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November 19, 2018

British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC
V6Z 2N3

Attention: Mr. Patrick Wruck, Commission Secretary and Manager, Regulatory Support

Dear Mr. Wruck:

Re: FortisBC Inc. (FBC)

Application for a Certificate of Public Convenience and Necessity (CPCN) for the Grand Forks Terminal Station Reliability Project (the Application)

Pursuant to sections 45 and 46 of the *Utilities Commission Act* (the Act), FBC applies to the British Columbia Utilities Commission (the BCUC) for a CPCN for the Grand Forks Terminal Station (GFT) Reliability Project.

In particular, FBC seeks approval under sections 45 and 46 of the Act to:

- Install a second transformer at GFT by purchasing a new 161/63kV transformer as described in the Application; and
- Remove 44.6 km of the 65.4 km of transmission lines 9 Line (9L) and 10 Line (10L) from Christina Lake substation to Cascade substation and repurpose the remaining 20.8 km of transmission lines 9L and 10L to distribution lines to continue to supply power to customers.

Requests for Confidential Treatment of Certain Appendices

To support the Application, FBC has filed several Appendices, with the following ones being filed confidentially in accordance with the BCUC's Rules of Practice and Procedure, established by Order G-1-16.

- Appendix C DBS Condition Assessment Report
- Appendix H Detailed Station Upgrade Estimate
- Appendix I Alternative B Capital Cost Summary

- Appendix J Financial Schedules

FBC respectfully requests that the BCUC hold the above listed documents confidential, and believes that such information should remain confidential even after the regulatory process for this Application is completed. Below, FBC will outline the reasons for keeping the information confidential.

Appendix C

Appendix C is an engineering document and should be kept confidential on the basis that it contains sensitive financial and technical information pertaining to the Company's assets. In particular, it identifies vulnerable points on the Company's electrification system. FBC reasonably expects that the release of this information may jeopardize the safety and security of the Company's assets.

Appendices H I, and J

Appendices H, I and J are cost estimates, containing capital cost estimates for the Project. They should be kept confidential on the basis that FBC may be going to the market to seek competitive bids for the materials and construction work for the Project. If the estimated costs for the material and construction work are disclosed, FBC reasonably expects that its negotiating position may be prejudiced. For instance, the bidding parties with knowledge about the estimated costs may use the estimate costs as a reference for their bidding.

Access to Confidential Information for Interveners

Should parties that choose to register in the review of this Application require access to some or all of the information filed confidentially, FBC has provided a proposed Undertaking of Confidentiality in Appendix K, to be executed before confidential information may be released to registered parties under the terms of the undertaking. FBC has no objection to providing confidential information to its customary and routine intervener groups representing customer interests. FBC requests that the BCUC provide it with the opportunity to file comments on any objections or concerns that it may have, should any other registered parties seek access to confidential information.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC INC.

Original signed:

Diane Roy

Attachments

cc (email only): Registered Parties in the Annual Review for 2019 Rates

FORTISBC INC.

Application for a Certificate of Public Convenience and Necessity for the Grand Forks Terminal Station Reliability Project

Volume 1 - Application

November 19, 2018

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1. APPROVAL SOUGHT AND EXECUTIVE SUMMARY

1.1 *SUMMARY OF APPROVAL SOUGHT*

FortisBC Inc. (FBC or the Company) hereby applies to the British Columbia Utilities Commission (BCUC) pursuant to Sections 45 and 46 of the *Utilities Commission Act* (the Act or UCA), for a Certificate of Public Convenience and Necessity (CPCN) for the Grand Forks Terminal Station Reliability Project (referred to as the GFT Reliability Project, the Project, or the Application).

In summary, FBC seeks approval from the BCUC to:

- Install a second transformer at Grand Forks Terminal Station (GFT) by purchasing a new 161/63kV transformer as described in the Application; and
- Remove 44.6 km of the 65.4 km of transmission lines 9 Line (9L) and 10 Line (10L) from Christina Lake substation (CHR) to Cascade substation (CSC) and repurpose the remaining 20.8 km of transmission lines 9L and 10L to distribution lines to continue to supply power to customers.

The estimated total cost of the Project in as-spent dollars is $13.171 million, which includes Allowance for Funds Used During Construction (AFUDC) and the cost of removal of transmission lines 9L and 10L.

If the Application is approved, FBC plans to initiate the detailed design and procurement for the Project early in the third quarter of 2019. FBC plans to begin construction at the end of the third quarter of 2019, and is expecting to have the new transformer in service by the third quarter of 2020, with the retirement, salvage, and removal of the non-repurposed portion of 9L and 10L being completed by the third quarter of 2021. Repurposing work related to portions of 9L and 10L is also scheduled for completion by the third quarter of 2021.

1.2 *CONFIDENTIAL FILINGS REQUEST*

Certain Appendices to the Application contain operationally sensitive information, including detailed information that, if disclosed, could impede FBC's ability to safely and reliably operate its electric system assets and could risk the safety of both its workers and the public. As well, the Confidential Appendices contain market sensitive information that the Company believes should be kept confidential so as not to influence the construction contractor selection process for the Project. FBC has and will continue to mark all confidential information as such, where applicable.

In accordance with the BCUC's Rules of Practice and Procedure established by Order G-1-16 regarding Confidential Documents, FBC requests that the BCUC direct that the Confidential Appendices and any future filings which address confidential information be kept confidential and that interveners requesting access to confidential information be required to execute a

Confidentiality Declaration and Undertaking in the form acceptable to the BCUC, a copy of which is provided in Appendix K.

1.3 *EXECUTIVE SUMMARY*

1.3.1 Introduction

GFT is supplied at 161 kV from both AS Mawdsley Terminal Station (ASM), which is located near Warfield, via 11 Line E (11EL) and from Kettle Valley Terminal Station (KET), which is located near Rock Creek, via 11 Line West (11WL). The 161 kV voltage is stepped-down to 63 kV via a single 161/63 kV transformer referred to as Grand Forks Terminal T1 transformer (GFT T1). GFT T1 provides the local 63 kV transmission supply to the City of Grand Forks, Town of Christina Lake, and the surrounding area.[1]

In the event of an outage to GFT T1, the system is designed for a 63 kV backup supply from Warfield Terminal Station (WTS) via the 63 kV transmission lines 9L and 10L. However, due to the condition of transmission lines 9L and 10L, this backup 63 kV supply is not sufficiently reliable. A dependable secondary 63 kV supply is required to maintain reliability for the Grand Forks area in the event of a GFT T1 outage or failure.

1.3.2 Need for GFT Reliability Project

There are two key drivers behind the proposal for the Project:

- Condition of the existing facilities; and
- Reliability for the Grand Forks area.

The GFT Reliability Project is essential to meet the Company's transmission system design criteria of single contingency reliability as further described in Section 3.1.

GFT T1 is of 1965 vintage and is now 53 years old, exceeding the expected transformer lifespan of 40 years. A comprehensive condition assessment of GFT T1 was performed by ABB Inc. (ABB) in 2018. Based on the analysis, ABB recommends GFT T1 should not be kept in service for more than 15 years after 2018.[2] The condition of GFT T1 will be discussed further in Section 3.2.1.1.

In the event of a GFT T1 outage or failure, the system is designed for 63 kV supply to be delivered via 9L and 10L. However, 9L and 10L transmission lines were originally constructed in 1908 and are in poor condition,[3] with 10L requiring visual assessment and rehabilitation to minimum standards before it can be energized. Portions of 9L and 10L also traverse the

1 Please refer to Figure 3-1 for a diagram of the existing Grand Forks Area transmission system.
2 Appendix B: GFT Condition Assessment Report - Page 18, Section 10 – Risk of Failure Assessment.
3 Confidential Appendix C: 9L and 10L Condition Assessment Report.

Rossland Mountain Range making them extremely difficult to access in the winter. As such, the switching required to reconfigure the system to 63 kV supply from 9L and 10L can result in lengthy restoration times and energization of 10L may not be possible if the line cannot be accessed. To support the Grand Forks area load during peak conditions, 9L and 10L must run in parallel operation. Extensive rehabilitation work would be required to ensure both lines are available when needed in order to use them as the backup 63 kV supply. The condition of 9L and 10L will be discussed further in Section 3.2.1.3.

Due to the condition of the existing facilities, there is a significant reliability concern for the Grand Forks area. In the event of a failure to GFT T1, it would likely take more than a year to procure and install a replacement transformer. In the meantime, the on-site spare transformer would be used as an emergency backup. It could take three to four weeks to install the on-site spare transformer. If transmission lines 9L and 10L could not be reconfigured to provide the 63 kV supply while the on-site spare transformer was being installed, it may result in extended outages to customers. Furthermore, the on-site spare transformer is of 1971 vintage and is now 47 years old, exceeding the expected transformer lifespan of 40 years. The condition of the on-site spare transformer will be discussed further in Section 3.2.1.2.

In order to meet the minimum reliability standards (expanded on in Section 3.2.2), FBC must provide a reliable secondary 63 kV supply for the Grand Forks area in the event of a GFT T1 outage or failure.

1.3.3 The Recommended Solution

The Company has identified three alternatives with respect to the GFT Reliability Project:

- Alternative A: Provide a second transformer at GFT (GFT T2) by installing the on-site spare, remove 44.6 km of the 9L and 10L transmission lines, and repurpose 20.8 km of the 9L and 10L transmission lines to distribution lines.
- Alternative B: Provide a second transformer at GFT (GFT T2) by purchasing and installing a new 161/63kV transformer, remove 44.6 km of the 9L and 10L transmission lines, and repurpose 20.8 km of the 9L and 10L transmission lines to distribution lines.
- Alternative C: Rehabilitate the 9L and 10L transmission lines.

To assess each of these alternatives, the following eight criteria were identified and compared.

Technical Criteria

1. Meets Single Contingency N-1 Transmission Planning Criteria;
2. Operations Accessibility and Operability;
3. Lifecycle Utilization;
4. Project Risk;

5. System Reliability;

Financial Criteria

1. O&M and Sustainment Capital Costs;
2. Present Value of Incremental Revenue Requirement; and
3. Rate Impact.

Based on these criteria, the Company submits that the best alternative for the Project is Alternative B, i.e., to provide a second transformer at GFT (GFT T2) by purchasing and installing a new 161/63 kV transformer, remove 44.6 km of the 9L and 10L transmission lines between CHR and CSC, and repurpose 20.8 km of the 9L and 10L transmission lines to distribution lines. Alternative B best addresses the condition of existing facilities and reliability issues for the Grand Forks area. The evaluation of the alternatives and selection of the recommended solution will be discussed in detail in Section 3.4 and Section 3.5.

1.3.4 Project Costs and Rate Impact

The Project is estimated to have a capital cost of approximately $13.171 million in as-spent dollars, including AFUDC of $0.531 million and including net removal costs of $4.528 million. Table 1-1 and

Table 1-2 below summarize the total forecast capital costs and financial analysis of the Project, respectively.

Based on the total Project costs, the rate impact in 2022 is estimated to be 0.26 percent when all assets have been transferred to their appropriate plant asset account. For a typical FBC residential customer consuming an annual average of 11,500 kWh, this would equate to an approximate annual bill increase of $3.36 in 2022.

Table 1-1: Summary of Forecast Capital Costs ($ millions)

Particular	2018 $	As-Spent $	AFUDC	Total
Total Additions Charged to Plant	7.9	8.1	0.4	8.5
Net Removal Costs[4]	4.3	4.5	0.1	4.6
Total Project Capital Cost	***12.2***	***12.6***	***0.5***	***13.1***

Table 1-2: Summary of Financial Measure – Rate Impact

Particular	
2022 Rate Increase %	0.26%
Levelized % Rate Impact 40 Years	0.18%

[4] Net removal costs will be recorded in Accumulated Depreciation.

Section 6 provides a summary of the Project capital cost estimate. The financial schedule for the analysis described in

Table 1-2 can be found in Confidential Appendix J.

1.3.5 Stakeholder and Indigenous Consultation

FBC believes that its First Nations engagement on this Project should focus on the transmission lines component of the GFT Reliability Project. The transformer component consists of work that is being completed within the existing GFT substation and, as such, will have no adverse effect on Indigenous communities or their rights.

FBC has consulted with potentially affected Indigenous communities regarding this Project. Section 4 of the Application provides details on the consultation.

FBC believes that it has adequately engaged and consulted with Indigenous and other key stakeholders.

Based on the information summarized above and provided in the Application, the Company believes it has demonstrated that the Project is in the public interest and should be approved.

1.4 REGULATORY HISTORY

FBC first proposed the installation of a second 161/63 kV transformer at GFT and the removal of 9L and 10L between CSC and CHR in its 2012-2013 Capital Expenditure Plan. In that application, the transformer addition project was linked to the Grand Forks to Warfield Fibre Project as the infrastructure required to integrate the transformer into the substation would be greatly reduced by the availability of a secure fibre-optic communications link to the remote substations. At that time, FBC also sought approval for expenditures related to the relocation and storage of a spare transformer at GFT.

In its Decision and Order G-110-12, the BCUC endorsed the relocation of the spare transformer, but rejected the proposed expenditures related to the installation of the second transformer because the need for increased reliability was not apparent. The BCUC also directed FBC to apply for a separate CPCN for approval of the project.

FBC has since relocated the spare 161/63 kV transformer to the GFT site. Fibre has not been included as part of the Project scope for this Application because FBC has entered into a long term contract for dark fibre with a third party.

1.5 PROPOSED REGULATORY REVIEW OF CPCN APPLICATION

1.5.1 The CPCN Threshold and the PBR Materiality Threshold

Pursuant to the Company's Performance Based Ratemaking (PBR) Plan for the period 2014 through 2019 (which was approved by Order G-139-14) and the Capital Exclusion Criteria under Order G-120-15, the BCUC set both a CPCN dollar threshold and a PBR materiality threshold of $20 million.[5]

The Project addresses issues discussed in the Company's 2012 Integrated System Plan (2012 ISP) and 2012 Long Term Capital Plan[6] (2012 LTCP); specifically addressed are issues from the Grand Forks Terminal Transformer Addition (Section 2.8.3 of the 2012 LTCP).

With respect to the CPCN threshold, FBC is directed to apply to the BCUC for a CPCN for projects that require in excess of $20 million in capital expenditures. The total forecast cost of the Project is not expected to exceed $20 million, and FBC does not anticipate any significant public concerns with the proposed solution. On that basis, the Company would not typically file a CPCN application for a project of this nature.

As mentioned above, FBC first proposed this project in its 2012-2013 Capital Expenditure Plan application. In that application, FBC sought approval to recover only engineering/estimating expenditures with a subsequent application to propose procurement and installation of the fibre cable. At the time, the BCUC denied approval for the preliminary costs and directed that a CPCN be filed for the project.

The BCUC confirmed the requirement for a CPCN application in Order G-80-16. FBC is therefore filing this CPCN Application to ensure that the regulatory process can proceed in a timely manner to accommodate the Project schedule and in-service date.

1.5.2 Proposed Regulatory Process

The information presented in this Application accords with the BCUC's 2015 CPCN Guidelines. FBC believes that a written hearing process with one round of information requests will provide for an appropriate and efficient review of the Application.

As mentioned above, the Project is well within the CPCN threshold. The alternatives available to FBC are straightforward, with the selected alternative addressing all identified issues and providing the best value for investment over a 40 year analysis period. Construction will be confined to property and facilities wholly owned by FBC or where FBC has an existing ROW. The Application provides information on all areas required by the CPCN Guidelines. Any

[5] In the Decision accompanying Order G-139-14 (FBC Application for Approval of a Multi-Year PBR Plan for the years 2014 through 2018) at pp. 161-162, 175, the CPCN criteria was approved as the PBR materiality threshold, pending a further process. This further process occurred in FortisBC Energy Inc/FBC Capital Exclusion Criteria in PBR, and by Order G-120-15 the BCUC ordered that FBC's CPCN dollar threshold will be maintained at $20 million and that the PBR materiality threshold be set at $20 million.

[6] FBC 2012 ISP, Vol. 1 2012 Long Term Capital Plan, pp. 54-55.

additional areas of concern in this Application can be adequately addressed through a written process.

FBC respectfully proposes the regulatory timetable set out in Table 1-3 below. If the Application is approved by end of May 2019, FBC plans to initiate the detailed design and procurement for the Project early in the third quarter of 2019. FBC plans to begin construction by the end of the third quarter 2019, and is expecting to have the Project in service by the third quarter of 2021.

Table 1-3: Proposed Regulatory Timetable

ACTION	DATE (2018)
BCUC Issues Procedural Order by	Thursday, November 29
FBC Publishes Notice by	Week of December 10
ACTION	**DATE (2019)**
Intervener Registration	Thursday, January 3
BCUC Information Request (IR) No. 1	Thursday, January 10
Intervener IR No. 1	Thursday, January 17
FBC Response to IRs No. 1	Thursday, January 31
FBC Final Written Submission	Tuesday, February 12
Intervener Final Written Submission	Tuesday, February 19
FBC Written Reply Submission	Tuesday, February 26

1.6 *ORGANIZATION OF THE APPLICATION*

The Application provides detailed information in support of the Project. The remainder of the Application is organized into the following sections:

- Section 2 provides an overview of the Applicant, and provides information on its financial and technical capabilities for the Project;
- Section 3 provides an overview of the existing facilities in the Grand Forks area, provides a summary of the justifications for the Project, describes the alternatives considered, and compares and evaluates each of the alternatives against a list of technical and financial criteria;
- Section 4 discusses FBC's public consultation, indigenous consultation and communication efforts regarding the Project;
- Section 5 provides a detailed description of the proposed Project, including construction, design, resource planning and management, schedule, as well as setting out a risk analysis and discusses potential Project impacts;
- Section 6 provides the cost estimates, the assumptions upon which the financial analysis is based and the rate impacts; and

- Section 7 provides an overview of the BC Provincial Government energy objectives and policy considerations with relation to the Project.

2. APPLICANT

2.1 NAME, ADDRESS, AND NATURE OF BUSINESS

FortisBC Inc.
Suite 100, 1975 Springfield Road
Kelowna, B.C. V1Y 7V7

FBC is an investor-owned utility engaged in the business of generation, transmission, distribution and bulk sale of electricity in the southern interior of British Columbia. It is an integrated utility serving approximately 175 thousand customers directly and indirectly. FBC was incorporated in 1897 and is regulated by the BCUC pursuant to the UCA.

2.2 FINANCIAL AND TECHNICAL CAPACITY

FBC is capable of financing the Project. FBC has credit ratings for senior unsecured debentures from DBRS and Moody's Investors Service of A (low) and Baa1 respectively.

The Company has a rate base of approximately $1.3 billion, including four hydroelectric generating plants with an aggregate capacity of 225 MW and approximately 7,200 km of transmission and distribution power lines for the delivery of electricity to major load centres and customers in its service area. FBC has approximately 500 full-time and part-time employees.

FBC will provide the necessary resources to manage the design and construction of the GFT Reliability Project. FBC has experience in managing the design, construction, operation and maintenance of substations and transmission lines in British Columbia.

In recent years the Company has completed several major projects including the Advanced Metering Infrastructure project (total value of approximately $51 million) and the Kootenay Operations Centre project (total value of approximately $21 million).

2.3 COMPANY CONTACT

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2.4 *LEGAL COUNSEL*

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3. PROJECT NEED, ALTERNATIVES, AND JUSTIFICATION

In this section, FBC will:

- Provide an overview of the existing facilities, equipment, and components in the Grand Forks area that are relevant to the Application;
- Describe the Project need with respect to reliability for our customers, and asset condition;
- Identify the alternatives considered for the Project;
- Provide a comparison and evaluation of the alternatives; and
- Describe the preferred solution for the Project.

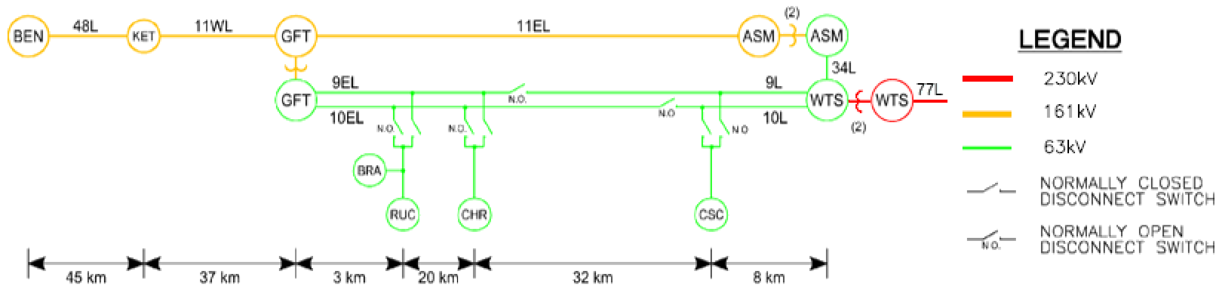
3.1 *OVERVIEW OF EXISTING FACILITIES*

GFT is supplied at 161 kV both from ASM, which is located near Warfield, via 11 Line E (11EL) and from KET, which is located near Rock Creek, via 11 Line West (11WL). Given there are two reliable 161 kV sources of supply, single contingency (N-1) criteria[7] for the 161 kV system is met at GFT. GFT has a single 161/63 kV transformer, which is nominally rated 45/60 MVA and is referred to as Grand Forks Terminal T1 transformer (GFT T1). GFT T1 provides the local 63 kV transmission supply to Grand Forks Terminal T3 distribution transformer (GFT T3), and to the distribution substations Ruckles (RUC), Christina Lake (CHR) and Bradford/Roxul (BRA) via 63 kV transmission lines 9 Line E (9EL) and 10 Line E (10EL). Cascade distribution substation (CSC), which is located near Rossland, is supplied from WTS, which is located near Warfield, via 9L and 10L in normal operation. A single-line diagram of the transmission system between WTS and KET is shown below in Figure 3-1.

In the event of an outage to GFT T1, the 63 kV supply can be provided to these distribution substations from WTS via the 63 kV transmission lines 9 Line (9L) and 10 Line (10L). However, this secondary 63 kV supply is unreliable given the age and condition of both 9L and 10L.

[7] Single contingency reliability, also referred to as N-1 reliability, means that an outage of a single element with all other elements of the power system in service (a single transmission line, transformer, generating unit, power conditioning unit like a shunt capacitor bank, a shunt reactor bank, a series capacitor, a series reactor, etc.) will result in no load loss. This is a normal transmission system design criterion.

Figure 3-1: Existing Grand Forks Area Transmission System

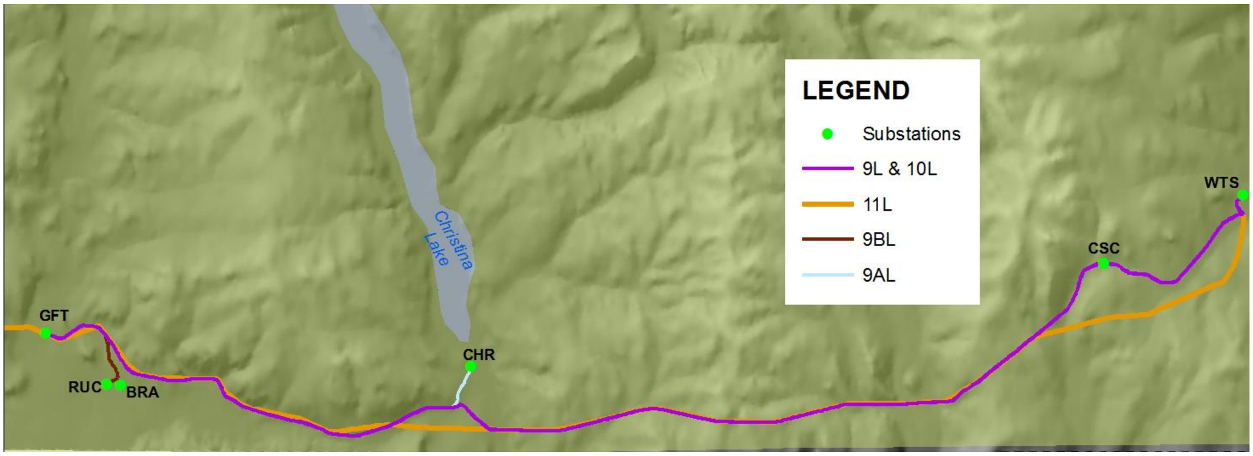


Over the past five years, the maximum winter and summer peak loads on GFT T1 were approximately 34 MW and 29 MW, respectively. GFT T1, with a nominal rating of 45/60 MVA, has sufficient capacity to meet the forecasted distribution demand for the Grand Forks area load over the system planning horizon of 20 years. The characteristics of the four distribution transformers from which GFT T1 serves the local customer base are as follows:

- GFT has a single distribution transformer (GFT T3), which has a nominal rating of 12/16/20 MVA. It serves approximately 1,650 direct residential and commercial customers of FBC in addition to the City of Grand Forks electric utility with approximately 2,200 customers (considered indirect customers of FBC);
- RUC consists of a single distribution transformer (RUC T3), which has a nominal rating of 24/32/40 MVA. It serves approximately 460 FBC residential and commercial customers, one FBC industrial customer, and provides a second source of distribution supply to the City of Grand Forks electric utility;
- CHR consists of a single distribution transformer (CHR T1), which has a nominal rating of 3.75/5 MVA. It serves approximately 1,460 FBC residential and commercial customers; and
- BRA serves a single, primary-metered, 63 kV industrial customer.

The 63 kV transmission lines 9L and 10L were originally constructed in 1908 and supplied power from the West Kootenay to customers in the Boundary and South Okanagan. Taps off these transmission lines were later built to supply a number of substations including CHR and RUC. In 1965, Grand Forks Terminal was constructed and GFT T1 was installed to connect the 63 kV transmission facilities to the 161 kV system via 11L. After GFT T1 was installed, it became the primary 63 kV supply for the Grand Forks area with 9L and 10L remaining as the backup supply. Both 9L and 10L each cover a total distance of 62.4 km between WTS and GFT. A geographic map of 9L and 10L is provided below in 3-2.

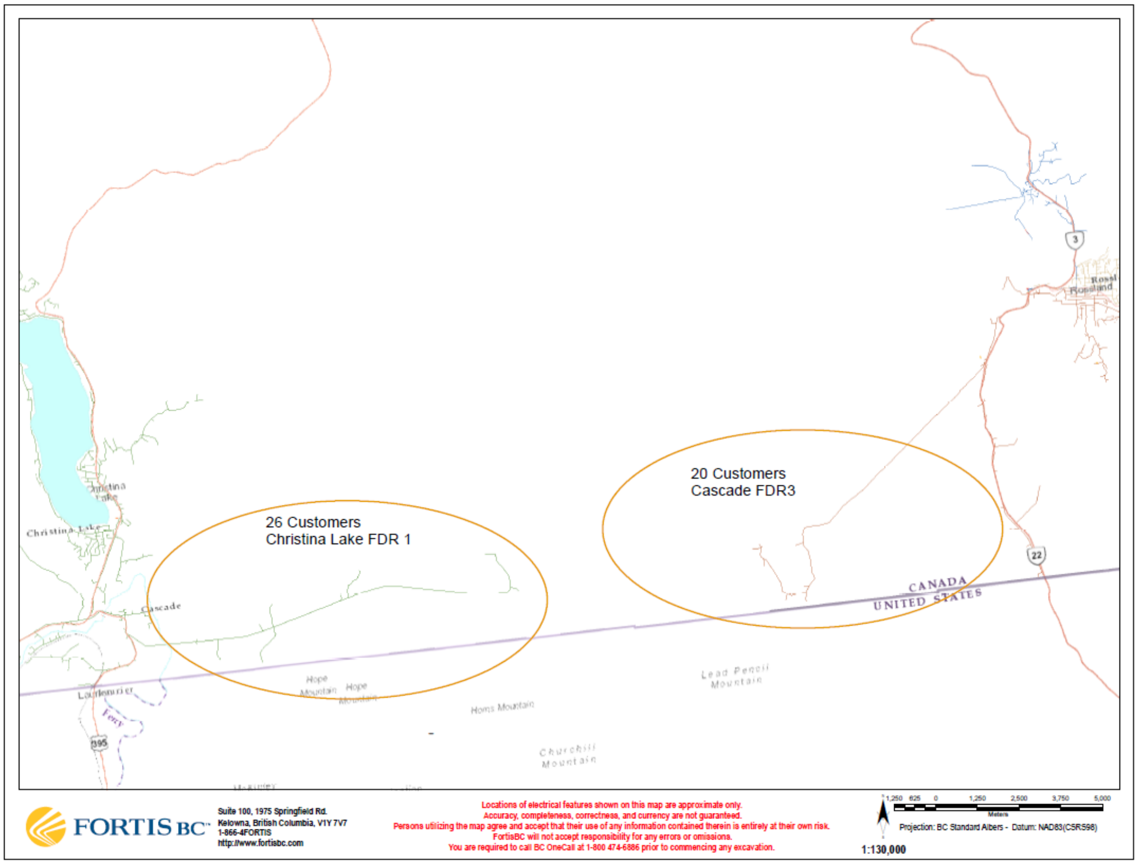
Figure 3-2: Geographic Map of 9L and 10L



In normal operation, 9L is open and 10L is de-energized between the CHR tap and CSC substation. As well, in normal operation, approximately 32.7 km of 10L is de-energized between the CHR tap and CSC substation due to its poor condition, and must be visually assessed and confirmed to be in suitable condition (and rehabilitated to minimum standards if necessary) before it can be placed in service. The condition of 9L and 10L will be discussed further in Section 3.2.1.3. Please refer to Appendix A for the existing 9L and 10L circuit arrangement.

Over the years, underbuilt distribution circuits were constructed on portions of both 9L and 10L to serve customers in the vicinity of the lines right of way. There are currently 46 customers supplied from distribution underbuild on 9L and 10L transmission structures as highlighted in Figure 3-3. Along 10L, 9.8 km of distribution underbuild serves 26 customers from CHR Feeder 1 (8.5 km single phase and 1.3 km three phase). Along 9L, 11.0 km of distribution underbuild serves 20 customers from CSC Feeder 3 (10.5 km single phase and 0.5 km three phase).

Figure 3-3: 9L and 10L Distribution Underbuild and Customers



The maximum load that can be supplied by either 9L or 10L is 27 MW, which is insufficient to meet peak load conditions for the Grand Forks area.[8] If both lines are operated in parallel, the maximum load that can be supplied increases to 45 MW. During seasonal peaks, both lines must operate in parallel to meet the load requirements in the event of an outage or failure to GFT T1. However, mountainous terrain, particularly in winter, can make it impossible to operate 9L and 10L in parallel since the lines traverse the Rossland Mountain Range, restricting physical access and making it extremely difficult to visually assess and rehabilitate 10L before it can be energized. As such, 9L and 10L are not a reliable secondary 63 kV supply for the Grand Forks area.

3.2 PROJECT NEED

The GFT Reliability Project is a reliability-driven project, as FBC cannot meet the single contingency (N-1) criteria for the 63 kV system in the Grand Forks area since parallel operation of 9L and 10L cannot be relied upon. As will be explained below, the likelihood of failure and the

[8] The maximum load on GFT T1 was approximately 34 MVA in the winter and 29 MVA in the summer over the past five years.

ability to restore customers is further impacted by the condition of the existing facilities at GFT and transmission lines 9L and 10L.

The purpose of the Project is to ensure FBC customers continue to receive safe and reliable service in the event of an outage or failure of GFT T1.

3.2.1 Facilities Condition Assessment

3.2.1.1 GFT T1 Condition

GFT T1 is of 1965 vintage and is now 53 years old, exceeding the expected transformer lifespan of 40 years. In recent years, the load tap changer (LTC) tanks have been replaced and the oil has been processed. The unit is closely monitored and recent Dissolved Gas Analysis (DGA) results have been relatively stable.

ABB, a qualified transformer design contractor, performed a comprehensive condition assessment in 2018 for GFT T1 on behalf of the Company, which is provided in Appendix B. Based on the analysis, ABB recommends GFT T1 should not be kept in service for more than 15 years.[9]

The condition assessment calculated the Risk of Failure (RoF) for this transformer to be 2.6 percent based on the most recent DGA and the available test/maintenance data.[10] The RoF for this unit is on the high side when compared to a typical utility population.

ABB's report identifies the second most failed component for this type of transformer is the LTC and the single most common cause of failure is inadequate short circuit strength. Both of these components are weak in this unit. Also, based on the age profile for over 7 thousand units in a particular subset of in-service transformers contained in the Transformer Industry-Wide Database (IDB), the most common end of life for a transformer occurs in the 35 to 45 year portion of the population. This unit is 53 years old. With each passing year, the probability of failure of this unit increases.

3.2.1.2 OLI T1 On-site Spare Transformer Condition

Oliver T1 (OLI T1) is a cold standby (normally de-energized) spare transformer located at GFT. It is a 161/63 kV transformer with a nominal rating of 45/60 MVA. The transformer was previously located at the Oliver Terminal, but was disconnected in 2011 as part of the Okanagan Transmission Reinforcement Project and relocated to GFT in 2014. The unit is of 1971 vintage and is now 47 years old, exceeding the expected transformer lifespan of 40 years.

In the event GFT T1 fails, it would likely take more than a year to repair or replace the unit based on historical procurement timelines. In the interim, FBC could install OLI T1 until a replacement unit could be procured. Although OLI T1 is on-site, it may take several weeks to

[9] Page 18, Section 10 – Risk of Failure Assessment
[10] Page 17-19, Section 10 – Risk of Failure Assessment, and Section 11 – Conclusions

install due to substation reconfiguration and civil work required to accommodate the spare transformer.

A field inspection assessment of OLI T1 was performed in 2013 by ABB prior to its relocation to GFT. The field inspection assessment report is included as Appendix D. The report concluded the tensile strength of the insulation paper is in the upper “Mid-Life” category.[11] Therefore, once refurbished, this indicates the unit could be used for another 10 to 15 years.

Given that OLI T1 is normally de-energized, there is always some uncertainty with the condition of the unit and its availability for service. Further, if the transformer were damaged in the process of installing it in the location of the failed GFT T1, then both transformers could be unavailable for an extended period. This would leave FBC with no alternative but to attempt to serve whatever load it could in the Grand Forks area using only the aging 9L and 10L.

3.2.1.3 9L and 10L Condition

The 63 kV transmission lines 9L and 10L were originally constructed in 1908 as primarily single wood pole designs. Many of the older vintage structures on 9L have been replaced over the years but approximately 32 percent of early vintage poles (1960’s and earlier) are still in service between CHR and CSC. On 10L, approximately 76 percent of early vintages poles are still in service between CHR and CSC, with only some structures having been replaced on an as-needed basis.

DBS Energy Services Inc. (DBS), a qualified line design contractor, performed a condition assessment in 2016 for 9L and 10L between the CHR tap and CSC substation on behalf of the Company. The 2016 assessment found that even though 9L has had considerable rehabilitation work in past years, much of the line still requires attention and approximately 37 percent of the structures were recommended for replacement. The assessment also found that 10L requires even more rehabilitation work, with approximately 69 percent of the entire line in need of replacement. The report concludes that 9L and 10L are generally in quite poor condition overall and are a considerable risk as to reliability and safety. The condition assessment report is included as Confidential Appendix C.

To mitigate further deterioration, the transmission lines have required continual work. However, only urgent repairs have been performed on 10L since 2014 pending a decision on the future of the line as described in this Project. Between 2015 and 2017, urgent repairs on 9L and 10L cost an average of $0.121 million per year (2018$).

Both 9L and 10L pass over the Rossland mountain range, making them difficult to access due to heavily treed, steep, and mountainous terrain with limited road access. In the winter, access is further impeded by ice and heavy snowfall. Figure 3-4 below shows a typical example of the mountainous terrain along the transmission line route.

[11] Page 4, Section 3.1 - Main Tank

Figure 3-4: 9L and 10L Rossland Mountain Range Terrain

Given the extremely poor condition of 10L, it is normally de-energized between the CHR tap and CSC substation. The line must be visually assessed and rehabilitated to minimum operating standards before it can be energized in the event of an emergency. In winter this can be nearly impossible, as 10L cannot be accessed from the ground due to the snowy and mountainous terrain.

If there is a GFT T1 outage or failure, customers will be left without power until the system is reconfigured to the backup 63 kV supply from 9L and 10L. The reconfiguration can result in lengthy restoration times and energization of 10L may not be possible if the line cannot be accessed. With only 9L in service, the maximum load that can be supplied is only 27 MW, which is insufficient to meet the seasonal peak loads for the Grand Forks area. In order to use 9L and 10L as the secondary 63 kV supply for the Grand Forks area, extensive rehabilitation work will be required to ensure both lines are available when needed.

3.2.2 Reliability

Typical industry transmission planning standards require the system to be planned such that all projected customer loads are served during both normal (N-0)[12] operation and single contingency (N-1)[13] operation. As such, FBC transmission planning criteria specifies that firm customer load should be able to be supplied in N-0 and N-1 conditions.

FBC's transmission outage statistics show there have been a combined total of 54 outages on 9L and 10L over the past five years. The table below categorizes the total 9L and 10L outages by cause and shows the average duration, minimum duration, and maximum duration. Most outages to 9L and 10L are caused by snow unloading and lightning.

Table 3-1: 9L and 10L Outage Statistics (June 2013 - June 2018)

Description of Cause	Number of Outages	Avg Duration (hrs)	Min Duration (hrs)	Max Duration (hrs)
Snow	18	1.839	0.001	16.159
Tree Into Line	5	12.451	0.002	27.847
Equipment Failure	3	22.069	5.680	39.378
Pole Issue	5	9.096	1.176	17.052
Lightning	12	0.061	0.001	0.230
Human Interference	1	5.286	5.286	5.286
Conductor Issue	3	83.098	5.240	152.361
Flood	1	1.198	1.198	1.198
Forest Fire	2	0.914	0.127	1.701
Unknown	4	6.356	0.001	15.088
Total	**54**			

FBC's transmission outage statistics show there has been only a single outage to GFT T1 over the past five years, which was caused by lightning. The table below provides the outage cause and outage duration.

[12] Normal operation, also referred to as N-0 reliability, means that with all major elements of the power system in service, the network can be operated to meet projected customer demand in order to avoid a load loss (customer outage).

[13] Single contingency, also referred to as N-1 reliability, means that an outage of a single element with all other elements of the power system in service (a single transmission line, transformer, generating unit, power conditioning unit like a shunt capacitor bank, a shunt reactor bank, a series capacitor, a series reactor, etc.) results in no load loss.

Table 3-2: GFT T1 Outage Statistics (June 2013 - June 2018)

Description of Cause	Number of Outages	Avg Duration (hrs)	Min Duration (hrs)	Max Duration (hrs)
Lightning	1	0.003	0.003	0.003
Total	**1**			

In the event of a GFT T1 outage, the secondary 63 kV supply for the Grand Forks area has been historically provided by 9L and 10L from WTS. In order to supply all customers during peak load conditions, both 9L and 10L must be in-service. However, before 10L can be energized, it must be visually assessed and rehabilitated to meet minimum operating standards. Due to the mountainous terrain, in winter this can be impossible, as some sections are inaccessible. Even if 9L and 10L could be operated in parallel, customers would likely experience an increased number of outages as the transmission outage statistics indicate in Table 3-2 above. Given the poor condition of 9L and 10L and their access issues, this backup supply can no longer be depended on and is the limiting factor for providing 63 kV N-1 reliability for the Grand Forks area.

The GFT T1 condition assessment concluded that the useful remaining life of the transformer is approximately 15 years, leaving sufficient time to plan for its replacement. Although the risk is relatively low that the transformer would fail in the near term, if it were to fail during peak load conditions, FBC's ability to supply all customer load would be restricted until either 10L could be energized or the on-site spare transformer (OLI T1) could be installed as a replacement.

3.2.3 Project Need Summary

The existing 63 kV backup supply for the Grand Forks area is unreliable and as such, does not effectively meet N-1 planning criteria under peak load conditions. The likelihood of a failure of GFT T1 and the ability to restore customers is further impacted by the condition of the existing facilities at GFT (GFT T1 and OLI T1) and transmission lines 9L and 10L.

GFT T1 is 53 years old, exceeding the expected 40-year lifespan of the transformer. The condition assessment performed by ABB in 2018 concluded that GFT T1 should not remain in service for more than 15 years.

OLI T1 is 47 years old, also exceeding the expected 40-year lifespan of the transformer. However, the field inspection performed by ABB in 2013 concluded the tensile strength of the insulation paper is in the upper "Mid-Life" category. Therefore, once refurbished, this indicates the unit could be used for another 10 to 15 years.

The DBS condition assessment performed in 2016 concluded the transmission lines 9L and 10L are in poor condition between the CHR tap and CSC substation. The lines require extensive rehabilitation, with 37 percent of 9L and 67 percent of 10L requiring replacement. Given the extremely poor condition of 10L, it is normally de-energized between CHR tap and CSC substation. In an emergency, it may not be possible to energize the line if it cannot be accessed due to the mountainous terrain.

In the event of a GFT T1 outage under peak load conditions, if both 9L and 10L cannot be reconfigured to provide the 63 kV supply from WTS, the Grand Forks area load cannot be entirely supported.

In the event of a GFT T1 failure, it would likely take more than a year to procure and install a replacement transformer. In the meantime, the on-site spare transformer could be used as an emergency backup. However, if 9L and 10L could not be reconfigured to provide the 63 kV supply while the on-site spare transformer was being installed, this could result in extended customer outages for the Grand Forks area under peak load conditions.

To meet 63 kV N-1 criteria for the Grand Forks area in the event of a GFT T1 outage or failure, a second 161/63 kV supply at GFT could be provided or the existing 63 kV supply from WTS could be rehabilitated. These required upgrades are essential to improve the reliability concerns for the Grand Forks area and meet N-1 criteria under all load conditions.

3.3 *ALTERNATIVES CONSIDERED*

To provide a reliable 63 kV supply to the Grand Forks area, two types of project solutions were considered: provide a second 161/63 kV supply at GFT, or rehabilitate the existing 63 kV supply from WTS. Based on the above, the following three feasible alternatives were considered for the Project.

- Alternative A: Provide a second transformer at GFT (GFT T2) by installing the on-site spare (OLI T1), remove 44.6 km of the 9L and 10L transmission lines, and repurpose 20.8 km of the 9L and 10L transmission lines to distribution lines;
- Alternative B: Provide a second transformer at GFT (GFT T2) by purchasing and installing a new 161/63kV transformer, remove 44.6 km of the 9L and 10L transmission lines, and repurpose 20.8 km of the 9L and 10L transmission lines to distribution lines; and
- Alternative C: Rehabilitate 9L and 10L transmission lines.

Do nothing or Status Quo was not considered an option because FBC cannot currently meet the N-1 transmission planning criteria in the event of a GFT T1 failure during seasonal peaks.

FBC also considered consolidating 9L and 10L into a single circuit using 477 ACSR (Aluminium Conductor Steel-Reinforced) but rejected this option because the capacity of the new line could not support the Grand Forks area load.

Each of the three alternatives are briefly discussed in this section. To ensure that the alternatives could be appropriately compared, the cost estimates were developed to an AACE14 Class 3 level of definition. Section 3.5 provides a summary of the preferred alternative.

3.3.1 Alternative A: Install Existing On-site Spare Transformer (OLI T1)

Alternative A involves installing the existing on-site spare transformer (OLI T1) as the second GFT transformer, removing 44.6 km of the 9L and 10L transmission lines, and repurposing 20.8 km of the 9L and 10L transmission lines to distribution lines. The second transformer, previously designated OLI T1, would be designated as GFT T2.

Because the GFT station was originally laid out for a second transformer, no new land acquisition would be required and all construction would be contained within the existing fence-line. The substation would need to be reconfigured, including the installation of two new 63 kV circuit breakers (CBT1 and CBT2). Oil containment for GFT T2 would also need to be installed, along with new current transformers and a vertical break disconnect switch.

Given that the installation of a second transformer at GFT would achieve 63 kV N-1 criteria, transmission lines 9L and 10L would no longer be required as the backup 63 kV supply. Therefore, this alternative includes the removal of 44.6 km of 9L and 10L from CSC in Rossland to disconnect switches CHR 9-1 and CHR 10-1 in Christina Lake. The 4/0 copper transmission conductor and any poles that do not have underbuild can be removed, with the remaining structures rehabilitated as distribution. For a detailed map identifying the proposed transmission removal and distribution repurposing, please refer to the condition assessment report in Confidential Appendix C.[15]

The capital cost of this alternative is $11.3 million (2018$).

3.3.1.1 Advantages:

- Provides 63 kV N-1 reliability at GFT.
- Reduces exposure to transmission line outages.[16]
- Reduces 9L and 10L transmission O&M expenses by approximately $60 thousand per year.
- Reduces 9L and 10L brushing costs by approximately $30 thousand per year.
- Reduces 9L and 10L transmission rehabilitation capital costs, the estimated cost savings of which would be approximately $500 thousand for every 8-year cycle.
- Reduces 9L and 10L urgent repairs by approximately $121 thousand per year.

[14] Please refer to Section 6 for further details.
[15] Appendix VII – Option 2 Layout 9L/10L (CSC to CHR) – 63 kV Salvage & Re-use as Dx
[16] Between 2015-2018, there were a combined total of 54 outages between 9L and 10L.

3.3.1.2 Disadvantages:

- Increases station O&M expenses at GFT by approximately $5 thousand per year.
- Given the existing condition of GFT T1 and OLI T1, there is some risk that both transformers could fail within a year from one another. In this (N-2)[17] scenario, there would be no reliable 63 kV backup supply for GFT.

3.3.2 Alternative B: Install New Transformer

Alternative B, like Alternative A, also involves providing a second 161/63 kV supply at GFT, except that it includes purchasing and installing a new 161/63 kV transformer with a nominal rating of 45/60 MVA. The new transformer would be designated as GFT T2. This leaves OLI T1 as an on-site spare which might be considered as a replacement for GFT T1 when it reaches end of life.

Alternative B, like Alternative A, also involves removing 44.6 km of the 9L and 10L transmission lines, and repurposing 20.8 km of the 9L and 10L transmission lines to distribution. For a detailed map identifying the proposed transmission removal and distribution repurposing, please refer to the condition assessment report in Confidential Appendix C.[18]

The capital cost of this alternative is $12.2 million (2018$).

3.3.2.1 Advantages:

- Provides 63 kV N-1 reliability at GFT.
- Reduced risk that both GFT T1 and GFT T2 could fail simultaneously given that GFT T2 is a new transformer.
- Reduces exposure to transmission line outages.[19]
- Reduces 9L and 10L transmission O&M expenses by approximately $60 thousand per year.
- Reduces 9L and 10L brushing costs by $30 thousand per pear.
- Reduces 9L and 10L transmission rehabilitation capital costs, the cost savings would be approximately $500 thousand for every 8-year cycle.
- Reduces 9L and 10L urgent repairs by approximately $121 thousand per year.

3.3.2.2 Disadvantages:

- Increases station O&M expenses by approximately $5 thousand per year.

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[17] N-2 reliability means that given the outage of two elements, with all other elements of the power system in service, there is no load loss. This is not a normal transmission system design criterion.

[18] Appendix VII – Option 2 Layout 9L/10L (CSC to CHR) – 63 kV Salvage & Re-use as Dx

[19] Between 2015-2018, there were a combined total of 54 outages between 9L and 10L.

3.3.3 Alternative C: Transmission Rehabilitation of 9L and 10L

Alternative C includes the rehabilitation of 9L and 10L transmission lines with a like-for-like replacement of the existing facilities and with all work completed to current FortisBC standards. No reconductoring (i.e., replacement of the existing transmission line conductors) is contemplated. In this alternative, 9L and 10L would remain the secondary 63 kV backup supply for GFT. No second transformer would be installed at GFT.

A recommended scope of work (SOW) for 9L and 10L is provided in the condition assessment report in Confidential Appendix C.[20] The SOW was based on data collected from the 2014 condition assessment patrols and was reconciled against the 2015 urgent work completed on the lines. To summarize, the work that would be completed is as follows:

- Replacement of numerous red-tagged (failing) structures;
- Staged replacement of numerous structures that have been blue-tagged (temporarily reinforced with pole stubs) for several condition assessment cycles (i.e., at end-of-life);
- Repair and replacement of failing or damaged insulation mostly at the end of life; often 50 to 60 plus years old;
- Repair and replacement of failing or damaged cross arms at the end of life; 30 plus years old;
- Repair and replacement of numerous poles with major wood pecker damage; and
- Removal of old structures.

The capital cost of this alternative is $9.259 million (2018$).

3.3.3.1 Advantages:

- Provides 63 kV N-1 reliability for the Grand Forks area.
- Improves condition of 9L and 10L, extending the life of the transmission lines.
- 10L remains energized resulting in shorter restoration times since the line no longer needs to be visually assessed and rehabilitated prior to being placed in service.
- Reduces 9L and 10L urgent repairs by approximately $97 thousand per year.

3.3.3.2 Disadvantages:

- Limited reduction in transmission outages when GFT T1 is out of service since 9L and 10L still traverse the Rossland Mountain Range.

[20] Appendix II - 9L (CSC to CHR) Condition Assessment – Recommended Summary of Work, and Appendix III – 10L (CSC to CHR) Condition Assessment – Recommended Summary of Work.

- Sections of 9L and 10L remain difficult to access in winter with some sections inaccessible due to ice, heavy snow, and steep terrain.
- No reduction in 9L and 10L O&M costs.
- No reduction in 9L and 10L transmission line condition assessment and rehabilitation capital costs.

3.4 *ALTERNATIVES COMPARISON*

FBC conducted a technical and financial evaluation of the three alternatives discussed above. The following section discusses the assumptions used in the financial analysis and provides a comparison of the alternatives against the technical and financial criterion.

The financial analysis calculates the present value and rate impact of the three alternatives over an assumed 40-year life for a new transformer. The analysis further assumes that both the existing GFT T1 transformer and the on-site spare OLI T1 will need to be replaced within this 40 year period. The analysis includes the following future capital requirements in Years 10, 15 and 25, which are not being requested for approval in this Application:

- Alternative A: Install Existing On-site Spare Transformer
  - Year 10 - Replace GFT T1 with new transformer
  - Year 15 - Replace OLI T1 with new transformer
- Alternative B: Install New Transformer
  - Year 10 - Replace GFT T1 with OLI T1
  - Year 25 - Replace OLI T1 with new transformer
- Alternative C: Transmission Rehabilitation 9L and 10L
  - Year 10 - Replace GFT T1 with OLI T1
  - Year 25 - Replace OLI T1 with new transformer

The comparative merits of the alternatives, including the financial impact, are summarized in the table below. The criteria that were evaluated are as follows:

1. <u>Meets Single Contingency N-1 Transmission Planning Criteria:</u> Ability to continue to serve all load during the outage of a single element.
2. <u>Operations Accessibility and Operability:</u> Considers the accessibility and operability of the facilities by FBC employees and contractors working on system repairs, performing routine maintenance, or transferring load during real-time outages.
3. <u>Lifecycle Utilization:</u> Considers the full lifecycle of the existing assets.

