detect any wall thicknesses lower than the original wall thickness. (*Note: due to access restrictions, both UT and NOTIS wall thickness measurements were taken on the trailing edge of tubes (often associated with reduced thinning when compared to the leading edge); however, metallurgical examination did not show evidence of preferential thinning occurring on the leading edge [R-7].)*

- Reheater tubes (9th floor, below feet, Row 14), in the bends, showed minor evidence of thinning at selected locations in the obtained from obtained from all UT inspection. Two of the twelve tubes exhibited wall thicknesses lower than MWT (tube # 28 and 40), up to a maximum of 3% wall loss.

Therefore wall thinning is a confirmed degradation mechanism exhibited in varying degrees of severity depending on the region of the boiler.

3.2 Steam-Side Oxide Scale Thickness

The initial assessment [R-1] used design temperatures [R-2] and pre-September 2016 UT outage data as an input to estimating remaining boiler tube life. To refine the initial assessment, additional inspection data was obtained that would allow for the estimation of effective metal temperatures that could be used in the analysis. These temperatures were expected to be below design temperatures and result in improved life estimates.

Both the NOTIS report and the metallurgical report used steam-side oxide measurements to estimate effective metal temperatures. Maximum oxide thickness values and associated effective metal temperature estimates were noted to be similar between the two techniques. However, estimated remaining life estimates varied based on the approach taken. The maximum reported temperatures generated by NOTIS were bounding and these values were used as final temperatures to update the initial assessment. A comparison of NOTIS and metallographic assessment results is provided in Table 3. Remaining life estimates for Unit 3, updated with NOTIS estimated temperatures, are provided in Appendix A [R-6].

Calculation of the ratio of maximum wall loss to steam-side oxide scale thickness was greater than five for all three removed tubes. This is consistent with criteria used to differentiate between fireside corrosion and overheating as the dominant degradation mechanism [R-8], where fireside corrosion is considered dominant when the ratio is greater than five.

3.3 Tube Outer Diameter Deposit Characterization

3.3.1 Macroscopic Examination

The outer diameter (OD) deposits composed of scale and ash from the removed primary superheater and reheater tubes exhibited several macroscopic features consistent with typical fireside corrosion [R-8]:

- a hard and porous outer layer and a dark inner layer strongly adhered to the tube
- an uneven or rough surface on the OD of the tube after removal of the deposits

3.3.2 Chemical Analysis

Chemical analysis of the OD scale was conducted by two methods (inductively coupled plasma atomic emission spectroscopy (ICP-AES) and x-ray diffraction (XRD)) [R-7].

Analysis by ICP-AES found the deposits comprised mixed sulphates ($MeSO_4$, where Me = Fe, Na, Ca, and K). Sulphur (26-30 wt%) and sodium (10-22 wt%) were major constituents. Vanadium was also detected but in lesser amounts (1-2 wt%). Other minor elements detected in the OD oxide (i.e. magnesium, manganese, aluminum, silicon, and calcium), are suspected to be additives in the fuel used to control corrosion. These additives work by raising the fusion point of the ash or combining chemically with the corrosive agents.

Analysis by XRD was considered to be inconclusive since the phases detected did not align with elements found in the ICP-AES results. The major phase reported ($CaSO_4$) is suspected to be a component of the fly ash; this is stable at operating temperatures and would not actively participate in corrosion. Low melting point compounds were not detected. It should be noted that a sample was collected by using a chisel to remove the deposits on the OD "as much as practicable", and it is suspected that strongly adherent deposits adjacent to the tube surface would have been more difficult to collect compared to the porous outer layer.

Deposits on OD superheater and reheater tube surfaces can be formed by the firing of residual oils; the exact compounds formed depend on the incoming composition of the fuel oil. Fireside corrosion occurs when these deposits disrupt the tube's protective oxides. Compounds which contain vanadium, sodium, and sulphur are particularly aggressive [R-8]. Operating temperatures of these particular boiler tubes are considered to be too low for fireside corrosion by a molten salt mechanism, and it is suspected that a sulfidation mechanism is more likely.

Holyrood switched fuel sources approximately 10 years ago to a source with low residuals. Fuel oil compositions for key elements relevant to are shown in Table 4 [R-2][R-9]. Information on the current fuel was taken from a recent manifest and is assumed to be representative [R-9]. The high sulphur content of the deposits may be due to the high sulphur content of the original fuel. OD scale is considered to be sulfatic, with the corrosion rate controlled by the dissolution or disruption of protective oxides.

The boiler tubes have not been previously cleaned of OD oxide scale [R-7], thus any sulphatic deposits formed during operation with the original fuel would still be present on the OD surface. It is possible that the corrosion degradation mechanism is active. Repeat inspections of the above areas would provide more data to estimate a thinning rate.

3.4 Degradation Mechanism and Apparent Cause

Wall thinning was observed in localized areas of the reheater and superheater tubes. Metallurgical examination confirmed that the thinning observed on the reheater tubes is due to fireside corrosion. The degree of thinning is expected to be more severe in areas operating at higher temperatures.

Although the September 2016 inspection did not directly examine waterwall, economizer, or low temperature superheater tubes, it is important to note that wall thickness values lower than the MWT were also previously reported in these other areas of the boiler (see Appendix A). The degradation mechanism in these areas may or may not be similar to that observed in the reheater tubes.

Despite the lower temperatures, the high sulphur content of the original fuel may be similarly responsible for wall thinning observed on these tubes. Fireside corrosion is known to be a degradation mechanism for both waterwall and superheater/reheater tubes [R-8, R-10]. Alternatively, erosion is another potential degradation mechanism especially for bends in high velocity areas. Erosion may be confirmed or eliminated as a potential mechanism by visual examination.

If the OD scale which causes corrosion to occur is strongly adherent to the tube surface, corrosion may continue to occur as long as it is present; however the rate of corrosion is unknown. To address future degradation of boiler tubes, it is recommended that high-risk tubes be monitored and the inspection interval be re-assessed at the next outage. An inspection plan is provided in Appendix B.

4.0 CONCLUSIONS AND RECOMMENDATIONS

Based on the recently obtained inspection data from the September 2016 outage, a de-rate of the Unit 3 boiler is not required.

Wall thinning was exhibited in varying degrees of severity depending on the region of the boiler. The degradation mechanism observed on the inspected reheater tube (9^{th} floor, overhead) was confirmed to be caused by fireside corrosion.

Targeted tube inspections and replacements are recommended to be performed during the 2017 Unit 3 maintenance outage. Recommendations for future inspections, including locations and acceptance criteria are provided in Appendix B. These inspections are considered to be in addition to the inspections conducted as part of the regular boiler maintenance program.

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References

[R-1] Correspondence, "Holyrood TGS Boiler Tube Thinning Assessment", AmecFW File No. AM212/015/000001 R01, 2016-08-08.

[R-2] Report, "Thermal Study – Superheater and Reheater Metal" B&W File No. TP900932 R02, 2016-07-05.

[R-3] Email from John Adams to David McNabb, "Fw: NOTIS Data", AmecFW File No. AM212/RE/001 R00, 2016-10-12.

[R-4] Report, "NOTIS Inspection of Superheater Tubes for Newfoundland and Labrador Hydro Holyrood Generating Station, Unit 3," B&W File No. BA9254020, 2016-09.

[R-5] Email from John Adams to David McNabb, "Fw: 2016 U#3 Primary Superheater & Reheater UT Data", AmecFW File No. AM212/RE/002 R00, 2016-10-12.

[R-6] Correspondence, "Holyrood TGS Boiler Tube Thinning Assessment (October 2016 Update)," AmecFW File No. AM212/015/000002 R00, 2016-10-19.

[R-7] Report, "Analysis of Newfoundland & Labrador Hydro Holyrood Unit 3 Boiler Tubes," Kinectrics File No. K-700390-RA-001-R01, 2016-11-28.

[R-8] EPRI TR-105261-V3, "Boiler Tube Failures: Theory and Practice Volume 3: Steam-Touched Tubes," 1996.

[R-9] Email from John Adams to David McNabb, "Fuel Analysis Report," AmecFW File No. AM212/RE/004, 2016-12-02.

[R-10] EPRI TR-105261-V2, "Boiler Tube Failures: Theory and Practice Volume 2: Water-Touched Tubes," 1996.

[R-11] B&W Plant Service Bulletin, "Tube Thickness Evaluation Repair or Replacement Guide", B&W File No. PSB-26, 1994-06-01.

[R-12] API 579-1/ASME FFS-1 (2007), "Fitness-for-Service".

[R-13] Email from Jamie Curtis to David McNabb, "Unit 3 Material Diagram," AmecFW File No. AM212/RE/012, 2016-08-02.

Table 1 Wall thickness measurements from selected *straight* sections

Location	Original (Ordered) Wall Thickness [R-2][R-6]	Pre-September 2016 Outage Lowest UT Measured Wall Thickness [R-1]	2016 NOTIS Measured Wall Thickness [R-4]	2016 UT Measured Wall Thickness [R-5]	2016 Metallography Measured Wall Thickness [R-7]
Low Temperature Superheater, 10th Floor, Below Feet (Economizer Side)	0.338”	0.347”	min.-max.: 0.349” - 0.376” average: 0.363”	min.-max.: 0.350” - 0.406” average: 0.375”	min.-max.: 0.335” - 0.349” average: 0.343”
Reheater Tubes, 9th Floor, Overhead (SA-213 T22)	0.180”	0.140”	min.-max.: 0.152” - 0.207” average: 0.168”	min.-max.: 0.165” - 0.222” average: 0.205”	min.-max.: 0.148” - 0.178” average: 0.165”
Reheater Tubes, 9th Floor, Below Feet (SA-213 T11)	0.180”	0.161”	min.-max.: 0.186” - 0.212” average: 0.196”	min.-max.: 0.173” - 0.223” average: 0.194”	min.-max.: 0.171” - 0.184” average: 0.176”

Table 2 Wall thickness measurements from selected *bends*

Location	Original (Ordered) Wall Thickness [R-2][R-6]	Pre-2016 UT (Lowest) Measured Wall Thickness [R-1]	2016 UT Measured Wall Thickness [R-5]	
Low Temperature Superheater, 10th Floor, Below Feet (Economizer Side)	0.338”	0.310”	Extrados of North Bend	min.-max.: 0.306” - 0.344” average: 0.329”
			Extrados of South Bends	min.-max.: 0.350” - 0.415” average: 0.377”
Reheater Tubes, 9th Floor, Overhead (SA-213 T22)	0.180”	0.116”	Extrados of North Bend	min.-max.: 0.199” - 0.229” average: 0.209”
			Extrados of South Bends	min.-max.: 0.149” - 0.186” average: 0.166”
Reheater Tubes, 9th Floor, Below Feet (SA-213 T11)	0.180”	No data available	Extrados of North Bend	min.-max.: 0.175” - 0.211” average: 0.190”

Table 3 Estimates of Effective Metal Temperatures by NOTIS and Metallographic Assessment

Location	Design Temp. [R-1][R-2]	NOTIS [R-4]		Metallography [R-7]	
		Max. Meas. ID Ox.	OD Temp.	Max. Meas. ID Ox.	Max. Temp (Max. ID Ox.)
Low Temperature Superheater, 10th Floor, Below Feet, Economizer Side, (Tube)	993 °F	0.006”	959 °F	0.006”	914 °F
Reheater, 9th Floor, Overhead (Tube)	1107 °F	0.019”	1063 °F	0.011”	1030 °F
Reheater, 9th Floor, Below Feet (Tube, SA-213 T11)	1063 °F	0.008”	991 °F	0.009”	941 °F

Table 4 Selected Elemental Composition Limits for Fuels

Element	Original Fuel [R-2]	Current Fuel [R-9]	
		(Specified Limit)	(Actual)
Sodium	-	50 ppm max.	33 ppm
Sulphur	2.3 wt%	0.7 wt% max.	0.643 wt%
Vanadium	-	200 ppm max.	12 ppm
Aluminum	-	50 ppm	38 ppm
Silicon	-	75 ppm	35 ppm
Ash	0.10 wt%	0.10 wt%	0.08 wt%

- not specified

APPENDIX A: UNIT 3 BOILER TUBE LIFE ESTIMATES

Unit 3																											
#	Inspection Location	Physical Properties					B&W Plant Service Bulletin PSB-26					MAWP (ASME BPVC Section I, PG-27.2.1)							MAWP (ASME BPVC Section I, A-317.2.1)							Larson-Miller at 100% Operating Pressure	
		Lowest Measured Wall Thickness (inch)	Assumed 100% Operating Pressure (psi)	Material	Temp. (°F)	Tube OD (inches)	PSB-26 Requirement (t = specified wall)	Percent Remaining from Original	Required Wall (inches)	Margin at Design Pressure (inches)	Criteria Satisfied?	MAWP (psi)	Max. Operating Pressure Margin (psi)	Margin with 2% pressure reduction (psi)	Margin with 5% pressure reduction (psi)	Margin with 10% pressure reduction (psi)	Margin with 15% pressure reduction (psi)	Margin with 20% pressure reduction (psi)	MAWP (psi)	Max. Operating Pressure Margin (psi)	Margin with 2% pressure reduction (psi)	Margin with 5% pressure reduction (psi)	Margin with 10% pressure reduction (psi)	Margin with 15% pressure reduction (psi)	Margin with 20% pressure reduction (psi)	Minimum Predicted Life (hours)	*Mean Predicted Life (hours)*
1	Economizer Tubes, 6th Floor, Lower Tube Wall (South Bend)	0.153	2200	SA210A1	700	2.5	70%t	75%	0.142	0.011	YES	1858	-342	-298	-232	-122	-12	98	2037	-163	-119	-53	57	167	277	5.49E+06	6.85E+07
2	Economizer Tubes, 6th Floor, Lower Tube Wall (North Bend)	0.155	2200	SA210A1	700	2.5	70%t	76%	0.142	0.013	YES	1886	-314	-270	-204	-94	16	126	2065	-135	-91	-25	85	195	305	6.33E+06	7.76E+07
3	Economizer Tubes, 6th Floor, Lower Tube Wall (Tube)	0.189	2200	SA210A1	700	2.5	70%t	93%	0.142	0.047	YES	2370	170	214	280	390	500	610	2557	357	401	467	577	687	797	5.06E+07	4.85E+08
4	Economizer Tubes, 8th Floor, Lower (Under Sootblower)	0.178	2200	SA210A1	700	2.5	70%t	88%	0.142	0.036	YES	2212	12	56	122	232	342	452	2396	196	240	306	416	526	636	2.75E+07	2.83E+08
5	Economizer Tubes, 8th Floor, Lower (North Bend)	0.218	2200	SA210A1	700	2.5	70%t	107%	0.142	0.076	YES	2794	594	638	704	814	924	1034	2990	790	834	900	1010	1120	1230	2.05E+08	1.69E+09
6	Economizer Tubes, 8th Floor, Lower (North Bend)	0.186	2200	SA210A1	700	2.5	70%t	92%	0.142	0.044	YES	2327	127	171	237	347	457	567	2513	313	357	423	533	643	753	4.31E+07	4.20E+08
7	Economizer Tubes, 8th Floor, Upper (South Bend)	0.171	2200	SA210A1	700	2.5	70%t	84%	0.142	0.029	YES	2112	-88	-44	22	132	242	352	2295	95	139	205	315	425	535	1.81E+07	1.96E+08
8	Economizer Tubes, 8th Floor, Upper (Tube)	0.178	2200	SA210A1	700	2.5	70%t	88%	0.142	0.036	YES	2212	12	56	122	232	342	452	2396	196	240	306	416	526	636	2.75E+07	2.83E+08
9	Economizer Tubes, 8th Floor, Upper (North Bend)	0.178	2200	SA210A1	700	2.5	70%t	88%	0.142	0.036	YES	2212	12	56	122	232	342	452	2396	196	240	306	416	526	636	2.75E+07	2.83E+08
10	Low Temperature Superheater, 8th Floor, Overhead (Bend)	0.180	2010	SA210A1	696	2.5	85%t	89%	0.173	0.007	YES	2258	248	288	348	449	549	650	2444	434	474	535	635	736	836	8.91E+07	8.29E+08
11	Low Temperature Superheater, 8th Floor, Overhead (Tube)	0.194	2010	SA210A1	696	2.5	85%t	96%	0.173	0.021	YES	2461	451	491	552	652	753	853	2651	641	681	742	842	943	1043	1.85E+08	1.59E+09
12	Low Temperature Superheater, 9th Floor, Below Feet (Bend)	0.179	2010	SA210A1	741	2.5	85%t	88%	0.173	0.006	YES	1922	-88	-48	12	113	213	314	2081	71	112	172	272	373	473	7.58E+06	6.52E+07
13	Low Temperature Superheater, 9th Floor, Below Feet (Tube)	0.216	2010	SA210A1	741	2.5	85%t	106%	0.173	0.043	YES	2387	377	417	477	578	678	779	2555	545	585	645	746	846	947	4.29E+07	3.08E+08
14	Low Temperature Superheater, 9th Floor, Overhead (Bend)	0.170	2010	SA209T1A	766	2.5	85%t	84%	0.173	-0.003	NO	2184	174	214	274	375	475	576	2374	364	404	465	565	666	766	2.75E+08	8.72E+08
15	Low Temperature Superheater, 9th Floor, Overhead (Tube)	0.210	2010	SA209T1A	756	2.5	85%t	103%	0.173	0.037	YES	2803	793	833	894	994	1095	1195	3005	995	1035	1096	1196	1297	1397	1.30E+09	4.09E+09
16	Low Temperature Superheater, 10th Floor, Below Feet (Boiler Side) (Bend)[2]	0.374	2010	SA213T11	985	2.5	85%t	95%	0.335	0.039	YES	2434	424	464	525	625	726	826	2560	550	590	650	751	851	952	6.84E+05	3.99E+06
17	Low Temperature Superheater, 10th Floor, Below Feet (Boiler Side) (Tube)[3]	0.430	2010	SA213T11	985	2.5	85%t	109%	0.335	0.095	YES	2887	877	917	977	1078	1178	1279	3035	1025	1066	1126	1226	1327	1427	1.38E+06	8.13E+06
18	Low Temperature Superheater, 10th Floor, Below Feet (Economizer Side) (Bend)[4]	0.310	2010	SA213T2	959	2.5	85%t	92%	0.287	0.023	YES	2325	315	355	415	516	616	717	2453	443	483	543	644	744	845	4.47E+05	1.20E+06
19	Low Temperature Superheater, 10th Floor, Below Feet (Economizer Side) (Tube)[5]	0.306	2010	SA213T2	959	2.5	85%t	91%	0.287	0.019	YES	2289	279	320	380	480	581	681	2416	406	447	507	607	708	808	4.23E+05	1.14E+06
20	High Temperature Superheater, 8th Floor, Overhead (Bend)	0.216	2010	SA209T1A	941	2.25	85%t	66%	0.278	-0.062	NO	1840	-170	-130	-69	31	132	232	1959	-51	-11	50	150	251	351	3.23E+05[6]	8.75E+05
21	High Temperature Superheater, 8th Floor, Overhead (Tube)	0.228	2010	SA209T1A	941	2.25	85%t	70%	0.278	-0.050	NO	1959	-51	-10	50	150	251	351	2081	71	112	172	272	373	473	4.05E+05	1.10E+06
22	High Temperature Superheater, 8th Floor, Below Feet	0.221	2010	SA209T1A	905	2.25	85%t	78%	0.242	-0.021	NO	2704	694	734	794	895	995	1096	2876	866	906	967	1067	1168	1268	1.68E+06	4.66E+06
23	High Temperature Superheater, 8.5 Floor, Overhead (Bend)	0.275	2010	SA213T22	1037	2	85%t	84%	0.278	-0.003	NO	1924	-86	-46	14	115	215	316	2025	15	56	116	216	317	417	4.52E+05	1.76E+06
24	High Temperature Superheater, 8.5 Floor, Overhead (Tube)	0.283	2010	SA213T22	1034	2	85%t	87%	0.278	0.005	YES	2035	25	65	125	226	326	427	2141	131	171	232	332	433	533	6.23E+05	2.39E+06
25	High Temperature Superheater, 8.5 Floor, Below Feet (Bend)	0.279	2010	SA213T22	1021	2.25	85%t	98%	0.242	0.037	YES	1900	-110	-70	-9	91	192	292	2005	-5	35	95	196	296	397	4.12E+05	1.70E+06
26	High Temperature Superheater, 8.5 Floor, Below Feet (Tube)	0.275	2010	SA213T22	1021	2.25	85%t	96%	0.242	0.033	YES	1868	-142	-102	-41	59	160	260	1972	-38	2	62	163	263	364	3.72E+05	1.54E+06
27	Reheater Tubes, 7th Floor, Top of Scaffold (Bend)	0.113	600	SA213TP347H	1017	2.25	85%t	76%	0.126	-0.013	NO	1547	947	959	977	1007	1037	1067	1729	1129	1141	1159	1189	1219	1249	1.22E+09	3.76E+09
28	Reheater Tubes, 7th Floor, Top of Scaffold (Tube)	0.129	600	SA213TP347H	1017	2.25	85%t	87%	0.126	0.003	YES	1804	1204	1216	1234	1264	1294	1324	1989	1389	1401	1419	1449	1479	1509	2.56E+09	7.87E+09

2 Revised effective metal temperatures based on NOTIS data collected in Q3-2016 used in revised MAWP and Larson-Miller calculations.
3 Revised effective metal temperatures based on NOTIS data collected in Q3-2016 used in revised MAWP and Larson-Miller calculations.
4 Revised effective metal temperatures based on NOTIS data collected in Q3-2016 used in revised MAWP and Larson-Miller calculations.
5 Revised effective metal temperatures based on NOTIS data, and lowest measured wall thickness data collected in Q3-2016 inspection campaign used in revised MAWP and Larson-Miller calculations.
6 Yellow highlight indicates tube life estimate is marginal when compared to target creep life of 368,000 hours [R-1].

Unit 3																											
#	Inspection Location	Physical Properties					B&W Plant Service Bulletin PSB-26					MAWP (ASME BPVC Section I, PG-27.2.1)							MAWP (ASME BPVC Section I, A-317.2.1)							Larson-Miller at 100% Operating Pressure	
		Lowest Measured Wall Thickness (inch)	Assumed 100% Operating Pressure (psi)	Material	Temp. (ºF)	Tube OD (inches)	PSB-26 Requirement (t = specified wall)	Percent Remaining from Original	Required Wall (inches)	Margin at Design Pressure (inches)	Criteria Satisfied?	MAWP (psi)	Max. Operating Pressure Margin (psi)	Margin with 2% pressure reduction (psi)	Margin with 5% pressure reduction (psi)	Margin with 10% pressure reduction (psi)	Margin with 15% pressure reduction (psi)	Margin with 20% pressure reduction (psi)	MAWP (psi)	Max. Operating Pressure Margin (psi)	Margin with 2% pressure reduction (psi)	Margin with 5% pressure reduction (psi)	Margin with 10% pressure reduction (psi)	Margin with 15% pressure reduction (psi)	Margin with 20% pressure reduction (psi)	Minimum Predicted Life (hours)	*Mean Predicted Life (hours)*
29	Reheater Tubes, 9th Floor, Overhead (Bend)[7]	0.116	600	SA213T22	1063	2.25	85%t	64%	0.153	-0.037	**NO**	**508**	-92	*-80*	*-62*	*-32*	*-2*	**28**	**567**	-33	-21	-3	**27**	*57*	*87*	**3.40E+05**[8]	*1.21E+06*
30	Reheater Tubes, 9th Floor, Overhead (Tube)[9]	0.140	600	SA213T22	1063	2.25	85%t	78%	0.153	-0.013	**NO**	**632**	**32**	*44*	*62*	*92*	*122*	*152*	**692**	**92**	*104*	*122*	*152*	*182*	*212*	**1.02E+06**	*3.14E+06*
31	Reheater Tubes, 9th Floor, Below Feet (SA-213 T11)[10]	0.161	600	SA213T11	991	2.5	85%t	89%	0.153	0.008	**YES**	**864**	**264**	*276*	*294*	*324*	*354*	*384*	**943**	**343**	*355*	*373*	*403*	*433*	*463*	**1.57E+06**	*9.20E+06*
32	Reheater Tubes, 9th Floor, Below Feet (SA-213 T22)[11]	0.160	600	SA213T22	991	2.5	85%t	89%	0.153	0.007	**YES**	**1066**	**466**	*478*	*496*	*526*	*556*	*586*	**1165**	**565**	*577*	*595*	*625*	*655*	*685*	**2.34E+07**	*7.44E+07*
33	Boiler Roof Tubes (Boiler Side)	0.188	-	-	-	-	70%t	78%	0.168	0.020	**YES**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
34	Water Wall Knee Region	0.213	-	-	-	-	70%t	101%	0.147	0.066	**YES**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
35	*Boiler Floor Tubes[12]*	*0.110*	-	-	-	-	*70%t*	*52%*	*0.147*	*-0.037*	*NO*	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
36	Water Wall at Buners (Elevation 1)	0.169	-	-	-	-	70%t	80%	0.147	0.022	**YES**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
37	Water Wall at Buners (Elevation 2)	0.199	-	-	-	-	70%t	95%	0.147	0.052	**YES**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
38	Water Wall at Buners (Elevation 3)	0.191	-	-	-	-	70%t	91%	0.147	0.044	**YES**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

[7] Revised effective metal temperatures based on NOTIS data collected in Q3-2016 used in revised MAWP and Larson-Miller calculations.
[8] Yellow highlight indicates tube life estimate is marginal when compared to target creep life of 368,000 hours [R-1].
[9] Revised effective metal temperatures based on NOTIS data collected in Q3-2016 used in revised MAWP and Larson-Miller calculations.
[10] Revised effective metal temperatures based on NOTIS data collected in Q3-2016 used in revised MAWP and Larson-Miller calculations.
[11] Revised effective metal temperatures based on NOTIS data collected in Q3-2016 used in revised MAWP and Larson-Miller calculations.

APPENDIX B: UNIT 3 2017 INSPECTION PLAN

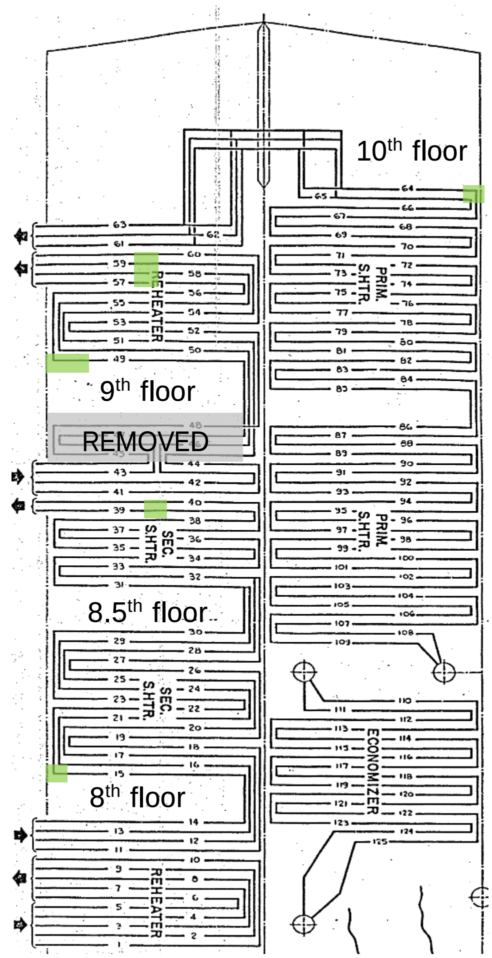
Note that boiler tubes in several areas are nearing end of life conditions. The proposed inspection plan is intended to provide a high degree of reliability; however avoidance of tube failures altogether may not be feasible. The objective of this inspection plan is to select tubes with the highest risk of failure before 2021 and to identify if there is an active thinning rate in reheater and superheater tubes.

It is assumed that the number of current operating hours for Unit 3 is 152,000 and that there are another 32,000 operating hours to end of life in 2021. Conservative acceptance criteria was determined as the minimum wall thickness for a target creep life of 368,000 hours, twice the number of estimated total operational hours at end of life (i.e., (152000 + 32000)*2 = 368,000) [R-1]. Tubes inspected with wall thicknesses below the acceptance criteria should be replaced.

A summary of inspection locations and their location shown on a cross-sectional view of the boiler [R-13] is shown below in Table B1.

Table B1 Summary of Recommended 2017 UT Inspections

Location	Extent of Inspection	Acceptance Criteria, Tmin
High Temperature Superheater, 8th Floor, Overhead (South Bend)	Accessible tubes, select higher temperature locations	0.225″
Reheater, 9th Floor, Overhead (South Bend)	Accessible tubes, select higher temperature locations	0.120″
Reheater, 9th Floor, Overhead (Tube adjacent to South Bend)	Tubes: 8, 12, 16, 20, 24, 28, 32, 36, 40 (numbered from west to east)	0.120″
Low Temperature Superheater, 10th floor, Below Feet, Economizer Side (North Bend)	Tubes: 7, 14, 21, 28, 35, 42, 49, 56, 63, 70, 77, 84 (numbered from west to east)	0.300″
High Temperature Superheater, 8.5th floor, Overhead (Tube)	Nested tubes, row 39, select higher temperature locations	TBD[13]
Reheater, 9th floor, overhead (Tube)	Nested tubes, row 57-60, select higher temperature locations	TBD[13]



Inspections on the high temperature superheater (8th floor, overhead, south bend) and reheater, 9th floor, overhead, south bend) are recommended to confirm minimum wall thicknesses, as these are areas which marginally meet target creep life criteria as identified in Appendix A.

[13] TBD – to be determined after 2017 inspection data is collected.

Inspections on the reheater (9th floor, overhead, tube adjacent to south bend) and the low temperature superheater (10th floor, below feet, economizer side, north bend) are repeat inspections identical to the inspection locations used in September 2016. These are recommended to estimate thinning rate.

Consideration should also be given to inspecting the high temperature superheater (8.5th floor, overhead, row 39 in the boiler material diagram above) and the reheater outlet bank tubing (9th floor, overhead, tube rows 57-60 in the boiler material diagram above) using the NOTIS inspection technique to confirm minimum wall thickness and creep life. The areas suggested for inspection are within the nested tubes adjacent to the outlet headers. Access to these nested areas will be more difficult and requires separating the elements; however, these locations represent areas with the highest predicted metal temperatures from the design report and have the highest potential for corrosion. These areas are also less represented by the previously collected data used to date from accessible tubing.

Extent of Inspections

Unless otherwise noted, the extent of inspection is limited to accessible tubes. Where possible, it is preferable that the highest temperature tubes are inspected, as these have the highest risk of failure. For superheater tubes, this is in the centre of the boiler, based on secondary superheat outlet temperatures taken in 2012, 2013, and 2014. For reheater tubes, this is across approximately 2/3 of the boiler on the east side, based on reheat outlet heater temperatures taken in 2012, 2013, and 2014. Temperature profile data was previously retrieved from the unit control system. It is also preferable if inspections can be conducted on the highest temperature areas of the tube (i.e., leading edge).

Inspection and Test Techniques

The primary technique to determine remaining wall thickness is UT. It is recommended that visual inspection of the OD surface of the bends be conducted at the same time, to confirm or eliminate erosion as a degradation mechanism. Photographs or video of the tubes prior to cleaning may be taken to document the condition.

The NOTIS inspection technique is an optional technique. Use of NOTIS was successful during the Unit 3 outage. Data was found to be consistent with conventional UT and metallographic findings. Its use for future inspections may be beneficial for its unique ability to simultaneously measure tube wall thickness, steam-side oxide thickness, and estimate effective tube metal temperatures; however, it is a specialized technique that is not required to be broadly applied to all wall thickness measurements.

If tube replacements are conducted, it is further recommended that a sample (approximately 12" in length) of the removed tubes be retained, from each region of the boiler where replacements were made, as a contingency measure. Should inspections reveal that thinning is more severe than anticipated, then the removed tube(s) are then readily available for additional metallurgical testing to provide more detail on the nature of the degradation mechanism. If possible, samples should be collected from a tube with maximum wastage and in an area where the OD scale and ash layers are undisturbed.

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September 6, 2017

John Adams
Manager Long Term Asset Planning
Thermal Generation – Holyrood TGS
TG LT Asset Planning
Newfoundland and Labrador Hydro - a Nalcor Energy company

Re: Unit 3 2017 Boiler Tube Inspection – Preliminary Assessment of Results

Dear Mr. Adams,

The boiler tubing in the three boilers at Holyrood TGS have experienced tube wall thinning due primarily to fireside corrosion and erosion. The impact of these mechanisms has typically been managed through routine inspections and corrective maintenance, replacement or repair. An assessment was completed by Amec Foster Wheeler in 2016 which concluded the three units could be operated reliably to the end of 2021 within the current operating regime without de-rating. However, a particular vulnerability was noted for Unit 3 where specific sections had remaining life that only marginally met the remaining life acceptance criteria [1]. Targeted re-inspection in 2017 was recommended to determine whether there was active wall thinning, and to assess nested areas that had not been previously inspected [1].

In June 2017 an opinion was requested on a reduced inspection scope due to outage limitations. It was recommended that accessible areas be inspected and the NOTIS inspection of the nested areas be differed if there was not significant change in the wall thickness findings from 2016. The following is a preliminary assessment of the wall thickness data reported in July 2017. The inspection reports are attached.

With the exception of the 9th floor Reheat tubing (RH), Overhead location, tube wall thicknesses in all areas inspected were above the wall thickness acceptance criteria identified in the summary report [1], and showed minimal change.

For the 9th floor RH, Overhead, the difference in wall thickness at the south bend was significant. The minimum reported in 2016 was 0.116" versus a current minimum of 0.084". The average reported in 2016 at this location was 0.166", where the current average is 0.124". However, at a short distance (12") from the south bend measurement area, and in straight sections, the current measurements were greater than the acceptance criteria, and consistent with data reported in 2016. Pad weld repairs were applied to 21 of 60 tubes, about 30%, to restore wall thickness to minimum requirements to meet to 2021 end of life.

The reason for the change in wall thickness at the south bend at the 9th floor RH Overhead location since 2016 is unlikely to be in-service damage unless it is previously undetected damage and the 2016 data reflected measurements from a slightly different location. There is a possibility that the tubes were damaged in the cleaning process in 2017 or were insufficiently cleaned in the 2016 inspection campaign. However, no such problems were reported in the present outage, and the level of oversight in 2016 both for NOTIS and metallurgical evaluations do not support mechanical damage related to cleaning, or insufficient cleaning.

Based on the data presented the following conclusions and recommendations are provided:

- Deferral of the NOTIS inspection of nested tube areas to 2018 is considered acceptable given all but one location showed no significant change in condition.

- Spare tubing in bent configuration for the 9th floor RH Overhead, south bend location should be procured as a contingency in the event of tube failure during the next operating period. Despite the repairs, the nature of the damage means there is a risk that further damaged areas have gone undetected and unrepaired. There is also a risk of weld defects being introduced during the pad weld repair process.

  For end of life reliability, consideration should be given to replacing the tubing at the 9th floor RH Overhead south bend.

- Inspection of the RH and Superheat (SH) tube bends at the furnace wall lug connection is recommended. Similar to the present case, there is a possibility that the bend areas inspected in previous campaigns did not detect advanced damage in the lug region. Lugs will be exposed to higher temperatures during operation and may promote local damage in advance of areas of the tube further from the lug. The lug material should also be considered. If stainless steel, the dissimilar metal weld to carbon or low alloy ferritic tubing under mechanical bending load may promote cracking of the tube at the lug weld.

Please contact us if there are any questions.

Prepared by:

REGISTERED PROFESSIONAL ENGINEER
D. D. McNABB
06/09/17
PROVINCE OF ONTARIO

David McNabb P. Eng.
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Verified by:

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Amec Foster Wheeler Nuclear Canada

Approved by:

Daniel Gammage

Daniel Gammage P. Eng.
Manager, Inspection and Maintenance Engineering
Amec Foster Wheeler Nuclear Canada

References

[1] C. Taufique, "Holyrood Generating Station Unit 3 Boiler Tube Life and De-Rate Analysis Summary Report" File: AM212/016/000001 R00, January 2017

Enclosure: 2017 Unit #3 RH SSH PSH Data

cc: Jamie Curtis - HTGS

newfoundland labrador hydro
a nalcor energy company

UNIT #3 - BOILER

SECONDARY SUPERHEAT PLATEN TUBES

NDE SHEET No.: U3 - 23.1 Rev. 3 (pg. 1 of 2)
NON-DESTRUCTIVE EXAMINATION
MAINTENANCE FILE NUMBER 102.81.58/1
USE ADDITIONAL SHEETS IF NECESSARY

Inspector's Name & Signature:	S. RANSOME / T. OLIVER
Certification Level & CGSB #:	Level: II/I CGSB #: 17346
Instrument Type & Serial #:	Type: 37DL Serial #: 071524109
Date of Inspection:	JULY 7TH 2017

Area of Boiler and General Description of Non-Destructive Examination to be Performed		U.T. READING (in.)		
	PLATEN #	SOUTH BEND	5 FEET FROM NORTH BEND	10 FEET FROM NORTH BEND
Secondary Superheat Tube Assemblies 1.) U.T. Thickness Measurements Of Specified Platens *ABOVE HEAD* - Readings To Be Taken On First Tube Above Head *Access On 8th Floor Through East Or West Bottom Manways At The Middle Of The Unit* **NOTE - AT EACH LOCATION, TUBE TO BE SCANNED FROM THE 3-9 O'CLOCK POSITIONS, LOWEST READING IS TO BE RECORDED** *See Drawing For Details* *(Tubes Numbered East To West)*	1	0.256	0.247	0.265
	4	0.246	0.249	0.266
	7	0.243	0.256	0.248
	10	0.243	0.254	0.259
	13	0.230	0.253	0.268
	16	N/A	0.251	N/A
	19	N/A	0.249	N/A
	22	N/A	N/A	N/A
	25	N/A	N/A	N/A
	28	N/A	N/A	N/A
	30	N/A	0.256	N/A

COMMENTS:

N/A = AREAS NOT CLEANED

		U.T. READING (in.)	
	PLATEN #	10 FEET FROM NORTH BEND	5 FEET FROM NORTH BEND
Secondary Superheat Tube Assemblies 1.) U.T. Thickness Measurements Of Specified Platens *BELOW FEET* - Readings To Be Taken On First Tube Below Feet *Access On 8th Floor Through East Or West Bottom Manways At The Middle Of The Unit* **NOTE - AT EACH LOCATION, TUBE TO BE SCANNED FROM THE 3-9 O'CLOCK POSITIONS, LOWEST READING IS TO BE RECORDED** *See Drawing For Details* *(Tubes Numbered East To West)*	1	0.258	0.272
	4	0.258	0.252
	7	0.256	0.257
	10	0.257	0.253
	13	0.257	0.243
	16	0.262	0.254
	19	N/A	0.262
	22	N/A	0.252
	25	N/A	0.256
	28	N/A	0.256
	30	0.256	0.249

COMMENTS:

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UNIT #3 - BOILER

SECONDARY SUPERHEAT PLATENS

NDE SHEET No.: U3 - 23.1 Rev. 3 (pg. 2 of 2)
NON-DESTRUCTIVE EXAMINATION
MAINTENANCE FILE NUMBER 102-05-1-17
USE ADDITIONAL SHEETS IF NECESSARY

Inspector's Name & Signature:	Mike Granter	/S. Ransome
Certification Level & CGSB #:	Level: II/I	CGSB #: 14004/17346
Instrument Type & Serial #:	Type: 37DL	Serial #: 071524109
Date of Inspection:	July 6th 2017	

Area of Boiler and General Description of Non-Destructive Examination to be Performed	PLATEN #	U.T. READING (in.) SOUTH BEND	OVER SOUTH SOOTBLOWER	CENTRE OF ELEMENT
Secondary Superheat Tube Assemblies 1.) U.T. Thickness Measurements Of Specified Platens *ABOVE HEAD* - Readings To Be Taken On First Tube Above Head *Access On 8th Floor Through East Or West Top Manways At The Middle Of The Unit* **NOTE(1) - AT EACH LOCATION, TUBE TO BE SCANNED FROM THE 3-9 O'CLOCK POSITIONS, LOWEST READING IS TO BE RECORDED** **NOTE(2) - SCAFFOLD REQUIRED FOR ACCESS TO MANWAY** *See Drawing For Details* *(Tubes Numbered East To West)*	1	0.285	0.336	0.321
	7	0.285	0.308	0.304
	13	0.289	0.278	0.298
	19	0.291	0.317	0.303
	26	0.285	0.312	0.294
	32	0.297	0.323	0.295
	38	0.279	0.314	0.274
	44	0.277	0.319	0.296
	50	0.284	0.301	0.301
	56	0.297	0.324	0.310
	60	0.288	0.330	0.315

COMMENTS:

Area of Boiler and General Description of Non-Destructive Examination to be Performed	PLATEN #	U.T. READING (in.) SOUTH BEND	OVER SOUTH SOOTBLOWER	CENTRE OF ELEMENT
Secondary Superheat Tube Assemblies 1.) U.T. Thickness Measurements Of Specified Platens *BELOW FEET* - Readings To Be Taken On First Tube Below Feet *Access On 8th Floor Through East Or West Top Manways At The Middle Of The Unit* ***NOTE(1) - AT EACH LOCATION, TUBE TO BE SCANNED FROM THE 3-9 O'CLOCK POSITIONS, LOWEST READING IS TO BE RECORDED*** ***NOTE(2) - SCAFFOLD REQUIRED FOR ACCESS TO MANWAY*** *See Drawing For Details* *(Tubes Numbered East To West)*	1	0.316	0.339	0.331
	4	0.294	0.310	0.315
	7	0.299	0.308	0.324
	10	0.288	0.328	0.296
	13	0.282	0.331	0.310
	16	0.306	0.299	0.295
	19	0.279	0.307	0.294
	22	0.294	0.314	0.310
	25	0.271	0.316	0.298
	28	0.296	0.313	0.300
	30	0.291	0.330	0.301

COMMENTS:

newfoundland labrador **hydro** a nalcor energy company

UNIT #3 - BOILER

REHEAT PLATENS

NDE SHEET No.: U3 - 24.1 Rev. 4 (pg. 2 of 2)
NON-DESTRUCTIVE EXAMINATION
MAINTENANCE FILE NUMBER 102-05-1-17
USE ADDITIONAL SHEETS IF NECESSARY

Inspector's Name & Signature:	Mike Gran for Mil St / Sid Rowsome SR
Certification Level & CGSB #:	Level: II / I CGSB #: 14084 / 17346
Instrument Type & Serial #:	Type: Olympus 37DL plus Serial #: 071524109
Date of Inspection:	July 6 / 2017

12" NOT 4"

Area of Boiler and General Description of Non-Destructive Examination to be Performed	PLATEN #	U.T. READING (in.) CENTRE OF MANWAY	SOUTH BEND	OVER NORTH SOOTBLOWER	4" FROM SOUTH BEND
Reheater Tube Assemblies - Upper Section 1.) U.T. Thickness Measurements On Specified Platens *ABOVE HEAD* - Readings To Be Taken On First Tube Above Head *Access On 9th Floor Through East Or West Manways Towards The Center Of The Unit* **NOTE - AT EACH LOCATION, TUBE TO BE SCANNED FROM THE 3-9 O'CLOCK POSITIONS, LOWEST READING IS TO BE RECORDED** *See Drawing For Details* *(Tubes Numbered East To West)*	1	0.174	0.124	0.173	0.195
	7	0.164	0.109	0.161	N/A
	13	0.158	0.113	0.161	0.164
	19	0.146	0.122	0.150	N/A
	21	N/A	0.131	N/A	0.152
	25	0.148	0.121	0.148	0.161
	29	N/A	0.111	N/A	0.155
	31	0.150	N/A	0.159	N/A
	33	N/A	0.124	N/A	0.172
	37	0.162	0.120	0.163	0.168
	41	N/A	0.117	N/A	0.160
	43	0.170	0.084	0.154	0.164
	45	N/A	0.119	N/A	0.171
	49	0.163	0.133	0.172	0.168
	53	N/A	0.133	N/A	0.158
	55	0.157	0.141	0.151	0.164
	60	0.169	0.121	0.171	0.187

COMMENTS:
SPOTS MARKED N/A HAVE NOT BEEN CLEANED, SO COULD NOT CARRY OUT OUR INSPECTION, S.R

Reheater Tube Assemblies - Upper Section 1.) U.T. Thickness Measurements On Specified Platens *BELOW FEET* - Readings To Be Taken On First Tube Below Feet *Access On 9th Floor Through East Or West Manways Towards The Center Of The Unit* **NOTE - AT EACH LOCATION, TUBE TO BE SCANNED FROM THE 3-9 O'CLOCK POSITIONS, LOWEST READING IS TO BE RECORDED** *See Drawing For Details* *(Tubes Numbered East To West)*	PLATEN #	U.T. READING (in.) CENTRE OF MANWAY	BELOW NORTH SOOTBLOWER	1' FROM SOUTH WALL
	1	0.186	0.182	0.196
	7	0.177	0.188	0.185
	13	0.148	0.163	0.186
	19	0.166	0.171	0.202
	25	0.174	0.179	0.206
	31	0.188	0.174	0.197
	37	0.177	0.170	0.188
	43	0.184	0.180	0.196
	49	0.168	0.160	0.192
	55	0.181	0.180	0.188
	60	0.174	0.175	0.199

COMMENTS:

newfoundland labrador hydro
a nalcor energy company

UNIT #3 - BOILER

PRIMARY SUPERHEAT PLATENS

NDE SHEET No.: U3 - 22.1 Rev. 3 (pg. 4 of 5)
NON-DESTRUCTIVE EXAMINATION
MAINTENANCE FILE NUMBER 102-05-1-17
USE ADDITIONAL SHEETS IF NECESSARY

Inspector's Name & Signature:	Mike Gronke / Sid Ransome / Terry Olivier
Certification Level & CGSB #:	Level: II / I / II / CGSB #: 14004/17346
Instrument Type & Serial #:	Type: 37DL Plus Serial #: 071524109
Date of Inspection:	9 Jun 17 + 23 Jun 17

Area of Boiler and General Description of Non-Destructive Examination to be Performed	PLATEN #	U.T. READING (in.) NORTH BEND	SOUTH BEND TO.	UNDER SOOBLOWER (APPROXIMATELY CENTER)
Primary Superheat Tube Asssemblies - Upper Section, Back Pass 1.) U.T. Thickness Measurements Of Specified Platens *BELOW FEET* - Readings To Be Taken On First Tube Below Feet *Access On 10th Floor Through East Or West Manways Towards The North Side Of The Unit* ***(Tubes Numbered East To West)***	1	.315	.311	.376
	6	.323	.345	.355
	12	.343	.322	.378
	18	.328	.348	.392
	24	.322	.341	.374
	30	.320	.345	.387
	36	.321	.347	.385
	42	.321	.348	.356
	48	.337	.349	.389
	54	.320	.329	.382
	60	.331	.346	.387
	66	.327	.337	.352
	72	.314	.335	.372
	78	.348	.321	.377
	84	.314	.337	.375
	90	.337	.328	.370

COMMENTS:

newfoundland labrador hydro
a nalcor energy company

UNIT #3 - BOILER

PRIMARY SUPERHEAT PLATENS

NDE SHEET No.: U3 - 22.1 Rev. 3 (pg. 5 of 5)
NON-DESTRUCTIVE EXAMINATION
MAINTENANCE FILE NUMBER 102-05-1-17
USE ADDITIONAL SHEETS IF NECESSARY

Inspector's Name & Signature:	Terry Oliver
Certification Level & CGSB #:	Level: II CGSB #: 11416
Instrument Type & Serial #:	Type: 37DL Plus Serial #: 071524109
Date of Inspection:	23 JUN 2017

Area of Boiler and General Description of Non-Destructive Examination to be Performed	PLATEN #	U.T. READING (in.) NORTH BEND	CENTER OF ELEMENT (BELOW MANWAY)	12" FROM SOUTH WALL
Primary Superheat Tube Asssemblies - Upper Section, Front Side 1.) U.T. Thickness Measurements Of Specified Platens *BELOW FEET* - Readings To Be Taken On First Tube Below Feet *Access On 10th Floor Through East Or West Manways Towards The South Side Of The Unit* *(Tubes Numbered East To West)*	1	.389	.433	.432
	6	.379	.448	.447
	12	.378	.432	.449
	18	.366	.442	.448
	24	.373	.434	.440
	30	.376	.428	.432
	36	.379	.422	.433
	42	.372	.427	.429
	48	.388	.439	.430
	54	.371	.443	.443
	60	.379	.440	.437
	66			
	72			
	78	n/a	n/a	n/a
	84			
	90			

COMMENTS:

2017 Unit # 3 Upper RH Tube Build Up Weld Map						
Platen # (West to East)	Pad Size(W x L)	Welder ID	Date Welded	Visual	MT	UT Reading (Prior to Pad)
1	N/A	N/A	N/A	N/A	N/A	0.121
2	N/A	N/A	N/A	N/A	N/A	0.141
3	N/A	N/A	N/A	N/A	N/A	0.142
4	N/A	N/A	N/A	N/A	N/A	0.139
5	N/A	N/A	N/A	N/A	N/A	0.141
6	N/A	N/A	N/A	N/A	N/A	0.131
7	2 1/4" x 2 3/4"	EY.3	10-Jul	12-Jul	12-Jul	0.105
8	N/A	N/A	N/A	N/A	N/A	0.133
9	N/A	N/A	N/A	N/A	N/A	0.13
10	N/A	N/A	N/A	N/A	N/A	0.128
11	N/A	N/A	N/A	N/A	N/A	0.122
12	N/A	N/A	N/A	N/A	N/A	0.133
13	N/A	N/A	N/A	N/A	N/A	0.136
14	N/A	N/A	N/A	N/A	N/A	0.128
15	N/A	N/A	N/A	N/A	N/A	0.13
16	2" x 3 1/2"	EY.3	10-Jul	12-Jul	12-Jul	0.119
17	N/A	N/A	N/A	N/A	N/A	0.141
18	4" x 4"	EY.3	10-Jul	12-Jul	12-Jul	0.084
19	N/A	N/A	N/A	N/A	N/A	0.131
20	2 1/4" x 3 1/4"	EY.3	10-Jul	12-Jul	12-Jul	0.117
21	1 3/4" x 2 1/2"	EY.3	12-Jul	12-Jul	12-Jul	0.108
22	N/A	N/A	N/A	N/A	N/A	0.127
23	N/A	N/A	N/A	N/A	N/A	0.124
24	2 1/2" x 2 3/4"	EY.3	12-Jul	12-Jul	12-Jul	0.12
25	N/A	N/A	N/A	N/A	N/A	0.129
26	N/A	N/A	N/A	N/A	N/A	0.135
27	N/A	N/A	N/A	N/A	N/A	0.129
28	N/A	N/A	N/A	N/A	N/A	0.124
29	2 1/4" x 2 1/4"	EY.3	12-Jul	12-Jul	12-Jul	0.111
30	2" x 3"	EY.3	12-Jul	12-Jul	12-Jul	0.116
31	N/A	N/A	N/A	N/A	N/A	0.125
32	1 3/4" x 3"	LC.6	10-Jul	12-Jul	12-Jul	0.111
33	2" x 2 3/4"	LC.6	12-Jul	12-Jul	12-Jul	0.112
34	N/A	N/A	N/A	N/A	N/A	0.133
35	N/A	N/A	N/A	N/A	N/A	0.127
36	N/A	N/A	N/A	N/A	N/A	0.121
37	N/A	N/A	N/A	N/A	N/A	0.123
38	N/A	N/A	N/A	N/A	N/A	0.134
39	2" x 3"	LC.6	12-Jul	12-Jul	12-Jul	0.11
40	N/A	N/A	N/A	N/A	N/A	0.131
41	N/A	N/A	N/A	N/A	N/A	0.127
42	N/A	N/A	N/A	N/A	N/A	0.122
43	N/A	N/A	N/A	N/A	N/A	0.13
44	1 1/2" x 2 3/4"	LC.6	12-Jul	12-Jul	12-Jul	0.112
45	1 1/2" x 3 1/4"	LC.6	12-Jul	12-Jul	12-Jul	0.108
46	1 3/4" x 2 1/2"	LC.6	12-Jul	12-Jul	12-Jul	0.115
47	N/A	N/A	N/A	N/A	N/A	0.131
48	2" x 2 1/2"	LC.6	11-Jul	12-Jul	12-Jul	0.113
49	N/A	N/A	N/A	N/A	N/A	0.127
50	2" x 3"	LC.6	11-Jul	12-Jul	12-Jul	0.11
51	1 3/4" x 2 1/4"	LC.6	11-Jul	12-Jul	12-Jul	0.107
52	2" x 2"	LC.6	11-Jul	12-Jul	12-Jul	0.113
53	1 1/4" x 2"	LC.6	10-Jul	12-Jul	12-Jul	0.116
54	1 1/2" x 2 1/2"	LC.6	10-Jul	12-Jul	12-Jul	0.109
55	1 1/4" x 1 1/2"	LC.6	10-Jul	12-Jul	12-Jul	0.116
56	N/A	N/A	N/A	N/A	N/A	0.14
57	N/A	N/A	N/A	N/A	N/A	0.134
58	N/A	N/A	N/A	N/A	N/A	0.141
59	N/A	N/A	N/A	N/A	N/A	0.137
60	N/A	N/A	N/A	N/A	N/A	0.124

rpc

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3rd April 2017

Mr. Dale Fraser
Northland Consulting Ltd.
4 Atlee Court
Bedford, NS B4A 3V4
Email: northland@eastlink.ca

Dear Mr. Fraser:

Re: Metallurgical Evaluation of Boiler Waterwall Tube #84
Holyrood Generating Station – Unit #1
RPC Report No.: PM/17/J5610R1

1.0 Introduction

A Section of waterwall boiler tube from Unit #1 boiler at Holyrood Generating Station was received at RPC for examination. The scope of work included:

- Visual examination of the waterwall tubes
- Metallurgical analysis of the waterwall tube material
- Dimensional measurements (OD and wall thickness) at 45° intervals
- DWD (oxide loading) tests on both the hot and cold sides of the waterwall tube
- Chemical analysis by EDX of the internal oxide scale on the hot and cold sides of the waterwall tube
- Hardness testing

This letter summarizes the results of the examination.

2.0 Visual Examination

The section of waterwall tube received at RPC is shown in Figure 1. The tube was labeled as #84, hot and cold side. There was no significant bulging of the tube wall. The tube exterior on the hot side was covered with grayish white deposits and on the cold side with a thin mill scale. The tube interior shows a relatively thin well-adhered oxide deposit all around with no significant spalling of the oxide deposit.

Samples of the internal oxide deposits, one each from the hot and cold side of tube #84 was later removed and submitted for elemental analysis. This is further discussed in Section 4.0 of this report.

3.0 Metallographic Examination

A transverse ring section was cut from the waterwall tube, near one end and prepared for metallographic analysis. Dimensional measurements were taken approximately 45° intervals on the ring section and the results are discussed in Section 3.1. Later the ring section was polished down to a 1 micron finish and etched using a nital solution to reveal the microstructure. The etched ring section as examined under an optical microscope at magnifications up to 1000x and the findings are discussed in Section 3.2.

3.1 Dimensions

The ring section from the waterwall tube is shown in Figure 2, along with dimensional measurements. There were no significant variations in the outer diameter and wall thickness of the tube. The outer diameter was relatively consistent, varying between 2.484 and 2.502 inches (63.1 and 63.6 mm), while the wall thickness varied between 0.232 inches (5.89 mm) on the hot side and 0.240 inches (6.10 mm) on the cold side. The inner diameter was also relatively consistent, averaging approximately 2.02 inches (51.3 mm).

3.2 Microstructure

The microstructure on the hot and cold sides of the tube are very similar. The microstructure consists of ferrite and lamellar pearlite, as shown in Figure 3. The material specifications are not known, although this microstructure is consistent with medium carbon steels typically used for boiler tube applications such as SA-210 steels. Some of the lamellar pearlite colonies are aligned in a banded formation, suggesting that the tube was hot-worked during manufacturing (e.g. hot-rolled or hot-extruded). The steel at the OD surface shows a small amount of carbon loss (less volume of pearlite) and minor corrosion pitting, extending less than 200 microns (0.008 in) deep, as shown in Figure 4. On the ID surface, no significant corrosion pitting is noted. Overall, the tube shows no signs of overheating or creep-related damage from service.

4.0 Internal Deposit Analysis

Samples of the internal oxide deposits, one each from the hot and cold sides of tube #84 were removed and submitted for elemental analysis, using the energy dispersive x-ray analyzer (EDX) on a scanning electron microscope (SEM). The EDX method is capable of analyzing small sample sizes. Fourteen deposit particles from each sample were selected for analysis and later averaged. The results of the EDX analysis are given in Table 1. Most of the deposit is iron (likely as iron oxides) with small amounts of chromium, nickel and manganese and trace amounts of calcium, aluminum, zinc, phosphorus, sulfur, silicon, vanadium and sodium.

5.0 Boiler Tub Deposit Mass Loading (DWD)

A section of the waterwall tube, approximately 102 mm (4.0 in) long was cut lengthwise into two halves, one hot side and the other cold side. When the waterwall tube was cut open, a thin internal deposit was observed on both the hot side and cold side of the tube. The internal deposits were removed by sandblasting following the ASTM Standard D3483 test method C.

The sections were weighted to the nearest 0.01 grams both before and after cleaning. The results of the oxide loading are summarized in Table 2. Minor pitting was noted on both the hot and cold side internal surface of the waterwall tube. Metal loss from pitting on the internal surface was minor. Photographs of the DWD test specimens before and after cleaning are given in Figure 5. Photographs showing a few corrosion pitting on the internal surface are given in Figure 6.

6.0 Hardness Testing

Vickers hardness measurements were performed on both the hot and cold sides on the cross sectional ring of the tube. The results are summarized in Table 3. The results showed that the tube had a Vickers hardness (HV) of 121 (or 121 Brinell hardness, HB) on the hot side and 126 HV (or 126 HB) on the cold side. The measured hardnesses correspond approximately to an ultimate tensile strength (UTS) of about 57,500 psi (397 MPa) on the hot side and 59,500 psi (411 MPa) on the cold side.

7.0 Summary

From the present metallurgical investigation, waterwall tube #84 shows no significant degradation from overheating in service. The microstructures of the hot and cold sides of the tube are similar with no thermal degradation of the pearlite colonies and no signs of creep cavitation damage. The extent of the corrosion pitting and metal wall loss on the tube is minor. Outer diameter and wall thickness measurements show a relatively uniform cross section. The internal oxide deposits were relatively thin and the deposit mass loading was determined to be less than 7 mg/cm^2 on the hot side and less than 5 mg/cm^2 on the cold side.

I trust that the contents of this report are satisfactory. Please note that all pieces related to this job will be retained or at least 60 days unless further notification is received by RPC. If you have any questions about the report, please contact the undersigned.

Regards,

Patrick Chan

Patrick Chan
Metallurgist
Physical Metallurgy

Ryan Tarr
Technician

rpc

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Table 1
EDX Results of Waterside Deposit Analysis

Analytes	Water Tube #84 (wt%)	
	Hot Side	Cold Side
Aluminum	0.20	0.09
Calcium	2.02	0.36
Chromium	7.25	6.41
Nickel	2.81	2.07
Iron	63.84	73.62
Manganese	3.44	2.20
Oxygen	16.83	13.19
Phosphorus	1.24	0.16
Silicon	0.22	0.23
Sulfur	0.23	0.23
Vanadium	0.44	0.45
Zinc	1.09	0.63
Sodium	0.41	0.36

Elements <0.15% are below reporting limits.

Table 2
Internal Oxide Loading – Tube #84

Deposit Loading	Hot Side	Cold Side
Area, cm^2	80.58	80.58
Wt before cleaning, grams	486.80	430.14
Wt after cleaning, grams	486.30	429.75
Wt loss, milligrams	500	390
Loading, mg/cm^2	6.21	4.84
Wall thickness, mm	5.92	6.07
Maximum pit depth, mm	0.15	0.25

Table 3
Hardness Results of Tube #84

Location of Tube	Hardness		Ultimate Tensile Strength (UTS)	
	Vickers Hardness, HV	Brinell Hardness, HB	Ksi	MPa
Hot Side	121	121	57.5	397
Cold Side	126	126	59.5	411

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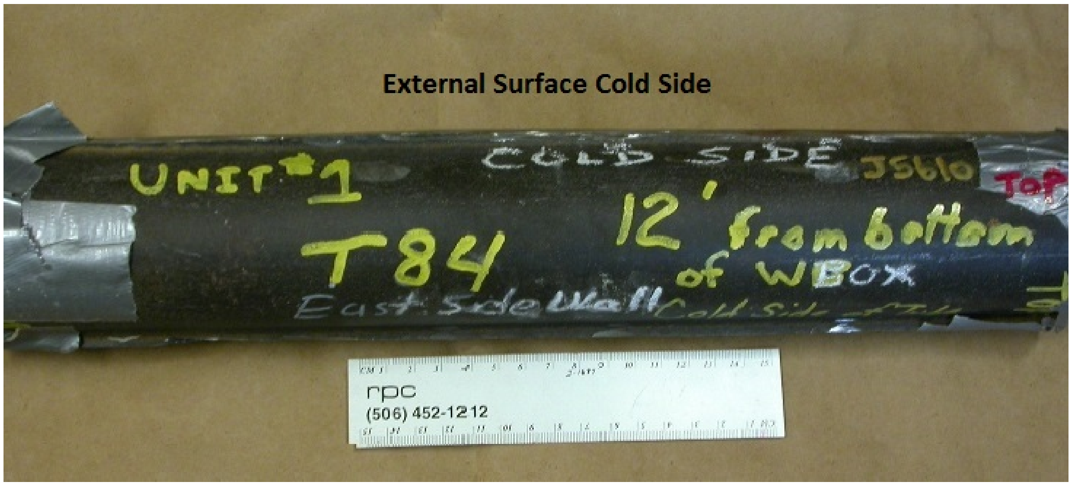

Figure 1. The top photograph shows the external surface on the cold while the bottom photograph the hot side of the waterwall tube section. The cold side has a thin mill scale and the hot side is covered with grayish white deposits. The external surface has been marked as Unit #1, east side wall, 12' from the bottom of w. box.

Photos: J5610/macro-1/C-1 copy and H-1 copy.

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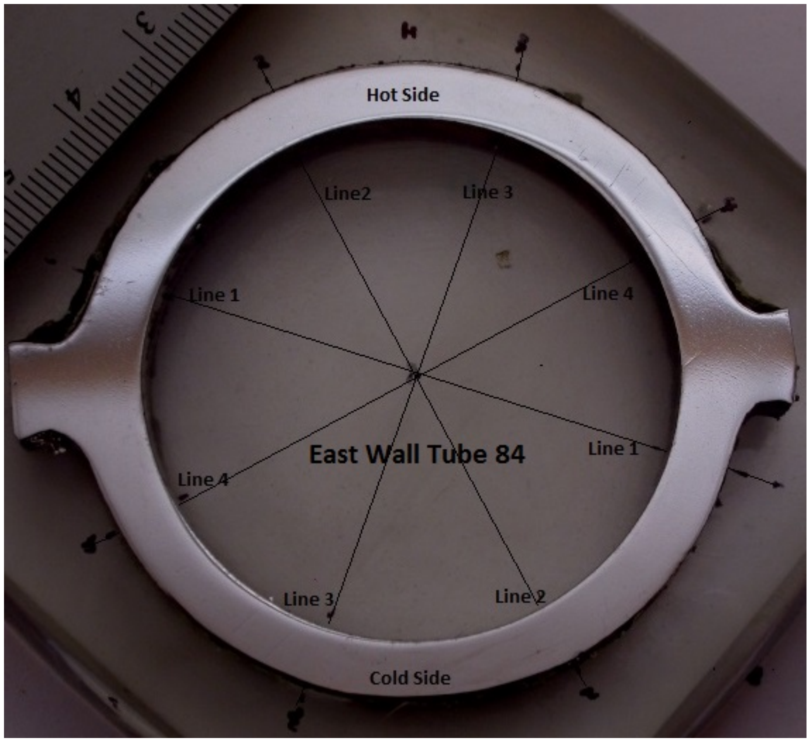

Waterwall Tube #84

Description	Outer Diameter (in)	Inner Diameter (in)	Wall Thickness (in)	
			Hot Side	Cold Side
Line 1	2.502	2.030	0.232	0.240
Line 2	2.484	2.010	0.236	0.238
Line 3	2.500	2.030	0.234	0.236
Line 4	2.493	2.017	0.237	0.239

Figure 2. Photograph of the cross-section through waterwall tube #84. The outer diameter, inner diameter and wall thickness along four transverse lines are given in the above table.

Photo: J5610/Ring/R-2 copy.

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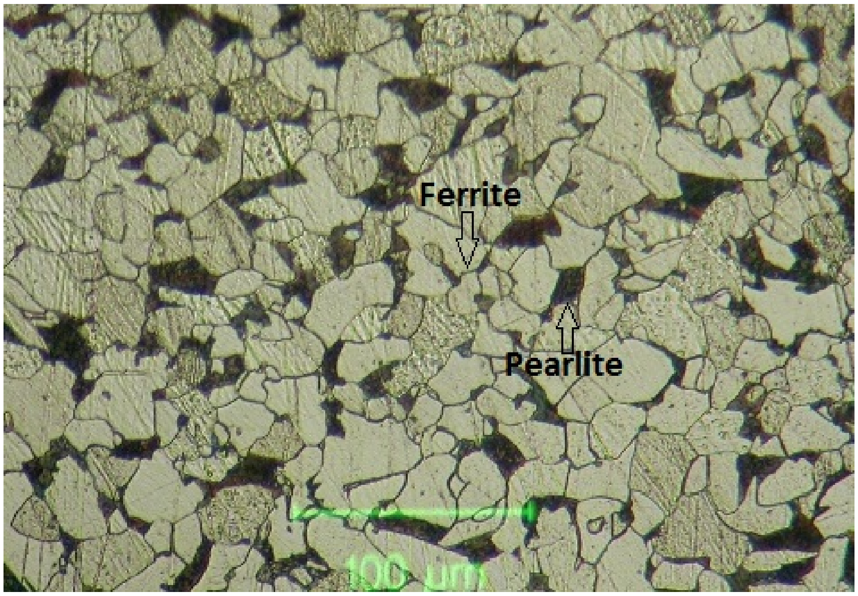

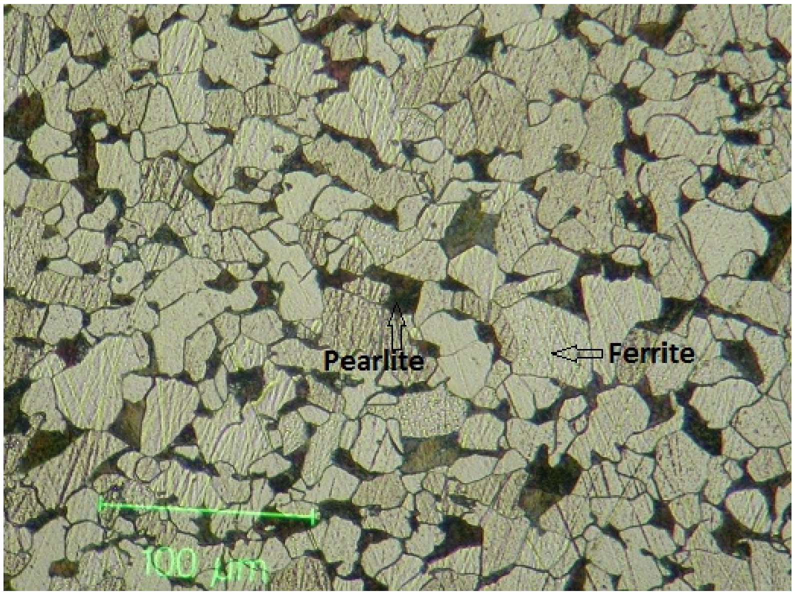

Figure 3. Magnifications of original image: 250x.
Photomicrographs from the cross-section prepared through waterwall tube #84. The microstructures on the hot (top) and cold (bottom) sides of the tube are very similar. The microstructure consists of ferrite and lamellar pearlite. Some of the lamellar pearlite colonies are aligned in a banded formation, suggesting that the tubes were hot-worked (e.g. hot-rolled or hot-extruded). The scale bar is in microns.

Photos: J5610/Micro/M-h copy and M-c copy.

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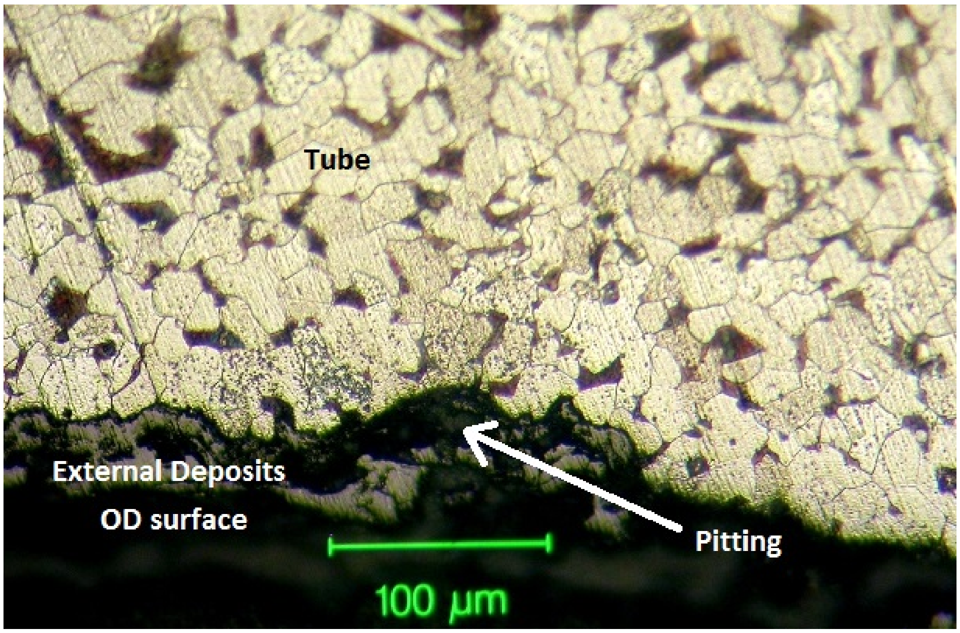

Figure 4. Magnification of original image: 250x.
Photomicrograph from the cross-section prepared through waterwall tube #84. The external surface shows an adhered deposit and minor pitting, less than 200 microns deep. The scale bar is in microns.

Photo: J5610/Micro/M-ec copy.

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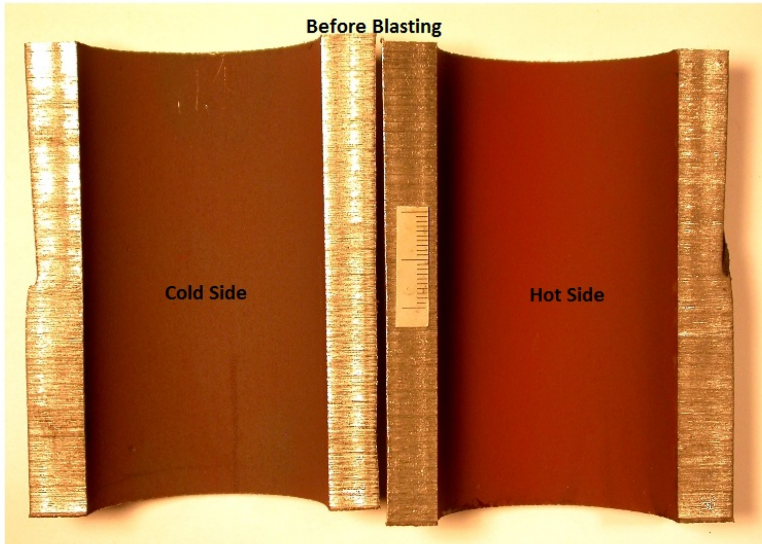

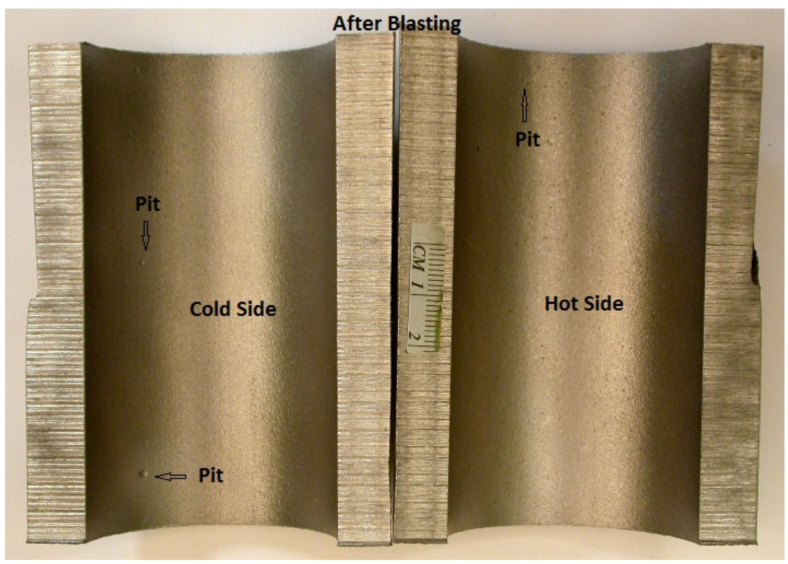

Figure 5. Photographs show the DWD test specimens, one from each of the hot side and cold side, from waterwall tube #84. The photographs show the tube internal surface, prior to testing (top) and after sandblasting clean (bottom). Before the test, the tube interior shows a relatively thin well-adhered oxide deposit all around with no significant spalling of the oxide deposit, as can be seen in the top photograph. After cleaning, minor pitting was noted on both the hot and cold side internal surface of tube #84 (see close-up in Figure 6). Ruler is graduated in millimeters.

Photos: J5610/Loading/L-before copy and L-after copy.

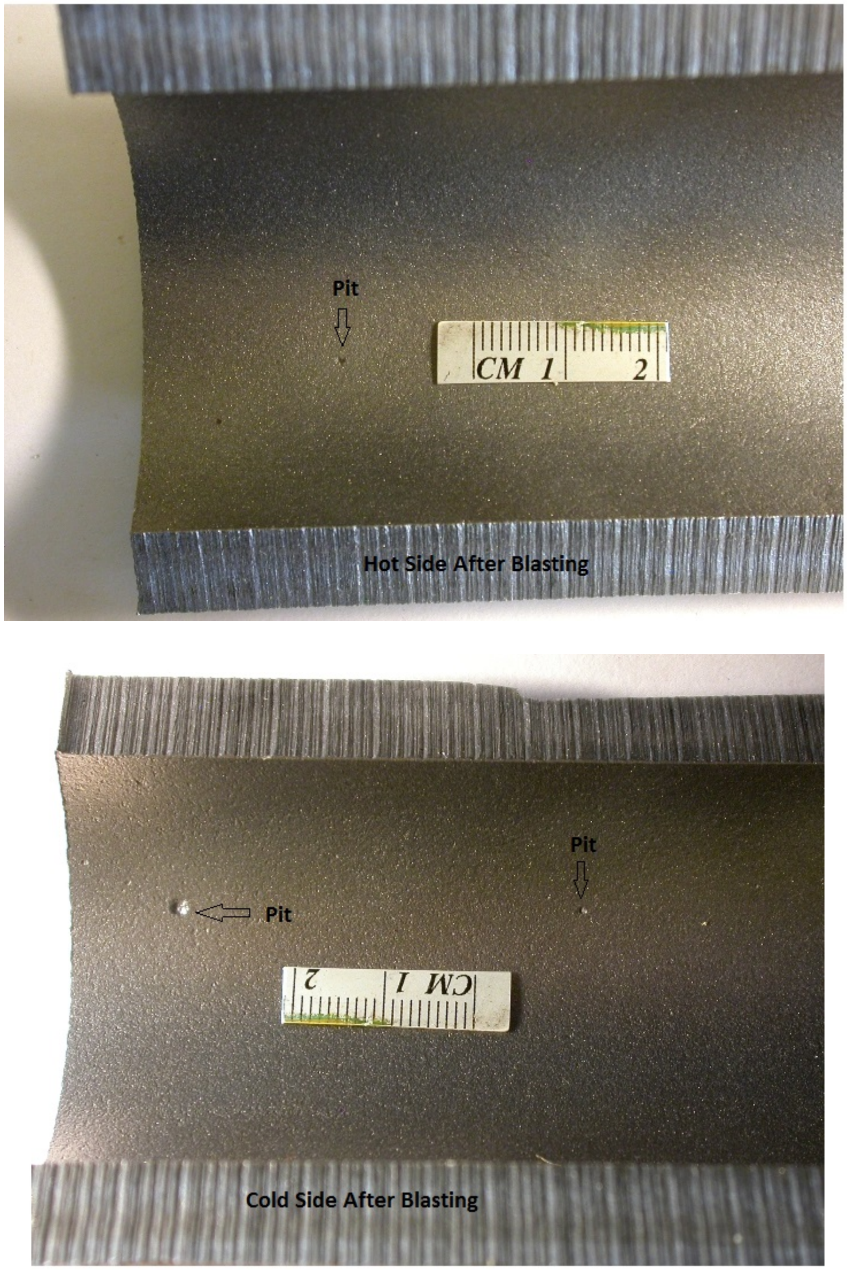

Figure 6. Photographs show the pitting on the tube hot side (top) and cold side (bottom) internal surface, after sandblasting clean. The maximum pit depth on the hot side was measured to be 0.15 mm (0.006 in) and on the cold side was 0.25 mm (0.010 in). Ruler is graduated in millimeters.

Photos: J5610/Loading/L-hot pit copy and L-cold pit copy.

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1st November 2017

Mr. Dale Fraser
Northland Consulting Ltd.
4 Atlee Court
Bedford, NS B4A 3V4
Email: northland@eastlink.ca

Dear Mr. Fraser:

Re: DWD & Corrosion Evaluation of Boiler Tubes
RPC report: MSD/17/J9465R1

Two sets of waterwall boiler tubes (see Figure 1) were received from Northland Consulting Ltd. for internal deposit and corrosion evaluation. The tubes are from Holyrood Generating Station, Holyrood, Newfoundland. The tubes are identified as follows:

Tube 117: West Wall of Unit #1
Tube 18: East Wall of Unit #2

It was requested to perform internal deposit loading (or deposit weight density, DWD) on the hot and cold sides of the above tubes. It was also asked to measure wall thickness and maximum pit depth on the internal surface of the tube. Chemical analysis of the internal deposits was also performed on both the hot and cold sides of the tubes. This letter summarizes the results of the analysis.

Boiler Tube Deposit Loading (DWD)

The internal deposits were removed using the 'glass-bead' method following ASTM Standard D3483. The results are summarized in Table 1. The results indicated that Tube 18-hot side had the highest DWD deposit (7.00 mg/cm^2) while Tube 117-cold side had the lowest DWD deposit (2.95 mg/cm^2). Generally, the cold side had lower deposit loading value than the hot side of the tube. Photographs showing the internal surfaces before and after glass-bead blasting are given in Figures 2-5. Visual examination of the internal surfaces before the blasting showed that the inside surfaces (hot and cold) of the tubes were covered with oxide deposits. On the cold side of Tube 117, some pits were noted, but not on the other three internal surfaces (hot and cold sides of Tube 18 and hot side of Tube 117). Visual examination of the internal surfaces after the blasting showed relatively significant pitting on the cold side of Tube 117. The pitting was mainly concentrated in a narrow band along the whole length of the section on the cold side of the tube. The other three sections of tubes showed very slight pitting. Greatest pit depth (0.013”) was found on the cold side of the 117. All boiler tubes showed wall thicknesses of 0.224” to 0.226”.

Internal Deposit Analysis

Internal deposits were collected from the hot and cold sides of the two tubes. The deposits were subjected to wet chemistry analysis (ICP-MS). The results of the analysis are summarized in Table 2. The results indicated that the deposits from the hot and cold sides apparently contained a major amount of iron, relatively significant amounts of chromium, nickel, calcium and sulfur and small amounts of aluminum, copper, manganese, sodium, potassium, phosphorus and zinc. The total carbon included both the organic and inorganic carbons. These elements are probably in the form of oxides either individually or in combination of oxides. Because of insufficient internal deposits, separated carbons and silicon could not be analyzed.

I trust that the contents of this report are satisfactory. Please note that the components related to this job will be discarded after 60 days, unless further notification is received by RPC. If you have any questions about this report, please contact the undersigned.

Regards,

Patrick Chan

Patrick Chan
Metallurgist
Engineering Services

J L Speelman

John Speelman, P.Eng.
Sr. Metallurgist
Engineering Services
506-460-5674

Table 1
Summary of Boiler Tube Deposit Loading (Deposit weight density or DWD) and Pit Depth Measurements on Tubes 117 and 18

Deposit Loading	Tube 117		Tube 18	
	Hot	Cold	Hot	Cold
Area, cm^2	118.0	121.9	118.6	120.8
Wt. before blasting, gm	668.71	681.15	656.67	673.09
Wt. after blasting, gm	668.18	680.79	655.84	672.54
Wt. loss, mg	530	360	830	550
Loading, mg/cm^2	4.50	2.95	7.00	4.55
Wall Thickness, inch	0.226	0.224	0.224	0.224
Maximum pit depth, inch	0.006	0.013	0.006	0.005

Table 2
Results of Internal Deposit Analysis on the Hot and Cold Sides of Tubes 117 and 18

Element	Concentration (wt%)			
	Tube 117		Tube 18	
	Hot Side	Cold Side	Hot Side	Cold Side
Aluminum	0.160	0.112	0.435	0.666
Barium	0.078	0.015	0.243	0.100
Beryllium	<0.005	<0.005	<0.005	<0.005
Boron	<0.005	<0.005	<0.005	<0.005
Cadmium	<0.005	<0.005	<0.005	<0.005
Calcium	0.984	0.368	3.450	1.680
Chromium	4.13	4.90	3.08	2.98
Cobalt	0.040	0.037	0.024	0.028
Copper	0.146	0.114	0.193	0.135
Iron	66.2	70.6	49.6	58.5
Lead	0.028	<0.005	0.041	0.008
Magnesium	0.069	0.032	0.129	0.117
Manganese	1.16	0.971	0.611	0.824
Molybdenum	0.055	0.071	0.084	0.074
Nickel	1.88	2.27	1.45	1.38
Phosphorus	0.148	0.048	0.838	0.489
Potassium	0.922	0.034	1.54	0.223
Sodium	0.980	0.238	0.99	0.584
Sulfur	2.88	0.60	7.31	7.84
Strontium	0.012	<0.005	0.050	0.023
Vanadium	0.106	0.133	0.196	0.172
Zinc	0.334	0.058	0.469	0.232
Total carbon	0.90	0.69	0.64	0.47
Oxygen	Bal.	Bal.	Bal.	Bal.

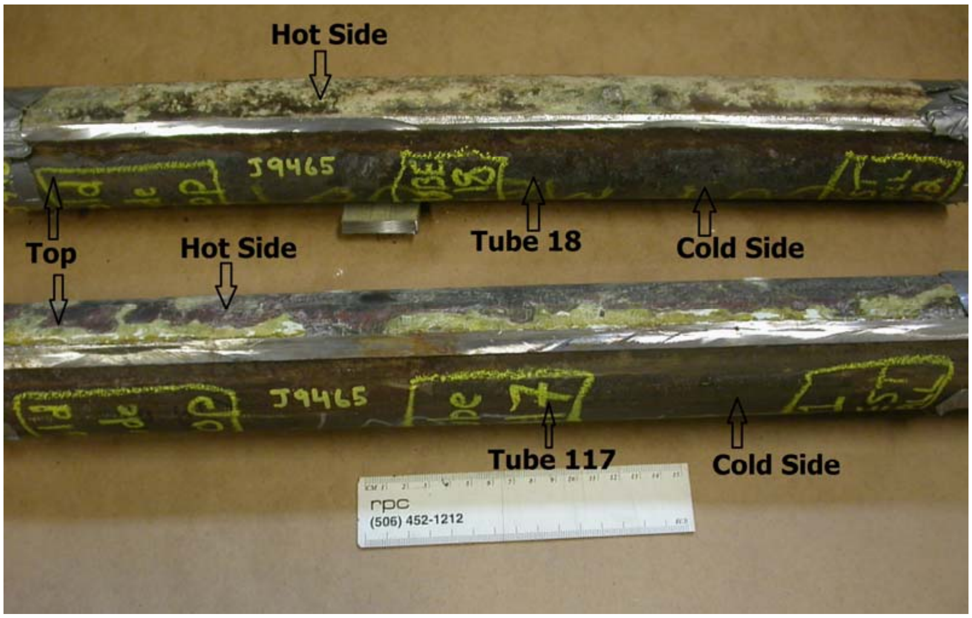
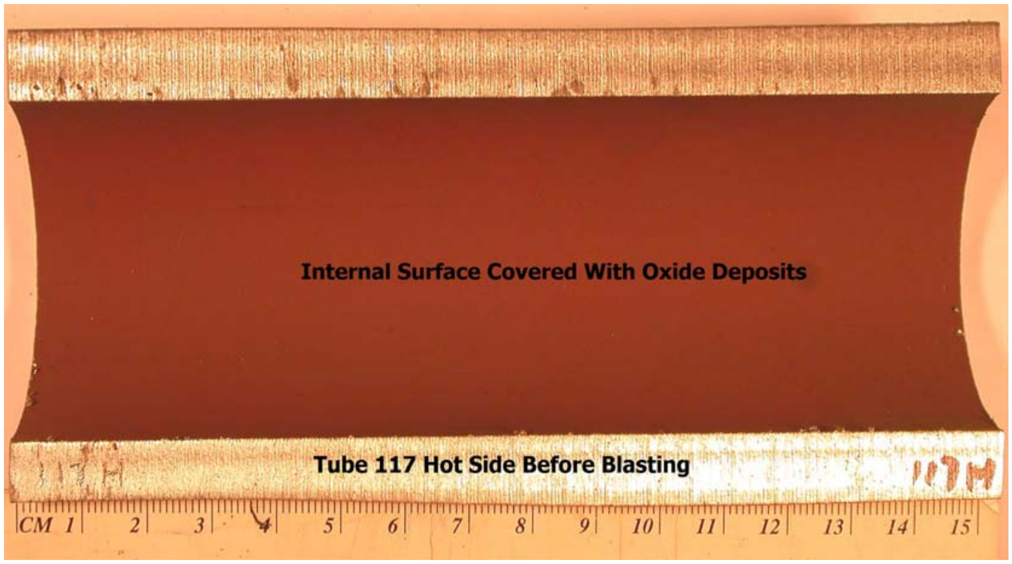


Figure 1. Magnification: 30%x.
This photograph shows the tube sections (Tubes 117 and 18) received. The hot sides were covered with a heavy accumulation of whitish dark deposits while the cold sides with dark brown deposits on the outside surfaces of the tubes.

Photo: J9465-Original-OR-2.copy



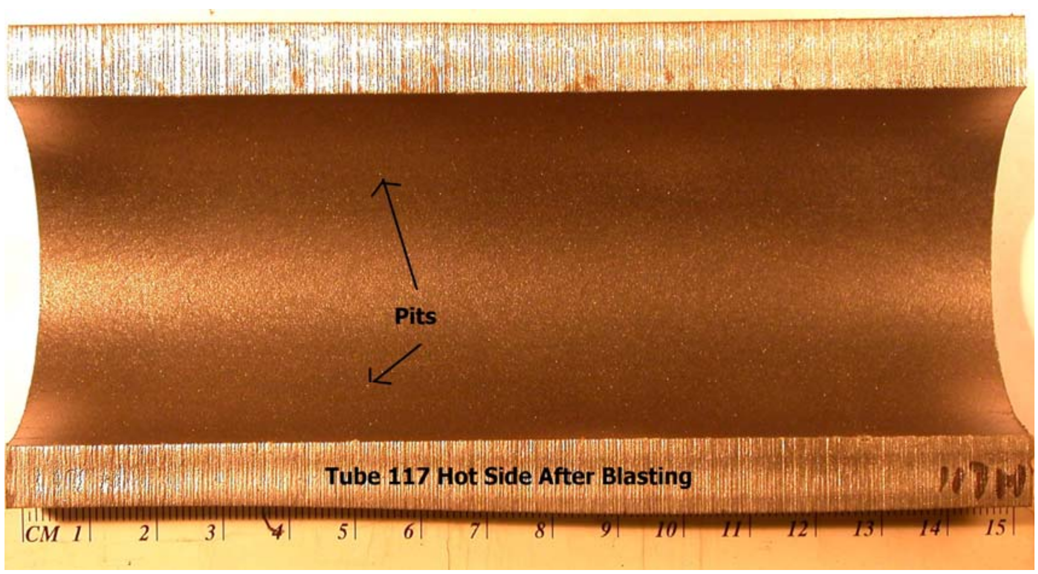
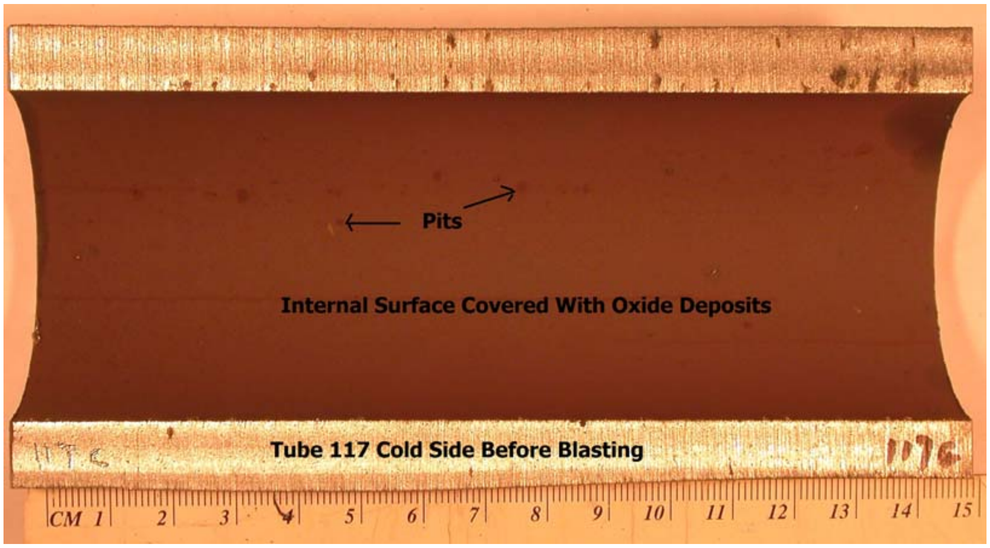


Figure 2. Magnifications: Top 90% full scale, Bottom 90% full scale.
Photographs showing the internal surface before (top) and after (bottom) blasting on the hot side of Tube 117. Before blasting the internal surface was covered with oxide deposits. After blasting the oxide deposit layer was removed and a few tiny pits were noted.

Photos: J9465/Before Blasting-B117-H.copy & After Blasting-A117-H.copy



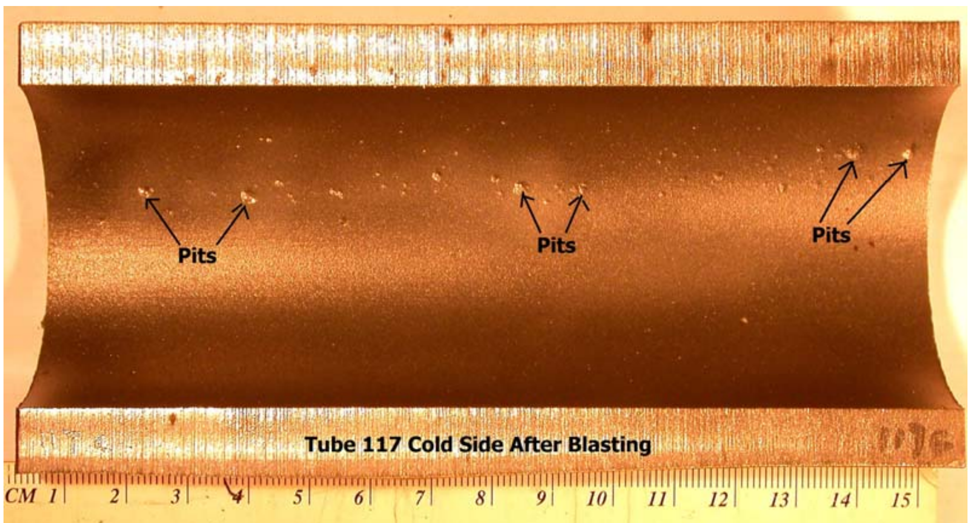
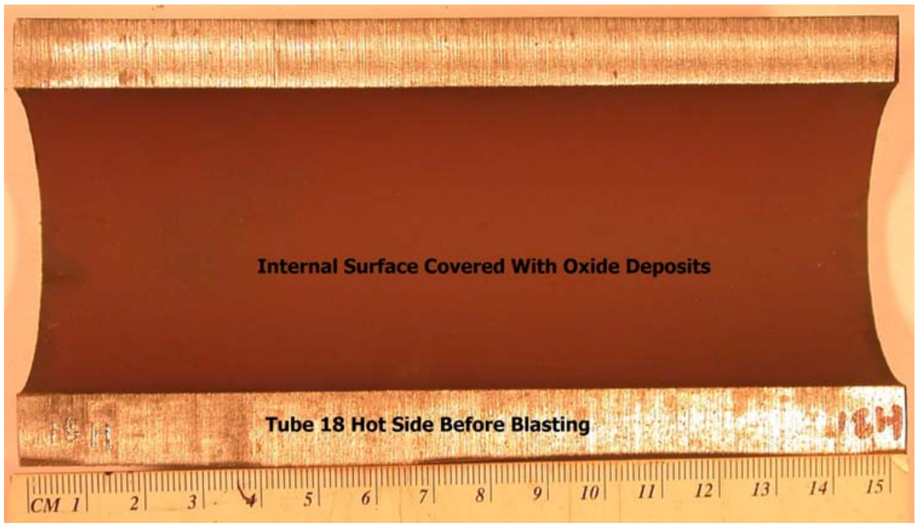


Figure 3. Magnifications: Top 90% full scale, Bottom 85% full scale.
Photographs showing the internal surface before (top) and after (bottom) blasting on the cold side of Tube 117. Before blasting the internal surface was covered with oxide deposits and some pits were also noted. After blasting the oxide deposit layer was removed and the pits, which had been noted before blasting, became very clearly seen. It appears that these pits were concentrated in a narrow band along the whole length of the section on the cold side of the tube. The maximum depth of the pitting on this section was measured to be about 0.013" or about 6% of the wall thickness.

Photos: Top-J9465-Before Blasting-B117-C.copy & After Blasting-A117-C.copy



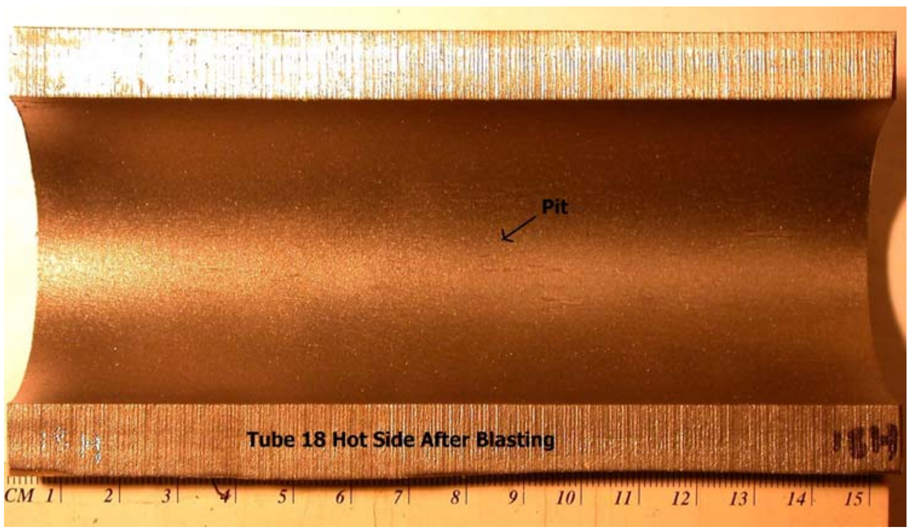
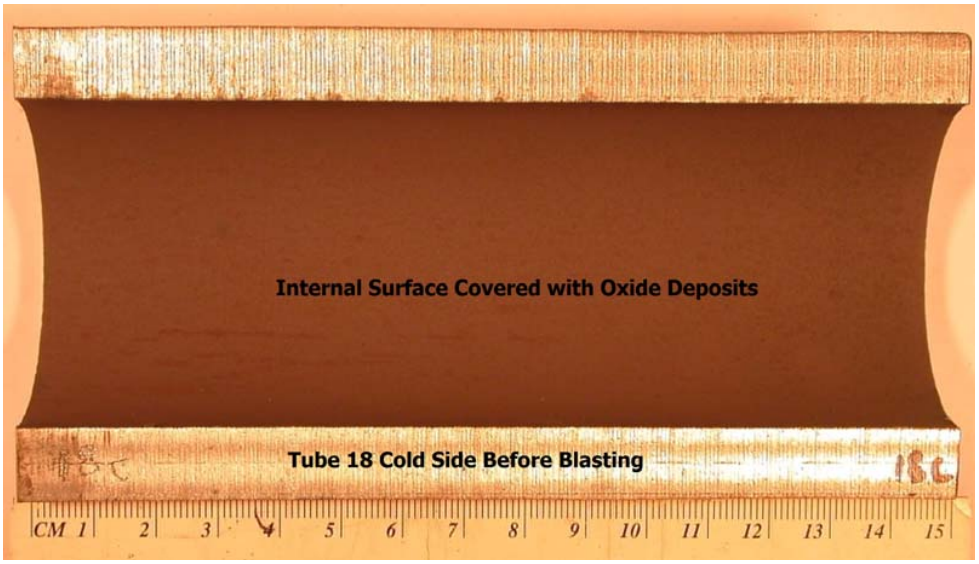


Figure 4. Magnifications: Top 80% full scale, Bottom 80% full scale.
Photographs showing the internal surface before (top) and after (bottom) blasting on the hot side of Tube 18. Before blasting the internal surface was covered with oxide deposits. After blasting the oxide deposit layer was removed and a few tiny pits were noted.

Photos: J9465-Before Blasting-B18-Hot-copy & After Blasting-A18-Hot.copy



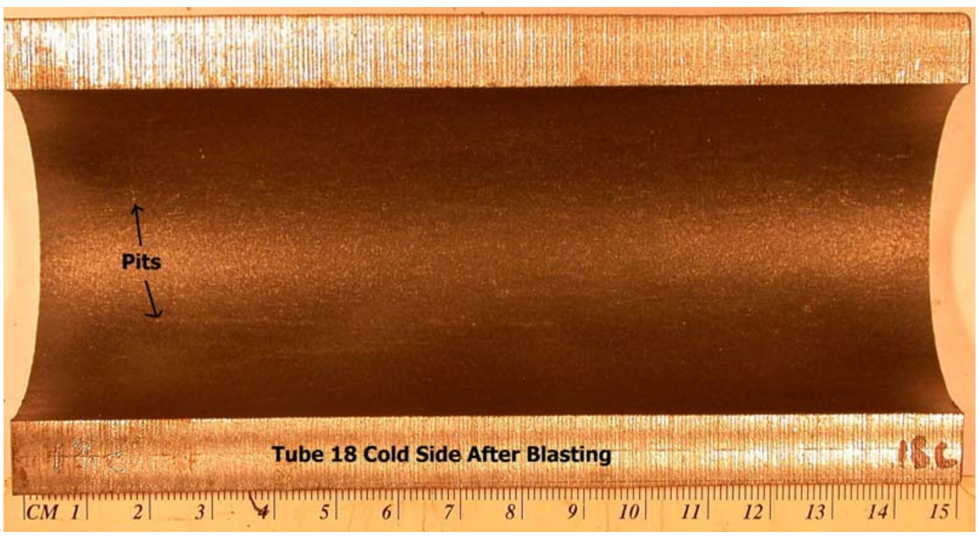


Figure 5. Magnifications: Top 85% full scale, Bottom 85% full scale.
Photograph showing the internal surface before (top) and after (bottom) blasting on the cold side of Tube 18. Before blasting the internal surface was covered with oxide deposits. After blasting the deposit layer was removed and a few tiny pits were seen.

Photos: J9465-Before Blasting-B18-cold.copy & After Blasting-A18-cold.copy

WAYLAND ENGINEERING LTD.

9B-2 Lakeside Park Dr.
Lakeside, Nova Scotia
B3T 1L7

January 7, 2019

Mr. Shaun Lingley, P.Eng.
Babcock & Wilcox PPG
479 Rothesay Ave.
Saint John, N.B.
E2J 2C6

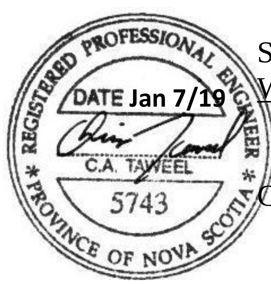
Dear Mr. Lingley,

Wayland Engineering Ltd. was asked to determine the internal deposit weight density (DWD) for a boiler tube sample as per ASTM D3483-14 (glass bead method). The tube was from Holyrood Unit 3 and was identified as Tube #35 (counting left to right) from the west waterwall: 5-1/2 floor.

The tube is shown as received in Figure 1. There was a thick, white deposit on the external hot side of the tube. There was no appreciable corrosion/degradation of the tube observed after removal of this external deposit. A 3" segment removed for DWD testing is highlighted in Figure 1. The 3" segment was split longitudinally to provide a hot and cold side. The external deposits were removed and the weight of each half was determined. After removal of the internal scale/deposit, the sections were re-weighed and DWD calculated. DWD for the hot and cold sides were 6.28g/ft^2 & 4.80g/ft^2, respectively. Results are presented in Table 1 below. There were a few isolated pits observed on the interior tube surface after deposit removal (<0.015"). Measurements of the tube wall thickness showed no appreciable variation around the circumference, Table 2. Figures 2 & 3 show sample interiors before and after deposit removal.

Internal scale/deposit from the hot side was removed and examined by SEM-EDS to determine its chemical composition. Analysis was performed on three separate samples and the average values for the elements are presented in Table 3. The deposit was comprised primarily of Fe and O with minor amounts of Mn, N, & Cu. Trace amounts of Na, Mg, P, Ca, & Cr were also reported.

If you have any questions or would like further analysis performed, please do not hesitate to call.



Sincerely yours,
WAYLAND ENGINEERING LTD.

Chris Taweel, P. Eng.

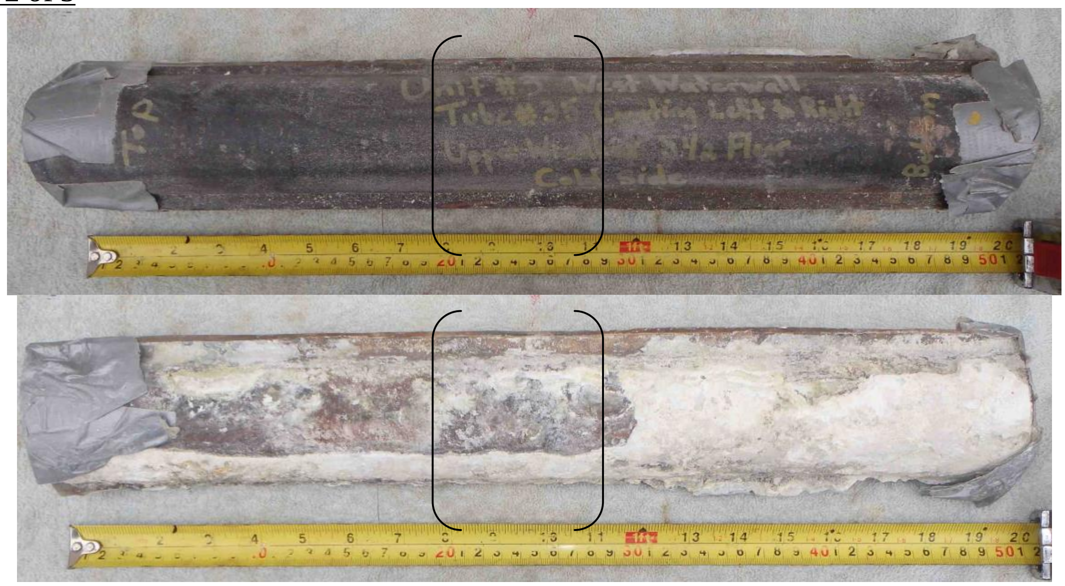


Figure 1: Length of Boiler Tube Showing Location of Test Segment.

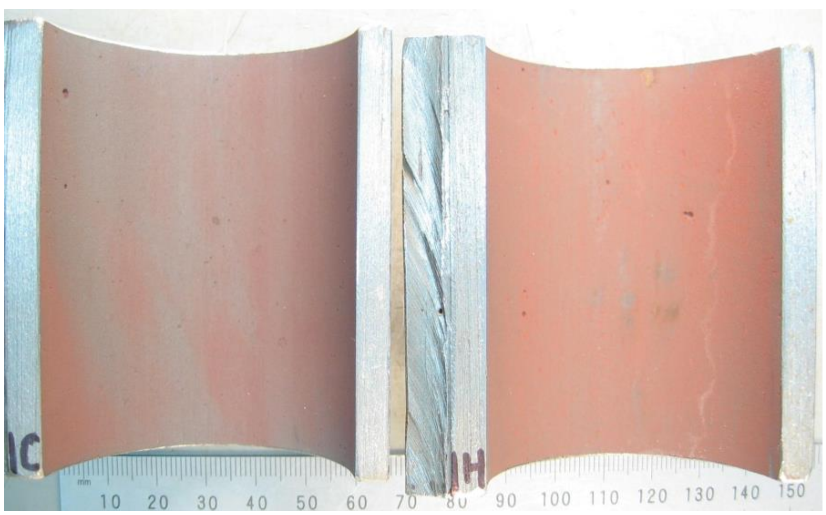


Figure 2: Tube Interior Surface Prior to Scale/Deposit Removal.

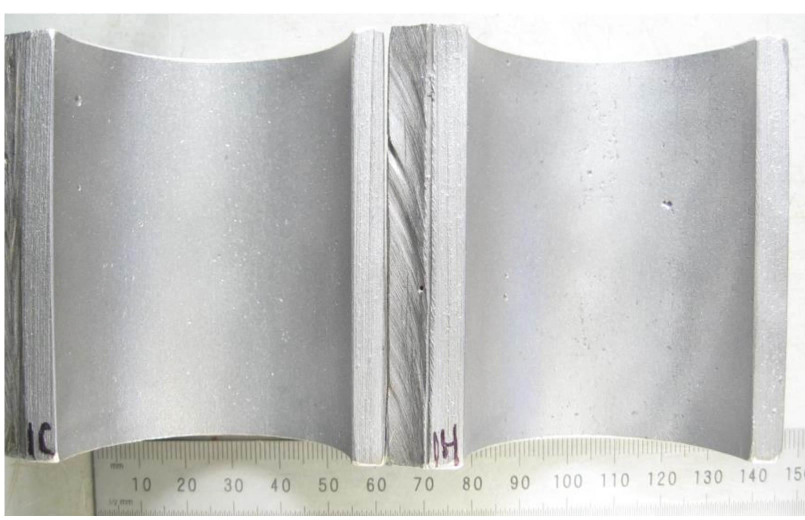


Figure 3: Tube Interior Surface After Scale/ Deposit Removal.

Sample ID	Original Weight (g)	Final Weight (g)	Weight Loss (g)	Sample Length (mm)	Sample Width (mm)	Total Area (mm^2)	DWD (g/ft^2)
1838-1 Hot	321.90	321.50	0.40	76.0	77.8	5912.8	6.28
1838-1 Cold	343.80	343.49	0.31	76.0	78.9	5996.4	4.80

Table 1: Measurements Taken for DWD Determination.

Measurement Location	0^O	45^O	85^O *	135^O	180^O	225^O	275^O *	315^O
Wall Thickness (inches)	0.21	0.21	0.21	0.23	0.23	0.23	0.22	0.21

Table 2: Tube Wall Thickness Measurements. 0^O Arbitrarily Chosen as Crown of Tube Hot Side.
* Reading Taken on Hot Side of Webs.

EDS of Scale, Hot Side of Tube				
	Area 1	Area 2	Area 3	Average
N		5.17	2.15	2.44
O	17.6	19.61	15.95	17.72
Na	0.45	0.27		0.24
Mg	0.17	0.09	0.16	0.14
Al	0.12	0.08		0.07
Si	0.2	0.17	0.22	0.20
Cl				0.00
P	0.55	0.39	0.61	0.52
S			0.26	0.09
K	0.11		0.11	0.07
Ca	0.54	0.42	0.63	0.53
Cr	0.76	0.76	0.67	0.73
Mn	2.61	1.64	2.07	2.11
Fe	76.27	70.93	75.65	74.28
Mo	0.62	0.46		0.36
Cu			1.38	0.46
Ni				0.00
Zn			0.14	0.05

Table 3: Results of SEM-EDS Semi-Quantitative Analysis of Internal Deposit from Hot Side of Tube. (Weight % Normalized After Removal of Carbon.)

CONDITION ASSESSMENT OF FURNACE TUBES

For:

Newfoundland and Labrador Hydro

Holyrood Generating Station, Unit 2

June 2018 Outage

B&W Project Number: BA9272278

By:

The Babcock & Wilcox Company
Field Engineering Services

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TABLE OF CONTENTS

INSPECTION SUMMARY

This report documents the examinations conducted by The Babcock & Wilcox Company (B&W) at Newfoundland and Labrador Hydro's Holyrood Generation Station, Unit 2 in Holyrood, Newfoundland. The inspections were performed during June 2018 outage to inspect lower front slope water-wall tube failures. Techniques employed for the inspection include Ultrasonic Thickness (UTT) "scanning" and remote video probe inspection. Indication forms and photo images contained in this report provide data and detailed information for this assessment. The pertinent results of the inspection are summarized and follow:

Right (East) Side Front Furnace Wall

Two (2) tube leaks were identified on Unit 2's furnace front wall slope, tubes 113 and 114. They were located at approximately 38.28 inches above the Lower Water Wall Header centerline near a furnace wall weld line. Tube 114 appeared to fail from pin hole leaks that formed a pattern of holes circumferentially around the backside of the tube weld. This is the elevation where the lower slope tube meets the lower header nipple (antler). The tube failed above the weld between the front wall slope tube and weld (top side of weld). Tube 113 appeared to fail from a hole made by the jetting of high pressure water from the failure at tube 114. Access was made for repairs through the lower vestibule. Metal skirting was removed from tubes 108 to 118 in a rectangular area, approximately 4 inches above and 10 inches below the furnace tube to header nipple weld transition, to permit access for repairs. UTT thickness readings and ID damage scanning were performed on these (11) tubes on the right-hand side of front wall. Of the 11 tubes scanned, 8 of the tubes had wall thickness at or below 70% of the specified manufactured minimum wall thickness (MWT). Eight (8) tubes showed moderate to severe (6-10db loss) tube ID surface damage with increasing ID damage and thinning closer to the welds.

Oil Ash was chiseled from six (6) tubes 109 to 115 for visual inspection at an elevation of about 4-1/2 linear feet above the leak on the furnace "hot side" of the tubes. Of the 6 tubes uncovered all had moderate corrosion pitting covering the entirety of the tube from crown to membrane. 3 of the 6 tubes were cleaned for UTT scanning by sanding to the pit depths. The cleaned tubes had had measurements slightly above 0.140 inch (70 %) wall thickness. Tube number 114 indicated severe (≥10db loss) ID surface damage in this location with 0.151inch remaining wall thickness. Tube 115 had moderate to severe ID damage (6-10db loss), and 0.159 inches remaining, and tube 111 showed minor (≤6db loss) ID damage with 0.177 inch remaining wall.

Left (West) Side Front Furnace Wall

Access was made from the lower vestibule and the metal skirting removed from tubes 11 to 20 in a rectangular area approximately 4 inches above and 10 inches below the lower slope tube-to header nipple weld transition. UTT thickness readings and ID damage scanning were performed on these left-hand side tubes in the uncovered area. Of the (10) tube areas scanned, all had wall thickness greater than 70% of the specified manufactured wall thickness (MWT). All tubes showed minor (≤6db loss) tube ID surface damage.

Remote Video Inspection

In addition to visual examination of the lower water wall header ID surfaces, the cut tubes around the leak allowed access for the video scope to view the ID of 5 front slope and wall tube surfaces. Tubes 111-115 were examined form about 4 feet above the Water Wall header centerline into the burner areas on the front wall.

Tube ID surface conditions show moderate to heavy deposits and pitting on the lower slope tubes. Moderate pitting reappears in the burner areas. Tubes with a slope, including small bends around burners tend to collect deposits. It is not unusual to find under deposit corrosion on the ID surfaces on sloped tubes. An active condition of oil ash corrosion is forming pits on the OD surfaces of the lower slopes. Separately these conditions are not as concerning. The Header ID surfaces appeared to be in good condition.

Summary

Variations in pit depths, corrosion rates, and thickness outside of the small number of tubes inspected will likely reveal additional tubes close to failure. The boiler has reached an age where the likelihood of ID and OD damage occurring in the same tube proximities has increased to the point of causing one leak. The lower slope on unit 2, considering the current associated data, appears to have the potential to contain these localized areas which have become candidates for increased failures.

No single mechanism of tube degradation appears to be the cause of all the furnace tube failures, but instead a combination of tube thinning, OD pitting, and ID corrosion are each contributing factors, particularly in areas such as weld lines or the lower slope.

Recommendations

B&W recommends water wall tubes with wall thickness at or below 70% of their original specified tube wall should be considered for analysis or replacement. Such tubes may not be tolerant of temperature excursions, continued wall loss, mechanical overloading, or other stresses. Not enough points were measured on the right-hand side of the wall to ascertain how rapidly the damage near the weld line will progress to leaks. There is ample data to suggest that the corrosion has advanced to a condition where failures are probable at the same elevation.

Other areas on the front wall slope also appeared to contain moderate to heavy inside diameter surface pitting above the transition weld on the ID surface as seen in the examination records. No other leaks have been reported on the furnace walls on Unit 2. B&W recommends annually cleaning of the lower slope to slow the progression of oil ash corrosion on the fireside of the furnace tubes. Furthermore, B&W recommends the purchase of spare bent header “antlers” and lower slope bends to facilitate repairs during a forced outage.

Failed Tube Area Examination Record

Customer: Newfoundland and Labrador Hydro

Date: June 2018

Location & Unit #: Holyrood Generating Station, Unit #2

Component: **Lower Slope Right Side on Front Water Wall**

B&W Job #: BA9272278

Examiner: Roger Weinberg

Dwg. #: CE **E-**68-119-214-2

Tube Mat'l.: SA-210-A1

Tube Dia.: 2.50 inch

Temperature of Component: 60°F

Wall Thk: 0.200 inches

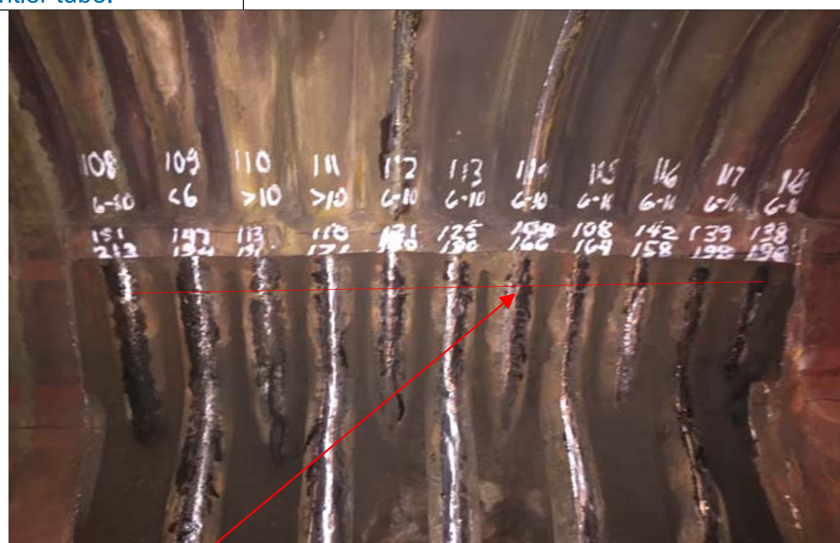
Location of Damage: Backside of tube weld, where lower slope tube connects to lower water wall header antler tube.

Element Count: Pendants 108 to 118

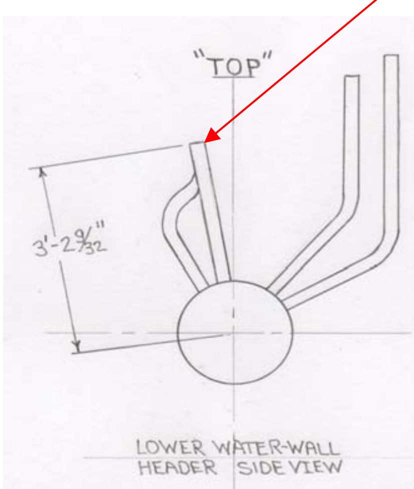
Indications Found

None
Linear Ind
Pitting X
Mach Marks
Tube Seat
Other X
See Remarks

Add'l Photos Provided
Yes



Sketch:



Remarks:

Photo shows the metal skirt cut away from backside of lower slope tubes. A leak on Tube 114 was found at weld transition (shown in red). The weld line is located between the front wall lower slope tubes and the Lower Water Wall Header Nipples (antler tubes).

There was tube wall thinning, Tube OD pitting, and tube ID surface damage on surrounding tubes.

Additional Photographs

Photo #1: Image of every other antler tube having a bend. The bends have thinning close to 70% of remaining wall on the extrados in the cleaned areas.

Photo #2: Image shows OD pits on some of the antler tube bends are deeper than the cleaned areas, now less than 70% remaining wall.

Additional Photographs

Photo #3: Image shows front side of lower slope tubes approximately 4 ft. above the leak area. Three are cleaned for UTT scanning.

Photo #4: Images of pitting on the same tubes. Tubes have been exposed to oil ash deposits for extended periods. The pitting is active.

RECORDABLE INDICATIONS

CUSTOMER: Newfoundland and Labrador Hydro				DATE: 6/13/18	
LOCATION & UNIT #: Holyrood Station Unit 2				JOB #: BA9272278	
COMPONENT: FURNACE LOWER SLOPE Above Backside of Weld			TUBE WALL:	DIA.: 2.5	WALL: 0.200
COMPONENT: HEADER ANTLER TUBE Below Backside of Weld			HEADER NIPPLE:	DIA.: 2.5	WALL: 0.200

			T&R[3]		
Tube No.	T/W/B[1]	EMAT[2]	dB Loss[4]	Thickness	Location/Remarks
108			6-10	0.151	Above weld
108			6-10	0.213	Below Weld
109			≤6	0.147	Above weld
109			≤6	0.194	Below Weld
110			≥10	0.113	Above Weld
110			≥10	0.191	Below Weld
111			≥10	0.110	Above Weld
111			≥10	0.121	Below Weld
112			6-10	0.171	Above Weld
112			6-10	0.190	Below Weld
113			6-10	0.125	Above Weld Failure Caused by Tube 114
113			6-10	0.190	Below Weld
114			6-10	0.104	Above Weld Failed Tube Weld
114			6-10	0.166	Below Weld
115			6-10	0.108	Above Weld
115			6-10	0.164	Below Weld
116			6-10	0.142	Above Weld
116			6-10	0.158	Below Weld
117			6-10	0.139	Above Weld
117			6-10	0.198	Below Weld
118			6-10	0.138	Above Weld
118			6-10	0.198	Below Weld

Tubes highlighted in yellow are at or below 70% of original specified wall thickness

Limitations and Remarks: [1]T-tube, B-bend, W-weld, [2]A = Amp, W = Wall, [3]T&R UT transducer

[4]>10 dB is severe.

We assume no responsibility of any kind due to our interpretation of the quality of the material submitted. All data and information will be held strictly confidential.

Babcock & Wilcox

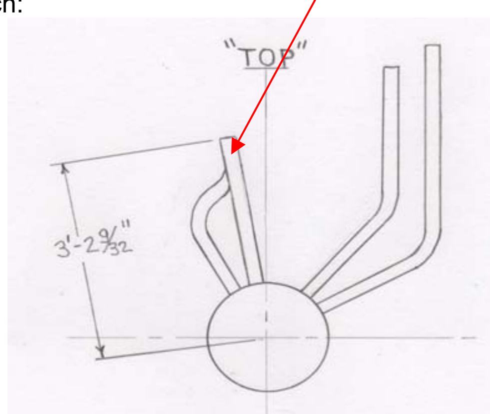
Newfoundland and Labrador Hydro
Holyrood Generating Station, Unit 2

Comparison Front Wall Slope Examination Record

Customer: Newfoundland and Labrador Hydro		Date: June 2018
Location & Unit #: Holyrood Generating Station, Unit #2		
Component: Lower Slope Left Side on Front Water Wall		B&W Job #: BA9272278
Examiner: Roger Weinberg	**Dwg. #:** CE **E-**68-119-214-2	**Tube Mat'l.:** SA-210-A1
Tube Dia.: 2.50 inch	**Temperature of Component: 60°F**	**Wall Thk:** 0.200 inches
Location of Damage: Backside of tube weld, where lower slope tube connects to lower water wall header antler tube.	**Element Count:** Pendants 11 to 20 (RHSW)	

Indications Found None Linear Ind Pitting X Mach Marks Tube Seat Other See Remarks	
Add'l Photos Provided **Yes**	

Sketch:



Remarks:
Metal skirt shown cut away from backside of lower slope tubes closer to Left Hand Side wall. This is to compare the tube conditions close to the leak with tubes at the opposite end of the wall.

Only moderate pitting was found on the uncovered tubes OD. Only minor ID surface damage was indicated. No tubes had wall thickness below 70% of specified wall.

RECORDABLE INDICSTIONS

CUSTOMER: Newfoundland and Labrador Hydro			DATE: 6/13/18		
LOCATION & UNIT #: Holyrood Station Unit 2			JOB #:		
COMPONENT: FURNACE LOWER SLOPE Above Backside of Weld		TUBE WALL:	DIA.: 2.5	WALL: 0.200	
COMPONENT: HEADER ANTLER TUBE Below Backside of Weld		HEADER NIPPLE:	DIA.: 2.5	WALL: 0.200	

			T&R[3]		
Tube No.	T/W/B[1]	EMAT[2]	dB Loss[4]	Thickness	Location/Remarks
11			≤6	0.158	Above weld
11			≤6	0.231	Below Weld
12			≤6	0.171	Above weld
12			≤6	0.238	Below Weld
13			≤6	0.169	Above Weld
13			≤6	0.237	Below Weld
14			≤6	0.168	Above Weld
14			≤6	0.220	Below Weld
15			≤6	0.171	Above Weld
15			≤6	0.204	Below Weld
16			≤6	0.167	Above Weld
16			≤6	0.197	Below Weld
17			≤6	0.160	Above Weld
17			≤6	0.234	Below Weld
18			≤6	0.180	Above Weld
18			≤6	0.214	Below Weld
19			≤6	0.181	Above Weld
19			≤6	0.230	Below Weld
20			≤6	0.174	Above Weld
20			≤6	0.214	Below Weld

Limitations and Remarks: [1]T-tube, B-bend, W-weld, [2]A = Amp, W = Wall, [3]T&R UT transducer
[4]>10 dB is severe.

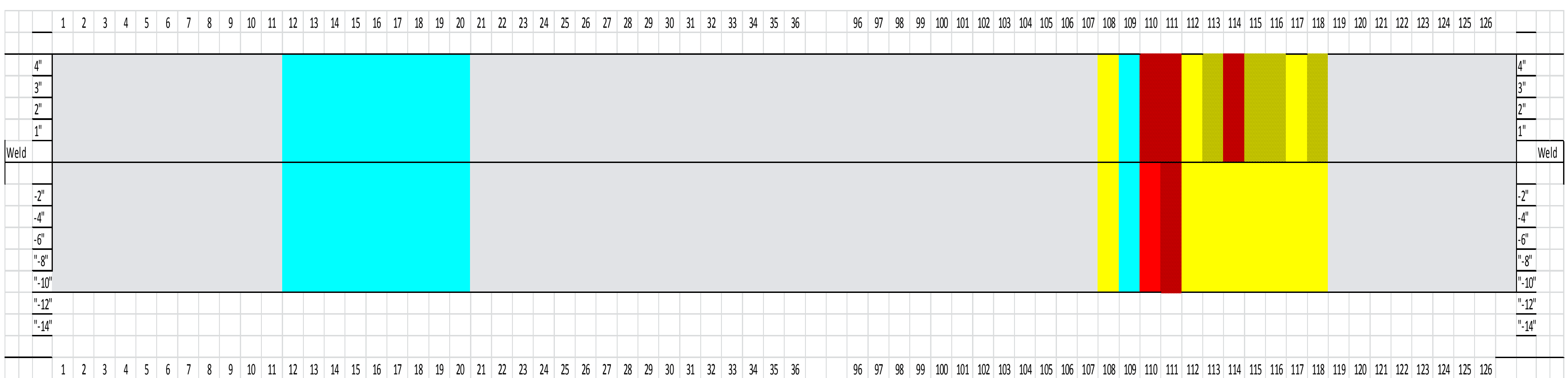
We assume no responsibility of any kind due to our interpretation of the quality of the material submitted. All data and information will be held strictly confidential.

UTT MAPPING OF FURNACE WALL LOWER SLOPE TUBES

BACK SIDE OF TUBES

No Damage	Minor Damage < 6 dB Loss	Moderate Damage 6 dB to 10 dB Loss	Severe Damage > 10 dB Loss	
≤ 70% of MWT[1]	< 6 dB Loss ≤ 70% MWT[1]	6 dB to 10 dB Loss ≤ 70% MWT[1]	> 10 dB Loss ≤ 70% MWT[1]	Un- Scanned

WELD ELEVATION; 38-9/32" ABOVE LOWER WATER WALL HEADER CENTERLINE

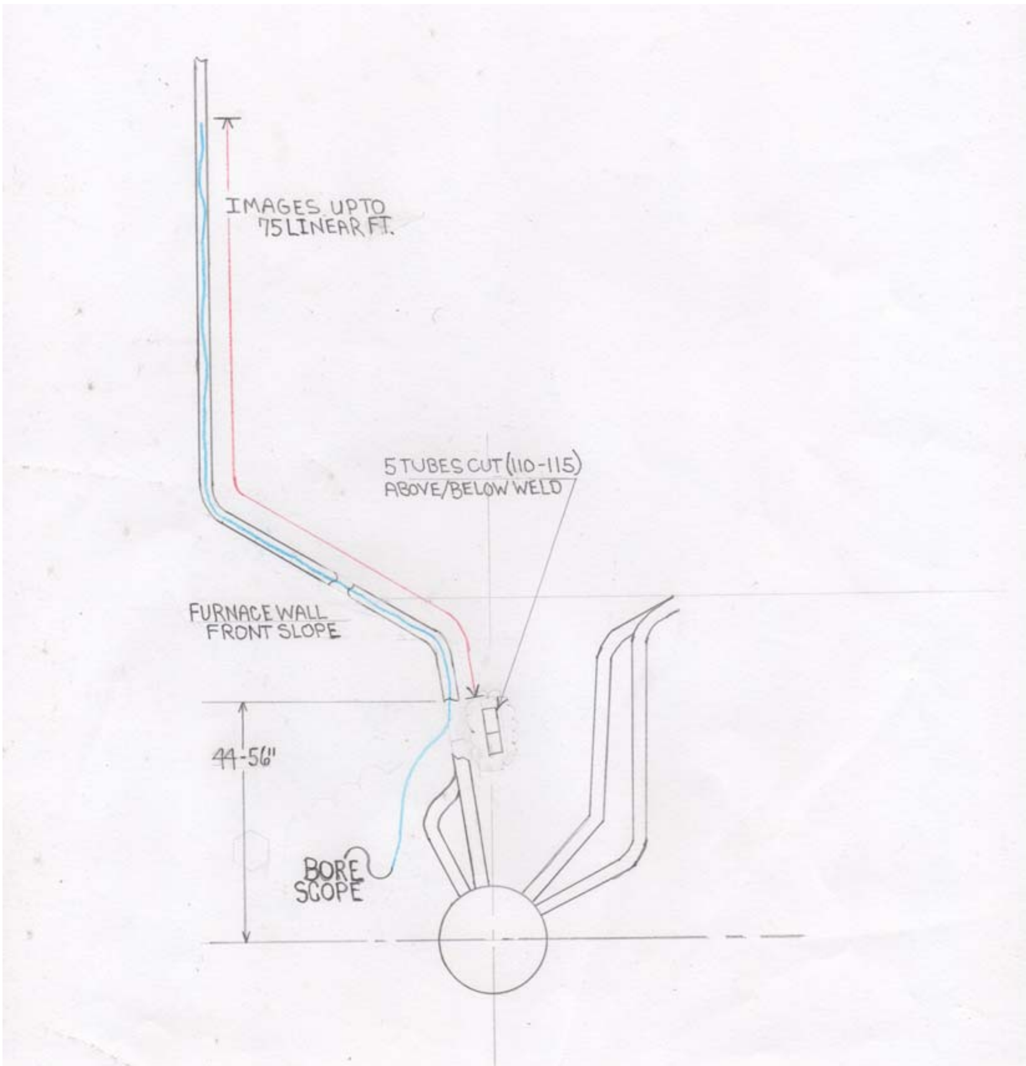


NOTES 1: MWT (Minimum Wall Tube) Refers to Specified Manufactured Thickness, not ASME Min.Wall.
2: Tubes numbered from Left Hand Side Wall to Right Hand Side Wall while facing the front wall.

Front Slope Cut Tube Examination Record

Customer: Newfoundland and Labrador Hydro			Date: June 2018
Location & Unit #: Holyrood Generating Station, Unit #2			
Component: **Lower Slope on Front Water Wall**			B&W Job #: BA9272278
Examiner: Roger Weinberg		**Dwg. #:** CE E-68-119-214-2	**Tube Mat'l.:** SA-210-A1
Tube Dia.: 2.50 inch	**Temperature of Component: 60°F**		**Wall Thk:** 0.200 inches
Point of Tube Access: Backside of tube weld, where lower slope tube connects to lower water wall header antler tube.	**Element Count:** Pendants 110 to 115		
Indications Found None Linear Ind Pitting X Mach Marks Tube Seat Other X See Remarks			
Add'l Photos Provided **Yes**			
See Sketch Next Page:	Remarks: The arrow points to pitting that was similar in the 5 sample tubes (110-115). ID surface Pitting images showed pits were closer together and deeper at lower elevations. As the scope reached burner elevations the pitting reappeared. The image in the rectangle has formed on the ID of the hot side of the tube surface.		

Sketch



Shows Remote Video Scope access to view tube IDs from failed tube area. The Blue represents the probe with camera lens. The scope was pushed into the tubes on a best effort basis as far as the crew could get it. It went just over 75 linear feet up the front wall on one of the tubes, and between 50 to 60 linear feet into the other 4 cut tubes.

Additional Photographs

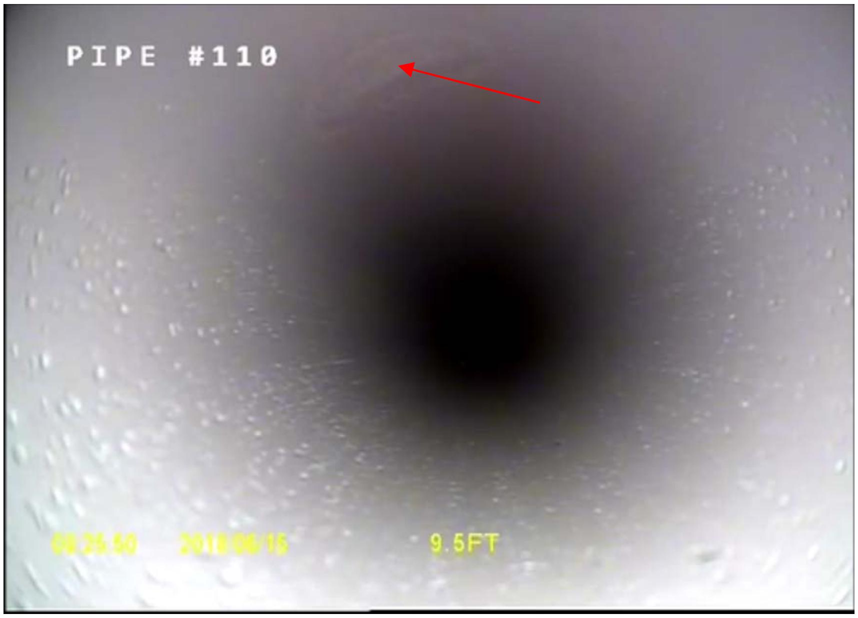


Photo #5: View of corrosion formation on the hot side of the tube.

Photo #6: Image of hot side deposit beginning to exfoliate. Could be similar corrosion as in Photo # 5 above. This tube has an additional layer of deposits possibly resulting in under-deposit corrosion.

Additional Photographs

Photo #7: View of hot side of tube exfoliation. Approximately one (1) foot in from transition weld.

Photo #8: View of deep pitting approximately 37 feet into the tube (In the burner area).

Additional Photographs

Photo #9: Image is a pit in a smooth layer of deposit.

Photo #10: Image of deposit layer. It doesn't take much of a slope or offset to collect layers of deposits, affecting flow and heat transfer.

Lower Water Wall Front Slope Header Examination Record

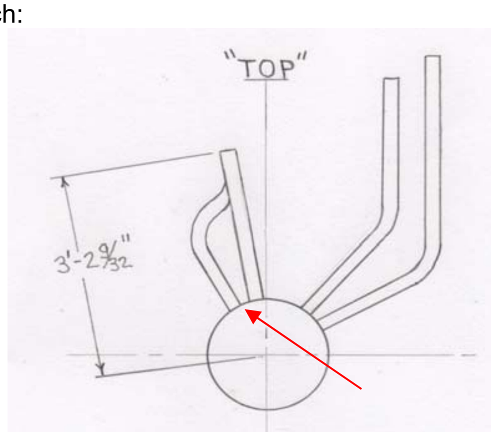
Customer: Newfoundland and Labrador Hydro		Date: June 2018
Location & Unit #: Holyrood Generating Station, Unit #2		
Component: Lower Slope on Front Water Wall		B&W Job #: BA9272278
Examiner: Roger Weinberg	**Dwg. #:** CE **E-**68-119-214-2	**Header Mat'l.:** SA-515-70
Header Dia.: 22.000 inch OD	**Temperature of Component: 60°F**	**Wall Thk:** 1.938 inches
Point of Tube Access: Backside of tube weld, where lower slope tube connects to lower water wall header antler tube.	**Element Count:** Pendants 110 to 115	

Indications Found

None
Linear Ind
Pitting
Mach Marks
Tube Seat
Other
See Remarks

Add'l Photos Provided
Yes

Sketch:



Remarks:
Shows Header looking at bore holes and ligaments.

Additional Photographs

Photo #11: Header Girth with weld ring taken from 22 feet in.

Photo #12: Minor pitting surrounds drain.

Additional Photographs

Photo #13: View of girth weld with moderate damage crossing the weld and a bit more severe nearby.

Photo #14: View of the same pits a bit closer. This depth is not too alarming if the boiler is to be decommissioned in 3 years. Pits of this depth on a circumferential weld would be more concerning.

NOTIS® INSPECTION OF SUPERHEATER TUBES

For:

NEWFOUNDLAND AND LABRADOR HYDRO

Holyrood Generating Station, Unit 3

September 2018 Outage

B&W Project Number: BA9272278
B&W Original Contract: 122-7391

By:

The Babcock & Wilcox Company
Field Engineering Services

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CONTENTS

Inspection Summary

This report documents the results of a nondestructive remaining tube life exam performed at Newfoundland and Labrador Hydro's Holyrood Generating Station, Unit 3. Between June 5th to 7th 2018, The Babcock & Wilcox Company (B&W) performed an inspection utilizing the Nondestructive Oxide Thickness Inspection Service (NOTIS®) to measure the internal oxide thickness and tube wall thickness at a total of forty-three (43) locations on the secondary, reheat and primary superheater tube banks of this unit. This data is utilized along with B&W databases for steam oxidation kinetics and creep-rupture properties of tube steels to generate remaining life estimates for the tubes. The pertinent results of this inspection are summarized by component and follow:

Secondary Superheater Tubes

Testing on the secondary superheater included four (4) locations in tube rows 29 and 30 near the center of pendant rows, and nine (9) tube bends in the leading edge of the gas pass on row 5. An assumption is being made that tube sizes and materials are still in accordance with the layout after the 2001 bank modifications (Ref: BW Eng. Study Report TP9000932_R2 "Current Layout"). Remaining creep life is based on these referenced tube specifications and the data collected from site.

Of the 4 locations in the outlet bank tested, no tubes had estimated remaining creep-life less than 200,000 hours. No tubes have wall thickness below 85% of the original specified wall. The thinnest wall and thickest oxide reading was located on Pendant 30, row 29. The remaining wall measured 0.373", or 94% of the original specified 0.398" MWT. This tube had an oxide thickness of 0.018", which suggests that it is not suffering from long term overheating due to the age of the tube.

Of the 9 locations tested on a leading-edge row bends of the inlet bank, no tubes had a remaining life of less than 200,000 hours. The lowest tube wall thickness was found on Pendant 22 and was 0.242", or 93% of original specified wall. A visual inspection in the measurement areas did not reveal excessive pitting or active corrosion on the OD of the bends. Wall thickness and ovality vary considerably in bends and a stress for remaining life calculations cannot be readily determined. In the remaining life calculations for these bends, stress was calculated based on a straight tube section and thus does not accurately reflect true remaining life. However, thickness readings are reliable and oxides on measured tubes were ≤ 0.006 thousandths of an inch with low variation in oxide thickness signals between tubes.

Reheat Superheater Tubes

Testing on the reheater included eight (8) locations in 4 rows on pendants 41 and 42, and an additional ten (10) locations on tube bends in row 19 (leading edge). Tube rows 15 through 18 were removed from the bank in 2001 as part of a reheater modification. There currently are no tube rows between rows 14 and 19; however, the numbering was kept for consistency with previous records. An assumption is being made that tube sizes and materials are still in accordance with the current layout after the 2001 bank modifications (Ref: BW Eng Study Report TP9000932_R2 “Current Layout”). Remaining creep life calculations are based on tube size, material specifications, and test data taken at the elevations provided in the following appendices.

Of the 8 locations in the outlet bank tested, one (1) tube had an estimated remaining creep-life of less than 200,000 hours. The lowest remaining hours was measured on pendant 41, row 27 and had a remaining life of 180,000 hours. None of the tubes measured below 85% of specified minimum wall thickness (MWT) on this small sample of tubes.

All ten (10) of the pendant bends tested in tube row 19 had a measured wall thickness below B&W’s suggested repair or replacement of steam-cooled tubes with a wall thickness at or below 0.153", or 85% of original specified tube wall. Some minor thinning would be expected on the bend extrados during manufacturing. Pendant 19, row 11 was the most significantly reduced tube wall measuring 0.117", or approximately 65% of original 0.180" specified wall. This tube also had the lowest remaining creep life at 130,000 hours. The average thickness of the 10 bends is 15% below B&W recommended repair or replace value. Row 19 was inspected on the leading-edge bend where wall thinning is more prevalent. A visual inspection of the cleaned areas of reheater bends did not reveal excessive corrosion or pitting damage. The oxide growth appears to be low on the measured bends indicating no long-term overheating. The tube bend’s walls thicknesses are uniformly thin. The plant has reported no leaks on this row yet.

Primary Superheater Tube Bends

Testing on the primary superheater included a total of twelve (12) locations in tube row 4 (leading edge tube on the economizer side of the convection pass).

All tubes were found to have good remaining creep lives (200,000 hours). No tubes measured below B&W’s suggested repair or replacement of steam-cooled tubes with a wall thickness below 85% of original specified tube wall. Pendant 28 was the most significantly reduced tube and measured 0.294", or approximately 87% of original 0.338" specified wall thickness. All twelve (12) tubes had a measured oxide thickness of ≤0.006" thousandths of an inch. There was no appearance of OD damage from pitting or corrosion.

Recommendations

The four (4) NOTIS points tested the secondary superheater outlet bank were in reasonably good condition. This is a small representation of the remaining secondary outlet bank tubes. B&W would recommend a larger sample size to improve remaining life estimates on this bank.

The leading-edge tube bends on the reheater outlet bank are thin. While the remining hours of creep life are good, the remaining wall thickness may not be tolerant of temperature excursions, continued wall loss, mechanical overloading, or other stresses. There have been no leaks reported and the wear is very uniform, suggesting good start-up and operating procedures. B&W recommends that the plant order enough spare bends to prevent a long outage situation.

The Primary superheater is not likely to require inspection within the next 3 years. A copy of B&W's Plant Service Bulletin 26; Tube Thickness Evaluation Repair or Replacement Guideline is included for reference in Appendix F.

Should plans dictate operation of unit 3 past 2021, B&W suggests re-inspection with the NOTIS® system on the reheat superheater and secondary superheat outlet tubes. Furthermore, we would suggest expanding the scope to include additional locations on the reheater and superheater. This will allow a targeted replacement of only the tubes close to failure.

Notes on the Color Plots Provided in Appendices A thru E

Due to the limited number of test locations on each component accurate trends could not be established; therefore, no graphical presentations (i.e., plots, graphs) were generated. The tabular data is provided in each of the appendices.

The information included in the Appendices is presented in the following order:

1. Inspection Information Sheet

2. Locations of Testing

3. Tabular Data

Unit Information

Customer: Newfoundland and Labrador Hydro   Contract: 122-7391

Station & Unit: Holyrood, Unit #3   Location: Holyrood, NL

Steam Capacity, lbs/hr: Main Steam 1,072,200   Hot Reheat 963,700

Outlet Temperature, °F: Main Steam 1,005   Hot Reheat 1,005

Operating Pres., psig: Superheater 1,757   Reheater 471

Design Pressure, psig: Superheater 2,200   Reheater 650

Start-Up Date: Late 1970's

NOTIS® General Inspection Information

Date(s) of Inspection: June 6th, 2018

Surface Preparation by: Boilermakers   Method: Flap Wheel   Quality: OK

Approximate Hours in Service at Time of Inspection: 156,000

Appendix Ref.	Component	Number of Inspected Elements	Number of Inspected Tube Rows	Number of Locations Tested	Largest Measured Oxide, Inches
A	Secondary Bank	2	2	4	0.008"
B	Secondary Bends	9	1	9	0.006"
C	Reheat Bank	2	4	8	0.020"
D	Reheat Bends	10	1	10	0.012"
E	Primary Bends	12	1	12	0.006"

Total Number of Inspected Locations: 43

Introduction and Background

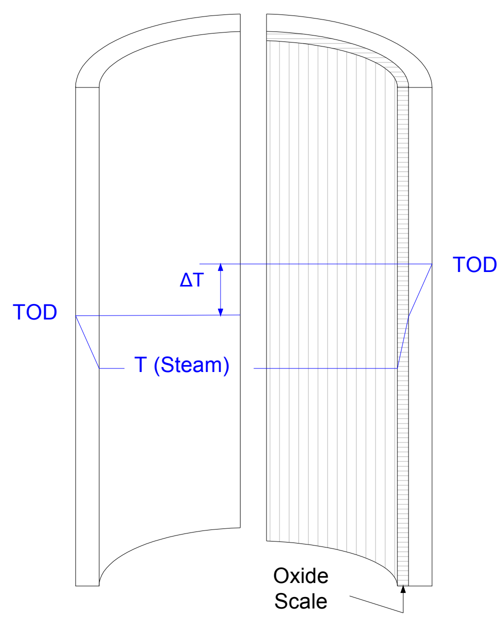
Steam carrying superheater and reheater tubes operating above 900°F (482°C) are subject to failure by creep-rupture. Creep is the process by which metal, when exposed to high temperature and sustained stress, gradually deforms over time. If the applied (hoop) stress due to internal steam pressure and the temperature of operation of a tube are known, the expected creep life can be estimated from tabulated creep data.

