EDTI Asset Assessment – Major Equipment
Kennedale Substation

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Contents

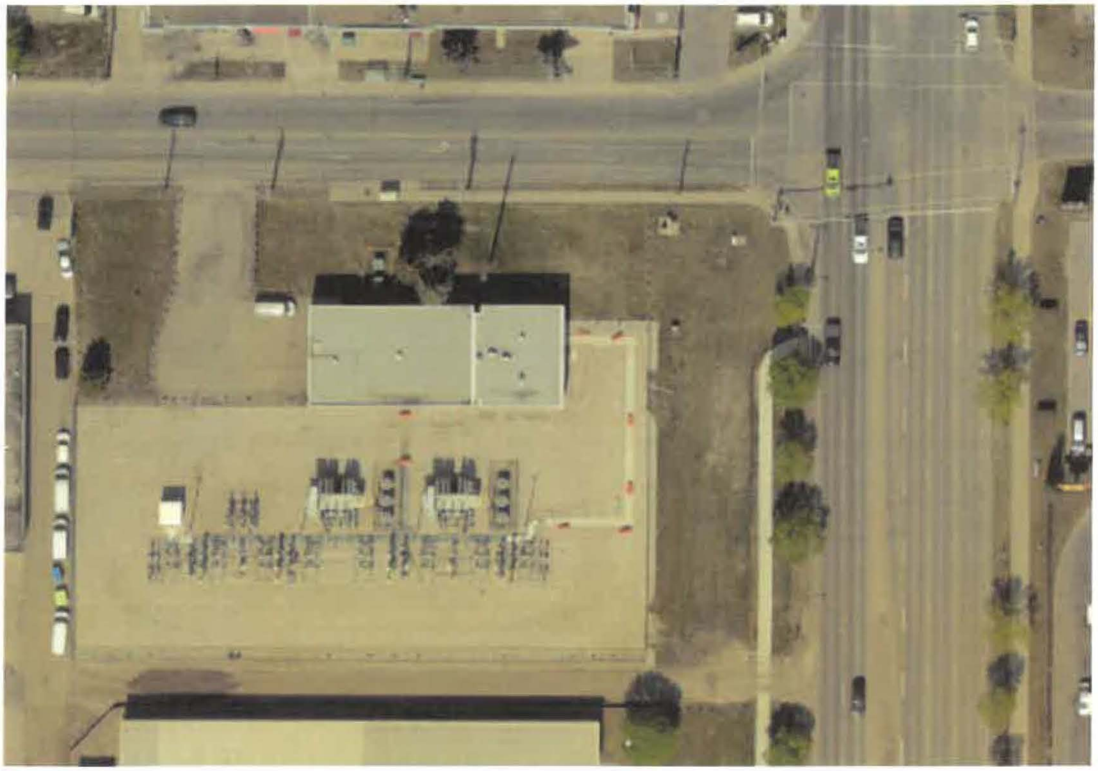
1.0 INTRODUCTION

As a TFO, EPCOR Distribution and Transmission Inc. (EDTI) is obligated under Section 39(1) of the *Electric Utilities Act* to maintain its transmission facilities in a manner that is consistent with the safe, reliable and economic operation of the interconnected electric system. EDTI has aging transmission substation infrastructure within the existing Kennedale substation that is approaching the end of its service life.

Kennedale substation was built in 1973 and has a firm capacity of 60 MVA. It is wholly owned and operated by EDTI. This substation is located in the NE area of Edmonton and supplies power to several communities such as Homesteader, Hermitage, Belmont, Clareview, Bannerman, Ebbers, Fraser and Kernohan. The substation includes the following major pieces of equipment:

(a) two (2) 72/14.4 kV transformers,
(b) four (4) 72 kV circuit breakers,
(c) associated high-voltage (HV) equipment (disconnect switches, instrument transformers),
(d) two (2) 15 kV reactors, and
(e) two (2) 15 kV medium voltage switchgear lineup (breaker and a half design), housed within a substation building.

Figure 1
Plan View of Kennedale Substation



EDTI has done well in maintaining Kennedale substation systems, keeping it in service and providing decades of reliable service. Even with EDTI's maintenance efforts, these systems have limited service life. Their condition is deteriorating with age, and the technology is becoming obsolete.