4. Project Risk: Considers Project risks, such as schedule, lands, and unforeseen environmental and archeological discoveries.
5. System Reliability: Refers to the availability of electrical supply on the transmission, distribution and substation facilities.
6. O&M and Sustainment Capital Costs: Costs related to maintaining the assets in place.
7. Present Value Incremental Revenue Requirement: The discounted value of the revenue requirement over 40 years.
8. Rate Impact: The levelized rate impact over the 40 year period.

Table 3-3: Grand Forks Reliability Project Alternatives Comparison

Criteria	Alternative A	Alternative B	Alternative C
Technical			
Meets N-1 Transmission Planning Criteria	• Second transformer at GFT provides alternate 161/63 kV supply at GFT.	• Second transformer at GFT provides alternate 161/63 kV supply at GFT.	• 9L and 10L provide alternate 63 kV supply from WTS for Grand Forks area.
Operations	• GFT T1 load transfer can be transferred to GFT T2, and vice versa, remotely by System Control Centre (SCC).	• GFT T1 load transfer can be transferred to GFT T2, and vice versa, remotely by SCC. • OLI T1 remains as an onsite spare which can be used in the event either GFT T1 or GFT T2 fail.	• Field staff must manually close switches on 9L and 10L to reconfigure for 63kV supply from WTS. • OLI T1 remains as an onsite spare which can be used in the event GFT T1 fails.
Lifecycle Utilization[21]	• Makes use of remaining life of OLI T1 (15 years). • Removes portions of the legacy transmission lines 9L and 10L. • Given the condition of GFT T1 and OLI T1, both units could fail within a year of each other. This is considered to be a low risk.	• OLI T1 remains as on-site spare and available for future use. • Removes portions of the legacy transmission lines 9L and 10L.	• OLI T1 remains as on-site spare and available for future use. • Rehabilitates legacy transmission lines 9L and 10L.

[21] For each alternative the life cycle for GFT T1 is fully utilized.

Criteria	Alternative A	Alternative B	Alternative C
Project Risk	• Schedule Risk: Construction and removal window for 9L and 10L is impacted seasonally. • Lands Risk: Confirm distribution ROW for portion of 9L and 10L that will be repurposed for distribution. Considered to be low risk. • Environmental and Archeological Risk: Considered to be low risk.	• Schedule Risk: Construction and removal window for 9L and 10L is impacted seasonally. Lead time for a new transformer can be up to a year. • Lands Risk: Confirm distribution ROW for portion of 9L and 10L that will be repurposed for distribution. Considered to be low risk. • Environmental and Archeological Risk: Considered to be low risk.	• Schedule Risk: Construction window impacted seasonally. • Lands Risk: None, no changes to transmission or distribution routes. • Environmental and Archeological Risk: Considered to be low risk.
System Reliability	• Fewer outages are associated with transformers.	• Fewer outages are associated with transformers.	• More frequent outages are associated with transmission lines.
Financial			
O&M and Sustainment Capital Costs	• Reduces 9L and 10L transmission O&M costs. • Reduces 9L and 10L transmission rehabilitation capital costs. • Reduces 9L and 10L urgent repairs.	• Reduces 9L and 10L transmission O&M costs. • Reduces 9L and 10L transmission rehabilitation capital costs. • Reduces 9L and 10L urgent repairs.	• No reduction in 9L and 10L transmission O&M. • No reduction in transmission rehabilitation capital costs. • Reduces 9L and 10L urgent repairs
Present Value of 40 year Cost of Service	$9.959 million	$9.960 million	$14.004 million
Levelized Rate Impact	0.18 % $0.20 $/MWh ($0.00020 $/KWh)	0.18% $0.20 $/MWh ($0.00020 $/KWh)	0.26% $0.28 $/MWh ($0.00028 $/KWh)
Alternative Evaluation			
Ranking	2	1	3

3.5 *PREFERRED ALTERNATIVE AND JUSTIFICATION*

Based on the technical and financial evaluation of the three alternatives considered above, the preferred option is Alternative B, which involves installing a new second transformer at GFT, removing 44.6 km of 9L and 10L transmission lines, and repurposing 20.8 km of 9L and 10L transmission lines as distribution lines.

The sections below summarize the evaluation of each alternative against the criteria provided in Section 3.4.

3.5.1 Technical Evaluation

All three alternatives would meet the Company's transmission planning criteria to provide 63 kV N-1 reliability for the Grand Forks area. Alternative A and Alternative B achieve this through the installation of a second transformer at GFT, and Alternative C achieves this by rehabilitating 9L and 10L.

Alternative A and Alternative B would make it easier to transfer load in the event of a GFT transformer outage, as the System Control Centre (SCC) could remotely operate the station switches to transfer load to the second GFT transformer. Load transfer would take longer under Alternative C, as field staff would have to manually close the normal open switches on 9L and 10L in order to reconfigure the 63 kV supply from WTS.

Maintaining an on-site spare in Alternative B and Alternative C would also provide more operational flexibility as compared to Alternative A in the event GFT T1 fails, as the on-site spare could be installed as a replacement while a new transformer is procured.

All three alternatives utilize the full lifecycle of the existing assets. Alternative A makes use of the remaining life of OLI T1 by installing it as the second transformer GFT T2 and includes removal of portions of the transmission lines 9L and 10L. Alternative C makes use of OLI T1 as an on-site spare and rehabilitates the transmission lines 9L and 10L. Alternative B makes use of OLI T1 as an on-site spare and includes removal of portions of the transmission lines 9L and 10L.

As discussed in section 3.4, both the existing GFT T1 transformer and the on-site spare OLI T1 will need to be replaced within the 40-year analysis period. Because Alternative A involves installing the on-site spare now, these future capital requirements mean that two new transformers will later need to be installed at GFT for Alternative A, whereas only one new transformer will need to be installed in Alternative B and Alternative C.

Alternative B provides an additional benefit over Alternative A. Because Alternative B includes installation of a new second transformer at this time as opposed to installing the on-site spare, it reduces the risk that both GFT T1 and GFT T2 could fail simultaneously. As mentioned in section 3.2.1, GFT T1 has a useful remaining life of 10 years and the on-site spare has a useful remaining life of 10 to 15 years, whereas a new transformer would have a useful remaining life of at least 40 years.

All three alternatives have Project risks associated with them. The schedule risk is lowest for Alternative A since OLI T1 is already on site, Alternative B is dependent on the approximately one year lead time for procurement of a new transformer, and Alternative C has a greater likelihood of being impacted by seasonal construction windows. The lands risk is lowest for Alternative C since the distribution and transmission routes will not be changing, while Alternative A and Alternative B both require distribution rights-of-way to be confirmed for the portions of 9L and 10L that will not be removed. All alternatives have low unforeseen environmental and archaeological discovery risk during the construction phase based on FBC's historical experience in the GFT and along the 9L and 10L right-of-way.

Alternative A and Alternative B further improve system reliability by reducing exposure to transmission line outages through the removal of 9L and 10L, compared to Alternative C which rehabilitates the lines.

Based on the technical evaluation, Alternative A and Alternative B better address the technical criteria by supplying a second 161/63 kV supply at GFT as compared to Alternative C. However, Alternative B offers improved reliability compared to Alternative A since it includes installation of a new second transformer at GFT as opposed to installation of the on-site spare, thereby addressing the existing condition of GFT T1, which has exceeded the expected transformer lifespan of 40 years. This is because the on-site spare has a useful remaining life of only 10 to 15 years, whereas a new transformer would have a useful remaining life of 40 years. Furthermore, Alternative B is a more reliable option for the additional reason that OLI T1 would remain as an on-site spare at GFT. Therefore, Alternative B is the preferred solution as it best addresses the issue of transmission reliability for the Grand Forks area.

3.5.2 Financial Evaluation

Alternative A and Alternative B will have a net reduction in O&M costs since a large portion of 9L and 10L will be removed. There will be no change in O&M costs for Alternative C. In addition, FBC transmission condition assessment and rehabilitation (sustainment capital) occurs on an eight-year cycle; removal of a portion of 9L and 10L will reduce these costs in Alternative A and Alternative B. All three alternatives will see a reduction in urgent repairs on 9L and 10L, with the largest reduction in Alternative A and Alternative B since a portion of the lines will be removed.

Although the initial capital cost of Alternative A is less than Alternative B, the present value of the incremental cost of service between Alternative A and Alternative B is substantially equal, since the levelized rate impact percentage and the $ / MWh is the same (the present value for Alternative A is only $1 thousand lower than Alternative B). Even though Alternative C has the lowest initial capital cost, its present value of incremental cost of service is highest because of the higher O&M and sustainment capital costs for 9L and 10L.

Based on the financial analysis, both Alternative A and Alternative B better minimize the financial impact of the Project than Alternative C. Of these two options, the Company prefers Alternative B since it results in the same rate impact to customers as Alternative A based on a levelized lifecycle analysis over a 40 year period and was the preferred alternative based on the technical criteria as explained above.

3.5.3 Recommended Solution

The Company recommends Alternative B: Provide a second transformer at GFT (GFT T2) by purchasing and installing a new 161/63kV transformer, removing 44.6 km of the 9L and 10L transmission lines, and repurposing 20.8 km of the 9L and 10L transmission lines to distribution.

From a financial perspective, Alternative A and Alternative B are very similar, with both alternatives resulting in the same rate impact to customers based on a levelized lifecycle analysis over a 40-year period. However, Alternative B will be a more reliable option than Alterative A since it seeks to install a new second transformer as GFT T2 as opposed to installing the on-site spare. As mentioned above, the on-site spare has a useful remaining life of only 10 to 15 years, whereas a new transformer would have a useful remaining life of at least 40 years. Furthermore, Alternative B is a more reliable option because OLI T1 would remain as an on-site spare at GFT. Therefore, Alternative B is the preferred solution as it better addresses the issue of reliability for the Grand Forks area.

Of the three alternatives considered, Alternative B provides the best financial and technical solution that would allow the Company to meet all Project objectives and requirements. It mitigates the reliability risk and meets the Company's transmission planning criteria. It is also a long-term, cost-effective solution when all factors are considered. On this basis, Alternative B is selected as the recommended solution for the GFT Reliability Project.

4. CONSULTATION

FBC regards its responsibility to engage Indigenous communities and other stakeholders in a meaningful and comprehensive consultation process as a key consideration in the successful development and execution of its projects necessary to provide electrical service that is safe, reliable, and cost-effective. Consultation activities are determined on a project by project basis.

All the proposed work is either being completed within the existing property and fence boundaries of the GFT substation or within the established ROW over the Rossland mountain pass.

4.1 *INDIGENOUS CONSULTATION*

FBC is committed to building good working relationships with Indigenous communities. FBC seeks to engage with the identified Indigenous communities in a thorough, timely, and meaningful way.

In this section, FBC outlines the Company's engagement of potentially impacted Indigenous communities to date, and details the Company's Indigenous engagement plan going forward.

4.1.1 Engagement Approach

FBC believes that its Indigenous engagement on this Project should focus on the transmission line component, which for Alternative A and Alternative B includes the salvaging of a portion of 9L and 10L and the repurposing to distribution of another portion of 9L and 10L. The transformer component consists of work that will be done completely within the current FBC substation and as such will have no effect on Indigenous communities or their rights.

A list of potentially affected Indigenous communities was developed using the Province of British Columbia's Consultative Areas Database (CAD) to create a comprehensive list of those Indigenous whose territory is located along the transmission line route. The list includes:

- Okanagan Nation Alliance
- Osoyoos Indian Band
- Upper Nicola Indian Band
- Penticton Indian Band
- Lower Similkameen Indian Band
- Okanagan Indian Band
- Splats'in First Nation
- Shuswap Indian Band

4.1.2 Description of Consultation to Date

On July 4, 2018, representatives of FBC and the Osoyoos Indian Band (OIB) held an update meeting at the OIB office in Okanagan Falls to discuss ongoing work within OIB traditional territory. At this meeting the Grand Forks Terminal Project was brought up. The OIB asked for Shapefiles and Keyhole Markup language Zipped (KMZ) files of the transmission component of the Project. These were sent via email on July 10, 2018.

During the meeting, the OIB asked to know the exact locations of the poles that were going to be replaced during the Project. The OIB wants to cross reference the locations where poles are going to be set with their cultural mapsets to determine if the OIB wants monitors to be present during the ground disturbance.

Currently FBC has not completed its field pole assessment to determine the exact poles that will need to be replaced. However, at the meeting FBC committed to getting shapefiles and kmz files to the OIB as soon as the poles were identified. FBC also committed to providing funding for the monitors should any culturally sensitive sites be identified. The OIB agreed with this approach and FBC will continue to work with the OIB during project planning and construction.

On July 13, 2018, notification letters included as Appendix E were sent to all Indigenous communities identified through the CAD. The letter provided information about the Project including:

- Types of work that may occur;
- Mapping to show the proposed areas where there may be pole replacements; and
- Contact information for the FBC Community & Indigenous Relations Manager.

As of filing, no responses were received from the letters sent on July 13, 2018. FBC will discuss the project with any Indigenous community should questions arise subsequent to filing.

FBC believes that with the activities already completed and with the ongoing discussions with the OIB that its Indigenous engagement efforts have been and will continue to be adequate and appropriate in all the circumstances.

4.2 PUBLIC CONSULTATION

As the substation is located within an industrial park on the outskirts of Grand Forks public impact will be limited to increased transportation on various roads on days when equipment is brought to site during mobilization. Therefore, FBC believes public consultation is not required.

4.3 SUMMARY

FBC believes that to date it has adequately engaged and consulted with key stakeholders including Indigenous communities. FBC has addressed and will continue to address issues that may arise, and will continue to engage Indigenous communities and other stakeholders throughout Project detailed design and implementation.

5. PROJECT DESCRIPTION

In this section, FBC will describe the proposed GFT Reliability Project in more detail, including information on project components, schedule, resource requirements, and risks and management.

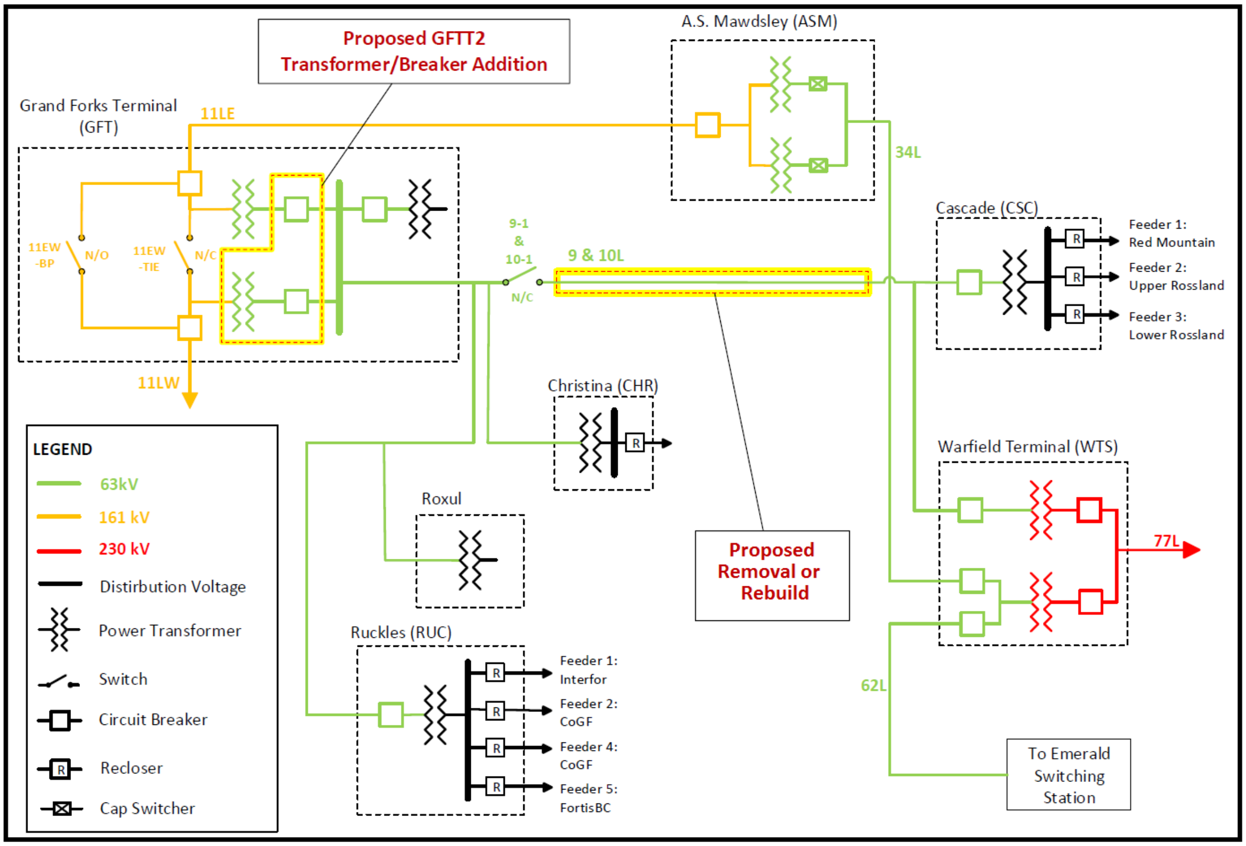
5.1 OVERVIEW

The scope of the GFT Reliability Project includes, but is not limited to, the following:

- Provide new 161kV/63kV 45/60MVA transformer with OLTC (referred to as "GFT T2");
- Provide new 161 kV and 63 kV bus for GFT T2;
- Provide two (2) new 72.5kV circuit breakers (referred to as "CBT1" and "CBT2");
- Provide new transformer foundation, containment and sound wall;
- Provide new foundations to support new high voltage bus;
- Provide new foundation for CBT2;
- Provide new support structure over GFT T1 containment for CBT1;
- Provide new high voltage bus required for new GFT T2;
- Provide new high voltage vertical break disconnect switch (referred to as "T2-2");
- Provide six (6) new 161 kV current transformers (referred to as "CT T1" (three transformers) and "CT T2" (another three transformers));
- Provide new SEL-487B bus protection relays;
- Provide new SEL-487E transformer primary protection relays;
- Relocation of existing SEL-387 differential relay;
- Removal of existing T1 LV CTs;
- Provide new protection, control and metering equipment;
- Provide new SCADA control and communications infrastructure;
- Repurpose 20.8 km of 9L and 10L structures with distribution underbuild required to serve 46 existing customers; and
- Remove approximately 44.6 km of the remaining 9L and 10L transmission line structures.

Figure 5-1 shows a single line drawing of the proposed GFT T2 installation. Preliminary drawings showing the single line diagram and general arrangement are included in Appendix F-1 and Appendix F-2, respectively.

Figure 5-1: Grand Forks Area Single Line Drawing



5.2 *PROJECT ENGINEERING AND DETAILED DESIGN*

Engineering and detailed design is expected to start immediately upon Project approval. Activities will encompass all engineering calculations, validations and drawings required to cover the Project needs. Engineering activities will be organized in order of priority, in relation to the fabrication/procurement lead times and scheduled date for each component to be on the work site.

Engineering packages to be completed are:

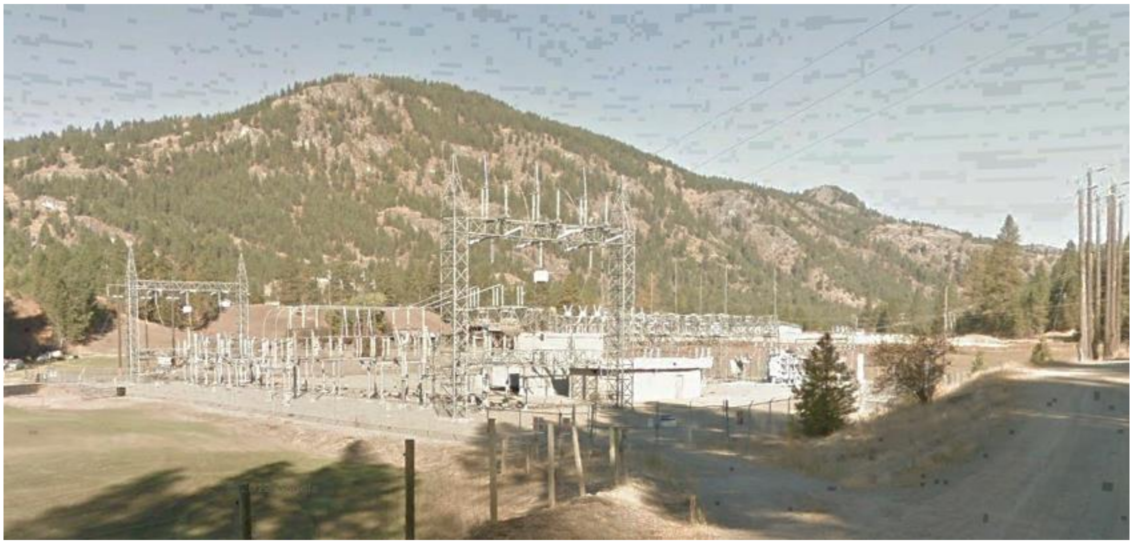
- GFT T2 Addition; and
- Remove 9L and 10L and repurpose a portion for distribution.

Each engineering package will be reviewed and accepted by FBC. Environmental permits, approvals, and authorizations will be identified and application processes initiated. The design phase will be concluded by the final design review, planned for civil design in early Q3-2019 and electrical design in late Q3-2019.

5.3 PROJECT ACCESS AND STAGING AREA

GFT is located in a rural area, accessible by a service road connected to North Fork Road in Grand Forks. The service road is in good condition, and the site has good accessibility as shown in Figure 5-2 below.

Figure 5-2: Grand Forks Terminal Substation, Google Earth



Access roads for 9L and 10L may need work to facilitate construction. Where possible, FBC plans to use its warehouses in Grand Forks and Warfield for material storage. Any field staging areas will be discussed with local landowners or businesses.

5.4 CONSTRUCTION AND OPERATING SCHEDULE

Engineering and Procurement for the Project will begin immediately upon Project approval. FBC has standard equipment specifications for all equipment relevant to the Project scope and therefore only a minimal engineering effort is required to order the long-lead time material. The only exception is the power transformer which will be competitively bid. The bid process for transformers typically lasts two to three months.

Construction will require a high degree of coordination to complete. Initially, FBC will focus on the substation component of the Project as the station can remain energized during the majority of construction. No equipment outages will be required until FBC is ready to connect CBT2 to the 63kV bus. Once FBC is ready to make this connection, FBC will transfer the distribution load to the Ruckles Substation in order to de-energize the 63kV system at GFT. If the load cannot be transferred to Ruckles Substation, FBC will install the mobile transformer. The 63kV side of the mobile transformer can be connected to 9L directly, allowing FBC to de-energize the 63kV system at GFT. The civil construction will begin in Q3-2019, with electrical construction beginning in the fourth quarter of 2019. The final commissioning/handovers are scheduled for the third quarter of 2020.

Work on 9L and 10L will be done in two stages. The first stage will be the removal of 10L beginning in early third quarter of 2020 with completion in mid fourth quarter of 2020. The second stage will be the removal of 9L beginning in late first quarter of 2021 with completion in late second quarter of 2021. This staging is meant to address three considerations:

- The fire risk posed in the summer months makes it desirable to avoid completing construction during the summer months;
- In the event of a failure on GFT T1 before GFT T2 is placed in-service, FBC would be able to use 9L; and
- To facilitate the CBT2 connection, FBC may need to connect the 63kV side of the mobile transformer to 9L to bypass the 63kV bus.

Final construction and commissioning is expected to be complete for the Project by the end of the second quarter of 2021. If Project approval is delayed, the schedule will be modified as necessary. A detailed Project schedule is attached as Appendix G.

5.5 *PROJECT RESOURCES*

5.5.1 Project Management

FBC plans to have an FBC Project Manager who will manage all aspects of the Project, including, but not limited to, engineering, procurement, and construction. The Project Manager is responsible for coordinating all Project activity.

Additionally, FBC plans to have an FBC Construction Manager on site who will manage both internal and external construction resources. The Construction Manager is responsible for coordinating all on-site activity.

5.5.2 Engineering

FBC plans to have an FBC Project Engineer and an FBC Design Technologist manage the engineering component of the Project. External engineering support may be required to complete design for the foundations and transformer pad/containment.

5.5.3 Construction Services

The construction activities will be managed directly on site by FBC. Construction will be performed by qualified construction workers and supervisors.

5.6 *RISK ANALYSIS*

FBC has assessed the risks to completing the Project by the in-service date of late second quarter of 2021. Circumstances that could delay the Project or increase costs include:

- Unforeseen environmental or archaeological discoveries during the construction phase. The risk of such occurrences is considered to be low, based on FBC's experience in the GFT and along the 9L and 10L right-of-way.
- Narrow construction work windows for environmental impact mitigation and for transmission equipment outages leading to delays and increased costs. Extensive effort in the planning and scheduling of work will be used to reduce that risk along with the provision of schedule buffers to mitigate impacts.
- Wildfire risk along the 9L and 10L corridor may impact FBC's ability to complete work from late Spring to early Fall.
- Shortage of qualified contractors and/or equipment and materials. FBC considers the likelihood of this risk to be low based on the following:
    - Contract Labour – FBC has several substation and power line contractors on its pre-approved contractors list. There are no indications that these resources will be unavailable due to increased labour demand elsewhere in Western Canada.
    - Equipment/Materials – FBC has agreements in place for all major equipment, with the exception of the new GFT T2 transformer. As a result, FBC has certainty with respect to lead times and pricing for major equipment, although some equipment pricing may be subject to CAD/USD foreign exchange rate volatility. Materials are likely to be impacted by world commodity prices, however FBC does not believe this will be a major impact because FBC has purchasing contracts in place for standardized equipment items for purchases of equipment other than the new transformer (GFT T2).

5.7 *PROJECT IMPACTS*

The transmission line component of the Project is not expected to have any impact on the physical, biological, or social environments.

To facilitate construction, FBC will have to complete some civil work on existing access roads however this is not expected to have any substantive negative impact on the environment. FBC may be required to complete some vegetation management during construction. FBC is mindful that there is a risk of interaction with nesting birds during construction. Where possible, vegetation clearing and laydown areas will be undertaken outside of the sensitive nesting window. If vegetation clearing occurs within the sensitive nesting window, bird surveys will be undertaken and active nests will be protected in accordance with federal and provincial regulatory requirements.

The substation component of the Project will be contained within the existing GFT and is therefore expected to have no impact on the physical, biological and social environments.

The Project is not expected to have any public impact as work will take place within the existing substation and within existing right-of-ways.

5.8 *REQUIRED APPROVALS*

There are no federal, provincial or municipal approvals, permits, licenses or authorizations required to complete the Project.

5.9 *SUMMARY*

In this section, FBC has described the proposed GFT Reliability Project in detail, including information on project components, schedule, resources requirements, and risks and management.

6. PROJECT COST ESTIMATE

As previously discussed, the recommended alternative for the Project is Alternative B, which includes:

- Installing a second transformer at Grand Forks Terminal Station (GFT) by purchasing a new 161/63kV transformer as described in the Application; and
- Removing 44.6 km of the transmission lines 9 Line (9L) and 10 Line (10L) from CHR to CSC, and repurposing 20.8 km of transmission lines 9L and 10L to distribution lines.

The total capital cost of the Project is forecasted to be $13.171 million in as spent dollars (including AFUDC of $0.531 million and net removal costs of $4.528 million mainly associated with 9L and 10L transmission lines).

The cost estimate for the GFT Reliability Project has been developed to a Class 3 degree of accuracy as defined by the AACE Recommended Practice, in accordance with the CPCN Guidelines.

The subsections below will provide details on the total project capital cost, operations and maintenance, financial evaluation, accounting treatment and rate impacts associated with the Project.

6.1 PROJECT CAPITAL COST ESTIMATE

The capital cost estimate meets a minimum of an AACE Class 3 level of Project definition and design. The expected accuracy of the cost estimate is as defined in AACE: Low: -10% to -20% and High: +10% to +30%.

Table 6-1 presents a summary of the total estimated capital costs for the GFT Reliability Project. The cost estimate presented in Table 6-1 is divided into two major categories with corresponding subtotals: Construction costs and Net Removal costs. A detailed breakdown of the estimated cost for the Project can be found in Confidential Appendix I.

Table 6-1: Summary of Estimated Project Capital Costs ($000)

Particular	2018 $	As–spent $
Pre-Approval Costs	257	257
Construction	6,414	6,630
Contingency	1,184	1,225
AFUDC		400
Subtotal – Construction	**7,855**	**8,512**
Net Removal Costs	3,475	3,625
Contingency	866	903

Particular	2018 $	As–spent $
AFUDC		131
Subtotal – Net Removal	**4,341**	**4,659**
Total Project	**12,196**	**13,171**

The Project capital cost estimate was developed based on consideration of the substation upgrade work and the transmission/distribution work. FBC requested quotes from potential suppliers to compile the station upgrade estimate. FBC engaged DBS Energy, an engineering consulting company, to provide the 9L and 10L transmission lines estimate as part of the condition assessment. FBC's estimate for the station upgrade can be found in Confidential Appendix H, and the DBS estimate for the 9L and 10L work can be found in the condition assessment report in Confidential Appendix C.[22]

The Project is planned to be completed in phases, with the station upgrade work to be completed by early third quarter of 2020, 10L work to be completed by mid fourth quarter of 2020, and 9L work to be completed by late second quarter of 2021.

The Pre-Approval Project Costs are related to costs for engineering work and CPCN development up to CPCN approval. Upon BCUC approval of the CPCN, these costs will be transferred to work-in-progress and be included in the total Project capital cost.

The total Project cost shown in Table 6-1 above is composed of stations work, and transmission and distribution work. Further detail on these two components is provided in sections 6.1.1 and 6.1.2 below.

6.1.1 Stations Work

Table 6-2 shows a breakdown of the stations portion of the estimate. The stations work will begin in 2019 and is expected to take two years. Key assumptions of the estimate include, but are not limited to, the following:

- Work will be done by using a mix of internal and external resources; and
- No changes will be made to the existing grounding grid.

A detailed cost estimate for the stations work is provided in Confidential Appendix H.

Table 6-2: Stations Capital Cost Summary ($000)

Particular	2018 $	As–spent $
Pre-Approval Costs	170	170
Construction	4,277	4,401
Contingency	757	779

[22] Page 11, Section 4.4 - Design Option 2.

Particular	2018 $	As–spent $
AFUDC		310
Subtotal – Construction	**5,203**	**5,660**
Net Removal Costs	46	47
Contingency	9	9
AFUDC		3
Subtotal – Net Removal	**55**	**59**
Total Stations Cost	**5,258**	**5,719**

6.1.2 Transmission and Distribution

Transmission and distribution work will begin in 2020 after GFT T2 is installed. It is expected to take two years for 9L and 10L to be removed or have a portion repurposed for distribution. Work will occur primarily outside of winter. Transmission line work activities will be confined to existing FBC rights-of-way (ROW) and access roads. Distribution ROW will need to be acquired for the 9L and 10L distribution repurposing work.

Table 6-3 details the Project estimate which includes transmission line and conductor removal, distribution repurposing, recommended urgent work to stabilize the lines, and access road re-establishment. Conductor salvage credits are included in the net removal cost; based on $2.50 per pound of copper which is subject to market changes.

The detailed cost estimate for the transmission and distribution work is provided in the 9L and 10L condition assessment report in Confidential Appendix C.[23]

Table 6-3: Transmission and Distribution Capital Cost Summary ($000)

Particular	2018 $	As–spent $
Pre-Approval Costs	87	87
Construction	2,137	2,229
Contingency	427	446
AFUDC		90
Subtotal – Construction	**2,652**	**2,852**
Net Removal Costs	3,429	3,578
Contingency	857	894
AFUDC		128
Subtotal – Net Removal	**4,286**	**4,600**
Total T&D Costs	**6,938**	**7,452**

[23] Page 11, Section 4.4 - Design Option 2.

6.1.3 Project Contingency Model and Determination of Project Contingency

Contingency has been applied to the Project to account for certain items, conditions, or events which may occur throughout the Project lifecycle. A contingency of 17.7 percent (including Project loadings) was used for the stations component and a contingency of 20 percent was used for the transmission and distribution component.

6.1.4 Escalation Amounts (including inflation)

The as-spent capital cost estimates in Table 6-1 include inflation escalation using FBC's 2018 approved CPI/AWE of 1.701 percent (Order G-38-18).

6.2 *OPERATION AND MAINTENANCE*

FBC expects that the retirement of 9L and 10L transmission lines will reduce transmission line O&M expenditures by approximately $60 thousand per year and reduce brushing costs by an average of $31 thousand per year. However, it is expected that O&M expenditures related to substation equipment will increase by approximately $5 thousand per year. Overall, the Project is expected to reduce net O&M expenditures by approximately $85 thousand[24] annually starting in 2021.

6.3 *FINANCIAL EVALUATION AND ACCOUNTING TREATMENT*

The financial evaluation of the Project consists of the following:

- Project capital cost estimate, including financing costs and net removal costs, as described in Section 6.1;
- Incremental cost of service (revenue requirements), present value of the incremental cost of service, rate impact as a percentage of the 2018 Revenue Requirement; and
- Levelized rate impact over a 40 year analysis period.

FBC will include the capital costs associated with the construction of the Project in Construction Work-in-Progress, attracting AFUDC. FBC will transfer the costs to the appropriate plant asset accounts on January 1 of the year following construction completion and in-service. The specific asset will begin depreciating at the start of that year. The Project is scheduled to be completed and placed in-service over a three year period. Table 6-4 below shows the year that the planned work is to be completed, the estimated asset amounts, as well as when they will be transferred to their appropriate plant asset accounts.

[24] In 2018 dollars.

Table 6-4: Schedule of Completion Inclusion in Rate Base (excluding AFUDC)

Year of Construction Complete	Construction Work to be completed	Estimated amount of capital (As-Spent $) transfer to Plant-in-Service ($ millions)	Date transfer to Opening Balance of Plant-in-Service
2020	Station	$ 5.3	January 1, 2021
2020	Distribution Rebuild	$ 1.4	January 1, 2021
2021	Distribution Rebuild	$ 1.4	January 1, 2022
2020	Station Removal	$ 0.1	January 1, 2021
2020	Transmission Removal	$ 2.2	January 1, 2021
2021	Transmission Removal	$ 2.3	January 1, 2022
	TOTAL	**$12.7**	

6.3.1 Retirement of Existing Assets

As described in Section 3.3.2, a portion of the 9L and 10L transmission lines will be removed, sold for scrap and retired from plant. The gross book value of the electric plant related to transmission lines 9L and 10L that is being retired from electric plant in service and also from accumulated depreciation is $3.22 million. This retirement has been planned in two phases and will be recorded when the distribution conversion work enters rate base. The book value of the remaining portions of the 9L and 10L transmission lines that are to be repurposed as distribution lines will be reclassed as distribution assets. This reclassification has no impact on the financial analysis.

6.4 RATE IMPACT

The Project construction period is between 2019 – 2021 with assets going into service in 2021 and 2022. A 40 year cost of service model was used to evaluate this option (Alternative B) against the others described in section 3. The levelized 40 year rate impact is 0.18% or $0.20 per MWh. The annual bill impact for an average residential customer using 11,500 KWh at the 40 year levelized rate would be $2.14. The rate impact in 2022 the year when all assets have been transferred into plant asset accounts will be 0.26 percent. This would equate to annual bill increase of $3.36 for an average residential customer using 11,500 KWh.

6.5 SUMMARY

In this section, FBC has described the Project cost estimate, the financial evaluation, accounting treatment, and the rate impact. The Project will cost $12.2 million in 2018 dollars including net removal costs of $4.3 million. The levelized rate impact of Alternative B is projected to be 0.18% or $0.20 per MWh, and will add $2.32 to the annual bill for the average customer using 11,500 KWh.

7. PROVINCIAL GOVERNMENT ENERGY OBJECTIVES AND POLICY CONSIDERATIONS

7.1 RELIABILITY CONSIDERATIONS

Typical industry transmission planning standards require the system to be planned such that all projected customer loads are served during normal operation (N-0)[25] and single contingency (N-1).[26] As such, FBC transmission planning criteria ensure customer load can be supplied in N-0 and N-1 conditions.

Mandatory Reliability Standards (MRS) do not apply to the 9L and 10L transmission lines or the GFT transformers since these elements are not included as part of the Bulk Electric System (BES). To be included as part of the BES, transmission lines need to be operated at 100 kV or higher and transformers require the primary terminal and at least one secondary terminal operated at 100 kV or higher.

7.2 CLEAN ENERGY ACT

Section 46(3.1)(a) and (b) of the UCA state that in considering whether to issue a CPCN, the BCUC must consider: (a) the applicable of British Columbia's energy objectives, and (b) the most recent long-term resource plan filed by the public utility under section 44.1, if any.

With respect to section 46(3.1)(a), British Columbia's energy objectives are provided in the *Clean Energy Act* (CEA). The Company was mindful of these energy objectives when designing the Project and the following of British Columbia's energy objectives were identified as being applicable to the present Application, as defined in section 2 of the CEA:

(a) to achieve electricity self-sufficiency;

(c) to generate at least 93% of the electricity in British Columbia from clean or renewable resources and to build the infrastructure necessary to transmit that electricity;

(d) to use and foster the development in British Columbia of innovative technologies that support energy conservation and efficiency and the use of clean or renewable resources; and

(k) to encourage economic development and the creation and retention of jobs.

[25] Normal operation, also referred to as N-0 reliability, means that with all major elements of the power system in service, the network can be operated to meet projected customer demand in order to avoid a load loss (customer outage).

[26] Single contingency, also referred to as N-1 reliability, means that an outage of a single element with all other elements of the power system in service (a single transmission line, transformer, generating unit, power conditioning unit like a shunt capacitor bank, a shunt reactor bank, a series capacitor, a series reactor, etc.) results in no load loss.

In particular, the GFT Reliability Project will ensure reliable 63kV power delivery to residential, commercial, and industrial customers in the Grand Forks area.

Under section 46(3.1)(b), the BCUC must consider the most recent long-term resource plan filed by the public utility. As was discussed in section 6.3 of the 2016 Long Term Electric Resource Plan Application, the Project (which was described at the time as the Grand Forks Terminal Transformer Addition) was originally proposed in FBC's 2012 Long Term Capital Plan and identified in the most recent long-term resource plan, as being a transmission reinforcement project to be completed some time in 2018-2020.

8. CONCLUSION

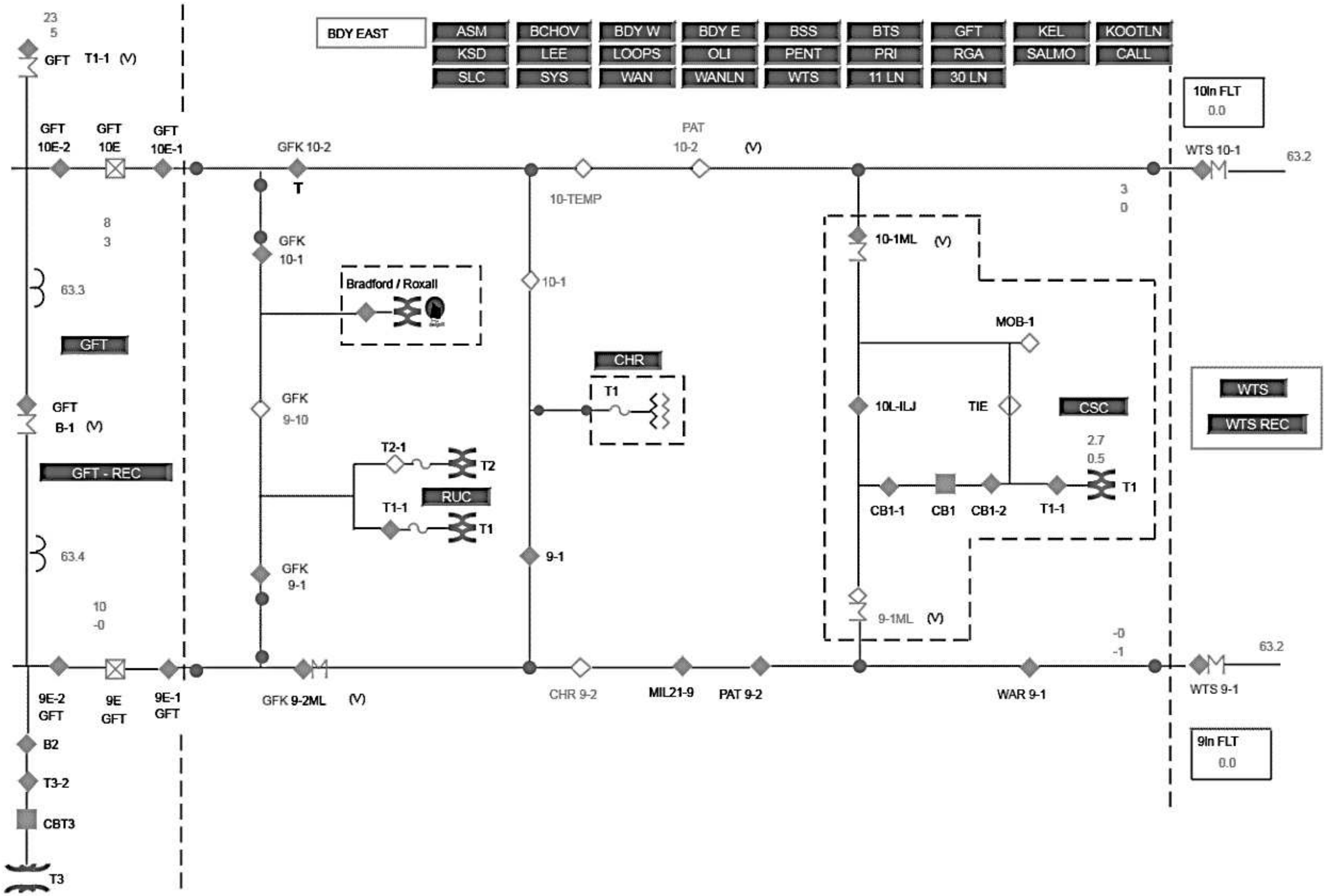
The Company respectfully submits that the GFT Reliability Project is necessary to maintain reliability of service for the Grand Forks area. The existing 63 kV backup supply for the Grand Forks area is unreliable and as such FBC does not meet N-1 criteria under peak load conditions. The likelihood of a failure to GFT T1 and the ability to restore customers is further impacted by the condition of the existing facilities at GFT (GFT T1, OLI T1) and the transmission lines 9L and 10L.

Based on the evaluation of all feasible alternatives, proposed Alternative B provides the best financial and technical solution that would allow the Company to meet all Project objectives and requirements. It mitigates the reliability risk and meets the Company's transmission planning criteria by installing a new second transformer at GFT, removing 44.6 km of the 9L and 10L transmission lines between CSC and CHR, and repurposing 20.8 km of 9L 10L as Distribution lines, while also minimizing the financial impacts and providing the best value for investment over a 40 year analysis period.

The Company requests that the BCUC approve the Project as it is set out in the Application. If the Application is approved, FBC plans to initiate the detailed design and procurement for the Project early in the second quarter of 2019, and to begin construction in the fourth quarter of 2019. The Project is planned to be completed over three years, starting in 2019. The final commissioning/handover for the substation work is scheduled for early in the third quarter of 2020, with transmission/distribution work completed by the late second quarter of 2021.

Appendix A

EXISTING 9L AND 10L CIRCUIT CONFIGURATION


BDY EAST
ASM
BCHOV
BDY W
BDY E
BSS
BTS
GFT
KEL
KOOTLN
KSD
LEE
LOOPS
OLI
PENT
PRI
RGA
SALMO
CALL
SLC
SYS
WAN
WANLN
WTS
11 LN
30 LN
10ln FLT
0.0
23
5
GFT T1-1 (V)
GFT 10E-2
GFT 10E
GFT 10E-1
GFK 10-2
T
PAT 10-2
(V)
WTS 10-1
63.2
10-TEMP
3
0
8
3
GFK 10-1
10-1ML (V)
63.3
Bradford / Roxall
10-1
MOB-1
GFT
CHR
T1
GFT B-1 (V)
GFK 9-10
10L-ILJ
TIE
CSC
WTS
WTS REC
2.7
0.5
GFT - REC
T2-1
T2
RUC
T1-1
T1
CB1-1
CB1
CB1-2
T1-1
T1
63.4
GFK 9-1
9-1
10
-0
9-1ML (V)
-0
-1
63.2
9E-2 GFT
9E GFT
9E-1 GFT
GFK 9-2ML (V)
CHR 9-2
MIL21-9
PAT 9-2
WAR 9-1
WTS 9-1
9ln FLT
0.0
B2
T3-2
CBT3
T3

Appendix B

ABB GFT T1 CONDITION ASSESSMENT REPORT

CONDITION AND LIFE ASSESSMENT OF THE AUTO-TRANSFORMER AT FORTIS BC GRAND FORKS TERMINAL

GFT T1 - CGE TRANSFORMER SERIAL # 285733

PREPARED BY

ABB Inc.
Transformer Remanufacturing &
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ABB Project Number: 711997 - 10

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July 16, 2018; Rev 2

Rev 0	June 29, 2018:	Initial release.
Rev 1	July 11, 2018:	Revised after discussion with the customer.
Rev 2	July 16, 2018	Added future Risk of Failure.

Table of Contents

1. Introduction

This report represents a comprehensive condition assessment of a CGE auto-transformer with serial number 285733 at the Fortis BC Grand Forks Terminal site.

The design parameters and identification items are shown in **Table 1** below.

Table 1 – Transformer Identification

Manufacturer	Canadian General Electric
Rating	45/60 MVA, ONS/ONP, 65°C Rise, 3Ph, 60Hz
Voltage	HV: 161 kV Wye, ± 8 x 1.875% ON Load Taps LV: 63 kV Wye TV: 8.8 kV Delta
Lightning Insulation Levels	HV: 750 kV BIL LV: 350 kV BIL TV: 95 kV BIL Neutral: 110 kV BIL
Core	3 phase, 3 legged design
Windings	On each leg from the core outward: TV Winding: Layer LV Winding (Common): Layer HV Winding (Series): Layer
Cooling Equipment	6 Radiators, 8 Fans
Customer ID	GFT T1
Manufacturing Date	1965 in Guelph, Ontario

2. Site Inspection

Below is the site inspection report for the auto-transformer GFT T1 which was inspected on June 19, 2018.

Photo 1: GFT T1 in operation

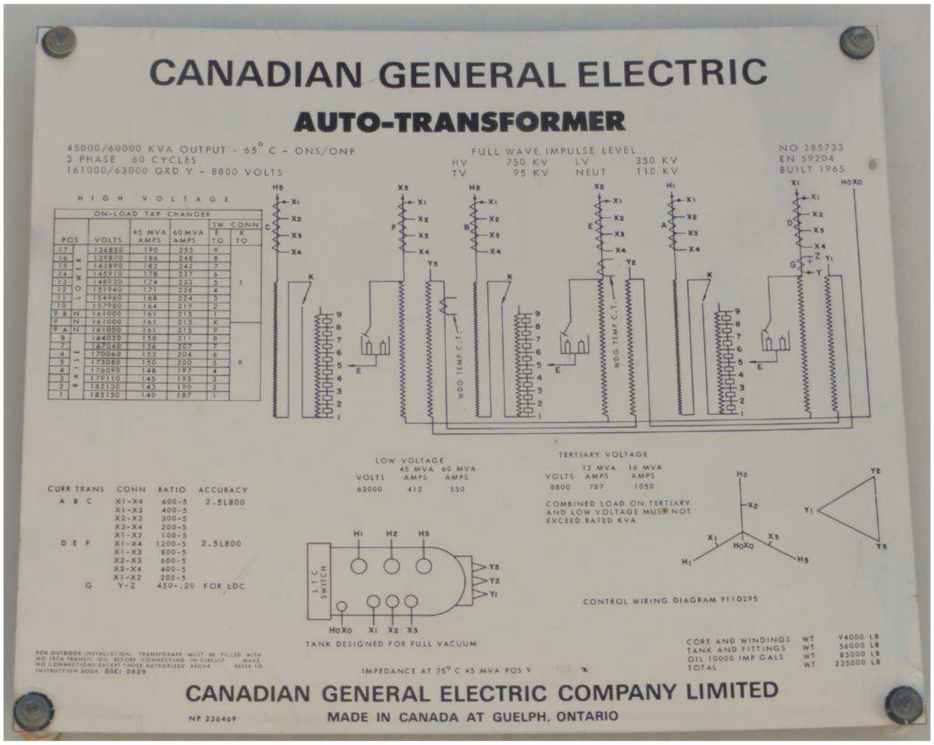


Photo 2: Nameplate

Photos 3 - 8: Tanks sides, controls, and accessories of the unit

Oil Temperatues Guages Readings:

Table 2 – Temperatures Indicators

Oil Temperature Gauges (Ambient was 28°C)	**Top Oil Temp.**	**Main Winding Temp.**	**Tertiary Winding Temp.**
Displayed Temperature °C	59	58	58
Maximum Temperature °C	59	58	60

Cooling Equipment:

Table 3 – Cooling Apparatus

Cooling	**Quantity**	**Condition**
Radiators	6	Visually in good condition
Fans	8	Visually in good condition
Valves	12	Visually in good condition

Observations:

- The unit was operating at 23.5 MVA at the time of inspection.
- The on load tap changer was in position 9 at time of inspection.
- The on load tap changer counter at time of inspection was 1,310,095.
- None of the fans were on (cooling was set to Auto).
- The winding temperature should be higher than the oil temperature – thus the temperature gauges need to be calibrated.
- The oil level indicators are reading normal levels considering the ambient temperature.
- Silica gel containers were good.
- Radiators are in good condition.
- Some evidence of leaking was observed on the tank wall and ground of LTC side (see Photo 1). This seems to be due to the oil leaking from one of the LTC mounting flange gaskets.
- Minor rust was found on the tank wall at the tertiary bushing side.
- The control cabinet was clean.

3. Dissolved Gas in Oil Analysis (DGA) in Main Tank

The gas analysis review has been done according to Table 1 of IEEE C57.104-2008. The limits for different gasses suggested in this Table are used as a guide to assess the severity of the problem. A higher level indicates a worsening condition that requires increased monitoring and actions. Below is a short description of the four conditions referred to in the analysis.

Condition 1: Transformer is operating satisfactorily.
Condition 2: A fault may be present. Take DGA samples at least often enough to calculate the amount of gas generation per day for each gas.
Condition 3: Indicates a high level of decomposition of cellulose insulation and/or oil. Take DGA samples at least often enough to calculate the amount of gas generation per day.
Condition 4: Indicates excessive decomposition of cellulose insulation and/or oil. Continued operation could result in failure of the transformer.

Below is the assessment of the available DGA data for the period of 2013 to 2018. The gas signatures for this transformer are shown in Figures 1, 2 & 3.