When a tube enters service, the metal in contact with the internal steam begins to form a layer of oxide scale known as magnetite (Fe_3O_4). As the tube's service life progresses, the inside diameter (ID) oxide gradually grows in thickness at a rate that is dependent on temperature. This scale acts as a barrier to heat transfer from gas side to steam side and causes an increase in tube metal temperature as depicted in Figure A. Therefore, metal temperature and oxide scale growth are interrelated. Oxide growth is dependent on metal temperature which, in turn, increases as a function of oxide thickness. The magnitude of the increase in metal temperature can range from 1° to 2°F (½ to 1°C) per 0.001 inch (0.025 mm) of scale. This increase in temperature can greatly affect a tube's creep life.

Knowing the thickness of a tube's internal oxide scale makes it possible to estimate the average operating temperature it has experienced in service. Once the average temperature of the tube is determined, the calculation of remaining creep life for use in assessing the general condition of the superheater is possible. In the past, such measurements were obtained by removing tube samples for laboratory examination. This method is costly and time-consuming and gives data for only a few locations. To address these problems, B&W developed NOTIS® (Nondestructive Oxide Thickness Inspection Service). NOTIS® is a patented (U.S. No. 4,669,310) ultrasonic inspection system that nondestructively measures the thickness of a tube's internal oxide and eliminates the need for costly tube sample removal. Although this technique is similar to standard ultrasonic wall thickness tests, this system provides the high resolution needed to detect and measure the ID scale.

Tube wall thickness measurements also provide valuable information needed for the condition assessment of the superheater. Wall thinning due to wastage from such mechanisms as corrosion or erosion must be considered in any remaining life analysis. Wall loss will result in increased stresses in the thinned areas that in turn reduce creep-rupture life. NOTIS® incorporates both ultrasonic wall thickness and oxide thickness measurements in evaluating the condition of the superheater tube. These two measurements are made concurrently for each tube inspected.

Superheater Tube Temperature Profile



0.001" (0.025 mm) scale = 2 °F (1°C) increase in TOD (typical)
For oxide thickness of 0.010 to 0.030" (0.25 to 0.76 mm)
ΔT = 20 to 60°F (11 to 33°C)

Figure A: Schematic illustrating internal oxide scale build-up and its subsequent affect on tube metal temperature.

The NOTIS® technique has distinct advantages over tube sample removal. Many tubes may be assessed with NOTIS® in a short time during a scheduled outage. Decisions regarding future replacement of superheater tubing can be based upon a larger, more representative sampling. ♦

Tube Identification

NOTIS® can be used to measure the oxide and wall thicknesses of a large number of tubes. To avoid confusion, proper identification of each tube is necessary. B&W utilizes a standard numbering scheme that eliminates the possibility of mixing-up data. Typically, many oxide thickness measurements are taken in the same plane lying normal to the tubes (i.e., the same elevation). This plane is called the plane of inspection. The intersection of the superheater with the plane of inspection is a grid like that shown in Figure B. A set of coordinates are assigned to each tube within the grid. The abscissa of the subject tube is the element number counted from the unit's left hand sidewall. The ordinate of the subject tube is the depth of the tube into the element; normally this is counted from front to rear (or from bottom to top for horizontal tubes). Each tube location is, therefore, described by these two coordinates. Figure B shows an example of this numbering system. Oxide and wall thickness measurements are assigned the same coordinates as the tube on which they are taken. The precise location of a thickness measurement is described by attaching an elevation to the tube coordinates. This is especially important when the same tube is inspected at two different inspection planes. ♦

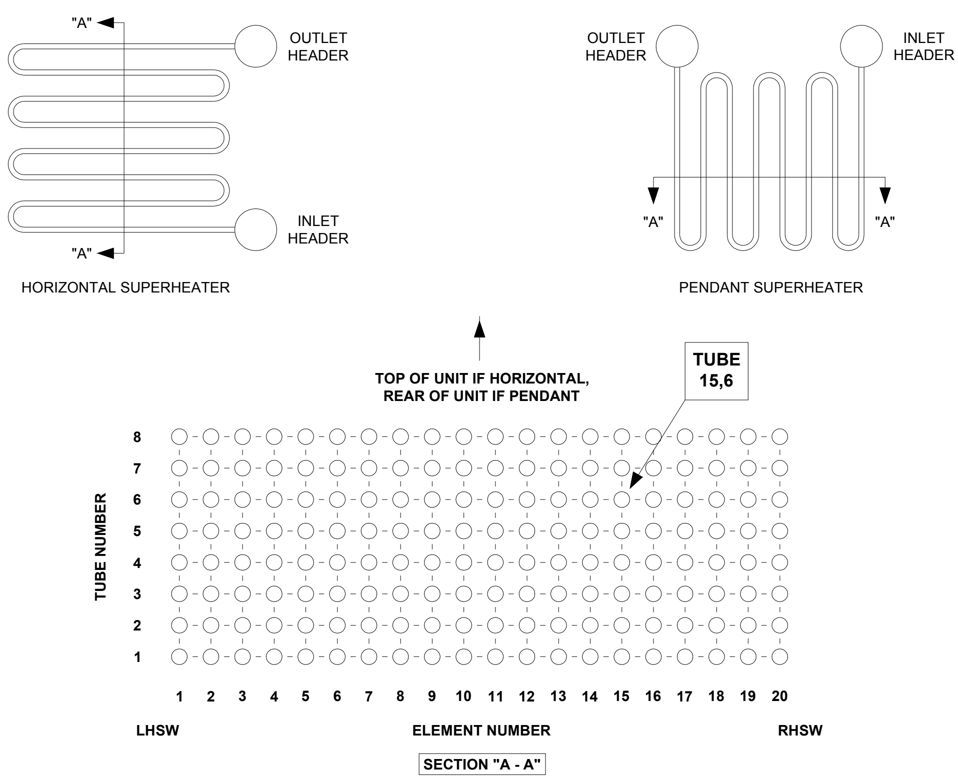


Figure B: Diagrams illustrating the standard numbering system used for NOTIS® inspections.

The NOTIS® System

Basic Theory

The NOTIS® system is able to measure the thickness of iron oxide scale that forms on the inside surface of steam cooled boiler tubes. This thickness measurement is performed using a patented ultrasonic method developed by B&W. A transducer is coupled to a tube's prepared outside diameter (OD) surface and a short pulse of ultrasound is directed into the tube. The reflections from the metal-oxide interface and the oxide-air interface are displayed on the NOTIS® equipment. The time the sound takes to travel between these interfaces, and from the tube's OD surface to the metal-oxide interface, are measured. Oxide and wall thicknesses are then calculated using equations that correlate the time measurements to thicknesses. •

Accuracy and Resolution

NOTIS® provides a resolution of 0.001 inch (0.025 mm) and accuracy of ±0.002 inch (0.05 mm), in the measurement of internal oxides of 0.004 inch (0.10 mm) or greater. These figures are predicated upon the tube OD surface being properly prepared. It should be noted that internal oxide scales less than 0.004 inch (0.10 mm) have only a slight effect on heat transfer and therefore on overall tube creep remaining life. •

Oxide Measurement Capabilities

At elevated temperatures, both the external and internal surfaces of boiler tubes slowly oxidize. The external scale, exposed to combustion gases, is normally removed by a variety of mechanisms whereas the internal scale usually remains intact. Typically, the scale formed on the inner surface is multi-layered and is normally characterized by two separate oxide layers, an iron-rich inner layer and an oxygen-rich outer layer. The oxygen-rich layer generally contains numerous pores or voids. The NOTIS® system can differentiate the small responses (interface signals) between these inner and outer oxide layers. Photomicrographs of these iron-rich and oxide-rich layers are shown in Figure C on the following page. Since the ultrasonic signals from the tube ID-to-oxide scale interface and oxide scale-to-air interface are much greater than those from the iron-rich and oxygen-rich scale layers, a tightly adhering porous oxide layer does not affect the accuracy of the NOTIS® system.

If the iron-rich and/or oxygen-rich oxide layers become disbonded, the NOTIS® system will only measure the oxide thickness to the separation. This situation, indicative of exfoliation, is readily identifiable by the NOTIS® operator due to the abrupt variations in oxide thickness measurements.

Exfoliation is the flaking of scale particles from the internal oxide layer. This condition is undesirable because accumulations of these flakes can become entrapped in lower tube bends, resulting in reduced steam flow, elevated tube temperatures, and reduced tube creep life. Exfoliated scale particles can also cause solid particle erosion when they are entrained in the steam flow and carried to the turbine.

The NOTIS® operator can identify tubes with possible exfoliation. During the inspection, exfoliation is suggested when the amount of scale detected varies in a step fashion within the region on the tube being inspected. For example, a tube may have a 0.010 inch (0.25 mm) thick oxide in an exfoliated area immediately adjacent to a 0.020 inch (0.51 mm) oxide measurement. The irregular disbonding of the oxide scale can produce marked differences in thickness data in the same tube. If an area is found during the inspection where exfoliation is suspected, the largest oxide measured for that tube is recorded and the area is noted as having possible exfoliation.

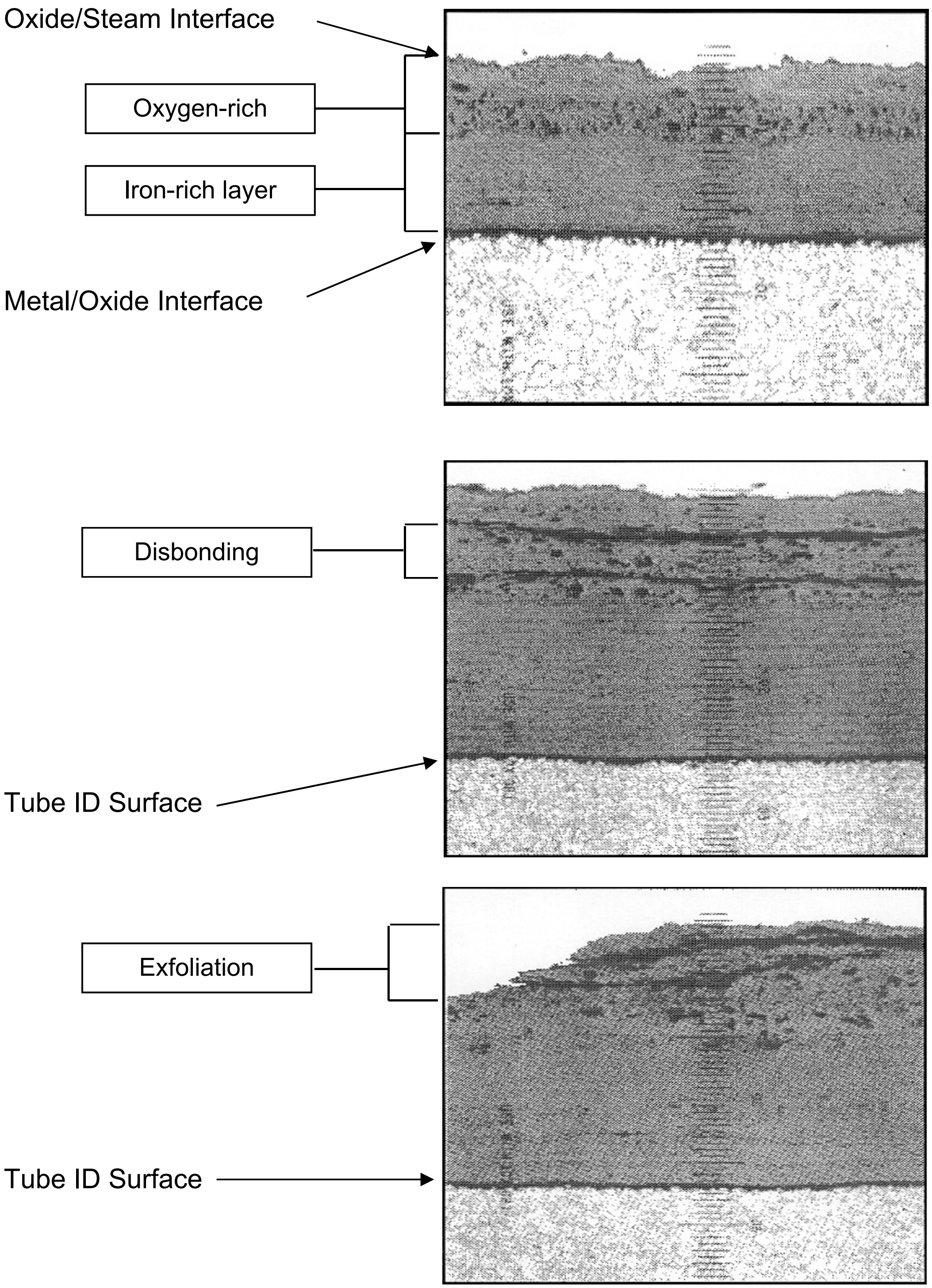


Figure C: Photomicrographs of transverse cross-sections through three (3) tube samples displaying various internal oxide conditions.

The occurrence of exfoliation may also be indicated by the oxide scale thicknesses measured in adjacent tubes within the same row. A thin measured oxide in a tube next to others having thick oxide scales may suggest exfoliation. If exfoliation is suggested by contrast to adjacent tubes, this may also be noted in the report on the inspection data sheets. ♦

Life Prediction Methodology

Basic Theory - The LMP

The prediction of tube creep life is made possible by creep rupture laboratory studies. Laboratory creep specimens, similar to cylindrical tensile test specimens, are machined from various steels. Specimens are then heated to a known temperature (**T**), pulled uniaxially at a known stress (**S**) and the time (**t**) to failure measured. By testing various combinations of stress and temperature, the creep-rupture properties for a selected material can be quantified.

There are numerous ways to present or illustrate a material's creep-rupture properties. One method is to plot laboratory test data using the Larson-Miller Parameter (LMP). The LMP is a function relating **T**emperature and **t**ime. This parameter is defined as:

$$\text{LMP} = [\, \mathbf{T} \times (20 + \log \mathbf{t})\,]$$

where, **T** is the temperature of the test specimen in degrees Rankine [(degrees F + 459.67), or (degrees C + 273.15) X 1.8)], and **t** is the time (in hours) the material is at this temperature. Every tube in service has an associated LMP number that increases as time continues. This LMP data can be related to stress as illustrated in Figure D. This relationship between stress and LMP is used to predict a most probable time to creep rupture failure. Given two of the three factors affecting creep rupture, i.e., temperature and stress (calculated hoop stress of tube), the third factor, time, can be determined from the LMP creep life plots. These factors are utilized by the NOTIS® program to estimate the total expected creep rupture life of a tube in service. The remaining life of the tube is the total life expectancy less the time spent in service.

ASTM has compiled and published creep-rupture data from several sources, including B&W. This data, which uses the LMP to plot creep-rupture curves of LMP versus stress, may be found in the ASTM Data Series publications. There is, unfortunately, a large amount of scatter in LMP values contained in the ASTM data.

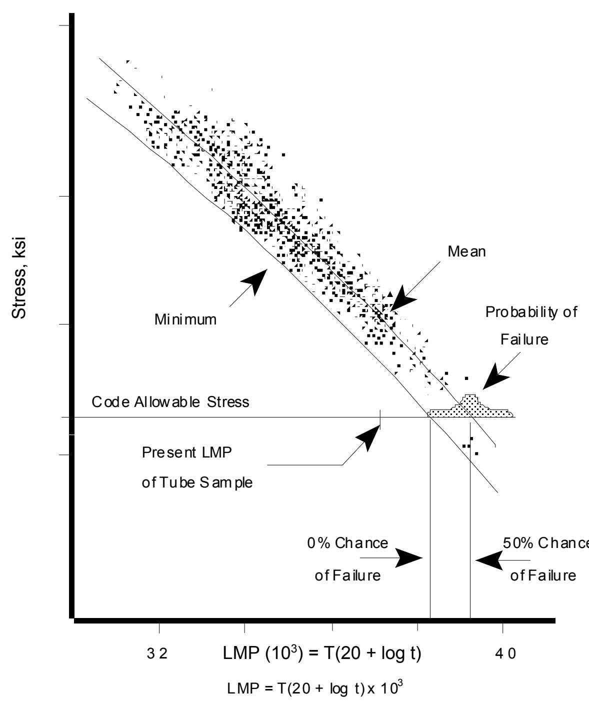


Figure D: Stress vs. LMP plot illustrating the statistical distribution of failures for a specific classification of tubing.

Since at a given stress there is a large variation in the LMP, an absolute time to failure cannot be predicted for a single tube. Instead, a statistical distribution of failures among a large number of similar tubes must be considered.

Among a large sampling of like tubes, the number of failures versus LMP number will follow a normal or bell-shaped curve as shown in Figure D. Failures are less likely at first when the tube LMP approximates the minimum of the LMP scatter. The failure rate will rise to a peak when the tube LMP equals the mean of the LMP data scatter and then finally drop off again. For a single tube, the probability of failure follows a similar distribution curve. •

Creep Life Fraction Analysis

To evaluate the ever changing stress and temperature conditions normally experienced by a superheater or reheater tube, creep life fractions are used. A creep life fraction is the ratio (t/t_f) of time the tube spends at a specific stress and temperature (t), to the time that it would take to cause creep rupture failure at these conditions (t_f). In general, the life fraction method is a way of assessing the relative amount of damage to a tube at a certain set of conditions.

Robinson's Rule of life fractions states that if the applied stress and temperature conditions vary, the sum of the life fractions (or damage) associated with each set of conditions should equal 1 at failure. Robinson's Rule is expressed as follows:

$$(t/t_f)_1 + (t/t_f)_2 + \ldots + (t/t_f)_n = 1 \text{ at failure}$$

where the subscripts 1 through n indicate each condition of stress and temperature.

Example

Part I:

A tube operates at a hoop stress of 5,000 psi (34.5 MPa) and a temperature of 1050°F (565.56°C). What is the predicted time to failure?

Using these parameters and the Stress-LMP curve in Figure D, the effective minimum LMP at failure is 38,100.

From the LMP equation the expected time to failure (t_f) can be calculated.

LMP	=	$[°F + 459.67] \times [20 + \log t_f]$	or	$[(°C + 273.15) \times 1.8] \times [20 + \log t_f]$
38,100	=	$[1050 + 459.67] \times [20 + \log t_f]$	or	$[(565.56 + 273.15) \times 1.8 \times [20 + \log t_f]$
38,100	=	$[1509.67] \times [20 + \log t_f]$	or	$[1509.67] \times [20 + \log t_f]$
25.237	=	$20 + \log t_f$		
$\log t_f$	=	5.237		
t_f	=	172,584 hours		

Thus, this tube would be expected to have a life of approximately 172,584 hours at these operating parameters. If this tube has operated for 100,000 hours at these parameters, what life fraction has been used up?

The creep life fraction expended is:

Life fraction expended = $f_{(expended)}$ = t/t_f = 100,000 ÷ 172,584 = 0.57943

The creep life fraction remaining is:

Life fraction remaining = $f_{(remaining)}$ = 1 - $f_{(expended)}$ = 1 - 0.57943 = 0.42057

$t_{(remaining)} = f_{(remaining)} \times (t_f)$
$t_{(remaining)} = 0.42057 \times 172{,}584 = 72{,}584$ hours

Therefore, this tube has used up approximately 58% of its predicted life (172,584 hours) and is expected to last 72,584 hours if service is continued at these operating parameters.

Part II:

Assume that after operating at 1050°F (565.56°C) for 100,000 hours, this same tube now increases in temperature to 1065°F (573.89°C). The LMP equation is used to calculate t_f at 1065°F (573.89°C) as follows:

LMP	=	$[°F + 459.67] \times [20 + \log t_f]$	or	$[(°C + 273.15) \times 1.8] \times [20 + \log t_f]$
38,100	=	$[1065 + 459.67] \times [20 + \log t_f]$	or	$[(573.89 + 273.15) \times 1.8 \times [20 + \log t_f]$
38,100	=	$[1524.67] \times [20 + \log t_f]$	or	$[1524.67] \times [20 + \log t_f]$
24.989	=	$20 + \log t_f$		
$\log t_f$	=	4.989		
t_f	=	97,499 hours		

Thus, a new tube operating at 1065°F (573.89°C) would have an expected life of 97,499 hours. Recall from Part I, however, that the tube in this example has already used up 58% of its life at 1050°F (565.56°C) giving it a remaining life fraction of 0.42057. Robinson's Rule can now be applied to determine the time this tube can be in service at the higher temperature (1065°F / 573.89°C) after experiencing 100,000 hours operation at 1050°F (565.56°C).

Robinson's Rule: Sum of the life fractions is equal to unity, or one (1), at failure.

$(t/t_f)_{1050} + (t/t_f)_{1065} = 1$
$(100{,}000 \div 172{,}584) + (t \div 97{,}499) = 1$
$t \div 97{,}499 = 0.42057$
$t = 41{,}005$ hours

For the two sets of conditions presented in this example, the combined total life would be 141,005 hours, not the 172,584 hours predicted by the first set of conditions only. This illustrates the effect rising tube metal temperature has on tube life.

In service, superheater and reheater tubes are subjected to varying combinations of stress and temperature. Computer technology is required to calculate and sum the many life fractions needed to predict time to failure. The NOTIS® program performs such a computer analysis. •

Basis of the Remaining Life Analysis

The following assumptions are used for the analysis:

- Creep-rupture is the primary failure mode.
- Tube wastage, or wall thinning rates, are constant with time (i.e., wall thickness is a linear function of time). Wall thinning will continue in the future at the same rate as in the past.
- The original tube wall thickness prior to service is greater than the specified wall thickness. The manufacturer's tube wall tolerance is assumed.
- At time zero, ID oxide thickness is equal to zero.
- The steam side oxide forms an insulating barrier which increases the tube metal temperature with time.
- Steam temperature within the tube remains constant with time.
- The unit will operate in the future much as it has in the past.
- The tube will not suffer a short-term overheat as a result of starvation or pluggage.
- B&W has separated its own LMP data from the ASTM compilation and has fitted a single (minimum) curve to it. This data is used in the remaining creep life calculations.
- For tubes suspected of having exfoliation of the internal scale, the largest oxide measurement obtained from the tube is used for the remaining life analysis. •

• Analysis Procedure

- The past and future life of the tube is broken into specific intervals of time.
  - An oxide growth rate is determined for the tube based on the present oxide thickness, as measured by NOTIS®, and the time in service. The initial oxide thickness is assumed to be zero. Once a mathematical function describing oxide thickness with time and temperature is defined, the oxide thickness in each analysis interval is known. The tube metal temperature in each interval, considering the insulating property of the oxide, is calculated.
  - A linear wall thinning rate is determined for the tube based on the present tube wall thickness measured by NOTIS®, the assumed original tube wall thickness, and the service time of the tube. Once a function describing wall thickness with time is defined, the wall thickness in each analysis interval is known. A hoop stress is calculated using the ASME Boiler Code Section I tube formula in each interval.
- The creep life fraction used in each interval is determined.
  - Given the stress, the LMP of failure may be determined from the creep database.
  - Given the temperature and the LMP of failure, the time (t_f) a new tube would last at each set of conditions is determined.
  - The interval creep life fraction used is t/t_f.

The life fractions are summed over the analysis intervals until the total is 1, at which time failure by creep is possible. The remaining life is obtained by subtracting the tube service time from this total life. •

Accuracy of Creep Life Prediction

Life fraction analysis is the most accurate and widely accepted method for estimating tube lives. Although this method is straight-forward and well documented, it is not exact.

The major problem influencing accuracy is the scatter inherent in material properties. Tubes with the same material classification will possess different creep-rupture properties as illustrated in Figure D. Thus, at a given level of stress and temperature, failure times will vary significantly from tube to tube. Additionally, during service, short excursions to higher temperatures can tend to lower the actual remaining life fraction.

Pin-pointing the exact time to creep-rupture failure for a tube is virtually impossible. Therefore, a range of most probable expected lives is presented. As discussed and illustrated in the Presentation of Results section of this report, each inspected tube is placed into a band of expected remaining life. The range of these bands takes into account the shortcomings of the life fraction analysis as well as the accuracy of the actual operating parameters for the unit. In effect, these bands are confidence limits.

Although remaining life estimates should be viewed qualitatively rather than absolutely, much useful information can be realized. Decisions regarding repair or replacement of critical locations can be made based on the findings. Re-inspection intervals can also be based on the remaining life estimates of critical locations. •

NOTIS® Re-inspection Intervals

A NOTIS® re-inspection period will often be recommended. The benefit of a re-inspection is two-fold. First, it is set so that worsening conditions can be tracked, thus minimizing the possibility of forced downtime due to creep-rupture failures. Secondly, re-inspection is used for fine tuning life predictions. Comparisons can be made between expected and actual internal oxide growth and projected wall thinning rates. The re-inspection will increase the confidence level of subsequent life predictions and ultimately provide more accurate estimates. ♦

Interpretation of Results

Careful examination of the oxide thickness, wall thickness, and remaining life provided in the data sheets and graphs can reveal much about the operation of the unit. B&W has inspected many units with NOTIS® and correlated certain patterns observed in the data with known unit operation. Some examples follow.

- Within a single tube row, oxide thickness is an indication of relative temperature exposure. In opposed wall fired units, gas temperatures will be lower at the sidewalls and peak toward the centerline and/or quarter points of the unit. In tangentially fired units, gas temperature peaks usually occur near the sidewalls. Within a tube row, oxide thickness tends to follow furnace gas temperature, so localized peaks on single elevation oxide plots can be an indication of gas temperature unbalance across the boiler. Other reasons for locally high oxides, which indicate elevated metal temperatures, can indicate the presence of a steam flow obstruction or imbalance in the circuit.

- Depending upon the circumstances, wall thickness data may indicate the occurrence of certain phenomena. If all tubes that exhibit reduced wall thickness are in the same area of the component, this is a strong indication of erosion or ash corrosion. If elevated oxide readings are found in the same area, this region may be running hotter due to higher gas velocity and temperature. Higher gas temperatures, and the insulating effects of the thicker oxides, would promote ash corrosion which can account for thinner walls. Thinner walls in tubes on either side of a soot blower cavity, regardless of the location from sidewall to sidewall, may be the result of soot blower erosion.

-

- Remaining life estimates are an effective way of combining a tube's wall and oxide thickness into a relative measure of creep damage. Remaining life decreases with increasing oxide thickness (temperature) and wall loss (stress). Hence, remaining life graphs will reflect the above mentioned phenomena.

- Although NOTIS® provides much useful information, it is not absolute. The NOTIS® remaining life analysis provides a relative assessment of the inspected component's condition. While the data collected with the NOTIS® system is quite accurate, the results should be viewed on a qualitative rather than an absolute basis. ♦

APPENDIX A

Secondary Superheater Outlet Bank Tubes

NOTIS® Component Inspection Information

Component: Secondary Superheater

Elements Inspected (Numbered from Left Hand Side Wall)

Elements: 29 & 30

Total Number of Inspected Elements 2

Tube Rows Inspected (Numbered bottom of bank to top)

Rows: 29 & 30

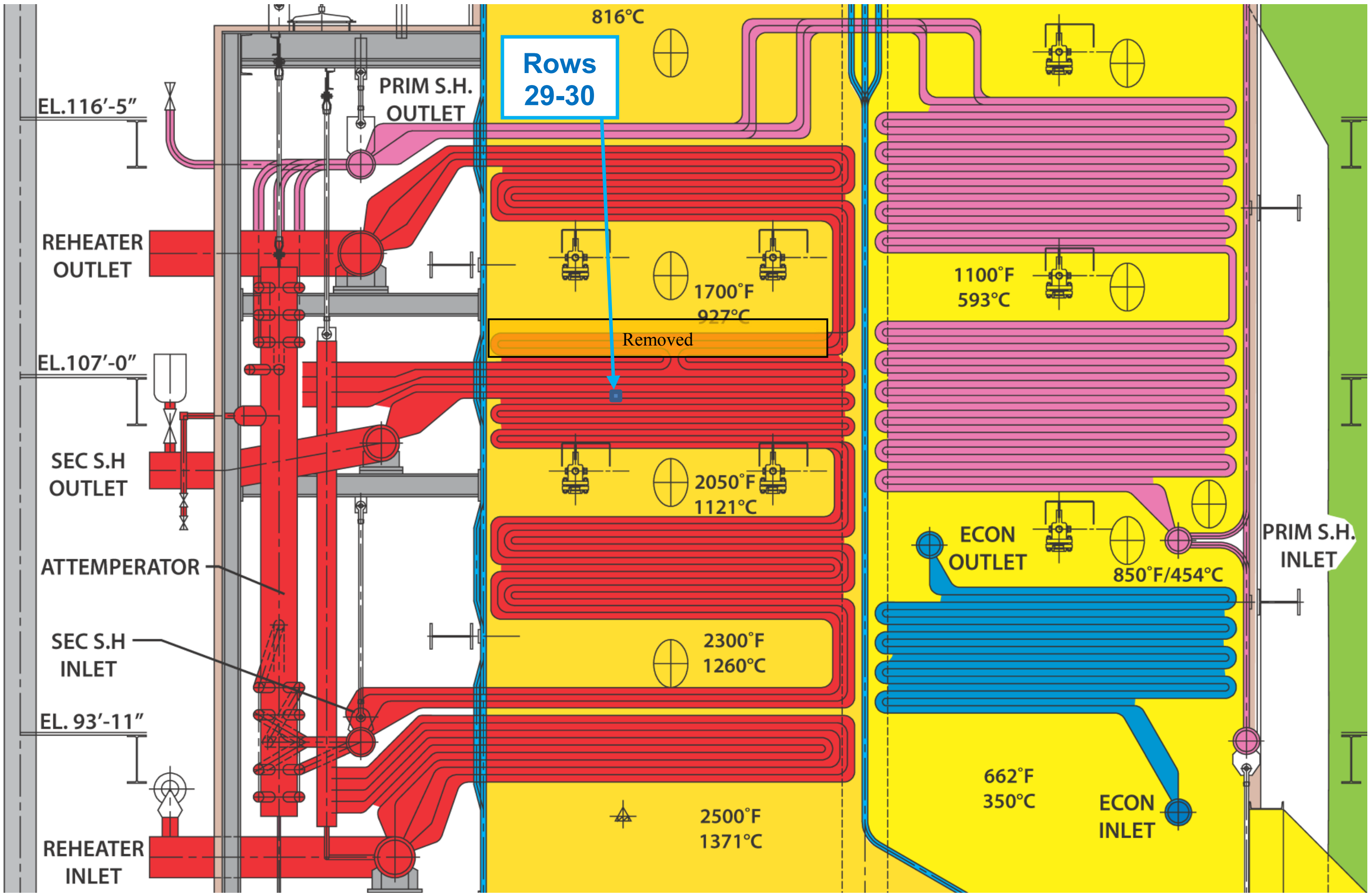
Total Number of Inspected Locations 4

Minimum Measured Wall Thickness 0.373"
Largest Measured Oxide Thickness 0.018"

Notes:
Specifications for Installed Tubes

Tube Row	OD, in.	Wall, in.	Material Specification	Approx. Unit Elevation
29	2.000	0.398	SA-213 T22 (2¼Cr-1Mo)	106.5 ft.
30	2.000	0.387	SA-213 T22 (2¼Cr-1Mo)	106.5 ft.

Superheater Bank NOTIS Test Locations



Tabular Data

NONDESTRUCTIVE TUBE REMAINING LIFE PREDICTIONS: NOTIS

CUSTOMER NAME: NEWFOUNDLAND AND LABRADOR HYDRO, HOLYROOD STATION, UNIT 3
COMPONENT NAME: SECONDARY SUPERHEATER
OUTLET PRESSURE: 1,757 P.S.I.G.
OPERATING TIME: 156,000 HOURS
DATE OF TESTING: 6/4/2018

ELEMENT	TUBE NUMBER	ALLOY CODE	SPEC. WALL in.	SPEC. DIAM. in.	MEAS. WALL in.	MEAS. I.D. OX. in.	NOTES	REMAINING LIFE hrs.
29	29	5	0.398	2.000	0.413	0.016		200,000
29	30	5	0.398	2.000	0.373 *	0.018		200,000
30	29	5	0.387	2.000	0.381 *	0.017		200,000
30	30	5	0.387	2.000	0.383 *	0.014		200,000

ALLOY CODES

Alloy Code 5 = ASME SA-213 Grade T22

NOTES

* Thickness Below Original Specified Tube Wall

** Thickness is 85% of Original Specified Tube Wall or Less

NOTES ON TUBE AND ELEMENT NUMBERING

Elements are numbered from Left Hand Side Wall to Right Hand Side Wall.

Tube rows are referenced in the previous drawing.

APPENDIX B

Secondary Superheater
Inlet Bank Bends

NOTIS® Component Inspection Information

Component: Secondary Superheater Leading Edge Inlet Bends

Elements Inspected (Numbered from Left Hand Side Wall)

Elements: 1,3,6,9,15,18,22,29,32

Total Number of Inspected Elements 9

Tube Rows Inspected (Numbered bottom of bank to top)

Row: 5

Total Number of Inspected Locations 9

Minimum Measured Wall Thickness 0.242"
Largest Measured Oxide Thickness 0.006"

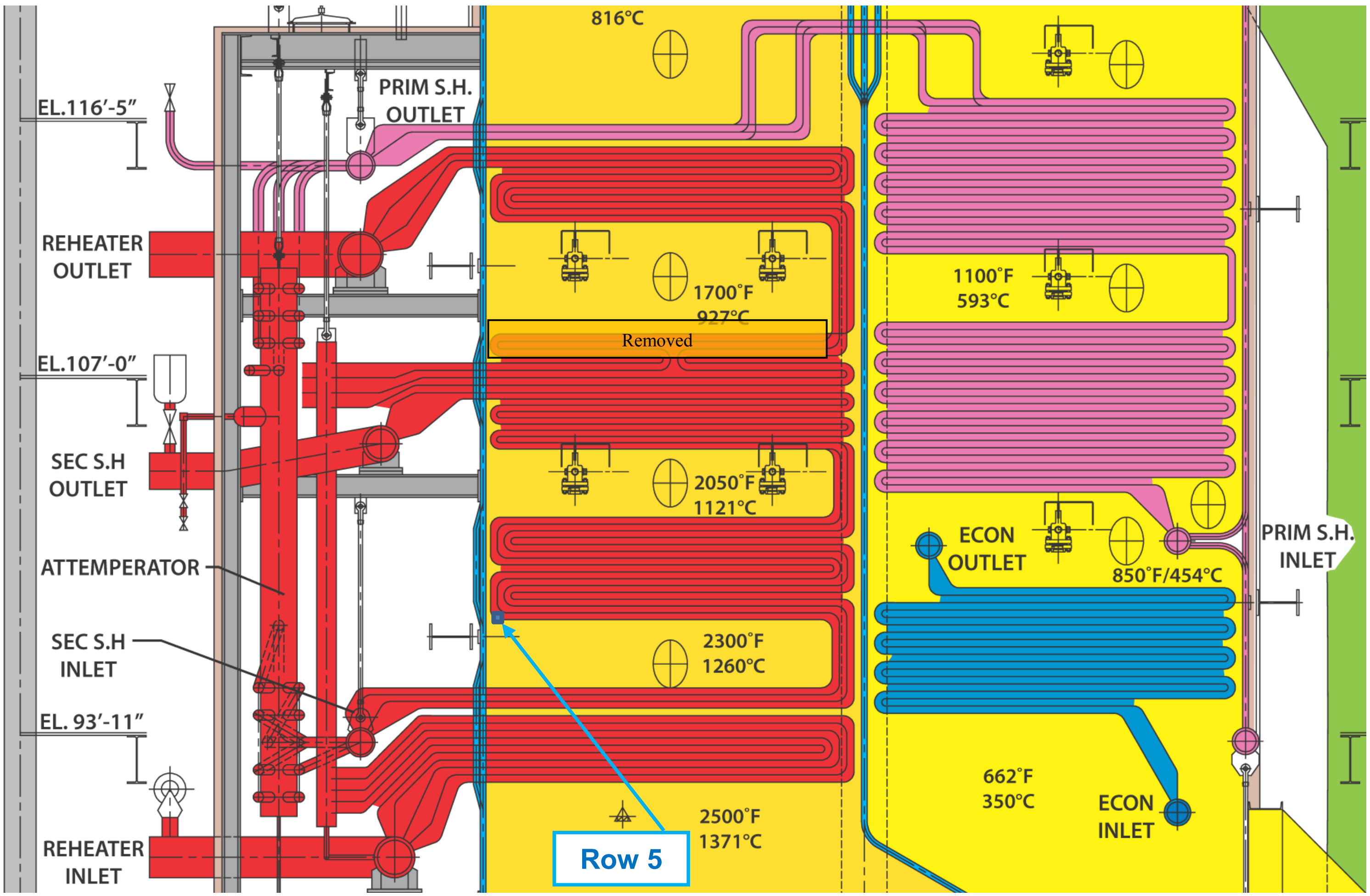
Notes:

Specifications for Installed Tubes

Tube Row	OD, in.	Wall, in.	Material Specification	Unit Elevation
5	2.250	0.260	SA209-T1a (½Mo)	

Babcock & Wilcox

Superheater NOTIS Test Locations



Tabular Data

NONDESTRUCTIVE TUBE REMAINING LIFE PREDICTIONS: NOTIS

CUSTOMER NAME: NEWFOUNDLAND AND LABRADOR HYDRO, HOLYROOD STATION, UNIT 3
COMPONENT NAME: SECONDARY SUPERHEATER
OUTLET PRESSURE: 1,757 P.S.I.G.
OPERATING TIME: 156,000 HOURS
DATE OF TESTING: 6/4/2018

ELEMENT	TUBE NUMBER	ALLOY CODE	SPEC. WALL in.	SPEC. DIAM. in.	MEAS. WALL in.	MEAS. I.D. OX. in.	NOTES	REMAINING LIFE hrs.
1	5	2	0.260	2.250	0.266	0.006		200,000
3	5	2	0.260	2.250	0.255 *	0.006		200,000
6	5	2	0.260	2.250	0.250 *	0.006		200,000
9	5	2	0.260	2.250	0.264	0.006		200,000
15	5	2	0.260	2.250	0.247 *	0.006		200,000
18	5	2	0.260	2.250	0.248 *	0.006		200,000
22	5	2	0.260	2.250	0.242 *	0.006		200,000
29	5	2	0.260	2.250	0.252 *	0.006		200,000
32	5	2	0.260	2.250	0.250 *	0.006		200,000

ALLOY CODES

Alloy Code 5 = ASME SA-213 Grade T22

NOTES

* Thickness Below Original Specified Tube Wall

** Thickness is 85% of Original Specified Tube Wall or Less

NOTES ON TUBE AND ELEMENT NUMBERING

Elements are numbered from Left Hand Side Wall to Right Hand Side Wall.

Tube rows are referenced in the previous drawing.

APPENDIX C

Reheat Superheater

NOTIS® Component Inspection Information

Component Reheat Superheater

Elements Inspected (Numbered from Left Hand Side Wall)

Elements: 41 & 42

Total Number of Inspected Elements 2

Tube Rows Inspected (Numbered Front to Rear)

Rows: 27,28,29,30 on pendants 41 & 42

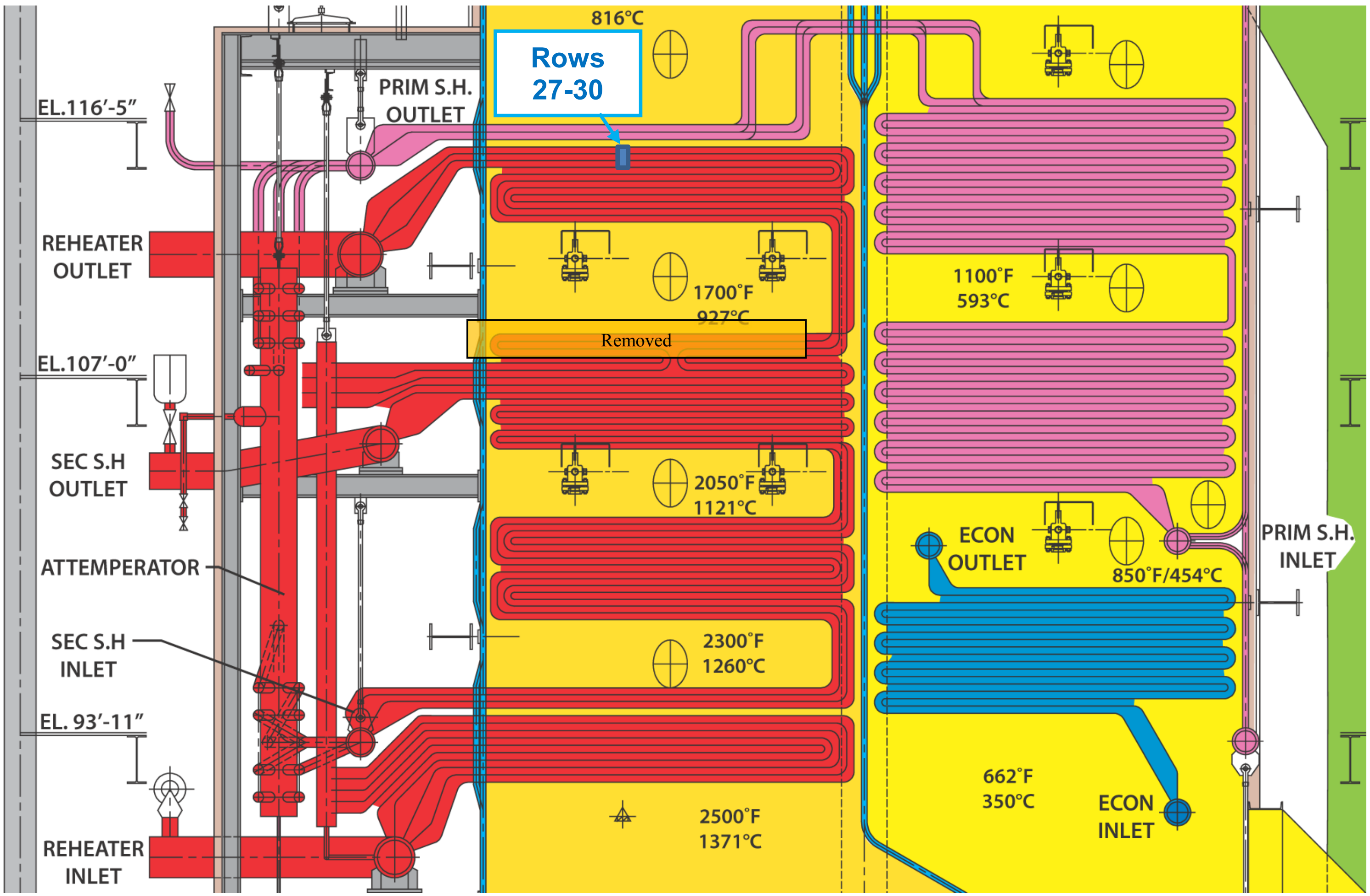
Total Number of Inspected Locations 8

Minimum Measured Wall Thickness 0.173"
Largest Measured Oxide Thickness 0.020"

Notes:
Specifications for Installed Tubes

Tube	OD,	Wall,	Material
27-30	2.250	0.252	SA-213 T22 (2¼Cr-1Mo)

Reheat Superheater NOTIS Bank Test Locations



Tabular Data

NONDESTRUCTIVE TUBE REMAINING LIFE PREDICTIONS: NOTIS

CUSTOMER NAME: NEWFOUNDLAND AND LABRADOR HYDRO, HOLYROOD STATION, UNIT 3
COMPONENT NAME: REHEAT SUPERHEATER
OUTLET PRESSURE: 471 P.S.I.G.
OPERATING TIME: 156,000 HOURS
DATE OF TESTING: 6/4/2018

ELEMENT	TUBE NUMBER	ALLOY CODE	SPEC. WALL in.	SPEC. DIAM. in.	MEAS. WALL in.	MEAS. I.D. OX. in.	NOTES	REMAINING LIFE hrs.
41	27	5	0.252	2.250	0.225 *	0.019		180,000
42	27	5	0.252	2.250	0.261	0.020		200,000
41	28	5	0.252	2.250	0.228 *	0.014		200,000
42	28	5	0.252	2.250	0.241 *	0.018		200,000
41	29	5	0.252	2.250	0.261	0.020		200,000
42	29	5	0.252	2.250	0.250 *	0.020		200,000
41	30	5	0.252	2.250	0.255	0.019		200,000
42	30	5	0.252	2.250	0.230 *	0.017		200,000

ALLOY CODES

Alloy Code 5 = ASME SA-213 Grade T22

NOTES

* Thickness Below Original Specified Tube Wall

** Thickness is 85% of Original Specified Tube Wall or Less

NOTES ON TUBE AND ELEMENT NUMBERING

Elements are numbered from Left Hand Side Wall to Right Hand Side Wall.

Tube rows are referenced in the previous drawing.

APPENDIX D

Reheat Superheater Leading Edge Bends

NOTIS® Component Inspection Information

Component: Reheat Superheater Leading Edge Tube Bends

Elements Inspected (Numbered from Left Hand Side Wall)

Elements: 8,10,11,15,19,23,28,31,36,40

Total Number of Inspected Elements 10

Tube Rows Inspected (Numbered Front to Rear)

Row: 19

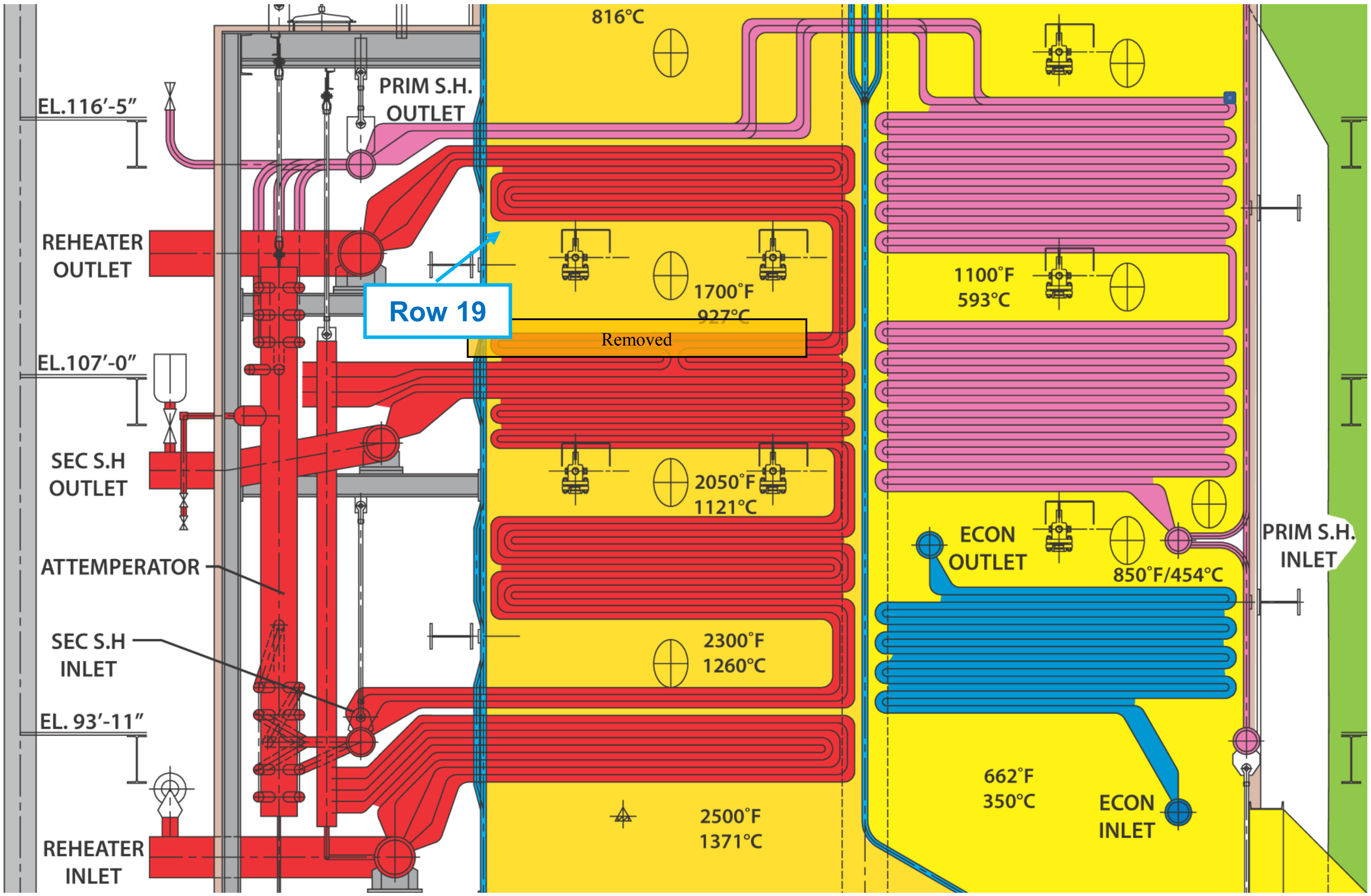
Total Number of Inspected Locations 10

Minimum Measured Wall Thickness 0.117"
Largest Measured Oxide Thickness 0.012"

Notes:
Specifications for Installed Tubes

Tube Row	OD, in.	Wall, in.	Material Specification
19	2.250	0.180	SA-213 T22 (2¼Cr-1Mo)

Reheat Superheater NOTIS Test Locations



Tabular Data

NONDESTRUCTIVE TUBE REMAINING LIFE PREDICTIONS: NOTIS

CUSTOMER NAME: NEWFOUNDLAND AND LABRADOR HYDRO, HOLYROOD STATION, UNIT 3
COMPONENT NAME: REHEAT SUPERHEATER
OUTLET PRESSURE: 471 P.S.I.G.
OPERATING TIME: 156,000 HOURS
DATE OF TESTING: 6/4/2018

ELEMENT	TUBE NUMBER	ALLOY CODE	SPEC. WALL in.	SPEC. DIAM. in.	MEAS. WALL in.	MEAS. I.D. OX. in.	NOTES	REMAINING LIFE hrs.
8	19	5	0.180	2.250	0.118 **	0.010		140,000
10	19	5	0.180	2.250	0.129 **	0.008		200,000
11	19	5	0.180	2.250	0.117 **	0.011		130,000
15	19	5	0.180	2.250	0.130 **	0.010		190,000
19	19	5	0.180	2.250	0.131 **	0.006		200,000
23	19	5	0.180	2.250	0.134 **	0.004		200,000
28	19	5	0.180	2.250	0.122 **	0.012		140,000
31	19	5	0.180	2.250	0.135 **	0.010		200,000
36	19	5	0.180	2.250	0.128 **	0.009	3	190,000
40	19	5	0.180	2.250	0.123 **	0.008		170,000

ALLOY CODES

Alloy Code 5 = ASME SA-213 Grade T22

NOTES

* Thickness Below Original Specified Tube Wall

** Thickness is 85% of Original Specified Tube Wall or Less

3 - Variations in oxide thickness were noted within the test area. This suggests possible exfoliation of the internal oxide. The recorded thickness is the maximum detected.

NOTES ON TUBE AND ELEMENT NUMBERING

Elements are numbered from Left Hand Side Wall to Right Hand Side Wall.

Tube rows are referenced in the previous drawing.

APPENDIX E

Primary Superheater Leading Edge Bends

NOTIS® Component Inspection Information

Component: Primary Superheater Leading Edge Tube Bends (Going down the convection pass)

Elements Inspected (Numbered from Left Hand Side Wall)

Elements: 7,14,21,28,35,42,49,56,63,70,77,84

Total Number of Inspected Elements 12

Tube Rows Inspected (Numbered Front to Rear)

Row: 4

Total Number of Inspected Locations 12

Minimum Measured Wall Thickness 0.302"
Largest Measured Oxide Thickness 0.006"

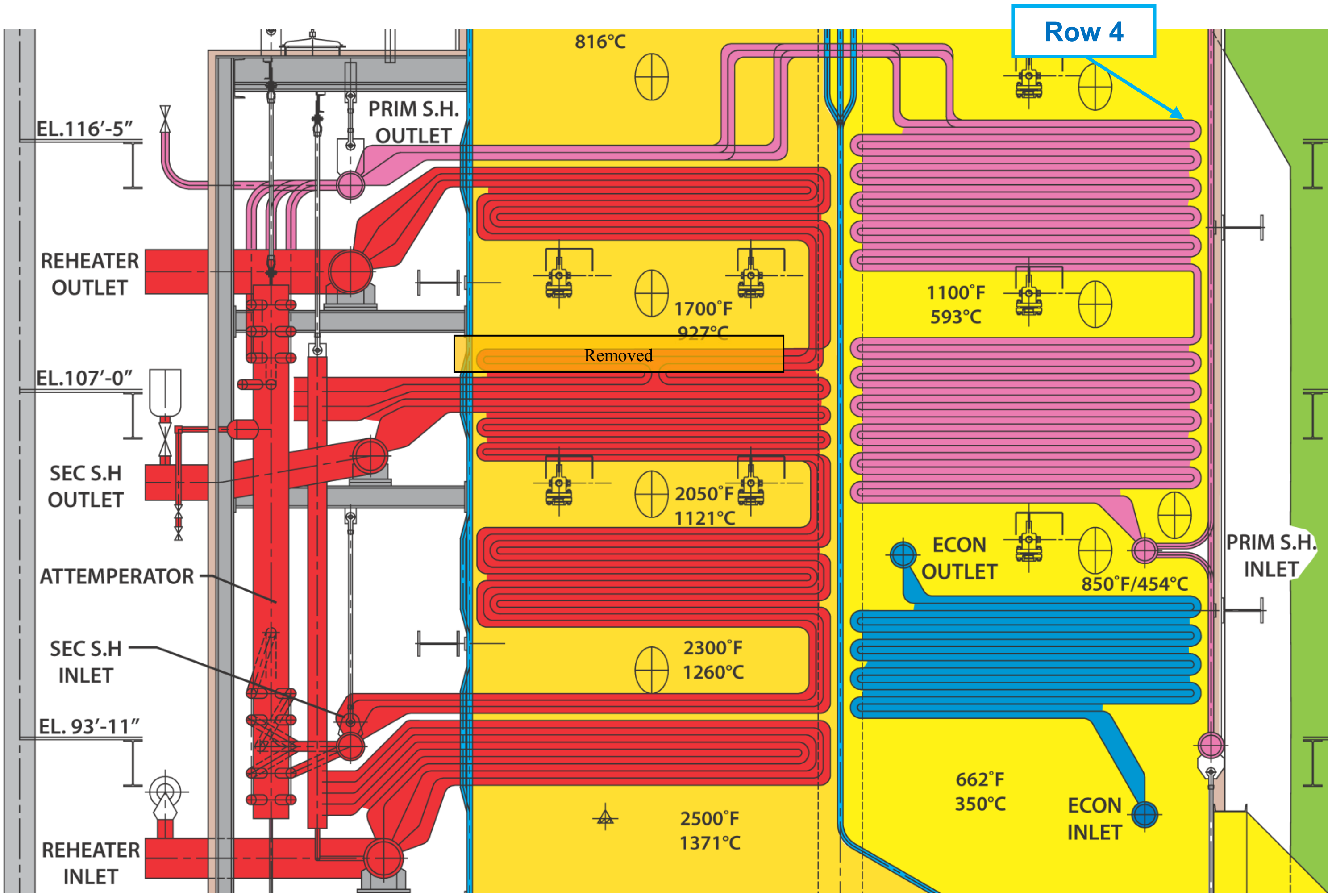
Notes:
Specifications for Installed Tubes

Tube Row	OD, in.	Wall, in.	Material Specification	Unit Elevation
4	2.500	0.302	SA-213 T11 (1¼Cr- ½ Mo)	

Babcock & Wilcox

Newfoundland and Labrador Hydro
Holyrood Generating Station, Unit 3

Primary Superheater NOTIS Test Locations



Tabular Data

NONDESTRUCTIVE TUBE REMAINING LIFE PREDICTIONS: NOTIS

CUSTOMER NAME: NEWFOUNDLAND AND LABRADOR HYDRO, HOLYROOD STATION, UNIT 3
COMPONENT NAME: PRIMARY SUPERHEATER
OUTLET PRESSURE: 1,757 P.S.I.G.
OPERATING TIME: 156,000 HOURS
DATE OF TESTING: 6/4/2018

ELEMENT	TUBE NUMBER	ALLOY CODE	SPEC. WALL in.	SPEC. DIAM. in.	MEAS. WALL in.	MEAS. I.D. OX. in.	NOTES	REMAINING LIFE hrs.
7	4	3	0.338	2.500	0.310 *	0.006		200,000
14	4	3	0.338	2.500	0.310 *	0.006		200,000
21	4	3	0.338	2.500	0.322 *	0.006		200,000
28	4	3	0.338	2.500	0.294 *	0.006		200,000
35	4	3	0.338	2.500	0.306 *	0.006		200,000
42	4	3	0.338	2.500	0.307 *	0.006		200,000
49	4	3	0.338	2.500	0.317 *	0.006		200,000
56	4	3	0.338	2.500	0.315 *	0.006		200,000
63	4	3	0.338	2.500	0.316 *	0.006		200,000
70	4	3	0.338	2.500	0.310 *	0.006		200,000
77	4	3	0.338	2.500	0.302 *	0.006		200,000
84	4	3	0.338	2.500	0.315 *	0.006		200,000

ALLOY CODES

Alloy Code 3 = ASME SA-213 Grade T2

NOTES

* Thickness Below Original Specified Tube Wall

** Thickness is 85% of Original Specified Tube Wall or Less

3 - Variations in oxide thickness were noted within the test area. This suggests possible exfoliation of the internal oxide. The recorded thickness is the maximum detected.

NOTES ON TUBE AND ELEMENT NUMBERING

Elements are numbered from Left Hand Side Wall to Right Hand Side Wall.

Tube rows are referenced in the previous drawing.

APPENDIX F

B&W Plant Service Bulletin 26; Tube Thickness Evaluation Repair or Replacement Guideline

babcock & wilcox power generation group

Plant Service Bulletin

Tube Thickness Evaluation Repair or Replacement Guideline

Purpose

This bulletin was written to assist customers in evaluating existing boiler tube wall thicknesses and defining when repair or replacement is recommended.

Background

Experience has shown that many tubes do not necessarily fail when operating at thicknesses below the minimum wall calculated, according to the ASME Code. However, operation in this manner encroaches on the ASME Code design margin. A tube that is below minimum wall thickness may or may not be tolerant of temperature excursions, thermal cycling, mechanical loading or other stresses.

Cognizant of this, some operators have elected to take a practical approach, based on actual operating experience, to determine when to repair or replace thinned tubes. A practical minimum wall thickness criterion can be established through a record-keeping process to track the wall thickness of various boiler tubes over time, and to relate tube failure history of those tubes to tube thicknesses. This is an effective method for locating troubled areas before they lead to forced outages. With this method, the decision to take action for thinned tubes is based on a percentage of the original wall thickness (t) of the tubes.

Table 1
Guidelines for Tube Repair/Replacement

Location	Actual Tube Wall Thickness Relative to Percent Specified Wall Thickness, t	Course of Action
1. Furnace Support Tubes and Economizer Stringer Support Tubes	Tubes equal to or greater than 85% t	Monitor thickness
	Tubes less than 85% t	Restore tube wall thickness or replace tube *
2. Economizer, Furnace Wall and Other Water-Cooled Tubes	Tubes equal to or greater than 70% t	Monitor thickness
	Tube less than 70% t	Restore tube wall thickness or replace tube*
3. Superheater, Reheater and Other Steam-Cooled Tubes	Tubes equal to or greater than 85% t	Monitor thickness
	Tubes less than 85% t	Restore tube wall thickness or replace tube*

* It is difficult to restore the wall thickness for tubes below 0.090 inch due to possible weld burn-through and distortion. On Kraft recovery boilers, refuse boilers, and boilers operating below 1000 psig, the tubes should be replaced when below the ASME minimum wall thickness.

Because high-temperature (steam-cooled) tubes usually fail by creep rupture, and water-cooled tubes usually operate below the creep-rupture regime, a different set of evaluation criteria is required for each of these two types of tubes. Furnace tubes of once-through boilers operate at high temperatures and therefore, are classified as steam-cooled tubes when evaluating tube thickness. A guideline for determining what course of action to take is shown in Table 1.

Many factors were used and taken into consideration for establishing the usable thickness guideline. One of these factors is the need to avoid material yielding as the tube thins in service.

The decision to repair or replace tubing that is under the original specified minimum wall thickness should be evaluated by the operating company and discussed with the local jurisdiction and/or insurance carrier. This evaluation should consider the following:

1. History of previous failure of similar tubes
2. Wastage rate
3. Susceptibility to temperature excursion
4. Thermal cycling
5. Mechanical loading
6. Scheduling of outages of sufficient length to replace tubes
7. Risk of injury to personnel from primary failure or subsequent reactions

Recommendations

Customers should develop a program for their individual boilers using this as a guide to collect the specific information needed for reliable maintenance planning.

When replacing short tube segments, it is recommended that replacement tubing be the same OD, thickness and material specification as the original. When replacing large sections, an engineering review should be made to determine the advisability of upgrading to the latest design criteria or to apply other design changes that may eliminate existing problems. Arbitrarily increasing the tube wall thickness or alloy grade is not recommended, as it may lead to additional problems.

All boiler tubes may be replaced without weld restriction provided a qualified welding procedure is employed, together with a welding filler metal that is appropriate for the alloy content, tensile strength and service temperature of the tubing.

ALL REPAIRS MUST BE ACCEPTABLE TO THE GOVERNING CODE JURISDICTION AND/OR INSURANCE CARRIER.

Support

If you elect to follow the above guidelines, The Babcock & Wilcox Company (B&W) can assist in developing the specific information needed for an individual unit. Contact your regional B&W Field Engineering Services office if you have any questions or need assistance.

babcock & wilcox power generation group

While others may use the Babcock name, we are the original Babcock & Wilcox with experience in engineering, constructing and servicing steam generating systems since 1867. Insist on us by name.

For more information, or a complete listing of our sales and service offices, call 1-800-BABCOCK (222-2625), send an e-mail to info@babcock.com or access our Web site at www.babcock.com.

PSB-26 1MU3L

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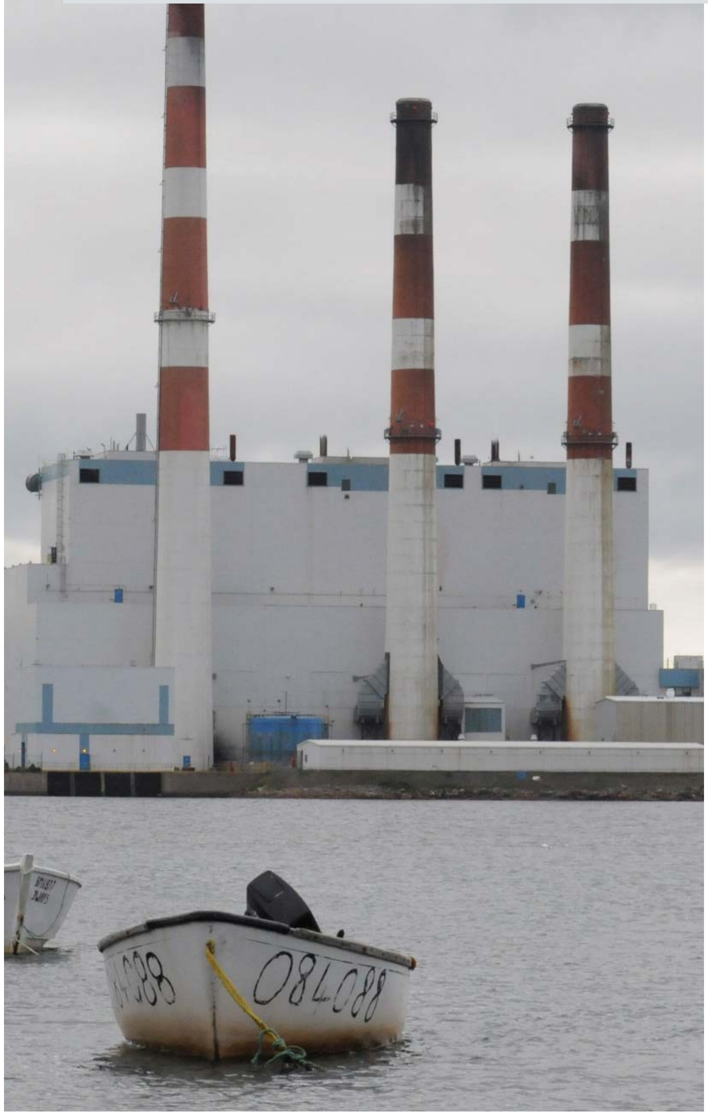

SIEMENS

NL Hydro - Nalcor
Holyrood Plant

Siemens Site Visit – July 6-7, 2016

Objectives:

1) Determine root cause of VFD reliability issues – Units 1, 2, & 3 FD Fan VFDs
2) Prescribe corrective actions and report on path forward

SIEMENS

The Siemens Team

Introductions

Background

Identified Issues

Site Work Plan

Findings

Recommended Actions

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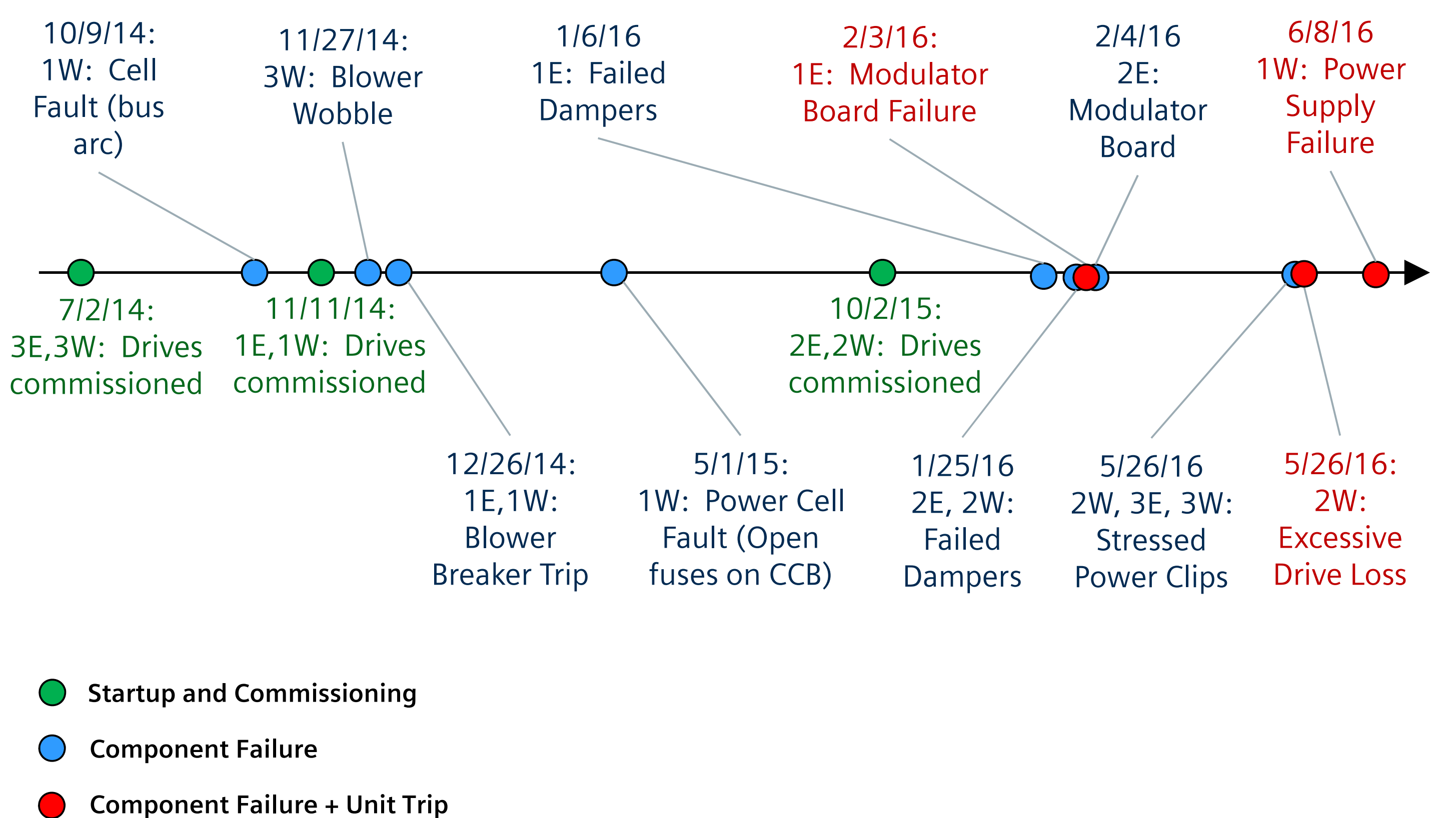
SIEMENS

Background

Chronology of Incidents – All Units



SIEMENS

Identified Issues

X – Failure resulting in Unit Trip
X – Failure identified
O – Issue Identified

Failure Mode	Unit No 1 E	Unit No 1 W	Unit No 2 E	Unit No 2 W	Unit No 3 E	Unit No 3 W	Actions taken	Possible Root Cause
Damper Failures	X		X	X			• Commitment to replace all damper assemblies	• Component durability
Power Cell fault		X					• Repair only	• Unknown - Cell bus arc • Unknown - Open CCB Fuse
a. Modulator Board	X (unit trip)		X				• Replace Modulator Board • Upgrade firmware • New cables	• Firmware bug • Loose connection • Vibration levels
Power Supply		X (unit trip)					• New power supply • RMA – part at NL Hydro site	• TBD - RCA in progress
Excessive Loss &/or Input Protection Fault				X (unit trip)			• Upgraded firmware • RMA – part at NL Hydro site	• Firmware bug • TBD - RCA in progress
Stressed Power Clips				O	O	O	• Airflow test done at Siemens R&D center	• Vibration levels • TBD - RCA in progress
Cooling fan breakers tripping	X	X					• Filters replaced • Thermal overloads returned to factory set point	• Clogged filters • Preventative maintenance will address
Blower fan wobble						O	• Vendor involved at startup; however no action at site	• Shipping and handling

SIEMENS

Site Work Plan

SIEMENS Industry

Siemens Onsite Testing/Inspection Plan – Newfoundland Hydro Drives

1.1 Vibration Testing

1.1.1 Summary

Siemens will use accelerometers to measure vibration on the drive and near the drive. Siemens will measure many locations both in/on the VFD and near the VFD in the installation house. Measurements will be taken with different drive operation conditions and ambient conditions. This will help determine the source of vibration. The tests are broken down by operation conditions, points of measurement are listed by importance, and some may be excluded due to timing or site conditions
Siemens may request additional points of measurement or conditions when onsite. It is understood some conditions identified below may not be feasible due to site constraints.

1.1.2 Tools Used

1. Accelerometers
2. Data Acquisition System
3. PC
4. Mounting Fixtures

1.1.3 Tests

Test 1 – VFD OFF, VFD Blowers off, Nearby Customer Rotating Equipment On
Measurement Points
- a. VFD Transformer
- b. On installation floor near VFD and/or VFD Base structure
- c. VFD Cells
- d. Blower Unit

Test 2 – VFD OFF, VFD Blowers On, Nearby Customer Rotating Equipment On
Measurement Points
- a. VFD Transformer
- b. On installation floor near VFD and/or VFD Base structure
- c. VFD Cells
- d. Blower Unit

Test 3 – VFD OFF, VFD Blowers On, Nearby Customer Rotating Equipment Off
Measurement Points
- a. a. VFD Transformer
- b. On installation floor near VFD and/or VFD Base structure
- c. VFD Cells
- d. Blower Unit

Test 4 – VFD OFF, VFD Blowers off, Nearby Customer Rotating Equipment Off
Measurement Points
- e. VFD Transformer
- f. On installation floor near VFD and/or VFD Base structure
- g. VFD Cells
- h. Blower Unit

SIEMENS Industry

1.2 Visual Inspection

1.2.1 Summary

Siemens will inspect the drive for damage and condition. Photos will be taken with digital cameras and a scope camera. If possible Siemens would request removal of some external panels to inspect the internals of the drive.

1.2.2 Tools Used

1. Digital Cameras
2. Scope Camera (camera on a long narrow flexible wire)
3. Cell lifter

1.2.3 Areas of inspection

1. Blowers
   - a. Cage
   - b. Fans
   - c. Dampers (if installed)
2. Power Cells
   - a. Power Clips
   - b. Boards and connections
   - c. Fiber optics
3. NXG Control
   - a. Modulator boards and connections
   - b. Connections
4. Transformer
   - a. General inspection
   - b. Connections

1.3 Airflow Measurements

1.3.1 Summary

Siemens may request to take airflow measurements while the fan unit is running

1.3.2 Tools Used

1. Anemometer

SIEMENS

Site Work Plan

Introductions

Background

Identified Issues

Site Work Plan

Findings

Recommended Actions

Vibration Testing

Objective: Test for excessive or disruptive vibration levels that may affect equipment reliability

Description: Measure vibration levels at four points per drive:

a. VFD Transformer
b. On installation floor near VFD and/or VFD Base structure
c. VFD Cells
d. Blower Unit

Test	VFD	Blowers	Nearby Equipment
1	Off	On	Off
2	Off	Off	Off
3	Off	On	On
4	Off	Off	On

SIEMENS

Site Work Plan

Introductions
Background
Identified Issues
Site Work Plan
Findings
Recommended Actions

Visual Inspection

Objective: Determine possible root causes

Description: Inspect the drive for damage and condition

Focus Areas:

1. Blowers
   a. Cage
   b. Fans
   c. Dampers (if installed)
2. Power Cells
   a. Power Clips
   b. Boards and connections
   c. Fiber optics
3. NXG Control
   a. Modulator boards and connections
   b. Connections
4. Transformer
   a. General inspection
   b. Connections

SIEMENS

Findings

- Measured vibration levels are within Siemens design specifications. No available data for actual operating vibration levels.
- No obvious root causes detected that could lead to premature power cell clip stress and wear.
- Units look well-kept and maintained. No obvious causes of past/future failures.
- Damper failures are evident on all six VFDs
- Wobble found in Unit 2W middle blower.

SIEMENS

Recommended Actions

	Focus	Action	Status	
1	Dampers	Replace all dampers with UE CB601 series dampers	U2,U3: Complete U1: TBD	
2	Modulator Boards	Replace all modulator boards with latest firmware	U2,U3: Complete U1: TBD	
3	Power supply	Perform RCA on failed part	Awaiting return material	
4	Power cells	Perform RCA on failed part	Awaiting return material	
5	Power Cell Clips	U1: Replace all T1/T2 connections Perform detailed RCA of U1 parts	TBD – NL Hydro (August) Not started	
6	Drive – Overall Vibration	Assess vibration levels with all components and surrounding equipment running	TBD	
7	Blower	Replace 2W blower assembly	TBD	
8	Spare part inventory audit	Audit spare parts inventory for qtys, revision levels, etc., Make recommendations.	7/30/16 target	
9	Controls audit	Assure all firmware and software are to current revision levels	7/30/16 target	
10	Readiness Check	PM and inspection in October	TBD	

SIEMENS

Questions?

babcock & wilcox canada ltd.

Site Visit Report	Location/Date: Holyrood Generating Station Holyrood, Nfld. October 6, 2016
Contract: Newfoundland and Labrador Hydro	Meeting Purpose: Operation Review
Prepared By: Dan Regan	Issued: October 13, 2016
Customer Contacts:	
B&W Representatives: Dan Regan Shaun Lingley Tim Hayter	
Visit Objectives**:** 1. Monitor load tests on CE unit – Boiler #2 2. Monitor load tests on B&W Unit – Boiler #3 3. Comment on limitations on unit load 4. Recommend resolution to restore unit capacity	

Unit 2 Capacity Tests

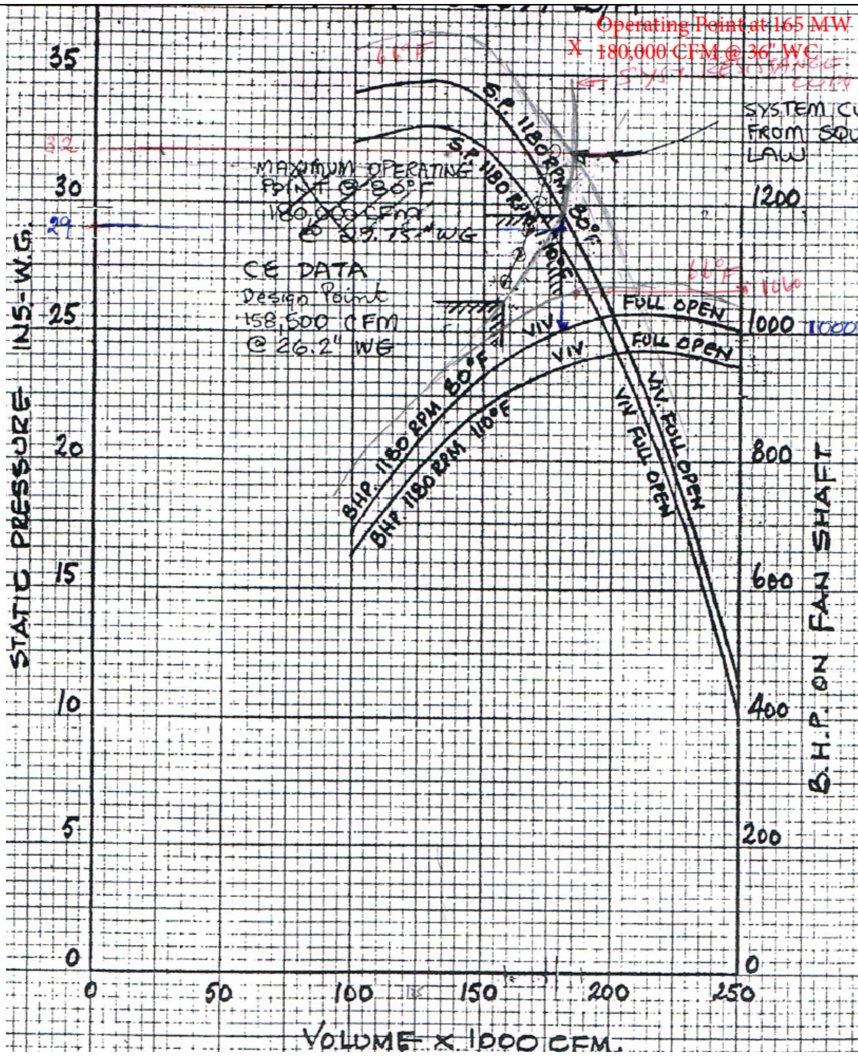
During the week of October 3rd, several load tests were conducted to establish the maximum achievable load on Unit 2. Initial testing was carried out with air flow to the boiler being controlled by the variable frequency drives (VFD's) which drive the FD fans. Fan speed was limited by the operator's reluctance to push the drives to 100% speed due to the perception that the combustion system at that point would be out of control range. (Due to the characteristics of the VIV's, 100% airflow is achieved before the damper is between 80 and 90% open, however, in speed control, to get 100% air flow you must run at 100% speed. This presents the illusion that you can make a higher load on VIV control, because you get more air flow at 85% VIV opening and 100% speed than you do at 85% speed and 100% VIV opening. Maximum air flow to the boiler will be the same on VIV or VFD control if the fan speed is allowed to operate at maximum speed.)

The maximum load that was achieved with VFD control was approximately 157 $MW_{(E)}$ with the fan controllers at 93.73% and fan speed of approximately 1125 RPM. (As noted above, air flow is proportional to fan speed – increasing the speed to the maximum 1195 RPM would have produced more air flow and therefore more load.) Flue gas oxygen was 0.97%. At this point, increased opacity and lack of additional fan capacity prevented raising the load any further.

The fan control was switched to Variable Inlet Vane (VIV) control and the load test was repeated. In this case, fan speed was fixed at 1195 RPM and airflow was controlled by modulating the inlet vanes. Maximum load was increased to approximately 165 $MW_{(E)}$. Flue Gas Oxygen was 1.39%. At this point, high opacity necessitated a reduction in load.

Discussion – Centrifugal fans are fixed volume devices that are limited by the static pressure or back pressure in the system they are discharging into. The fan curve on the next page illustrates that as the static pressure increases, the fan capacity decreases. The design point for full load operation is 158,500 CFM at 26.2" of water. The illustrated system curve shows that as the system static pressure increases above about 30 " of water, further increases in static pressure will not result in any significant increase in air flow. Testing at high loads demonstrated a fan discharge pressure in the range of 32 to over 36" of water. In order to get more air to the boiler to increase steam generation, the system static pressure must be reduced.

Higher than normal pressure drops were measured across the steam coil air heaters, the air side of the Ljungstrom air heaters, the boiler furnace, the economizer and the gas side of the Ljungstrom air heaters. These high pressure drops have to be a result of either higher than normal flows, or flow restrictions of some kind. Each one of these possibilities will be discussed individually.



Fan Curve for Unit 2 FD fans (2)

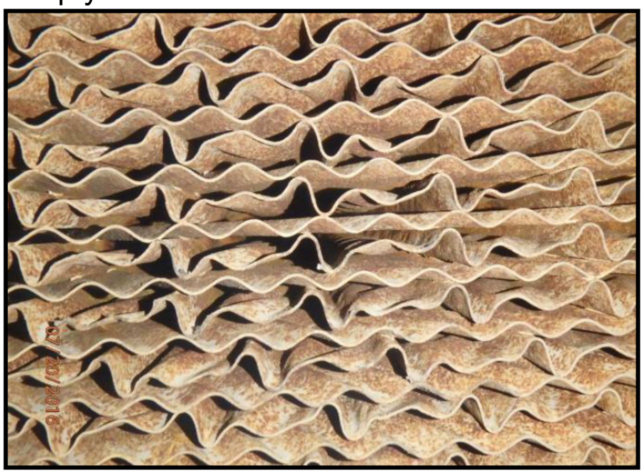
Flow Restrictions

Flow restrictions can usually be attributed to accumulation of fuel ash in the boiler components. Wide spacing in the superheater and reheater normally do not allow restrictions to accumulate, but when they do, they are typically hardened molten ash which are difficult to remove. Mechanical cleaning is often required. The high gas temperatures in these areas results in a very low flue gas density, and higher gas volume. Because of this these areas should be kept clean with regular soot blowing and cleaning during maintenance outages. Note that this area was last cleaned in 2015. The 2016 outage was classified as a minor outage, which typically does not include gas side cleaning, so no cleaning was carried out in the boiler.

The economizer on these boilers incorporates finned tubes which are staggered in the gas stream. While this provides effective heat transfer, it also provides a location where loose fuel ash can accumulate and pack. This area is extremely difficult to clean due to the close spacing and tube fin arrangement. This area is showing a higher pressure drop than historically noted and every effort should be made to clean the ash out to reduce the pressure drop.

The ljungstrom air heaters consist of two layers (hot end and cold end) of corrugated plates arranged in pie shaped segments. The tight packing of these plates provides an opportunity for plugging which is also very hard to clean effectively. In situ sootblowers work to keep the elements clean during operation, however manual cleaning is often required with high pressure systems to get the elements clean top to bottom. The ljungstrom air heater provides pressure drop on the air inlet side and the gas outlet side, so blockage in this area provides a double increase in system pressure drop. When cleaning the air heaters, ensure that there are no pieces of corroded element material lodged between the two layers of baskets. This material has been identified as an issue in these air heater years ago, and **cannot** be washed away. These plates have to be physically removed.

The inspection of Unit 2 carried out by the Howden representative states that there was "no signs of severe pluggage." Note that from the photos below, it appears that the plates in the hot end baskets are what are known as "Double Undulated", and the cold end baskets appear to be enamel coated "Notched Flat" elements. The deeper hot end baskets are difficult to see through to establish cleanliness. The cold end basket design should allow a light to be seen through the complete basket. Pluggage can be seen in the photo taken of a cold end basket in the metal scrap yard below.



Hot end elements

Enameled Cold end elements

Plugged Cold End Elements in Scrap Yard

Steam coil air heaters are located at the outlet of the FD fan under the Ljungstrom air heaters. These steam coils preheat the incoming combustion air to protect the Ljungstrom air heater and breaching to the stack from corrosion. These heaters consist of banks of 1" OD tubes with 2 ¼" OD aluminium fins on them to enhance heat transfer. Over the years, these light gauge fins can be bent and deformed which will restrict air flow through the elements. Additionally, debris drawn in by the fans and material carried through from off line cleaning can plug off the air passages between the tight spaced fins further restricting air flow.

Damaged Fins in Steam Coil Air Heater – Unit 1

It appears that all of the above areas are contributing to the air flow issues on the boiler. (See tables in appendix 1) Differential pressures across all of these components point to signs of plugging and restriction. Every effort should be made to ensure the air heaters, economizer and superheater and reheater gas lanes are clean in unit 1 before it returns to service.

The top row of steam coils are being replaced on Unit 1 during the present outage. The steam coils consist of 2 rows of 4 coil banks on each air heater inlet duct (Four on top and four on the bottom). Therefore, a total of 8 coils are being installed. There are another 8 new coil banks on order to provide a complete new set of top coils for unit 2. We have discussed removing the top row of coils to reduce pressure drop until the new coils arrive. With the boiler in operation at loads as high a 70MW, the steam coil control valves are open providing steam to all the coils. This is to protect the air heater cold end and stack breaching from corrosion. Even with low sulphur fuel, B&W still recommend a minimum Average Cold End Temperature (ACET) in the range of 100^{o}C. Testing has indicated that the average cold end temperature set point can be maintained with the top row of coils isolated at 70 MW. Additional testing should be carried out to establish what minimum load can be sustained with the bottom row of coils in service. If this is acceptable, the top row of coils could be removed temporarily to reduce pressure drop.

High Air Flows

A requirement to burn more fuel to make load increases the amount of air required to be fed to the boiler. The increased air flow, and increased volume of products of combustion also can increase the pressure drop through all of the components noted above. Therefore, improving the efficiency of the unit will reduce fuel costs, but also reduce the pressure drop. The same ash accumulations that cause blockage in the system and higher pressure drop also can impede heat transfer and impact unit and plant efficiency. For example, the stack gas temperature at maximum load is 40°C (72°F) above the design value. A general rule of thumb is that 40 °F increase in stack temperature is equivalent to about 1% efficiency loss. Therefore, the plant is potentially firing 1.8% more fuel and air to make up for this efficiency loss if it is operating at full load. This additional fuel and air adds pressure drop throughout the system. The same holds true for the low reheat steam temperature. The reduced steam temperature from the reheater could result in a loss of 3-5 MW. Any opportunity to increase the reheater outlet steam temperature would reduce the fuel and air flow required to be fed to the boiler for a given load. Note that comparing load tests on Unit 2 at 150 MW from 2015 to 2016, fuel flow and air flow is similar for this load, however, gas outlet temperature is up approximately 7°C (12°F) and total system pressure drop is up 1.2 KPa (4.8" W.C.).

Air heater leakage is also an issue that could add to the fan capacity problem. It was noted that when the boiler is operating at maximum load with a flue gas oxygen level of 1.39%, the oxygen concentration in the stack at the CEMS unit was reading 4.2%. This would indicate roughly 20% air leakage across the ljungstrom air heaters (Ljungstrom air heaters typically perform with about 10% leakage when new). If this air is leaking by the seals on the top (hot end) of the air heater, this additional 20% of the air will add to the pressure drop on both the air and gas sides of the system.
The Howden inspection report indicates that the air heater seals are not routinely set to the design seal settings. In some applications, the design settings are not the optimum setting for a specific heater. When this is the case, it is sometimes beneficial to install aluminium triangular tabs on the diaphragm plates in several locations. These soft aluminium tabs will wear down to illustrate the true running location of the seals during normal operation. This information is then used to determine the proper seal setting point.

Opacity

High stack Opacity prevented load increases at several times during this exercise. High opacity is often combated by operating at elevated levels of excess air, which is a luxury that we do not have at high loads. It also encourages the operators to reduce the burner tilt angle. Reducing the tilt angle effectively increases the resonance time in the furnace, which provides more time for the carbon to be burned out before reaching the convective pass. While this can be effective at reducing opacity, it also results in lower reheat outlet steam temperatures, which reduces the output of the unit for a given steam flow. Both the tilt angle reduction and additional excess air could be correcting high opacity conditions which have different root causes. High opacity can be caused by several burner related issues:

1) **High oil viscosity** – Normally, oil temperature is set to provide the optimum oil viscosity for atomization at the burner tip. Oil samples are routinely checked for viscosity, and a target temperature is selected to deliver the oil at the proper viscosity to the gun. If there are variations in oil viscosity in the system, these may not be picked up in routine sampling of bulk storage tanks. If opacity is high, increasing the oil temperature to the burner can help by reducing the oil viscosity, resulting in better atomization. (Note that this could not be done during this exercise as the oil temperature control valve was 100% open and the oil temperature was below set point. Operators report that this is because the oil delivered to the day tank has to be kept colder than normal or pump capacity is lost due to the light nature of the oil.) Fouled oil heaters can also contribute to low oil temperature.

2) **Atomizing Steam Pressure** – The J-tips on the CE boilers are external mix tips that do not need to have a controlled differential pressure between the atomizing steam and oil during operation. The atomizing steam is normally controlled at a constant pressure regardless of oil pressure. The current set point for atomizing steam pressure is around 700 KPa. At high loads, an increase in atomizing steam pressure may improve atomization and reduce opacity. Unlike internal mix tips, increasing the atomizing steam pressure should not impact oil pressures or flow. A trial should be scheduled when a high load can be sustained to determine if increasing the atomizing steam pressure helps reduce opacity at high loads. Increase the atomizing steam pressure in 100 KPa increments to a maximum of 1000 KPa while monitoring opacity. Note that if successful, it would still be a good practice to reduce the atomizing steam pressure to 700 KPa at lower loads to minimize aux steam consumption and tip wear.

3) **Atomizing Steam Temperature** – Atomizing steam should have approximately 50ºF degrees of superheat when it gets to the gun. Low temperatures can result in condensate which can reduce atomization. Higher temperatures can lead to coking of the oil in the tip which can plug them off.

4) **Burner Cleanliness** – Dirty burners can have a severe effect on atomizing efficiency and opacity. Guns should be routinely cleaned and scavenged when taken out of service. Several burners were cleaned during this testing, and no chronic fouling was noted. Operators seem to be able to recognized dirty guns and correct the problems as required.

5) **Burner tip wear**- Burner tip wear can lead to poor atomization and high opacity. Tip hole size and mix plate and atomizer assembly wear should be checked when each gun is cleaned. If the tip hole size increases by one drill bit size, it should be replaced. Operators noted that there are several worn nozzle bodies in the guns. The burner tips appeared to be in good condition, with many reported to have been replaced during the recent outage.

6) **Burner Adjustment** – If the burner tip to diffuser dimension gets out of tolerance due to changes in gun length or retract cylinder location, the opacity can be affected. This can be determined by noting the opacity change when individual burners are removed from service. Measuring and logging the oil gun length during cleaning should help this from becoming a problem. The inspection report from the 2016 outage indicates that the gun locations were all correct. This of course is subject to the length of the atomizer assemblies. If gun length is changed this setting can get out of adjustment.

7) **Windbox Damper Operation** – The position of the fuel air and auxiliary air dampers should be checked whenever opacity becomes an issue. Generally speaking, the fuel air damper associated with a burner in service should be 100% open when the burner is in service, and the auxiliary air dampers (the ones above and below the fuel air damper) should be modulating to control windbox to furnace differential pressure. Note that the auxiliary air dampers often appear to operate very near the full closed position. This is normal. All dampers appeared to be functioning during this testing. Dampers are identified as Fuel Air (Red) and Auxiliary Air (Blue in the field, and the internal damper position is scribed on the outside end of the damper shaft, allowing the operators to establish damper position visually.

Recommendations – Unit 2

The following recommendations should be considered to restore the unit to full capacity.

1) Every effort must be made to reduce the pressure drops through the system. Cleaning the Ljungstrom air heater should be the number one priority, as it has a double impact on the high pressure drop. When shut down, it may be possible to gauge air heater cleanliness by looking down through the baskets from the top while someone shines a strong light up from below. Many coal fired plants stock a complete spare set of baskets that can be quickly exchanged if the air heater becomes fouled. The removed baskets can then be sent off site for cleaning and be available for the next unit outage. Pay particular attention to the cavity between the hot and cold end baskets to ensure there are no pieces of air heater element collected in between the two sections.

2) The economizer should be thoroughly cleaned in unit 1 to minimize the pressure drop before it is returned to service.

3) Cleaning the superheater and reheater gas lanes should provide reductions in pressure drop.

4) Investigate and correct the high pressure drop through the steam coil air heaters. This may be caused by bent tube fins, dirt accumulation between the fins, or a combination of both. As discussed above, if the average cold end temperature can be maintained on unit 2 with only the lower coils in service at an acceptable minimum load, the upper coils could be temporarily removed from service to reduce the current pressure drop.

5) When new replacement steam coils are installed, the top of the upper air heater coils should be protected either with permanent floor grating, or before access for Ljungstrom air heater servicing with scaffold planks prior to entering. This will protect the coil fins from further damage.

6) Take steps to minimize opacity as much as possible (See actions 1-7 on pages 5 & 6). This may provide the opportunity to reduce excess air and windbox to furnace differential pressure, both of which will increase the boiler load if air limited.

7) If opacity is under control, attempt to cycle the burner tilts to increase the reheat outlet temperature. This will increase unit output without requiring additional fuel and air.

8) Reduction of air heater leakage by adjusting/replacing seals may reduce the pressure drop through the system.

Unit 3 Capacity Tests

A brief capacity test was carried out on Unit 3. The maximum achievable load for this test was 130 $MW_{(E)}$ due to issues with Turbine Backpressure. During this test period, the boiler load was ramped from 70 to 130 $MW_{(E)}$ to verify air to fuel ratio and tuning parameters.

At this load there was no indication of limitations from a boiler perspective. It was noted however that the air heater pressure drop and flue gas outlet temperatures at this load were higher than the predicted values at Maximum Continuous Rating (MCR). This would indicate that while the issues noted to limit load on unit 2 may not prevent unit 3 from reaching full load, they are still in fact an issue on unit 3, and if not corrected could result in eventual de-rating. Even if these issues do not limit the maximum load, they will impact unit efficiency and fan power consumption.

The Flue Gas graphic on the DCS for unit 3 is missing some data points that were very helpful in troubleshooting issues on unit 2. There are no fan discharge pressure, air heater air inlet pressure, and air heater gas inlet pressure indications. These points do not need to be connected back to the DCS, however, local taps with isolation valves that could be monitored with a local hand held meter during the test would be helpful in determining the location and extent of individual system restrictions. These could be installed on the run using a hot tap method and isolated with a manual valve.

If you have any Questions or comments on this material, please feel free to contact me at any time.

Regards

Dan Regan
Babcock & Wilcox PGG Canada

Appendix 1 – Holyrood Unit 1 Pressure Drop Data – October 3-7 2016 power generation group

Holyrood Generating Station Boiler Performance Investigation Recap

30 June 2017

Dan Regan

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Work Completed this week

- Reviewed available historical data
- Reviewed sootblower piping and steam supply to air heater sootblowers
- Discussed plugging issues with air heater and sootblower suppliers
- Reviewed air flow control logic
- Located test ports for local measurements
- Attempted load test
- Summarized observations

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Observations

- Unit 2
  - Water Flow and Oil flow are higher than design to make full load (by up to 15%)
  - This correlation has been present since at least 2007
  - Steam flow indication matches design value, but is **<u>not</u>** a true flow measurement.
  - Some Data is inconsistent from test to test

Observations

- Unit 1
  - Steam Flow, Feedwater Flow and Oil flow match pretty well with design data for most loads
  - There is not much data available at higher loads, and no data available at 175 MW to review.
  - Some Data is inconsistent from test to test

Observations

- Units 1 and 2
  - Air heater fouling has historically always been a problem
  - In the past, when economizer differentials were low, much higher levels of air heater fouling could be accommodated before load was limited.
  - Economizer differential pressures have been steadily increasing over at least the last 10 years

Observations

- Units 1 and 2
  - With higher economizer differentials pressures, capacity limitations due to air heater fouling are more frequent and occur at lower air heater differential pressures.
  - Dry Ice Cleaning removed a significant amount of material but did not produce a sustained significant reduction in economizer differentials

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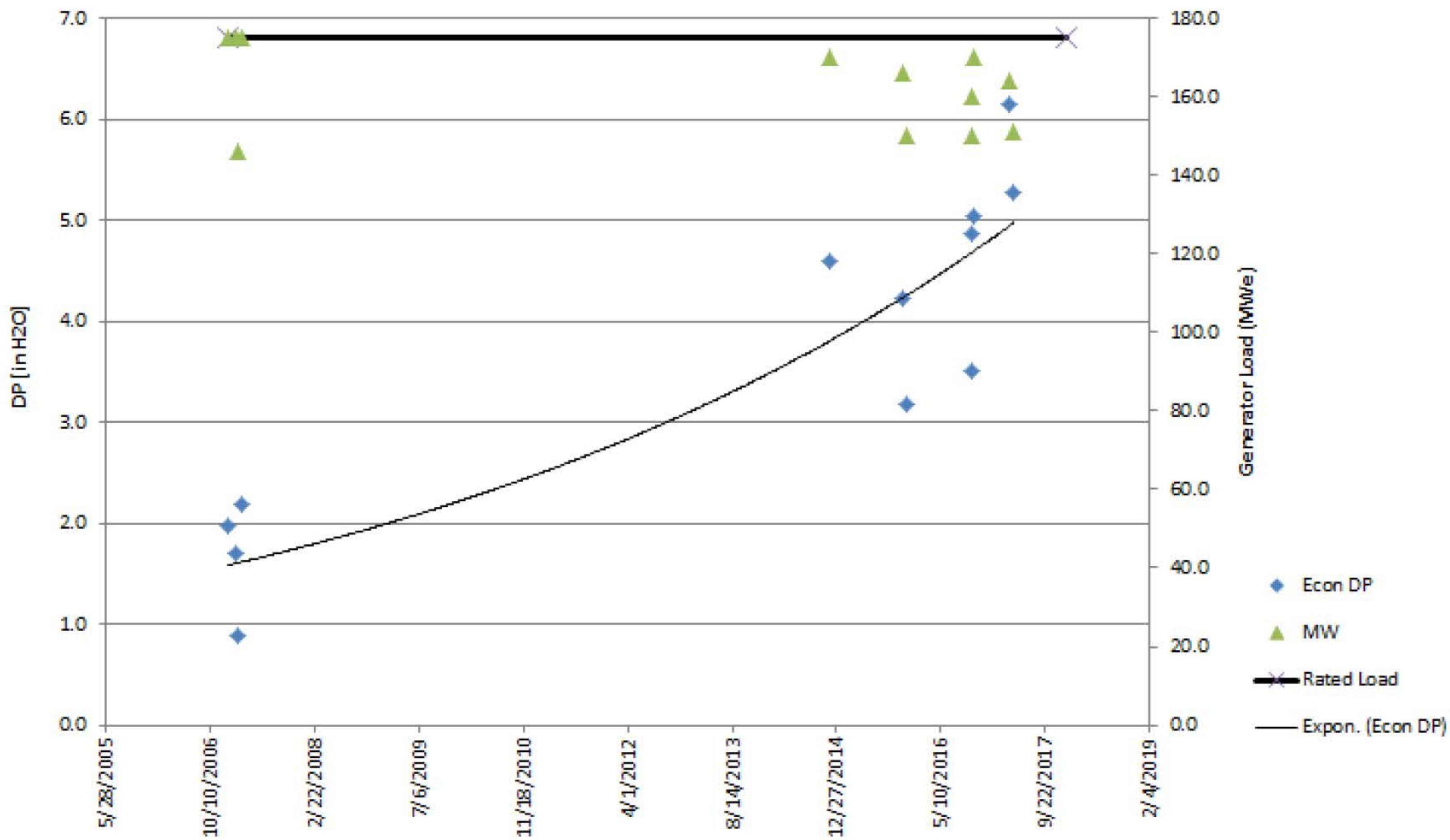
Economizer DP Above Design (2007-2017)



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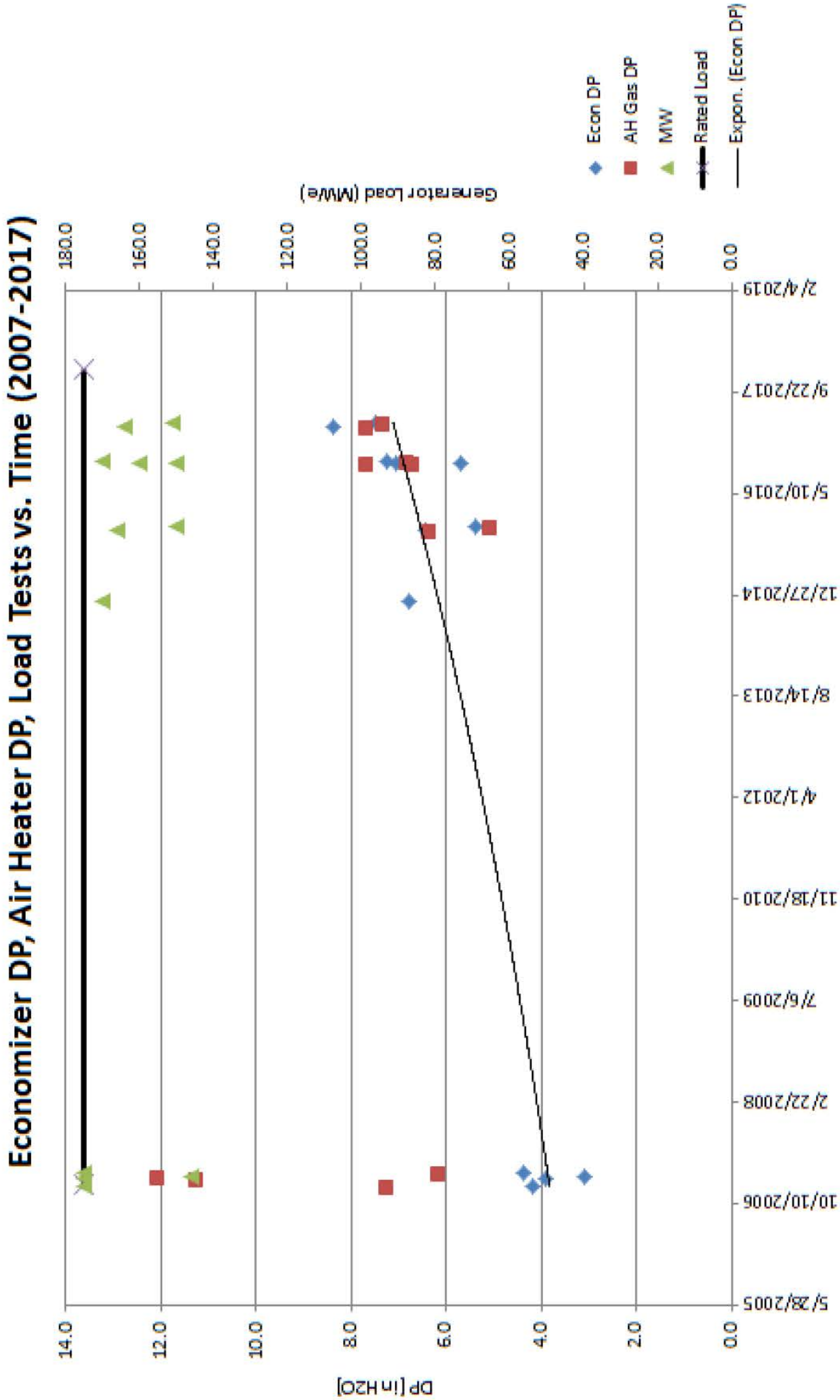

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Differential Pressures 2007-2017
(Percent of design, compensated)

	AH Gas Side DP	Econ. DP	Superheater DP	Windbox to Furnace DP	Cold Side AH+WB DP	MW
1/1/2007	142%	190%	124%	96%	101%	175
2/12/2007	221%	177%	119%	96%	121%	175
2/21/2007	313%	186%	116%	8%	157%	146
3/8/2007	121%	199%	130%	99%	96%	175
11/20/2014	130%	323%	131%	90%	139%	170
11/12/2015	135%	318%	129%	85%	138%	166
12/1/2015	126%	311%	121%	104%	127%	150
10/1/2016	167%	330%	131%	107%	174%	150
10/5/2016	173%	370%	132%	102%	235%	160
10/18/2016	140%	344%	137%	111%	98%	170
4/4/2017	167%	421%	120%	93%	112%	164
4/23/2017	181%	428%	122%	88%	112%	151

Impact of VFD Drives on Capacity

- Fan Capacity on VFD control with VIV's wide open and fan at 100% speed is exactly the same as fan capacity on VIV control with VIV's wide open and fan at maximum speed.
- Reducing fan speed results in reduced fan output and reduced fan power consumption.
- Boiler combustion controls have a runback if the demand for airflow is greater than the current air flow, and the fan controller is at 100%- This is why operators are reluctant to go above 90% output

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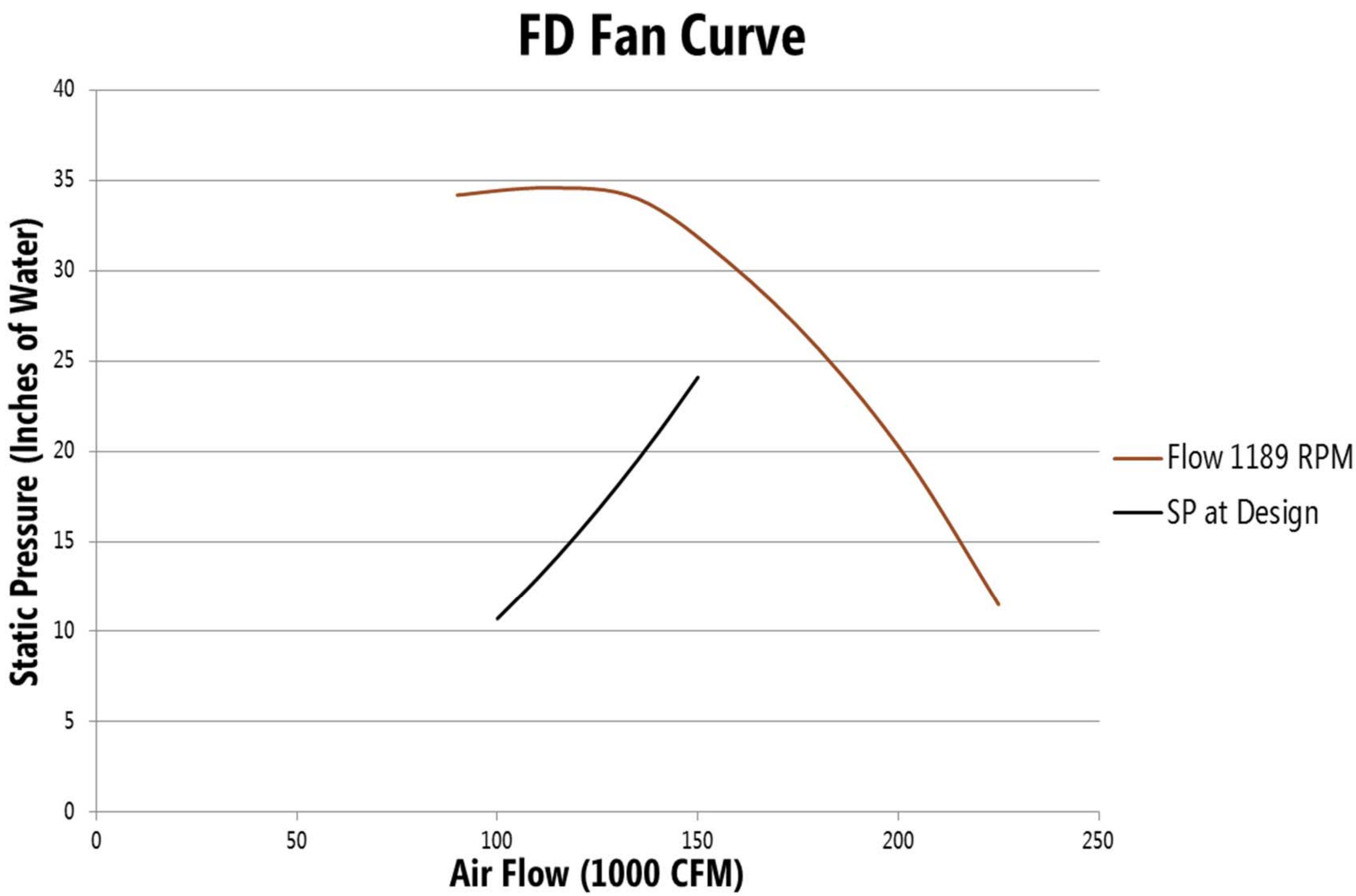
Fan and System Pressure Curves



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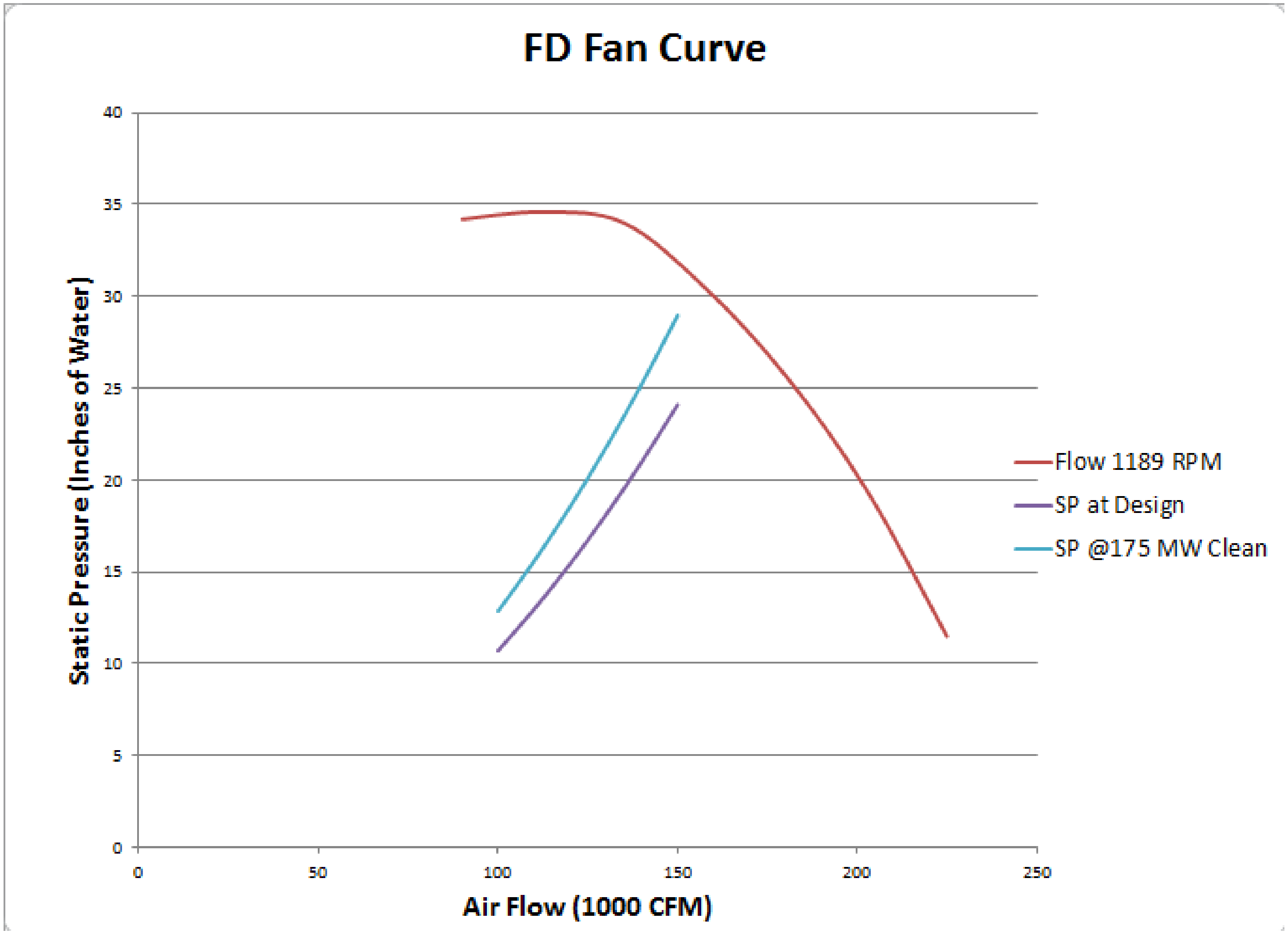
Fan and System Pressure Curves



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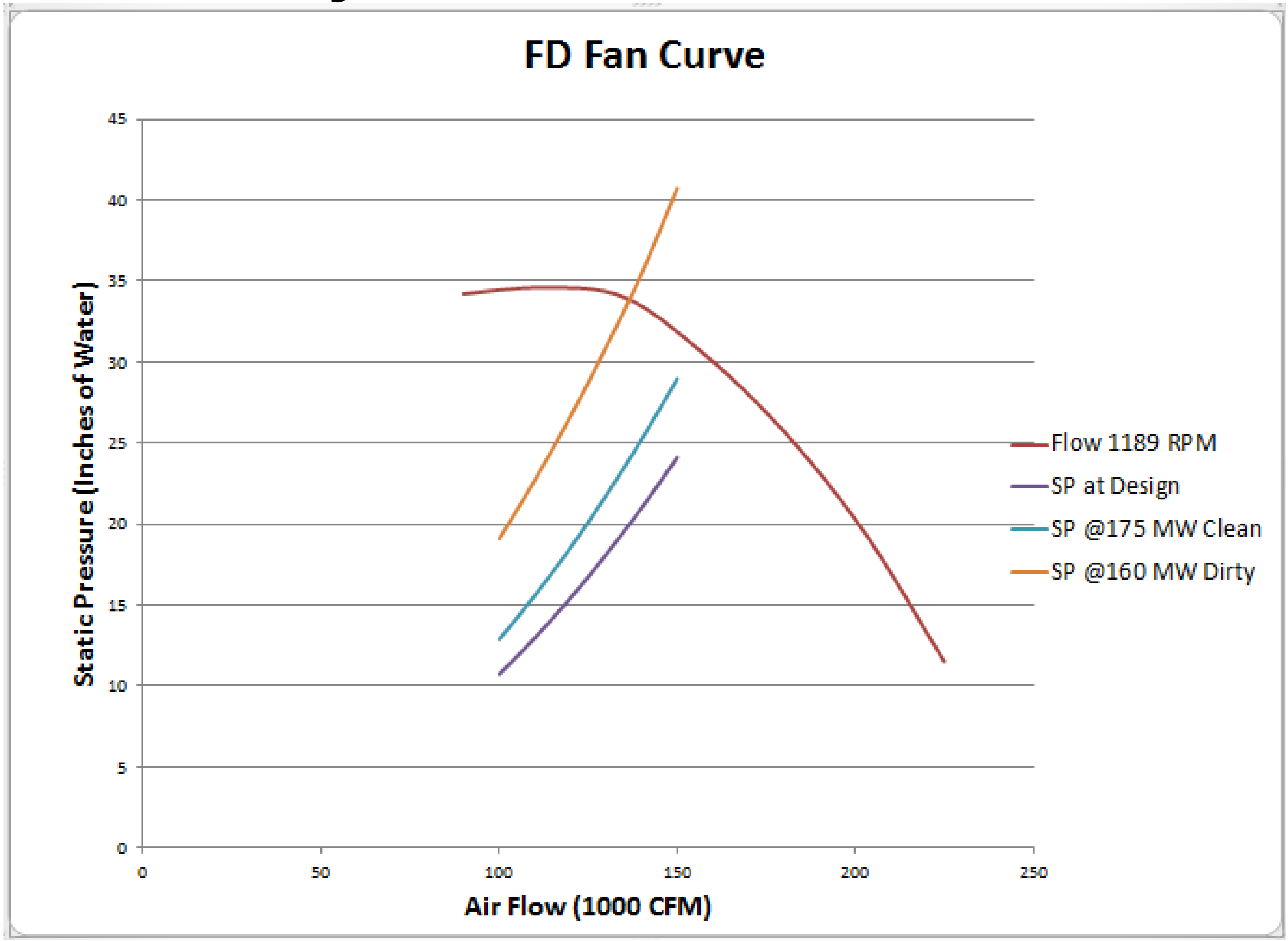

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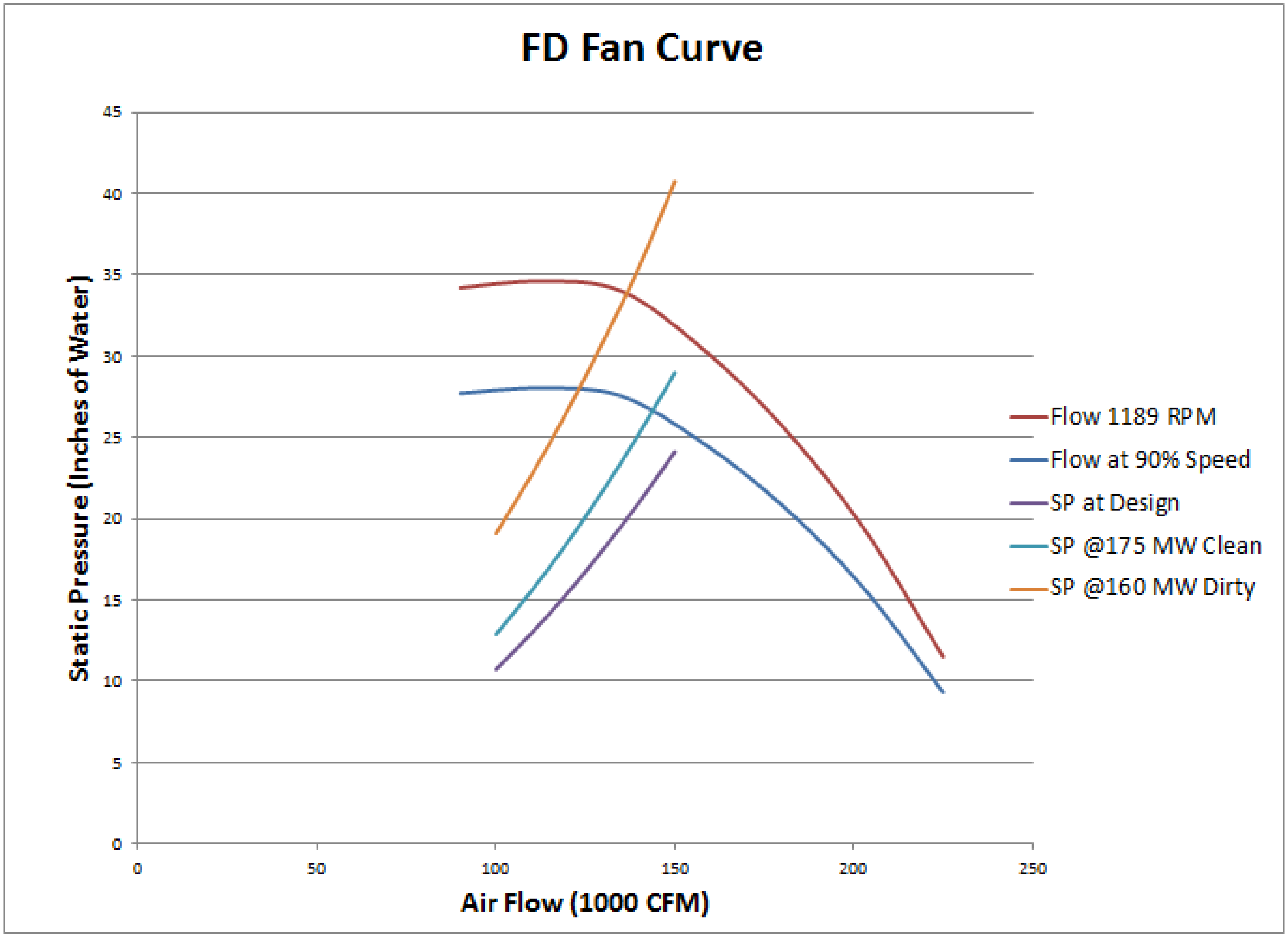
Fan and System Pressure Curves



Summary

- Boiler Capacity issues are largely a result of higher than design pressure drop through the system.
- High air heater differential pressures are caused by ash accumulation in the air heater heat transfer elements. These deposits can sometimes be removed with water washing, but if left to build up can be tenacious and difficult to remove.
- Longer term deposition in the economizer adds to the system resistance and reduces the tolerance to air heater fouling.

Summary

- Unit 2 appears to require more steam flow to make load than designed.
- This increased steam flow requirement requires higher air and fuel flows, that make the unit more sensitive to fouling and high differential pressures.
- This trend is not a recent issue – the 2007 data displays the same discrepancy.

Summary

- Any reduction in cycle efficiency increases the required firing rate on boiler.
- At high loads, these inefficiencies increase the potential for load limitations.
  - Steam Temperature
  - Condenser vacuum
  - Boiler efficiency.

Root Cause

- Air heater fouling can be caused by moisture mixing with ash to make it adhere to the air heater elements.

Where does the moisture come from?

- Condensate in sootblower steam
- Condensed moisture in the flue gas at low loads

Root Cause

Condensate in Sootblower Steam

- Howden's Air heater and Diamond Power both recommend between 200^{o}F and 300^{o}F superheat in the steam supply to the air heater sootblowers.
- Existing steam supply has 80^{o}F superheat at source.
- Piping should be sloped to drain, well insulated, and ***Thermal Drain Valves*** are preferred over using steam traps to keep the system at operating temperature.

Root Cause

Condensate in Sootblower Steam

- To provide proper steam conditions to the air heaters, steam supply would have to be taken off the secondary superheater outlet header.

- Piping and poppet valve upgrades will be required due to the higher steam temperature.

- ***Thermal Drain Valves*** should be considered to replace traps in current system. This will keep the system above saturation temperature.

Root Cause

Condensed Moisture in the Flue Gas at Low Loads

- Review average cold end temperature control at low load

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Issue	Cause	Effect	Remedy
Air Heater pluggage	Wet steam from sootblower	Ash sticks to elements – increased Delta P	Upgrade Steam supply to poppet valve Clean or replace baskets.
Air Heater Pluggage	Condensation of flue gas at low load	Ash sticks to elements – increased Delta P	Review air heater ACET at low loads Clean or replace baskets.
Air Heater Pluggage	Ineffective water wash cycle	Air heater baskets not completely cleaned – increased Delta P	Modify plant procedure for water wash
Economizer Pluggage	Accumulation over life of economizer. May be aggravated by SB steam conditions.	Steadily increasing differentials reduce fan capacity	Clean Economizer thoroughly before returning to service
Limited fan capacity on VFD control	Unable to operate at 100% fan speed at high load	Significant reduction in fan performance	Modify logic or implement auto-switch to vane control above 80% output
Increased Steam flow to No.2 Turbine	Unknown	Requires more fuel and air flow to make load – Poor heat rate	Investigate further – Turbine overhaul?
Low Heat Rate	Low steam temperature	Requires more fuel and air flow to make load –	Utilize burner tilts and sootblowers to ensure steam temperature set points are met.

Issue	Recommendation	Priority	Cost/Benefit
Air Heater Pluggage	Upgrade steam piping to provide dry steam to air heaters.	High	High/High
Air Heater Pluggage	Thoroughly clean or replace Air heater Baskets	High	High/High
Air Heater Pluggage	Verify air heater ACET is effective at low loads	High	Low/High
Economizer Pluggage	Mechanically clean economizer to reduce differential pressure	High	High/High
Economizer Pluggage	Mechanically clean economizer to reduce differential pressure	High	High/High
Air Flow Control	Configure control system to enable fans to operate at full speed	High	Low/medium to high
Heat Rate	Improve heat rate to reduce required firing rate in boiler to make load	Medium	????/????

Discussion Topics

Economizer Cleaning

- Mechanical Cleaning – Dry Ice
  - Effective removal of bulk deposits
  - Difficult to clean as probe gets further into bundle
  - Difficult to gauge cleanliness deep in bundle
  - Previous cleaning moved a lot of material however, economizer differentials did not return to “Clean Condition” levels

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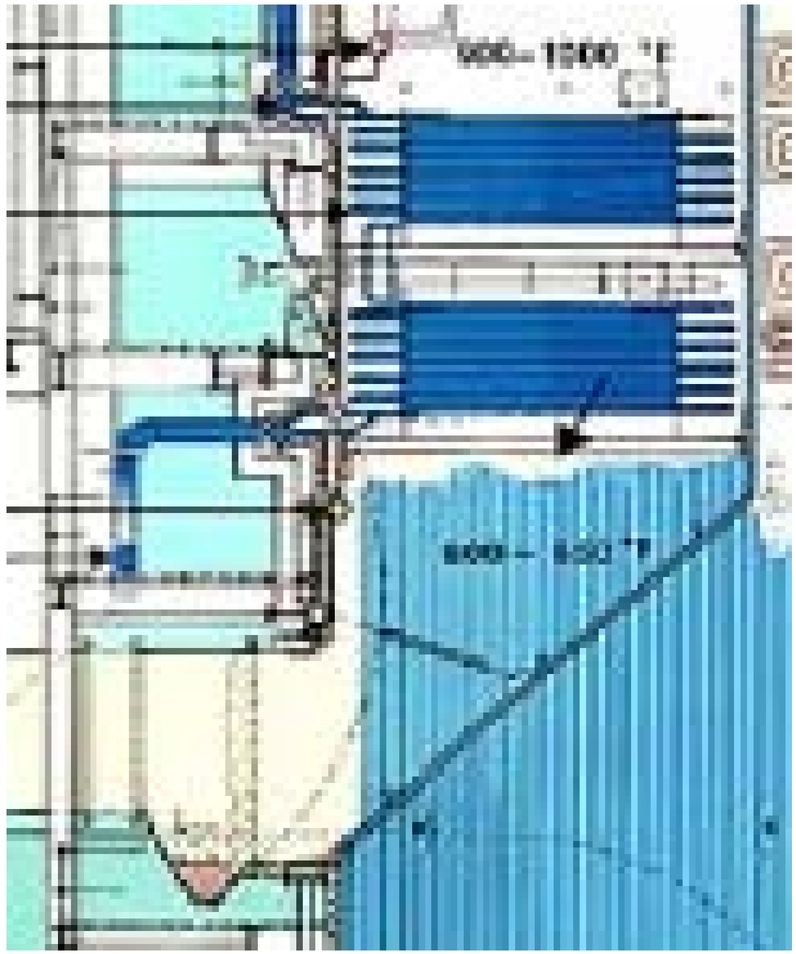
Discussion Topics

Economizer Cleaning

- Chemical Clean – Solvent
  - Send sample to Lab for analysis
  - Carry out bench testing to determine required solvent and solvent effectiveness
  - Circulate solvent through economizer (Gas side) – Spray in through cavities
  - Collect effluent in ash hopper
  - Flow effluent to settling tanks – recirculate solvent
  - Flush following cleaning with water

Discussion Topics



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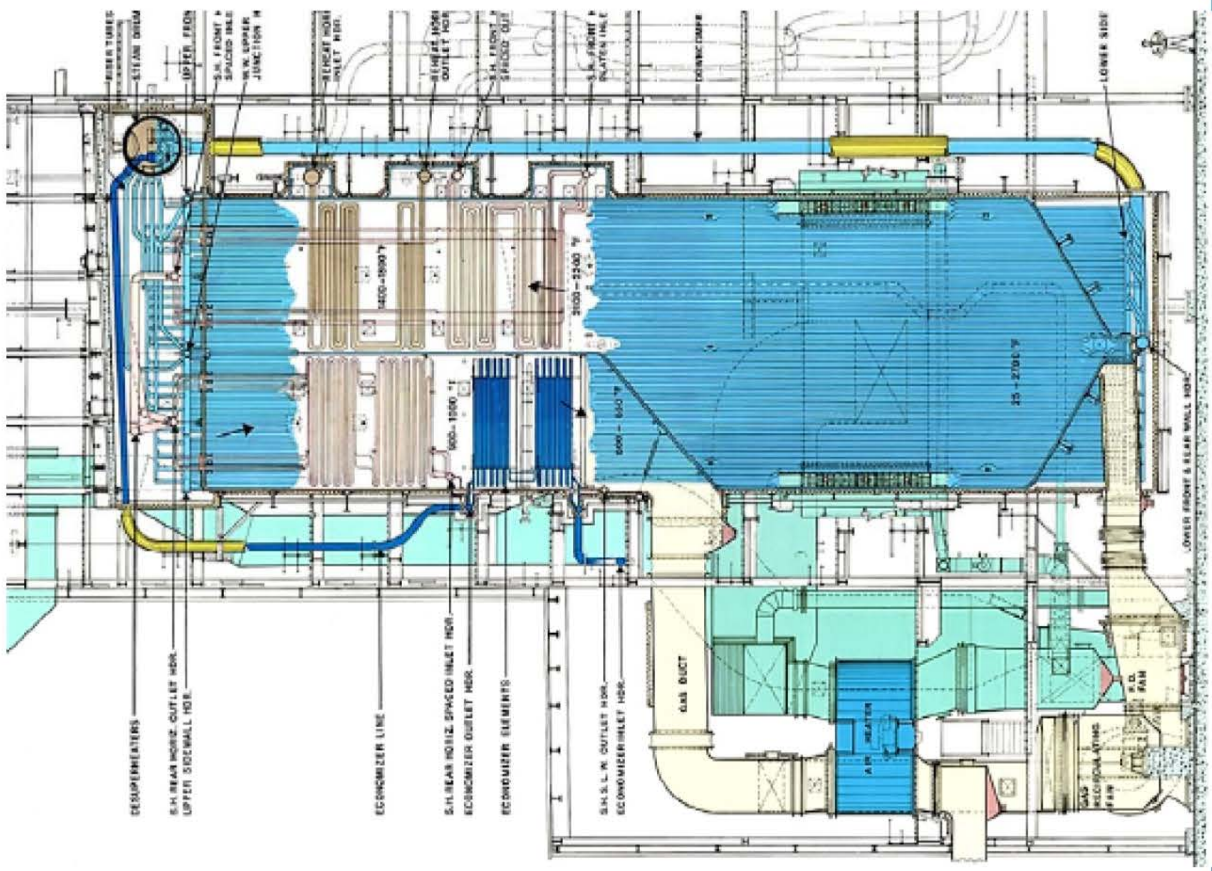

Discussion Topics

Air Heater Cleaning

- Chemical Clean – Solvent for Economizer should be effective at cleaning air heater baskets.
- May be more cost effective to clean baskets than replace (if baskets are mechanically sound)

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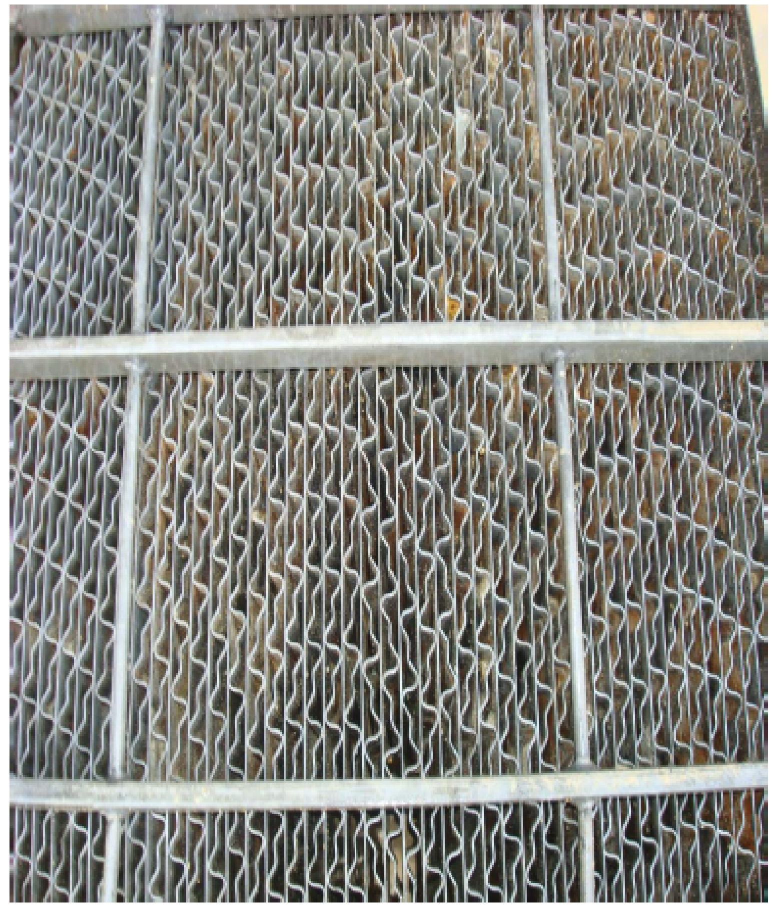
Discussion Topics

Chemical clean of air heater baskets at a power plant in India

Discussion Topics

Before cleaning

After cleaning



B&W power generation group

Discussion

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FIELD SERVICE REPORT

PROJECT INFORMATION			
Project #:	A031090/03	**Customer:**	Babcock & Wilcox Power Generation Group Canada Corp.
On-site Date & Time:	12-2-17	**Project Site:**	NALCOR Energy Newfoundland Labrador Hydro HOLYROOD STATION 1 Thermal Plant Road Holyrood, NL A0A 2R0
Estimated Duration On-site:	2 DAYS	**Site Contact Information:**	Shaun Lingley (B&W) sclingley@babcock.com 506.633.2880 Cell (506) 647.7802
Equipment:	Unit #1 East Unit #1 West APH's 21.5 VIRX-40	**Sales Office & Rep Info:**	Gary C Seely Ltd Rick Lawrence, CET rick.gcs@nb.aibn.com 506.847.0990
Original Equipment Order Number:	HOW-0828-1202	**Customer PO:**	TPX284373
Serial #:	1202-1 1202-2	**Assigned Field Engineer:**	G GOETSCHIUS
G.A. Drawing #:		**Field Service Supervisor:**	M. COATSWORTH
Parts Project No.	NA	**Project Manager**	NA
Testing Equipment Used On Project (Brand-Model & S/N):	None	**Project Completion Date:**	12-4-1
FOLLOW UP (TA…check appropriate boxes)			
Service Complete:	☒Yes ☐No	Quote Required:	☒Yes ☐No
Return Trip Required:	☐Yes ☒No	Parts List provided to Customer:	☐Yes ☐No
Additional Info. Required:	☒Yes ☐No	Does HNA Sales Rep need to contact Customer:	☒Yes ☐No

24/7 EMERGENCY SERVICE 800.458.FANS (3267)

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Objective/Job Scope:

Howden has been requested to be on site to provide consultation on a high pressure drop issue.

Conclusions / Recommendations:

Return to using MgO as a fuel additive.
Replace the hot end layer of element.
See below.

Work Performed/Observations:

The customer is experiencing high pressure drops through the air heaters on both units 1 and 2. On unit 1, this has been going on since before we changed the cold end element. The design gas side pressure drop was 5.1" H2O. The design air side pressure drop was 3.4" H2O. They are running 8.44 gas side and 6.43 air side now.

These are size 21.5-VI-40" air heaters supplied by Howden. The hot end element is 28" deep 24 gauge DU-2.5 LACR. The cold end is 12" deep 22 gauge NF-6 enameled decarb. Howden supplied the cold end element within the last 2 years and it is in good condition. Howden also supplied the hot end element in the east APH in 2012. Alstom, now ARVOS, supplied the hot end baskets in the west APH in about 2009.

The unit has a Combustion Engineering Type R.R.P.-70 pressurized boiler. It was built in 1969. The unit burns #6 fuel oil. There are no additives used with the fuel. The use of Magnesium Oxide (MgO) as an additive was discontinued in 2014. The high pressure differential did not seem to be a problem until relatively recently. We are still trying to determine how long ago it started.

There are cold end Diamond retractable soot blowers on the air heaters. They are run at about 160 PSIG. The recommended maximum is 145 PSIG. 70 degrees F of superheat is all that is obtainable for the steam. The recommended amount superheat is 200 degrees F. The steam supply system is original.

The air heaters were washed prior to my arrival on site for about 7 hours. They used to original wash headers, hot end and cold end. They cycled through the headers one by one for the wash, CE east for ½ hour, CE west for ½ hour, HE east for 1 hour, HE west for 3 hours, HE east for 2 hours. There seems to be a water supply/removal issue with running more than one at a time. At the start of the wash, the water coming out of the heaters was very muddy. At the end, the water was clear. A cold air test was completed after the wash and there was no significant change in pressure drop. The water is combined with steam to bring the temperature of the wash water up to 90 degree C.

A hot end basket was pulled in each air heater. The baskets looked relatively clean from the hot end. A ¼" diameter rod was run down the notches of the element with varying degrees of success. In approximately 1/3 of the notches tried, we were able to run the rod all the way through the depth with

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little or no effort. About 1/6 of the notches required some effort. On approximately ½ of the notches, the rod could not be forced through the entire depth of the element. Inspection of the sides of the element sheet showed deposits in the middle ¾ of the depth of the element. Samples of the deposit were removed for analysis by B&W. A small amount of deposit was put into water and did not dissolve. A magnet would pick up a substantial amount of the deposits indicating a significant amount of iron was present.

Since the deposits were not soluble, the baskets were high pressure washed using 2500 PSI water with a nozzle approximately 1/8" diameter. The water was initially very dirty coming out of the heater but would clean up. The rod was run down the notches again. Approximately 90% of the notches required little if any effort to get the rod through the basket. In less than 10 percent, the rod could not be pushed through the element. Both rotors were completed by 8:00 Sunday night with a final flush with a fire hose.

Another air test was run prior to putting the unit back on line. There was a significant improvement in the pressure drop. The actual improvement was not provided to me.

With respect to the fuel additives, I received the following comments from Jim Cooper, the Howden Chief Engineer – Heater Technology:

Although I have been busy on other things, I have had a quick look at this and make the following initial comments, which may or may not be proven be correct of relevant

a) If they are presently running at 8.4" H2O compared to design of 5.1" H2O, the pressure drop has increased by around 65% compared to clean plate using up much of the fan margin before load limitations might start to occur. However, as with most NA installations of that vintage are concerned, I would guess that they had plenty fan margin to play with in the first place.
b) Although you said that the boiler fires #6 fuel oil (a typical residual fuel oil), the fuel analyses do not appear to suggest that. The analyzed sulphur content of 0.7% is much lower than the more typical levels of around 3.5% for such fuels (see attached document that I have just downloaded from the web. Equally, their measured viscosity levels also appear to be much too low for such a fuel and the specification (viz. 88 cSt v 700 cSt measured). If it is this low, it strikes me as being more of a light oil (distillate). This is further reflected in the ash content being around 2.5 – 5 times lower than in typical #6 fuel oil (see https://en.wikipedia.org/wiki/Fuel_oil).
c) The combination of low sulphur and low viscosity, immediately suggests to me that they should not be suffering from either acid condensation enhanced fouling or fouling due to poor oil atomization.
d) However, the vanadium content of around 200 ppm is not insignificant (see Fig 3 below from report), and probably warrants the use of an additive (such as MgO to mitigate the effects of forming Vanadium/sodium eutectic mixes producing the possibility of molten salt deposits in the upper zones of the furnace.

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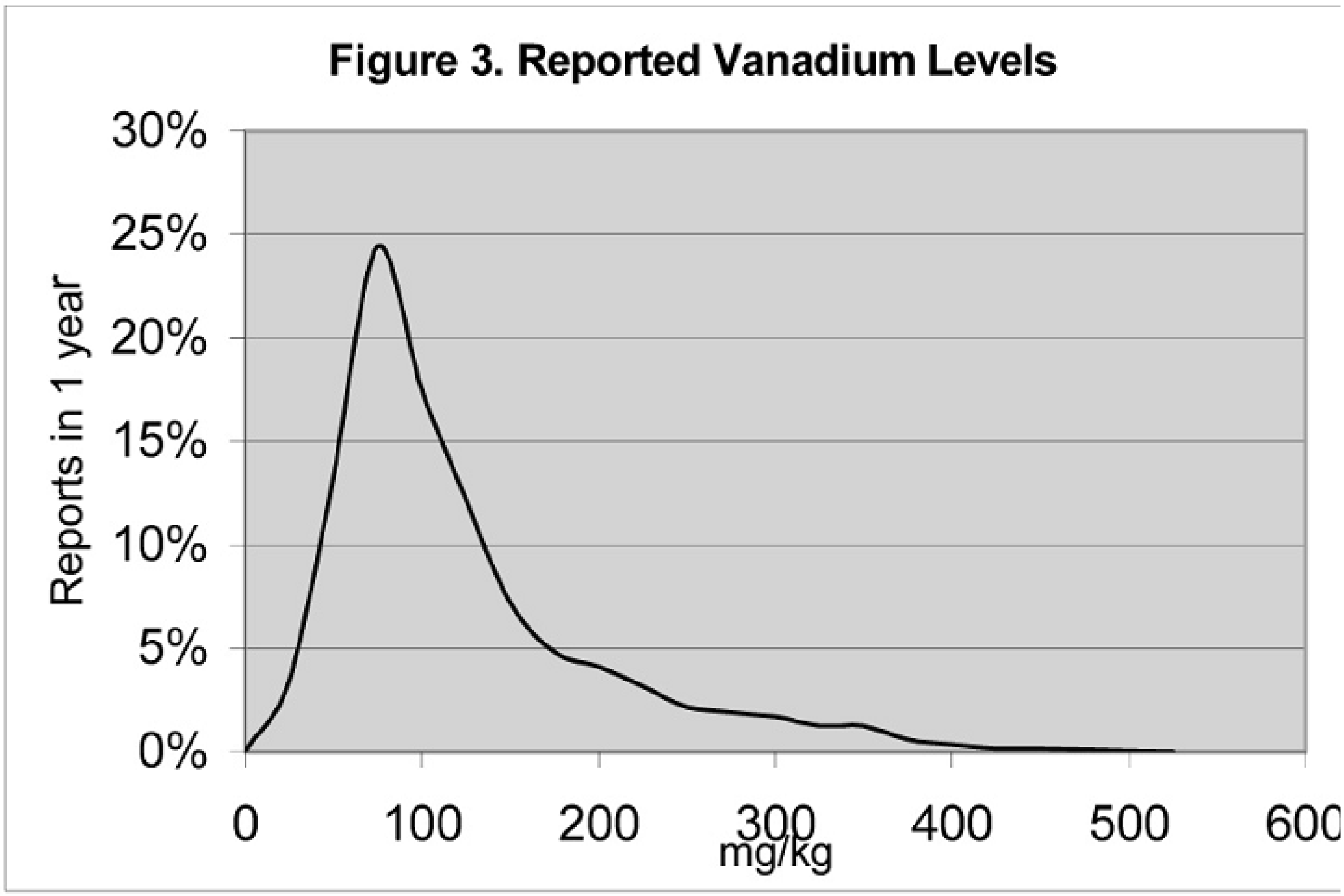

e) Indeed, as is shown from the red line I have drawn on Fig 5 below, showing the measured Va/Na ratio of 4.0 for the fuel oil, this is in the zone where the report suggests that molten deposits are likely and additive injection would be recommended.

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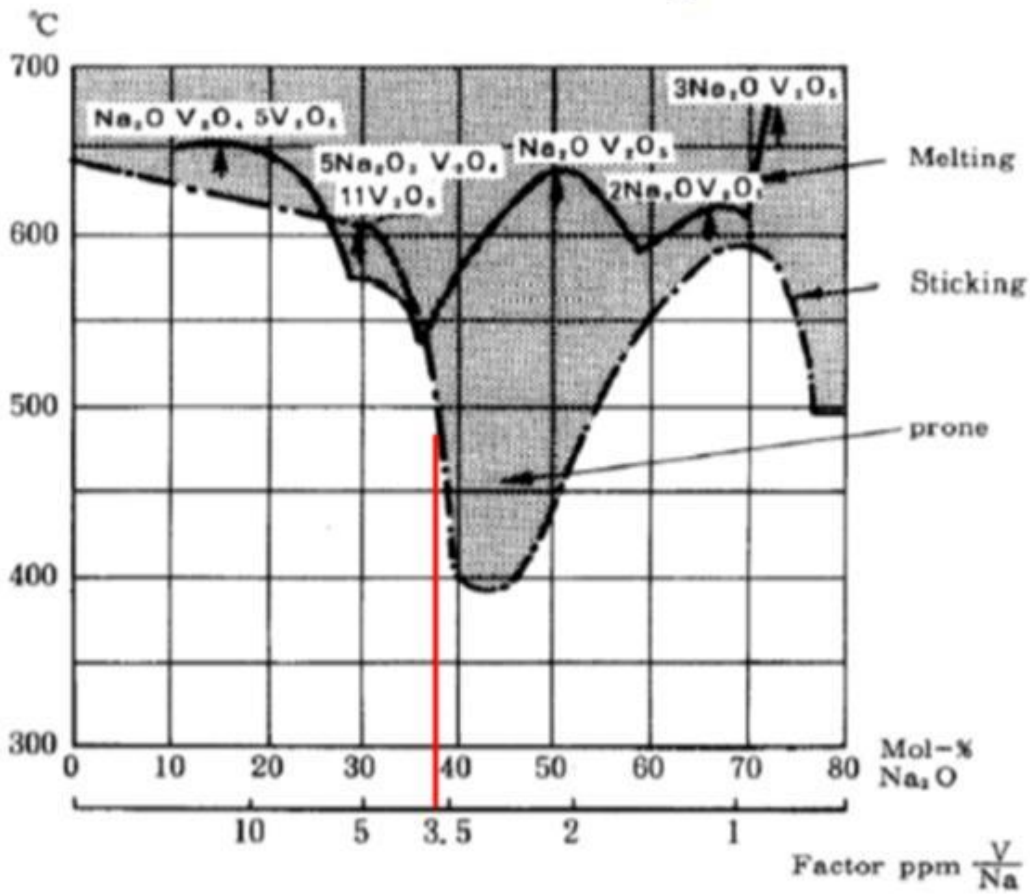
Figure 5

V / Na Eutectic Diagram



f) Given the combination of the above factors and the fact that you have reported that some of the deposit has been found to be magnetic, I would hazaerd a guess that, ceasing the use of MgO additives, has promoted vanadium attack in the upper zones of the furnace ausing pregressive corrosion releasing iron scale type deposits that have subsequently found their way ito the APH producing progressive build up and fouling. In that case, on examining the long term fouling over the APH you might find that it would slowly start to progress after a reasonable delay after when additive injection was ceased.

g) Moreover, given the long term operation of the plant, if this were the main factor that has changed, it must remain the main suspect. (I'm sure I could quote Sherlock Holmes more correctly if I took time to look up the quote. ☺)

I hope these quick thoughts help. I know that the attached paper refers to diesil engines but there is a direct analogy to boiler combustion.