3.1. *Hydrocarbon gases*

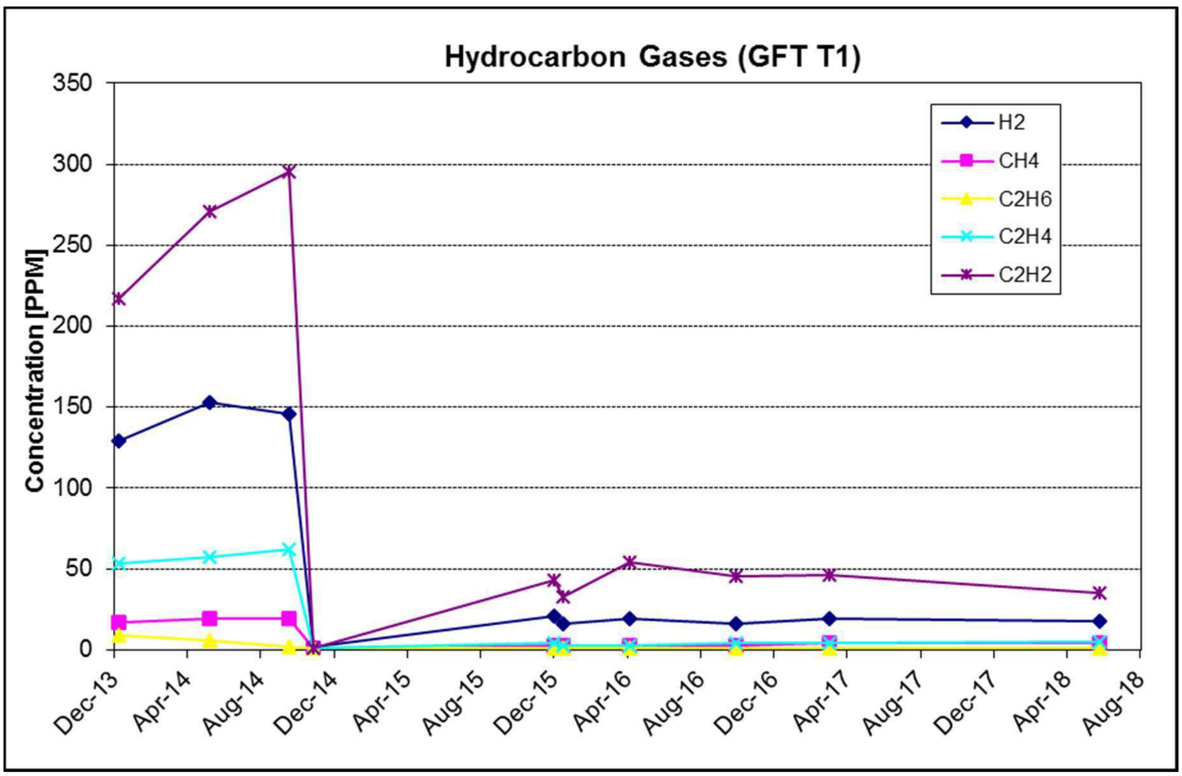


Fig 1: Hydrocarbon Gasses

- The concentrations of Hydrogen (H2), Methane (CH4), Ethane (C2H6), and Ethylene (C2H4) in the latest DGA sampled in May 2018 were below IEEE C57.104-2008 guide condition Level 1.
- The transformer maintenance records provided by the customer indicate that 3 LTC diverter tubes were replaced in October 2014 due to their leaks. The high concentration of Hydrogen (H2), Ethane (C2H4), and Acetylene (C2H2) shown in DGA sampled before October 2014 was from the diverter contamination. The 33 ppm to 54 ppm of Acetylene (C2H2) were found the years after the new oil was filled in October 2014, which were believed from the residual Acetylene (C2H2)

in the insulations. Note: Normally a level of 46 ppm Acetylene corresponds to an unacceptable high probability of failure. Additional monitoring is required to monitor the gassing trend.

3.2. *Carbon Oxides*

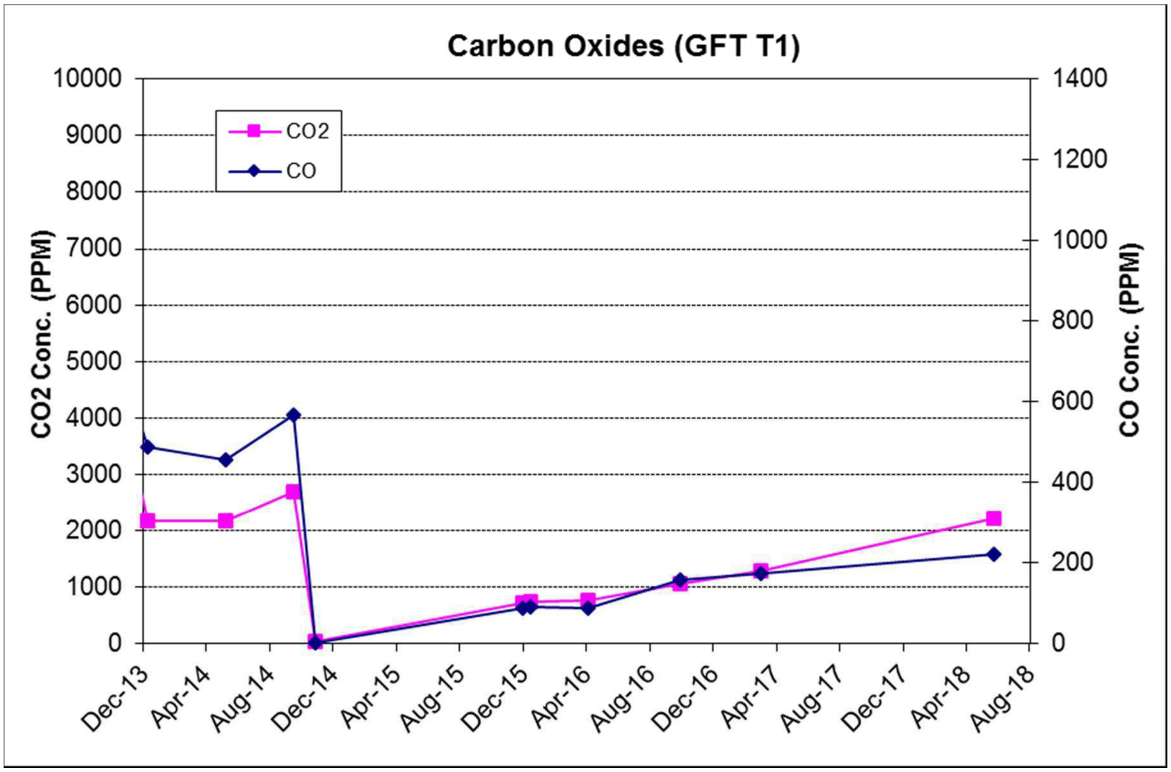


Fig 2: Carbon Oxides

- The carbon oxides levels were below the IEEE C57.104-2008 guide Condition Level 1 for the last few years. It is to be noted however that in 2014 this unit had the oil replaced and some of the markers of normal or abnormal aging were probably erased in the process. This observation is triggered by increased DGA levels recorded between 2003 and 2005. The CO_2/CO ratio is between 4 and 10. The normal CO_2/CO ratios are typically in the range of 5 to 9. The ratio of the carbon oxides suggests that these gas concentrations are likely due to the normal aging process of the transformer. For free breathing transformers with an ample supply of oxygen, there are typically high levels of carbon oxides generated under normal loading conditions. It is also typical that some of the CO will be converted to CO_2 in the presence of large quantities of oxygen. Oxygen acts as a catalyst to increase the generation rates of CO, CO_2 and combustible gases.

3.3. *Atmospheric Gases*

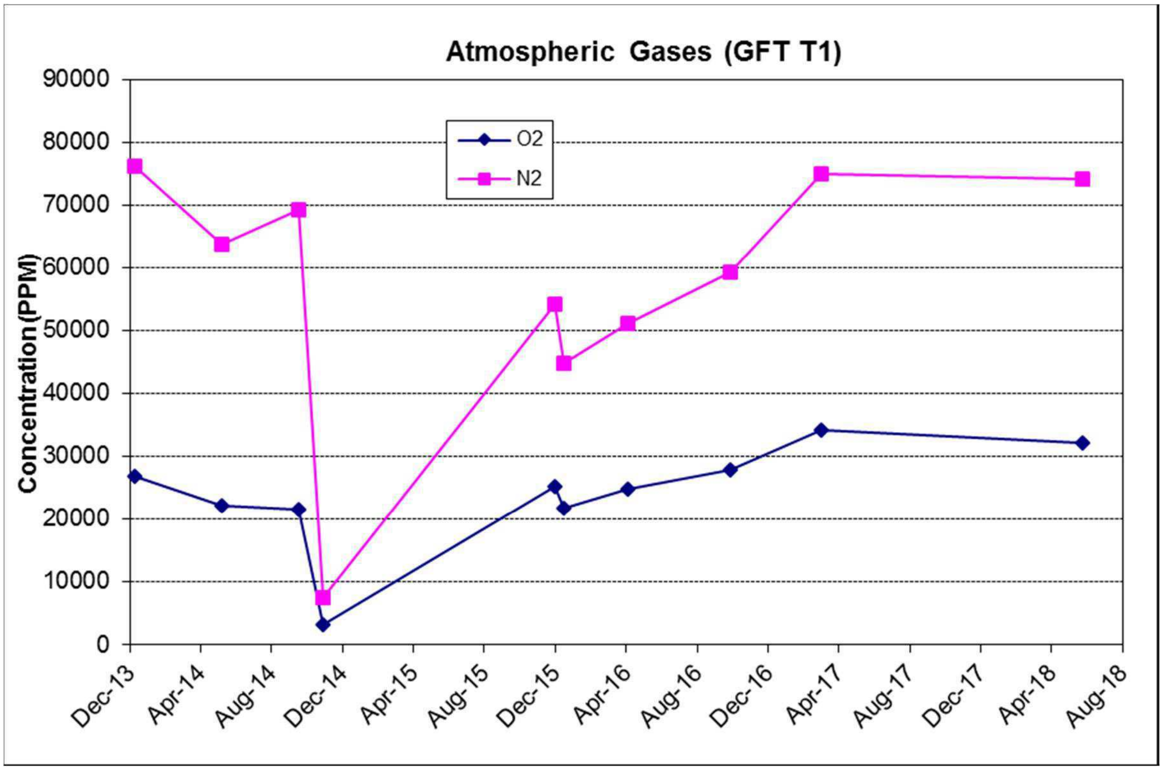


Fig 3: Atmospheric gases

- The oil samples for this transformer have consistently shown high oxygen concentrations. For free breathing transformers, the oxygen will generally end up ~30,000 ppm (Saturated). If the unit conservator has a bag, there are no oil leaks, and the unit is filled with degassed oil then the Oxygen in oil could range between 1000 and 3000 ppm.
- The presence of large concentrations of oxygen in oil can promote the formation of acids in the oil and cellulose, accelerate the aging rate of the insulation and aid for more gas generation.
- The source of this high oxygen is either the free-breathing oil conservator or oil leaks. To reduce the oxygen in transformer oil and eliminate the uncertainty concerning the gas generation, it is recommended to add a conservator diaphragm. The diaphragm prevents oil from coming in contact with the air. This will prevent moisture, excessive atmospheric gases from dissolving into the oil and it also helps to keep all gases generated by the transformer in oil for more accurate diagnostics.

4. General Oil Quality in Main Tank

Table 4 shows a summary of the latest oil quality measurements performed on this unit which was filled with new mineral oil during the PCB mitigation work in 2014.

Table 4 – Oil Quality Measurements

Sample Date	Fluid Temp (ºC)	Dielectric Breakdown D1816 (1mm) (kV)	Acid Number D974 (mg KOH/g)	Interfacial Tension D971 (mN/m)	Power Factor 25°C D924 (%)	Water Content (ppm)	Relative Saturation (%)	Oxidation Inhibitor Content (%)
10/27/2014	10	38	0.006	43.0	0.008	6	6	0.159
04/21/2015	40	44	0.007	41.9	0.011	6	5	-
09/27/2016	42	40	0.009	40.3	0.012	6	4	-
03/02/2017	35	41	0.014	37.7	0.009	6	6	-
05/24/2018	48	-	-	-	-	15	9	-

The following can be observed from the assessment of the oil quality using the Standard IEEE C57.106-2015, Tables 2 and 3 test limits for new and in-service mineral oil.

- **The measured breakdown voltages** varied from 38 to 44 kV/mm based on D1816-1mm method. They were all above the suggested limits of 30 kV or 28 kV minimum for a > 69 to < 230 kV transformer with new or in-service mineral oil.
- **The interfacial tension** should have a minimum 30 mN/m. In this case the interfacial tensions were measured between 43 mN/m and 37.7 mN/m from 2014 to 2017.
- **The measured acid numbers** in the past few years were all below the recommended maximum of 0.15 mg KOH/g by IEEE C57.106-2015 for >69 to <230 kV transformers.
- **The measured power factor** values at 25°C are all below the recommended limit of 0.5%. The measured values were between 0.008% and 0.012%. The power factor values at 100°C were not measured. ABB does recommend that the 100°C value also be included in recommended tests as this can show issues due to contaminants.
- **The water content** remained 6 ppm in oil samples taken from the main tank over the years, which is below the recommended maximum of 25 ppm by IEEE C57.106-2015 for >69 to <230 kV transformers. The water content in the latest oil sample increased to 15 ppm, and relative saturation increased from 6% to 9%, which could be due to the moisture ingress.
- **The oxidation inhibitor** value was measured at 0.159% with the new oil in 2014. A range of 0.08% to 0.30% is recommended. There were not any recent measurements. Oxygen inhibitors are helpful to minimize the effects of oxidation of oil. The first choice of attack by oxygen in the oil is the inhibitor molecules. This keeps the oil free from oxidation and its harmful by-products. As transformer ages, the oxidation inhibitor is used up and needs to be replaced. It is recommended to always measure oxidation inhibitor in the oil.
- **Furan Analysis** is a measure of the degradation of the cellulose paper. As paper ages, the degree of polymerization is reduced and the mechanical strength also decreases. The degree of polymerization (DP) can only be measured by testing a sample of the paper in question which is not practical for a transformer still in service. However, a byproduct of aging are so called Furans and there are mathematical correlations the Furans concentration in the oil and the DP value. It should be noted that when the oil in a transformer is changed (as in a reprocessing operation), most of the furanic compounds are lost. There was a furan results taken in May 2014. The low values (<10) of Furanic compounds indicate that the insulation of this transformer most probably has good life remaining. <u>Note: As per provided results some oil work was performed in 2008. If the oil was replaced it is possible that some of the insulation aging markers were erased.</u>

5. DGA and General Oil Quality in LTC Diverter

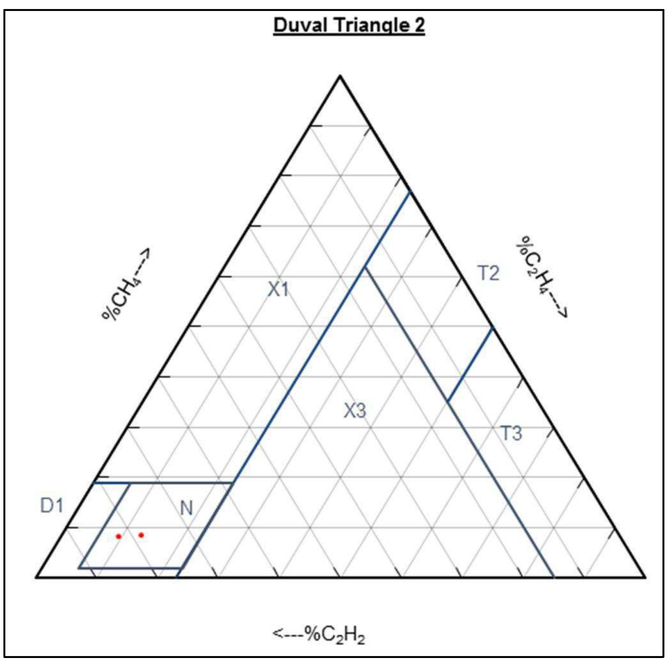
The Stenestam ratio ($[CH_4+C_2H_4+C_2H_6]/C_2H_2$) is used for the interpretation of DGA in the LTC diverter. The ratios based on the recent DGA were calculated as shown in **Table 5** and results indicate normal condition of the LTC diverter. Also, the results were shown to be normal based on the Duval triangle for LTC oil (C57.139-2015). The diverter style LTC 3XD1400 is an obsolete Reinhausen product and overhaul parts might be hard to procure. As per provided records the LTC counter has recorded 1,310,095 operations. The maintenance schedule for such a tap changer could not be found but tapchanger successor to the D type (type R) recommends the diverter to be replaced after 800,000 operations and the selector to be changed after 1,000,000 operations. Also, a routine maintenance should be conducted every 100,000 operations.

Table 5 – LTC DGA and Stenestam Ratios

SAMPLE DATE	FLUID TEMP	H2	CH4	C2H6	C2H4	C2H2	CO	CO2	O2	N2	[CH4+C2H4+C2H6]/C2H2
2015-10-06	35	7409	597	139.0	681.0	5894.0	146	930	21865	64323	0.24
2017-03-03	40	676	147	25.0	222.0	1342.0	207	1736	32861	83421	0.29

The following can be observed from the assessment of the oil quality using the IEEE Standard C57-106-2015, **Table 7** limits for continued use of in-service oil for load tap changers.

- **The measured breakdown voltage** was 24 kV based on D1816-1mm method. <u>It is below the limits of 25 kV minimum for the LTC located in ≤69 kV line end with in-service mineral oil.</u>
- **The interfacial tension** should have a minimum 25 mN/m. In this case the interfacial tension was measured 36.4 mN/m in 2017.
- **The measured acid number** was below the recommended maximum of 0.20 mg KOH/g by IEEE C57.106-2015 for the LTC located in ≤69 kV line end with in-service mineral oil.
- **The water content** remained over the years below the recommended maximum of 30 ppm by IEEE C57.106-2015 for the LTC located in ≤69 kV line end with in-service mineral oil.



6. Power Factor Measurements

The latest Doble test was completed during the outage on October 26, 2014. The overall test results and bushings test results for this transformer are shown in **Tables 6 & 7**. The following is noted:

- The measured power factors for overall are good.
- The power factor and capacitance values for the bushings are acceptable compared to nameplate values. Also the power factor values are all below 0.5% as recommended in IEEE Standard C57.19.01-2000 for oil impregnated paper insulated bushings. ABB recommends that bushings should be replaced whenever the power factor approaches double the nameplate value.
- The tertiary bushings were neither replaced nor tested. ABB recommends that hot collar tests should be performed on these bushings during the next outage.

Table 6 – Doble Overall Test on 10/26/2014

Overall Tests

	Insulation	Test kV	mA	Watts	% PF corr	Corr Fctr	Cap(pF)	FRANK™	Manual
1	CH+CHT	10.010	110.309	3.182	0.266	0.923	29259.986		Good
2	CH	10.003	109.036	3.161	0.267	0.923	28922.384	Good	Good
3	CHT(UST)	10.003	1.258	0.021	0.156	0.923	333.790	Good	Good
4	CHT	0	1.273	0.021	0.153	0.923	337.602		Good
5	CT+CHT	8.009	114.569	3.333	0.268	0.923	30390.268		Good
6	CT	8.005	113.323	3.319	0.270	0.923	30059.605	Good	Good
7	CHT(UST)	8.002	1.259	0.023	0.170	0.923	333.853		Good
8	CHT	0	1.247	0.015	0.108	*	330.663	Good	Good

Table 7 – Doble test for HV, LV and H0X0 bushings on 10/26/2014

Bushing C1

ID	Serial #	NP %PF	NP Cap	Test kV	mA	Watts	% PF corr	Corr Fctr	Cap(pF)	FRANK™	Manual
H0X0	1000070901	0.26	315	8.004	1.184	0.032	0.269	1	314.173	Good	Good
H1	1000070712	0.26	328	10.008	1.228	0.033	0.278	1.024	325.837	Good	Good
H2	1000070714	0.26	329	10.006	1.228	0.033	0.277	1.024	325.706	Good	Good
H3	1000070717	0.26	329	10.005	1.227	0.033	0.278	1.024	325.446	Good	Good
X1	1000071880	0.29	246	10.005	0.923	0.026	0.286	1.024	244.764	Good	Good
X2	1000071879	0.27	245	10.006	0.918	0.025	0.281	1.024	243.498	Good	Good
X3	1000071878	0.27	245	10.006	0.919	0.025	0.280	1.024	243.835	Good	Good

Bushing C2

ID	Serial #	NP %PF	NP Cap	Test kV	mA	Watts	% PF corr	Corr Fctr	Cap(pF)	FRANK™	Manual
H0X0	1000070901	0.6	210	0.499	0.770	0.029	0.380	1	204.252	Investigate	Good
H1	1000070712	0.26	3301	2.000	12.381	0.338	0.273	1	3284.195	Good	Good
H2	1000070714	0.26	3376	2.000	12.664	0.367	0.290	1	3359.099	Good	Good
H3	1000070717	0.26	3392	2.000	12.725	0.344	0.271	1	3375.266	Good	Good
X1	1000071880	0.16	484	0.500	1.814	0.034	0.189	1	481.249	Good	Good
X2	1000071879	0.23	490	0.500	1.847	0.033	0.179	1	489.812	Good	Good
X3	1000071878	0.16	486	0.500	1.827	0.044	0.241	1	484.656	Good	Good

7. Infrared Scan

Infrared scan (thermography) is a method of inspecting electrical and mechanical equipment by obtaining heat distribution pictures. This inspection method is based on the fact that most components in a system show an up normal increase in temperature when malfunctioning. Any localized problems caused by a change in local resistance will consume more power and generate heat. The local temperature of the resulting hotspot will be higher than the surrounding temperatures or that of a reference point. By observing the heat patterns in operational system components, infrared thermography is now used to detect loose connections, unbalanced load and overload conditions, component deterioration, and other potential problems.

Infrared scans on the transformer was performed on June 19th, 2018 and the findings are below:

- The highest temperature was 49.7°C and seen on the top wall of HV side.
- Thermal scans showed a radiator gradient of around 9.5°C. This is typical for ONAN cooling.

The ambient temperature during the infrared scan was 28°C.

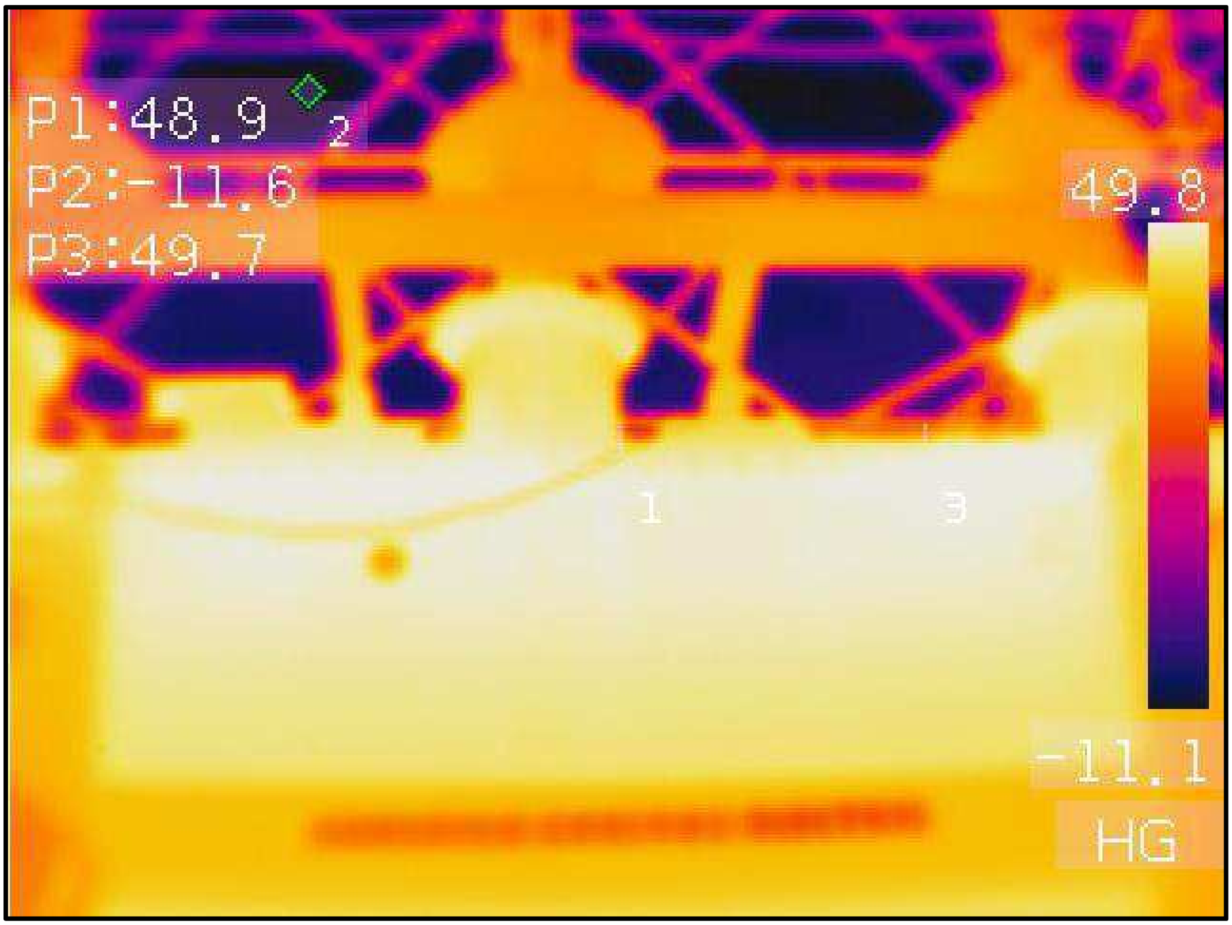


Fig 4: Thermal Scan

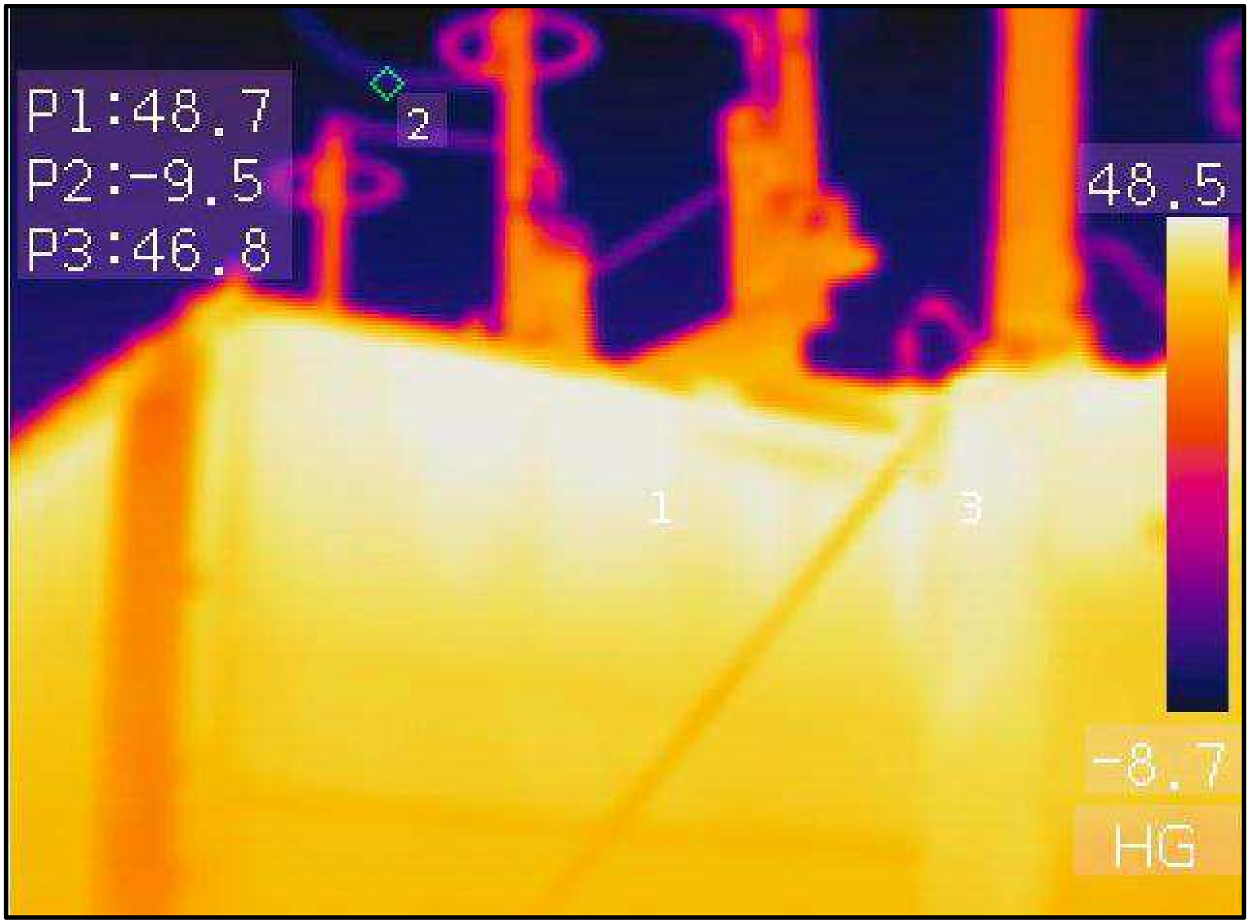


Fig 5: Thermal Scan

8. Maintenance History

PCB mitigation work was completed by ABB TRES in 2014 including the following:

- The HV & LV bushings and gaskets were replaced.
- The neutral bushing was replaced with a spare and a new gasket was installed.
- The 3 MR Tap Changer Diverter assemblies and tubes were replaced with new.
- All the radiators were removed, re-gasketed and re-installed.
- The snorkel type relief device was replaced with a Qualitrol style relief device.
- Leak repairs were done for the piping, valves, LTC and Victaulic couplings.
- The transformer was refilled with new oil.

Some electrical tests were performed during this outage and all test results were acceptable.

9. Loss of Life calculation

This section assesses the loss of transformer insulation life. Aging or deterioration of insulation is a time function of temperature, moisture content and oxygen content. With a good oil preservation system, the moisture and oxygen content contribution can be minimized leaving insulation temperature as the controlling parameter. In aging studies, it is the norm to consider the aging effects produced by the highest (hot spot) temperature. The hot spot temperature is dependent on the load, the top oil rise over ambient and the ambient temperature. In this case, the average monthly loads for one year were used. The average monthly ambient was taken from Environment Canada for the specific location of the transformer. The top oil rise was calculated using the transformer thermal capacity (Watt-Hours/°C) which is dependent on the weight of the core and coils, the oil volume and the type of cooling. The cumulative loss of life was calculated for the year chosen as a representation of the loading during the service life of the transformer. This evaluation does not take into account the high oxygen in the oil nor does it account for the moisture content in the insulation which are contributors to the insulation aging.

The calculations were done using the methodology outlined in Standard IEEE C57.91-2011 Section 5.

For the purpose of this study, the IEEE method was used with the following:

- The transformer specifics such as the weights and volume of oil were taken from the Outline Drawing.
- The transformer losses, winding hot spot temperature, and top oil temperature rise were taken from the factory final test report.
- The calculation assumes that the cooling was working as efficiently as when the equipment was new.
- The loading over 2017 (one year) was used. The readings were averaged for each month.
- The statistical monthly average temperatures were used as ambient.
- Over the 1 year period, the percent loss of life was calculated monthly and the cumulative aging for the year was calculated to be about 0.0261 %.
- Over the 53 years of service life of this transformer (1965-2018), this would amount to about 1.38% which means the transformer loss of life is very low.
- It should also be noted that the moisture and high oxygen content in the oil would push this number much higher however it would still be fairly negligible aging (< 10%).
- The very low calculated insulation loss of life is due to the very low average yearly ambient temperature (6.4°C) and the low transformer loading over the years; at or less than 50% of the nameplate rating which results in only 25% of the losses and low oil and winding temperatures.

<u>Note: It is to be noted that transformer history before 2005 was not available and the calculation assumptions relies only on 2018 data.</u>

<u>Note: For remaining life of transformer, see 'Risk of Failure Assessment' section.</u>

10. Risk of Failure Assessment

In this report, the term “risk of failure” is defined to include not only potential failures of the transformer main core/coil assembly, but also any condition that would require removal from service for a significant period of time.

For this transformer, a risk of failure (RoF) was calculated. Table 8 below presents the risk of failure of the transformer with three different scenarios. The first scenario represents the transformer as is, with C_2H_2 in oil and assuming that no inhibitor in oil. However since it is speculated that the C_2H_2 in oil is the result of oil leaking form the LTC and not an active arcing issue in the active part and probably there is still some inhibitor in the oil, the (RoF) is calculated at this condition too. The (RoF) of a new unit with a verified short circuit design is also calculated for comparison.

Risk of Failure (%)	Condition
2.600	Transformer as is (C2H2 in oil and assuming no inhibitor)
0.524	Considering no acetylene in oil and inhibitor in oil.
0.262	New transformer design. (No gas in oil, inhibitor in oil, better short circuit withstand design)

Table 8 – Risk of Failure

The results above indicate a high risk of failure (2.6) for this transformer based on the current DGA in oil and available test and maintenance data. The below figure shows the Risk of Failure (RoF) compared to a transmission utility population. It can be seen that RoF is on the high side for this unit.

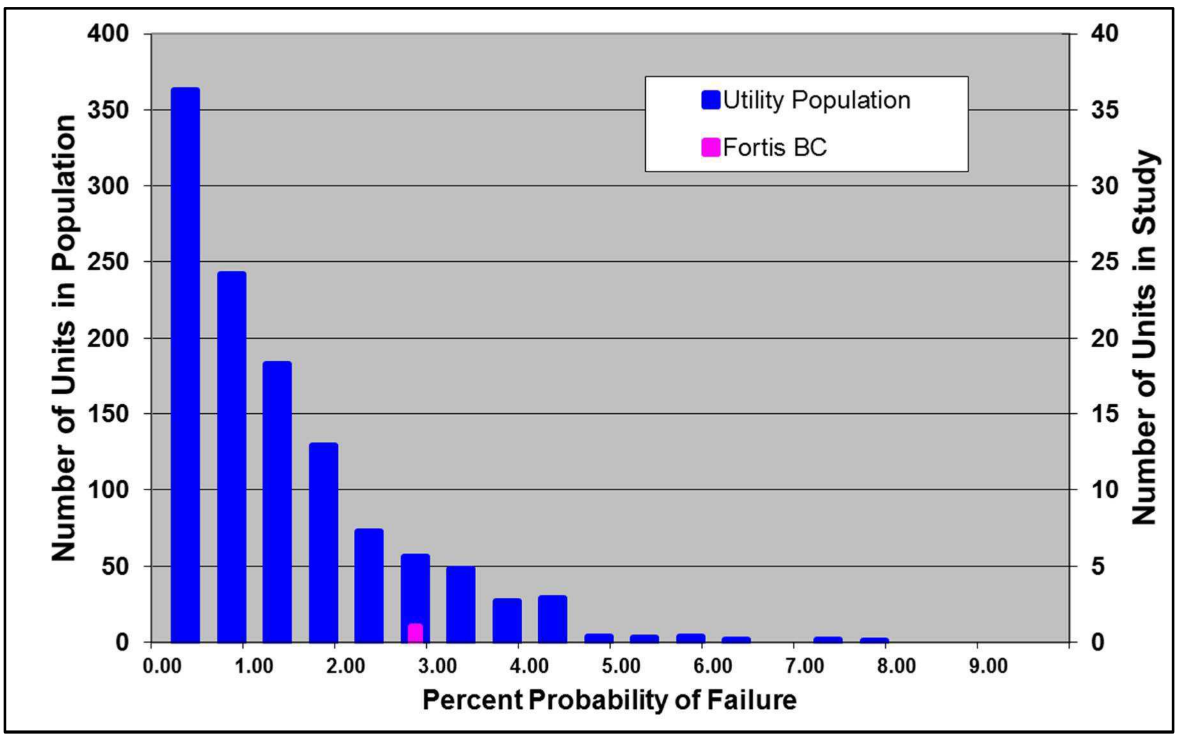


Figure 6 – Risk of Failure Compared to a Transmission Utility

In the previous section, it was shown that the insulation has not aged much because of the assumed low loading over the years. Based on the loading sample provided earlier, the insulation aging wouldn't be a factor for the transformer to fail and shouldn't be used to determine the remaining life. To determine the remaining life of the unit, we must look at the increase on risk of life of the unit, as the transformer ages.

Assuming the transformer condition and test results do not change, the following is the Risk of Failure for the transformer as it ages;

Year	Risk of Failure
2018 (00 years)	2.60
2028 (10 years)	3.05
2033 (15 years)	3.26
2038 (20 years)	3.47
2043 (25 years)	3.49
2048 (30 years)	3.50

Table 9 – Projected Future Risk of Failure

Using the risk of failure on the transmission utility population in figure 6, we can determine the 90th percentile of the population. 90th percentile is the value below which 90% of the population have a lower risk of failure. 90th percentile of the population is 3.25% risk of failure. Using this value as the maximum risk, **ABB would recommend not to keep this transformer in service more than 15 years.** However any change in the DGA, test data, and any system short circuit incidents can affect the risk of failure.

11. Conclusions

This report represents a comprehensive condition assessment of a CGE auto-transformer with serial number 285733 at the Fortis BC Grand Forks Terminal site.

This transformer was in service for about 53 years and did not suffer any major failures. It is assumed that the transformer has been lightly loaded during its lifetime.

The site visit showed:

- The temperature gauges need calibration.
- One of LTC mounting flange gaskets is leaking oil.
- The tank wall at the tertiary bushing side has minor rust.

The Dissolved Gas in Oil Analysis (DGA) of main tank showed no significant gassing issues:

- The concentration of Acetylene (C2H2) is from an old LTC oil leak.
- The carbon oxides levels are below the IEEE C57.104-2008 guide Condition Level 1 and are likely due to the normal aging process of the transformer.
- The oil samples for this transformer have consistently shown high oxygen concentrations (around 30,000 ppm).

The oil analysis of main tank showed the oil to be in good condition.

The Dissolved Gas in Oil Analysis (DGA) of LTC diverter showed no overheating issues.

The oil analysis of LTC diverter showed the oil had low breakdown voltage. The measured breakdown voltage was 24 kV based on the D1816-1mm method. It is below the limits of 25 kV minimum for the LTC located in ≤69 kV line end with in-service mineral oil.

The Doble overall tests showed the capacitance and power factor measurements were acceptable. The power factor and capacitance values of Doble test for the HV, LV and neutral bushings were acceptable compared to nameplate values.

The Infrared scans on the transformer showed no abnormality.

The loss of insulation life calculation showed very low consumed loss of life. The very low calculated insulation loss of life is due to the very low average yearly ambient temperature and the assumption of low transformer loading over the years.

The calculated risk of failure for this transformer is 2.6 based on the current DGA in oil and available test and maintenance data. This RoF is on the high side for this unit when compared to a typical utility population.

It is to be noted that in CIGRE Reliability Survey 642 (A2.37), the 2nd most failed component was the load tap changer and the single most cause of failure is inadequate short circuit strength based on the Transformer Industry-Wide Database (IDB). Both of these components are weak in this unit. Also, based on the age profile for over 7,000 units in a particular subset of in-service transformers contained in the IDB, the most common end of life for a transformer seems to occur in the 35 to 45 year age bracket. This unit is 53 old. With each passing year, the probability of failure on this unit increases.

12. Recommendations

The following is recommended:

- Calibrate the temperature gauges.
- Replace the oil leaking gasket of LTC mounting flange.
- Reprocess or replace the oil in the LTC diverters.
- Perform hot collar tests for tertiary bushings on next outage.
- Add a conservator diaphragm to keep oxygen and moisture away from the oil.
- Measure oxidation inhibitor every oil sample.
- Measure oil power factor for both 25°C and 100°C.
- Clean rust on the tank wall and touch up with the paint.
- Perform LTC inspection and determine when an LTC overhaul will be required.
- Closely monitor the Acetylene levels to early determine changes in the existing trend.
- Periodically perform a winding resistance test to determine if gassing is due to issues with the LTC selector switch.
- Reprocess the oil to reduce the high acetylene levels in the tank.
- Repeat the risk of failure assessment in five years.

Appendix C

DBS 9L AND 10L CONDITION ASSESSMENT REPORT

FILED CONFIDENTIALLY

Appendix D

ABB OLI T1 FIELD INSPECTION ASSESSMENT REPORT

Issued By: CA / PP Service
Approved By: Shane R. Hunter

OLI T1 Transformer

Document ID:	Revision:
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Document Type:	Document Subcode:
EBB	2413
Release Date:	Language:
01/30/2013	en

ABB Project No.:	502009-10
Customer:	FortisBC Inc.
Customer P.O.#:	4500200130
Substation:	Oliver Substation

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Contents

Figures

Informative Summary

The work detailed in this report is for the field inspection assessment of Oliver T1 transformer Serial #287732. The site inspection and testing work took place December 3rd to 7th. The work included an exterior visual inspection, load tap changer inspection, inspection and function test for auxiliary devices, electrical tests and oil sample from the main tank.

No major anomalies were identified through the above listed tests. Items worth noting include:

- Paint oxidation and surface corrosion normal for the age and location of the transformer
- Tertiary winding temperature gauge has faulty contacts
- Dissolved gas analysis of the main tank oil shows a low level of acetylene present (1.6ppm)
- Results of the oil quality tests indicate the oil may benefit from reclamation
- The oil lab reports a somewhat elevated level of dissolved furans
- PCB level of 6.7 ppm reported in the main tank
- A minor oil leak exists between the main and tap changer tank
- Minor oil leaks identified

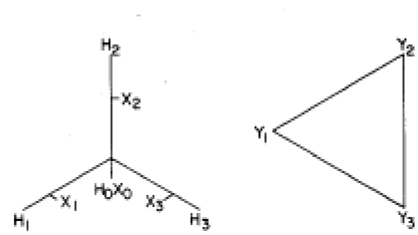
Should this transformer unit be utilized in the future for service it would be beneficial to repair oil leaks and retrofill the unit. The PCB content of the oil inside the tank is in excess of published standards for PCB limits. The electrical test results may serve as fingerprint for future test result comparison if factory or installation test results are not made available.

1 General:

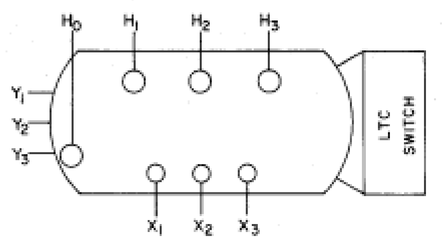
This report will detail the field inspection and testing results for Oliver T1 transformer Serial #:287732. This work took place December 3rd to 7th. The transformer is the former Oliver T1 which was moved during the OTR Upgrade and stored on a temporary pad surrounded by oil containment. There have been discussions indicating a potential move of this transformer to Grand Forks substation for use at a later date. The inspections and testing activities carried out serve as the first step in determining the condition of the unit. It is recommended that a complete design review of the transformer be conducted.

Transformer Nameplate Details			
Rating:	45/60 MVA	Manufacture:	CGE
Type:	ONAN/ONAF	Serial Number:	287732
Voltage (HV):	161 kV	Customer ID:	OLI T1
Voltage (LV):	63 kV	Manufacture Date:	1971
Voltage (TV):	13 kV	%Z	7.1%

Vector Diagram



Layout



Transformer Nameplate

2 Transformer Inspection

2.1 Main Tank

The main tank shows normal signs of wear, paint oxidation and surface corrosion. Three oil leaks were identified, two of these are shown in figures 1 and 2; they include the main tank pressure relief device and thermal well plate respectively. The third oil leak is located at the core ground terminal; an oil leak was made visible when the core ground cover was loosened to access the terminal for testing, the cover was not removed to prevent further oil leak. Two core ground terminal covers are located on top of the transformer, both found with similar problem.

Figure 1: Main tank pressure relief device,the debris below the device is evidence of an oil leak

Figure 2: Signs of an oil leak on the side of transformer tank are visible stemming from the thermal

Figure 3: Tap changer compartment and conservator showing surface corrosion

2.2 Radiators and Cooling Fans

The radiators appear to be in generally good condition with no signs of abnormal wear or oil leak. The valves and header flanges appear in good condition with no oil leaks visible. All valves operated freely.

The four cooling fans rotate freely, appear in normal condition and passed an insulation resistance test.

2.3 Bushings

Visual condition of the bushings is good with no signs of damage, contamination or leaks visible on any of the bushings. Oil level is normal on the high and low side bushings.

2.4 Gauges

The transformer is equipped with four temperature gauges, conservator and tap changer level gauges and one gas detector relay. All devices were inspected and function tested. The tertiary winding temperature gauge labeled 13kV shown in figure 4 was found to have faulty contacts.

Figure 4: The Model FW temperature gauge contains a faulty contact used for fan control

2.5 Breathers

Both the tap changer and main tank conservators breathe through a moisture absorbing desiccant located near the bottom of the transformer. The old desiccant was removed and replaced with new blue desiccant. The desiccant columns shown in figure 5 appear to be in good condition.

Figure 5: Desiccant columns shown with new desiccant installed

3 Oil Analysis

3.1 Main Tank

No anomalies were identified by dissolved gas analysis (DGA) with the exception of a low level of dissolved acetylene (1.6ppm) present in the main tank. It is possible the acetylene originates from the tap changer compartment; an oil leak between the main and tap changer tanks was identified.

The fluid quality analysis results are normal for the age of transformer; the results do indicate levels of PCB's that exceed acceptable limits.

The presence of elevated levels of 2-Furaldehyde (furfuraldehyde) indicate general overheating of the transformer. Given the age and location of the transformer these levels would be expected. The calculated value of DP per Chendong equation is 740. This would put the tensile strength of the paper in the upper "Mid-Life" category.

4 Electrical Tests

A brief summary for each of the electrical tests listed are contained in this section. The detailed field results are included in Appendix A.

4.1 Sweep Frequency Response Analysis (SFRA)

No fingerprint measurements on the unit or measurements on an identical sister transformer are available for interpretation, therefore the measurements on separately tested phases are compared. No significant deviation exists in the SFRA results for the separately tested phases. The slight deviations between different phases are likely due to lead assembly, tank design and tap changer. Should the unit be relocated in future these SFRA results can be used as fingerprint for future analysis.

4.2 Leakage Reactance (%Z)

Leakage reactance was measured on tap positions one, nine and seventeen. The nameplate indicates impedance to be 7.1% at LTC position nine, the measured value is 7.19%.

4.3 Frequency Response of Stray Losses (FRSL)

Results indicate no suspected short circuit parallel strands within the windings. The greatest Rk deviation between windings measured at 400Hz is 6.5% for phase B.

4.4 Insulation Power Factor

Insulation power factor was measured; the measured results closely match previous test records (FortisBC 2001). Corrected power factor was 0.37 and 0.35 for the series-common and tertiary windings respectively. The results of the test suggest shielding existing between the windings. From original design records ABB has confirmed all windings to be layered type with shields between windings. The construction from the core outwards; tertiary winding, shield, common winding, shield, tap winding, series winding, shield.

4.5 Winding Insulation Resistance

Winding insulation resistance was measured and polarization index (PI) calculated. The calculated PI value for the series-common and tertiary windings is 1.4 and 5.8 respectively.

4.6 Exciting Current

An excitation current measurement was made on all tap positions. Measured results show a normal current pattern for the transformer type and connection. The difference between the two higher readings is less than 1% on all tap positions.

4.7 Transformer Turns Ratio

The transformer turns ratio at no load was measured, all measured results are within one half percent of the nameplate readings.

4.8 Winding Resistance

The static and dynamic resistance on all tap positions was measured for the series-tapped windings. Static resistance was measured on the common and tertiary windings. Comparisons of measured resistance values on a per phase basis prove difference in values to be less than 2% for all static resistance measurements. The dynamic resistance measurements (slope and ripple) show good matching between the three phases.

5 Load Tap Changer Inspection

5.1 Main Mechanism

The tap selector and contactor assembly were inspected; contact wear is normal with no sign of arcing on the main and selector contacts. Spring and contact pressure is good. Inspection of the tap changer switch components including geneva gears and drivers, push rods, bearings, levers, and operating shafts revealed no abnormal wear or defects. Inspection of mechanical fasteners revealed no loose, broken or missing components.

An oil leak on phase A is identified by the yellow arrow shown in figure 6; this corresponds to the diverter switch support bushing R indicated by the red arrow on the contact assembly layout drawing (note the contact assembly layout is shown from the transformer side of the panel).

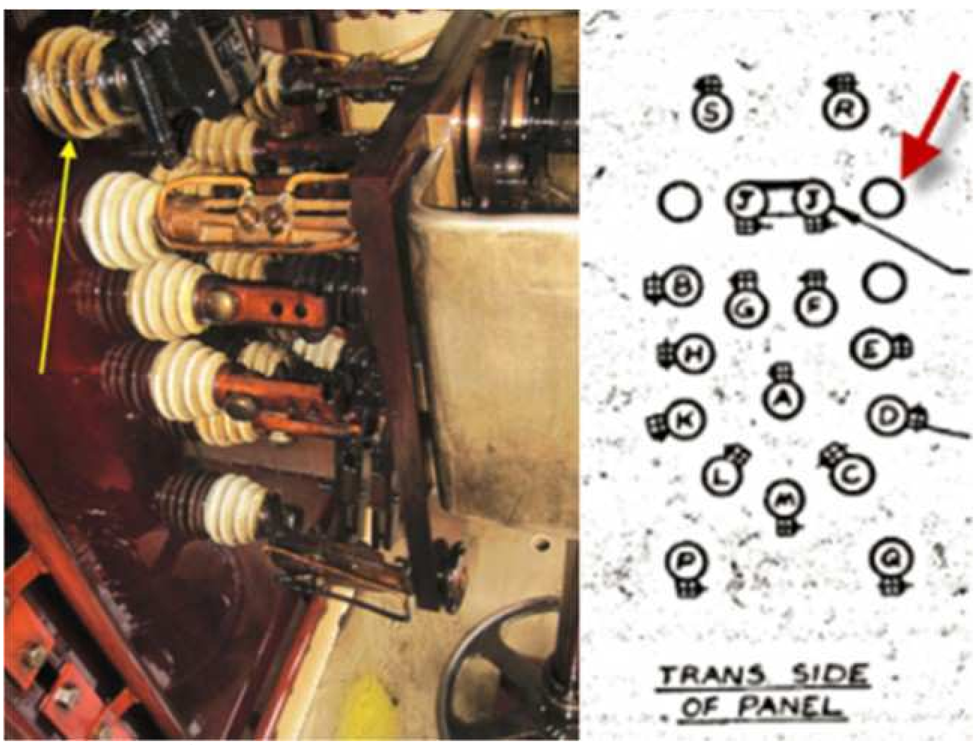


Figure 6: Oil leak on A phase diverter switch support bushing

5.2 Drive Mechanism

The motor drive mechanism appeared in generally good condition for the age of tap changer. The tap changer was operated through all positions, end stops functioned correctly, dynamic brake operated correctly, limit switches and cams are secure and operate correctly, and the drive shaft oil seal shows no signs of oil leak.

6 Concluding Remarks:

Ex-Oliver T1 transformer has passed all electrical tests. Some minor oil leaks exist at the temperature probe well plate and pressure relief device. There is a suspected oil leak at the core ground bushings.

Inspection of the tap changer switch compartment revealed an oil leak between the main and tap changer tank at the diverter switch support bushing R. A small amount of acetylene was reported in the main tank oil, it is a possibility the acetylene is originating from the tap changer compartment.

PCB analysis of the main tank oil indicates a concentration of 6.7 ppm. This value is higher than the latest published values with respect to acceptable levels of PCB's. The concentration of Furans in the oil indicates that the tensile strength of the paper is excellent. This tensile strength along with the low levels of moisture in oil as well as the low value of insulation power factor indicate that the solid insulation is in excellent condition for the age of the transformer.

It is recommended that a complete design review of the transformer be conducted. According to the obtained data the active part of the transformer is in excellent condition. The exterior oil leaks are minor and can easily be repaired upon relocation. Due to the high concentrations of PCB's this oil would need to be disposed of. New or reclaimed oil would have to be supplied to re-fill the unit. It is recommended that all the oil leaks be repaired. It is also recommended that a new thermo plate and wells be installed. Temperature monitoring and controls should be upgraded to and Electronic Temperature Monitor (ETM) system.

Please note that all statements in this documentation are made without prejudice. They are based solely on the extent of the data provided and obtained.

We trust that the above is to your satisfaction and thank you for allowing ABB Power Technology Services in assisting FortisBC with this project. Should you have any questions regarding the aforementioned documentation or any of our other services please feel free to contact us at your convenience.

Regards

ABB Inc.
Per

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Mobile: (250) 878-9011

APPENDIX A: **Electrical Test Results**

A.1 SFRA

Sweep Frequency Response Analyzer Test Report

Transformer Count: 1
Total Test Count: 3

1. Manufacturer: Canadian GE Co., Serial Number: 287732, Special ID: PI# 20186 (OLI T1)

TestDate: 12/4/2012 10:40 AM, Trace Name: H1-X1_2012-12-04_10-40-38
TestDate: 12/4/2012 10:52 AM, Trace Name: H2-X2_2012-12-04_10-52-34
TestDate: 12/4/2012 10:59 AM, Trace Name: H3-X3_2012-12-04_10-59-12

Nameplate Details

1. Manufacturer: Canadian GE Co., Serial Number: 287732, Special ID: PI# 20186 (OLI T1)

TestTemplate: 3-Ph AT w Tertiary

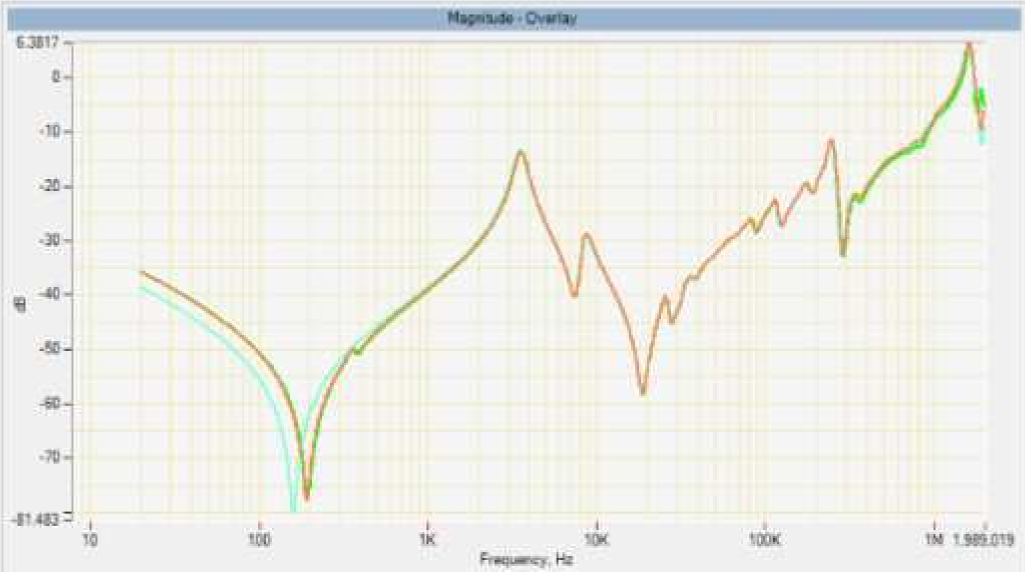
Serial Number: 287732
Manufacturer: Canadian GE Co.
Year of Manufacture: 1971
Special ID: PI# 20186 (OLI T1)
Current: 550
Phases: 3
Windings: 2
Type: TRANS
HV: 161
LV1: 63
LV2: 0
Tertiary: 13
Impedance HV-LV1: 0
Impedance HV-LV2: 0
Impedance HV-Tertiary: 0
Impedance LV-Tertiary: 0

MVA Maximum: 73.5
MVA1: 58.6
MVA2: 0
MVA3: 0
Notes:
Template: 3-Ph AT w Tertiary
LTC Serial Number: OLTC 287732
LTC Manufacturer: CGE
LTC Year of Mfr: 1971
LTC Range: 1-17
LTC Notes:
DETC Serial Number:
DETC Manufacturer:
DETC Year of Mfr: 0
DETC Range:
DETC Notes:

Page 1 Monday, January 28, 2013

Test Setup: LTC Position 1, Open Circuit Test, No Shorted Bushings, No Grounded Bushings

Sweep Frequency Response Analyzer Test Report



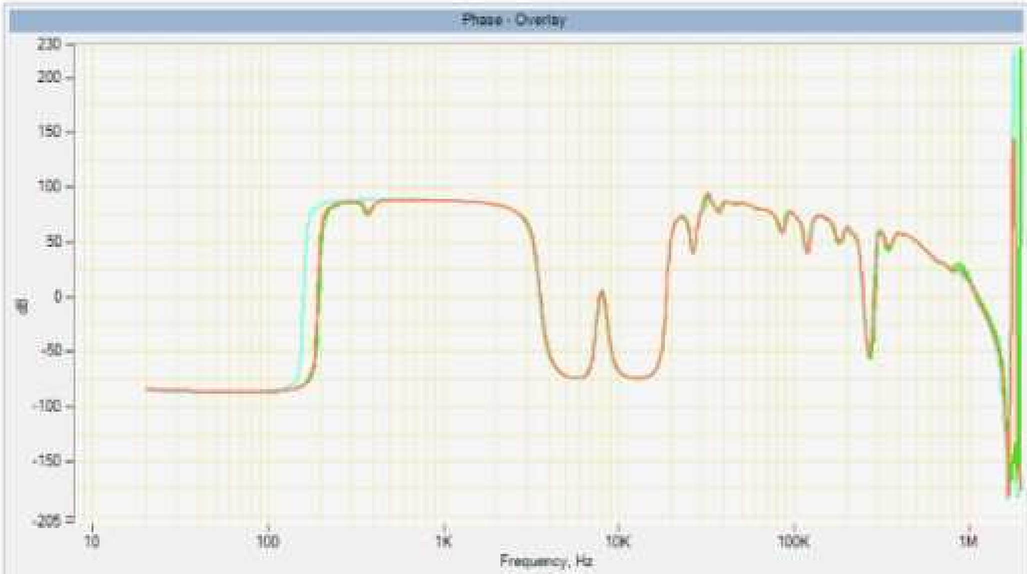
H1-X1_2012-12-04_10-40-38 - Manufacturer: Canadian GE Co.Serial Number: 287732Date: 12/4/2012 10:40:38 AM LTC 1MVA Maximum: 73.5KW 161/63/13

H2-X2_2012-12-04_10-52-34 - Manufacturer: Canadian GE Co.Serial Number: 287732Date: 12/4/2012 10:52:34 AM LTC 1MVA Maximum: 73.5KW 161/63/13

H3-X3_2012-12-04_10-59-12 - Manufacturer: Canadian GE Co.Serial Number: 287732Date: 12/4/2012 10:59:12 AM LTC 1MVA Maximum: 73.5KW 161/63/13

Test Setup: LTC Position 1, Open Circuit Test, No Shorted Bushings, No Grounded Bushings

Sweep Frequency Response Analyzer Test Report

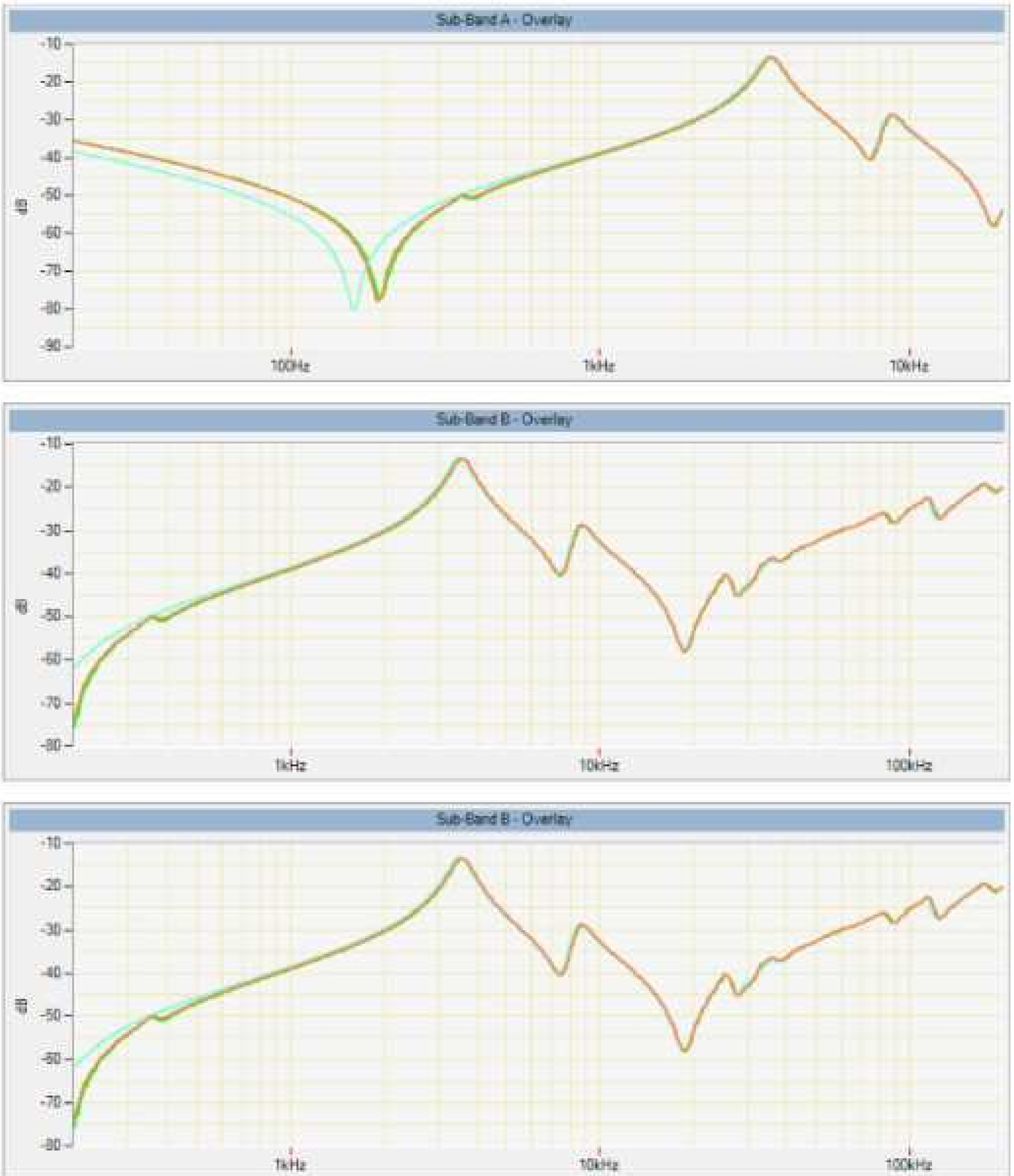


Page 3

Monday, January 28, 2013

Test Setup: LTC Position 1, Open Circuit Test, No Shorted Bushings, No Grounded Bushings

Sweep Frequency Response Analyzer Test Report



Monday, January 28, 2013

Test Setup: LTC Position 1, Open Circuit Test, No Shorted Bushings, No Grounded Bushings

Transformer Count: 1
Total Test Count: 3

1. Manufacturer: Canadian GE Co., Serial Number: 287732, Special ID: PI# 20186 (OLI T1)

TestDate: 12/4/2012 11:09 AM, Trace Name: X1-H0X0_2012-12-04_11-09-06
TestDate: 12/4/2012 11:13 AM, Trace Name: X2-H0X0_2012-12-04_11-13-24
TestDate: 12/4/2012 11:18 AM, Trace Name: X3-H0X0_2012-12-04_11-18-25

Nameplate Details

1. Manufacturer: Canadian GE Co., Serial Number: 287732, Special ID: PI# 20186 (OLI T1)

TestTemplate: 3-Ph AT w Tertiary

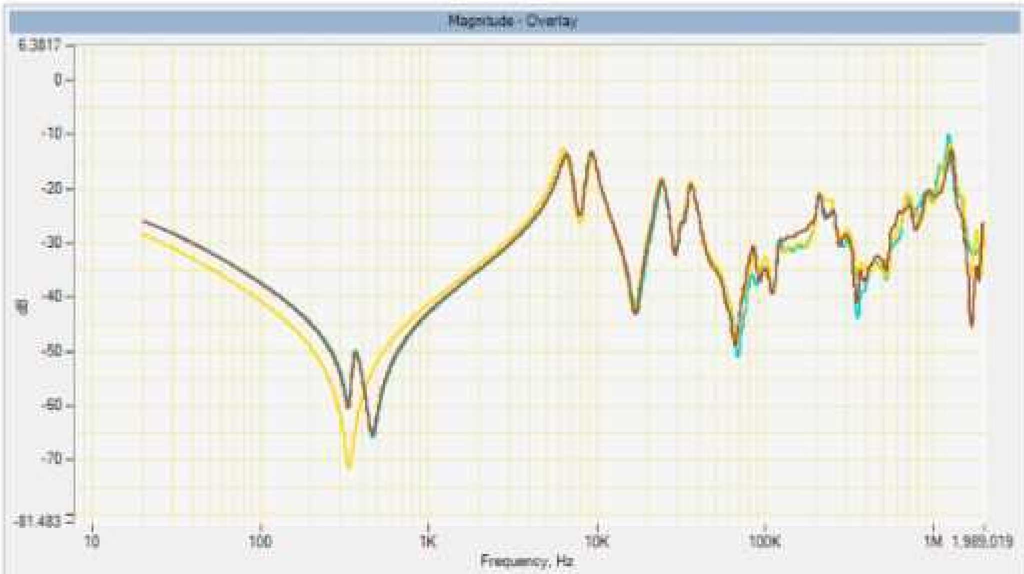
Serial Number: 287732
Manufacturer: Canadian GE Co.
Year of Manufacture: 1971
Special ID: PI# 20186 (OLI T1)
Current: 550
Phases: 3
Windings: 2
Type: TRANS
HV: 161
LV1: 63
LV2: 0
Tertiary: 13
Impedance HV-LV1: 0
Impedance HV-LV2: 0
Impedance HV-Tertiary: 0
Impedance LV-Tertiary: 0

MVA Maximum: 73.5
MVA1: 58.5
MVA2: 0
MVA3: 0
Notes:
Template: 3-Ph AT w Tertiary
LTC Serial Number: OLTC 287732
LTC Manufacturer: CGE
LTC Year of Mfr: 1971
LTC Range: 1-17
LTC Notes:
DETC Serial Number:
DETC Manufacturer:
DETC Year of Mfr: 0
DETC Range:
DETC Notes:

 Monday, January 28, 2013

Test Setup: LTC Position 1, Open Circuit Test, No Shorted Bushings, No Grounded Bushings

Sweep Frequency Response Analyzer Test Report



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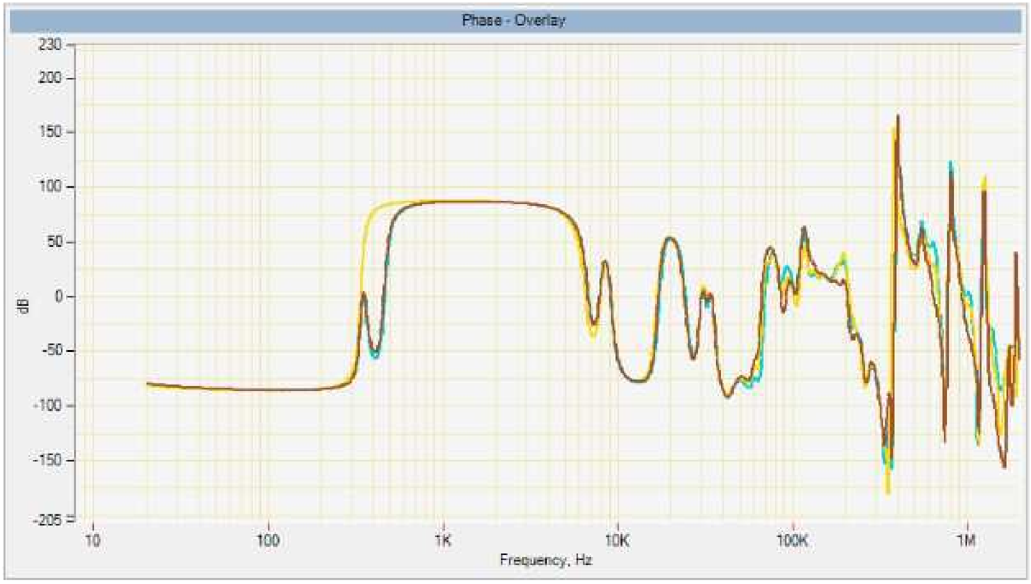
X2-H000_2012-12-04_11-13-24 - Manufacturer: Canadian GE Co.Serial Number: 287732Date: 12/4/2012 11:13:24 AM LTC: 1MVA Maximum: 73.5Kh 161/63/13

X3-H000_2012-12-04_11-18-25 - Manufacturer: Canadian GE Co.Serial Number: 287732Date: 12/4/2012 11:18:25 AM LTC: 1MVA Maximum: 73.5Kh 161/63/13

Page 2 Monday, January 28, 2013

Test Setup: LTC Position 1, Open Circuit Test, No Shorted Bushings, No Grounded Bushings

Sweep Frequency Response Analyzer Test Report

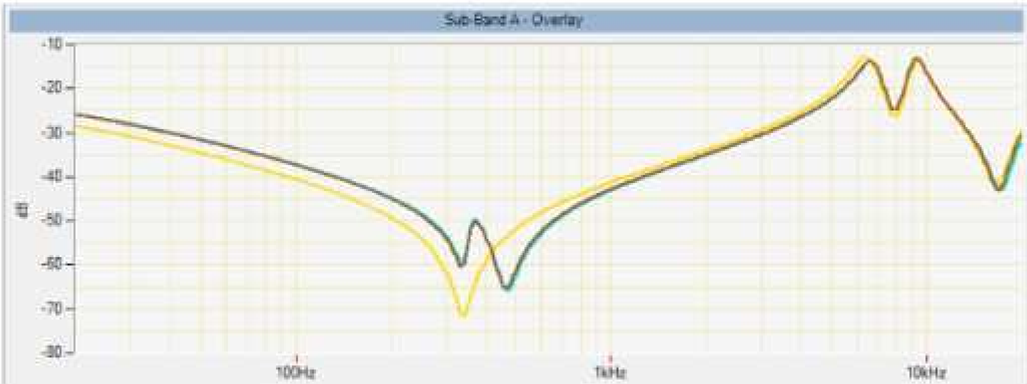


Page 3

Monday, January 28, 2013

Test Setup: LTC Position 1, Open Circuit Test, No Shorted Bushings, No Grounded Bushings

Sweep Frequency Response Analyzer Test Report



Test Setup: LTC Position 1, Open Circuit Test, No Shorted Bushings, No Grounded Bushings

Sweep Frequency Response Analyzer Test Report

Transformer Count: 1
Total Test Count: 3

1. Manufacturer: Canadian GE Co., Serial Number: 287732, Special ID: PI# 20186 (OLI T1)

TestDate: 12/4/2012 11:25 AM, Trace Name: Y1-Y3_2012-12-04_11-25-01
TestDate: 12/4/2012 11:31 AM, Trace Name: Y2-Y1_2012-12-04_11-31-01
TestDate: 12/4/2012 11:41 AM, Trace Name: Y3-Y2_2012-12-04_11-41-53

Nameplate Details

1. Manufacturer: Canadian GE Co., Serial Number: 287732, Special ID: PI# 20186 (OLI T1)

TestTemplate: 3-Ph AT w Tertiary

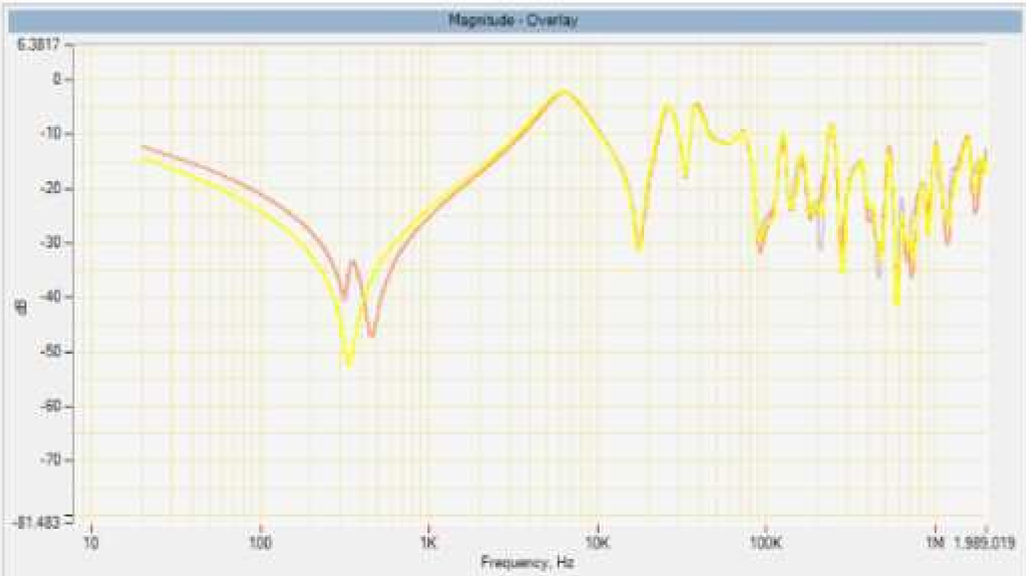
Serial Number: 287732
Manufacturer: Canadian GE Co.
Year of Manufacture: 1971
Special ID: PI# 20186 (OLI T1)
Current: 550
Phases: 3
Windings: 2
Type: TRANS
HV: 161
LV1: 63
LV2: 0
Tertiary: 13
Impedance HV-LV1: 0
Impedance HV-LV2: 0
Impedance HV-Tertiary: 0
Impedance LV-Tertiary: 0

MVA Maximum: 73.5
MVA1: 58.5
MVA2: 0
MVA3: 0
Notes:
Template: 3-Ph AT w Tertiary
LTC Serial Number: OLTC 287732
LTC Manufacturer: CGE
LTC Year of Mfr: 1971
LTC Range: 1-17
LTC Notes:
DETC Serial Number:
DETC Manufacturer:
DETC Year of Mfr: 0
DETC Range:
DETC Notes:

Page 1 Monday, January 28, 2013

Test Setup: LTC Position 1, Open Circuit Test, No Shorted Bushings, No Grounded Bushings

Sweep Frequency Response Analyzer Test Report



Y1-Y3_2012-12-04_11-29-01 - Manufacturer: Canadian GE Co.Serial Number: 287732Date: 12/4/2012 11:29:01 AM LTC: 1MVA Maximum: 73.5KW 161/63/13

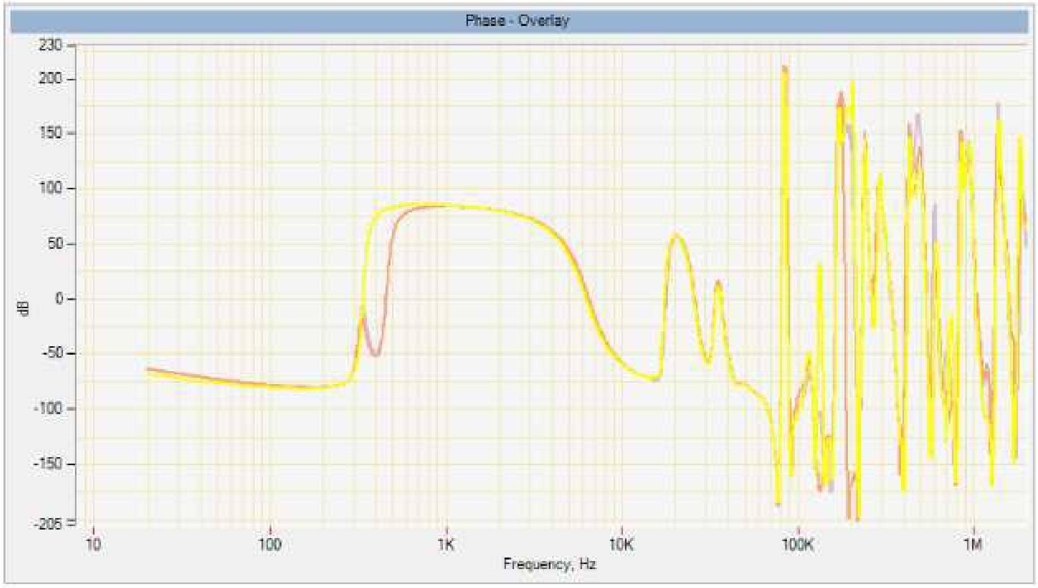
Y2-Y1_2012-12-04_11-31-01 - Manufacturer: Canadian GE Co.Serial Number: 287732Date: 12/4/2012 11:31:01 AM LTC: 1MVA Maximum: 73.5KW 161/63/13

Y3-Y2_2012-12-04_11-41-53 - Manufacturer: Canadian GE Co.Serial Number: 287732Date: 12/4/2012 11:41:53 AM LTC: 1MVA Maximum: 73.5KW 161/63/13

Page 2 Monday, January 28, 2013

Test Setup: LTC Position 1, Open Circuit Test, No Shorted Bushings, No Grounded Bushings

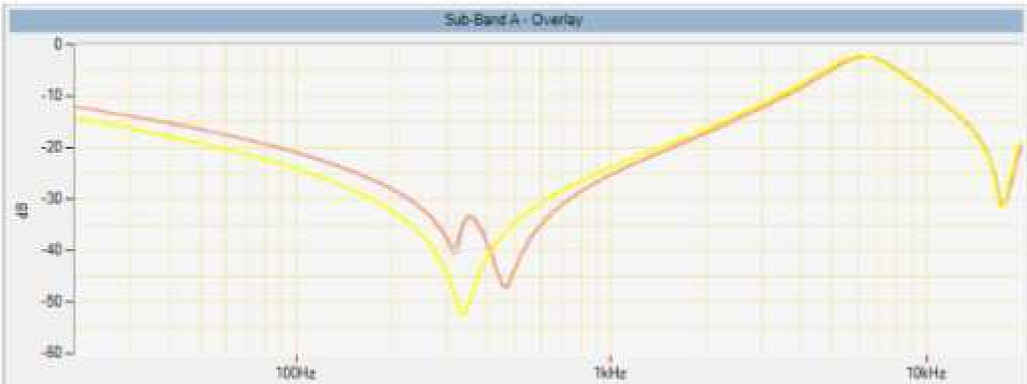
Sweep Frequency Response Analyzer Test Report



 Monday, January 28, 2013

Test Setup: LTC Position 1, Open Circuit Test, No Shorted Bushings, No Grounded Bushings

Sweep Frequency Response Analyzer Test Report



Page 4 Monday, January 28, 2013

Test Setup: LTC Position 1, Open Circuit Test, No Shorted Bushings, No Grounded Bushings

Transformer Count: 1
Total Test Count: 3

1. Manufacturer: Canadian GE Co., Serial Number: 287732, Special ID: PI# 20186 (OLI T1)

TestDate: 12/4/2012 11:49 AM, Trace Name: H1-H0X0_2012-12-04_11-49-40
TestDate: 12/4/2012 11:54 AM, Trace Name: H2-H0X0_2012-12-04_11-54-16
TestDate: 12/4/2012 11:59 AM, Trace Name: H3-H0X0_2012-12-04_11-59-08

Nameplate Details

1. Manufacturer: Canadian GE Co., Serial Number: 287732, Special ID: PI# 20186 (OLI T1)

TestTemplate: 3-Ph AT w Tertiary

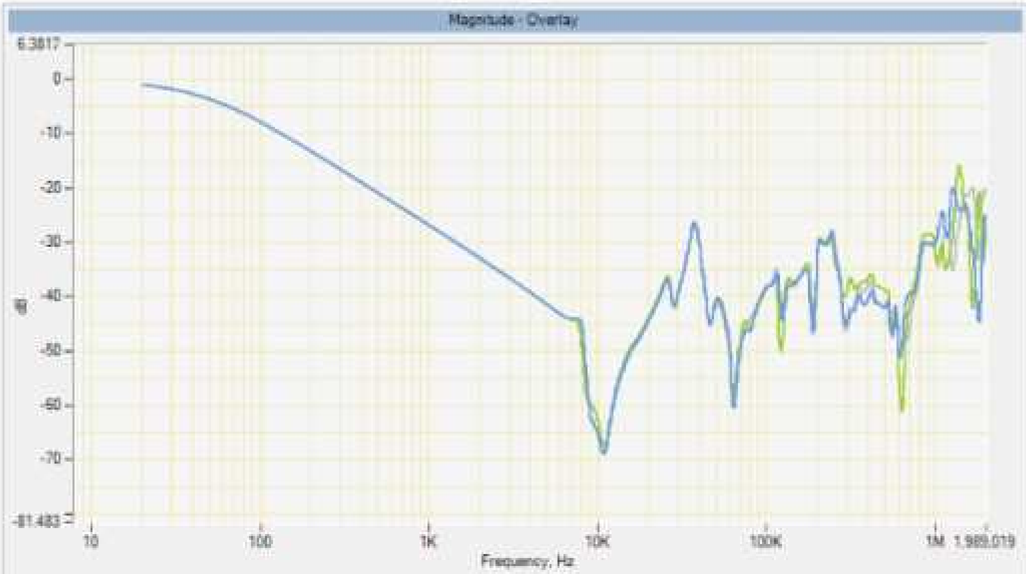
Serial Number: 287732
Manufacturer: Canadian GE Co.
Year of Manufacture: 1971
Special ID: PI# 20186 (OLI T1)
Current: 550
Phases: 3
Windings: 2
Type: TRANS
HV: 161
LV1: 63
LV2: 0
Tertiary: 13
Impedance HV-LV1: 0
Impedance HV-LV2: 0
Impedance HV-Tertiary: 0
Impedance LV-Tertiary: 0

MVA Maximum: 73.5
MVA1: 58.5
MVA2: 0
MVA3: 0
Notes:
Template: 3-Ph AT w Tertiary
LTC Serial Number: OLTC 287732
LTC Manufacturer: CGE
LTC Year of Mfr: 1971
LTC Range: 1-17
LTC Notes:
DETC Serial Number:
DETC Manufacturer:
DETC Year of Mfr: 0
DETC Range:
DETC Notes:

 Monday, January 28, 2013

Test Setup: LTC Position 1, Short Circuit Test, Short X1-X2-X3, No Grounded Bushings

Sweep Frequency Response Analyzer Test Report



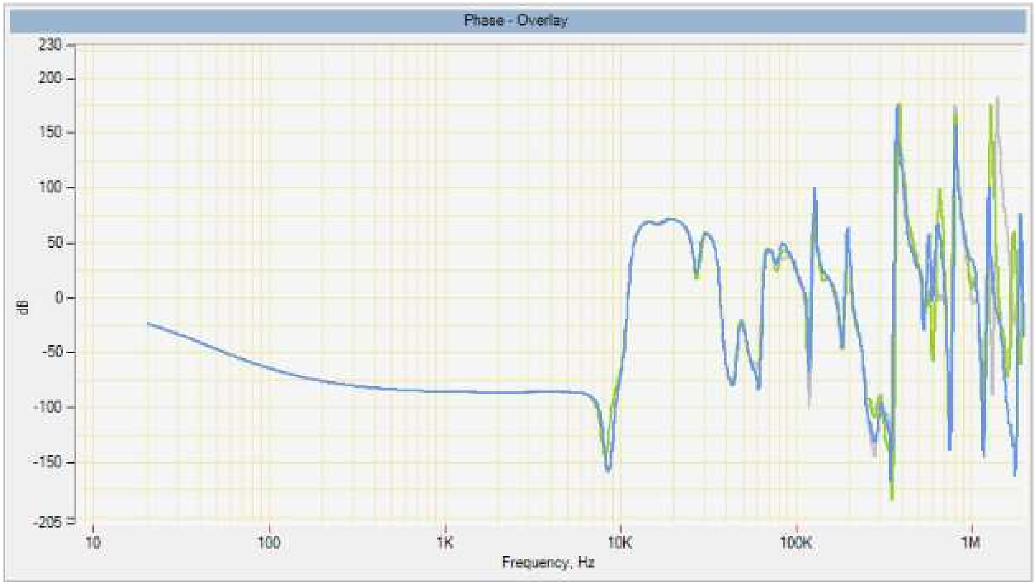
H1-H0X0_2012-12-04_11-49-40 - Manufacturer: Canadian GE Co.Serial Number: 287732Date: 12/4/2012 11:49:40 AM
LTC: 1MVA Maximum: 73.5KV: 161/63/12
H2-H0X0_2012-12-04_11-54-16 - Manufacturer: Canadian GE Co.Serial Number: 287732Date: 12/4/2012 11:54:16 AM
LTC: 1MVA Maximum: 73.5KV: 161/63/12
H3-H0X0_2012-12-04_11-59-38 - Manufacturer: Canadian GE Co.Serial Number: 287732Date: 12/4/2012 11:59:38 AM
LTC: 1MVA Maximum: 73.5KV: 161/63/12

Page 2

Monday, January 28, 2013

Test Setup: LTC Position 1, Short Circuit Test, Short X1-X2-X3, No Grounded Bushings

Sweep Frequency Response Analyzer Test Report

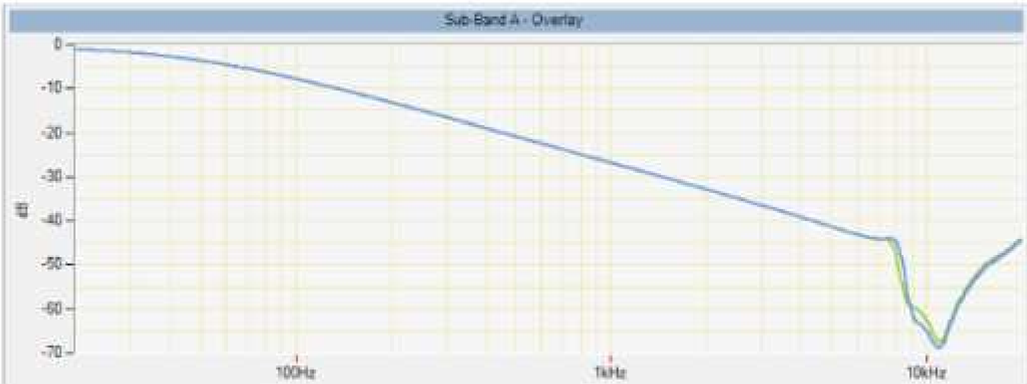


Page 3

Monday, January 28, 2013

Test Setup: LTC Position 1, Short Circuit Test, Short X1-X2-X3, No Grounded Bushings

Sweep Frequency Response Analyzer Test Report



Page 4

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Test Setup: LTC Position 1, Short Circuit Test, Short X1-X2-X3, No Grounded Bushings

Sweep Frequency Response Analyzer Test Report

Transformer Count: 1
Total Test Count: 3

1. Manufacturer: Canadian GE Co., Serial Number: 287732, Special ID: PI# 20186 (OLI T1)

TestDate: 12/4/2012 12:05 PM, Trace Name: H3-H0X0_2012-12-04_12-05-54
TestDate: 12/4/2012 12:10 PM, Trace Name: H2-H0X0_2012-12-04_12-10-11
TestDate: 12/4/2012 12:14 PM, Trace Name: H1-H0X0_2012-12-04_12-14-35

Nameplate Details

1. Manufacturer: Canadian GE Co., Serial Number: 287732, Special ID: PI# 20186 (OLI T1)

TestTemplate: 3-Ph AT w Tertiary

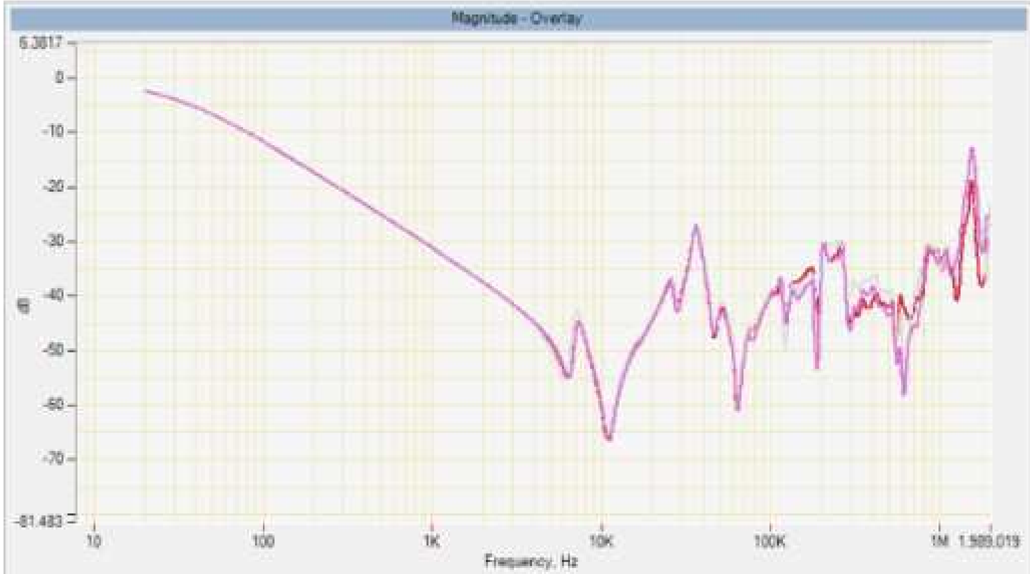
Serial Number: 287732
Manufacturer: Canadian GE Co.
Year of Manufacture: 1971
Special ID: PI# 20186 (OLI T1)
Current: 550
Phases: 3
Windings: 2
Type: TRANS
HV: 161
LV1: 63
LV2: 0
Tertiary: 13
Impedance HV-LV1: 0
Impedance HV-LV2: 0
Impedance HV-Tertiary: 0
Impedance LV-Tertiary: 0

MVA Maximum: 73.5
MVA1: 58.5
MVA2: 0
MVA3: 0
Notes:
Template: 3-Ph AT w Tertiary
LTC Serial Number: OLTC 287732
LTC Manufacturer: CGE
LTC Year of Mfr: 1971
LTC Range: 1-17
LTC Notes:
DETC Serial Number:
DETC Manufacturer:
DETC Year of Mfr: 0
DETC Range:
DETC Notes:

Page 1 Monday, January 28, 2013

Test Setup: LTC Position 1, Short Circuit Test, Short Y1-Y2-Y3, No Grounded Bushings

Sweep Frequency Response Analyzer Test Report



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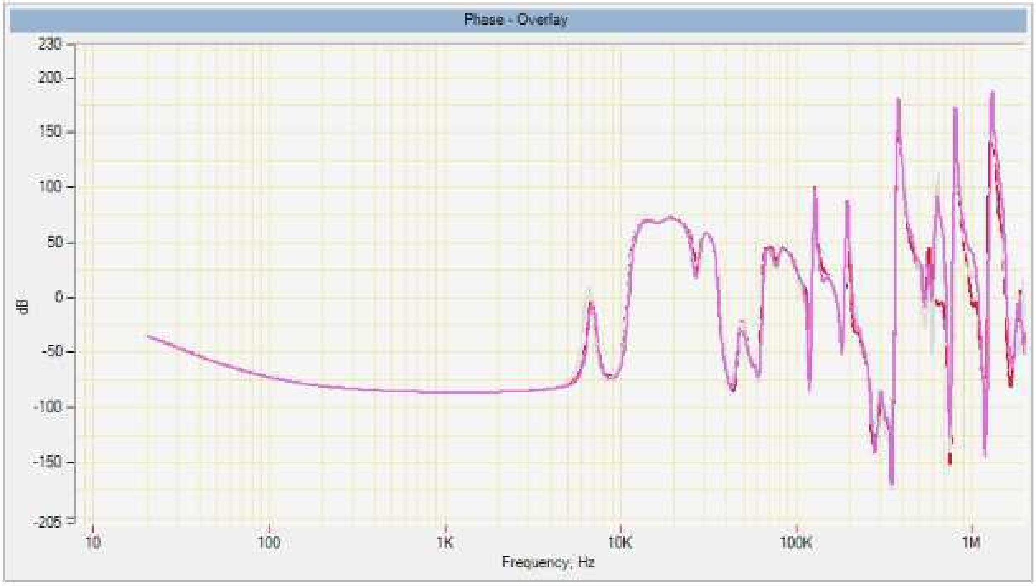
LTC: 1MVA Maximum: 73.5KA 161/63/13
H2-H0X0_2012-12-04_12-10-11 - Manufacturer: Canadian GE Co.Serial Number: 287732Date: 12/4/2012 12:10:11 PM
LTC: 1MVA Maximum: 73.5KA 161/63/13
H1-H0X0_2012-12-04_12-14-35 - Manufacturer: Canadian GE Co.Serial Number: 287732Date: 12/4/2012 12:14:35 PM
LTC: 1MVA Maximum: 73.5KA 161/63/13

Page 2

Monday, January 28, 2013

Test Setup: LTC Position 1, Short Circuit Test, Short Y1-Y2-Y3, No Grounded Bushings

Sweep Frequency Response Analyzer Test Report

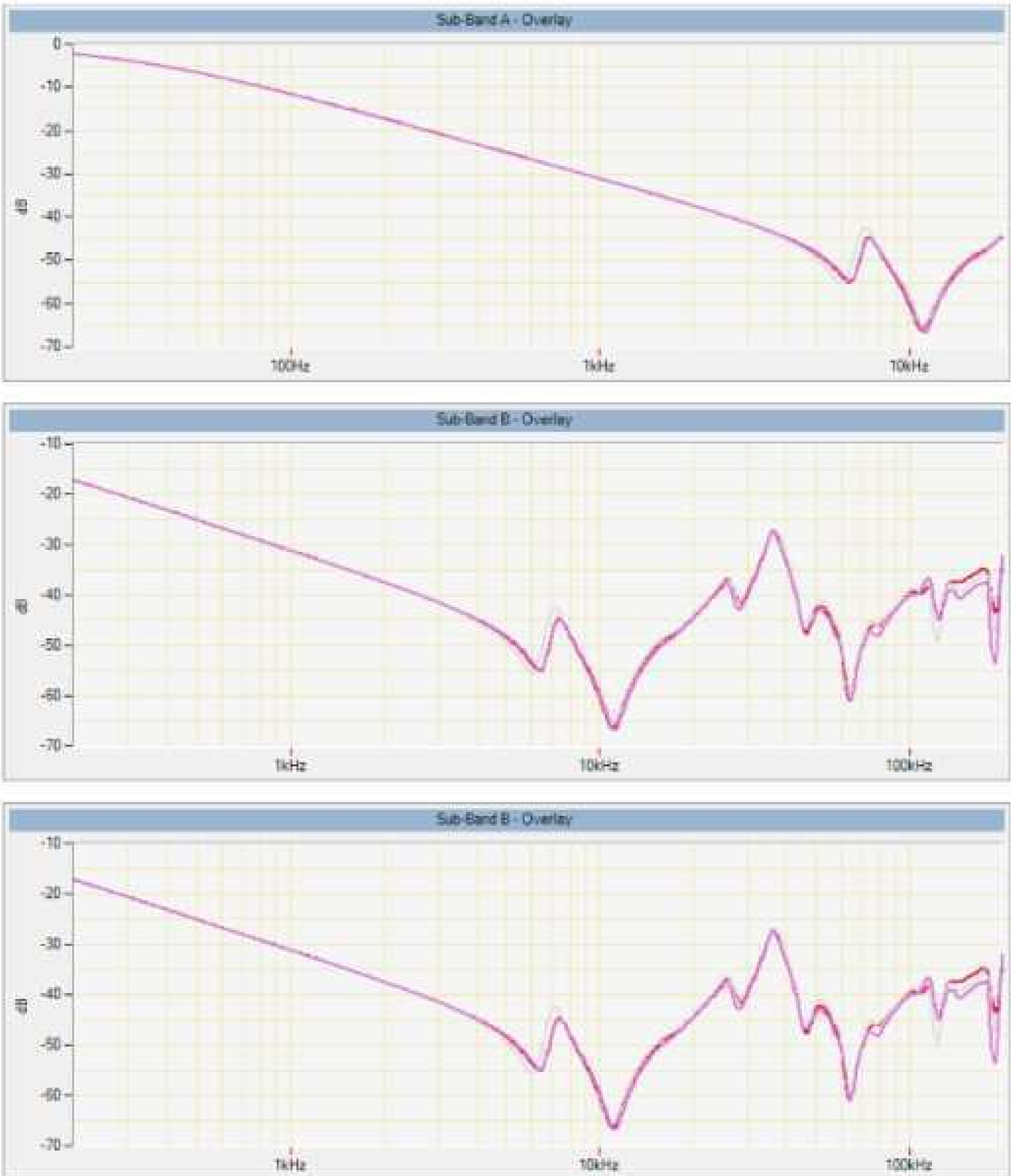


Page 3

Monday, January 28, 2013

Test Setup: LTC Position 1, Short Circuit Test, Short Y1-Y2-Y3, No Grounded Bushings

Sweep Frequency Response Analyzer Test Report



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Monday, January 28, 2013

Test Setup: LTC Position 1, Short Circuit Test, Short Y1-Y2-Y3, No Grounded Bushings

Sweep Frequency Response Analyzer Test Report

Transformer Count: 1
Total Test Count: 3

1. Manufacturer: Canadian GE Co., Serial Number: 287732, Special ID: PI# 20186 (OLI T1)

TestDate: 12/4/2012 12:19 PM, Trace Name: X1-H0X0_2012-12-04_12-19-07
TestDate: 12/4/2012 12:24 PM, Trace Name: X2-H0X0_2012-12-04_12-24-17
TestDate: 12/4/2012 12:28 PM, Trace Name: X3-H0X0_2012-12-04_12-28-31

Nameplate Details

1. Manufacturer: Canadian GE Co., Serial Number: 287732, Special ID: PI# 20186 (OLI T1)

TestTemplate: 3-Ph AT w Tertiary

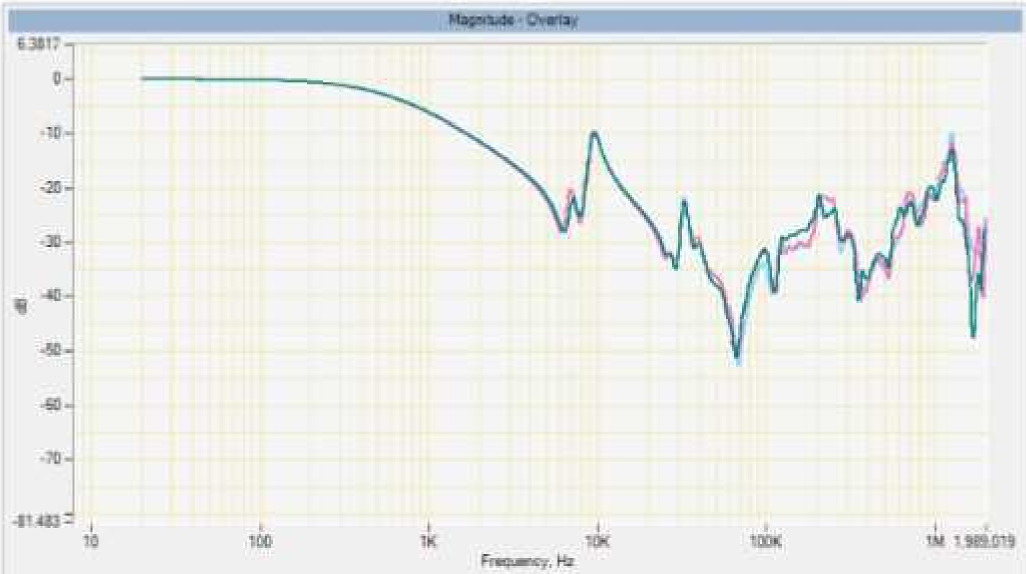
Serial Number: 287732
Manufacturer: Canadian GE Co.
Year of Manufacture: 1971
Special ID: PI# 20186 (OLI T1)
Current: 550
Phases: 3
Windings: 2
Type: TRANS
HV: 161
LV1: 63
LV2: 0
Tertiary: 13
Impedance HV-LV1: 0
Impedance HV-LV2: 0
Impedance HV-Tertiary: 0
Impedance LV-Tertiary: 0

MVA Maximum: 73.5
MVA1: 58.5
MVA2: 0
MVA3: 0
Notes:
Template: 3-Ph AT w Tertiary
LTC Serial Number: OLTC 287732
LTC Manufacturer: CGE
LTC Year of Mfr: 1971
LTC Range: 1-17
LTC Notes:
DETC Serial Number:
DETC Manufacturer:
DETC Year of Mfr: 0
DETC Range:
DETC Notes:

Page 1 Monday, January 28, 2013

Test Setup: LTC Position 1, Short Circuit Test, Short Y1-Y2-Y3, No Grounded Bushings

Sweep Frequency Response Analyzer Test Report



X1-H0X0_2012-12-04_12-19-07 - Manufacturer: Canadian GE Co.Serial Number: 287732Date: 12/4/2012 12:19:07 PM LTC: 1MVA Maximum: 73.59(h 161/63/13