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I will forward the paper that Jim refers to.

Based on Jim's comments above, the fouling in the boiler that we discussed during my visit and the quick bit of investigation we did before I left site, a partial solution to the boiler and air heater fouling would be to reintroduce the MgO additive. (I think that was being discussed with the plant after I left site.)

We did talk about loose packed element while I was on site. After reviewing type of deposits that we found, I feel that a loose packed element configuration is not part of the solution here. The fouling that we observed was more of a deposit, relatively uniform, conforming to the surfaces of the undulations. It looked as if it had started to break free of the element surface after it had dried, after the first wash. The high pressure water wash, that was completed after our inspection, did not clean it out completely, based on the reported pressure drops. Loose packed element was developed for ash particles that wedge between the element sheets, that do not adhere to the element sheets, that will fall through a passage that suddenly get larger when a soot blower jet hits the element sheets.

I was planning on asking Howden UK to estimate the amount of fouling that would be required to increase the pressure drops to the levels that reported prior to the outage. Based on the type of fouling found, any estimate of fouling rate would have a range large enough to make it not useful.

The low superheat on the soot blowing steam will be a factor in the rate at which deposits like this build up. Because the soot blowing steam supply system is the original design, that it seemed to work adequately for years, and that it has never been high on any list to be upgraded, I would not push increasing the superheat temperature now.

Parts Consumed/Recommendations:

Howden will provide an updated quote for replacing the hot end baskets on an expedited delivery.

Sincerely,

Gary C. Goetschius
Field Engineer
Howden North America, Inc.

Thermal Power Department

Technical Services

Engineering Study Report

Customer: **Newfoundland and Labrador Hydro (NLH)**
Holyrood Units #1, #2, #3

Subject: **Performance Study**
Unit Capacity Limitations

Ref No: B&W Project 312C
Rev 04, June 20 / 2018

Prepared By: Brian Jordan P. Eng
Project Engineer

Reviewed By: Malcolm Mackenzie, P. Eng.

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1 INTRODUCTION

The three oil fired units at Newfoundland and Labrador Hydro's Holyrood station are currently not capable of generating their rated megawatt outputs. Newfoundland and Labrador Hydro (NLH) requested B&W to perform this engineering study to identify the causes of the current limitations and make recommendations to return the units to full load capability. The B&W proposal for this study was B&W reference TP001082 issued on 21 November 2017. A two stage approach was proposed. The first stage identifies the causes of load limitations and the second stage focuses on the steam generator heating surface effectiveness. This report summarizes the results of both stages.

The Unit #1 and #2 boilers at Holyrood are Combustion Engineering (CE) units built in the late 1960's. The Unit #3 boiler was provided by Babcock & Wilcox Canada (B&W) in 1979. All three boilers are pressurized (i.e. forced draft fans only). The turbine-generator sets for all three units were supplied by Hitachi Ltd. The three units were originally rated at 150 MW (Gross). Units #1 and #2 were up-rated to 174.2 MW in 1988 and 1989 respectively.

The maximum unit load for Units #1 and #2 was limited to 133 and 125 MW (gross) respectively by furnace pressure per the January / February 2018 operating data considered in this study. The maximum load for Unit #3 was limited by FD fan capacity to128 MW per January 2018 operating data.

The load limitation for Unit #1 and #2 is maximum furnace pressure thus this study focuses on the factors which affect furnace pressure for these units. The load limiting factor for Unit #3 is FD fan capacity so the focus is on fan capacity.

The common fuel oil supply system is also considered with respect to issues that affect boiler performance.

2 EXECUTIVE SUMMARY

Recent losses in the capacity of the three Holyrood units are primarily a result of:

i) Increases in air and flue gas pressure drops across the cold end boiler heating surfaces (economizers and air heaters) due to oil firing deposits (fouling) on these surfaces. These deposits form predominantly during periods of low load and startup when the heating surfaces are cold and combustion efficiency is low.

ii) Degradation of unit heat rate which increases the required heat input per MW. These increases lead to increased furnace pressure and FD fan loading in turn.

Units #1 and #2 are currently load limited by the maximum allowable furnace pressure. Unit #3 is load limited by the FD fans.

Reductions in maximum load capability for Units #1 and #2 have been present since 2015/2016. The reduction in maximum load for Unit #3 occurred relatively quickly in the Oct 2017-Jan 2018 time period.

Due to excessive deposition, all three units experience increased draft losses. The air heaters on all three units are affected. Units 1&2 are equipped with extended surface (finned) economizers which also experience increased draft losses. Replacing or cleaning of fouled heat transfer surfaces to ‘as new’ condition (if possible) will restore the design maximum unit load capability.

If unit load capability is restored by cleaning and/or replacing heat transfer surfaces, reoccurrence of unit de-rates caused by fouling can be prevented by:

- Ensuring air heater Average Cold End Temperatures (ACET) are maintained above 212 F (100 C) at all times.

- Reinstating use of the fuel MgO dosing system

- Increasing the fuel oil atomizing temperature to ensure proper atomization and combustion.

- Ensuring sootblowing steam is dry

The key findings of this study are outlined below.

2.1 Units #1 and #2

The maximum output of Units #1 and #2 is currently limited by the maximum allowable furnace pressure. Maximum furnace pressure is established by the boiler manufacturer according to the structural design of the boiler and furnace. Unit #1 was limited to 133 MW on Jan 18, 2018 at a furnace pressure of 17.9” wg. Unit #2 was limited to 125 MW on Feb 2, 2018 at a furnace pressure of 19.9” wg. Loads of 170 MW were last achieved in Jan 2015 and Oct 2016 for Units #1 and #2 respectively.

The operating furnace pressures are significantly higher than design primarily due to the combination of:

a) Higher than design air heater and economizer pressure drop due to fouling of the heating surfaces
b) Higher than design unit heat rate due to reduced boiler efficiency and increased Turbine Generator (T-G) heat rate.
c) Higher than design air flows

The potential increases in unit load as limited by furnace pressure that would occur if the above issues are corrected are illustrated in Figures #1 and #2. The gains associated with restoring economizer / air heater pressure drops are based on new heating surfaces or surfaces restored to ''as new' condition and are thus best case scenarios.

Unit heat rate could be restored by restoring T-G efficiency, correcting lower than design hot reheat steam temperatures, and restoring air heater / economizer heat transfer efficiency (Boiler efficiency).

The higher than design air flows are due to underestimation of the combustion air quantity as indicated by the OEM boiler supplier data sheets (Appendix 8.1) and are therefore not considered 'correctable'.

Figure 1 Unit #1 Potential MW Output Increases

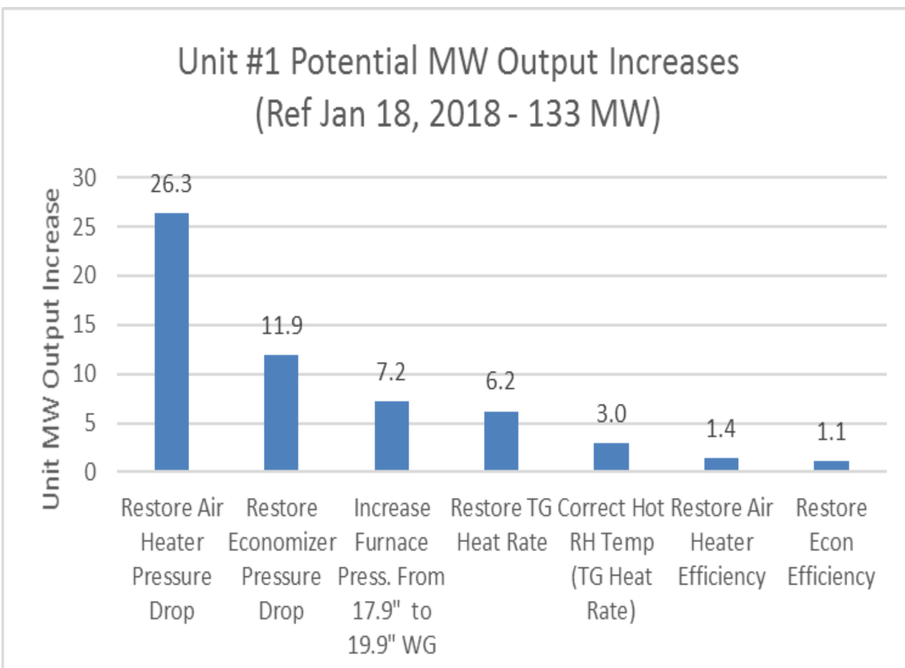
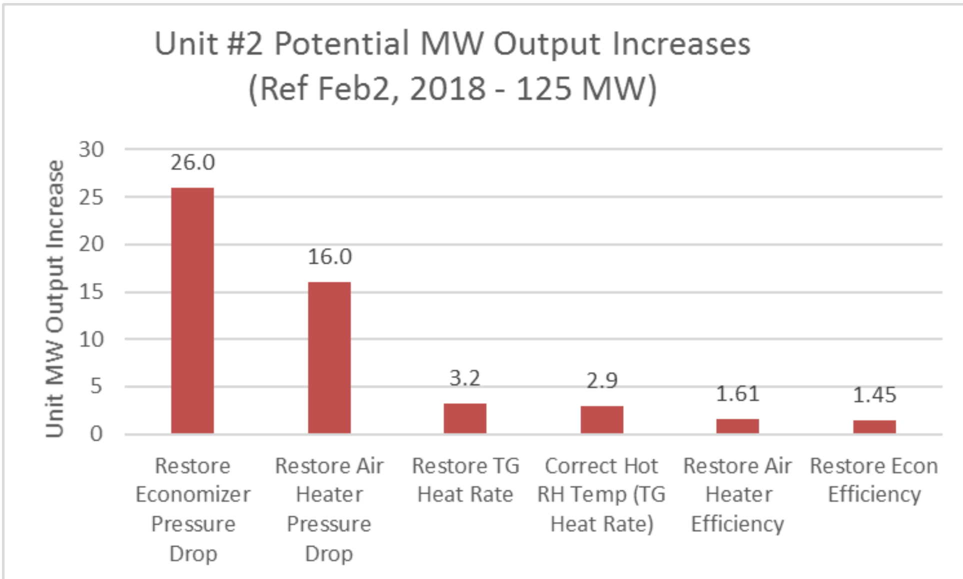


Figure 2 Unit #2 Potential MW Output Increases



If both air heater and economizer pressure drops are restored, the full rated 174.2 MW will be achievable on both units without exceeding the current 20" WG furnace pressure alarm point limit. According to site reports, cleaning of these heating surfaces has proven very difficult in the past. Unless more effective methods can be employed such as chemical cleaning the most effective means of reducing furnace pressure would be to replace the fouled air heater elements. Replacement of economizer surfaces would very likely not be economically viable.

Less significant increases in maximum unit load capability are possible by restoring turbine / generator (T-G) heat rate.and/or restoring the heat transfer effectiveness of the boiler heating surfaces. Results of the 'Stage 2' study indicate poor heat transfer effectiveness of the air heaters and economizers. It is important to note that if pressure drops as above are restored by surface cleaning or replacement, a significant portion of the MW gains from increased boiler efficiency will also be realized along with the associated fuel savings.

Unit # 1 was operating at a furnace pressure of 17.9" wg on January 18, 2018, reportedly load limited by furnace pressure. The reason for this lower operating pressure at that time is unknown. If the maximum operating furnace pressure is increased to 19.9" as per Unit #2, an increase in maximum load of 7.2 MW would be realized.

The reheaters on both units are underperforming significantly. While the cause of poor air heater and economizer performance is clearly fouling as evidenced by high pressure drops, the cause of poor reheater heat transfer performance is not known and should be investigated. Sootblower usage patterns and blowing pressures may need to be adjusted to improve effectiveness. Poor reheater heat transfer effectiveness reduces unit efficiency (and MW output) on four fronts:

a) Low hot reheat temperature (increased T-G heat rate)
b) High burner tilts (less furnace effectiveness – loss of boiler efficiency)
c) High superheat sprayflows (increased T-G heat rate).
d) Increase in stack temperature. (loss of boiler efficiency)

Of the above, item a) is the most significant.

2.2 Unit #3

Unit #3 is load limited by the current capability of the FD fans. Maximum load dropped from 150 MW in October 2017 to 128 MW on January 4, 2018 as air heater pressure drop increased. The pressure drop increased most significantly during lower load operation (less than 100 MW) and when air heater Average Cold End Temperature was less than 100 C (212 F).

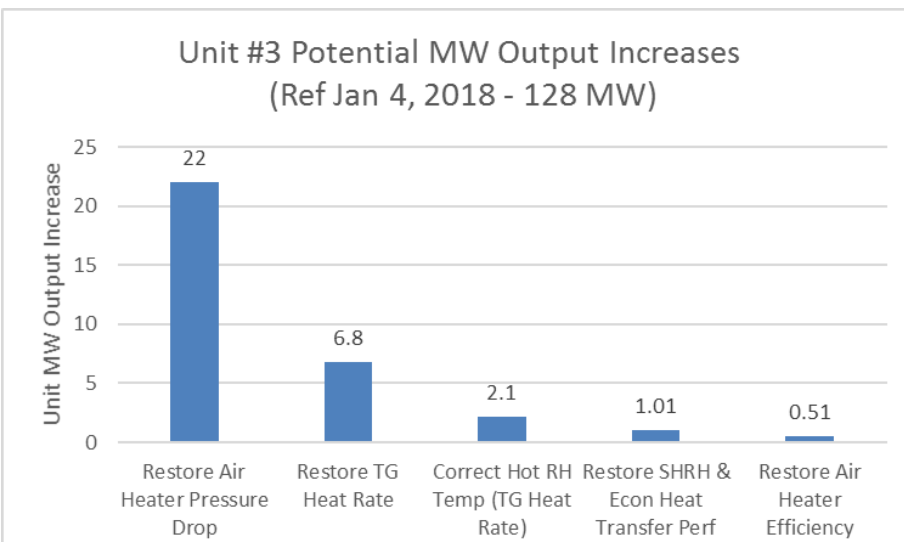
The fan VIV's have been restricted to 54/70% open on the east/west fans respectively due to inlet ducting vibration which occurs at higher openings under some operating conditions.

Without this restriction, full load operation would have been attainable on January 4, 2018 when load was limited to 133 MW. An inspection and test program should be implemented to determine how the full fan capacity can be restored.

The required FD fan duty is higher than design primarily due to higher than expected air heater pressure drop and higher than design Unit heat rate (lower than design unit efficiency). Full load operation would be restored given the current FD fan VIV restrictions if the fouled hot end air heater elements are replaced with the proposed "ARVOS" elements and if the existing cold end baskets are clean and in good condition.

With reference to the Jan 4, 2018 operating point (128 MW), increases in unit load capability as per Figure #3 would be possible for fixed fuel input. The largest contributor to unit efficiency reductions is turbine – generator inefficiencies. The largest boiler related contributor to the increase in unit heat rate is low hot reheat temperature.

Figure 3 Unit #3 Potential MW Output Increases



The heat transfer effectiveness of the Unit #3 superheater and reheater declined significantly during the time period from Oct 2017 to Jan 2018. These surfaces should be inspected for cleanliness to determine the cause of this decline. Sootblowing patterns and/or blowing pressures may need to be revised to improve cleanliness.

2.3 Fuel Related Issues (Common Units 1,2,3)

The quality of fuel oil has improved significantly in recent years. A significant reduction in fuel oil Vanadium and Sulphur content occurred in 2006. These improvements would be expected to reduce the tendency towards boiler cold end (air heater and economizer) fouling and boiler corrosion. From a combustion standpoint, the currently utilized fuels are very close to the original Unit #3 design fuel.

The current fuel oil atomizing temperature (approx. 187 F) is at times lower than required for optimal combustion. It is recommended to increase firing temperature to achieve target oilviscosities as discuused in Section 6.1. The MgO additive system was taken out of service in 2014 and reductions in unit load capability for Units #1 and #2 started to occur in 2015-2016 and Unit #3 in late 2017. This system should be placed back into service and the oil dosed at a rate of 1 lb. MgO per lb. V2O in the fuel oil.

The Unit #3 air heater fouled rapidly between Oct 2017 to Jan 2018. During this time period, air heater pressure drop increased most notably during periods of both low load operation and low ACET. When ACET was maintained above 212 F there was no significant increase in pressure drop. It is recommended that air heater ACET is maintained at a minimum of 212 F for all three units.

For Unit #3, the combination of low load operation (possibly poor combustion due to low atomizing temperatures), the lack of MgO additives, and low ACET is the most likely cause air heater fouling that occurred between October 2017 and January 2018.

Fouling in the Unit #1 and Unit #2 air heaters and economizers occurred between 2015-16 and 2018. The operating conditions during which this fouling occurred is unknown. It is most likely that the economizer fouling occurred start-up operation and the air heater during low load and/or start-up operation.

3 CONCLUSIONS AND RECOMMENDATIONS

The conclusions and recommendations of this study are summarized below:

3.1 Units #1 and #2

3.1.1 Conclusions

a) The current maximum achievable load of Units #1 and #2 is limited by furnace pressure due to the combination of the following factors:
   i. The draft loss across boiler surfaces is higher than design, most notably the economizer and air heater
   ii. Unit efficiency is lower than design
   iii. The calculated fuel air flow requirements (per unit fuel flow) are higher than original design
b) The air heater and economizer pressure drops have increased significantly between the 2015/16 and 2018
c) Pressure drops across the superheater and reheater are significantly higher than design but are not a major contributor to higher than design furnace pressure.
d) Reheater heat absorption is lower than design as evidenced by lower than design hot reheat steam temperatures. Low hot reheat temperatures are leading to an up to 1.5% increase in TG heat rate.
e) The current largest contributors to higher than design furnace pressures and unit derating are:
   i. For Unit #1, high air heater pressure drop

ii. For Unit #2, high economizer pressure drop

f) Restoring the air heater and/or economizer pressure drops to original design would increase maximum load as limited by furnace pressure per the following table: (Note that restoring both components results in increase above that of individual components- if just one component is restored, furnace pressure is still limited by restriction in the other)

MAXIMUM LOAD AS LIMITED BY FURNACE PRESSURE			
		Unit #1	Unit #2
Maximum Load Per 2018 Data	MW	133	125
Increase Maximum Furnace Pressure up to 19.9" WG (Unit #1)	MW	140	125
Restore Design Air Heater Pressure Drop	MW	159	141
Restore Design Economizer Pressure Drop	MW	145	151
Restore Both Economizer and Air Heater	MW	175	175

g) Improved heat transfer and boiler efficiency will follow restoration of heating surface cleanliness. FD fan power consumption will also be reduced.

h) Alternate methods of economizer / boiler surface cleaning such as explosives or acoustic shock – blast methods could be considered if it is not possible to clean these surfaces by conventional means.

i) Maximum boiler load as limited by furnace pressure may be increased if modifications/repairs to the turbine/generator set are made to improve heat rate.

j) It may be possible to increase the current furnace pressure alarm and trip points. The original boiler supplier could advise if this is possible.

k) The heat transfer performance of the economizer and air heater on both units is significantly lower than design, reducing boiler efficiency significantly

l) The heat transfer performance of the reheater heating surfaces is significantly lower than design, reducing Turbine-Generator efficiency significantly and boiler efficiency.

m) Removal of air heater heating surfaces is not recommended due to the negative effect on combustion efficiency and structural limitations of downstream flues/stack.

n) Partial removal of economizer heating surfaces to reduce pressure drop should be considered as a last resort only due to negative effect on downstream boiler structure and boiler performance.
o) Increasing the maximum furnace pressure of Unit #1 to 19.9" as per Unit #2 operation will account for 7.2 MW of additional unit output.

3.1.2 Recommendations

a) Reduce the pressure drop across the air heaters and/or economizers by cleaning and/or replacement of heating surfaces. Prioritize this work as follows:
   1) Unit # 1 air heater
   2) Unit #2 Economizer
   3) Unit #2 Air Heater
   4) Unit #1 Economizer
b) If economizer and boiler surfaces cannot be cleaned by 'conventional' methods investigate alternative methods such as explosive or acoustic shock-blasting
c) Ensure that the steam supply to economizers and air heater sootblowers is dry
d) Determine if the current furnace pressure alarm/trip setpoints can be increased. (By original boiler supplier)
e) Inspect the reheaters to determine the cause of low reheater heat transfer performance.
f) Use burner tilts within manufacturers recommended range as required to increase hot reheat temperatures
g) Consider turbine – generator – condenser upgrades which would improve heat rate.
h) Consider increasing the maximum furnace operating pressure of Unit #1 to 19.9" wg
i) Consider increasing the furnace pressure alarm pressures.

3.2 UNIT #3

3.2.1 Conclusions

a) The current maximum achievable load Unit #3 is limited by the capacity of the FD fans due to the combination of the following factors:
   i. The FD fans capacity are currently not operated at their maximum capacity
   ii. Air heater leakage rates are up to 3 times higher than design
   iii. Air heater pressure drops are 3 to 4 times higher than design
   iv. Unit heat rate approximately is approximately 10% higher than design due to lower than design boiler efficiency and higher than design Turbine Generator Heat Rate
   v. Operating excess air to burners approximately 2% higher than design

b) If the existing FD fan capacity was unrestricted, the full 150 MW unit output could have been attained for the January 4, 2018 operating conditions when maximum load was 128 MW.

c) Replacing the air heater hot end baskets will restore the unit full load capability of 150 MW if the cold end baskets to be re-used are clean and in good condition.

d) The combustion air flow requirement of the fuel oil currently utilized at site is very close to design on a lb/btu input basis.

e) The calculated fuel flows based on unit PI data and the measured fuel flow are both significantly higher than expected confirming that unit efficiency is lower than design. The calculated and measured fuel oil flows are within 3% of each other.

f) Removal of air heater heating surfaces is not recommended due to the negative effect on combustion efficiency and structural limitations of downstream flues/stack.

3.2.2 Recommendations

a) Establish if the current operating restrictions placed on the FD fans can be removed.
   i. Perform an operating test with increased FD fan VIV position and RPM at high load to determine current operating limitations (duct vibration?)

ii. Inspect the FD fan internals, instrumentation, inlet/outlet ducts and correct any anomalies which may lead to operating problems.
iii. Perform an FD fan test after inspections, including inlet/outlet pressure measurements and inlet airflow measurements.

b) Refurbish the air heater seals to reduce leakage and FD fan power consumption.
c) Clean or replace air heater heating elements which are leading to the high pressure drop and load limitations.
d) Ensure that the steam supply to economizer and air heater sootblowers is dry.
e) Consider turbine – generator - condenser upgrades / repairs which would improve TG heat rate

3.3 Fuel Related Issues (Common Units 1,2,3)

3.3.1 Conclusions

a) From a combustion and heating value standpoint, the fuel oil currently utilized is very close to the original Unit #3 design fuel.
b) Fuel oil Sulphur and Vanadium content have been reduced significantly since 2009.
c) Fouling of the Holyrood units leading to reduced maximum load capability has occurred between 2015 and 2018, following the discontinuation of fuel oil MgO injection.
d) The unit #3 operating conditions between October 2017 and January 2018 show increasing air heater pressure drop occurs at reduced loads, and when air heater ACET drops below 212 F.
e) Atomizing fuel oil temperatures must be sufficient to ensure proper atomization / combustion of the range of fuels currently burned (Up to 200 SFS @ 122 F)

3.3.2 Recommendations

a) Recommission the fuel oil MgO injection system and inject MgO into the fuel oil supply at a rate of 1 lb. MGO per lb. V2O in fuel oil.
b) Maintain a minimum air heater ACET of 212 F
c) Maintain atomizing oil atomization as follows for fuel oil viscosities up to 200 SFS@122 ^{o}F

a. Units #1 and #2 that temperature required to achieve 100 SSU or in the absence of viscosity data 230 ^{o}F
b. Unit #3: that temperature required to achieve 135 SSU or in the absence of viscosity data 225 ^{o}F

4 UNITS #1 and #2

4.1 Unit Description and History

The Unit #1 and #2 boilers were supplied by Combustion Engineering Canada in 1969. The boilers supply main and reheated steam at a design 1000 F to Hitachi steam turbines. Air is supplied by two Forced Draft fans through steam coil air heaters and regenerative air heaters to tilting tangentially fired burners in the furnace. Products of combustion leaving the furnace pass through a parallel flow secondary superheater, followed by a counter flow reheater, primary superheater, and finned tube economizer before entering two Ljungström regenerative air heaters.

The units were uprated to deliver 174.2 MW in 1987. Four rows of primary superheater were removed and tube material upgrades were made to the secondary superheater as part of the uprate. The unit was originally designed to control steam temperatures with the combination of flue gas recirculation and burner tilts. The gas recirculation fans have been removed from service.

Neither unit has been capable of operating at loads above 170 MW in recent years. The most recent time period that operating data was available for 170 MW was February 2015 for Unit #1 and October 2016 for Unit #2. The maximum load achievable is currently limited by maximum furnace pressure which has an alarm setpoint of 20” wg. The units will trip if furnace reaches 25” wg. Operators currently maintain furnace pressure below the 20” wg alarm point.

4.2 Basis of Study

This study is based on information provided by NLH as outlined below.

4.2.1 Fuel

NLH supplied a spreadsheet summary of the analysis of fuel oil deliveries to Holyrood between 1997 and 2017. Heating value, density, and trace element composition was included in this spreadsheet. A discussion of the fuel characteristics is included in a following section of this report.

4.2.2 Base Heat Balance Information

The expected original design plant operating information for the uprated unit was supplied by NLH as follows:

- Alstom letter to NF Power “Boiler Predicted Performance Data for Boiler #1 & 2” dated Aug 03, 2000. This document is the predicted boiler performance in the “Uprated” condition
- Turbine heat balance conditions as outlined in document “TIR# 10236-893A, UPRATE” Dated 8/5/88.
- The original Combustion Engineering ‘Contract Data Sheet’ (Contract 68119)

These documents are included in Appendices 8.1 and 8.2 for reference.

4.2.3 Unit Operating Data

B&W requested historical operating data representative of unit operation which was not restricted by furnace pressure and current restricted operating data. In response, ‘PI’ plant historian data was provided by Newfoundland and Labrador Hydro (NLH) in spreadsheet form for the two units at two time periods as outlined in Table 1.

Table 1 Units #1 and #2 Operating Data Conditions

	Unit 1		Unit 2	
Date	Jan 18, 2018	Feb 9, 2015	Oct 18, 2016	Feb 2, 2018
Unit Output MW	133	169	170	125
Operating Condition	Load Limited by Furnace Pressure @ 17.9” WG	Not Restricted	Not Restricted	Load Limited by Furnace Pressure @ 19.9” WG

It is not known why furnace pressure was limited to 17.9” wg on Unit #1 in January 2018. On possibility is that unstable furnace pressures may have led operators to reduce load to keep furnace pressure out of alarm.

4.2.4 Unit Physical Arrangement

NLH provided boiler general arrangement drawings defining the boiler heat transfer surface arrangement.

4.2.5 Heat and Mass Balance Calculations

B&W Single Heat and Material Balance Program – P08475 was used to calculate flue gas flow, flue gas analysis, combustion air flow, and boiler efficiency based on the fuel analysis, and the operating steam/water, and the air/gas boundary conditions.

4.2.6 Boiler Surface Heat Transfer Effectiveness Calculations

The boiler convective component heat transfer effectiveness (Kf) calculations were performed using B&W’s proprietary convective surface heat transfer program “P140”. The inputs to this program are the FEGT, the flue gas flow / composition from P08475, and the boiler tube bank heating surface geometry.

The thermal performance of the boiler heat transfer components (superheater, reheater, and economizer) heating surfaces is characterized by B&W as ‘Kf’ factors. Kf is calculated by P140 based on the operating data, (component outlet gas temperature and calculated flue gas flow, steam or water inlet and outlet conditions and flow). The component Kf factor is the ratio of ‘test’ gas side heat transfer conductance to ‘expected’ gas side conductance:

$$Kf = Ug_{test} / Ug_{\exp}$$

The tube bank geometry and flue gas flow are known. P140 calculates the expected gas side heat transfer conductance Ug_{exp} (Btu/hr/ft^2/ºF) on this basis using the standard Kf. For oil fired units, the expected Kf is 1.0 for superheater, reheater, and economizer surfaces. The overall component heat absorption is calculated from the measured steam or water inlet/outlet conditions (enthalpies) from which a test gas side conductance is determined (Ug_{test}). For oil firing Kf less than 1.0 indicates the heating surfaces are absorbing less heat than expected due to fouling, gas bypassing, unexpected gas flow patterns, etc.

The flue gas temperatures throughout the boiler are calculated by heat balance starting with the measured temperature at the economizer outlet.

4.2.7 Furnace Heat Transfer Effectiveness Calculations

The actual Furnace Exit Gas Temperature (FEGT) is calculated by heat balance around the convective heating surfaces. The difference in temperature between the calculated FEGT and the FEGT as predicted by Alstom is an indication of relative furnace effectiveness. An actual FEGT higher than the expected FEGT indicates underperforming (dirty) furnace surfaces (or higher than expected burner tilts).

4.2.8 Air Heater Heat Transfer Effectiveness Calculations

B&W relies on air heater vendors calculations to predict thermal performance of regenerative air heaters. Air heater heat transfer effectiveness Kf values are thus calculated based on the ratio of the actual heat transfer to the air heater vendors heat transfer adjusted to the actual operating conditions. The 'base' Kf factor to match air heater vendor predicted performance is set to 1.0 thus a calculated Kf value of less than 1.0 indicates heating surfaces are under performing. For Units #1 and #2 the base performance operating condition was taken from the Alstom August 2000 predicted performance data 'MCR' load case.

4.3 DISCUSSION OF RESULTS – Units #1 and #2

Both Units #1 and #2 are currently limited by the maximum allowable furnace pressure. Furnace pressure is a function of the flow resistance (geometry, cleanliness) of the downstream boiler components and the flue gas flow through these components. Flue gas temperature is also a factor, (higher temperatures = higher resistance at a given mass flow) but this effect is small relative to resistance and flue gas flow and is not considered in this study.

4.3.1 Review of Operating Data

The 'PI' system operating data used in this study analysis is generated by the plant permanent instrumentation. It is adequate for detecting trends but not always accurate for measuring 'bulk flow' parameters such as flue gas and air temperatures in large ducts were temperature stratification is expected. As such, the analysis which is based on plant instruments can be considered accurate from a relative standpoint (i.e. to illustrate trends) only. Evaluation of absolute plant performance requires calibrated instruments and air/gas temperature grids in large flues and ducts.

In general, the most accurate plant instruments are those indicating the conditions of major unit inputs/outputs (i.e. fuel flow, MW output), and the 'terminal point' connections between boiler and turbine cycle (i.e. feedwater flow, steam temperatures and pressures). Steam flow as indicated by HP turbine pressure is not considered as accurate as feedwater flow thus steam flow was calculated from the measured (*feedwater flow – blowdown flow – Aux steam flow*). Reheat steam flow was calculated based on *(calculated steam flow - HP turbine 'leakages' - #6 feedwater heater steam flow)*. The HP turbine leakages were taken from the Hitachi 1988 turbine heat balances, and the #6 feedwater flow is calculated by heat balance around the heater based on operating data.

The heat transfer effectiveness analysis (Kf study) requires steam and water – side enthalpies in and out of each boiler component. For units with superheat attemperators, attemperator water flow and attemperator inlet steam temperature are required to determine the heat absorption of the primary and secondary superheater. The measured attemperator steam outlet temperature is prone to reading low due and is not considered accurate. The Units #1 and #2 attemperator inlet steam temperatures are not available, thus only total superheater surface effectiveness (Kf) can be evaluated.

The effect on calculated Kf values of the above factors can be significant. The accuracy of the calculated Kf values would not be expected to be better than +/- 0.1.

4.3.2 Unit Heat Rate

The resistance (Pressure drop) of boiler components and thus the furnace pressure is proportional to the square of flue gas flow. The required flue gas flow is a function of the required unit MW output, the unit efficiency, the fuel theoretical air flow requirements, and the excess air required for complete combustion. Unit efficiency is the combination of Turbine-Generator (TG) efficiency (Heat Rate) and boiler efficiency. These parameters are shown in Table 2.

Table 2 Units #1 and #2 Heat Rate Effect on Furnace Pressure

UNIT HEAT RATE EFFECT ON FURNACE PRESSURE						
		Design	UNIT #1		UNIT #2	
Date		Uprate 2000	Feb9, 2015	Jan18, 2018	Oct18,2016	Feb2,2018
Unit Output	MW	174.2	169.5	132.6	170	125.2
TG Heat Rate	Btu/kWhr	7982	8541	8540	8156	8377
Boiler Efficiency	%	90.01* 88.06**	85.1	86.51	85.14	86.07
Unit Heat Rate	Btu/kWhr	9053	10037	9871	9579	9733
Fuel Theoretical Air	Lb/10,000 btu	6.865	7.407	7.407	7.407	7.407
Excess Air	%	5	5.4	8.1	3.6	7.3

*Design boiler efficiency per Alstom data based on 18,600 btu/lb fuel, steam coil and oil heating steam provided by external supply.

**Efficiency based on 18,450 Btu/lb fuel, steam coil and oil heating steam provided by unit (For direct comparison to B&W calculations – this study)

Significant observations from Table 2:

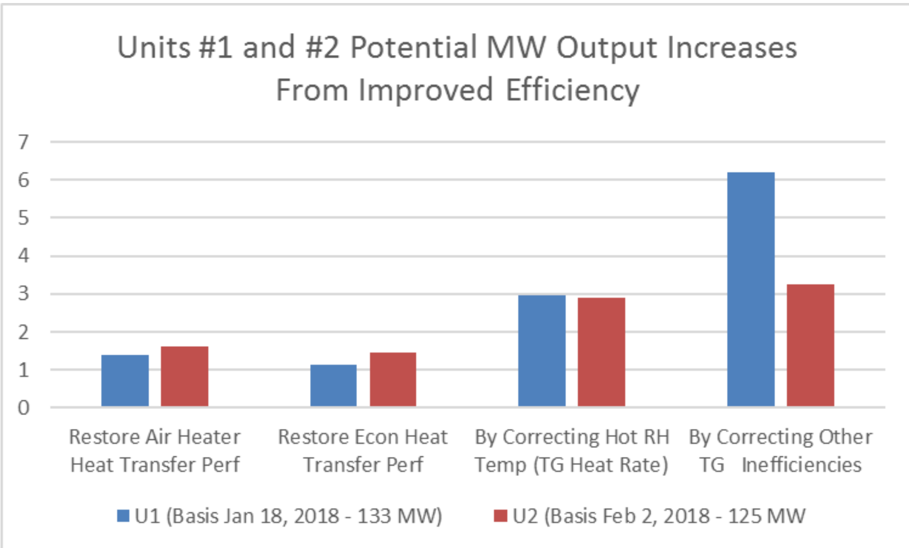
- The TG heat rates are both higher than design.
    - Unit #1 approximately 7% higher
    - Unit #2 approximately 2-5% higher

- Boiler efficiency is approximately 4% lower than design with heat credits (aux steam from ‘outside’), approximately 2% lower than design without heat credits.

- The theoretical combustion air used by Alstom is inconsistent with the fuel analysis. The airflows reported by Alstom in the updated expected performance are not consistent with the combustion airflow required for heavy fuel oil. Per the Alstom 2000 uprate letter data sheet, the MCR theoretical airflow used was 6.73 lb air per 10,000 btu input i.e. (air heater outlet airflow / excess air) / (fuel flow * 18,600 Btu/lb) / 10,000. Heavy fuel oils typically require theoretical combustion air 7.4 to 7.6 lb. per 10,000 Btu input. My calculations are based on a theoretical air requirement of 7.35 lb per 10,000 Btu thus my calculated airflows are higher than the Alstom airflows. This additional airflow contributes to higher furnace pressure.

Figure 3 illustrates the MW gains that would be expected for a fixed firing rate if the original design T-G heat rate and boiler efficiency were restored (ref the 2018 operating data)

Figure 4 Units #1 and #2 Potential MW Output Increases from Improved Efficiency



A significant portion of the increased T-G heat rate is due to lower than design hot reheat steam temperatures. Unit #2 was operating at 898 F at the turbine in February 2018 leading to a T-G heat rate increase of approximately 1.5%. The reheaters on Units #1 and 2 should be inspected to identify the cause of the performance shortfall.

The net effect of the increased unit heat rate, the higher theoretical air, and change in excess air is an increase in unit flue gas flow for a given unit MW output. The increased flue gas flows by themselves are responsible for a significant increase in furnace pressure (reference original design draft losses). The MCR expected furnace pressure per the Alstom data is 11.3" wg @ 174.2 MW. The increased flue gas flow associated with increased unit heat rates alone increases expected furnace pressure to 13.9" wg for Unit #1 and 12.7" wg for Unit #2.

4.3.3 Fuel Oil Flow

The measured and calculated fuel oil flow in relation to expected oil flow provide an indication of unit heat rate. Table 3 illustrates these quantities for the two units and test times. The Expected / Calculated Oil Flows are consistently above 1.0, which is an indication of higher than design unit heat rate.

Table 3 Fuel Oil Flow Calculated/Expected Units #1 and #2

Fuel Oil Flow Calculated/Expected Units #1 and #2					
Unit		1		2	
Date		Feb 9 2015	Jan 18 2018	Oct 18, 2016	Feb 2, 2018
Unit Output	MW	170	133	170	125
Expected Oil Flow (18,450 btu/lb HHV, HR and Blr Efficiency)	Lbs/hr	82176	64175	82383	60487
Calculated Oil Flow	Lbs/hr	92392	71110	88436	66170
Calculated/Expected Oil Flow	-	1.12	1.11	1.07	1.09
Plant Measured Oil Flow	Lbs/hr	90628	68157	90466	65602
Oil HHV	Btu/lb	17,193 - 18,702 (2015-2017 Deliveries)			

4.3.4 Restore Unit Output by Reducing Flue Gas Pressure Drops

Furnace pressure is driven by the pressure drops of the 'downstream' boiler components. These are the superheater/reheater, economizer, air heater, flues to stack. The predicted and actual pressure drops (i.e. the furnace pressure) for Units #1 and #2 are illustrated in Figures 4 and 5.

Figure 5 Unit #1 Furnace Pressure Design Vs Actual

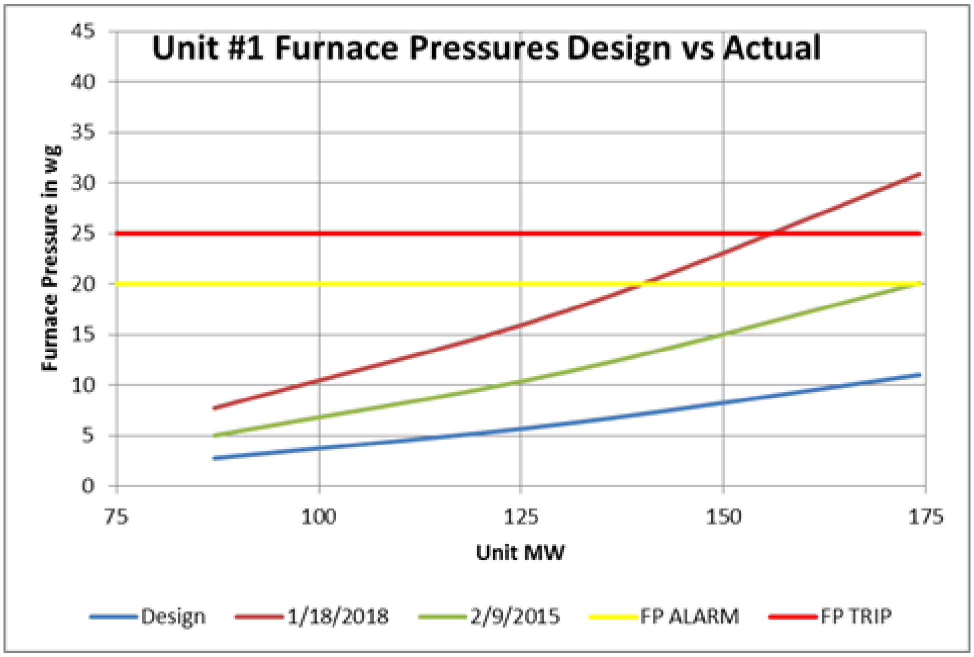
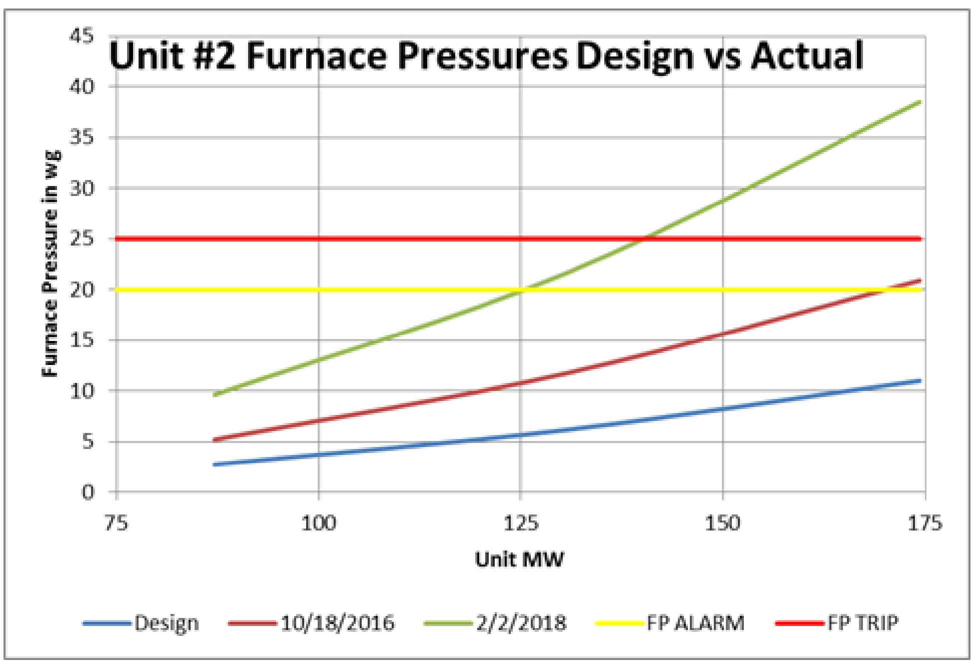


Figure 6 Unit #2 Furnace Pressure Design Vs Actual



The original pressure drops were almost doubled at the times when full load was nearly (170 MW) achieved in the 2015/2016 data with furnace pressures approaching the 20” wg alarm. Between that time and 2018, pressure drops increased even further, predominantly due to increases in economizer and regenerative air heater pressure drops. As these pressure drops increased, unit load was restricted in step. It is not known if the pressure drop increases were gradual or associated with particular operating scenarios. A review of all operating data between 2015-2016 and current would be required to reveal trends.

The predicted, 2015/2016, and current flue gas pressure drops by boiler component are shown in Figures 6 and 7. Pressure drops were prorated from actual operating conditions to 174.2 MW for illustration. The 174.2 MW output is not currently achievable on either unit with the current furnace pressure constraint. For Unit #1, the air heater is the largest contributor to current total pressure drop. For Unit #2, the economizer is currently the largest pressure drop contributor.

The superheater and reheater pressure drops are also significantly higher than design, indicating fouling in these components and / or tube misalignment. The magnitude of this contribution to furnace pressure is small relative to the air heater and economizer. Hot reheat temperatures are currently much lower than design, which combined with the high pressure drop suggests that the cleanliness of these surfaces is also poor.

Figure 7 Unit #1 Pressure Drops Prorated to 174.2 MW

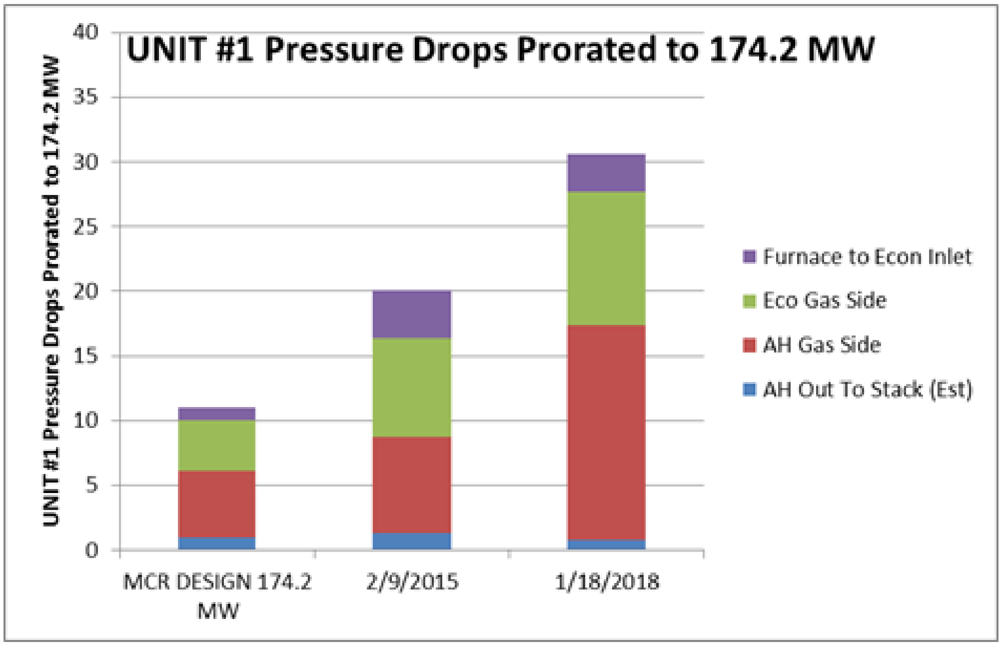
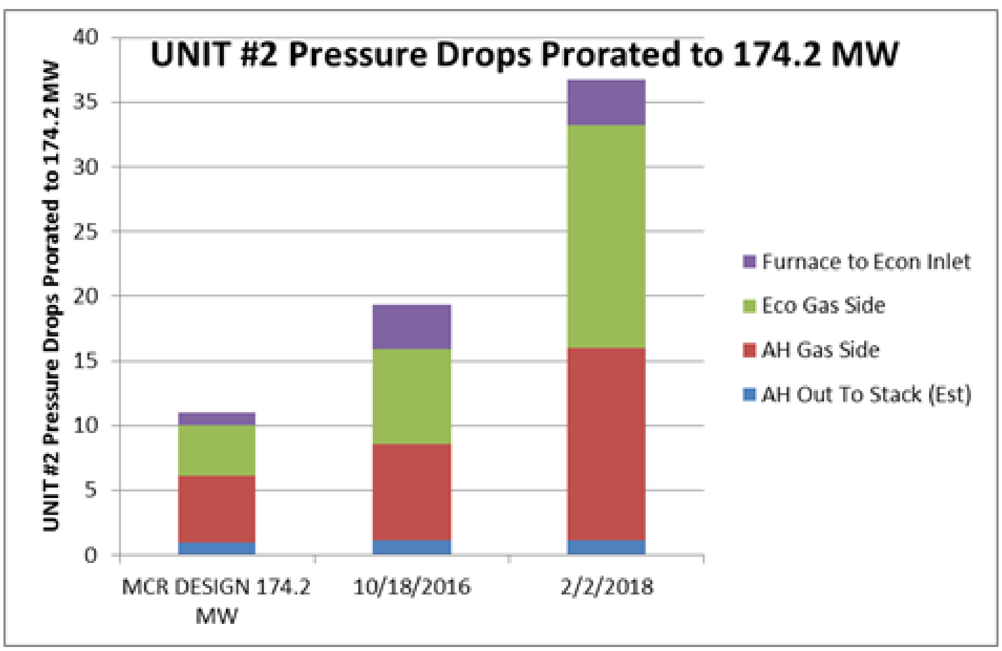


Figure 8 Unit #2 Pressure Drops Prorated to 174.2 MW



Figures 8 and 9 illustrate the current load limitations of Units 1 and 2 and the expected increases in load capability if:

- The air heater pressure drops can be restored to original design
- The economizer pressure drops can be restored to original design
- Both air heater and economizer pressure drops are restored to original design
- Both air heater and economizer pressure drops and boiler efficiency restored to original design. (Reduced stack temperature will be associated with cleaner surfaces)

Figure 9 Unit #1 Furnace Pressure - Restore Surface Cleanliness/Efficiency

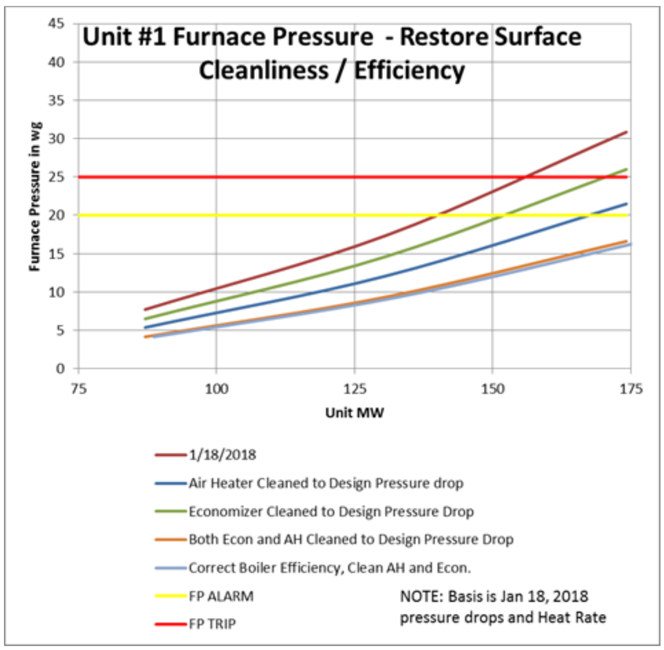
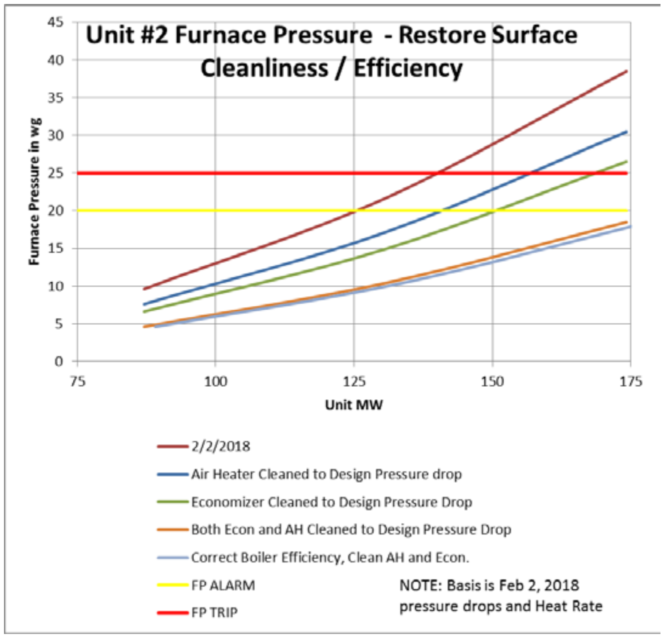


Figure 10 Unit #2 Furnace Pressure - Restore Surface Cleanliness / Efficiency



The potential increases in maximum load as limited by the furnace alarm pressure are shown in the Table 4:

Table 4 Maximum Load As Limited by Current Furnace Pressure- Restore A/H and/or Econ Pressure Drop

MAXIMUM LOAD AS LIMITED BY CURRENT FURNACE PRESSURE – RESTORE A/H AND/OR ECON PRESS. DROP					
		Unit #1 (Per Jan 18, 2018 Data @ 133 MW)		Unit #2 (Per Feb 2, 2018 Data @ 125 MW)	
Action	Units	Maximum Load	Load Increase	Max Load	Load Increase
Increase Maximum Furnace Pressure to 19.9” (UNIT #1)	MW	140	+7	-	-
Restore Design Air Heater Pressure Drop	MW	161	+28	141	+16
Restore Design Economizer Pressure Drop	MW	145	+12	151	+26
Restore Both Economizer and Air Heater (Max 175 MW)	MW	175	+42	175	+50

Table 4 shows that the largest gain in MW output for Unit #1 is restoring the air heater pressure drop. For unit #2, the biggest gain is in restoring the economizer pressure drop. If both economizer and air heater pressure drops are restored on both units, they will not be load limited below 174.2 MW by furnace pressure. Please note that correcting bot results in load increases that exceed the individual increases.

From the charts above, it can be seen that the gains in unit MW output from largest to smallest are:

1) The Unit #1 Air Heater
2) The Unit #2 Economizer
3) The Unit #2 Air Heater
4) The Unit #1 Economizer

If cleaning air heater surfaces is not possible, replacement of heating surfaces which are fouled would restore air heater pressure drop.

Replacement of economizer surface is likely not economically viable if conventional cleaning methods are ineffective. Other methods of cleaning such as the use of explosives or acoustic shock methods (Shock pulse) should be considered.

Improvements in surface cleanliness will increase boiler efficiency, slightly increasing maximum load (if limited by furnace pressure) and reducing fuel oil consumption. There will also be a reduction in FD fan power consumption. These effects were not calculated as part of the current study.

4.3.5 Other Considerations to Restore Unit Load

Improvements in TG heat rate through modifications / repairs to the turbine-generator-condenser would increase unit output when unit input is limited by furnace pressure. The effect of this type of modifications has not been considered in this study.

It may be possible to increase the furnace pressure alarm and trip settings. This would increase the maximum achievable load. The original boiler structural design calculations would need to be reviewed. This review would need to be done by the original boiler designer.

Once cleaned (or heating surfaces replaced), methods of preventing future fouling of air heater and economizer surfaces should be employed. For the air heater, a sufficiently high Average Cold End Temperature (ACET) must be maintained at all loads and during startups. Air heater pressure drop trends from Unit #3 (See Unit #3 section of this report) suggest a minimum ACET of 212 F should be maintained. For the economizer, temperatures are high enough during operation to prevent fouling. Fouling may occur during start ups when feedwater temperatures and/or flows are low.

Sootblowing steam must be dry to prevent the formation of sticky oil-ash deposits. This is particularly important during low loads and startups when combustion efficiency is at its lowest.

Unit #1 could deliver an additional 7 MW of output if furnace pressure is increased to the 19.9” wg level per the Unit #2 Feb, 2018 data. While it is unlikely that the furnace trip point of 25” wg may be increased, it may be possible to increase the alarm point from the current 20” wg dependant on the stability of furnace pressure during high load operation.

4.3.6 Heating Surface Effectiveness (Kf Study)

B&W performance program P140 was used to calculate the convective surface Kf values of the boiler components for the operating periods which were considered. FEGT is also calculated by P140 based on heat balance around the boiler components. The air heater Kf values were determined with reference (Kf = 1.0) to the Alstom predicted performance data (2000). The expected and actual Kf’s are shown in Table 5. The expected Kf for bare tube surfaces is 1.0. The expected Kf for finned tube economizer surface is 1.2.

Table 5 Kf and FEGT Summary, Units #1 and #2

Kf and FEGT Summary, Units #1 and #2					
Unit #	1 & 2	1		2	
Date	Expected	Feb, 2015	Jan, 2018	Oct, 2016	Feb, 2018
Unit Load	174.2	170	133	170	125
Air Heater Kf	1.0	0.66	0.7	0.53	0.67
Economizer Kf	1.2	0.67	0.74	0.65	0.64
Superheater Kf (Avg Prim+Sec)	1.0	0.92	0.88	0.93	0.78
Reheater Kf	1.0	0.88	0.67	0.72	0.72
FEGT(ºF) (Expected/Actual)	2589	2577 2590	2438 2439	2577 2669	2408 2396
Burner Tilt (Deg) (Expected/Actual)	+10	+10.5 -1.4	+14.8 4.7	+10.5 -6.3	+15.7 +0.2
Hot Reheat Temp (Deg F)	1000	966	901	947	898

Table 5 illustrates that Kf factors in all cases are less than expected, thus all surfaces downstream of the furnace are underperforming from a heat transfer standpoint. The Unit #1 reheater and the Unit #2 superheater Kf's have dropped significantly between 2015/16 and current operation. As expected from the observed greater than expected draft losses, the economizer and air heater surfaces have the lowest Kf's. On the other hand, there is not a significant difference between the 2015/16 Kf's and current Kf's of the economizer and air heater when draft losses were seen to increase. The cause of this apparent anomaly is not clear. It is possible that some sections of these components are currently cleaner than they were, but blockages in other sections (i.e. center of bank where washing has not penetrated) have increased.

The reheater performance is significantly lower than expected. This has the effect of both increasing stack gas temperature (reducing boiler efficiency) and increasing heat rate.

Burner tilts are not being utilized to maintain design hot reheat temperatures. Positive burner tilts between 10 and 15 degrees would be expected; actual burner tilts are in the +/- 5 degree range. The calculated FEGTs are generally higher than expected, even with the lower than expected burner tilts, suggesting that the furnace surfaces are also underperforming.

In general, the most effective means of reducing stack temperature to improve boiler efficiency is by improving the performance of boiler components in the low gas temperature regions i.e. the air heater and then the economizer. Table 6 illustrates the effect of a 10 F reduction in gas temperature on stack temperature and boiler efficiency.

Table 6 Stack Temperature Change for Change in Upstream Gas Temperature

Stack Gas Temperature Change for Change in Upstream Gas Temperature			
Component / Location	Change in Component Gas Outlet Temperature (F)	Change in Stack Temperature (F)	Change in Boiler Efficiency (%)
Air Heater Gas Outlet	10	10	+0.2
Economizer Gas Outlet	10	4	+0.08
Primary SH Gas Outlet	10	0.8	+0.016

Improvements of boiler heat transfer performance to improve unit efficiency should be prioritized as follows:

1) Air heater (Increased Boiler Efficiency)
2) Economizer (Increased Boiler Efficiency)

3) Reheater (Increased Boiler Efficiency and Reduced T-G Heat Rate)
4) Superheater

Note that improvements in reheater heat transfer performance will have three positive effects on unit efficiency:

- A small improvement in on boiler efficiency due to lower stack temperature
- A reduction in T-G heat rate by means of higher hot reheat temperature
- Lowering of burner tilts leading to lower superheat spray quantity

If burner tilts are modulating to control hot reheat steam temperature, improvements in furnace surface performance will have little to no effect on unit efficiency. Burner tilts respond to the required hot reheat steam temperature and adjust for reduced furnace cleanliness until the maximum negative tilt (Normally -30 Degrees) is approached. Excessively dirty furnace surface can lead to slag falls and this must be monitored visually and controlled accordingly.

5 UNIT #3

5.1 Unit Description and History

Holyrood Unit #3 is a B&W ‘El Paso’ type boiler. The unit is coupled to a 150 MW Hitachi steam turbine. The boiler delivers a nominal 1000/1000 F steam to the HP/IP turbine. Steam temperature is controlled by biasing the firing rate between the three levels of burners. Air is supplied by two “Sheldons” FD fans. Air flows from the two fans to steam coil air heaters for ACET control and then into two “Howdens” Ljungström type regenerative air heaters. Oil is burned in nine circular oil burners arranged in three levels. Flue gas exits the furnace to the reheater and secondary superheater, then down through the primary superheater and bare tube economizer before passing through the regenerative air heater to the stack.

Reheater surface was removed by Alstom in 2001. The intent of this modification is unknown. The most likely reason to would have been to reduce high load reheater sprayflow.

The FD fan VIV's have been limited to approximately 54% and 70% open on the East and West fans respectively due to vibration of the fan inlet ducting.

B&W are not aware of any other modifications to the unit which would affect the results of this study

5.2 Basis of Study

5.2.1 Fuel

The fuel oil analysis as used in the original Unit #3 design was used (Ref discussion in following sections of this report).

5.2.2 Base Heat Balance Information

Baseline predicted unit performance was taken from the original boiler design B&W boiler Performance Data (PD) sheet dated 9/5/78 and the original heat balance diagram sheet NLH Drawing AO-1403-200-M001 Rev 2. These documents are included in Appendices 8.3 and 8.4 for reference.

5.2.3 Unit Operating Data

B&W requested unit operating data representative of operation for a time period when the unit was capable of full load and another when unit was not capable of full load. NLH subsequently provided plant 'PI' data from Oct 22, 2017 with the unit at 150 MW and January 4, 2018 when the maximum attainable load was 128 MW.

Due to the relatively short time period over which maximum attainable unit load was reduced, B&W requested hourly operating data for the time period between Oct 22, 2017 and January 4, 2018 in order to understand the conditions that were leading to maximum load reductions.

5.2.4 Unit Physical Arrangement

The original B&W boiler arrangement drawings of the boiler physical arrangement were used as basis of the calculated performance. The performance model (P140) was adjusted to reflect the 2001 reheater surface removal.

5.2.5 Heat and Mass Balance Calculations

B&W Single Heat and Material Balance Program – P08475 was used to calculate flue gas flow, flue gas analysis, combustion air flow, furnace heat absorption, **F**urnace **E**xit **G**as **T**emperature (**FEGT**), and boiler efficiency based on the fuel analysis, steam/water, air/gas boundary conditions, and furnace heating surface arrangement.

5.2.6 Boiler Surface Heat Transfer Calculations

Convective surface heat transfer was calculated using B&W program “P140”. The methodology is described in the above discussion for Units #1 and #2.

5.2.7 Furnace Heat Transfer Effectiveness Calculations

As described above, for Units #1 and #2, furnace performance is quantified by the difference between the actual and predicted FEGT. For the B&W unit, the predicted FEGT is calculated by P8475 per B&W standard methods. FEGT higher than predicted indicates underperforming furnace surfaces and/or large amounts of burner fuel input biasing.

5.2.8 Air Heater Heat Transfer Effectiveness Calculations

Air heater heat transfer effectiveness is calculated as per the above discussion for Units #1 and #2.

5.3 DISCUSSION OF RESULTS

5.3.1 Review of Operating Data

A discussion of the limitations of PI operating data vs test data and the effect on calculations is included in the above Units #1 and #2 analysis.

Notable omissions and anomalies in the data received were:

- The FD fan inlet/outlet pressures are not available
    - Assumptions were required to estimate FD fan pressure rise
- The #6 Feedwater heater water inlet temperature reading is not valid.
    - Assumptions were required to calculate reheater steam flow
- The PI reported superheater spraywater flow was implausible
    - Assumptions were required in Stage 2 (Kf) analysis

5.3.2 Turbine Generator Heat Rate

The original design and the current turbine heat rates for the Oct 22 and Jan 4 data are shown in Table 7.

Table 7 Turbine - Generator Heat Rate Design vs Current Unit #3

TURBINE – GENERATOR HEAT RATE DESIGN vs CURRENT				
		Design (Ref AG 1403-200-M001 Rev2	Oct 22, 2017	Jan 4, 2018
Gross Output	MW	150	149.2	128.2
Turbine Heat Rate Expected	Btu/kwhr	7621	7623	7665
Turbine Heat Rate (Adjusted for off design boiler boundary Conditions i.e. hot RH Temp)	Btu/kwhr	-	7597	7720
Turbine Heat Rate Actual	Btu/kwhr	-	8188	8260
Required Boiler Output To Turbine	Btu/hr/10^6	1143	1222	1059
Increase in Turbine Heat Rate	%	-	7.4	7.8

The current heat rates are significantly higher than design, increasing the required boiler output per MW generated.

Note that the boiler heat output also includes other loads such as Aux steam to other units/building heat, etc. and output to blowdown. These outputs were not included in the turbine heat rate calculations. The boiler output calculations assumed that:

- No aux steam flowed into or out of the Unit 3 boiler envelope
- The aux steam extracted from the boiler was used within the boiler envelope (Predominantly steam coil air heaters, fuel atomization and fuel oil heating)
- No sootblowing steam consumption
- Boiler blowdown flow 1% of main steam flow

Steam flows for calculation of turbine heat input were determined as follows:

- HP Steam flow to turbine = (Feed Water Flow) – (Blowdown Flow) – (Aux Steamflow)

- Reheater Flow = (HP Steam flow) – (Design HP Turbine Leakages) - (#6 Heater Steam Extraction Steam Flow calc. by heat balance)

HP steam flow calculated from feed water flow is generally more accurate than the commonly used steam flow inferred from HP turbine inlet pressure, particularly for older turbines.

5.3.3 Deviations from Design Turbine – Boiler Boundary Conditions

The operating turbine heat rates illustrated above are affected by deviations in boiler operating conditions from design. These conditions are:

- Main steam temperature / pressure
- Hot reheat temperature
- Superheater and reheater sprayflows
- Boiler blowdown and aux steam flows
- Reheater pressure drop

The magnitude of these corrections is relatively small. The corrections are indicated in Table 8 were made using heat rate correction curves for a Hitachi turbine of similar vintage, size, and design conditions.

Table 8 Heat Rate Corrections Unit #3

HEAT RATE CORRECTIONS DEVIATIONS FROM DESIGN TURBINE – BOILER BOUNDARY CONDITIONS EFFECT						
			Oct 22, 2017		Jan 4, 2018	
Unit Output	MW	150	149.2		128.2	
		Design	Measured	Heat Rate Correction	Measured	Heat Rate Correction
Main Steam Temperature	F	1000	1000	1.0000	1000.4	0.9999
Main Steam Pressure	Psig	1800	1799	1.0000	1798	1.0000
Hot Reheat Temperature	F	1000	1005.5	0.9992	941	1.0089
Superheat Spray flow	Lb/hr	0	48000*	1.0022	48000*	1.0026
Reheat Spray flow	Lb/hr	0	2140	1.0011	2196	1.0013
Boiler Blowdown & Aux Steam Flows	Lb/hr	0	16500	0.9942	12700	0.9945
Overall Turbine Heat Rate Correction Due to Deviations in Boiler Boundary Conditions (Positive=Increased HR)	- (%)	1.0000 (0)	-	0.99660 -0.3%	-	1.0071 0.7%

*Estimated (Plant superheater spray flow measurement is implausible)

A further correction for reheater pressure drop is available but was not applied since total reheat pressure drop (including piping) was not measured. This correction is normally very small. The correction for Condenser vacuum was also not applied. This correction can be substantial, but was not considered as it is outside of the scope of this study.

The small boundary condition corrections here indicate that the majority of the increased T-G heat rate is due to T-G inefficiencies. In general aging steam turbines experience heat rate increases due to high condenser pressure, higher than design turbine valve and gland leakages, depositions on and wear of turbine blades. B&W has seen heat rate increases similar to those indicated in the above table on T-G units of similar vintage and size.

5.3.4 Fuel Oil Flow

Although inaccuracies exist in measurements of the fuel oil flow to the unit and there are variations in fuel heating value, fuel oil flow relative to unit MW load is an indicator of unit heat rate. Table 9 shows the expected, calculated, and measured fuel oil flows for the Oct 22 and Jan 4 data. Calculated oil flows are based on 18450 Btu/Lb. The calculated oil flows are within 3% of the measured oil flows.

Table 9 Fuel Oil Flow Calculated/Expected Unit #3

Unit Output	MW	149.2 (Oct 22, 2017)	128.2 (Jan4, 2018)
Expected Oil Flow (Design HHV, HR and Blr Efficiency)	Lbs/hr	69,579,	60,114
Calculated Oil Flow	Lbs/hr	77,367	67,138
Calculated/Expected Oil Flow	-	1.11	1.12
Plant Measured Oil Flow	Lbs/hr	79,276	67,199
Oil HHV	Btu/lb	18,278-18,472 (2017 Deliveries)	

5.3.5 Boiler Efficiency and Air Heater Leakage

Boiler Efficiency is predominantly driven by excess air and the difference between inlet air temperature and outlet flue gas temperature (Corrected for no a/h leakage i.e. undiluted). Other factors such as atomizing steam flow, radiation loss, and unburned carbon loss are small for oil fired units. The key parameters are illustrated in Table 10 with reference to the original design conditions.

Table 10 Boiler Efficiency and Air Heater Leakage (Unit #3)

BOILER EFFICIENCY AND AIR HEATER LEAKAGE				
		Design (B&W PD Sheet C/7391, MCR Load)	Oct 22, 2017	Jan 4, 2018
Excess air To Burners	%	3	5	7
Air Inlet Temperature	F	80	45	61
Gas Temperature Entering A/H	F	662	747	737
Stack Gas Temperature (Diluted)	F	280	318	324
Air Heater Leakage (% of Inlet Gas Flow)	%	9.5	22.2	27.5
Stack Gas Temperature (Corrected for No Leakage)	F	297	364	376
Boiler Efficiency	%	88.59	86.45	86.46
Air Heater Leakage Flow	Lb/hr	103,000	267,000	305,000

The boiler efficiency is approximately 2% lower than design, mainly due to the higher than design corrected air heater outlet temperature and the lower than design air inlet temperature. The reduction in efficiency combined with the higher than design excess air and much higher than design air heater leakage increases the required FD fan air flows significantly. These increases compound with the additional air flow required by the increased T-G heat rate discussed above.

5.3.6 FD Fan Duty Requirements – Design vs Current

5.3.6.1 Required Air Flows

The required boiler airflows to achieve a 150 MW unit output at current operating conditions are summarized in Table 11. The required air flow leaving the air heater is calculated based on TG heat rate, boiler efficiency, and excess air from the Oct 22 (149.2 MW) site data. The required air flow entering the air heater was calculated based on both the Oct 22 and Jan 4 data to illustrate the effect of the increased air heater leakage resulting from the higher Jan 4 air heater air/gas side differential pressure.

Table 11 FD Fan Airflow Requirements - Design vs Current (Unit #3)

FD FAN AIRFLOW REQUIREMENTS – DESIGN vs CURRENT OPERATION (150 MW)				
		Design (MCR, 150 MW)	Oct 22, 2017	Jan 4, 2018 (Additional AH Leakage)
Original Design Airflow Leaving AH	Lb/hr	1,029,700	-	-
Additional AirFlow due to TG Heat Rate Increases	%	-	7.4	
Additional AirFlow due to Boiler Efficiency Loss	%	-	2.5	
Additional AirFlow due to higher Excess Air	%	-	2.0	
Total Additional AirFlow to Burners (Entering AHs)	%	-	12.3	
Required Air Flow Leaving Air Heaters	Lb/hr	1,029,700	1,156,000	
Additional Flow Air heater leakage (% Air Leaving)	%	10	23.1	26.4
Required AirFLow Entering Air Heaters	Lb/hr	1,132,700	1,423,000	1,461,000
Required Airflow Entering Air Heaters / Fan	Lb/hr/fan		715,500	753,000
% Increase in FD Fan Outlet Airflow vs 150 MW Design	%		25.6	29.0

5.3.6.2 Required FD Fan Pressure Rise

The boiler air and flue gas side pressure drops during Oct 22 and Jan 4 operation vs the design pressure drops are summarized in Table 12. Pressure drops are higher than design due to the combination of increased required air and flue gas flow along with increased resistance. Due to the assumptions made regarding air heater and steam coil air heater air-side pressure drop, the pressure drop summary should be considered ‘approximate only’ until actual FD fan pressure rises can be confirmed.

The pressure drop in the FD fan inlet ducts is not measured thus it has been assumed unchanged from original design. The FD fan outlet pressures are also not available. This was estimated by adding the Ljungström air heater air-side pressure drop (proration of the design pressure drop by the ratio of measured/design gas side pressure drop), and an estimated steam coil air heater pressure drop (estimated at two times a ‘typical’ steam coil since the steam coils are reportedly fouled/damaged).

Table 12 Fd Fan Pressure Rise - Design Vs Operating Unit #3

AIR AND GAS SID PRESSURE DROPS – DESIGN VS OPERATING				
		Design 150 MW	Oct 22, 2017 (149.2 MW)	Jan 4, 2018 (Prorate to 150 MW)
Airflow To burners	Lb/hr	1,029,700	1,156,000	1,156,000
Air Heater Leakage	Lb/hr	103,000	267,000	305,000
Airflow Leaving FD Fans (Inc AH Leakage)	Lb/hr	1,132,700	1,423,000	1,461,000
Draft loss Burners	in Wg	4.9	7.2	9.9
Draft loss Furn and CP	in Wg	6.3	9.2	6.6
Draft Loss AH Gas Side	in Wg	3.1	8.6	11.4
Draft Loss AH Air Side (Prorate from Gas Side)	in Wg	2.4	6.6	8.8
Draft Loss SCAH (Est)	in Wg	1.7	6.4	6.8
Ducts Draft loss (Prorate from Design)	in Wg	5.4	6.8	6.8
Flues Draft Loss (Prorate from Design)	in Wg	2.1	2.6	2.6
Total Draft Losses	in Wg	25.7	47.3	52.8

The largest contributor to additional fan pressure rise duty is the additional flow associated with the combination of increased turbine heat rate, higher than design excess air, and reduced boiler efficiency. The additional pressure drop in the regenerative air heaters and the steam coil air heater are the next most significant contributor to additional fan loading.

5.3.7 FD Fan Capacity Discussion

The combination of turbine heat rate increases, boiler efficiency reduction, air heater leakage, and higher than design combustion system excess air increase the required airflows as discussed above. The increased flows inherently increase the system pressure drop by approximately 26% relative to the original design. Pressure drop increases of a similar magnitude are observed due to changes in flow path resistance, such as dampers throttled, burner air register settings, boiler convection pass and air heater fouling. The expected performance for each fan as operating on Jan 4, 2018 is illustrated in Figures 10 and 11. The curves are based on the original Sheldons Eng. fan curve (Ref Appendix 8.5), corrected for inlet air density and fan RPM.

Figure 11 West FD Fan Jan 4/18 Unit #3

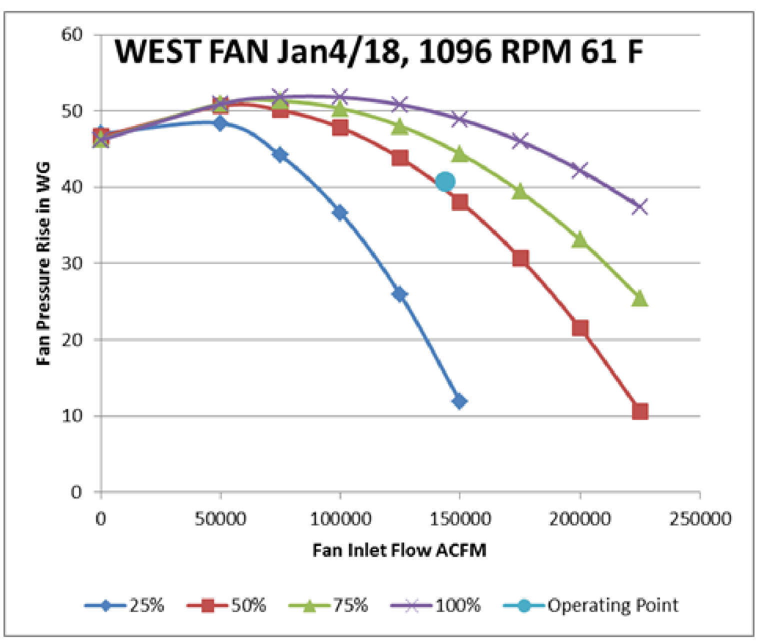
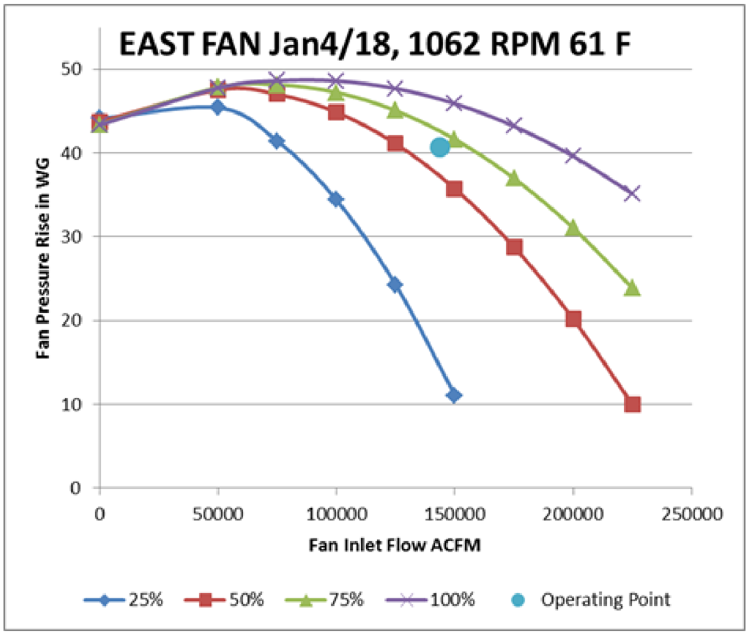
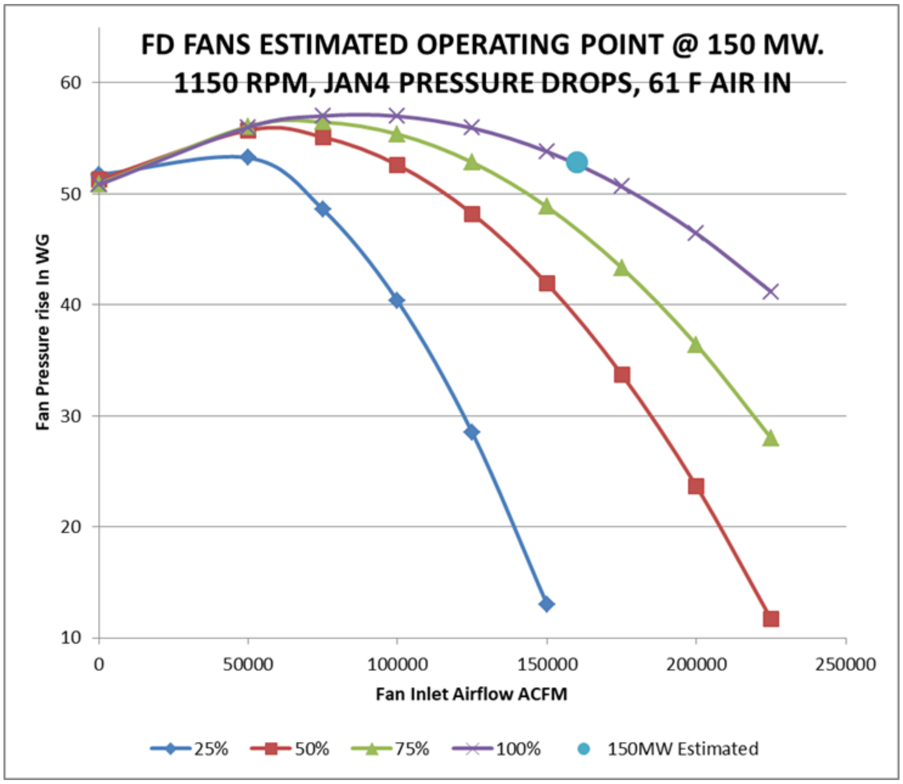


Figure 12 East Fan Jan 4/18 Unit #3



Under the Jan. 4, 2018 operating conditions, the FD fans would have been capable of delivering the required air flow to the unit if operated at the rated 1150 RPM and 100 % VIV opening. On that day, the fan speed was limited to approximately 1080 RPM and the VIV's were in the 54%/70% east/west position with the unit at 128 MW. The required fan duty to make 150 MW per the Jan 4 data is illustrated in Figure 12. This curve is based on the original Sheldons fan curve. A correction was required for lower than design inlet air temperature (Sheldons Fan Curve temperature basis was 105 F).

Figure 13 FD Fans Estimated Operating Point, 150 MW, Jan 4/18 Unit #3



5.3.8 Air Heater 'ARVOS' basket replacement

A proposal from ARVOS for replacement air heater hot end heating elements was reviewed from the standpoint of the restoration of maximum boiler load capability and FD fan capacity. The expected performance as received from ARVOS for the new elements if installed with the existing cold end elements (assumed to be in 'as new' condition from a heat transfer / pressure drop standpoint) is included in Appendix 8.6. Table 13 outlines the required fan performance with the new heating elements installed. The existing FD fans will easily deliver sufficient airflow for 150 MW operation at approximately 960 RPM and 60-65 % average VIV opening.

Table 13 Arvos Replacement Hot End Heating Elements Performance

FAN PERFORMANCE SUMMARY - NEW AIR HEATER HOT END BASKETS / SEALS				
			New Hot End	New Hot End
	10/22/2017	1/4/2018	Baskets and Seals	Baskets, Old Seals
	150 MW	128 MW	150 MW	150 MW
Flows Mlb/hr (Oct Data Unit @ 150 Mw)				
Air Entering AH	1,390,100	1,312,800	1,279,870	1,354,177
Leakage Air	267,000	305,000	156,770	231,077
Air Leaving Air Heater	1,123,100	1,007,800	1,123,100	1,123,100
Temperatures F				
Air Entering FD Fan	45	61	45	45
Air Entering Air Heater	99	128	128	128
Pressures In WG				
FD Fan Pressure Rise	45.2	40.7	34.4	34.9
AH Outlet Plenum	27.4	26.9	20.9	20.9
Air Heater Air Side Pressure Drop	6.6	7.1	1.9	1.9
Air Heater Hot End Differential	22.4	18.0	22.4	22.4
Air Heater Gas Side Differential	8.6	9.2	3.2	3.2
Fan Performance				
FD Fan Volume Flow ACFM/Fan	147,816	143,842	135,991	143,886
FD Fan RPM	1018	1062	960	960
FD Fan VIV %	54/70	54/70	60.0	65.0
Horsepower/ Fan (Predicted)	867	940	727	772

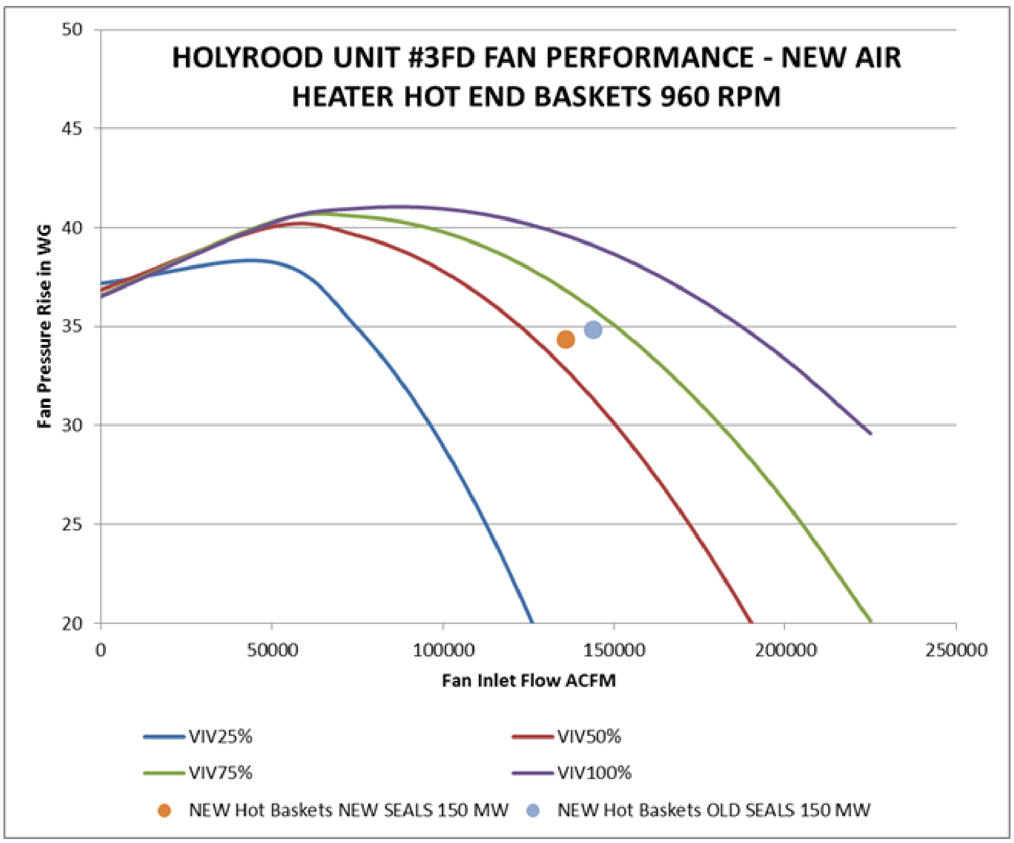
Note the following:

- Combustion air flows requirements are based on boiler operating data Oct 22, 2017 @ 150 MW
  - o No adjustments were made for improved efficiency (Which should be achieved with AH basket replacement). This will result in a conservative capacity estimate
- Air heater leakage calculated two ways to assist in evaluation value in new seals
  - o Without new seals, air heater leakage adjusted from Oct 22, 2017 calculated leakage for reduced differential pressures with the new baskets
  - o With new seals, air leakage adjusted from ARVOS predicted data based on higher hot end air heater differential pressure
- FD Fan performance is calculated based on 'typical' current operating VIV openings, Fan RPM selected to match required pressure rise

- Air Heater Outlet plenum pressure setpoint reduced due to reduced air heater pressure drop
- There is a savings in fan power as shown (estimated) in Table 13.

Figure 13 illustrates the estimated fan operating points @ 960 RPM with the proposed air heater upgrades.

Figure 14 FD Fan Performance - New ARVOS Air Heater Hot End Elements Unit #3



5.4 Heating Surface Effectiveness (Kf Study)

Heating surface effectiveness factors (Kf's) were calculated by B&W program P140. Table 14 summarizes the results.

Table 14 Kf and FEGT Summary Unit #3

Kf and FEGT Summary, Unit #3			
Date	Expected	Oct 22, 2017	Jan 4, 2018
Unit Load	150	150	128
Air Heater Kf	1.0	0.91	0.88
Economizer Kf	1.0	0.91	0.98
Superheater Kf (Avg Prim+Sec)*	1.0	0.90	0.75
Reheater Kf	1.0	0.96	0.71
FEGT(ºF) (Expected/Actual)	2482	2482 2528	2394 2476
Main Steam Temp (Deg F)	1000	1000	1000
Hot Reheat Temp (Deg F)	1000	1006	941

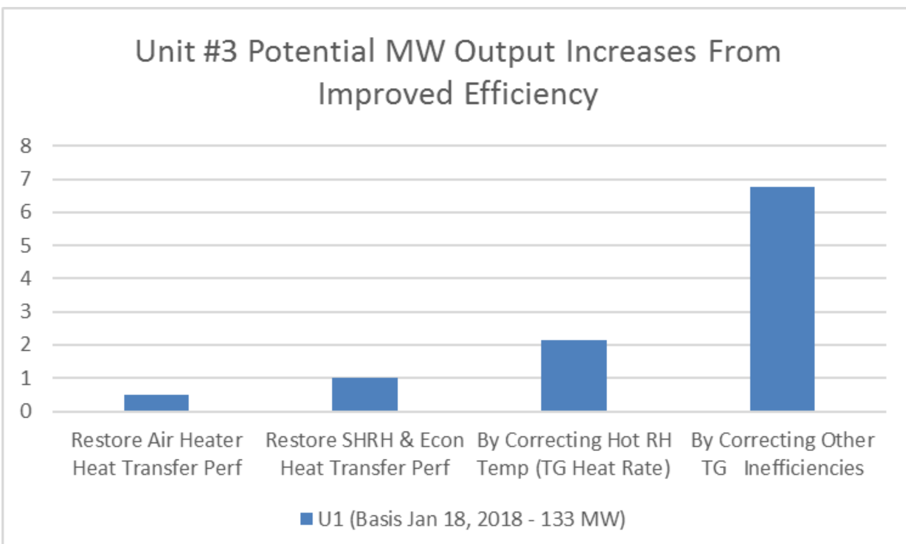
*Superheater Kf Estimated (Spraywater Flow Not Available)

The Kf analysis shows that all surfaces are underperforming from a heat transfer effectiveness standpoint. The effectiveness of the superheater and reheater surfaces dropped significantly during the Oct 2017 – Jan 2018 time period. The air heater and economizer Kf's, while below expected, did not change significantly during that time period; this is somewhat unexpected for the air heater given the large increase in pressure drop seen during this time. One possible explanation may be that localized depositions are blocking flow in a relatively small portion of the depth of the heating surfaces. Flow patterns may also have changed if the two air heaters are not fouling at the same rate, leading to an air and flow 'shift' between them. This could affect the indication of stack temperature from the plant instrumentation.

As discussed above, the major deficiencies in the Unit #2 performance as they affect efficiency as based on the January 2018 data are the higher than expected Turbine-Generator heat rate and reheat cleanliness / hot reheat temperature. The low heat transfer effectiveness of the superheater and reheater surfaces is not a major factor in terms of boiler efficiency due to the relatively good thermal performance of the air heaters and economizers. The significant reduction in superheater and reheater Kf values should be investigated i.e. the surfaces should be inspected for cleanliness. Increases in sootblowing frequency and/or blowing pressures may be necessary to maintain cleanliness of these surfaces.

Figure 14 illustrates the additional unit output that that would be expected if the boiler and T-G inefficiencies are corrected.

Figure 15 Unit #3 Potential MW Output Increase from Improved Efficiency



6 FUEL OIL RELATED ISSUES (COMMON UNITS #1,2,3)

Fuel oil is supplied to the three units from common storage tanks. Oil is pumped and heated to the required pressure and temperature for burner atomization by independent pumping / heating sets for each unit.

The fuel oil analysis data in the NLH supplied spreadsheet database was reviewed. From a combustion and heating value standpoint, the fuel analysis in recent years is very close to the Unit #3 original design fuel. Combustion calculations were therefore based on the Unit #3 design fuel. The Sulphur content has been consistently below 1% since early 2009 per Figure 15. The Vanadium (V2O) content dropped significantly in late 2005 and is currently consistently less than 50 ppm per Figure 16. Overall the fuels currently burned are better than 'typical' Bunker fuels with lower than normal levels of both Sulphur and Vanadium.

Figure 16 Fuel Oil Sulphur % by Wt. (1995-2017)

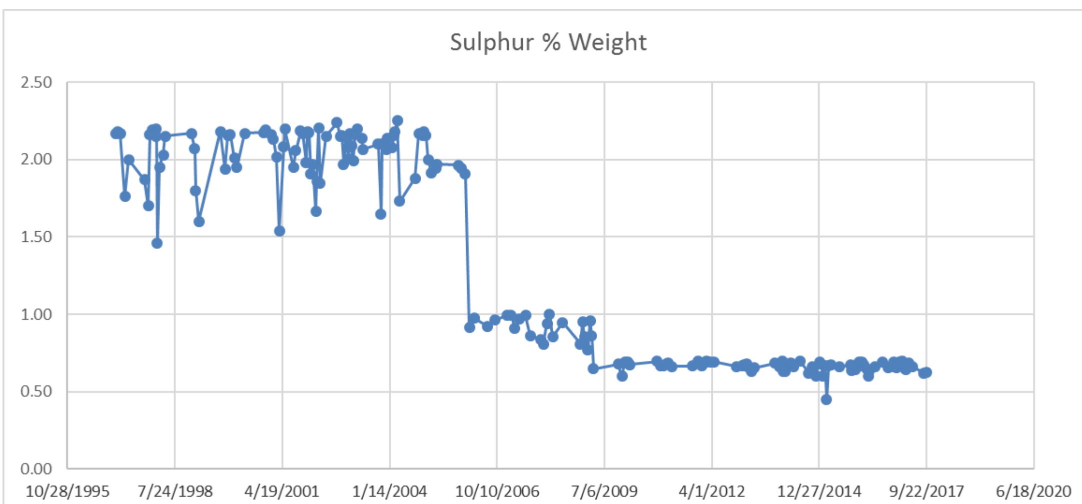
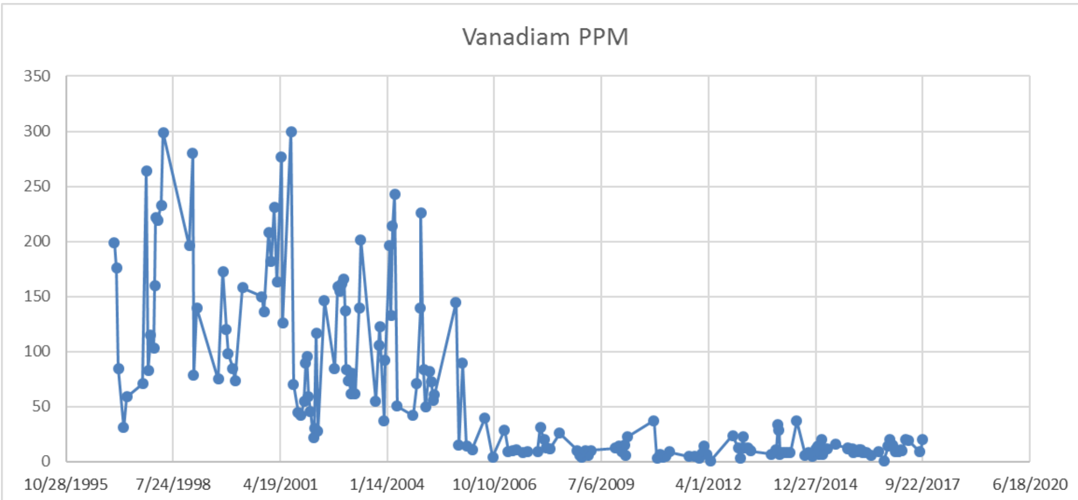


Figure 17 Fuel Oil Vanadium PPM (1995-2017)



Interactions of Vanadium, SO_2 / SO_3, and unburned carbon in the products of combustion lead to air heater fouling. These deposits can block the flue gas passages on air heater heating surfaces, increasing pressure drop and reducing heat transfer effectiveness. Finned tube economizers may also be affected during start-up and very low load operation. Unburned carbon is the largest component of these deposits and it is typically highest during start-up and low load operation.

Low air heater metal temperature as indicated by the Average Cold End Temperatures (ACET) increase the condensation rate of SO3 on the baskets and increase the tendency for deposits to form. Air heater metal temperatures are also lowest at low loads if sufficient inlet air preheating is not supplied. It is thus imperative that air heater ACET is maintained at all loads and operating conditions.

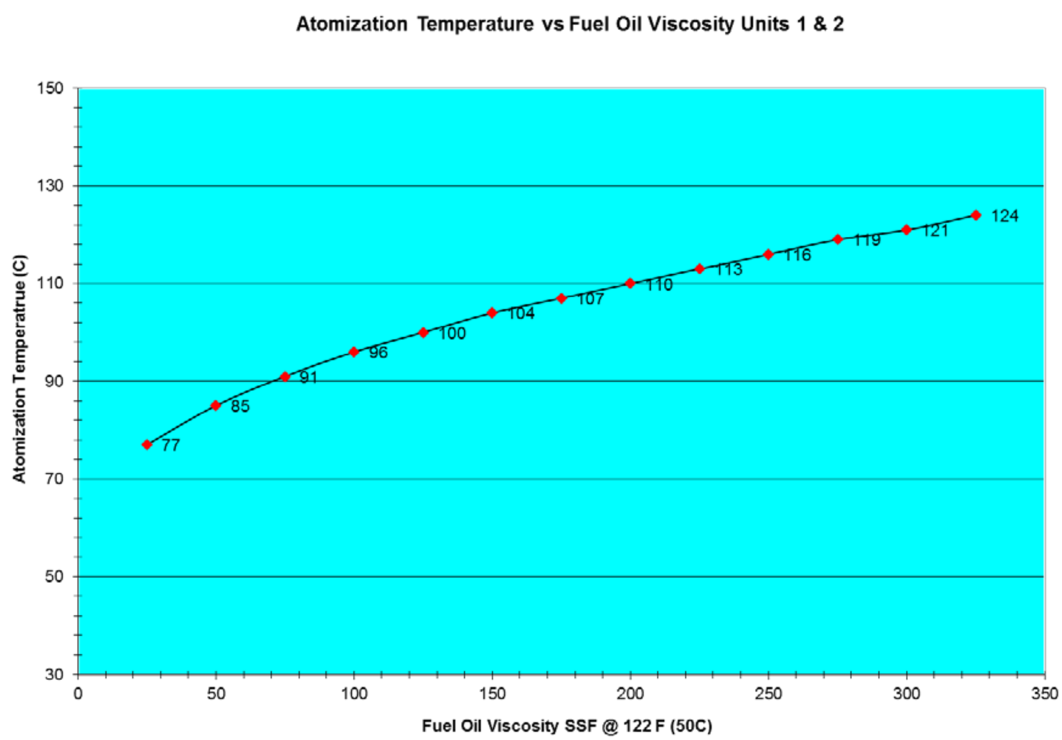
The regenerative air heaters of all three units and the finned tube economizers of units #1 and #2 are experiencing significantly higher than design pressure drops.

6.1 Atomizing Temperature

The viscosity of oils currently utilized at Holyrood range between 50 and 189 SFS (@ 122 F). Sufficient fuel oil heating must be supplied to ensure proper atomization and complete combustion.

The required atomizing temperature for Units #1 and #2 atomizers as a function of SFS viscosity is shown in Figure 17 (Ref. Alstom info supplied to B&W by NLH). According to site reports, atomizing temperatures are currently approximately 187 F (86 C)

Figure 18 Atomization Temperature vs Fuel Oil Viscosity Units 1 & 2



The Unit #3 B&W atomizers are designed for 135 SSU viscosity at the burners. Figures 18 and 19 illustrates the required atomizing temperature as a function of the fuel oil SFS @122 F to achieve the required atomizing viscosity.

Figure 19 Recommended Oil Atomizing Temperature, Holyrood Unit #3 (Celsius)

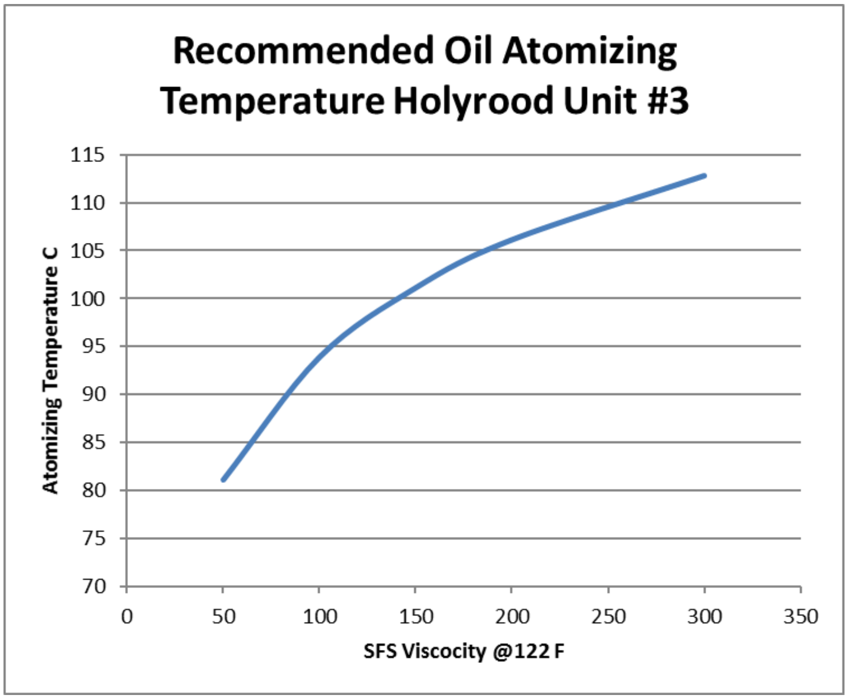
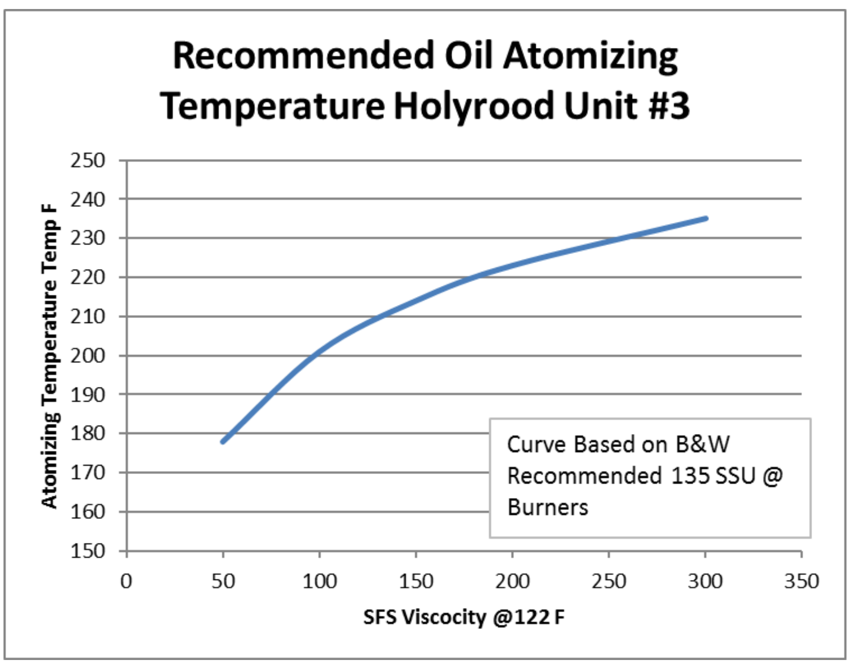


Figure 20 Recommended Oil Atomizing Temperature, Holyrood Unit #3 (Fahrenheit)



To accommodate fuel oil viscosities up to 200 SFS (@122 F):

For Units 1 & 2, an atomizing temperature sufficient to achieve 100 SSU Is recommended or in the absence of viscosity data 110 C (230 F)

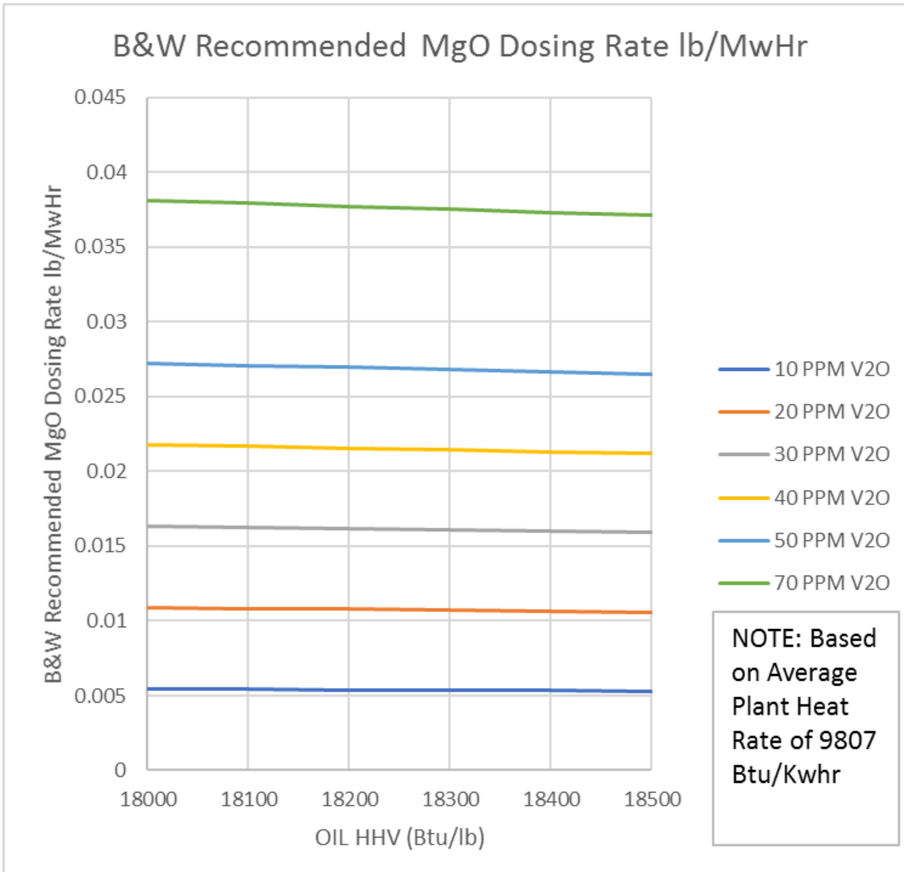
For Unit #3, an atomizing temperature sufficient to achieve 135 SSU Is recommended or in the absence of viscosity data 225 F.

Low atomizing temperature leads to incomplete combustion and increased unburned carbon in fly ash. This ash combined with SO3 condensate in low temperature regions of the boiler lead to corrosion and fouling.

6.2 Fuel Oil Additives

Fuel oil additives reduce the potential for high temperature corrosion and low temperature fouling due to the fuel oil Vanadium. These issues are linked to the catalysing effect of Vanadium on high temperature tube metal corrosion and on the conversion of SO2 to SO3. MgO added to the fuel stream is effective in reducing these effects. B&W recommends a minimum dosing rate of 1 lb MgO per lb V2O in the fuel oil to reduce the potential for both corrosion and fouling. Figure 20 illustrates this recommended dosing rate per unit MWhr output based on an average unit heat rate of 9807 Btu/Kwhr. If a higher dosage rate is recommended by the supplier of the additive due to the specific composition of his additive package, the higher recommended dosage rate should be implemented.

Figure 21 B&W Recommended MgO Dosing Rate lb/Mwhr



NLH discontinued the use of the plant fuel oil additive system in 2014. The decision to take the system out of service may have been based on the improved fuel quality in 2006 and 2009. Load limitations started to occur in 2015 and 2016 on Unit #1 and #2 respectively and 2017 on Unit #3. No significant changes are seen in the fuel analysis between 2009 and 2015. With no other apparent changes in operating conditions, the MgO system was most likely reducing the tendency towards fouling of the air heater surfaces. It is recommended that the MgO dosing system is returned to service.

Vendors of oil additive packages often supply and recommend fuel oil additives which are designed to improve combustion. B&W has not seen any benefit to using these 'combustion improvers' in utility boilers as it relates to fouling or ash 'stickiness'.

6.3 Air Heater Differential Trend – Oct 22, 2017 to Jan 4, 2018 (Unit #3)

Unit #3 experienced a relatively rapid increase in air heater pressure drop associated with a reduction in load capability between Oct 22, 2017 and Jan 4, 2018. A trend of air heater differential vs. time based on Unit #3 PI operating data on an hourly basis was developed to identify if low load operation and/or low ACET was leading to increased fouling. An 'index' of air heater cleanliness was calculated i.e. (Air Heater Differential)/(Total Air Flow). If no further pluggage is occurring this index would be a constant over time. The index is plotted below In Figure 21. A plot of the unit MW output follows in Figure 22, and Figure 23 illustrates the air heater Average Cold End Temperatures (ACET) trend. Although these trends are based on Unit #3 data, they are also relevant to the similar air heaters of Units #1 and #2.

Figure 22 Air Heater Differential Index - Unit 3

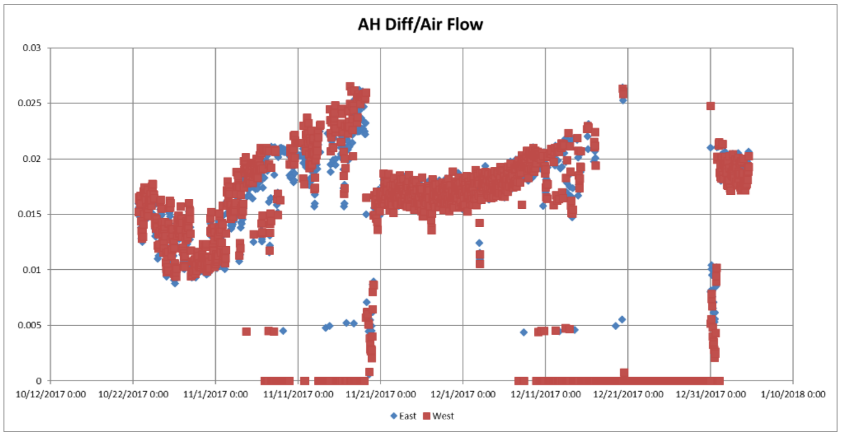


Figure 23 Unit 3 MW Output Oct 2017- Jan 2018

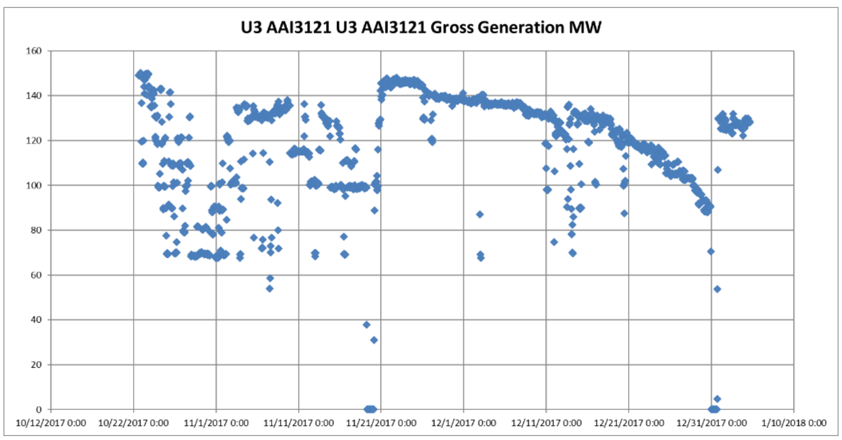
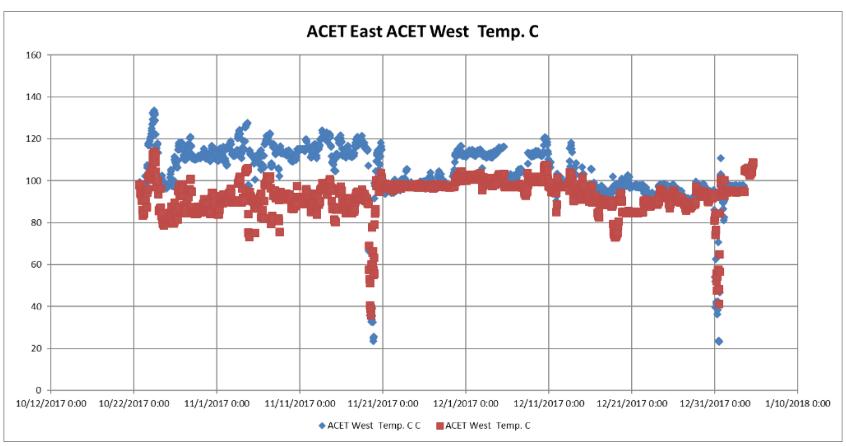


Figure 24 Air Heater ACET Oct 2017- Jan 2018 Unit 3



Gaps in the chart data correspond to times when unit was off line or the differential pressure measurement was not available. The most rapid rise in differential index was during the November operating time frame. During this time period the unit operated for significant periods at loads less than 100 MW. The ACET for the west air heater was significantly lower than the east side, often dropping to as low as 80 C (176 F). The B&W recommended minimum ACET for regenerative air heaters on oil fired units is 190 F (88C). Although the operating ACET was not significantly lower than recommended there is a correlation between low ACET and increased draft loss.

Air heater differential pressure measurements were not available from mid December until a short shutdown on December 31 as the economizer gas outlet gas pressure transmitter appeared to be malfunctioning (Pegged?). During this time period, load dropped rapidly and the ACET's were at even lower levels. This further suggests that low ACET is leading to high rates of air heater pressure drop increase. Note that the air heater differential did not increase during the period from Nov 21 to mid December when the ACET was maintained above 100 C and unit load was above 140 MW. Based on this, a minimum 100 C (212 F) ACET target is recommended.

Figure 21 shows a significant drop in the differential index on or about November 20 and another on December 31, suggesting that the air heaters were washed at that time.

6.4 Heating Surface Removal

Removal of boiler heating surfaces (economizer or heater surfaces) which are leading to increased pressure drop would reduce furnace pressures and reduce FD fan loading. Surface removal can have multiple negative effects on boiler performance and mechanical integrity as follows:

6.4.1 Air Heater Heating Surface Removal

If removing just the 'hot end' elements, the air heater vender predicted performance with only cold end baskets installed would be required to evaluate the effect on boiler performance and efficiency. The air heater vendor would need to advise the effect if the air heaters structural integrity is suitable for the higher outlet gas temperatures under these conditions and any effect on air heater leakage rates.

Other problems that may occur if removing only the hot end baskets are as follows:

- Reduced combustion air temperature leading to unacceptable combustion i.e. high CO, high unburned carbon loss, and a visible plume. (Likely at part loads, possible for high loads)

- High flue gas outlet temperatures leading to possible structural damage to the air heater, downstream expansion joints, flues, and stack. (Likely at high loads, possibly at low loads)

- A significant drop in boiler efficiency (Certainly - all loads)

- Reheat spray flow required at high loads (Likely at high loads)

- Overheating of superheater and reheater tube metals, particularly primary outlets due to increased superheat sprayflow and high fluegas/steam flow ratio (Possibly - all loads)

The removal of hot end air heater baskets for continued operation is therefore not recommended.

Complete removal of air heater surfaces would certainly lead to very poor combustion and very likely structural damage of the flues / expansion joints / stack and thus would not be recommended.

6.4.2 Economizer Heating Surface Removal

Limited removal of economizer surfaces which are blocked by fouling may be a viable option to reduce pressure drop if cleaning these surfaces is not possible. Any removal of economizer heating surfaces must consider the following:

- Increases in flue gas temperature to the air heaters which could lead to structural damage to air heaters and air heater inlet gas flues/expansion joints.

- Increases in air heater outlet gas temperature possibly leading to similar structural problems discussed for air heater surface removal.

- Exceedance of maximum stack temperature limitations structurally or environmentally

- Combustion air temperature increases, possibly beyond the temperature limitations of structural design and expansion joints in the ducts and burners.

- Higher levels of s/h spray and possible overheating of superheater tube metallurgy

- Possible negative effects on boiler natural circulation issues due to low feedwater temperature to drum (Would require review by boiler designer)

A thorough ‘survey’ of where the current areas of blockage are located in both banks would be required to estimate performance and performance predictions of the remaining surface would be ‘estimates’ at best. The path forward would be dependent on the results and accuracy of the survey.

If the blockages are primarily in the bottom bank simplest would be removal of entire bank (After investigating the constraints listed above). If the blockage is in the top bank, and that bank is removed the temperature limitations of the bottom bank supports would also need to be understood.

Considering the above issues, partial removal of economizer surfaces should be considered as a last resort solution. It would also require a considerable inspection, engineering (including pressure part modifications), and construction effort.

Complete removal of economizer surfaces would certainly lead to boiler structural and operational problems and is thus not recommended.

7 WARRANTY / LIMITATION OF LIABILITY

B&W warrants that advice and consultation services and engineering studies will be performed in a manner consistent with generally accepted industry standards and practices. The sole remedy is that any portion of the services furnished to Purchaser which is shown not to have been so performed shall be corrected or re-performed to the standards in effect at the time of original performance at B&W expense; provided all necessary information and access requested by B&W is given to substantiate such claim, and further provided that such non-conformance is detected by Purchaser within ninety (90) days following completion of that portion of the services, and B&W is immediately notified in writing.

The foregoing shall not apply to services performed under the direct supervision of Purchaser. B&W shall not be responsible for suitability or performance of work done by others or for loss or expense arising from same, unless it is specifically ordered by B&W.

There is no warranty or representation, express or implied, with respect to the accuracy, completeness or usefulness of the information contained in any report, or that the use of any report contents may not infringe privately-owned rights. Moreover, B&W will assume no liability for any direct or indirect damages, however caused, including (without limitation) by professional negligence or fundamental breach of contract, resulting from reliance upon or application of the contents of the report by any person.

IN CONSIDERATION OF THE ABOVE EXPRESS WARRANTY EXTENDED BY B&W, ALL OTHER WARRANTIES *OR CONDITIONS, EITHER EXPRESS OR IMPLIED WHETHER ARISING AT LAW, IN EQUITY, BY STATUTE, CUSTOM OF TRADE, OR OTHERWISE, INCLUDING MERCHANTABILITY AND FITNESS FOR A PARTICULAR PURPOSE ARE EXCLUDED.*

End of Report

8 APPENDICES

8.1 Alstom Letter Fritz Vogel – NLH Aug 3, 2000 "Predicted Performance Data For Boiler #1 & 2

RECEIVED
AUG 7 2000

ABB ALSTOM
POWER

2000 Metric

Customer Services Division
Canada

Aug.03.2000

Newfoundland and Labrador Hydro
P.O.Box 29
Holyrood, NF
A0A 2R0

Attention: Herb Dowden-George Moore-Ray Rossiter-John Mallam-Jerry Goulding
Mike Taylor-Alonzo Pollard-Bob Garland
Cc
Terry LeDrew

Dear Gentlemen:

Reference: Predicted Performance Data for Boiler #1 & 2

Our performance design engineer has completed the review of the performance data and attached you will find the following:

Two (2) Tables of Performance Data in metric units
One (1) Graph indicating the recommended Burner Tilt while operating the boiler

The data are based upon the same parameters as applied during the upgrade review and are in no way reflecting Station Data as the basis for recalculation.

Our engineering department emphasizes the fact that the burner tilt must be kept horizontal at all times while operating at less then Control Load i.e. 70 % of MCR.

To assure that these information winds up at the appropriate location I suggest that copies be included in every available instruction/operation instruction manual.

Should you find any discrepancies or have questions with regard to the data feel free to get in touch with John Adams or me.

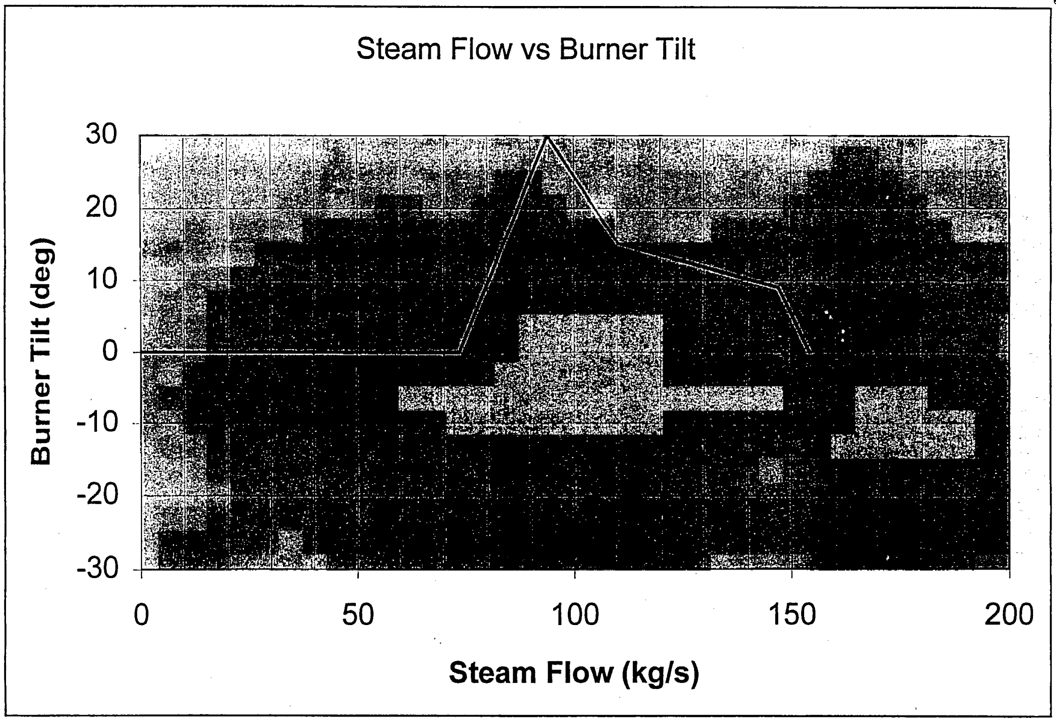
Yours truly,
F. Vogel
Fritz Vogel
ALSTOM Power Canada Inc.

P.O. Box 246
Upper Gullies, Newfoundland, Canada
A0A 4C0
Tel.: (709) 744-4666
Fax: (709) 744-4666

178 179.8 131.25

Load	%	MCR	VWO	75%	50%	25%
STEAM						
Steam Generated	kg/s	147.1	154.4	110.3	73.5	36.8
Reheater Flow	kg/s	131.7	138.1	99.5	67.0	33.9
Operating Pressures	kPa(g)					
Drum		14162	14286	13700	13287	13025
Primary SH Outlet		13976	14080	13590	13238	13011
Final SH Inlet		13907	14004	13550	13219	13006
Final SH Outlet		13480	13542	13300	13094	12969
Reheater Inlet		3399	3572	2558	1696	814
Reheater Outlet		3185	3337	2386	1579	752
Operating Temperatures	°C					
Primary SH Outlet		377	376	377	365	353
Final SH Inlet		370	376	363	365	353
Final SH Outlet		541	541	541	541	531
Reheater Inlet		353	358	329	308	289
Reheater Outlet		541	539	528	495	468
Design Pressures	kPa(g)					
Waterwalls & Headers		15203				
Superheater		15203				
Reheater		4254				
BOILER FEEDWATER						
Economizer flow	kg/s	147.6	157.3	108.9	75.5	38.4
Blowdown	kg/s	1.47	1.54	1.10	0.74	0.37
Operating Pressures	kPa(g)					
At Economizer Inlet (incl. static)		14348	14480	13845	13390	13107
Economizer Outlet		14162	14286	13700	13287	13025
Operating Temperatures	°C					
Economizer Inlet		240	243	225	205	174
Economizer Outlet		302	303	294	270	241
Design Pressure	kPa(g)					
Economizer		15548				
DESUPERHEATING WATER						
Source		Boiler Feed Pump				
Pressure at Pump Discharge	kPa(g)	16286	16286	16286	16286	16286
Temperature	°C	149	151	140	127	107
SH Spray Flow (Operating)	kg/s	2.3	0.0	3.8	0.0	0.0
SH Spray Flow (Design)	kg/s	13.86				
RH Spray Flow (Operating)	kg/s	0.0	0.0	0.0	0.0	0.0
RH Spray Flow (Design)	kg/s	5.27				
FLUE GAS						
Flow	kg/s					
Through Boiler - Economizer		159.8	166.7	134.6	94.9	53.0
Air Heater Inlet		159.8	166.7	134.6	94.9	53.0
Air Heater Outlet (corrected)		173.8	181.2	146.4	104.6	57.6
Operating Drafts	Pa(g)					
Furnace Outlet		2816	3063	1996	997	309
Final SH Outlet		2741	2982	1943	970	301
RH Outlet		2567	2792	1820	909	282
Economizer Outlet		1595	1735	1131	566	175
Air Heater Outlet		324	352	230	117	36

Load	%	MCR	VWO	75%	50%	25%
Operating Temperatures	°C					
Furnace Outlet		1421	1407	1333	1177	1008
Final SH Outlet		1124	1122	1051	919	764
Primary SH Outlet		570	575	536	475	407
RH Outlet		827	831	768	665	543
Economizer Outlet		323	327	299	262	214
Air Heater Outlet (uncorrected)		172	174	164	151	136
Air Heater Outlet (corrected)		163	165	156	144	133
Gas Velocities (Average)	m/sec					
SH Platen 1 - 12" transverse pitch		16.9	17.5	13.5	8.6	4.2
SH Platen 2 - 12" transverse pitch		16.5	17.1	13.1	8.4	4.1
SH Finish - 12" transverse pitch		15.1	15.7	12.0	7.7	3.7
RH Finish - 6" transverse pitch		17.1	17.8	13.6	8.6	4.2
RH Inlet - 6" transverse pitch		16.4	17.2	13.1	8.3	4.0
Primary SH - 4" transverse pitch		17.1	18.0	13.7	8.8	4.4
Economizer		12.5	13.2	10.1	6.6	3.4
AIR						
Flow	kg/s					
Air Heater Inlet		158.4	165.1	134.1	96.1	53.1
Air Heater Outlet (corrected)		144.4	150.6	122.3	86.5	48.5
Air to Burners		144.4	150.6	122.3	86.5	48.5
Operating Pressures	Pa(g)					
Air Heater Inlet		6006	6417	4642	2977	1262
Air Heater Outlet		5158	5495	4041	2678	1169
Windbox		4137	4384	3317	2317	1057
Operating Temperatures	°C					
Air Heater Inlet		54	52	63	76	90
Air Heater Outlet		233	234	222	204	179
Excess Air	%					
Leaving Furnace		5	5	15	20	30
Leaving Economizer		5	5	15	20	30
FUEL BURNT						
No. Burners in Service		12	12	12	8	8
#6 Fuel Oil (Total)	kg/s	10.99	11.46	8.50	5.76	2.98
#6 Fuel Oil (Per Burner)	kg/s	0.92	0.96	0.71	0.72	0.37
Burner Tilts	+ / - Deg	+9	0	+15	0	0
ATOMIZING STEAM						
No. Burners in Service		12	12	12	8	8
Flow (Total)	kg/s	0.961	0.957	0.998	0.680	0.736
Pressure	kPa(g)	724	724	724	724	724
Temperature	°C	193	193	193	193	193
HEAT BALANCE	%					
Dry Gas Loss		3.87	4	3.62	2.8	1.86
Moisture in Fuel		0	0	0	0	0
Moisture from Hydrogen		4.83	4.85	4.73	4.58	4.42
Moisture in Air		0.09	0.1	0.09	0.07	0.05
Carbon Loss		0	0	0	0	0
Radiation Loss		0.2	0.2	0.28	0.4	0.85
Unaccounted Loss		0.5	0.5	0.5	0.5	0.5
Manufacturers Margin		0.5	0.5	0.5	0.5	0.5
Total Losses		9.99	10.15	9.72	8.85	8.18
Overall Efficiency		90.01	89.85	90.28	91.15	91.82


Steam Flow vs Burner Tilt
30
20
10
0
-10
-20
-30
Burner Tilt (deg)
0
50
100
150
200
Steam Flow (kg/s)

8.2 Turbine Heat Balance Conditions Units #1 and #2 Uprated 1988

VWO at 1875 psig

NEWFOUNDLAND TB. NO. 940310+940311 8/5/88
TIR# 10236-893A, UPRATE
1875G-1000/1000F-1.5 IN. HGA

GROSS HEAT RATE = 7991 BTU/KWHR
GENERATOR OUTPUT = 181198 KW -- RATED 194445 KVA, .90 P.F., CONV COOLED
GENERATOR LOSS = 1864 KW AT .93 P.F., 45 PSIG H2, MECH LOSS = 609 KW
STEAM CONDITIONS 1875 PSIG, 1000/1000 F, 1.5 IN HGA 3600 RPM

	F LB/HR	P PSIA	T F	H BTU/LB
HEAT SOURCE				
STEAM FROM BOILER	1225560	1890.	1000.0	1477.70
BLOWDOWN	0			
WATER TO ATTEMPERATOR	0			288.54
FEEDWATER TO BOILER	1225560		470.2	453.82
STEAM FROM REHEATER	1095677	488.6		1520.66
STEAM TO REHEATER	1095677	542.9	681.3	1344.42
TURBINE				
STEAM TO THROTTLE	1225560	1890.	1000.0	1477.70
VALVE STEM LEAKAGE				
TO H.P. TURB. EXHAUST	1431	542.9		1477.70
TO STEAM SEAL REG.	999	16.70		1477.70
ENTERING 1-R CONTROL STAGE NO. 1	1223130	1856.		1477.70
ENTERING DIAPHRAGM STAGE NO. 2	1204254	1507.		1456.74
3-R PACKING				
LEAK-OFF TO HEATER NO. 4 EXTR.	6794	155.9		1344.26
SEAL FLOW TO STEAM SEAL REG.	2952	16.70		1344.26
VENT FLOW TO GLAND SEAL COND.	182			1344.26
BEFORE PRESSURE DROP	1194326	548.4		1344.26
BEFORE FLOW ENTRY	1194326	542.9	681.0	1344.26
BEFORE PRESSURE DROP	1095677	488.6		1520.66
BEFORE ENTRY OF LEAKAGE	1095677	478.9		1520.66
1-R PACKING				
FLOW FROM STAGE 1 SHELL	18876	1507.		1456.74
ENTERING DIAPHRAGM STAGE NO. 11	1114553	478.9		1519.57
ENTERING DIAPHRAGM STAGE NO. 14	1064554	259.5		1440.09
ENTERING DIAPHRAGM STAGE NO. 16	1034026	155.9		1380.28
2-R PACKING				
SEAL FLOW TO STEAM SEAL REG.	1800	16.70		1310.25
VENT FLOW TO GLAND SEAL COND.	287			1310.25
BEFORE PRESSURE DROP	995045	79.82		1310.25
MAIN FLOW DIVIDED BY 2 AT THIS POINT				
ENTERING DIAPHRAGM STAGE NO. 18	497523	78.23		1310.25
ENTERING DIAPHRAGM STAGE NO. 19	465096	46.04		1260.23
ENTERING DIAPHRAGM STAGE NO. 21	423646	12.68		1160.41
ENTERING COND. LAST STAGE NO. 22	423646	5.607		1109.39
BEFORE ENTRY OF LEAKAGE	423646	1.006		1044.37
2-R PACKING				
SEAL FLOW FROM STEAM SEAL REG.	1401	16.70		1356.80
VENT FLOW TO GLAND SEAL COND.	499			1356.80
BEFORE PRESSURE DROP	424096	1.006		1044.70
EXHAUST FLOW	424096	0.7367	91.7	1044.70

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HEATER NO. 6 (CLOSED WITH D.C.)				
CONDITIONS AT H.P. TURB. EXHAUST		542.9	681.3	1344.42
STEAM TO HEATER (5.0 PC DELTA P)	100080	515.8		1344.42
FEEDWATER LEAVING (0 DEG TTD)	1225560		470.2	453.82
FEEDWATER ENTERING DRAIN COOLER	1225560		397.9	375.38
DRAINS LEAVING D.C. (10 DEG TD)	100080	515.8	407.9	383.89
HEATER NO. 5 (CLOSED WITH D.C.)				
TURBINE SHELL CONDITIONS		259.5	832.9	1440.09
STEAM TO HEATER (7.0 PC DELTA P)	49999	241.3		1440.09
FEEDWATER LEAVING (0 DEG TTD)	1225560		397.9	375.38
FEEDWATER ENTERING DRAIN COOLER	1225560		350.8	326.09
DRAINS ENTERING	100080			383.89
DRAINS LEAVING D.C. (10 DEG TD)	150079	241.3	360.8	333.24
HEATER NO. 4 (CLOSED WITH D.C.)				
TURBINE SHELL CONDITIONS		155.9	707.3	1380.28
STEAM EXTRACTED FROM TURBINE	30528	155.9		1380.28
STEAM FROM 3-R PACKING LEAK	6794			1344.26
EXTRACTION STEAM (7.0 PC DELTA P)	37322	145.0		1373.72
FEEDWATER LEAVING (5 DEG TTD)	1225560		350.8	326.09
FEEDWATER ENTERING DRAIN COOLER	1225560		314.3	288.54
DRAINS ENTERING	150079			333.24
DRAINS LEAVING D.C. (10 DEG TD)	187401	145.0	324.3	294.91
FLOW FROM F.W. TO BOILER	0	2362.	314.3	288.54
FEEDWATER PUMP (12. BTU HEAT RISE)				
FEEDWATER LEAVING	1225560	2362.	314.3	288.54
FEEDWATER ENTERING	1225560		306.9	276.84
HEATER NO. 3 (OPEN)				
TURBINE SHELL CONDITIONS		79.82	558.2	1310.25
EXTRACTION STEAM (7 PC DELTA P)	36894	74.24		1310.25
FEEDWATER LEAVING	1225560	74.24	306.9	276.84
FEEDWATER ENTERING	1001265		266.4	235.38
DRAINS ENTERING	187401			294.91
HEATER NO. 2 (CLOSED WITH D.C.)				
TURBINE SHELL CONDITIONS		46.04	450.3	1260.23
STEAM TO HEATER (7.0 PC DELTA P)	64854	42.82		1260.23
FEEDWATER LEAVING (5 DEG TTD)	1001265		266.4	235.38
FEEDWATER ENTERING DRAIN COOLER	1001265		196.8	165.09
DRAINS LEAVING D.C. (10 DEG TD)	64854	42.82	206.8	175.02

HEATER NO. 1 (PUMPED DRAINS)				
TURBINE SHELL CONDITIONS		12.68	231.2	1160.41
STEAM EXTRACTED FROM TURBINE	82900			1160.41
STEAM FROM STEAM SEAL DUMP	4350			1356.80
STEAM TO HEATER (7 PC DELTA P)	87250	11.79		1170.20
FLOW FROM MAKEUP SOURCE	0			453.82
FLOW FROM FW. BELOW HEATER 1	0			453.82
DRAINS ENTERING	64854			175.02
DRAINS PUMPED TO FEEDWATER	152104	11.79	201.1	169.18
FEEDWATER AFTER DRAIN ENTRY	1001265		196.8	165.09
FEEDWATER LEAVING (5 DEG TTD)	849161		196.1	164.36
FEEDWATER ENTERING	849161		92.8	61.06
STEAM SEAL REGULATOR				
FLOW FROM VALVE STEM PACKING	999			1477.70
FLOW FROM 3-R PACKING SEAL	2952			1344.26
FLOW FROM 2-R PACKING SEAL	1800			1310.25
FLOW TO 2-R PACKING SEAL	1401			1356.80
MAKE-UP FROM TURBINE INLET	0			1477.70
DUMP TO HEATER NO. 1 EXTR	4350	12.68		1356.80
GLAND SEAL CONDENSER				
STEAM FROM 3-R PACKING VENT	182			1344.26
STEAM FROM 2-R PACKING VENT	287			1310.25
STEAM FROM 2-R PACKING VENT	499			1356.80
FEEDWATER LEAVING	849161		92.8	61.06
FEEDWATER ENTERING	849161		91.5	59.74
DRAINS TO CONDENSER	968			179.48
FLOW FROM F.W. TO HEATER NO. 1	0	11.79	91.5	453.82
FEEDWATER PUMP (0. BTU HEAT RISE)				
FEEDWATER LEAVING	849161	100.0	91.5	59.74
FEEDWATER ENTERING	849161		91.7	59.74
CONDENSER				
STEAM TO CONDENSER	424096	0.7367		1044.70
DRAINS ENTERING	968			
FEEDWATER LEAVING	849161	0.7367	91.7	59.74

RATING FLOW (GUARANTEED) IS 1167200 LB/HR AT INITIAL STEAM CONDITIONS OF 1875 PSIG, 1000 F. TO ASSURE THAT THE TURBINE WILL PASS THIS FLOW, CONSIDERING VARIATIONS IN FLOW COEFFICIENTS FROM EXPECTED VALUES, MANUFACTURING TOLERANCES ON DRAWING AREAS, ETC., WHICH MAY AFFECT THE FLOW, THE TURBINE IS BEING DESIGNED FOR AN EXPECTED FLOW OF 1225560 LB/HR.

CALCULATED DATA NOT GUARANTEED.

MCR

NEWFOUNDLAND TB. NO. 940310+940311 6/5/88
TIR# 10236-893A, UPRATE
1875G-1000/1000F-1.5 IN. HGA

GROSS HEAT RATE = 7982 BTU/KWHR
GENERATOR OUTPUT = 174160 KW -- RATED 194445 KVA, .90 P.F., CONV COOLED
GENERATOR LOSS = 1864 KW AT .90 P.F., 45 PSIG H2, MECH LOSS = 609 KW
STEAM CONDITIONS 1875 PSIG, 1000/1000 F, 1.5 IN HGA 3600 RPM

	F LB/HR	P PSIA	T F	H BTU/LB
HEAT SOURCE				
STEAM FROM BOILER	1167200	1890.	1000.0	1477.70
BLOWDOWN	0			
WATER TO ATTEMPERATOR	0			285.40
FEEDWATER TO BOILER	1167200		465.4	448.44
STEAM FROM REHEATER	1044878	466.3		1521.31
STEAM TO REHEATER	1044878	518.1	672.0	1340.63
TURBINE				
STEAM TO THROTTLE	1167200	1890.	1000.0	1477.70
VALVE STEM LEAKAGE				
TO H.P. TURB. EXHAUST	1477	518.1		1477.70
TO STEAM SEAL REG.	953	16.70		1477.70
ENTERING 1-R CONTROL STAGE NO. 1	1164770	1860.		1477.70
ENTERING DIAPHRAGM STAGE NO. 2	1146779	1432.		1451.49
3-R PACKING				
LEAK-OFF TO HEATER NO. 4 EXTR.	6503	149.0		1340.46
SEAL FLOW TO STEAM SEAL REG.	2824	16.70		1340.46
VENT FLOW TO GLAND SEAL COND.	183			1340.46
BEFORE PRESSURE DROP	1137269	523.3		1340.46
BEFORE FLOW ENTRY	1137269	518.1	671.7	1340.46
BEFORE PRESSURE DROP	1044878	466.3		1521.31
BEFORE ENTRY OF LEAKAGE	1044878	457.0		1521.31
1-R PACKING				
FLOW FROM STAGE 1 SHELL	17991	1432.		1451.49
ENTERING DIAPHRAGM STAGE NO. 11	1062869	457.0		1520.13
ENTERING DIAPHRAGM STAGE NO. 14	1015914	247.8		1440.67
ENTERING DIAPHRAGM STAGE NO. 16	987378	149.0		1380.86
2-R PACKING				
SEAL FLOW TO STEAM SEAL REG.	1705	16.70		1310.80
VENT FLOW TO GLAND SEAL COND.	287			1310.80
BEFORE PRESSURE DROP	950578	76.31		1310.80
MAIN FLOW DIVIDED BY 2 AT THIS POINT				
ENTERING DIAPHRAGM STAGE NO. 18	475289	74.79		1310.80
ENTERING DIAPHRAGM STAGE NO. 19	444689	44.05		1260.78
ENTERING DIAPHRAGM STAGE NO. 21	405879	12.16		1160.98
ENTERING COND. LAST STAGE NO. 22	405879	5.369		1109.82
BEFORE ENTRY OF LEAKAGE	405879	0.9833		1045.02
2-R PACKING				
SEAL FLOW FROM STEAM SEAL REG.	1402	16.70		1355.10
VENT FLOW TO GLAND SEAL COND.	500			1355.10
BEFORE PRESSURE DROP	406330	0.9833		1045.36
EXHAUST FLOW	406330	0.7367	91.7	1045.36

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page 1 of 3

HEATER NO. 6 (CLOSED WITH D.C.)				
CONDITIONS AT H.P. TURB. EXHAUST		518.1	672.0	1340.63
STEAM TO HEATER (5.0 PC DELTA P)	93868	492.2		1340.63
FEEDWATER LEAVING (0 DEG TTD)	1167200		465.4	448.44
FEEDWATER ENTERING DRAIN COOLER	1167200		393.9	371.15
DRAINS LEAVING D.C. (10 DEG TD)	93868	492.2	403.9	379.54
HEATER NO. 5 (CLOSED WITH D.C.)				
TURBINE SHELL CONDITIONS		247.8	833.2	1440.67
STEAM TO HEATER (7.0 PC DELTA P)	46955	230.4		1440.67
FEEDWATER LEAVING (0 DEG TTD)	1167200		393.9	371.15
FEEDWATER ENTERING DRAIN COOLER	1167200		347.2	322.43
DRAINS ENTERING	93868			379.54
DRAINS LEAVING D.C. (10 DEG TD)	140823	230.4	357.2	329.49
No. 5	46955			
HEATER NO. 4 (CLOSED WITH D.C.)				
TURBINE SHELL CONDITIONS		149.0	707.8	1380.86
STEAM EXTRACTED FROM TURBINE	28536	149.0		1380.86
STEAM FROM 3-R PACKING LEAK	6503			1340.46
EXTRACTION STEAM (7.0 PC DELTA P)	35039	138.5		1373.36
FEEDWATER LEAVING (5 DEG TTD)	1167200		347.2	322.43
FEEDWATER ENTERING DRAIN COOLER	1167200		311.2	285.40
DRAINS ENTERING	140823			329.49
DRAINS LEAVING D.C. (10 DEG TD)	175862	138.5	321.2	291.70
No. 4	35039			
FLOW FROM F.W. TO BOILER	0	2362.	311.2	285.40
FEEDWATER PUMP (12. BTU HEAT RISE)				
FEEDWATER LEAVING	1167200	2362.	311.2	285.40
FEEDWATER ENTERING	1167200		303.9	273.70
HEATER NO. 3 (OPEN)				
TURBINE SHELL CONDITIONS		76.31	558.8	1310.80
EXTRACTION STEAM (7 PC DELTA P)	34809	70.97		1310.80
FEEDWATER LEAVING	1167200	70.97	303.9	273.70
FEEDWATER ENTERING	956529		263.7	232.64
DRAINS ENTERING	175862			291.70
HEATER NO. 2 (CLOSED WITH D.C.)				
TURBINE SHELL CONDITIONS		44.05	451.0	1260.78
STEAM TO HEATER (7.0 PC DELTA P)	61200	40.97		1260.78
FEEDWATER LEAVING (5 DEG TTD)	956529		263.7	232.64
FEEDWATER ENTERING DRAIN COOLER	956529		194.8	163.04
DRAINS LEAVING D.C. (10 DEG TD)	61200	40.97	204.8	172.96

HEATER NO. 1 (PUMPED DRAINS)				
TURBINE SHELL CONDITIONS		12.16	232.0	1160.98
STEAM EXTRACTED FROM TURBINE	77619			1160.98
STEAM FROM STEAM SEAL DUMP	4079			1355.10
STEAM TO HEATER (7 PC DELTA P)	81699	11.30		1170.67
FLOW FROM MAKEUP SOURCE	0			448.44
FLOW FROM FW. BELOW HEATER 1	0			448.44
DRAINS ENTERING	61200			172.96
DRAINS PUMPED TO FEEDWATER	142899	11.30	199.1	167.14
FEEDWATER AFTER DRAIN ENTRY	956529		194.8	163.04
FEEDWATER LEAVING (5 DEG TTD)	813630		194.1	162.32
FEEDWATER ENTERING	813630		92.8	61.12
STEAM SEAL REGULATOR				
FLOW FROM VALVE STEM PACKING	953			1477.70
FLOW FROM 3-R PACKING SEAL	2824			1340.46
FLOW FROM 2-R PACKING SEAL	1705			1310.80
FLOW TO 2-R PACKING SEAL	1402			1355.10
MAKE-UP FROM TURBINE INLET	0			1477.70
DUMP TO HEATER NO. 1 EXTR	4079	12.16		1355.10
GLAND SEAL CONDENSER				
STEAM FROM 3-R PACKING VENT	183			1340.46
STEAM FROM 2-R PACKING VENT	287			1310.80
STEAM FROM 2-R PACKING VENT	500			1355.10
FEEDWATER LEAVING	813630		92.8	61.12
FEEDWATER ENTERING	813630		91.5	59.74
DRAINS TO CONDENSER	970			179.48
FLOW FROM F.W. TO HEATER NO. 1	0	11.30	91.5	448.44
FEEDWATER PUMP (0. BTU HEAT RISE)				
FEEDWATER LEAVING	813630	100.0	91.5	59.74
FEEDWATER ENTERING	813630		91.7	59.74
CONDENSER				
STEAM TO CONDENSER	406330	0.7367		1045.36
DRAINS ENTERING	970			
FEEDWATER LEAVING	813630	0.7367	91.7	59.74

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75% MCR

NEWFOUNDLAND TB. NO. 940310+940311 8/5/88
TIR# 10236-893A, UPRATE
1875G-1000/1000F-1.5 IN. HGA

GROSS HEAT RATE = 7987 BTU/KWHR
GENERATOR OUTPUT = 135841 KW -- RATED 194445 KVA, .90 P.F., CONV COOLED
GENERATOR LOSS = 1566 KW AT .90 P.F., 20 PSIG H2, MECH LOSS = 609 KW
STEAM CONDITIONS 1875 PSIG, 1000/1000 F, 1.5 IN HGA 3600 RPM

	F LB/HR	P PSIA	T F	H BTU/LB
HEAT SOURCE				
STEAM FROM BOILER	875400	1890.	1000.0	1477.70
BLOWDOWN	0			
WATER TO ATTEMPERATOR	0			267.37
FEEDWATER TO BOILER	875400		437.9	418.26
STEAM FROM REHEATER	789636	353.6		1524.61
STEAM TO REHEATER	789636	392.9	629.9	1325.08
TURBINE				
STEAM TO THROTTLE	875400 693,273	1890.	1000.0	1477.70
VALVE STEM LEAKAGE				
TO H.P. TURB. EXHAUST	1707	392.9		1477.70
TO STEAM SEAL REG.	723	16.70		1477.70
ENTERING 1-R CONTROL STAGE NO. 1	872970	1873.		1477.70
ENTERING DIAPHRAGM STAGE NO. 2	859428	1061.		1429.55
3-R PACKING				
LEAK-OFF TO HEATER NO. 4 EXTR.	4992	113.8		1324.77
SEAL FLOW TO STEAM SEAL REG.	2147	16.70		1324.77
VENT FLOW TO GLAND SEAL COND.	186			1324.77
BEFORE PRESSURE DROP	852103	396.9		1324.77
BEFORE FLOW ENTRY	852103	392.9	629.3	1324.77
BEFORE PRESSURE DROP	789636	353.6		1524.61
BEFORE ENTRY OF LEAKAGE	789636	346.5		1524.61
1-R PACKING				
FLOW FROM STAGE 1 SHELL	13542	1061.		1429.55
ENTERING DIAPHRAGM STAGE NO. 11	803178	346.5		1523.01
ENTERING DIAPHRAGM STAGE NO. 14	770653	188.7		1443.67
ENTERING DIAPHRAGM STAGE NO. 16	751484	113.8		1383.86
2-R PACKING				
SEAL FLOW TO STEAM SEAL REG.	1216	16.70		1313.68
VENT FLOW TO GLAND SEAL COND.	286			1313.68
BEFORE PRESSURE DROP	[illegible]	58.46		1313.68
MAIN FLOW DIVIDED BY 2 AT THIS POINT				
ENTERING DIAPHRAGM STAGE NO. 18	[illegible]	57.29		1313.68
ENTERING DIAPHRAGM STAGE NO. 19	340875	33.89		1263.72
ENTERING DIAPHRAGM STAGE NO. 21	314735	9.473		1164.08
ENTERING COND. LAST STAGE NO. 22	314735	4.148		1112.09
BEFORE ENTRY OF LEAKAGE	314735	0.8826		1049.49
2-R PACKING				
SEAL FLOW FROM STEAM SEAL REG.	1408	16.70		1348.53
VENT FLOW TO GLAND SEAL COND.	503			1348.53
BEFORE PRESSURE DROP	315187	0.8826		1045.92
EXHAUST FLOW	315187	0.7367	91.7	1045.92

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HEATER NO. 6 (CLOSED WITH D.C.)				
CONDITIONS AT H.P. TURB. EXHAUST		392.9	629.9	1325.08
STEAM TO HEATER (5.0 PC DELTA P)	64174	373.3		1325.08
FEEDWATER LEAVING (0 DEG TTD)	875400		437.9	418.26
FEEDWATER ENTERING DRAIN COOLER	875400		~~371.0~~	347.14
DRAINS LEAVING D.C. (10 DEG TD)	64174	373.3	381.0	354.87
HEATER NO. 5 (CLOSED WITH D.C.)				
TURBINE SHELL CONDITIONS		188.7	834.5	1443.67
STEAM TO HEATER (7.0 PC DELTA P)	32525	175.5		1443.67
FEEDWATER LEAVING (0 DEG TTD)	875400		371.0	347.14
FEEDWATER ENTERING DRAIN COOLER	875400		~~328.9~~	301.52
DRAINS ENTERING	64174			354.87
DRAINS LEAVING D.C. (10 DEG TD)	96698	175.5	336.9	308.14
HEATER NO. 4 (CLOSED WITH D.C.)				
TURBINE SHELL CONDITIONS		113.8	710.2	1383.86
STEAM EXTRACTED FROM TURBINE	19169	113.8		1383.86
STEAM FROM 3-R PACKING LEAK	4992			1324.77
EXTRACTION STEAM (7.0 PC DELTA P)	24161	105.8		1371.65
FEEDWATER LEAVING (5 DEG TTD)	875400		326.9	301.52
FEEDWATER ENTERING DRAIN COOLER	875400	136	293.5	267.37
DRAINS ENTERING	96698			308.14
DRAINS LEAVING D.C. (10 DEG TD)	120860	105.8	303.5	273.35
FLOW FROM F.W. TO BOILER	0	2362.	293.5	267.37
FEEDWATER PUMP (12. BTU HEAT RISE)				
FEEDWATER LEAVING	875400	2362.	293.5	267.37
FEEDWATER ENTERING	875400		286.3	255.67
HEATER NO. 3 (OPEN)				
TURBINE SHELL CONDITIONS		58.46	561.9	1313.68
EXTRACTION STEAM (7 PC DELTA P)	24734	54.37		1313.68
FEEDWATER LEAVING	875400	54.37	286.3	255.67
FEEDWATER ENTERING	729806		248.2	216.88
DRAINS ENTERING	120860			273.35
HEATER NO. 2 (CLOSED WITH D.C.)				
TURBINE SHELL CONDITIONS		33.89	454.7	1263.72
STEAM TO HEATER (7.0 PC DELTA P)	43499	31.52		1263.72
FEEDWATER LEAVING (5 DEG TTD)	729806	110	248.2	216.88
FEEDWATER ENTERING DRAIN COOLER	729806	73	182.9	151.16
DRAINS LEAVING D.C. (10 DEG TD)	43499	31.52	192.9	161.03

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HEATER NO. 1 (PUMPED DRAINS)				
TURBINE SHELL CONDITIONS		9.473	236.6	1164.08
STEAM EXTRACTED FROM TURBINE	52280			1164.08
STEAM FROM STEAM SEAL DUMP	2678			1348.53
STEAM TO HEATER (7 PC DELTA P)	54958	8.810		1173.07
FLOW FROM MAKEUP SOURCE	0			418.26
FLOW FROM FW. BELOW HEATER 1	0			418.26
DRAINS ENTERING	43499			161.03
DRAINS PUMPED TO FEEDWATER	98457	8.810	187.3	155.31
FEEDWATER AFTER DRAIN ENTRY	729806		182.9	151.16
FEEDWATER LEAVING (5 DEG TTD)	631350	73	182.3	150.51
FEEDWATER ENTERING	631350	26	93.2	61.52
STEAM SEAL REGULATOR				
FLOW FROM VALVE STEM PACKING	723			1477.70
FLOW FROM 3-R PACKING SEAL	2147			1324.77
FLOW FROM 2-R PACKING SEAL	1216			1313.68
FLOW TO 2-R PACKING SEAL	1408			1348.53
MAKE-UP FROM TURBINE INLET	0			1477.70
DUMP TO HEATER NO. 1 EXTR	2678	9.473		1348.53
GLAND SEAL CONDENSER				
STEAM FROM 3-R PACKING VENT	186			1324.77
STEAM FROM 2-R PACKING VENT	286			1313.68
STEAM FROM 2-R PACKING VENT	503			1348.53
FEEDWATER LEAVING	631350		93.2	61.52
FEEDWATER ENTERING	631350		91.5	59.74
DRAINS TO CONDENSER	975			179.48
FLOW FROM F.W. TO HEATER NO. 1	0	8.810	91.5	418.26
FEEDWATER PUMP (0. BTU HEAT RISE)				
FEEDWATER LEAVING	631350	100.0	91.5	59.74
FEEDWATER ENTERING	631350		91.7	59.74
CONDENSER				
STEAM TO CONDENSER	315187	0.7367		1049.92
DRAINS ENTERING	975			
FEEDWATER LEAVING	631350	0.7367	91.7	59.74

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NEWFOUNDLAND TE. NO. 940310+940311 8/5/88
TIR# 10236-893A, UPRATE
1875G-1000/1000F-1.5 IN. HGA

GROSS HEAT RATE = 8109 BTU/KWHR
GENERATOR OUTPUT = 93140 KW --- RATED 194445 KVA, .90 P.F., CONV COOLED
GENERATOR LOSS = 1092 KW AT .90 P.F., .50 PSIG H2, MECH LOSS = 609 KW
STEAM CONDITIONS 1875 PSIG, 1000/1000 F, 1.5 IN HGA 3600 RPM

	F LB/HR	P PSIA	T F	H BTU/LB
HEAT SOURCE				
STEAM FROM BOILER	583600	1890.	1000.0	1477.70
BLOWDOWN	0			
WATER TO ATTEMPERATOR	0			243.38
FEEDWATER TO BOILER	583600		401.7	379.49
STEAM FROM REHEATER	531457	238.9		1527.96
STEAM TO REHEATER	531457	265.5	590.6	1312.75
TURBINE				
STEAM TO THROTTLE	583600	1890.	1000.0	1477.70
VALVE STEM LEAKAGE				
TO H.P. TURB. EXHAUST	1942	265.5		1477.70
TO STEAM SEAL REG.	488	16.70		1477.70
ENTERING 1-R CONTROL STAGE NO. 1	581170	1882.		1477.70
ENTERING DIAPHRAGM STAGE NO. 2	572116	699.9		1411.47
3-R PACKING				
LEAK-OFF TO HEATER NO. 4 EXTR.	3412	77.52		1312.19
SEAL FLOW TO STEAM SEAL REG.	1412	16.70		1312.19
VENT FLOW TO GLAND SEAL COND.	188			1312.19
BEFORE PRESSURE DROP	567104	268.2		1312.19
BEFORE FLOW ENTRY	567104	265.5	589.6	1312.19
BEFORE PRESSURE DROP	531457	238.9		1527.96
BEFORE ENTRY OF LEAKAGE	531457	234.1		1527.96
1-R PACKING				
FLOW FROM STAGE 1 SHELL	9054	699.9		1411.47
ENTERING DIAPHRAGM STAGE NO. 11	540511	234.1		1526.00
ENTERING DIAPHRAGM STAGE NO. 14	520981	128.1		1446.88
ENTERING DIAPHRAGM STAGE NO. 16	510064	77.52		1387.12
2-R PACKING				
SEAL FLOW TO STEAM SEAL REG.	694	16.70		1316.86
VENT FLOW TO GLAND SEAL COND.	285			1316.86
BEFORE PRESSURE DROP	493763	39.99		1316.86
MAIN FLOW DIVIDED BY 2 AT THIS POINT				
ENTERING DIAPHRAGM STAGE NO. 18	246882	39.19		1316.86
ENTERING DIAPHRAGM STAGE NO. 19	233427	23.30		1267.02
ENTERING DIAPHRAGM STAGE NO. 21	218791	6.624		1167.74
ENTERING COND. LAST STAGE NO. 22	218791	2.868		1114.65
BEFORE ENTRY OF LEAKAGE	218791	0.8069		1058.92
2-R PACKING				
SEAL FLOW FROM STEAM SEAL REG.	1411	16.70		1344.61
VENT FLOW TO GLAND SEAL COND.	505			1344.61
BEFORE PRESSURE DROP	219245	0.8069		1059.51
EXHAUST FLOW	219245	0.7367	91.7	1059.51

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HEATER NO. 6 (CLOSED WITH D.C.)				
CONDITIONS AT H.P. TURB. EXHAUST		265.5	590.6	1312.75
STEAM TO HEATER (5.0 PC DELTA P)	37588	252.2		1312.75
FEEDWATER LEAVING (0 DEG TTD)	583600		~~401.7~~	379.49
FEEDWATER ENTERING DRAIN COOLER	583600		340.7	315.73
DRAINS LEAVING D.C. (10 DEG TD)	37588	252.2	350.7	322.71
HEATER NO. 5 (CLOSED WITH D.C.)				
TURBINE SHELL CONDITIONS		128.1	836.2	1446.88
STEAM TO HEATER (7.0 PC DELTA P)	19530	119.2		1446.88
FEEDWATER LEAVING (0 DEG TTD)	583600		340.7	315.73
FEEDWATER ENTERING DRAIN COOLER	583600		299.9	273.93
DRAINS ENTERING	37588			322.71
DRAINS LEAVING D.C. (10 DEG TD)	57118	119.2	309.9	280.03
HEATER NO. 4 (CLOSED WITH D.C.)				
TURBINE SHELL CONDITIONS		77.52	713.1	1387.12
STEAM EXTRACTED FROM TURBINE	10917	77.52		1387.12
STEAM FROM 3-R PACKING LEAK	3412			1312.19
EXTRACTION STEAM (7.0 PC DELTA P)	14329	72.10		1369.28
FEEDWATER LEAVING (5 DEG TTD)	583600		299.9	273.93
FEEDWATER ENTERING DRAIN COOLER	583600		269.8	243.38
DRAINS ENTERING	57118			280.03
DRAINS LEAVING D.C. (10 DEG TD)	71447	72.10	279.8	248.99
FLOW FROM F.W. TO BOILER	0	2362.	269.8	243.38
FEEDWATER PUMP (12. BTU HEAT RISE)				
FEEDWATER LEAVING	583600	2362.	269.8	243.38
FEEDWATER ENTERING	583600		262.9	231.68
HEATER NO. 3 (OPEN)				
TURBINE SHELL CONDITIONS		39.99	565.6	1316.86
EXTRACTION STEAM (7 PC DELTA P)	15322	37.19		1316.86
FEEDWATER LEAVING	583600	37.19	262.9	231.68
FEEDWATER ENTERING	496831		227.3	195.73
DRAINS ENTERING	71447			248.99
HEATER NO. 2 (CLOSED WITH D.C.)				
TURBINE SHELL CONDITIONS		23.30	459.1	1267.02
STEAM TO HEATER (7.0 PC DELTA P)	26909	21.67		1267.02
FEEDWATER LEAVING (5 DEG TTD)	496831		227.3	195.73
FEEDWATER ENTERING DRAIN COOLER	496831		166.8	134.95
DRAINS LEAVING D.C. (10 DEG TD)	26909	21.67	176.8	144.78

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HEATER NO. 1 (PUMPED DRAINS)				
TURBINE SHELL CONDITIONS		6.624	242.6	1167.74
STEAM EXTRACTED FROM TURBINE	29272			1167.74
STEAM FROM STEAM SEAL DUMP	1183			1344.61
STEAM TO HEATER (7 PC DELTA P)	30454	6.160		1174.61
FLOW FROM MAKEUP SOURCE	0			379.49
FLOW FROM FW. BELOW HEATER 1	0			379.49
DRAINS ENTERING	26909			144.78
DRAINS PUMPED TO FEEDWATER	57363	6.160	171.2	139.18
FEEDWATER AFTER DRAIN ENTRY	496831		166.8	134.95
FEEDWATER LEAVING (5 DEG TTD)	439468		166.2	134.40
FEEDWATER ENTERING	439468		94.0	62.30
STEAM SEAL REGULATOR				
FLOW FROM VALVE STEM PACKING	488			1477.70
FLOW FROM 3-R PACKING SEAL	1412			1312.19
FLOW FROM 2-R PACKING SEAL	694			1316.86
FLOW TO 2-R PACKING SEAL	1411			1344.61
MAKE-UP FROM TURBINE INLET	0			1477.70
DUMP TO HEATER NO. 1 EXTR	1183	6.624		1344.61
GLAND SEAL CONDENSER				
STEAM FROM 3-R PACKING VENT	188			1312.19
STEAM FROM 2-R PACKING VENT	285			1316.86
STEAM FROM 2-R PACKING VENT	505			1344.61
FEEDWATER LEAVING	439468		94.0	62.30
FEEDWATER ENTERING	439468		91.5	59.74
DRAINS TO CONDENSER	979			179.48
FLOW FROM F.W. TO HEATER NO. 1	0	6.160	91.5	379.49
FEEDWATER PUMP (0. BTU HEAT RISE)				
FEEDWATER LEAVING	439468	100.0	91.5	59.74
FEEDWATER ENTERING	439468		91.7	59.74
CONDENSER				
STEAM TO CONDENSER	219245	0.7367		1059.51
DRAINS ENTERING	979			
FEEDWATER LEAVING	439468	0.7367	91.7	59.74

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25% MCR

NEWFOUNDLAND TB. NO. 940310+940311
TIR# 10236-893A, UPRATE
1875G-1000/1000F-1.5 IN. HGA

8/5/88

GROSS HEAT RATE = 8752 BTU/KWHR
GENERATOR OUTPUT = 45259 KW --- RATED 194445 KVA, .90 P.F., CONV COOLED
GENERATOR LOSS = 817 KW AT .90 P.F., .50 PSIG H2, MECH LOSS = 609 KW
STEAM CONDITIONS 1875 PSIG, 1000/1000 F, 1.5 IN HGA 3600 RPM

	F LB/HR	P PSIA	T F	H BTU/LB
HEAT SOURCE				
STEAM FROM BOILER	291800	1890.	1000.0	1477.70
BLOWDOWN	0			
WATER TO ATTEMPERATOR	0		174 C	205.89
FEEDWATER TO BOILER	291800		346.3	321.46
STEAM FROM REHEATER	268940	121.5		1531.37
STEAM TO REHEATER	268940	135.0	572.3 300	1313.12
TURBINE				
STEAM TO THROTTLE	291344	1890.	1000.0	1477.70
VALVE STEM LEAKAGE				
TO H.P. TURB. EXHAUST	2182	135.0		1477.70
TO STEAM SEAL REG.	248	16.70		1477.70
ENTERING 1-R CONTROL STAGE NO. 1	288914	1888.		1477.70
ENTERING DIAPHRAGM STAGE NO. 2	284403	348.7		1408.92
3-R PACKING				
LEAK-OFF TO HEATER NO. 4 EXTR.	1775	39.88		1311.84
SEAL FLOW TO STEAM SEAL REG.	583	16.70		1311.84
VENT FLOW TO GLAND SEAL COND.	189			1311.84
BEFORE PRESSURE DROP	281857	136.3		1311.84
BEFORE FLOW ENTRY	281857	135.0	569.8	1311.84
BEFORE PRESSURE DROP	268940	121.5		1531.37
BEFORE ENTRY OF LEAKAGE	268940	119.1		1531.37
1-R PACKING				
FLOW FROM STAGE 1 SHELL	4511	348.7		1408.92
ENTERING DIAPHRAGM STAGE NO. 11	273450	119.1		1529.35
ENTERING DIAPHRAGM STAGE NO. 14	265148	65.57		1450.61
ENTERING DIAPHRAGM STAGE NO. 16	261049	39.88		1391.03
2-R PACKING				
SEAL FLOW TO STEAM SEAL REG.	49	16.70		1320.80
VENT FLOW TO GLAND SEAL COND.	284			1320.80
BEFORE PRESSURE DROP	253909	20.69		1320.80
MAIN FLOW DIVIDED BY 2 AT THIS POINT				
ENTERING DIAPHRAGM STAGE NO. 18	126954	20.27		1320.80
ENTERING DIAPHRAGM STAGE NO. 19	121021	12.14		1271.18
ENTERING DIAPHRAGM STAGE NO. 21	116204	3.546		1172.79
ENTERING COND. LAST STAGE NO. 22	116204	1.520		1118.34
BEFORE ENTRY OF LEAKAGE	116204	0.7571		1087.86
2-R PACKING				
SEAL FLOW FROM STEAM SEAL REG.	1336	16.70		1399.65
VENT FLOW TO GLAND SEAL COND.	479			1399.65
BEFORE PRESSURE DROP	116633	0.7571		1089.01
EXHAUST FLOW	116633	0.7367	91.7	1089.01

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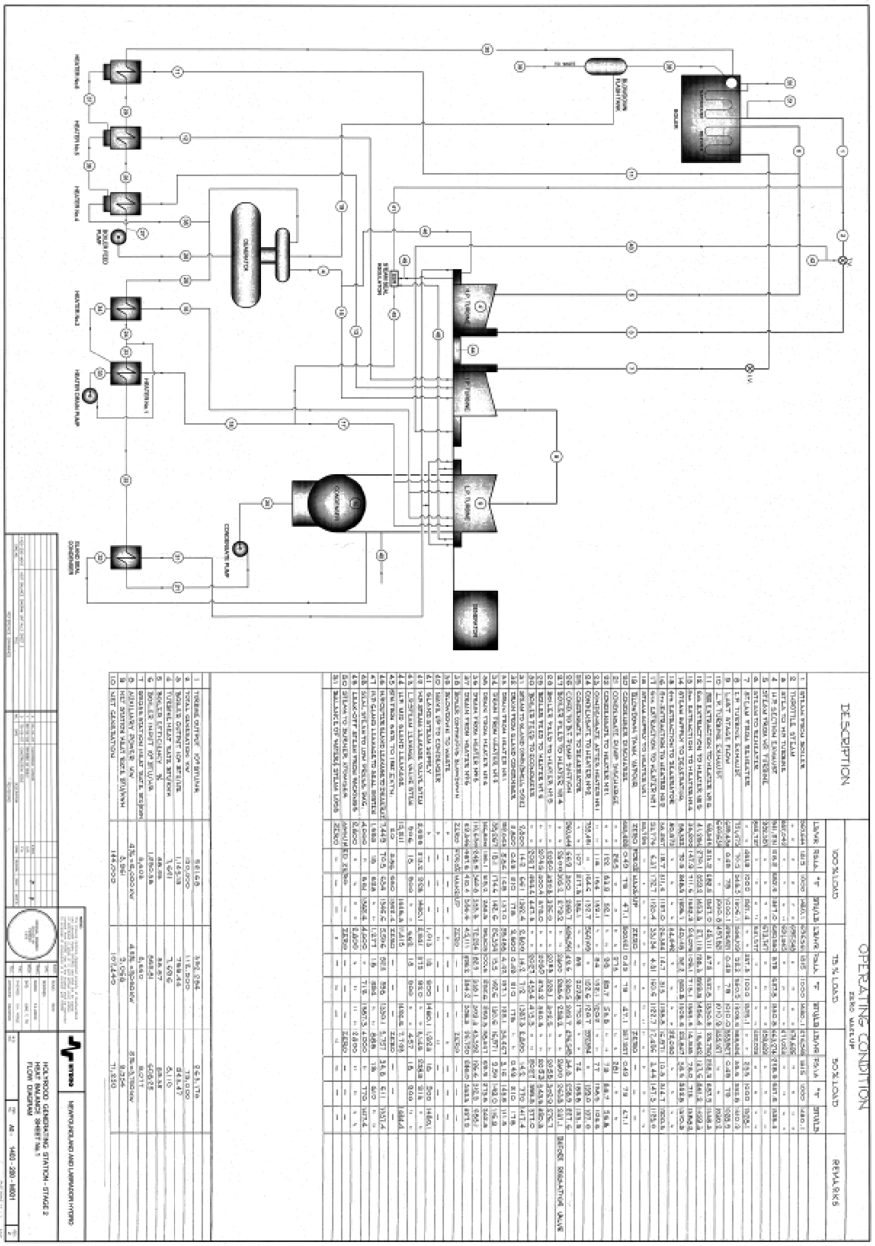
HEATER NO. 6 (CLOSED WITH D.C.)				
CONDITIONS AT H.P. TURB. EXHAUST		135.0	572.3	1313.12
STEAM TO HEATER (5.0 PC DELTA P)	15099	128.2		1313.12
FEEDWATER LEAVING (0 DEG TTD)	291800		346.3	321.46
FEEDWATER ENTERING DRAIN COOLER	291800		293.8	267.68
DRAINS LEAVING D.C. (10 DEG TD)	15099	128.2	303.8	273.71
HEATER NO. 5 (CLOSED WITH D.C.)				
TURBINE SHELL CONDITIONS		65.57	838.8	1450.61
STEAM TO HEATER (7.0 PC DELTA P)	8302	60.98		1450.61
FEEDWATER LEAVING (0 DEG TTD)	291800		293.8	267.68
FEEDWATER ENTERING DRAIN COOLER	291800		257.7	231.22
DRAINS ENTERING	15099			273.71
DRAINS LEAVING D.C. (10 DEG TD)	23401	60.98	267.7	236.66
no. 5	8302			
HEATER NO. 4 (CLOSED WITH D.C.)				
TURBINE SHELL CONDITIONS		39.88	717.2	1391.03
STEAM EXTRACTED FROM TURBINE	4100	39.88		1391.03
STEAM FROM 3-R PACKING LEAK	1775			1311.84
EXTRACTION STEAM (7.0 PC DELTA P)	5875	37.09		1367.10
FEEDWATER LEAVING (5 DEG TTD)	291800		257.7	231.22
FEEDWATER ENTERING DRAIN COOLER	291800		232.5	205.89
DRAINS ENTERING	23401			236.66
DRAINS LEAVING D.C. (10 DEG TD)	29276	37.09	242.5	210.99
FLOW FROM F.W. TO BOILER NO. 4	5875	2362.	232.5	205.89
FEEDWATER PUMP (12. BTU HEAT RISE)				
FEEDWATER LEAVING	291800	2362.	232.5	205.89
FEEDWATER ENTERING	291800		225.9	194.19
HEATER NO. 3 (OPEN)				
TURBINE SHELL CONDITIONS		20.69	570.9	1320.80
EXTRACTION STEAM (7 PC DELTA P)	6808	19.24		1320.80
FEEDWATER LEAVING	291800	19.24	225.9	194.19
FEEDWATER ENTERING	255717		194.0	162.27
DRAINS ENTERING	29276			210.99
HEATER NO. 2 (CLOSED WITH D.C.)				
TURBINE SHELL CONDITIONS		12.14	465.4	1271.18
STEAM TO HEATER (7.0 PC DELTA P)	11866	11.29		1271.18
FEEDWATER LEAVING (5 DEG TTD)	255717		194.0	162.27
FEEDWATER ENTERING DRAIN COOLER	255717		140.6	108.79
DRAINS LEAVING D.C. (10 DEG TD)	11866	11.29	150.6	118.57

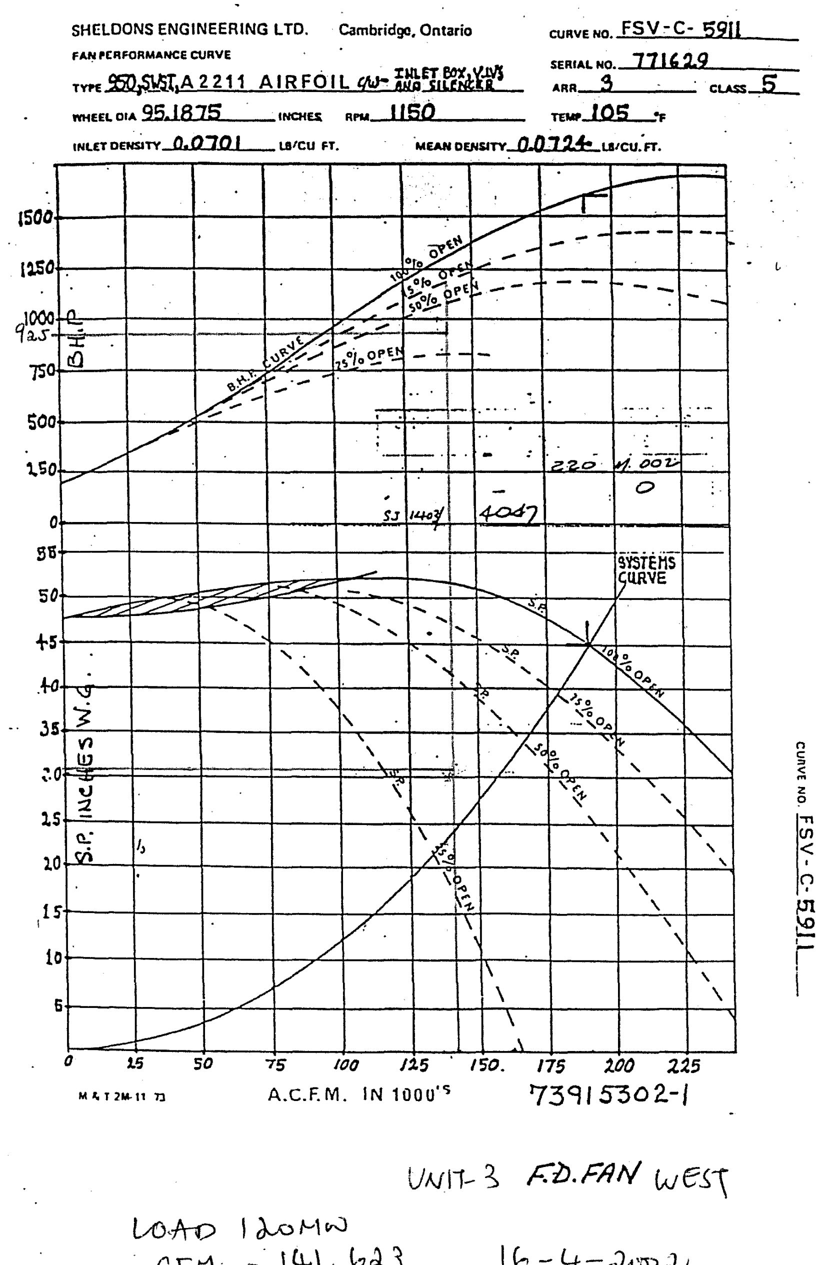
HEATER NO. 1 (PUMPED DRAINS)				
TURBINE SHELL CONDITIONS		3.546	251.5	1172.79
STEAM EXTRACTED FROM TURBINE	9635			1172.79
STEAM FROM STEAM SEAL DUMP	0			1399.65
STEAM TO HEATER (7 PC DELTA P)	9635	3.298		1172.79
FLOW FROM MAKEUP SOURCE	0			321.46
FLOW FROM FW. BELOW HEATER 1	0			321.46
DRAINS ENTERING	11866			118.57
DRAINS PUMPED TO FEEDWATER	21501	3.298	145.2	113.15
FEEDWATER AFTER DRAIN ENTRY	255717		140.6	108.79
FEEDWATER LEAVING (5 DEG TTD)	234216		140.2	108.39
FEEDWATER ENTERING	234216		96.3	64.53
STEAM SEAL REGULATOR				
FLOW FROM VALVE STEM PACKING	248			1477.70
FLOW FROM 3-R PACKING SEAL	583			1311.84
FLOW FROM 2-R PACKING SEAL	49			1320.80
FLOW TO 2-R PACKING SEAL	1336			1399.65
MAKE-UP FROM TURBINE INLET	456			1477.70
DUMP TO HEATER NO. 1 EXTR	0	3.546		1399.65
GLAND SEAL CONDENSER				
STEAM FROM 3-R PACKING VENT	189			1311.84
STEAM FROM 2-R PACKING VENT	284			1320.80
STEAM FROM 2-R PACKING VENT	479			1399.65
FEEDWATER LEAVING	234216		96.3	64.53
FEEDWATER ENTERING	234216		91.5	59.74
DRAINS TO CONDENSER	951			179.48
FLOW FROM F.W. TO HEATER NO. 1	0	3.298	91.5	321.46
FEEDWATER PUMP (0. BTU HEAT RISE)				
FEEDWATER LEAVING	234216	100.0	91.5	59.74
FEEDWATER ENTERING	234216		91.7	59.74
CONDENSER				
STEAM TO CONDENSER	116633	0.7367		1089.01
DRAINS ENTERING	951			
FEEDWATER LEAVING	234216	0.7367	91.7	59.74

8.3 B&W Boiler Performance Data Sheet (C/7391)

8.4 Unit #3 Heat Balance Diagram (NLH 1403-200-M001 Rev 2)



8.5 Unit #3 FD Fan Performance Curve (Sheldons Engineering)



8.6 ARVOS Replacement Hot End Heating Surfaces Performance (Unit #3)

Performance Tabulation	LAP-HOW1019	01/17/18
Selection Designation:	HOW-1019 Present	HOW-1019 Proposed
Model Number:	2-22.5-VI	2-22.5-VI
Element Configuration:	HE: 32.0" 22LA DU ND CE: 12.0" 22/20E NF6 FW	HE: 30.0" 22LA DN7™ ND CE: 12.0" 22/20E NF6 FW
Elevation:	100	100
Flows, LBS./HR.	Design	Design
AIR ENTERING	1,111,000	1,110,500
AIR LEAVING	1,000,000	1,000,000
GAS ENTERING	1,071,000	1,071,000
GAS LEAVING	1,182,000	1,181,500
Temperatures, DEG. F.		
AIR ENTERING	128.3	128.3
AIR LEAVING	560.	560.
GAS ENTERING	734.	734.
GAS LEAVING UNCORR.	362.	362.
GAS LEAVING CORR.	342.	342.
AVE COLD END TEMP	245.	245.
Pressures, IN.WC..		
PRESSURE DROP AIR	2.1	1.85
PRESSURE DROP GAS	2.85	2.5
HOT END DIFFERENTIAL	11.0	11.0
COLD END DIFFERENTIAL	15.95	15.35
RATIO OF SPECIFIC HEATS	0.923	0.923

Note: The information included herein is the proprietary and confidential property of ARVOS Ljungstrom LLC, and is not to be copied or disseminated without written permission from ARVOS Ljungstrom LLC. Performance tabulation is for reference only.

Holyrood Generating Station

Units Performance Review

November 2017 to April2018

2018-06-13

Background

Holyrood Generating Station Units 1 and 2 were commissioned in 1969/70 and Unit 3 in 1979. Thermal generating units are generally considered to have a useful lifespan for base load operation of about 30 years before major life extension actions are initiated. As no major life extension actions have been implemented at Holyrood, the three units can be considered to have reached the end of their useful lives. Despite this, the units continue to operate with a high degree of reliability, aided by the relatively low operating hours these units have accumulated. In recent years performance has deteriorated dramatically, most notably as an ability to achieve design maximum continuous rating (MCR) throughout the operating season. MCR for Unit 3 is 150 MW, although when new it achieved in excess of 160MW, due to design margins built into the equipment. Units 1 and 2 had a design MCR of 150 MW and were also capable of exceeding this when new due to design margins. In the 1980s a chance remark by a representative of the boiler manufacturer of Units 1 and 2, about the significant design margin included in those boilers, motivated Hydro to investigate the feasibility of increasing the MCR of these two units. This was eventually implemented and the MCR of these two units was revised to 175MW, using the built in design margins and by replacing and modifying other components. Indeed, testing revealed that both units could achieve almost 180 MW. However experience with the units over several years following modification indicated that the MCR should be reduced. The relatively small size of the Island electrical system dictated that when the units were started in the Fall at the beginning of each operating season, they would operate for extended periods at low loads, which caused fouling of convective heat exchange surfaces in the boiler. When the units were called upon to produce high output,175 MW could not be achieved due to fouling. Thus the MCR for Units 1 and 2 was reduced to 170 MW.

In recent years the maximum capability of all three units has deteriorated markedly during each operating season. In December 2017 a Project Team was assembled, including personnel from Hydro’s Engineering group, Holyrood Generating Station, Babcock and Wilcox (B&W is Hydro’s current prime maintenance and technical support contractor for Holyrood) and JEM Consulting. The team was tasked with identifying the causes for the unit deratings and determining possible remedies. A major consideration in this exercise is the fact that this plant will be retired in near future, probably after only two more operating seasons, thus major expenditures cannot be considered. The team met on numerous occasions to consider information gathered, to direct investigations and to consider results. This document summarizes the activities and findings for the period ending 2018-04-30.

Review Scope

The initial scope for JEM Consulting was to provide technical advice and assistance to Hydro Engineering personnel. This has involved participating in meetings, reviewing operating data and other information to assist in identifying causes for the deterioration in performance. It was identified that it would be useful to compare current operating data with original design, as a way to pinpoint areas of performance degradation. To this end Figure 1 was prepared, based on operating data for Unit 2.

Note: Design air and flue gas pressures are in Pa, measurements are in kPa									
	Design	<< Interpolated >>		Design	Design	2017-11-28		2016-10-18	
	MCR			75%	50%	Unit 2	Measured/	Unit 2	Measured/
MW	175	170	160	131.25	87.5	160	Design	170.4	Design
Steam Generated kg/s	147.1	142.9	134.5	110.3	73.5	141.3		145	
Drum Press kPa	14162	14109.2	14003.6	13700	13287				
SH Outlet Press kPa	13480	13459.4	13418.3	13300	13094	12900		12965	
SH Outlet Temp C	541	541.0	541.0	541	541	533		542	
RH Outlet Press kPa	3185	3093.7	2911.1	2386	1696			3060	
RH Inlet Temp C	353	350.3	344.8	329	308	346		354	
RH Outlet Temp C	541	540.8	540.3	539	528	494		512	
Economizer Flow	147.6	143.2	134.3	108.9	75.5				
Econ Inlet Water C	240	238.3	234.9	225	205				
Econ Outlet Water C	302	301.1	299.3	294	270				
SH Spray kgs	2.3	2.5	2.8	3.8	0	2.8		10	
RH Spray kgs	0	0.0	0.0	0	0				
Flue Gas Pressure Pa									
Furnace Outlet	2816	2722.3	2534.9	1996	309	5.1	201%	5	184%
SH Outlet	2741	2649.8	2467.4	1943	301				
RH Outlet	2569	2483.4	2312.2	1820	282	4.5		4.2	
SH + RH dp	0.247	0.239	0.223	0.176	0.027	0.6	0.4	0.8	0.8
Econ Outlet	1595	1542.0	1435.9	1131	175	2.8		2.6	
Econ diff press	0.974	0.941	0.876	0.689	0.107	1.7	194%	1.6	170%
Air Heater Outlet	324	313.3	291.8	230	36				
Air Heater diff press Pa	1.271	1.229	1.144	0.901	0.139	2.48	217%		
Flue Gas Temperature C									
Furnace Outlet	1421	1410.9	1390.8	1333	1177				
Final SH Outlet	1124	1115.7	1099.0	1051	919				
Primary SH Outlet	570	566.1	558.3	536	475				
RH Outlet	827	820.3	806.8	768	665				
Econ Outlet	323	320.3	314.8	299	262	363			
Air Heater Outlet	172	171.1	169.3	164	151	180			
Econ dp Temp C	151	149.1714	145.5143	135	111	183			
Air Pa									
Air Heater Inlet	6006	5850.1	5538.3	4642	2977	8.14		8.1	2.2
Air Heater Outlet	5158	5030.3	4775.0	4041	2678	6.41		6.36	1.3
Air Heater Air side dp	0.848	0.819771	0.763314	0.601	0.299	1.73	227%	1.75	213%
Windbox	4137	4043.3	3855.9	3317	2317				
Furnace Press	2816	2722.3	2534.9	1996	997	5		5	
Windbox/Furnace dp	1.321	1.321	1.321	1.321	1.32	1.3		1.36	
Air C									
Air Heater Inlet	54	55.0	57.1	63	76	26		51	
Air Heater Outlet	233	231.7	229.2	222	204	232		253	
						-206			
Fuel kg/s	10.99	10.7	10.1	8.5	5.76	10.53		11.5	

Figure 1

It quickly became obvious that high pressure drops across the economizer and regenerative air heaters were severely restricting performance. It was also noted that other operating parameters throughout the power cycle were also off design, but not by amounts which would degrade performance to as great an extent as the pressure drops across the economizer and regenerative air heaters. It was also noted that although the percentage pressure drop increase across the economizer and regenerative air heater are of similar magnitude, the actual increase in pressure drop is greater across the regenerative air heater. Therefore, it appeared that there would be a greater benefit in first addressing the pressure drop across the regenerative air heater. At this time B&W was tasked with having its engineering group use its computer based mathematical steam plant modeling capability to analyse the performance of the entire power cycle in greater detail. JEM Consulting concentrated on the performance history of the regenerative air heaters and economizers and factors which may have contributed to the deterioration in their performance.

Findings

Fuel

As the primary cause of unit deratings appears to be boiler fouling, fuel quality is an important consideration. Fuel analysis for deliveries between January 2008 and December 2017 were obtained. This covers the period from before performance degradation began to the present. Fuel constituents which are likely to contribute to fouling were reviewed and the constituents likely to contribute to fouling were plotted in the graphs below.

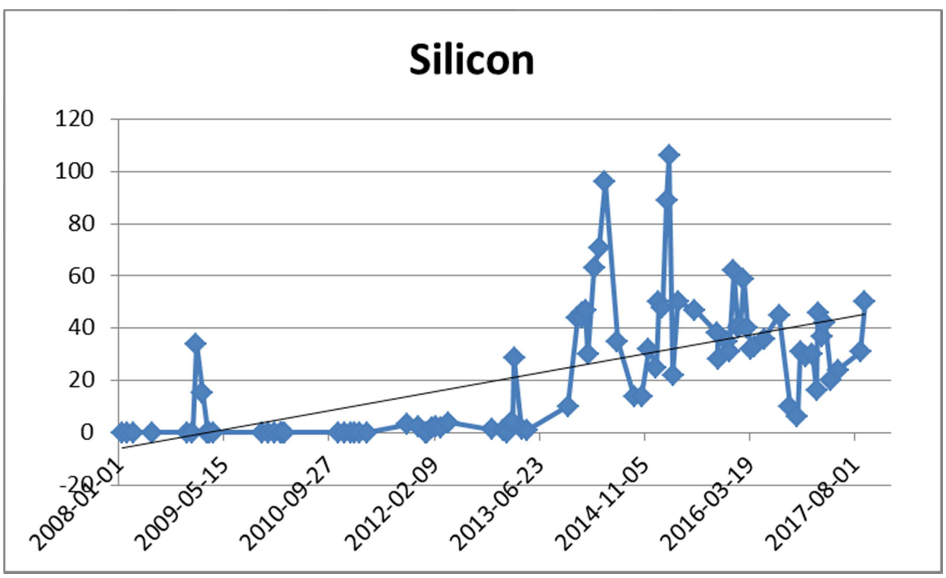


Figure 2

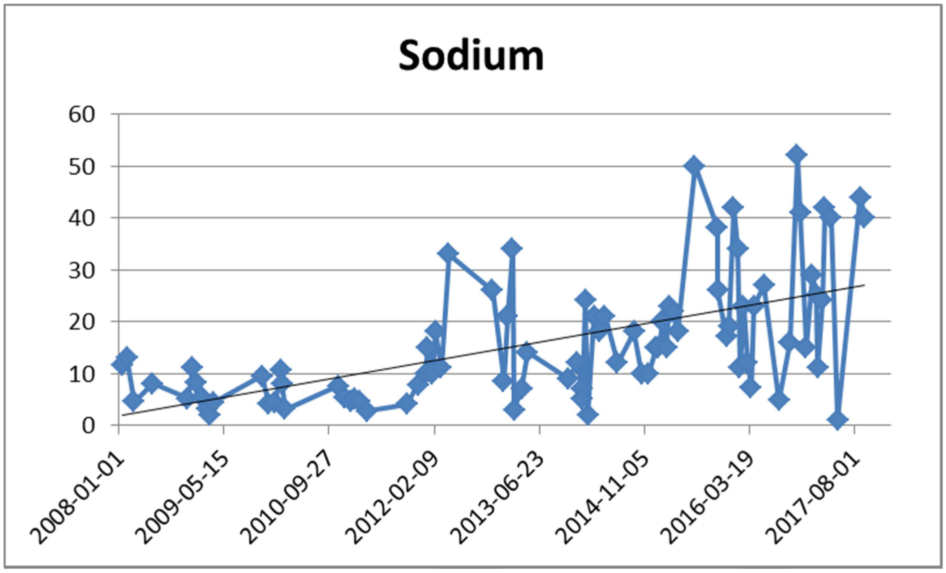


Figure 3

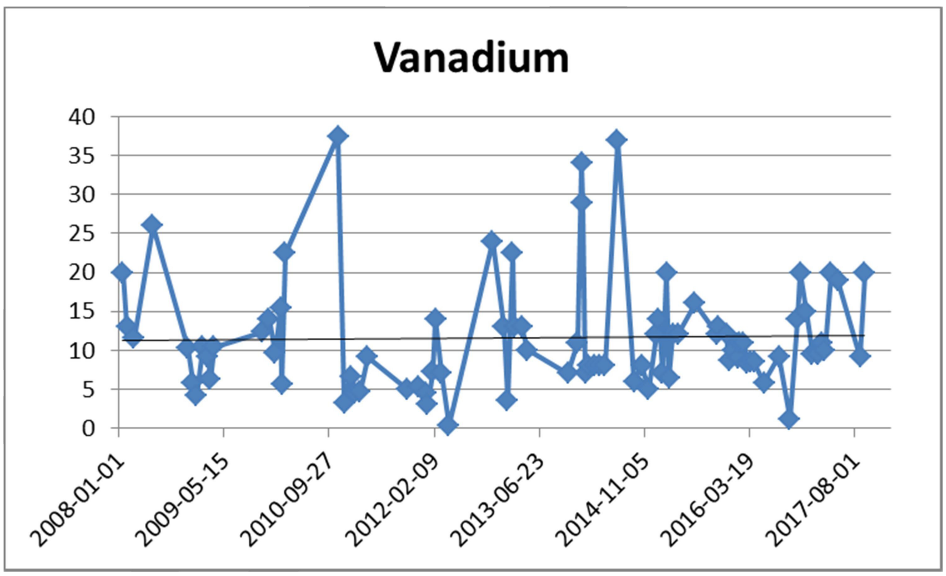


Figure 4

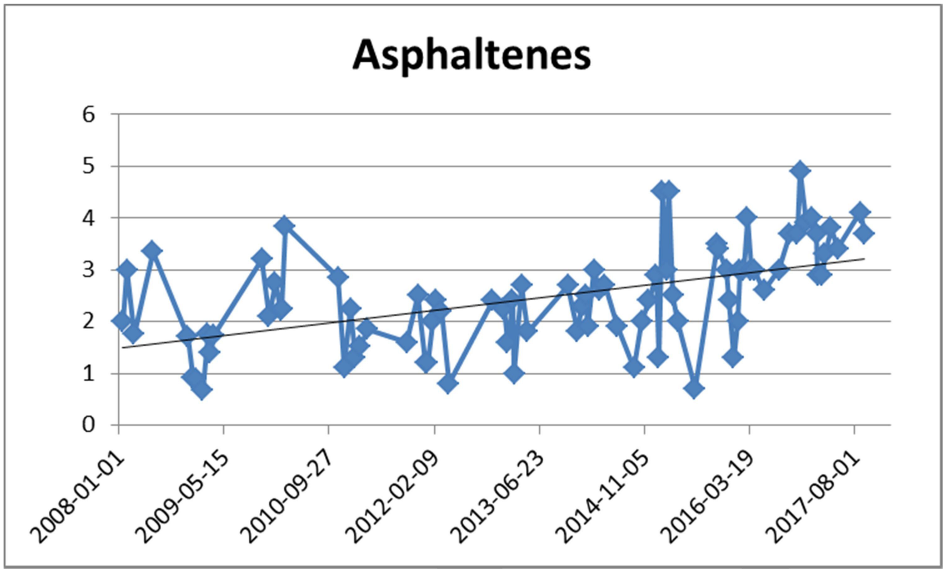


Figure 5

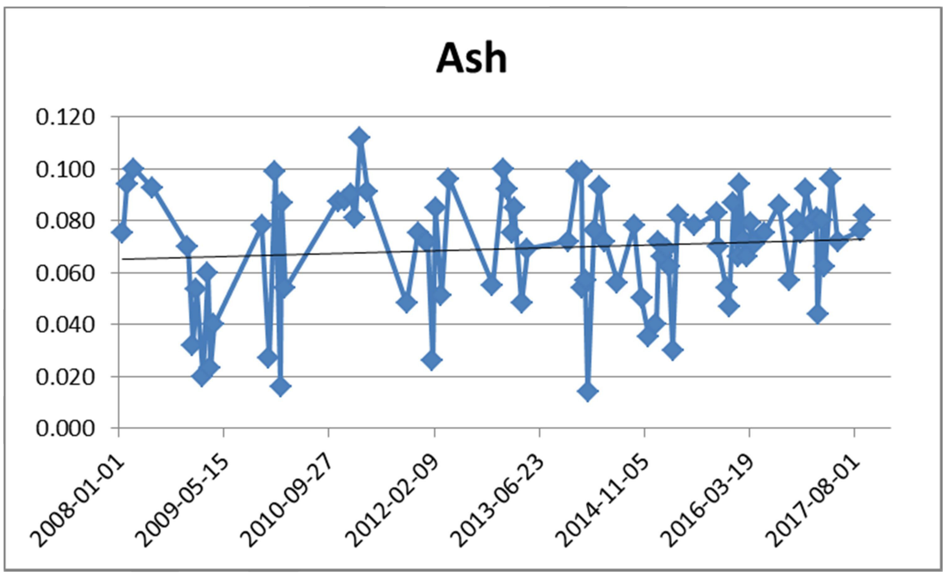


Figure 6

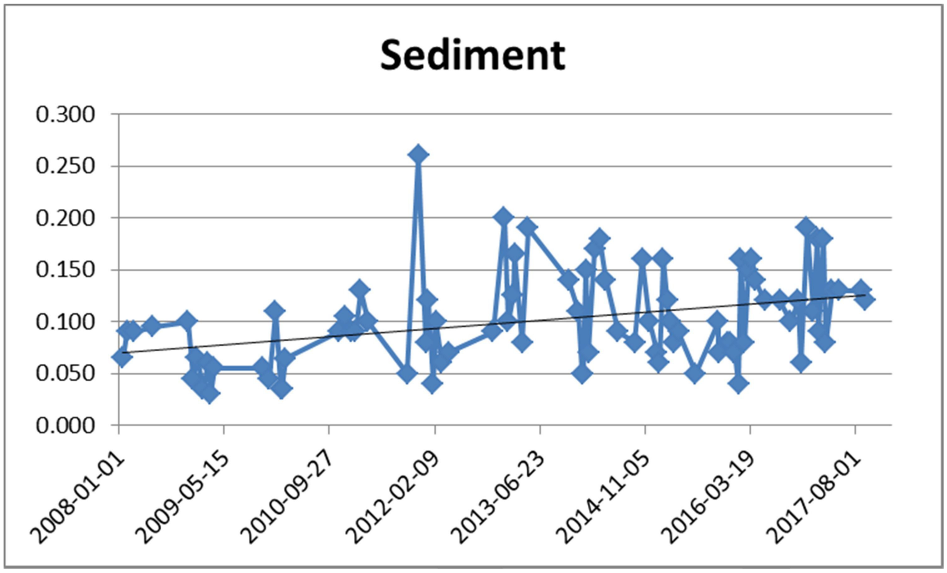


Figure 7

It should be noted that for almost all deliveries the fuel supplied met the specification, that exceedances were few and relatively small. However, as the trend lines in the graphs indicate, fuel quality has deteriorated with regards to constituents which tend to contribute to fouling and as will be seen in the pressure drop graphs, increased pressure drop correlates with a deterioration in fuel quality.

Regenerative Air Heater and Economizer Fouling

Unit performance data was obtained from Etapro to identify how fouling has changed in recent years. As with fuel data, the period from January 2008 and December 2017 was used to review the period from before performance degradation began, to the present. Unfortunately, there is a data gap in Etapro from Spring 2011 to Fall 2014 for which no data is available. The methodology used for each unit was to select a unit load at which data was available in each year in the early Fall (unit still clean after summer maintenance) and Spring (unit fouled after the operating season). This was done so that the air and gas flows would be similar for both the clean and fouled conditions. The data gap is unfortunate but it does cover the period before the unit deratings begin and therefore probably does not affect the inferences drawn from the data. Unit 1 data was obtained at150 MW, Unit 2 at120 MW and Unit 3 at 140 MW. The results are presented in the graphs below. Any gaps in the graphs, other than the Spring 2011 to Fall 2014 period, are due to the preferred unit loading not being available at a particular time.

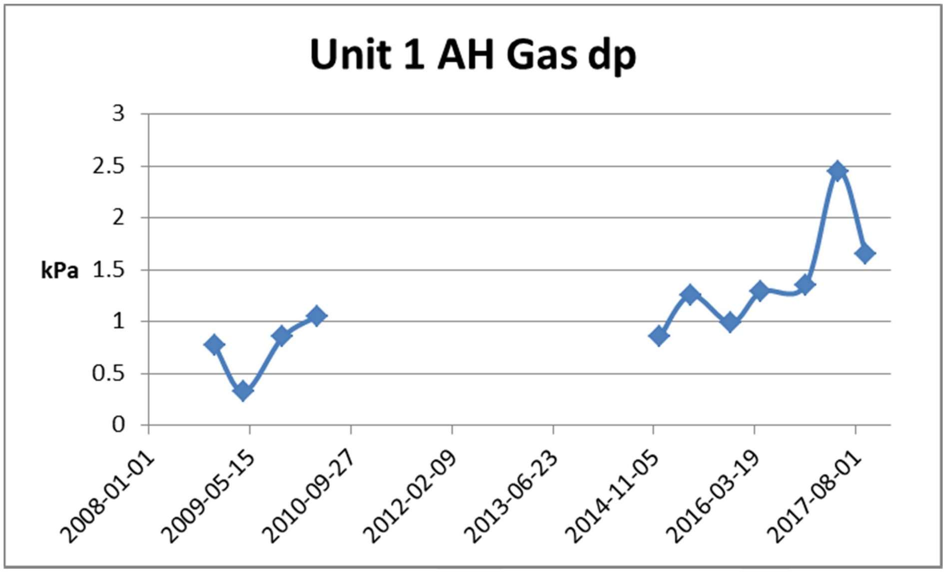


Figure 8

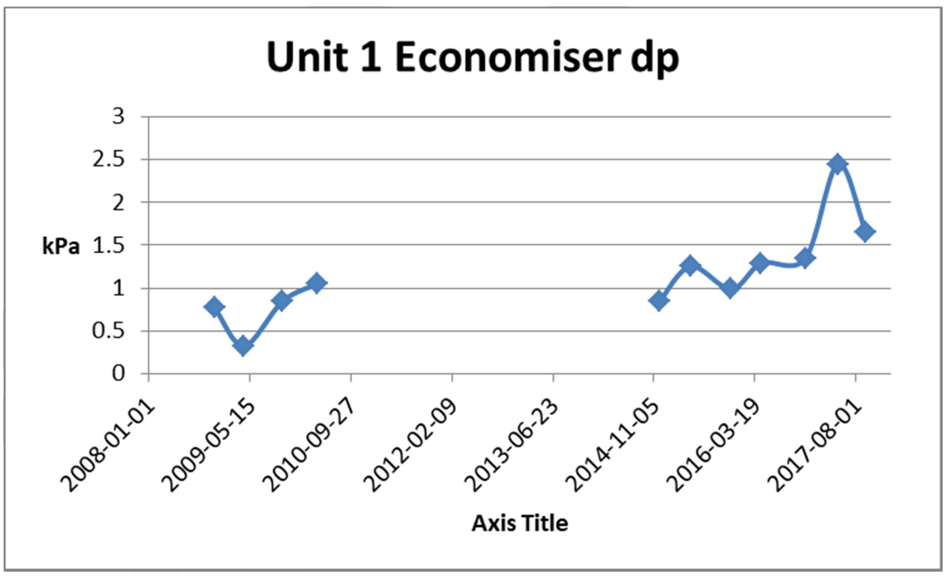


Figure 9

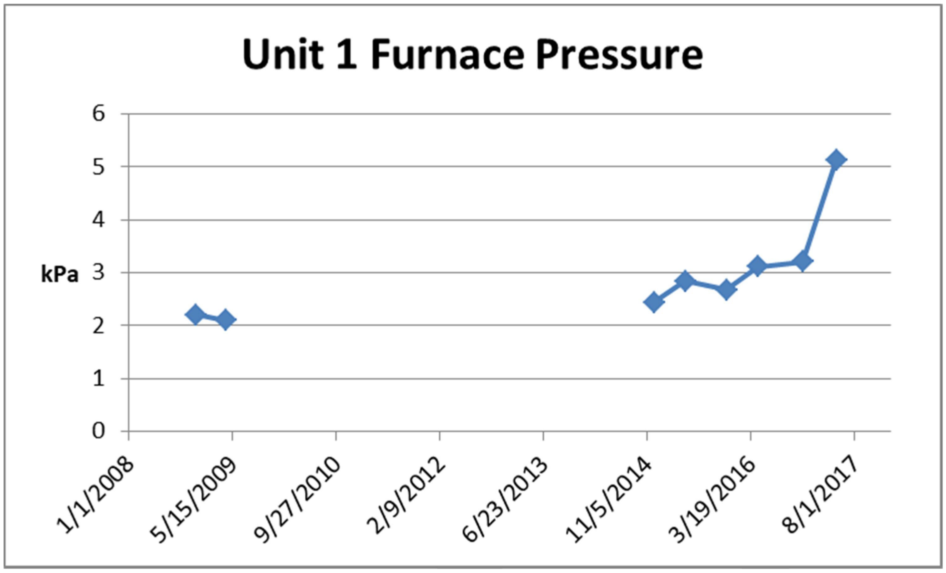


Figure 10

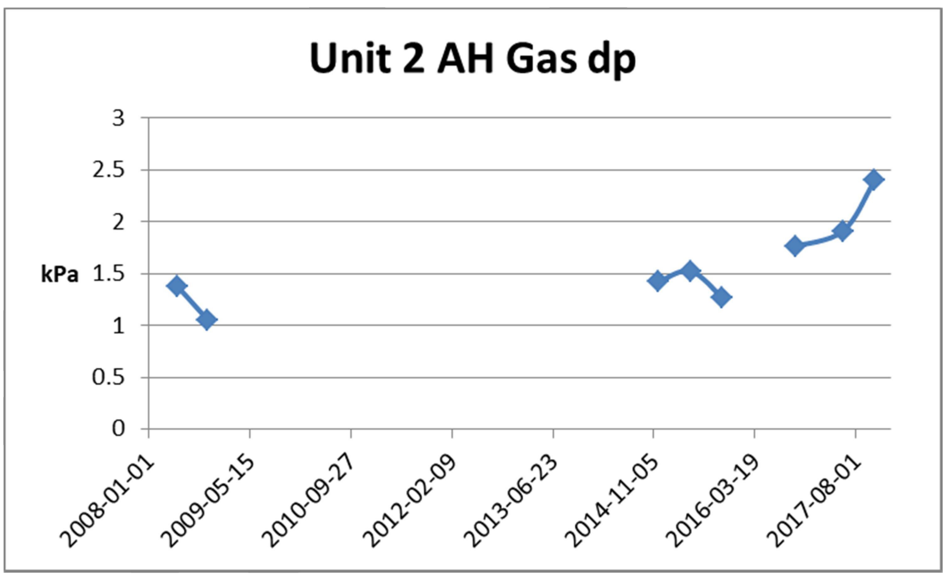


Figure 11

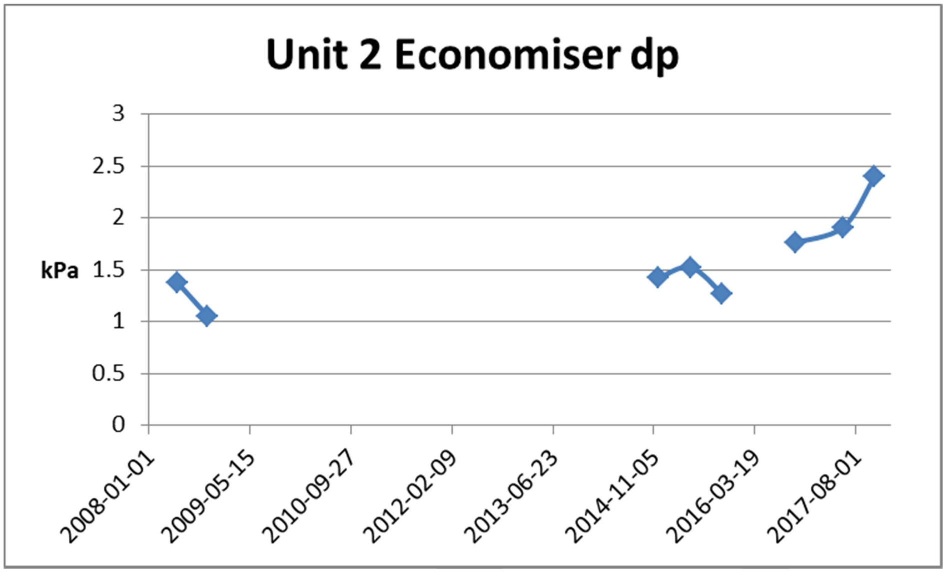


Figure 12

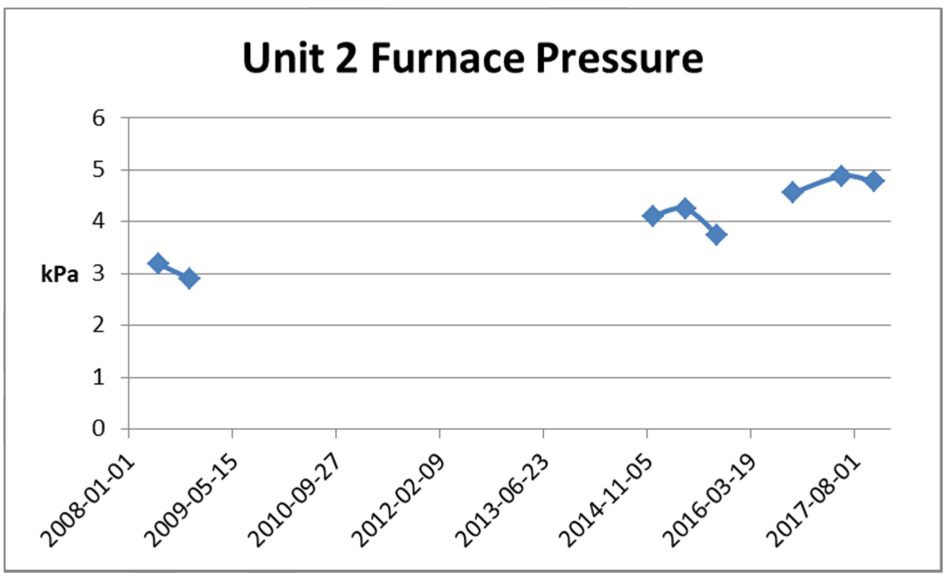


Figure 13

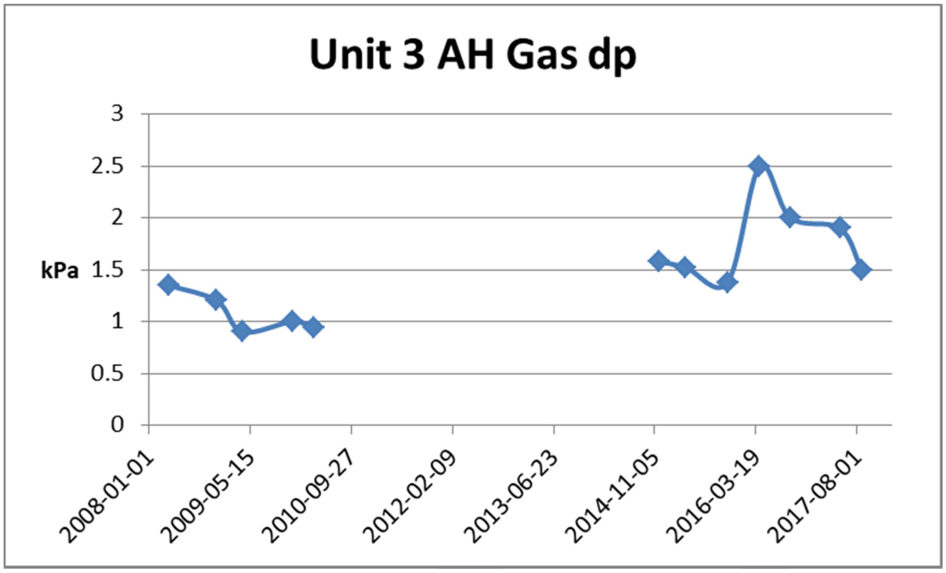


Figure 14

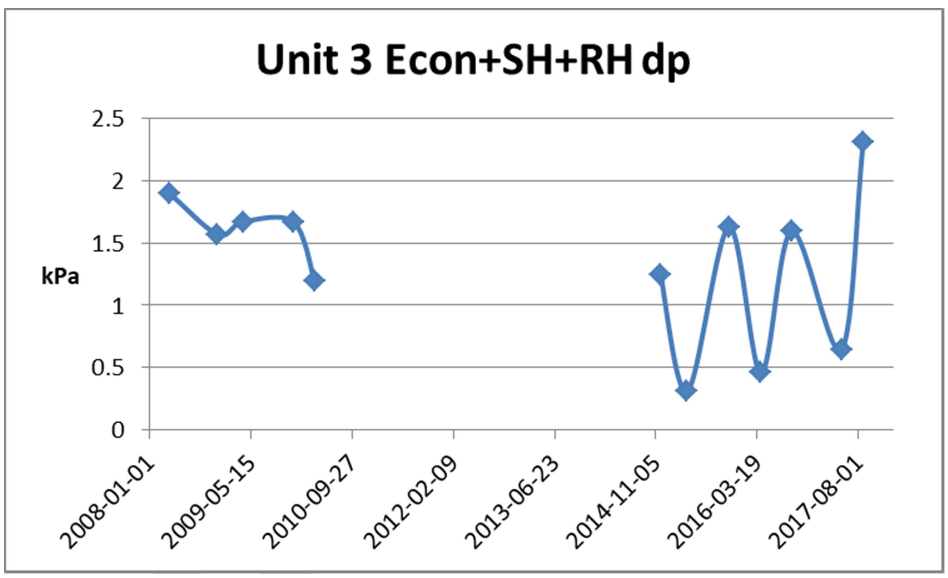


Figure 15 (Note that Economizer only data is not available for Unit 3)

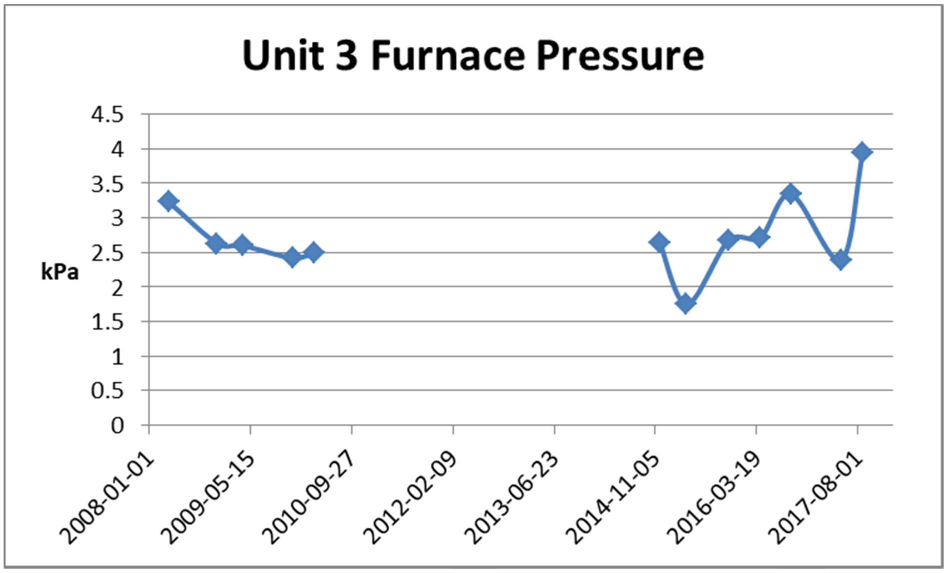


Figure 16

It is unfortunate that such a large gap exists in the Etapro data. Anecdotal information suggests that the boiler pressure drop increases started in the period after the data gap and the graphed data tend to support this suggestion. The graphs clearly show the increased pressure drop at the end of each operating season, which occurs despite performing air heater washes. The graphs also show a reduction in pressure drop following the summer maintenance operations, when the boilers are cleaned. From 2014 to 2017, the graphs demonstrate that, despite thorough cleaning during the summer outages, boiler pressure drop has steadily increased.

Fuel Additives

Fuel additives (primarily MgO) have been used at Holyrood to condition ash. The additive combines with the fuel produced ash to render it more friable and therefore easier to clean from convective surfaces using the sootblowers and manually during summer maintenance. The benefits of ash conditioning are most pronounced in the back end of the boiler (economizer, regenerative air heater and steam coil air heater). Fuel additive use ceased on Unit 1 in May 2014, on Unit 2 in June 2012 and on Unit 3 in December 2014. Cessation of MgO injection correlates with an increase in boiler pressure drop.

Gas Recirculation Fans

Units 1 and 2 were originally equipped with gas recirculation fans, which recirculated flue gases from a point between the economizer and the regenerative air heater to the bottom of the boiler furnace. The purpose of these fans was to improve temperature control at low loads, particularly in the back end of the boilers and to increase gas velocity at low loads. They proved to be a very high maintenance item and when it was concluded in the late 1970s that the three units would spend little time at low loads in the future, they were removed.

Sootblowing

It was discovered that at times sootblowing steam may be saturated, or even contain significant quantities of water, which will decrease the effectiveness of sootblowing, particularly in the back end of the boilers.

Conclusions:

It was concluded that the boilers had become derated primarily because of fouling in the regenerative air heaters and economizers, caused by a combination of poorer fuel quality, cessation of MgO injection and problems with sootblowing.

The Project Team reviewed all the information available and concluded that boiler back end fouling (economizer and regenerative air heater) were likely the principal causes of performance deterioration. It was also recognized that there was deterioration of boiler performance in other areas (eg, Reheat temperature) so it was decided to proceed with a more detailed analysis of the power cycle.

B&W Investigation

B&W was engaged to provide specialized personnel and to utilize their computer based mathematical boiler and thermal power cycle model to review performance data to identify all possible problem areas. A report titled “Newfoundland and Labrador Hydro (NLH) Holyrood Units #1, #2, #3 Performance Study Unit Capacity Limitations Ref No: B&W Project 312C Rev 02, April 15 / 2018” details their findings and recommendations. Readers are directed to that report for details. The findings briefly summarised below, using figures from the report.

Unit 1

The B&W analysis identified the primary sources of performance degradation and their relative affects on the capacity of the unit. Figure 17 below from the report presents their conclusions.

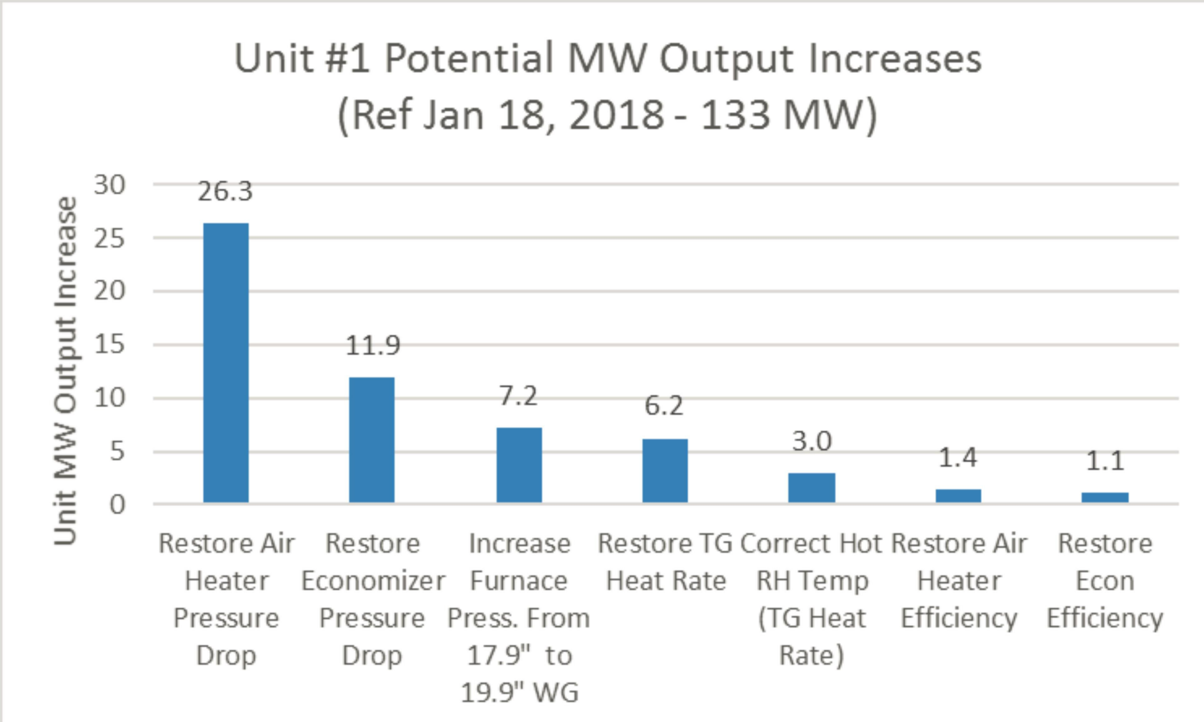


Figure 17

Figure 17 indicates that, as suspected, the two principal contributors to the inability of Unit 1 to achieve rated output are fouling of the regenerative air heater and economizer. Fouling of the regenerative air heater can be corrected by cleaning or replacing the air heater baskets and fouling of the economizer can be corrected by cleaning economizer tubing. Both these activities are relatively simple to implement and can be performed within normal planned outage schedules.

The next significant cause, maximum allowable furnace pressure, was considered but rejected. Implementing this change would require a structural analysis of the boiler and would likely require reinforcement of the boiler gas pressure envelope. This would require extensive construction activities requiring a lengthy outage and would involve recertification of the boiler design with the regulatory authority and Hydro's insurer. Given the relatively small gain in capacity compared to the two principal causes, the expected high cost and extensive outage required to implement, this was not considered further.

The fourth significant cause of reduction in output results from deterioration of the turbine generator, caused by wear and deposits within the steam path of the machine. This is normal deterioration which occurs over time and correcting this would involve a complete overhaul. Given the anticipated short remaining required operating life for this turbine generator (two operating seasons), the high cost of an overhaul and the extensive outage required, this was not considered further.

The three remaining causes (Hot reheat temperature, air heater efficiency, economizer efficiency) are all relatively small and will be either partially or completely corrected by correcting the two principal problems and by boiler cleaning which will be performed during the normal outages during the summer of 2018.

Unit 2

The B&W analysis identified the primary sources of performance degradation and their relative effect on the capacity of the unit. Figure 18 below from the report presents their conclusions.

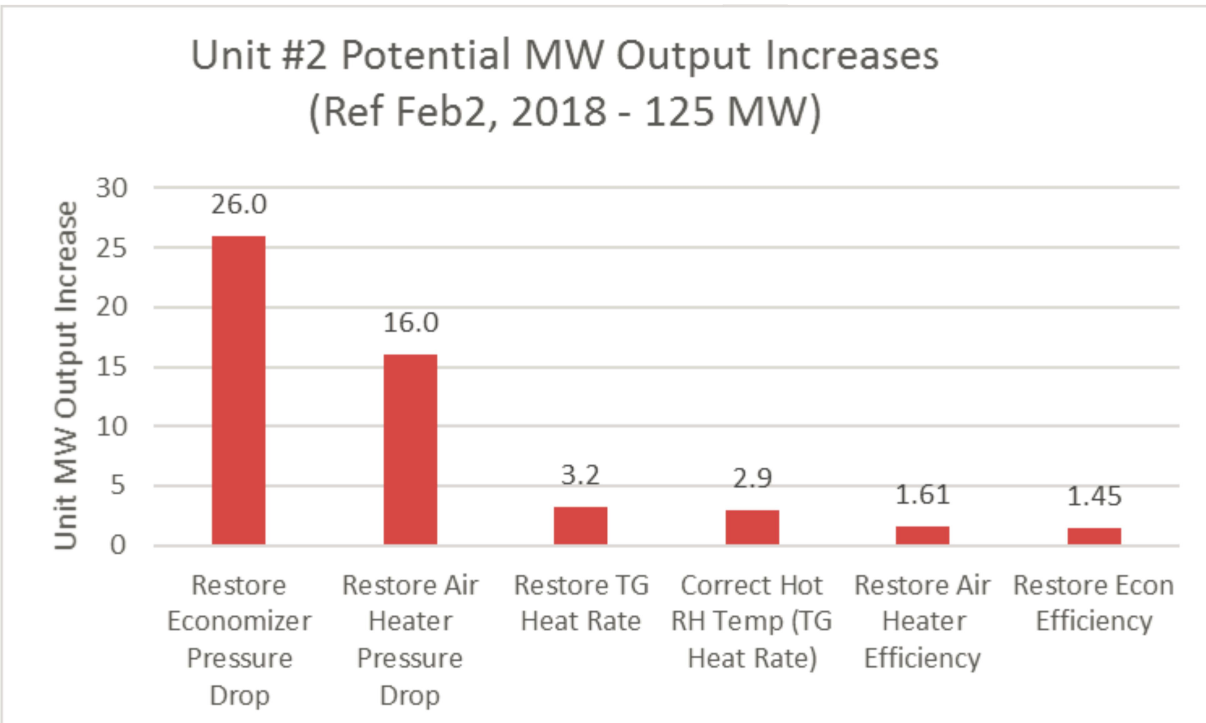


Figure 18

Figure 18 indicates that the problems with Unit 2 are essentially identical to those of Unit 1 and the actions which are practical to implement to correct them are the same.

Unit 3

The B&W analysis identified the primary sources of performance degradation and their relative effect on the capacity of the unit. Figure 19 below from the report presents their conclusions.

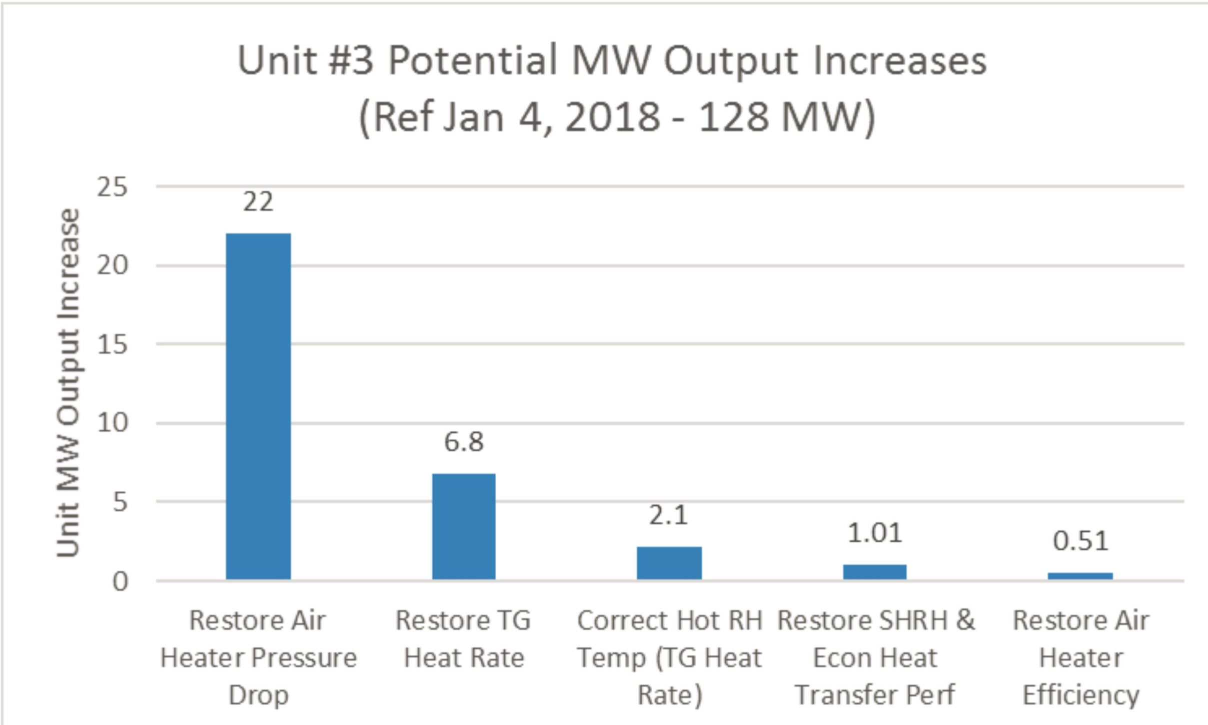


Figure 19

Figure 19 indicates that, as with Units 1 and 2, the principal cause of loss of capacity for Unit 3 is fouling of the regenerative air heater. What is different about Unit 3 is that fouling of the economizer does play a less significant role in the inability of this unit to reach rated capacity. It is concluded that this is because the economizer of Unit three is formed from bare tubes while those of Units 1 and 2 are formed from finned tubing, which is more prone to fouling and more difficult to clean, both while on line using sootblowers and offline using manual methods. Discussions with operating staff revealed that there is a duct vibration problem which is preventing the forced draft fans being used to full capacity and which is contributing to the loss of unit capacity.

Remediation Plan

Information and analytical results from all sources were considered by the Project Team and the following activities have been identified to restore unit capacities:

1. Reduce the pressure drop across the regenerative air heaters of Units 1, 2 and 3. The ability to thoroughly clean the high temperature air heater baskets (hot end baskets) was tested on Unit 1 using very high pressure water wash (12,500 psi) and the results were disappointing. The viability of chemical cleaning of the air heater baskets has been investigated. It was determined that the only way to thoroughly clean the baskets would be by the removal of baskets and immersion in a chemical bath. It was estimated that this process would be more costly than simply replacing the baskets and it was decided to purchase new baskets for replacement during the 2018 maintenance outages.

2. Reduce the pressure drop across the economizers on Units 1 and 2. Previously, cleaning has been performed using pressure washers, which removes the majority of deposits but does not completely clean the heat exchange surfaces. A chemical cleaning process was identified and will be used to clean the economizers on Units 1 and 2 during the 2018 maintenance outages. This cleaning is performed using a high-pressure water jet containing a chemical to soften and dissolve fouling deposits on the economizer tubes. The deposits can then be removed by the mechanical action of the high-pressure water jet.
3. Replace the regenerative air heater sector plate liners and seals on Unit 3 to minimize air leakage.
4. After replacement of hot air heater baskets (all units) and chemical cleaning of economizers (Units 1 and 2), reinstate MgO fuel oil additive injection on all three units to reduce the potential for future low temperature fouling. Steps have already been taken to recommission the existing equipment and a supply of fuel additive has been obtained.
5. Improve the condition of the steam to the sootblowers to ensure that it is as dry and hot as possible. New drip leg steam traps have been installed to ensure efficient removal of condensate and the soot blowing procedure has been modified to maximize the effectiveness of sootblowing.
6. Increase the frequency of sootblowing, especially at low loads, to reduce deposit formation,
7. Use burner tilts within manufacturers recommended range as required to increase hot reheat temperatures.
8. For Unit 3 only, investigate if the current operating restrictions placed on the FD fans, caused by air duct vibrations under certain operating conditions, can be removed.
9. Maintain a minimum regenerative air heater average cold end temperature of 212F, to discourage deposit formation.
10. Maintain fuel oil temperature at optimum value to control viscosity thereby ensuring efficient atomization. Babcock and Wilcox recommends that for fuel oil viscosities up to 200 SFS@122 F a temperature of 230F for Units 1 and 2 and 225F for Unit 3, to improve combustion efficiency.
11. Improve fuel quality within the limits of the current contract specification. A discussion was held with the current fuel supplier on 2018-02-01, which revealed that they have had difficulty properly blending fuels in recent years. They previously sourced fuel from the US. Much of the fuel is from shale deposits which, when processed through US refineries using catalytic crackers, which produce higher Sodium and Silica levels, both of which contribute to fouling. They committed to investigating sourcing fuel from European refineries, which they have done and the first two deliveries received have been of better quality. They also commented that they had heard that our previous fuel supplier used pitch and possibly used lubricating oil when blending fuel, which may have contributed to reducing fuel quality, if true.
12. To the greatest extent possible, reduce the amount of time all three units spend at low load.

A number of other recommendations made by Babcock and Wilcox were considered but were rejected:

1. Perform overhauls on the turbine-generator sets to improve their performance and restore efficiency. This was considered and rejected due to the very high cost and lengthy outages required compared to other actions identified.
2. Increase the maximum furnace operating pressure. This was considered and rejected due to the anticipated high cost and lengthy outage required to reinforce the boiler structural elements.

As of the date of preparation of this report, activities are in progress to implement the remedial actions identified. Mathematical modeling by Babcock and Wilcox indicates that if these actions are completed and the design performance of air heaters and economizers has been restored, rated output of all three units should be achievable. As each unit is returned to service it should be load tested to verify the efficacy of the work performed. Hydro expects to restore close to full unit capacity following the combined efforts of air heater hot end baskets replacement on all units, planned chemical cleaning of the economizers on Units 1 and 2 and replacement of the Unit 3 air heater sector plate liners and seals on Unit 3 during the 2018 annual maintenance outage. The chemical cleaning of the economizer is a new activity for Hydro and while expectations are that it will be effective, the exact outcome following cleaning and therefore the resulting maximum capacity that will be attained, will be dependent on the effectiveness of this heretofore untried economizer cleaning method.

It should be noted that all three units are sensitive to fouling of the heat exchange surfaces, but especially Units 1 and 2 (original design margins were exploited when these units were rerated in the 1990s). Operators must be diligent to ensure that the highest degree of cleanliness is maintained if rated capacity is to be retained throughout the operating season. This requires special attention by operators to:

1. Reheat temperature. Maintaining design operating temperature improves unit efficiency, reducing both fuel consumption and combustion air requirements.
2. Minimizing operation at low loads. Low load operation is a major contributor to boiler fouling, especially in the back end of the boiler where the fouling occurred which caused the derating of the three units.
3. Sootblowing must be performed more frequently to maintain boiler cleanliness.
4. The sootblowing procedure must include steps to remove moisture from the sootblower piping to ensure that dry hot steam reaches the sootblowers.
5. The minimum average cold end temperature (ACET) recommended by Babcock and Wilcox must be achieved under all operating conditions to maintain the cleanliness of the regenerative air heaters.

6. Fuel temperature recommendations must be followed to ensure efficient fuel atomization.
7. The MgO injection system must be operated at all times. Plugging of the feed equipment must be corrected immediately.

John Mallam
JEM Consulting Ltd.

PENNECON

DOCUMENT NUMBER:	19-PEHS-NL-DOC-049, Rev. 0
DOCUMENT TITLE:	Documentation Package
PROJECT:	Service/Maintenance on Unit #1
PHS REFERENCE NUMBER:	HSA005177
PHS CONTACT NAME:	Dave Barnes
CLIENT:	NL Hydro
CLIENT PURCHASE ORDER:	N/A

0	4-Mar-19	Original Issue	K. Dunphy	D. Barnes	E. Knox
REVISION	**DATE**	**DESCRIPTION**	**ORIGINATOR**	**CHECKED BY**	**APPROVED BY**

Table of Contents

PENNECON

1.0 Cylinder Strip & Assess Sheets

PENNECON

ISO 9001:2008

Cylinder Sheet

Page _____ of 5	**Work Order No.:HSA005177**
	Customer Reference No.:

1. CUSTOMER INFORMATION

Date: November 10, 2018	Contact:
Customer: NL Hydro	Contact Phone No.:
Address:	Customer Stock Code No.:

Customer Instructions/Notes: Strip and assess "throttle" cylinder from unit #1.

Allocated To: Adam G/Chris K	**Date: Nov 10th, 2018**

2. NAMEPLATE DATA / RECEIVING INSPECTION

Bore ∅ N/A	[x] Hydraulic	[ ] Pneumatic	[ ] Welded
Stroke N/A	[x] Tie Rod	[ ] Other	
Rod ∅ N/A			

Manufacturer:N/A	Model No.:N/A
Unit No.:N/A	Serial No.:N/A

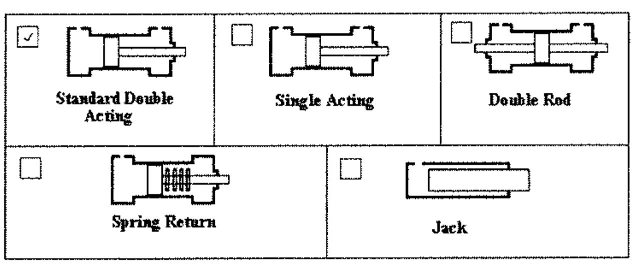
General Condition of Equipment:	[x] Dirty	[x] Oily	[ ] Rusty	[ ] Clean

List any Missing, Broken or Damaged Parts: Name tag/ Data plate is missing.

Other/Description: Cylinder is in good overall condition, however there appears to be very little resistance between the seals and the barrel. The rod can be pushed in/pulled out and rotated it very easily.

Unit Location:	[x] Unit Tagged	[x] Photography
Receiving Inspection Completed By: Adam G/ Chris K		**Date: Nov 10th, 2018**

3. INITIAL INSPECTION



[ ] Indexed for Disassembly	[x] Job Unit Stamped

CYLINDER MOUNTING

Tie Rod Extended		
[ ] Head End	[ ] Base End	[ ] Both Ends
Trunnion		
[ ] Head End	[ ] Base End	[ ] Both Ends
Lugs		
[ ] Side	[ ] Side End	[ ] Center Line

PENNECON

ISO 9001:2008

Cylinder Sheet

Page _____ of 5	**Work Order No.:HSA005177**

Base Flange

☐ Square	☑ Rectangle

Head Flange

☐ Square	☑ Rectangle

Clevis (Male/Female)

☐ Fixed	☐ Detachable	
	☐ Other	☐ Side End Angles

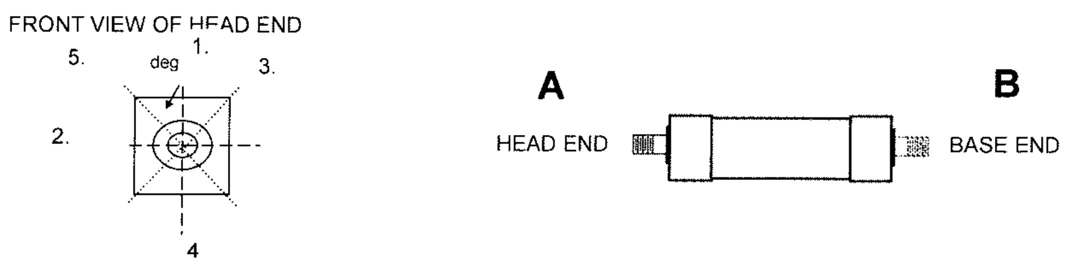
Rod End Mounting (e.g. rod eye, spherical brg, etc):

Technician: Adam G/Chris K	**Date: Nov 10th, 2018**

4. PORT / FITTING IDENTIFICATION

☐ Double Ended Cylinder

Size/Thread (A):	Size/Thread (B):



PIN TO PIN DIMENSIONS

Closed: 35" inches	Open: 48" inches	Stoke: 13" inches

HEAD END

Port Size:	Location(i.e.1-5):	Port Type:
Fittings:	Size:	Type:
Hoses:	Size:	Type:

BASE END

Port Size:	Location(i.e.1-5):	Port Type:
Fittings:	Size:	Type:
Hoses:	Size:	Type:

Valve(s) with Cylinder:	☐ Yes	☑ No	
Model No.: N/A		Type: N/A	
Valves Checked:	☐ Repair	☐ Replace	☑ Not Applicable

Comments/Notes: This cylinder is flange mounted to an external plate/valve block. The ports for A & B functions are on this valve body.

Technician: Adam G/Chris K	**Date: Nov 10th, 2018**

PENNECON

Cylinder Sheet

Page _____ of 5	Work Order No.:HSA005177

5. INSPECTION DATA / SPECIFICATIONS

TUBE	ID 4.003"	OD 4.744"	Length 20.375"	Material Steel	Other Info Scoring present.
ROD	OD 2.500"	Length 33.50"	Head End Thread (dia/tpi) 1.85"/12 tpi	Piston End Thread (dia/tpi) 1.235"/12 tpi	Material steel
PISTON	OD 3.978"-3.981"	Length 1.740"	No. of Pieces 1	Material Steel	Other Info Scoring present.
HEAD	OD 4.300"	Length 1.611"	(e.g. thread/snap ring) Flanged	Material Steel	Other Info
ATTACHMENTS	Type(clevis etc.)	Size/Dimensions	Material	Other Info	

Technician: Adam G/Chris K | **Date: Nov 10th, 2018**

6. WELDING

☑ Not Applicable

Procedure Used:

Notes:

Technician: | **Date:**

7. HONING

☐ Not Applicable

Stones Used: | RPM Utilized:

Notes: Recommend having this barrel honed due to scoring present in some places inside the barrel.

Technician: Adam G/Chris K | **Date:Nov 10th, 2018**

8. MACHINING

☐ Not Applicable

Components Machined:

Results: Recommend having a new brass bushing made, and possibly a new piston.

Technician: Adam G/Chris K | **Date: Nov 10th, 2018**

9. NEW ITEMS INSTALLED

☐ Not Applicable

Items installed (valves, seals, etc): New seal kit to be sourced and installed.

Technician: Adam G/Chris K | **Date: Nov 10th, 2018**

10. SUBCONTRACTED WORK (e.g. chroming)

☐ Not Applicable

Work Completed: Recommend having the rod rechromed due to wear/discoloration.

PENNECON

Cylinder Sheet

Page _____ of 5	Work Order No.:HSA005177
Technician: Adam G/Chris K	**Date: Nov 10th, 2018**

11. FINAL ASSEMBLY/TESTING

☐ Not Applicable

Internal Rod/Piston Threads Checked:	☐ Loc-tite 271 Applied ☐ Vice Torqued
Type of Testing Completed:	
Test Certificate Completed:	Certificate No.:
Technician:	**Date:**

12. PRE-SHIPPING INSPECTION

Nameplate(s) Correct and Secure?	☐ Yes	☐ No	☐ Not Applicable
All Covers/Hardware are Secure?	☐ Yes	☐ No	☐ Not Applicable
Special Shipping Instructions?	☐ Yes	☐ No	☐ Not Applicable
Paint Acceptable?	☐ Yes	☐ No	☐ Not Applicable
Certificate attached:	☐ Yes	☐ No	☐ Not Applicable
Packaging:	☐ Weatherproof	☐ Crate	☐ Skid Mount
Technician:			**Date:**
QA Inspection Completed By:			**Date:**

13. MATERIALS

Item	Qty	Part No.	Size/Description	Supplier	Cost	Sell
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						

Comments (Indicate seal direction and location if necessary):

Technician:	**Date:**

PENNECON

ISO 9001: 2008

Cylinder Sheet

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14. ESTIMATE					
Disassembly:	hrs @ $	/hr = $	Machining:	hrs @ $	/hr = $
Assembly:	hrs @ $	/hr = $	Welding:	hrs @ $	/hr = $
Testing:	hrs @ $	/hr = $	Honing:	hrs @ $	/hr = $
Pick-up/Del.:	hrs @ $	/hr = $			

Notes:		Labour	$
		Parts	$
		Shop	$
Replacement Cost	$	**Total**	**$**

☐ Repair ☐ Return ☐ Replace ☐ Scrap

Authorized by: Dave Bass For A 9/CK Date: ____________

PENNECON

ISO 9001:2008

Cylinder Sheet

Page _____ of 5	**Work Order No.: HSA005177**
	Customer Reference No.:

1. CUSTOMER INFORMATION

Date: November 10, 2018	Contact:
Customer: NL Hydro	Contact Phone No.:
Address:	Customer Stock Code No.:

Customer Instructions/Notes: Strip and assess cylinder for "Left side re-heat" function.

Allocated To: Adam G/Chris K	**Date: Nov 10th, 2018**

2. NAMEPLATE DATA / RECEIVING INSPECTION

Bore ∅ N/A	☑ Hydraulic	☐ Pneumatic	☐ Welded
Stroke N/A	☑ Tie Rod	☐ Other	
Rod ∅ N/A			

Manufacturer: N/A	Model No.: N/A
Unit No.: N/A	Serial No.: N/A

General Condition of Equipment:	☑ Dirty	☑ Oily	☐ Rusty	☐ Clean

List any Missing, Broken or Damaged Parts: Name tag/data plate is missing.

Other/Description: This cylinder appears to be in good overall condition. There is a large amount of dirt accumulated near the gland nut.

Unit Location:	☑ Unit Tagged	☑ Photography

Receiving Inspection Completed By: Adam G/Chris K	**Date: Nov 10th, 2018**

3. INITIAL INSPECTION

☑ Standard Double Acting	☐ Single Acting	☐ Double Rod
☐ Spring Return	☐ Jack	

☐ Indexed for Disassembly	☑ Job Unit Stamped

CYLINDER MOUNTING

Tie Rod Extended

☐ Head End	☐ Base End	☐ Both Ends

Trunnion

☐ Head End	☐ Base End	☐ Both Ends

Lugs

☐ Side	☐ Side End	☐ Center Line

PENNECON

Cylinder Sheet

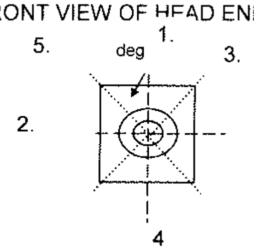
Page _____ of 5	**Work Order No.: HSA005177**	
Base Flange		
☑ Square	☐ Rectangle	
Head Flange		
☑ Square	☐ Rectangle	
Clevis (Male/Female)		
☐ Fixed	☐ Detachable	
	☐ Other	☐ Side End Angles
Rod End Mounting (e.g. rod eye, spherical brg, etc):		
Technician: Adam G/Chris K	**Date: Nov 10th, 2018**	

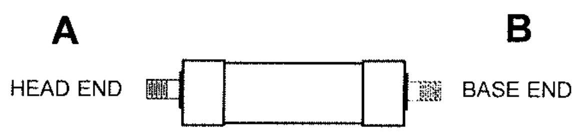
4. PORT / FITTING IDENTIFICATION

☐ Double Ended Cylinder

Size/Thread (A):	Size/Thread (B):

FRONT VIEW OF HEAD END





PIN TO PIN DIMENSIONS								
Closed:	26"	inches	Open:	40"	inches	Stoke:	14"	inches

HEAD END			
Port Size:	Location(i.e.1-5):	Port Type: Flanged Ports	
Fittings:	Size:	Type:	
Hoses:	Size:	Type:	
BASE END			
Port Size:	Location(i.e.1-5):	Port Type: Flanged Ports	
Fittings:	Size:	Type:	
Hoses:	Size:	Type:	
Valve(s) with Cylinder:	☑ Yes	☐ No	
Model No.: N/A		Type: N/A	
Valves Checked:	☐ Repair	☐ Replace	☑ Not Applicable

Comments/Notes: Cylinder mounts to an external valve block which has A & B ports and P&T ports.

Technician: Adam G/Chris K	**Date: Nov 10th, 2018**

PENNECON

Cylinder Sheet

Page _____ of 5	Work Order No.: HSA005177

5. INSPECTION DATA / SPECIFICATIONS

TUBE	ID 5.000"	OD 6.010"	Length 16.75"	Material Steel	Other Info N/A
ROD	OD 2.996"	Length 24"	Head End Thread (dia/tpi) 2.235"/12tpi	Piston End Thread (dia/tpi) 1.485" / 12 tpi	Material Steel
PISTON	OD 4.996"	Length 2.565"	No. of Pieces 3	Material Steel	Other Info N/A
HEAD	OD 4.750"	Length 1.625"	(e.g. thread/snap ring) flanged	Material Steel	Other Info N/A
ATTACHMENTS	Type(clevis etc.)	Size/Dimensions	Material	Other Info	

Technician: Adam G/Chris K **Date: Nov 10th, 2018**

6. WELDING

☑ Not Applicable

Procedure Used:

Notes:

Technician: **Date:**

7. HONING

☑ Not Applicable

Stones Used: RPM Utilized:

Notes:

Technician: **Date:**

8. MACHINING

☑ Not Applicable

Components Machined:

Results:

Technician: **Date:**

9. NEW ITEMS INSTALLED

☐ Not Applicable

Items installed (valves, seals, etc): New seal kit to be installed.

Technician: Adam G/Chris K Date: Nov 10th, 2018

10. SUBCONTRACTED WORK (e.g. chroming)

☑ Not Applicable

Work Completed:

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ISO 9001: 2008

Cylinder Sheet

Page _____ of 5	Work Order No.: HSA005177
Technician:	**Date:**

11. FINAL ASSEMBLY/TESTING

☐ Not Applicable

Internal Rod/Piston Threads Checked:	☐ Loc-tite 271 Applied	☐ Vice Torqued
Type of Testing Completed:		
Test Certificate Completed:	Certificate No.:	
Technician:		**Date:**

12. PRE-SHIPPING INSPECTION

Nameplate(s) Correct and Secure?	☐ Yes	☐ No	☐ Not Applicable
All Covers/Hardware are Secure?	☐ Yes	☐ No	☐ Not Applicable
Special Shipping Instructions?	☐ Yes	☐ No	☐ Not Applicable
Paint Acceptable?	☐ Yes	☐ No	☐ Not Applicable
Certificate attached:	☐ Yes	☐ No	☐ Not Applicable
Packaging: ☐ Weatherproof	☐ Crate		☐ Skid Mount
Technician:			**Date:**
QA Inspection Completed By:			**Date:**

13. MATERIALS

Item	Qty	Part No.	Size/Description	Supplier	Cost	Sell
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						

Comments (Indicate seal direction and location if necessary):

Technician:	**Date:**

PENNECON

Cylinder Sheet

Page _____ of 5	Work Order No.: HSA005177

14. ESTIMATE

Disassembly:	hrs @ $	/hr = $	Machining:	hrs @ $	/hr = $
Assembly:	hrs @ $	/hr = $	Welding:	hrs @ $	/hr = $
Testing:	hrs @ $	/hr = $	Honing:	hrs @ $	/hr = $
Pick-up/Del.:	hrs @ $	/hr = $			

Notes:		Labour	$
		Parts	$
		Shop	$
Replacement Cost	$	**Total**	**$**

☐ Repair ☐ Return ☐ Replace ☐ Scrap

Authorized by: Dan Barr FOR A 9/CK Date: ____________

PENNECON

Cylinder Sheet

Page _____ of 5	**Work Order No.: HSA005177**
	Customer Reference No.:

1. CUSTOMER INFORMATION

Date: November 11, 2018	Contact:
Customer: NL Hydro	Contact Phone No.:
Address:	Customer Stock Code No.:
Customer Instructions/Notes: Strip and assess left side "Intercept" cylinder.	
Allocated To: Adam G/Chris K	**Date: Nov 11th, 2018**

2. NAMEPLATE DATA / RECEIVING INSPECTION

Bore ∅ N/A	☑ Hydraulic	☐ Pneumatic	☐ Welded
Stroke N/A	☑ Tie Rod	☐ Other	
Rod ∅ N/A			

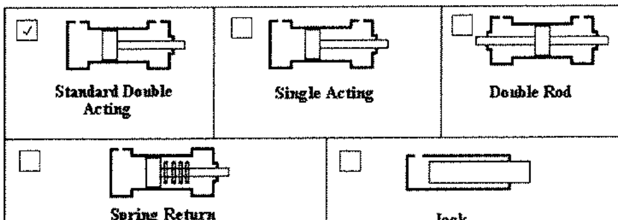
Manufacturer:N/A		Model No.:N/A		
Unit No.:N/A		Serial No.:N/A		
General Condition of Equipment:	☑ Dirty	☑ Oily	☐ Rusty	☐ Clean

List any Missing, Broken or Damaged Parts: Name tag/ Data plate are missing.

Other/Description: Cylinder appears to be in good overall condition.

Unit Location:	☑ Unit Tagged	☑ Photography
Receiving Inspection Completed By: Adam G/Chris K		**Date: Nov 11th, 2018**

3. INITIAL INSPECTION



☑ Standard Double Acting | ☐ Single Acting | ☐ Double Rod | ☐ Spring Return | ☐ Jack

☐ Indexed for Disassembly	☑ Job Unit Stamped

CYLINDER MOUNTING

Tie Rod Extended

☐ Head End	☐ Base End	☐ Both Ends

Trunnion

☐ Head End	☐ Base End	☐ Both Ends

Lugs

☐ Side	☐ Side End	☐ Center Line

PENNECON

Cylinder Sheet

Page ______ of 5	**Work Order No.: HSA005177**

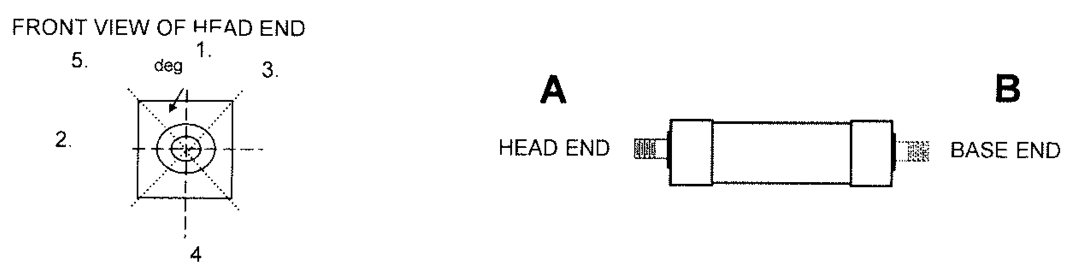
Base Flange	
☑ Square	☐ Rectangle
Head Flange	
☑ Square	☐ Rectangle
Clevis (Male/Female)	
☐ Fixed	☐ Detachable

	☐ Other	☐ Side End Angles
Rod End Mounting (e.g. rod eye, spherical brg, etc):		
Technician: Adam G/Chris K		**Date: Nov 11th, 2018**

4. PORT / FITTING IDENTIFICATION

☐ Double Ended Cylinder

Size/Thread (A):	Size/Thread (B):



PIN TO PIN DIMENSIONS

Closed: 27.5" inches	Open: 47.5" inches	Stoke: 18" inches

HEAD END

Port Size:	Location(i.e.1-5):	Port Type: Flanged Port
Fittings:	Size:	Type:
Hoses:	Size:	Type:

BASE END

Port Size:	Location(i.e.1-5):	Port Type: Flanged Port
Fittings:	Size:	Type:
Hoses:	Size:	Type:

Valve(s) with Cylinder:	☑ Yes	☐ No	
Model No.: N/A		Type: N/A	
Valves Checked:	☐ Repair	☐ Replace	☑ Not Applicable

Comments/Notes: Cylinder mounts to an external valve block which has A, B, P & T ports.

Technician: Adam G/Chris K	**Date: Nov 11th, 2018**

PENNECON

Cylinder Sheet

Page ______ of 5	Work Order No.: HSA005177

5. INSPECTION DATA / SPECIFICATIONS

TUBE	ID 4.999"	OD 6.010"	Length 19.5"	Material Steel	Other Info N/A
ROD	OD 2.495"	Length 27.25"	Head End Thread (dia/tpi) 1.86" /12tpi	Piston End Thread (dia/tpi) 1.489"/12 tpi	Material Steel
PISTON	OD 4.926"	Length 2.500"	No. of Pieces 1	Material Steel	Other Info N/A
HEAD	OD 3.500"	Length 1.615"	(e.g. thread/snap ring) Flanged	Material Steel	Other Info Fit between Flanges
ATTACHMENTS	Type(clevis etc.)	Size/Dimensions	Material	Other Info	

Technician:Adam G/Chris K	Date: Nov 11th, 2018

6. WELDING

☑ Not Applicable

Procedure Used:

Notes:

Technician:	Date:

7. HONING

☑ Not Applicable

Stones Used:	RPM Utilized:

Notes:

Technician:	Date:

8. MACHINING

☑ Not Applicable

Components Machined:

Results:

Technician:	Date:

9. NEW ITEMS INSTALLED

☐ Not Applicable

Items installed (valves, seals, etc): New seal kit to be installed.

Technician: Adam G/Chris K	Date: Nov 11th, 2018

10. SUBCONTRACTED WORK (e.g. chroming)

☐ Not Applicable

Work Completed: Possible rechrome of rod.

PENNECON

Cylinder Sheet

Page ______ of 5	Work Order No.: HSA005177
Technician:	**Date:**

11. FINAL ASSEMBLY/TESTING

☐ Not Applicable

Internal Rod/Piston Threads Checked:	☐ Loc-tite 271 Applied	☐ Vice Torqued
Type of Testing Completed:		
Test Certificate Completed:	Certificate No.:	
Technician:		**Date:**

12. PRE-SHIPPING INSPECTION

Nameplate(s) Correct and Secure?	☐ Yes	☐ No	☐ Not Applicable
All Covers/Hardware are Secure?	☐ Yes	☐ No	☐ Not Applicable
Special Shipping Instructions?	☐ Yes	☐ No	☐ Not Applicable
Paint Acceptable?	☐ Yes	☐ No	☐ Not Applicable
Certificate attached:	☐ Yes	☐ No	☐ Not Applicable
Packaging: ☐ Weatherproof	☐ Crate		☐ Skid Mount
Technician:			**Date:**
QA Inspection Completed By:			**Date:**

13. MATERIALS

Item	Qty	Part No.	Size/Description	Supplier	Cost	Sell
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						

Comments (Indicate seal direction and location if necessary):

Technician:	**Date:**

PENNECON

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Cylinder Sheet

Page ____ of 5			**Work Order No.: HSA005177**		
14. ESTIMATE					
Disassembly:	hrs @ $	/hr = $	Machining:	hrs @ $	/hr = $
Assembly:	hrs @ $	/hr = $	Welding:	hrs @ $	/hr = $
Testing:	hrs @ $	/hr = $	Honing:	hrs @ $	/hr = $
Pick-up/Del.:	hrs @ $	/hr = $			

Notes:		Labour	$
		Parts	$
		Shop	$
Replacement Cost	$	**Total**	**$**

☐ Repair ☐ Return ☐ Replace ☐ Scrap

Authorized by: Dave Benno for A9/CK Date: ____________

PENNECON

Cylinder Sheet

Page _____ of 5	**Work Order No.:HSA005177**
	Customer Reference No.:

1. CUSTOMER INFORMATION

Date: November 11, 2018	Contact:
Customer: NL Hydro	Contact Phone No.:
Address:	Customer Stock Code No.:
Customer Instructions/Notes: Strip and assess 4" Spare cylinder	
Allocated To: Adam G/Chris K	**Date: Nov 11th, 2018**

2. NAMEPLATE DATA / RECEIVING INSPECTION

Bore ∅ N/A	[x] Hydraulic	[ ] Pneumatic	[ ] Welded
Stroke N/A	[x] Tie Rod	[ ] Other	
Rod ∅ N/A			

Manufacturer: N/A	Model No.:N/A
Unit No.: N/A	Serial No.: N/A

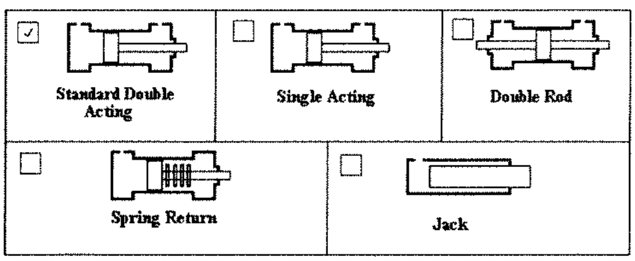
General Condition of Equipment:	[x] Dirty	[x] Oily	[ ] Rusty	[ ] Clean

List any Missing, Broken or Damaged Parts: Name tag/Data plate is missing.

Other/Description: This cylinder appears to be in good overall condition.

Unit Location:	[x] Unit Tagged	[x] Photography
Receiving Inspection Completed By: Adam G/Chris K		**Date: Nov 11th, 2018**

3. INITIAL INSPECTION



[ ] Indexed for Disassembly	[ ] Job Unit Stamped

CYLINDER MOUNTING

Tie Rod Extended		
[ ] Head End	[ ] Base End	[ ] Both Ends
Trunnion		
[ ] Head End	[ ] Base End	[ ] Both Ends
Lugs		
[ ] Side	[ ] Side End	[ ] Center Line

PENNECON

Cylinder Sheet

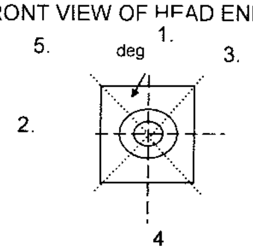
Page ______ of 5	**Work Order No.:HSA005177**
Base Flange	
☐ Square	☑ Rectangle
Head Flange	
☑ Square	☐ Rectangle
Clevis (Male/Female)	
☐ Fixed	☐ Detachable
☐ Other	☐ Side End Angles
Rod End Mounting (e.g. rod eye, spherical brg, etc):	
Technician: Adam G/Chris K	**Date: Nov 11th, 2018**

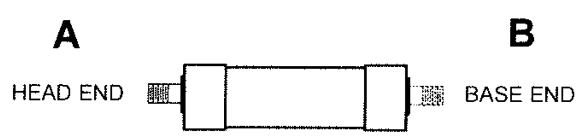
4. PORT / FITTING IDENTIFICATION

☐ Double Ended Cylinder

Size/Thread (A):	Size/Thread (B):

FRONT VIEW OF HEAD END





PIN TO PIN DIMENSIONS

Closed: 35" inches	Open: 48" inches	Stoke: 13" inches

HEAD END

Port Size:	Location(i.e.1-5):	Port Type: Flanged port
Fittings:	Size:	Type:
Hoses:	Size:	Type:

BASE END

Port Size:	Location(i.e.1-5):	Port Type: Flanged port
Fittings:	Size:	Type:
Hoses:	Size:	Type:

Valve(s) with Cylinder:	☐ Yes	☑ No	
Model No.: N/A		Type: N/A	
Valves Checked:	☐ Repair	☐ Replace	☑ Not Applicable

Comments/Notes: No valve was included with this cylinder.

Technician: Adam G/Chris K	**Date: Nov 11th, 2018**

PENNECON

Cylinder Sheet

Page ____ of 5	Work Order No.:HSA005177

5. INSPECTION DATA / SPECIFICATIONS

TUBE	ID 4.003"	OD 4.761"	Length 20"	Material Steel	Other Info
ROD	OD 2.498"	Length 34.25	Head End Thread (dia/tpi) 1.866"/12tpi	Piston End Thread (dia/tpi) 1.485" / 12tpi	Material Steel
PISTON	OD 3.912"	Length 2.005"	No. of Pieces 1	Material Steel	Other Info N/A
HEAD	OD 4.236"	Length 1.602"	(e.g. thread/snap ring) Flanged	Material Steel	Other Info N/A
ATTACHMENTS	Type(clevis etc.)	Size/Dimensions	Material	Other Info	

Technician: Adam G/Chris K | **Date: Nov 11th, 2018**

6. WELDING

☑ Not Applicable

Procedure Used:

Notes:

Technician: | **Date:**

7. HONING

☑ Not Applicable

Stones Used: | RPM Utilized:

Notes:

Technician: | **Date:**

8. MACHINING

☑ Not Applicable

Components Machined:

Results:

Technician: | **Date:**

9. NEW ITEMS INSTALLED

☐ Not Applicable

Items installed (valves, seals, etc): New Seal Kit to be installed.

Technician: Adam G/Chris K | Date: Nov 11th, 2018

10. SUBCONTRACTED WORK (e.g. chroming)

☑ Not Applicable

Work Completed:

PENNECON

ISO 9001:2008

Cylinder Sheet

Page ______ of 5	Work Order No.:HSA005177
Technician:	**Date:**

11. FINAL ASSEMBLY/TESTING			
☐ Not Applicable			
Internal Rod/Piston Threads Checked:	☐ Loc-tite 271 Applied	☐ Vice Torqued	
Type of Testing Completed:			
Test Certificate Completed:		Certificate No.:	
Technician:		**Date:**	

12. PRE-SHIPPING INSPECTION			
Nameplate(s) Correct and Secure?	☐ Yes	☐ No	☐ Not Applicable
All Covers/Hardware are Secure?	☐ Yes	☐ No	☐ Not Applicable
Special Shipping Instructions?	☐ Yes	☐ No	☐ Not Applicable
Paint Acceptable?	☐ Yes	☐ No	☐ Not Applicable
Certificate attached:	☐ Yes	☐ No	☐ Not Applicable
Packaging: ☐ Weatherproof	☐ Crate		☐ Skid Mount
Technician:		**Date:**	
QA Inspection Completed By:		**Date:**	

13. MATERIALS

Item	Qty	Part No.	Size/Description	Supplier	Cost	Sell
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						

Comments (Indicate seal direction and location if necessary):

Technician:	**Date:**

PENNECON

Cylinder Sheet

Page _____ of 5	**Work Order No.:HSA005177**

14. ESTIMATE

Disassembly:	hrs @ $	/hr = $	Machining:	hrs @ $	/hr = $
Assembly:	hrs @ $	/hr = $	Welding:	hrs @ $	/hr = $
Testing:	hrs @ $	/hr = $	Honing:	hrs @ $	/hr = $
Pick-up/Del.:	hrs @ $	/hr = $			

Notes:		Labour	$
		Parts	$
		Shop	$
Replacement Cost	$	**Total**	**$**

☐ Repair ☐ Return ☐ Replace ☐ Scrap

Authorized by: Dave Bavo FOR A 9/K/K Date: ____________________

PENNECON

ISO 9001:2008

Cylinder Sheet

Page ______ of 5	**Work Order No.:HSA005177**
	Customer Reference No.:

1. CUSTOMER INFORMATION

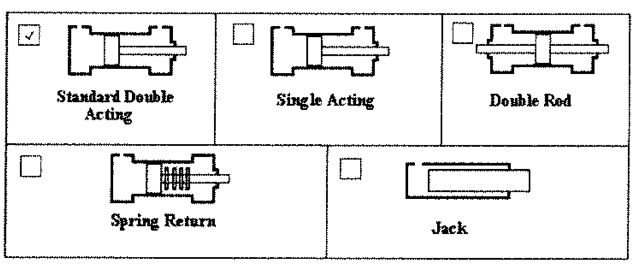
Date: November 13, 2018	Contact:
Customer: NL Hydro	Contact Phone No.:
Address:	Customer Stock Code No.:
Customer Instructions/Notes: Strip and assess right side Intercept cylinder (5")	
Allocated To: Adam G	**Date: Nov 13th, 2018**

2. NAMEPLATE DATA / RECEIVING INSPECTION

Bore ∅ N/A	[x] Hydraulic	[ ] Pneumatic	[ ] Welded
Stroke N/A	[x] Tie Rod	[ ] Other	
Rod ∅ N/A			

Manufacturer: Miller Fluid Power		Model No.: N/A		
Unit No.: N/A		Serial No.: 89861170		
General Condition of Equipment:	[x] Dirty	[x] Oily	[ ] Rusty	[ ] Clean
List any Missing, Broken or Damaged Parts: Name tag/ Data plate is missing.				
Other/Description: Cylinder is dirty, but otherwise appears to be in good overall condition.				
Unit Location:	[x] Unit Tagged	[x] Photography		
Receiving Inspection Completed By: Adam G		**Date: Nov 13th, 2018**		

3. INITIAL INSPECTION



[ ] Indexed for Disassembly	[x] Job Unit Stamped

CYLINDER MOUNTING

Tie Rod Extended		
[ ] Head End	[ ] Base End	[ ] Both Ends
Trunnion		
[ ] Head End	[ ] Base End	[ ] Both Ends
Lugs		
[ ] Side	[ ] Side End	[ ] Center Line

PENNECON

ISO 9001:2008

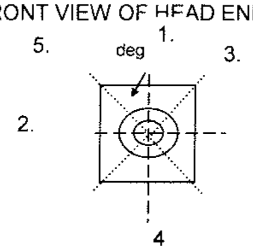
Cylinder Sheet

Page _____ of 5		**Work Order No.:HSA005177**	
Base Flange			
☑ Square		☐ Rectangle	
Head Flange			
☑ Square		☐ Rectangle	
Clevis (Male/Female)			
☐ Fixed		☐ Detachable	
	☐ Other		☐ Side End Angles
Rod End Mounting (e.g. rod eye, spherical brg, etc):			
Technician: Adam G			**Date: Nov 13th, 2018**

4. PORT / FITTING IDENTIFICATION

☐ Double Ended Cylinder	
Size/Thread (A):	Size/Thread (B):

FRONT VIEW OF HEAD END



PIN TO PIN DIMENSIONS					
Closed: 31" inches		Open: 47" inches		Stoke: 16" inches	
HEAD END					
Port Size:	Location(i.e.1-5):	Port Type: Flanged			
Fittings:	Size:	Type:			
Hoses:	Size:	Type:			
BASE END					
Port Size:	Location(i.e.1-5):	Port Type: Flanged			
Fittings:	Size:	Type:			
Hoses:	Size:	Type:			
Valve(s) with Cylinder:	☑ Yes		☐ No		
Model No.: N/A		Type: N/A			
Valves Checked:	☐ Repair		☐ Replace	☑ Not Applicable	
Comments/Notes: Cylinder is mounted to a flanged valve block containing all porting for normal operation.					
Technician: Adam G				**Date: Nov 13th, 2018**	

PENNECON

ISO 9001: 2008

Cylinder Sheet

Page ______ of 5	Work Order No.:HSA005177

5. INSPECTION DATA / SPECIFICATIONS

TUBE	ID 5.001"	OD 6.003"	Length 19.5"	Material Steel	Other Info N/A
ROD	OD 2.497"	Length 27.25"	Head End Thread (dia/tpi) 1.857"/12tpi	Piston End Thread (dia/tpi) 1.853"/12 tpi	Material Steel
PISTON	OD 4.927"	Length 1.610"	No. of Pieces 1	Material Steel	Other Info N/A
HEAD	OD 3.493"	Length 1.610"	(e.g. thread/snap ring) Flanged	Material Steel	Other Info N/A
ATTACHMENTS	Type(clevis etc.)	Size/Dimensions	Material	Other Info	

Technician: Adam G **Date: Nov 13th, 2018**

6. WELDING

☑ Not Applicable

Procedure Used:

Notes:

Technician: **Date:**

7. HONING

☐ Not Applicable

Stones Used: RPM Utilized:

Notes: Barrel was sent out for polishing.

Technician: Adam G **Date: Nov 13th, 2018**

8. MACHINING

☐ Not Applicable

Components Machined:

Results:

Technician: **Date:**

9. NEW ITEMS INSTALLED

☐ Not Applicable

Items installed (valves, seals, etc): New seal kit to be installed.

Technician: Adam G Date: Nov 13th, 2018

10. SUBCONTRACTED WORK (e.g. chroming)

☐ Not Applicable

Work Completed:

PENNECON

Cylinder Sheet

Page _____ of 5	Work Order No.:HSA005177
Technician:	**Date:**

11. FINAL ASSEMBLY/TESTING		
☐ Not Applicable		
Internal Rod/Piston Threads Checked:	☐ Loc-tite 271 Applied	☐ Vice Torqued
Type of Testing Completed:		
Test Certificate Completed:	Certificate No.:	
Technician:		**Date:**

12. PRE-SHIPPING INSPECTION			
Nameplate(s) Correct and Secure?	☐ Yes	☐ No	☐ Not Applicable
All Covers/Hardware are Secure?	☐ Yes	☐ No	☐ Not Applicable
Special Shipping Instructions?	☐ Yes	☐ No	☐ Not Applicable
Paint Acceptable?	☐ Yes	☐ No	☐ Not Applicable
Certificate attached:	☐ Yes	☐ No	☐ Not Applicable
Packaging: ☐ Weatherproof	☐ Crate		☐ Skid Mount
Technician:			**Date:**
QA Inspection Completed By:			**Date:**

13. MATERIALS

Item	Qty	Part No.	Size/Description	Supplier	Cost	Sell
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						

Comments (Indicate seal direction and location if necessary):

Technician:	**Date:**

PENNECON

Cylinder Sheet

Page ______ of 5			Work Order No.:HSA005177		
14. ESTIMATE					
Disassembly:	hrs @ $	/hr = $	Machining:	hrs @ $	/hr = $
Assembly:	hrs @ $	/hr = $	Welding:	hrs @ $	/hr = $
Testing:	hrs @ $	/hr = $	Honing:	hrs @ $	/hr = $
Pick-up/Del.:	hrs @ $	/hr = $			

Notes:		Labour	$
		Parts	$
		Shop	$
Replacement Cost	$	**Total**	**$**

☐ Repair ☐ Return ☐ Replace ☐ Scrap

Authorized by: [signature] FOR A G Date: ______________

PENNECON

Cylinder Sheet

Page _____ of 5	**Work Order No.: HSA005177**
	Customer Reference No.:

1. CUSTOMER INFORMATION

Date: November 12th, 2018	Contact:
Customer:NL Hydro	Contact Phone No.:
Address:	Customer Stock Code No.:
Customer Instructions/Notes: Strip and assess right side "reheat cylinder".	
Allocated To: Adam G/Chris K	**Date: Nov 12th, 2018**

2. NAMEPLATE DATA / RECEIVING INSPECTION

Bore ∅ N/A	[x] Hydraulic	[ ] Pneumatic	[ ] Welded
Stroke N/A	[x] Tie Rod	[ ] Other	
Rod ∅ N/A			

Manufacturer: Miller Fluid Power	Model No.: N/A
Unit No.: N/A	Serial No.: N/A

General Condition of Equipment:	[x] Dirty	[x] Oily	[ ] Rusty	[ ] Clean

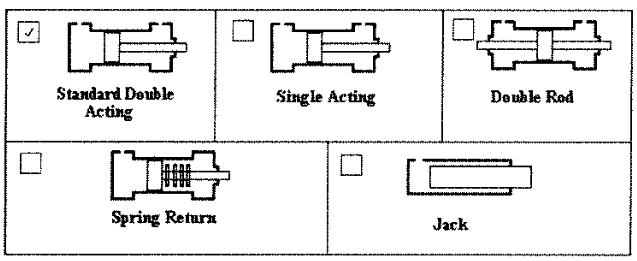
List any Missing, Broken or Damaged Parts: Name plate/Data tag is missing.

Other/Description: Cylinder appears to be in good overall condition.

Unit Location:	[x] Unit Tagged	[x] Photography

Receiving Inspection Completed By: Adam G/Chris K	**Date: Nov 12th, 2018**

3. INITIAL INSPECTION



[ ] Indexed for Disassembly	[x] Job Unit Stamped

CYLINDER MOUNTING

Tie Rod Extended		
[ ] Head End	[ ] Base End	[ ] Both Ends
Trunnion		
[ ] Head End	[ ] Base End	[ ] Both Ends
Lugs		
[ ] Side	[ ] Side End	[ ] Center Line

PENNECON

Cylinder Sheet

Page _____ of 5	**Work Order No.: HSA005177**

Base Flange

☑ Square	☐ Rectangle

Head Flange

☑ Square	☐ Rectangle

Clevis (Male/Female)

☐ Fixed	☐ Detachable

	☐ Other	☐ Side End Angles

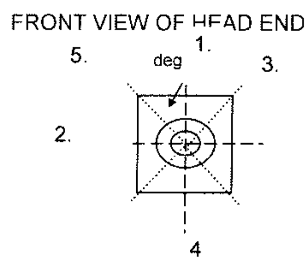
Rod End Mounting (e.g. rod eye, spherical brg, etc):

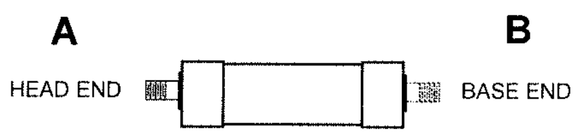
Technician: Adam G/Chris K	**Date: Nov 12th, 2018**

4. PORT / FITTING IDENTIFICATION

☐ Double Ended Cylinder

Size/Thread (A):	Size/Thread (B):





Closed:	26.5"	inches	Open:	41"	inches	Stoke:	14.5"	inches

HEAD END

Port Size:	Location(i.e.1-5):	Port Type: Flanged Ports
Fittings:	Size:	Type:
Hoses:	Size:	Type:

BASE END

Port Size:	Location(i.e.1-5):	Port Type: Flanged Ports
Fittings:	Size:	Type:
Hoses:	Size:	Type:

Valve(s) with Cylinder:	☑ Yes	☐ No	
Model No.: N/A		Type: N/A	
Valves Checked:	☐ Repair	☐ Replace	☑ Not Applicable

Comments/Notes: Cylinder mounts to an external valve block which has A & B ports and P&T ports.

Technician: Adam G/Chris K	**Date: Nov 12th, 2018**

PENNECON

Cylinder Sheet

Page ____ of 5	**Work Order No.: HSA005177**

5. INSPECTION DATA / SPECIFICATIONS

TUBE	ID 5.001"	OD 6.002"	Length 16.5"	Material Steel	Other Info N/A
ROD	OD 2.995"	Length 24.25	Head End Thread (dia/tpi) 2.235"/12tpi	Piston End Thread (dia/tpi) 1.496" / 12 tpi	Material Steel
PISTON	OD 4.992"	Length 2.534	No. of Pieces 3	Material Steel	Other Info N/A
HEAD	OD 4.752"	Length 1.610"	(e.g. thread/snap ring) flanged	Material Steel	Other Info N/A
ATTACHMENTS	Type(clevis etc.)	Size/Dimensions	Material	Other Info	

Technician: Adam G/Chris K | **Date: Nov 12th, 2018**

6. WELDING

☑ Not Applicable

Procedure Used:

Notes:

Technician: | **Date:**

7. HONING

☑ Not Applicable

Stones Used: | RPM Utilized:

Notes: Very light marking on inside of the barrel. However the barrel is still smooth inside. No high spots present.

Technician: Adam G/Chris K | **Date: Nov 12th, 2018**

8. MACHINING

☑ Not Applicable

Components Machined:

Results:

Technician: | **Date:**

9. NEW ITEMS INSTALLED

☐ Not Applicable

Items installed (valves, seals, etc): New Seal kit to be installed.

Technician: Adam G/Chris K | Date: Nov 12th, 2018

10. SUBCONTRACTED WORK (e.g. chroming)

☑ Not Applicable

Work Completed:

PENNECON

ISO 9001: 2008

Cylinder Sheet

Page _____ of 5	**Work Order No.: HSA005177**
Technician:	**Date:**

11. FINAL ASSEMBLY/TESTING

☐ Not Applicable

Internal Rod/Piston Threads Checked:	☐ Loc-tite 271 Applied	☐ Vice Torqued
Type of Testing Completed:		
Test Certificate Completed:	Certificate No.:	
Technician:	**Date:**	

12. PRE-SHIPPING INSPECTION

Nameplate(s) Correct and Secure?	☐ Yes	☐ No	☐ Not Applicable
All Covers/Hardware are Secure?	☐ Yes	☐ No	☐ Not Applicable
Special Shipping Instructions?	☐ Yes	☐ No	☐ Not Applicable
Paint Acceptable?	☐ Yes	☐ No	☐ Not Applicable
Certificate attached:	☐ Yes	☐ No	☐ Not Applicable
Packaging:	☐ Weatherproof	☐ Crate	☐ Skid Mount
Technician:		**Date:**	
QA Inspection Completed By:		**Date:**	

13. MATERIALS

Item	Qty	Part No.	Size/Description	Supplier	Cost	Sell
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						

Comments (Indicate seal direction and location if necessary):

Technician:	**Date:**

PENNECON

ISO 9001:2008

Cylinder Sheet

Page _____ of 5	**Work Order No.: HSA005177**

14. ESTIMATE

Disassembly:	hrs @ $	/hr = $	Machining:	hrs @ $	/hr = $
Assembly:	hrs @ $	/hr = $	Welding:	hrs @ $	/hr = $
Testing:	hrs @ $	/hr = $	Honing:	hrs @ $	/hr = $
Pick-up/Del.:	hrs @ $	/hr = $			

Notes:		Labour	$
		Parts	$
		Shop	$
Replacement Cost	$	**Total**	**$**

☐ Repair ☐ Return ☐ Replace ☐ Scrap

Authorized by: David Burns FOR D 9/C K Date: ____________

PENNECON

Cylinder Sheet

Page _____ of 5	**Work Order No.: HSA005177**
	Customer Reference No.:

1. CUSTOMER INFORMATION

Date: November 15th, 2018	Contact:
Customer: NL Hydro	Contact Phone No.:
Address:	Customer Stock Code No.:
Customer Instructions/Notes: Strip and assess spare cylinder.	
Allocated To: Randy Lomond	**Date: Nov 15th, 2018**

2. NAMEPLATE DATA / RECEIVING INSPECTION

Bore ∅ N/A	☑ Hydraulic	☐ Pneumatic	☐ Welded
Stroke N/A	☑ Tie Rod	☐ Other	
Rod ∅ N/A			

Manufacturer: Miller Fluid Power	Model No.: N/A
Unit No.: N/A	Serial No.: 94134770

General Condition of Equipment:	☐ Dirty	☐ Oily	☐ Rusty	☑ Clean

List any Missing, Broken or Damaged Parts: Name tag/ Data plate is missing.

Other/Description: Cylinder is clean; was never in service.

Unit Location:	☑ Unit Tagged	☑ Photography

Receiving Inspection Completed By: Randy Lomond	**Date: Nov 15th, 2018**

3. INITIAL INSPECTION

☑ Standard Double Acting	☐ Single Acting	☐ Double Rod
☐ Spring Return	☐ Jack	

☐ Indexed for Disassembly	☑ Job Unit Stamped

CYLINDER MOUNTING

Tie Rod Extended

☐ Head End	☐ Base End	☐ Both Ends

Trunnion

☐ Head End	☐ Base End	☐ Both Ends

Lugs

☐ Side	☐ Side End	☐ Center Line

PENNECON

ISO 9001:2008

Cylinder Sheet

Page _____ of 5	**Work Order No.: HSA005177**

Base Flange

☑ Square	☐ Rectangle

Head Flange

☑ Square	☐ Rectangle

Clevis (Male/Female)

☐ Fixed	☐ Detachable	
	☐ Other	☐ Side End Angles

Rod End Mounting (e.g. rod eye, spherical brg, etc):

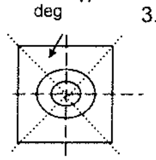
Technician: Randy L	**Date: Nov 15th, 2018**

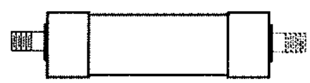
4. PORT / FITTING IDENTIFICATION

☐ Double Ended Cylinder

Size/Thread (A):	Size/Thread (B):

FRONT VIEW OF HEAD END





PIN TO PIN DIMENSIONS

Closed: 31" inches	Open: 47" inches	Stoke: 14" inches

HEAD END

Port Size:	Location(i.e.1-5):	Port Type: Flanged
Fittings:	Size:	Type:
Hoses:	Size:	Type:

BASE END

Port Size:	Location(i.e.1-5):	Port Type: Flanged
Fittings:	Size:	Type:
Hoses:	Size:	Type:

Valve(s) with Cylinder:	☑ Yes	☐ No	
Model No.: N/A		Type: N/A	
Valves Checked:	☐ Repair	☐ Replace	☑ Not Applicable

Comments/Notes: Cylinder is not mounted to valve block as this cylinder is a spare and never been in service.

Technician: Randy Lomond	**Date: Nov 15th, 2018**

PENNECON

Cylinder Sheet

Page _____ of 5	**Work Order No.: HSA005177**

5. INSPECTION DATA / SPECIFICATIONS

TUBE	ID 6.985"	OD 8.000"	Length 17.250"	Material Steel	Other Info N/A
ROD	OD 3.000"	Length 25.500"	Head End Thread (dia/tpi) 1.857"/12tpi	Piston End Thread (dia/tpi) 2.250"/12 tpi	Material Steel
PISTON	OD 6.618"	Length 3.000"	No. of Pieces 1	Material Steel	Other Info N/A
HEAD	OD 3.315"	Length 1.610"	(e.g. thread/snap ring)	Material Steel	Other Info N/A
ATTACHMENTS	Type(clevis etc.)	Size/Dimensions	Material	Other Info	

Technician: Randy Lomond | **Date: Nov 15th, 2018**

6. WELDING

☑ Not Applicable

Procedure Used:

Notes:

Technician: | **Date:**

7. HONING

☑ Not Applicable

Stones Used: | RPM Utilized:

Notes:

Technician: Randy Lomond | **Date: Nov 15th, 2018**

8. MACHINING

☐ Not Applicable

Components Machined:

Results:

Technician: | **Date:**

9. NEW ITEMS INSTALLED

☐ Not Applicable

Items installed (valves, seals, etc): New seal kit to be installed.

Technician: | Date:

10. SUBCONTRACTED WORK (e.g. chroming)

☐ Not Applicable

Work Completed:

PENNECON

Cylinder Sheet

Page _____ of 5	Work Order No.: HSA005177
Technician:	**Date:**

11. FINAL ASSEMBLY/TESTING

☐ Not Applicable

Internal Rod/Piston Threads Checked:	☐ Loc-tite 271 Applied	☐ Vice Torqued
Type of Testing Completed:		
Test Certificate Completed:	Certificate No.:	
Technician:	**Date:**	

12. PRE-SHIPPING INSPECTION

Nameplate(s) Correct and Secure?	☐ Yes	☐ No	☐ Not Applicable
All Covers/Hardware are Secure?	☐ Yes	☐ No	☐ Not Applicable
Special Shipping Instructions?	☐ Yes	☐ No	☐ Not Applicable
Paint Acceptable?	☐ Yes	☐ No	☐ Not Applicable
Certificate attached:	☐ Yes	☐ No	☐ Not Applicable
Packaging:	☐ Weatherproof	☐ Crate	☐ Skid Mount
Technician:		**Date:**	
QA Inspection Completed By:		**Date:**	

13. MATERIALS

Item	Qty	Part No.	Size/Description	Supplier	Cost	Sell
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						

Comments (Indicate seal direction and location if necessary):

Technician:	**Date:**

PENNECON

ISO 9001: 2008

Cylinder Sheet

Page ______ of 5			Work Order No.: HSA005177		
14. ESTIMATE					
Disassembly:	hrs @ $	/hr = $	Machining:	hrs @ $	/hr = $
Assembly:	hrs @ $	/hr = $	Welding:	hrs @ $	/hr = $
Testing:	hrs @ $	/hr = $	Honing:	hrs @ $	/hr = $
Pick-up/Del.:	hrs @ $	/hr = $			

Notes:		Labour	$
		Parts	$
		Shop	$
Replacement Cost	$	**Total**	**$**

☐ Repair ☐ Return ☐ Replace ☐ Scrap

Authorized by: David Bois for RL

Date: ______________________

PENNECON

ISO 9001:2008

Cylinder Sheet

Page __ of 5	Work Order No.: HSA005177
	Customer Reference No.:

1. CUSTOMER INFORMATION

Date: December 2, 2018	Contact:
Customer: NL Hydro	Contact Phone No.:
Address:	Customer Stock Code No.:

Customer Instructions/Notes: Strip and assess right side "reheat cylinder".

Allocated To: Xavier V/ Randy L/ Adam G	**Date: Dec 2nd, 2018**

2. NAMEPLATE DATA / RECEIVING INSPECTION

Bore ∅ 5"	☑ Hydraulic	☐ Pneumatic	☐ Welded
Stroke 14"	☑ Tie Rod	☐ Other	
Rod ∅ 3"			

Manufacturer: Miller Fluid Power	Model No.: H53B2N
Unit No.: N/A	Serial No.: 89162592

General Condition of Equipment:	☑ Dirty	☑ Oily	☐ Rusty	☐ Clean

List any Missing, Broken or Damaged Parts:

Other/Description: Cylinder appears to be in good overall condition. Fairly dirty around the head end of cylinder/Gland nut and wiper seal.

Unit Location:	☑ Unit Tagged	☑ Photography

Receiving Inspection Completed By: Xavier V/ Randy L/ Adam G	**Date: Dec 2nd, 2018**

3. INITIAL INSPECTION

☑ Standard Double Acting	☐ Single Acting	☐ Double Rod
☐ Spring Return	☐ Jack	

☐ Indexed for Disassembly	☑ Job Unit Stamped

CYLINDER MOUNTING

Tie Rod Extended

☐ Head End	☐ Base End	☐ Both Ends

Trunnion

☐ Head End	☐ Base End	☐ Both Ends

Lugs

☐ Side	☐ Side End	☐ Center Line

PENNECON

Cylinder Sheet

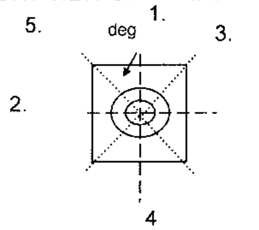
Page __ of 5		**Work Order No.: HSA005177**
Base Flange		
☑ Square		☐ Rectangle
Head Flange		
☑ Square		☐ Rectangle
Clevis (Male/Female)		
☐ Fixed		☐ Detachable
	☐ Other	☐ Side End Angles
Rod End Mounting (e.g. rod eye, spherical brg, etc):		
Technician: Xavier V/ Randy L/ Adam G		**Date: Dec 2nd, 2018**

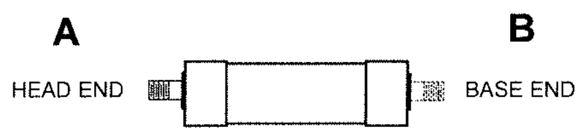
4. PORT / FITTING IDENTIFICATION

☐ Double Ended Cylinder

Size/Thread (A):	Size/Thread (B):

FRONT VIEW OF HEAD END





Closed: 26" inches			Open: 41" inches		Stoke: 14" inches	
HEAD END						
Port Size:	Location(i.e.1-5):		Port Type: Flanged Ports			
Fittings:	Size:		Type:			
Hoses:	Size:		Type:			
BASE END						
Port Size:	Location(i.e.1-5):		Port Type: Flanged Ports			
Fittings:	Size:		Type:			
Hoses:	Size:		Type:			
Valve(s) with Cylinder:		☑ Yes			☐ No	
Model No.: N/A			Type: N/A			
Valves Checked:		☐ Repair		☐ Replace		☑ Not Applicable
Comments/Notes: Cylinder mounts to an external valve block which has A & B ports and P&T ports.						
Technician: Xavier V/ Randy L/ Adam G					**Date: Dec 2nd, 2018**	

PENNECON

Cylinder Sheet

Page __ of 5	**Work Order No.: HSA005177**

5. INSPECTION DATA / SPECIFICATIONS

TUBE	ID 5.001"	OD 6.000"	Length 16.5"	Material Steel	Other Info N/A
ROD	OD 2.989"	Length 24.25"	Head End Thread (dia/tpi) 2.235"/12tpi	Piston End Thread (dia/tpi) 1.496" / 12 tpi	Material Steel
PISTON	OD 4.926"	Length 2.501"	No. of Pieces 1	Material Steel	Other Info N/A
HEAD	OD 4.755"	Length 1.615"	(e.g. thread/snap ring) flanged	Material Steel	Other Info N/A
ATTACHMENTS	Type(clevis etc.)	Size/Dimensions	Material	Other Info	

Technician: Xavier V/ Randy L/ Adam G | **Date: Dec 2nd, 2018**

6. WELDING

☑ Not Applicable

Procedure Used:

Notes:

Technician: | **Date:**

7. HONING

☑ Not Applicable

Stones Used: | RPM Utilized:

Notes:

Technician: | **Date:**

8. MACHINING

☑ Not Applicable

Components Machined:

Results:

Technician: | **Date:**

9. NEW ITEMS INSTALLED

☐ Not Applicable

Items installed (valves, seals, etc): New Seal kit to be installed.