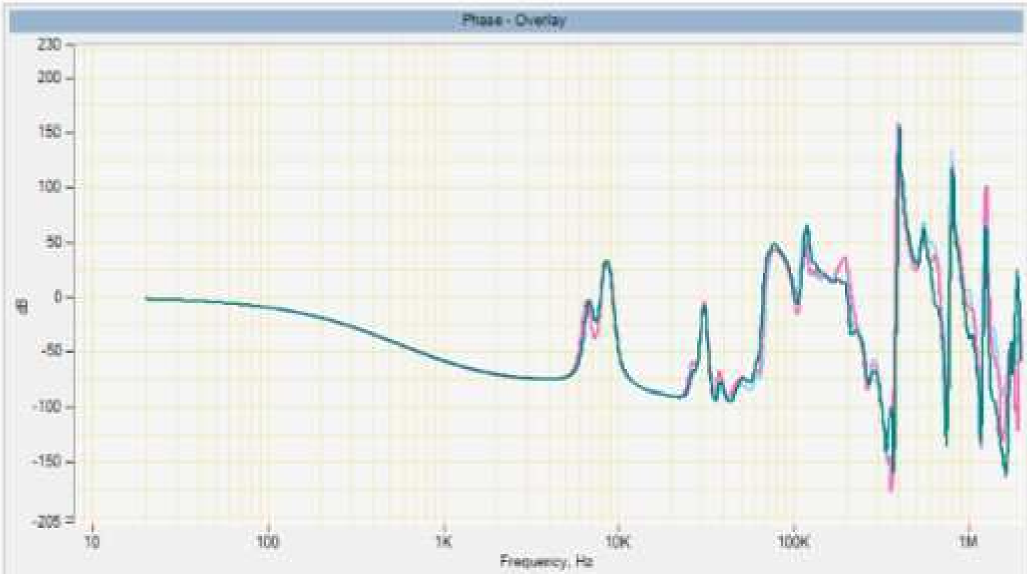
X2-H0X0_2012-12-04_12-24-17 - Manufacturer: Canadian GE Co.Serial Number: 287732Date: 12/4/2012 12:24:17 PM LTC: 1MVA Maximum: 73.59(h 161/63/13

X3-H0X0_2012-12-04_12-28-31 - Manufacturer: Canadian GE Co.Serial Number: 287732Date: 12/4/2012 12:28:31 PM LTC: 1MVA Maximum: 73.59(h 161/63/13

Page 2 Monday, January 28, 2013

Test Setup: LTC Position 1, Short Circuit Test, Short Y1-Y2-Y3, No Grounded Bushings

Sweep Frequency Response Analyzer Test Report



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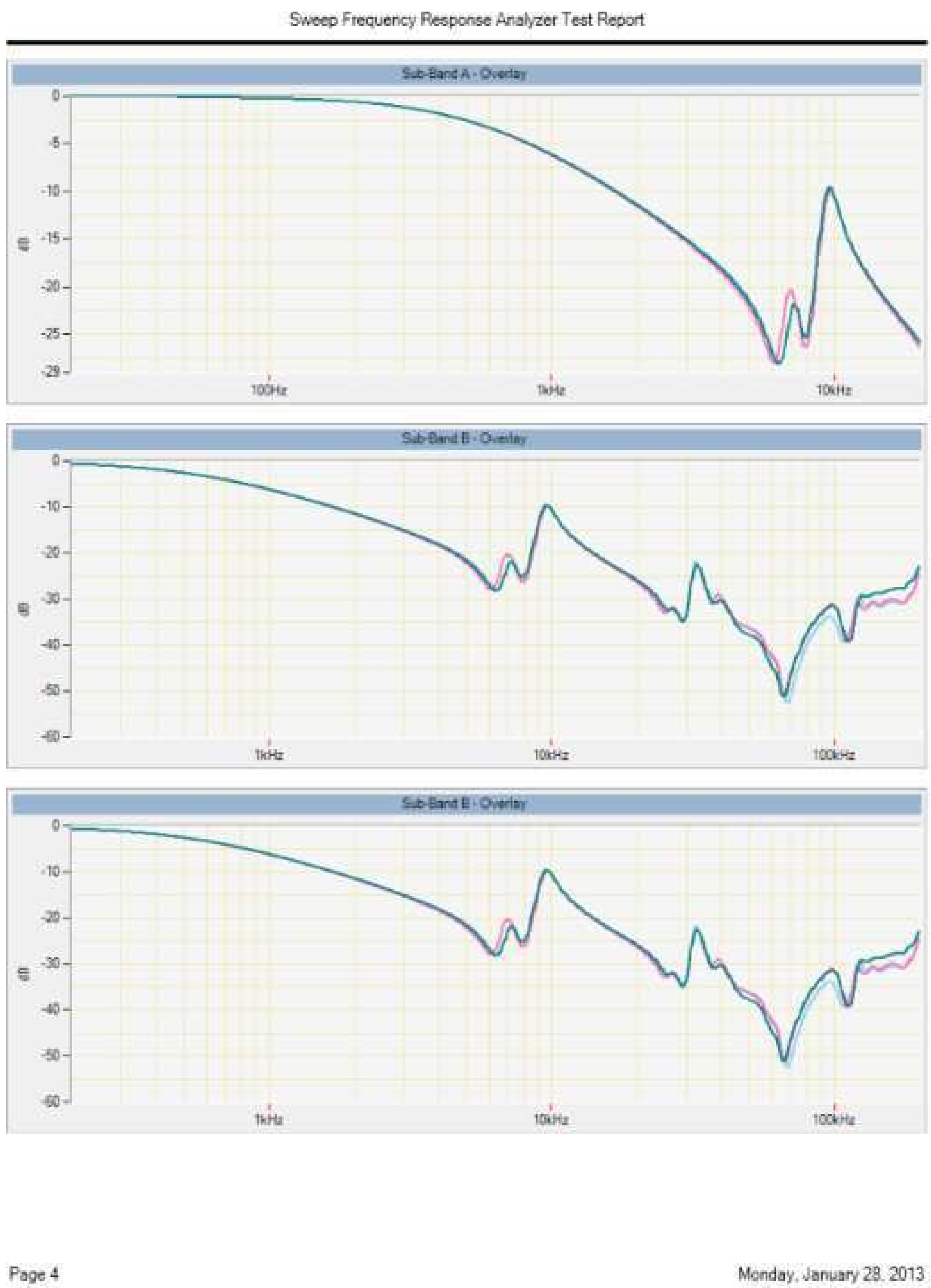
Monday, January 28, 2013

Test Setup: LTC Position 1, Short Circuit Test, Short Y1-Y2-Y3, No Grounded Bushings



Test Setup: LTC Position 1, Short Circuit Test, Short Y1-Y2-Y3, No Grounded Bushings

A.2 Leakage Reactance and Frequency Response of Stray Losses

Leakage Reactance H-X			
Test Current	1.0 A	OLTC Position	1
Winding temperature	10 °C		
Temperature Corr. Factor (K)	1.27		

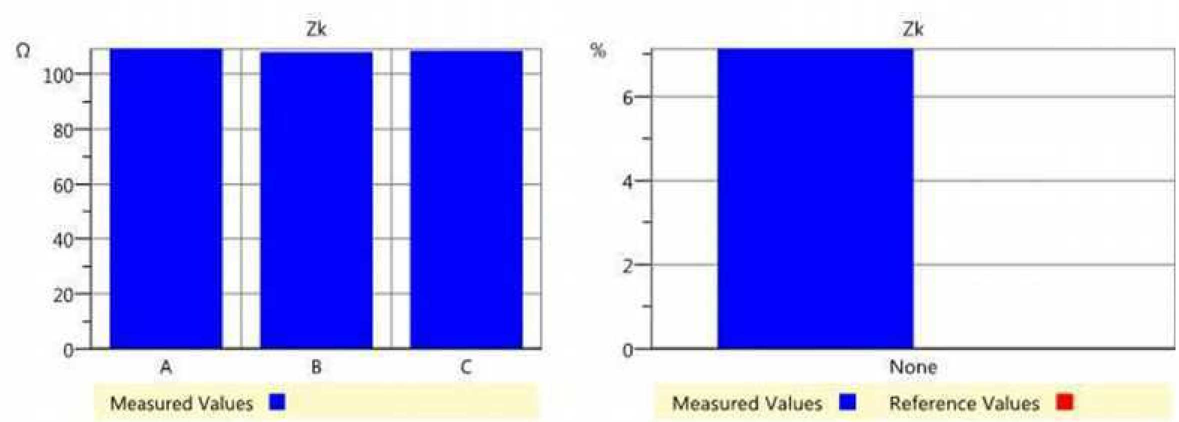
3P Equiv Test Results

Leakage Reactance Results (Zk)

Phase	I AC sel	V1 AC sel	V1 AC sel Phase	Watt Losses	Zk	Rk	Xk	Lk
A	1.07 A	116.38 V	87.64 °	5.114 W	109.116 Ω	4.491 Ω	108.966 Ω	289.042 mH
B	1.07 A	115.16 V	87.65 °	5.038 W	107.999 Ω	4.426 Ω	107.853 Ω	286.089 mH
C	1.07 A	115.58 V	87.58 °	5.208 W	108.358 Ω	4.573 Ω	108.203 Ω	287.017 mH

Assessment of Zk

Zk% mea.	Zk% ref.	Dev. Zk%	Xk% mea.	Xk.% ref.	Dev. Xk%	Assessment
7.12 %	%	%	7.11 %	%	%	None

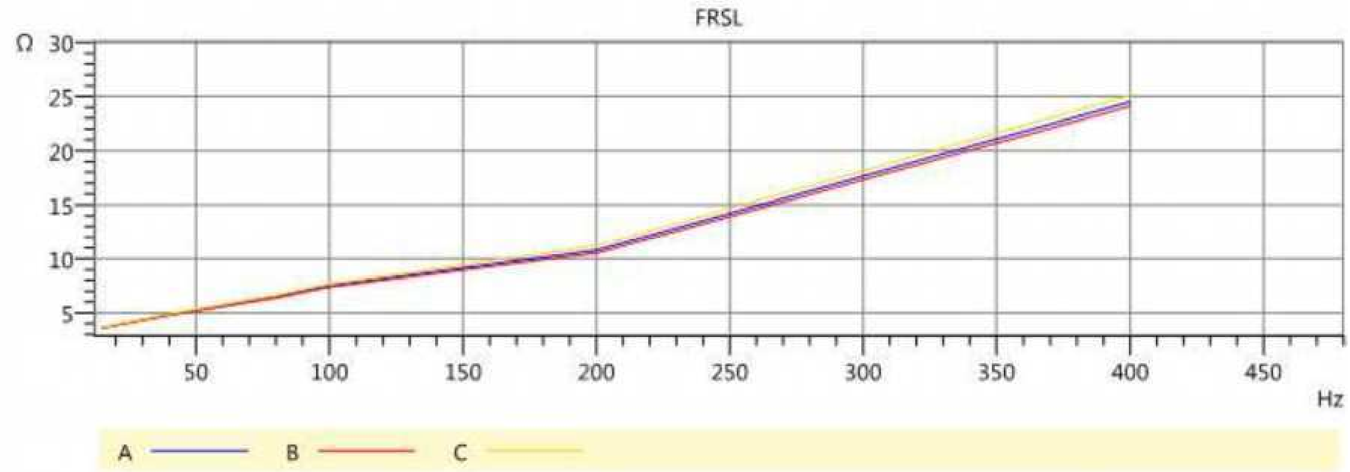


FRSL Results (Rk)

Phase	15 Hz	40 Hz	60 Hz	80 Hz	100 Hz	200 Hz
A	3.65 Ω	4.85 Ω	5.70 Ω	6.53 Ω	7.50 Ω	10.79 Ω
B	3.61 Ω	4.78 Ω	5.62 Ω	6.40 Ω	7.39 Ω	10.53 Ω
C	3.67 Ω	4.91 Ω	5.81 Ω	6.64 Ω	7.69 Ω	11.18 Ω

Assessment of Rk at 400 Hz

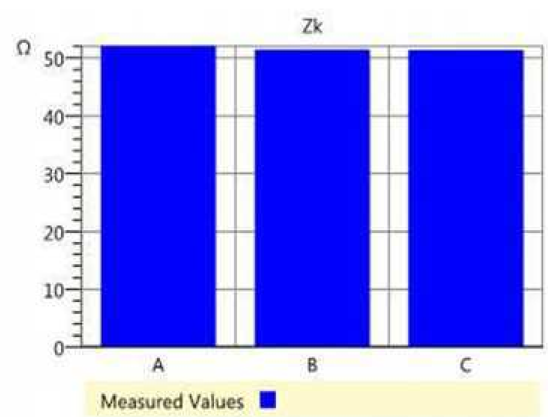
Rk ave.	Dev. Rk Phase A %	Dev. Rk Phase B %	Dev. Rk Phase C %	Assessment
24.58 Ω	0.25 %	1.89 %	-2.14 %	None

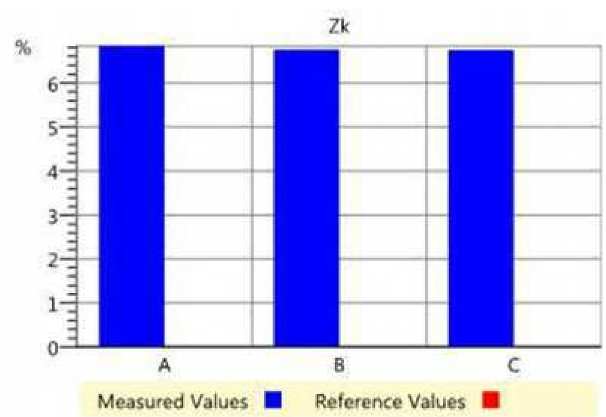


Per Phase Test Results

Leakage Reactance Results (Zk)							
Phase	I AC sel	V1 AC sel	V1 AC sel Phase	Watt Losses	Zk	Rk	Xk
A	1.05 A	54.48 V	87.01 °	2.976 W	52.062 Ω	2.713 Ω	51.948 Ω
B	1.05 A	53.80 V	86.84 °	3.106 W	51.423 Ω	2.832 Ω	51.297 Ω
C	1.05 A	53.76 V	86.91 °	3.035 W	51.372 Ω	2.767 Ω	51.252 Ω

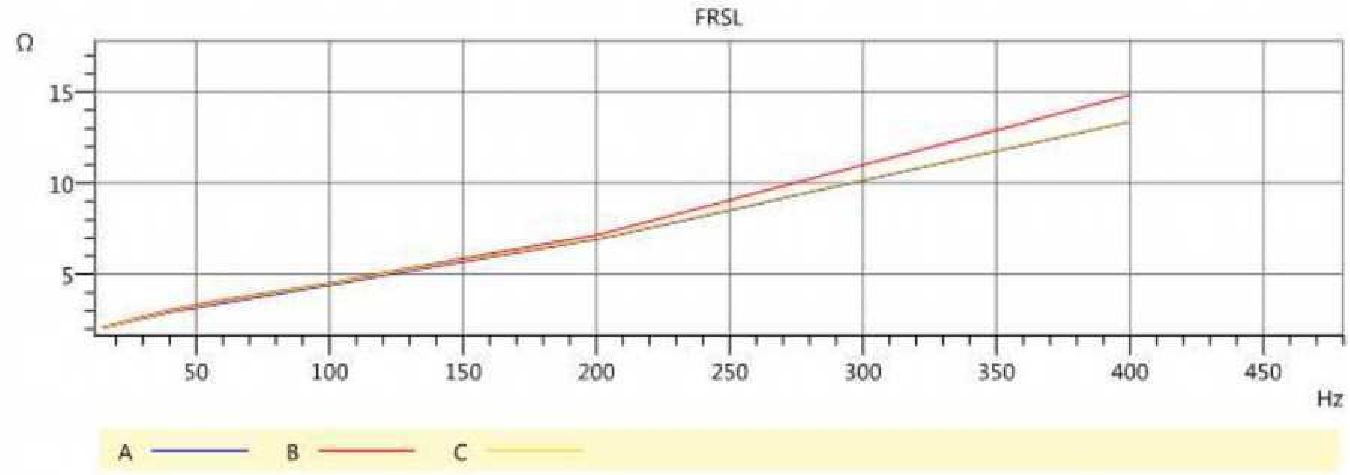
Assessment of Zk								
Phase	Zk% mea.	Zk% ref.	Dev. Zk%	Xk% mea.	Xk.% ref.	Dev. Xk%	Dominance Order	Assessment
A	6.83 %	%	%	6.82 %	%	%	0	None
B	6.75 %	%	%	6.73 %	%	%	0	None
C	6.74 %	%	%	6.73 %	%	%	0	None





FRSL Results (Rk)						
Phase	15 Hz	40 Hz	60 Hz	80 Hz	100 Hz	200 Hz
A	2.06 Ω	2.92 Ω	3.45 Ω	3.94 Ω	4.43 Ω	6.92 Ω
B	2.11 Ω	3.04 Ω	3.60 Ω	4.08 Ω	4.52 Ω	7.16 Ω
C	2.06 Ω	2.98 Ω	3.51 Ω	3.98 Ω	4.47 Ω	6.97 Ω

Assessment of Rk at 400 Hz				
Rk ave.	Dev. Rk Phase A %	Dev. Rk Phase B %	Dev. Rk Phase C %	Assessment
13.88 Ω	3.57 %	-6.84 %	3.28 %	None



Leakage Reactance H-Y			
Test Current	1.0 A	OLTC Position	1
Winding temperature	10 °C		
Temperature Corr. Factor (K)	1.27		

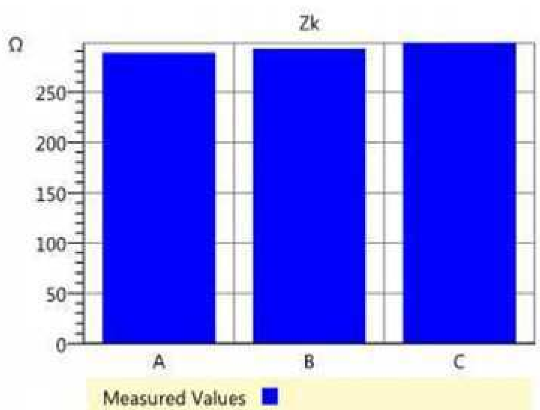
Comments

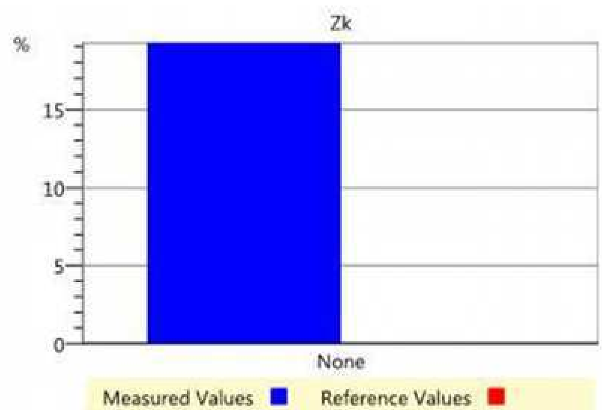
OLTC POSITION 1

3P Equiv Test Results

Leakage Reactance Results (Zk)								
Phase	I AC sel	V1 AC sel	V1 AC sel Phase	Watt Losses	Zk	Rk	Xk	Lk
A	481.07 mA	135.37 V	73.32 °	18.691 W	288.405 Ω	80.766 Ω	269.548 Ω	714.999 mH
B	470.49 mA	134.21 V	73.07 °	18.387 W	292.568 Ω	83.065 Ω	272.887 Ω	723.855 mH
C	466.06 mA	135.18 V	72.20 °	19.260 W	298.242 Ω	88.667 Ω	276.167 Ω	732.555 mH

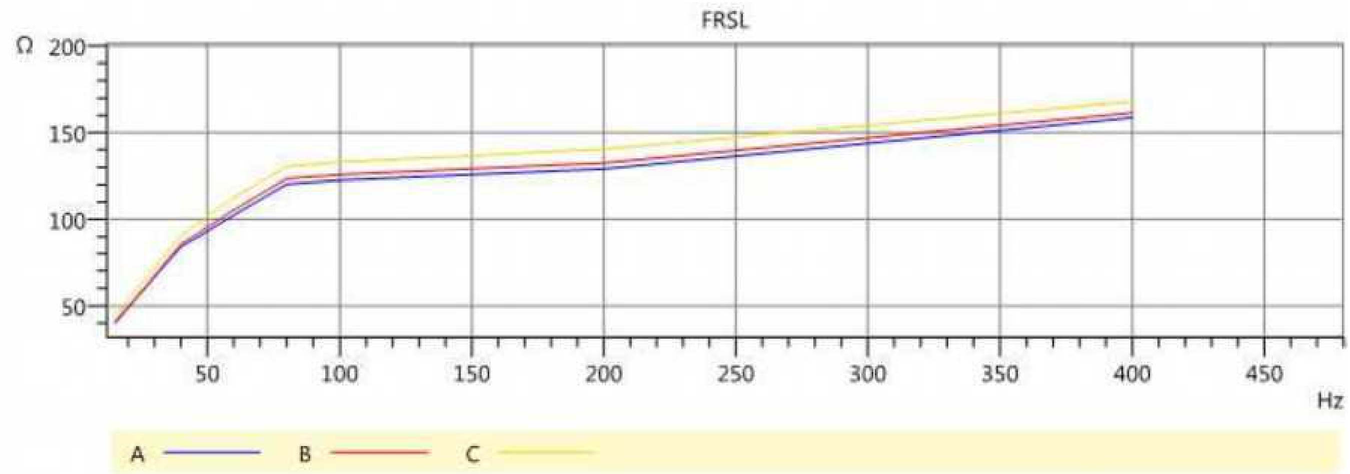
Assessment of Zk						
Zk% mea.	Zk% ref.	Dev. Zk%	Xk% mea.	Xk.% ref.	Dev. Xk%	Assessment
19.24 %	%	%	17.91 %	%	%	None





FRSL Results (Rk)						
Phase	15 Hz	40 Hz	60 Hz	80 Hz	100 Hz	200 Hz
A	40.62 Ω	83.87 Ω	102.57 Ω	120.29 Ω	122.55 Ω	128.94 Ω
B	39.72 Ω	85.50 Ω	105.49 Ω	123.47 Ω	125.76 Ω	132.40 Ω
C	43.84 Ω	90.75 Ω	112.61 Ω	130.41 Ω	132.88 Ω	140.45 Ω

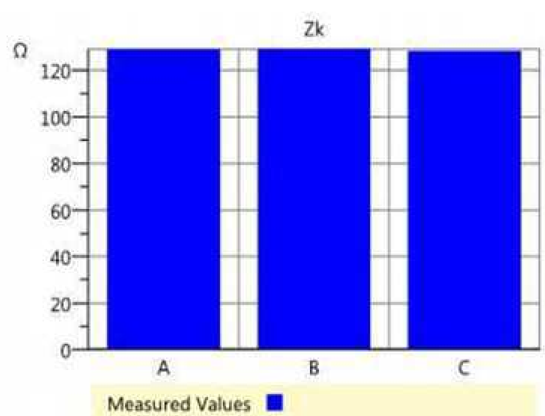
Assessment of Rk at 400 Hz				
Rk ave.	Dev. Rk Phase A %	Dev. Rk Phase B %	Dev. Rk Phase C %	Assessment
162.67 Ω	2.48 %	0.77 %	-3.25 %	None

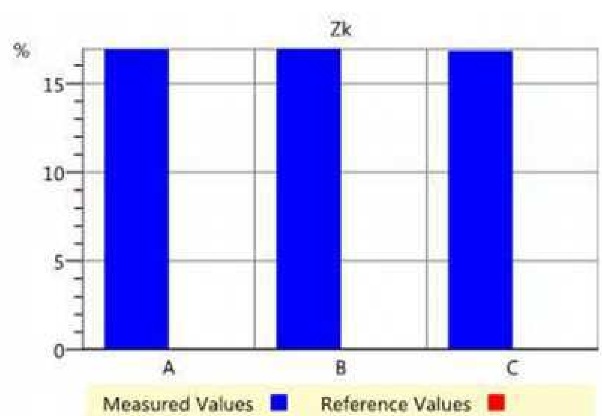


Per Phase Test Results

Leakage Reactance Results (Zk)							
Phase	I AC sel	V1 AC sel	V1 AC sel Phase	Watt Losses	Zk	Rk	Xk
A	1.05 A	132.38 V	74.62 °	36.813 W	128.952 Ω	33.486 Ω	121.738 Ω
B	1.05 A	132.61 V	74.65 °	36.857 W	128.990 Ω	33.435 Ω	121.800 Ω
C	1.05 A	131.86 V	74.71 °	36.518 W	128.198 Ω	33.108 Ω	121.106 Ω

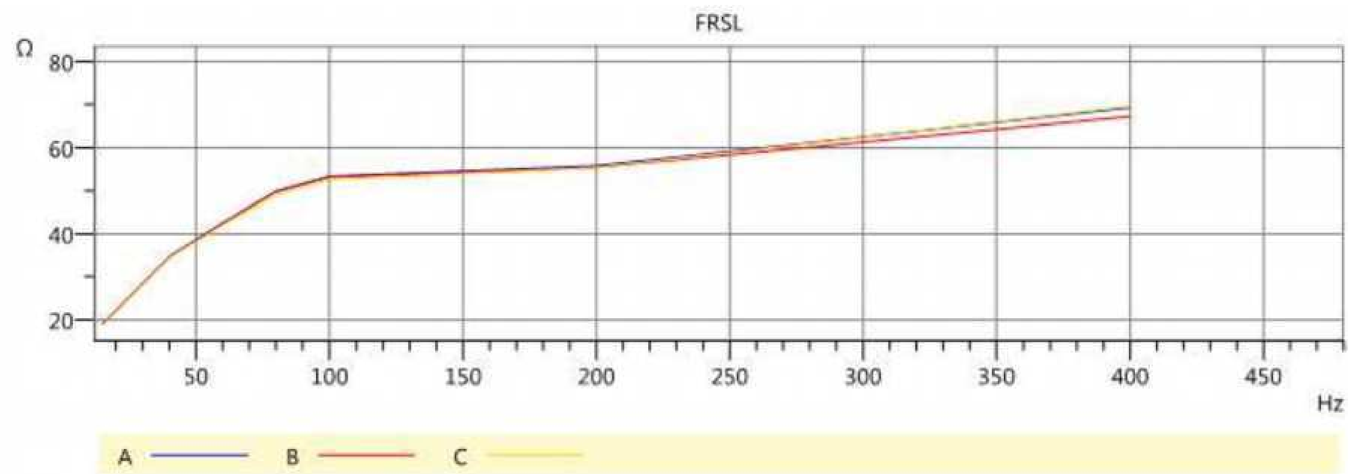
Assessment of Zk								
Phase	Zk% mea.	Zk% ref.	Dev. Zk%	Xk% mea.	Xk.% ref.	Dev. Xk%	Dominance Order	Assessment
A	16.93 %	%	%	15.98 %	%	%	0	None
B	16.93 %	%	%	15.99 %	%	%	0	None
C	16.83 %	%	%	15.90 %	%	%	0	None





FRSL Results (Rk)						
Phase	15 Hz	40 Hz	60 Hz	80 Hz	100 Hz	200 Hz
A	18.91 Ω	34.62 Ω	42.53 Ω	49.86 Ω	53.31 Ω	55.78 Ω
B	19.03 Ω	34.51 Ω	42.46 Ω	49.83 Ω	53.16 Ω	55.40 Ω
C	18.86 Ω	34.30 Ω	42.05 Ω	49.12 Ω	52.58 Ω	55.32 Ω

Assessment of Rk at 400 Hz				
Rk ave.	Dev. Rk Phase A %	Dev. Rk Phase B %	Dev. Rk Phase C %	Assessment
68.70 Ω	-0.83 %	2.14 %	-1.31 %	None



Leakage Reactance X-Y

Test Current	1.0 A
Winding temperature	10 °C
Temperature Corr. Factor (K)	1.27

OLTC Position

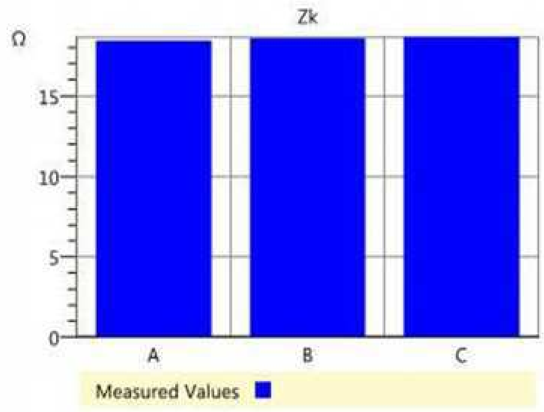
Comments

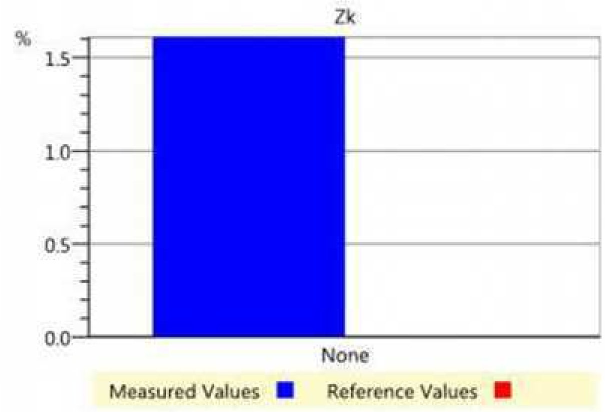
OLTC POSITION 1

3P Equiv Test Results

Leakage Reactance Results (Zk)					
Phase	I AC sel	V1 AC sel	V1 AC sel Phase	Watt Losses	Zk
A	1.00 A	17.39 V	62.79 °	7.975 W	18.423 Ω
B	1.00 A	17.61 V	63.15 °	7.991 W	18.588 Ω
C	1.00 A	17.64 V	63.14 °	7.994 W	18.650 Ω

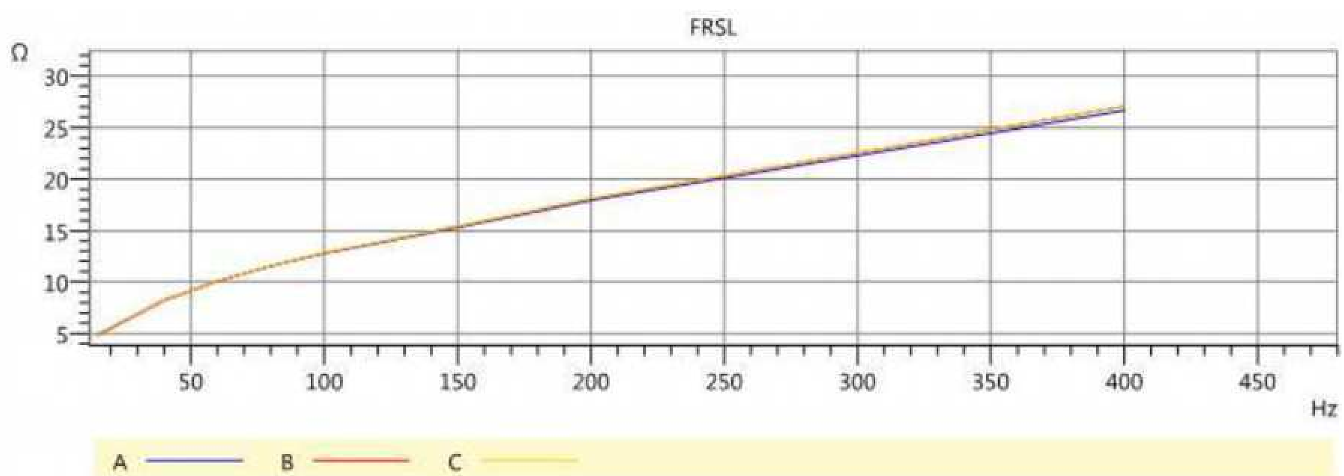
Assessment of Zk						
Zk% mea.	Zk% ref.	Dev. Zk%	Xk% mea.	Xk.% ref.	Dev. Xk%	Assessment
1.61 %	%	%	1.35 %	%	%	None





FRSL Results (Rk)						
Phase	15 Hz	40 Hz	60 Hz	80 Hz	100 Hz	200 Hz
A	4.93 Ω	8.30 Ω	10.07 Ω	11.54 Ω	12.79 Ω	17.94 Ω
B	4.82 Ω	8.21 Ω	10.05 Ω	11.53 Ω	12.81 Ω	18.08 Ω
C	4.95 Ω	8.27 Ω	10.09 Ω	11.55 Ω	12.87 Ω	18.13 Ω

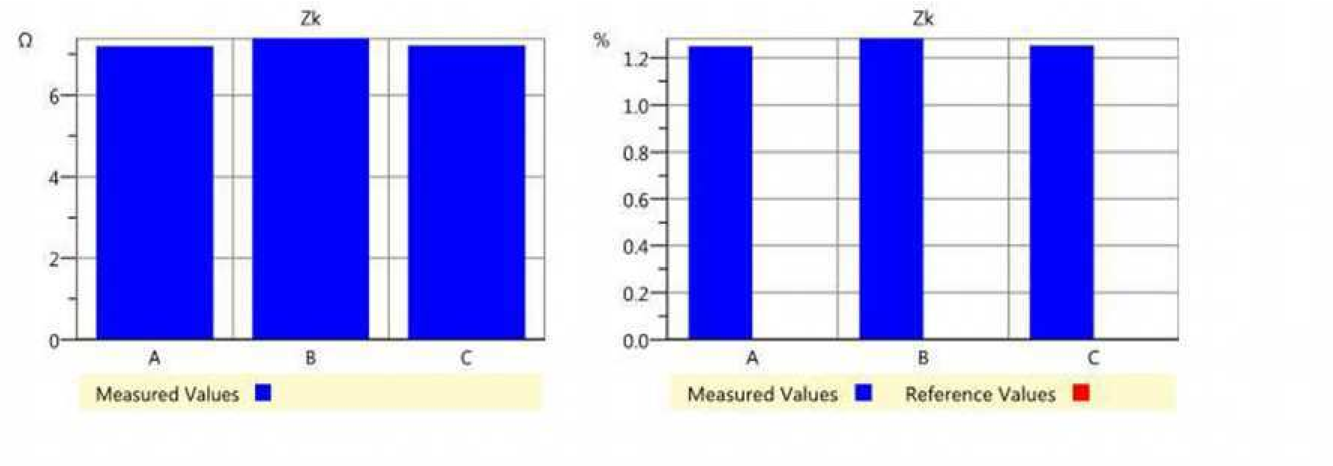
Assessment of Rk at 400 Hz				
Rk ave.	Dev. Rk Phase A %	Dev. Rk Phase B %	Dev. Rk Phase C %	Assessment
26.90 Ω	0.95 %	-0.52 %	-0.43 %	None



Per Phase Test Results

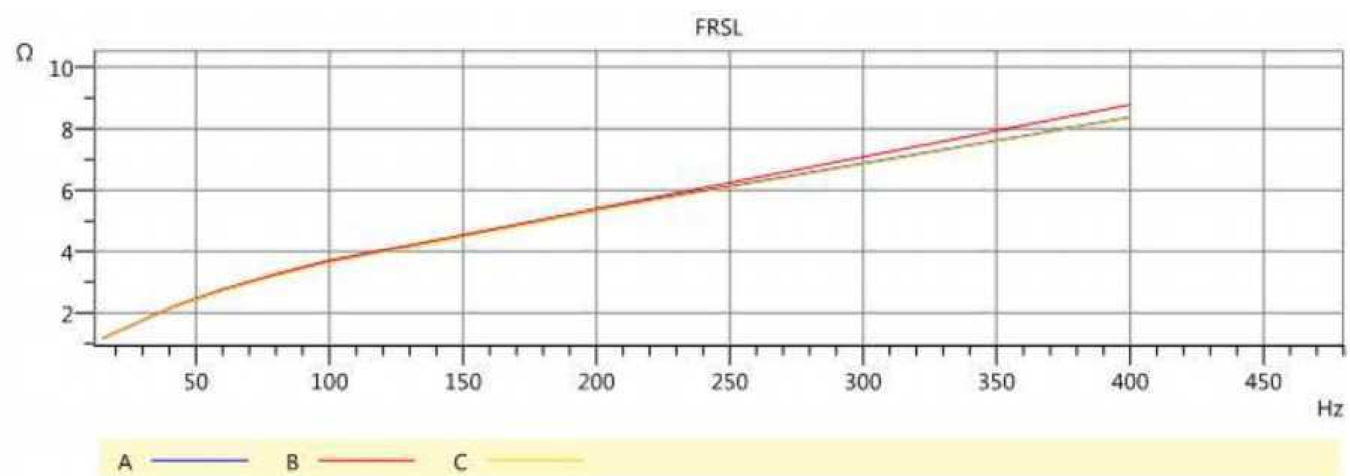
Leakage Reactance Results (Zk)								
Phase	I AC sel	V1 AC sel	V1 AC sel Phase	Watt Losses	Zk	Rk	Xk	Lk
A	999.93 mA	7.00 V	72.11 °	2.150 W	7.199 Ω	2.150 Ω	6.661 Ω	17.669 mH
B	1.00 A	7.20 V	72.40 °	2.178 W	7.388 Ω	2.174 Ω	6.853 Ω	18.177 mH
C	998.75 mA	7.02 V	72.29 °	2.132 W	7.223 Ω	2.138 Ω	6.694 Ω	17.756 mH

Assessment of Zk								
Phase	Zk% mea.	Zk% ref.	Dev. Zk%	Xk% mea.	Xk.% ref.	Dev. Xk%	Dominance Order	Assessment
A	1.25 %	%	%	1.16 %	%	%	0	None
B	1.28 %	%	%	1.19 %	%	%	0	None
C	1.25 %	%	%	1.16 %	%	%	0	None



FRSL Results (Rk)						
Phase	15 Hz	40 Hz	60 Hz	80 Hz	100 Hz	200 Hz
A	1.17 Ω	2.14 Ω	2.73 Ω	3.23 Ω	3.67 Ω	5.38 Ω
B	1.18 Ω	2.16 Ω	2.76 Ω	3.26 Ω	3.71 Ω	5.45 Ω
C	1.18 Ω	2.13 Ω	2.71 Ω	3.20 Ω	3.64 Ω	5.34 Ω

Assessment of Rk at 400 Hz				
Rk ave.	Dev. Rk Phase A %	Dev. Rk Phase B %	Dev. Rk Phase C %	Assessment
8.50 Ω	1.54 %	-3.31 %	1.77 %	None



Leakage Reactance H-X

Test Current	1.0 A		OLTC Position
Winding temperature	10 °C		
Temperature Corr. Factor (K)	1.27		

Comments

OLTC POSITION 9

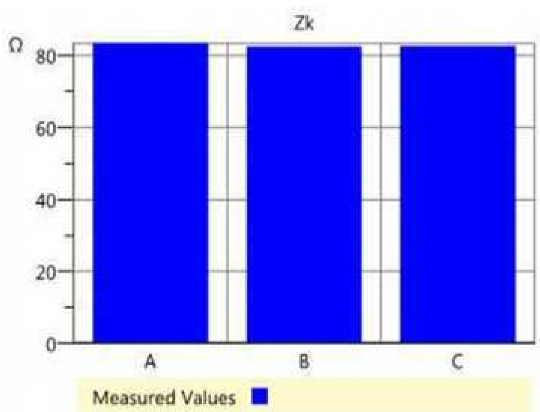
3P Equiv Test Results

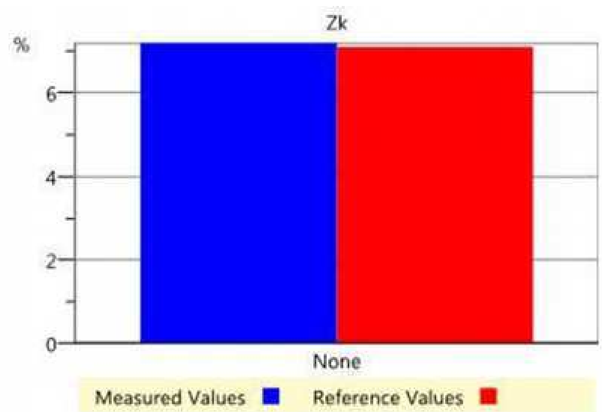
Leakage Reactance Results (Zk)

Phase	I AC sel	V1 AC sel	V1 AC sel Phase	Watt Losses	Zk
A	1.07 A	89.26 V	87.66 °	3.904 W	83.370 Ω
B	1.07 A	88.27 V	87.69 °	3.811 W	82.441 Ω
C	1.07 A	88.40 V	87.60 °	3.964 W	82.597 Ω

Assessment of Zk

Zk% mea.	Zk% ref.	Dev. Zk%	Xk% mea.	Xk.% ref.	Dev. Xk%	Assessment
7.19 %	7.10 %	%	7.18 %	%	%	None



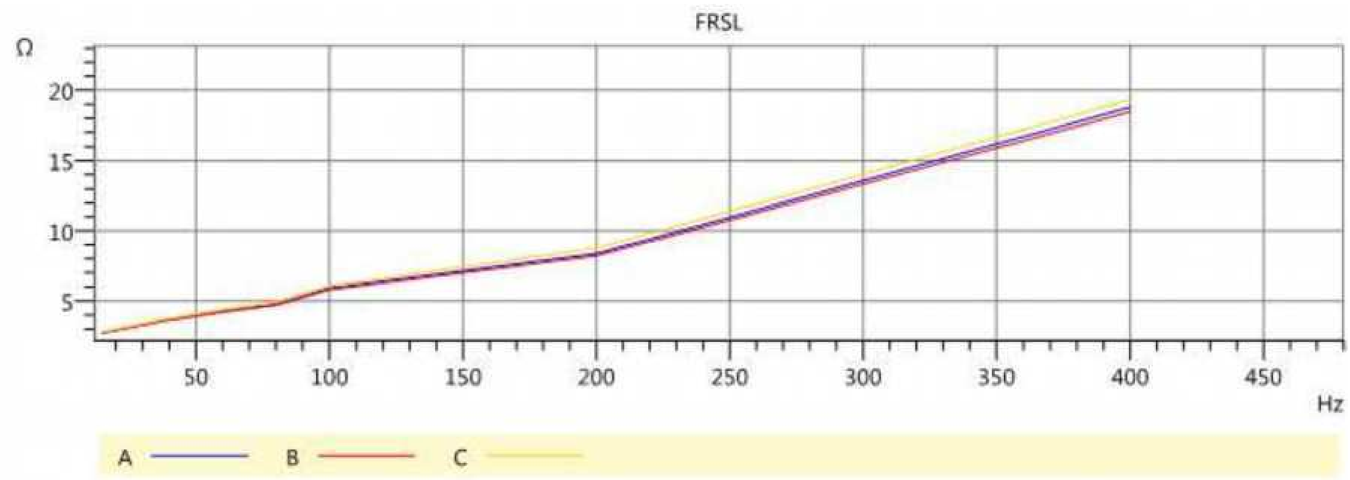


FRSL Results (Rk)

Phase	15 Hz	40 Hz	60 Hz	80 Hz	100 Hz	200 Hz
A	2.74 Ω	3.69 Ω	4.32 Ω	4.76 Ω	5.92 Ω	8.37 Ω
B	2.72 Ω	3.64 Ω	4.22 Ω	4.71 Ω	5.79 Ω	8.21 Ω
C	2.80 Ω	3.77 Ω	4.39 Ω	4.94 Ω	6.07 Ω	8.76 Ω

Assessment of Rk at 400 Hz

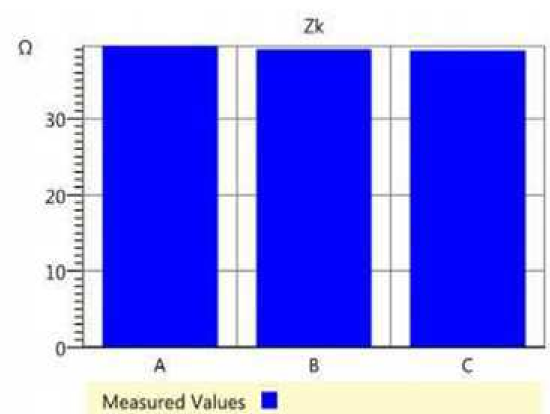
Rk ave.	Dev. Rk Phase A %	Dev. Rk Phase B %	Dev. Rk Phase C %	Assessment
18.86 Ω	0.36 %	2.07 %	-2.43 %	None

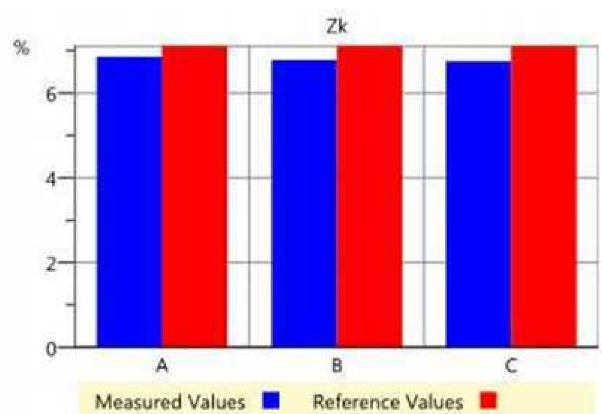


Per Phase Test Results

Leakage Reactance Results (Zk)							
Phase	I AC sel	V1 AC sel	V1 AC sel Phase	Watt Losses	Zk	Rk	Xk
A	1.03 A	40.54 V	87.31 °	1.957 W	39.449 Ω	1.850 Ω	39.379 Ω
B	1.03 A	40.07 V	87.27 °	1.960 W	39.032 Ω	1.858 Ω	38.960 Ω
C	1.03 A	39.86 V	87.28 °	1.943 W	38.844 Ω	1.842 Ω	38.773 Ω

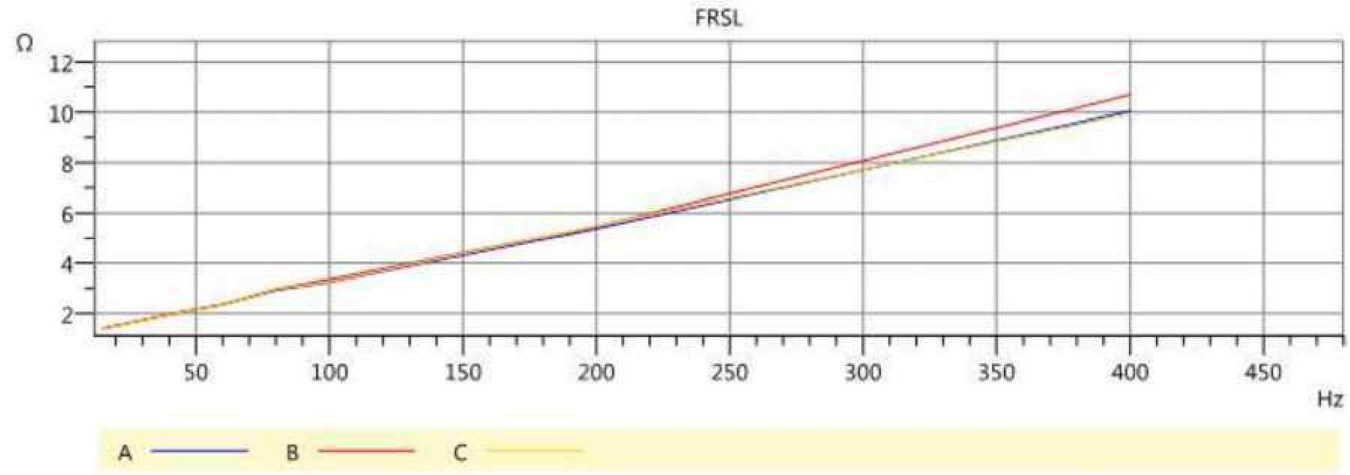
Assessment of Zk								
Phase	Zk% mea.	Zk% ref.	Dev. Zk%	Xk% mea.	Xk.% ref.	Dev. Xk%	Dominance Order	Assessment
A	6.85 %	7.10 %	%	6.84 %	%	%	3	None
B	6.78 %	7.10 %	%	6.76 %	%	%	2	None
C	6.74 %	7.10 %	%	6.73 %	%	%	1	None





FRSL Results (Rk)							
Phase	15 Hz	40 Hz	60 Hz	80 Hz	100 Hz	200 Hz	400 Hz
A	1.39 Ω	1.95 Ω	2.35 Ω	2.93 Ω	3.24 Ω	5.38 Ω	10.05 Ω
B	1.41 Ω	1.98 Ω	2.36 Ω	2.98 Ω	3.35 Ω	5.46 Ω	10.69 Ω
C	1.40 Ω	1.95 Ω	2.34 Ω	2.97 Ω	3.26 Ω	5.38 Ω	9.95 Ω

Assessment of Rk at 400 Hz				
Rk ave.	Dev. Rk Phase A %	Dev. Rk Phase B %	Dev. Rk Phase C %	Assessment
10.23 Ω	1.78 %	-4.51 %	2.72 %	None



Leakage Reactance H-Y

Test Current	1.0 A	OLTC Position	
Winding temperature	10 °C		
Temperature Corr. Factor (K)	1.27		

Comments

OLTC POSITION 9

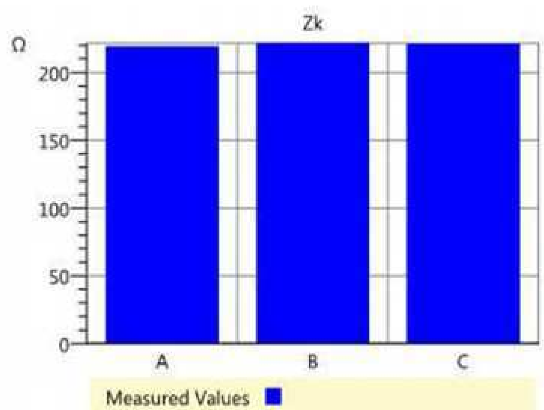
3P Equiv Test Results

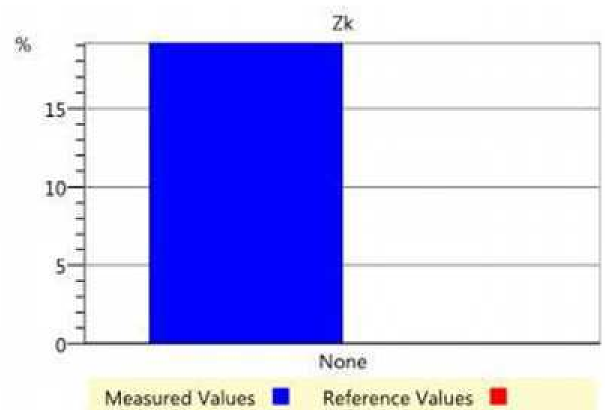
Leakage Reactance Results (Zk)

Phase	I AC sel	V1 AC sel	V1 AC sel Phase	Watt Losses	Zk
A	745.73 mA	158.81 V	71.64 °	37.303 W	219.332 Ω
B	741.21 mA	159.49 V	71.70 °	37.118 W	221.577 Ω
C	741.07 mA	159.07 V	71.74 °	36.936 W	221.013 Ω