Technician: Xavier V/ Randy L/ Adam G | Date: Dec 2nd, 2018

10. SUBCONTRACTED WORK (e.g. chroming)

☑ Not Applicable

Work Completed:

PENNECON

ISO 9001:2008

Cylinder Sheet

Page __ of 5	**Work Order No.: HSA005177**
Technician:	**Date:**

11. FINAL ASSEMBLY/TESTING

☐ Not Applicable

Internal Rod/Piston Threads Checked: ☐ Loc-tite 271 Applied ☐ Vice Torqued

Type of Testing Completed:

Test Certificate Completed:	Certificate No.:
Technician:	**Date:**

12. PRE-SHIPPING INSPECTION

Nameplate(s) Correct and Secure?	☐ Yes	☐ No	☐ Not Applicable
All Covers/Hardware are Secure?	☐ Yes	☐ No	☐ Not Applicable
Special Shipping Instructions?	☐ Yes	☐ No	☐ Not Applicable
Paint Acceptable?	☐ Yes	☐ No	☐ Not Applicable
Certificate attached:	☐ Yes	☐ No	☐ Not Applicable
Packaging: ☐ Weatherproof	☐ Crate		☐ Skid Mount
Technician:		**Date:**	
QA Inspection Completed By:		**Date:**	

13. MATERIALS

Item	Qty	Part No.	Size/Description	Supplier	Cost	Sell
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						

Comments (Indicate seal direction and location if necessary):

Technician:	**Date:**

PENNECON

ISO 9001:2008

Cylinder Sheet

Page __ of 5			Work Order No.: HSA005177		
14. ESTIMATE					
Disassembly:	hrs @ $	/hr = $	Machining:	hrs @ $	/hr = $
Assembly:	hrs @ $	/hr = $	Welding:	hrs @ $	/hr = $
Testing:	hrs @ $	/hr = $	Honing:	hrs @ $	/hr = $
Pick-up/Del.:	hrs @ $	/hr = $			

Notes:		Labour	$
		Parts	$
		Shop	$
Replacement Cost	$	**Total**	**$**

☐ Repair ☐ Return ☐ Replace ☐ Scrap

Authorized by: David Bass FOR XU/RL/AG Date: ____________

PENNECON

Cylinder Sheet

Page __ of 5	**Work Order No.: HSA005177**
	Customer Reference No.:

1. CUSTOMER INFORMATION

Date: December 2nd, 2018	Contact:
Customer: NL Hydro	Contact Phone No.:
Address:	Customer Stock Code No.:
Customer Instructions/Notes: Strip and assess "Left side re-heat" cylinder.	
Allocated To: Xavier V / Randy L / Adam G	**Date: Dec 2nd, 2018**

2. NAMEPLATE DATA / RECEIVING INSPECTION

Bore ∅ 5"	☑ Hydraulic	☐ Pneumatic	☐ Welded
Stroke 14"	☑ Tie Rod	☐ Other	
Rod ∅ 3"			

Manufacturer: Miller Fluid Power	Model No.: H53B2N
Unit No.: N/A	Serial No.: Not Legible

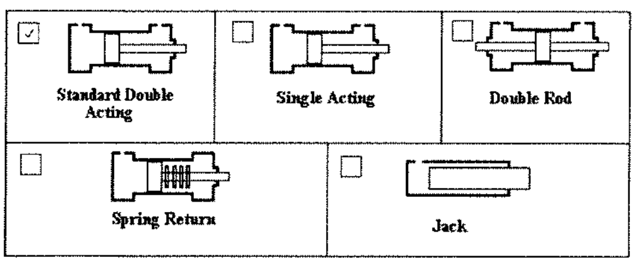
General Condition of Equipment:	☑ Dirty	☑ Oily	☐ Rusty	☐ Clean

List any Missing, Broken or Damaged Parts: Name tag present, but some info is not legible.

Other/Description: This cylinder appears to be in good overall condition. There is a large amount of dirt & rust accumulated near the gland nut.

Unit Location:	☑ Unit Tagged	☑ Photography
Receiving Inspection Completed By: Xavier V / Randy L / Adam G		**Date: Dec 2nd, 2018**

3. INITIAL INSPECTION



☑ Standard Double Acting	☐ Single Acting	☐ Double Rod
☐ Spring Return	☐ Jack	

☐ Indexed for Disassembly	☑ Job Unit Stamped

CYLINDER MOUNTING

Tie Rod Extended

☐ Head End	☐ Base End	☐ Both Ends

Trunnion

☐ Head End	☐ Base End	☐ Both Ends

Lugs

☐ Side	☐ Side End	☐ Center Line

PENNECON

Cylinder Sheet

Page __ of 5	Work Order No.: HSA005177
Base Flange	
☑ Square	☐ Rectangle
Head Flange	
☑ Square	☐ Rectangle
Clevis (Male/Female)	
☐ Fixed	☐ Detachable
☐ Other	☐ Side End Angles
Rod End Mounting (e.g. rod eye, spherical brg, etc):	
Technician: Xavier V / Randy L / Adam G	**Date: Dec 2nd, 2018**

4. PORT / FITTING IDENTIFICATION

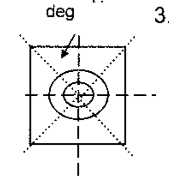
☐ Double Ended Cylinder

Size/Thread (A):	Size/Thread (B):

FRONT VIEW OF HEAD END

5. deg 1. 3.

2.



4

A — HEAD END

B — BASE END

PIN TO PIN DIMENSIONS

Closed: 26" inches	Open: 40" inches	Stoke: 14" inches

HEAD END

Port Size:	Location(i.e.1-5):	Port Type: Flanged Ports
Fittings:	Size:	Type:
Hoses:	Size:	Type:

BASE END

Port Size:	Location(i.e.1-5):	Port Type: Flanged Ports
Fittings:	Size:	Type:
Hoses:	Size:	Type:

Valve(s) with Cylinder:	☑ Yes		☐ No
Model No.: N/A		Type: N/A	
Valves Checked:	☐ Repair	☐ Replace	☑ Not Applicable

Comments/Notes: Cylinder mounts to an external valve block which has A & B ports and P&T ports.

Technician: Xavier V / Randy L / Adam G	**Date: Dec 2nd, 2018**

PENNECON

Cylinder Sheet

Page __ of 5	Work Order No.: HSA005177

5. INSPECTION DATA / SPECIFICATIONS

TUBE	ID 5.000"	OD 6.008"	Length 16.75"	Material Steel	Other Info N/A
ROD	OD 2.988"	Length 24"	Head End Thread (dia/tpi) 2.235"/12tpi	Piston End Thread (dia/tpi) 1.485" / 12 tpi	Material Steel
PISTON	OD 4.928"	Length 2.500"	No. of Pieces 1	Material Steel	Other Info N/A
HEAD	OD 4.750"	Length 1.625"	(e.g. thread/snap ring) flanged	Material Steel	Other Info N/A
ATTACHMENTS	Type(clevis etc.)	Size/Dimensions	Material	Other Info	

Technician: Xavier V / Randy L / Adam G | **Date: Dec 2nd, 2018**

6. WELDING

☑ Not Applicable

Procedure Used:

Notes:

Technician: | **Date:**

7. HONING

☑ Not Applicable

Stones Used: | RPM Utilized:

Notes:

Technician: | **Date:**

8. MACHINING

☑ Not Applicable

Components Machined:

Results:

Technician: | **Date:**

9. NEW ITEMS INSTALLED

☐ Not Applicable

Items installed (valves, seals, etc): New seal kit to be installed.

Technician: Xavier V / Randy L / Adam G | Date: Dec 2nd, 2018

10. SUBCONTRACTED WORK (e.g. chroming)

☑ Not Applicable

Work Completed:

PENNECON

Cylinder Sheet

Page __ of 5	Work Order No.: HSA005177
Technician:	**Date:**

11. FINAL ASSEMBLY/TESTING

☐ Not Applicable		
Internal Rod/Piston Threads Checked:	☐ Loc-tite 271 Applied	☐ Vice Torqued
Type of Testing Completed:		
Test Certificate Completed:	Certificate No.:	
Technician:	**Date:**	

12. PRE-SHIPPING INSPECTION

Nameplate(s) Correct and Secure?	☐ Yes	☐ No	☐ Not Applicable
All Covers/Hardware are Secure?	☐ Yes	☐ No	☐ Not Applicable
Special Shipping Instructions?	☐ Yes	☐ No	☐ Not Applicable
Paint Acceptable?	☐ Yes	☐ No	☐ Not Applicable
Certificate attached:	☐ Yes	☐ No	☐ Not Applicable
Packaging:	☐ Weatherproof	☐ Crate	☐ Skid Mount
Technician:		**Date:**	
QA Inspection Completed By:		**Date:**	

13. MATERIALS

Item	Qty	Part No.	Size/Description	Supplier	Cost	Sell
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						

Comments (Indicate seal direction and location if necessary):

Technician:	**Date:**

PENNECON

ISO 9001:2008

Cylinder Sheet

Page __ of 5	Work Order No.: HSA005177

14. ESTIMATE

Disassembly:	hrs @ $	/hr = $	Machining:	hrs @ $	/hr = $
Assembly:	hrs @ $	/hr = $	Welding:	hrs @ $	/hr = $
Testing:	hrs @ $	/hr = $	Honing:	hrs @ $	/hr = $
Pick-up/Del.:	hrs @ $	/hr = $			

Notes:		Labour	$
		Parts	$
		Shop	$
Replacement Cost	$	**Total**	**$**

☐ Repair ☐ Return ☐ Replace ☐ Scrap

Authorized by: David Bews FOR XU/RL/AG Date: ____________

PENNECON

2.0 Pressure Testing

a. Certificates w/ Charts

PENNECON

TEST CERTIFICATE

Certificate No. NF5931P

1. CUSTOMER INFORMATION

Customer: NL Hydro	PHS Work Order No.: HS005177
Contact Name:	Customer Reference No.:
Customer Instructions/Notes: Rebuild, test and flush cylinders.	

2. EQUIPMENT SPECIFICATIONS

☑ Pressure ☐ Hose ☐ Tube Spool Test

☐ Other/Specify

3. TEST SPECIFICATIONS

Recorder No.: HS0214NF
Recorder Cert. No.: 132664-18-04
Gauge No.: HS0403NF
Gauge Cert. No.: 132661-18-03
Test Result: ☑ Pass ☐ Fail
Test Pressure: 2000 PSI

Test Medium: Fryquil

Start Time: 11:30 PM
Stop Time: 12:45 AM
Stabilization: 15 minutes
Hold: 15 minutes

4. TEST DESCRIPTION

Hose(s) / Tube Spool(s)	No. of Pieces	Hose/Tube Size and/or Brand	Hose/Tube Service No. (if applicable)	N/A
	1	Rightside Reheat, ROD side		☐
				☐
				☐
				☐
				☐
				☐
				☐
				☐
				☐

For Additional Pages please see Attached

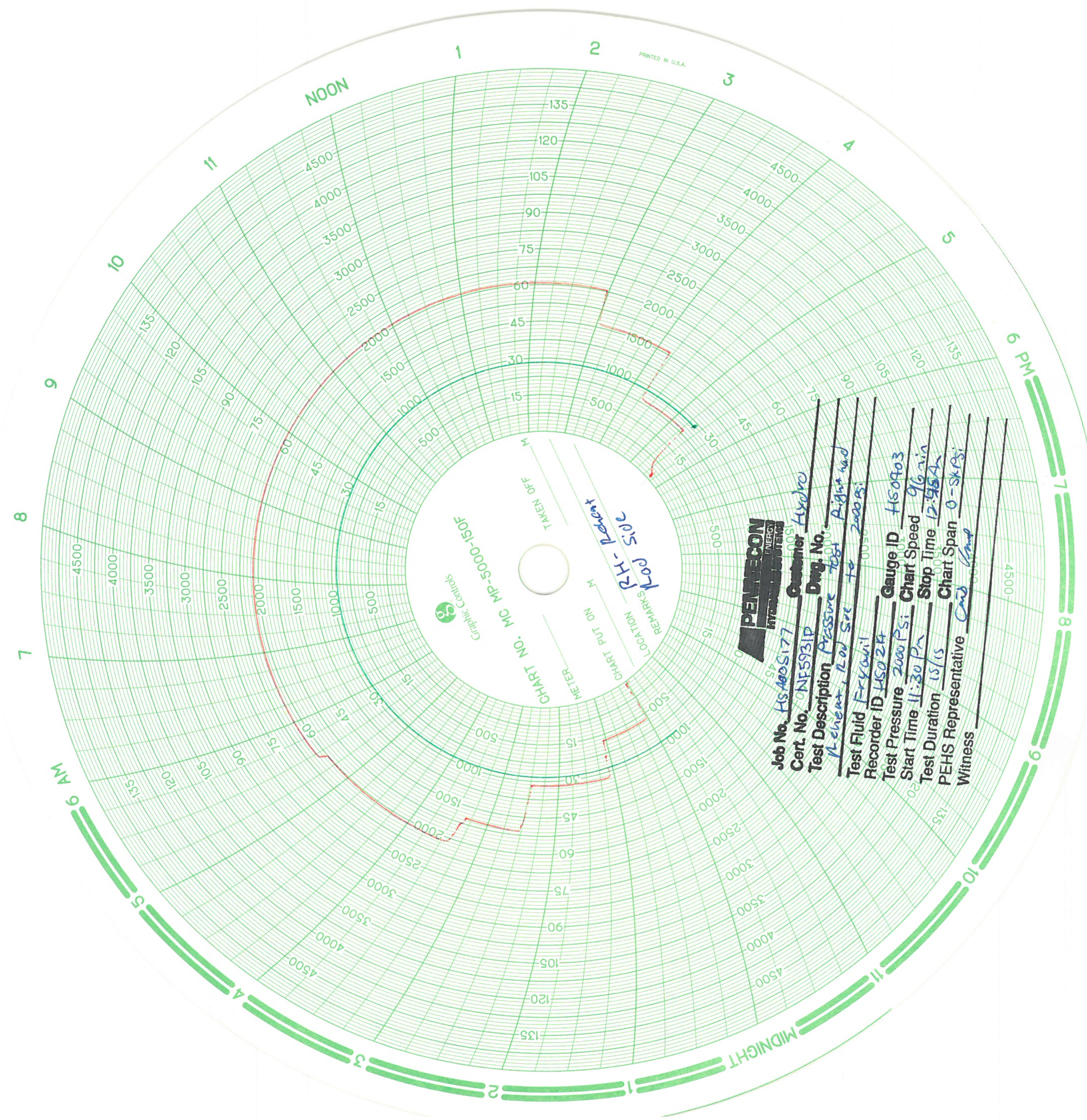
Brief Description of Test	Pressure test of right side reheat - rod side of cylinder to 2000 PSI with 15 minute stabilization and 15 minute hold.
Comments/ Notes	

Signed by: PEHS Representative
Signature: David Barnes FOR C.K.
Print Name: Chris Klomp
Position: Hydraulic Tech.
Date: 17-Nov-18

Accepted by: Client Representative
Signature:
Print Name:
Position:
Date:

Accepted by: Regulatory Rep.
Signature:
Print Name:
Position:
Date:

Accepted by: QC Representative
Signature:
Print Name:
Position:
Date:


NOON
MIDNIGHT
6 PM
6 AM
PRINTED IN U.S.A.
Graphic Controls
CHART NO. MC MP-5000-150F
METER
TAKEN OFF
CHART PUT ON
LOCATION
REMARKS
PENNECON
Job No.
Cert. No.
Customer
Test Description
Dwg. No.
Test Fluid
Recorder ID
Gauge ID
Test Pressure
Chart Speed
Start Time
Stop Time
Test Duration
Chart Span
PEHS Representative
Witness

PENNECON

ISO 9001:2008

TEST CERTIFICATE

Certificate No. NF5932P

1. CUSTOMER INFORMATION

Customer: NL Hydro	PHS Work Order No.: HS005177
Contact Name:	Customer Reference No.:
Customer Instructions/Notes: Rebuild, test and flush cylinders.	

2. EQUIPMENT SPECIFICATIONS

☑ Pressure ☐ Hose ☐ Tube Spool Test

☐ Other/Specify

3. TEST SPECIFICATIONS

Recorder No.: HS0214NF
Recorder Cert. No.: 132664-18-04
Gauge No.: HS0403NF
Gauge Cert. No.: 132661-18-03
Test Result: ☑ Pass ☐ Fail
Test Pressure: 2000 PSI

Test Medium: Fryquel

Start Time: 1:30 AM
Stop Time: 2:45 AM
Stabilization: 15 minutes
Hold: 15 minutes

4. TEST DESCRIPTION

Hose(s) / Tube Spool(s)

No. of Pieces	Hose/Tube Size and/or Brand	Hose/Tube Service No. (if applicable)	N/A
1	Right side Reheat, Piston Side		☐
			☐
			☐
			☐
			☐
			☐
			☐
			☐
			☐

For Additional Pages please see Attached

Brief Description of Test	Pressure test of right side reheat - piston side of cylinder to 2000 PSI with 15 minute stabilization and 15 minute hold.
Comments/ Notes	

Signed by: PEHS Representative
Signature: David Bevs FOR C.K.
Print Name: Chris Klomp
Position: Hydraulic Tech.
Date: 18-Nov-18

Accepted by: Client Representative
Signature:
Print Name:
Position:
Date:

Accepted by: Regulatory Rep.
Signature:
Print Name:
Position:
Date:

Accepted by: QC Representative
Signature:
Print Name:
Position:
Date:

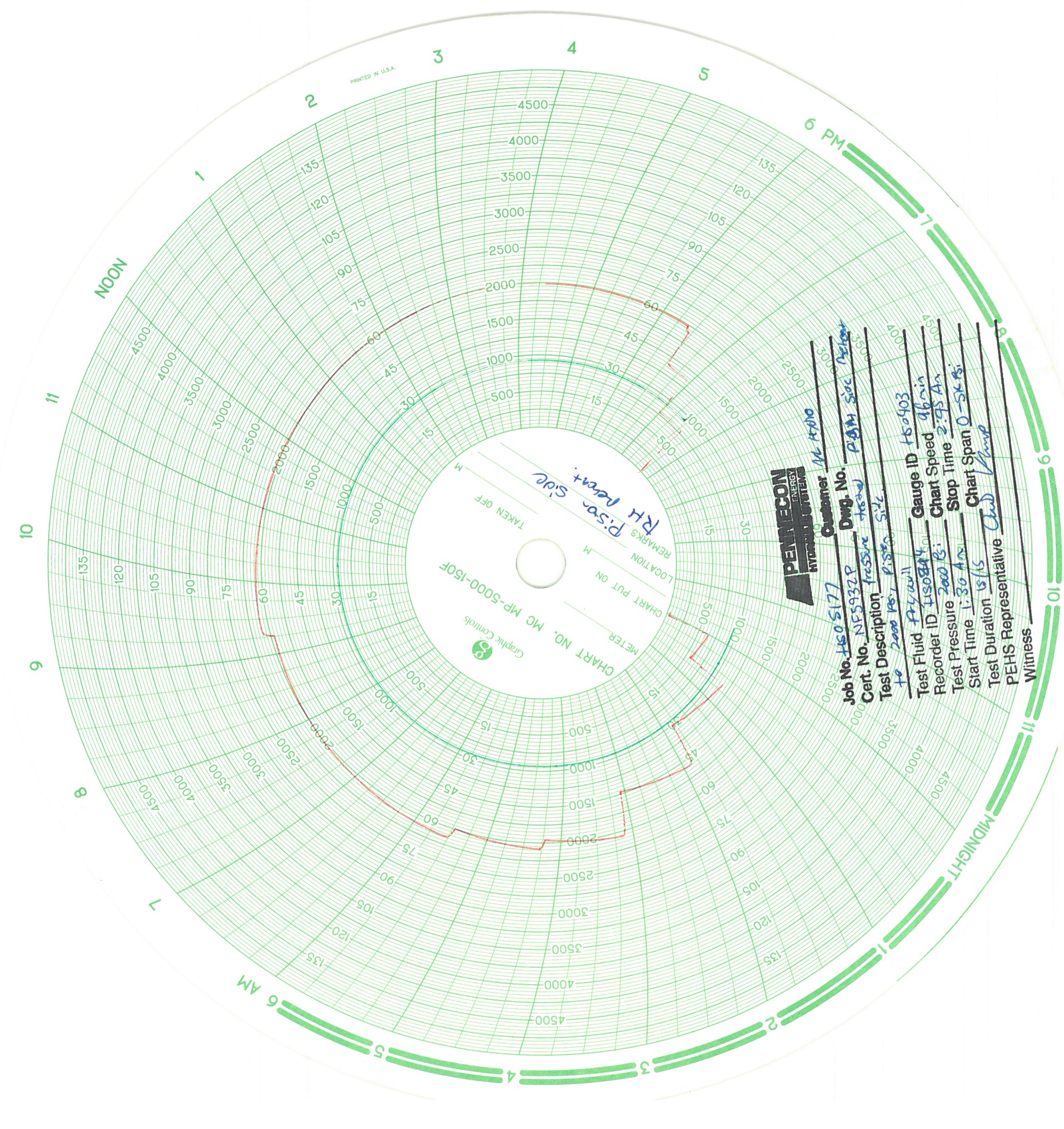


CHART NO. MC MP-5000-150F
Graphic Controls
NOON
6 PM
MIDNIGHT
6 AM
PRINTED IN U.S.A.
PENNECON
Job No.
Cert. No.
Test Description
Test Fluid
Gauge ID
Recorder ID
Chart Speed
Test Pressure
Stop Time
Start Time
Chart Span
Test Duration
PEHS Representative
Witness
REMARKS
LOCATION
CHART PUT ON
TAKEN OFF
METER

PENNECON

ISO 9001:2008

TEST CERTIFICATE

Certificate No. NF5933P

1. CUSTOMER INFORMATION

Customer: NL Hydro	Work Order No.: HS005177
Contact Name:	Customer Reference No.:
Customer Instructions/Notes: Rebuild, test and flush cylinders.	

2. EQUIPMENT SPECIFICATIONS

☑ Pressure ☐ Hose ☐ Tube Spool Test

☐ Other/Specify

3. TEST SPECIFICATIONS

Recorder No.: HS0214NF
Recorder Cert. No.: 132664-18-04
Gauge No.: HS0403NF
Gauge Cert. No.: 132661-18-03
Test Result: ☑ Pass ☐ Fail
Test Pressure: 2000 PSI

Test Medium: Fryquel

Start Time: 2:00 AM
Stop Time: 3:00 AM
Stabilization: 15 minutes
Hold: 15 minutes

4. TEST DESCRIPTION

Hose(s) / Tube Spool(s)	No. of Pieces	Hose/Tube Size and/or Brand	Hose/Tube Service No. (if applicable)	N/A
	1	Right Intercept - Piston side		☐
				☐
				☐
				☐
				☐
				☐
				☐
				☐
				☐

For Additional Pages please see Attached

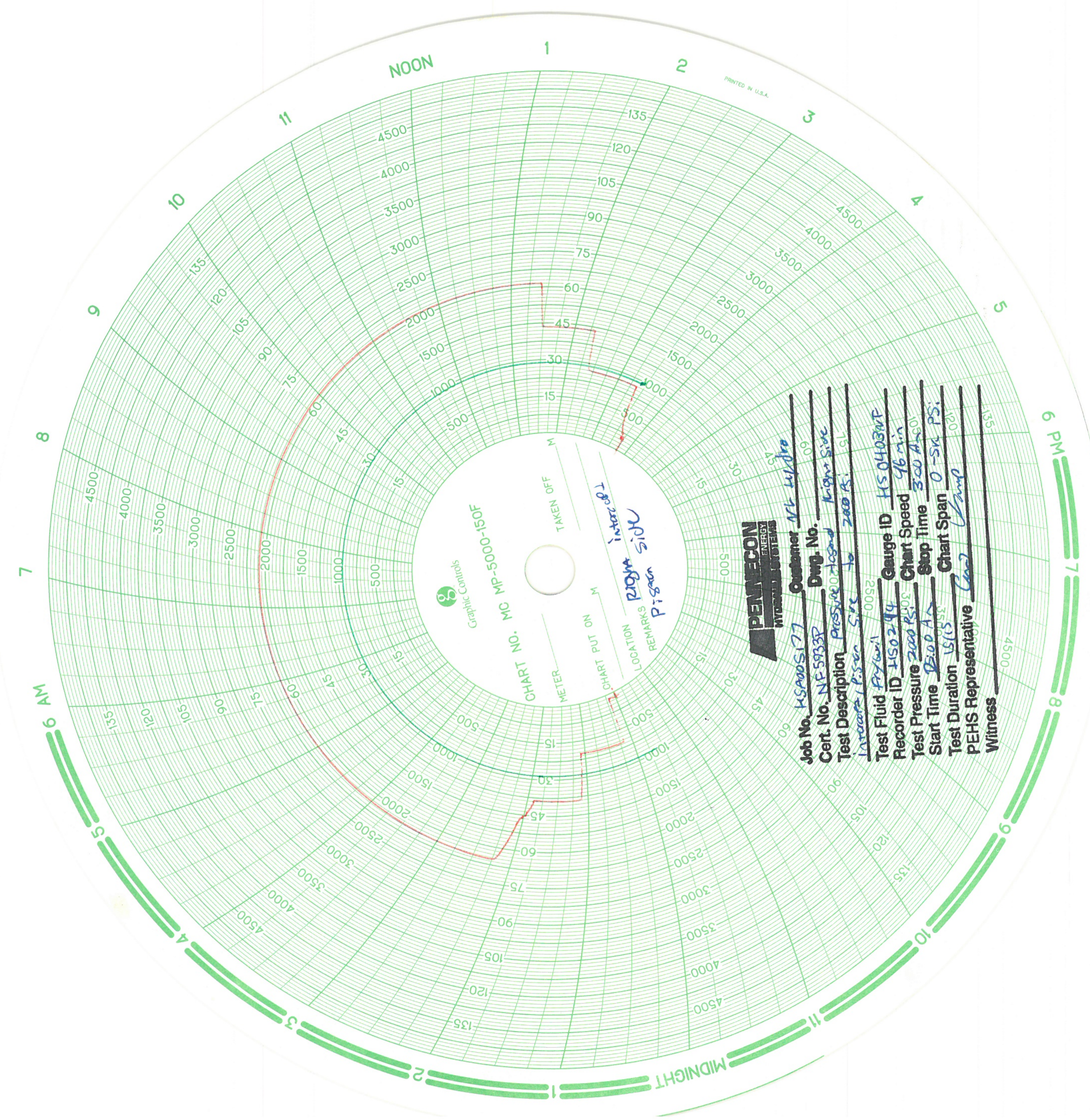
Brief Description of Test	Pressure test of right hand intercept - piston side of cylinder to 2000 PSI with 15 minute stabilization and 15 minute hold.
Comments/ Notes	

Signed by: PEHS Representative
Signature: David Barnes for C K
Print Name: Chris Klomp
Position: Hydraulic Tech.
Date: 18-Nov-18

Accepted by: Client Representative
Signature:
Print Name:
Position:
Date:

Accepted by: Regulatory Rep.
Signature:
Print Name:
Position:
Date:

Accepted by: QC Representative
Signature:
Print Name:
Position:
Date:


NOON
MIDNIGHT
Graphic Controls
CHART NO. MC MP-5000-150F
PRINTED IN U.S.A.

PENNECON

ISO 9001:2008

TEST CERTIFICATE

Certificate No. NF5934P

1. CUSTOMER INFORMATION

Customer: NL Hydro	Work Order No.: HS005177
Contact Name:	Customer Reference No.:
Customer Instructions/Notes: Rebuild, test and flush cylinders.	

2. EQUIPMENT SPECIFICATIONS

☑ Pressure ☐ Hose ☐ Tube Spool Test

☐ Other/Specify

3. TEST SPECIFICATIONS

Recorder No.: HS0214NF Gauge No.: HS0403NF Test Result: ☑ Pass ☐ Fail

Recorder Cert. No.: 132664-18-04 Gauge Cert. No.: 132661-18-03 Test Pressure: 2000 PSI

Test Medium: Fryquel

Start Time: 4:30 AM Stop Time: 5:30 AM Stabilization: 15 minutes

Hold: 15 minutes

4. TEST DESCRIPTION

Hose(s) / Tube Spool(s)	No. of Pieces	Hose/Tube Size and/or Brand	Hose/Tube Service No. (if applicable)	N/A
	1	Main stop cylinder Rod side		☐
				☐
				☐
				☐
				☐
				☐
				☐
				☐
				☐

For Additional Pages please see Attached

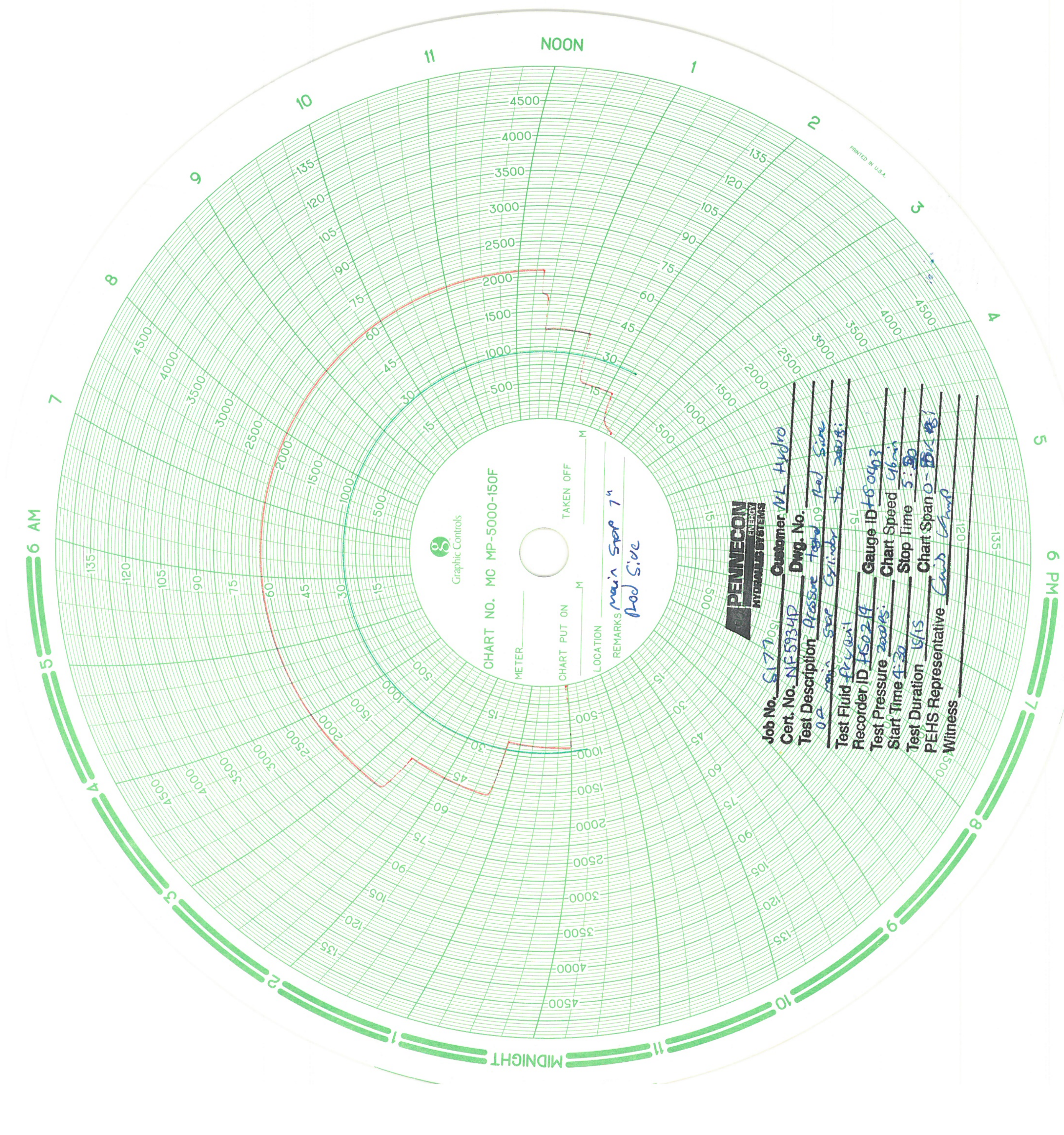
Brief Description of Test	Pressure test of main stop - rod side of cylinder to 2000 PSI with 15 minute stabilization and 15 minute hold.
Comments/ Notes	

Signed by: PEHS Representative
Signature: David Bores For C/K
Print Name: Chris Klomp
Position: Hydraulic Tech.
Date: 18-Nov-18

Accepted by: Client Representative
Signature:
Print Name:
Position:
Date:

Accepted by: Regulatory Rep.
Signature:
Print Name:
Position:
Date:

Accepted by: QC Representative
Signature:
Print Name:
Position:
Date:


NOON
MIDNIGHT
6 AM
6 PM
Graphic Controls
CHART NO. MC MP-5000-150F
METER
CHART PUT ON
TAKEN OFF
LOCATION
REMARKS
PENNECON
ENERGY
HYDRAULIC SYSTEMS
Job No.
Customer
Cert. No.
Dwg. No.
Test Description
Test Fluid
Recorder ID
Gauge ID
Test Pressure
Chart Speed
Start Time
Stop Time
Test Duration
Chart Span
PEHS Representative
Witness

PENNECON

ISO 9001:2008

TEST CERTIFICATE

Certificate No. NF5935P

1. CUSTOMER INFORMATION

Customer: NL Hydro	Work Order No.: HS005177
Contact Name:	Customer Reference No.:
Customer Instructions/Notes: Rebuild, test and flush cylinders.	

2. EQUIPMENT SPECIFICATIONS

☑ Pressure ☐ Hose ☐ Tube Spool Test

☐ Other/Specify

3. TEST SPECIFICATIONS

Recorder No.: HS0214NF
Recorder Cert. No.: 132664-18-04
Gauge No.: HS0403NF
Gauge Cert. No.: 132661-18-03
Test Result: ☑ Pass ☐ Fail
Test Pressure: 2000 PSI

Test Medium: Fryquel

Start Time: 8:30 PM
Stop Time: 9:40 PM
Stabilization: 15 minutes
Hold: 15 minutes

4. TEST DESCRIPTION

Hose(s) / Tube Spool(s)	No. of Pieces	Hose/Tube Size and/or Brand	Hose/Tube Service No. (if applicable)	N/A
	1	Left hand Intercept, Piston Side		☐
				☐
				☐
				☐
				☐
				☐
				☐
				☐
				☐
				☐

For Additional Pages please see Attached

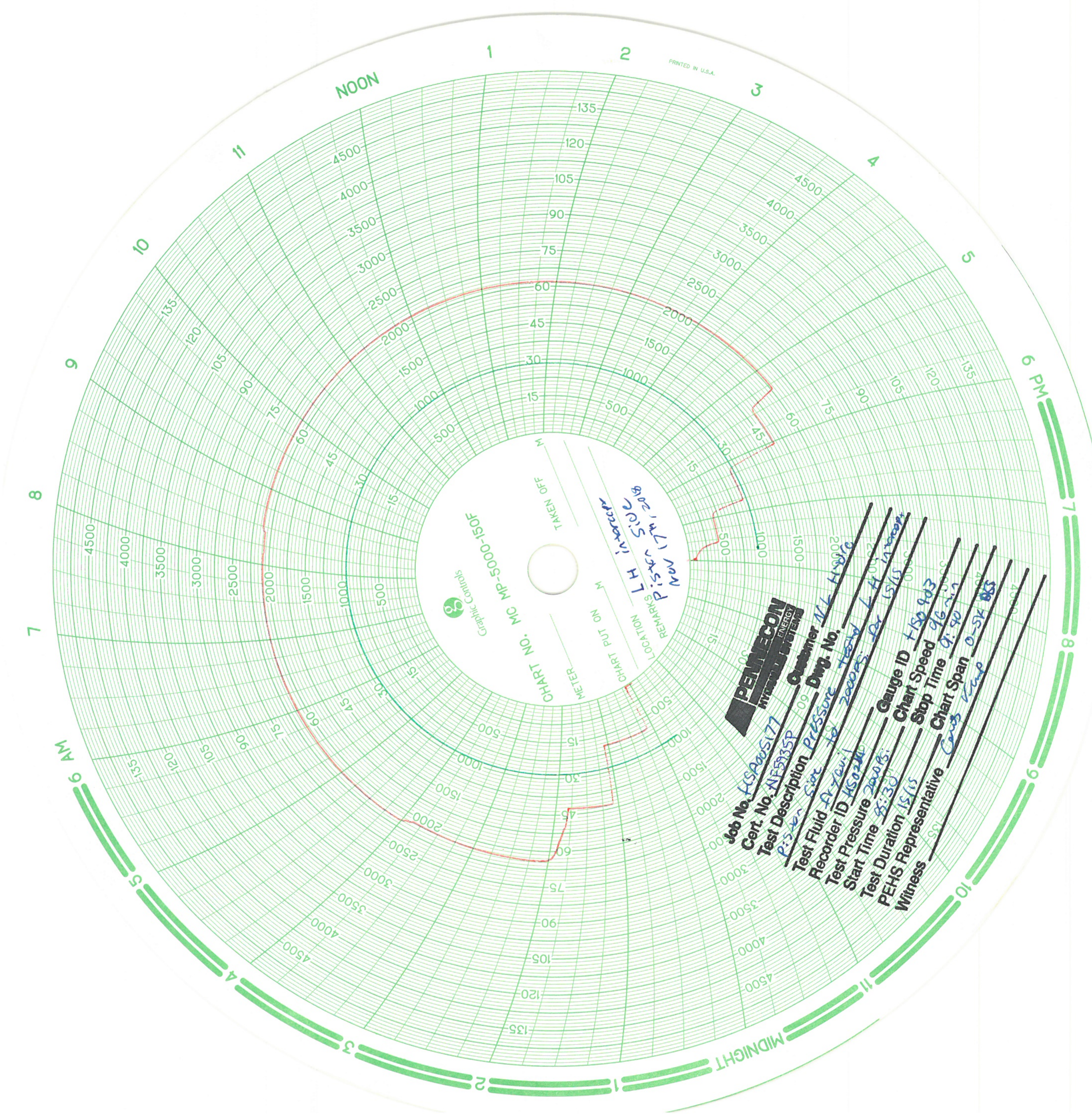
Brief Description of Test	Pressure test of Left hand intercept - Piston side of cylinder to 2000 PSI with 15 minute stabilization and 15 minute hold.
Comments/ Notes	

Signed by: PEHS Representative
Signature: David Bows FOR CK.
Print Name: Chris Klomp
Position: Hydraulic Tech.
Date: 18-Nov-18

Accepted by: Client Representative
Signature:
Print Name:
Position:
Date:

Accepted by: Regulatory Rep.
Signature:
Print Name:
Position:
Date:

Accepted by: QC Representative
Signature:
Print Name:
Position:
Date:


Graphic Controls
CHART NO. MC MP-5000-150F
METER
CHART PUT ON
TAKEN OFF
LOCATION
REMARKS
PENNECON
Job No.
Cert. No.
Test Description
Customer
Dwg. No.
Test Fluid
Recorder ID
Test Pressure
Start Time
Test Duration
PEHS Representative
Witness
Gauge ID
Chart Speed
Stop Time
Chart Span
NOON
MIDNIGHT
6 AM
6 PM

PENNECON

ISO 9001: 2008

TEST CERTIFICATE

Certificate No. NF5936P

1. CUSTOMER INFORMATION

Customer: NL Hydro	Work Order No.: HS005177
Contact Name:	Customer Reference No.:
Customer Instructions/Notes: Rebuild, test and flush cylinders.	

2. EQUIPMENT SPECIFICATIONS

- [x] Pressure
- [ ] Hose
- [ ] Tube Spool Test
- [ ] Other/Specify

3. TEST SPECIFICATIONS

Recorder No.: HS0214NF
Recorder Cert. No.: 132664-18-04
Gauge No.: HS0403NF
Gauge Cert. No.: 132661-18-03
Test Result: [x] Pass [ ] Fail
Test Pressure: 2000 PSI
Test Medium: Fryquel
Start Time: 8:30 PM
Stop Time: 9:45 PM
Stabilization: 15 minutes
Hold: 15 minutes

4. TEST DESCRIPTION

Hose(s) / Tube Spool(s)	No. of Pieces	Hose/Tube Size and/or Brand	Hose/Tube Service No. (if applicable)	N/A
	1	Right intercep Rod side		

For Additional Pages please see Attached

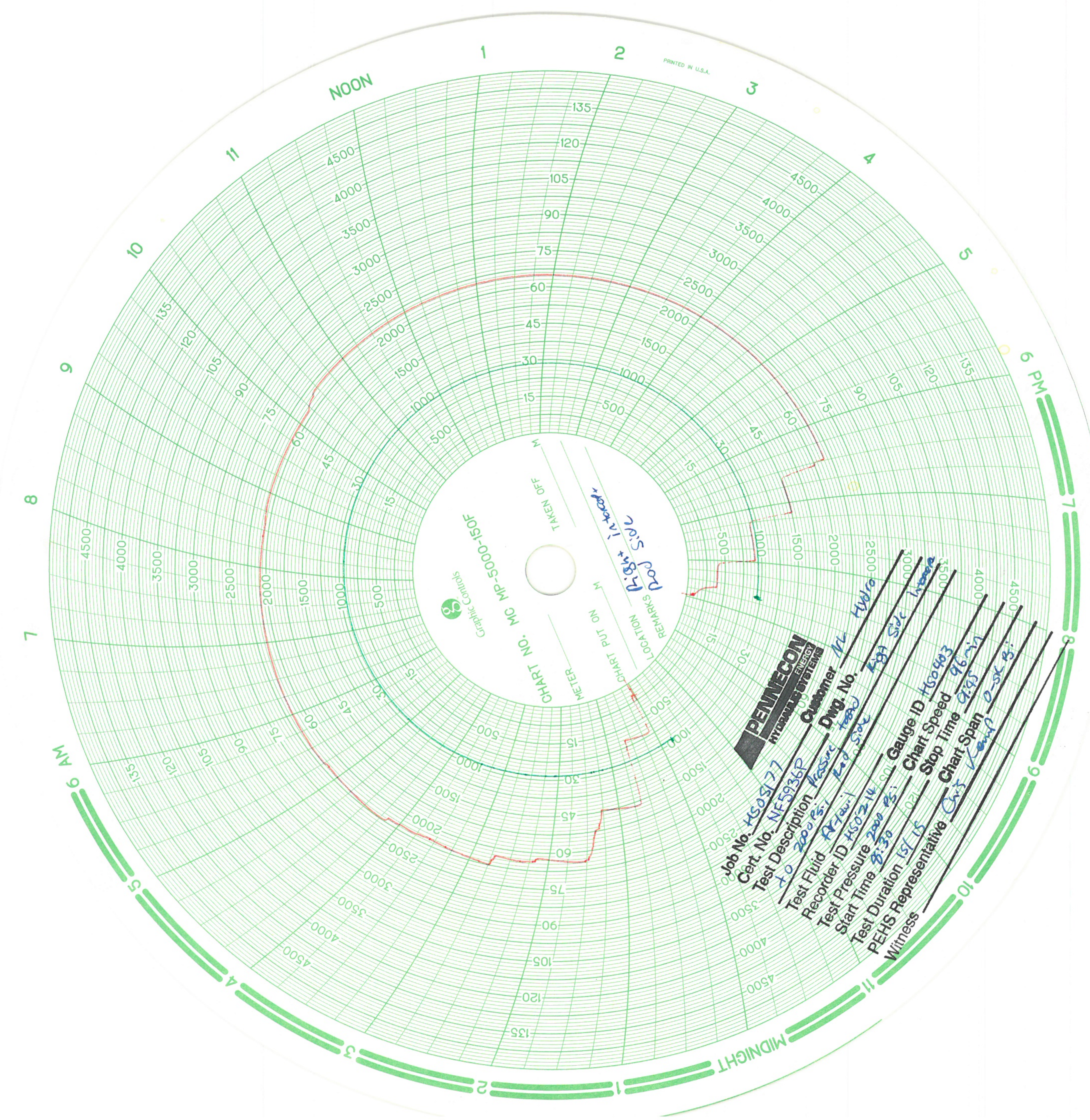
Brief Description of Test	Pressure test of right hand intercept - rod side of cylinder to 2000 PSI with 15 minute stabilization and 15 minute hold.
Comments/ Notes	

Signed by: PEHS Representative
Signature: David Bows FOR C.K.
Print Name: Chris Klomp
Position: Hydraulic Tech.
Date: 18-Nov-18

Accepted by: Client Representative
Signature:
Print Name:
Position:
Date:

Accepted by: Regulatory Rep.
Signature:
Print Name:
Position:
Date:

Accepted by: QC Representative
Signature:
Print Name:
Position:
Date:


Graphic Controls
CHART NO. MC MP-5000-150F
METER
TAKEN OFF
CHART PUT ON
LOCATION
REMARKS
PRINTED IN U.S.A.
NOON
MIDNIGHT
6 PM
6 AM
PENNECON ENERGY HYDRAULIC SYSTEMS
Job No.
Cert. No.
Test Description
Test Fluid
Recorder ID
Test Pressure
Start Time
Test Duration
PEHS Representative
Witness
Customer
Dwg. No.
Gauge ID
Chart Speed
Stop Time
Chart Span

PENNECON

TEST CERTIFICATE

Certificate No. NF6041P

1. CUSTOMER INFORMATION

Customer: NL Hydro	PHS Work Orde No.: HSA005177
Contact Name:	Customer Reference No.:
Customer Instructions/Notes: Pressure test heat exchanger to 120 PSI.	

2. EQUIPMENT SPECIFICATIONS

☑ Pressure ☐ Hose ☐ Tube Spool Test

☐ Other/Specif

3. TEST SPECIFICATIONS

Recorder No.: HS0468NF
Recorder Cert. No.: 132604-18-05
Gauge No.: HS0349NF
Gauge Cert. No.: 132653-18-05
Test Result: ☑ Pas ☐ Fail
Test Pressure: 120 PSI
Test Medium: Fryquel
Start Time: 9:00 AM
Stop Time: 9:30 AM
Stabilization: 15 minutes
Hold: 15 minutes

4. TEST DESCRIPTION

Hose(s) / Tube Spool(s)	No. of Pieces	Hose/Tube Size and/or Brand	Hose/Tube Service No. (if applicable)	N/A
	1	Young Touchstone Heat Exchanger	F-502-EY-2P	☐
			307124	☐
			WCM (1)	☐
			58000073	☐
				☐
				☐
				☐
				☐
				☐

For Additional Pages please see Attached

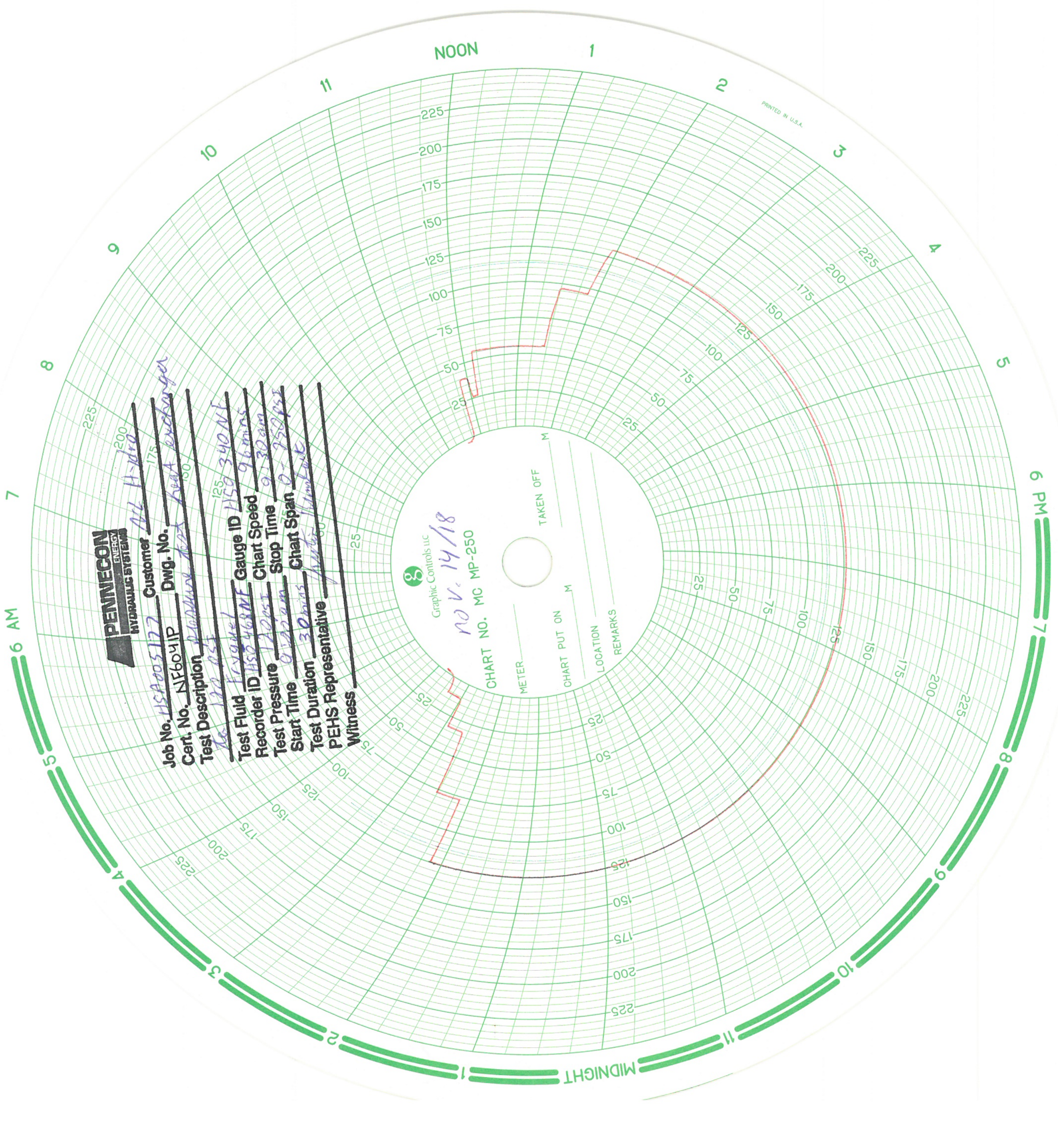
Brief Description of Test	Pressure test of Young Touchstone heat exchanger to 120 PSI with 15 minute stabilization and 15 minute hold.
Comments/ Notes	

Signed by: PEHS Representative
Signature: David Bems For JR.
Print Name: Justin Rumbolt
Position: Hydraulic Tech.
Date: 14-Nov-18

Accepted by: Client Representative
Signature:
Print Name:
Position:
Date:

Accepted by: Regulatory Rep.
Signature:
Print Name:
Position:
Date:

Accepted by: QC Representative
Signature:
Print Name:
Position:
Date:


NOON
MIDNIGHT
6 AM
6 PM
PRINTED IN U.S.A.
PENNECON ENERGY HYDRAULIC SYSTEMS
Job No.
Customer
Cert. No. NF604IP
Dwg. No.
Test Description
Test Fluid
Gauge ID
Recorder ID
Chart Speed
Test Pressure
Stop Time
Start Time
Chart Span
Test Duration
PEHS Representative
Witness
Graphic Controls LLC
CHART NO. MC MP-250
METER
TAKEN OFF M
CHART PUT ON M
LOCATION
REMARKS
nov. 14/18

PENNECON

TEST CERTIFICATE

Certificate No. NF6042P

1. CUSTOMER INFORMATION

Customer: NL Hydro	Work Order: HSA005177
Contact Name:	Customer Reference No.:
Customer Instructions/Notes: Pressure test heat exchanger to 120 psi.	

2. EQUIPMENT SPECIFICATIONS

☑ Pressure ☐ Hose ☐ Tube Spool Test

☐ Other/Specif

3. TEST SPECIFICATIONS

Recorder No.: HS0468NF Gauge No.: HS0349NF Test Result: ☑ Pas ☐ Fail

Recorder Cert. No.: 132604-18-05 Gauge Cert. No.: 132653-18-05 Test Pressure: 120 psi

Test Medium: Fryquel

Start Time: 3:00 PM Stop Time: 3:30 PM Stabilization: 15 minutes

Hold: 15 minutes

4. TEST DESCRIPTION

Hose(s) / Tube Spool(s)	No. of Pieces	Hose/Tube Size and/or Brand	Hose/Tube Service No. (if applicable)	N/A
	1	Young Touchstone	F-502-EY-2P	☐
		heat exchanger	307124	☐
			WCM (3)	☐
			58000073	☐
				☐
				☐
				☐
				☐
				☐

For Additional Pages please see Attached

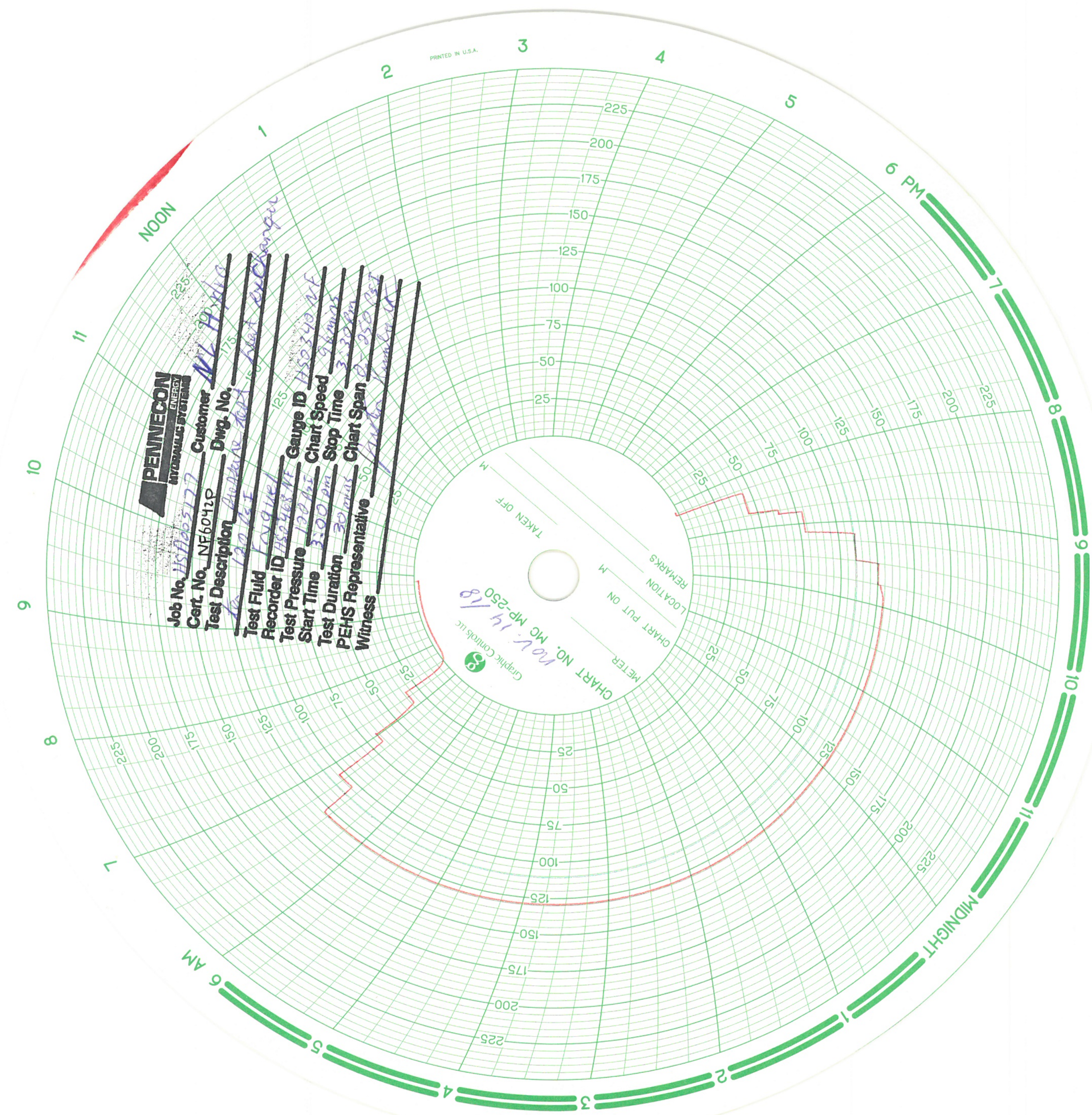
Brief Description of Test	Pressure tested heat exchanger to 120 psi with 15 minute stabilization and 15 minute hold.
Comments/ Notes	

Signed by: PEHS Representative
Signature: David Bens For J.R.
Print Name: Justin Rumbolt
Position: Hydraulic Tech
Date: 14-Nov-18

Accepted by: Client Representative
Signature:
Print Name:
Position:
Date:

Accepted by: Regulatory Rep.
Signature:
Print Name:
Position:
Date:

Accepted by: QC Representative
Signature:
Print Name:
Position:
Date:


PENNECON ENERGY
HYDRAULIC SYSTEMS
Job No.
Customer
Cert. No.
Dwg. No.
Test Description
Test Fluid
Recorder ID
Gauge ID
Test Pressure
Chart Speed
Start Time
Stop Time
Test Duration
Chart Span
PEHS Representative
Witness
CHART NO. MC MP-250
Graphic Controls LLC
METER
CHART PUT ON
LOCATION
REMARKS
TAKEN OFF
PRINTED IN U.S.A.
NOON
6 PM
MIDNIGHT
6 AM

PENNECON

TEST CERTIFICATE

Certificate No. NF6043P

1. CUSTOMER INFORMATION

Customer: N.L. Hydro	Work Order: HSA005177
Contact Name:	Customer Reference No.:
Customer Instructions/Notes: Pressure test 7" main steam stop cylinder on the piston side to 2000 psi.	

2. EQUIPMENT SPECIFICATIONS

☑ Pressure ☐ Hose ☐ Tube Spool Test

☐ Other/Specif

3. TEST SPECIFICATIONS

Recorder No.: HS0214NF Gauge No.: HS0403NF Test Result: ☑ Pas ☐ Fail

Recorder Cert. No.: 132664-18-04 Gauge Cert. No.: 132661-18-03 Test Pressure: 2000 psi

Test Medium: Fyrquel

Start Time: 10:00 AM Stop Time: 10:30 AM Stabilization: 15 minutes

Hold: 15 minutes

4. TEST DESCRIPTION

Hose(s) / Tube Spool(s)	No. of Pieces	Hose/Tube Size and/or Brand	Hose/Tube Service No. (if applicable)	N/A
	1	7" main steam stop cylinder		☐
				☐
				☐
				☐
				☐
				☐
				☐
				☐
				☐

For Additional Pages please see Attached

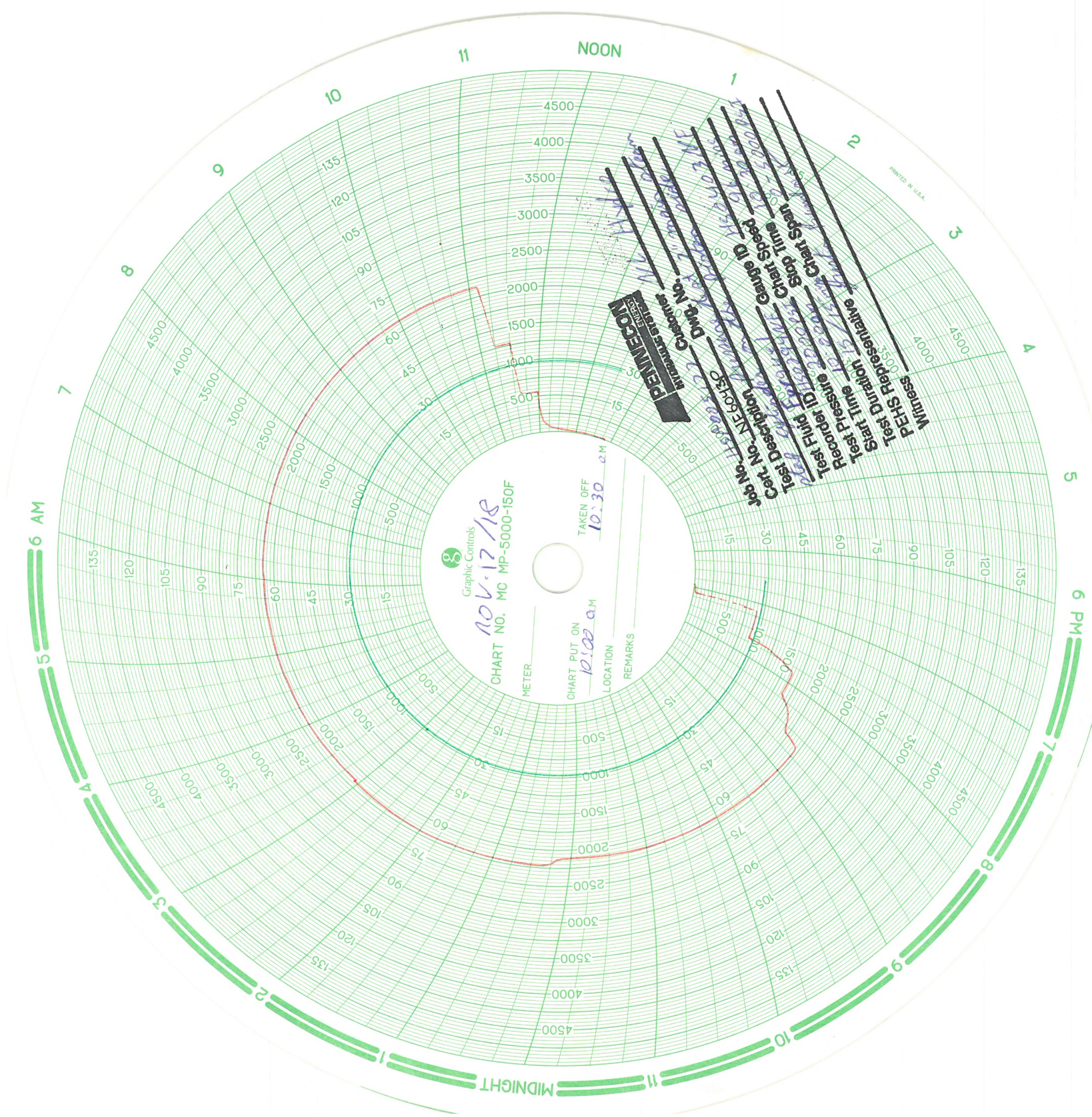
Brief Description of Test	Pressure tested 7" main steam stop cylinder on the piston side to 2000 PSI with 15 minute stabilization and 15 minute hold.
Comments/ Notes	

Signed by: PEHS Representative
Signature: David Bonas For J.R.
Print Name: Justin Rumbolt
Position: Hydraulic Tech
Date: 17-Nov-18

Accepted by: Client Representative
Signature:
Print Name:
Position:
Date:

Accepted by: Regulatory Rep.
Signature:
Print Name:
Position:
Date:

Accepted by: QC Representative
Signature:
Print Name:
Position:
Date:


NOON
MIDNIGHT
6 AM
6 PM
Graphic Controls
CHART NO. MC MP-5000-150F
NOV. 17 /18
CHART PUT ON 10:02 A.M
TAKEN OFF 10:30 A.M
METER
LOCATION
REMARKS
PENNECON ENERGY
Job No.
Customer
Cert. No.
Dwg. No.
Test Description
Gauge ID
Chart Speed
Test Fluid ID
Chart Time
Stop Time
Recorder Pressure
Chart Span
Test Pressure
Start Time
Duration
Test Duration
PEHS Representative
Witness
PRINTED IN U.S.A.

PENNECON

TEST CERTIFICATE

Certificate No. NF6044P

1. CUSTOMER INFORMATION

Customer: N.L. Hydro	Work Order: HSA005177
Contact Name:	Customer Reference No.:
Customer Instructions/Notes: Pressure test left reheat cylinder on the piston side to 2000 psi.	

2. EQUIPMENT SPECIFICATIONS

☑ Pressure ☐ Hose ☐ Tube Spool Test

☐ Other/Specif

3. TEST SPECIFICATIONS

Recorder No.: HS0214NF Gauge No.: HS0403NF Test Result: ☑ Pas ☐ Fail

Recorder Cert. No.: 132664-18-04 Gauge Cert. No.: 132661-18-03 Test Pressure: 2000 psi

Test Medium: Fyrquel

Start Time: 1:30 PM Stop Time: 2:00 PM Stabilization: 15 minutes

Hold: 15 minutes

4. TEST DESCRIPTION

Hose(s) / Tube Spool(s)	No. of Pieces	Hose/Tube Size and/or Brand	Hose/Tube Service No. (if applicable)	N/A
	1	left reheat cylinder		☐
				☐
				☐
				☐
				☐
				☐
				☐
				☐
				☐

For Additional Pages please see Attached

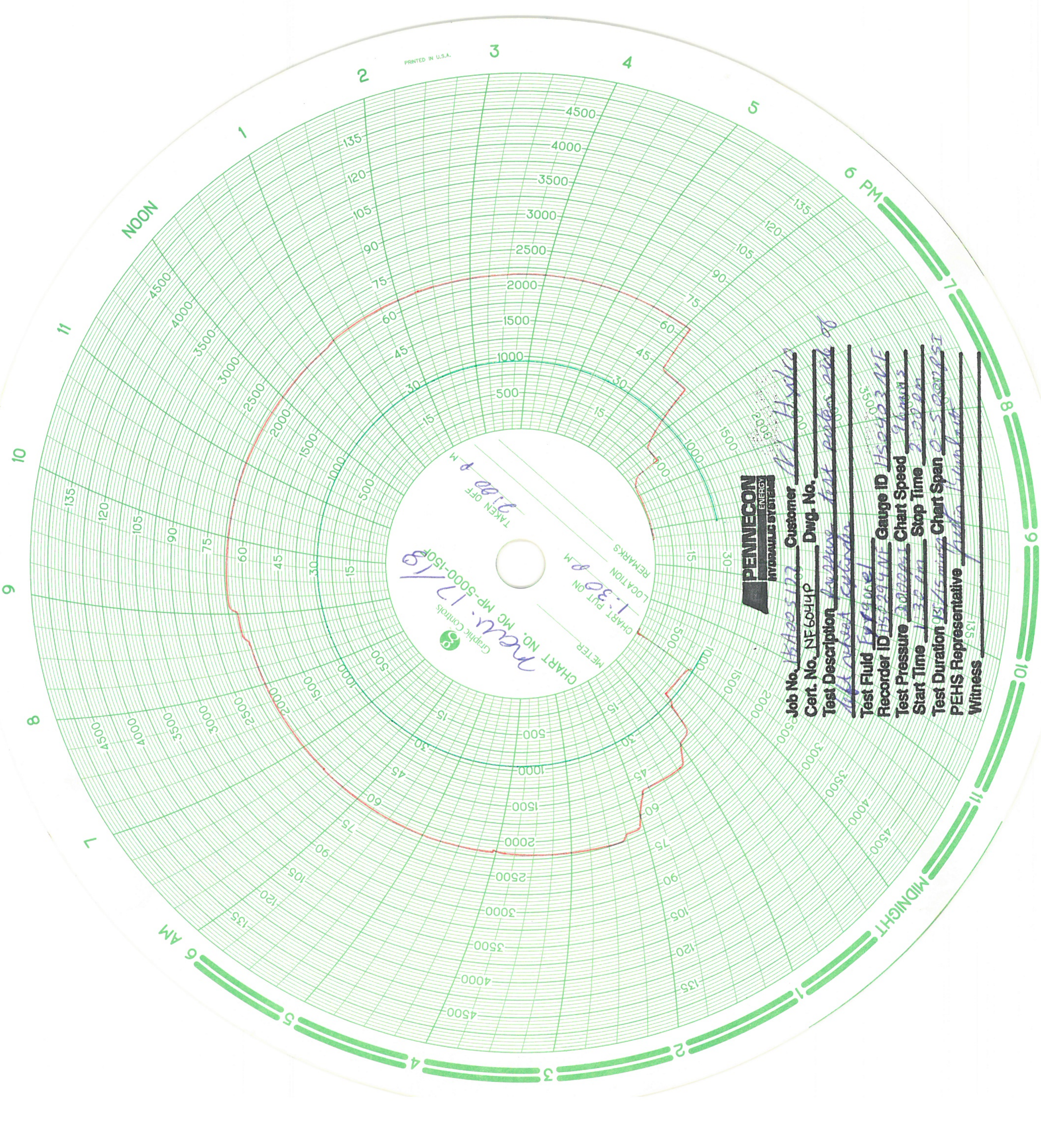
Brief Description of Test	Pressure tested left reheat cylinder on the piston side to 2000 psi with 15 minute stabilization and 15 minute hold.
Comments/ Notes	

Signed by: PEHS Representative
Signature: David Bass FOR J.R.
Print Name: Justin Rumbolt
Position: Hydraulic Tech
Date: 17-Nov-18

Accepted by: Client Representative
Signature:
Print Name:
Position:
Date:

Accepted by: Regulatory Rep.
Signature:
Print Name:
Position:
Date:

Accepted by: QC Representative
Signature:
Print Name:
Position:
Date:


PENNECON ENERGY
HYDRAULIC SYSTEMS
Job No.
Customer
Cert. No.
Dwg. No.
Test Description
Test Fluid
Recorder ID
Gauge ID
Test Pressure
Chart Speed
Start Time
Stop Time
Test Duration
Chart Span
PEHS Representative
Witness
CHART NO. MC MP-5000-150F
Graphic Controls
METER
CHART PUT ON
LOCATION
REMARKS
TAKEN OFF
PRINTED IN U.S.A.

PENNECON

TEST CERTIFICATE

Certificate No. NF6045P

1. CUSTOMER INFORMATION

Customer: NL Hydro	Work Order: HSA005177
Contact Name:	Customer Reference No.:
Customer Instructions/Notes: Pressure test left reheat cylinder on the rod side to 2000 psi.	

2. EQUIPMENT SPECIFICATIONS

☑ Pressure ☐ Hose ☐ Tube Spool Test

☐ Other/Specif

3. TEST SPECIFICATIONS

Recorder No.: HS0214NF
Recorder Cert. No.: 132664-18-04
Gauge No.: HS0403NF
Gauge Cert. No.: 132661-18-03
Test Result: ☑ Pas ☐ Fail
Test Pressure: 2000 psi
Test Medium: Fyrquel
Start Time: 3:00 PM
Stop Time: 3:30 PM
Stabilization: 15 minutes
Hold: 15 minutes

4. TEST DESCRIPTION

Hose(s) / Tube Spool(s)

No. of Pieces	Hose/Tube Size and/or Brand	Hose/Tube Service No. (if applicable)	N/A
1	left reheat cylinder		☐
			☐
			☐
			☐
			☐
			☐
			☐
			☐
			☐

For Additional Pages please see Attached

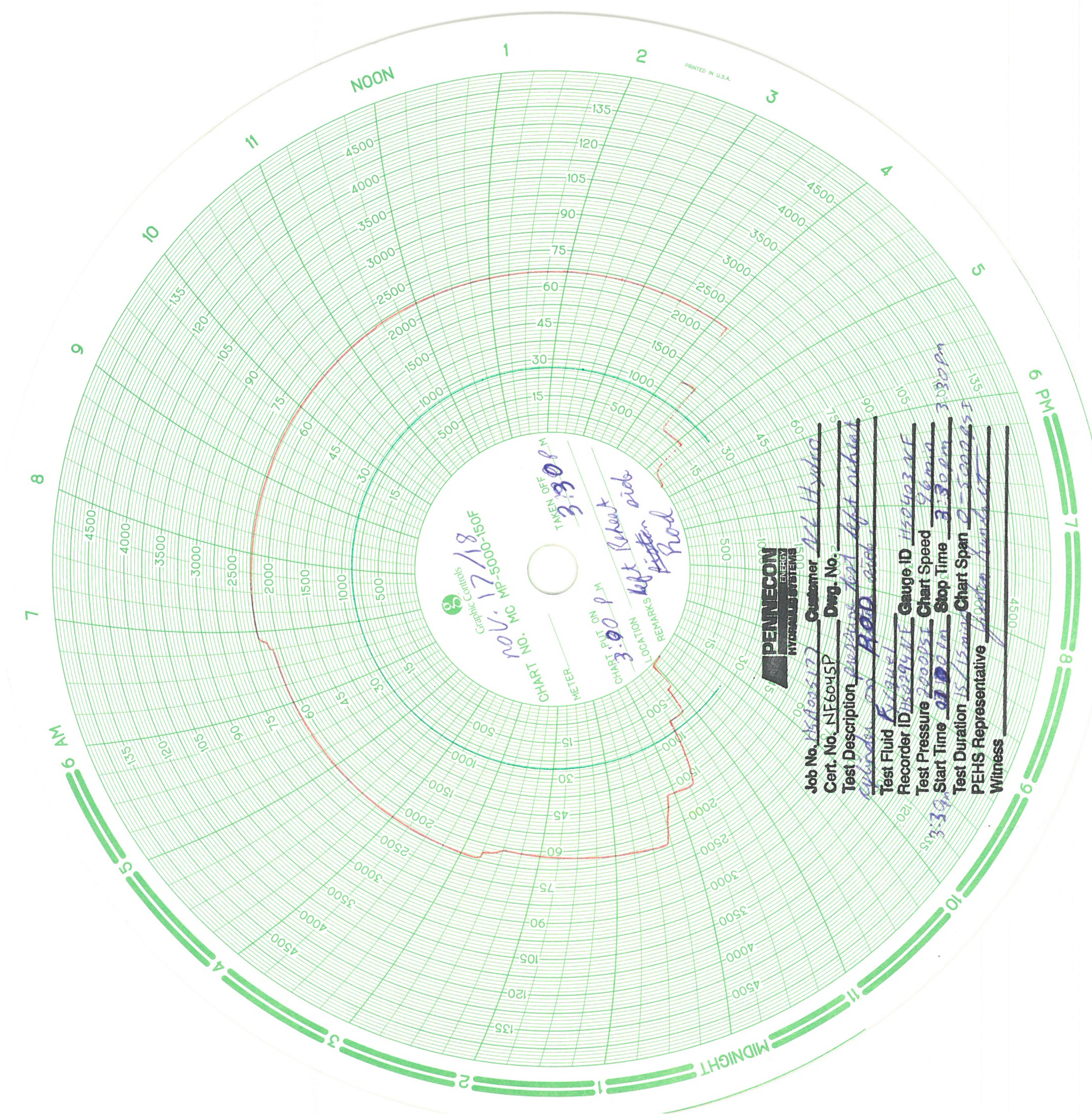
Brief Description of Test	Pressure tested left reheat cylinder on the rod side to 2000 psi with 15 minute stabilization and 15 minute hold.
Comments/ Notes	

Signed by: PEHS Representative
Signature: Don Bowes For JR
Print Name: Justin Rumbolt
Position: Hydraulic Tech
Date: 17-Nov-18

Accepted by: Client Representative
Signature:
Print Name:
Position:
Date:

Accepted by: Regulatory Rep.
Signature:
Print Name:
Position:
Date:

Accepted by: QC Representative
Signature:
Print Name:
Position:
Date:


NOON
MIDNIGHT
AM
PM
Graphic Controls
CHART NO. MC MP-5000-150F
METER
CHART PUT ON
TAKEN OFF
LOCATION
REMARKS
PRINTED IN U.S.A.
PENNECON
ENERGY
HYDRAULIC SYSTEMS
Job No.
Customer
Cert. No.
Dwg. No.
Test Description
Test Fluid
Gauge ID
Recorder ID
Chart Speed
Test Pressure
Stop Time
Start Time
Chart Span
Test Duration
PEHS Representative
Witness

PENNECON

TEST CERTIFICATE

Certificate No. NF6046P

1. CUSTOMER INFORMATION

Customer: N.L. Hydro	Work Order: HSA005177
Contact Name:	Customer Reference No.:
Customer Instructions/Notes: Pressure test main steam control cylinder on the rod side to 2000 psi.	

2. EQUIPMENT SPECIFICATIONS

☑ Pressure ☐ Hose ☐ Tube Spool Test

☐ Other/Specif

3. TEST SPECIFICATIONS

Recorder No.: HS0214NF
Recorder Cert. No.: 132664-18-04
Gauge No.: HS0403NF
Gauge Cert. No.: 132661-18-03
Test Result: ☑ Pas ☐ Fail
Test Pressure: 2000 psi
Test Medium: Fyrquel
Start Time: 4:00 PM
Stop Time: 4:30 PM
Stabilization: 15 minutes
Hold: 15 minutes

4. TEST DESCRIPTION

Hose(s) / Tube Spool(s)	No. of Pieces	Hose/Tube Size and/or Brand	Hose/Tube Service No. (if applicable)	N/A
	1	main steam control cylinder		☐
				☐
				☐
				☐
				☐
				☐
				☐
				☐
				☐

For Additional Pages please see Attached

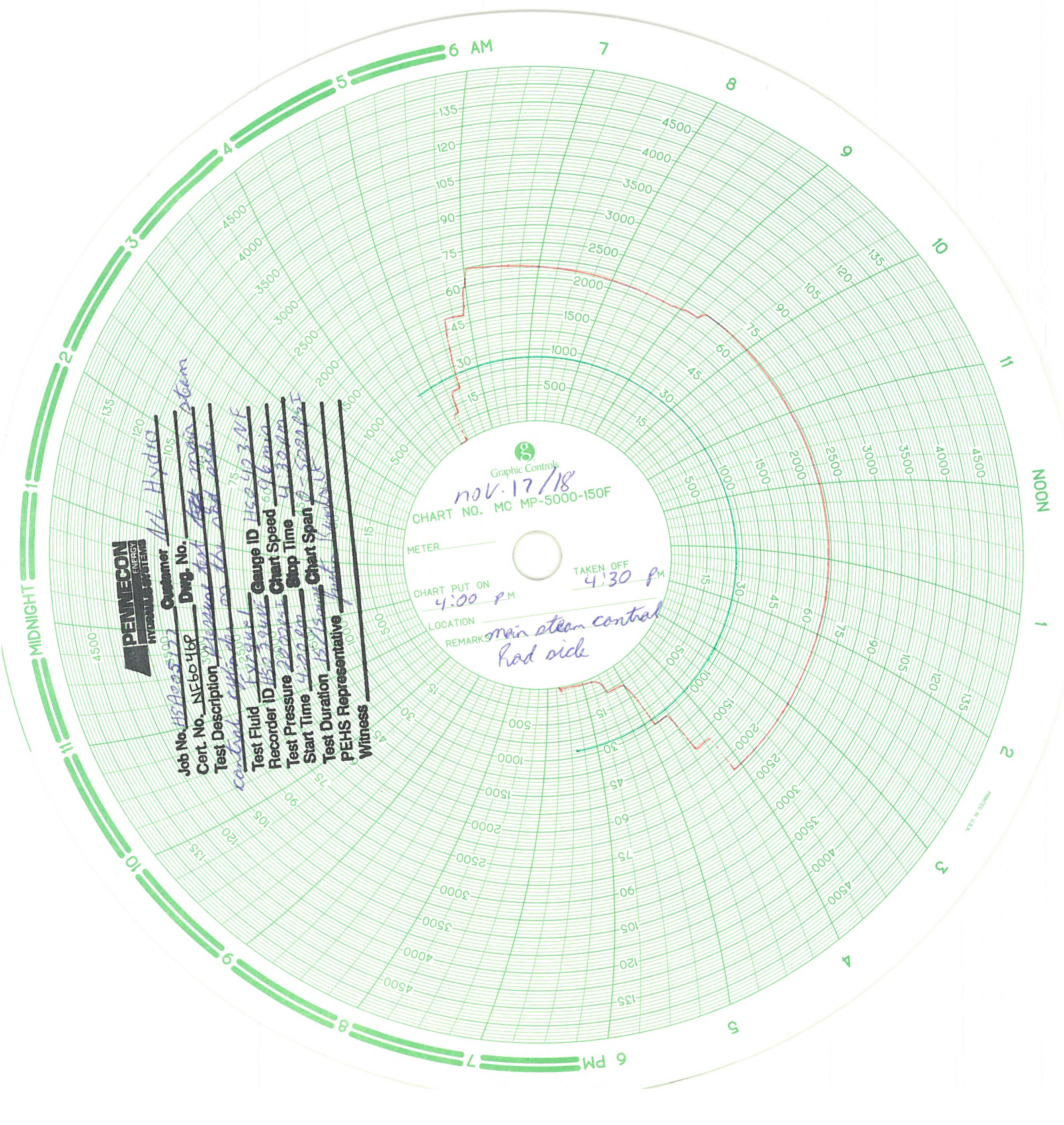
Brief Description of Test	Pressure tested main steam control cylinder on the rod side to 2000 psi.
Comments/ Notes	

Signed by: PEHS Representative
Signature: Dawi Bores For J.R.
Print Name: Justin Rumbolt
Position: Hydraulic Tech
Date: 17-Nov-18

Accepted by: Client Representative
Signature:
Print Name:
Position:
Date:

Accepted by: Regulatory Rep.
Signature:
Print Name:
Position:
Date:

Accepted by: QC Representative
Signature:
Print Name:
Position:
Date:


Graphic Controls
nov. 17/18
CHART NO. MC MP-5000-150F
METER
CHART PUT ON
4:00 pm
TAKEN OFF
4:30 pm
LOCATION
REMARKS main steam control
Rod side
PENNECON ENERGY
HYDRAULIC SYSTEMS
Job No.
Customer NL Hydro
Cert. No.
Dwg. No.
Test Description
Test Fluid
Gauge ID
Recorder ID
Chart Speed
Test Pressure
Stop Time
Start Time
Chart Span
Test Duration
PEHS Representative
Witness
6 AM
NOON
6 PM
MIDNIGHT

PENNECON

TEST CERTIFICATE

Certificate No. NF6047P

1. CUSTOMER INFORMATION

Customer: NL Hydro	PHS Work Order: HSA005177
Contact Name:	Customer Reference No.:
Customer Instructions/Notes: Pressure test main steam control cylinder on the piston side to 2000 psi.	

2. EQUIPMENT SPECIFICATIONS

☑ Pressure ☐ Hose ☐ Tube Spool Test

☐ Other/Specif

3. TEST SPECIFICATIONS

Recorder No.: HS0214NF
Recorder Cert. No.: 132664-18-04
Gauge No.: HS0403NF
Gauge Cert. No.: 132661-18-03
Test Result: ☑ Pas ☐ Fail
Test Pressure: 2000 psi
Test Medium: Fyrquel
Start Time: 5:15 PM
Stop Time: 5:45 PM
Stabilization: 15 minutes
Hold: 15 minutes

4. TEST DESCRIPTION

Hose(s) / Tube Spool(s)

No. of Pieces	Hose/Tube Size and/or Brand	Hose/Tube Service No. (if applicable)	N/A
1	main steam control cylinder		☐
			☐
			☐
			☐
			☐
			☐
			☐
			☐
			☐

For Additional Pages please see Attached

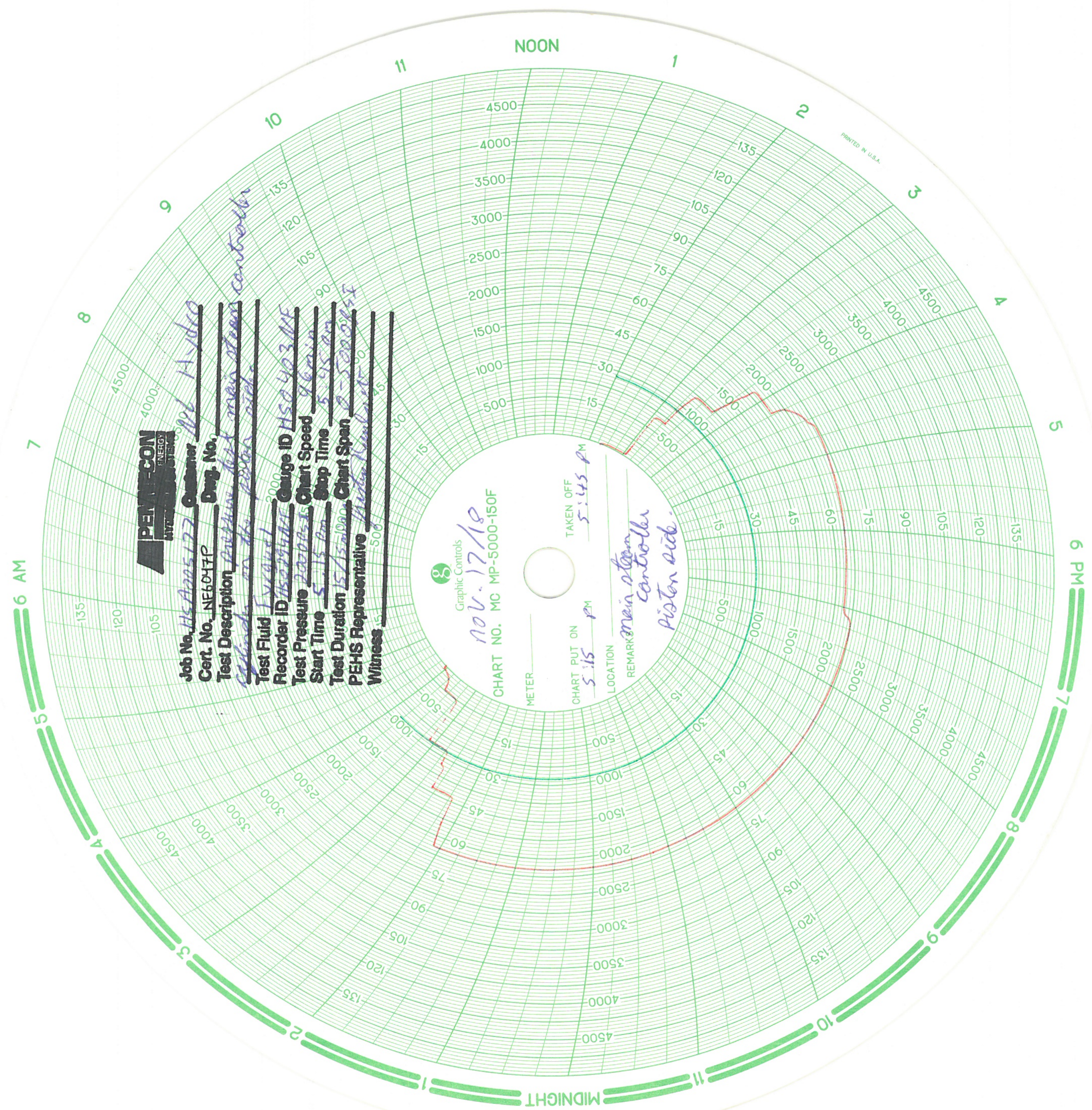
Brief Description of Test	Pressure tested main steam control cylinder on the piston side to 2000 psi.
Comments/ Notes	

Signed by: PEHS Representative
Signature: Dan Bonn FOR JR
Print Name: Justin Rumbolt
Position: Hydraulic Tech
Date: 17-Nov-18

Accepted by: Client Representative
Signature:
Print Name:
Position:
Date:

Accepted by: Regulatory Rep.
Signature:
Print Name:
Position:
Date:

Accepted by: QC Representative
Signature:
Print Name:
Position:
Date:


NOON
MIDNIGHT
6 AM
6 PM
Graphic Controls
CHART NO. MC MP-5000-150F
nov. 17/18
METER
CHART PUT ON 5:15 pm
TAKEN OFF 5:45 pm
LOCATION
REMARKS main steam controller piston side.
PRINTED IN U.S.A.

PENNECON

TEST CERTIFICATE

Certificate No. NF6048P

1. CUSTOMER INFORMATION

Customer: NL Hydro	PHS Work Order: HSA005177
Contact Name:	Customer Reference No.:
Customer Instructions/Notes: Pressure test left hand intercept cylinder on the piston side to 2000 PSI.	

2. EQUIPMENT SPECIFICATIONS

☑ Pressure ☐ Hose ☐ Tube Spool Test

☐ Other/Specif

3. TEST SPECIFICATIONS

Recorder No.: HS0214NF
Recorder Cert. No.: 132664-18-04
Gauge No.: HS0403NF
Gauge Cert. No.: 132661-18-03
Test Result: ☑ Pas ☐ Fail
Test Pressure: 2000 PSI
Test Medium: Fyrquel
Start Time: 7:00 PM
Stop Time: 7:30 PM
Stabilization: 15 minutes
Hold: 15 minutes

4. TEST DESCRIPTION

Hose(s) / Tube Spool(s)

No. of Pieces	Hose/Tube Size and/or Brand	Hose/Tube Service No. (if applicable)	N/A
1	left hand intercept valve cylinder		☐
			☐
			☐
			☐
			☐
			☐
			☐
			☐
			☐

For Additional Pages please see Attached

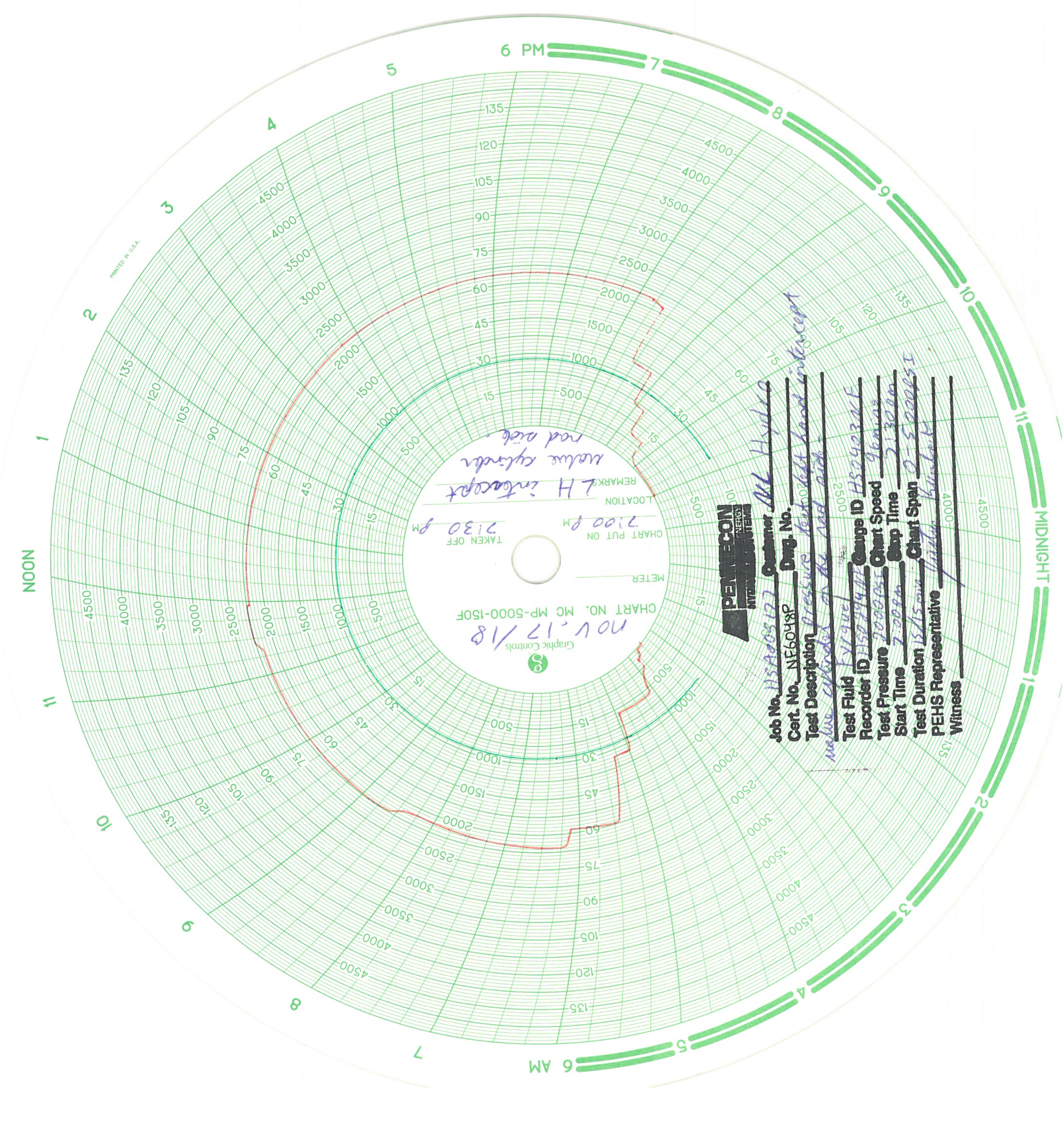
Brief Description of Test	Pressure tested left hand intercept valve cylinder on the piston side to 2000 psi with 15 minute stabilization and 15 minute hold.
Comments/ Notes	

Signed by: PEHS Representative
Signature: David Bems For JR
Print Name: Justin Rumbolt
Position: Hydraulic Tech
Date: 17-Nov-18

Accepted by: Client Representative
Signature:
Print Name:
Position:
Date:

Accepted by: Regulatory Rep.
Signature:
Print Name:
Position:
Date:

Accepted by: QC Representative
Signature:
Print Name:
Position:
Date:


6 PM
MIDNIGHT
6 AM
NOON
CHART NO. MC MP-5000-150F
Graphic Controls
METER
CHART PUT ON
TAKEN OFF
LOCATION
REMARKS
PENNECON
Job No.
Cert. No.
Test Description
Test Fluid
Recorder ID
Gauge ID
Test Pressure
Chart Speed
Start Time
Stop Time
Test Duration
Chart Span
PEHS Representative
Witness

PENNECON

2.0 Pressure Testing

b. Gear Calibration Certificates

Certificate Number 132664-18-04

iEAS
Keeping you in Control...

1218-1220 Kenmount Road
Paradise, NL A1L 1N3
Tel: 709-747-0816
Fax: 709-747-0825

Certificate Of Calibration

Customer	Hydraulic Systems	***Manufacturer***	WGI
Job Number	132-664	***ID***	HS0214NF
PO Number	PHSA020987	***Description***	1000 PSI Gauge 0.5%
Initial Condition	In Tolerance	***Model Number***	Elite 600
Complete Condition	In Tolerance	***Serial Number***	HS0214NF

iEAS Ltd. certifies that the above listed instrument meets or exceeds all specifications as stated in the referenced procedure (unless otherwise noted). It has been calibrated using measurement standards traceable to the National Institute of Standards and Technology (NIST), or to NIST accepted intrinsic standards of measurement, or derived by the ratio type of self-calibration techniques. This calibration complies with ANSI/NCSL Z540-1. Unless otherwise specified iEAS Ltd maintains a minimum of a 4:1 ratio between the equipment under test and the measurement system.

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Work Order Notes:

CALIBRATION INFORMATION

Service Date	10/3/2018	***Temperature***	21	***WO Results***	Pass
Due Date	10/3/2019	***Humidity***	45	***Service Type***	Calibration

STANDARDS USED FOR CALIBRATION

Description	Service Date	Due Date	ID
16 000 PSI Dead Weight Tester	10/17/2017	10/17/2022	I101

Adam Thompson
Laboratory Representative

Matt B
Quality Representative

Print Date: 10/3/2018 4:02:52 PM

iEAS
Keeping you in Control

Certificate Number 132661-18-03

1218-1220 Kenmount Road
Paradise, NL A1L 1N3
Tel: 709-747-0816
Fax: 709-747-0825

Certificate Of Calibration

Customer	Hydraulic Systems	***Manufacturer***	WGI
Job Number	132-661	***ID***	HS0403NF
PO Number	PHSA020811	***Description***	5000 psi Pressure Gauge
Initial Condition	In Tolerance	***Model Number***	Elite 400
Complete Condition	In Tolerance	***Serial Number***	HS0403NF

iEAS Ltd. certifies that the above listed instrument meets or exceeds all specifications as stated in the referenced procedure (unless otherwise noted). It has been calibrated using measurement standards traceable to the National Institute of Standards and Technology (NIST), or to NIST accepted intrinsic standards of measurement, or derived by the ratio type of self-calibration techniques. This calibration complies with ANSI/NCSL Z540-1. Unless otherwise specified iEAS Ltd maintains a minimum of a 4:1 ratio between the equipment under test and the measurement system.

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Work Order Notes:

CALIBRATION INFORMATION

Service Date	9/19/2018	***Temperature***	21	***WO Results***	Pass
Due Date	9/19/2019	***Humidity***	45	***Service Type***	Calibration

STANDARDS USED FOR CALIBRATION

Description	Service Date	Due Date	ID
16 000 PSI Dead Weight Tester	10/17/2017	10/17/2022	I101

Adam Thompson
Laboratory Representative

Quality Representative

Print Date: 9/19/2018 1:33:25 PM

iEAS
Keeping you in Control

Certificate Number 132604-18-05

1218-1220 Kenmount Road
Paradise, NL A1L 1N3
Tel: 709-747-0816
Fax: 709-747-0825

Certificate Of Calibration

Customer	Hydraulic Systems	***Manufacturer:***	Tech Cal
Job Number	132-604	***ID***	
PO Number	PHSA01869	***Description***	250 psi/150 Deg F Chart Recorder
Initial Condition	In Tolerance		
Complete Condition	In Tolerance	***Model Number***	HS0468NF
		Serial Number	HS0468NF

iEAS Ltd. certifies that the above listed instrument meets or exceeds all specifications as stated in the referenced procedure (unless otherwise noted). It has been calibrated using measurement standards traceable to the National Institute of Standards and Technology (NIST), or to NIST accepted intrinsic standards of measurement, or derived by the ratio type of self-calibration techniques. This calibration complies with ANSI/NCSL Z540-1. Unless otherwise specified iEAS Ltd maintains a minimum of a 4:1 ratio between the equipment under test and the measurement system.

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Work Order Notes:

CALIBRATION INFORMATION

Service Date	01/15/2018	***Temperature***	20	***WO Results***	Pass
Due Date	01/15/2019	***Humidity***	40	***Service Type***	Calibration

STANDARDS USED FOR CALIBRATION

Description	Service Date	Due Date	ID
16,000 PSI Dead Weight Tester	10/17/2017	10/17/2022	I101
9103 Dry Well Calibrator	10/19/2017	10/19/2018	I102

Adam Thompson
Laboratory Representative

Renee Haines
Quality Representative

Print Date: 1/15/2018 9:43:42 AM

Certificate Number 132653-18-05

iEAS
Keeping you in Control

1218-1220 Kenmount Road
Paradise, NL A1L 1N3
Tel: 709-747-0816
Fax: 709-747-0825

Certificate Of Calibration

Customer	Hydraulic Systems	***Manufacturer***	WGI
Job Number	132-653	***ID***	HS0349NF
PO Number	PHSA02042	***Description***	200 PSI Gauge
Initial Condition	Out of Tolerance	***Model Number***	Elite 400
Complete Condition	In Tolerance	***Serial Number***	HS0349NF

iEAS Ltd. certifies that the above listed instrument meets or exceeds all specifications as stated in the referenced procedure (unless otherwise noted). It has been calibrated using measurement standards traceable to the National Institute of Standards and Technology (NIST), or to NIST accepted intrinsic standards of measurement, or derived by the ratio type of self-calibration techniques. This calibration complies with ANSI/NCSL Z540-1. Unless otherwise specified iEAS Ltd maintains a minimum of a 4:1 ratio between the equipment under test and the measurement system.

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Work Order Notes:

CALIBRATION INFORMATION

Service Date	8/6/2018	***Temperature***	21	***WO Results***	Pass
Due Date	8/6/2019	***Humidity***	45	***Service Type***	Calibration

STANDARDS USED FOR CALIBRATION

Description	Service Date	Due Date	ID
16 000 PSI Dead Weight Tester	10/17/2017	10/17/2022	I101

Adam Thompson
Laboratory Representative

Curtis Lee
Quality Representative

Print Date: 8/6/2018 10:11:31 AM

3.0 Valve Lab Reports

Date: November 30 2018

Lab Report

Customer:

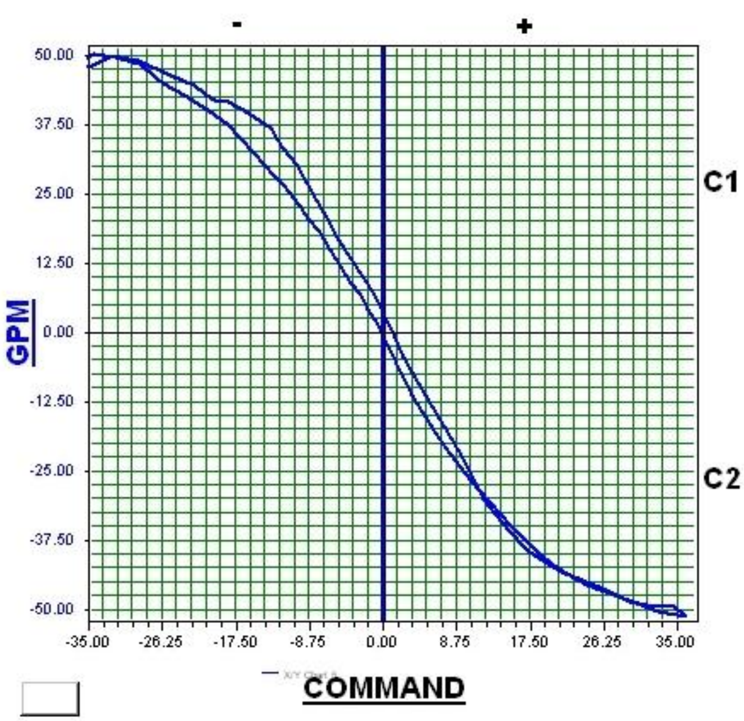
Customer PO # : PHSA021358

Pennecon Energy Hydraulic Systems
2 Maverick Place
Paradise, Newfoundland
A1L 0H6
709-726-3490

IES Job # :
923882

Make:	Model #:	Serial #:	Customer Order #:
Parker Servo Valve	450-1180	220	PHSA021358

RUN OUT



NOTES:
Heavy Contamination
Replaced O-Ring
Replaced Filter
Marginal Leakage

Date: November 30 2018

Lab Report

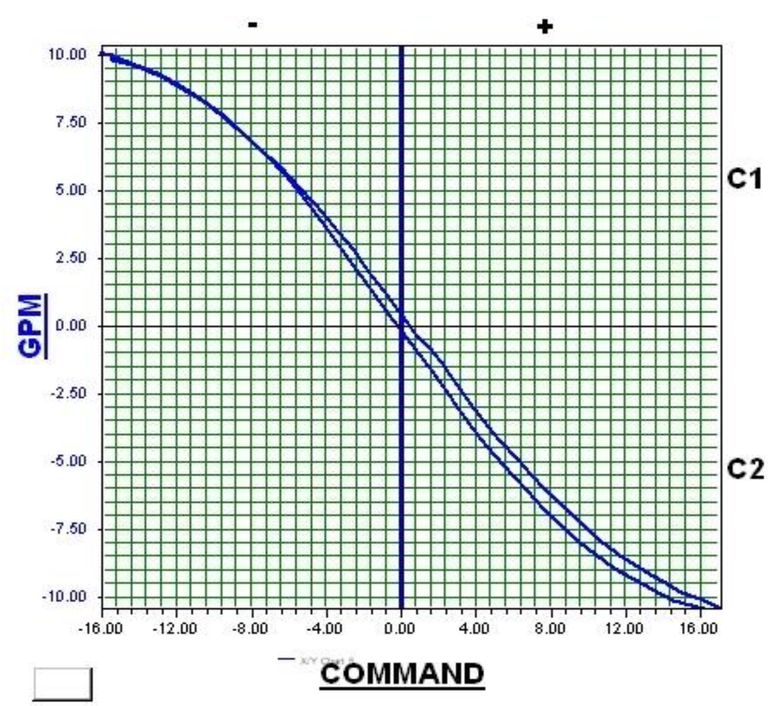
Customer: **Customer PO # :** PHSA021358

Pennecon Energy Hydraulic Systems
2 Maverick Place
Paradise, Newfoundland
A1L 0H6
709-726-3490

IES Job # : 923887

Make:	**Model #:**	**Serial #:**	**Customer Order #:**
Parker Servo Valve	415-1294	6132	PHSA021358

RUN OUT



NOTES:
Heavy Contamination
Replaced O-Ring
Replaced Filter
Chemically Cleaned

INDUSTRIAL ELECTRONIC SERVICES LTD

Date: November 30 2018

Lab Report

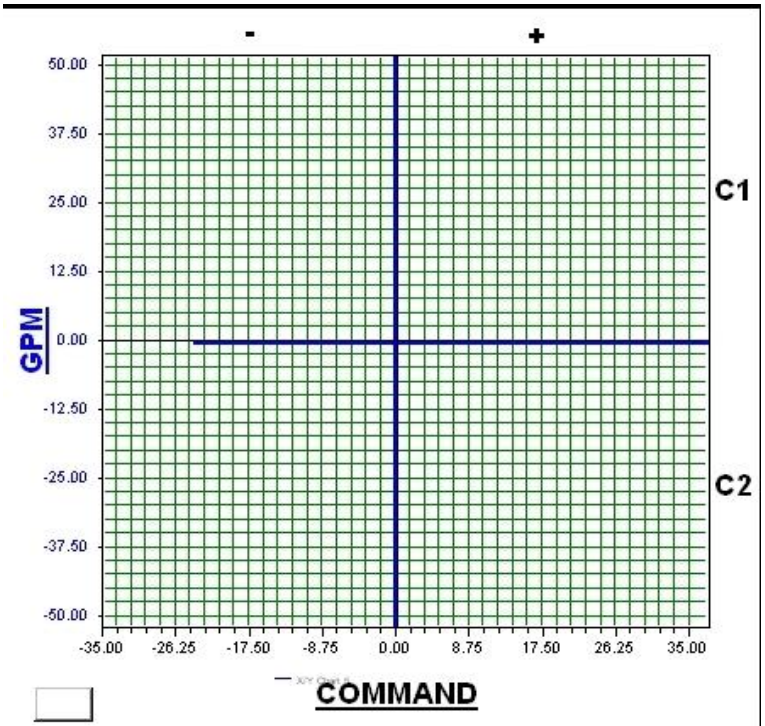
Customer: **Customer PO # :** PHSA021358

Pennecon Energy Hydraulic Systems
2 Maverick Place
Paradise, Newfoundland
A1L 0H6
709-726-3490

IES Job # : 923884

Make:	Model #:	Serial #:	Customer Order #:
Parker Servo Valve	450-1180	2313	PHSA021358

RUN OUT



NOTES:
Heavy Contamination
Hard Over
Chemically Cleaned
Rebuilt
Replaced O-Ring
Replaced Filter

INDUSTRIAL ELECTRONIC SERVICES LTD

Date: November 30 2018

Lab Report

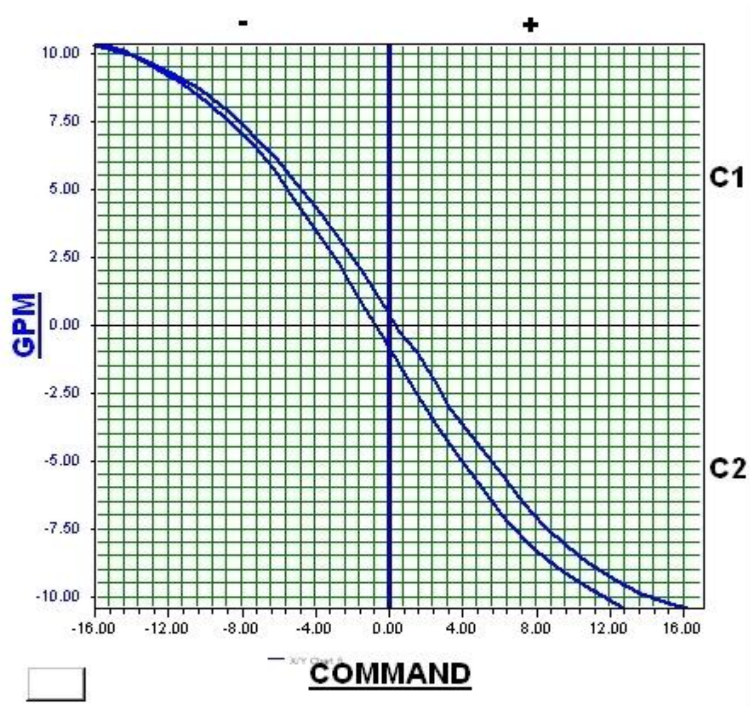
Customer: **Customer PO # :** PHSA021358

Pennecon Energy Hydraulic Systems
2 Maverick Place
Paradise, Newfoundland
A1L 0H6
709-726-3490

IES Job # : 923885

Make:	Model #:	Serial #:	Customer Order #:
Parker Servo Valve	415-1294	6036	PHSA021358

RUN OUT



NOTES:
Heavy Contamination
Replace O-Ring
Replace Filter
Chemically Cleaned

INDUSTRIAL ELECTRONIC SERVICES LTD

Date: November 30 2018

Lab Report

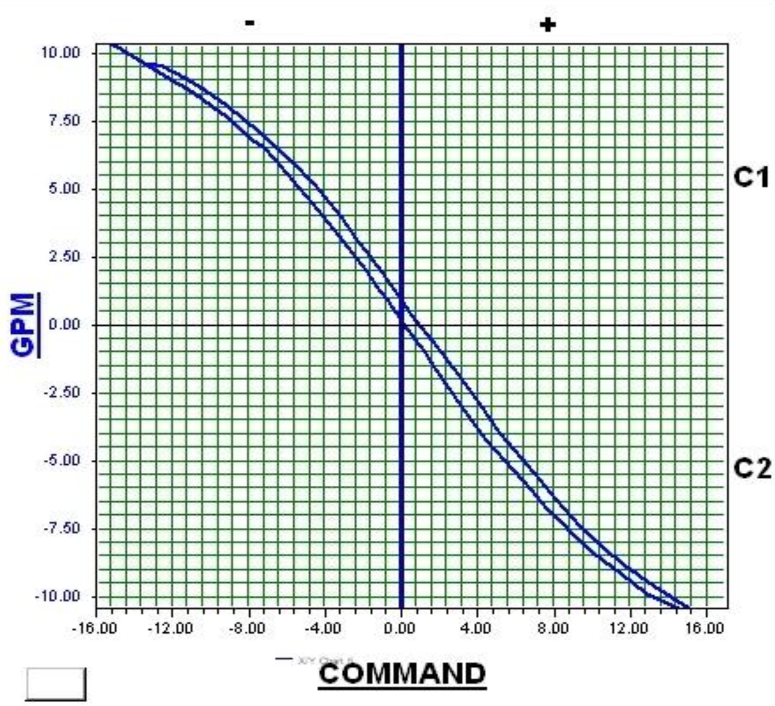
Customer: **Customer PO # :** PHSA021358

Pennecon Energy Hydraulic Systems
2 Maverick Place
Paradise, Newfoundland
A1L 0H6
709-726-3490

IES Job # :
923888

Make:	Model #:	Serial #:	Customer Order #:
Parker Servo Valve	415-1294	389	PHSA021358

RUN OUT



NOTES:
Heavy Contamination
Replaced O-Ring
Replaced Filter
Chemically Cleaned

Date: November 30 2018

Lab Report

Customer:

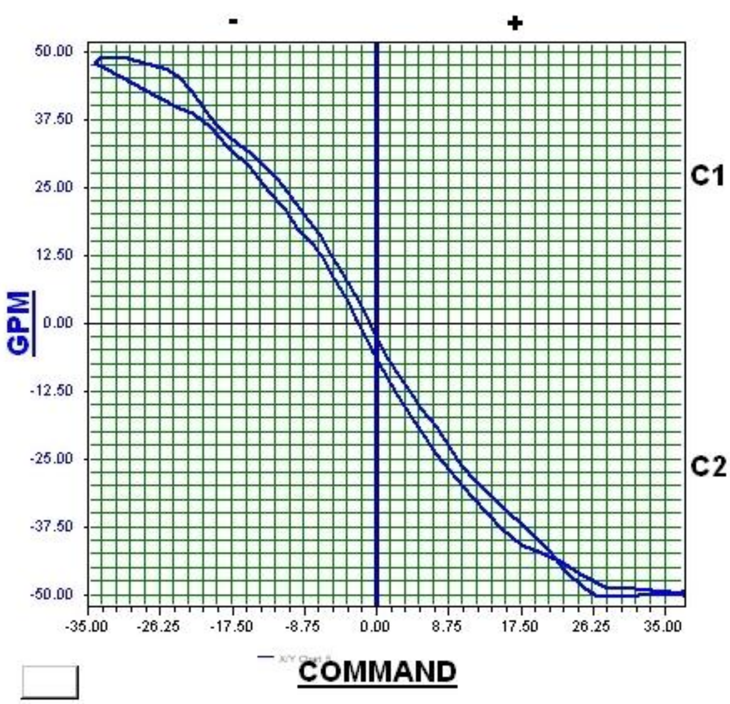
Customer PO # : PHSA021358

Pennecon Energy Hydraulic Systems
2 Maverick Place
Paradise, Newfoundland
A1L 0H6
709-726-3490

IES Job # :
923881

Make:	Model #:	Serial #:	Customer Order #:
Parker Servo Valve	450-1180	296	PHSA021358

RUN OUT



NOTES:
Heavy Contamination
Replaced O-Ring
Replaced Filter
Marginal Leakage

PENNECON

4.0 Flushing Reports

PENNECON

Flushing/Particle Count Form

Certificate No.: NF8964F

1.0 CUSTOMER INFORMATION	
Customer: NL Hydro	PHS Job No.: HSA005177
Contact Name:	Customer Reference No.:
Customer Instructions Notes: Flush Accumulator #1 (10-68-35894) to NAS1638 Class 06 cleanliness.	

2.0 JOB REQUIREMENTS / INFORMATION		
Job Type:	☐ Sample Reading Only - No Flushing	☑ Flushing with Sample
Cleanliness Level Required: NAS1638 Class 06		
Fluid Type: Fryquel		

3.0 FLUSHING	☐ N/A
☐ Line Flushing (Hoses, Tubing, Piping,	Flowrate: 30 GPM
☐ Container Flushing (Drum, Tote, Pail) - Full Volume Circulated Minimum 5	
☑ Accumulator Flushing - Minimum 10 Fill-Drain Cycles Completed	
Temperature:	
Equipment Details (type, qty., size, manufacturer): Accumulator #1	
Equipment ID (model, S/N): 10-68-35894	

4.0 WATER CONTENT READING	☑ N/A
Meter Used:	Reading Obtained:

5.0 PARTICLE COUNT READINGS (PER AS598 for Ocular Microscope Readings)

Particle Measurements					
(NAS 1638) Particle Size / Micrometers	5 – 15	15 – 25	25 – 50	50 – 100	100 +
Particles per 100 ml	9139	1760	445	20	13
(SAE AS4059) Particle Size / Micrometers	>5	>15	>25	>50	>100
Particles per 100 ml					
(ISO 4406) Particle Size / Micrometers	>4	>6	>14		
Scale Number					

6.0 PARTICLE COUNT RESULTS	
Standard Achieved: NAS1638 Class 06	☑ PASS ☐ FAIL
Additional Notes: Flush #1 - Sample of Fryquel taken while flushing Accumulator #1, 10-68-35894, achieved NAS1638 Class 06.	

7.0 SIGNATURE	
Technician: Pat Maher *Dave Bass For P M*	Date: November 6, 2018

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PENNECON

Flushing/Particle Count Form

Certificate No.: NF8965F

1.0 CUSTOMER INFORMATION	
Customer: NL Hydro	PHS Job No.: HSA005177
Contact Name:	Customer Reference No.:
Customer Instructions Notes: Flush Accumulator #2 (10-67-34409) to NAS1638 Class 06 cleanliness.	

2.0 JOB REQUIREMENTS / INFORMATION
Job Type: ☐ Sample Reading Only - No Flushing ☑ Flushing with Sample
Cleanliness Level Required: NAS1638 Class 06
Fluid Type: Fryquel

3.0 FLUSHING ☐ N/A
☐ Line Flushing (Hoses, Tubing, Piping, Flowrate: 30 GPM ☐ Container Flushing (Drum, Tote, Pail) - Full Volume Circulated Minimum 5 ☑ Accumulator Flushing - Minimum 10 Fill-Drain Cycles Completed
Temperature:
Equipment Details (type, qty., size, manufacturer): Accumulator #2
Equipment ID (model, S/N): 10-67-34409

4.0 WATER CONTENT READING	☑ N/A
Meter Used:	Reading Obtained:

5.0 PARTICLE COUNT READINGS (PER AS598 for Ocular Microscope Readings)

Particle Measurements					
(NAS 1638) Particle Size / Micrometers	5 – 15	15 – 25	25 – 50	50 – 100	100 +
Particles per 100 ml	10,344	1563	264	15	9
(SAE AS4059) Particle Size / Micrometers	>5	>15	>25	>50	>100
Particles per 100 ml					
(ISO 4406) Particle Size / Micrometers	>4	>6	>14		
Scale Number					

6.0 PARTICLE COUNT RESULTS	
Standard Achieved: NAS1638 Class 06	☑ PASS ☐ FAIL
Additional Notes: Flush #2 - Sample of Fryquel taken while flushing Accumulator #2, 10-67-34409, achieved NAS1638 Class 06.	

7.0 SIGNATURE	
Technician: Pat Maher *David Bonnell for P.M.*	Date: November 6, 2018

PENNECON

Flushing/Particle Count Form

Certificate No.: NF8966F

1.0 CUSTOMER INFORMATION	
Customer: NL Hydro	PHS Job No.: HSA005177
Contact Name: Bill Kilfoy	Customer Reference No.:
Customer Instructions Notes: Flush Unit #1 HPU & system to NAS1638 Class 06 cleanliness.	

2.0 JOB REQUIREMENTS / INFORMATION
Job Type: ☐ Sample Reading Only - No Flushing ☑ Flushing with Sample
Cleanliness Level Required: NAS1638 Class 06
Fluid Type: Fryquel

3.0 FLUSHING ☐ N/A
☑ Line Flushing (Hoses, Tubing, Piping, Flowrate: 30 GPM ☐ Container Flushing (Drum, Tote, Pail) - Full Volume Circulated Minimum 5 ☐ Accumulator Flushing - Minimum 10 Fill-Drain Cycles Completed
Temperature:
Equipment Details (type, qty., size, manufacturer): Left Interceptor Valve
Equipment ID (model, S/N):

4.0 WATER CONTENT READING ☑ N/A	
Meter Used:	Reading Obtained:

5.0 PARTICLE COUNT READINGS (PER AS598 for Ocular Microscope Readings)

Particle Measurements					
(NAS 1638) Particle Size / Micrometers	5 – 15	15 – 25	25 – 50	50 – 100	100 +
Particles per 100 ml	39,658	8096	1354	196	88
(SAE AS4059) Particle Size / Micrometers	>5	>15	>25	>50	>100
Particles per 100 ml					
(ISO 4406) Particle Size / Micrometers	>4	>6	>14		
Scale Number					

6.0 PARTICLE COUNT RESULTS	
Standard Achieved: NAS1638 Class 09	☐ PASS ☑ FAIL
Additional Notes: Sample of Fryquel taken while flushing Left Interceptor Valve failed to achieve NAS1638 Class 06. More flushing required.	

7.0 SIGNATURE	
Technician: Pat Maher David Bows For PM	Date: November 12, 2018

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PENNECON

Flushing/Particle Count Form

Certificate No.: NF8967F

1.0 CUSTOMER INFORMATION	
Customer: NL Hydro	PHS Job No.: HSA005177
Contact Name: Bill Kilfoy	Customer Reference No.:
Customer Instructions Notes: Flush Unit #1 HPU & system to NAS1638 Class 06 cleanliness.	

2.0 JOB REQUIREMENTS / INFORMATION
Job Type: ☐ Sample Reading Only - No Flushing ☑ Flushing with Sample
Cleanliness Level Required: NAS1638 Class 06
Fluid Type: Fryquel

3.0 FLUSHING ☐ N/A
☑ Line Flushing (Hoses, Tubing, Piping, Flowrate: 30 GPM ☐ Container Flushing (Drum, Tote, Pail) - Full Volume Circulated Minimum 5 ☐ Accumulator Flushing - Minimum 10 Fill-Drain Cycles Completed
Temperature:
Equipment Details (type, qty., size, manufacturer): Left Interceptor Valve
Equipment ID (model, S/N):

4.0 WATER CONTENT READING ☑ N/A	
Meter Used:	Reading Obtained:

5.0 PARTICLE COUNT READINGS (PER AS598 for Ocular Microscope Readings)

Particle Measurements

(NAS 1638) Particle Size / Micrometers	5 – 15	15 – 25	25 – 50	50 – 100	100 +
Particles per 100 ml	7186	1319	130	25	14
(SAE AS4059) Particle Size / Micrometers	>5	>15	>25	>50	>100
Particles per 100 ml					
(ISO 4406) Particle Size / Micrometers	>4	>6	>14		
Scale Number					

6.0 PARTICLE COUNT RESULTS	
Standard Achieved: NAS1638 Class 06	☑ PASS ☐ FAIL
Additional Notes: Flush #3 - Sample of Fryquel taken while flushing Left Interceptor Valve achieved NAS1638 Class 06.	

7.0 SIGNATURE	
Technician: Pat Maher Dou Bon For PM	Date: November 12, 2018

PENNECON

Flushing/Particle Count Form

Certificate No.: NF8968F

1.0 CUSTOMER INFORMATION	
Customer: NL Hydro	PHS Job No.: HSA005177
Contact Name: Bill Kilfoy	Customer Reference No.:
Customer Instructions Notes: Flush Unit #1 HPU & system to NAS1638 Class 06 cleanliness.	

2.0 JOB REQUIREMENTS / INFORMATION		
Job Type:	☐ Sample Reading Only - No Flushing	☑ Flushing with Sample
Cleanliness Level Required: NAS1638 Class 06		
Fluid Type: Fryquel		

3.0 FLUSHING	☐ N/A
☑ Line Flushing (Hoses, Tubing, Piping,	Flowrate: 30 GPM
☐ Container Flushing (Drum, Tote, Pail) - Full Volume Circulated Minimum 5	
☐ Accumulator Flushing - Minimum 10 Fill-Drain Cycles Completed	
Temperature:	
Equipment Details (type, qty., size, manufacturer): Left Reheat Valve	
Equipment ID (model, S/N):	

4.0 WATER CONTENT READING	☑ N/A
Meter Used:	Reading Obtained:

5.0 PARTICLE COUNT READINGS (PER AS598 for Ocular Microscope Readings)

Particle Measurements					
(NAS 1638) Particle Size / Micrometers	5 – 15	15 – 25	25 – 50	50 – 100	100 +
Particles per 100 ml	7373	1258	317	24	10
(SAE AS4059) Particle Size / Micrometers	>5	>15	>25	>50	>100
Particles per 100 ml					
(ISO 4406) Particle Size / Micrometers	>4	>6	>14		
Scale Number					

6.0 PARTICLE COUNT RESULTS	
Standard Achieved: NAS1638 Class 06	☑ PASS ☐ FAIL
Additional Notes: Flush #4 - Sample of Fryquel taken while flushing Left Reheat Valve achieved NAS1638 Class 06.	

7.0 SIGNATURE	
Technician: Pat Maher [signature] For PM	Date: November 12, 2018

PEHS-OF-01 Rev. 1

PENNECON

Flushing/Particle Count Form

Certificate No.: NF8969F

1.0 CUSTOMER INFORMATION	
Customer: NL Hydro	PHS Job No.: HSA005177
Contact Name: Bill Kilfoy	Customer Reference No.:
Customer Instructions Notes: Flush Unit #1 HPU & system to NAS1638 Class 06 cleanliness.	

2.0 JOB REQUIREMENTS / INFORMATION		
Job Type:	☐ Sample Reading Only - No Flushing	☑ Flushing with Sample
Cleanliness Level Required: NAS1638 Class 06		
Fluid Type: Fryquel		

3.0 FLUSHING	☐ N/A
☑ Line Flushing (Hoses, Tubing, Piping,	Flowrate: 30 GPM
☐ Container Flushing (Drum, Tote, Pail) - Full Volume Circulated Minimum 5	
☐ Accumulator Flushing - Minimum 10 Fill-Drain Cycles Completed	
Temperature:	
Equipment Details (type, qty., size, manufacturer): Main Stop Valve	
Equipment ID (model, S/N):	

4.0 WATER CONTENT READING	☑ N/A
Meter Used:	Reading Obtained:

5.0 PARTICLE COUNT READINGS (PER AS598 for Ocular Microscope Readings)

Particle Measurements					
(NAS 1638) Particle Size / Micrometers	5 – 15	15 – 25	25 – 50	50 – 100	100 +
Particles per 100 ml	6689	1123	200	17	8
(SAE AS4059) Particle Size / Micrometers	>5	>15	>25	>50	>100
Particles per 100 ml					
(ISO 4406) Particle Size / Micrometers	>4	>6	>14		
Scale Number					

6.0 PARTICLE COUNT RESULTS	
Standard Achieved: NAS1638 Class 06	☑ PASS ☐ FAIL
Additional Notes: Flush #5 - Sample of Fryquel taken while flushing Main Stop Valve achieved NAS1638 Class 06.	

7.0 SIGNATURE	
Technician: Pat Maher David Banks For P.M.	Date: November 12, 2018

PENNECON

Flushing/Particle Count Form

Certificate No.: NF8970F

1.0 CUSTOMER INFORMATION	
Customer: NL Hydro	PHS Job No.: HSA005177
Contact Name: Bill Kilfoy	Customer Reference No.:
Customer Instructions Notes: Flush Unit #1 HPU tubing to NAS1638 Class 06 cleanliness.	

2.0 JOB REQUIREMENTS / INFORMATION

Job Type: ☐ Sample Reading Only - No Flushing ☑ Flushing with Sample

Cleanliness Level Required: NAS1638 Class 06

Fluid Type: Fryquel

3.0 FLUSHING ☐ N/A

☑ Line Flushing (Hoses, Tubing, Piping, Flowrate: 30 GPM

☐ Container Flushing (Drum, Tote, Pail) - Full Volume Circulated Minimum 5

☐ Accumulator Flushing - Minimum 10 Fill-Drain Cycles Completed

Temperature: 45°C

Equipment Details (type, qty., size, manufacturer): Interceptor Valve Right

Equipment ID (model, S/N):

4.0 WATER CONTENT READING	☑ N/A
Meter Used:	Reading Obtained:

5.0 PARTICLE COUNT READINGS (PER AS598 for Ocular Microscope Readings)

Particle Measurements					
(NAS 1638) Particle Size / Micrometers	5 – 15	15 – 25	25 – 50	50 – 100	100 +
Particles per 100 ml	2233	1043	343	29	3
(SAE AS4059) Particle Size / Micrometers	>5	>15	>25	>50	>100
Particles per 100 ml					
(ISO 4406) Particle Size / Micrometers	>4	>6	>14		
Scale Number					

6.0 PARTICLE COUNT RESULTS	
Standard Achieved: NAS1638 Class 06	☑ PASS ☐ FAIL
Additional Notes: Flush #6 - Sample of Fryquel taken while flushing Interceptor Valve Right achieved NAS1638 Class 06.	

7.0 SIGNATURE	
Technician: Matt Fagan Dail Barr For M F	Date: November 12, 2018

PENNECON

Flushing/Particle Count Form

Certificate No.: NF8971F

1.0 CUSTOMER INFORMATION	
Customer: NL Hydro	PHS Job No.: HSA005177
Contact Name: Bill Kilfoy	Customer Reference No.:
Customer Instructions Notes: Flush Unit #1 HPU tubing to NAS1638 Class 06 cleanliness.	

2.0 JOB REQUIREMENTS / INFORMATION		
Job Type:	☐ Sample Reading Only - No Flushing	☑ Flushing with Sample
Cleanliness Level Required: NAS1638 Class 06		
Fluid Type: Fryquel		

3.0 FLUSHING	☐ N/A
☑ Line Flushing (Hoses, Tubing, Piping,	Flowrate: 30 GPM
☐ Container Flushing (Drum, Tote, Pail) - Full Volume Circulated Minimum 5	
☐ Accumulator Flushing - Minimum 10 Fill-Drain Cycles Completed	
Temperature:	
Equipment Details (type, qty., size, manufacturer): Reheat Valve Right	
Equipment ID (model, S/N):	

4.0 WATER CONTENT READING	☑ N/A
Meter Used:	Reading Obtained:

5.0 PARTICLE COUNT READINGS (PER AS598 for Ocular Microscope Readings)

Particle Measurements					
(NAS 1638) Particle Size / Micrometers	5 – 15	15 – 25	25 – 50	50 – 100	100 +
Particles per 100 ml	6853	1463	301	40	1
(SAE AS4059) Particle Size / Micrometers	>5	>15	>25	>50	>100
Particles per 100 ml					
(ISO 4406) Particle Size / Micrometers	>4	>6	>14		
Scale Number					

6.0 PARTICLE COUNT RESULTS	
Standard Achieved: NAS1638 Class 06	☑ PASS ☐ FAIL
Additional Notes: Flush #7 - Sample of Fryquel taken while flushing Reheat Valve Right achieved NAS1638 Class 06.	

7.0 SIGNATURE	
Technician: Matt Fagan David Bows For MF	Date: November 12, 2018

PENNECON

Flushing/Particle Count Form

Certificate No.: NF8972F

1.0 CUSTOMER INFORMATION

Customer: NL Hydro	PHS Job No.: HSA005177
Contact Name: Bill Kilfoy	Customer Reference No.:

Customer Instructions Notes: Flush components and tubing to NAS1638 Class 06 cleanliness.

2.0 JOB REQUIREMENTS / INFORMATION

Job Type: ☐ Sample Reading Only - No Flushing ☑ Flushing with Sample

Cleanliness Level Required: NAS1638 Class 06

Fluid Type: Fryquel

3.0 FLUSHING ☐ N/A

☑ Line Flushing (Hoses, Tubing, Piping, Flowrate: 30 GPM

☐ Container Flushing (Drum, Tote, Pail) - Full Volume Circulated Minimum 5

☐ Accumulator Flushing - Minimum 10 Fill-Drain Cycles Completed

Temperature:

Equipment Details (type, qty., size, manufacturer): #6, Control Valve (3rd Floor)

Equipment ID (model, S/N):

4.0 WATER CONTENT READING ☑ N/A

Meter Used:	Reading Obtained:

5.0 PARTICLE COUNT READINGS (PER AS598 for Ocular Microscope Readings)

Particle Measurements

(NAS 1638) Particle Size / Micrometers	5 – 15	15 – 25	25 – 50	50 – 100	100 +
Particles per 100 ml	5671	1133	379	55	12
(SAE AS4059) Particle Size / Micrometers	>5	>15	>25	>50	>100
Particles per 100 ml					
(ISO 4406) Particle Size / Micrometers	>4	>6	>14		
Scale Number					

6.0 PARTICLE COUNT RESULTS

Standard Achieved: NAS1638 Class 06 ☑ PASS ☐ FAIL

Additional Notes: Flush #8 - Sample of Fryquel taken while flushing #6, Control Valve (3rd Floor) achieved NAS1638 Class 06.

7.0 SIGNATURE

Technician: Chris Klomp CK	Date: November 13, 2018

PENNECON

Flushing/Particle Count Form

Certificate No.: NF8973F

1.0 CUSTOMER INFORMATION	
Customer: NL Hydro	PHS Job No.: HSA005177
Contact Name: Bill Kilfoy	Customer Reference No.:
Customer Instructions Notes: Set up and flush both main pumps with E16V to NAS1638 Class 06 cleanliness.	

2.0 JOB REQUIREMENTS / INFORMATION		
Job Type:	☐ Sample Reading Only - No Flushing	☑ Flushing with Sample
Cleanliness Level Required: NAS1638 Class 06		
Fluid Type: FryQuel		

3.0 FLUSHING	☐ N/A
☑ Line Flushing (Hoses, Tubing, Piping,	Flowrate: 7 GPM
☐ Container Flushing (Drum, Tote, Pail) - Full Volume Circulated Minimum 5	
☐ Accumulator Flushing - Minimum 10 Fill-Drain Cycles Completed	
Temperature:	
Equipment Details (type, qty., size, manufacturer): Both main pumps on HPU skid	
Equipment ID (model, S/N):	

4.0 WATER CONTENT READING	☑ N/A
Meter Used:	Reading Obtained:

5.0 PARTICLE COUNT READINGS (PER AS598 for Ocular Microscope Readings)

Particle Measurements					
(NAS 1638) Particle Size / Micrometers	5 – 15	15 – 25	25 – 50	50 – 100	100 +
Particles per 100 ml	3233	2437	398	36	9
(SAE AS4059) Particle Size / Micrometers	>5	>15	>25	>50	>100
Particles per 100 ml					
(ISO 4406) Particle Size / Micrometers	>4	>6	>14		
Scale Number					

6.0 PARTICLE COUNT RESULTS	
Standard Achieved: NAS1638 Class 06	☑ PASS ☐ FAIL
Additional Notes: Sample of FryQuel taken while flushing both main pumps on HPU skid achieved NAS1638 Class 06.	

7.0 SIGNATURE	
Technician: Chris Klomp [signature] for CK	Date: November 14, 2018

PENNECON

Flushing/Particle Count Form

Certificate No.: NF8974F

1.0 CUSTOMER INFORMATION

Customer: NL Hydro	PHS Job No.: HSA005177
Contact Name: Bill Kilfoy	Customer Reference No.:
Customer Instructions Notes: Flush overflow tank to NAS1638 Class 06 cleanliness.	

2.0 JOB REQUIREMENTS / INFORMATION

Job Type: ☐ Sample Reading Only - No Flushing ☑ Flushing with Sample

Cleanliness Level Required: NAS1638 Class 06

Fluid Type: FryQuel

3.0 FLUSHING ☐ N/A

☑ Line Flushing (Hoses, Tubing, Piping, Flowrate: 11 GPM

☐ Container Flushing (Drum, Tote, Pail) - Full Volume Circulated Minimum 5

☐ Accumulator Flushing - Minimum 10 Fill-Drain Cycles Completed

Temperature:

Equipment Details (type, qty., size, manufacturer): Overflow tank attached to Main HPU

Equipment ID (model, S/N):

4.0 WATER CONTENT READING ☑ N/A

Meter Used:	Reading Obtained:

5.0 PARTICLE COUNT READINGS (PER AS598 for Ocular Microscope Readings)

Particle Measurements

(NAS 1638) Particle Size / Micrometers	5 – 15	15 – 25	25 – 50	50 – 100	100 +
Particles per 100 ml	1684	1403	298	43	12
(SAE AS4059) Particle Size / Micrometers	>5	>15	>25	>50	>100
Particles per 100 ml					
(ISO 4406) Particle Size / Micrometers	>4	>6	>14		
Scale Number					

6.0 PARTICLE COUNT RESULTS

Standard Achieved: NAS1638 Class 06 ☑ PASS ☐ FAIL

Additional Notes: Sample of FryQuel taken while flushing overflow tank attached to Main HPU achieved NAS1638 Class 06.

7.0 SIGNATURE

Technician: Chris Klomp Dan Bass for C/K Date: November 14, 2018

PENNECON

Flushing/Particle Count Form

Certificate No.: NF8975F

1.0 CUSTOMER INFORMATION	
Customer: NL Hydro	PHS Job No.: HSA005177
Contact Name: Bill Kilfoy	Customer Reference No.:
Customer Instructions Notes: Flush Valve block for 4” control valve cylinder to NAS1638 Class 06 cleanliness.	

2.0 JOB REQUIREMENTS / INFORMATION
Job Type: ☐ Sample Reading Only - No Flushing ☑ Flushing with Sample
Cleanliness Level Required: NAS1638 Class 06
Fluid Type: FryQuel EHC-S

3.0 FLUSHING ☐ N/A
☑ Line Flushing (Hoses, Tubing, Piping, Flowrate: 20 GPM ☐ Container Flushing (Drum, Tote, Pail) - Full Volume Circulated Minimum 5 ☐ Accumulator Flushing - Minimum 10 Fill-Drain Cycles Completed
Temperature: 45-50°C
Equipment Details (type, qty., size, manufacturer): Valve Block for 4” Control Valve cylinder
Equipment ID (model, S/N): N/A

4.0 WATER CONTENT READING ☑ N/A	
Meter Used:	Reading Obtained:

5.0 PARTICLE COUNT READINGS (PER AS598 for Ocular Microscope Readings)

Particle Measurements

(NAS 1638) Particle Size / Micrometers	5 – 15	15 – 25	25 – 50	50 – 100	100 +
Particles per 100 ml	8460	927	207	10	3
(SAE AS4059) Particle Size / Micrometers	>5	>15	>25	>50	>100
Particles per 100 ml					
(ISO 4406) Particle Size / Micrometers	>4	>6	>14		
Scale Number					

6.0 PARTICLE COUNT RESULTS	
Standard Achieved: NAS1638 Class 06	☑ PASS ☐ FAIL
Additional Notes: Sample of FryQuel taken while flushing Valve Block for 4” Control Valve cylinder achieved NAS1638 Class 06.	

7.0 SIGNATURE	
Technician: Adam Gruchy	Date: November 14, 2018

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PENNECON

Flushing/Particle Count Form

Certificate No.: NF8976F

1.0 CUSTOMER INFORMATION	
Customer: NL Hydro	PHS Job No.: HSA005177
Contact Name: Bill Kilfoy	Customer Reference No.:
Customer Instructions Notes: Flush LH Reheat cylinder control block to NAS1638 Class 06 cleanliness.	

2.0 JOB REQUIREMENTS / INFORMATION
Job Type: ☐ Sample Reading Only - No Flushing ☑ Flushing with Sample
Cleanliness Level Required: NAS1638 Class 06
Fluid Type: FryQuel EHC-S

3.0 FLUSHING ☐ N/A
☑ Line Flushing (Hoses, Tubing, Piping, Flowrate: 10 GPM ☐ Container Flushing (Drum, Tote, Pail) - Full Volume Circulated Minimum 5 ☐ Accumulator Flushing - Minimum 10 Fill-Drain Cycles Completed
Temperature: 45-50°C
Equipment Details (type, qty., size, manufacturer): LH Reheat cylinder control block
Equipment ID (model, S/N): N/A

4.0 WATER CONTENT READING ☑ N/A	
Meter Used:	Reading Obtained:

5.0 PARTICLE COUNT READINGS (PER AS598 for Ocular Microscope Readings)

Particle Measurements					
(NAS 1638) Particle Size / Micrometers	5 – 15	15 – 25	25 – 50	50 – 100	100 +
Particles per 100 ml	7587	1674	468	28	13
(SAE AS4059) Particle Size / Micrometers	>5	>15	>25	>50	>100
Particles per 100 ml					
(ISO 4406) Particle Size / Micrometers	>4	>6	>14		
Scale Number					

6.0 PARTICLE COUNT RESULTS	
Standard Achieved: NAS1638 Class 06	☑ PASS ☐ FAIL
Additional Notes: Sample of FryQuel taken while flushing LH Reheat cylinder control block achieved NAS1638 Class 06.	

7.0 SIGNATURE	
Technician: Adam Gruchy [signature] for A G	Date: November 15, 2018

PEHS-OF-01 Rev. 1

PENNECON

Flushing/Particle Count Form

Certificate No.: NF8977F

1.0 CUSTOMER INFORMATION	
Customer: NL Hydro	PHS Job No.: HSA005177
Contact Name: Bill Kilfoy	Customer Reference No.:
Customer Instructions Notes: Flush Emergency Trip Valve (#1) to NAS1638 Class 06 cleanliness. Emergency Trip Pressure	

2.0 JOB REQUIREMENTS / INFORMATION	
Job Type: ☐ Sample Reading Only - No Flushing	☑ Flushing with Sample
Cleanliness Level Required: NAS1638 Class 06	
Fluid Type: FryQuel EHC-S	

3.0 FLUSHING	☐ N/A
☑ Line Flushing (Hoses, Tubing, Piping,	Flowrate: -
☐ Container Flushing (Drum, Tote, Pail) - Full Volume Circulated Minimum 5	
☐ Accumulator Flushing - Minimum 10 Fill-Drain Cycles Completed	
Temperature:	
Equipment Details (type, qty., size, manufacturer): Emergency Trip Valve (#1) - Emergency Trip Pressure	
Equipment ID (model, S/N): N/A	

4.0 WATER CONTENT READING	☑ N/A
Meter Used:	Reading Obtained:

5.0 PARTICLE COUNT READINGS (PER AS598 for Ocular Microscope Readings)

Particle Measurements					
(NAS 1638) Particle Size / Micrometers	5 – 15	15 – 25	25 – 50	50 – 100	100 +
Particles per 100 ml	3756	2481	354	49	13
(SAE AS4059) Particle Size / Micrometers	>5	>15	>25	>50	>100
Particles per 100 ml					
(ISO 4406) Particle Size / Micrometers	>4	>6	>14		
Scale Number					

6.0 PARTICLE COUNT RESULTS	
Standard Achieved: NAS1638 Class 06	☑ PASS ☐ FAIL
Additional Notes: Flush #9 - Sample of FryQuel taken while flushing Emergency Trip Valve (#1) - Emergency Trip Pressure achieved NAS1638 Class 06.	

7.0 SIGNATURE	
Technician: Chris Klomp DB per CK	Date: November 15, 2018

PENNECON

Flushing/Particle Count Form

Certificate No.: NF8978F

1.0 CUSTOMER INFORMATION	
Customer: NL Hydro	PHS Job No.: HSA005177
Contact Name: Bill Kilfoy	Customer Reference No.:
Customer Instructions Notes: Flush Emergency Trip Valve (#2) to NAS1638 Class 06 cleanliness. Main Supply Pressure	

2.0 JOB REQUIREMENTS / INFORMATION	
Job Type: ☐ Sample Reading Only - No Flushing	☑ Flushing with Sample
Cleanliness Level Required: NAS1638 Class 06	
Fluid Type: FryQuel EHC-S	

3.0 FLUSHING	☐ N/A
☑ Line Flushing (Hoses, Tubing, Piping,	Flowrate: -
☐ Container Flushing (Drum, Tote, Pail) - Full Volume Circulated Minimum 5	
☐ Accumulator Flushing - Minimum 10 Fill-Drain Cycles Completed	
Temperature:	
Equipment Details (type, qty., size, manufacturer): Emergency Trip Valve (#2) - Main Supply Pressure	
Equipment ID (model, S/N): N/A	

4.0 WATER CONTENT READING	☑ N/A
Meter Used:	Reading Obtained:

5.0 PARTICLE COUNT READINGS (PER AS598 for Ocular Microscope Readings)

Particle Measurements					
(NAS 1638) Particle Size / Micrometers	5 – 15	15 – 25	25 – 50	50 – 100	100 +
Particles per 100 ml	2948	1210	239	39	15
(SAE AS4059) Particle Size / Micrometers	>5	>15	>25	>50	>100
Particles per 100 ml					
(ISO 4406) Particle Size / Micrometers	>4	>6	>14		
Scale Number					

6.0 PARTICLE COUNT RESULTS	
Standard Achieved: NAS1638 Class 06	☑ PASS ☐ FAIL
Additional Notes: Flush #10 - Sample of FryQuel taken while flushing Emergency Trip Valve (#2) - Main Supply Pressure achieved NAS1638 Class 06.	

7.0 SIGNATURE	
Technician: Chris Klomp *[signature]* for C/K	Date: November 15, 2018

PENNECON

Flushing/Particle Count Form

Certificate No.: NF8979F

1.0 CUSTOMER INFORMATION	
Customer: NL Hydro	PHS Job No.: HSA005177
Contact Name: Bill Kilfoy	Customer Reference No.:
Customer Instructions Notes: Flush cylinder control blocks to NAS1638 Class 06 cleanliness.	

2.0 JOB REQUIREMENTS / INFORMATION
Job Type: ☐ Sample Reading Only - No Flushing ☑ Flushing with Sample
Cleanliness Level Required: NAS1638 Class 06
Fluid Type: FryQuel EHC-S

3.0 FLUSHING	☐ N/A
☑ Line Flushing (Hoses, Tubing, Piping, Flowrate: 20 GPM ☐ Container Flushing (Drum, Tote, Pail) - Full Volume Circulated Minimum 5 ☐ Accumulator Flushing - Minimum 10 Fill-Drain Cycles Completed	
Temperature: 45-50°C	
Equipment Details (type, qty., size, manufacturer): Cylinder control block for RH Reheat Cylinder	
Equipment ID (model, S/N): N/A	

4.0 WATER CONTENT READING	☑ N/A
Meter Used:	Reading Obtained:

5.0 PARTICLE COUNT READINGS (PER AS598 for Ocular Microscope Readings)

Particle Measurements

(NAS 1638) Particle Size / Micrometers	5 – 15	15 – 25	25 – 50	50 – 100	100 +
Particles per 100 ml	2458	440	253	26	9
(SAE AS4059) Particle Size / Micrometers	>5	>15	>25	>50	>100
Particles per 100 ml					
(ISO 4406) Particle Size / Micrometers	>4	>6	>14		
Scale Number					

6.0 PARTICLE COUNT RESULTS	
Standard Achieved: NAS1638 Class 06	☑ PASS ☐ FAIL
Additional Notes: Sample of FryQuel taken while flushing cylinder control block for RH Reheat Cylinder achieved NAS1638 Class 06.	

7.0 SIGNATURE	
Technician: Matt Fagan [signature] For M F	Date: November 15, 2018

PENNECON

Flushing/Particle Count Form

Certificate No.: NF8980F

1.0 CUSTOMER INFORMATION

Customer: NL Hydro	PHS Job No.: HSA005177
Contact Name: Bill Kilfoy	Customer Reference No.:

Customer Instructions Notes: Flush Miller Fluid Power main stop cylinder (serial no. 94134770) to NAS1638 Class 06 cleanliness.

2.0 JOB REQUIREMENTS / INFORMATION

Job Type: ☐ Sample Reading Only - No Flushing ☑ Flushing with Sample

Cleanliness Level Required: NAS1638 Class 06

Fluid Type: FryQuel EHC-S

3.0 FLUSHING ☐ N/A

☑ Line Flushing (Hoses, Tubing, Piping, Flowrate:

☐ Container Flushing (Drum, Tote, Pail) - Full Volume Circulated Minimum 5

☐ Accumulator Flushing - Minimum 10 Fill-Drain Cycles Completed

Temperature: 45-50°C

Equipment Details (type, qty., size, manufacturer): Miller Fluid Power - Main Stop Cylinder

Equipment ID (model, S/N): 94134770

4.0 WATER CONTENT READING ☑ N/A

Meter Used:	Reading Obtained:

5.0 PARTICLE COUNT READINGS (PER AS598 for Ocular Microscope Readings)

Particle Measurements					
(NAS 1638) Particle Size / Micrometers	5 – 15	15 – 25	25 – 50	50 – 100	100 +
Particles per 100 ml	14,551	2837	502	56	15
(SAE AS4059) Particle Size / Micrometers	>5	>15	>25	>50	>100
Particles per 100 ml					
(ISO 4406) Particle Size / Micrometers	>4	>6	>14		
Scale Number					

6.0 PARTICLE COUNT RESULTS

Standard Achieved: NAS1638 Class 06 ☑ PASS ☐ FAIL

Additional Notes: Sample of FryQuel taken while flushing Miller Fluid Power - Main Stop Cylinder, serial no. 94134770, achieved NAS1638 Class 06.

7.0 SIGNATURE

Technician: Randy Lomond [signature] for R L	Date: November 17, 2018

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PENNECON

Flushing/Particle Count Form

Certificate No.: NF8981F

1.0 CUSTOMER INFORMATION

Customer: NL Hydro	PHS Job No.: HSA005177
Contact Name: Bill Kilfoy	Customer Reference No.:

Customer Instructions Notes: Flush Miller Fluid Power LH Reheat cylinder to NAS1638 Class 05 cleanliness.

2.0 JOB REQUIREMENTS / INFORMATION

Job Type: ☐ Sample Reading Only - No Flushing ☑ Flushing with Sample

Cleanliness Level Required: NAS1638 Class 05

Fluid Type: FryQuel EHC-S

3.0 FLUSHING ☐ N/A

☑ Line Flushing (Hoses, Tubing, Piping, Flowrate:

☐ Container Flushing (Drum, Tote, Pail) - Full Volume Circulated Minimum 5

☐ Accumulator Flushing - Minimum 10 Fill-Drain Cycles Completed

Temperature:

Equipment Details (type, qty., size, manufacturer): Miller Fluid Power - LH Reheat Cylinder

Equipment ID (model, S/N):

4.0 WATER CONTENT READING ☑ N/A

Meter Used:	Reading Obtained:

5.0 PARTICLE COUNT READINGS (PER AS598 for Ocular Microscope Readings)

Particle Measurements

(NAS 1638) Particle Size / Micrometers	5 – 15	15 – 25	25 – 50	50 – 100	100 +
Particles per 100 ml	7364	826	434	30	8
(SAE AS4059) Particle Size / Micrometers	>5	>15	>25	>50	>100
Particles per 100 ml					
(ISO 4406) Particle Size / Micrometers	>4	>6	>14		
Scale Number					

6.0 PARTICLE COUNT RESULTS

Standard Achieved: NAS1638 Class 05 ☑ PASS ☐ FAIL

Additional Notes: Sample of FryQuel taken while flushing Miller Fluid Power - LH Reheat Cylinder achieved NAS1638 Class 05.

7.0 SIGNATURE

Technician: Randy Lomond RL | Date: November 17, 2018

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PENNECON

Flushing/Particle Count Form

Certificate No.: NF8982F

1.0 CUSTOMER INFORMATION

Customer: NL Hydro	PHS Job No.: HSA005177
Contact Name: Bill Kilfoy	Customer Reference No.:
Customer Instructions Notes: Flush LH Intercept Valve Cylinder to NAS1638 Class 06 cleanliness.	

2.0 JOB REQUIREMENTS / INFORMATION

Job Type: ☐ Sample Reading Only - No Flushing ☑ Flushing with Sample

Cleanliness Level Required: NAS1638 Class 06

Fluid Type: FryQuel EHC-S

3.0 FLUSHING ☐ N/A

☑ Line Flushing (Hoses, Tubing, Piping, Flowrate:

☐ Container Flushing (Drum, Tote, Pail) - Full Volume Circulated Minimum 5

☐ Accumulator Flushing - Minimum 10 Fill-Drain Cycles Completed

Temperature:

Equipment Details (type, qty., size, manufacturer): LH Intercept Valve Cylinder

Equipment ID (model, S/N):

4.0 WATER CONTENT READING ☑ N/A

Meter Used:	Reading Obtained:

5.0 PARTICLE COUNT READINGS (PER AS598 for Ocular Microscope Readings)

Particle Measurements

(NAS 1638) Particle Size / Micrometers	5 – 15	15 – 25	25 – 50	50 – 100	100 +
Particles per 100 ml	3476	934	263	16	11
(SAE AS4059) Particle Size / Micrometers	>5	>15	>25	>50	>100
Particles per 100 ml					
(ISO 4406) Particle Size / Micrometers	>4	>6	>14		
Scale Number					

6.0 PARTICLE COUNT RESULTS

Standard Achieved: NAS1638 Class 06 ☑ PASS ☐ FAIL

Additional Notes: Sample of FryQuel taken while flushing LH Intercept Valve Cylinder achieved NAS1638 Class 06.

7.0 SIGNATURE

Technician: Randy Lomond RL Date: November 18, 2018

PENNECON

Flushing/Particle Count Form

Certificate No.: NF9094F

1.0 CUSTOMER INFORMATION

Customer: NL Hydro	PEHS Job No.: HSA005177
Contact Name:	Customer Reference No.:

Customer Instructions Notes: Flush and read sample from HPU after system has been running

2.0 JOB REQUIREMENTS / INFORMATION

Job Type: ☐ Sample Reading Only - No Flushing ☑ Flushing with Sample

Cleanliness Level Required: NAS1638 Class 06

Fluid Type: Fyrquel

3.0 FLUSHING ☐ N/A

☐ Line Flushing (Hoses, Tubing, Piping, Flowrate: N/A

☐ Container Flushing (Drum, Tote, Pail) - Full Volume Circulated Minimum 5

☐ Accumulator Flushing - Minimum 10 Fill-Drain Cycles Completed

Temperature:

Equipment Details (type, qty., size, manufacturer):

Equipment ID (model, S/N):

4.0 WATER CONTENT READING ☑ N/A

Meter Used:	Reading Obtained:

5.0 PARTICLE COUNT READINGS (PER AS598 for Ocular Microscope Readings)

Particle Measurements					
(NAS 1638) Particle Size / Micrometers	5 – 15	15 – 25	25 – 50	50 – 100	100 +
Particles per 100 ml	2690	899	172	14	5
(SAE AS4059) Particle Size / Micrometers	>5	>15	>25	>50	>100
Particles per 100 ml					
(ISO 4406) Particle Size / Micrometers	>4	>6	>14		
Scale Number					

6.0 PARTICLE COUNT RESULTS

Standard Achieved: NAS1638 Class 06 ☑ PASS ☐ FAIL

Additional Notes: Sample of Fyrquel taken from HPU after system has been running achieved NAS1638 Class 06.

7.0 SIGNATURE

Technician: Grant Lush [signature] for GL	Date: November 25, 2018

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PENNECON

FLUSHING/PARTICLE COUNT FORM

Certificate No.: NF9000F

1.0 CUSTOMER INFORMATION	
Customer: NL Hydro	PHS Job No.: HSA005177
Contact Name: Craig Dwyer	Customer Reference No.:
Customer Instructions Notes: Check sample from 75 gallon HPU tank on unit #1	

2.0 JOB REQUIREMENTS / INFORMATION
Job Type: ☐ Sample Reading Only - No Flushing Required ☑ Flushing with Sample Reading
Cleanliness Level Required: NAS1638 Class 06
Fluid Type: Fryquel

3.0 FLUSHING ☐ N/A
☐ Line Flushing (Hoses, Tubing, Piping, Systems) Flowrate: ☑ Container Flushing (Drum, Tote, Pail) - Full Volume Circulated Minimum 5 Times ☐ Accumulator Flushing - Minimum 10 Fill-Drain Cycles Completed
Temperature:
Equipment Details (type, qty., size, manufacturer): 75 gallon HPU tank on unit #1
Equipment ID (model, S/N):

4.0 WATER CONTENT READING ☑ N/A	
Meter Used:	Reading Obtained:

5.0 PARTICLE COUNT READINGS (PER AS598 for Ocular Microscope Readings)

Particle Measurements					
(NAS 1638) Particle Size / Micrometers	5 – 15	15 – 25	25 – 50	50 – 100	100 +
Particles per 100 ml	2000	835	110	14	3
(SAE AS4059) Particle Size / Micrometers	>5	>15	>25	>50	>100
Particles per 100 ml					
(ISO 4406) Particle Size / Micrometers	>4	>6	>14		
Scale Number					

6.0 PARTICLE COUNT RESULTS	
Standard Achieved: NAS1638 Class 05	☑ PASS ☐ FAIL
Additional Notes: Sample taken from 75 gallon HPU tank on unit #1 achieved NAS1638 Class 05.	

7.0 SIGNATURE	
Technician: Grant Lush	Date: December 10, 2018

PENNECON

DOCUMENT NUMBER:	19-PEHS-NL-DOC-050, Rev. 0
DOCUMENT TITLE:	Documentation Package
PROJECT:	Service/Maintenance on Unit #2
PHS REFERENCE NUMBER:	HSA005213
PHS CONTACT NAME:	Dave Barnes
CLIENT:	NL Hydro
CLIENT PURCHASE ORDER:	N/A

0	4-Mar-19	Original Issue	K. Dunphy	D. Barnes	E. Knox
REVISION	**DATE**	**DESCRIPTION**	**ORIGINATOR**	**CHECKED BY**	**APPROVED BY**

PENNECON

Table of Contents

PENNECON

1.0 Cylinder Strip & Assess Sheets

PENNECON

ISO 9001:2008

Cylinder Sheet

Page __ of 5	**Work Order No.: HSA005213**
	Customer Reference No.:

1. CUSTOMER INFORMATION

Date: December 3, 2018	Contact:
Customer: NL Hydro	Contact Phone No.:
Address:	Customer Stock Code No.:
Customer Instructions/Notes: Strip and assess right side Intercept cylinder (5")	
Allocated To: Xavier V / Randy L / Adam G	**Date: Dec 3rd, 2018**

2. NAMEPLATE DATA / RECEIVING INSPECTION

Bore ∅ N/A	☑ Hydraulic	☐ Pneumatic	☐ Welded
Stroke N/A	☑ Tie Rod	☐ Other	
Rod ∅ N/A			

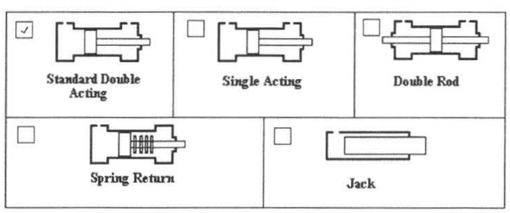
Manufacturer: Miller Fluid Power		Model No.: N/A		
Unit No.: N/A		Serial No.:		
General Condition of Equipment:	☑ Dirty	☑ Oily	☐ Rusty	☐ Clean

List any Missing, Broken or Damaged Parts: Name tag is present but not legible.

Other/Description: Cylinder is dirty, but otherwise appears to be in good overall condition.

Unit Location:	☑ Unit Tagged	☑ Photography
Receiving Inspection Completed By: Xavier V / Randy L / Adam G		**Date: Dec 3rd, 2018**

3. INITIAL INSPECTION



☐ Indexed for Disassembly	☑ Job Unit Stamped

CYLINDER MOUNTING

	Tie Rod Extended	
☐ Head End	☐ Base End	☐ Both Ends
	Trunnion	
☐ Head End	☐ Base End	☐ Both Ends
	Lugs	
☐ Side	☐ Side End	☐ Center Line

PENNECON

ISO 9001:2008

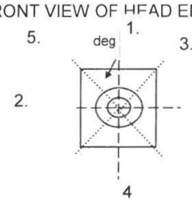
Cylinder Sheet

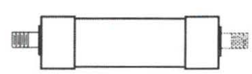
Page __ of 5		**Work Order No.: HSA005213**	
Base Flange			
☑ Square		☐ Rectangle	
Head Flange			
☑ Square		☐ Rectangle	
Clevis (Male/Female)			
☐ Fixed		☐ Detachable	
	☐ Other		☐ Side End Angles
Rod End Mounting (e.g. rod eye, spherical brg, etc):			
Technician: Xavier V / Randy L / Adam G			**Date: Dec 3rd, 2018**

4. PORT / FITTING IDENTIFICATION

☐ Double Ended Cylinder	
Size/Thread (A):	Size/Thread (B):

FRONT VIEW OF HEAD END





PIN TO PIN DIMENSIONS								
Closed:	31"	inches	Open:	47"	inches	Stoke:	16"	inches

HEAD END			
Port Size:	Location(i.e.1-5):	Port Type: Flanged	
Fittings:	Size:	Type:	
Hoses:	Size:	Type:	
BASE END			
Port Size:	Location(i.e.1-5):	Port Type: Flanged	
Fittings:	Size:	Type:	
Hoses:	Size:	Type:	
Valve(s) with Cylinder:	☑ Yes		☐ No
Model No.: N/A		Type: N/A	
Valves Checked:	☐ Repair	☐ Replace	☑ Not Applicable
Comments/Notes: Cylinder is mounted to a flanged valve block containing all porting for normal operation.			
Technician: Xavier V / Randy L / Adam G			**Date: Dec 3rd, 2018**

PENNECON

Cylinder Sheet

Page __ of 5			**Work Order No.: HSA005213**		
5. INSPECTION DATA / SPECIFICATIONS					
TUBE	ID 5.004"	OD 5.998"	Length 19.5"	Material Steel	Other Info N/A
ROD	OD 2.496"	Length 27.25"	Head End Thread (dia/tpi) 1.858"/12tpi	Piston End Thread (dia/tpi) 1.853"/12 tpi	Material Steel
PISTON	OD 4.927"	Length 1.610"	No. of Pieces 1	Material Steel	Other Info N/A
HEAD	OD 3.500"	Length 1.610"	(e.g. thread/snap ring) Flanged	Material Steel	Other Info N/A
ATTACHMENTS	Type(clevis etc.)	Size/Dimensions	Material	Other Info	
Technician: Xavier V / Randy L / Adam G				**Date: Dec 3rd, 2018**	

6. WELDING

☑ Not Applicable

Procedure Used:

Notes:

Technician: | **Date:**

7. HONING

☑ Not Applicable

Stones Used: | RPM Utilized:

Notes:

Technician: | **Date:**

8. MACHINING

☑ Not Applicable

Components Machined:

Results:

Technician: | **Date:**

9. NEW ITEMS INSTALLED

☐ Not Applicable

Items installed (valves, seals, etc): New seal kit to be installed. Slight wear was found on old piston seals.

Technician: Xavier V / Randy L / Adam G | Date: Dec 3rd, 2018

10. SUBCONTRACTED WORK (e.g. chroming)

☑ Not Applicable

Work Completed:

PENNECON

Cylinder Sheet

Page __ of 5	**Work Order No.: HSA005213**
Technician:	**Date:**

11. FINAL ASSEMBLY/TESTING

☐ Not Applicable

Internal Rod/Piston Threads Checked:	☐ Loc-tite 271 Applied	☐ Vice Torqued
Type of Testing Completed:		
Test Certificate Completed:	Certificate No.:	
Technician:		**Date:**

12. PRE-SHIPPING INSPECTION

Nameplate(s) Correct and Secure?	☐ Yes	☐ No	☐ Not Applicable
All Covers/Hardware are Secure?	☐ Yes	☐ No	☐ Not Applicable
Special Shipping Instructions?	☐ Yes	☐ No	☐ Not Applicable
Paint Acceptable?	☐ Yes	☐ No	☐ Not Applicable
Certificate attached:	☐ Yes	☐ No	☐ Not Applicable
Packaging:	☐ Weatherproof	☐ Crate	☐ Skid Mount
Technician:			**Date:**
QA Inspection Completed By:			**Date:**

13. MATERIALS

Item	Qty	Part No.	Size/Description	Supplier	Cost	Sell
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						

Comments (Indicate seal direction and location if necessary):

Technician:	**Date:**

PENNECON

Cylinder Sheet

Page __ of 5	**Work Order No.: HSA005213**

14. ESTIMATE

Disassembly:	hrs @ $	/hr = $	Machining:	hrs @ $	/hr = $
Assembly:	hrs @ $	/hr = $	Welding:	hrs @ $	/hr = $
Testing:	hrs @ $	/hr = $	Honing:	hrs @ $	/hr = $
Pick-up/Del.:	hrs @ $	/hr = $			

Notes:		Labour	$
		Parts	$
		Shop	$
Replacement Cost	$	**Total**	**$**

☐ Repair ☐ Return ☐ Replace ☐ Scrap

Authorized by: David Bows FOR XV/RL/AS Date: ______________________

PENNECON

Cylinder Sheet

Page __ of 5	**Work Order No.: HSA005213**
	Customer Reference No.:

1. CUSTOMER INFORMATION

Date: December 11, 2018	Contact:
Customer: NL Hydro	Contact Phone No.:
Address:	Customer Stock Code No.:
Customer Instructions/Notes: Strip and assess 7" main steam cylinder.	
Allocated To: Grant Lush	**Date: December 11, 2018**

2. NAMEPLATE DATA / RECEIVING INSPECTION

Bore ∅ 7.0035"	☑ Hydraulic	☐ Pneumatic	☐ Welded
Stroke 19.00"	☑ Tie Rod	☐ Other	
Rod ∅ 3.0015			

Manufacturer: Miller Fluid Power	Model No.: N/A
Unit No.: N/A	Serial No.:

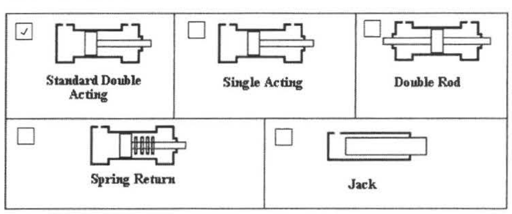
General Condition of Equipment:	☑ Dirty	☑ Oily	☑ Rusty	☐ Clean

List any Missing, Broken or Damaged Parts: Barrel, rod / seal kit, tie rods, bolts

Other/Description:

Unit Location:	☐ Unit Tagged	☑ Photography
Receiving Inspection Completed By: Grant Lush		**Date: December 11, 2018**

3. INITIAL INSPECTION



☐ Indexed for Disassembly	☐ Job Unit Stamped

CYLINDER MOUNTING

Tie Rod Extended		
☑ Head End	☐ Base End	☐ Both Ends
Trunnion		
☐ Head End	☐ Base End	☐ Both Ends
Lugs		
☐ Side	☐ Side End	☐ Center Line

PENNECON

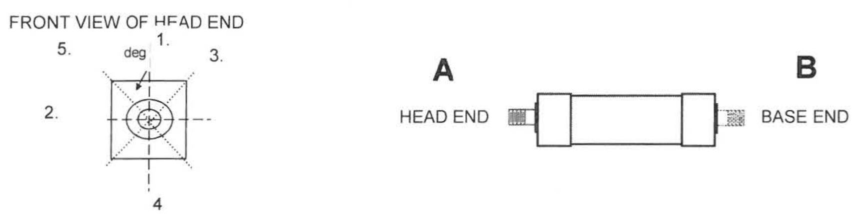
Cylinder Sheet

Page __ of 5	**Work Order No.: HSA005213**
Base Flange	
☐ Square	☐ Rectangle
Head Flange	
☐ Square	☐ Rectangle
Clevis (Male/Female)	
☐ Fixed	☐ Detachable
☐ Other	☐ Side End Angles
Rod End Mounting (e.g. rod eye, spherical brg, etc):	
Technician: Grant Lush	**Date: December 11, 2018**

4. PORT / FITTING IDENTIFICATION

☐ Double Ended Cylinder

Size/Thread (A):	Size/Thread (B):



PIN TO PIN DIMENSIONS

Closed: 31" inches	Open: 47" inches	Stoke: 16" inches

HEAD END

Port Size:	Location(i.e.1-5):	Port Type: Flanged
Fittings:	Size:	Type:
Hoses:	Size:	Type:

BASE END

Port Size:	Location(i.e.1-5):	Port Type: Flanged
Fittings:	Size:	Type:
Hoses:	Size:	Type:
Valve(s) with Cylinder:	☑ Yes	☐ No
Model No.: N/A		Type: N/A
Valves Checked:	☐ Repair ☐ Replace	☑ Not Applicable

Comments/Notes: Cylinder is mounted to a flanged valve block containing all porting for normal operation.

Technician: Grant Lush	**Date: December 11, 2018**

PENNECON

Cylinder Sheet

Page __ of 5	Work Order No.: HSA005213

5. INSPECTION DATA / SPECIFICATIONS

TUBE	ID 7.0035"	OD 8.1535"	Length 17.500"	Material N/A	Other Info
ROD	OD 3.0015"	Length 25.750"	Head End Thread (dia/tpi) 14 tpi	Piston End Thread (dia/tpi) N/A	Material
PISTON	OD 6.9225"	Length 3.0325	No. of Pieces 1	Material N/A	Other Info
HEAD	OD 3.7790"	Length 1.6280"	(e.g. thread/snap ring) Bolts	Material N/A	Other Info
ATTACHMENTS	Type(clevis etc.)	Size/Dimensions	Material	Other Info	

Technician: Grant Lush **Date: December 11, 2018**

6. WELDING

☑ Not Applicable

Procedure Used:

Notes:

Technician: **Date:**

7. HONING

☑ Not Applicable

Stones Used: RPM Utilized:

Notes:

Technician: **Date:**

8. MACHINING

☑ Not Applicable

Components Machined:

Results:

Technician: **Date:**

9. NEW ITEMS INSTALLED

☑ Not Applicable

Items installed (valves, seals, etc):

Technician: Date:

10. SUBCONTRACTED WORK (e.g. chroming)

☑ Not Applicable

Work Completed:

PENNECON

ISO 9001: 2008

Cylinder Sheet

Page __ of 5	**Work Order No.: HSA005213**
Technician:	**Date:**

11. FINAL ASSEMBLY/TESTING

☑ Not Applicable		
Internal Rod/Piston Threads Checked:	☐ Loc-tite 271 Applied	☐ Vice Torqued
Type of Testing Completed:		
Test Certificate Completed:	Certificate No.:	
Technician:		**Date:**

12. PRE-SHIPPING INSPECTION

Nameplate(s) Correct and Secure?	☐ Yes	☐ No	☐ Not Applicable
All Covers/Hardware are Secure?	☐ Yes	☐ No	☐ Not Applicable
Special Shipping Instructions?	☐ Yes	☐ No	☐ Not Applicable
Paint Acceptable?	☐ Yes	☐ No	☐ Not Applicable
Certificate attached:	☐ Yes	☐ No	☐ Not Applicable
Packaging:	☐ Weatherproof	☐ Crate	☐ Skid Mount
Technician:			**Date:**
QA Inspection Completed By:			**Date:**

13. MATERIALS

Item	Qty	Part No.	Size/Description	Supplier	Cost	Sell
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						

Comments (Indicate seal direction and location if necessary):

Technician:	**Date:**

PENNECON

Cylinder Sheet

Page __ of 5			**Work Order No.: HSA005213**		
14. ESTIMATE					
Disassembly:	hrs @ $	/hr = $	Machining:	hrs @ $	/hr = $
Assembly:	hrs @ $	/hr = $	Welding:	hrs @ $	/hr = $
Testing:	hrs @ $	/hr = $	Honing:	hrs @ $	/hr = $
Pick-up/Del.:	hrs @ $	/hr = $			

Notes:		Labour	$
		Parts	$
		Shop	$
Replacement Cost	$	**Total**	**$**

☐ Repair ☐ Return ☐ Replace ☐ Scrap

Authorized by: Dave Bas FOR QC

Date: ____________________

PENNECON

2.0 Pressure Testing

a. Certificates w/ Charts

PENNECON

TEST CERTIFICATE

Certificate No. NF5965P

1. CUSTOMER INFORMATION

Customer: NL Hydro	Work Order No.: HSA005213
Contact Name: Craig Dwyer	Customer Reference No.:
Customer Instructions/Notes: Hydro test of Heat Exchanger- Oil Side	

2. EQUIPMENT SPECIFICATIONS

☑ Pressure Test ☐ Hose Test ☐ Tube Spool Test

☑ Other/Specify

3. TEST SPECIFICATIONS

Recorder No.:	HS0367NF	Gauge No.:	HS0370NF	Test Result:	☑ Pass ☐ Fail
Recorder Cert. No.:	132650-18-02	Gauge Cert. No.:	132623-18-03	Test Pressure:	120 PSI
Test Medium:	FRYQUEL ECH-S				
Start Time:	12:30 PM	Stop Time:	1:00 PM	Stabilization:	15 Minutes
				Hold:	15 Minutes

4. TEST DESCRIPTION

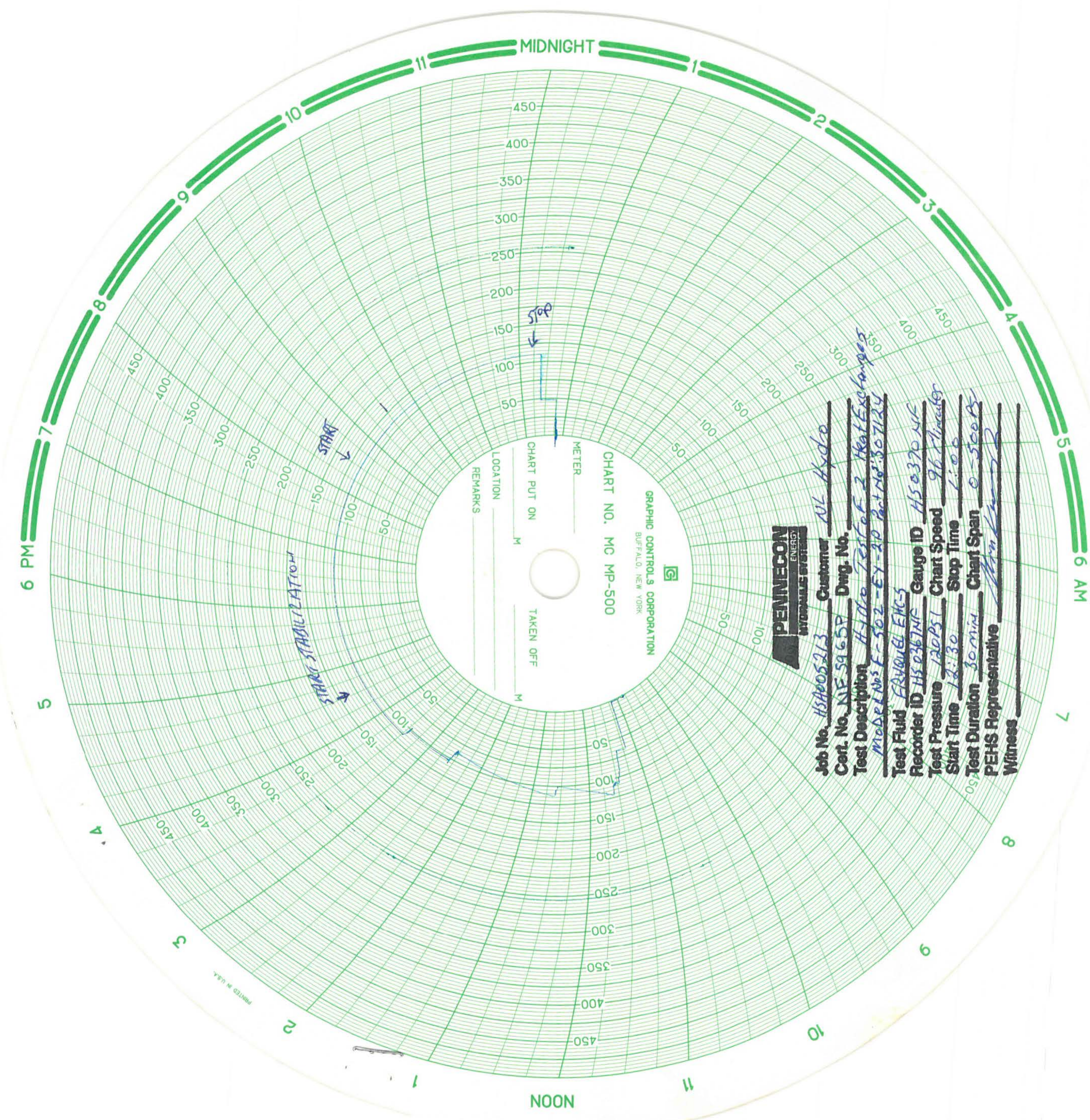
Hose(s) / Tube Spool(s)	No. of Pieces	Hose/Tube Size and/or Brand	Hose/Tube Service No. (if applicable)	N/A
				☐
				☐
				☐
				☐
				☐
				☐
				☐
				☐
				☐
				☐

For Additional Pages please see Attached

Brief Description of Test	Hydro Test of Heat Exchanger - Oil Side - 15 stabilization and 15 minute Hold at 120 PSI
Comments/ Notes	

Signed by: PEHS Representative		Accepted by: Client Rep.		Accepted by: Regulatory Rep.	
Signature:	[signature]	Signature:		Signature:	
Print Name:	Steve Keough	Print Name:		Print Name:	
Position:	Hydraulic Tech	Position:		Position:	
Date:	2-Dec-18	Date:		Date:	

Accepted by: QC Representative
Signature:
Print Name:
Position:
Date:


MIDNIGHT
NOON
6 AM
6 PM
GRAPHIC CONTROLS CORPORATION
BUFFALO, NEW YORK
CHART NO. MC MP-500
METER
CHART PUT ON
TAKEN OFF
LOCATION
REMARKS
PENNECON
Job No.
Customer
Cert. No.
Dwg. No.
Test Description
Test Fluid
Recorder ID
Gauge ID
Test Pressure
Chart Speed
Start Time
Stop Time
Test Duration
Chart Span
PEHS Representative
Witness

PENNECON

TEST CERTIFICATE

Certificate No. NF5957P

1. CUSTOMER INFORMATION	
Customer: NL Hydro	Work Order No.: HSA005213
Contact Name: Craig Dwyer	Customer Reference No.:
Customer Instructions/Notes: Hydro test cylinder after rebuild	

2. EQUIPMENT SPECIFICATIONS

☑ Pressure Test ☐ Hose Test ☐ Tube Spool Test

☑ Other/Specify

3. TEST SPECIFICATIONS

Recorder No.: HS0295NF
Recorder Cert. No.: 132671-18-02
Gauge No.: HS0261NF
Gauge Cert. No.: 132617-18-06
Test Result: ☑ Pass ☐ Fail
Test Pressure: 2000 PSI

Test Medium: FRYQUEL ECH-S

Start Time: 1:30 PM
Stop Time: 2:00PM
Stabilization: 15 Minutes
Hold: 15 Minutes

4. TEST DESCRIPTION

Hose(s) / Tube Spool(s)

No. of Pieces	Hose/Tube Size and/or Brand	Hose/Tube Service No. (if applicable)	N/A
			☐
			☐
			☐
			☐
			☐
			☐
			☐
			☐
			☐
			☐

For Additional Pages please see Attached

Brief Description of Test	Hydro Test of Right Hand Reheat Cylinder ROD Side - 15 stabilization and 15 minute Hold at 2000 PSI
Comments/ Notes	

Signed by: PEHS Representative
Signature: [signature]
Print Name: Steve Keough
Position: Hydraulic Tech
Date: 2-Dec-18

Accepted by: Client Rep.
Signature:
Print Name:
Position:
Date:

Accepted by: Regulatory Rep.
Signature:
Print Name:
Position:
Date:

Accepted by: QC Representative
Signature:
Print Name:
Position:
Date:

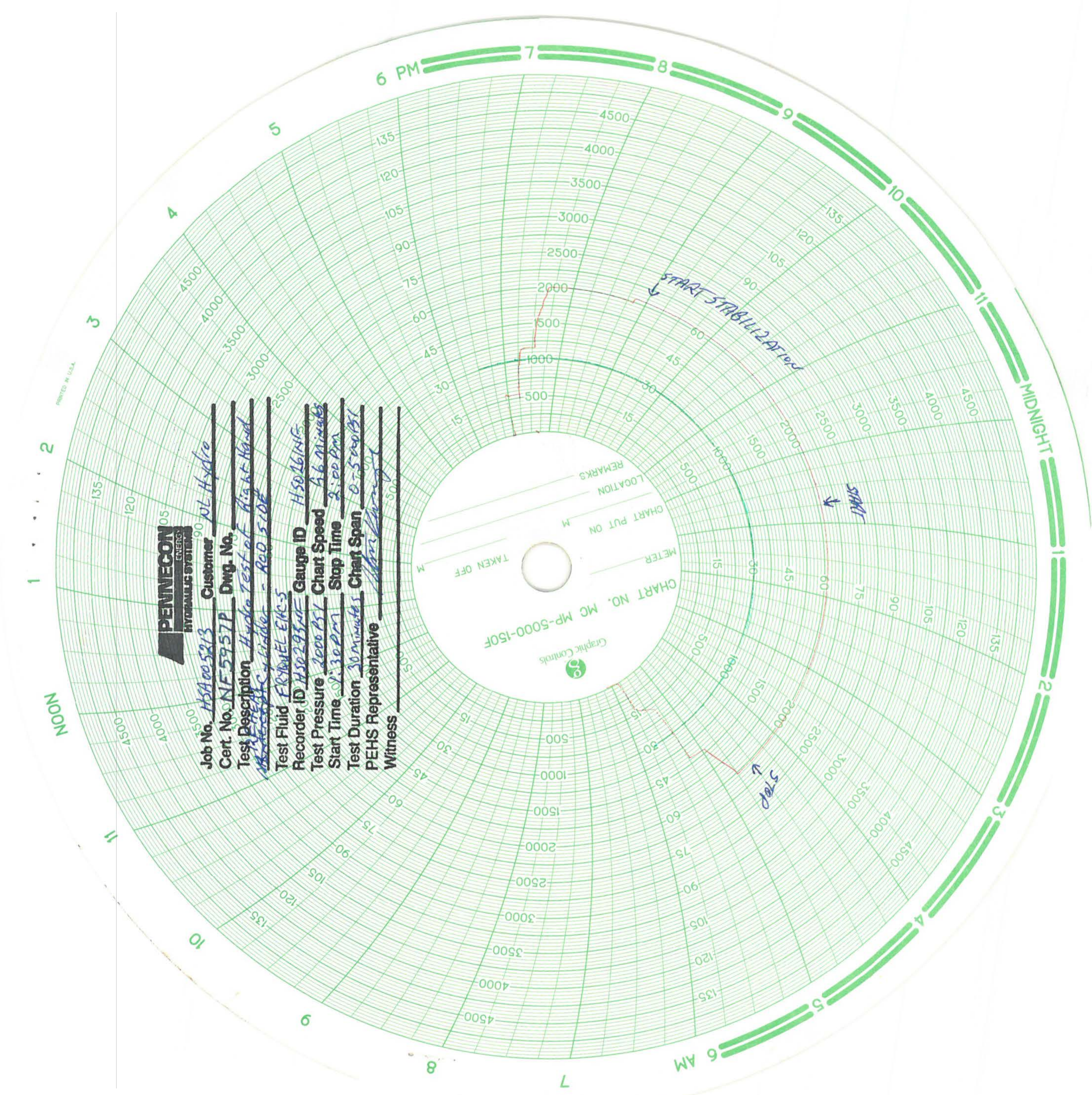


CHART NO. MC MP-5000-150F
Graphic Controls
PENNECON
Job No.
Customer
Cert. No.
Dwg. No.
Test Description
Test Fluid
Recorder ID
Gauge ID
Test Pressure
Chart Speed
Start Time
Stop Time
Test Duration
Chart Span
PEHS Representative
Witness
START STABILIZATION
STOP

PENNECON

TEST CERTIFICATE

Certificate No. NF5958P

1. CUSTOMER INFORMATION

Customer: NL Hydro	Work Order No.: HSA005213
Contact Name: Craig Dwyer	Customer Reference No.:
Customer Instructions/Notes: Hydro test cylinder after rebuild	

2. EQUIPMENT SPECIFICATIONS

- [x] Pressure Test
- [ ] Hose Test
- [ ] Tube Spool Test
- [x] Other/Specify

3. TEST SPECIFICATIONS

Recorder No.: HS0295NF
Recorder Cert. No.: 132671-18-02
Gauge No.: HS0261NF
Gauge Cert. No.: 132617-18-06
Test Result: [x] Pass [ ] Fail
Test Pressure: 2000 PSI

Test Medium: FRYQUEL ECH-S

Start Time: 3:30 PM
Stop Time: 4:00PM
Stabilization: 15 Minutes
Hold: 15 Minutes

4. TEST DESCRIPTION

Hose(s) / Tube Spool(s)	No. of Pieces	Hose/Tube Size and/or Brand	Hose/Tube Service No. (if applicable)	N/A
				☐
				☐
				☐
				☐
				☐
				☐
				☐
				☐
				☐
				☐

For Additional Pages please see Attached

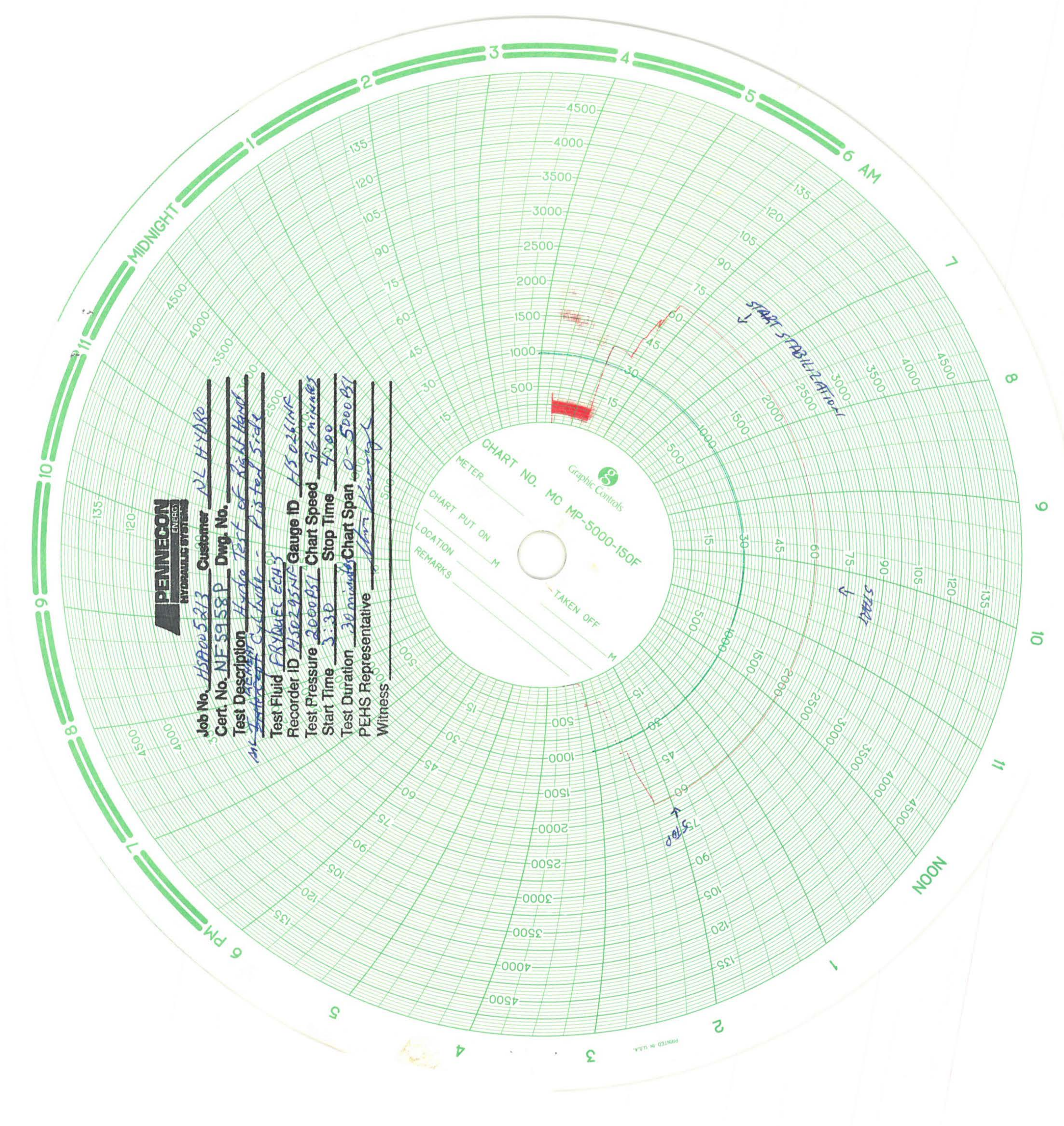
Brief Description of Test	Hydro Test of Right Hand Reheat Cylinder Piston Side - 15 stabilization and 15 minute Hold at 2000 PSI
Comments/ Notes	

Signed by: PEHS Representative
Signature: [signature]
Print Name: Steve Keough
Position: Hydraulic Tech
Date: 2-Dec-18

Accepted by: Client Rep.
Signature:
Print Name:
Position:
Date:

Accepted by: Regulatory Rep.
Signature:
Print Name:
Position:
Date:

Accepted by: QC Representative
Signature:
Print Name:
Position:
Date:



PENNECON

TEST CERTIFICATE

Certificate No. NF5956P

1. CUSTOMER INFORMATION

Customer: NL Hydro	Work Order No.: HSA005213
Contact Name: Craig Dwyer	Customer Reference No.:
Customer Instructions/Notes: Hydro test cylinder after rebuild	

2. EQUIPMENT SPECIFICATIONS

☑ Pressure Test ☐ Hose Test ☐ Tube Spool Test

☑ Other/Specify

3. TEST SPECIFICATIONS

Recorder No.: HS0295NF
Recorder Cert. No.: 132671-18-02
Gauge No.: HS0261NF
Gauge Cert. No.: 132617-18-06
Test Result: ☑ Pass ☐ Fail
Test Pressure: 2000 PSI

Test Medium: FRYQUEL ECH-S

Start Time: 6:30 PM
Stop Time: 7:00PM
Stabilization: 15 Minutes
Hold: 15 Minutes

4. TEST DESCRIPTION

Hose(s) / Tube Spool(s)	No. of Pieces	Hose/Tube Size and/or Brand	Hose/Tube Service No. (if applicable)	N/A
				☐
				☐
				☐
				☐
				☐
				☐
				☐
				☐
				☐
				☐

For Additional Pages please see Attached

Brief Description of Test	Hydro Test of Main Stop Cylinder ROD Side - 15 stabilization and 15 minute Hold at 2000 PSI
Comments/ Notes	

Signed by: PEHS Representative
Signature: [signature]
Print Name: Steve Keough
Position: Hydraulic Tech
Date: 2-Dec-18

Accepted by: Client Rep.
Signature:
Print Name:
Position:
Date:

Accepted by: Regulatory Rep.
Signature:
Print Name:
Position:
Date:

Accepted by: QC Representative
Signature:
Print Name:
Position:
Date:

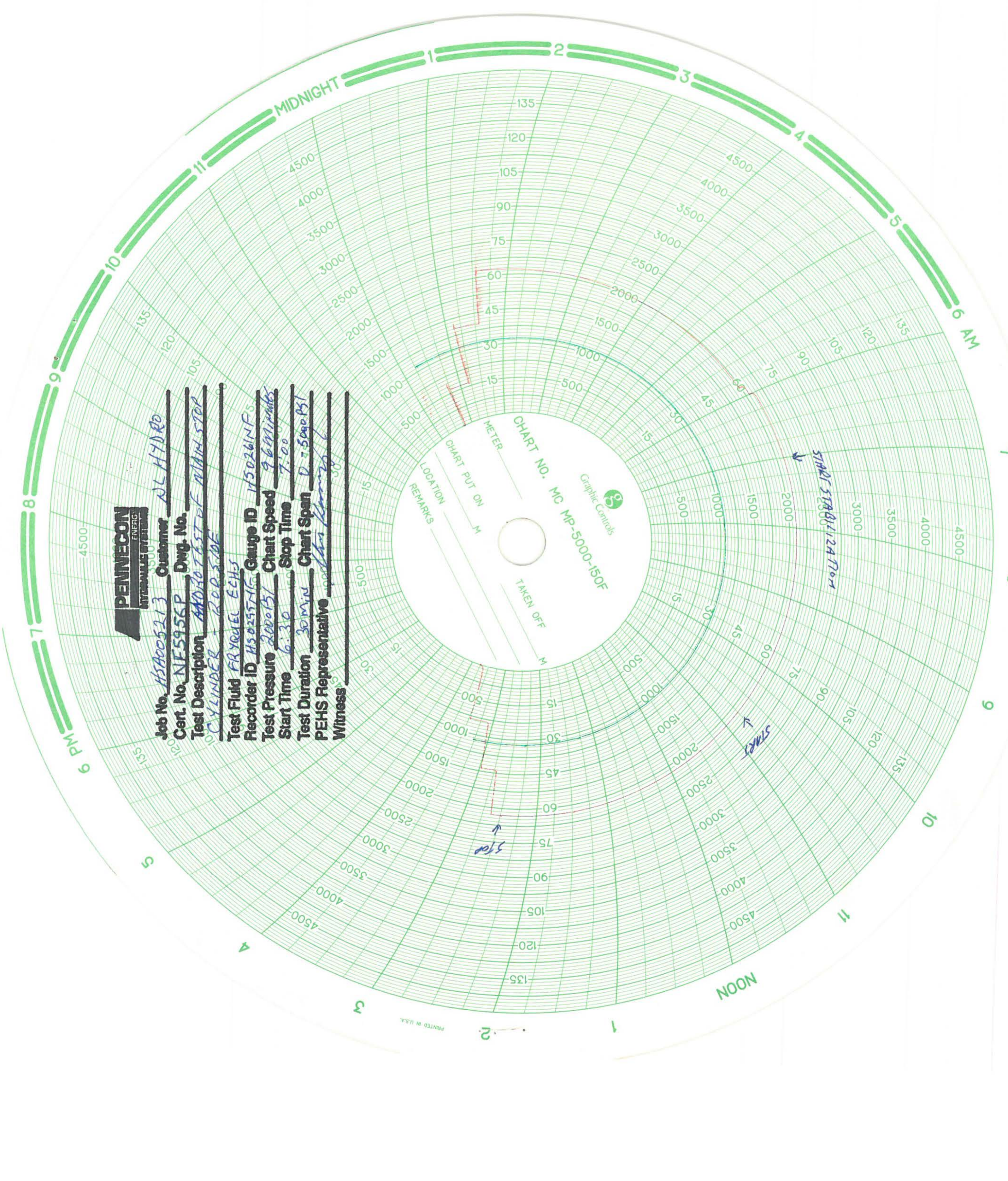


CHART NO. MC MP-5000-150F
Graphic Controls
MIDNIGHT
NOON
PENNECON

PENNECON

TEST CERTIFICATE

Certificate No. NF5955P

1. CUSTOMER INFORMATION	
Customer: NL Hydro	Work Order No.: HSA005213
Contact Name: Craig Dwyer	Customer Reference No.:
Customer Instructions/Notes: Hydro test cylinder after rebuild	

2. EQUIPMENT SPECIFICATIONS

☑ Pressure Test ☐ Hose Test ☐ Tube Spool Test

☑ Other/Specify

3. TEST SPECIFICATIONS

Recorder No.: HS0295NF
Recorder Cert. No.: 132671-18-02
Gauge No.: HS0261NF
Gauge Cert. No.: 132617-18-06
Test Result: ☑ Pass ☐ Fail
Test Pressure: 2000 PSI

Test Medium: FRYQUEL ECH-S

Start Time: 8:00 AM
Stop Time: 8:30 AM
Stabilization: 15 Minutes
Hold: 15 Minutes

4. TEST DESCRIPTION

Hose(s) / Tube Spool(s)	No. of Pieces	Hose/Tube Size and/or Brand	Hose/Tube Service No. (if applicable)	N/A
				☐
				☐
				☐
				☐
				☐
				☐
				☐
				☐
				☐
				☐

For Additional Pages please see Attached

Brief Description of Test	Hydro Test of Main Stop Cylinder Piston Side- 15 stabilization and 15 minute Hold at 2000 PSI
Comments/ Notes	

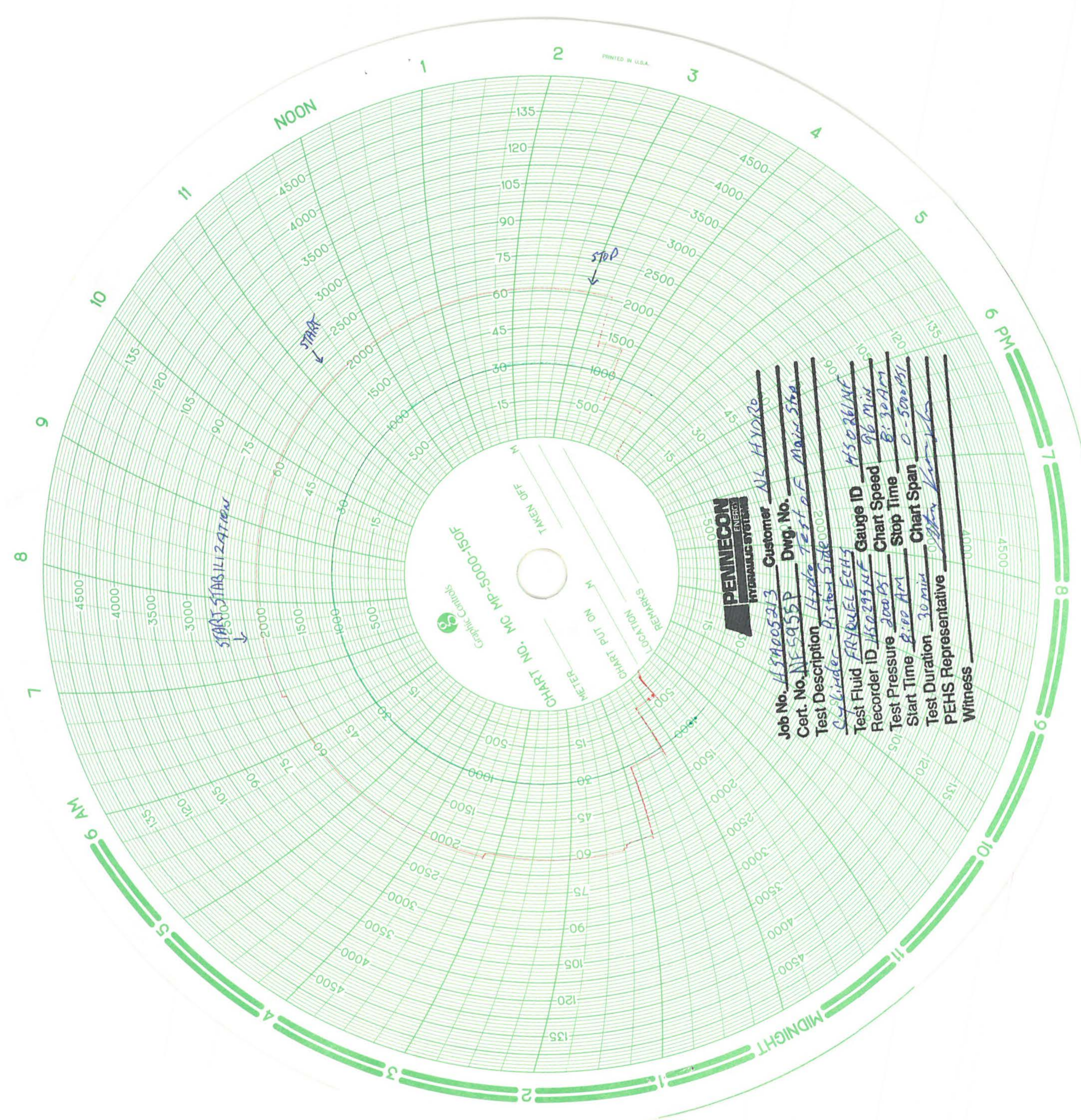
Signed by: PEHS Representative
Signature:
Print Name: Steve Keough
Position: Hydraulic Tech
Date: 3-Dec-18

Accepted by: Client Rep.
Signature:
Print Name:
Position:
Date:

Accepted by: Regulatory Rep.
Signature:
Print Name:
Position:
Date:

Accepted by: QC Representative
Signature:
Print Name:
Position:
Date:

PEHS-OF-06 Rev. 1


PENNECON ENERGY HYDRAULIC SYSTEMS
Job No. 45A005213
Customer NL HYDRO
Cert. No. NE5955P
Dwg. No.
Test Description Hydro Test of Main Stop
Cylinder - Piston Side
Test Fluid FRYQUEL EHS
Gauge ID HS0261NF
Recorder ID HS0295NF
Chart Speed 96 MIN
Test Pressure 2000 PSI
Stop Time 8:30 AM
Start Time 8:00 AM
Chart Span 0-5000 PSI
Test Duration 30 MIN
PEHS Representative
Witness
CHART NO. MC MP-5000-1SOF
START STABILIZATION
START
STOP
NOON
MIDNIGHT
6 PM
6 AM
PRINTED IN U.S.A.

PENNECON

TEST CERTIFICATE

Certificate No. NF5960P

1. CUSTOMER INFORMATION	
Customer: NL Hydro	Work Order No.: HSA005213
Contact Name: Craig Dwyer	Customer Reference No.:
Customer Instructions/Notes: Hydro test cylinder after rebuild	

2. EQUIPMENT SPECIFICATIONS

☑ Pressure Test ☐ Hose Test ☐ Tube Spool Test

☑ Other/Specify

3. TEST SPECIFICATIONS

Recorder No.: HS0295NF
Recorder Cert. No.: 132671-18-02
Gauge No.: HS0261NF
Gauge Cert. No.: 132617-18-06
Test Result: ☑ Pass ☐ Fail
Test Pressure: 2000 PSI

Test Medium: FRYQUEL ECH-S

Start Time: 9:00 AM
Stop Time: 9:30AM
Stabilization: 15 Minutes
Hold: 15 Minutes

4. TEST DESCRIPTION

Hose(s) / Tube Spool(s)

No. of Pieces	Hose/Tube Size and/or Brand	Hose/Tube Service No. (if applicable)	N/A
			☐
			☐
			☐
			☐
			☐
			☐
			☐
			☐
			☐
			☐

For Additional Pages please see Attached

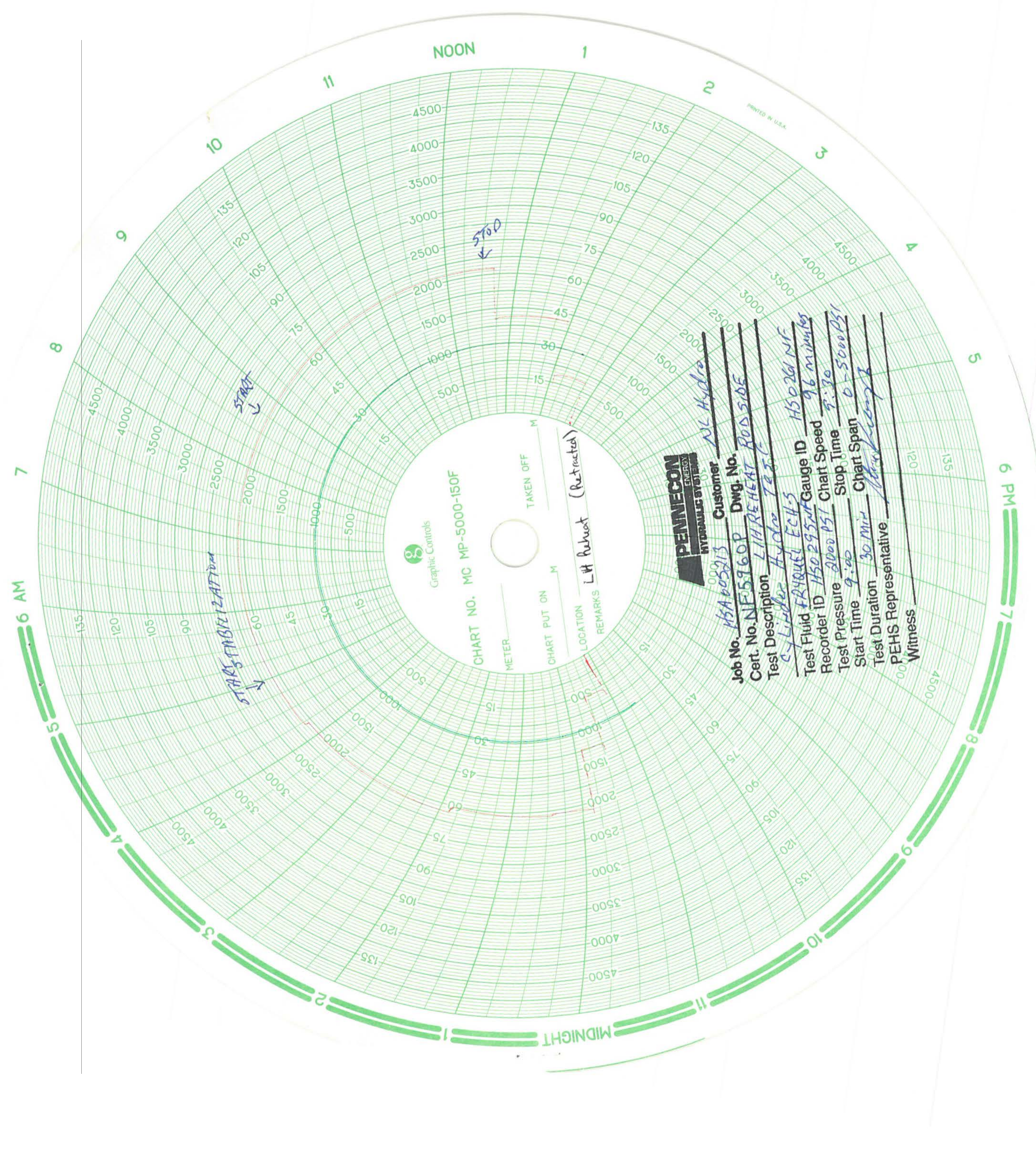
Brief Description of Test	Hydro Test of Left Hand Reheat Cylinder ROD Side - 15 stabilization and 15 minute Hold at 2000 PSI
Comments/ Notes	

Signed by: PEHS Representative
Signature:
Print Name: Steve Keough
Position: Hydraulic Tech
Date: 3-Dec-18

Accepted by: Client Rep.
Signature:
Print Name:
Position:
Date:

Accepted by: Regulatory Rep.
Signature:
Print Name:
Position:
Date:

Accepted by: QC Representative
Signature:
Print Name:
Position:
Date:



PENNECON

TEST CERTIFICATE

Certificate No. NF5959P

1. CUSTOMER INFORMATION	
Customer: NL Hydro	Work Order No.: HSA005213
Contact Name: Craig Dwyer	Customer Reference No.:
Customer Instructions/Notes: Hydro test cylinder after rebuild	

2. EQUIPMENT SPECIFICATIONS

☑ Pressure Test ☐ Hose Test ☐ Tube Spool Test

☑ Other/Specify

3. TEST SPECIFICATIONS

Recorder No.:	HS0295NF	Gauge No.:	HS0261NF	Test Result:	☑ Pass ☐ Fail
Recorder Cert. No.:	132671-18-02	Gauge Cert. No.:	132617-18-06	Test Pressure:	2000 PSI
Test Medium:	FRYQUEL ECH-S				
Start Time:	10:00 AM	Stop Time:	10:30 AM	Stabilization:	15 Minutes
				Hold:	15 Minutes

4. TEST DESCRIPTION

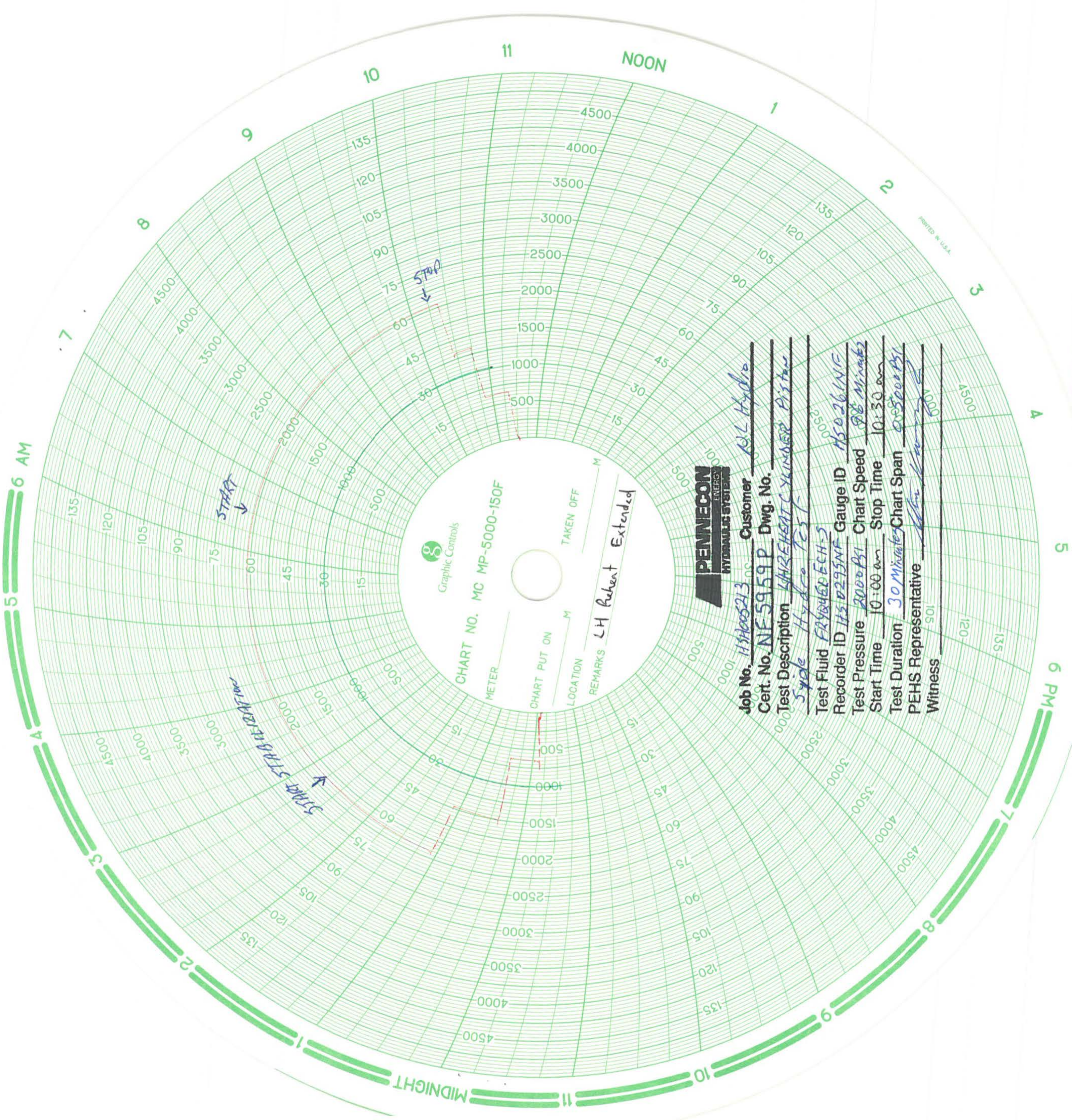
Hose(s) / Tube Spool(s) No. of Pieces	Hose/Tube Size and/or Brand	Hose/Tube Service No. (if applicable)	N/A
			☐
			☐
			☐
			☐
			☐
			☐
			☐
			☐
			☐
			☐

For Additional Pages please see Attached

Brief Description of Test	Hydro Test of Left Hand Reheat Cylinder Piston Side - 15 stabilization and 15 minute Hold at 2000 PSI
Comments/ Notes	

Signed by: PEHS Representative		Accepted by: Client Rep.		Accepted by: Regulatory Rep.	
Signature:	[signature]	Signature:		Signature:	
Print Name:	Steve Keough	Print Name:		Print Name:	
Position:	Hydraulic Tech	Position:		Position:	
Date:	3-Dec-18	Date:		Date:	

Accepted by: QC Representative
Signature:
Print Name:
Position:
Date:


NOON
MIDNIGHT
6 AM
6 PM
Graphic Controls
CHART NO. MC MP-5000-150F
METER
CHART PUT ON
TAKEN OFF
LOCATION
REMARKS LH Reheat Extended
PENNECON
START
STOP
START STABILIZATION
Job No.
Customer NL Hydro
Cert. No. NE5959P
Dwg. No.
Test Description
Test Fluid
Gauge ID
Recorder ID
Test Pressure
Chart Speed
Start Time 10:00 am
Stop Time 10:30 am
Test Duration 30 Minutes
Chart Span
PEHS Representative
Witness

PENNECON

TEST CERTIFICATE

Certificate No. NF5962P

1. CUSTOMER INFORMATION

Customer: NL Hydro	Work Order No.: HSA005213
Contact Name: Craig Dwyer	Customer Reference No.:
Customer Instructions/Notes: Hydro test cylinder after rebuild	

2. EQUIPMENT SPECIFICATIONS

☑ Pressure Test ☐ Hose Test ☐ Tube Spool Test

☑ Other/Specify

3. TEST SPECIFICATIONS

Recorder No.: HS0295NF
Recorder Cert. No.: 132671-18-02
Gauge No.: HS0261NF
Gauge Cert. No.: 132617-18-06
Test Result: ☑ Pass ☐ Fail
Test Pressure: 2000 PSI

Test Medium: FRYQUEL ECH-S

Start Time: 10:00 AM
Stop Time: 10:30AM
Stabilization: 15 Minutes
Hold: 15 Minutes

4. TEST DESCRIPTION

Hose(s) / Tube Spool(s)	No. of Pieces	Hose/Tube Size and/or Brand	Hose/Tube Service No. (if applicable)	N/A
				☐
				☐
				☐
				☐
				☐
				☐
				☐
				☐
				☐
				☐

For Additional Pages please see Attached

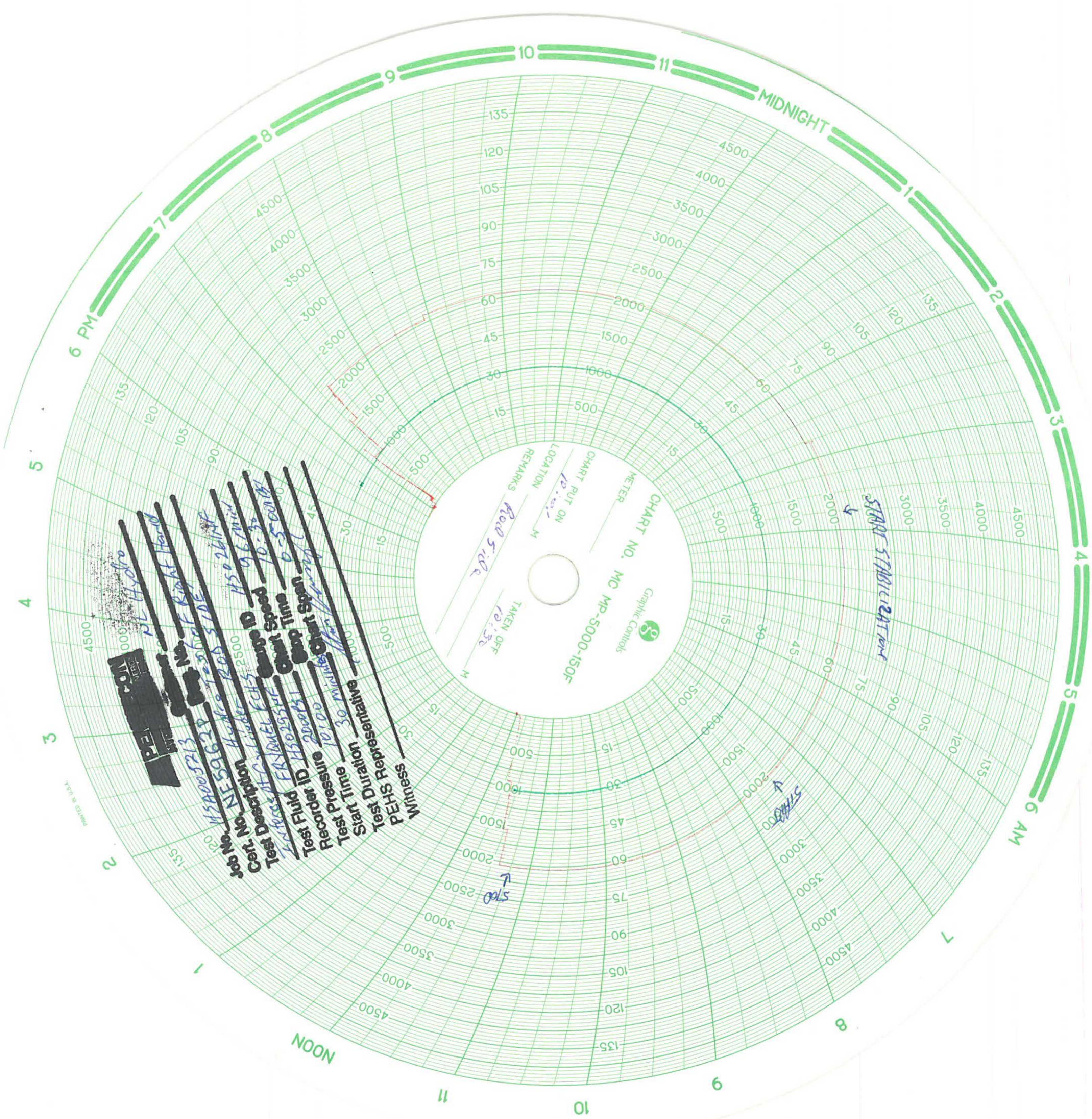
Brief Description of Test	Hydro Test of Right Hand Intercept Cylinder Rod Side - 15 stabilization and 15 minute Hold at 2000 PSI
Comments/ Notes	

Signed by: PEHS Representative
Signature: [signature]
Print Name: Steve Keough
Position: Hydraulic Tech
Date: 4-Dec-18

Accepted by: Client Rep.
Signature:
Print Name:
Position:
Date:

Accepted by: Regulatory Rep.
Signature:
Print Name:
Position:
Date:

Accepted by: QC Representative
Signature:
Print Name:
Position:
Date:



PENNECON

TEST CERTIFICATE

Certificate No. NF5961P

1. CUSTOMER INFORMATION

Customer: NL Hydro	Work Order No.: HSA005213
Contact Name: Craig Dwyer	Customer Reference No.:
Customer Instructions/Notes: Hydro test cylinder after rebuild	

2. EQUIPMENT SPECIFICATIONS

☑ Pressure Test ☐ Hose Test ☐ Tube Spool Test

☑ Other/Specify

3. TEST SPECIFICATIONS

Recorder No.: HS0295NF
Recorder Cert. No.: 132671-18-02
Gauge No.: HS0261NF
Gauge Cert. No.: 132617-18-06
Test Result: ☑ Pass ☐ Fail
Test Pressure: 2000 PSI

Test Medium: FRYQUEL ECH-S

Start Time: 11:00 AM
Stop Time: 11:30 AM
Stabilization: 15 Minutes
Hold: 15 Minutes

4. TEST DESCRIPTION

Hose(s) / Tube Spool(s)	No. of Pieces	Hose/Tube Size and/or Brand	Hose/Tube Service No. (if applicable)	N/A
				☐
				☐
				☐
				☐
				☐
				☐
				☐
				☐
				☐
				☐

For Additional Pages please see Attached

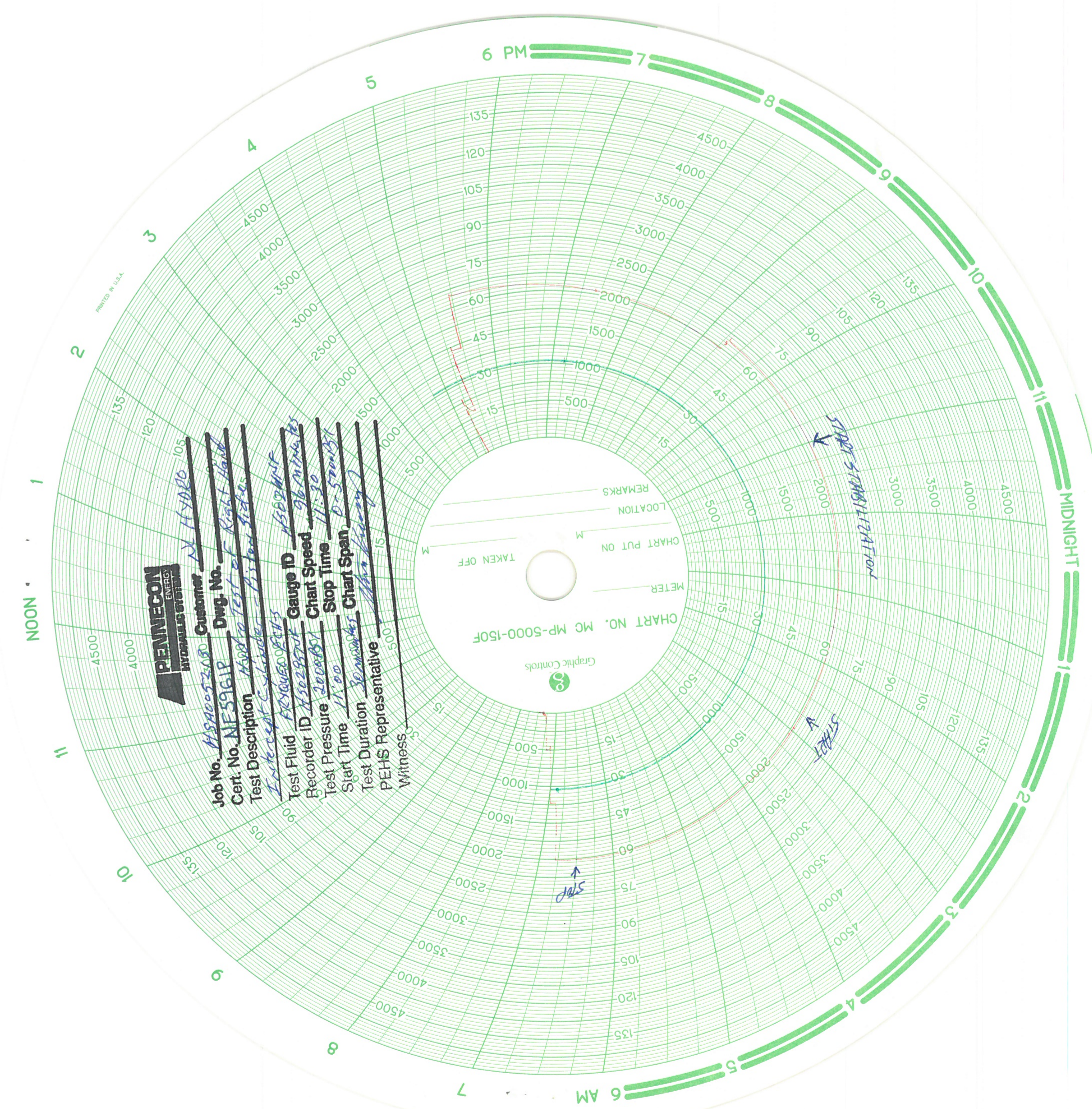
Brief Description of Test	Hydro Test of Right Hand Intercept Cylinder Piston Side - 15 stabilization and 15 minute Hold at 2000 PSI
Comments/ Notes	

Signed by: PEHS Representative
Signature: [signature]
Print Name: Steve Keough
Position: Hydraulic Tech
Date: 4-Dec-18

Accepted by: Client Rep.
Signature:
Print Name:
Position:
Date:

Accepted by: Regulatory Rep.
Signature:
Print Name:
Position:
Date:

Accepted by: QC Representative
Signature:
Print Name:
Position:
Date:


PENNECON ENERGY HYDRAULIC SYSTEMS
Customer NL HYDRO
Dwg. No.
Job No.
Cert. No. NE5961P
Test Description
Test Fluid
Gauge ID
Recorder ID
Chart Speed
Test Pressure
Stop Time
Start Time
Chart Span
Test Duration
PEHS Representative
Witness
CHART NO. MC MP-5000-150F
Graphic Controls
METER
CHART PUT ON
TAKEN OFF
LOCATION
REMARKS
START STABILIZATION
START
STOP
NOON
MIDNIGHT
6 PM
6 AM
PRINTED IN U.S.A.

PENNECON

TEST CERTIFICATE

Certificate No. NF5954P

1. CUSTOMER INFORMATION

Customer: NL Hydro	Work Order No.: HSA005213
Contact Name: Craig Dwyer	Customer Reference No.:
Customer Instructions/Notes: Hydro test cylinder after rebuild	

2. EQUIPMENT SPECIFICATIONS

☑ Pressure Test ☐ Hose Test ☐ Tube Spool Test

☑ Other/Specify

3. TEST SPECIFICATIONS

Recorder No.: HS0295NF
Recorder Cert. No.: 132671-18-02

Gauge No.: HS0261NF
Gauge Cert. No.: 132617-18-06

Test Result: ☑ Pass ☐ Fail
Test Pressure: 2000 PSI

Test Medium: FRYQUEL ECH-S

Start Time: 10:45 AM
Stop Time: 11:15AM
Stabilization: 15 Minutes
Hold: 15 Minutes

4. TEST DESCRIPTION

Hose(s) / Tube Spool(s)	No. of Pieces	Hose/Tube Size and/or Brand	Hose/Tube Service No. (if applicable)	N/A
				☐
				☐
				☐
				☐
				☐
				☐
				☐
				☐
				☐
				☐

For Additional Pages please see Attached

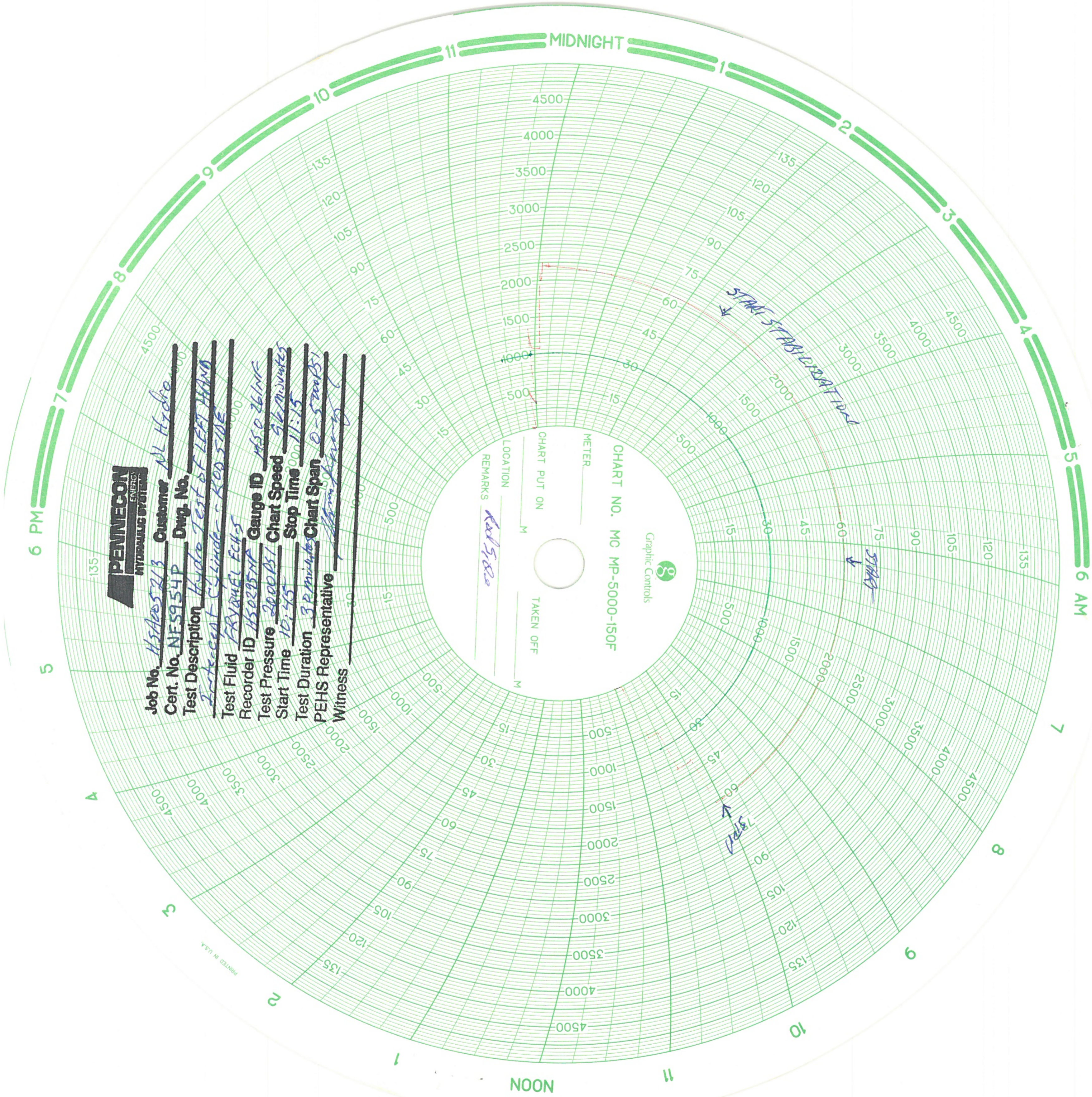
Brief Description of Test	Hydro Test of Left Hand Intercept Cylinder Rod Side- 15 stabilization and 15 minute Hold at 2000 PSI
Comments/ Notes	

Signed by: PEHS Representative
Signature:
Print Name: Steve Keough
Position: Hydraulic Tech
Date: 5-Dec-18

Accepted by: Client Rep.
Signature:
Print Name:
Position:
Date:

Accepted by: Regulatory Rep.
Signature:
Print Name:
Position:
Date:

Accepted by: QC Representative
Signature:
Print Name:
Position:
Date:


MIDNIGHT
NOON
6 AM
6 PM
CHART NO. MC MP-5000-150F
Graphic Controls
METER
CHART PUT ON
TAKEN OFF
LOCATION
REMARKS
PENNECON
HYDRAULIC SYSTEMS
Job No.
Customer
Cert. No.
Dwg. No.
Test Description
Test Fluid
Recorder ID
Gauge ID
Test Pressure
Chart Speed
Start Time
Stop Time
Test Duration
Chart Span
PEHS Representative
Witness

PENNECON

TEST CERTIFICATE

Certificate No. NF5953P

1. CUSTOMER INFORMATION

Customer: NL Hydro	Work Order No.: HSA005213
Contact Name: Craig Dwyer	Customer Reference No.:
Customer Instructions/Notes: Hydro test cylinder after rebuild	

2. EQUIPMENT SPECIFICATIONS

☑ Pressure Test ☐ Hose Test ☐ Tube Spool Test

☑ Other/Specify

3. TEST SPECIFICATIONS

Recorder No.: HS0295NF
Recorder Cert. No.: 132671-18-02

Gauge No.: HS0261NF
Gauge Cert. No.: 132617-18-06

Test Result: ☑ Pass ☐ Fail
Test Pressure: 2000 PSI

Test Medium: FRYQUEL ECH-S

Start Time: 11:45 AM
Stop Time: 12:15 PM
Stabilization: 15 Minutes
Hold: 15 Minutes

4. TEST DESCRIPTION

Hose(s) / Tube Spool(s)	No. of Pieces	Hose/Tube Size and/or Brand	Hose/Tube Service No. (if applicable)	N/A
				☐
				☐
				☐
				☐
				☐
				☐
				☐
				☐
				☐
				☐

For Additional Pages please see Attached

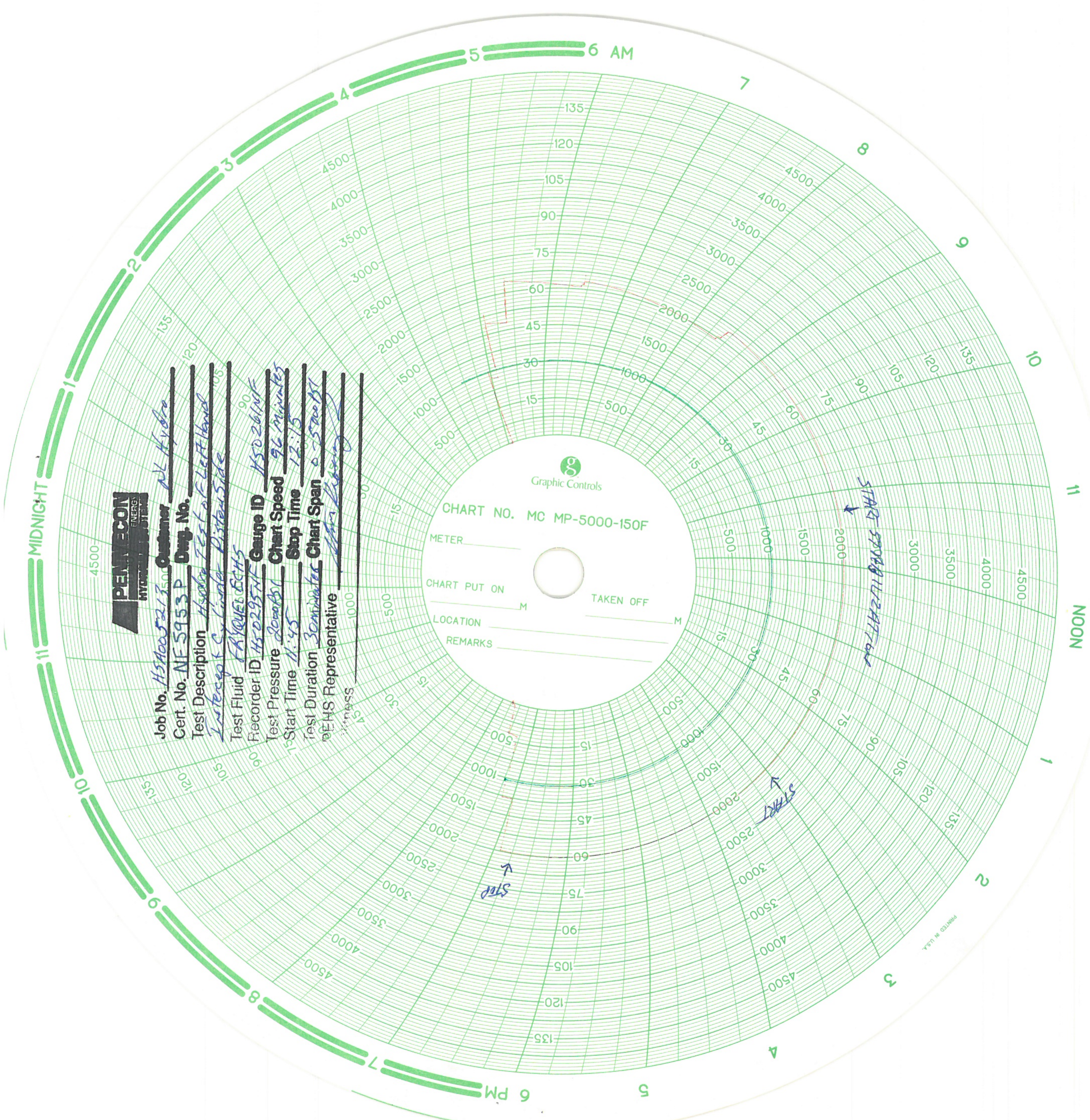
Brief Description of Test	Hydro Test of Left Hand Intercept Cylinder Piston Side -15 stabilization and 15 minute Hold at 2000 PSI
Comments/ Notes	

Signed by: PEHS Representative
Signature: [signature]
Print Name: Steve Keough
Position: Hydraulic Tech
Date: 5-Dec-18

Accepted by: Client Rep.
Signature:
Print Name:
Position:
Date:

Accepted by: Regulatory Rep.
Signature:
Print Name:
Position:
Date:

Accepted by: QC Representative
Signature:
Print Name:
Position:
Date:


Graphic Controls
CHART NO. MC MP-5000-150F
METER
CHART PUT ON
TAKEN OFF
LOCATION
REMARKS
MIDNIGHT
6 AM
NOON
6 PM
Job No.
Customer
Cert. No.
Dwg. No.
Test Description
Test Fluid
Gauge ID
Recorder ID
Chart Speed
Test Pressure
Stop Time
Start Time
Test Duration
Chart Span
Representative
Witness
START
STOP

PENNECON

TEST CERTIFICATE

Certificate No. NF5952P

1. CUSTOMER INFORMATION

Customer: NL Hydro	Work Order No.: HSA005213
Contact Name: Craig Dwyer	Customer Reference No.:
Customer Instructions/Notes: Hydro test cylinder after rebuild	

2. EQUIPMENT SPECIFICATIONS

- [x] Pressure Test
- [ ] Hose Test
- [ ] Tube Spool Test
- [x] Other/Specify

3. TEST SPECIFICATIONS

Recorder No.: HS0295NF
Recorder Cert. No.: 132671-18-02
Gauge No.: HS0261NF
Gauge Cert. No.: 132617-18-06
Test Result: [x] Pass [ ] Fail
Test Pressure: 2000 PSI
Test Medium: FRYQUEL ECH-S
Start Time: 9:30 PM
Stop Time: 10:00 PM
Stabilization: 15 Minutes
Hold: 15 Minutes

4. TEST DESCRIPTION

Hose(s) / Tube Spool(s)

No. of Pieces	Hose/Tube Size and/or Brand	Hose/Tube Service No. (if applicable)	N/A
			☐
			☐
			☐
			☐
			☐
			☐
			☐
			☐
			☐
			☐

For Additional Pages please see Attached

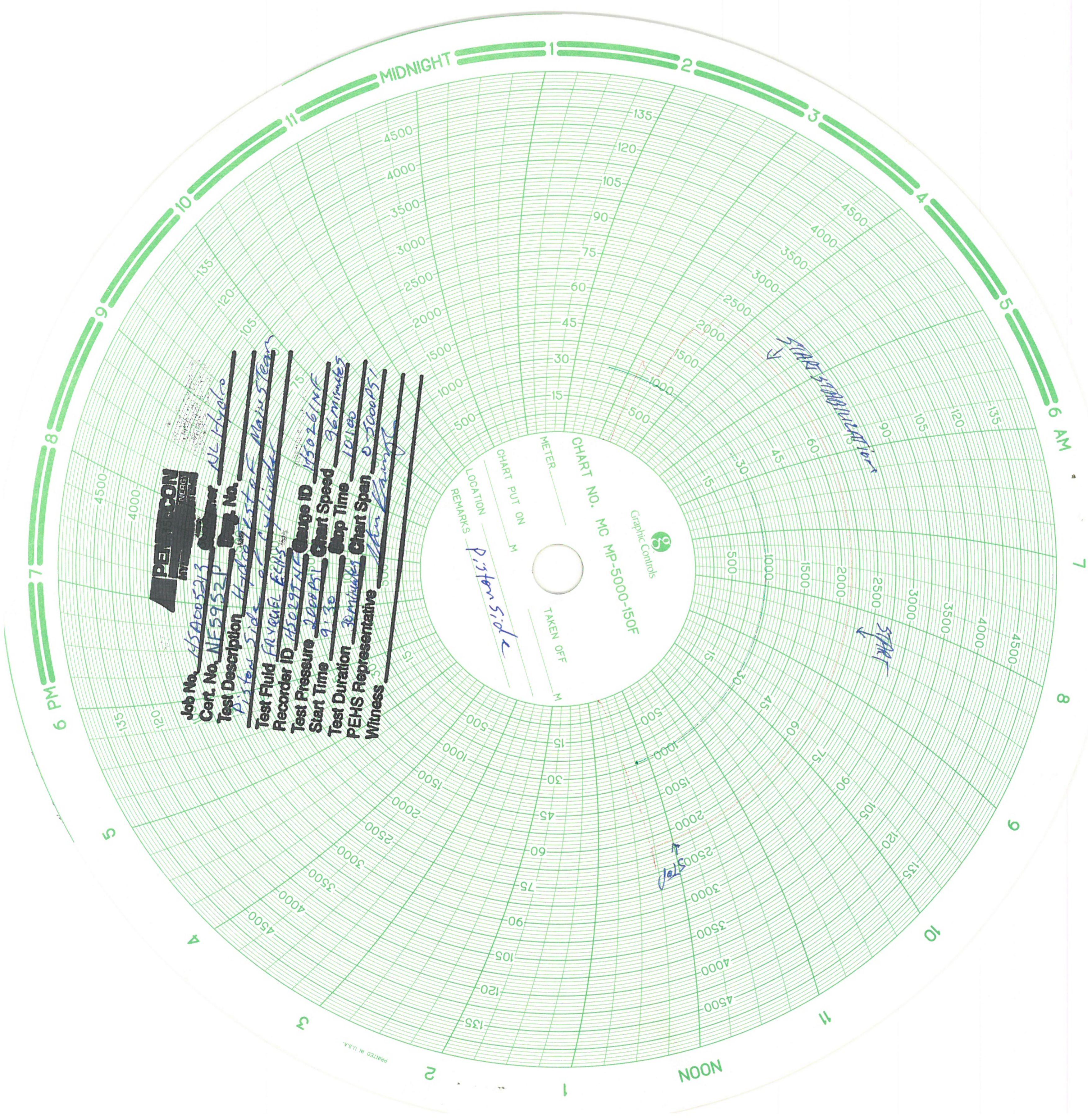
Brief Description of Test	Hydro Test of Main Steam Cylinder Piston Side - 15 stabilization and 15 minute Hold at 2000 PSI
Comments/ Notes	

Signed by: PEHS Representative
Signature:
Print Name: Steve Keough
Position: Hydraulic Tech
Date: 5-Dec-18

Accepted by: Client Rep.
Signature:
Print Name:
Position:
Date:

Accepted by: Regulatory Rep.
Signature:
Print Name:
Position:
Date:

Accepted by: QC Representative
Signature:
Print Name:
Position:
Date:


MIDNIGHT
NOON
CHART NO. MC MP-5000-150F
Graphic Controls
METER
CHART PUT ON
LOCATION
REMARKS
TAKEN OFF
Job No.
Cert. No.
Test Description
Test Fluid
Recorder ID
Test Pressure
Start Time
Test Duration
PEHS Representative
Witness
Gauge ID
Chart Speed
Stop Time
Chart Span

PENNECON

TEST CERTIFICATE

Certificate No. NF5963P

1. CUSTOMER INFORMATION	
Customer: NL Hydro	Work Order No.: HSA005213
Contact Name: Craig Dwyer	Customer Reference No.:
Customer Instructions/Notes: Hydro test cylinder after rebuild	

2. EQUIPMENT SPECIFICATIONS

☑ Pressure Test ☐ Hose Test ☐ Tube Spool Test

☑ Other/Specify

3. TEST SPECIFICATIONS

Recorder No.: HS0295NF Gauge No.: HS0261NF Test Result: ☑ Pass ☐ Fail

Recorder Cert. No.: 132671-18-02 Gauge Cert. No.: 132617-18-06 Test Pressure: 2000 PSI

Test Medium: FRYQUEL ECH-S

Start Time: 10:15 PM Stop Time: 10:45PM Stabilization: 15 Minutes

Hold: 15 Minutes

4. TEST DESCRIPTION

Hose(s) / Tube Spool(s)	No. of Pieces	Hose/Tube Size and/or Brand	Hose/Tube Service No. (if applicable)	N/A
				☐
				☐
				☐
				☐
				☐
				☐
				☐
				☐
				☐
				☐

For Additional Pages please see Attached

Brief Description of Test	Hydro Test of Main Steam Cylinder ROD Side - 15 stabilization and 15 minute Hold at 2000 PSI
Comments/ Notes	

Signed by: PEHS Representative
Signature: [signature]
Print Name: Steve Keough
Position: Hydraulic Tech
Date: 5-Dec-18

Accepted by: Client Rep.
Signature:
Print Name:
Position:
Date:

Accepted by: Regulatory Rep.
Signature:
Print Name:
Position:
Date:

Accepted by: QC Representative
Signature:
Print Name:
Position:
Date:

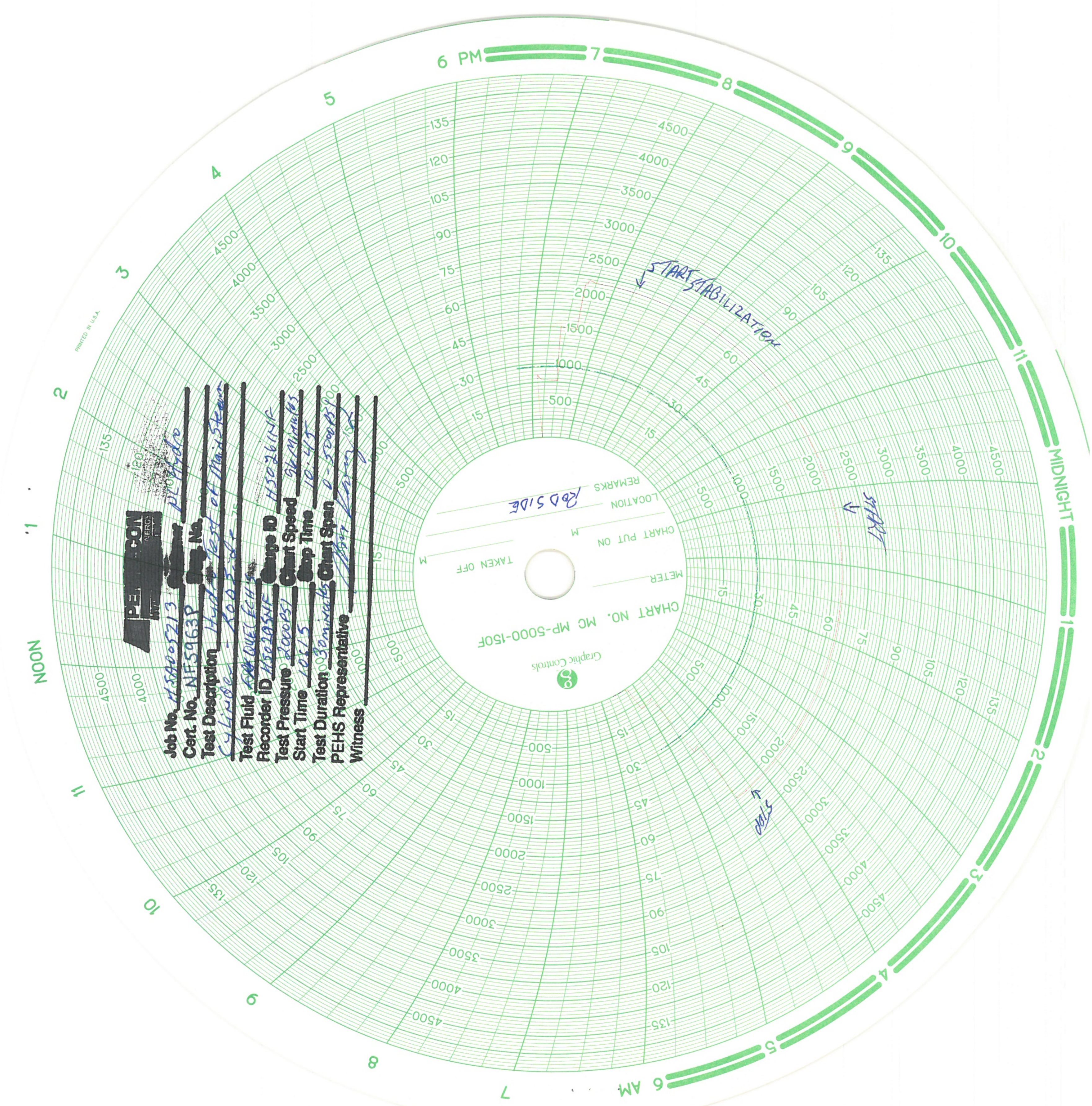


CHART NO. MC MP-5000-150F
Graphic Controls
START STABILIZATION
START
STOP
ROD SIDE
Job No.
Cert. No.
Test Description
Test Fluid
Recorder ID
Test Pressure
Start Time
Test Duration
PEHS Representative
Witness
Chart Speed
Stop Time
Chart Span

PENNECON

TEST CERTIFICATE

Certificate No. NF5964P

1. CUSTOMER INFORMATION

Customer: NL Hydro	Work Order No.: HSA005213
Contact Name: Craig Dwyer	Customer Reference No.:
Customer Instructions/Notes: Hydro test of Heat Exchanger- Oil Side	

2. EQUIPMENT SPECIFICATIONS

☑ Pressure Test ☐ Hose Test ☐ Tube Spool Test

☑ Other/Specify

3. TEST SPECIFICATIONS

Recorder No.: HS0367NF
Recorder Cert. No.: 132650-18-02
Gauge No.: HS0349NF
Gauge Cert. No.: 132653-18-05
Test Result: ☑ Pass ☐ Fail
Test Pressure: 120 PSI

Test Medium: FRYQUEL ECH-S

Start Time: 10:30 AM
Stop Time: 11:00 AM
Stabilization: 15 Minutes
Hold: 15 Minutes

4. TEST DESCRIPTION

Hose(s) / Tube Spool(s)	No. of Pieces	Hose/Tube Size and/or Brand	Hose/Tube Service No. (if applicable)	N/A
	2	Model F-502-FY-2P P/N YT- 307124	S/N IBS & S/N WCM	☐
				☐
				☐
				☐
				☐
				☐
				☐
				☐
				☐
				☐

For Additional Pages please see Attached

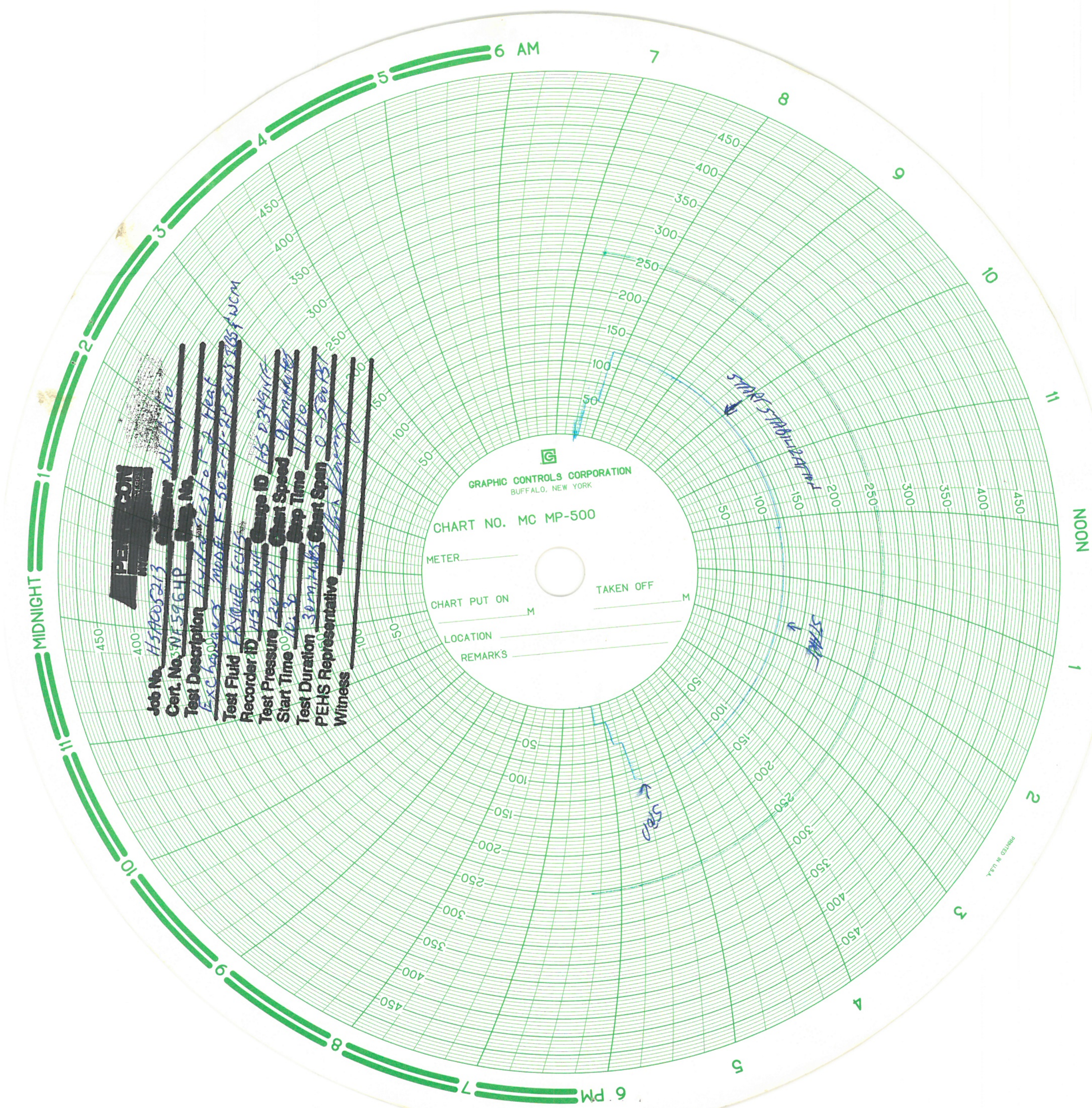
Brief Description of Test	Hydro Test of Heat Exchangers - Oil Side - 15 stabilization and 15 minute Hold at 120 PSI
Comments/ Notes	

Signed by: PEHS Representative
Signature: [signature]
Print Name: Steve Keough
Position: Hydraulic Tech
Date: 6-Dec-18

Accepted by: Client Rep.
Signature:
Print Name:
Position:
Date:

Accepted by: Regulatory Rep.
Signature:
Print Name:
Position:
Date:

Accepted by: QC Representative
Signature:
Print Name:
Position:
Date:


GRAPHIC CONTROLS CORPORATION
BUFFALO, NEW YORK
CHART NO. MC MP-500
METER
CHART PUT ON
M
TAKEN OFF
M
LOCATION
REMARKS
6 AM
NOON
6 PM
MIDNIGHT
Job No.
Cert. No.
Test Description
Test Fluid
Recorder ID
Test Pressure
Start Time
Test Duration
PEHS Representative
Witness
Gauge ID
Chart Speed
Stop Time
Chart Span

PENNECON

2.0 Pressure Testing

b. Gear Calibration Certificates

iEAS
Keeping you in Control

Certificate Number 132653-18-05

1218-1220 Kenmount Road
Paradise, NL A1L 1N3
Tel: 709-747-0816
Fax: 709-747-0825

Certificate Of Calibration

Customer	Hydraulic Systems	*Manufacturer*	WGI
Job Number	132-653	*ID*	HS0349NF
PO Number	PHSA02042	*Description*	200 PSI Gauge
Initial Condition	Out of Tolerance	*Model Number*	Elite 400
Complete Condition	In Tolerance	*Serial Number*	HS0349NF

iEAS Ltd. certifies that the above listed instrument meets or exceeds all specifications as stated in the referenced procedure (unless otherwise noted). It has been calibrated using measurement standards traceable to the National Institute of Standards and Technology (NIST), or to NIST accepted intrinsic standards of measurement, or derived by the ratio type of self-calibration techniques. This calibration complies with ANSI/NCSL Z540-1. Unless otherwise specified iEAS Ltd maintains a minimum of a 4:1 ratio between the equipment under test and the measurement system.

Work Order Notes:

CALIBRATION INFORMATION

Service Date	8/6/2018	*Temperature*	21	*WO Results*	Pass
Due Date	8/6/2019	*Humidity*	45	*Service Type*	Calibration

STANDARDS USED FOR CALIBRATION

Description	Service Date	Due Date	ID
16 000 PSI Dead Weight Tester	10/17/2017	10/17/2022	I101

Adam Thompson
Laboratory Representative

Curtis Lee
Quality Representative

Print Date: 8/6/2018 10:11:31 AM

iEAS
Keeping you in Control...

Certificate Number 132671-18-02

1218-1220 Kenmount Road
Paradise, NL A1L 1N3
Tel: 709-747-0816
Fax: 709-747-0825

Certificate Of Calibration

Customer	Hydraulic Systems	*Manufacturer*	TechCal
Job Number	132-671	*ID*	HS0295NF
PO Number	PHSA021320	*Description*	5000 psi / 100 DegC Chart Recorder
Initial Condition	In Tolerance	*Model Number*	2R4T0
Complete Condition	In Tolerance	*Serial Number*	HS0295NF

iEAS Ltd. certifies that the above listed instrument meets or exceeds all specifications as stated in the referenced procedure (unless otherwise noted). It has been calibrated using measurement standards traceable to the National Institute of Standards and Technology (NIST), or to NIST accepted intrinsic standards of measurement, or derived by the ratio type of self-calibration techniques. This calibration complies with ANSI/NCSL Z540-1. Unless otherwise specified iEAS Ltd maintains a minimum of a 4:1 ratio between the equipment under test and the measurement system.

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Work Order Notes:

CALIBRATION INFORMATION

Service Date	11/8/2018	*Temperature*	21	*WO Results*	Pass
Due Date	11/8/2019	*Humidity*	45	*Service Type*	Calibration

STANDARDS USED FOR CALIBRATION

Description	Service Date	Due Date	ID
16 000 PSI Dead Weight Tester	10/17/2017	10/17/2022	I101
9103 Dry Well Calibrator	10/17/2018	10/17/2019	I102

Adam Thompson
Laboratory Representative

Quality Representative

Print Date: 08/11/2018 10:46:23 AM

iEAS
Keeping you in Control...

Certificate Number 132617-18-06

1218-1220 Kenmount Road
Paradise, NL A1L 1N3
Tel: 709-747-0816
Fax: 709-747-0825

Certificate Of Calibration

Customer	Hydraulic Systems	***Manufacturer***	McDaniel Controls
Job Number	132-617	***ID***	HS0261NF
PO Number	PHSA019145	***Description***	6000 psi pressure gauge
Initial Condition	In Tolerance	***Model Number***	E9
Complete Condition	In Tolerance	***Serial Number***	HS0261NF

iEAS Ltd. certifies that the above listed instrument meets or exceeds all specifications as stated in the referenced procedure (unless otherwise noted). It has been calibrated using measurement standards traceable to the National Institute of Standards and Technology (NIST), or to NIST accepted intrinsic standards of measurement, or derived by the ratio type of self-calibration techniques. This calibration complies with ANSI/NCSL Z540-1. Unless otherwise specified iEAS Ltd maintains a minimum of a 4:1 ratio between the equipment under test and the measurement system.

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Work Order Notes:

CALIBRATION INFORMATION

Service Date	3/7/2018	***Temperature***	20	***WO Results***	Pass
Due Date	3/7/2019	***Humidity***	40	***Service Type***	Calibration

STANDARDS USED FOR CALIBRATION

Description	Service Date	Due Date	ID
15,000 psi Pressure Gauge	5/12/2017	5/12/2018	I120

Adam Thompson
Laboratory Representative

Quality Representative

Print Date: 3/7/2018 10:41:32 AM

iEAS
Keeping you in Control...

Certificate Number 132650-18-02

1218-1220 Kenmount Road
Paradise, NL A1L 1N3
Tel: 709-747-0816
Fax: 709-747-0825

Certificate Of Calibration

Customer	Hydraulic Systems	*Manufacturer*	TechCal
Job Number	132-650	*ID*	HS0367NF
PO Number	PHSA020304	*Description*	Chart Recorder 0-500 psi / 0-150 DegF
Initial Condition	In Tolerance	*Model Number*	2BFT0
Complete Condition	In Tolerance	*Serial Number*	HS0367NF

iEAS Ltd. certifies that the above listed instrument meets or exceeds all specifications as stated in the referenced procedure (unless otherwise noted). It has been calibrated using measurement standards traceable to the National Institute of Standards and Technology (NIST), or to NIST accepted intrinsic standards of measurement, or derived by the ratio type of self-calibration techniques. This calibration complies with ANSI/NCSL Z540-1. Unless otherwise specified iEAS Ltd maintains a minimum of a 4:1 ratio between the equipment under test and the measurement system.

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Work Order Notes:

CALIBRATION INFORMATION

Service Date	8/2/2018	*Temperature*	20	*WO Results*	Pass
Due Date	8/2/2019	*Humidity*	40	*Service Type*	Calibration

STANDARDS USED FOR CALIBRATION

Description	Service Date	Due Date	ID
16 000 PSI Dead Weight Tester	10/17/2017	10/17/2022	I101
9103 Dry Well Calibrator	10/19/2017	10/19/2018	I102

Laboratory Representative

Quality Representative

Print Date: 8/2/2018 11:39:21 AM

Certificate Number 132623-18-03

iEAS
Keeping you in Control...

1218-1220 Kenmount Road
Paradise, NL A1L 1N3
Tel: 709-747-0816
Fax: 709-747-0825

Certificate Of Calibration

Customer	Hydraulic Systems	*Manufacturer*	WGI
Job Number	132-623	*ID*	HS0370NF
PO Number	PHSA019479	*Description*	600 PSI Gauge
Initial Condition	Out of Tolerance	*Model Number*	Elite 400
Complete Condition	In Tolerance	*Serial Number*	HS0370NF

iEAS Ltd. certifies that the above listed instrument meets or exceeds all specifications as stated in the referenced procedure (unless otherwise noted). It has been calibrated using measurement standards traceable to the National Institute of Standards and Technology (NIST), or to NIST accepted intrinsic standards of measurement, or derived by the ratio type of self-calibration techniques. This calibration complies with ANSI/NCSL Z540-1. Unless otherwise specified iEAS Ltd maintains a minimum of a 4:1 ratio between the equipment under test and the measurement system.

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Work Order Notes:

CALIBRATION INFORMATION

Service Date	4/11/2018	*Temperature*	20	*WO Results*	Pass
Due Date	4/11/2019	*Humidity*	40	*Service Type*	Calibration

STANDARDS USED FOR CALIBRATION

Description	Service Date	Due Date	ID
15,000 psi Pressure Gauge	5/12/2017	5/12/2018	I120

Adam Thompson
Laboratory Representative

Quality Representative

Print Date: 4/12/2018 11:16:59 AM

PENNECON

3.0 Flushing Reports

PENNECON

Flushing/Particle Count Form

Certificate No.: NF8961F

1.0 CUSTOMER INFORMATION

Customer: NL Hydro	PHS Job No.: HSA005213
Contact Name:	Customer Reference No.:
Customer Instructions Notes: Sample from HPU. Hydraulic unit #2	

2.0 JOB REQUIREMENTS / INFORMATION

Job Type: ☑ Sample Reading Only - No Flushing ☐ Flushing with Sample

Cleanliness Level Required: NAS1638 Class 06

Fluid Type: Fryquil

3.0 FLUSHING ☐ N/A

☐ Line Flushing (Hoses, Tubing, Piping, Flowrate: N/A

☐ Container Flushing (Drum, Tote, Pail) - Full Volume Circulated Minimum 5

☐ Accumulator Flushing - Minimum 10 Fill-Drain Cycles Completed

Temperature:

Equipment Details (type, qty., size, manufacturer): Hydraulic tank

Equipment ID (model, S/N):

4.0 WATER CONTENT READING ☑ N/A

Meter Used:	Reading Obtained:

5.0 PARTICLE COUNT READINGS (PER AS598 for Ocular Microscope Readings)

Particle Measurements					
(NAS 1638) Particle Size / Micrometers	5 – 15	15 – 25	25 – 50	50 – 100	100 +
Particles per 100 ml	xxx	xxx	xxx	xxx	xxx
(SAE AS4059) Particle Size / Micrometers	>5	>15	>25	>50	>100
Particles per 100 ml					
(ISO 4406) Particle Size / Micrometers	>4	>6	>14		
Scale Number					

6.0 PARTICLE COUNT RESULTS

Standard Achieved: NAS12 or higher ☐ PASS ☑ FAIL

Additional Notes: Cleanliness is a NAS1638 Class 12 or higher. Sample is too dirty to get an accurate reading. Sample was taken with a hand pump through a port in the top of the tank.

7.0 SIGNATURE

Technician: Grant Lush DaviBas FOR GL	Date: November 28th, 2018

PENNECON

Flushing/Particle Count Form

Certificate No.: NF8962F

1.0 CUSTOMER INFORMATION	
Customer: NL Hydro	PHS Job No.: HSA005213
Contact Name:	Customer Reference No.:
Customer Instructions Notes: Sample from HPU. Hydraulic unit #2	

2.0 JOB REQUIREMENTS / INFORMATION		
Job Type:	☑ Sample Reading Only - No Flushing	☐ Flushing with Sample
Cleanliness Level Required: NAS1638 Class 06		
Fluid Type: Fryquil		

3.0 FLUSHING	☐ N/A
☐ Line Flushing (Hoses, Tubing, Piping,	Flowrate: N/A
☐ Container Flushing (Drum, Tote, Pail) - Full Volume Circulated Minimum 5	
☐ Accumulator Flushing - Minimum 10 Fill-Drain Cycles Completed	
Temperature:	
Equipment Details (type, qty., size, manufacturer): Hydraulic tank	
Equipment ID (model, S/N):	

4.0 WATER CONTENT READING	☑ N/A
Meter Used:	Reading Obtained:

5.0 PARTICLE COUNT READINGS (PER AS598 for Ocular Microscope Readings)

Particle Measurements					
(NAS 1638) Particle Size / Micrometers	5 – 15	15 – 25	25 – 50	50 – 100	100 +
Particles per 100 ml	10041	3567	402	63	19
(SAE AS4059) Particle Size / Micrometers	>5	>15	>25	>50	>100
Particles per 100 ml					
(ISO 4406) Particle Size / Micrometers	>4	>6	>14		
Scale Number					

6.0 PARTICLE COUNT RESULTS	
Standard Achieved: NAS1638 Class 07	☐ PASS ☑ FAIL
Additional Notes: Cleanliness is a NAS1638 Class 07. Sample taken from fill / filter pump without purging oil through lines as directed.	

7.0 SIGNATURE	
Technician: Grant Lush David Bons For GL	Date: November 28th, 2018

PEHS-OF-01 Rev. 1

PENNECON

Flushing/Particle Count Form

Certificate No.: NF8963F

1.0 CUSTOMER INFORMATION	
Customer: NL Hydro	PHS Job No.: HSA005213
Contact Name:	Customer Reference No.:
Customer Instructions Notes: Sample from HPU. Hydraulic unit #2	

2.0 JOB REQUIREMENTS / INFORMATION		
Job Type:	☑ Sample Reading Only - No Flushing	☐ Flushing with Sample
Cleanliness Level Required: NAS1638 Class 06		
Fluid Type: Fryquil		

3.0 FLUSHING ☐ N/A

☐ Line Flushing (Hoses, Tubing, Piping, Flowrate: N/A
☐ Container Flushing (Drum, Tote, Pail) - Full Volume Circulated Minimum 5
☐ Accumulator Flushing - Minimum 10 Fill-Drain Cycles Completed

Temperature:

Equipment Details (type, qty., size, manufacturer): Hydraulic tank

Equipment ID (model, S/N):

4.0 WATER CONTENT READING ☑ N/A

Meter Used:	Reading Obtained:

5.0 PARTICLE COUNT READINGS (PER AS598 for Ocular Microscope Readings)

	Particle Measurements				
(NAS 1638) Particle Size / Micrometers	5 – 15	15 – 25	25 – 50	50 – 100	100 +
Particles per 100 ml	14531	4747	923	131	52
(SAE AS4059) Particle Size / Micrometers	>5	>15	>25	>50	>100
Particles per 100 ml					
(ISO 4406) Particle Size / Micrometers	>4	>6	>14		
Scale Number					

6.0 PARTICLE COUNT RESULTS	
Standard Achieved: NAS1638 Class 08	☐ PASS ☑ FAIL
Additional Notes: Cleanliness is a Nas1638 Class 08. Sample taken from fill / filter pump after purging out 2.5 liters.	

7.0 SIGNATURE	
Technician: Grant Lush, Dave Burr For GL	Date: November 28th, 2018

PENNECON

FLUSHING/PARTICLE COUNT FORM

Certificate No.: NF8985F

1.0 CUSTOMER INFORMATION

Customer: NL Hydro	PHS Job No.: HSA005213
Contact Name: Craig Dwyer	Customer Reference No.:

Customer Instructions Notes: Flush unit #2 expansion tank to NAS1638 Class 06 cleanliness level.

2.0 JOB REQUIREMENTS / INFORMATION

Job Type: ☐ Sample Reading Only - No Flushing Required ☑ Flushing with Sample Reading

Cleanliness Level Required: NAS1638 Class 06

Fluid Type: Fryquel

3.0 FLUSHING

☐ N/A

☑ Line Flushing (Hoses, Tubing, Piping, Systems) Flowrate:

☐ Container Flushing (Drum, Tote, Pail) - Full Volume Circulated Minimum 5 Times

☐ Accumulator Flushing - Minimum 10 Fill-Drain Cycles Completed

Temperature: Approximately 55°C

Equipment Details (type, qty., size, manufacturer): Expansion tank unit #2

Equipment ID (model, S/N):

4.0 WATER CONTENT READING

☑ N/A

Meter Used:	Reading Obtained:

5.0 PARTICLE COUNT READINGS (PER AS598 for Ocular Microscope Readings)

Particle Measurements					
(NAS 1638) Particle Size / Micrometers	5 – 15	15 – 25	25 – 50	50 – 100	100 +
Particles per 100 ml	5051	1060	137	18	12
(SAE AS4059) Particle Size / Micrometers	>5	>15	>25	>50	>100
Particles per 100 ml					
(ISO 4406) Particle Size / Micrometers	>4	>6	>14		
Scale Number					

6.0 PARTICLE COUNT RESULTS

Standard Achieved: NAS1638 Class 06 ☑ PASS ☐ FAIL

Additional Notes: Expansion tank flushed until NAS1638 Class 06 cleanliness level achieved

7.0 SIGNATURE

Technician: Pat Maher P Maher	Date: December 1, 2018

PENNECON

FLUSHING/PARTICLE COUNT FORM

Certificate No.: NF8986F

1.0 CUSTOMER INFORMATION	
Customer: NL Hydro	PHS Job No.: HSA005213
Contact Name: Craig Dwyer	Customer Reference No.:
Customer Instructions Notes: Flush both accumulators in Unit #2 to NAS1638 Class 06 cleanliness level	

2.0 JOB REQUIREMENTS / INFORMATION
Job Type: ☐ Sample Reading Only - No Flushing Required ☑ Flushing with Sample Reading
Cleanliness Level Required: NAS1638 Class 06
Fluid Type: Fryquel

3.0 FLUSHING ☐ N/A
☐ Line Flushing (Hoses, Tubing, Piping, Systems) Flowrate: ☐ Container Flushing (Drum, Tote, Pail) - Full Volume Circulated Minimum 5 Times ☑ Accumulator Flushing - Minimum 10 Fill-Drain Cycles Completed
Temperature: Approximately 55°C
Equipment Details (type, qty., size, manufacturer): Accumulators, qty. 2
Equipment ID (model, S/N):

4.0 WATER CONTENT READING ☑ N/A	
Meter Used:	Reading Obtained:

5.0 PARTICLE COUNT READINGS (PER AS598 for Ocular Microscope Readings)

Particle Measurements					
(NAS 1638) Particle Size / Micrometers	5 – 15	15 – 25	25 – 50	50 – 100	100 +
Particles per 100 ml	7467	1164	285	25	11
(SAE AS4059) Particle Size / Micrometers	>5	>15	>25	>50	>100
Particles per 100 ml					
(ISO 4406) Particle Size / Micrometers	>4	>6	>14		
Scale Number					

6.0 PARTICLE COUNT RESULTS	
Standard Achieved: NAS1638 Class 06	☑ PASS ☐ FAIL
Additional Notes: Accumulators flushed until NAS1638 Class 06 cleanliness level achieved	

7.0 SIGNATURE	
Technician: Pat Maher *(signature)*	Date: December 1, 2018

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PENNECON

FLUSHING/PARTICLE COUNT FORM

Certificate No.: NF8987F

1.0 CUSTOMER INFORMATION	
Customer: NL Hydro	PHS Job No.: HSA005213
Contact Name: Craig Dwyer	Customer Reference No.:
Customer Instructions Notes: Flush Unit #2 hydraulic pump to NAS1638 Class 06 cleanliness level	

2.0 JOB REQUIREMENTS / INFORMATION
Job Type: ☐ Sample Reading Only - No Flushing Required ☑ Flushing with Sample Reading
Cleanliness Level Required: NAS1638 Class 06
Fluid Type: Fryquel

3.0 FLUSHING ☐ N/A
☑ Line Flushing (Hoses, Tubing, Piping, Systems) Flowrate: ☐ Container Flushing (Drum, Tote, Pail) - Full Volume Circulated Minimum 5 Times ☐ Accumulator Flushing - Minimum 10 Fill-Drain Cycles Completed
Temperature: Approximately 55°C
Equipment Details (type, qty., size, manufacturer): Hydraulic Pump
Equipment ID (model, S/N):

4.0 WATER CONTENT READING	☑ N/A
Meter Used:	Reading Obtained:

5.0 PARTICLE COUNT READINGS (PER AS598 for Ocular Microscope Readings)

Particle Measurements					
(NAS 1638) Particle Size / Micrometers	5 – 15	15 – 25	25 – 50	50 – 100	100 +
Particles per 100 ml	7348	527	229	14	3
(SAE AS4059) Particle Size / Micrometers	>5	>15	>25	>50	>100
Particles per 100 ml					
(ISO 4406) Particle Size / Micrometers	>4	>6	>14		
Scale Number					

6.0 PARTICLE COUNT RESULTS	
Standard Achieved: NAS1638 Class 06	☑ PASS ☐ FAIL
Additional Notes: Hydraulic pump flushed until NAS1638 Class 06 cleanliness level achieved	

7.0 SIGNATURE	
Technician: Matt Fagan *Matt Fagan*	Date: December 2, 2018

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PENNECON

FLUSHING/PARTICLE COUNT FORM

Certificate No.: NF9016F

1.0 CUSTOMER INFORMATION

Customer: NL Hydro	PHS Job No.: HSA005213
Contact Name: Craig Dwyer	Customer Reference No.:

Customer Instructions Notes: Flush Right Hand Reheat Cylinder Piston Side to meet requirements of NAS1638 Class 6

2.0 JOB REQUIREMENTS / INFORMATION

Job Type: ☐ Sample Reading Only - No Flushing Required ☑ Flushing with Sample Reading

Cleanliness Level Required: NAS1638 Class 6

Fluid Type: FYRQUEL EHC-S

3.0 FLUSHING ☐ N/A

☑ Line Flushing (Hoses, Tubing, Piping, Systems) Flowrate: 20 GPM

☐ Container Flushing (Drum, Tote, Pail) - Full Volume Circulated Minimum 5 Times

☐ Accumulator Flushing - Minimum 10 Fill-Drain Cycles Completed

Temperature: 32 Deg. C

Equipment Details (type, qty., size, manufacturer): MILLER Fluid Power - Right Hand Reheat Cylinder Piston Side

Equipment ID: S/N 89162592

4.0 WATER CONTENT READING ☑ N/A

Meter Used:	Reading Obtained:

5.0 PARTICLE COUNT READINGS (PER AS598 for Ocular Microscope Readings)

Particle Measurements					
(NAS 1638) Particle Size / Micrometers	5 – 15	15 – 25	25 – 50	50 – 100	100 +
Particles per 100 ml	9552	1158	165	21	10
(SAE AS4059) Particle Size / Micrometers	>5	>15	>25	>50	>100
Particles per 100 ml					
(ISO 4406) Particle Size / Micrometers	>4	>6	>14		
Scale Number					

6.0 PARTICLE COUNT RESULTS

Standard Achieved: NAS1638 CLASS 6 ☑ PASS ☐ FAIL

Additional Notes: Sample of FYRQUEL EHC-S, taken while flushing the Piston Side of the right hand reheat cylinder, achieved NAS1638 Class 06.

7.0 SIGNATURE

Technician: Steve Keough [signature] Date: December 2, 2018

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PENNECON

FLUSHING/PARTICLE COUNT FORM

Certificate No.: NF9017F

1.0 CUSTOMER INFORMATION

Customer: NL Hydro	PHS Job No.: HSA005213
Contact Name: Craig Dwyer	Customer Reference No.:
Customer Instructions Notes: Flush Right Hand Reheat Cylinder Rod Side to meet requirements of NAS1638 Class 6	

2.0 JOB REQUIREMENTS / INFORMATION

Job Type: ☐ Sample Reading Only - No Flushing Required ☑ Flushing with Sample Reading

Cleanliness Level Required: NAS1638 Class 6

Fluid Type: FYRQUEL EHC-S

3.0 FLUSHING ☐ N/A

☑ Line Flushing (Hoses, Tubing, Piping, Systems) Flowrate: 20 GPM

☐ Container Flushing (Drum, Tote, Pail) - Full Volume Circulated Minimum 5 Times

☐ Accumulator Flushing - Minimum 10 Fill-Drain Cycles Completed

Temperature: 32 Deg. C

Equipment Details (type, qty., size, manufacturer): MILLER Fluid Power - Right Hand Reheat Cylinder Rod Side

Equipment ID: S/N 89162592

4.0 WATER CONTENT READING ☑ N/A

Meter Used:	Reading Obtained:

5.0 PARTICLE COUNT READINGS (PER AS598 for Ocular Microscope Readings)

	Particle Measurements				
(NAS 1638) Particle Size / Micrometers	5 – 15	15 – 25	25 – 50	50 – 100	100 +
Particles per 100 ml	7203	609	147	15	9
(SAE AS4059) Particle Size / Micrometers	>5	>15	>25	>50	>100
Particles per 100 ml					
(ISO 4406) Particle Size / Micrometers	>4	>6	>14		
Scale Number					

6.0 PARTICLE COUNT RESULTS

Standard Achieved: NAS1638 CLASS 6 ☑ PASS ☐ FAIL

Additional Notes: Sample of FYRQUEL EHC-S, taken while flushing the rod side of the Right Hand Reheat Cylinder, achieved NAS1638 Class 06.

7.0 SIGNATURE

Technician: Steve Keough	Date: December 2, 2018

PENNECON

FLUSHING/PARTICLE COUNT FORM

Certificate No.: NF9018F

1.0 CUSTOMER INFORMATION	
Customer: NL Hydro	PHS Job No.: HSA005213
Contact Name: Craig Dwyer	Customer Reference No.:
Customer Instructions Notes: Flush Coolers to meet requirements of NAS1638 Class 6	

2.0 JOB REQUIREMENTS / INFORMATION
Job Type: ☐ Sample Reading Only - No Flushing Required ☑ Flushing with Sample Reading
Cleanliness Level Required: NAS1638 Class 6
Fluid Type: FYRQUEL EHC-S

3.0 FLUSHING ☐ N/A
☑ Line Flushing (Hoses, Tubing, Piping, Systems) Flowrate: 24 GPM ☐ Container Flushing (Drum, Tote, Pail) - Full Volume Circulated Minimum 5 Times ☐ Accumulator Flushing - Minimum 10 Fill-Drain Cycles Completed
Temperature: 30 Deg. C
Equipment Details (type, qty., size, manufacturer): Young Touchstone (Wabtec Company) Heat Exchanger
Equipment ID (model, S/N): Heat Exchanger Model: F-502-EY-2P, Part No. 307124, S/N 's MBK & MBK, 150 PSI 350 Deg. F Rated (Note: same S/N On Both Units)

4.0 WATER CONTENT READING	☑ N/A
Meter Used:	Reading Obtained:

5.0 PARTICLE COUNT READINGS (PER AS598 for Ocular Microscope Readings)

Particle Measurements					
(NAS 1638) Particle Size / Micrometers	5 – 15	15 – 25	25 – 50	50 – 100	100 +
Particles per 100 ml	4021	704	115	9	7
(SAE AS4059) Particle Size / Micrometers	>5	>15	>25	>50	>100
Particles per 100 ml					
(ISO 4406) Particle Size / Micrometers	>4	>6	>14		
Scale Number					

6.0 PARTICLE COUNT RESULTS	
Standard Achieved: NAS1638 CLASS 5	☑ PASS ☐ FAIL
Additional Notes: Sample of FYRQUEL EHC-S, taken while flushing heat exchanger, achieved NAS1638 Class 05.	

7.0 SIGNATURE	
Technician: Steve Keough	Date: December 2, 2018

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PENNECON

FLUSHING/PARTICLE COUNT FORM

Certificate No.: NF9019F

1.0 CUSTOMER INFORMATION

Customer: NL Hydro	PHS Job No.: HSA005213
Contact Name: Craig Dwyer	Customer Reference No.:

Customer Instructions Notes: Flush Coolers to meet requirements of NAS1638 Class 6

2.0 JOB REQUIREMENTS / INFORMATION

Job Type: [ ] Sample Reading Only - No Flushing Required [x] Flushing with Sample Reading

Cleanliness Level Required: NAS1638 Class 6

Fluid Type: FYRQUEL EHC-S

3.0 FLUSHING

[ ] N/A

[x] Line Flushing (Hoses, Tubing, Piping, Systems) Flowrate: 24 GPM

[ ] Container Flushing (Drum, Tote, Pail) - Full Volume Circulated Minimum 5 Times

[ ] Accumulator Flushing - Minimum 10 Fill-Drain Cycles Completed

Temperature: 30 Deg. C

Equipment Details (type, qty., size, manufacturer): Young Touchstone (Wabtec Company) Heat Exchanger

Equipment ID (model, S/N): Heat Exchanger Model: F-502-EY-2P Part No. 307124 S/N 's MBK & MBK, 150 PSI, 350 Deg. F Rated (Note: same S/N On Both Units)

4.0 WATER CONTENT READING

[x] N/A

Meter Used:	Reading Obtained:

5.0 PARTICLE COUNT READINGS (PER AS598 for Ocular Microscope Readings)

Particle Measurements

(NAS 1638) Particle Size / Micrometers	5 – 15	15 – 25	25 – 50	50 – 100	100 +
Particles per 100 ml	4833	522	108	16	7
(SAE AS4059) Particle Size / Micrometers	>5	>15	>25	>50	>100
Particles per 100 ml					
(ISO 4406) Particle Size / Micrometers	>4	>6	>14		
Scale Number					

6.0 PARTICLE COUNT RESULTS

Standard Achieved: NAS1638 CLASS 5 [x] PASS [ ] FAIL

Additional Notes: Sample of FYRQUEL EHC-S, taken while flushing heat exchangers, achieved NAS1638 Class 06.

7.0 SIGNATURE

Technician: Steve Keough	Date: December 2, 2018

PENNECON

FLUSHING/PARTICLE COUNT FORM

Certificate No.: NF9021F

1.0 CUSTOMER INFORMATION	
Customer: NL Hydro	PHS Job No.: HSA005213
Contact Name: Craig Dwyer	Customer Reference No.:
Customer Instructions Notes: Loop out and flush right hand reheat cylinder valve block.	

2.0 JOB REQUIREMENTS / INFORMATION
Job Type: ☐ Sample Reading Only - No Flushing Required ☑ Flushing with Sample Reading
Cleanliness Level Required: NAS1638 Class 06
Fluid Type: Fryquel

3.0 FLUSHING ☐ N/A
☐ Line Flushing (Hoses, Tubing, Piping, Systems) Flowrate: ☐ Container Flushing (Drum, Tote, Pail) - Full Volume Circulated Minimum 5 Times ☐ Accumulator Flushing - Minimum 10 Fill-Drain Cycles Completed
Temperature: 40-45° C
Equipment Details (type, qty., size, manufacturer): Valve block from Miller 5" Tie rod cylinder, Right-Hand Reheat Cylinder.
Equipment ID (model, S/N): H53B2N, S/N: 89162592

4.0 WATER CONTENT READING ☑ N/A	
Meter Used:	Reading Obtained:

5.0 PARTICLE COUNT READINGS (PER AS598 for Ocular Microscope Readings)

Particle Measurements					
(NAS 1638) Particle Size / Micrometers	5 – 15	15 – 25	25 – 50	50 – 100	100 +
Particles per 100 ml	8708	1624	329	12	5
(SAE AS4059) Particle Size / Micrometers	>5	>15	>25	>50	>100
Particles per 100 ml					
(ISO 4406) Particle Size / Micrometers	>4	>6	>14		
Scale Number					

6.0 PARTICLE COUNT RESULTS	
Standard Achieved: NAS1638 Class 06	☑ PASS ☐ FAIL
Additional Notes: Sample of Fryquel, taken while flushing control block on right hand reheat cylinder, achieved NAS1638 Class 06.	

7.0 SIGNATURE	
Technician: Adam Gruchy	Date: Dec 2nd, 2018

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PENNECON

FLUSHING/PARTICLE COUNT FORM

Certificate No.: NF8988F

1.0 CUSTOMER INFORMATION	
Customer: NL Hydro	PHS Job No.: HSA005213
Contact Name: Craig Dwyer	Customer Reference No.:
Customer Instructions Notes: Flush left intercept valve to NAS1638 Class 06 cleanliness level	

2.0 JOB REQUIREMENTS / INFORMATION
Job Type: ☐ Sample Reading Only - No Flushing Required ☑ Flushing with Sample Reading
Cleanliness Level Required: NAS1638 Class 06
Fluid Type: Fryquel

3.0 FLUSHING ☐ N/A
☑ Line Flushing (Hoses, Tubing, Piping, Systems) Flowrate: ☐ Container Flushing (Drum, Tote, Pail) - Full Volume Circulated Minimum 5 Times ☐ Accumulator Flushing - Minimum 10 Fill-Drain Cycles Completed
Temperature: Approximately 55°C
Equipment Details (type, qty., size, manufacturer): Left Intercept Valve
Equipment ID (model, S/N):

4.0 WATER CONTENT READING ☑ N/A	
Meter Used:	Reading Obtained:

5.0 PARTICLE COUNT READINGS (PER AS598 for Ocular Microscope Readings)

Particle Measurements					
(NAS 1638) Particle Size / Micrometers	5 – 15	15 – 25	25 – 50	50 – 100	100 +
Particles per 100 ml	3418	559	134	21	9
(SAE AS4059) Particle Size / Micrometers	>5	>15	>25	>50	>100
Particles per 100 ml					
(ISO 4406) Particle Size / Micrometers	>4	>6	>14		
Scale Number					

6.0 PARTICLE COUNT RESULTS	
Standard Achieved: NAS1638 Class 06	☑ PASS ☐ FAIL
Additional Notes: Left intercept valve flushed until NAS1638 Class 06 cleanliness level achieved	

7.0 SIGNATURE	
Technician: Pat Maher *PMaher*	Date: December 3, 2018

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PENNECON

FLUSHING/PARTICLE COUNT FORM

Certificate No.: NF8989F

1.0 CUSTOMER INFORMATION

Customer: NL Hydro	PHS Job No.: HSA005213
Contact Name: Craig Dwyer	Customer Reference No.:
Customer Instructions Notes: Sample tank on Unit #1	

2.0 JOB REQUIREMENTS / INFORMATION

Job Type: ☐ Sample Reading Only - No Flushing Required ☑ Flushing with Sample Reading

Cleanliness Level Required: NAS1638 Class 06

Fluid Type: Fryquel

3.0 FLUSHING ☐ N/A

☐ Line Flushing (Hoses, Tubing, Piping, Systems) Flowrate:

☑ Container Flushing (Drum, Tote, Pail) - Full Volume Circulated Minimum 5 Times

☐ Accumulator Flushing - Minimum 10 Fill-Drain Cycles Completed

Temperature:

Equipment Details (type, qty., size, manufacturer): HPU tank unit #1

Equipment ID (model, S/N):

4.0 WATER CONTENT READING ☑ N/A

Meter Used:	Reading Obtained:

5.0 PARTICLE COUNT READINGS (PER AS598 for Ocular Microscope Readings)

Particle Measurements

(NAS 1638) Particle Size / Micrometers	5 – 15	15 – 25	25 – 50	50 – 100	100 +
Particles per 100 ml	5475	825	183	34	8
(SAE AS4059) Particle Size / Micrometers	>5	>15	>25	>50	>100
Particles per 100 ml					
(ISO 4406) Particle Size / Micrometers	>4	>6	>14		
Scale Number					

6.0 PARTICLE COUNT RESULTS

Standard Achieved: NAS1638 Class 06 ☑ PASS ☐ FAIL

Additional Notes: Sample taken while flushing HPU tank on unit #1 achieved NAS1638 Class 06.

7.0 SIGNATURE

Technician: Grant Lush	Date: December 3, 2018

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PENNECON

FLUSHING/PARTICLE COUNT FORM

Certificate No.: NF9010F

1.0 CUSTOMER INFORMATION	
Customer: NL Hydro	PHS Job No.: HSA005213
Contact Name: Craig Dwyer	Customer Reference No.:
Customer Instructions Notes: Flush Main Stop Control Block to meet requirements of NAS1638 Class 6	

2.0 JOB REQUIREMENTS / INFORMATION
Job Type: ☐ Sample Reading Only - No Flushing Required ☑ Flushing with Sample Reading
Cleanliness Level Required: NAS1638 Class 6
Fluid Type: FYRQUEL EHC-S

3.0 FLUSHING ☐ N/A
☑ Line Flushing (Hoses, Tubing, Piping, Systems) Flowrate: 15 GPM ☐ Container Flushing (Drum, Tote, Pail) - Full Volume Circulated Minimum 5 Times ☐ Accumulator Flushing - Minimum 10 Fill-Drain Cycles Completed
Temperature: 38 Deg. C
Equipment Details (type, qty., size, manufacturer): Main Stop Control Block
Equipment ID: Main Stop Control Block

4.0 WATER CONTENT READING	☑ N/A
Meter Used:	Reading Obtained:

5.0 PARTICLE COUNT READINGS (PER AS598 for Ocular Microscope Readings)

	Particle Measurements				
(NAS 1638) Particle Size / Micrometers	5 – 15	15 – 25	25 – 50	50 – 100	100 +
Particles per 100 ml	5893	722	160	26	10
(SAE AS4059) Particle Size / Micrometers	>5	>15	>25	>50	>100
Particles per 100 ml					
(ISO 4406) Particle Size / Micrometers	>4	>6	>14		
Scale Number					

6.0 PARTICLE COUNT RESULTS	
Standard Achieved: NAS1638 CLASS 6	☑ PASS ☐ FAIL
Additional Notes: Sample of FYRQUEL EHC-S, taken while flushing Main Stop Control Block, achieved NAS1638 Class 06.	

7.0 SIGNATURE	
Technician: Steve Keough [signature]	Date: December 3, 2018

PENNECON

FLUSHING/PARTICLE COUNT FORM

Certificate No.: NF9011F

1.0 CUSTOMER INFORMATION	
Customer: NL Hydro	PHS Job No.: HSA005213
Contact Name: Craig Dwyer	Customer Reference No.:
Customer Instructions Notes: Flush LH East Reheat Control Block to meet requirements of NAS1638 Class 6	

2.0 JOB REQUIREMENTS / INFORMATION
Job Type: ☐ Sample Reading Only - No Flushing Required ☑ Flushing with Sample Reading
Cleanliness Level Required: NAS1638 Class 6
Fluid Type: FYRQUEL EHC-S

3.0 FLUSHING ☐ N/A
☑ Line Flushing (Hoses, Tubing, Piping, Systems) Flowrate: 20 GPM ☐ Container Flushing (Drum, Tote, Pail) - Full Volume Circulated Minimum 5 Times ☐ Accumulator Flushing - Minimum 10 Fill-Drain Cycles Completed
Temperature: 32 Deg. C
Equipment Details (type, qty., size, manufacturer): LH East Reheat Control Block
Equipment ID: LH East Reheat Control Block

4.0 WATER CONTENT READING	☑ N/A
Meter Used:	Reading Obtained:

5.0 PARTICLE COUNT READINGS (PER AS598 for Ocular Microscope Readings)

Particle Measurements					
(NAS 1638) Particle Size / Micrometers	5 – 15	15 – 25	25 – 50	50 – 100	100 +
Particles per 100 ml	7250	940	194	23	14
(SAE AS4059) Particle Size / Micrometers	>5	>15	>25	>50	>100
Particles per 100 ml					
(ISO 4406) Particle Size / Micrometers	>4	>6	>14		
Scale Number					

6.0 PARTICLE COUNT RESULTS	
Standard Achieved: NAS1638 CLASS 6	☑ PASS ☐ FAIL
Additional Notes: Sample of FYRQUEL EHC-S, taken while flushing LH East Reheat Control Block, achieved NAS1638 Class 06.	