Assessment of Zk

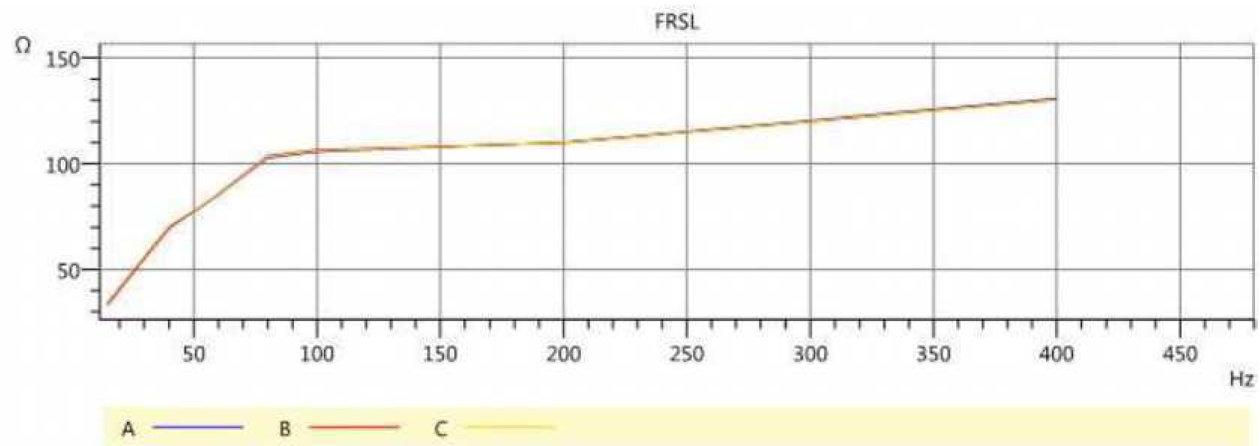
Zk% mea.	Zk% ref.	Dev. Zk%	Xk% mea.	Xk.% ref.	Dev. Xk%	Assessment
19.15 %	%	%	17.66 %	%	%	None





FRSL Results (Rk)						
Phase	15 Hz	40 Hz	60 Hz	80 Hz	100 Hz	200 Hz
A	34.16 Ω	70.04 Ω	85.19 Ω	102.68 Ω	105.74 Ω	110.17 Ω
B	32.88 Ω	69.74 Ω	85.80 Ω	103.79 Ω	106.57 Ω	109.86 Ω
C	34.43 Ω	70.84 Ω	85.42 Ω	103.22 Ω	106.21 Ω	110.01 Ω

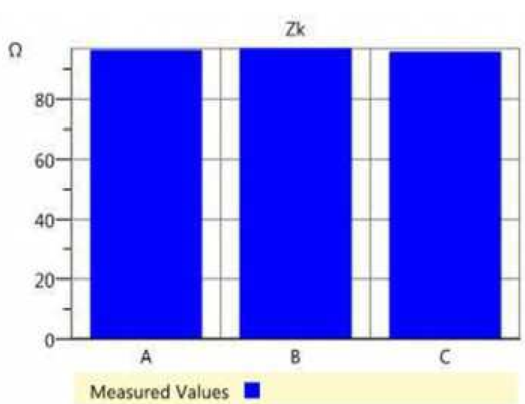
Assessment of Rk at 400 Hz				
Rk ave.	Dev. Rk Phase A %	Dev. Rk Phase B %	Dev. Rk Phase C %	Assessment
130.22 Ω	-0.33 %	0.16 %	0.17 %	None

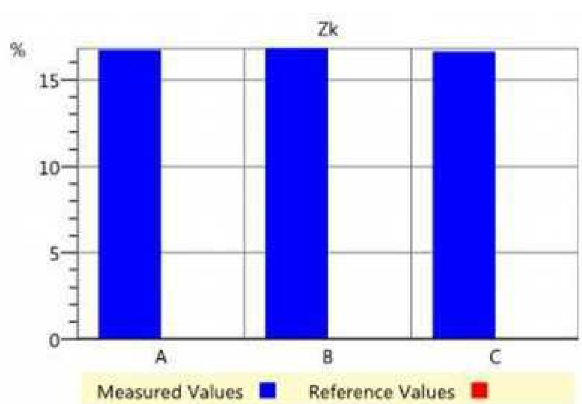


Per Phase Test Results

Leakage Reactance Results (Zk)								
Phase	I AC sel	V1 AC sel	V1 AC sel Phase	Watt Losses	Zk	Rk	Xk	Lk
A	1.06 A	99.77 V	75.33 °	26.663 W	96.392 Ω	23.945 Ω	91.469 Ω	242.630 mH
B	1.06 A	100.25 V	75.32 °	26.817 W	96.816 Ω	24.066 Ω	91.865 Ω	243.680 mH
C	1.05 A	99.16 V	75.46 °	26.257 W	95.817 Ω	23.604 Ω	91.007 Ω	241.403 mH

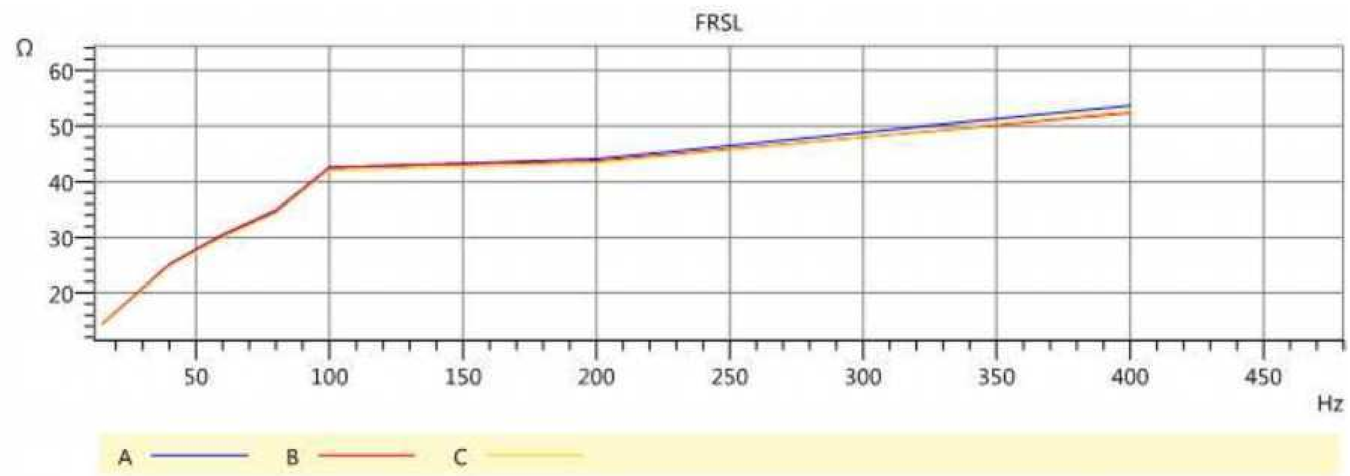
Assessment of Zk								
Phase	Zk% mea.	Zk% ref.	Dev. Zk%	Xk% mea.	Xk.% ref.	Dev. Xk%	Dominance Order	Assessment
A	16.73 %	%	%	15.88 %	%	%	0	None
B	16.81 %	%	%	15.95 %	%	%	0	None
C	16.63 %	%	%	15.80 %	%	%	0	None





FRSL Results (Rk)						
Phase	15 Hz	40 Hz	60 Hz	80 Hz	100 Hz	200 Hz
A	14.39 Ω	25.04 Ω	30.41 Ω	34.69 Ω	42.51 Ω	44.09 Ω
B	14.51 Ω	25.11 Ω	30.56 Ω	34.99 Ω	42.61 Ω	43.72 Ω
C	14.30 Ω	24.64 Ω	29.98 Ω	34.31 Ω	41.98 Ω	43.38 Ω

Assessment of Rk at 400 Hz				
Rk ave.	Dev. Rk Phase A %	Dev. Rk Phase B %	Dev. Rk Phase C %	Assessment
52.88 Ω	-1.41 %	1.07 %	0.34 %	None



Leakage Reactance X-Y

Test Current	1.0 A		OLTC Position
Winding temperature	10 °C		
Temperature Corr. Factor (K)	1.27		

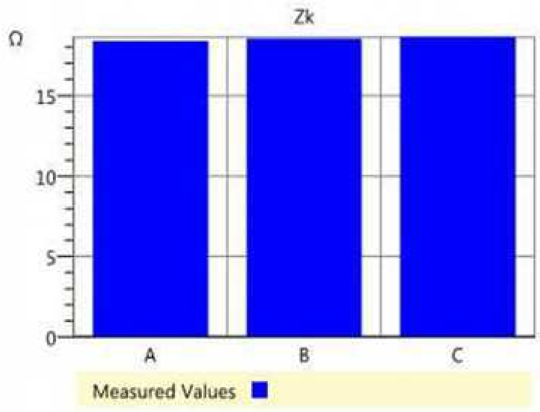
Comments

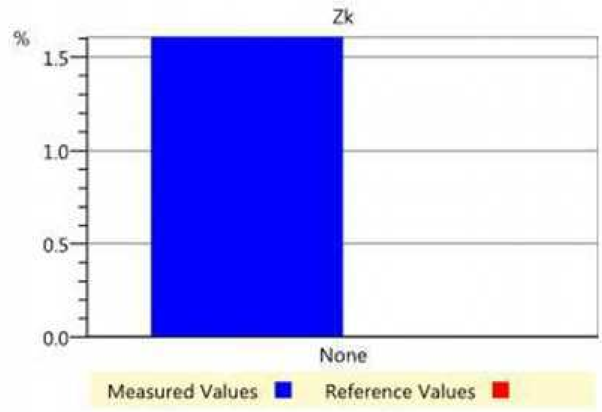
OLTC POSITION 9

3P Equiv Test Results

Leakage Reactance Results (Zk)					
Phase	I AC sel	V1 AC sel	V1 AC sel Phase	Watt Losses	Zk
A	1.00 A	17.38 V	62.98 °	7.928 W	18.381 Ω
B	1.00 A	17.56 V	63.33 °	7.905 W	18.547 Ω
C	1.00 A	17.63 V	63.26 °	7.955 W	18.630 Ω

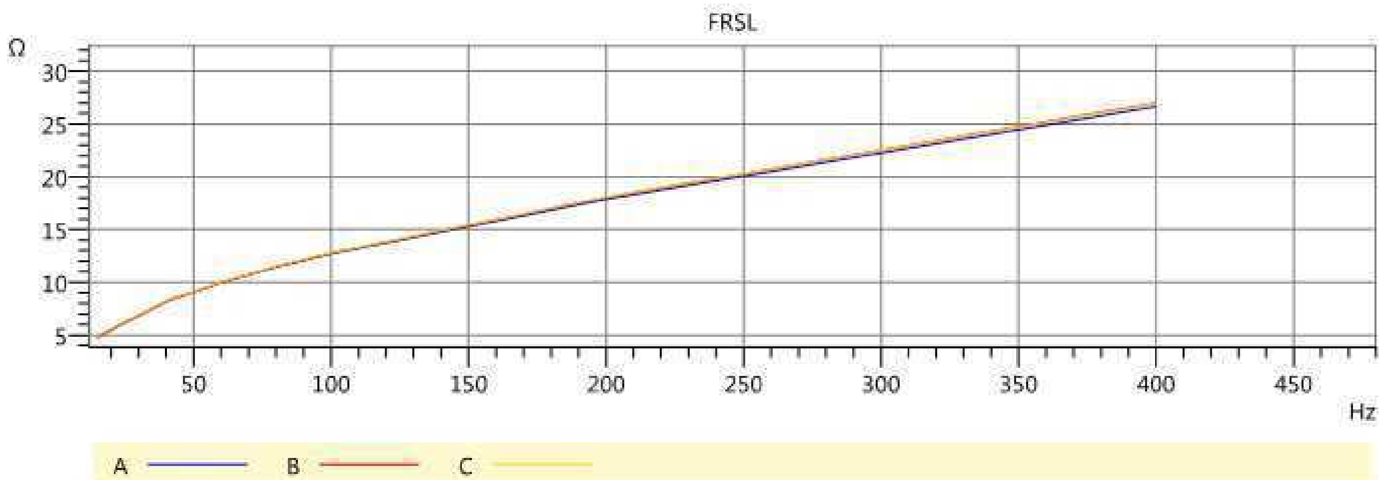
Assessment of Zk						
Zk% mea.	Zk% ref.	Dev. Zk%	Xk% mea.	Xk.% ref.	Dev. Xk%	Assessment
1.61 %	%	%	1.35 %	%	%	None





FRSL Results (Rk)						
Phase	15 Hz	40 Hz	60 Hz	80 Hz	100 Hz	200 Hz
A	4.89 Ω	8.21 Ω	9.99 Ω	11.45 Ω	12.71 Ω	17.87 Ω
B	4.79 Ω	8.15 Ω	9.97 Ω	11.46 Ω	12.77 Ω	18.06 Ω
C	4.93 Ω	8.25 Ω	10.04 Ω	11.53 Ω	12.82 Ω	18.10 Ω

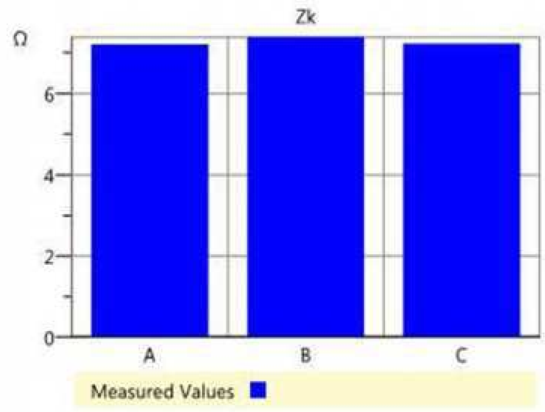
Assessment of Rk at 400 Hz				
Rk ave.	Dev. Rk Phase A %	Dev. Rk Phase B %	Dev. Rk Phase C %	Assessment
26.88 Ω	0.77 %	-0.52 %	-0.26 %	None

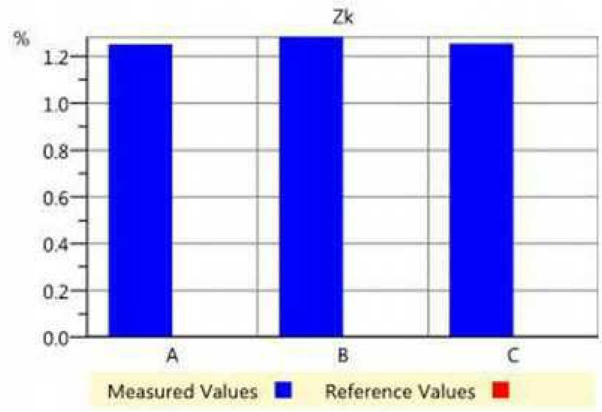


Per Phase Test Results

Leakage Reactance Results (Zk)							
Phase	I AC sel	V1 AC sel	V1 AC sel Phase	Watt Losses	Zk	Rk	Xk
A	1.00 A	7.00 V	72.09 °	2.154 W	7.201 Ω	2.153 Ω	6.661 Ω
B	998.39 mA	7.17 V	72.44 °	2.161 W	7.384 Ω	2.168 Ω	6.851 Ω
C	999.46 mA	7.02 V	72.29 °	2.135 W	7.223 Ω	2.137 Ω	6.693 Ω

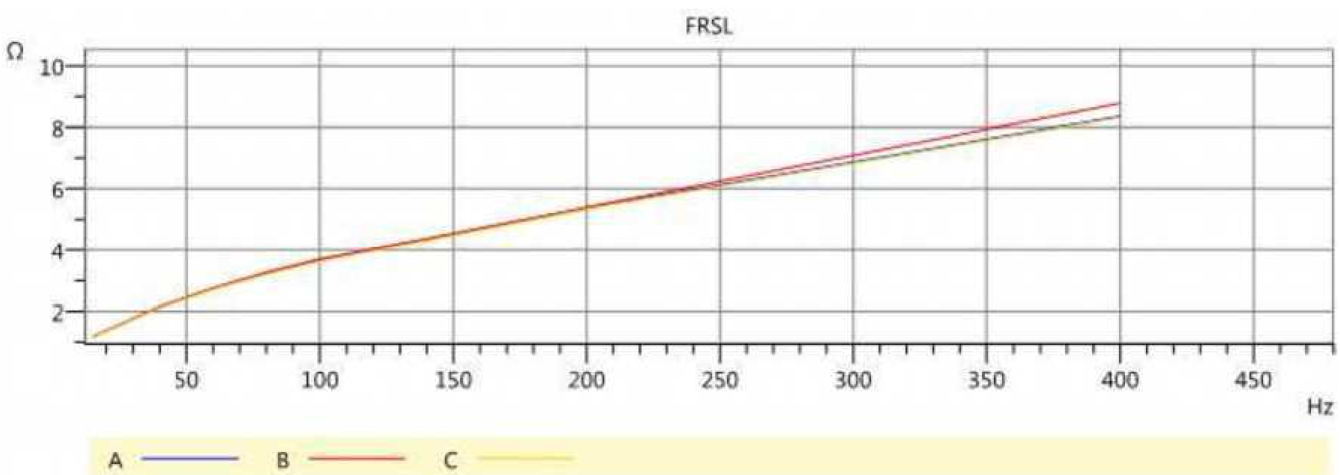
Assessment of Zk								
Phase	Zk% mea.	Zk% ref.	Dev. Zk%	Xk% mea.	Xk.% ref.	Dev. Xk%	Dominance Order	Assessment
A	1.25 %	%	%	1.16 %	%	%	0	None
B	1.28 %	%	%	1.19 %	%	%	0	None
C	1.25 %	%	%	1.16 %	%	%	0	None





FRSL Results (Rk)						
Phase	15 Hz	40 Hz	60 Hz	80 Hz	100 Hz	200 Hz
A	1.17 Ω	2.14 Ω	2.73 Ω	3.24 Ω	3.67 Ω	5.38 Ω
B	1.18 Ω	2.15 Ω	2.75 Ω	3.27 Ω	3.70 Ω	5.44 Ω
C	1.17 Ω	2.12 Ω	2.71 Ω	3.20 Ω	3.63 Ω	5.34 Ω

Assessment of Rk at 400 Hz				
Rk ave.	Dev. Rk Phase A %	Dev. Rk Phase B %	Dev. Rk Phase C %	Assessment
8.49 Ω	1.54 %	-3.49 %	1.95 %	None



Leakage Reactance H-X

Test Current	1.0 A
Winding temperature	10 °C
Temperature Corr. Factor (K)	1.27

OLTC Position

Comments

OLTC POSITION 17

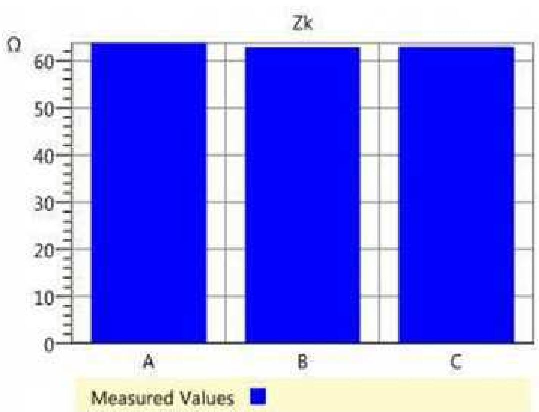
3P Equiv Test Results

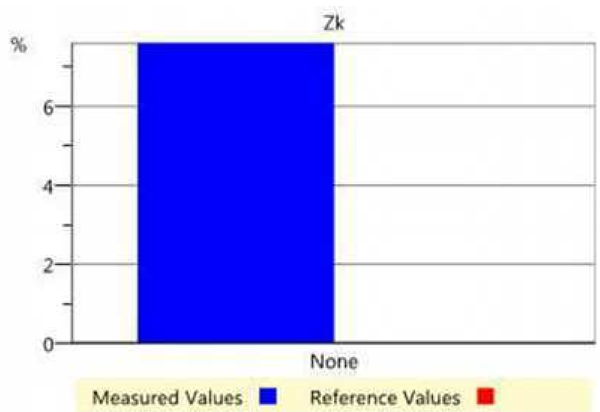
Leakage Reactance Results (Zk)

Phase	I AC sel	V1 AC sel	V1 AC sel Phase	Watt Losses	Zk
A	1.07 A	68.06 V	87.54 °	3.122 W	63.707 Ω
B	1.07 A	67.11 V	87.51 °	3.112 W	62.901 Ω
C	1.07 A	66.98 V	87.39 °	3.248 W	62.923 Ω

Assessment of Zk

Zk% mea.	Zk% ref.	Dev. Zk%	Xk% mea.	Xk.% ref.	Dev. Xk%	Assessment
7.59 %	%	%	7.58 %	%	%	None



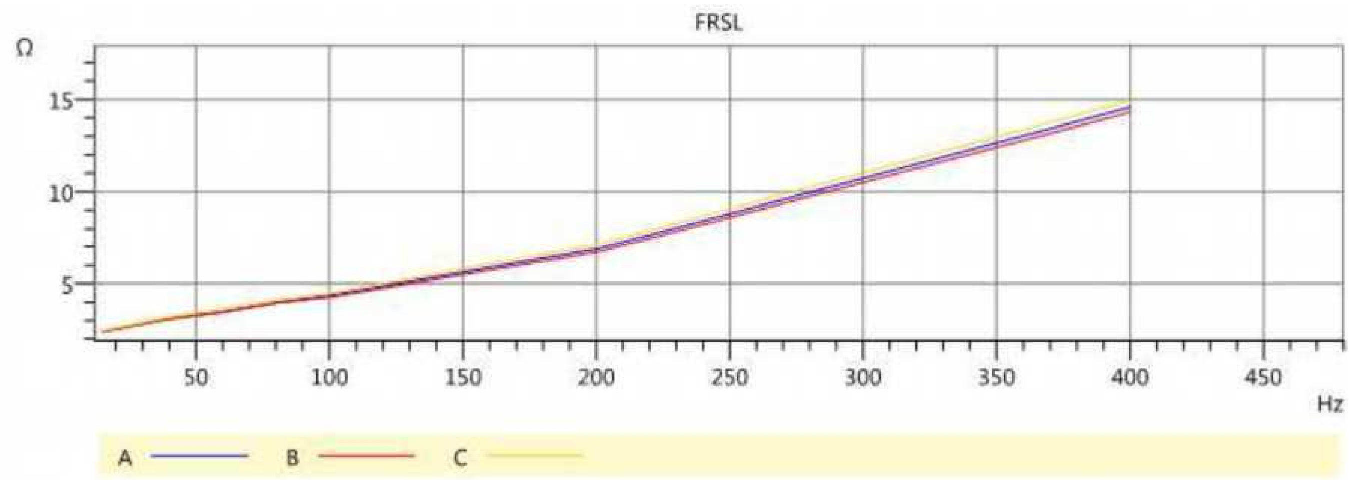


FRSL Results (Rk)

Phase	15 Hz	40 Hz	60 Hz	80 Hz	100 Hz	200 Hz
A	2.41 Ω	3.12 Ω	3.47 Ω	3.99 Ω	4.37 Ω	6.89 Ω
B	2.40 Ω	3.08 Ω	3.47 Ω	3.96 Ω	4.27 Ω	6.72 Ω
C	2.46 Ω	3.19 Ω	3.64 Ω	4.11 Ω	4.50 Ω	7.13 Ω

Assessment of Rk at 400 Hz

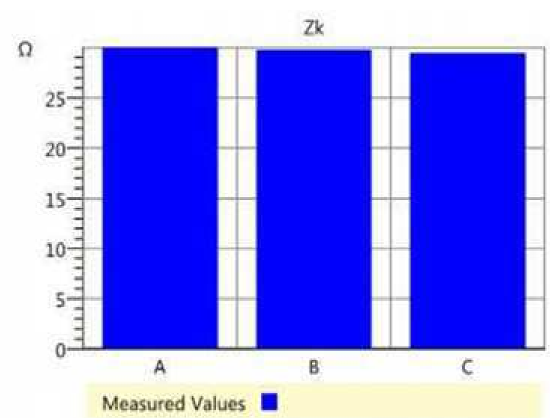
Rk ave.	Dev. Rk Phase A %	Dev. Rk Phase B %	Dev. Rk Phase C %	Assessment
14.61 Ω	0.20 %	2.03 %	-2.23 %	None

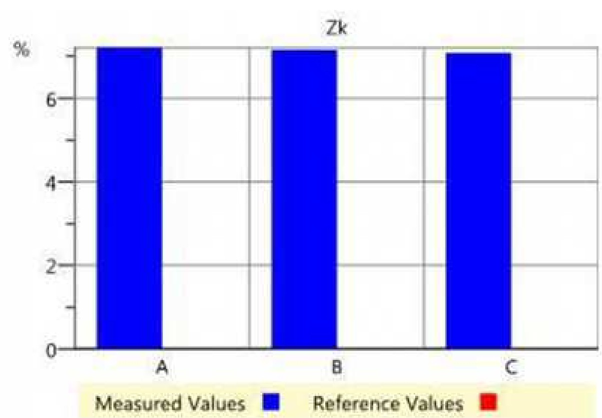


Per Phase Test Results

Leakage Reactance Results (Zk)							
Phase	I AC sel	V1 AC sel	V1 AC sel Phase	Watt Losses	Zk	Rk	Xk
A	1.02 A	30.51 V	87.17 °	1.534 W	29.979 Ω	1.479 Ω	29.920 Ω
B	1.02 A	30.30 V	87.13 °	1.546 W	29.758 Ω	1.489 Ω	29.698 Ω
C	1.02 A	29.99 V	87.13 °	1.531 W	29.445 Ω	1.473 Ω	29.385 Ω

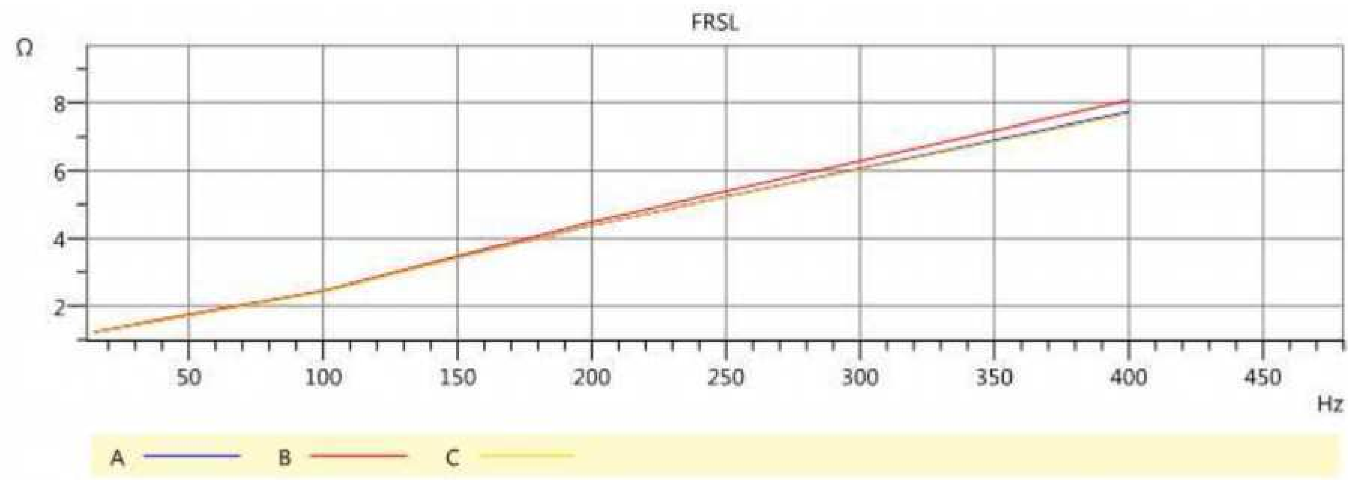
Assessment of Zk								
Phase	Zk% mea.	Zk% ref.	Dev. Zk%	Xk% mea.	Xk.% ref.	Dev. Xk%	Dominance Order	Assessment
A	7.20 %	%	%	7.19 %	%	%	0	None
B	7.15 %	%	%	7.14 %	%	%	0	None
C	7.08 %	%	%	7.06 %	%	%	0	None





FRSL Results (Rk)						
Phase	15 Hz	40 Hz	60 Hz	80 Hz	100 Hz	200 Hz
A	1.22 Ω	1.60 Ω	1.88 Ω	2.15 Ω	2.44 Ω	4.40 Ω
B	1.24 Ω	1.62 Ω	1.89 Ω	2.17 Ω	2.45 Ω	4.50 Ω
C	1.22 Ω	1.59 Ω	1.87 Ω	2.16 Ω	2.42 Ω	4.40 Ω

Assessment of Rk at 400 Hz				
Rk ave.	Dev. Rk Phase A %	Dev. Rk Phase B %	Dev. Rk Phase C %	Assessment
7.82 Ω	1.24 %	-3.14 %	1.90 %	None



Leakage Reactance H-Y

Test Current	1.0 A	OLTC Position	
Winding temperature	10 °C		
Temperature Corr. Factor (K)	1.27		

Comments

OLTC POSITION 17

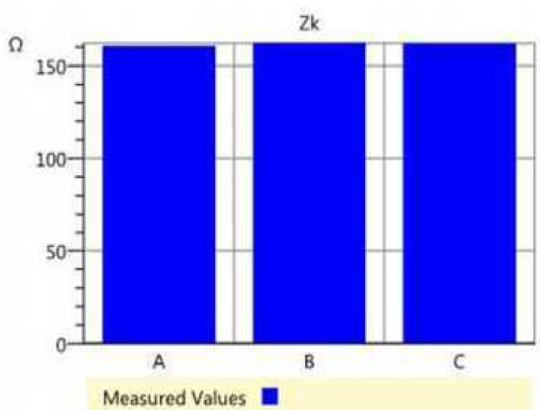
3P Equiv Test Results

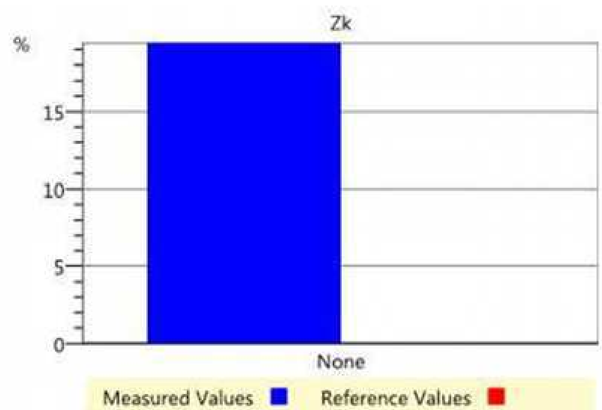
Leakage Reactance Results (Zk)

Phase	I AC sel	V1 AC sel	V1 AC sel Phase	Watt Losses	Zk
A	1.00 A	155.36 V	69.86 °	53.564 W	160.686 Ω
B	994.14 mA	155.68 V	69.96 °	53.034 W	162.133 Ω
C	993.57 mA	155.28 V	69.81 °	53.247 W	161.886 Ω

Assessment of Zk

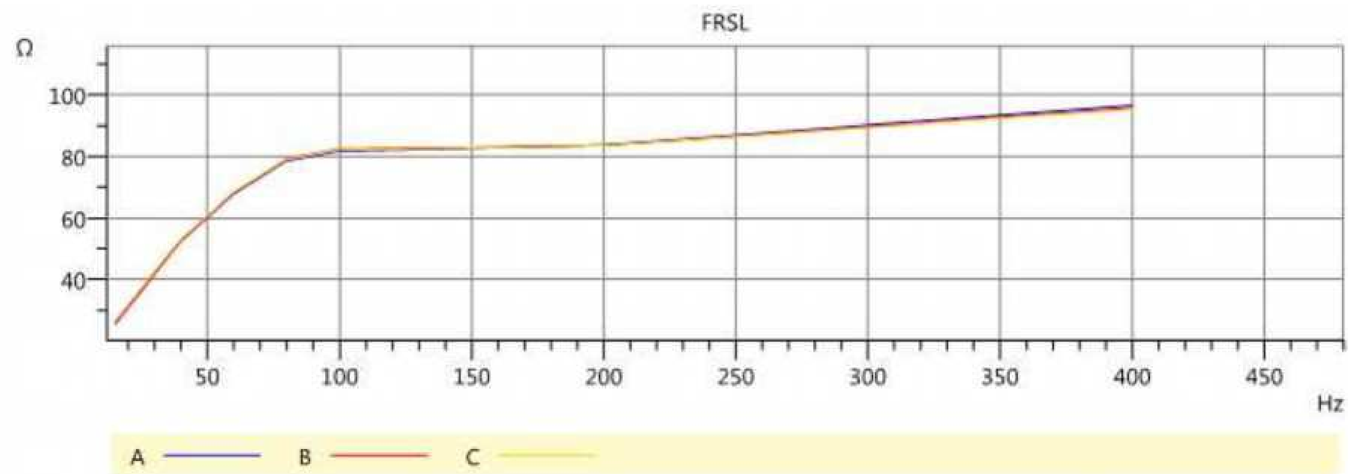
Zk% mea.	Zk% ref.	Dev. Zk%	Xk% mea.	Xk.% ref.	Dev. Xk%	Assessment
19.41 %	%	%	17.60 %	%	%	None





FRSL Results (Rk)						
Phase	15 Hz	40 Hz	60 Hz	80 Hz	100 Hz	200 Hz
A	26.21 Ω	52.76 Ω	67.84 Ω	78.57 Ω	81.76 Ω	83.79 Ω
B	25.27 Ω	52.50 Ω	68.15 Ω	79.20 Ω	82.46 Ω	83.59 Ω
C	26.42 Ω	53.16 Ω	68.50 Ω	79.05 Ω	82.23 Ω	83.63 Ω

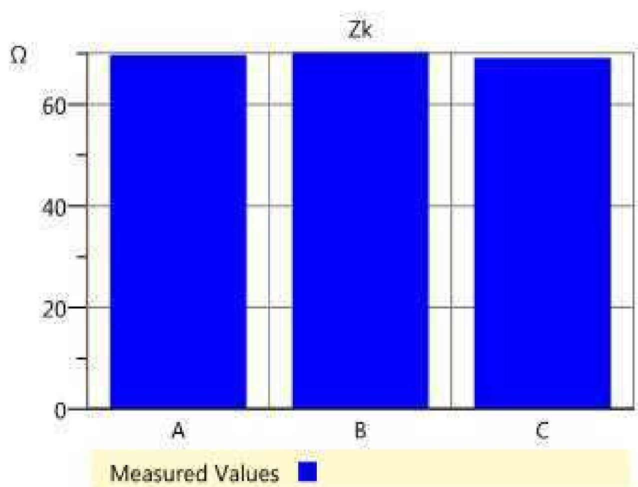
Assessment of Rk at 400 Hz				
Rk ave.	Dev. Rk Phase A %	Dev. Rk Phase B %	Dev. Rk Phase C %	Assessment
95.85 Ω	-0.72 %	0.09 %	0.63 %	None

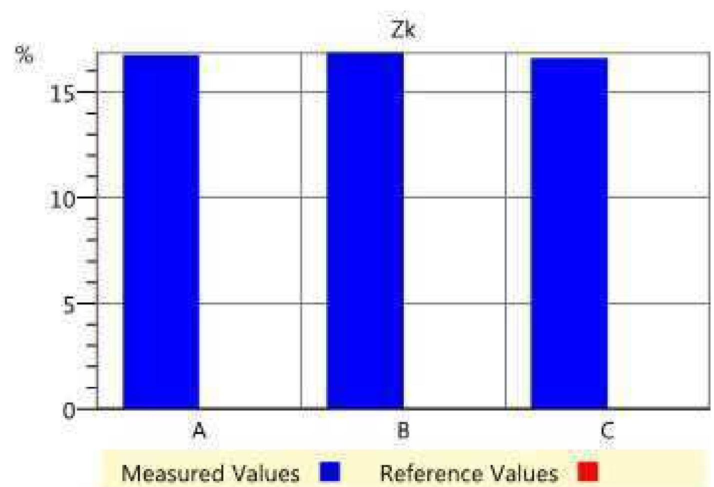


Per Phase Test Results

Leakage Reactance Results (Zk)							
Phase	I AC sel	V1 AC sel	V1 AC sel Phase	Watt Losses	Zk	Rk	Xk
A	1.05 A	71.82 V	76.42 °	17.657 W	69.748 Ω	16.107 Ω	66.681 Ω
B	1.04 A	72.06 V	76.40 °	17.698 W	70.150 Ω	16.223 Ω	67.057 Ω
C	1.05 A	71.15 V	76.48 °	17.398 W	69.156 Ω	15.903 Ω	66.141 Ω

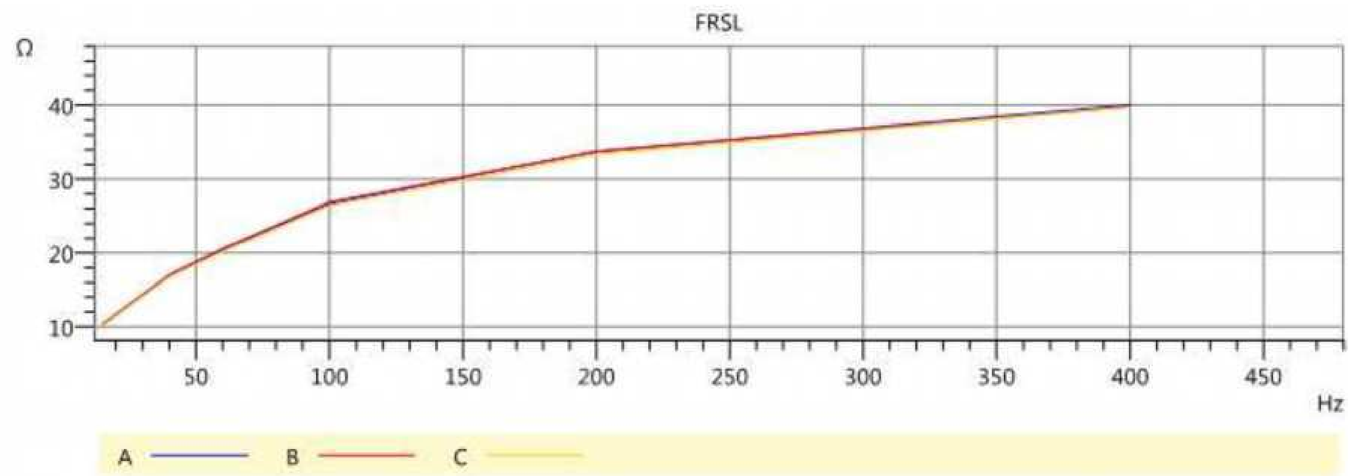
Assessment of Zk								
Phase	Zk% mea.	Zk% ref.	Dev. Zk%	Xk% mea.	Xk.% ref.	Dev. Xk%	Dominance Order	Assessment
A	16.76 %	%	%	16.02 %	%	%	0	None
B	16.86 %	%	%	16.11 %	%	%	0	None
C	16.62 %	%	%	15.89 %	%	%	0	None





FRSL Results (Rk)						
Phase	15 Hz	40 Hz	60 Hz	80 Hz	100 Hz	200 Hz
A	10.25 Ω	16.91 Ω	20.46 Ω	23.58 Ω	26.72 Ω	33.78 Ω
B	10.40 Ω	17.05 Ω	20.60 Ω	23.75 Ω	26.94 Ω	33.74 Ω
C	10.20 Ω	16.74 Ω	20.20 Ω	23.30 Ω	26.40 Ω	33.37 Ω

Assessment of Rk at 400 Hz				
Rk ave.	Dev. Rk Phase A %	Dev. Rk Phase B %	Dev. Rk Phase C %	Assessment
39.86 Ω	-0.40 %	0.18 %	0.23 %	None



Leakage Reactance X-Y

Test Current	1.0 A
Winding temperature	10 °C
Temperature Corr. Factor (K)	1.27

OLTC Position

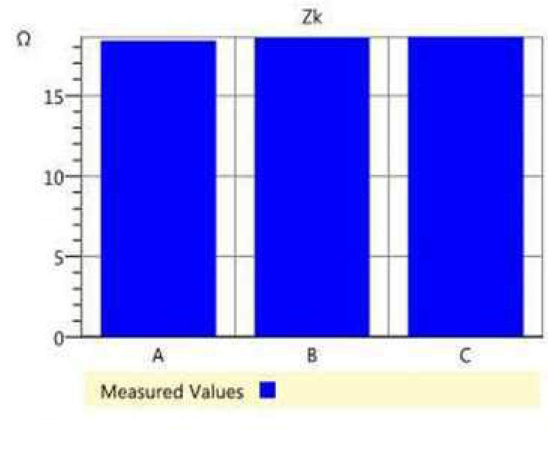
Comments

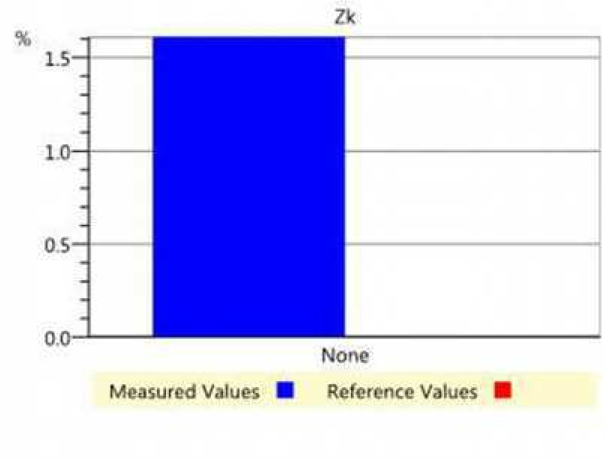
OLTC POSITION 17

3P Equiv Test Results

Leakage Reactance Results (Zk)					
Phase	I AC sel	V1 AC sel	V1 AC sel Phase	Watt Losses	Zk
A	1.00 A	17.40 V	62.84 °	7.972 W	18.415 Ω
B	1.00 A	17.61 V	63.28 °	7.956 W	18.579 Ω
C	1.01 A	17.66 V	63.23 °	7.994 W	18.632 Ω

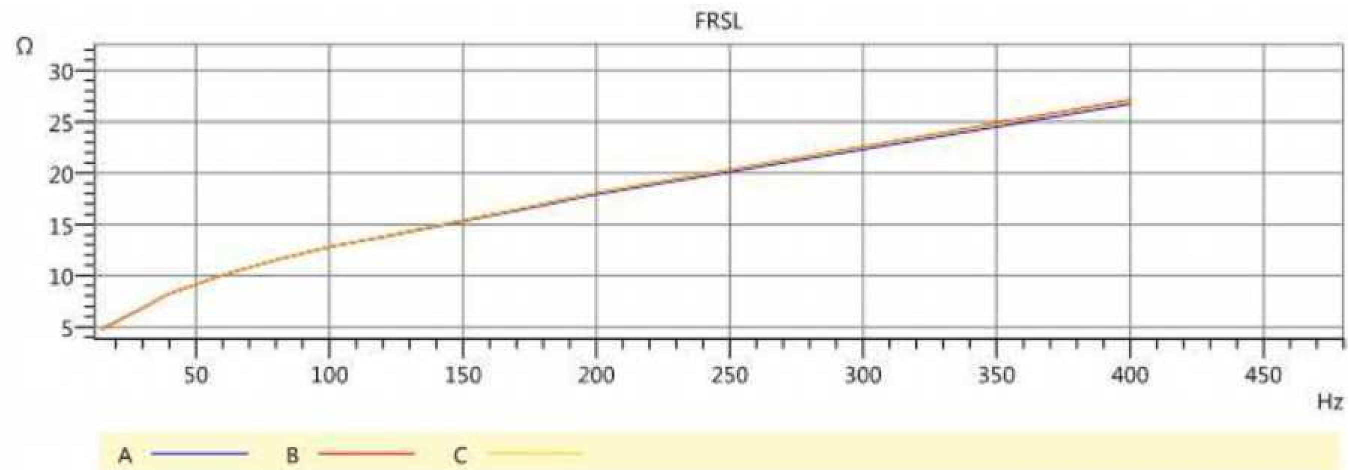
Assessment of Zk						
Zk% mea.	Zk% ref.	Dev. Zk%	Xk% mea.	Xk.% ref.	Dev. Xk%	Assessment
1.61 %	%	%	1.35 %	%	%	None





FRSL Results (Rk)						
Phase	15 Hz	40 Hz	60 Hz	80 Hz	100 Hz	200 Hz
A	4.91 Ω	8.26 Ω	10.05 Ω	11.52 Ω	12.78 Ω	17.94 Ω
B	4.80 Ω	8.19 Ω	10.01 Ω	11.51 Ω	12.80 Ω	18.10 Ω
C	4.93 Ω	8.25 Ω	10.05 Ω	11.53 Ω	12.82 Ω	18.11 Ω

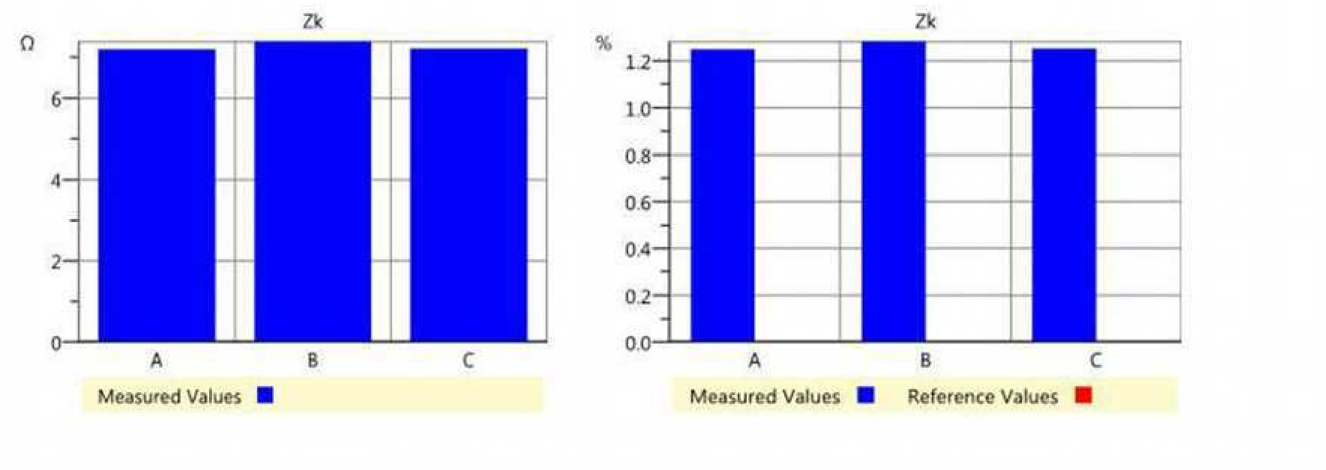
Assessment of Rk at 400 Hz				
Rk ave.	Dev. Rk Phase A %	Dev. Rk Phase B %	Dev. Rk Phase C %	Assessment
26.94 Ω	0.78 %	-0.65 %	-0.13 %	None



Per Phase Test Results

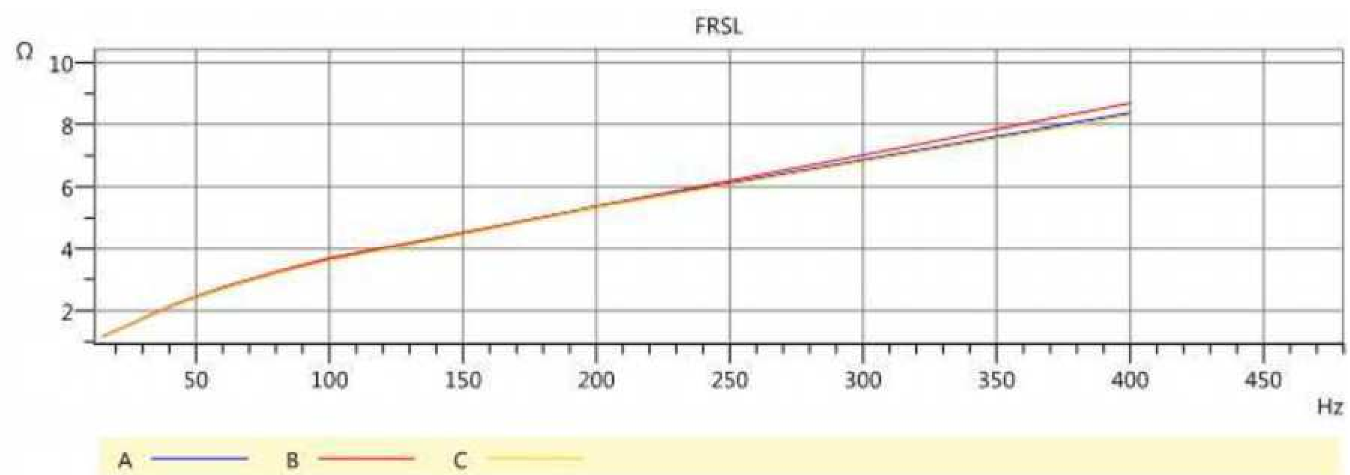
Leakage Reactance Results (Zk)							
Phase	I AC sel	V1 AC sel	V1 AC sel Phase	Watt Losses	Zk	Rk	Xk
A	999.71 mA	6.99 V	72.21 °	2.135 W	7.189 Ω	2.136 Ω	6.658 Ω
B	1.00 A	7.19 V	72.45 °	2.171 W	7.383 Ω	2.167 Ω	6.851 Ω
C	1.00 A	7.03 V	72.34 °	2.133 W	7.218 Ω	2.130 Ω	6.691 Ω

Assessment of Zk								
Phase	Zk% mea.	Zk% ref.	Dev. Zk%	Xk% mea.	Xk.% ref.	Dev. Xk%	Dominance Order	Assessment
A	1.25 %	%	%	1.16 %	%	%	0	None
B	1.28 %	%	%	1.19 %	%	%	0	None
C	1.25 %	%	%	1.16 %	%	%	0	None



FRSL Results (Rk)						
Phase	15 Hz	40 Hz	60 Hz	80 Hz	100 Hz	200 Hz
A	1.16 Ω	2.12 Ω	2.71 Ω	3.21 Ω	3.65 Ω	5.37 Ω
B	1.17 Ω	2.14 Ω	2.75 Ω	3.25 Ω	3.69 Ω	5.45 Ω
C	1.16 Ω	2.11 Ω	2.71 Ω	3.20 Ω	3.62 Ω	5.33 Ω

Assessment of Rk at 400 Hz				
Rk ave.	Dev. Rk Phase A %	Dev. Rk Phase B %	Dev. Rk Phase C %	Assessment
8.45 Ω	0.97 %	-2.77 %	1.80 %	None



A.3 Insulation Power Factor

Nameplate - Autotransformer with Tertiary

Company	FortisBC	**Serial Number**	287732
Location	OLI - Oliver Terminal	**Special ID**	20186
Division	OKANAGAN	**Circuit Designation**	T1
Manufacturer	GE	**Configuration**	Y-Y-D
Year Manufactured	1971	**Tank Type**	OPEN-CONSER
Mfr Location	Guelph, Ontario	**Oil Volume**	8500 kg
Phases	3	**BIL**	kV
Class	ONAN/OFAF	**Coolant**	OIL
Weight	231000 kg		
kV	161, 63, 13	**VA Rating**	45, 60, , MVA
Note			