7.0 SIGNATURE	
Technician: Steve Keough	Date: December 3, 2018

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PENNECON

FLUSHING/PARTICLE COUNT FORM

Certificate No.: NF9012F

1.0 CUSTOMER INFORMATION

Customer: NL Hydro	PHS Job No.: HSA005213
Contact Name: Craig Dwyer	Customer Reference No.:

Customer Instructions Notes: Flush Left Hand Reheat Cylinder Piston Side to meet requirements of NAS1638 Class 6

2.0 JOB REQUIREMENTS / INFORMATION

Job Type: ☐ Sample Reading Only - No Flushing Required ☑ Flushing with Sample Reading

Cleanliness Level Required: NAS1638 Class 6

Fluid Type: FYRQUEL EHC-S

3.0 FLUSHING ☐ N/A

☑ Line Flushing (Hoses, Tubing, Piping, Systems) Flowrate: 20 GPM

☐ Container Flushing (Drum, Tote, Pail) - Full Volume Circulated Minimum 5 Times

☐ Accumulator Flushing - Minimum 10 Fill-Drain Cycles Completed

Temperature: 34 Deg. C

Equipment Details (type, qty., size, manufacturer): MILLER Fluid Power- Left Hand Reheat Cylinder Piston Side

Equipment ID: Left Hand Reheat Cylinder

4.0 WATER CONTENT READING ☑ N/A

Meter Used:	Reading Obtained:

5.0 PARTICLE COUNT READINGS (PER AS598 for Ocular Microscope Readings)

Particle Measurements					
(NAS 1638) Particle Size / Micrometers	5 – 15	15 – 25	25 – 50	50 – 100	100 +
Particles per 100 ml	7110	1080	243	36	15
(SAE AS4059) Particle Size / Micrometers	>5	>15	>25	>50	>100
Particles per 100 ml					
(ISO 4406) Particle Size / Micrometers	>4	>6	>14		
Scale Number					

6.0 PARTICLE COUNT RESULTS

Standard Achieved: NAS1638 CLASS 6 ☑ PASS ☐ FAIL

Additional Notes: Sample of FYRQUEL EHC-S, taken while flushing the piston side of the left hand reheat cylinder, achieved NAS1638 Class 06.

7.0 SIGNATURE

Technician: Steve Keough Date: December 3, 2018

PENNECON

FLUSHING/PARTICLE COUNT FORM

Certificate No.: NF9013F

1.0 CUSTOMER INFORMATION

Customer: NL Hydro	PHS Job No.: HSA005213
Contact Name: Craig Dwyer	Customer Reference No.:

Customer Instructions Notes: Flush Left Hand Reheat Cylinder ROD Side to meet requirements of NAS1638 Class 6

2.0 JOB REQUIREMENTS / INFORMATION

Job Type: ☐ Sample Reading Only - No Flushing Required ☑ Flushing with Sample Reading

Cleanliness Level Required: NAS1638 Class 6

Fluid Type: FYRQUEL EHC-S

3.0 FLUSHING ☐ N/A

☑ Line Flushing (Hoses, Tubing, Piping, Systems) Flowrate: 20 GPM

☐ Container Flushing (Drum, Tote, Pail) - Full Volume Circulated Minimum 5 Times

☐ Accumulator Flushing - Minimum 10 Fill-Drain Cycles Completed

Temperature: 34 Deg. C

Equipment Details (type, qty., size, manufacturer): MILLER Fluid Power- Left Hand Reheat Cylinder ROD Side

Equipment ID: Left Hand Reheat Cylinder

4.0 WATER CONTENT READING ☑ N/A

Meter Used:	Reading Obtained:

5.0 PARTICLE COUNT READINGS (PER AS598 for Ocular Microscope Readings)

Particle Measurements					
(NAS 1638) Particle Size / Micrometers	5 – 15	15 – 25	25 – 50	50 – 100	100 +
Particles per 100 ml	6301	944	190	27	10
(SAE AS4059) Particle Size / Micrometers	>5	>15	>25	>50	>100
Particles per 100 ml					
(ISO 4406) Particle Size / Micrometers	>4	>6	>14		
Scale Number					

6.0 PARTICLE COUNT RESULTS

Standard Achieved: NAS1638 CLASS 6 ☑ PASS ☐ FAIL

Additional Notes: Sample of FYRQUEL EHC-S, taken while flushing the rod side of the left hand reheat cylinder, achieved NAS1638 Class 06.

7.0 SIGNATURE

Technician: Steve Keough	Date: December 3, 2018

PENNECON

FLUSHING/PARTICLE COUNT FORM

Certificate No.: NF9014F

1.0 CUSTOMER INFORMATION

Customer: NL Hydro	PHS Job No.: HSA005213
Contact Name: Craig Dwyer	Customer Reference No.:
Customer Instructions Notes: Flush Main Stop Cylinder Piston Side to meet requirements of NAS1638 Class 6	

2.0 JOB REQUIREMENTS / INFORMATION

Job Type: ☐ Sample Reading Only - No Flushing Required ☑ Flushing with Sample Reading

Cleanliness Level Required: NAS1638 Class 6

Fluid Type: FYRQUEL EHC-S

3.0 FLUSHING ☐ N/A

☑ Line Flushing (Hoses, Tubing, Piping, Systems) Flowrate: 20 GPM

☐ Container Flushing (Drum, Tote, Pail) - Full Volume Circulated Minimum 5 Times

☐ Accumulator Flushing - Minimum 10 Fill-Drain Cycles Completed

Temperature: 32 Deg. C

Equipment Details (type, qty., size, manufacturer): MILLER Fluid Power 7" Main Stop Cylinder Piston Side

Equipment ID: Main Stop Cylinder

4.0 WATER CONTENT READING ☑ N/A

Meter Used:	Reading Obtained:

5.0 PARTICLE COUNT READINGS (PER AS598 for Ocular Microscope Readings)

Particle Measurements					
(NAS 1638) Particle Size / Micrometers	5 – 15	15 – 25	25 – 50	50 – 100	100 +
Particles per 100 ml	6139	1421	217	31	14
(SAE AS4059) Particle Size / Micrometers	>5	>15	>25	>50	>100
Particles per 100 ml					
(ISO 4406) Particle Size / Micrometers	>4	>6	>14		
Scale Number					

6.0 PARTICLE COUNT RESULTS

Standard Achieved: NAS1638 CLASS 6 ☑ PASS ☐ FAIL

Additional Notes: Sample of FYRQUEL EHC-S, taken while flushing the piston side of the main stop cylinder, achieved NAS1638 Class 06.

7.0 SIGNATURE

Technician: Steve Keough	Date: December 3, 2018

PEHS-OF-01 Rev. 2

PENNECON

FLUSHING/PARTICLE COUNT FORM

Certificate No.: NF9015F

1.0 CUSTOMER INFORMATION	
Customer: NL Hydro	PHS Job No.: HSA005213
Contact Name: Craig Dwyer	Customer Reference No.:
Customer Instructions Notes: Flush Main Stop Cylinder ROD Side to meet requirements of NAS1638 Class 6	

2.0 JOB REQUIREMENTS / INFORMATION		
Job Type:	☐ Sample Reading Only - No Flushing Required	☑ Flushing with Sample Reading
Cleanliness Level Required: NAS1638 Class 6		
Fluid Type: FYRQUEL EHC-S		

3.0 FLUSHING	☐ N/A
☑ Line Flushing (Hoses, Tubing, Piping, Systems) Flowrate: 20 GPM ☐ Container Flushing (Drum, Tote, Pail) - Full Volume Circulated Minimum 5 Times ☐ Accumulator Flushing - Minimum 10 Fill-Drain Cycles Completed	
Temperature: 32 Deg. C	
Equipment Details (type, qty., size, manufacturer): MILLER Fluid Power 7" Main Stop Cylinder ROD Side	
Equipment ID: Main Stop Cylinder	

4.0 WATER CONTENT READING	☑ N/A
Meter Used:	Reading Obtained:

5.0 PARTICLE COUNT READINGS (PER AS598 for Ocular Microscope Readings)

Particle Measurements					
(NAS 1638) Particle Size / Micrometers	5 – 15	15 – 25	25 – 50	50 – 100	100 +
Particles per 100 ml	7296	1209	366	37	15
(SAE AS4059) Particle Size / Micrometers	>5	>15	>25	>50	>100
Particles per 100 ml					
(ISO 4406) Particle Size / Micrometers	>4	>6	>14		
Scale Number					

6.0 PARTICLE COUNT RESULTS	
Standard Achieved: NAS1638 CLASS 6	☑ PASS ☐ FAIL
Additional Notes: Sample of FYRQUEL EHC-S, taken while flushing the rod side of the main stop cylinder, achieved NAS1638 Class 06.	

7.0 SIGNATURE	
Technician: Steve Keough	Date: December 3, 2018

PEHS-OF-01 Rev. 2

PENNECON

FLUSHING/PARTICLE COUNT FORM

Certificate No.: NF8990F

1.0 CUSTOMER INFORMATION

Customer: NL Hydro	PHS Job No.: HSA005213
Contact Name: Craig Dwyer	Customer Reference No.:
Customer Instructions Notes: Flush unit #2 left reheat control tubing	

2.0 JOB REQUIREMENTS / INFORMATION

Job Type: ☐ Sample Reading Only - No Flushing Required ☑ Flushing with Sample Reading

Cleanliness Level Required: NAS1638 Class 06

Fluid Type: Fryquel

3.0 FLUSHING ☐ N/A

☑ Line Flushing (Hoses, Tubing, Piping, Systems) Flowrate: 32 GPM

☐ Container Flushing (Drum, Tote, Pail) - Full Volume Circulated Minimum 5 Times

☐ Accumulator Flushing - Minimum 10 Fill-Drain Cycles Completed

Temperature: 68°C

Equipment Details (type, qty., size, manufacturer): Left reheat control tubing unit #2

Equipment ID (model, S/N):

4.0 WATER CONTENT READING ☑ N/A

Meter Used:	Reading Obtained:

5.0 PARTICLE COUNT READINGS (PER AS598 for Ocular Microscope Readings)

Particle Measurements					
(NAS 1638) Particle Size / Micrometers	5 – 15	15 – 25	25 – 50	50 – 100	100 +
Particles per 100 ml	2427	723	285	25	13
(SAE AS4059) Particle Size / Micrometers	>5	>15	>25	>50	>100
Particles per 100 ml					
(ISO 4406) Particle Size / Micrometers	>4	>6	>14		
Scale Number					

6.0 PARTICLE COUNT RESULTS

Standard Achieved: NAS1638 Class 06 ☑ PASS ☐ FAIL

Additional Notes: Sample taken while flushing left reheat control tubing from unit #2 achieved NAS1638 Class 06.

7.0 SIGNATURE

Technician: Matt Fagan *Matt Fagan* | Date: December 4, 2018

PENNECON

FLUSHING/PARTICLE COUNT FORM

Certificate No.: NF8991F

1.0 CUSTOMER INFORMATION	
Customer: NL Hydro	PHS Job No.: HSA005213
Contact Name: Craig Dwyer	Customer Reference No.:
Customer Instructions Notes: Flush unit #2 main stop loop control tubing to NAS1638 Class 06	

2.0 JOB REQUIREMENTS / INFORMATION		
Job Type:	☐ Sample Reading Only - No Flushing Required	☑ Flushing with Sample Reading
Cleanliness Level Required: NAS1638 Class 06		
Fluid Type: Fryquel		

3.0 FLUSHING	☐ N/A
☑ Line Flushing (Hoses, Tubing, Piping, Systems) Flowrate: ☐ Container Flushing (Drum, Tote, Pail) - Full Volume Circulated Minimum 5 Times ☐ Accumulator Flushing - Minimum 10 Fill-Drain Cycles Completed	
Temperature: 65°C	
Equipment Details (type, qty., size, manufacturer): Unit #2 main stop loop control tubing	
Equipment ID (model, S/N):	

4.0 WATER CONTENT READING	☑ N/A
Meter Used:	Reading Obtained:

5.0 PARTICLE COUNT READINGS (PER AS598 for Ocular Microscope Readings)

Particle Measurements					
(NAS 1638) Particle Size / Micrometers	5 – 15	15 – 25	25 – 50	50 – 100	100 +
Particles per 100 ml	768	492	201	16	5
(SAE AS4059) Particle Size / Micrometers	>5	>15	>25	>50	>100
Particles per 100 ml					
(ISO 4406) Particle Size / Micrometers	>4	>6	>14		
Scale Number					

6.0 PARTICLE COUNT RESULTS	
Standard Achieved: NAS1638 Class 06	☑ PASS ☐ FAIL
Additional Notes: Sample taken while flushing unit #2 main stop loop control tubing achieved NAS1638 Class 06.	

7.0 SIGNATURE	
Technician: Matt Fagan Matt Fagan	Date: December 4, 2018

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PENNECON

FLUSHING/PARTICLE COUNT FORM

Certificate No.: NF8993F

1.0 CUSTOMER INFORMATION	
Customer: NL Hydro	PHS Job No.: HSA005213
Contact Name: Craig Dwyer	Customer Reference No.:
Customer Instructions Notes: Flush unit #2 right hand reheat control tubing to NAS1638 Class 06	

2.0 JOB REQUIREMENTS / INFORMATION

Job Type: ☐ Sample Reading Only - No Flushing Required ☑ Flushing with Sample Reading

Cleanliness Level Required: NAS1638 Class 06

Fluid Type: Fryquel

3.0 FLUSHING ☐ N/A

☑ Line Flushing (Hoses, Tubing, Piping, Systems) Flowrate: 30 GPM

☐ Container Flushing (Drum, Tote, Pail) - Full Volume Circulated Minimum 5 Times

☐ Accumulator Flushing - Minimum 10 Fill-Drain Cycles Completed

Temperature: 65°C

Equipment Details (type, qty., size, manufacturer): Unit #2 right hand reheat control tubing

Equipment ID (model, S/N):

4.0 WATER CONTENT READING	☑ N/A
Meter Used:	Reading Obtained:

5.0 PARTICLE COUNT READINGS (PER AS598 for Ocular Microscope Readings)

Particle Measurements					
(NAS 1638) Particle Size / Micrometers	5 – 15	15 – 25	25 – 50	50 – 100	100 +
Particles per 100 ml	1059	453	114	10	5
(SAE AS4059) Particle Size / Micrometers	>5	>15	>25	>50	>100
Particles per 100 ml					
(ISO 4406) Particle Size / Micrometers	>4	>6	>14		
Scale Number					

6.0 PARTICLE COUNT RESULTS

Standard Achieved: NAS1638 Class 06	☑ PASS ☐ FAIL
Additional Notes: Sample taken while flushing unit #2 right hand reheat control tubing, achieved NAS1638 Class 06.	

7.0 SIGNATURE

Technician: Grant Lush	Date: December 4, 2018

PEHS-OF-01 Rev. 2

PENNECON

FLUSHING/PARTICLE COUNT FORM

Certificate No.: NF8994F

1.0 CUSTOMER INFORMATION	
Customer: NL Hydro	PHS Job No.: HSA005213
Contact Name: Craig Dwyer	Customer Reference No.:
Customer Instructions Notes: Flush right intercept valve to NAS1638 Class 06 cleanliness level.	

2.0 JOB REQUIREMENTS / INFORMATION
Job Type: ☐ Sample Reading Only - No Flushing Required ☑ Flushing with Sample Reading
Cleanliness Level Required: NAS1638 Class 06
Fluid Type: Fryquel

3.0 FLUSHING ☐ N/A
☑ Line Flushing (Hoses, Tubing, Piping, Systems) Flowrate: ☐ Container Flushing (Drum, Tote, Pail) - Full Volume Circulated Minimum 5 Times ☐ Accumulator Flushing - Minimum 10 Fill-Drain Cycles Completed
Temperature: Approximately 55°C
Equipment Details (type, qty., size, manufacturer): Right intercept valve
Equipment ID (model, S/N):

4.0 WATER CONTENT READING ☑ N/A	
Meter Used:	Reading Obtained:

5.0 PARTICLE COUNT READINGS (PER AS598 for Ocular Microscope Readings)

Particle Measurements					
(NAS 1638) Particle Size / Micrometers	5 – 15	15 – 25	25 – 50	50 – 100	100 +
Particles per 100 ml	4885	789	475	21	13
(SAE AS4059) Particle Size / Micrometers	>5	>15	>25	>50	>100
Particles per 100 ml					
(ISO 4406) Particle Size / Micrometers	>4	>6	>14		
Scale Number					

6.0 PARTICLE COUNT RESULTS	
Standard Achieved: NAS1638 Class 06	☑ PASS ☐ FAIL
Additional Notes: Sample taken while flushing right intercept valve achieved NAS1638 Class 06.	

7.0 SIGNATURE	
Technician: Pat Maher	Date: December 4, 2018

PEHS-OF-01 Rev. 2

PENNECON

FLUSHING/PARTICLE COUNT FORM

Certificate No.: NF8995F

1.0 CUSTOMER INFORMATION

Customer: NL Hydro	PHS Job No.: HSA005213
Contact Name: Craig Dwyer	Customer Reference No.:
Customer Instructions Notes: Flush main control valve (ramp) to NAS1638 Class 06 cleanliness level.	

2.0 JOB REQUIREMENTS / INFORMATION

Job Type: ☐ Sample Reading Only - No Flushing Required ☑ Flushing with Sample Reading

Cleanliness Level Required: NAS1638 Class 06

Fluid Type: Fryquel

3.0 FLUSHING ☐ N/A

☑ Line Flushing (Hoses, Tubing, Piping, Systems) Flowrate:

☐ Container Flushing (Drum, Tote, Pail) - Full Volume Circulated Minimum 5 Times

☐ Accumulator Flushing - Minimum 10 Fill-Drain Cycles Completed

Temperature: Approximately 55°C

Equipment Details (type, qty., size, manufacturer): main control valve (ramp)

Equipment ID (model, S/N):

4.0 WATER CONTENT READING ☑ N/A

Meter Used:	Reading Obtained:

5.0 PARTICLE COUNT READINGS (PER AS598 for Ocular Microscope Readings)

	Particle Measurements				
(NAS 1638) Particle Size / Micrometers	5 – 15	15 – 25	25 – 50	50 – 100	100 +
Particles per 100 ml	779	292	86	7	3
(SAE AS4059) Particle Size / Micrometers	>5	>15	>25	>50	>100
Particles per 100 ml					
(ISO 4406) Particle Size / Micrometers	>4	>6	>14		
Scale Number					

6.0 PARTICLE COUNT RESULTS

Standard Achieved: NAS1638 Class 06 ☑ PASS ☐ FAIL

Additional Notes: Sample taken while flushing main control valve (ramp) achieved NAS1638 Class 06.

7.0 SIGNATURE

Technician: Pat Maher	Date: December 4, 2018

PENNECON

FLUSHING/PARTICLE COUNT FORM

Certificate No.: NF8996F

1.0 CUSTOMER INFORMATION	
Customer: NL Hydro	PHS Job No.: HSA005213
Contact Name: Craig Dwyer	Customer Reference No.:
Customer Instructions Notes: Flush dump valves to NAS1638 Class 06 cleanliness level.	

2.0 JOB REQUIREMENTS / INFORMATION
Job Type: ☐ Sample Reading Only - No Flushing Required ☑ Flushing with Sample Reading
Cleanliness Level Required: NAS1638 Class 06
Fluid Type: Fryquel

3.0 FLUSHING ☐ N/A
☑ Line Flushing (Hoses, Tubing, Piping, Systems) Flowrate: ☐ Container Flushing (Drum, Tote, Pail) - Full Volume Circulated Minimum 5 Times ☐ Accumulator Flushing - Minimum 10 Fill-Drain Cycles Completed
Temperature: Approximately 63°C
Equipment Details (type, qty., size, manufacturer): dump valves
Equipment ID (model, S/N):

4.0 WATER CONTENT READING	☑ N/A
Meter Used:	Reading Obtained:

5.0 PARTICLE COUNT READINGS (PER AS598 for Ocular Microscope Readings)

Particle Measurements					
(NAS 1638) Particle Size / Micrometers	5 – 15	15 – 25	25 – 50	50 – 100	100 +
Particles per 100 ml	2598	615	141	14	6
(SAE AS4059) Particle Size / Micrometers	>5	>15	>25	>50	>100
Particles per 100 ml					
(ISO 4406) Particle Size / Micrometers	>4	>6	>14		
Scale Number					

6.0 PARTICLE COUNT RESULTS	
Standard Achieved: NAS1638 Class 05	☑ PASS ☐ FAIL
Additional Notes: Sample taken while flushing dump valves achieved NAS1638 Class 05.	

7.0 SIGNATURE	
Technician: Pat Maher	Date: December 4, 2018

PEHS-OF-01 Rev. 2

PENNECON

FLUSHING/PARTICLE COUNT FORM

Certificate No.: NF8997F

1.0 CUSTOMER INFORMATION	
Customer: NL Hydro	PHS Job No.: HSA005213
Contact Name: Craig Dwyer	Customer Reference No.:
Customer Instructions Notes: Flush unit #2 full system to NAS1638 Class 06 cleanliness level.	

2.0 JOB REQUIREMENTS / INFORMATION		
Job Type:	☐ Sample Reading Only - No Flushing Required	☑ Flushing with Sample Reading
Cleanliness Level Required: NAS1638 Class 06		
Fluid Type: Fryquel		

3.0 FLUSHING	☐ N/A
☑ Line Flushing (Hoses, Tubing, Piping, Systems)	Flowrate:
☐ Container Flushing (Drum, Tote, Pail) - Full Volume Circulated Minimum 5 Times	
☐ Accumulator Flushing - Minimum 10 Fill-Drain Cycles Completed	
Temperature: Approximately 63°C	
Equipment Details (type, qty., size, manufacturer): Unit #2 full system	
Equipment ID (model, S/N):	

4.0 WATER CONTENT READING	☑ N/A
Meter Used:	Reading Obtained:

5.0 PARTICLE COUNT READINGS (PER AS598 for Ocular Microscope Readings)

	Particle Measurements				
(NAS 1638) Particle Size / Micrometers	5 – 15	15 – 25	25 – 50	50 – 100	100 +
Particles per 100 ml	2790	423	144	11	7
(SAE AS4059) Particle Size / Micrometers	>5	>15	>25	>50	>100
Particles per 100 ml					
(ISO 4406) Particle Size / Micrometers	>4	>6	>14		
Scale Number					

6.0 PARTICLE COUNT RESULTS	
Standard Achieved: NAS1638 Class 05	☑ PASS ☐ FAIL
Additional Notes: Sample taken while flushing unit #2 full system, achieved NAS1638 Class 05.	

7.0 SIGNATURE	
Technician: Pat Maher	Date: December 4, 2018

PEHS-OF-01 Rev. 2

PENNECON

FLUSHING/PARTICLE COUNT FORM

Certificate No.: NF9008F

1.0 CUSTOMER INFORMATION

Customer: NL Hydro	PHS Job No.: HSA005213
Contact Name: Craig Dwyer	Customer Reference No.:
Customer Instructions Notes: Flush Right Hand Intercept Cylinder Piston Side to meet requirements of NAS1638 Class 6	

2.0 JOB REQUIREMENTS / INFORMATION

Job Type: ☐ Sample Reading Only - No Flushing Required ☑ Flushing with Sample Reading

Cleanliness Level Required: NAS1638 Class 6

Fluid Type: FYRQUEL EHC-S

3.0 FLUSHING ☐ N/A

☑ Line Flushing (Hoses, Tubing, Piping, Systems) Flowrate: 20 GPM

☐ Container Flushing (Drum, Tote, Pail) - Full Volume Circulated Minimum 5 Times

☐ Accumulator Flushing - Minimum 10 Fill-Drain Cycles Completed

Temperature: 34 Deg. C

Equipment Details (type, qty., size, manufacturer): MILLER Fluid Power- Right Hand Intercept Cylinder Piston Side

Equipment ID: Right Hand Intercept Cylinder

4.0 WATER CONTENT READING ☑ N/A

Meter Used:	Reading Obtained:

5.0 PARTICLE COUNT READINGS (PER AS598 for Ocular Microscope Readings)

Particle Measurements

(NAS 1638) Particle Size / Micrometers	5 – 15	15 – 25	25 – 50	50 – 100	100 +
Particles per 100 ml	9577	1133	190	27	11
(SAE AS4059) Particle Size / Micrometers	>5	>15	>25	>50	>100
Particles per 100 ml					
(ISO 4406) Particle Size / Micrometers	>4	>6	>14		
Scale Number					

6.0 PARTICLE COUNT RESULTS

Standard Achieved: NAS1638 CLASS 6 ☑ PASS ☐ FAIL

Additional Notes: Sample of FYRQUEL EHC-S taken while flushing the Piston Side of the Right Hand Intercept Cylinder, achieved NAS1638 Class 06.

7.0 SIGNATURE

Technician: Steve Keough	Date: December 4, 2018

PEHS-OF-01 Rev. 2

PENNECON

FLUSHING/PARTICLE COUNT FORM

Certificate No.: NF9009F

1.0 CUSTOMER INFORMATION	
Customer: NL Hydro	PHS Job No.: HSA005213
Contact Name: Craig Dwyer	Customer Reference No.:
Customer Instructions Notes: Flush Right Hand Intercept Cylinder ROD Side to meet requirements of NAS1638 Class 6	

2.0 JOB REQUIREMENTS / INFORMATION
Job Type: ☐ Sample Reading Only - No Flushing Required ☑ Flushing with Sample Reading
Cleanliness Level Required: NAS1638 Class 6
Fluid Type: FYRQUEL EHC-S

3.0 FLUSHING ☐ N/A
☑ Line Flushing (Hoses, Tubing, Piping, Systems) Flowrate: 20 GPM ☐ Container Flushing (Drum, Tote, Pail) - Full Volume Circulated Minimum 5 Times ☐ Accumulator Flushing - Minimum 10 Fill-Drain Cycles Completed
Temperature: 34 Deg. C
Equipment Details (type, qty., size, manufacturer): MILLER Fluid Power- Right Hand Intercept Cylinder ROD Side
Equipment ID: Right Hand Intercept Cylinder

4.0 WATER CONTENT READING ☑ N/A	
Meter Used:	Reading Obtained:

5.0 PARTICLE COUNT READINGS (PER AS598 for Ocular Microscope Readings)

Particle Measurements					
(NAS 1638) Particle Size / Micrometers	5 – 15	15 – 25	25 – 50	50 – 100	100 +
Particles per 100 ml	9934	524	232	16	12
(SAE AS4059) Particle Size / Micrometers	>5	>15	>25	>50	>100
Particles per 100 ml					
(ISO 4406) Particle Size / Micrometers	>4	>6	>14		
Scale Number					

6.0 PARTICLE COUNT RESULTS	
Standard Achieved: NAS1638 CLASS 6	☑ PASS ☐ FAIL
Additional Notes: Sample of FYRQUEL EHC-S, taken while flushing the rod side of the right hand intercept cylinder, achieved NAS1638 Class 06.	

7.0 SIGNATURE	
Technician: Steve Keough	Date: December 4, 2018

PEHS-OF-01 Rev. 2

PENNECON

FLUSHING/PARTICLE COUNT FORM

Certificate No.: NF9020F

1.0 CUSTOMER INFORMATION	
Customer: NL Hydro	PHS Job No.: HSA005213
Contact Name: Craig Dwyer	Customer Reference No.:
Customer Instructions Notes: Flush Right Hand Intercept Control Block to meet requirements of NAS1638 Class 6	

2.0 JOB REQUIREMENTS / INFORMATION		
Job Type:	☐ Sample Reading Only - No Flushing Required	☑ Flushing with Sample Reading
Cleanliness Level Required: NAS1638 Class 6		
Fluid Type: FYRQUEL EHC-S		

3.0 FLUSHING	☐ N/A
☑ Line Flushing (Hoses, Tubing, Piping, Systems) Flowrate: 5 GPM ☐ Container Flushing (Drum, Tote, Pail) - Full Volume Circulated Minimum 5 Times ☐ Accumulator Flushing - Minimum 10 Fill-Drain Cycles Completed	
Temperature: 25 Deg. C	
Equipment Details (type, qty., size, manufacturer): Right Hand Intercept Control Block	
Equipment ID: Right Hand Intercept Control Block	

4.0 WATER CONTENT READING	☑ N/A
Meter Used:	Reading Obtained:

5.0 PARTICLE COUNT READINGS (PER AS598 for Ocular Microscope Readings)

Particle Measurements					
(NAS 1638) Particle Size / Micrometers	5 – 15	15 – 25	25 – 50	50 – 100	100 +
Particles per 100 ml	3599	622	134	21	9
(SAE AS4059) Particle Size / Micrometers	>5	>15	>25	>50	>100
Particles per 100 ml					
(ISO 4406) Particle Size / Micrometers	>4	>6	>14		
Scale Number					

6.0 PARTICLE COUNT RESULTS	
Standard Achieved: NAS1638 CLASS 6	☑ PASS ☐ FAIL
Additional Notes: Sample of FYRQUEL EHC-S, taken while flushing right hand intercept control block, achieved NAS1638 Class 06.	

7.0 SIGNATURE	
Technician: Steve Keough	Date: December 4, 2018

PENNECON

FLUSHING/PARTICLE COUNT FORM

Certificate No.: NF9002F

1.0 CUSTOMER INFORMATION	
Customer: NL Hydro	PHS Job No.: HSA005213
Contact Name: Craig Dwyer	Customer Reference No.:
Customer Instructions Notes: Flush Left Hand Intercept Cylinder Control Block to meet requirements of NAS1638 Class 06	

2.0 JOB REQUIREMENTS / INFORMATION
Job Type: ☐ Sample Reading Only - No Flushing Required ☑ Flushing with Sample Reading
Cleanliness Level Required: NAS1638 Class 06
Fluid Type: FYRQUEL EHC-S

3.0 FLUSHING ☐ N/A
☑ Line Flushing (Hoses, Tubing, Piping, Systems) Flowrate: 8 GPM ☐ Container Flushing (Drum, Tote, Pail) - Full Volume Circulated Minimum 5 Times ☐ Accumulator Flushing - Minimum 10 Fill-Drain Cycles Completed
Temperature: 30 Deg. C
Equipment Details (type, qty., size, manufacturer): Left Hand Intercept Cylinder Control Block
Equipment ID: Left Hand Intercept Cylinder Control Block

4.0 WATER CONTENT READING	☑ N/A
Meter Used:	Reading Obtained:

5.0 PARTICLE COUNT READINGS (PER AS598 for Ocular Microscope Readings)

Particle Measurements					
(NAS 1638) Particle Size / Micrometers	5 – 15	15 – 25	25 – 50	50 – 100	100 +
Particles per 100 ml	5302	683	136	19	11
(SAE AS4059) Particle Size / Micrometers	>5	>15	>25	>50	>100
Particles per 100 ml					
(ISO 4406) Particle Size / Micrometers	>4	>6	>14		
Scale Number					

6.0 PARTICLE COUNT RESULTS	
Standard Achieved: NAS1638 CLASS 6	☑ PASS ☐ FAIL
Additional Notes: Left Hand Intercept Cylinder Control Block	

7.0 SIGNATURE	
Technician: Steve Keough	Date: December 5, 2018

PENNECON

FLUSHING/PARTICLE COUNT FORM

Certificate No.: NF9003F

1.0 CUSTOMER INFORMATION	
Customer: NL Hydro	PHS Job No.: HSA005213
Contact Name: Craig Dwyer	Customer Reference No.:
Customer Instructions Notes: Flush Left Hand Intercept Cylinder Piston Side to meet requirements of NAS1638 Class 6	

2.0 JOB REQUIREMENTS / INFORMATION
Job Type: ☐ Sample Reading Only - No Flushing Required ☑ Flushing with Sample Reading
Cleanliness Level Required: NAS1638 Class 6
Fluid Type: FYRQUEL EHC-S

3.0 FLUSHING ☐ N/A
☑ Line Flushing (Hoses, Tubing, Piping, Systems) Flowrate: 10 GPM ☐ Container Flushing (Drum, Tote, Pail) - Full Volume Circulated Minimum 5 Times ☐ Accumulator Flushing - Minimum 10 Fill-Drain Cycles Completed
Temperature: 32 Deg. C
Equipment Details (type, qty., size, manufacturer): MILLER Fluid Power- Left Hand Intercept Cylinder Piston Side
Equipment ID: Left Hand Intercept Cylinder

4.0 WATER CONTENT READING ☑ N/A	
Meter Used:	Reading Obtained:

5.0 PARTICLE COUNT READINGS (PER AS598 for Ocular Microscope Readings)

Particle Measurements					
(NAS 1638) Particle Size / Micrometers	5 – 15	15 – 25	25 – 50	50 – 100	100 +
Particles per 100 ml	6087	1410	228	28	9
(SAE AS4059) Particle Size / Micrometers	>5	>15	>25	>50	>100
Particles per 100 ml					
(ISO 4406) Particle Size / Micrometers	>4	>6	>14		
Scale Number					

6.0 PARTICLE COUNT RESULTS	
Standard Achieved: NAS1638 CLASS 6	☑ PASS ☐ FAIL
Additional Notes: Sample of FYRQUEL EHC-S taken while flushing Left Hand Intercept Cylinder, Piston Side, achieved NASA1638 Class 6.	

7.0 SIGNATURE	
Technician: Steve Keough	Date: December 5, 2018

PENNECON

FLUSHING/PARTICLE COUNT FORM

Certificate No.: NF9004F

1.0 CUSTOMER INFORMATION	
Customer: NL Hydro	PHS Job No.: HSA005213
Contact Name: Craig Dwyer	Customer Reference No.:
Customer Instructions Notes: Flush Left Hand Intercept Cylinder ROD Side to meet requirements of NAS1638 Class 6	

2.0 JOB REQUIREMENTS / INFORMATION
Job Type: ☐ Sample Reading Only - No Flushing Required ☑ Flushing with Sample Reading
Cleanliness Level Required: NAS1638 Class 6
Fluid Type: FYRQUEL EHC-S

3.0 FLUSHING ☐ N/A
☑ Line Flushing (Hoses, Tubing, Piping, Systems) Flowrate: 10 GPM ☐ Container Flushing (Drum, Tote, Pail) - Full Volume Circulated Minimum 5 Times ☐ Accumulator Flushing - Minimum 10 Fill-Drain Cycles Completed
Temperature: 32 Deg. C
Equipment Details (type, qty., size, manufacturer): MILLER Fluid Power- Left Hand Intercept Cylinder ROD Side
Equipment ID: Left Hand Intercept Cylinder

4.0 WATER CONTENT READING	☑ N/A
Meter Used:	Reading Obtained:

5.0 PARTICLE COUNT READINGS (PER AS598 for Ocular Microscope Readings)

Particle Measurements					
(NAS 1638) Particle Size / Micrometers	5 – 15	15 – 25	25 – 50	50 – 100	100 +
Particles per 100 ml	8699	1192	194	23	12
(SAE AS4059) Particle Size / Micrometers	>5	>15	>25	>50	>100
Particles per 100 ml					
(ISO 4406) Particle Size / Micrometers	>4	>6	>14		
Scale Number					

6.0 PARTICLE COUNT RESULTS	
Standard Achieved: NAS1638 CLASS 6	☑ PASS ☐ FAIL
Additional Notes: Sample of FYRQUEL EHC-S, taken while flushing the rod side of Left Hand Intercept Cylinder, achieved NAS1638 Class 06.	

7.0 SIGNATURE	
Technician: Steve Keough *[signature]*	Date: December 5, 2018

PEHS-OF-01 Rev. 2

PENNECON

FLUSHING/PARTICLE COUNT FORM

Certificate No.: NF9005F

1.0 CUSTOMER INFORMATION	
Customer: NL Hydro	PHS Job No.: HSA005213
Contact Name: Craig Dwyer	Customer Reference No.:
Customer Instructions Notes: Flush Main Steam Control Cylinder Control Block to meet requirements of NAS1638 Class 6	

2.0 JOB REQUIREMENTS / INFORMATION
Job Type: ☐ Sample Reading Only - No Flushing Required ☑ Flushing with Sample Reading
Cleanliness Level Required: NAS1638 Class 6
Fluid Type: FYRQUEL EHC-S

3.0 FLUSHING ☐ N/A
☑ Line Flushing (Hoses, Tubing, Piping, Systems) Flowrate: 10 GPM ☐ Container Flushing (Drum, Tote, Pail) - Full Volume Circulated Minimum 5 Times ☐ Accumulator Flushing - Minimum 10 Fill-Drain Cycles Completed
Temperature: 28 Deg. C
Equipment Details (type, qty., size, manufacturer): Main Steam Control Cylinder Control Block
Equipment ID: Right Main Steam Control Cylinder Control Block

4.0 WATER CONTENT READING ☑ N/A	
Meter Used:	Reading Obtained:

5.0 PARTICLE COUNT READINGS (PER AS598 for Ocular Microscope Readings)

Particle Measurements					
(NAS 1638) Particle Size / Micrometers	5 – 15	15 – 25	25 – 50	50 – 100	100 +
Particles per 100 ml	4704	903	231	17	11
(SAE AS4059) Particle Size / Micrometers	>5	>15	>25	>50	>100
Particles per 100 ml					
(ISO 4406) Particle Size / Micrometers	>4	>6	>14		
Scale Number					

6.0 PARTICLE COUNT RESULTS	
Standard Achieved: NAS1638 CLASS 6	☑ PASS ☐ FAIL
Additional Notes: Sample of FYRQUEL EHC-S, taken while flushing Main Steam Control Cylinder Control Block, achieved NAS1638 Class 06.	

7.0 SIGNATURE	
Technician: Steve Keough [signature]	Date: December 5, 2018

PEHS-OF-01 Rev. 2

PENNECON

FLUSHING/PARTICLE COUNT FORM

Certificate No.: NF9006F

1.0 CUSTOMER INFORMATION	
Customer: NL Hydro	PHS Job No.: HSA005213
Contact Name: Craig Dwyer	Customer Reference No.:
Customer Instructions Notes: Flush Main Steam Cylinder ROD Side to meet requirements of NAS1638 Class 6	

2.0 JOB REQUIREMENTS / INFORMATION		
Job Type:	☐ Sample Reading Only - No Flushing Required	☑ Flushing with Sample Reading
Cleanliness Level Required: NAS1638 Class 06		
Fluid Type: FYRQUEL EHC-S		

3.0 FLUSHING	☐ N/A
☑ Line Flushing (Hoses, Tubing, Piping, Systems) Flowrate: 10 GPM ☐ Container Flushing (Drum, Tote, Pail) - Full Volume Circulated Minimum 5 Times ☐ Accumulator Flushing - Minimum 10 Fill-Drain Cycles Completed	
Temperature: 32 Deg. C	
Equipment Details (type, qty., size, manufacturer): MILLER Fluid Power- Flush Main Steam Cylinder ROD Side	
Equipment ID: Flush Main Steam Cylinder	

4.0 WATER CONTENT READING	☑ N/A
Meter Used:	Reading Obtained:

5.0 PARTICLE COUNT READINGS (PER AS598 for Ocular Microscope Readings)

Particle Measurements					
(NAS 1638) Particle Size / Micrometers	5 – 15	15 – 25	25 – 50	50 – 100	100 +
Particles per 100 ml	4384	1486	289	21	9
(SAE AS4059) Particle Size / Micrometers	>5	>15	>25	>50	>100
Particles per 100 ml					
(ISO 4406) Particle Size / Micrometers	>4	>6	>14		
Scale Number					

6.0 PARTICLE COUNT RESULTS	
Standard Achieved: NAS1638 CLASS 6	☑ PASS ☐ FAIL
Additional Notes: Sample of FYRQUEL EHC-S, taken while flushing the rod side of the Main Steam Cylinder, achieved NAS1638 Class 06.	

7.0 SIGNATURE	
Technician: Steve Keough	Date: December 5, 2018

PEHS-OF-01 Rev. 2

PENNECON

FLUSHING/PARTICLE COUNT FORM

Certificate No.: NF9007F

1.0 CUSTOMER INFORMATION	
Customer: NL Hydro	PHS Job No.: HSA005213
Contact Name:	Customer Reference No.:
Customer Instructions Notes: Flush Main Steam Cylinder Piston Side to meet requirements of NAS1638 Class 6	

2.0 JOB REQUIREMENTS / INFORMATION
Job Type: ☐ Sample Reading Only - No Flushing Required ☑ Flushing with Sample Reading
Cleanliness Level Required: NAS1638 Class 6
Fluid Type: FYRQUEL EHC-S

3.0 FLUSHING ☐ N/A
☑ Line Flushing (Hoses, Tubing, Piping, Systems) Flowrate: 10 GPM ☐ Container Flushing (Drum, Tote, Pail) - Full Volume Circulated Minimum 5 Times ☐ Accumulator Flushing - Minimum 10 Fill-Drain Cycles Completed
Temperature: 32 Deg. C
Equipment Details (type, qty., size, manufacturer): MILLER Fluid Power- Flush Main Steam Cylinder Piston Side
Equipment ID: Flush Main Steam Cylinder

4.0 WATER CONTENT READING	☑ N/A
Meter Used:	Reading Obtained:

5.0 PARTICLE COUNT READINGS (PER AS598 for Ocular Microscope Readings)

Particle Measurements					
(NAS 1638) Particle Size / Micrometers	5 – 15	15 – 25	25 – 50	50 – 100	100 +
Particles per 100 ml	7538	1408	230	18	9
(SAE AS4059) Particle Size / Micrometers	>5	>15	>25	>50	>100
Particles per 100 ml					
(ISO 4406) Particle Size / Micrometers	>4	>6	>14		
Scale Number					

6.0 PARTICLE COUNT RESULTS	
Standard Achieved: NAS1638 CLASS 6	☑ PASS ☐ FAIL
Additional Notes: Sample of FYRQUEL EHC-S, taken while flushing the piston side of the main steam cylinder, achieved NAS1638 Class 06.	

7.0 SIGNATURE	
Technician: Steve Keough	Date: December 5, 2018

PENNECON

FLUSHING/PARTICLE COUNT FORM

Certificate No.: NF8984F

1.0 CUSTOMER INFORMATION

Customer: NL Hydro	PHS Job No.: HSA005213
Contact Name: John Adams	Customer Reference No.:

Customer Instructions Notes: Flush Coolers to meet requirements of NAS1638 Class 06

2.0 JOB REQUIREMENTS / INFORMATION

Job Type: ☐ Sample Reading Only - No Flushing Required ☑ Flushing with Sample Reading

Cleanliness Level Required: NAS1638 Class 06

Fluid Type: FYRQUEL EHC-S

3.0 FLUSHING ☐ N/A

☑ Line Flushing (Hoses, Tubing, Piping, Systems) Flowrate: 24 GPM

☐ Container Flushing (Drum, Tote, Pail) - Full Volume Circulated Minimum 5 Times

☑ Accumulator Flushing - Minimum 10 Fill-Drain Cycles Completed

Temperature: 30 Deg. C

Equipment Details (type, qty., size, manufacturer): Young Touchstone (Wabtec Company) Heat Exchanger

Equipment ID (model, S/N): Heat Exchanger Model: F-502-EY-2P Part No. 307124 S/N 's IBS & WCM 150 PSI 350 Deg. F Rated

4.0 WATER CONTENT READING ☑ N/A

Meter Used:	Reading Obtained:

5.0 PARTICLE COUNT READINGS (PER AS598 for Ocular Microscope Readings)

Particle Measurements					
(NAS 1638) Particle Size / Micrometers	5 – 15	15 – 25	25 – 50	50 – 100	100 +
Particles per 100 ml	3231	360	136	19	8
(SAE AS4059) Particle Size / Micrometers	>5	>15	>25	>50	>100
Particles per 100 ml					
(ISO 4406) Particle Size / Micrometers	>4	>6	>14		
Scale Number					

6.0 PARTICLE COUNT RESULTS

Standard Achieved: NAS1638 CLASS 5 ☑ PASS ☐ FAIL

Additional Notes: Flush # 2

7.0 SIGNATURE

Technician: Steve Keough [signature] Date: December 6, 2018

PEHS-OF-01 Rev. 2

PENNECON

FLUSHING/PARTICLE COUNT FORM

Certificate No.: NF8998F

1.0 CUSTOMER INFORMATION	
Customer: NL Hydro	PHS Job No.: HSA005213
Contact Name: Craig Dwyer	Customer Reference No.:
Customer Instructions Notes: Flush HPU unit #2 to NAS1638 Class 06 cleanliness level.	

2.0 JOB REQUIREMENTS / INFORMATION
Job Type: ☐ Sample Reading Only - No Flushing Required ☑ Flushing with Sample Reading
Cleanliness Level Required: NAS1638 Class 06
Fluid Type: Fryquel

3.0 FLUSHING ☐ N/A
☐ Line Flushing (Hoses, Tubing, Piping, Systems) Flowrate: ☑ Container Flushing (Drum, Tote, Pail) - Full Volume Circulated Minimum 5 Times ☐ Accumulator Flushing - Minimum 10 Fill-Drain Cycles Completed
Temperature: Approximately 63°C
Equipment Details (type, qty., size, manufacturer): Unit #2 HPU tank
Equipment ID (model, S/N):

4.0 WATER CONTENT READING ☑ N/A	
Meter Used:	Reading Obtained:

5.0 PARTICLE COUNT READINGS (PER AS598 for Ocular Microscope Readings)

Particle Measurements					
(NAS 1638) Particle Size / Micrometers	5 – 15	15 – 25	25 – 50	50 – 100	100 +
Particles per 100 ml	4736	1501	200	17	6
(SAE AS4059) Particle Size / Micrometers	>5	>15	>25	>50	>100
Particles per 100 ml					
(ISO 4406) Particle Size / Micrometers	>4	>6	>14		
Scale Number					

6.0 PARTICLE COUNT RESULTS	
Standard Achieved: NAS1638 Class 06	☑ PASS ☐ FAIL
Additional Notes: Sample taken while flushing unit #2 HPU tank achieved NAS1638 Class 06.	

7.0 SIGNATURE	
Technician: Grant Lush	Date: December 6, 2018

PEHS-OF-01 Rev. 2

PENNECON

FLUSHING/PARTICLE COUNT FORM

Certificate No.: NF9022F

1.0 CUSTOMER INFORMATION	
Customer: NL Hydro	PHS Job No.: HSA005213
Contact Name: Craig Dwyer	Customer Reference No.:
Customer Instructions Notes: Flush Coolers to meet requirements of NAS1638 Class 6	

2.0 JOB REQUIREMENTS / INFORMATION
Job Type: ☐ Sample Reading Only - No Flushing Required ☑ Flushing with Sample Reading
Cleanliness Level Required: NAS1638 Class 6
Fluid Type: FYRQUEL EHC-S

3.0 FLUSHING ☐ N/A
☑ Line Flushing (Hoses, Tubing, Piping, Systems) Flowrate: 24 GPM ☐ Container Flushing (Drum, Tote, Pail) - Full Volume Circulated Minimum 5 Times ☐ Accumulator Flushing - Minimum 10 Fill-Drain Cycles Completed
Temperature: 30 Deg. C
Equipment Details (type, qty., size, manufacturer): Young Touchstone (Wabtec Company) Heat Exchanger
Equipment ID (model, S/N): Heat Exchanger Model: F-502-EY-2P Part No. 307124, S/N 's IBS & WCM 150 PSI 350 Deg. F Rated

4.0 WATER CONTENT READING ☑ N/A	
Meter Used:	Reading Obtained:

5.0 PARTICLE COUNT READINGS (PER AS598 for Ocular Microscope Readings)

Particle Measurements					
(NAS 1638) Particle Size / Micrometers	5 – 15	15 – 25	25 – 50	50 – 100	100 +
Particles per 100 ml	3231	360	136	19	8
(SAE AS4059) Particle Size / Micrometers	>5	>15	>25	>50	>100
Particles per 100 ml					
(ISO 4406) Particle Size / Micrometers	>4	>6	>14		
Scale Number					

6.0 PARTICLE COUNT RESULTS	
Standard Achieved: NAS1638 CLASS 5	☑ PASS ☐ FAIL
Additional Notes: Flush # 2	

7.0 SIGNATURE	
Technician: Steve Keough	Date: December 6, 2018

PEHS-OF-01 Rev. 2

PENNECON

FLUSHING/PARTICLE COUNT FORM

Certificate No.: NF8999F

1.0 CUSTOMER INFORMATION

Customer: NL Hydro	PHS Job No.: HSA005213
Contact Name: Craig Dwyer	Customer Reference No.:

Customer Instructions Notes: Flush 75 gallon tank on unit #2 after start-up to NAS1638 Class 06 cleanliness level.

2.0 JOB REQUIREMENTS / INFORMATION

Job Type: ☐ Sample Reading Only - No Flushing Required ☑ Flushing with Sample Reading

Cleanliness Level Required: NAS1638 Class 06

Fluid Type: Fryquel

3.0 FLUSHING ☐ N/A

☐ Line Flushing (Hoses, Tubing, Piping, Systems) Flowrate:

☑ Container Flushing (Drum, Tote, Pail) - Full Volume Circulated Minimum 5 Times

☐ Accumulator Flushing - Minimum 10 Fill-Drain Cycles Completed

Temperature:

Equipment Details (type, qty., size, manufacturer): 75 gallon tank on unit #2

Equipment ID (model, S/N):

4.0 WATER CONTENT READING ☑ N/A

Meter Used:	Reading Obtained:

5.0 PARTICLE COUNT READINGS (PER AS598 for Ocular Microscope Readings)

Particle Measurements

(NAS 1638) Particle Size / Micrometers	5 – 15	15 – 25	25 – 50	50 – 100	100 +
Particles per 100 ml	4702	1535	166	20	7
(SAE AS4059) Particle Size / Micrometers	>5	>15	>25	>50	>100
Particles per 100 ml					
(ISO 4406) Particle Size / Micrometers	>4	>6	>14		
Scale Number					

6.0 PARTICLE COUNT RESULTS

Standard Achieved: NAS1638 Class 06 ☑ PASS ☐ FAIL

Additional Notes: Sample taken while flushing 75 gallon tank on unit #2 achieved NAS1638 Class 06. Sample taken at 4:30 PM.

7.0 SIGNATURE

Technician: Grant Lush	Date: December 7, 2018

PENNECON

Flushing/Particle Count Form

Certificate No.: NF9095F

1.0 CUSTOMER INFORMATION	
Customer: NL Hydro	PEHS Job No.: HSA005213
Contact Name: Craig Dwyer	Customer Reference No.:
Customer Instructions Notes: Sample from HPU. Hydraulic unit #1	

2.0 JOB REQUIREMENTS / INFORMATION
Job Type: ☐ Sample Reading Only - No Flushing ☑ Flushing with Sample
Cleanliness Level Required: NAS1638 Class 06
Fluid Type: Fyrquel

3.0 FLUSHING ☐ N/A
☐ Line Flushing (Hoses, Tubing, Piping, Flowrate: N/A ☑ Container Flushing (Drum, Tote, Pail) - Full Volume Circulated Minimum 5 ☐ Accumulator Flushing - Minimum 10 Fill-Drain Cycles Completed
Temperature:
Equipment Details (type, qty., size, manufacturer): Hydraulic Tank, Unit #1
Equipment ID (model, S/N):

4.0 WATER CONTENT READING	☑ N/A
Meter Used:	Reading Obtained:

5.0 PARTICLE COUNT READINGS (PER AS598 for Ocular Microscope Readings)

Particle Measurements					
(NAS 1638) Particle Size / Micrometers	5 – 15	15 – 25	25 – 50	50 – 100	100 +
Particles per 100 ml	2165	481	86	7	3
(SAE AS4059) Particle Size / Micrometers	>5	>15	>25	>50	>100
Particles per 100 ml					
(ISO 4406) Particle Size / Micrometers	>4	>6	>14		
Scale Number					

6.0 PARTICLE COUNT RESULTS	
Standard Achieved: NAS1638 Class 04	☑ PASS ☐ FAIL
Additional Notes: Sample of Fyrquel taken from HPU, hydraulic unit #1, achieved NAS1638 Class 04.	

7.0 SIGNATURE	
Technician:Grant Lush David Barr For GC	Date: December 7, 2018

PEHS-OF-01 Rev. 1

PENNECON

FLUSHING/PARTICLE COUNT FORM

Certificate No.: NF9001F

1.0 CUSTOMER INFORMATION

Customer: NL Hydro	PHS Job No.: HSA005213
Contact Name: Craig Dwyer	Customer Reference No.:

Customer Instructions Notes: Check sample from 75 gallon HPU tank on unit #2

2.0 JOB REQUIREMENTS / INFORMATION

Job Type: ☐ Sample Reading Only - No Flushing Required ☑ Flushing with Sample Reading

Cleanliness Level Required: NAS1638 Class 06

Fluid Type: Fryquel

3.0 FLUSHING ☐ N/A

☐ Line Flushing (Hoses, Tubing, Piping, Systems) Flowrate:

☑ Container Flushing (Drum, Tote, Pail) - Full Volume Circulated Minimum 5 Times

☐ Accumulator Flushing - Minimum 10 Fill-Drain Cycles Completed

Temperature:

Equipment Details (type, qty., size, manufacturer): 75 gallon HPU tank on unit #2

Equipment ID (model, S/N):

4.0 WATER CONTENT READING ☑ N/A

Meter Used:	Reading Obtained:

5.0 PARTICLE COUNT READINGS (PER AS598 for Ocular Microscope Readings)

	Particle Measurements				
(NAS 1638) Particle Size / Micrometers	5 – 15	15 – 25	25 – 50	50 – 100	100 +
Particles per 100 ml	4043	2005	137	18	6
(SAE AS4059) Particle Size / Micrometers	>5	>15	>25	>50	>100
Particles per 100 ml					
(ISO 4406) Particle Size / Micrometers	>4	>6	>14		
Scale Number					

6.0 PARTICLE COUNT RESULTS

Standard Achieved: NAS1638 Class 05 ☑ PASS ☐ FAIL

Additional Notes: Sample taken from 75 gallon HPU tank on unit #2 achieved NAS1638 Class 05.

7.0 SIGNATURE

Technician: Grant Lush	Date: December 10, 2018

PEHS-OF-01 Rev. 2

PENNECON

Flushing/Particle Count Form

Certificate No.: NF9041F

1.0 CUSTOMER INFORMATION	
Customer: NL Hydro	PEHS Job No.: HSA005213
Contact Name: Craig Dwyer	Customer Reference No.:
Customer Instructions Notes: Sample from HPU. Hydraulic unit #1	

2.0 JOB REQUIREMENTS / INFORMATION
Job Type: ☐ Sample Reading Only - No Flushing ☑ Flushing with Sample
Cleanliness Level Required: NAS1638 Class 06
Fluid Type: Fryquel

3.0 FLUSHING ☐ N/A
☐ Line Flushing (Hoses, Tubing, Piping, Flowrate: N/A ☑ Container Flushing (Drum, Tote, Pail) - Full Volume Circulated Minimum 5 ☐ Accumulator Flushing - Minimum 10 Fill-Drain Cycles Completed
Temperature:
Equipment Details (type, qty., size, manufacturer): Hydraulic tank
Equipment ID (model, S/N): Unit #1

4.0 WATER CONTENT READING ☑ N/A	
Meter Used:	Reading Obtained:

5.0 PARTICLE COUNT READINGS (PER AS598 for Ocular Microscope Readings)

Particle Measurements					
(NAS 1638) Particle Size / Micrometers	5 – 15	15 – 25	25 – 50	50 – 100	100 +
Particles per 100 ml	1030	482	85	8	3
(SAE AS4059) Particle Size / Micrometers	>5	>15	>25	>50	>100
Particles per 100 ml					
(ISO 4406) Particle Size / Micrometers	>4	>6	>14		
Scale Number					

6.0 PARTICLE COUNT RESULTS	
Standard Achieved: NAS1638 Class 03	☑ PASS ☐ FAIL
Additional Notes: Sample of Fryquel taken from HPU - Hydraulic Unit #1 achieved NAS1638 Class 03.	

7.0 SIGNATURE	
Technician: Grant Lush	Date: December 24, 2018

PENNECON

Flushing/Particle Count Form

Certificate No.: NF9042F

1.0 CUSTOMER INFORMATION	
Customer: NL Hydro	PHS Job No.: HSA005213
Contact Name: Craig Dwyer	Customer Reference No.:
Customer Instructions Notes: Sample from HPU. Hydraulic unit #2	

2.0 JOB REQUIREMENTS / INFORMATION
Job Type: ☐ Sample Reading Only - No Flushing ☑ Flushing with Sample
Cleanliness Level Required: NAS1638 Class 06
Fluid Type: Fryquel

3.0 FLUSHING ☐ N/A
☐ Line Flushing (Hoses, Tubing, Piping, Flowrate: N/A ☑ Container Flushing (Drum, Tote, Pail) - Full Volume Circulated Minimum 5 ☐ Accumulator Flushing - Minimum 10 Fill-Drain Cycles Completed
Temperature:
Equipment Details (type, qty., size, manufacturer): Hydraulic tank
Equipment ID (model, S/N): Unit #2

4.0 WATER CONTENT READING ☑ N/A	
Meter Used:	Reading Obtained:

5.0 PARTICLE COUNT READINGS (PER AS598 for Ocular Microscope Readings)

Particle Measurements					
(NAS 1638) Particle Size / Micrometers	5 – 15	15 – 25	25 – 50	50 – 100	100 +
Particles per 100 ml	1630	512	118	6	3
(SAE AS4059) Particle Size / Micrometers	>5	>15	>25	>50	>100
Particles per 100 ml					
(ISO 4406) Particle Size / Micrometers	>4	>6	>14		
Scale Number					

6.0 PARTICLE COUNT RESULTS	
Standard Achieved: NAS1638 Class 04	☑ PASS ☐ FAIL
Additional Notes: Sample of Fryquel taken from HPU - Hydraulic Unit #2 achieved NAS1638 Class 04.	

7.0 SIGNATURE	
Technician: Grant Lush	Date: December 24, 2018

PEHS-OF-01 Rev. 1

PENNECON

Flushing/Particle Count Form

Certificate No.: NF9043F

1.0 CUSTOMER INFORMATION	
Customer: NL Hydro	PEHS Job No.: HSA005213
Contact Name: Craig Dwyer	Customer Reference No.:
Customer Instructions Notes: Sample from HPU. Hydraulic unit #1	

2.0 JOB REQUIREMENTS / INFORMATION		
Job Type:	☐ Sample Reading Only - No Flushing	☑ Flushing with Sample
Cleanliness Level Required: NAS1638 Class 06		
Fluid Type: Fryquel		

3.0 FLUSHING	☐ N/A
☐ Line Flushing (Hoses, Tubing, Piping,	Flowrate: N/A
☑ Container Flushing (Drum, Tote, Pail) - Full Volume Circulated Minimum 5	
☐ Accumulator Flushing - Minimum 10 Fill-Drain Cycles Completed	
Temperature:	
Equipment Details (type, qty., size, manufacturer): Hydraulic Tank	
Equipment ID (model, S/N): Unit #1	

4.0 WATER CONTENT READING	☑ N/A
Meter Used:	Reading Obtained:

5.0 PARTICLE COUNT READINGS (PER AS598 for Ocular Microscope Readings)

Particle Measurements					
(NAS 1638) Particle Size / Micrometers	5 – 15	15 – 25	25 – 50	50 – 100	100 +
Particles per 100 ml	1275	488	205	11	4
(SAE AS4059) Particle Size / Micrometers	>5	>15	>25	>50	>100
Particles per 100 ml					
(ISO 4406) Particle Size / Micrometers	>4	>6	>14		
Scale Number					

6.0 PARTICLE COUNT RESULTS	
Standard Achieved: NAS1638 Class 05	☑ PASS ☐ FAIL
Additional Notes: Sample of Fryquel taken from HPU - Hydraulic Unit #1 achieved NAS1638 Class 05.	

7.0 SIGNATURE	
Technician: Grant Lush	Date: January 7, 2019

PENNECON

Flushing/Particle Count Form

Certificate No.: NF9044F

1.0 CUSTOMER INFORMATION	
Customer: NL Hydro	PEHS Job No.: HSA005213
Contact Name: Craig Dwyer	Customer Reference No.:
Customer Instructions Notes: Sample from HPU. Hydraulic unit #2	

2.0 JOB REQUIREMENTS / INFORMATION		
Job Type:	☐ Sample Reading Only - No Flushing	☑ Flushing with Sample
Cleanliness Level Required: NAS1638 Class 06		
Fluid Type: Fryquel		

3.0 FLUSHING	☐ N/A
☐ Line Flushing (Hoses, Tubing, Piping,	Flowrate: N/A
☑ Container Flushing (Drum, Tote, Pail) - Full Volume Circulated Minimum 5	
☐ Accumulator Flushing - Minimum 10 Fill-Drain Cycles Completed	
Temperature:	
Equipment Details (type, qty., size, manufacturer): Hydraulic tank	
Equipment ID (model, S/N): Unit #2	

4.0 WATER CONTENT READING	☑ N/A
Meter Used:	Reading Obtained:

5.0 PARTICLE COUNT READINGS (PER AS598 for Ocular Microscope Readings)

Particle Measurements					
(NAS 1638) Particle Size / Micrometers	5 – 15	15 – 25	25 – 50	50 – 100	100 +
Particles per 100 ml	1374	390	177	9	3
(SAE AS4059) Particle Size / Micrometers	>5	>15	>25	>50	>100
Particles per 100 ml					
(ISO 4406) Particle Size / Micrometers	>4	>6	>14		
Scale Number					

6.0 PARTICLE COUNT RESULTS	
Standard Achieved: NAS1638 Class 04	☑ PASS ☐ FAIL
Additional Notes: Sample of Fryquel taken from HPU - Hydraulic Unit #2 achieved NAS1638 Class 04.	

7.0 SIGNATURE	
Technician: Grant Lush	Date: January 7, 2019

PEHS-OF-01 Rev. 1

PENNECON

Flushing/Particle Count Form

Certificate No.: NF9045F

1.0 CUSTOMER INFORMATION	
Customer: NL Hydro	PEHS Job No.: HSA005213
Contact Name: Craig Dwyer	Customer Reference No.:
Customer Instructions Notes: Sample from HPU. Hydraulic unit #1	

2.0 JOB REQUIREMENTS / INFORMATION		
Job Type:	☐ Sample Reading Only - No Flushing	☑ Flushing with Sample
Cleanliness Level Required: NAS1638 Class 06		
Fluid Type: Fryquel		

3.0 FLUSHING	☐ N/A
☐ Line Flushing (Hoses, Tubing, Piping,	Flowrate: N/A
☑ Container Flushing (Drum, Tote, Pail) - Full Volume Circulated Minimum 5	
☐ Accumulator Flushing - Minimum 10 Fill-Drain Cycles Completed	
Temperature:	
Equipment Details (type, qty., size, manufacturer): Hydraulic tank	
Equipment ID (model, S/N): Unit #1	

4.0 WATER CONTENT READING	☑ N/A
Meter Used:	Reading Obtained:

5.0 PARTICLE COUNT READINGS (PER AS598 for Ocular Microscope Readings)

	Particle Measurements				
(NAS 1638) Particle Size / Micrometers	5 – 15	15 – 25	25 – 50	50 – 100	100 +
Particles per 100 ml	3640	707	112	12	6
(SAE AS4059) Particle Size / Micrometers	>5	>15	>25	>50	>100
Particles per 100 ml					
(ISO 4406) Particle Size / Micrometers	>4	>6	>14		
Scale Number					

6.0 PARTICLE COUNT RESULTS	
Standard Achieved: NAS1638 Class 05	☑ PASS ☐ FAIL
Additional Notes: Sample of Fryquel taken from HPU - Hydraulic Unit #1 achieved NAS1638 Class 05.	

7.0 SIGNATURE	
Technician: Pat Maher	Date: January 15, 2019

PENNECON

Flushing/Particle Count Form

Certificate No.: NF9046F

1.0 CUSTOMER INFORMATION

Customer: NL Hydro	PHS Job No.: HSA005213
Contact Name: Craig Dwyer	Customer Reference No.:

Customer Instructions Notes: Sample from HPU. Hydraulic unit #2

2.0 JOB REQUIREMENTS / INFORMATION

Job Type: ☐ Sample Reading Only - No Flushing ☑ Flushing with Sample

Cleanliness Level Required: NAS1638 Class 06

Fluid Type: Fryquel

3.0 FLUSHING ☐ N/A

☐ Line Flushing (Hoses, Tubing, Piping, Flowrate: N/A

☑ Container Flushing (Drum, Tote, Pail) - Full Volume Circulated Minimum 5

☐ Accumulator Flushing - Minimum 10 Fill-Drain Cycles Completed

Temperature:

Equipment Details (type, qty., size, manufacturer): Hydraulic tank

Equipment ID (model, S/N): Unit #2

4.0 WATER CONTENT READING ☑ N/A

Meter Used:	Reading Obtained:

5.0 PARTICLE COUNT READINGS (PER AS598 for Ocular Microscope Readings)

	Particle Measurements				
(NAS 1638) Particle Size / Micrometers	5 – 15	15 – 25	25 – 50	50 – 100	100 +
Particles per 100 ml	4959	1215	171	15	10
(SAE AS4059) Particle Size / Micrometers	>5	>15	>25	>50	>100
Particles per 100 ml					
(ISO 4406) Particle Size / Micrometers	>4	>6	>14		
Scale Number					

6.0 PARTICLE COUNT RESULTS

Standard Achieved: NAS1638 Class 06 ☑ PASS ☐ FAIL

Additional Notes: Sample of Fryquel taken from HPU - Hydraulic Unit #2 achieved NAS1638 Class 06.

7.0 SIGNATURE

Technician: Pat Maher	Date: January 15, 2019

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PENNECON

Flushing/Particle Count Form

Certificate No.: NF9047F

1.0 CUSTOMER INFORMATION	
Customer: NL Hydro	PHS Job No.: HSA005213
Contact Name: Craig Dwyer	Customer Reference No.:
Customer Instructions Notes: Sample from HPU. Hydraulic unit #1	

2.0 JOB REQUIREMENTS / INFORMATION		
Job Type:	☐ Sample Reading Only - No Flushing	☑ Flushing with Sample
Cleanliness Level Required: NAS1638 Class 06		
Fluid Type: Fryquel		

3.0 FLUSHING ☐ N/A

☐ Line Flushing (Hoses, Tubing, Piping, Flowrate: N/A

☑ Container Flushing (Drum, Tote, Pail) - Full Volume Circulated Minimum 5

☐ Accumulator Flushing - Minimum 10 Fill-Drain Cycles Completed

Temperature:

Equipment Details (type, qty., size, manufacturer): Hydraulic Tank

Equipment ID (model, S/N): Unit #1

4.0 WATER CONTENT READING	☑ N/A
Meter Used:	Reading Obtained:

5.0 PARTICLE COUNT READINGS (PER AS598 for Ocular Microscope Readings)

	Particle Measurements				
(NAS 1638) Particle Size / Micrometers	5 – 15	15 – 25	25 – 50	50 – 100	100 +
Particles per 100 ml	751	194	58	4	2
(SAE AS4059) Particle Size / Micrometers	>5	>15	>25	>50	>100
Particles per 100 ml					
(ISO 4406) Particle Size / Micrometers	>4	>6	>14		
Scale Number					

6.0 PARTICLE COUNT RESULTS	
Standard Achieved: NAS1638 Class 03	☑ PASS ☐ FAIL
Additional Notes: Sample of Fryquel taken from HPU - Hydraulic Unit #1 achieved NAS1638 Class 03.	

7.0 SIGNATURE	
Technician: Grant Lush	Date: January 21, 2019

PENNECON

Flushing/Particle Count Form

Certificate No.: NF9048F

1.0 CUSTOMER INFORMATION	
Customer: NL Hydro	PEHS Job No.: HSA005213
Contact Name: Craig Dwyer	Customer Reference No.:
Customer Instructions Notes: Sample from HPU. Hydraulic unit #2	

2.0 JOB REQUIREMENTS / INFORMATION		
Job Type:	☐ Sample Reading Only - No Flushing	☑ Flushing with Sample
Cleanliness Level Required: NAS1638 Class 06		
Fluid Type: Fryquel		

3.0 FLUSHING ☐ N/A

☐ Line Flushing (Hoses, Tubing, Piping, Flowrate: N/A
☑ Container Flushing (Drum, Tote, Pail) - Full Volume Circulated Minimum 5
☐ Accumulator Flushing - Minimum 10 Fill-Drain Cycles Completed

Temperature:

Equipment Details (type, qty., size, manufacturer): Hydraulic tank

Equipment ID (model, S/N): Unit #2

4.0 WATER CONTENT READING	☑ N/A
Meter Used:	Reading Obtained:

5.0 PARTICLE COUNT READINGS (PER AS598 for Ocular Microscope Readings)

	Particle Measurements				
(NAS 1638) Particle Size / Micrometers	5 – 15	15 – 25	25 – 50	50 – 100	100 +
Particles per 100 ml	1180	322	119	5	3
(SAE AS4059) Particle Size / Micrometers	>5	>15	>25	>50	>100
Particles per 100 ml					
(ISO 4406) Particle Size / Micrometers	>4	>6	>14		
Scale Number					

6.0 PARTICLE COUNT RESULTS	
Standard Achieved: NAS1638 Class 04	☑ PASS ☐ FAIL
Additional Notes: Sample of Fryquel taken from HPU - Hydraulic Unit #2 achieved NAS1638 Class 04.	

7.0 SIGNATURE	
Technician: Grant Lush	Date: January 21, 2019

PENNECON

Flushing/Particle Count Form

Certificate No.: NF9061F

1.0 CUSTOMER INFORMATION	
Customer: NL Hydro	PEHS Job No.: HSA005213
Contact Name: Craig Dwyer	Customer Reference No.:
Customer Instructions Notes: Sample from HPU. Hydraulic unit #1	

2.0 JOB REQUIREMENTS / INFORMATION		
Job Type:	☐ Sample Reading Only - No Flushing	☑ Flushing with Sample
Cleanliness Level Required: NAS1638 Class 06		
Fluid Type: Fryquil		

3.0 FLUSHING	☐ N/A
☐ Line Flushing (Hoses, Tubing, Piping,	Flowrate: N/A
☑ Container Flushing (Drum, Tote, Pail) - Full Volume Circulated Minimum 5	
☐ Accumulator Flushing - Minimum 10 Fill-Drain Cycles Completed	
Temperature:	
Equipment Details (type, qty., size, manufacturer): Hydraulic tank	
Equipment ID (model, S/N): Unit #1	

4.0 WATER CONTENT READING	☑ N/A
Meter Used:	Reading Obtained:

5.0 PARTICLE COUNT READINGS (PER AS598 for Ocular Microscope Readings)

Particle Measurements

(NAS 1638) Particle Size / Micrometers	5 – 15	15 – 25	25 – 50	50 – 100	100 +
Particles per 100 ml	901	422	82	11	4
(SAE AS4059) Particle Size / Micrometers	>5	>15	>25	>50	>100
Particles per 100 ml					
(ISO 4406) Particle Size / Micrometers	>4	>6	>14		
Scale Number					

6.0 PARTICLE COUNT RESULTS	
Standard Achieved: NAS1638 Class 04	☑ PASS ☐ FAIL
Additional Notes: Sample of Fryquil taken while flushing hydraulic tank, unit #1, achieved NAS1638 Class 04.	

7.0 SIGNATURE	
Technician: Grant Lush	Date: January 28, 2019

PENNECON

Flushing/Particle Count Form

Certificate No.: NF9062F

1.0 CUSTOMER INFORMATION	
Customer: NL Hydro	PEHS Job No.: HSA005213
Contact Name: Craig Dwyer	Customer Reference No.:
Customer Instructions Notes: Sample from HPU. Hydraulic unit #2	

2.0 JOB REQUIREMENTS / INFORMATION		
Job Type:	☐ Sample Reading Only - No Flushing	☑ Flushing with Sample
Cleanliness Level Required: NAS1638 Class 06		
Fluid Type: Fryquil		

3.0 FLUSHING ☐ N/A

☐ Line Flushing (Hoses, Tubing, Piping, Flowrate: N/A
☑ Container Flushing (Drum, Tote, Pail) - Full Volume Circulated Minimum 5
☐ Accumulator Flushing - Minimum 10 Fill-Drain Cycles Completed

Temperature:

Equipment Details (type, qty., size, manufacturer): Hydraulic Tank

Equipment ID (model, S/N): Unit #2

4.0 WATER CONTENT READING ☑ N/A

Meter Used:	Reading Obtained:

5.0 PARTICLE COUNT READINGS (PER AS598 for Ocular Microscope Readings)

Particle Measurements					
(NAS 1638) Particle Size / Micrometers	5 – 15	15 – 25	25 – 50	50 – 100	100 +
Particles per 100 ml	810	324	54	8	3
(SAE AS4059) Particle Size / Micrometers	>5	>15	>25	>50	>100
Particles per 100 ml					
(ISO 4406) Particle Size / Micrometers	>4	>6	>14		
Scale Number					

6.0 PARTICLE COUNT RESULTS	
Standard Achieved: NAS1638 Class 04	☑ PASS ☐ FAIL
Additional Notes: Sample of Fryquil taken while flushing hydraulic tank, unit #2, achieved NAS1638 Class 04.	

7.0 SIGNATURE	
Technician: Grant Lush	Date: January 28, 2019

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PENNECON

Flushing/Particle Count Form

Certificate No.: NF9067F

1.0 CUSTOMER INFORMATION	
Customer: NL Hydro	PEHS Job No.: HSA005213
Contact Name: Craig Dwyer	Customer Reference No.:
Customer Instructions Notes: Sample from HPU. Hydraulic unit #1	

2.0 JOB REQUIREMENTS / INFORMATION		
Job Type:	☐ Sample Reading Only - No Flushing	☑ Flushing with Sample
Cleanliness Level Required: NAS1638 Class 06		
Fluid Type: Fyrquel		

3.0 FLUSHING	☐ N/A
☐ Line Flushing (Hoses, Tubing, Piping,	Flowrate: N/A
☑ Container Flushing (Drum, Tote, Pail) - Full Volume Circulated Minimum 5	
☐ Accumulator Flushing - Minimum 10 Fill-Drain Cycles Completed	
Temperature:	
Equipment Details (type, qty., size, manufacturer): Hydraulic tank	
Equipment ID (model, S/N): Unit #1	

4.0 WATER CONTENT READING	☑ N/A
Meter Used:	Reading Obtained:

5.0 PARTICLE COUNT READINGS (PER AS598 for Ocular Microscope Readings)

	Particle Measurements				
(NAS 1638) Particle Size / Micrometers	5 – 15	15 – 25	25 – 50	50 – 100	100 +
Particles per 100 ml	1368	585	108	16	5
(SAE AS4059) Particle Size / Micrometers	>5	>15	>25	>50	>100
Particles per 100 ml					
(ISO 4406) Particle Size / Micrometers	>4	>6	>14		
Scale Number					

6.0 PARTICLE COUNT RESULTS	
Standard Achieved: NAS1638 Class 05	☑ PASS ☐ FAIL
Additional Notes: Sample of Fyrquel taken while flushing hydraulic unit #1 achieved NAS1638 Class 05.	

7.0 SIGNATURE	
Technician: Grant Lush	Date: February 4, 2019

PEHS-OF-01 Rev. 1

PENNECON

Flushing/Particle Count Form

Certificate No.: NF9068F

1.0 CUSTOMER INFORMATION

Customer: NL Hydro	PEHS Job No.: HSA005213
Contact Name: Craig Dwyer	Customer Reference No.:
Customer Instructions Notes: Sample from HPU. Hydraulic unit #2	

2.0 JOB REQUIREMENTS / INFORMATION

Job Type: ☐ Sample Reading Only - No Flushing ☑ Flushing with Sample

Cleanliness Level Required: NAS1638 Class 06

Fluid Type: Fyrquel

3.0 FLUSHING ☐ N/A

☐ Line Flushing (Hoses, Tubing, Piping, Flowrate: N/A

☑ Container Flushing (Drum, Tote, Pail) - Full Volume Circulated Minimum 5

☐ Accumulator Flushing - Minimum 10 Fill-Drain Cycles Completed

Temperature:

Equipment Details (type, qty., size, manufacturer): Hydraulic tank

Equipment ID (model, S/N): Unit #2

4.0 WATER CONTENT READING ☑ N/A

Meter Used:	Reading Obtained:

5.0 PARTICLE COUNT READINGS (PER AS598 for Ocular Microscope Readings)

	Particle Measurements				
(NAS 1638) Particle Size / Micrometers	5 – 15	15 – 25	25 – 50	50 – 100	100 +
Particles per 100 ml	810	261	54	8	3
(SAE AS4059) Particle Size / Micrometers	>5	>15	>25	>50	>100
Particles per 100 ml					
(ISO 4406) Particle Size / Micrometers	>4	>6	>14		
Scale Number					

6.0 PARTICLE COUNT RESULTS

Standard Achieved: NAS1638 Class 04 ☑ PASS ☐ FAIL

Additional Notes: Sample of Fyrquel taken while flushing hydraulic unit #2 achieved NAS1638 Class 04.

7.0 SIGNATURE

Technician: Grant Lush	Date: February 4, 2019

PENNECON

Flushing/Particle Count Form

Certificate No.: NF9071F

1.0 CUSTOMER INFORMATION

Customer: NL Hydro	PEHS Job No.: HSA005213
Contact Name: Craig Dwyer	Customer Reference No.:

Customer Instructions Notes: Sample from HPU. Hydraulic unit #1

2.0 JOB REQUIREMENTS / INFORMATION

Job Type: ☐ Sample Reading Only - No Flushing ☑ Flushing with Sample

Cleanliness Level Required: NAS1638 Class 06

Fluid Type: Fyrquel

3.0 FLUSHING ☐ N/A

☐ Line Flushing (Hoses, Tubing, Piping, Flowrate: N/A

☑ Container Flushing (Drum, Tote, Pail) - Full Volume Circulated Minimum 5

☐ Accumulator Flushing - Minimum 10 Fill-Drain Cycles Completed

Temperature:

Equipment Details (type, qty., size, manufacturer): Hydraulic Tank

Equipment ID (model, S/N): Unit #1

4.0 WATER CONTENT READING ☑ N/A

Meter Used:	Reading Obtained:

5.0 PARTICLE COUNT READINGS (PER AS598 for Ocular Microscope Readings)

Particle Measurements					
(NAS 1638) Particle Size / Micrometers	5 – 15	15 – 25	25 – 50	50 – 100	100 +
Particles per 100 ml	716	229	86	7	3
(SAE AS4059) Particle Size / Micrometers	>5	>15	>25	>50	>100
Particles per 100 ml					
(ISO 4406) Particle Size / Micrometers	>4	>6	>14		
Scale Number					

6.0 PARTICLE COUNT RESULTS

Standard Achieved: NAS1638 Class 04 ☑ PASS ☐ FAIL

Additional Notes: Sample of Fyrquel taken while flushing hydraulic tank, Unit #1, achieved NAS1638 Class 04.

7.0 SIGNATURE

Technician: Grant Lush	Date: February 11, 2019

PENNECON

Flushing/Particle Count Form

Certificate No.: NF9072F

1.0 CUSTOMER INFORMATION

Customer: NL Hydro	PEHS Job No.: HSA005213
Contact Name: Craig Dwyer	Customer Reference No.:

Customer Instructions Notes: Sample from HPU. Hydraulic unit #2

2.0 JOB REQUIREMENTS / INFORMATION

Job Type: ☐ Sample Reading Only - No Flushing ☑ Flushing with Sample

Cleanliness Level Required: NAS1638 Class 06

Fluid Type: Fyrquel

3.0 FLUSHING ☐ N/A

☐ Line Flushing (Hoses, Tubing, Piping, Flowrate: N/A

☑ Container Flushing (Drum, Tote, Pail) - Full Volume Circulated Minimum 5

☐ Accumulator Flushing - Minimum 10 Fill-Drain Cycles Completed

Temperature:

Equipment Details (type, qty., size, manufacturer): Hydraulic Tank

Equipment ID (model, S/N): Unit #2

4.0 WATER CONTENT READING ☑ N/A

Meter Used:	Reading Obtained:

5.0 PARTICLE COUNT READINGS (PER AS598 for Ocular Microscope Readings)

Particle Measurements					
(NAS 1638) Particle Size / Micrometers	5 – 15	15 – 25	25 – 50	50 – 100	100 +
Particles per 100 ml	712	359	82	11	2
(SAE AS4059) Particle Size / Micrometers	>5	>15	>25	>50	>100
Particles per 100 ml					
(ISO 4406) Particle Size / Micrometers	>4	>6	>14		
Scale Number					

6.0 PARTICLE COUNT RESULTS

Standard Achieved: NAS1638 Class 04 ☑ PASS ☐ FAIL

Additional Notes: Sample of Fyrquel taken while flushing hydraulic tank, Unit #2, achieved NAS1638 Class 04.

7.0 SIGNATURE

Technician: Grant Lush	Date: February 11, 2019

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PENNECON

FLUSHING/PARTICLE COUNT FORM

Certificate No.: NF9084F

1.0 CUSTOMER INFORMATION	
Customer: NL Hydro	PHS Job No.: HSA005213
Contact Name:	Customer Reference No.:
Customer Instructions Notes: Perform Particle count on samples taken from Generator #1.	

2.0 JOB REQUIREMENTS / INFORMATION
Job Type: ☑ Sample Reading Only - No Flushing Required ☐ Flushing with Sample Reading
Cleanliness Level Required: NAS1638 Class 06
Fluid Type: Fyrquel

3.0 FLUSHING	☑ N/A
☐ Line Flushing (Hoses, Tubing, Piping, Systems) Flowrate: ☐ Container Flushing (Drum, Tote, Pail) - Full Volume Circulated Minimum 5 Times ☐ Accumulator Flushing - Minimum 10 Fill-Drain Cycles Completed	
Temperature:	
Equipment Details (type, qty., size, manufacturer):	
Equipment ID (model, S/N):	

4.0 WATER CONTENT READING	☑ N/A
Meter Used:	Reading Obtained:

5.0 PARTICLE COUNT READINGS (PER AS598 for Ocular Microscope Readings)

Particle Measurements					
(NAS 1638) Particle Size / Micrometers	5 – 15	15 – 25	25 – 50	50 – 100	100 +
Particles per 100 ml	4652	2341	431	34	8
(SAE AS4059) Particle Size / Micrometers	>5	>15	>25	>50	>100
Particles per 100 ml					
(ISO 4406) Particle Size / Micrometers	>4	>6	>14		
Scale Number					

6.0 PARTICLE COUNT RESULTS	
Standard Achieved: NAS1638 Class 06	☑ PASS ☐ FAIL
Additional Notes: Cleanliness standard NAS1638 Class 06 achieved from Generator #1.	

7.0 SIGNATURE	
Technician: Chris Klomp David Bans FOR CK	Date: February 19th 2019

PENNECON

FLUSHING/PARTICLE COUNT FORM

Certificate No.: NF9085F

1.0 CUSTOMER INFORMATION	
Customer: NL Hydro	PHS Job No.: HSA005213
Contact Name:	Customer Reference No.:
Customer Instructions Notes: Perform Particle count on samples taken from Generator #2.	

2.0 JOB REQUIREMENTS / INFORMATION		
Job Type:	☑ Sample Reading Only - No Flushing Required	☐ Flushing with Sample Reading
Cleanliness Level Required: NAS1638 Class 06		
Fluid Type: Fyrquel		

3.0 FLUSHING	☑ N/A
☐ Line Flushing (Hoses, Tubing, Piping, Systems) Flowrate: ☐ Container Flushing (Drum, Tote, Pail) - Full Volume Circulated Minimum 5 Times ☐ Accumulator Flushing - Minimum 10 Fill-Drain Cycles Completed	
Temperature:	
Equipment Details (type, qty., size, manufacturer):	
Equipment ID (model, S/N):	

4.0 WATER CONTENT READING	☑ N/A
Meter Used:	Reading Obtained:

5.0 PARTICLE COUNT READINGS (PER AS598 for Ocular Microscope Readings)

	Particle Measurements				
(NAS 1638) Particle Size / Micrometers	5 – 15	15 – 25	25 – 50	50 – 100	100 +
Particles per 100 ml	8642	2509	452	75	15
(SAE AS4059) Particle Size / Micrometers	>5	>15	>25	>50	>100
Particles per 100 ml					
(ISO 4406) Particle Size / Micrometers	>4	>6	>14		
Scale Number					

6.0 PARTICLE COUNT RESULTS	
Standard Achieved: NAS1638 Class 06	☑ PASS ☐ FAIL
Additional Notes: Cleanliness standard NAS1638 Class 06 achieved from Generator #2.	

7.0 SIGNATURE	
Technician: Chris Klomp David Bowes FOR C/K	Date: February 19th 2019

PENNECON

Flushing/Particle Count Form

Certificate No.: NF9086F

1.0 CUSTOMER INFORMATION	
Customer: NL Hydro	PEHS Job No.: HSA005213
Contact Name: Craig Dwyer	Customer Reference No.:
Customer Instructions Notes: Sample from HPU. Hydraulic unit #1	

2.0 JOB REQUIREMENTS / INFORMATION		
Job Type:	☐ Sample Reading Only - No Flushing	☑ Flushing with Sample
Cleanliness Level Required: NAS1638 Class 06		
Fluid Type: Fyrquel		

3.0 FLUSHING ☐ N/A

☐ Line Flushing (Hoses, Tubing, Piping, Flowrate: N/A
☑ Container Flushing (Drum, Tote, Pail) - Full Volume Circulated Minimum 5
☐ Accumulator Flushing - Minimum 10 Fill-Drain Cycles Completed

Temperature:

Equipment Details (type, qty., size, manufacturer): Hydraulic tank

Equipment ID (model, S/N): Unit #1

4.0 WATER CONTENT READING ☑ N/A	
Meter Used:	Reading Obtained:

5.0 PARTICLE COUNT READINGS (PER AS598 for Ocular Microscope Readings)

	Particle Measurements				
(NAS 1638) Particle Size / Micrometers	5 – 15	15 – 25	25 – 50	50 – 100	100 +
Particles per 100 ml	812	385	56	6	2
(SAE AS4059) Particle Size / Micrometers	>5	>15	>25	>50	>100
Particles per 100 ml					
(ISO 4406) Particle Size / Micrometers	>4	>6	>14		
Scale Number					

6.0 PARTICLE COUNT RESULTS	
Standard Achieved: NAS1638 Class 04	☑ PASS ☐ FAIL
Additional Notes: Sample of Fyrquel taken while flushing Hydraulic Tank Unit #1 achieved NAS1638 Class 04.	

7.0 SIGNATURE	
Technician: Grant Lush	Date: February 25, 2019

PENNECON

Flushing/Particle Count Form

Certificate No.: NF9087F

1.0 CUSTOMER INFORMATION

Customer: NL Hydro	PHS Job No.: HSA005213
Contact Name: Craig Dwyer	Customer Reference No.:
Customer Instructions Notes: Sample from HPU. Hydraulic unit #2	

2.0 JOB REQUIREMENTS / INFORMATION

Job Type: ☐ Sample Reading Only - No Flushing ☑ Flushing with Sample

Cleanliness Level Required: NAS1638 Class 06

Fluid Type: Fyrquel

3.0 FLUSHING ☐ N/A

☐ Line Flushing (Hoses, Tubing, Piping, Flowrate: N/A

☑ Container Flushing (Drum, Tote, Pail) - Full Volume Circulated Minimum 5

☐ Accumulator Flushing - Minimum 10 Fill-Drain Cycles Completed

Temperature:

Equipment Details (type, qty., size, manufacturer): Hydraulic tank

Equipment ID (model, S/N): Unit #2

4.0 WATER CONTENT READING ☑ N/A

Meter Used:	Reading Obtained:

5.0 PARTICLE COUNT READINGS (PER AS598 for Ocular Microscope Readings)

Particle Measurements					
(NAS 1638) Particle Size / Micrometers	5 – 15	15 – 25	25 – 50	50 – 100	100 +
Particles per 100 ml	xxxx	xxxx	xxxx	426	148
(SAE AS4059) Particle Size / Micrometers	>5	>15	>25	>50	>100
Particles per 100 ml					
(ISO 4406) Particle Size / Micrometers	>4	>6	>14		
Scale Number					

6.0 PARTICLE COUNT RESULTS

Standard Achieved: NAS1638 Class 10 ☐ PASS ☑ FAIL

Additional Notes: Only Read The First 2 Counts. Sample taken from Hydraulic Tank Unit #2 failed to achieve NAS1638 Class 06.

7.0 SIGNATURE

Technician: Grant Lush	Date: February 25, 2019

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PENNECON

Flushing/Particle Count Form

Certificate No.: NF9088F

1.0 CUSTOMER INFORMATION

Customer: NL Hydro	PHS Job No.: HSA005213
Contact Name: Craig Dwyer	Customer Reference No.:
Customer Instructions Notes: Sample from HPU. Hydraulic unit #1	

2.0 JOB REQUIREMENTS / INFORMATION

Job Type: ☐ Sample Reading Only - No Flushing ☑ Flushing with Sample

Cleanliness Level Required: NAS1638 Class 06

Fluid Type: Fyrquel

3.0 FLUSHING ☐ N/A

☐ Line Flushing (Hoses, Tubing, Piping, Flowrate: N/A

☑ Container Flushing (Drum, Tote, Pail) - Full Volume Circulated Minimum 5

☐ Accumulator Flushing - Minimum 10 Fill-Drain Cycles Completed

Temperature:

Equipment Details (type, qty., size, manufacturer): Hydraulic Tank

Equipment ID (model, S/N): Unit #1

4.0 WATER CONTENT READING ☑ N/A

Meter Used:	Reading Obtained:

5.0 PARTICLE COUNT READINGS (PER AS598 for Ocular Microscope Readings)

	Particle Measurements				
(NAS 1638) Particle Size / Micrometers	5 – 15	15 – 25	25 – 50	50 – 100	100 +
Particles per 100 ml	1060	452	115	9	4
(SAE AS4059) Particle Size / Micrometers	>5	>15	>25	>50	>100
Particles per 100 ml					
(ISO 4406) Particle Size / Micrometers	>4	>6	>14		
Scale Number					

6.0 PARTICLE COUNT RESULTS

Standard Achieved: NAS1638 Class 04 ☑ PASS ☐ FAIL

Additional Notes: Sample of Fyrquel taken while flushing Hydraulic Tank Unit #1 achieved NAS1638 Class 04.

7.0 SIGNATURE

Technician: Grant Lush	Date: February 26, 2019

PENNECON

Flushing/Particle Count Form

Certificate No.: NF9089F

1.0 CUSTOMER INFORMATION	
Customer: NL Hydro	PHS Job No.: HSA005213
Contact Name: Craig Dwyer	Customer Reference No.:
Customer Instructions Notes: Sample from HPU. Hydraulic unit #2	

2.0 JOB REQUIREMENTS / INFORMATION		
Job Type:	☐ Sample Reading Only - No Flushing	☑ Flushing with Sample
Cleanliness Level Required: NAS1638 Class 06		
Fluid Type: Fyrquel		

3.0 FLUSHING ☐ N/A

☐ Line Flushing (Hoses, Tubing, Piping, Flowrate: N/A
☑ Container Flushing (Drum, Tote, Pail) - Full Volume Circulated Minimum 5
☐ Accumulator Flushing - Minimum 10 Fill-Drain Cycles Completed

Temperature:

Equipment Details (type, qty., size, manufacturer): Hydraulic tank

Equipment ID (model, S/N): Unit #2

4.0 WATER CONTENT READING ☑ N/A

Meter Used:	Reading Obtained:

5.0 PARTICLE COUNT READINGS (PER AS598 for Ocular Microscope Readings)

Particle Measurements					
(NAS 1638) Particle Size / Micrometers	5 – 15	15 – 25	25 – 50	50 – 100	100 +
Particles per 100 ml	1651	995	202	15	7
(SAE AS4059) Particle Size / Micrometers	>5	>15	>25	>50	>100
Particles per 100 ml					
(ISO 4406) Particle Size / Micrometers	>4	>6	>14		
Scale Number					

6.0 PARTICLE COUNT RESULTS

Standard Achieved: NAS1638 Class 05	☑ PASS ☐ FAIL

Additional Notes: Sample of Fyrquel taken while flushing Hydraulic Tank Unit #2 achieved NAS1638 Class 05.

7.0 SIGNATURE

Technician: Grant Lush	Date: February 26, 2019

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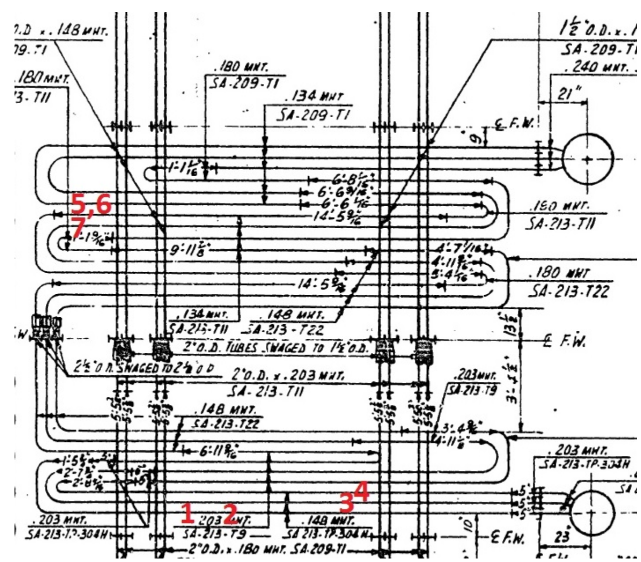
Unit 2 – Emergency RH Repairs

Unit #2 - Reheat Leaks

- **Indicators**
  - Make up Water Shortfall
  - Reduced Load <70MW
  - Moisture in Stack
  - Expected
  - B&W Called Jan 5th to mobilize
- **Inspection**
  - On Permit Jan 6th
  - Obvious Leaks in lower RH tubes, platens 5, and 8.
  - Plant air through RH Drains and performed ultrasonic test and found pin holes in Platen 18, 28 and 29.
  - Total of 7 leaks present.

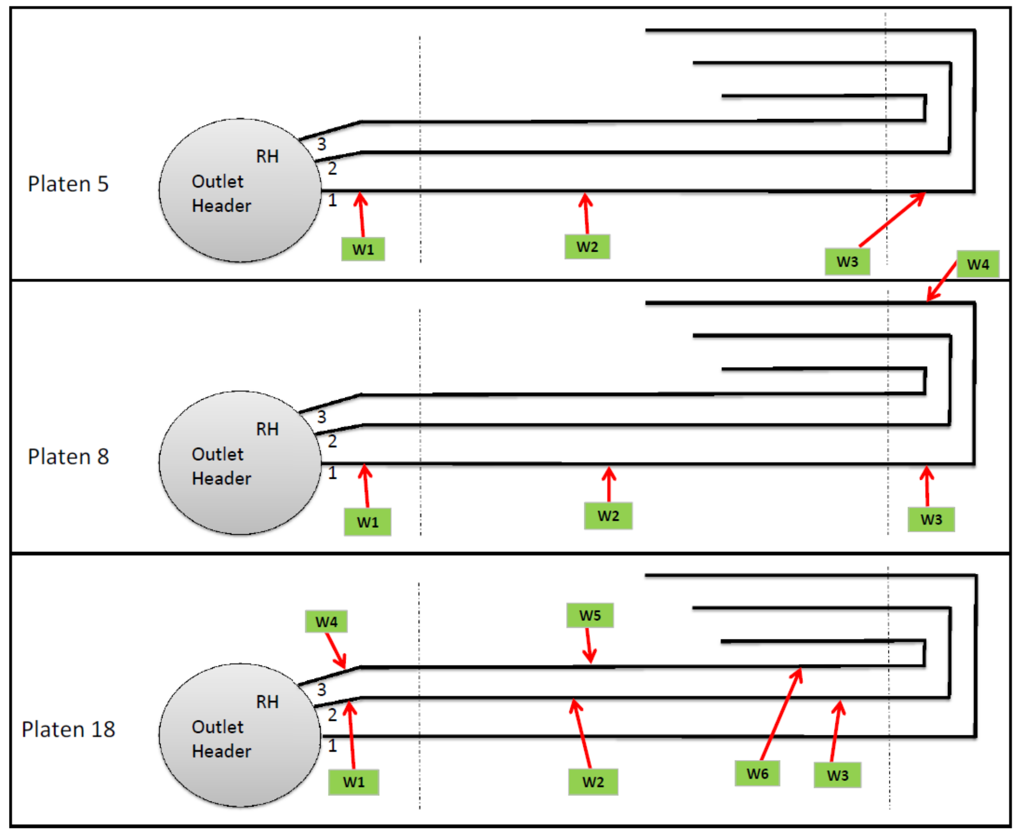


Unit 2 – Emergency RH Repairs

Unit #2 - Reheat Leaks

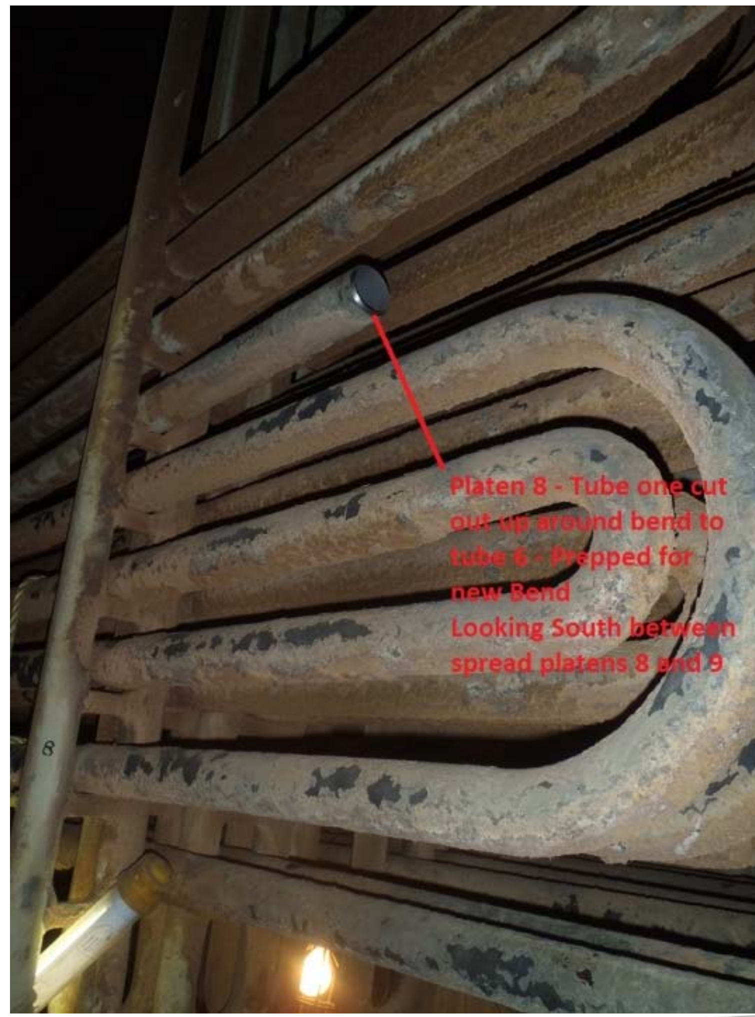
- **Work Done**
  - Jan 6th – Jan 14th
  - Around the clock
  - Repair All Leaks

- **Notes**
  - Material on hand
  - Extra Ordered (Bends Etc.)
  - SA 213 T22 (Safe Ends)
  - SA 213 TP 304H (SS Purge Welding)
  - Tight Quarters
  - Manual Welding
  - Welding New to Old
  - Draft – External/Internal
  - Refractory Seal
  - Complete Jan 14th
  - Lessons Learned for Project



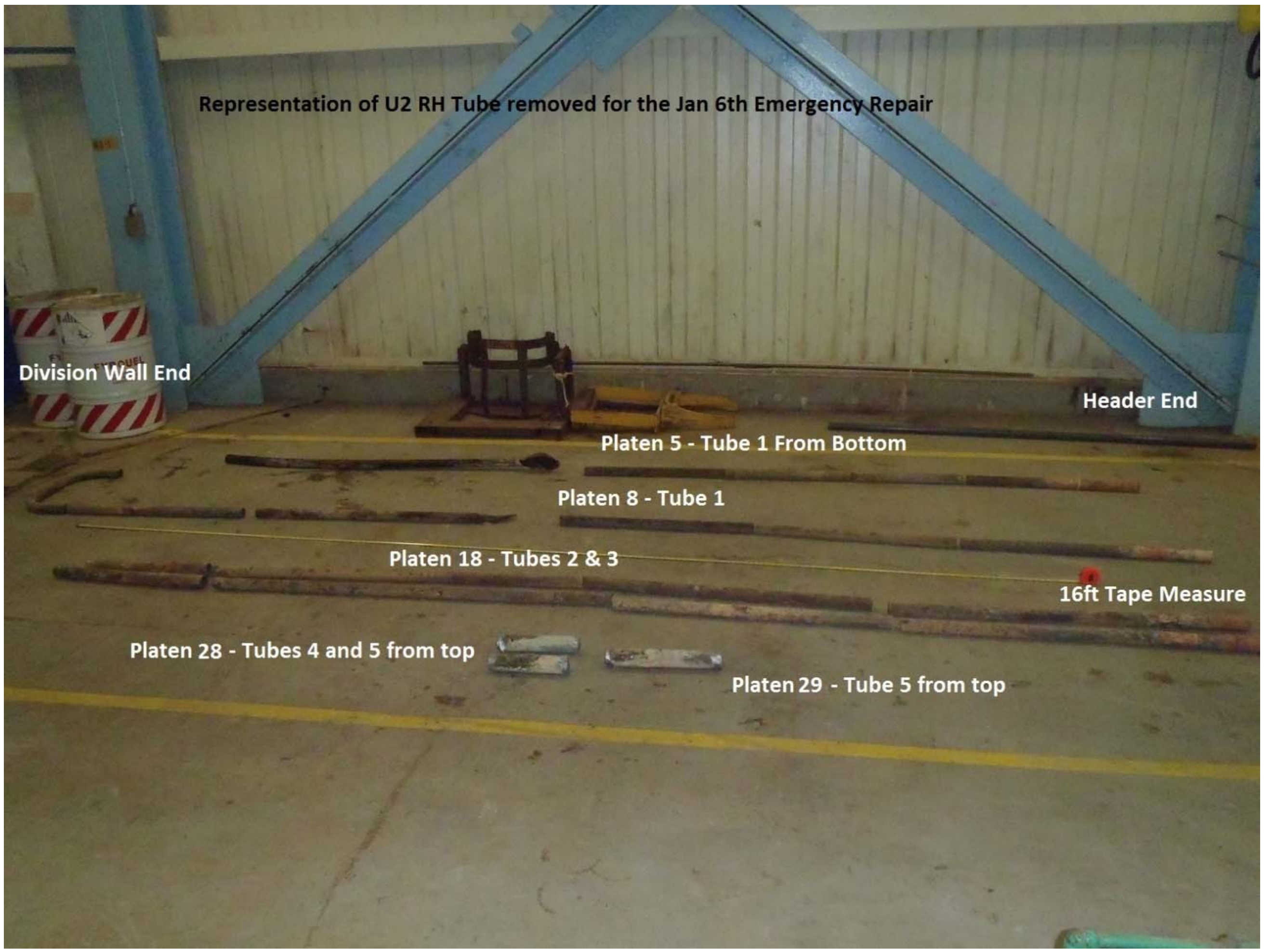
Unit 2 – Emergency RH Repairs

Unit #2 - Reheat Leaks



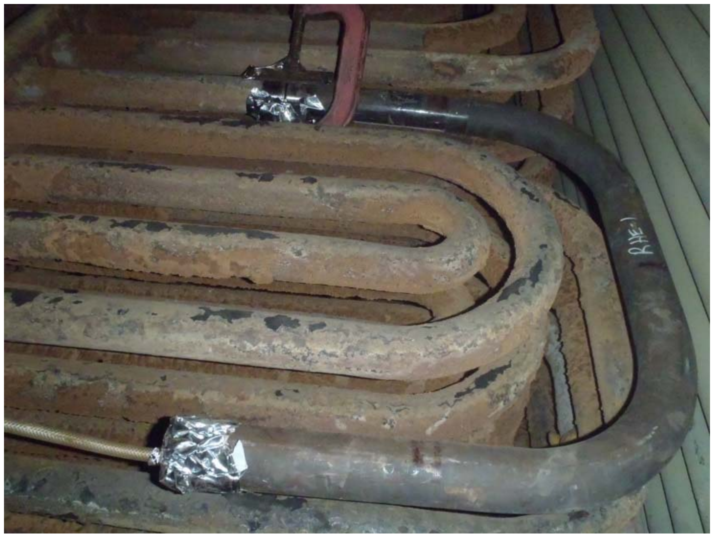
Unit 2 – Emergency RH Repairs

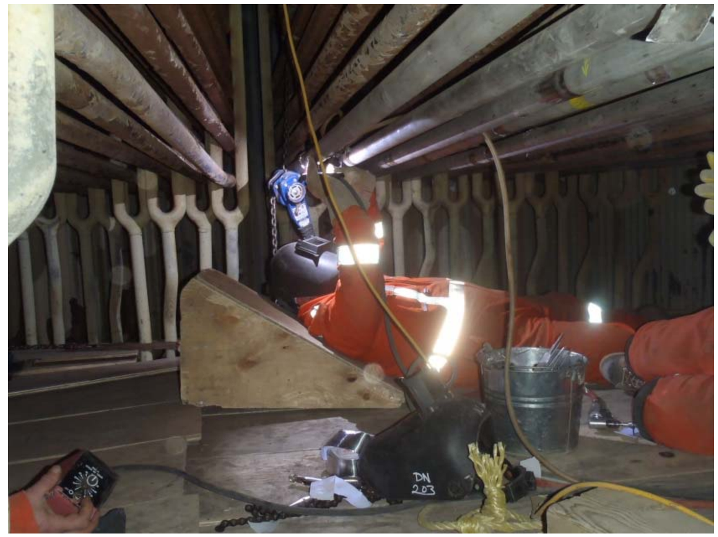
Unit #2 - Reheat Leaks Material Removed



Unit 2 – Emergency RH Repairs

Unit #2 - Reheat Leaks





Unit 2 – Emergency RH Repairs

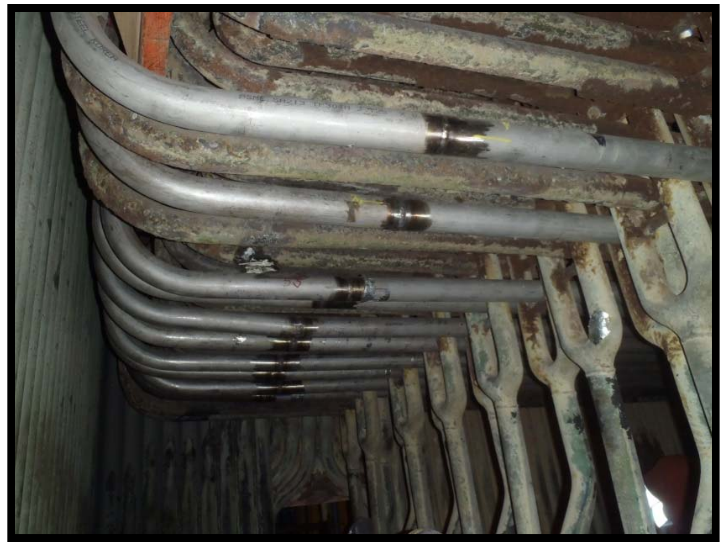
Unit #2 - Reheat Leaks (Round two)

- **Unit Back On-Line**
  - Jan 16th De-rated to 140MW
- **Leak Suspected**
  - Jan 19th Another RH Tube Leak Detected
  - Same Indicators
  - Jan 19th re-mob
- **Inspection**
  - On Permit Jan 20th
  - Obvious Leak platen 3.
  - Ultrasonic test and found no more leaks

Unit 2 – Emergency RH Repairs

Unit #2 - Reheat Leaks (Round Two)

- **Work Done**
  - Analyze UT data and Repair as Many as Possible – demand dictated
  - Jan 20th – Jan 31st
  - Repaired the 23 thinnest bottom tubes
  - Around the clock
  - Start up with De-rate to 120MW on Feb 3rd
  - Up-side - Lessons Learned for Project
  - Result - Major Push for Capital RH Project for 2016 outage



Unit 1 – Emergency RH Repairs

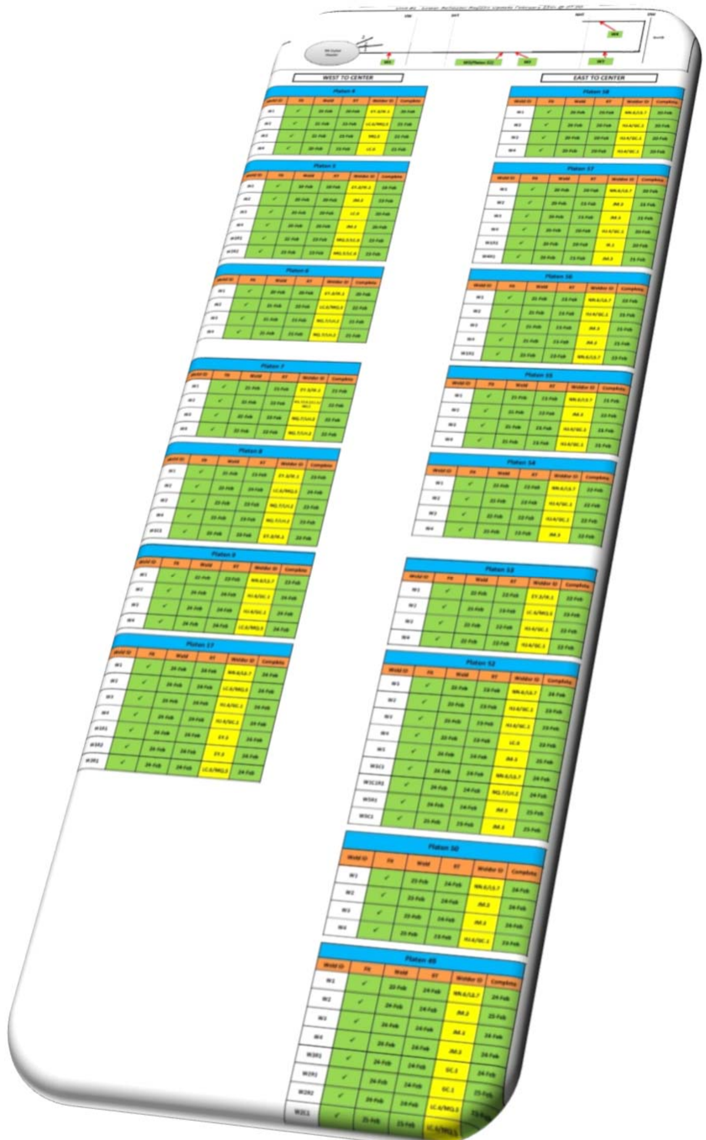
Unit #1 - Reheat Leaks

- **Indicators**
  - Couldn't Keep up Make up Water
  - Reduced Load 50MW
  - Moisture in Stack
  - Expected
  - Called Feb 7th to mobilize (Stand by)
- **Inspection**
  - On Permit Feb 18th
  - Obvious Leak in lower RH tubes on platen 4.
  - Plant air through RH Drains and performed ultrasonic test no further leaks.

Unit 1 – Emergency RH Repairs

Unit #1 - Reheat Leak

- **Work Done**
  - Feb 18th – Feb 25th
  - Around the clock
  - Tight Quarters
  - Manual Welding
  - Welding New to Old
  - Backing Rings Used
  - No Purge Gas Required
  - Draft – External
  - Material on hand
  - Extra Ordered (Bends Etc.)
  - SA 213 T22 (Safe Ends)
  - SA 213 TP 304H (SS)
  - Refractory Seal
  - Replaced 16 tubes
  - Start up with De-rate to 120MW on Feb 26th
  - Up-side - Lessons Learned for Project
  - Result - Major Push for Capital RH Project for 2016 outage



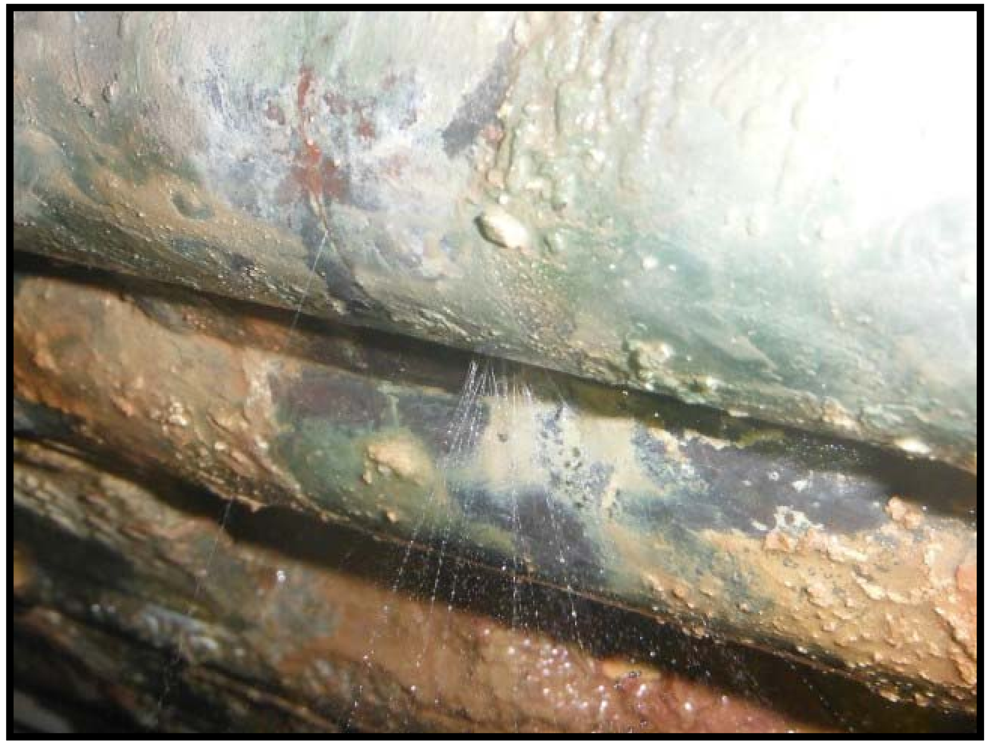
Unit 1 – Emergency RH Repairs

Unit #1 - Reheat Leaks

Unit 2 – Key Findings & Extra Work

SPT on Sept 7th

- 12-13K KPA
- Hold for 15mins +
- Leak on SH Tube Attachment
- Successful SPT on Sept 11th
- Alstom Performed Analysis
  - Not Overstressed
  - Fatigue Cracking
  - Cyclic Thermal Expansions
- Inspect Several Locations
  - Similar (50 every 6 yrs)
  - High Stress at Bottom



Unit 2 – Key Findings & Extra Work

PSH Tube Leak

Final Report

for an

Engineering Study

of

LTSH Tube Failure Review

at

Newfoundland and Labrador Hydro

Holyrood Generating Station Unit #2

Prepared by

Alstom Canada Inc.
Ottawa, ON

Reference # ES0-003817 **Nov. 26, 2014**

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Should the Purchaser subsequently retain Alstom to perform any of the work related to recommendations contained in this report, a separate contract governing such work shall be executed appropriately.

This document is furnished for the Purchaser's benefit only, and not for the benefit of any third party.

LICENSED PROFESSIONAL ENGINEER
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PROVINCE OF ONTARIO

Nov 26, 2014

This report was prepared by Eric Mondoux, P.Eng.

Table of Contents

ALSTOM

1. Executive Summary

Based on the analysis that Alstom has performed, there are no clear indications that the location where the tube failure occurred has any over-stressing from normal boiler operation. Factors such as spreading the assemblies for maintenance over the 40 years of operation as well as the number of start-ups and cool-downs may have caused cyclic fatigue in the attachment. When thermal cyclic fatigue is introduced to the attachment there is a possibility that the stresses in the tube material at the failure location may have been stressed beyond its fatigue limit. This results in a possibility of crack initiation.

The analysis has shown that the steady-state stresses in the failure location are high enough to propagate a crack. If the failed attachment in the Low Temperature Superheater (LTSH) had a pre-existing crack, the cyclic thermal fatigue of the material may have caused the crack to propagate and lead to failure.

2. Introduction

N&L Hydro recently experienced a tube failure in the Low Temperature Superheater of boiler #2, contract number CA-68219. Boiler #2 was built in 1970 and is a duplicate of unit #1, contract number CA-68119.

N&L Hydro has previously requested Alstom to review a tube failure in the LTSH section of Holyrood Unit #2. This was performed by Alstom's laboratory in Chattanooga, TN, and a final report was issued.

Further to receiving the final failure analysis report from Alstom's laboratory in Chattanooga, Alstom Ottawa Engineering was asked to investigate the possible cause of the fatigue failure at the welded attachment by completing a stress analysis on the LTSH. The approach was as follows:

1) Model the tube which failed in the upper assembly. The model to include the structural attachments welded between tubes.
2) Input into this model to be the metal temperatures of the attachments and the metal temperatures of the tubing, along with the vertical weight loading of the assembly that is supported by these attachments.
3) Perform a stress analysis of the tube and attachment to determine the level of thermal stress and dead load stress on the system.
4) If possible, develop conceptual modifications which would reduce the potential for future cracking.

The location of the attachment failure can be seen in the figures below:

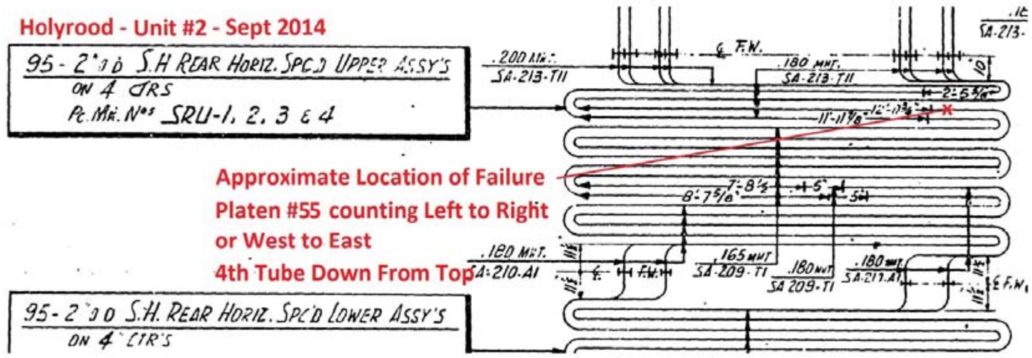

Figure 1: Location of LTSH attachment failure

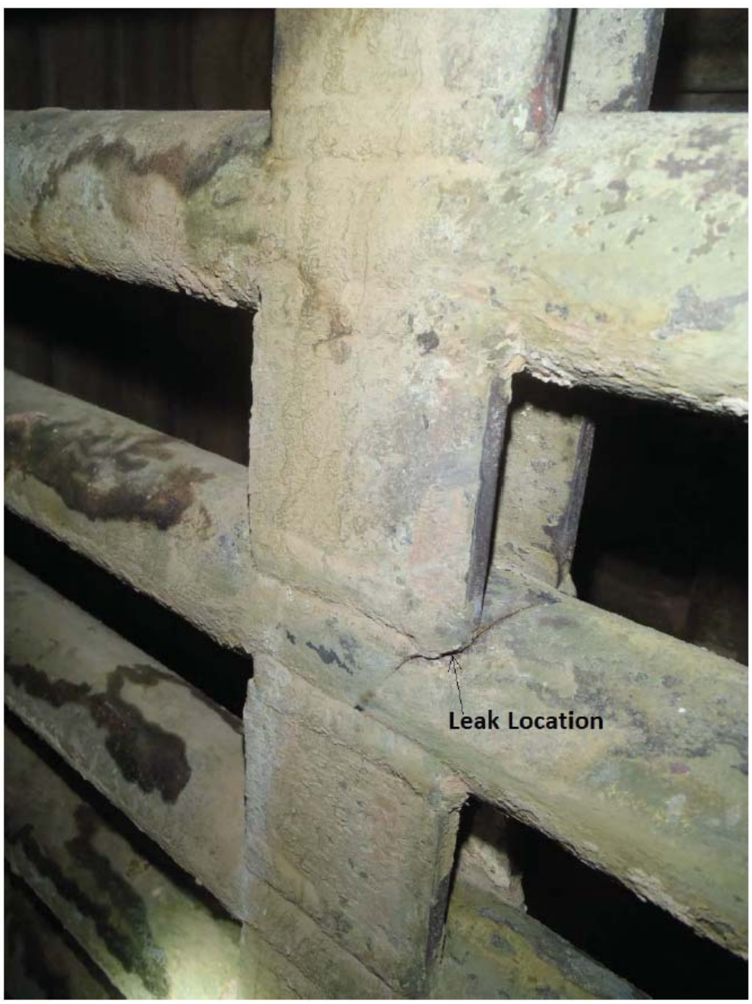

Figure 2: Location of LTSH attachment failure

3. Stress Model

The upper and lower LTSH bundles were modelled in a stress analysis program to calculate both the thermal stresses induced on the tubes and attachments as well as the stresses resulting from the weight of the tubing.

Below are the results of the stress analysis.

Note: the attachments in the figures below appear as hanger tubes, but are modelled with a rigid attachment between each superheater tubing. The attachments act as individual attachment supports to transfer loading from the bottom elements up to the top support.

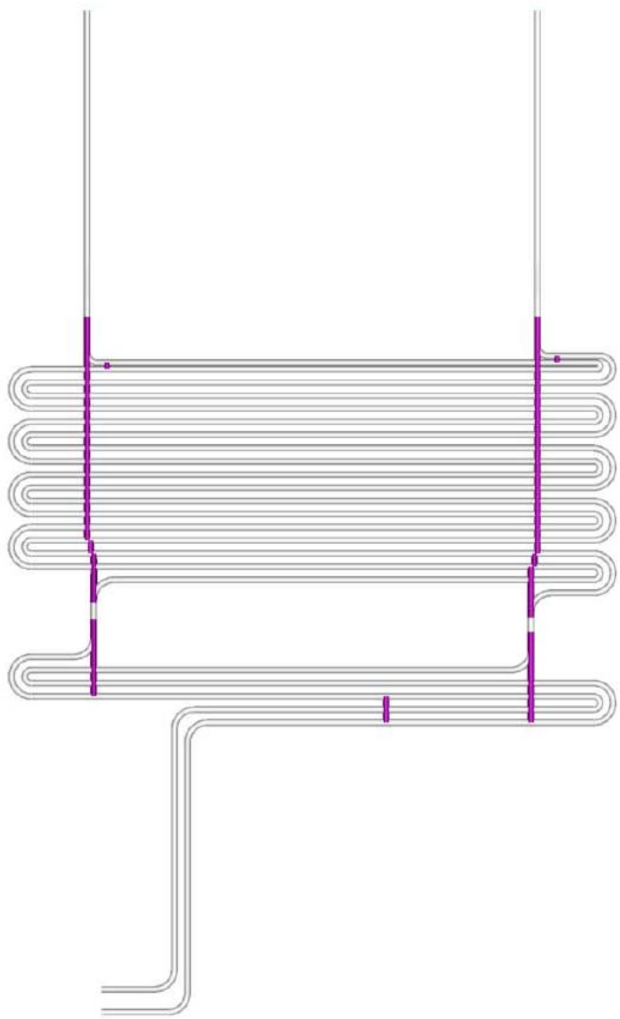

Figure 3: Model of LTSH used for analysis

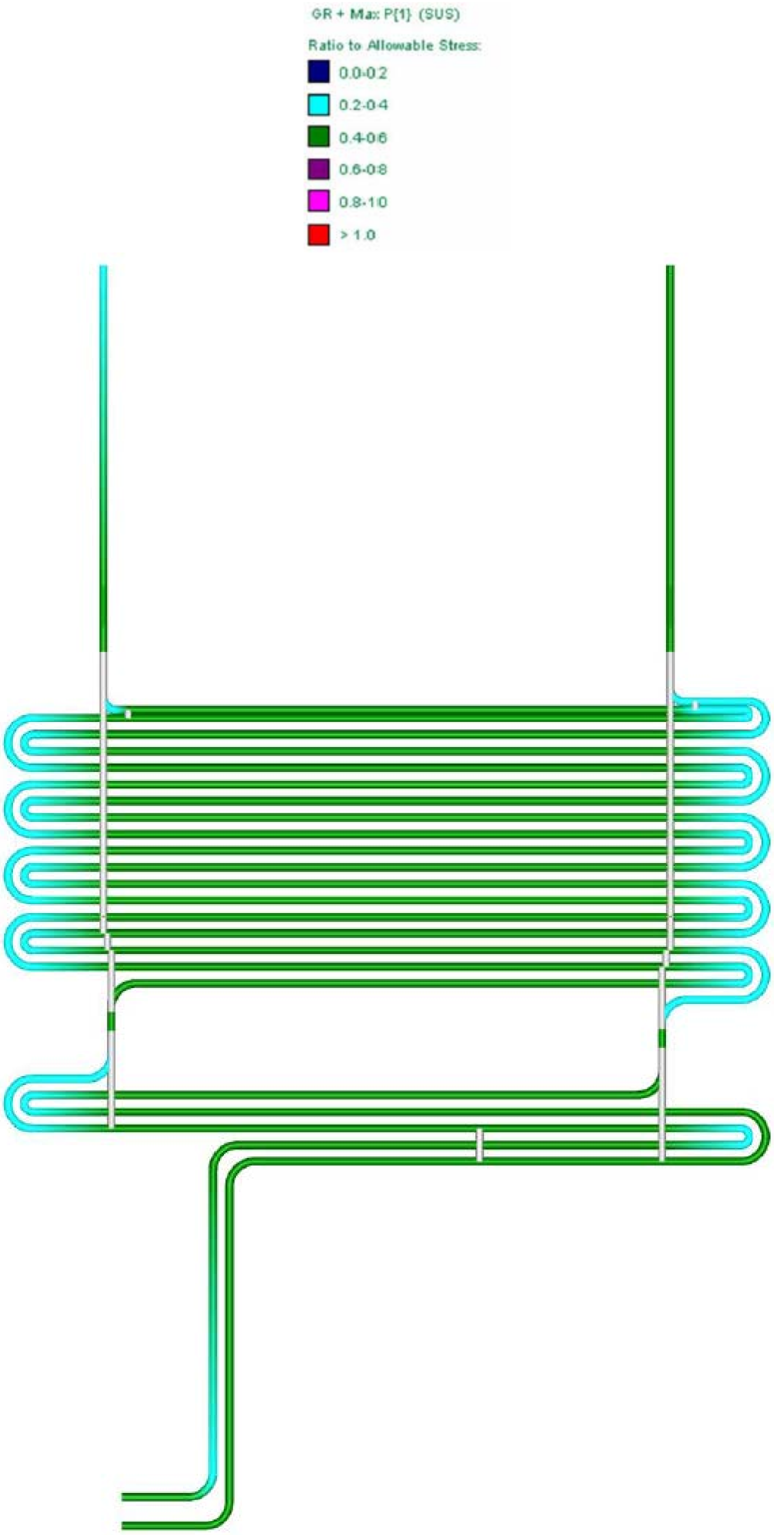

Figure 4: Pressure and dead weight sustained stress (SUS) ratio

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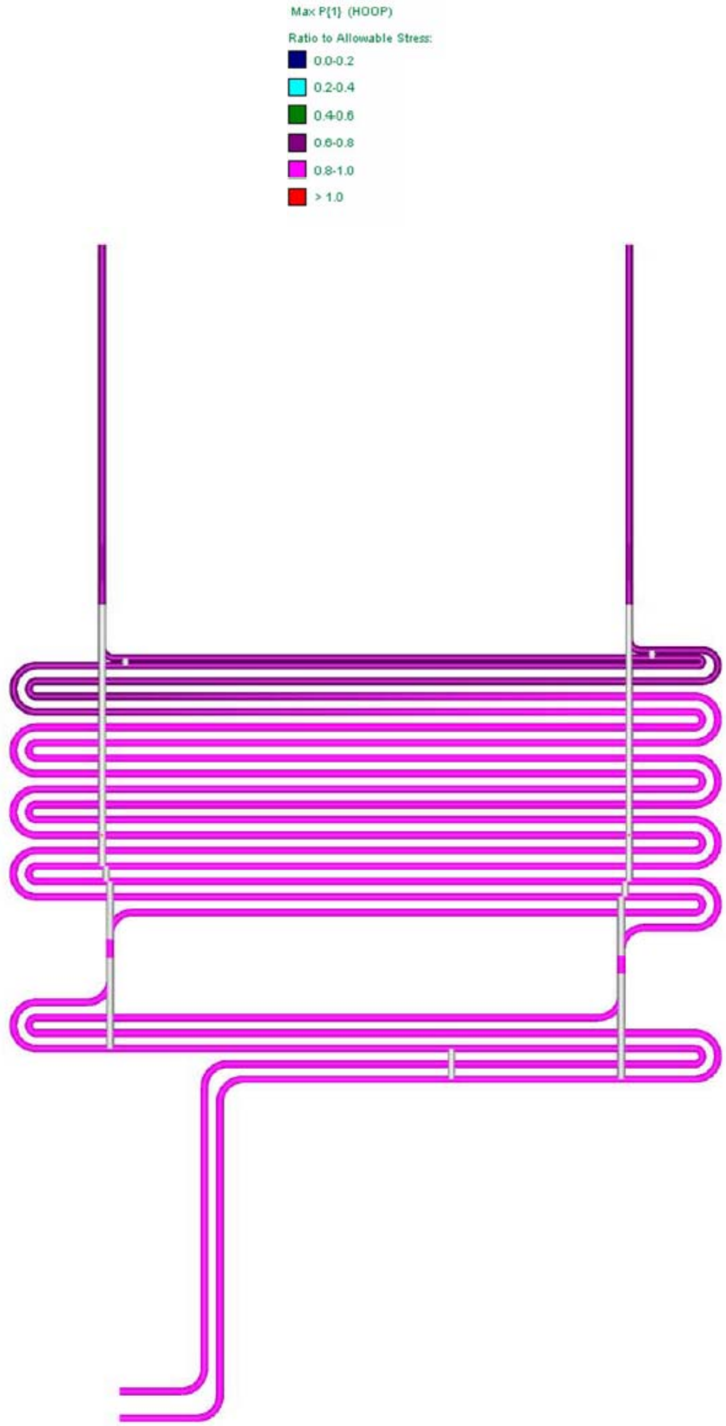

Figure 5: LTSH hoop stress ratio

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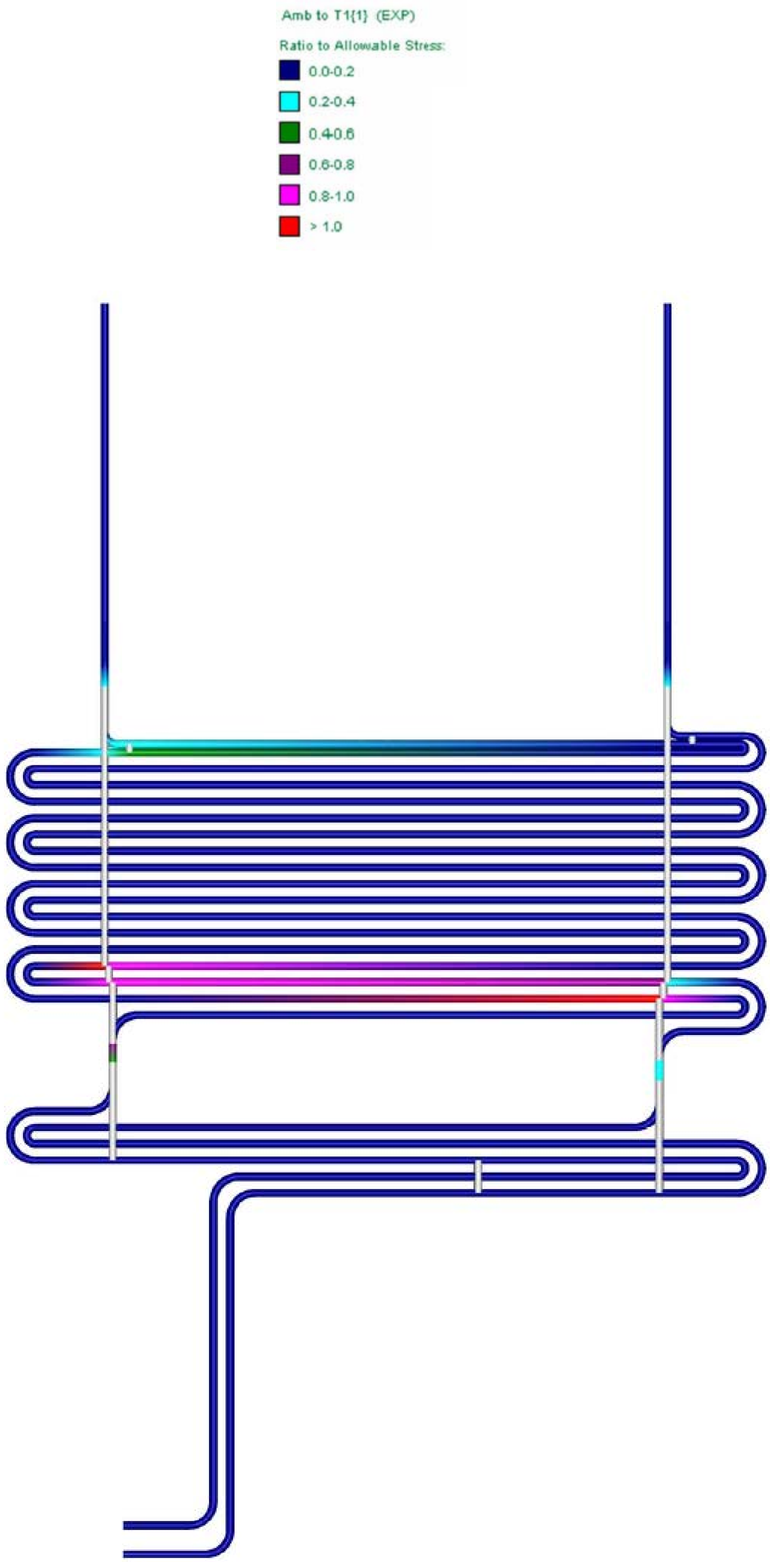

Figure 6: LTSH thermal displacement stress ratio – Expansion Stress (EXP)

The results of this stress analysis have shown that the location where the tube failure has occurred is not over-stressed either with the dead weight of the tubing or from the thermal expansion stresses caused by the transient temperature throughout the superheater.

- The thermal stress at the failure location is in the range of a few ksi vs an allowable stress of 25 ksi.
- The pressure hoop stress at the failure location is 11.6 ksi vs an allowable stress of 15 ksi.
- The pressure and dead weight sustained stress induced at the failure location is approx. 6.5 ksi vs an allowable stress of 15 ksi.

This analysis has also shown the superheater tie plates at the bottom of the upper bundle that offsets 1" to match the vertical supports of the lower bundle is over-stressed in a design criterion. Refer to Figure 7 below for offset location. The over-stress is seen by the red tubing in Figure 6. The investigation shows that failure due to over-stressing beyond the yield point of the material is not likely, but is a high stress location on a design criterion. Alstom has not been notified of failures at these locations, but may be a location where further inspections should be taken to ensure that crack initiation or crack propagation is not occurring.

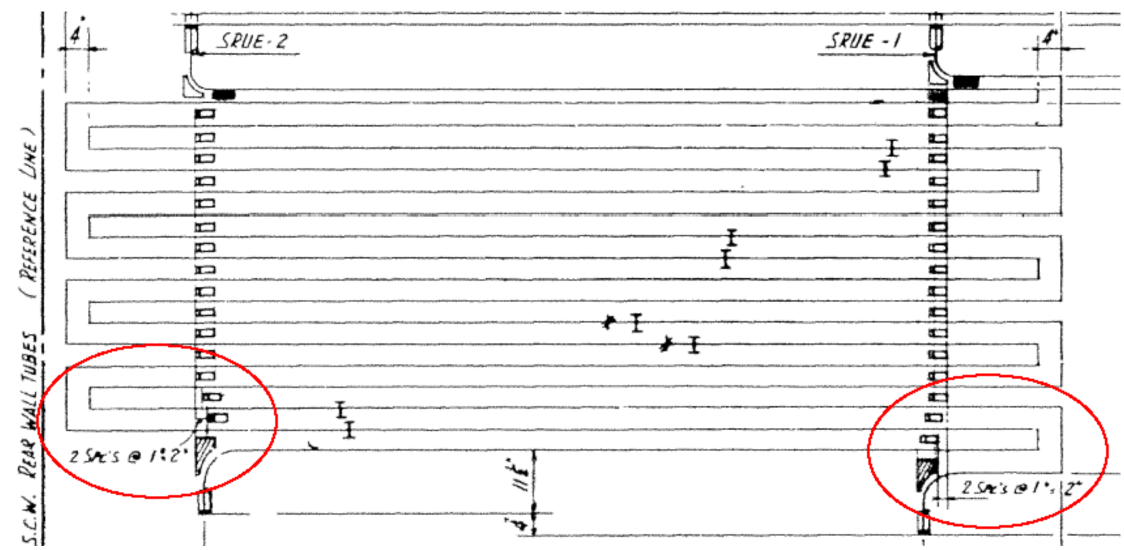

Figure 7: Upper LTSH Assembly - Highlighted Support Attachment Offsets

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4. Discussion

The investigation of the LTSH tube attachment did not indicate a potential for failures due to normal boiler operation thermal transients or over-stressing due to dead weight loading.

The metallurgical report issued by Alstom's Laboratory for the failed LTSH tube attachment indicated that the failure was due to fatigue cracking that initiated on the OD surface of the tube at the toe of the attachment weld. This document can be found in APPENDIX A of this report. The boiler, LTSH tube, and attachment have been operating for over 40 years. During those years, the boiler has experienced a number of start-ups and cool-downs. As the unit starts up, the attachment and LTSH tube are at flue gas temperatures until the introduction of steam through the tubing. As the steam passes through the tubing, the base metal of the attachment at the surface of the tube OD cools down, and the center of the attachment heats up due to an increase in flue gas temperature. The varying temperatures cause the attachments to heat up and cool down at different rates, resulting in a cyclic effect. However, the steady-state stresses involved at the failure location are not high enough to initiate a crack, but may propagate an existing crack.

This study investigation has not resulted in any concrete evidence to support a tube failure at the location indicated in the introduction of this report by crack initiation.

In Alstom's experience, when maintenance and inspection is required between elements, the distance of spreading the superheater assemblies may have an impact on local stressing of attachments. There is a possibility during an inspection over the 40 (+) years of operation that a hairline crack may have developed at this particular attachment location due to over-stressing. Even though the operational stresses at this attachment are not high enough to initiate a crack, they are high enough to propagate an existing crack. This would lead to cyclic fatigue and a mechanical fatigue failure.

As noted in Figure 6, there are elevated stress points at the LTSH tube attachments that are offset by 1". These are located at the lower portion of the upper LTSH bundle. Although this has not been noted as an area of high failure rates, it would be beneficial to inspect this area regularly and monitor any indications resulting from inspections.

An important factor to consider is that this failure location has occurred at the highest temperature location for the superheater tube material SA-209-T1. Beyond the attachment the tubing material changes to SA-213-T11 to account for the higher temperatures. The mid-wall temperature of the SA-209-T1 at the attachment and failure location is predicted to be 784^{o}F. However, the calculated surface temperature of the tubing at the attachment is predicted to be 893^{o}F due to the heat pickup from the attachment. See Figure 8 below:

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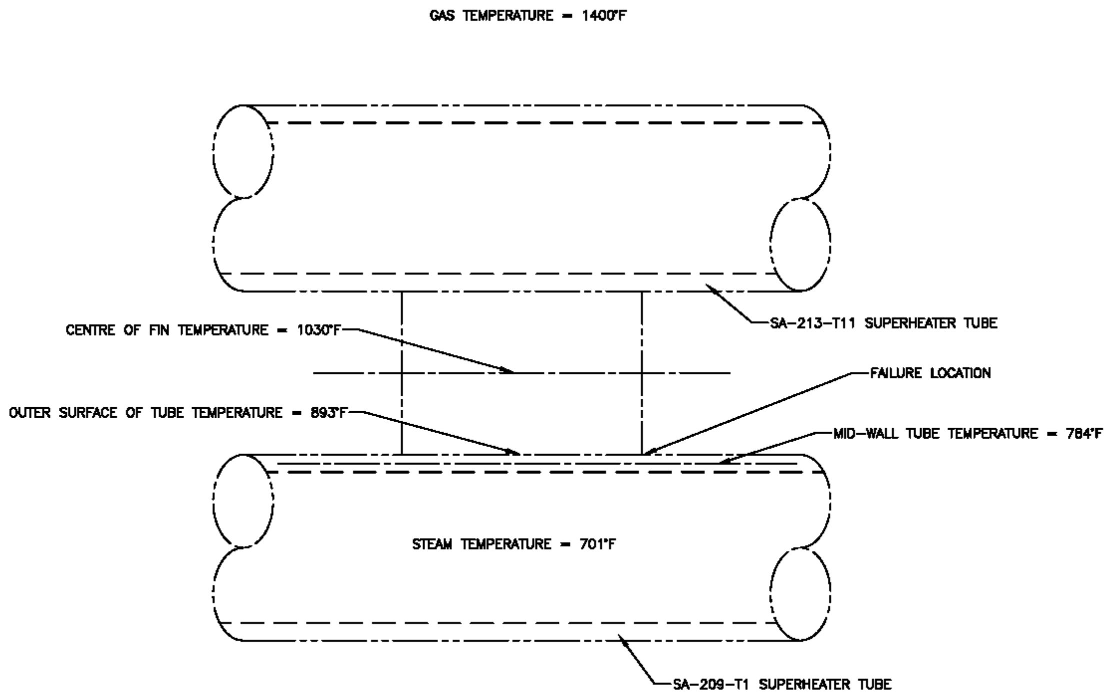

Figure 8: Predicted temperature distributions at the failed superheater attachment

ASME Section IIA states that for SA-209-T1:

> *Upon prolonged exposure to temperatures above 875°F, the carbide phase of carbon-molybdenum steel may be converted to graphite.*
>
> *When the steel is operating in the temperature range of 800°F to 1100°F and, depending on the nature of the distribution of the graphite particles in the microstructure, can result in a substantial loss of the material's strength and ductility.*

From the "Metals Handbook Volume 1, Properties and Selection: Iron and Steels" and the "Metals Handbook Volume 11, Failure Analysis and Prevention";

> *For most steels whose hardness is below 400 HB (not including precipitation hardening steels), the fatigue limit is about half of the ultimate strength.*
>
> *The fatigue limit (endurance limit) is the value of the stress below which a material can presumably endure an infinite number of stress cycles, that is, the stress at which the S-N diagram becomes and appears to remain horizontal.*

The ultimate strength of SA-209-T1 on the surface of the tube at operating temperature is 51.46 ksi. Therefore the fatigue limit is approximately 25.7 ksi.

Based on an analysis between the tube and the attachment at the failure location the thermal expansion stress created is 26.25 ksi. This calculated stress is slightly over the fatigue limit of 25.7 ksi which indicates that a crack can initiate due to cyclic fatigue from thermal expansions and over time can propagate into a tube failure.

5. Conclusion

Results from this study indicate that the location of the tube attachment failure is not over-stressed during normal boiler operation. However, the metallurgical laboratory analysis concluded that the failure was due to fatigue cracking. Therefore, from a fatigue analysis due to cyclic thermal expansions, it is possible that a crack may have developed between the tube and support plate. The cyclic thermal expansion differences resulting from start-ups and cool-downs of the boiler have a stress which is slightly higher than the fatigue stress limit for the tubing material SA-209-T1. These results indicate that it is possible for a crack to initiate due to fatigue loading and over time the crack could propagate into a failure.

Alstom's recommendation would be to inspect several attachments in and around the location of the failure to ensure no indications are prevalent. Continuous monitoring should be adhered to as per the inspection and test plan developed by Alstom per contract number 40733040 where fifty (50) superheater attachments are to be 100% MPI/LPI every 6 years, selected at random locations.