Test Date	12/3/2012	**Test Time**	3:07:55 PM	**Weather**	CLOUDY
Air Temperature	10 °C	**Tank Temperature**	7 °C	**Rel. Humidity**	20 %
Tested by	T.Varga	**Work Order #**		**Last Test Date**	9/23/2001
Checked by	S.Hunter	**Test Set Type**	M4K	**Retest Date**	
Checked Date		**Set Top S/N**		**Reason**	ROUTINE

Bushing Nameplate

Desig.	Serial #	Mfr	Type	C1 %PF	C1 Cap	C2 %PF	C2 Cap	kV	Amps	Year
H1	223318	CGE	U	0.3	286		2490	118	600	1971
H2	223335	CGE	U	0.28	286		2240	118	600	1971
H3	223339	CGE	U	0.26	286		2280	118	600	1971
X1	3771890693	A-BB	O+C	0.28	266			69	1200	1993
X2	3771890593	A-BB	O+C	0.28	267			69	1200	1993
X3	3771890393	A-BB	O+C	0.28	266			69	1200	1993
Y1	SN-Y1	GE	D					15	1200	1971
Y2	SN-Y2	GE	D					15	1200	1971
Y3	SN-Y3	GE	D					15	1200	1971
N	SN-N	CGE	LC	0.98				15	1200	1971

Overall Tests

Meas.	Test kV	mA	Watts	%PF corr	Corr Fctr	Cap(pF)	IR_{auto}	IR_{man}
CH + CHT	10.001	133.95	4.926		0.99	35531.3		
CH	10.000	132.89	4.903	0.37	0.99	35252.1	G	G
CHT(UST)	10.000	1.020	0.0040	0.04	0.99	270.67	I	G
CHT		1.060	0.023	0.22	0.99	279.200	I	G
CT + CHT	7.500	99.208	3.442		0.99	26316.1		
CT	7.500	98.182	3.440	0.35	0.99	26043.8	G	G
CHT(UST)	7.500	1.017	0.0060	0.06	0.99	269.66	I	G
CHT		1.026	0.002	0.02	0.99	272.300	I	G

Bushing C1

ID	Serial #	NP %PF	NP Cap	Test kV	mA	Watts	%PF corr	Corr Fctr	Cap (pF)	IR_{auto}	IR_{man}
X1	3771890693	0.28	266	10.000	0.9960	0.0330	0.30	0.92	264.31	G	G
X2	3771890593	0.28	267	10.000	0.9970	0.0310	0.29	0.92	264.37	G	G
X3	3771890393	0.28	266	10.000	0.9930	0.0300	0.28	0.92	263.46	G	G
H1	223318	0.3	286	10.001	1.073	0.0370	0.34	1.01	284.61	G	G
H2	223335	0.28	286	10.000	1.076	0.0350	0.33	1.01	285.51	G	G
H3	223339	0.26	286	10.000	1.068	0.0320	0.30	1.01	283.29	G	G

Bushing C2

ID	Serial #	NP %PF	NP Cap	Test kV	mA	Watts	%PF corr	Corr Fctr	Cap (pF)	IR_{auto}	IR_{man}
X1	3771890693			0.5000	1.940	0.0790	0.41	1.00	514.60	G	G
X2	3771890593			0.5000	1.904	0.0760	0.40	1.00	505.04	G	G
X3	3771890393			0.5000	1.939	0.0680	0.35	1.00	514.44	G	G

A.4 Winding Insulation Resistance

Transformer Winding Insulation Resistance Results

Description	Test Voltage	1 min	10 min	PI
H/L – T+G	5kV	3.02 GΩ	4.25 GΩ	1.407
T – H/L+G	5kV	3.66 GΩ	21.2 GΩ	5.7923

Ambient Conditions: Clear & Sunny
Top Oil Temperature = 7 Degrees Celcius

A.5 Exciting Current

	Mfr	Type	Steps	Boost %	Buck %	Position Found	Position Left	Oil Volume
On-Load Tap Changer	CGE	CLR-83	17	15	15			950

			H1 - HN			H2 - HN			H3 - HN				
DETC	LTC	Test kV	mA	Watts	X	mA	Watts	X	mA	Watts	X	IR_{auto}	IR_{man}
	1	10.001	28.711	257.73	L	19.144	177.47	L	28.523	255.30	L	G	G
	2	10.002	29.584	264.86	L	19.765	182.52	L	29.424	262.33	L	G	G
	3	10.001	30.556	272.38	L	20.454	188.15	L	30.400	270.15	L	G	G
	4	10.001	31.504	280.12	L	21.125	193.71	L	31.355	277.96	L	G	G
	5	10.001	32.548	288.77	L	21.855	199.84	L	32.396	286.68	L	G	G
	6	10.000	33.568	297.39	L	22.577	205.97	L	33.422	295.38	L	G	G
	7	10.000	34.680	306.99	L	23.366	212.76	L	34.536	305.05	L	G	G
	8	10.001	35.829	317.23	L	24.137	219.50	L	35.700	315.32	L	I	G
	9	10.001	37.309	327.67	L	25.157	226.99	L	37.156	325.65	L	G	G
	10	10.000	38.695	338.95	L	26.185	235.26	L	38.544	336.87	L	I	G
	11	10.001	40.049	350.19	L	27.159	243.15	L	39.907	348.08	L	G	G
	12	10.001	41.548	362.79	L	28.240	251.95	L	41.419	360.64	L	G	G
	13	10.001	43.023	375.39	L	29.308	260.85	L	42.913	373.24	L	G	G
	14	10.001	44.651	389.50	L	30.475	270.63	L	44.556	387.36	L	G	G
	15	10.001	46.280	403.79	L	31.629	280.54	L	46.181	401.57	L	G	G
	16	10.001	48.058	419.78	L	32.905	291.66	L	47.978	417.43	L	G	G
	17	10.001	49.937	436.84	L	34.162	302.98	L	49.868	434.52	L	I	G

A.6 Transformer Turns Ratio

TTR H-X			
Test Voltage	150 V	Type of Tap Changer	OLTC

		Phase A		Phase B		Phase C		
Tap	Nom. Ratio	TTR	Ratio Dev.	TTR	Ratio Dev.	TTR	Ratio Dev.	Assessment
1	2.9389	2.9411	0.07 %	2.9422	0.11 %	2.941	0.07 %	Pass
2	2.891	2.8947	0.13 %	2.8959	0.17 %	2.8946	0.13 %	Pass
3	2.843	2.8459	0.10 %	2.8469	0.14 %	2.8457	0.10 %	Pass
4	2.7951	2.7997	0.17 %	2.8005	0.19 %	2.7995	0.16 %	Pass
5	2.7473	2.7505	0.12 %	2.7515	0.15 %	2.7506	0.12 %	Pass
6	2.6994	2.7044	0.19 %	2.7052	0.22 %	2.7043	0.18 %	Pass
7	2.6514	2.6556	0.16 %	2.6563	0.19 %	2.6555	0.16 %	Pass
8	2.6035	2.6066	0.12 %	2.6099	0.25 %	2.6065	0.12 %	Pass
9	2.5556	2.5578	0.09 %	2.561	0.21 %	2.5577	0.08 %	Pass
10	2.5076	2.5088	0.05 %	2.5121	0.18 %	2.5089	0.05 %	Pass
11	2.4597	2.4626	0.12 %	2.4658	0.25 %	2.4625	0.11 %	Pass
12	2.4117	2.4137	0.08 %	2.4168	0.21 %	2.4135	0.07 %	Pass
13	2.364	2.3674	0.14 %	2.3702	0.26 %	2.3672	0.14 %	Pass
14	2.316	2.3184	0.10 %	2.3213	0.23 %	2.3182	0.10 %	Pass
15	2.2681	2.2721	0.18 %	2.2749	0.30 %	2.272	0.17 %	Pass
16	2.2202	2.2231	0.13 %	2.2259	0.26 %	2.223	0.13 %	Pass
17	2.1722	2.1743	0.10 %	2.1797	0.35 %	2.1743	0.10 %	Pass

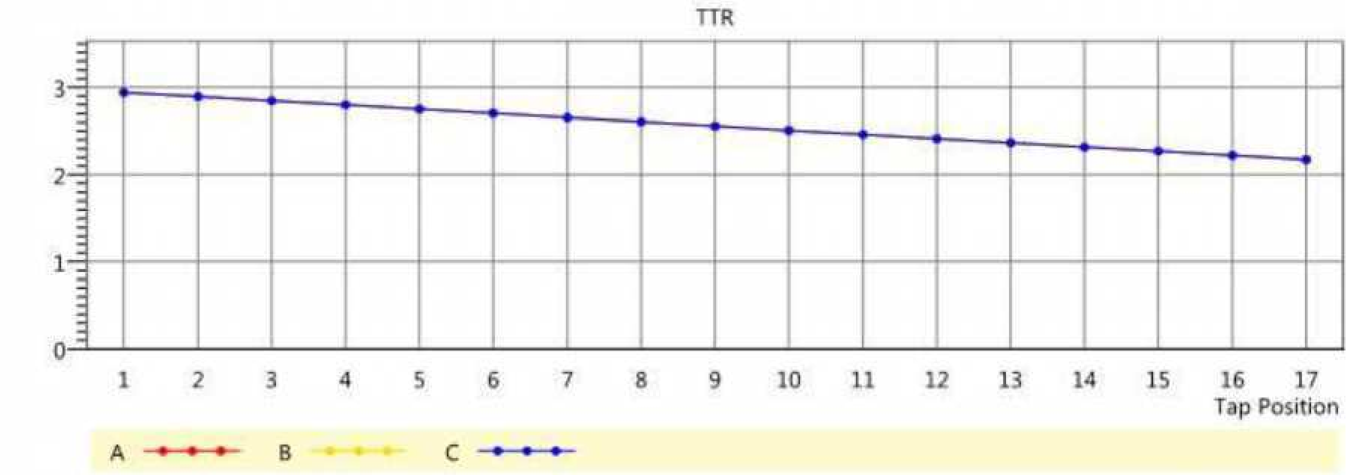
Phase A								
Tap	Nom. Ratio	V Prim	I Prim	I Phase	V Sec	V Phase	TTR	Ratio Dev.
1	2.9389	149.97 V	2.479 mA	-61.56 °	50.99 V	-0.040 °	2.9411	0.07 %
2	2.891	149.97 V	2.534 mA	-62.38 °	51.81 V	-0.050 °	2.8947	0.13 %
3	2.843	149.97 V	2.607 mA	-61.62 °	52.70 V	-0.040 °	2.8459	0.10 %
4	2.7951	149.98 V	2.680 mA	-61.67 °	53.57 V	-0.060 °	2.7997	0.17 %
5	2.7473	149.96 V	2.793 mA	-61.98 °	54.52 V	-0.050 °	2.7505	0.12 %
6	2.6994	149.97 V	2.878 mA	-62.25 °	55.45 V	-0.040 °	2.7044	0.19 %
7	2.6514	149.97 V	2.923 mA	-62.23 °	56.47 V	-0.050 °	2.6556	0.16 %
8	2.6035	149.97 V	3.024 mA	-62.13 °	57.53 V	-0.040 °	2.6066	0.12 %
9	2.5556	149.97 V	3.143 mA	-62.68 °	58.63 V	-0.040 °	2.5578	0.09 %
10	2.5076	149.97 V	3.253 mA	-62.00 °	59.78 V	-0.050 °	2.5088	0.05 %
11	2.4597	149.97 V	3.374 mA	-62.82 °	60.90 V	-0.050 °	2.4626	0.12 %
12	2.4117	149.97 V	3.458 mA	-62.34 °	62.13 V	-0.050 °	2.4137	0.08 %
13	2.364	149.97 V	3.619 mA	-62.44 °	63.35 V	-0.030 °	2.3674	0.14 %
14	2.316	149.97 V	3.725 mA	-62.26 °	64.69 V	-0.050 °	2.3184	0.10 %
15	2.2681	149.97 V	3.882 mA	-62.52 °	66.01 V	-0.040 °	2.2721	0.18 %
16	2.2202	149.97 V	4.032 mA	-62.72 °	67.46 V	-0.040 °	2.2231	0.13 %
17	2.1722	149.97 V	4.149 mA	-62.77 °	68.97 V	-0.040 °	2.1743	0.10 %

Phase B

Tap	Nom. Ratio	V Prim	I Prim	I Phase	V Sec	V Phase	TTR	Ratio Dev.
1	2.9389	149.97 V	1.813 mA	-61.09 °	50.97 V	-0.040 °	2.9422	0.11 %
2	2.891	149.97 V	1.867 mA	-61.95 °	51.79 V	-0.060 °	2.8959	0.17 %
3	2.843	149.97 V	1.939 mA	-61.27 °	52.68 V	-0.050 °	2.8469	0.14 %
4	2.7951	149.97 V	1.986 mA	-61.41 °	53.55 V	-0.040 °	2.8005	0.19 %
5	2.7473	149.97 V	2.062 mA	-61.50 °	54.50 V	-0.020 °	2.7515	0.15 %
6	2.6994	149.97 V	2.136 mA	-61.76 °	55.44 V	-0.030 °	2.7052	0.22 %
7	2.6514	149.96 V	2.172 mA	-62.26 °	56.45 V	-0.050 °	2.6563	0.19 %
8	2.6035	149.97 V	2.279 mA	-62.15 °	57.46 V	-0.040 °	2.6099	0.25 %
9	2.5556	149.97 V	2.325 mA	-62.47 °	58.56 V	-0.040 °	2.561	0.21 %
10	2.5076	149.97 V	2.422 mA	-62.14 °	59.70 V	-0.050 °	2.5121	0.18 %
11	2.4597	149.97 V	2.503 mA	-63.01 °	60.82 V	-0.040 °	2.4658	0.25 %
12	2.4117	149.97 V	2.576 mA	-62.83 °	62.05 V	-0.050 °	2.4168	0.21 %
13	2.364	149.97 V	2.679 mA	-62.46 °	63.27 V	-0.050 °	2.3702	0.26 %
14	2.316	149.97 V	2.782 mA	-62.48 °	64.61 V	-0.050 °	2.3213	0.23 %
15	2.2681	149.97 V	2.890 mA	-63.36 °	65.92 V	-0.050 °	2.2749	0.30 %
16	2.2202	149.96 V	3.007 mA	-62.63 °	67.37 V	-0.030 °	2.2259	0.26 %
17	2.1722	149.98 V	3.075 mA	-62.64 °	68.81 V	-0.040 °	2.1797	0.35 %

Phase C

Tap	Nom. Ratio	V Prim	I Prim	I Phase	V Sec	V Phase	TTR	Ratio Dev.
1	2.9389	149.97 V	2.468 mA	-61.53 °	50.99 V	-0.040 °	2.941	0.07 %
2	2.891	149.97 V	2.524 mA	-62.30 °	51.81 V	-0.060 °	2.8946	0.13 %
3	2.843	149.97 V	2.554 mA	-61.73 °	52.70 V	-0.060 °	2.8457	0.10 %
4	2.7951	149.97 V	2.681 mA	-61.79 °	53.57 V	-0.040 °	2.7995	0.16 %
5	2.7473	149.97 V	2.750 mA	-61.83 °	54.52 V	-0.040 °	2.7506	0.12 %
6	2.6994	149.97 V	2.852 mA	-61.91 °	55.46 V	-0.050 °	2.7043	0.18 %
7	2.6514	149.97 V	2.926 mA	-62.38 °	56.48 V	-0.060 °	2.6555	0.16 %
8	2.6035	149.97 V	3.011 mA	-62.48 °	57.54 V	-0.030 °	2.6065	0.12 %
9	2.5556	149.97 V	3.154 mA	-62.38 °	58.63 V	-0.040 °	2.5577	0.08 %
10	2.5076	149.97 V	3.205 mA	-62.42 °	59.78 V	-0.050 °	2.5089	0.05 %
11	2.4597	149.96 V	3.346 mA	-62.55 °	60.90 V	-0.040 °	2.4625	0.11 %
12	2.4117	149.97 V	3.481 mA	-63.00 °	62.14 V	-0.030 °	2.4135	0.07 %
13	2.364	149.97 V	3.573 mA	-62.64 °	63.35 V	-0.030 °	2.3672	0.14 %
14	2.316	149.97 V	3.717 mA	-62.52 °	64.69 V	-0.040 °	2.3182	0.10 %
15	2.2681	149.97 V	3.858 mA	-63.36 °	66.01 V	-0.040 °	2.272	0.17 %
16	2.2202	149.97 V	4.013 mA	-63.02 °	67.46 V	-0.050 °	2.223	0.13 %
17	2.1722	149.97 V	4.135 mA	-62.52 °	68.98 V	-0.030 °	2.1743	0.10 %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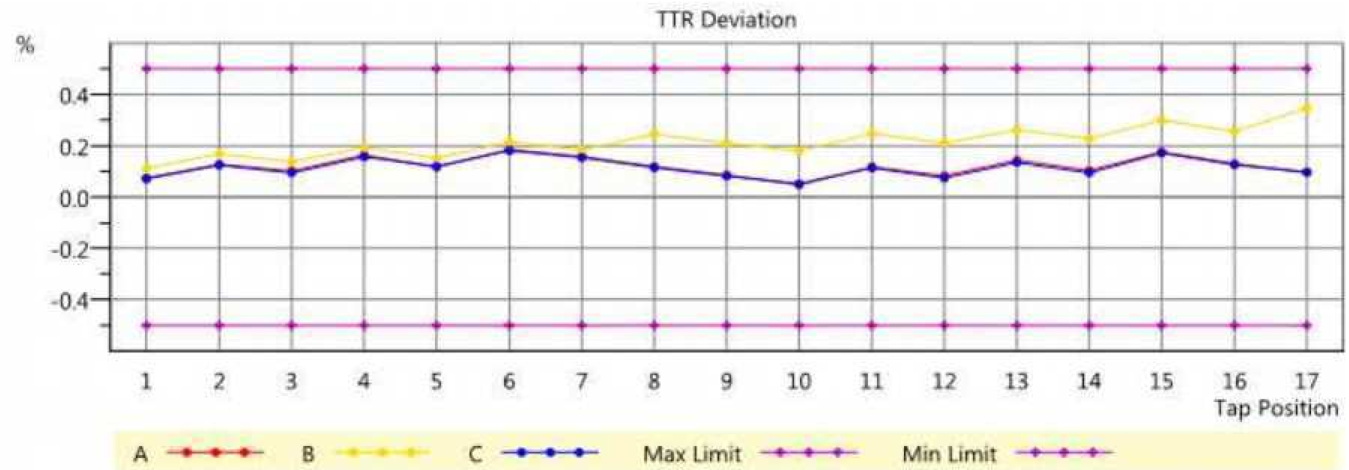
16
17
Tap Position
A
B
C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0.2
0.0
-0.2
-0.4
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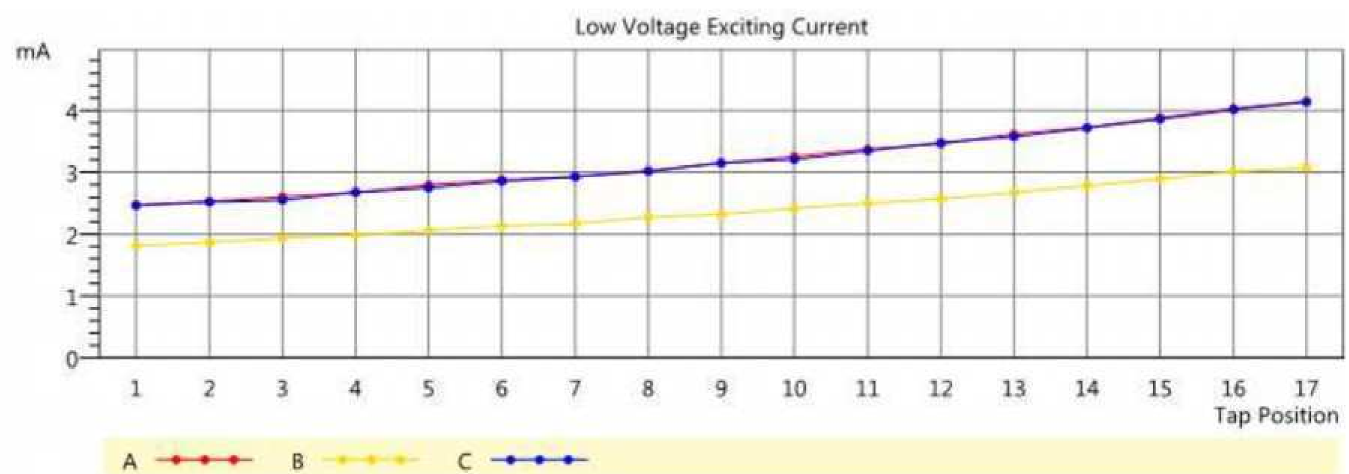
16
17
Tap Position
A
B
C
Max Limit
Min Limit


Low Voltage Exciting Current
mA
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3
2
1
0
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
Tap Position
A
B
C

TTR H-Y

Test Voltage	150 V		Type of Tap Changer	OLTC

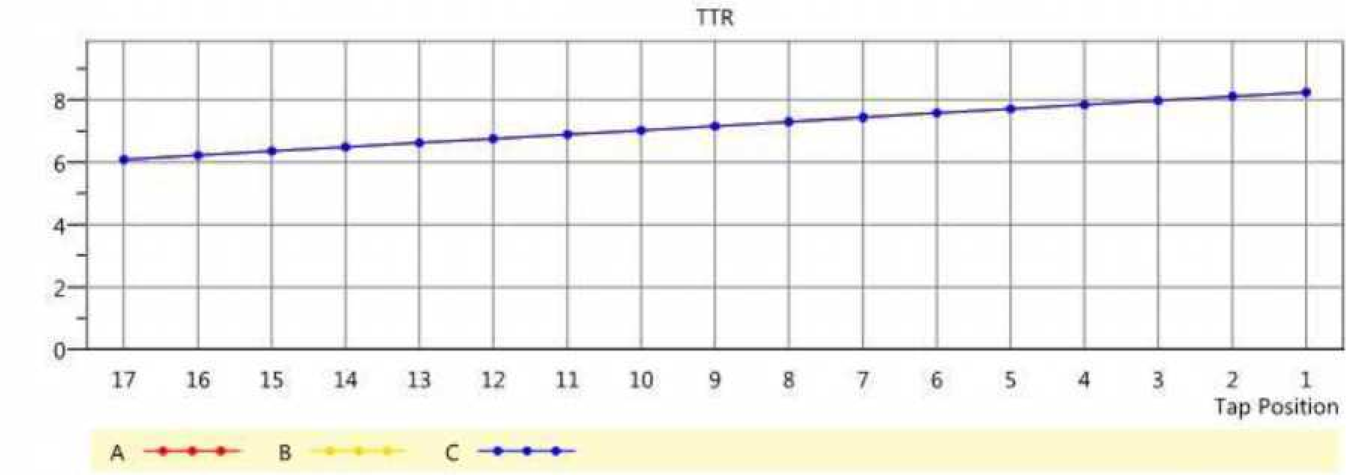
		Phase A		Phase B		Phase C	
Tap	Nom. Ratio	TTR	Ratio Dev.	TTR	Ratio Dev.	TTR	Ratio Dev.
17	6.0777	6.091	0.22 %	6.0978	0.33 %	6.0907	0.21 %
16	6.2118	6.2278	0.26 %	6.2272	0.25 %	6.2275	0.25 %
15	6.346	6.3646	0.29 %	6.3641	0.29 %	6.3647	0.30 %
14	6.4801	6.4945	0.22 %	6.4941	0.22 %	6.4943	0.22 %
13	6.6142	6.6314	0.26 %	6.6313	0.26 %	6.6316	0.26 %
12	6.7479	6.7613	0.20 %	6.761	0.19 %	6.7612	0.20 %
11	6.882	6.8984	0.24 %	6.8978	0.23 %	6.8979	0.23 %
10	7.0161	7.028	0.17 %	7.0276	0.16 %	7.028	0.17 %
9	7.1503	7.1653	0.21 %	7.1646	0.20 %	7.1649	0.20 %
8	7.2844	7.3019	0.24 %	7.3017	0.24 %	7.3018	0.24 %
7	7.4185	7.4393	0.28 %	7.4314	0.17 %	7.4388	0.27 %
6	7.5526	7.5761	0.31 %	7.5685	0.21 %	7.5754	0.30 %
5	7.6868	7.7063	0.25 %	7.6986	0.15 %	7.706	0.25 %
4	7.8204	7.8429	0.29 %	7.8353	0.19 %	7.843	0.29 %
3	7.9546	7.973	0.23 %	7.9652	0.13 %	7.9724	0.22 %
2	8.0887	8.1097	0.26 %	8.1021	0.17 %	8.1097	0.26 %
1	8.2228	8.2396	0.20 %	8.2321	0.11 %	8.2398	0.21 %

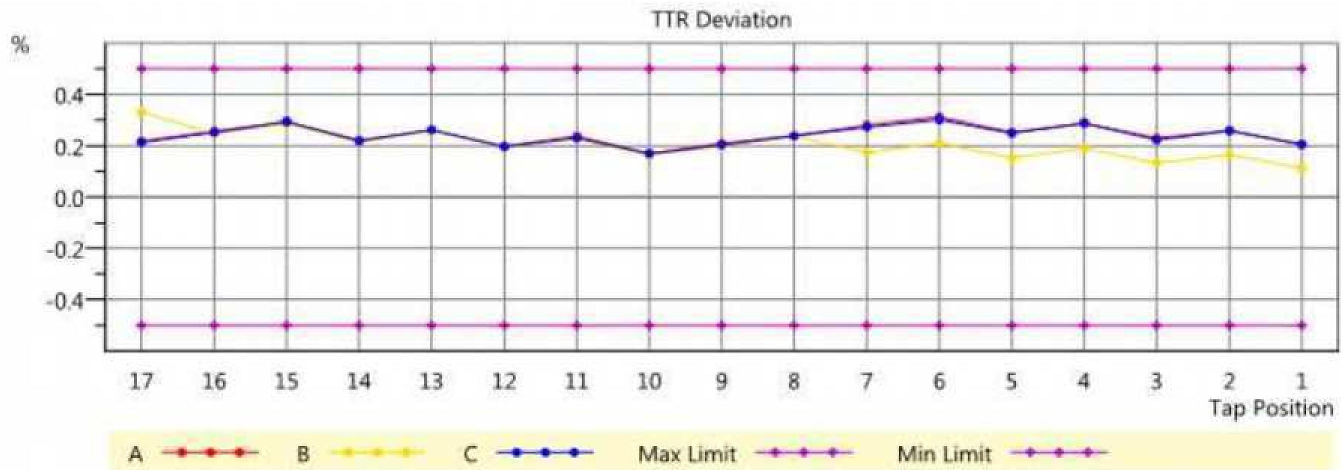
Phase A

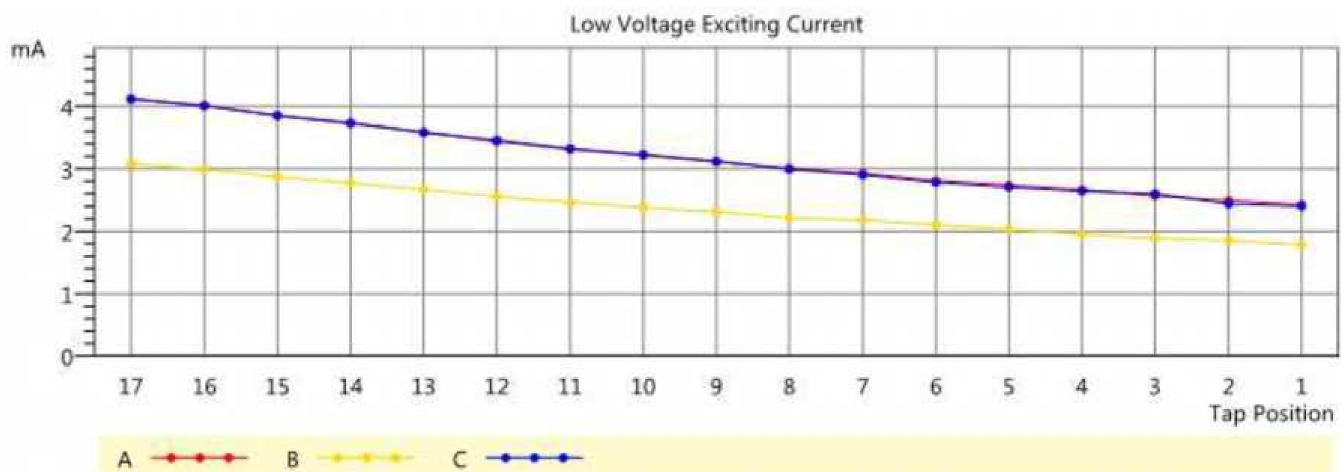
Tap	Nom. Ratio	V Prim	I Prim	I Phase	V Sec	V Phase	TTR	Ratio Dev.
17	6.0777	149.97 V	4.115 mA	-63.34 °	24.62 V	-0.080 °	6.091	0.22 %
16	6.2118	149.97 V	4.017 mA	-63.67 °	24.08 V	-0.090 °	6.2278	0.26 %
15	6.346	149.96 V	3.849 mA	-63.29 °	23.56 V	-0.100 °	6.3646	0.29 %
14	6.4801	149.97 V	3.725 mA	-63.61 °	23.09 V	-0.100 °	6.4945	0.22 %
13	6.6142	149.96 V	3.591 mA	-63.24 °	22.61 V	-0.090 °	6.6314	0.26 %
12	6.7479	149.97 V	3.440 mA	-63.47 °	22.18 V	-0.100 °	6.7613	0.20 %
11	6.882	149.97 V	3.317 mA	-63.14 °	21.74 V	-0.100 °	6.8984	0.24 %
10	7.0161	149.97 V	3.220 mA	-63.49 °	21.34 V	-0.100 °	7.028	0.17 %
9	7.1503	149.97 V	3.115 mA	-63.47 °	20.93 V	-0.110 °	7.1653	0.21 %
8	7.2844	149.97 V	3.010 mA	-62.78 °	20.54 V	-0.100 °	7.3019	0.24 %
7	7.4185	149.97 V	2.930 mA	-62.69 °	20.16 V	-0.100 °	7.4393	0.28 %
6	7.5526	149.98 V	2.811 mA	-63.08 °	19.80 V	-0.090 °	7.5761	0.31 %
5	7.6868	149.97 V	2.740 mA	-62.48 °	19.46 V	-0.100 °	7.7063	0.25 %
4	7.8204	149.96 V	2.664 mA	-62.48 °	19.12 V	-0.110 °	7.8429	0.29 %
3	7.9546	149.97 V	2.567 mA	-62.93 °	18.81 V	-0.100 °	7.973	0.23 %
2	8.0887	149.97 V	2.494 mA	-62.90 °	18.49 V	-0.100 °	8.1097	0.26 %
1	8.2228	149.97 V	2.422 mA	-62.73 °	18.20 V	-0.110 °	8.2396	0.20 %

Phase B								
Tap	Nom. Ratio	V Prim	I Prim	I Phase	V Sec	V Phase	TTR	Ratio Dev.
17	6.0777	149.97 V	3.086 mA	-64.31 °	24.59 V	-0.070 °	6.0978	0.33 %
16	6.2118	149.96 V	2.990 mA	-63.99 °	24.08 V	-0.080 °	6.2272	0.25 %
15	6.346	149.97 V	2.873 mA	-64.29 °	23.57 V	-0.080 °	6.3641	0.29 %
14	6.4801	149.97 V	2.772 mA	-64.09 °	23.09 V	-0.080 °	6.4941	0.22 %
13	6.6142	149.98 V	2.670 mA	-64.31 °	22.62 V	-0.100 °	6.6313	0.26 %
12	6.7479	149.97 V	2.554 mA	-63.85 °	22.18 V	-0.080 °	6.761	0.19 %
11	6.882	149.97 V	2.464 mA	-63.75 °	21.74 V	-0.090 °	6.8978	0.23 %
10	7.0161	149.97 V	2.384 mA	-63.90 °	21.34 V	-0.080 °	7.0276	0.16 %
9	7.1503	149.97 V	2.317 mA	-63.94 °	20.93 V	-0.090 °	7.1646	0.20 %
8	7.2844	149.97 V	2.219 mA	-63.06 °	20.54 V	-0.080 °	7.3017	0.24 %
7	7.4185	149.97 V	2.185 mA	-63.25 °	20.18 V	-0.080 °	7.4314	0.17 %
6	7.5526	149.97 V	2.111 mA	-62.97 °	19.82 V	-0.080 °	7.5685	0.21 %
5	7.6868	149.97 V	2.041 mA	-62.73 °	19.48 V	-0.090 °	7.6986	0.15 %
4	7.8204	149.97 V	1.953 mA	-63.40 °	19.14 V	-0.080 °	7.8353	0.19 %
3	7.9546	149.97 V	1.893 mA	-62.56 °	18.83 V	-0.090 °	7.9652	0.13 %
2	8.0887	149.97 V	1.852 mA	-62.16 °	18.51 V	-0.090 °	8.1021	0.17 %
1	8.2228	149.97 V	1.784 mA	-62.16 °	18.22 V	-0.090 °	8.2321	0.11 %

Phase C								
Tap	Nom. Ratio	V Prim	I Prim	I Phase	V Sec	V Phase	TTR	Ratio Dev.
17	6.0777	149.97 V	4.121 mA	-63.96 °	24.62 V	-0.080 °	6.0907	0.21 %
16	6.2118	149.97 V	4.005 mA	-63.81 °	24.08 V	-0.090 °	6.2275	0.25 %
15	6.346	149.98 V	3.853 mA	-64.14 °	23.56 V	-0.090 °	6.3647	0.30 %
14	6.4801	149.96 V	3.738 mA	-63.85 °	23.09 V	-0.090 °	6.4943	0.22 %
13	6.6142	149.97 V	3.584 mA	-64.23 °	22.61 V	-0.070 °	6.6316	0.26 %
12	6.7479	149.97 V	3.463 mA	-63.63 °	22.18 V	-0.080 °	6.7612	0.20 %
11	6.882	149.97 V	3.325 mA	-63.33 °	21.74 V	-0.080 °	6.8979	0.23 %
10	7.0161	149.98 V	3.231 mA	-63.67 °	21.34 V	-0.090 °	7.028	0.17 %
9	7.1503	149.97 V	3.127 mA	-63.74 °	20.93 V	-0.090 °	7.1649	0.20 %
8	7.2844	149.96 V	2.996 mA	-63.06 °	20.54 V	-0.080 °	7.3018	0.24 %
7	7.4185	149.97 V	2.906 mA	-63.35 °	20.16 V	-0.080 °	7.4388	0.27 %
6	7.5526	149.96 V	2.783 mA	-62.99 °	19.80 V	-0.090 °	7.5754	0.30 %
5	7.6868	149.97 V	2.706 mA	-62.80 °	19.46 V	-0.090 °	7.706	0.25 %
4	7.8204	149.96 V	2.643 mA	-62.70 °	19.12 V	-0.080 °	7.843	0.29 %
3	7.9546	149.97 V	2.601 mA	-62.84 °	18.81 V	-0.070 °	7.9724	0.22 %
2	8.0887	149.97 V	2.440 mA	-62.33 °	18.49 V	-0.080 °	8.1097	0.26 %
1	8.2228	149.97 V	2.407 mA	-62.12 °	18.20 V	-0.070 °	8.2398	0.21 %


TTR
0
2
4
6
8
17 16 15 14 13 12 11 10 9 8 7 6 5 4 3 2 1
Tap Position
A
B
C


TTR Deviation
%
0.4
0.2
0.0
-0.2
-0.4
17 16 15 14 13 12 11 10 9 8 7 6 5 4 3 2 1
Tap Position
A
B
C
Max Limit
Min Limit


Low Voltage Exciting Current
mA
0
1
2
3
4
17 16 15 14 13 12 11 10 9 8 7 6 5 4 3 2 1
Tap Position
A
B
C

A.7 Winding Resistance

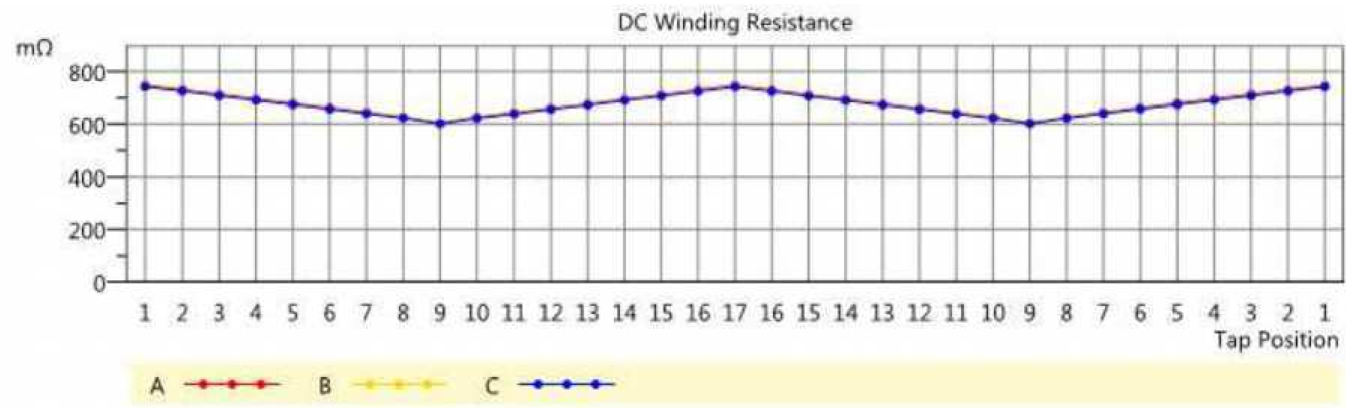
DC Winding Resistance H			
Test Current	5.0 A	Type of Tap Changer	OLTC
Winding temperature	1 °C		
Temperature Corr. Factor (K)	1.31		

Comments

H1-X1, H2-X2, H3-X3
Reference Temperature 75 °C

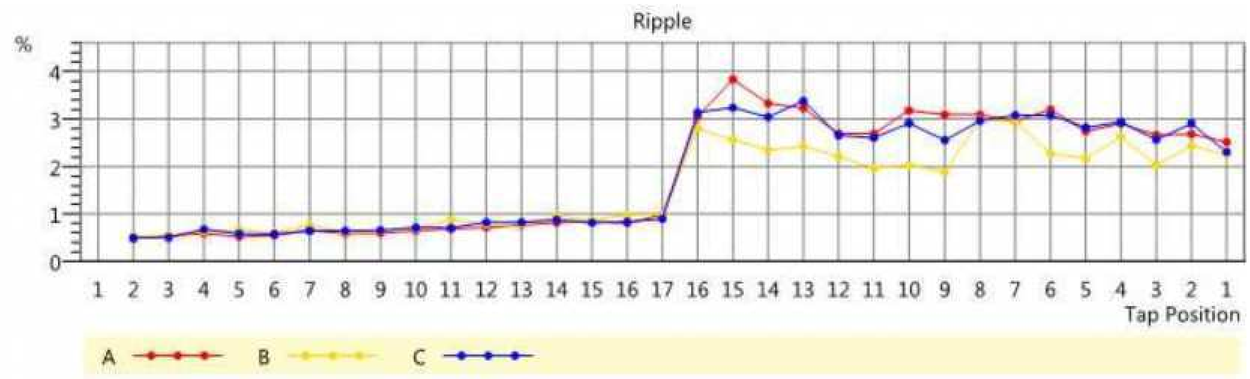
DC Winding Resistance Results

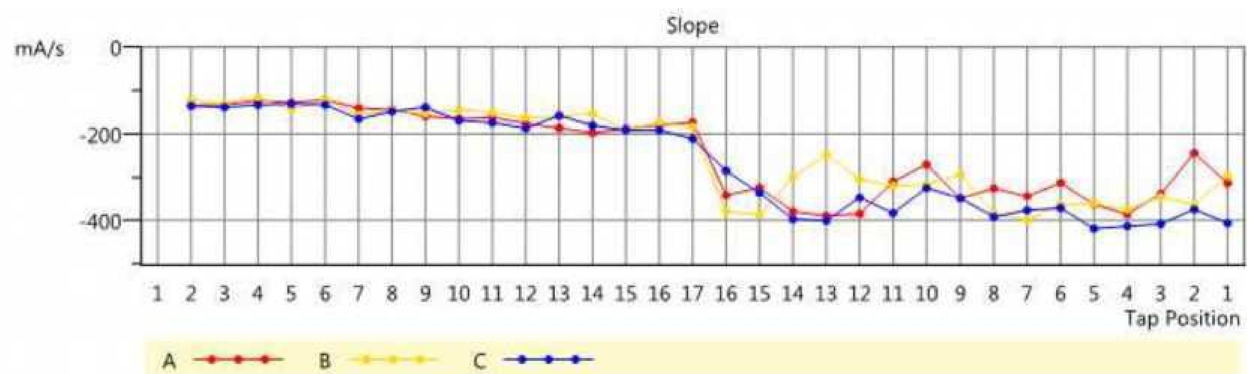
	Phase A			Phase B			Phase C			
Tap	R mea.	R dev.	R corr.	R mea.	R dev.	R corr.	R mea.	R dev.	R corr.	Assessment
1	0.571 Ω	0.085 %	0.748 Ω	0.568 Ω	0.045 %	0.744 Ω	0.566 Ω	0.072 %	0.742 Ω	Pass
2	0.558 Ω	0.025 %	0.731 Ω	0.555 Ω	0.029 %	0.727 Ω	0.554 Ω	0.088 %	0.725 Ω	Pass
3	0.545 Ω	0.046 %	0.714 Ω	0.542 Ω	0.051 %	0.710 Ω	0.540 Ω	0.055 %	0.708 Ω	Pass
4	0.532 Ω	0.017 %	0.697 Ω	0.529 Ω	0.053 %	0.694 Ω	0.528 Ω	0.091 %	0.691 Ω	Pass
5	0.519 Ω	0.055 %	0.680 Ω	0.516 Ω	0.049 %	0.676 Ω	0.514 Ω	0.076 %	0.674 Ω	Pass
6	0.506 Ω	0.029 %	0.663 Ω	0.503 Ω	0.062 %	0.660 Ω	0.501 Ω	0.089 %	0.657 Ω	Pass
7	0.492 Ω	0.095 %	0.645 Ω	0.490 Ω	0.049 %	0.642 Ω	0.489 Ω	0.059 %	0.640 Ω	Pass
8	0.479 Ω	0.023 %	0.627 Ω	0.478 Ω	0.038 %	0.626 Ω	0.475 Ω	0.075 %	0.623 Ω	Pass
9	0.462 Ω	0.083 %	0.605 Ω	0.462 Ω	0.038 %	0.605 Ω	0.459 Ω	0.051 %	0.602 Ω	Pass
10	0.479 Ω	0.080 %	0.627 Ω	0.477 Ω	0.055 %	0.626 Ω	0.475 Ω	0.073 %	0.622 Ω	Pass
11	0.492 Ω	0.072 %	0.644 Ω	0.490 Ω	0.037 %	0.642 Ω	0.488 Ω	0.062 %	0.639 Ω	Pass
12	0.505 Ω	0.063 %	0.661 Ω	0.503 Ω	0.049 %	0.659 Ω	0.501 Ω	0.028 %	0.656 Ω	Pass
13	0.518 Ω	0.091 %	0.678 Ω	0.516 Ω	0.038 %	0.676 Ω	0.513 Ω	0.086 %	0.672 Ω	Pass
14	0.531 Ω	0.074 %	0.695 Ω	0.529 Ω	0.034 %	0.693 Ω	0.527 Ω	0.070 %	0.690 Ω	Pass
15	0.544 Ω	0.064 %	0.712 Ω	0.542 Ω	0.030 %	0.710 Ω	0.539 Ω	0.084 %	0.707 Ω	Pass
16	0.558 Ω	0.056 %	0.731 Ω	0.555 Ω	0.020 %	0.727 Ω	0.553 Ω	0.060 %	0.724 Ω	Pass
17	0.571 Ω	0.093 %	0.748 Ω	0.568 Ω	0.034 %	0.744 Ω	0.566 Ω	0.059 %	0.741 Ω	Pass
16	0.558 Ω	0.094 %	0.730 Ω	0.555 Ω	0.031 %	0.727 Ω	0.553 Ω	0.047 %	0.724 Ω	Pass
15	0.544 Ω	0.076 %	0.712 Ω	0.542 Ω	0.053 %	0.710 Ω	0.539 Ω	0.079 %	0.707 Ω	Pass
14	0.531 Ω	0.067 %	0.695 Ω	0.529 Ω	0.049 %	0.693 Ω	0.527 Ω	0.047 %	0.690 Ω	Pass
13	0.518 Ω	0.070 %	0.678 Ω	0.516 Ω	0.044 %	0.676 Ω	0.513 Ω	0.084 %	0.673 Ω	Pass
12	0.505 Ω	0.065 %	0.661 Ω	0.503 Ω	0.055 %	0.660 Ω	0.501 Ω	0.072 %	0.656 Ω	Pass
11	0.492 Ω	0.071 %	0.644 Ω	0.490 Ω	0.039 %	0.642 Ω	0.488 Ω	0.089 %	0.639 Ω	Pass
10	0.479 Ω	0.084 %	0.627 Ω	0.478 Ω	0.020 %	0.626 Ω	0.475 Ω	0.095 %	0.622 Ω	Pass
9	0.462 Ω	0.087 %	0.605 Ω	0.462 Ω	0.042 %	0.605 Ω	0.459 Ω	0.092 %	0.602 Ω	Pass
8	0.479 Ω	0.083 %	0.628 Ω	0.478 Ω	0.050 %	0.626 Ω	0.475 Ω	0.066 %	0.623 Ω	Pass
7	0.492 Ω	0.063 %	0.645 Ω	0.490 Ω	0.067 %	0.642 Ω	0.489 Ω	0.070 %	0.640 Ω	Pass
6	0.506 Ω	0.079 %	0.663 Ω	0.504 Ω	0.063 %	0.660 Ω	0.502 Ω	0.082 %	0.657 Ω	Pass
5	0.519 Ω	0.032 %	0.680 Ω	0.516 Ω	0.062 %	0.676 Ω	0.515 Ω	0.075 %	0.674 Ω	Pass
4	0.532 Ω	0.070 %	0.697 Ω	0.529 Ω	0.067 %	0.693 Ω	0.528 Ω	0.071 %	0.691 Ω	Pass
3	0.545 Ω	0.068 %	0.714 Ω	0.542 Ω	0.065 %	0.710 Ω	0.540 Ω	0.082 %	0.708 Ω	Pass
2	0.558 Ω	0.096 %	0.731 Ω	0.555 Ω	0.053 %	0.728 Ω	0.553 Ω	0.080 %	0.725 Ω	Pass
1	0.571 Ω	0.093 %	0.748 Ω	0.568 Ω	0.060 %	0.744 Ω	0.566 Ω	0.092 %	0.742 Ω	Pass



TR Tap Check Results

	Phase A		Phase B		Phase C		
Tap	Ripple	Slope	Ripple	Slope	Ripple	Slope	Assessment
1	%	A/s	%	A/s	%	A/s	Pass
2	0.490 %	-135 mA/s	0.520 %	-123 mA/s	0.490 %	-136 mA/s	Pass
3	0.530 %	-133 mA/s	0.550 %	-130 mA/s	0.500 %	-139 mA/s	Pass
4	0.580 %	-124 mA/s	0.620 %	-117 mA/s	0.670 %	-134 mA/s	Pass
5	0.520 %	-128 mA/s	0.660 %	-144 mA/s	0.580 %	-132 mA/s	Pass
6	0.540 %	-122 mA/s	0.600 %	-122 mA/s	0.570 %	-133 mA/s	Pass
7	0.650 %	-141 mA/s	0.760 %	-157 mA/s	0.640 %	-166 mA/s	Pass
8	0.580 %	-144 mA/s	0.610 %	-146 mA/s	0.640 %	-149 mA/s	Pass
9	0.590 %	-160 mA/s	0.640 %	-154 mA/s	0.650 %	-139 mA/s	Pass
10	0.640 %	-165 mA/s	0.690 %	-145 mA/s	0.710 %	-170 mA/s	Pass
11	0.680 %	-162 mA/s	0.880 %	-151 mA/s	0.700 %	-174 mA/s	Pass
12	0.710 %	-176 mA/s	0.770 %	-163 mA/s	0.820 %	-187 mA/s	Pass
13	0.760 %	-187 mA/s	0.780 %	-161 mA/s	0.820 %	-158 mA/s	Pass
14	0.810 %	-198 mA/s	0.940 %	-154 mA/s	0.870 %	-181 mA/s	Pass
15	0.850 %	-188 mA/s	0.870 %	-192 mA/s	0.810 %	-192 mA/s	Pass
16	0.800 %	-180 mA/s	0.970 %	-174 mA/s	0.830 %	-191 mA/s	Pass
17	0.980 %	-174 mA/s	0.980 %	-184 mA/s	0.890 %	-211 mA/s	Pass
16	3.050 %	-342 mA/s	2.800 %	-379 mA/s	3.140 %	-285 mA/s	Pass
15	3.840 %	-324 mA/s	2.570 %	-387 mA/s	3.240 %	-336 mA/s	Pass
14	3.330 %	-381 mA/s	2.350 %	-300 mA/s	3.040 %	-398 mA/s	Pass
13	3.230 %	-390 mA/s	2.430 %	-248 mA/s	3.380 %	-401 mA/s	Pass
12	2.700 %	-385 mA/s	2.210 %	-304 mA/s	2.660 %	-347 mA/s	Pass
11	2.700 %	-309 mA/s	1.970 %	-319 mA/s	2.610 %	-384 mA/s	Pass
10	3.180 %	-271 mA/s	2.030 %	-316 mA/s	2.920 %	-324 mA/s	Pass
9	3.090 %	-349 mA/s	1.890 %	-294 mA/s	2.560 %	-349 mA/s	Pass
8	3.090 %	-326 mA/s	2.990 %	-383 mA/s	2.970 %	-392 mA/s	Pass
7	2.950 %	-344 mA/s	2.940 %	-400 mA/s	3.080 %	-377 mA/s	Pass
6	3.200 %	-312 mA/s	2.280 %	-364 mA/s	3.080 %	-372 mA/s	Pass
5	2.750 %	-364 mA/s	2.170 %	-362 mA/s	2.830 %	-420 mA/s	Pass
4	2.910 %	-386 mA/s	2.630 %	-376 mA/s	2.940 %	-414 mA/s	Pass
3	2.670 %	-338 mA/s	2.030 %	-345 mA/s	2.570 %	-409 mA/s	Pass
2	2.690 %	-244 mA/s	2.440 %	-364 mA/s	2.910 %	-375 mA/s	Pass
1	2.520 %	-313 mA/s	2.250 %	-296 mA/s	2.310 %	-407 mA/s	Pass





DC Winding Resistance X

Test Current	5.0 A
Winding temperature	3 °C
Temperature Corr. Factor (K)	1.3

Type of Tap Changer	None

Comments

X1-HO/XO, H2-HO/XO, H3-HO/XO
Reference Temperature 75 °C

DC Winding Resistance Results

	Phase A			Phase B			Phase C			
Tap	R mea.	R dev.	R corr.	R mea.	R dev.	R corr.	R mea.	R dev.	R corr.	Assessment
n/a	0.129 Ω	0.099 %	0.167 Ω	0.130 Ω	0.088 %	0.169 Ω	0.130 Ω	0.077 %	0.169 Ω	Pass

DC Winding Resistance Y

Test Current	6.0 A
Winding temperature	3 °C
Temperature Corr. Factor (K)	1.3

Type of Tap Changer	None

Comments

Reference Temperature 75 °C

DC Winding Resistance Results

	Phase A			Phase B			Phase C			
Tap	R mea.	R dev.	R corr.	R mea.	R dev.	R corr.	R mea.	R dev.	R corr.	Assessment
n/a	0.022 Ω	0.150 %	0.029 Ω	0.023 Ω	0.224 %	0.029 Ω	0.023 Ω	0.352 %	0.029 Ω	Pass

A.8 Auxiliary Devices

Fan Motor Insulation Resistance Results @ 1kV DC

- Top two fans = > 11 GΩ
- Bottom two fans = 5.4 GΩ

Gas Relay Test

- Slow Accumulation – Good
- Fast Gas – Good

Winding Temperature Gauge Test with Dry Block Calibrator

Setpoint	75 °C		105 °C		120 °C	
	Pick up	Drop Out	Pick up	Drop Out	Pick up	Drop Out
13kV Probe	Faulty	Faulty	Faulty	Faulty	Faulty	Faulty
63kV Probe	75 °C	62 °C	105 °C	96 °C	120 °C	109 °C
161kV Probe	75 °C	61 °C	103 °C	94 °C	119 °C	108 °C

Liquid Temperature Gauge Test with Dry Block Calibrator

Setpoint	90 °C	
	Pick up	Drop Out
Liquid Temp Probe	91 °C	82 °C

Oil Level Gauge Function Test

Tap Changer Tank and Conservator Liquid Level Gauges – Both active when oil level falls below “LOW”

APPENDIX B: **Load Tap Changer Inspection Results**

B.1 LTC Condition Assessment CGE Type CLR83

Station	Oliver
Designation	ex OLI T1
Serial Number	287732
Date	

1. Operations Counter

Funtion	OK
As Found	111

2. Oil Analysis

No oil sample taken, old oil disposed and tap changer left without oil.

3. External Inspection

Oil Level Gauge	OK, function tested low oil contact
Spring Relief Mechanism	OK, cover moves upwards freely
Dehydrating Breather	OK, old desiccant disposed, new desiccant installed
Motor Shaft Oil Seal	OK, no leaks visible
External Leaks	OK, no leaks visible

4. LTC Control Cabinet

Interior Inspection	OK, no signs of corrosion or condensation
Heater	OK
Thermostat	OK
Weather Seal	OK
Terminal Strips	OK, no signs of corrosion or overheating

5. Internal Inspection

LTC Switch Compartment - Phase A

Selector Switch Moving Contacts	OK, spring and contact pressure good
Selector Switch Fixed Contacts	OK, no signs of arcing
Main Moving Contact – Left Side	OK
Main Moving Contact – Right Side	OK
Main Fixed Contact – Left Side	OK
Main Fixed Contact – Right Side	OK
Moving Arcing Contact - Left Side	OK, 0.4”, 12 ft lb tension
Moving Arcing Contacts – Right Side	OK, 0.4”, 12 ft lb tension

Fixed Arcing Contact – Left Side	OK, 0.4”
Fixed Arcing Contact – Right Side	OK, 0.4”
Reversing Switch Moving Contact	OK
Reversing Switch Contact – Left Side	OK
Reversing Switch Contact – Right Side	OK
Bushing and Support Studs	Diverter switch support bushing R leaking

LTC Switch Compartment - Phase B

Selector Switch Moving Contacts	OK, spring and contact pressure good
Selector Switch Fixed Contacts	OK, no signs of arcing
Main Moving Contact – Left Side	OK
Main Moving Contact – Right Side	OK
Main Fixed Contact – Left Side	OK
Main Fixed Contact – Right Side	OK
Moving Arcing Contact - Left Side	OK, 0.4”, 15 ft lb tension
Moving Arcing Contacts – Right Side	OK, 0.4”, 11 ft lb tension
Fixed Arcing Contact – Left Side	OK, 0.4”
Fixed Arcing Contact – Right Side	OK, 0.4”
Reversing Switch Moving Contact	OK
Reversing Switch Contact – Left Side	OK
Reversing Switch Contact – Right Side	OK
Bushing and Support Studs	OK

LTC Switch Compartment - Phase C

Selector Switch Moving Contacts	OK, spring and contact pressure good
Selector Switch Fixed Contacts	OK, no signs of arcing
Main Moving Contact – Left Side	OK
Main Moving Contact – Right Side	OK
Main Fixed Contact – Left Side	OK
Main Fixed Contact – Right Side	OK
Moving Arcing Contact - Left Side	OK, 0.4”, 14 ft lb tension
Moving Arcing Contacts – Right Side	OK, 0.4”, 12 ft lb tension
Fixed Arcing Contact – Left Side	OK, 0.4”

Fixed Arcing Contact – Right Side	OK, 0.4”
Reversing Switch Moving Contact	OK
Reversing Switch Contact – Left Side	OK
Reversing Switch Contact – Right Side	OK
Bushing and Support Studs	OK

Mechanical Components

Geneva Gears	OK
Drivers	OK
Push Rods	OK
Bearings	OK
Operating Shafts	OK
Gears	OK

LTC Switch Assembly (Connections, Springs and Fasteners)

Phase A	OK
Phase B	OK
Phase C	OK

6. Motor Drive Mechanism

Mechanical Components	OK
Position Transmitter	OK
Operations Counter	OK
Dynamic Brake	OK
Limit Switches and Cam	OK
Drive Shaft Oil Seal	OK
Manual Operation	OK
Electrical Operation	OK
End Stops	OK

APPENDIX C: **Transformer Oil Lab Analysis Report**

C.1 The Chem Lab Analysis Report

THE Chem Lab
Unit 126, 3770 Westwinds Drive N.E.
Calgary, Alberta T3J 5H3
Tel. 403-293-8650 Fax. 403-293-5006

THE chemlab

LABORATORY QUALITY ASSURANCE RELEASE

ABB Power Services (Kelowna)
Shane R. Hunter
#104, 1641 Commerce Avenue
Kelowna, BC V1X 8A9

Site: Fortis BC Oliver
P.O.#: 4500538660
Job #: 50209-10

SAMPLE ID	RECEIVED DATE	REPORTED DATE	REPORT TYPE	PRIORITY
3423-1	4-Jan-13	17-Jan-13	DGA & FQA	ROUTINE
3423-1	4-Jan-13	17-Jan-13	PCBs & Furans	ROUTINE

NOTES & COMMENTS:

3423-1 (T-1 OLI 45 MVA TX) Total furan is high enough to raise concern about possible paper deterioration. TOA4.

3423-1 (T-1 OLI 45 MVA TX) Total PCBs level above Environment Canada's lowest current regulatory limit (2.0 ppm) for non-sensitive
Total PCBs level below 50 ppm regulatory threshold.

The reports listed above have been checked for accuracy and all results contained have passed THE Chem Lab's quality control requirements.

17-Jan-13

Report contents verified by: X Martin Linek

Martin Linek, B.Sc.
Lab Manager

THE Chem Lab
Unit 126, 3770 Westwinds Drive N.E.
Calgary, Alberta T3J 5H3
Tel. 403-293-8650 Fax. 403-293-5006

LAB ANALYSIS REPORT

ABB Power Services (Kelowna)
Shane R. Hunter
#104, 1641 Commerce Avenue
Kelowna, BC V1X 8A9

NAMEPLATE AND SAMPLE INFORMATION:

Site:	Fortis BC Oliver	Customer ID:	T1	P.O.#:	4500538660
Serial Number:	287732	Manufacturer/Year:	CGE / 1971	Job#:	50209-10
Apparatus Type:	XFMR	Equipment Model:	OLI T-1	Syringe ID:	AC622
Compartment:	Main	Breathing Config.:	Conservator	Received:	4-Jan-13
kV Rating:	161.000 / 63.000	MVA Rating:	45	Reported:	17-Jan-13
Fluid Type:	Mineral Oil; 8500 Gal.	Status:	Out of Service	Sampled By:	NA

Lab Control Number:	3423-1						
Date Sampled:	3-Dec-12						
Fluid Temperature (°C)	6.5						
Dissolved Gas Analysis [ASTM D-3612C]						**Reporting Limit:**	**Units**
Hydrogen: $[H_2]$	9					1	ppm
Methane: $[CH_4]$	3					1	ppm
Ethane: $[C_2H_6]$	3.1					0.1	ppm
Ethylene: $[C_2H_4]$	21					0.1	ppm
Acetylene: $[C_2H_2]$	1.6					0.1	ppm
Carbon Monoxide: [CO]	358					1	ppm
Carbon Dioxide: $[CO_2]$	3220					10	ppm
Oxygen: $[O_2]$	24300					500	ppm
Nitrogen: $[N_2]$	61000					2000	ppm
Total Dissolved Gas:	8.89					0.25	%
Total Dissolved Combustible Gas:	396					3	ppm
Equiv. Headspace Total Combustible Gas:	0.363					-	%
Total Partial Pressure:	0.918					-	atm
Estimated Safe Handling Limit:	10.9					-	%
Dissolved Gas Sample Comments:	No Bubble					-	-
Dissolved Gas Comments & Diagnostics:	No anomalies. TOA4.						
Fluid Quality Analysis [ASTM]						**Reporting Limit:**	**Units:**
Dissipation Factor @ 25°C: [D924-25]	0.050					0.001	%
Dissipation Factor @ 100°C: [D924-100]	1.90					0.001	%
Interfacial Tension: [D971]	28.8					1.0	mN/m
Total Acid Number: [D974]	0.04					0.01	mg KOH/g
Colour Number: [D1500]	<2.5					0.5	Relative
Visual Examination: [D1524]	CLR&SPRKLG					-	-
Moisture Content: [D1533B]	5					4	ppm (w/w)
Dielectric Breakdown @ 1mm: [D1816-1]	30 *(24)*					-	kV (°C)
Viscosity @ 40°C: [D445]	-					-	cSt
Dielectric Breakdown @ 2.5mm: [D877A]	-					-	kV (°C)
Corrosive Sulfur: [D1275B]	-					-	Relative
Oxidation Inhibitor: [D2668]	-					0.010	% (w/w)
Specific Gravity (15°C/15°C): [D4052]	0.8817					-	Unity
Fluid Quality Comments & Diagnostics:	No anomalies. IEEE C57.106.						

THE Chem Lab
Unit 126, 3770 Westwinds Drive N.E.
Calgary, Alberta T3J 5H3
Tel. 403-293-8650 Fax. 403-293-5006

LAB ANALYSIS REPORT

ABB Power Services (Kelowna)
Shane R. Hunter
#104, 1641 Commerce Avenue
Kelowna, BC V1X 8A9

NAMEPLATE AND SAMPLE INFORMATION:

Site:	Fortis BC Oliver	Customer ID:	T1	P.O.#:	4500538660
Serial Number:	287732	Manufacturer/Year:	CGE / 1971	Job#:	50209-10
Apparatus Type:	XFMR	Equipment Model:	OLI T-1	Syringe ID:	AC622
Compartment:	Main	Breathing Config.:	Conservator	Received:	4-Jan-13
kV Rating:	161.000 / 63.000	MVA Rating:	45	Reported:	17-Jan-13
Fluid Type:	Mineral Oil; 8500 Gal.	Status:	Out of Service	Sampled By:	NA

Lab Control Number:	3423-1						
Date Sampled:	3-Dec-12						
Fluid Temperature (°C)	7						
PCB Aroclor Analysis by GC-MS/MS						Reporting Limit	Units (w/w)
Aroclor 1242	<0.3					0.3	ppm
Aroclor 1254	1.9					0.1	ppm
Aroclor 1260	4.7					0.1	ppm
Sum of Aroclors 1242 / 1254 / 1260	6.7					0.5	ppm
PCB Comments & Diagnostics:	PCB analysis was performed by Manitoba Hydro Laboratories at Waverley, Manitoba on 2013-Jan-14. Canadian Association for Laboratory Accreditation Member Number 2774 (ISO 17025:2005).						

THE Chem Lab
Unit 126, 3770 Westwinds Drive N.E.
Calgary, Alberta T3J 5H3
Tel. 403-293-8650 Fax. 403-293-5006

THE chemlab

LAB ANALYSIS REPORT

ABB Power Services (Kelowna)
Shane R. Hunter
#104, 1641 Commerce Avenue
Kelowna, BC V1X 8A9

NAMEPLATE AND SAMPLE INFORMATION:

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Serial Number:	287732	Manufacturer/Year:	CGE / 1971	Job#:	50209-10
Apparatus Type:	XFMR	Equipment Model:	OLI T-1	Syringe ID:	AC622
Compartment:	Main	Breathing Config.:	Conservator	Received:	4-Jan-13
kV Rating:	161.000 / 63.000	MVA Rating:	45	Reported:	17-Jan-13
Fluid Type:	Mineral Oil; 8500 Gal.	Status:	Out of Service	Sampled By:	NA

Lab Control Number:	3423-1						
Date Sampled:	3-Dec-12						
Fluid Temperature (°C)	7						
Furan Analysis by HPLC (ASTM D5837)						Reporting Limit	Units (w/v)
Furfuraldehyde [FAL]	80					10	ppb
Furfurol [FOL]	<10					10	ppb
2-AcetylFuran [ACF]	<10					10	ppb
HydroxyMethylFurfuraldehyde [HMF]	<10					10	ppb
5-Methyl-2-Furaldehyde [MEF]	<10					10	ppb
Total Furans	100					50	ppb

Furans Comments & Diagnostics: ESTIMATED AVERAGE DEGREE OF POLYMERIZATION 740 (Chendong et al.)

Average DP	NEW CONDITION	AFTER DRYING	MID-LIFE	DEGRADED	END OF LIFE
Ranges:	> 1100	1100-800	500	300	<200

Furan analysis was performed by Manitoba Hydro Laboratories at Waverley, Manitoba on 2013-Jan-15.
Canadian Association for Laboratory Accreditation Member Number 2774 (ISO 17025:2005).
Total furan is high enough to raise concern about possible paper deterioration. TOA4.
Watch for any signs that total furan may be increasing. TOA4.

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Appendix E

FIRST NATIONS NOTIFICATION LETTER

Blair Weston
Community & Aboriginal Relations

FortisBC Inc.
908B Front Street
Nelson, BC V1L 4C2
Tel: 250-231-0176
Blair.weston@fortisbc.com
www.fortisbc.com

DATE

Mailing adress

RE: Grand Forks Reliability Project

Dear NAME:

FortisBC would like to notify the First Nation Community of a potential upgrade project to its substation in Grand Forks as well as some as the power lines feeding the substation.

The majority of the upgrade is installing a new transformer at the Grand Forks Terminal Station. All this work will be done within the current substation footprint. Along with the transformer replacement there will be transmission modifications in order to alleviate system constraints, maintain customer reliability, and reduce ongoing maintenance on the transmission lines.

The transmission modifications include the salvage of two power lines from Cascade Substation in Rossland to Christina Lake. The copper transmission conductor and any poles that do not have distribution underbuild can be salvaged, with the remaining structures rehabilitated. Some of the poles that will be switched to distribution are at end of life will need to be replaced which means the setting of new poles.

FortisBC still requires approval for this project from the British Columbia Utilities Commission, and is planning to apply for a Certificate of Public Convenience and Necessity (CPCN). We are hoping to submit this CPCN to the Commission in September 2018. If the application is approved, we estimate that the substation construction could begin in 2019 with a power line work done in 2020.

I have attached a mapset of the project area as well as a map of the general area where the pole replacements will be made. At this point we do not know the exact structures or number of structures that need to be replaced. Should the project go ahead, FortisBC will ensure the First Nation Community gets a shapefile and kmz file of the poles that will need replacement in 2019. At that time we can determine if there are either archeological or cultural values identified in the area and discuss next steps to minimize impacts.

I look forward to working with you on the project

Blair Weston
Community & Indigenous Relations Manager
250.231.0176

Appendix F

ALTERNATIVE B PRELIMINARY DRAWINGS

CONSTRUCTION NOTES:

1. USE EXISTING 87-T1 PY AS 87-T1 SY.

NOTES:

1. T3 SEL-387 RELAY MUST BE IN SETTING GROUP 2 IF 179 RECLOSER IS BY-PASSED.
2. AUTO LOAD RESTORATION ONLY FOR TRANSFORMER OVERLOAD TRIPPING (AT NO BREAKER FAILURE INITIATION).
3. TRIPPING BREAKERS ON 63kV BUS IS SUPERVISED BY B-1 STATUS LOGIC IN 87-LVB.
4. CURRENT INPUT REVERSED IN THE RELAY.

STATION ALARMS & STATUS

SCADA LEGEND

- SCADA INTERFACE
- T/C — TRIP/CLOSE COMMAND
- O/C — OPEN/CLOSE INDICATION
- AL — ALARM POINT
- MW / MVAR — COMBINED MEGAWATT/MEGAVAR TRANSDUCER

ALL C.T. RATIOS SHOWN ARE MAXIMUM AVAILABLE. SEE A.C. SCHEMATIC FOR SETTINGS.

CLASS 3 – APPROVAL

	NAME (PRINT/SIGNATURE)	DATE
SYSTEM PLANNING		
ENGINEERING		
PROJECT MANAGEMENT		
OPERATIONS		

REVISIONS					
4					
3					
2					
1					
REV	DATE	BY	CHECKED	DESCRIPTION	REVISION APPROVAL DATE

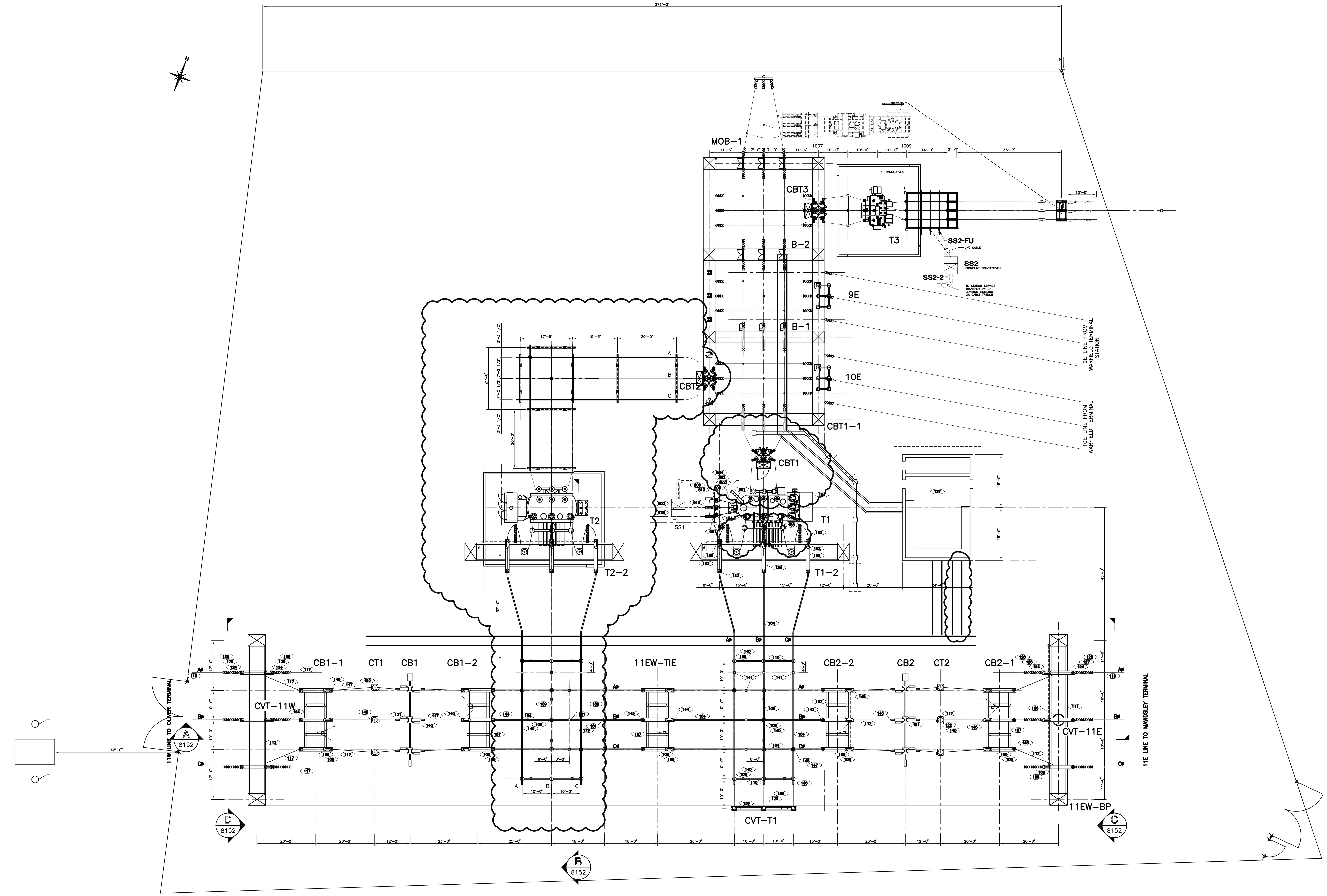
DRAWN BY: D. MCFARLANE	SEP/10	
DESIGNED BY: M. FRICKE	NOV/16	
CHECKED BY: M. FRICKE	NOV/16	
APPROVALS		
ELECTRICAL	CIVIL	MANAGEMENT

FORTIS BC

DIVISION	KOOTENAY
DEPARTMENT	PROTECTION-CONTROL
LOCATION	GRAND FORKS TERMINAL
TITLE	T2 ADDN. - CPCN ALT. B - SLD

SCALE: NONE — SCALE FACTOR: 1.5

DRAWING NUMBER	REVISION
3-275-8005	P0



CLASS 3 – APPROVAL	NAME (PRINT/SIGNATURE)	DATE
SYSTEM PLANNING		
ENGINEERING		
PROJECT MANAGEMENT		
OPERATIONS		

REVISIONS						
4						
3						
2						
1						
REV	DATE	BY	CHECKED	DESCRIPTION	REVISION APPROVAL	DATE

DRAWN BY:	R. PRATT	OCT/16
DESIGNED BY:	J. McINTOSH	OCT/16
CHECKED BY:	J. McINTOSH	NOV/16

APPROVALS: ELECTRICAL | CIVIL | MANAGEMENT

FORTIS BC

DIVISION	KOOTENAY
DEPARTMENT	PROTECTION-CONTROL
LOCATION	GRAND FORKS TERMINAL
TITLE	T2 ADDN. - CPCN ALT. B - 6A

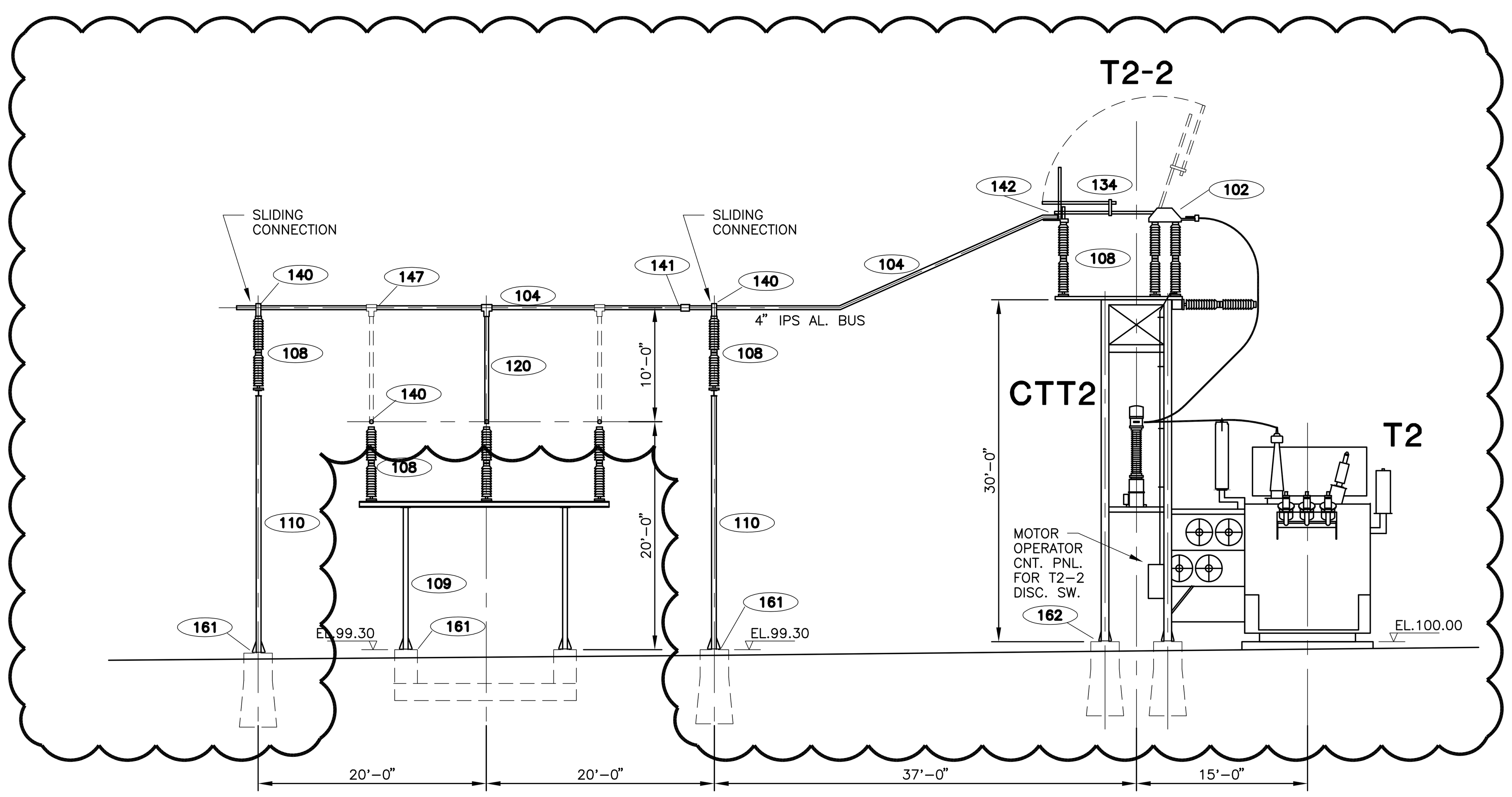
SCALE: NONE SCALE FACTOR: 200

DRAWING NUMBER: 3-275-8102

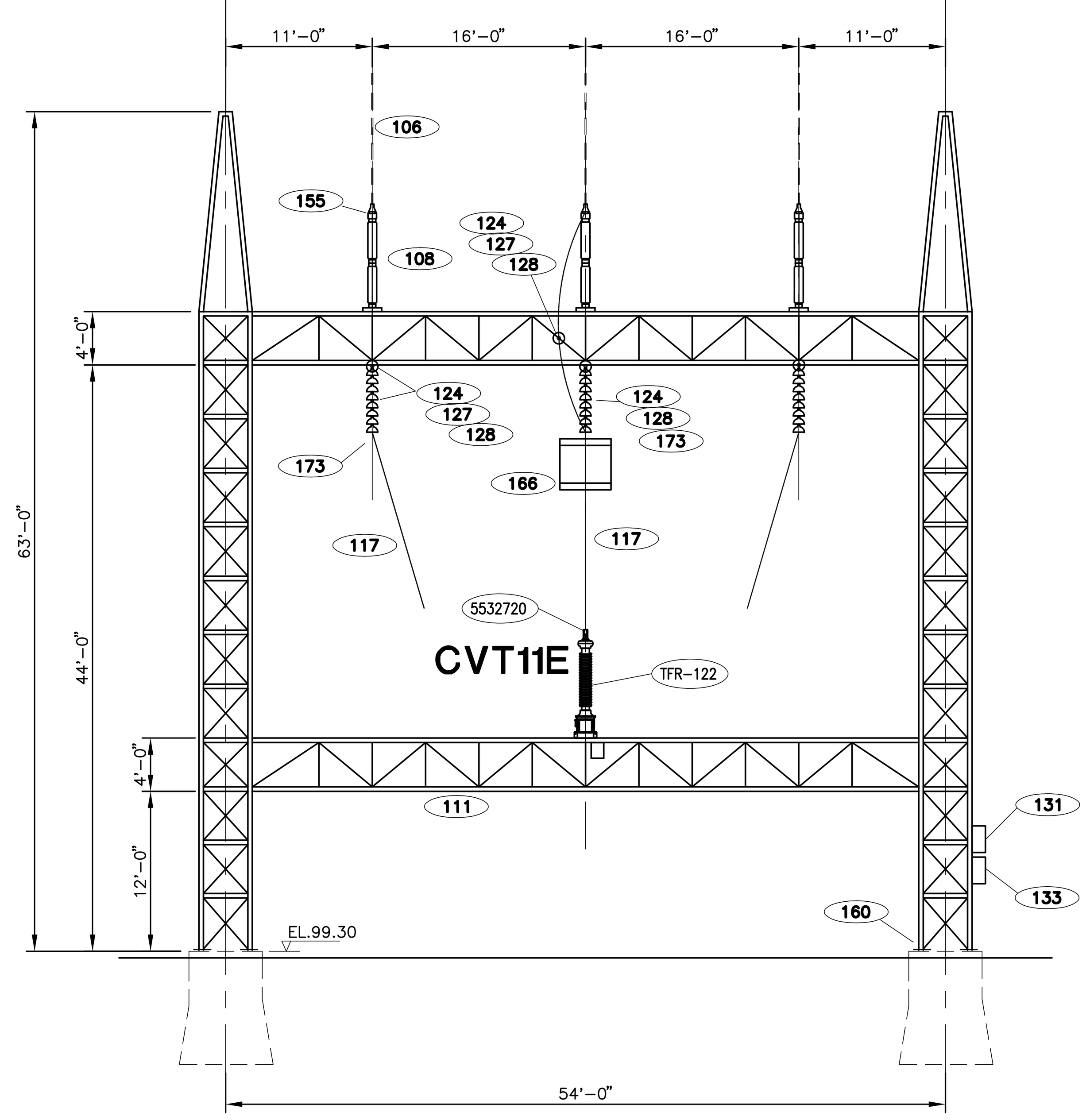
REVISION: P0

SECTION A
SCALE: 1"=10'-0"
8102

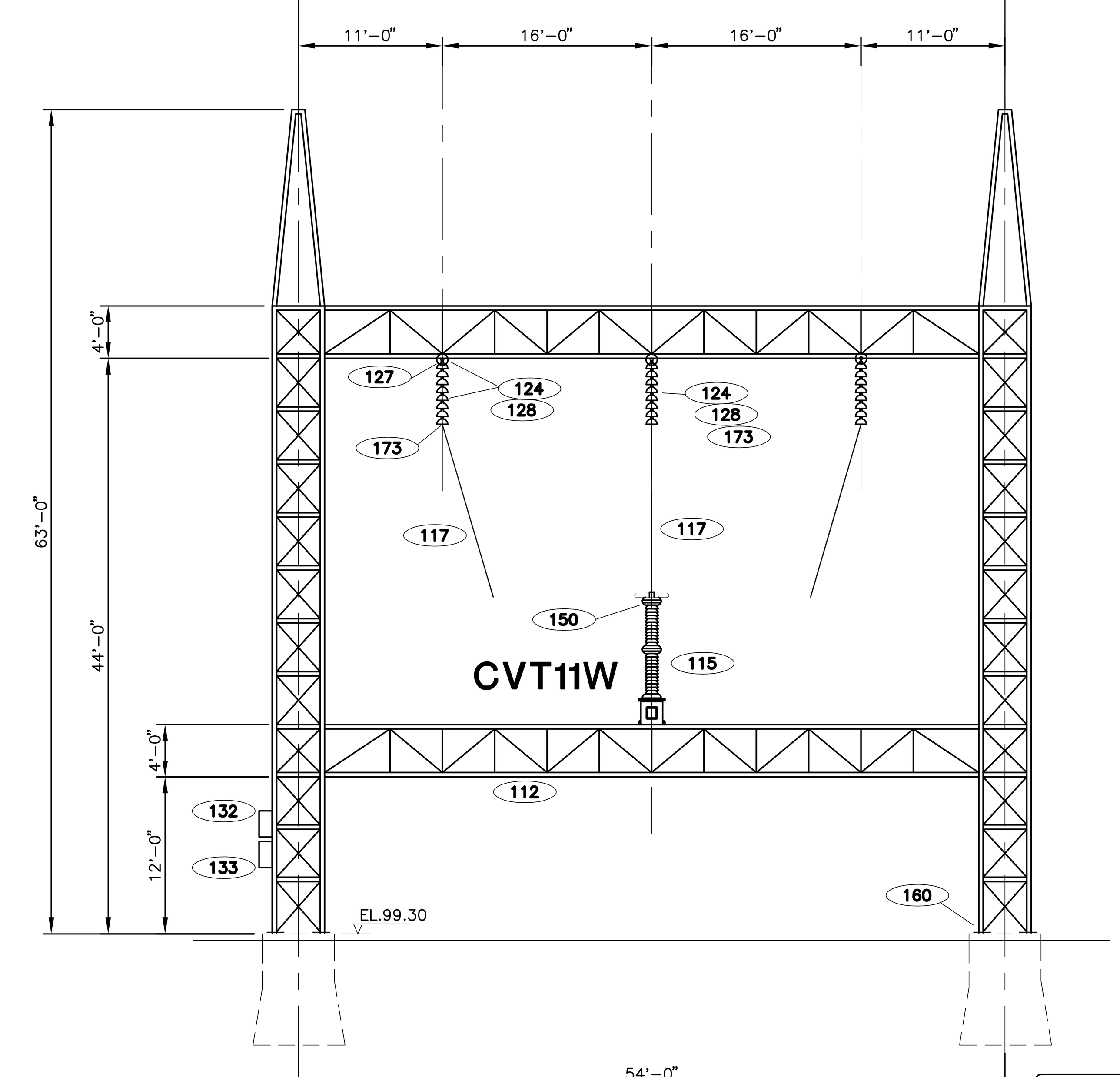
NOTE:
HIGH VOLTAGE BUS AND EQUIPMENT BUILT TO 230kV EXCEPT FOR EXISTING DISCONNECT LIVE PARTS AND BASES (ITEMS 102 & 105), LINE COUPLING CAPACITIVE VOLTAGE TRANSFORMERS (ITEMS 113 & 115), WAVE TRAPS (ITEMS 114 & 116).



SECTION B
SCALE: 1"=10'-0"
8102



SECTION C
SCALE: 1"=10'-0"
8102



SECTION D
SCALE: 1"=10'-0"
8102

CLASS 3 – APPROVAL	NAME (PRINT/SIGNATURE)	DATE
SYSTEM PLANNING		
ENGINEERING		
PROJECT MANAGEMENT		
OPERATIONS		

REVISIONS	DATE	BY	CHECKED	DESCRIPTION	REVISION APPROVAL	DATE
4						
3						
2						
1						
REV	DATE	BY	CHECKED	DESCRIPTION	REVISION APPROVAL	DATE

DRAWN BY: R. PRATT	OCT/16	
DESIGNED BY: J. McINTOSH	OCT/16	
CHECKED BY: J. McINTOSH	NOV/16	
APPROVALS: ELECTRICAL	CIVIL	MANAGEMENT

FORTIS BC

DIVISION	OKANAGAN
DEPARTMENT	TRANSMISSION-DISTRIBUTION
LOCATION	GRAND FORKS TERMINAL
TITLE	T2 ADDN. - CPCN ALT. B - 230kV SECTIONS

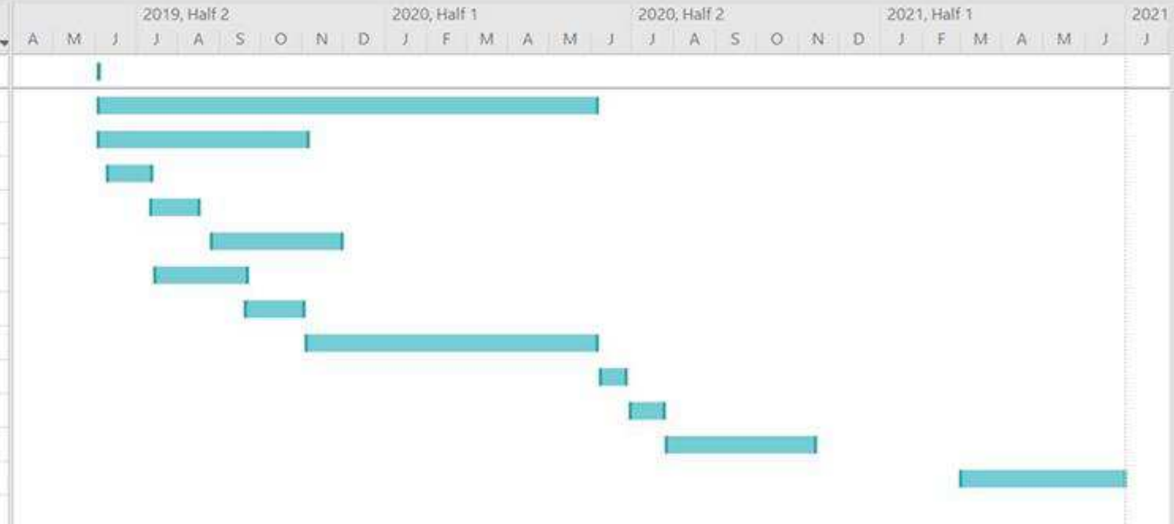
SCALE: 1" = 10'-0" SCALE FACTOR: 120

DRAWING NUMBER	REVISION
3-275-8152	P0

Appendix G

PROJECT SCHEDULE

Task Mode	Task Name	Duration	Start	Finish
	BCUC approval	1 day	Mon 19-06-03	Mon 19-06-03
	Transformer procurement	265 days	Mon 19-06-03	Fri 20-06-05
	Breaker/CT procurement	111 days	Mon 19-06-03	Mon 19-11-04
	Civil design	25 days	Mon 19-06-10	Fri 19-07-12
	Civil tender	26 days	Fri 19-07-12	Fri 19-08-16
	Civil construction	70 days	Mon 19-08-26	Fri 19-11-29
	Electrical design	50 days	Mon 19-07-15	Fri 19-09-20
	Electrical tender	31 days	Fri 19-09-20	Fri 19-11-01
	Electrical construction	155 days	Mon 19-11-04	Fri 20-06-05
	Transformer install	15 days	Mon 20-06-08	Fri 20-06-26
	Commissioning/Handovers	19 days	Tue 20-06-30	Fri 20-07-24
	10L removal	80 days	Mon 20-07-27	Fri 20-11-13
	9L removal	88 days	Mon 21-03-01	Wed 21-06-30



Appendix H

DETAILED STATION UPGRADE ESTIMATE

FILED CONFIDENTIALLY

Appendix I

ALTERNATIVE B CAPITAL COST SUMMARY

FILED CONFIDENTIALLY

Appendix J

FINANCIAL SCHEDULES

FILED CONFIDENTIALLY

Appendix K

CONFIDENTIAL DECLARATION AND UNDERTAKING FORM

Confidentiality Declaration and Undertaking Form

In accordance with the British Columbia Utilities Commission' (BCUC) Rules of Practice and Procedure, please provide a completed form to the party who filed the confidential document and copy Commission Secretary at commission.secretary@bcuc.com. If email is unavailable, please mail the form to the address above.

Undertaking

I, __[name]____, am representing the party ______________________________________ in the matter of __FortisBC Inc. Application for a Certificate of Public Convenience and Necessity for the Grand Forks Terminal Station Reliability Project ~ Project No. [xx].______

In this capacity, I request access to the confidential information in the record of this proceeding. I understand that the execution of this undertaking is a condition of an Order of the Commission, and the Commission may enforce this Undertaking pursuant to the provisions of the *Administrative Tribunal Act*.

Description of document:	Confidential materials filed in the proceeding, in unredacted form.

I hereby undertake:

(a) to use the information disclosed under the conditions of the Undertaking exclusively for duties performed in respect of this proceeding;

(b) not to divulge information disclosed under the conditions of this Undertaking except to a person granted access to such information or to staff of the Commission;

(c) not to reproduce, in any manner, information disclosed under the conditions of this Undertaking except for purposes of the proceeding;

(d) to keep confidential and to protect the information disclosed under the conditions of this Undertaking;

(e) to return to the applicant, _FortisBC Inc._, all documents and materials containing information disclosed under the conditions of this Undertaking, including notes and memoranda based on such information, or to destroy such documents and materials within fourteen (14) days of the Commission's final decision in the proceeding; and

(f) to report promptly to the BCUC any violation of this Undertaking.

Signed at ___[place]____ this _[day] day of [month] 2018___.

Signature: ________________________________

Name (please print): ___[Name]_______

Representing (if applicable): ________________________________

Appendix L

DRAFT ORDERS

bcuc
British Columbia
Utilities Commission

Suite 410, 900 Howe Street
Vancouver, BC Canada V6Z 2N3
bcuc.com

P: 604.660.4700
TF: 1.800.663.1385
F: 604.660.1102

ORDER NUMBER
G-xx-xx

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

FortisBC Inc.
Application for a Certificate of Public Convenience and Necessity for the
Grand Forks Terminal Station Reliability Project

BEFORE:
[Panel Chair]
Commissioner
Commissioner

on Date

ORDER

WHEREAS:

A. On [DATE], FortisBC Inc. (FBC) submitted an Application for a Certificate of Public Convenience and Necessity (CPCN) to the British Columbia Utilities Commission (BCUC) pursuant to section(s) 45 and 46 of the *Utilities Commission Act* (UCA) for the Grand Forks Terminal (GFT) Station Reliability Project (Project or Application);

B. In the Application, FBC seeks approval to:

  1. install a second transformer at GFT Station by purchasing a new 161/63kV transformer; and

  2. Remove 44.6 km of the transmission lines 9 Line (9L) and 10 Line (10L) from Christina Lake substation to Cascade substation, and repurpose the remaining 20.8 km of transmission lines 9L and 10L to distribution lines to continue to supply power to customers;

C. The estimated total cost of the Project in as-spent dollars is $13.171 million, which includes Allowance for Funds Used During Construction and the cost of removal of the transmission lines 9L and 10L;

D. The in service date for the new transformer service is expected to be during the third quarter of 2020, with the 9L/10L removal and repurposing work scheduled for completion by the third quarter of 2021;

E. FBC also requests that detailed information relating to equipment risk assessments and Project cost estimates for material and construction work be treated as confidential to maintain FBC's ability to negotiate contracts for the construction of the Project and to maintain the safety of its workers and the public;

F. The BCUC has determined that a public hearing is appropriate to review the Application and that a public hearing process should be commenced, a regulatory timetable should be established and a public notice should be issued.

NOW THEREFORE the BCUC orders as follows:

1. A written hearing is established for the review of the FortisBC Inc. (FBC) Application for a Certificate of Public Convenience and Necessity (CPCN) for the Grand Forks Terminal Station Reliability Project (Project or Application). The Regulatory Timetable is set out in Appendix A to this order.

2. FBC's request for confidentiality to maintain public safety and reliability and protect FBC's business interests is granted. The Commission will hold the four appendices listed in the Application cover letter, and Information Requests and responses directly relating to those appendices, as confidential. Interveners may obtain access to this information by executing standard form undertakings of confidentiality.

3. By no later than [DATE], FBC is to publish the Public Notice, attached as Appendix B to this Order, in such local and community newspapers as to provide adequate notice to those parties who may have an interest in or be affected by the Application.

4. The Application, together with any supporting materials, will be available for inspection at the FBC Office, Suite 100, 1975 Springfield Road, Kelowna, BC V1Y 7V7. The Application and supporting materials also will be available on the FortisBC website at www.fortisbc.com and on the BCUC website at www.bcuc.com.

5. Interveners who wish to participate in the regulatory proceeding are to register with the BCUC by completing a Request to Intervene Form, available on the BCUC's website at http://www.bcuc.com/Registration-Intervener-1.aspx by the date established in the Regulatory Timetable attached as Appendix A to this order and in accordance with the BCUC's Rules of Practice and Procedure attached to Order G-1-16.

6. Participants intending to apply for Participant Assistance/Cost Award (PACA) exceeding $10,000 must file a completed PACA Budget Estimate form by [DATE]. PACA applications should be consistent with the BCUC's PACA Guidelines and Order G-97-17. Copies of the PACA Guidelines are available upon request or can be downloaded from the BCUC's website at http://www.bcuc.com.

DATED at the City of Vancouver, in the Province of British Columbia, this (XX) day of (Month Year).

BY ORDER

(X. X. last name)
Commissioner

Attachment

FortisBC Inc.
Application for a Certificate of Public Convenience and Necessity for the
Grand Forks Terminal Station Reliability Project

REGULATORY TIMETABLE

Action	Date (2018)
FBC publishes Public Notice	Week of December 10
Action	**Date (2019)**
Registration of Interveners	Thursday, January 3
Deadline for Submitting Participant Assistance/Cost Award Budgets	[DATE]
BCUC Information Request (IR) No. 1	Thursday, January 10
Intervener IR No. 1	Thursday, January 17
FBC Response to IR No. 1	Thursday, January 31
FBC Final Written Submission	Tuesday, February 12
Intervener Final Written Submissions	Tuesday, February 19
FBC Written Reply Submission	Tuesday, February 26

APPENDIX B
to Order G-xx-xx

PUBLIC NOTICE

FortisBC Inc. Application for a Certificate of Public Convenience and Necessity for the Grand Forks Terminal Station Reliability Project.

On [DATE] FortisBC Inc. filed an Application for a Certificate of Public Convenience and Necessity (CPCN) requesting approval to install a second transformer at the Grand Forks Terminal Station. The project involves purchasing a new 161/63kV transformer as described in the Application and removing and repurposing sections of the 9 Line (9L) and 10 Line (10L), two transmission lines located between Christina Lake and Cascade substations. FortisBC Inc. states that the Project is required to maintain minimum reliability standards for the Grand Forks area in the event of an outage or failure of the Grand Forks Terminal Station. The estimated total cost of the Project in as-spent dollars is $13.17 million, including Allowance for Funds Used During Construction and the cost of removing and repurposing sections of the two transmission lines.

HOW TO PARTICIPATE

There are a number of ways to participate in a matter before the BCUC:

- **Submit a letter of comment**
- **Register as an interested party**
- **Request intervener status**

For more information, or to find the forms for any of the options above, please visit our website or contact us at the information below.

http://www.bcuc.com/forms/request-to-intervene.aspx

All submissions received, including letters of comment, are placed on the public record, posted on the BCUC's website and provided to the Panel and all participants in the proceeding.

NEXT STEPS [If necessary]

1. **[Intervener registration** Persons who are directly or sufficiently affected by the BCUC's decision or have relevant information or expertise and that wish to actively participate in the proceeding can request intervener status by submitting a completed Request to Intervene Form by [date].]

2. **[Procedural conference** A procedural conference is scheduled to take place on [date], commencing at [time] in the Commission Hearing Room, Twelfth Floor, 1125 Howe Street, Vancouver, BC. At the procedural conference, the BCUC will hear from the applicant and registered interveners on [the appropriate regulatory process]. Members of the public are welcome to attend.]

GET MORE INFORMATION

All documents filed on the public record are available on the "Current Proceedings" page of the BCUC's website at *www.bcuc.com*.

If you would like to review the material in hard copy, or if you have any other inquiries, please contact Patrick Wruck, Commission Secretary, at the following contact information.

British Columbia Utilities Commission

Suite 410, 900 Howe Street
Vancouver, BC Canada V6Z 2N3

E: Commission.Secretary@bcuc.com

P: 604.660.4700

bcuc
British Columbia
Utilities Commission

Suite 410, 900 Howe Street
Vancouver, BC Canada V6Z 2N3
bcuc.com

P: 604.660.4700
TF: 1.800.663.1385
F: 604.660.1102

ORDER NUMBER
C-xx-xx

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

FortisBC Inc.
Application for a Certificate of Public Convenience and Necessity for the
Grand Forks Terminal Station Reliability Project

BEFORE:
[Panel Chair]
Commissioner
Commissioner

on Date

CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

WHEREAS:

A. On [DATE], FortisBC Inc. (FBC) submitted an Application for a Certificate of Public Convenience and Necessity (CPCN) to the British Columbia Utilities Commission (BCUC) pursuant to section(s) 45 and 46 of the *Utilities Commission Act* (UCA) for the Grand Forks Terminal (GFT) Station Reliability Project (Project or Application);

B. In the Application, FBC seeks approval to:

    1. install a second transformer at GFT Station by purchasing a new 161/63kV transformer; and

    2. Remove 44.6 km of the transmission lines 9 Line (9L) and 10 Line (10L) from Christina Lake substation to Cascade substation, and repurpose the remaining 20.8 km of transmission lines 9L and 10L to distribution lines to continue to supply power to customers;

C. The estimated total cost of the Project in as-spent dollars is $13.171 million, which includes Allowance for Funds Used During Construction and the cost of removal of the transmission lines 9L and 10L;

D. The in-service date for the new transformer service is expected to be during the third quarter of 2020, with the 9L and 10L removal and repurposing work scheduled for completion by the third quarter of 2021;

E. FBC also requests that detailed information relating to equipment risk assessments and Project cost estimates for material and construction work be treated as confidential to maintain FBC's ability to negotiate contracts for the construction of the Project and to maintain the safety of its workers and the public;

F. On [Date], the BCUC issued Order G-##-##, granting FBC's request for confidentiality and establishing a written hearing process for the review of the Application;

G. The BCUC has considered the evidence and submissions and find the Grand Forks Terminal Station Reliability Project is in the public interest.

NOW THEREFORE pursuant to section 45 and 46 of the *Utilities Commission Act*, the British Columbia Utilities Commission orders as follows:

1. Pursuant to sections 45 and 46 of the Utilities Commission Act, a Certificate of Public Convenience and Necessity is granted to FortisBC Inc. (FBC) to design, construct and operate the Grand Forks Terminal Station Reliability Project.

2. FBC is directed to file with the BCUC the following reports:

    - Within 30 days of the end of each quarterly reporting period, and ending upon the filing of the Final Report, Quarterly Progress Reports; and

    - Within six months of the final in-service date, a Final Report.

3. The BCUC will hold the four appendices listed in the Application cover letter, and Information Requests and responses directly relating to those appendices, as confidential.

DATED at the City of Vancouver, in the Province of British Columbia, this (XX) day of (Month Year).

BY ORDER

(X. X. last name)
Commissioner