Since the stress analysis has also indicated a high stress point at the attachments near the offsets at the bottom of the upper assemblies, Alstom would also recommend to inspect the attachments in that location frequently. See Figure 9 below for inspections of attachment locations:

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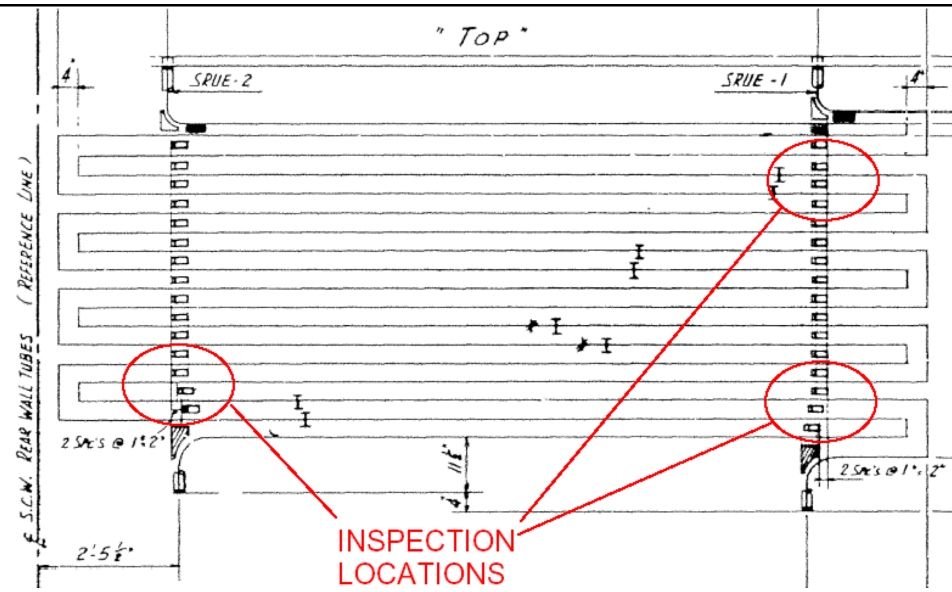

Figure 9: LTSH Attachment Inspection Locations

The current welding specification for these attachments is to weld the complete length of the tie plate to the tube. It is also recommended that when replacing any of the tie plate attachments, to weld not only the length of the attachment, but also to wrap the weld around the edges. This would reduce concentrated stress points in the welds.

Also, when replacing any tubing or attachments in the failure location, it is recommended to replace the tubing with SA-213-T11. This would carry the existing field weld and material change from SA-213-T11 to existing SA-209-T1 past the attachment. See Figure 10 below:

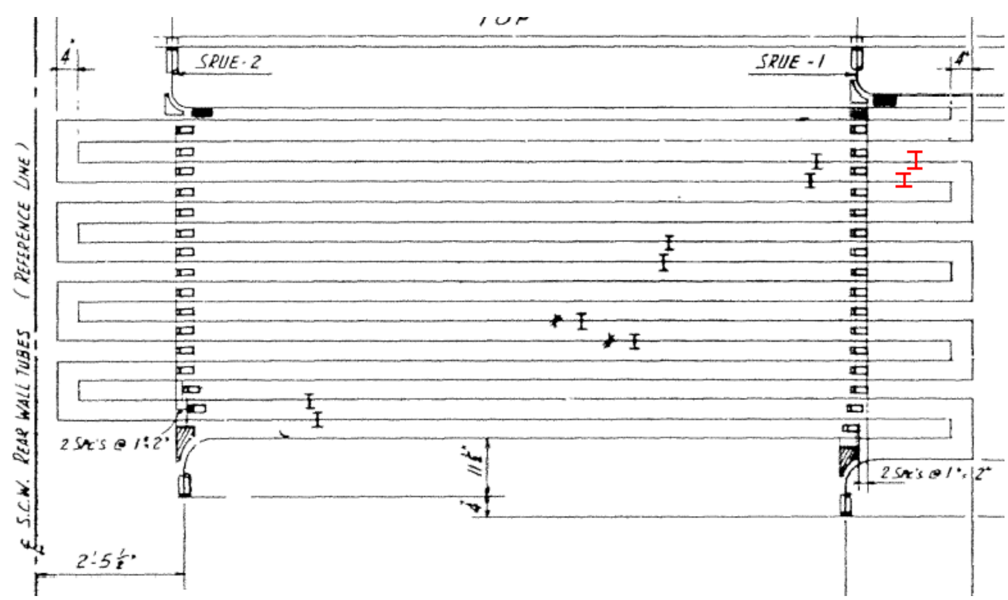

Figure 10: New field weld location between SA-213-T11 & SA-209-T1

APPENDIX A

ALSTOM

METALLURGICAL REPORT

October 28, 2014
(Revised November 24th, 2014)

EVALUATION OF A FAILED SUPERHEATER TUBE

NEWFOUNDLAND LABRADOR HYDRO
HOLYROOD THERMAL GENERATING STATION
UNIT NUMBER 2
CONTRACT NO. CA-68219
EBO-4100735518 / LN-14I302

PREPARED FOR:

NEWFOUNDLAND LABRADOR HYDRO

PREPARED BY:

ALSTOM POWER, INC.
TTT-M MATERIALS TESTING
1201 RIVERFRONT PARKWAY
CHATTANOOGA, TENNESSEE 37402

October 28, 2014
(Revised November 24th, 2014)

METALLURGICAL REPORT:

Evaluation Of A Failed Superheater Tube
Newfoundland Labrador Hydro
Holyrood Thermal Generating Station
Unit Number 2
Contract No. CA-68219
EBO-4100735518 / LN-14I302

1.0 INTRODUCTION

A failed section of superheater tubing removed from Unit Number 2 at the Holyrood Thermal Generating Station was submitted to the TTT-M Materials Testing Laboratory for metallurgical analysis. The sample is shown in Figure 1 as it appeared when received from the field. A photograph of the failed tube in the boiler prior to removal is shown in Figure 2. The sample was taken from Tube 4 of primary (rear) SH Assembly 55 at an elevation of 112' 11". A diagram showing the location from where the sample was taken is recorded in Figure 3. The tubing was specified to be 2.00" OD x 0.165" MWT SA-209, T1 material that had been in service for 178,979.5 hours prior to removal. In addition, the customer reported that the leak was found during hydro testing that was performed during the last outage.

The purpose of the analysis was to determine why the tube failed at the tie plate attachment weld.

2.0 CONCLUSIONS AND RECOMMENDATIONS

The metallurgical analysis established that the failure was the result of *fatigue cracking* that initiated on the OD surface of the tube at the toe of the attachment weld. Evidence of a relatively thick corrosion product along the fracture paths indicated that the cracking likely had progressed slowly over a long period of time. The remaining three intact tie-plate attachment welds on the sample were examined and there was no evidence of any cracking found.

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Based on the nature of the damage observed in the sample, it is possible that other primary (rear) SH wall tubes may have suffered similar damage and could be on the verge of failure. Therefore, it is recommended that the tubing in the vicinity of the failure be inspected for OD cracks along the toes of the tie-plate attachment welds. It is further recommended that unanticipated or excessive cyclic stresses (strains) at the attachment welds be identified and its effects eliminated during future operation.

3.0 SUPPORTING DOCUMENTATION

3.1 Visual Examination

The sample was examined visually using a low magnification stereomicroscope in order to characterize the failure site and to identify any secondary damage that might have caused the failure.

As shown in Figure 4, the failure was a non-ductile crack that followed the toe of the tie-plate attachment weld before progressing in a circumferential direction. The sample was sectioned and split to expose the fracture surface. The majority of the original fracture surface had been damaged as a result of operating for an extended period of time after the failure occurred. Based on the limited remaining evidence, the location and pattern of the fracture would indicate that the crack initiated at the OD surface of the tube at the toe of the tie-plate attachment weld. There was no evidence of any welding defect along the remaining fracture surface. The remaining intact tie-plate attachment welds on the sample were examined and showed no evidence of cracking.

3.2 Chemistry Results

A section of the tubing material was removed from the sample and chemically analyzed to verify that the correct material had been installed. The results of the analysis are presented in Table 1, where it may be seen that the chemical composition of the tubing was consistent with the requirements established by ASME for SA-209, T1 material.

3.4 Metallography

Metallographic specimens were removed from selected locations on the sample so that the macrostructural and microstructural features of the tubing could be evaluated in detail using light microscopy. The approximate locations from where metallographic specimens were taken are indicated in Figures 1 and 4.

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The examination of a cross-section taken from the center of the crack at the leak site is presented in Figure 5. As shown, the fracture was a non-branching, single, crack at the toe of the tie-plate attachment weld. The features of the damage were consistent with fatigue-cracking. In addition, a relatively thick oxide layer was seen along most of the fracture path, which suggested that the cracking had taken a long time to propagate to the point of failure.

The general condition of the macrostructure and microstructure away from the leak site is presented in Figures 6 and 7. As shown, this area contained no evidence of cracking or significant wastage. A microscopic examination of the material structure revealed no signs of microstructural degradation (overheating or creep damage) in any of the areas examined. In fact, the condition of the microstructure was normal for service-exposed SA-209, T1 material.

3.5 <u>Hardness</u>

Hardness measurements were made on a metallographic section using a Vickers Hardness Tester with a 20 kg test load. The results of the hardness measurements are presented in Table 2, where it may be seen that the hardness values for the sample were consistent with the observed microstructure and within the normal and expected range for service-exposed SA-209, T1 material.

If you have any questions pertaining to the information presented in this report, or if I can be of any further assistance in this matter, please feel free to contact me at 423-826-1153.

Author ______________________
Paul VanKooten

Reviewer ______________________
R. L. Miller

Table 1. Chemistry Results

Chemical Composition (Weight Percent)		
ELEMENT	**Sample**	**ASME Specification SA-209,T1**
CARBON	0.14	0.10 - 0.20
MANGANESE	0.54	0.30 - 0.80
PHOSPHORUS	0.007	0.025 (max)
SULFUR	0.016	0.025 (max)
SILICON	0.25	0.10 - 0.50
NICKEL	0.04	***
CHROMIUM	0.08	***
MOLYBDENUM	0.61	0.44 - 0.65
VANADIUM	0.003	***
COLUMBIUM	0.003	***
TITANIUM	0.001	***
COBALT	0.009	***
COPPER	0.05	***
ALUMINUM	0.003	***
BORON	0.0002	***
TUNGSTEN	<0.01	***
ANTIMONY	0.006	***
ARSENIC	0.010	***
TIN	0.005	***
ZIRCONIUM	0.001	***
LEAD	0.001	***
NITROGEN	0.005	***

ASTM-E415-08
2011 Section II, Part A

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Table 2. Hardness Measurements

VICKERS HARDNESS VALUES-HV (HRB)* Vickers hardness tester with a 20-kg test load				
Sample	***Location***	***Average***	***Range***	
			Min.	***Max.***
Micro A	Top Side	117 (66B)	117	118
	Bottom Side	117 (66B)	117	118

* The HRB numbers are approximate values converted from Vickers Hardness readings using the conversion tables in ASTM E140.

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Figure 1. Shown is the sample as it appeared when received by the TTT-M, along with the approximate location from where a metallographic section was taken.

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Figure 2. Shown is the failure site as it appeared prior to sample removal from the boiler.

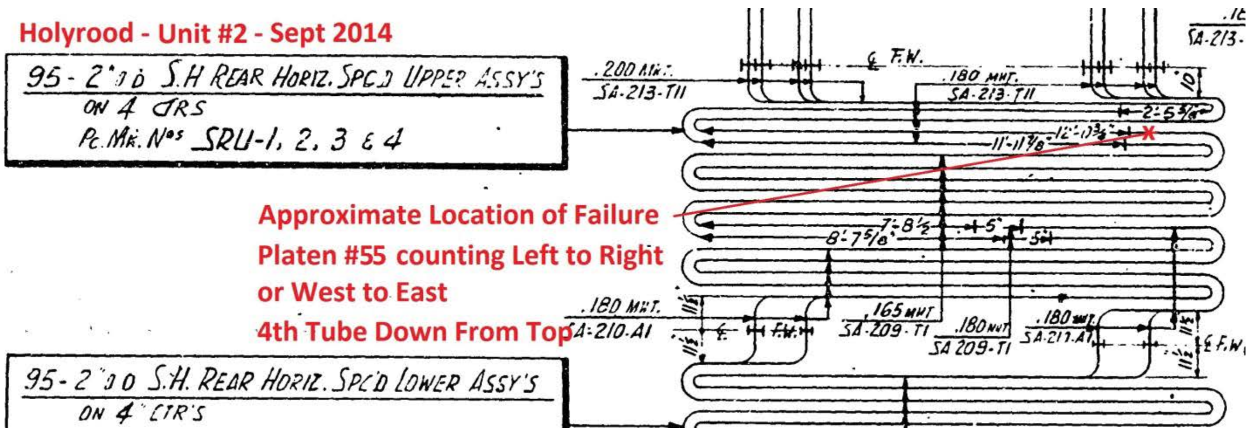
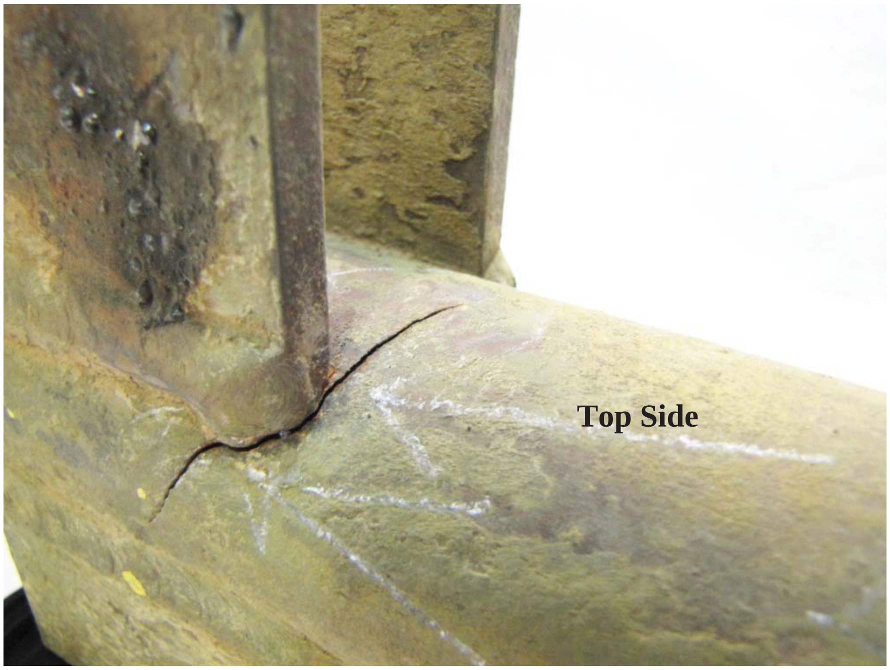


Figure 3. A sketch of the boiler location showing where the sample was taken.



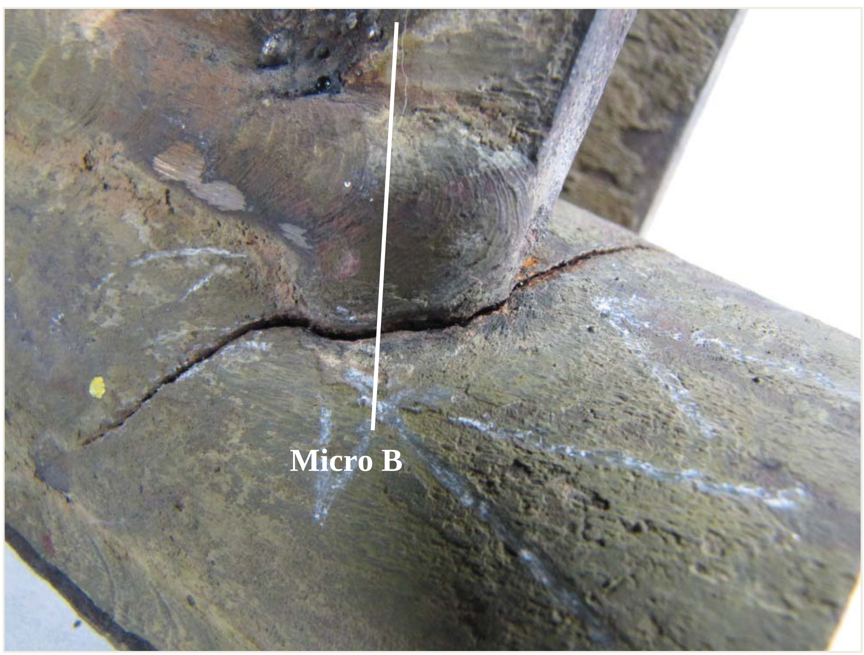


Figure 4. Close-up views of the failure site is shown, along with the approximate location from where a metallographic section was taken.

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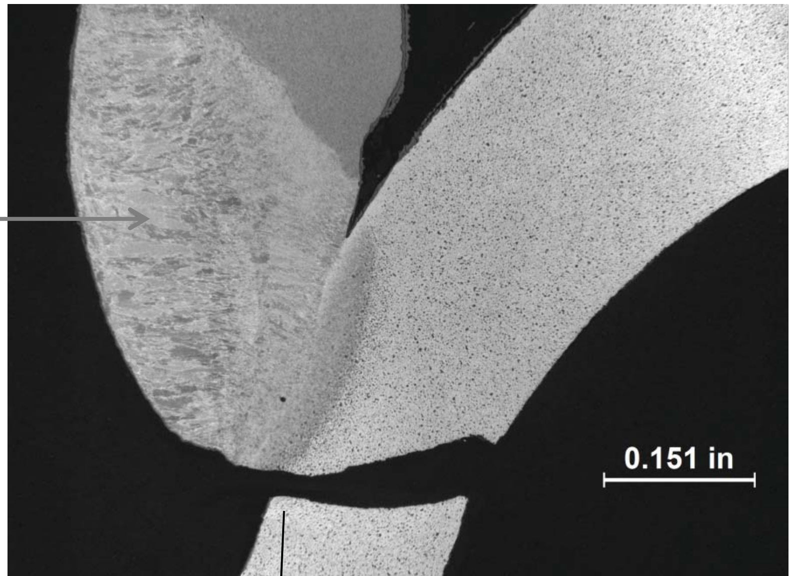
Attachment Weld



Micro B
Nital Etch

Failure site

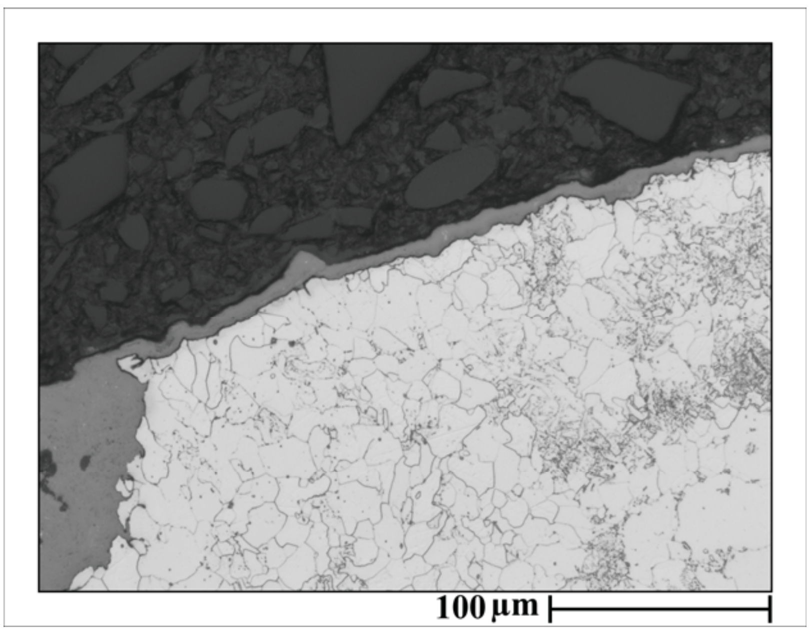
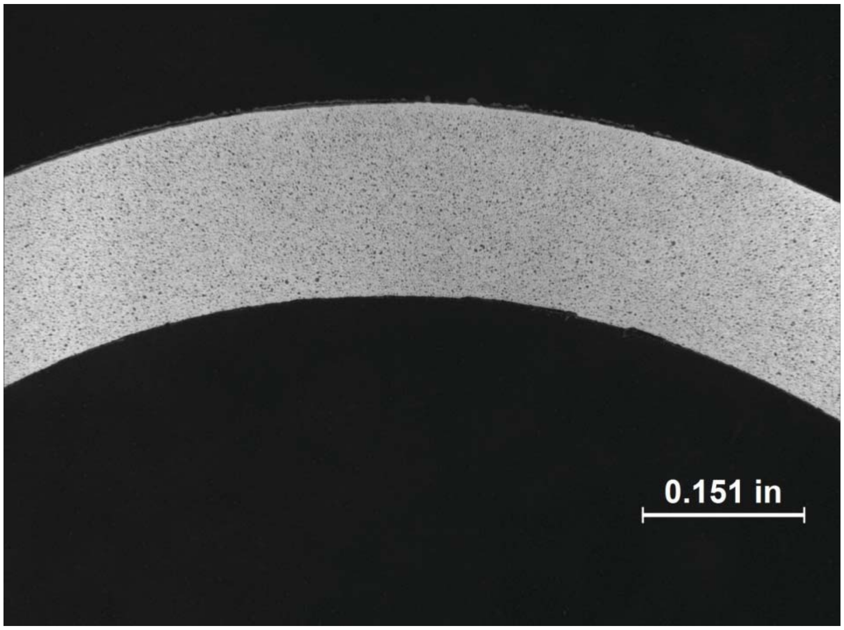
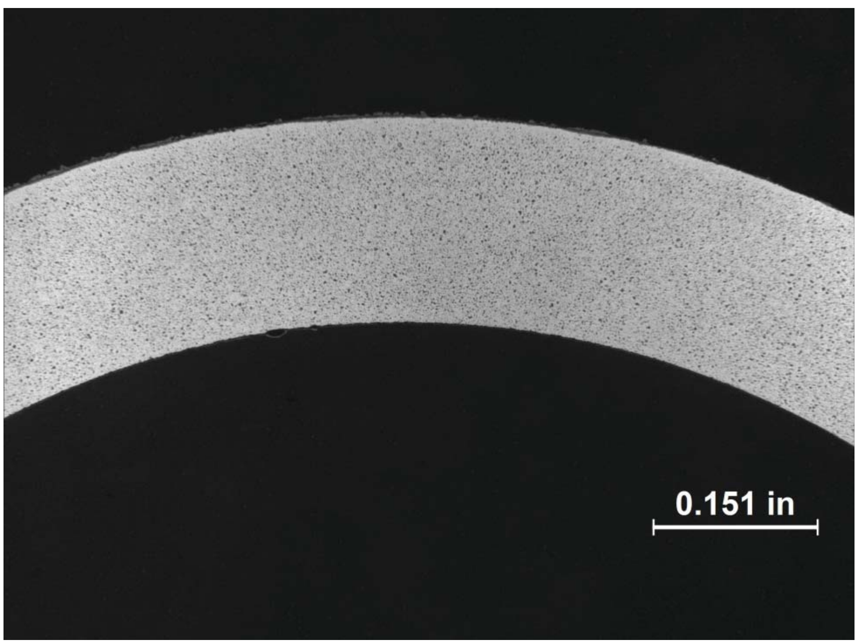


Figure 5. The condition of the macrostructure and microstructure at the failure site is shown.



Micro-A
Nital Etch

Top Side



Micro-A
Nital Etch

Bottom Side

Figure 6. Profiles of the tube wall from the top and bottom sides at the Micro A location are shown.

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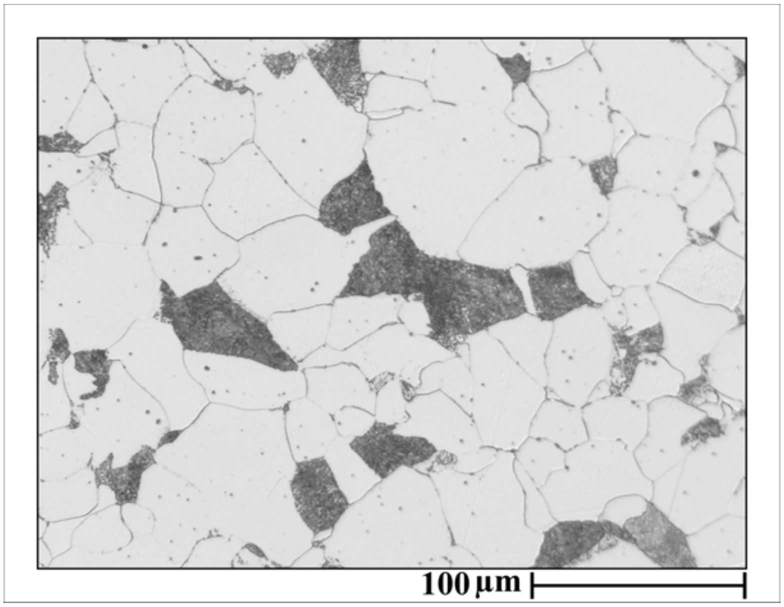
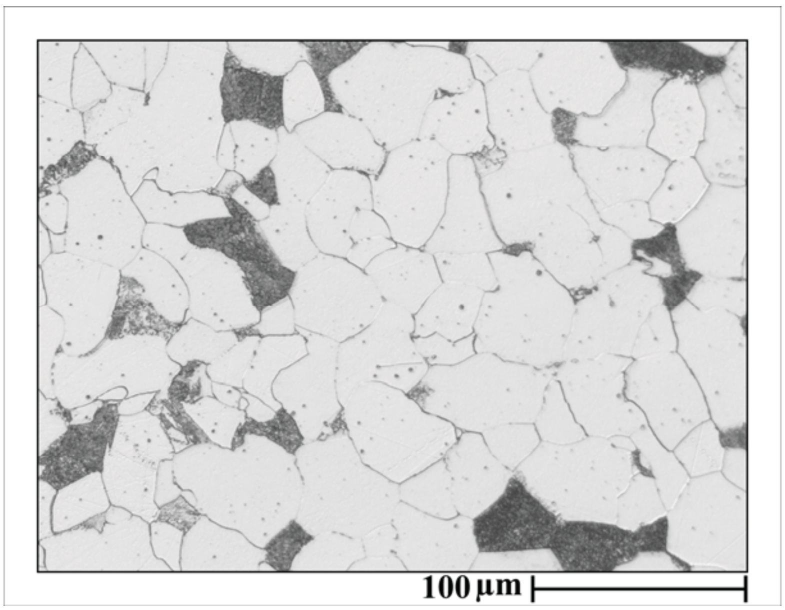


Micro A
Nital Etch

Top Side



Micro A
Nital Etch

Bottom Side

Figure 7. The general condition of the microstructure on the top and bottom sides at the Micro A location is shown.

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WAYLAND ENGINEERING LTD.

FAILURE ANALYSIS OF WATERWALL TUBE #114,
HOLYROOD G.S. UNIT #2

JUNE 2018

Prepared for: Babcock & Wilcox PPG
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Attn: Shaun Lingley, P.Eng.

Prepared by:

REGISTERED PROFESSIONAL ENGINEER
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PROVINCE OF NOVA SCOTIA

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Report No: 1820A
Date: June 28, 2018

1.0 EXECUTIVE SUMMARY

Wayland Engineering Ltd. was asked by Babcock & Wilcox PPG (B & W) to conduct an investigation on a length of waterwall tube (Tube ID #114) from the lower waterwall trough of Unit #2 at the Holyrood generating station. A segment of this tube was removed from service as the result of a leak detected during normal operation of the boiler. It was reported that the elevation of the leak was near the lower sealing skirt assembly. A second length of tube (Tube ID #111) was included for analysis and comparison purposes.

Based on the evidence obtained from this analysis, the mechanism responsible for the leak detected in the waterwall tube #114 is consistent with a cyclic fatigue mechanism. The morphology of the through wall penetration was consistent with crack growth by a corrosion fatigue mechanism. Additionally, there were numerous examples of cracks initiating at the tube external surface and propagating inward. The morphology of these external indications was consistent with thermal fatigue crack growth.

As the names suggest, both these mechanisms (corrosion fatigue and thermal fatigue) are influenced by cyclic or repetitive stresses on the component. The shutdown/start-up thermal cycles sustained by this unit are the most probable source of this repetitive stress. However, the geometry and associated attachments of the tube at the elevation of this leak were more critical in crack initiation and propagation. The presence of the welded sealing skirt limits the lateral movement of these tubes during any start-up/shutdown events; causing localized, elevated stresses at this elevation. The presence of the welded web between the waterwall tubes results in a relative increase of tube stiffness above the weld; imposing elevated cyclic stresses over the non-stiffened tube length during the normal thermal cycling of the unit. The presence of the circumferential weld at this location can also contribute to elevated stresses; the change in geometry associated with a weld is a common stress raiser. It was noted that all the indications observed initiated at either the toe or root of the circumferential weld.

Although the recent “flashing operation” of this unit could contribute to the thermally generated cyclic stresses at the tube to seal weld joint, the evidence suggests that the cracks have been propagating by these mechanisms for a significant period of time. There is no evidence to suggest that these cracks are solely the result of recent operation parameters.

Examination of cross sectional views of the circumferential weld of Tube #111 found no appreciable evidence of any corrosion fatigue on the internal surface or thermal fatigue on the external surface. While the absence of any appreciable cyclic damage at the circumferential weld of Tube ID#111 suggests that the damage may not be widespread, it is possible that other neighbouring tubes have partial through wall cracks; internal and/or external.

2.0 INTRODUCTION

Wayland Engineering Ltd. was asked by Babcock & Wilcox PPG (B & W) to conduct an investigation on a length of waterwall tube (Tube ID #114) from the lower waterwall trough of Unit #2 at the Holyrood generating station. A segment of this tube was removed from service on June 12, 2018 as the result of a leak detected during normal operation of the boiler [1]. It was reported that the elevation of the leak was near the lower sealing skirt assembly. A second length of tube (Tube ID #111) removed at this time was included for analysis and comparison purposes.

During normal operation at the elevation of the leak detected, the internal environment of the tube was reported to consist of treated boiler feed water (BFW) [2]. The temperature and pressure of the internal fluid were reported as approximately 628^{o}F and 1900psig, respectively [2]. It has been indicated that the section of tube provided for analysis was installed in 1970 (an original component of the boiler) and had been subjected to approximately 210,000 cumulative hours of service [2]. The specification for the tube material was reported as ASTM A210, Grade A-1 [2].

It has also been indicated that during the service life, this tube has experienced approximately 275 unit shutdown/start-up cycles [2]. In the last month of operation, Unit #2 was subject to "flashing" which increased the frequency of the shutdown/start-up thermal cycles to every 2-5 days [1].

B & W requested that Wayland Engineering provide an opinion on the mechanism(s) responsible for the leak detected in the section of tube provided for analysis.

3.0 EXAMINATION & RESULTS

3.1 Tube #114

Both tubes are shown in the as received condition in Figure 1. The tube segments were approximately 48” in length. The deposits on the external surfaces were characterized by a relatively thick, relatively loose layer with a “reddish-brown” coloration. Figure 2 is a close-up view highlighting the external surface of tube #114 at the leak. Numerous through wall penetrations were observed. As highlighted in Figure 2, the leaks were adjacent two geometric features of note; 1) the lower termination of the web weld between waterwall tubes, and 2) the fillet weld between the tube and the sealing skirt plate. A schematic view of the crack location within the boiler is shown in Figure 3.

The tubes were sectioned to allow visual assessment of the tube internal surface. The deposits on the internal surface were characterized by a relatively thin, uniform layer with a “brownish” coloration. Figure 4 shows a general view of the internal surface at the leak location. It was noted that the leak coincided with a circumferential weld. As evident in Figure 4, there was minor pitting on the internal surface of the tube above the circumferential weld (as oriented in the boiler). The pits were discrete and randomly dispersed. Pit depth measurements reported a maximum depth of 0.02” There was no appreciable pitting on the internal surface of the tube below the circumferential weld.

Several sections were removed from the cold side of the tube; adjacent and through the leaks, and prepared for metallographic analysis using light microscopy. Figure 5 contains micrographs of typical microstructures observed for the cold side tube material above and below the circumferential weld. The metallurgical condition of both tubes consisted of a banded microstructure with well defined pearlite colonies in a ferrite matrix. Both microstructures were consistent with an ASTM A210, Grade A1 material specification.

A cross sectional micrograph of a through hole leak are shown in Figure 6. There was an appreciable corrosion layer on the fracture surface. In addition, evidence of the remnants of secondary or occluded pits containing a corrosion deposit layer were observed, particularly toward the internal tube surface; Figure 7. At cross sectional views adjacent the leaks, there was evidence of deep, V-shaped, corrosion filled cracks originating at the external tube surface, Figure 8. All cracks observed coincided with the fusion line of the circumferential weld, either at the weld cap or the weld root.

The sections were then examined by scanning electron microscope (SEM). Figure 9 shows a cross sectional view SEM backscatter image of the through-wall leak at the tube internal surface. To determine the general composition of the corrosion deposit at the tube material interface, the samples were subjected to energy dispersive X-ray spectroscopy (EDS) elemental analyses. This focused primarily on the secondary pits associated with both the main leak and with the partial through wall cracks originating at the internal tube surface. The results of the analyses (Table 1) indicated that for the majority of the positions, the corrosion layer was comprised primarily of Fe and O (i.e. iron oxide) with small amounts of sulphur. At some pits there was trace amounts of chlorine while at one of the pits, there was evidence of sodium, magnesium, potassium, and calcium.

Hardness testing was conducted for both tube materials. The results of the testing indicated that the average bulk hardnesses were 162 HB & 146 HB; consistent with that expected for an ASTM A210, Grade A1 material based on the minimum tensile strength associated with the specification.

3.2 Tube #111

This tube was adjacent the failed tube and had a circumferential weld at the same elevation; near the lower termination of the web weld between adjacent waterwall tubes, and just below the fillet weld between the tube and the sealing skirt plate. The tube was sectioned on either side of the circumferential weld, Figure 10. The deposits on the internal surface were characterized by a relatively thin, uniform layer with a "brownish" coloration. As with the failed tube, there was pitting on the internal surface of the tube above the circumferential weld (as oriented in the boiler) but it was more prevalent on this tube. Again, the pits were discrete and randomly dispersed with a maximum measured pit depth of 0.03". There was no appreciable pitting on the internal surface of the tube below the circumferential weld.

Several sections were removed from the cold side of this tube through the circumferential weld and prepared for metallographic analysis. Figure 11 contains micrographs of typical microstructures observed for the cold side tube material above and below the circumferential weld. The metallurgical condition of both tubes consisted of a banded microstructure with well defined pearlite colonies in a ferrite matrix, consistent with an ASTM A210, Grade A1 material specification. Hardness testing of both tube materials gave average bulk hardnesses of 163 HB & 145 HB; typical for this alloy.

Examination of numerous cross sections found no evidence of the initiation of any cracks at the weld fusion lines. There was no evidence of any corrosion fatigue damage initiating at the interior, Figure 12; nor was there evidence of any thermal fatigue cracking initiating at the tube exterior surface, Figure 13.

4.0 DISCUSSION

The physical, chemical and microstructural evidence indicates that the mechanism responsible for the leak detected in the waterwall tube (Tube #114) from Unit #2 of Holyrood G.S submitted for analysis is consistent with a cyclic fatigue mechanism. Examination of the through wall penetration indicates that cracking initiated on the internal surface of the tube and propagated towards the external surface. The evidence of secondary corrosion pits observed at sites along the main propagation path is consistent with crack growth by a corrosion fatigue mechanism. There were also numerous examples of cracks initiating at the tube external surface and propagating inward. The deep, singular, V-shaped morphology of these external indications was consistent with thermal fatigue crack growth.

As the names suggest, both these mechanisms (corrosion fatigue and thermal fatigue) are influenced by cyclic or repetitive stresses on the component. The reported frequency of shutdown/start-up thermal cycles sustained by this unit are the most probable source of this repetitive stress. However, the geometry and associated attachments of the tube at the elevation of this leak likely played a more critical role in crack initiation and propagation. The presence of the welded sealing skirt limits the lateral movement of these tubes during any start-up/shutdown events; causing localized, elevated stresses at this elevation. In addition, the presence of the welded web between the waterwall tubes results in an increase of stiffness along the tube length. The relative stiffness of the tubes is lower below this web weld. Thus, any thermal expansion/contraction of the stiffened seal/tube interval may impose elevated cyclic stresses over the non-stiffened tube interval during the normal thermal cycling of the unit. The presence of the circumferential weld at this location can also contribute to elevated stresses. Although there were no defects observed, (i.e. lack of fusion, undercut, or poor root penetration), the change in geometry associated with a weld is a common stress raiser. It was noted that all the indications observed initiated at either the toe or root of the circumferential weld.

Although the recent "flashing operation" of this unit could contribute to the thermally generated cyclic stresses at the tube to seal weld joint, the evidence suggests that the cracks have been propagating by these mechanisms for a significant period of time. There is no evidence to suggest that these cracks are solely the result of recent operation parameters.

Examination of cross sectional views of the circumferential weld of Tube #111 found no appreciable evidence of any corrosion fatigue on the internal surface or thermal fatigue on the external surface. While the absence of any appreciable cyclic damage at the circumferential weld of Tube ID#111 suggests that the damage may not be widespread, it is possible that other neighbouring tubes have partial through wall cracks; internal and/or external.

The SEM EDS analyses conducted reported the presence of minor amounts of contaminant elements in the corrosion deposits within the cracks. Sulphur may be present due to the water treatment chemicals normally employed. Contaminants such as Cl, Mg, Na, & K can accelerate the corrosion fatigue mechanism, but their presence is not a necessity. Based on the minor amounts of these elements detected in the crack deposit, it is probable that they are not present due to recent operation conditions.

References:

[1] Email, S. Lingley, B&W, May 23, 2018.
[2] Email, S. Lingley, B&W, June 28, 2018.

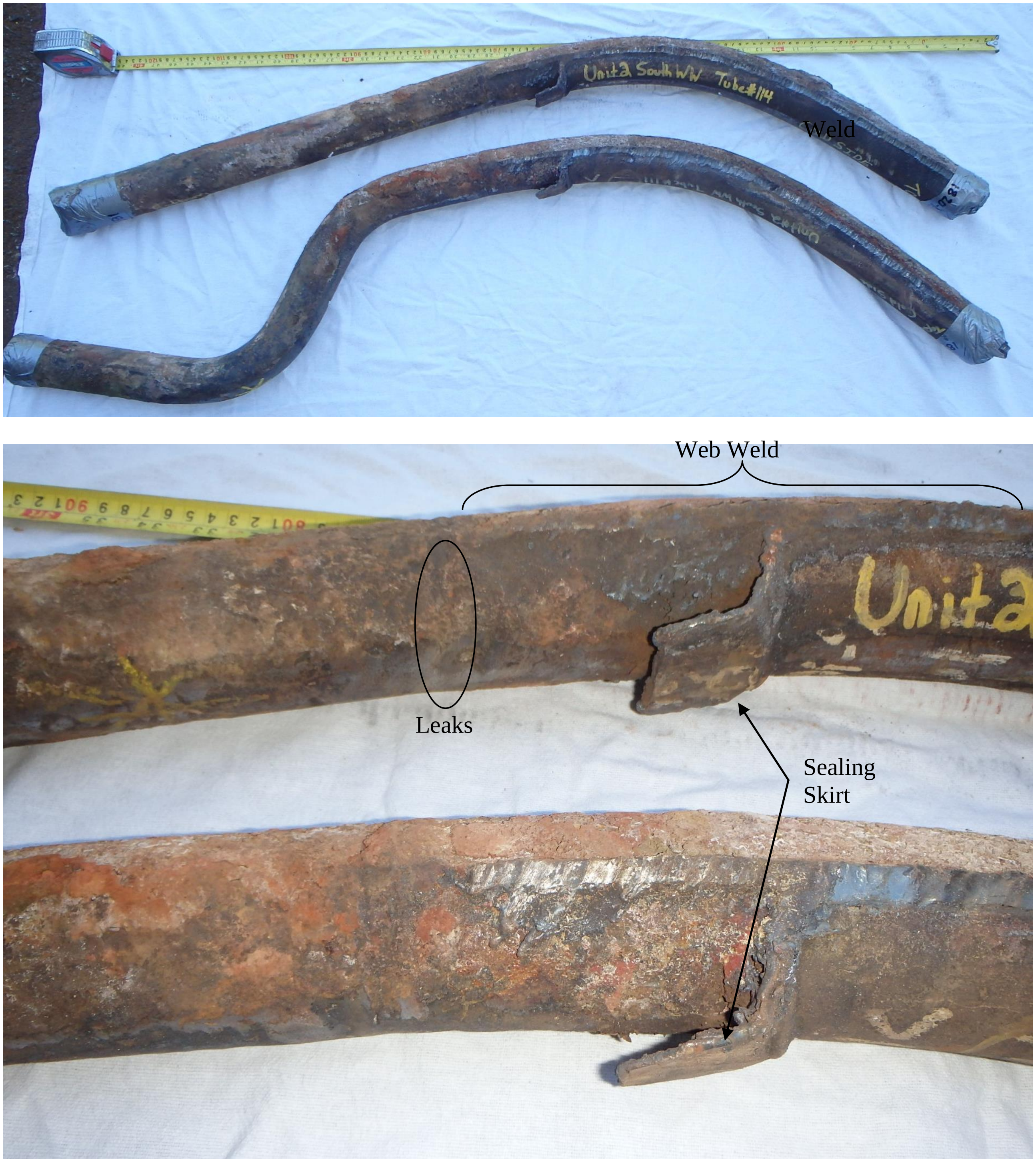

Figure 1: Tubes #111 & #114 In the As-Received Condition. Lower View Highlights Relationship Between Through Wall Perforations and Web Weld & Sealing Skirt.

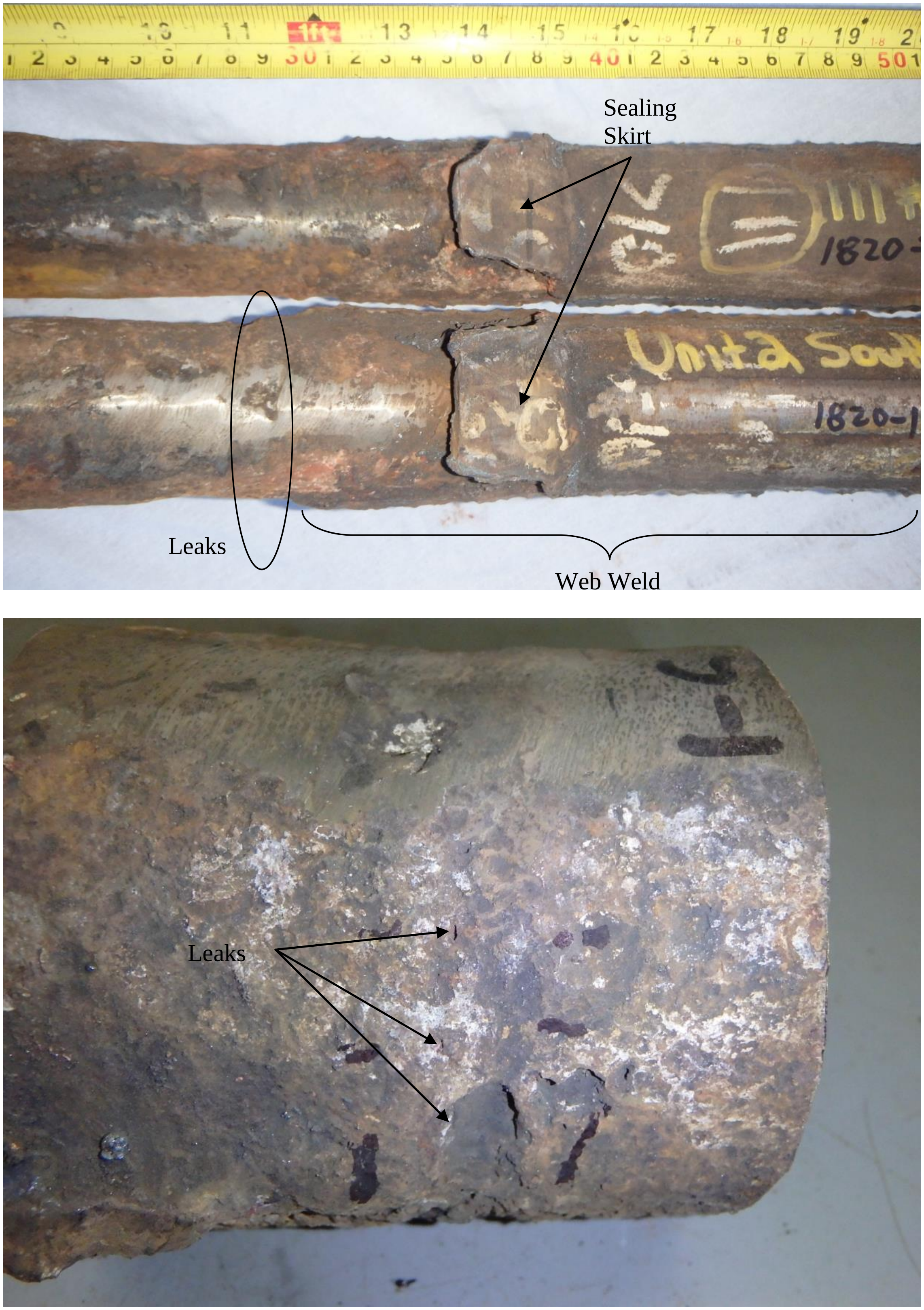

Figure 2: Close Up External Views of Through Wall Perforations on Tube #114

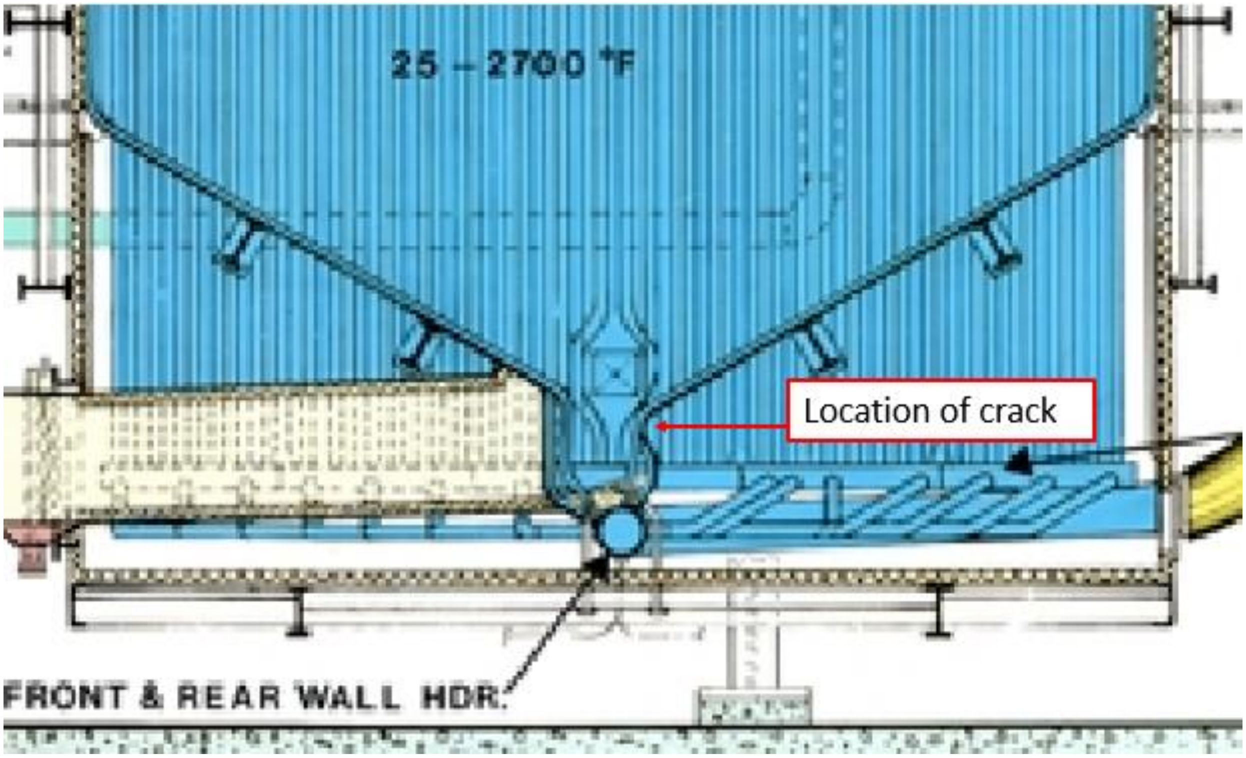

Figure 3: Schematic View Showing Orientation of Leak in Boiler.

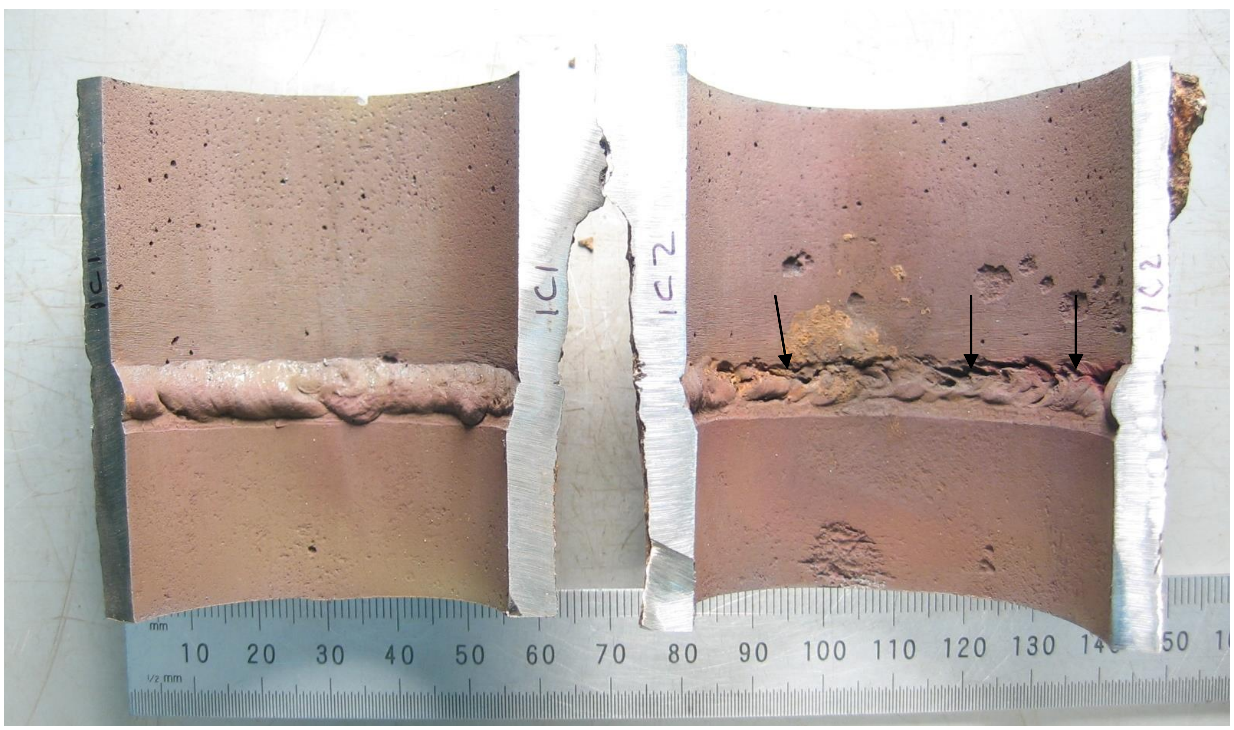

Figure 4: View of Internal Surfaces of Tube #114 Showing Leaks (Arrows) Coinciding with Circumferential Weld. Internal Pitting of Tube Segment Above Circ. Weld Was Noted.

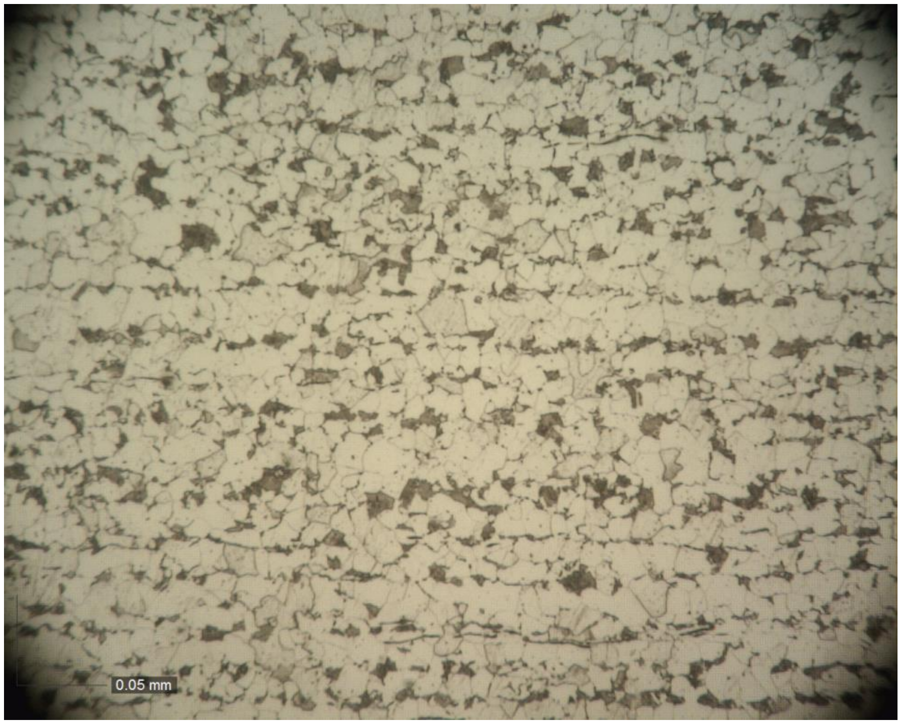

Figure 5(a): Microstructure of Tube #114 Segment Above Circ. Weld Consists of Banded Pearlite (Dark Regions) in a Ferrite Matrix.

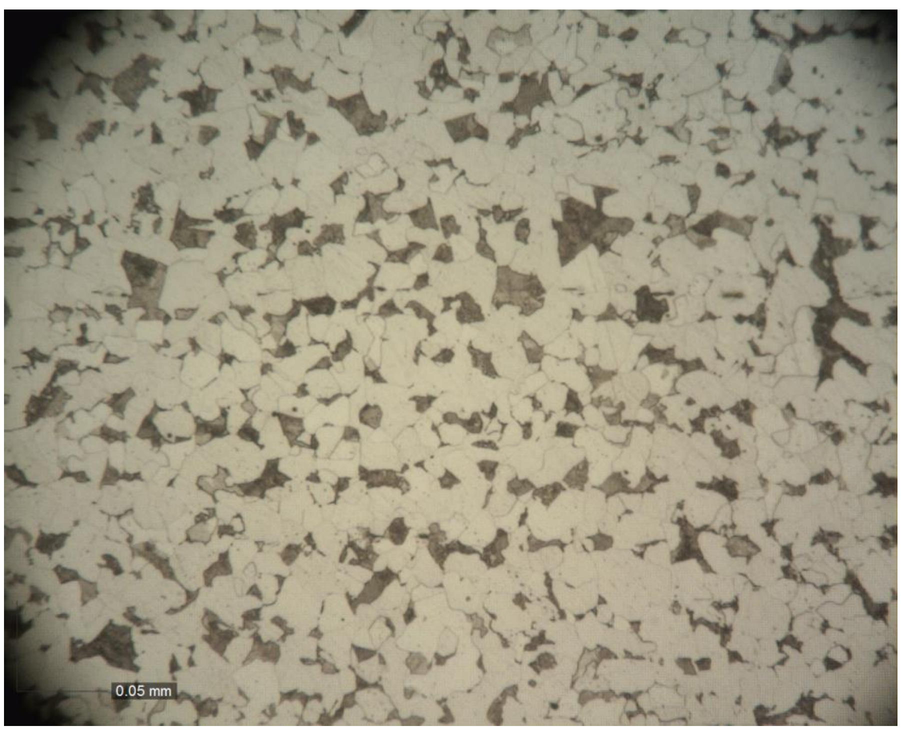

Figure 5(b): Microstructure of Tube #114 Segment Below Circ. Weld Consists of Banded Pearlite in a Ferrite Matrix.

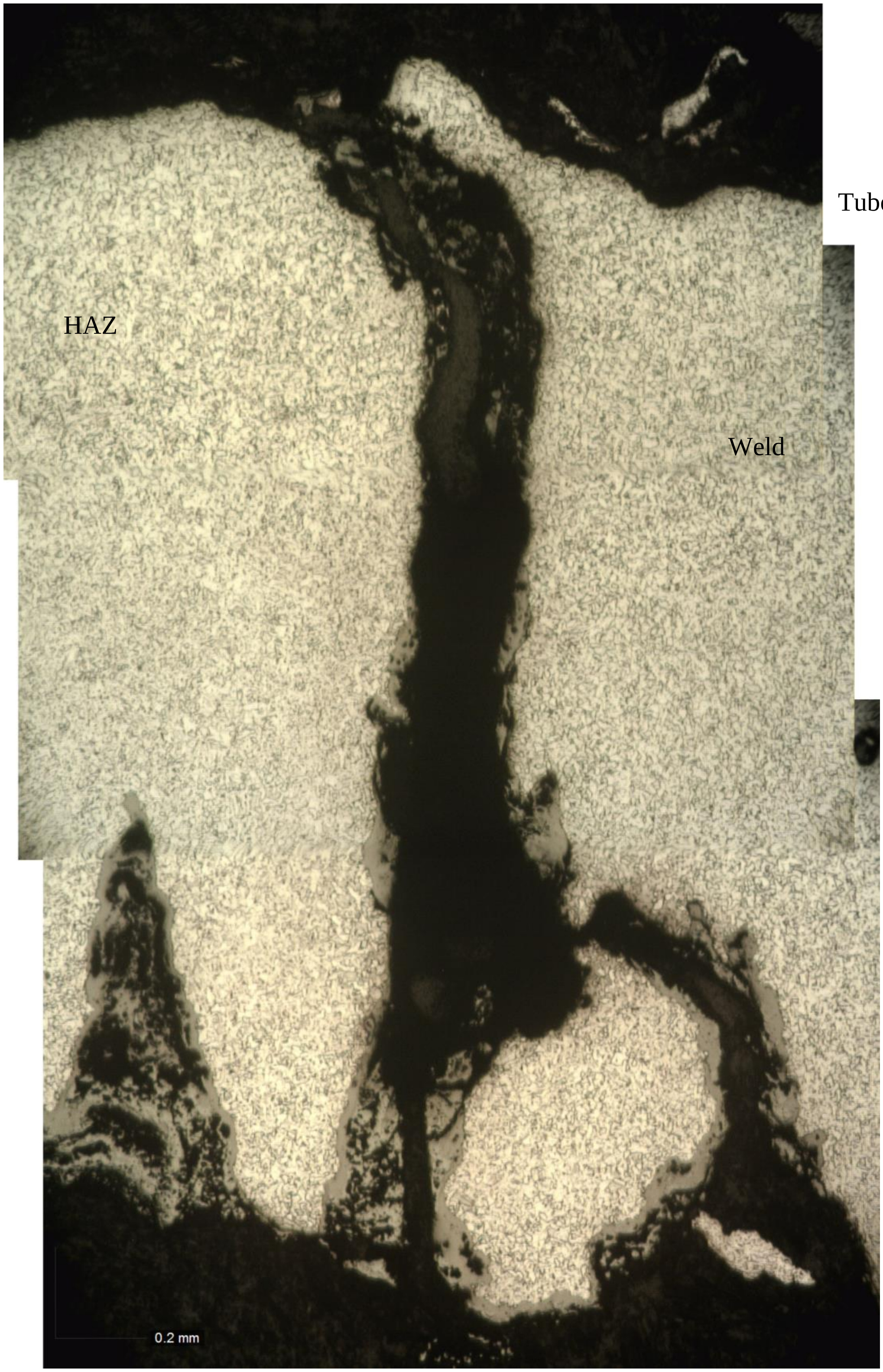

Figure 6: Cross Sectional View of Through Wall Perforation. Crack Appears to originate at Internal Surface and Propagate Through to the Exterior. There is An Appreciable Layer of Corrosion Along the Length of the Crack Fracture Face.

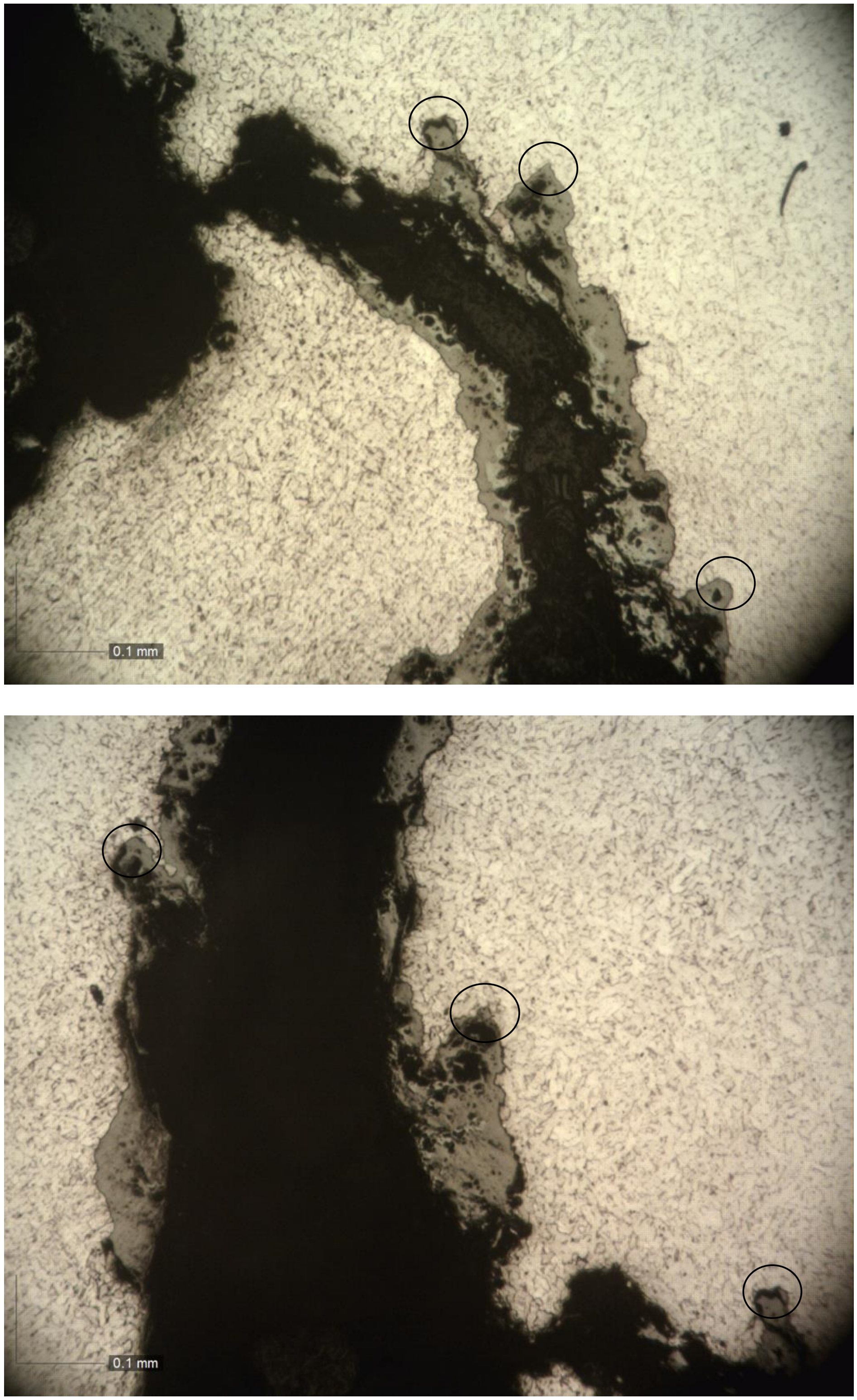

Figure 7: Numerous Secondary or Occluded Pits (Circled) Were Associated with The Crack Near the Internal Surface.

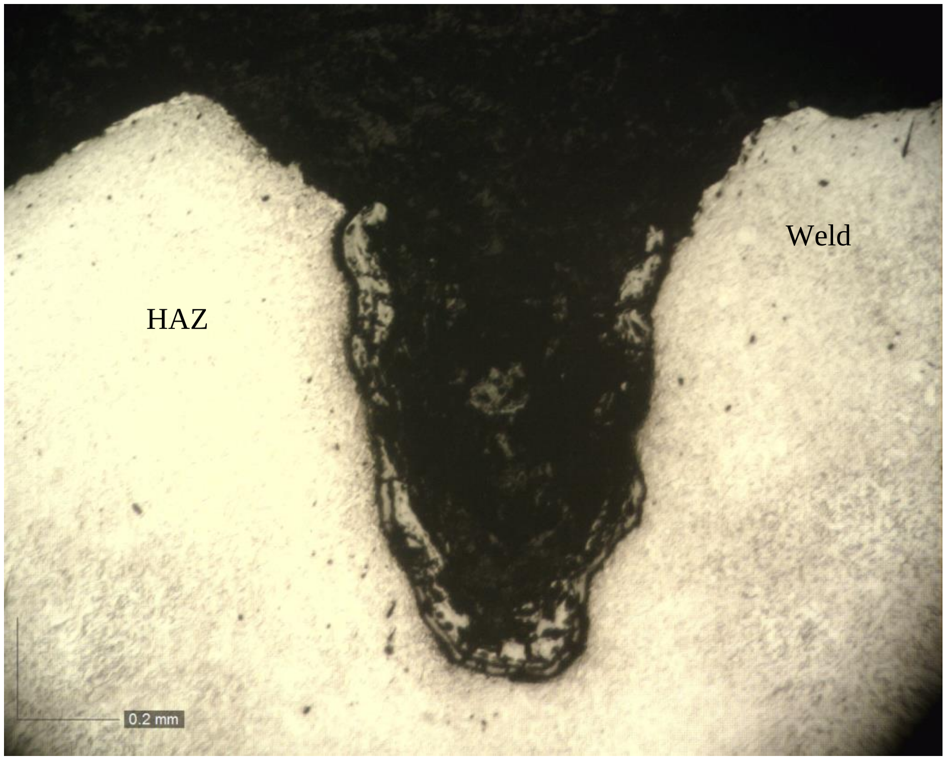

Figure 8: Deep, V-Shaped Cracks Were Observed Originating at the Weld Toe at The External Surface. These Were Filled with Corrosion Deposit.

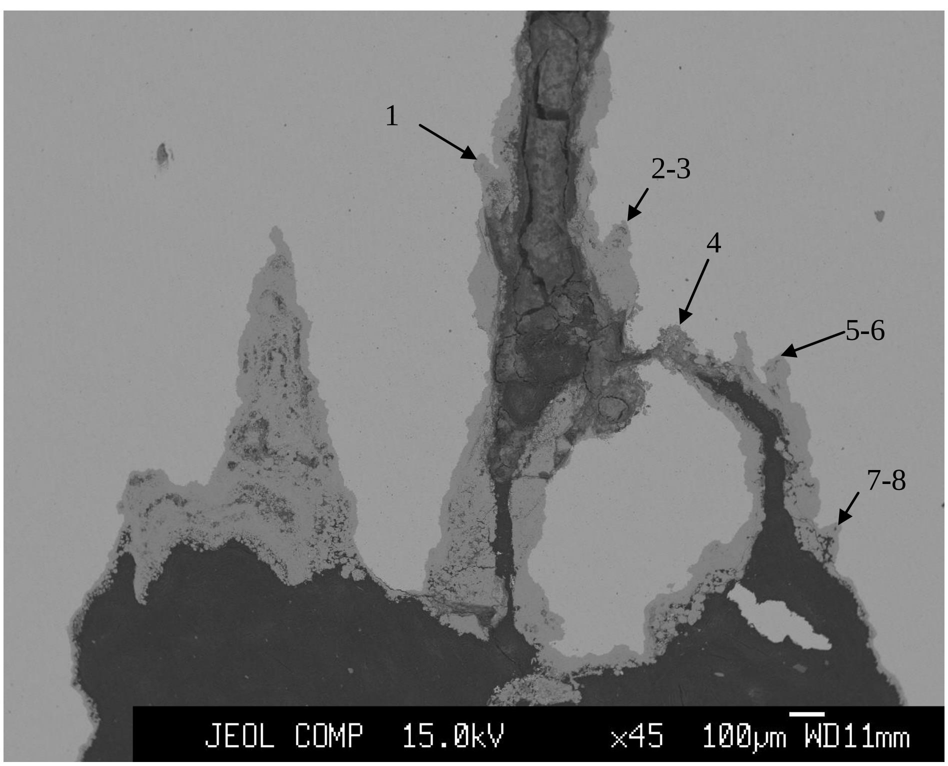

Figure 9: SEM Compositional View of Crack Origin at Internal Tube Surface. Secondary Corrosion Pitting Where EDS Analysis of Deposit Was Performed is Highlighted.

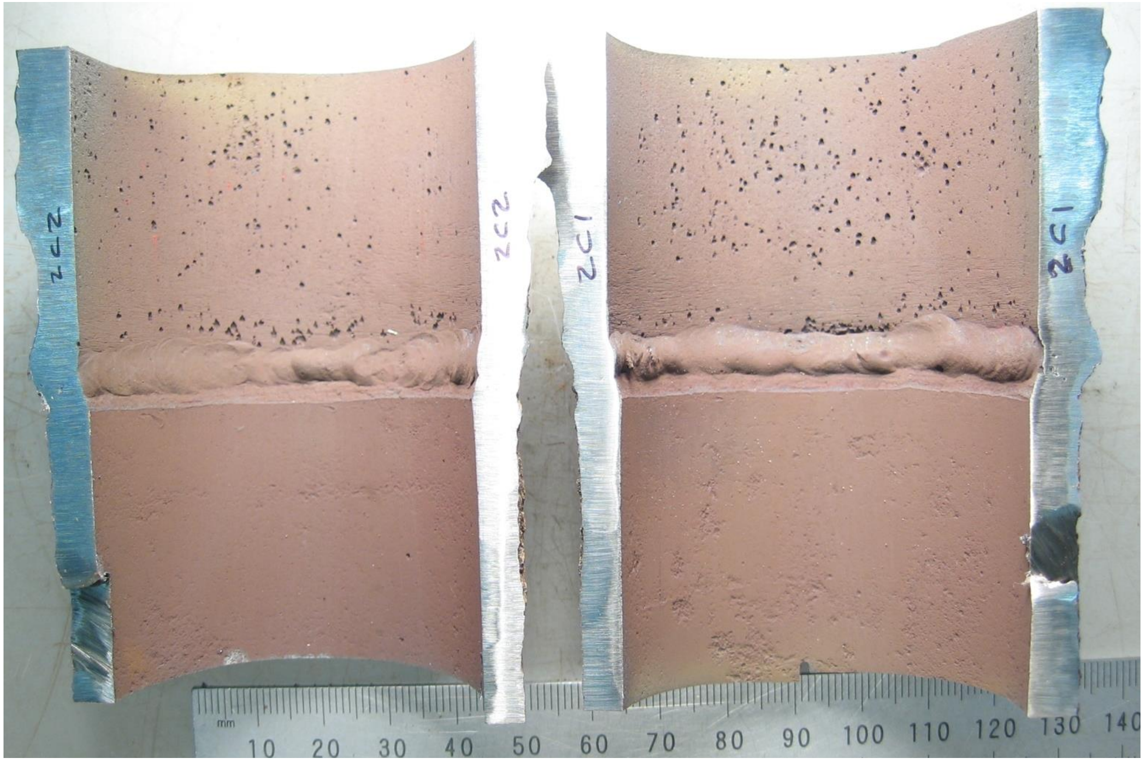

Figure 10: View of Internal Surface of Tube #111. Appreciable Internal Pitting of Tube Segment Above Circ. Weld Was Noted.

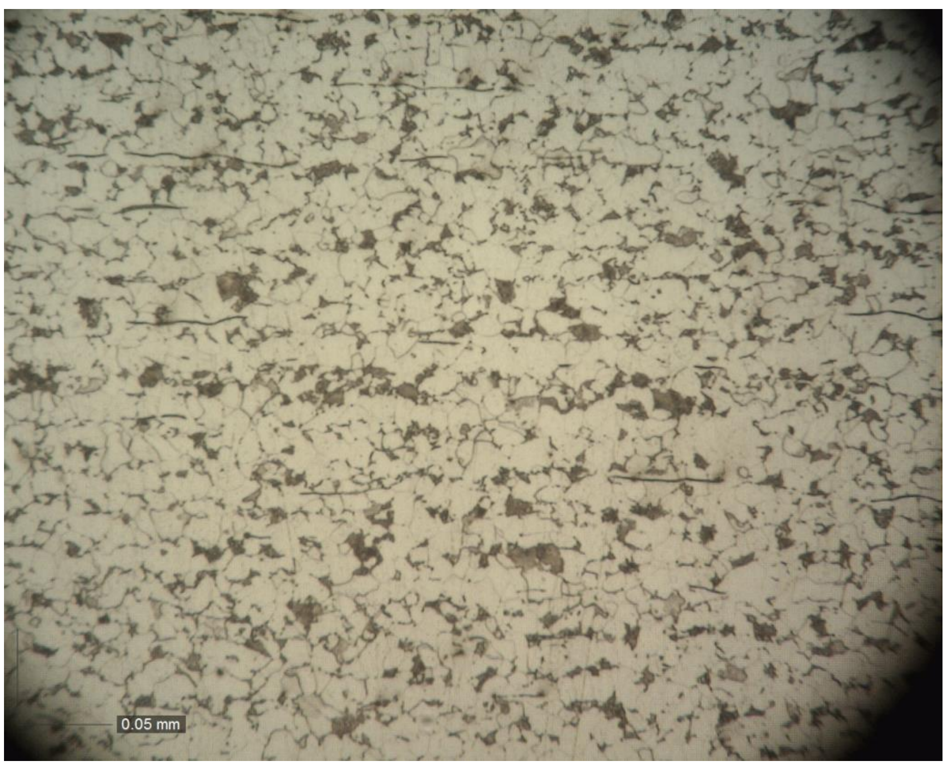

Figure 11(a): Microstructure of Tube #111 Segment Above Circ. Weld Consists of Banded Pearlite (Dark Regions) in a Ferrite Matrix.

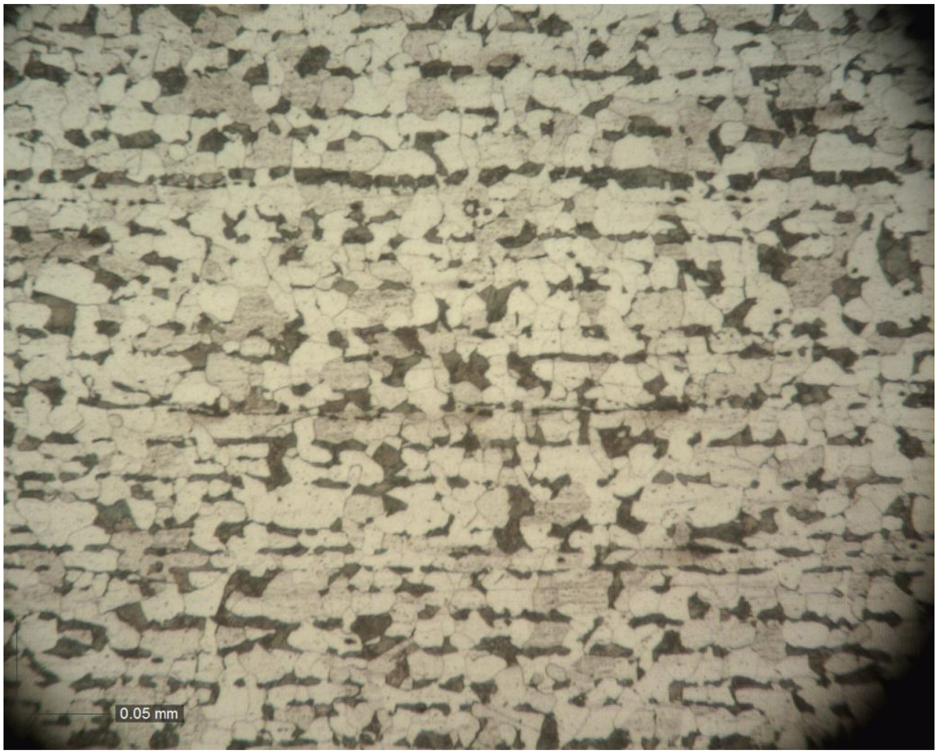

Figure 11(b): Microstructure of Tube #111 Segment Below Circ. Weld Consists of Banded Pearlite (Dark Regions) in a Ferrite Matrix.

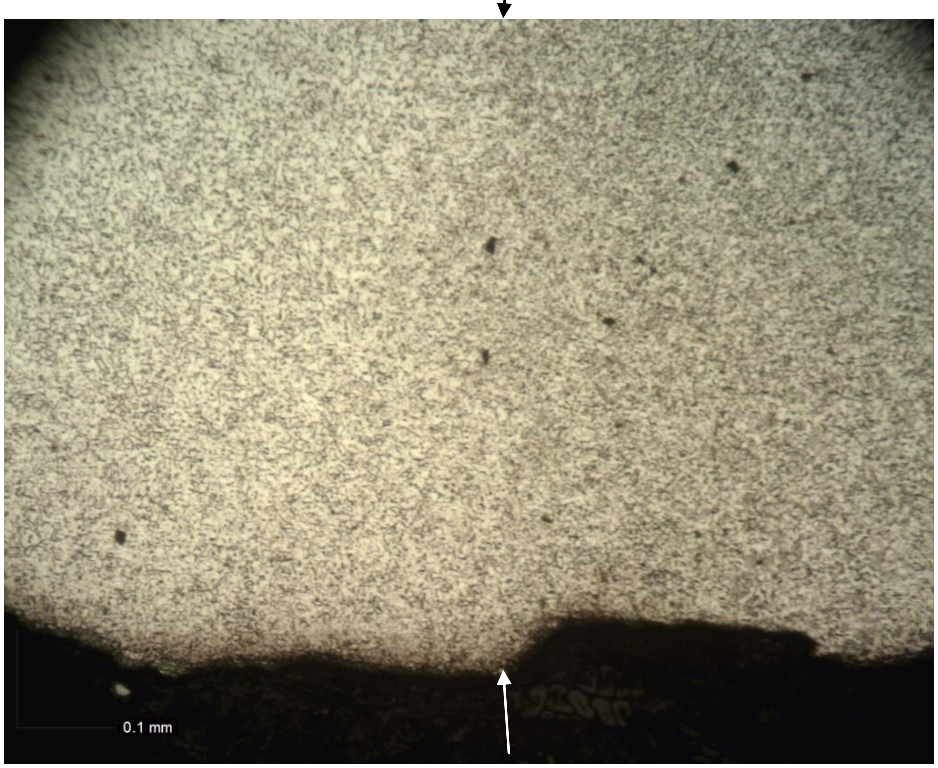

Figure 12: Cross Sectional View of Tube #111 Typical of Interior Surface at Weld Root. Arrows Indicate Fusion Line with Weld on Left Side. No Evidence of Corrosion Fatigue Cracking Was Observed.

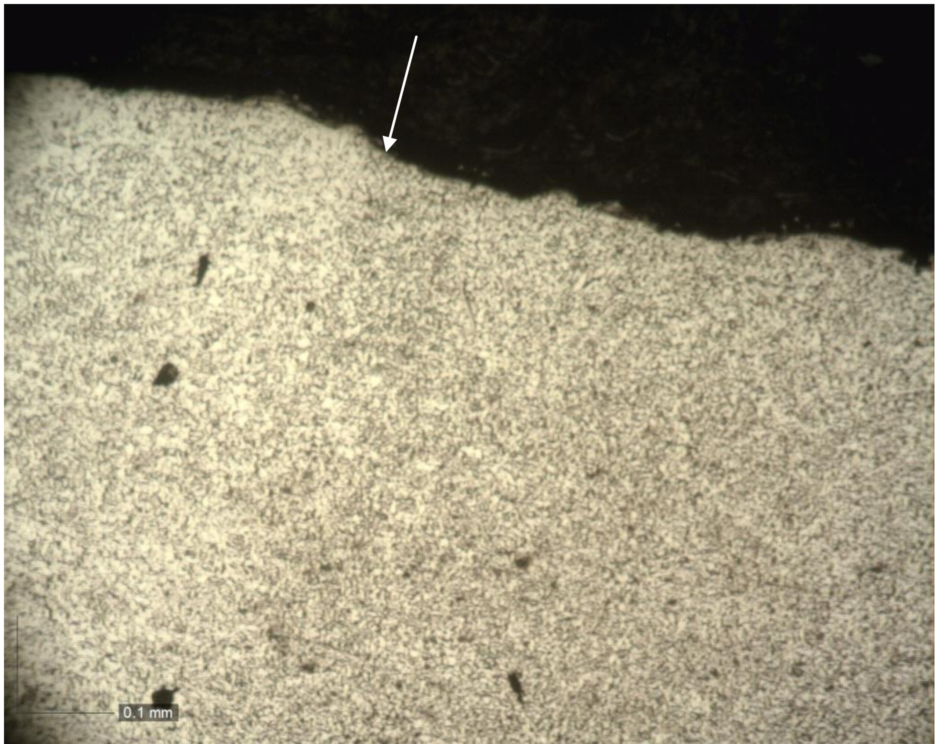

Figure 13: Cross Sectional View of Tube #111 Typical of Exterior Surface at Weld Crown. Arrows Indicate Fusion Line with Weld on Left Side. No Evidence of Thermal Fatigue Cracking Was Observed.

	Interior Loc 1	Interior Loc 2	Interior Loc 3	Interior Loc 4	Interior Loc 5	Interior Loc 6	Interior Loc 7	Interior Loc 8	Exterior Loc 1
C	1.8								
N	7.7		5.6						
O	25.3	14.6	18.2	10.7	25.1	19.5	23.4	18.2	25.5
Na	0.1				2.1	1.6	1.8		
Mg					0.3	0.1	0.2		
Al	0.4				0.1	0.1		0.4	0.3
Si	0.2		0.2		0.2	0.1	0.2	0.6	0.6
P	0.7								
S	0.8	0.3	0.4	0.5	0.5	0.5	0.5	1.8	2.4
Cl		0.1	0.1					0.1	0.2
K					0.4	0.4	0.4		
Ca					0.2	0.3	0.3		
Mn				1		0.6		1	
Fe	63	84.2	74.5	86.2	69	74.5	70.9	77.1	71
Cu		0.8	0.9	1.6	2	2.4	2.2	0.9	

Table 1: Results of SEM-EDS Chemical Analysis of Deposit in Secondary Pits Identified in Figure 9.

WAYLAND ENGINEERING LTD.

FAILURE ANALYSIS OF WATERWALL TUBE
HOLYROOD G.S. UNIT #3

OCTOBER 2018

Prepared for: Babcock & Wilcox PPG
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Prepared by:

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Report No: 1842A
Date: February 1, 2019

1.0 EXECUTIVE SUMMARY

Wayland Engineering Ltd. was asked by Babcock & Wilcox PPG (B & W) to conduct an investigation on a length of waterwall Tube #1 from the east wall of Unit #3 at the Holyrood generating station. A segment of this tube was removed from service as the result of a leak detected during normal operation of the boiler. The leak was identified as being at elevation 30' 7"; coincident with the lower sealing skirt assembly at the south east windbox.

Based on the evidence obtained from this analysis, the mechanism responsible for the leak detected in this waterwall tube is consistent with a cyclic fatigue mechanism. Multiple cracks were observed in the region of the leak. Cracks were observed originating at both the tube internal and external surfaces. The morphology of the cracks originating at the tube internal was consistent with crack growth by a corrosion fatigue mechanism. The morphology of the crack initiating at the tube external surface was consistent with fatigue crack growth. There was also a fatigue crack propagating through the filler block. This initiated at the root of the fillet weld to the seal skirt.

Both these mechanisms (corrosion fatigue and fatigue) are influenced by cyclic or repetitive stresses on the component. The shutdown/start-up thermal cycles sustained by this unit are the most probable source of this repetitive stress. However, the geometry and associated attachments to the tube at the elevation of this leak were more critical in crack initiation and propagation. The filler block between the tubes influences the diametrical expansion of the tube during these thermal events. Also, the presence of the welded sealing skirt limits the lateral movement of these tubes during any start-up/shutdown events; again resulting in localized, elevated stresses at this elevation. It was noted that all the external indications observed initiated at the root of a fillet weld. Changes in geometry at these welds are stress raisers which promote preferential sites for the initiation and propagation of fatigue cracks

2.0 INTRODUCTION

Wayland Engineering Ltd. was asked by Babcock & Wilcox PPG (B & W) to conduct an investigation on a length of waterwall tube from Unit #3 at the Holyrood generating station. The tube was identified as Tube #1 on the east wall in the south east corner of the unit [1]. A segment of this tube was removed from service on November 16, 2018 as the result of a leak detected during normal operation of the boiler [1]. It was reported that the elevation of the leak (30' 7") was coincident with the lower sealing skirt assembly.

During normal operation at the elevation of the leak, the internal environment of the tube was reported to consist of treated boiler feed water (BFW). The temperature and pressure of the internal fluid were reported as approximately 638^{o}F and 2002psig, respectively [1]. It has been indicated that the section of tube provided for analysis was installed in 1979 (an original component of the boiler) and had been subjected to approximately 164,000 cumulative hours of service [1]. The specification for the tube material was reported as ASTM A210, Grade A-1 [1]. It has also been indicated that during the service life, this tube has experienced approximately 150 unit shutdown/start-up cycles [1].

B & W requested that Wayland Engineering provide an opinion on the mechanism(s) responsible for the leak detected in the section of tube provided for analysis.

3.0 EXAMINATION & RESULTS

The tube is shown in the as received condition in Figure 1. The tube segment was approximately 15” in length. In addition to the membrane between adjacent tubes, there were segmented strips of plate shaped to fit between neighbouring tubes; referred to as filler blocks. These were welded in place to provide a continuous flat landing to facilitate attachment of the sealing skirt. The sealing skirt was welded across the crown of the tubes and the filler block with a fillet weld. The deposits on the external surfaces were characterized by a relatively thick, loose layer with a “whitish” coloration on the hot side and a thin, tenacious, reddish-brown layer on the cold side. Figure 2 is a close-up view highlighting the cold side external surface where the leak was reported. No obvious through wall penetration was observed. As highlighted in Figure 2, the leak was identified as being at the fillet weld between the cold side of the tube (at the filler block) and the horizontal sealing skirt.

The tube was sectioned to allow a visual assessment of the tube internal surface. The deposits on the internal surface were characterized by a relatively thin, uniform layer with a brownish coloration. Figure 3 shows a general view of the internal tube surface. As evident in Figure 3, there were numerous longitudinal indications on the internal surface, grouped primarily at the intersection of the filler block and sealing skirt on the cold side where the leak was observed. Needle gauge measurements reported a maximum depth of 0.05” There was no appreciable degradation or pitting on the hot side of the tube internal surface or away from the leak on the cold side.

Several sections were removed from the cold side of the tube adjacent to the leak location and prepared for metallographic analysis using light microscopy. Figure 4 contains micrographs of typical microstructures observed for the hot & cold side tube material. The metallurgical condition of both the hot and cold sides of the tube consisted of well-defined pearlite colonies in a ferrite matrix; consistent with an ASTM A210, Grade A1 material specification. Hardness testing conducted on the hot and cold sides of the tube indicated average bulk hardnesses values of 163 HB & 170 HB, respectively. These values are consistent with that expected for an ASTM A210, Grade A1 material based on the minimum tensile strength associated with the specification.

A cross sectional view through the fillet weld between the tube wall and the filler block (near the leak) is shown in Figure 5. There were numerous radial indications propagating from the internal surface of the tube. Some of the indications extended ~50% across the tube wall thickness. Microscopic views of typical indications are shown in Figure 6. Many of these indications varied in width and had secondary occluded pits propagating from them at several locations. All these indications were filled with corrosion deposits. There was also a single, narrow indication propagating inward from the tube external surface, extending ~60% across the tube wall thickness. This indication originated at the root of the fillet weld between the tube and the filler block. Microscopic views of this indication showed it to be singular and transgranular with no appreciable branching or secondary cracking. This indication was filled with corrosion deposits and also had a few isolated occluded pits evident along its length, Figure 7.

A cross sectional view through the fillet weld between the sealing skirt and the filler block adjacent the leak is shown in Figure 8. There was a single, narrow crack extending from the root of the weld ~70% across the through thickness of the filler block plate. Similar to the tube external crack, microscopic examination showed this crack to be singular, transgranular and filled with a corrosion product, Figure 9. It was noted that this crack had a “stepped” appearance. The microstructure of the filler block plate had significant stringers present, Figure 10. These are common in older vintage plain carbon steel plate material due to the presence of inclusions and the rolling process during fabrication. The general propagation of this crack was oblique along the weld heat affected zone. However, when it intersected one of these stringers, the stringer opened up, resulting in a localized horizontal gap. The crack then propagated past this stringer, usually at a location slightly offset from where it originally encountered the stringer. It is believed that the opening of the stringers combined with the re-initiation of the crack propagation path resulted in the stepped appearance of this crack. There were no occluded pits visible along the length of this crack.

Representative sections were then examined with a scanning electron microscope (SEM). To determine the general composition of the corrosion deposit at the tube material interface, typical corrosion layers were subjected to energy dispersive X-ray spectroscopy (EDS) elemental analyses away from the cracks. There was an intact, well adhered layer at the tube metal interface and a fractured second layer next to this. Analysis (at three random) locations of both layers showed them to consist primarily of iron and oxygen (i.e. iron oxide), with minor amounts of chromium & manganese present. Results of these analyses are presented in Table 1.

Figure 11 shows a cross sectional view SEM backscatter image of a typical crack originating at the tube internal surface. EDS analysis focused primarily on the ends of the occluded pits associated with this crack. The results of the analyses (Table 2) indicated that for the majority of the positions, the corrosion layer was comprised primarily of iron and oxygen with small amounts of chromium, manganese, copper, sulphur & chlorine. EDS analysis of the corrosion in other internal cracks showed similar results; Table 2. The corrosion deposit in the external crack originating at the fillet weld root contained similar elements; see Table 3.

4.0 DISCUSSION

The physical, chemical and microstructural evidence indicates that the mechanism responsible for the leak detected in the waterwall tube from Unit #3 of Holyrood G.S submitted for analysis is consistent with a cyclic fatigue mechanism. Examination indicates that cracking initiated on the internal surface of the tube and propagated towards the external surface. The significant variation of the width of these cracks is typical of crack growth by a corrosion fatigue mechanism. The presence of secondary, occluded pits observed propagating from the main crack path is also consistent of a corrosion fatigue mechanism.

The singular transgranular crack initiating from the root of the fillet weld between the tube external surface and the filler block (propagating inward across the tube wall through-thickness) was also typical of propagation by fatigue. However, this deep, narrow, transgranular morphology suggests that propagation of this crack was influenced primarily by cyclic stresses. Normally, an externally initiated crack on a boiler tube is not exposed to the aqueous environment necessary for corrosion fatigue. However, the presence of small occluded pits along the length of this crack suggests the presence of water. Due to the geometry of this joint between the filler block and neighbouring tubes, it is possible that a crack could propagate through wall within the confines of the filler block. This would release boiler feed water into the gap formed by the weld between the filler block and the tube. The presence of this aqueous environment coupled with cyclic stresses would provide conditions suitable for crack propagation by corrosion fatigue. The scarcity and shallow depth of these occluded pits suggests this specific mechanism was a minor factor in the propagation of this particular crack.

The cyclic stresses contributing to the internal and external cracking observed on this tube would also be expected to exert similar cyclic stresses at the fillet weld between the sealing skirt and the filler block. This is believed to be the stress which caused the deep, narrow fatigue crack observed propagating across the filler block plate. As the micrographs show, this crack morphology was also typical of a fatigue crack; singular and transgranular.

As the names suggest, both these mechanisms (corrosion fatigue and thermal fatigue) are influenced by cyclic or repetitive stresses on the component. The reported frequency of shutdown/start-up thermal cycles sustained by this unit are the most probable source of this repetitive stress. However, the geometry and associated attachments of the tube at the elevation of this leak likely played a more critical role in crack initiation and propagation. The presence of the welded sealing skirt limits the lateral movement of these tubes during any start-up/shutdown events; causing localized, elevated stresses at this elevation. In addition, the presence of the welded filler block between the waterwall tubes results in a localized restriction of tube circumferential expansion. It is not unexpected that the external indications observed initiated at the root of a fillet weld, as a change in geometry associated with a weld is a common stress raiser.

Classical thermal fatigue cracks (in the absence of water) are typically V-shaped due to the formation and influence of an oxide layer as it forms within the propagating crack. The deep, narrow morphology of the external cracks observed on this tube and filler block suggest that they propagated primarily due to cyclic stresses.

The SEM EDS analyses conducted reported the presence of minor amounts of contaminant elements in the corrosion deposits within the cracks. Sulphur may be present due to the water treatment chemicals normally employed. Contaminants such as Cl can accelerate the corrosion fatigue mechanism, but their presence is not a necessity. The detection of contaminants in the external tube crack suggests that BFW was present in the gap under the filler block for an appreciable period of time.

References:

[1] Email, S. Lingley, B&W, January 31, 2019.

Figure 1: East Wall Tube #1 In the As-Received Condition. Views Highlight Relationship Between Leak, Filler Block & Sealing Skirt.

Figure 2: Close Up External View of Leak on Tube #1.

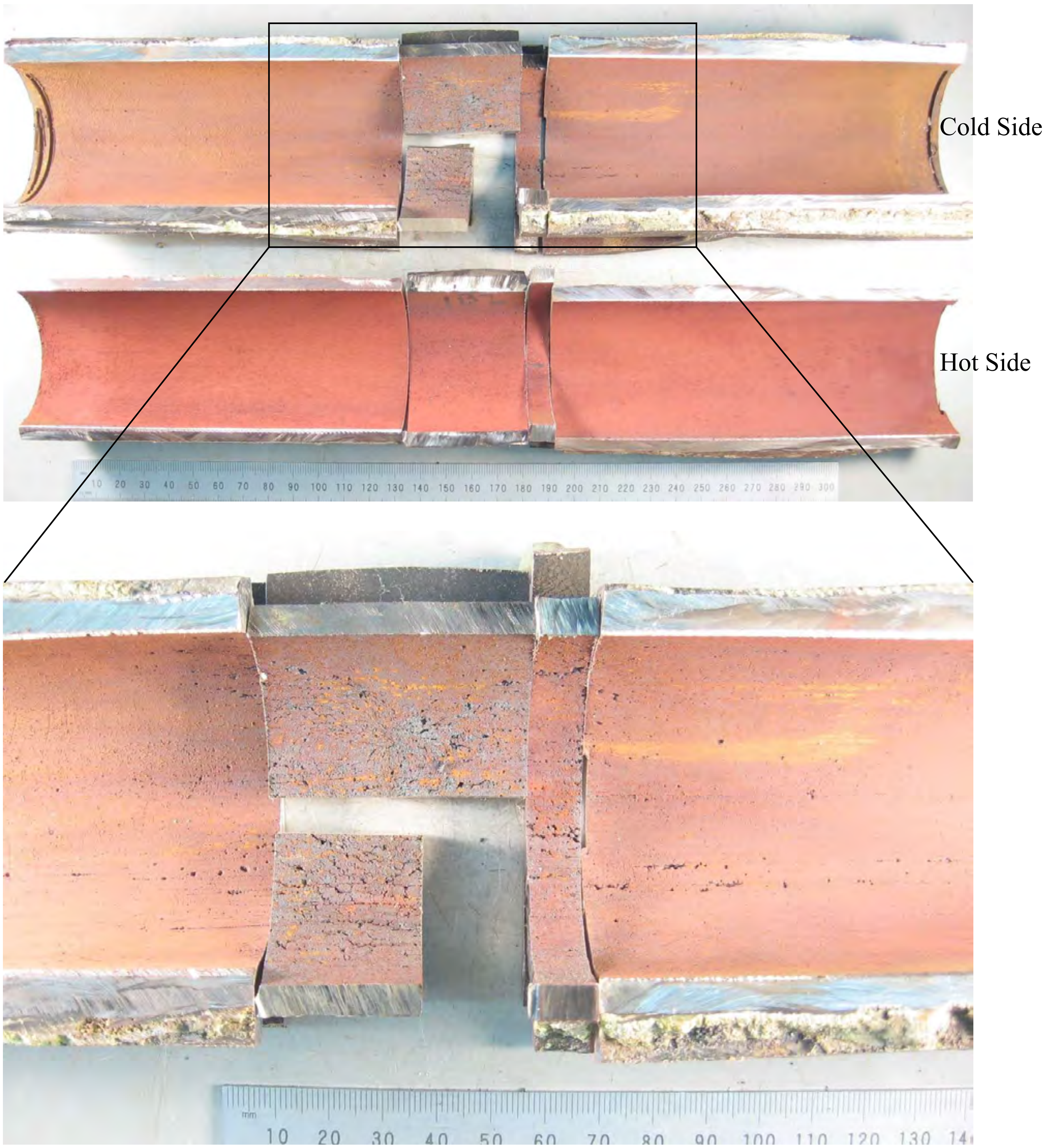


Figure 3: General View of Tube Internal Surfaces, Hot & Cold Side.

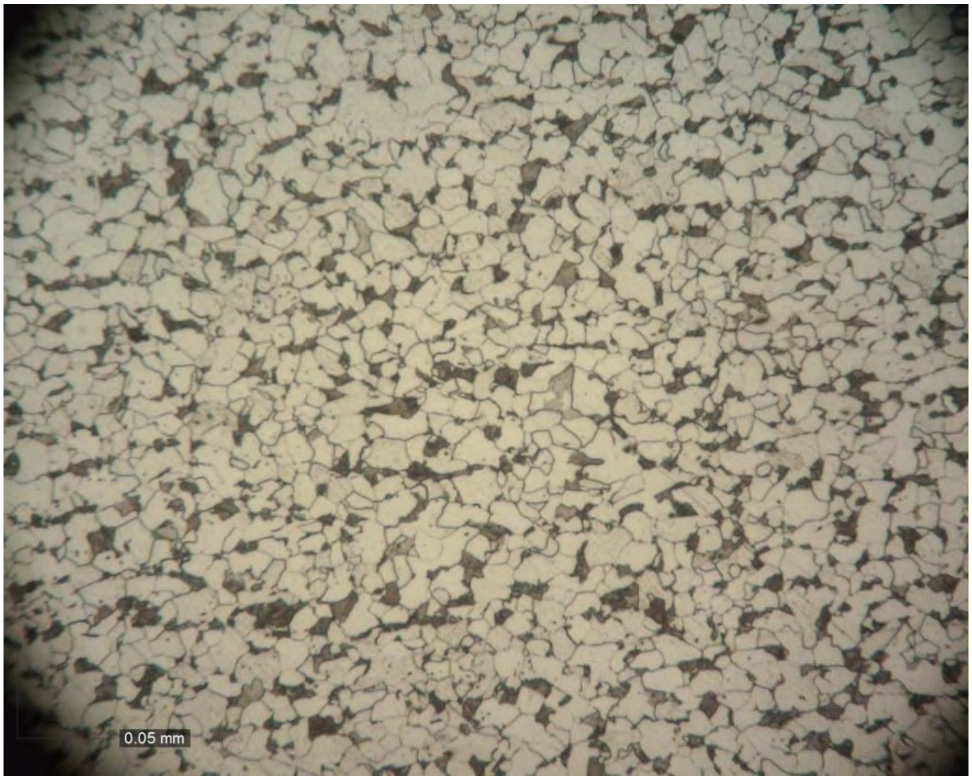


Figure 4(a): Microstructure of Tube Hot Side Consists of Banded Pearlite (Dark Regions) in a Ferrite Matrix.

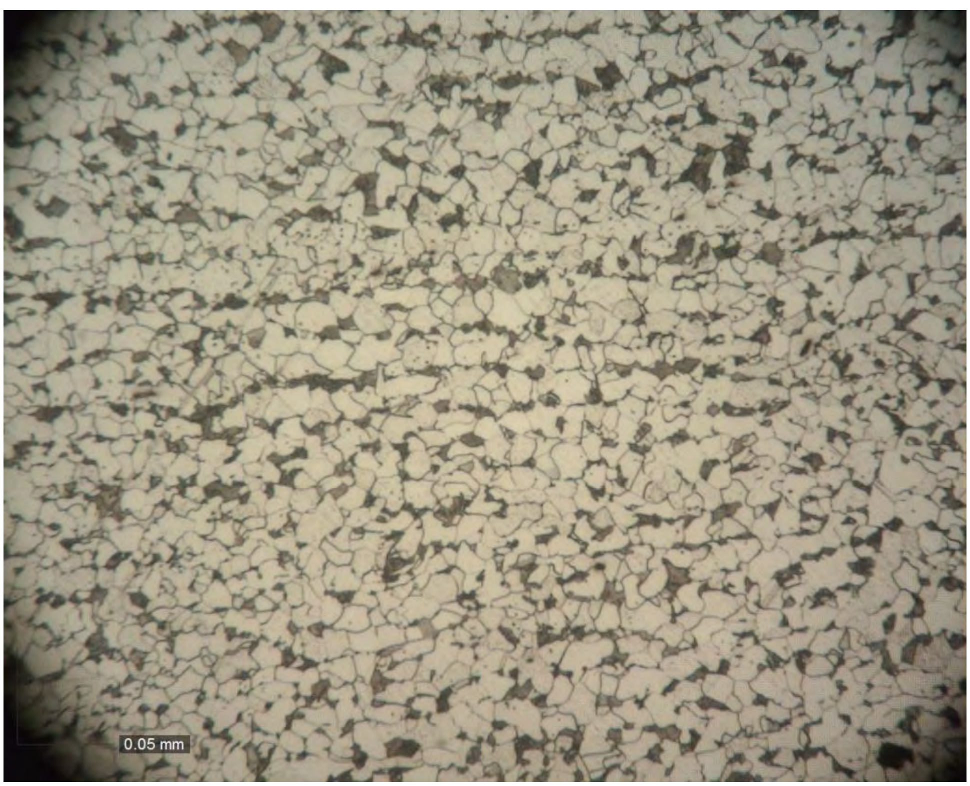


Figure 4(b): Microstructure of Tube Cold Side Also Consists of Banded Pearlite in a Ferrite Matrix.

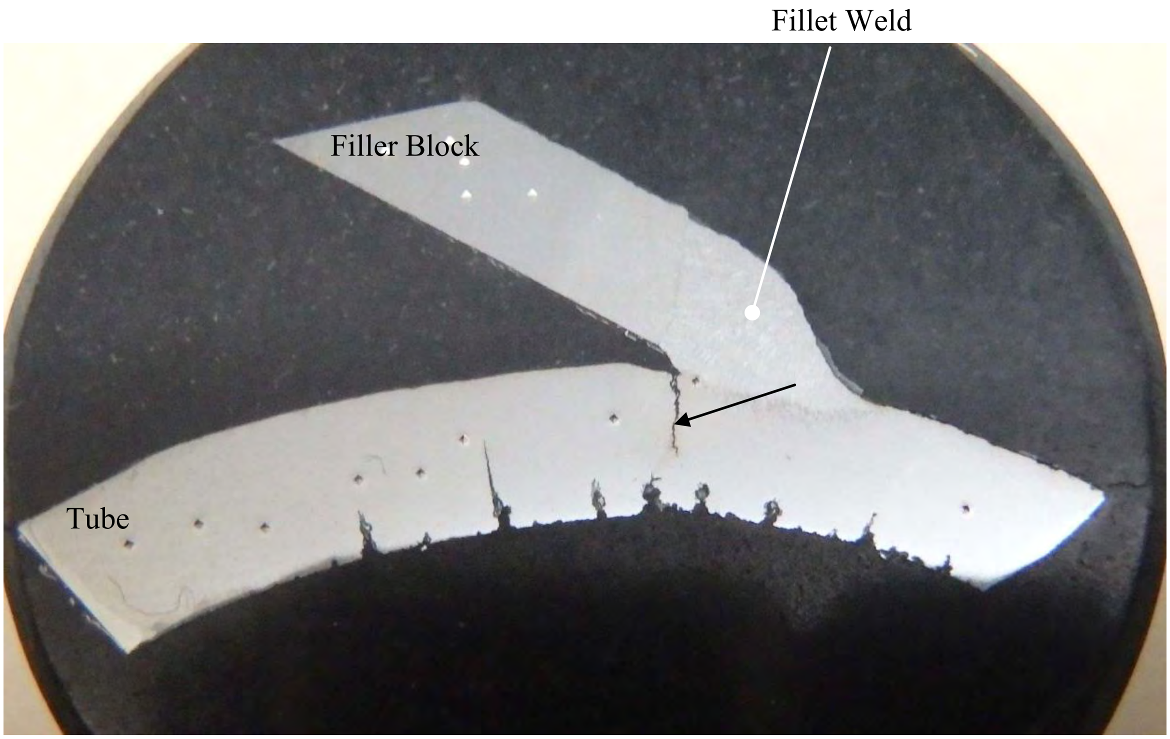


Figure 5: Cross Sectional View of Tube Wall and Filler Block Near Location of Leak. Numerous Indications Are Evident Originating at The Internal Surface. The Arrow Highlights the Singular Crack Propagating from the Weld Root Into the Tube.

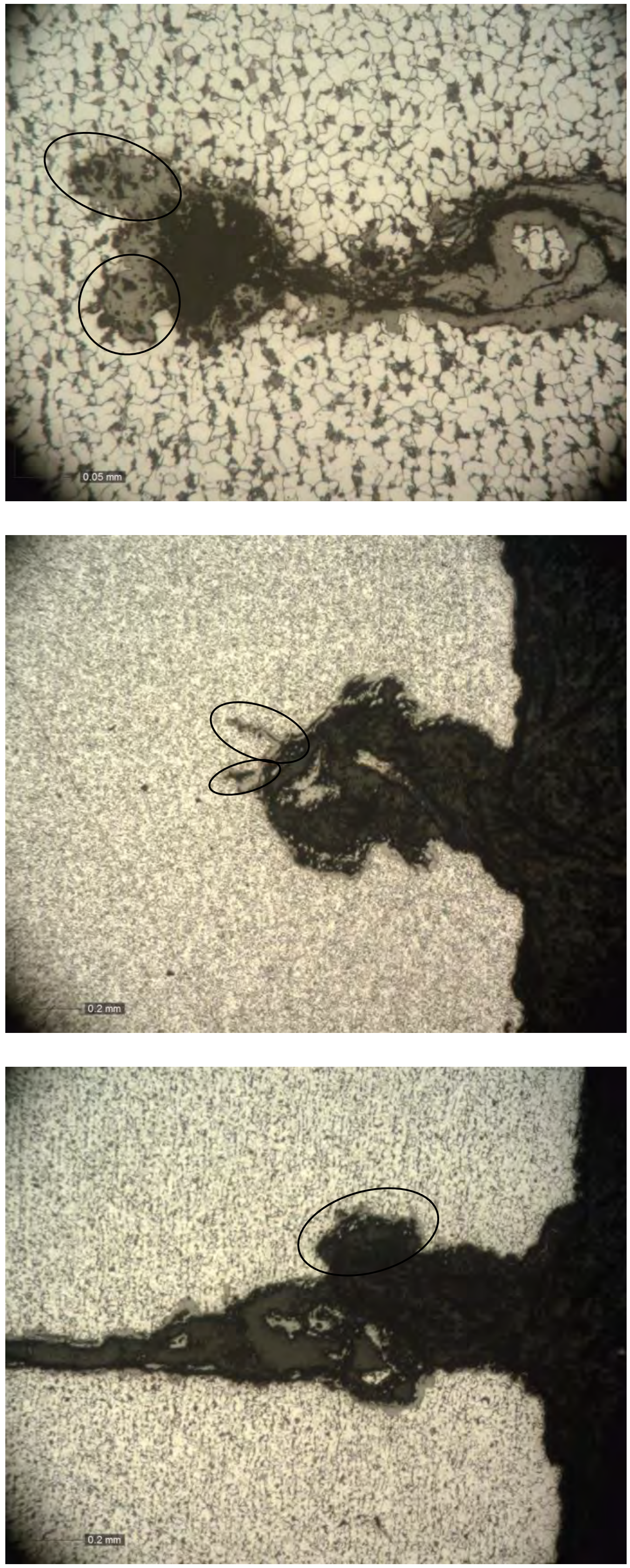
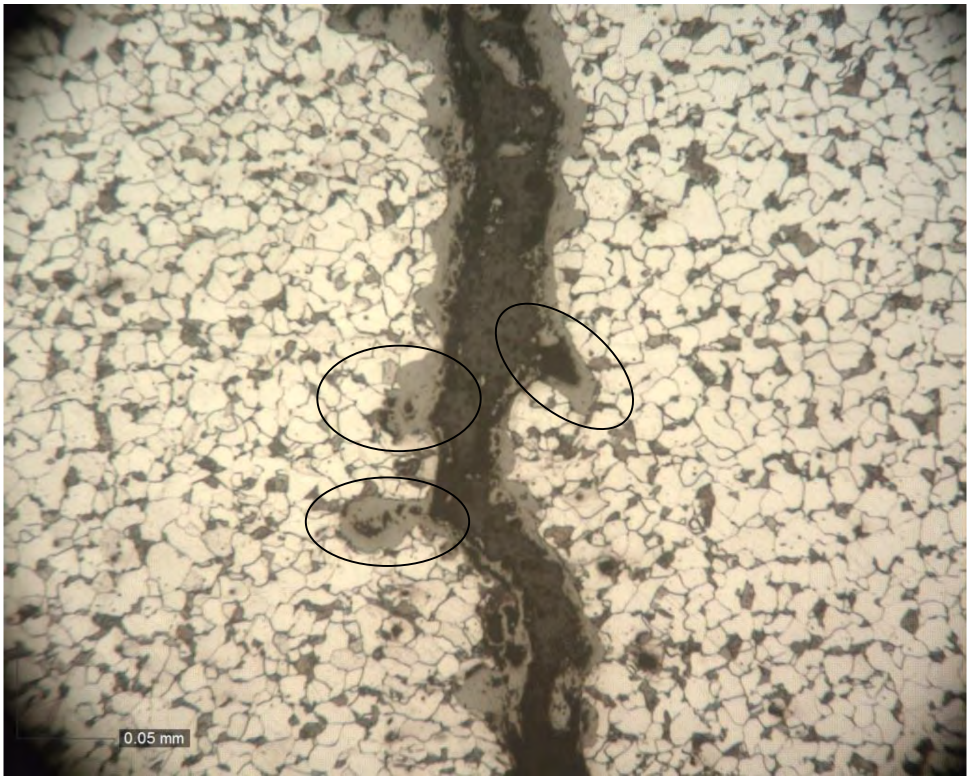


Figure 6: Microscopic Views of Typical Tube Internal Cracks. Variation in Crack Width is Evident. Occluded Pits Are Circled. Corrosion Product Is Visible Within Cracks.



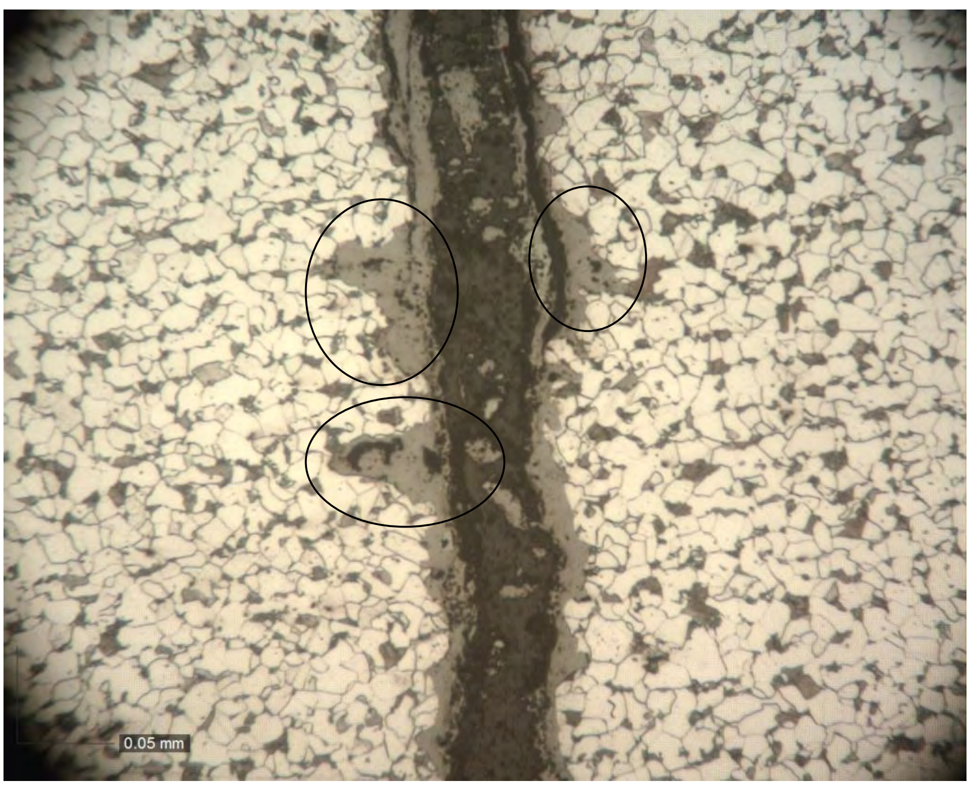


Figure 7: Microscopic Views of Singular Crack Originating at Tube External Surface. Crack Was Transgranular with No Visible Branching. Shallow, Random Occluded Pits Were Observed (Circled) Crack Was Filled with Corrosion Deposit.

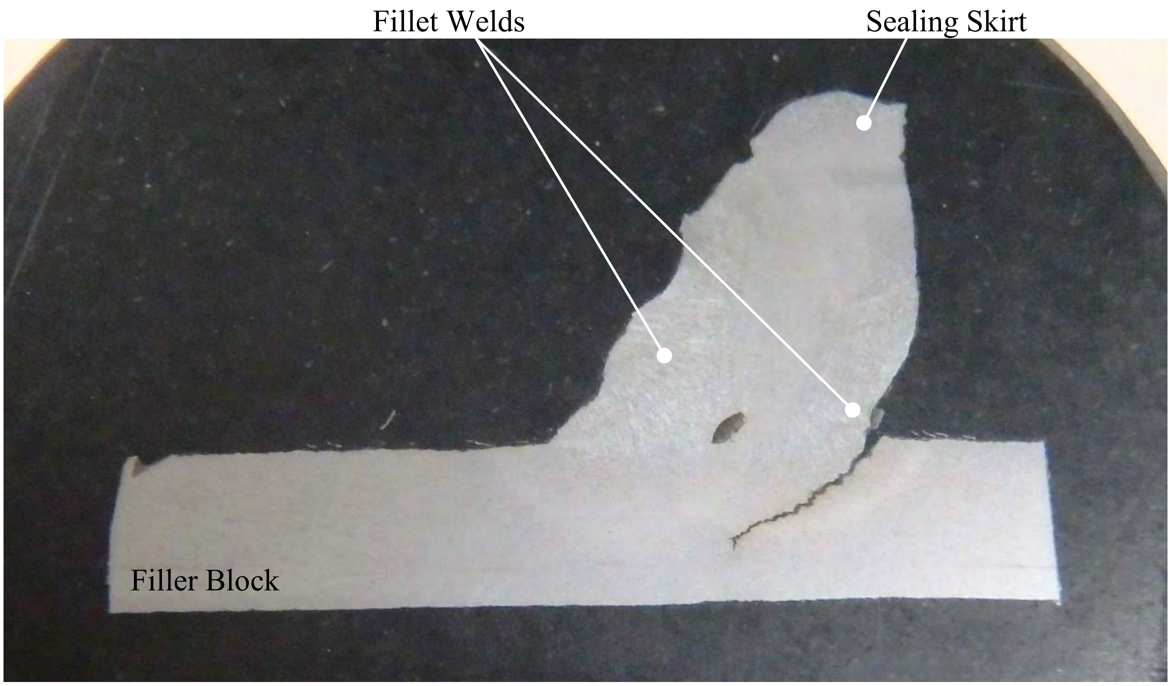


Figure 8: Cross Sectional View of Filler Block and Sealing Skirt Near Location of Leak Showing Singular Crack Propagating Across the Filler Block.

Figure 9: Microscopic Views of Singular Crack Propagating Across Filler Block. Crack Was Transgranular with No Visible Branching. Arrows Highlight Stringers. Crack Was Filled with Corrosion Deposit and Had A "Stepped" Appearance.

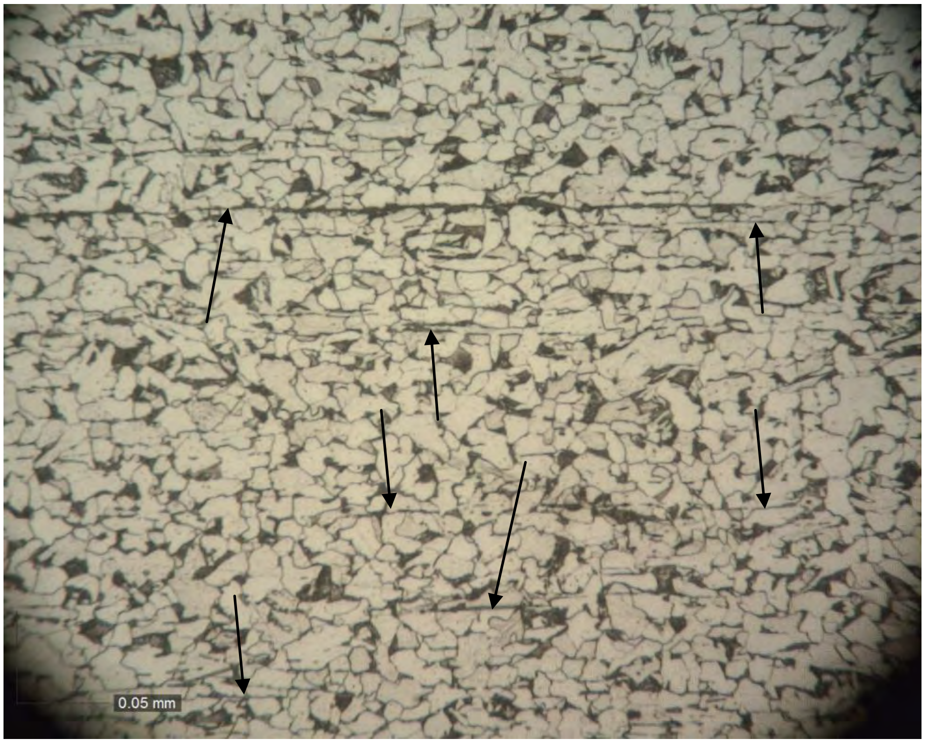


Figure 10: Microstructure of Filler Block Consists of Banded Pearlite in a Ferrite Matrix. There Were Numerous Stringers (Arrows) Evident Throughout This Material.

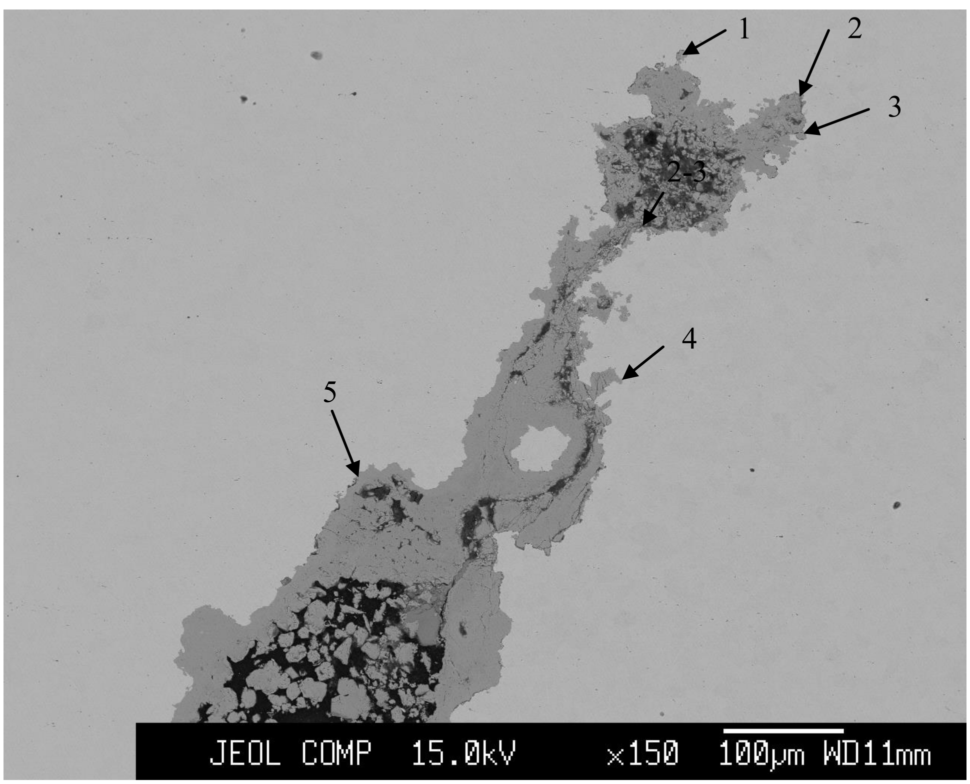


Figure 11: SEM Compositional View of Crack Originating at Internal Tube Surface. Occluded Pitting Where EDS Analysis of Deposit Was Performed is Identified.

Element	Layer Next to Tube Area A	Layer Next to Tube Area B	Layer Next to Tube Area C	2nd Layer from Tube Area A	2nd Layer from Tube Area B	2nd Layer from Tube Area C
C	0.0	0.0	0.0	0.6	1.4	0.0
N						
O	26.2	24.6	24.6	26.5	29.9	25.5
Na						
Mg						
Al			0.1		0.1	
Si		0.1	0.1		0.1	0.1
P		0.2	0.2			
S						
K						
Ca						
Cr	0.2	0.2	0.2	0.2	0.3	0.2
Cl						
Mn	0.4	1.8	1.2	0.3		1.5
Fe	73.2	72.6	73.5	72.4	68.2	72.8
Ni		0.3				
Zn						
Cu						
Mo						

Table 1: Results of SEM-EDS Chemical Analysis of Tube Internal Corrosion Layers. (Analysis Performed at Three Randomly Chosen Locations in Each Layer.)

Element	Internal Crack 1 Spot 1	Internal Crack 1 Spot 2	Internal Crack 1 Spot 3	Internal Crack 1 Spot 4	Internal Crack 1 Spot 5	Internal Crack 2 Spot 1	Internal Crack 3 Spot 1	Internal Crack 3 Spot 2	Internal Crack 4 Spot 1
C	3.5	0.9	4.8	0.8	1.2	1.7	1.3	0.0	0.0
N	10.1		9.4				5.1		
O	24.8	6.3	20.8	15.3	20.3	17.7	16.3	24.8	25.1
Na									
Mg									
Al	1.0	0.3	1.3		0.3	1.0	0.2	0.3	0.3
Si	0.3	0.4	0.4	0.3	0.5	0.4	0.3	0.3	0.4
P			0.1		0.1		0.4	5.8	1.4
S	0.8	0.2	0.7	1.0	1.2	0.4	0.1	0.0	0.3
K									
Ca							0.2		
Cr		0.2	0.2	0.2	0.2	0.2	0.1		0.2
Cl	0.3	0.1	0.4	0.1	0.2	0.1			
Mn	0.5	0.9	0.4	1.3	1.5	0.4	0.4	0.7	0.4
Fe	58.4	90.7	59.9	80.7	73.9	77.5	75.7	68.0	72.0
Ni			0.3		0.2				
Zn									
Cu	0.2	0.1	1.2	0.3	0.4	0.5			
Mo	0.1								

Table 2: Results of SEM-EDS Chemical Analysis of Deposit in Occluded Pits Identified in Figure 11. Also Included Are Results from Analyses from Other Internal Cracks.

Element	Extern Crack Spot 1	Extern Crack Spot 2	Extern Crack Spot 3	Extern Crack Spot 4
C	0.5	2.6	1.6	0.2
N		9.7	9.3	
O	20.4	27.7	24.9	17.0
Na				
Mg				
Al	0.2	0.2	0.1	0.2
Si	0.2		0.3	0.5
P		7.2	0.2	0.2
S	0.2	0.3	0.1	0.3
K				
Ca				
Cr	0.2			
Cl				0.1
Mn	0.4	0.7	0.5	0.8
Fe	77.9	51.6	62.9	80.3
Ni				
Zn				
Cu				0.3
Mo				

Table 3: Results of SEM-EDS Chemical Analysis of Deposit in Crack Originating at External Surface of Tube.

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Draft Report

For

Grand Falls Generating Station 2013 Freeze-up Event

H346170-0000-00-124-0001
Rev. A
February 14, 2014

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Grand Falls Generating Station 2013 Freeze-up Event

H346170-0000-00-124-0001
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Draft Report

Grand Falls Generating Station 2013 Freeze-up Event

H346170-0000-00-124-0001

			S. Thomas Lavender	J Shaw	T Chislett	
2014-02-14	A	Client Review	T. Lavender	J. Shaw	T. Chislett	W. Eddy
DATE	REV.	STATUS	PREPARED BY	CHECKED BY	APPROVED BY	APPROVED BY
						Client

Safety • Quality • Sustainability • Innovation

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1. Introduction

Beginning in late November and through December 2013, prevailing hydraulic and weather conditions in and over the Exploits River and Grand Falls headpond resulted in ice conditions which inhibited the flow of water through the Grand Falls Hydroelectric Generating Station intake channel, thereby significantly hampering the power output from the facility for a period of days. Following herewith is a review of these conditions.

2. Summary of Events

In mid-November there was snow on the ground prior to a warm weather event and significant rain on November 28 which resulted in tripling of the flow in the Exploits River through the following day. These high flows resulted in the loss of flash boards from the headpond dam for a crest length of approximately 200 ft late on November 29. This section of failed boards adjacent to the right abutment is evident in Figure 2-1.

Figure 2-1: Headpond Dam – Right Side (looking downstream)

The flows in the Exploits River remained high for the next couple of weeks as extra water was released from Red Indian Lake reservoir to position the reservoir level at the winter full supply level. The black line in Figure 2-2 indicates the prevailing 5-day running average flows for December 2013. Flows are seen to peak on December 8, falling off thereafter to a prevailing rate of about 220 m^3/s after December 17.

Flow statistics for the period from the years 1986 to 2012 are also indicated in Figure 2-2 for comparison. It is evident that the 2013 flows prior to December 15 exceed the average and median flows for the fore noted 26-year period by a large margin.

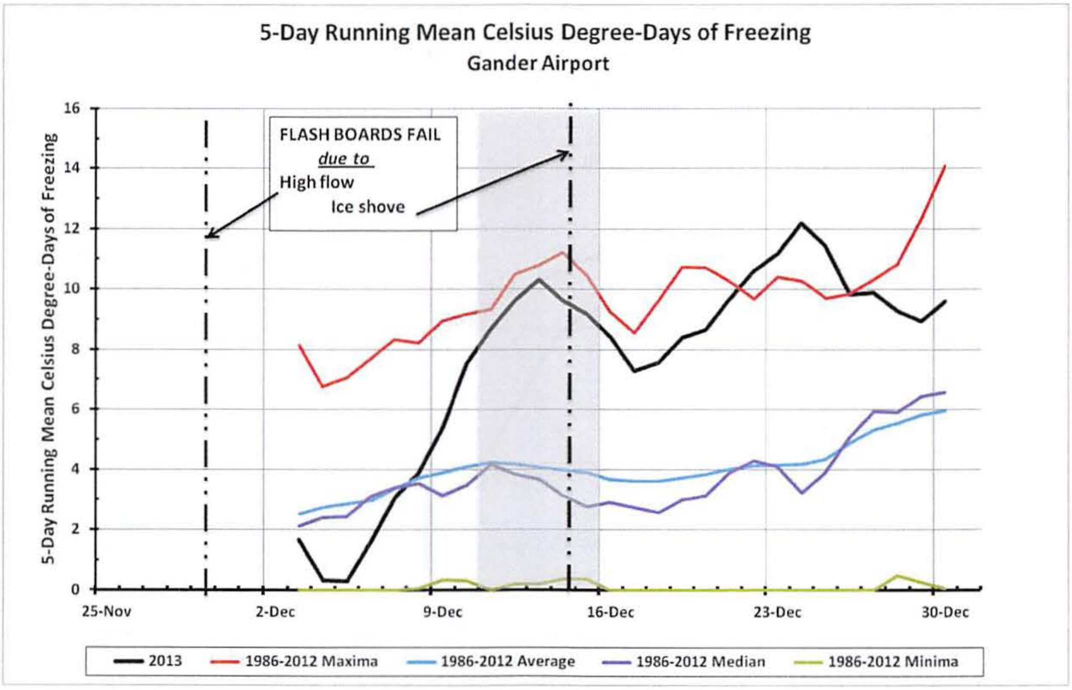

Figure 2-2: Exploits River below Noel Pauls Brook t-day Running Average Discharge

The corresponding timeline for weather conditions is shown in Figure 2-3, being the 5-day running average degree-days of freezing (DDF).

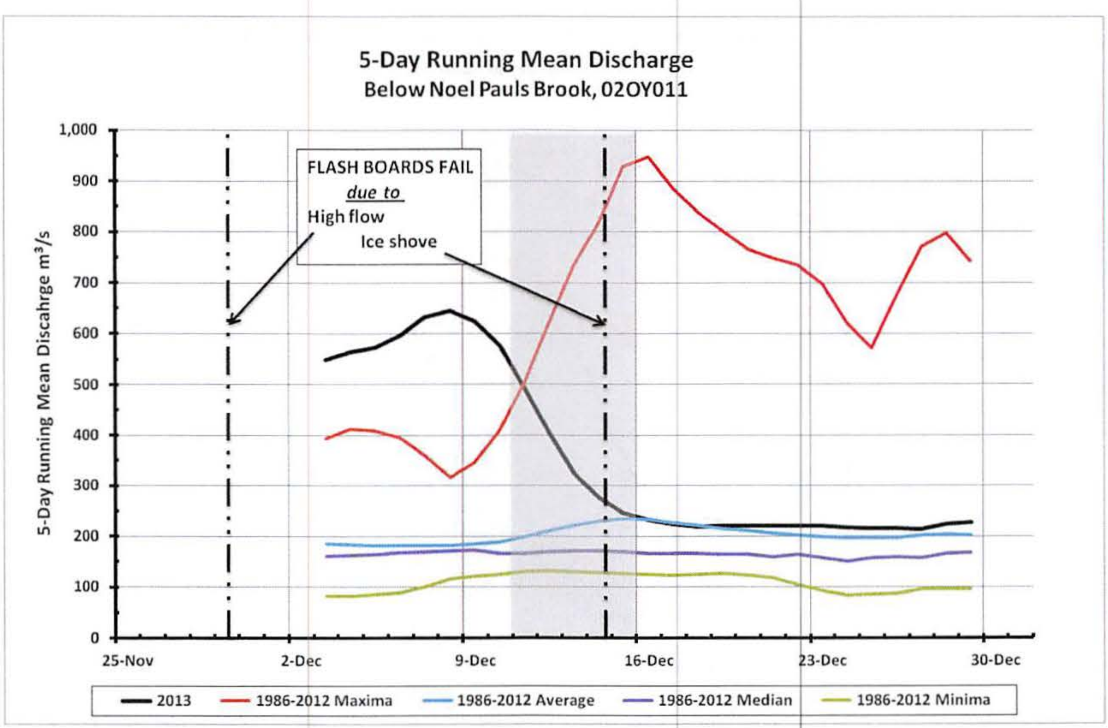

Figure 2-3: Degree-Days of Freezing at Gander Airport

DDF statistics for the period from the years 1986 to 2012 are also indicated in Figure 2-3 for comparison. The 2013 DDF in the period December 6 to December 13 is seen to be extraordinary relative to the 1986-2012 period of record average and median values, approaching the maxima of record near its upper end.

The onset of the 5-day spate of very low temperatures precipitated the initial stages of ice cover formation on the headpond and in the intake channel. A second consequence of the 5-day spate of low temperatures was the production of a very large volume of frazil ice in the open water reaches and rapids in the river upstream of the headpond. This frazil ice deposited in the relatively low velocity areas of the headpond until the headpond storage volume was filled. Thereafter, the inflowing frazil was carried directly into the intake channel along the main filament of flow through the headpond. This filament of flow in the headpond is evident at the top of Figure 2-1 (see open water) and is further illustrated at the intake structure in Figure 2-4. Local telescoping of the ice cover at the end of the open water lead is clearly evident.

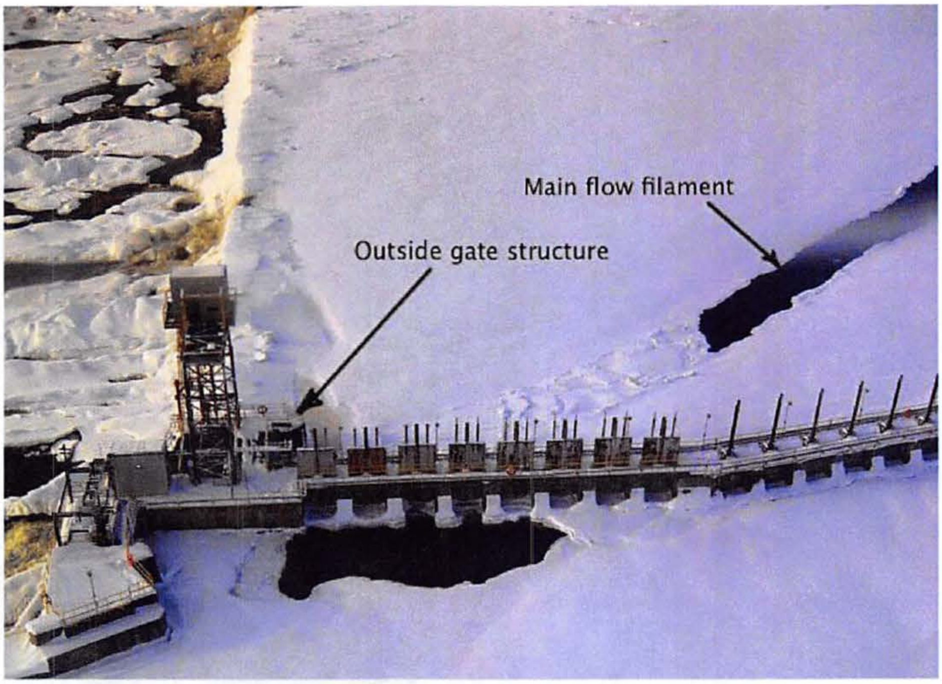

Figure 2-4: Intake Structure and Upstream Area Showing Main Flow Filament to Intake

At this time, the outside gate structure was open to encourage the by-passing of frazil ice to downstream of the dam. As most of the flow was in fact entering the intake channel to supply the power station, most of the frazil was transported into the intake channel where it deposited under the nascent thermal ice cover as an inverted dune, advancing toward the power station intakes until the central portion of the channel was filled to the power intake structure.

At some point in this progression, the main flow filament in the intake channel shifted from the centre line of the channel to lines of lower hydraulic resistance adjacent to and paralleling the right and left banks. This flow pattern is illustrated in Figure 2-5. Under this ice condition, the hydraulic conveyance of the channel is much reduced, inhibiting seriously the ability of the power station to generate electrical energy.

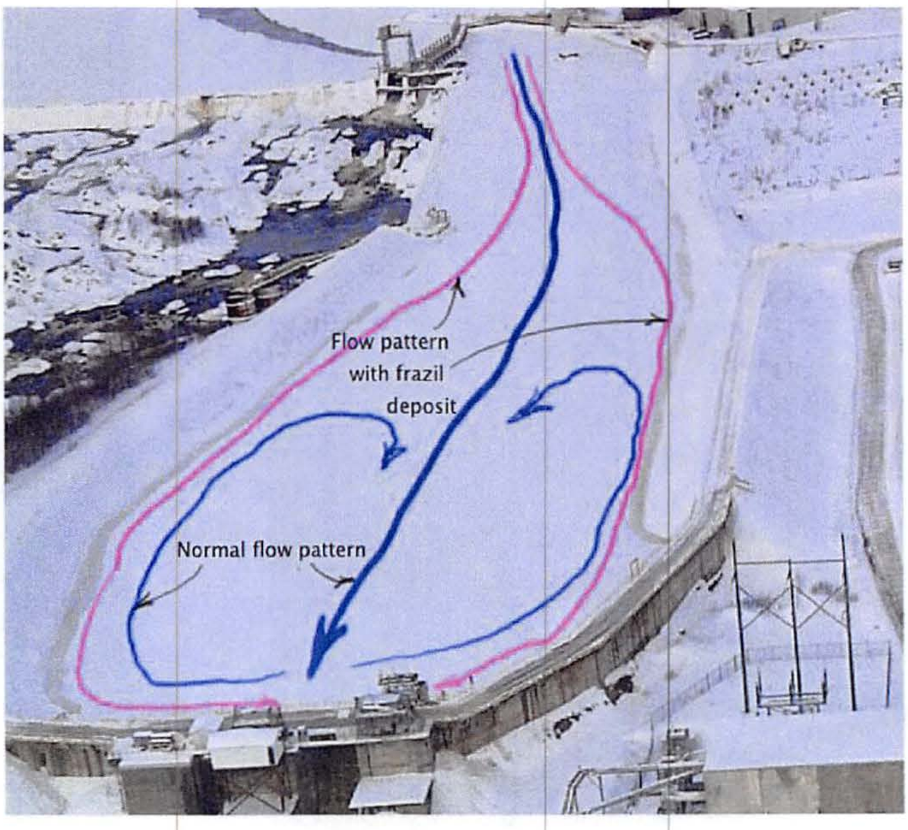

Figure 2-5: Flow Pattern in Intake Channel

Also, with the frazil storage capacity of the channel being full, all on-going inflow of frazil arrived and accumulated at the power intakes. To keep the intakes open and operating and the generating station operable to some degree, excavation of accumulated ice from the intake face was undertaken as illustrated in Figure 2-6.

Evident in the Figure 2-6 is the "crowning" of the deposited ice across the channel, with the frazil deposits along the main normal flow filament raising the ice surface level above the levels at the banks of the channel; i.e. above the "clear" ice filaments evident in Figure 2-5 and to a lesser extent in the background of Figure 2-6.

Figure 2-6: Excavation of Ice at Intake Face

It was found that the frazil deposits at the intake were very dense, requiring the use of a wrecking ball to break an opening for the back hoe to be able to begin excavation.

Late on December 14, in spite of declining flows, the nascent headpond ice cover telescoped, pushing ice onto and over the dam. Figure 2-7 shows the end result.

This event was the consequence of two factors; namely,

- frazil ice accumulation in the headpond increasing the hydraulic resistance to flow through the pond, resulting in a corresponding increase in water surface slope through the length of the pond. The increased slope resulted in increased body forces in the nascent ice cover.
- decreasing flows resulted in lower headpond levels thereby increasing the ratio of the already established ice depth to hydraulic depth, this being a significant factor in determining the stability of an ice cover[1].

[1] Pariset, Hausser and Gagnon, **Formation of Ice Covers and Ice Jams in Rivers**, Journal of the Hydraulics Division, Proceedings of the American Society of Civil Engineers, 4965 HY6, November 1966.

As evident in Figure 2-2, flows were still 20 to 25% above winter normal on December 14 when this ice event occurred. Thereafter, flows declined to normal winter values (Figure 2-2) whilst the frazil producing weather conditions persisted through to the end of December (Figure 2-3) and beyond.

Figure 2-7: Ice Pushed on to and Over the Dam

With the persisting supply of frazil ice to the generating station intakes, power production continued to be seriously inhibited.

3. Corrective Measures

Restoring the generating capability of the power station would require removal of much of the ice accumulated throughout the length of the intake channel. This could be achieved through mechanical removal or melting in place, both of which might be by intervention or by nature.

Mechanical removal by intervention is deemed to be technically and economically impractical because of the difficulty of access to the channel and the volume of ice to be removed on a continuous basis with continuing cold weather frazil production. With the maintenance of as much flow as possible through the channel, mechanical removal by erosion is achieved by nature. Nalcor's continual clearance of the intakes as described kept this natural measure in effect to the extent possible.

Removal by thermal intervention is also deemed to be technically and economically impractical because of the quantity of heat required; realistically only nature can provide heat on this scale. Nalcor's continual clearance of the intakes as described kept the flow of natural heat available from the passing flow in effect to the extent possible. Clearly, a warming trend in the prevailing weather enhances the effectiveness of this measure.

4. Technical Insights

4.1 Frazil Storage

One of the tacit and principal functions of the Grand Falls headpond in winter is to provide storage for frazil ice flowing in from open water reaches and rapids upstream, thereby limiting the amount of frazil reaching the intake canal.

In order for frazil ice to deposit, flow through velocities need to be less than 1.0 +/- m/s, this being the maximum velocity at which frazil can be deposited (i.e., the Equilibrium Deposition Velocity or EDV). Clearly, the greater the pond cross-sectional area, the lower the average flow-through velocity and the greater the ability to store ice.

The Grand Falls pond has proven to be capable over the years of handling normal to moderately severe frazil incidents with normal operating winter levels and flows. The 2013 freeze up was an unfortunate coincidence of above normal flows, below normal pond levels and well above normal frazil production.

4.2 Ice Cover Stability

The effect of reduced flow cross-sectional area and higher flows can be best illustrated with the following dimensional factor developed by Renee Hausser[2] to characterize the hydraulic and body forces acting on an ice cover on a sloping water surface.

$$\frac{BV^2}{C^2H^2} = \frac{Q^2}{BC^2H^4}$$

in which: B = channel width

Q = flow rate
V = velocity = Q/BH
H = hydraulic depth
C = Chezy roughness coefficient

A stable ice cover can only exist if this equation holds true. The greater the value of the dimensionless factor, the greater the hydraulic and body forces an ice cover must resist. Evidently a 20 to 25% increase in flow gives rise to a 44 to 56% increase in forces whilst the same range of percentage changes in depth gives rise to a 100 to 144% increase in forces. The importance of changes to flow rate and depth of flow to the stability of an ice cover is clearly evident.

[2] Pariset, Hausser and Gagnon, **ibid.**

5. Future Considerations

In light of the foregoing insights, implementation of measures to ensure the maintenance of favorable headpond water levels throughout the winter period are an obvious measure for serious consideration. The recommendations for refurbishment of the Grand Falls Main Dam in a study recently completed by Hatch[3] would accomplish this in large measure. There was no specific consideration given in that study; however, to the ice management function of the structure. A review of the proposed rehabilitation of the structure with its ice management function in mind may be worthwhile.

Another possibility for mitigating the risk of future blockage of the intake canal might be the near total diversion of flows anticipated to be bearing heavy loads of frazil ice over the dam rather than into the power canal. Such diversion would most commonly occur during periods of greatest frazil production which tend to be night-time hours when demand by the power system is at its lowest. A few hours of lost generation for two or three consecutive nights would be preferable to several full days lost generation including peak demand periods. This strategy could be enhanced by forecasting the likelihood of a severe frazil run using 5-day temperature forecasts or, possibly, the frazil forecasts that are currently in use for the Exploits River. Clearly the practicality and economic value of this operating strategy would require study and detailing before attempting implementation.

[3] Hatch, Newfoundland and Labrador Hydro, **Final Report for Grand Falls Main Dam Conceptual Design**, H345417-0000-00-124-0001 Rev. 0, December 20, 2013.

6. Summary and Conclusions

Above normal flows prior to freeze up in 2013 caused 200 ft of flashboard failure on the Grand Falls Main Dam resulting in below normal headpond volume available for frazil ice storage. Subsequent colder than normal weather yielded above normal quantities of frazil incoming to the headpond. Consequently, the Grand Falls power canal filled with frazil ice, reducing its hydraulic conveyance and thereby seriously inhibiting the power output of the generating station. The lower headpond levels also contributed to the reduction of flow through the power canal in as much as they resulted in a lower head to drive water through the ice-congested canal.

Subsequent to the restriction of flow to the power station by frazil ice accumulation in the power canal, Nalcor undertook excavation of ice from the powerhouse intakes, endeavoring to maintain flow through the canal to the maximum extent possible. This action ensured the earliest possible realistically viable clearing of the canal through erosion and melting of the accumulated frazil ice.

The below normal headpond levels and falling flow rates contributed to destabilization of the nascent ice cover on the headpond with the ice cover consequently advancing onto and over the Main Dam, thereby inflicting further damage to the flash boards on its crest.

Measures to mitigate the risk of the 2013 ice events could be implemented and may include the currently proposed rehabilitation of the main dam and an alternative power station operating strategy during periods of heavy frazil ice runs.

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