Equipment near end of life tends to experience increased failure rates and increasing cost of maintenance. EDTI is constantly measuring and assessing the condition of its assets, utilizing industry best practice and experienced personnel to mitigate negative impacts of aging infrastructure on the electrical system.

EDTI's approach to the operation and management of its transmission infrastructure is to actively monitor the condition of its assets, perform condition based maintenance, refurbish equipment, and only replace deteriorated assets when further refurbishment is no longer technically and/or economically feasible. EDTI selects those units which are deteriorating in regards to quality of service prior to actual failure. At Kennedale, there are three critical asset classes which are planned for future replacement: the two power transformers, the 15 kV switchgear, and the 72 kV breakers.

This document will summarize the technical drivers considered for the future replacement of these key assets at Kennedale Substation.

2.0 TRANSFORMERS

The average service life of a transmission power transformer for depreciation purposes is 50 years. While EDTI does not consider a specific transformer's age relative to its average service life (used for depreciation purposes) to be indicative of the need to replace the transformer, an analysis of the age of transformers in EDTI's fleet compared to the average service life can provide an approximate indication of the number of transformers expected to require replacement over different time horizons. As transformers approach the end of their useful lives, they are typically more susceptible to an increased probability of failure.

Transformer failures are infrequent events but have the potential to cause significant impacts, including environmental contamination, collateral damage to adjacent equipment, major fires, and injury to the public and EDTI personnel. Transformer failures can also result in prolonged forced outage times for customers. Substation transformers are typically the highest cost assets located in a substation, typically costing between $1 million and $6 million each, which varies with the transformer's voltage and capacity rating. Replacement transformers also take significant time to procure, with most having manufacturing and delivery times between 11-24 months

The transformers planned for replacement at Kennedale are now reaching their operational performance design limits. Condition based assessments and other indicators show they are approaching end of their useful lives. Given the state of the relevant indicators for the transformers, EDTI has determined that it is prudent to replace the transformers on a planned basis. EDTI is prioritizing the work to ensure it is prudently replacing assets at the end of their useful lives and optimizing the timing of such work to the extent practicable having regard for all relevant factors.

In the following sections, EDTI has provided details related to the power transformers proposed for replacement and key indicators relevant to the need to replace each transformer. This is summarized in Table 1 below.

Table 1
Summary of Kennedale Tx1 and Tx2 Condition

Tx	Winding Insulation Power Factor & Capacitance	Bushing Condition	Cable Box Condition	Oil Quality	Dissolved Gas Analysis	Age	Leaks
Tx1	Moderate	Acceptable	Deteriorated	Acceptable	Acceptable	Elevated	Mild
Tx2	Moderate	Acceptable	Deteriorated	Acceptable	Acceptable	Elevated	Mild

Appendix A within this document provides additional background on the technical tests EDTI considers when assessing the condition of its transformer assets.

2.1 KENNEDALE TX1

Table 2 below provides a summary of this asset, its age and conditions indicating the need for its replacement.

Table 2
Kennedale Tx1 Summary

	Asset	A Asset ID	B Age (2022)	C Asset Health Summary
1	Tx1	50MVTT6	49	- Recent DGA results show the transformer has no new indication of active or incipient faults. - A 2015 internal inspection found and repaired a suspected fault from DGA analysis. - Doble power factor and capacitance test results for overall insulation and HV bushings indicates both are in good condition. - Tapchanger is being regularly maintained, however the unit is obsolete and no longer supported by an OEM. Major failures or multiple minor failures may necessitate complete replacement, - LV cables use an obsolete design for connection to the LV bushings and are deteriorating - Minor oil weeping/sweating from various connections on the transformer. No significant leaks.

Table 3 summarizes the IEEE recommended DGA individual gas upper limits for normal condition (Condition 1) and also indicates the DGA values recorded from test samples taken in 2014 through 2022 from Kennedale Tx1.

Table 3
Kennedale Tx1 DGA Results and
IEEE C57.104 Guidelines for Gas Levels in Transformers
Parts per million (ppm)

	Dissolved Gas in Oil	A	B	C	D	E	F	G	H	I	J
		Condition 1 (<)	2014	2015	2016	2017	2018	2019	2020	2021	2022
1	H2 (Hydrogen)	100	1	**162!***	1	3	8	4	7	1	2
2	C2H2 (Acetylene)	1	0.2	**23!***	0.2	0.7	1	1	0	0	0
3	CH4 (Methane)	120	2	**294!***	2	2.9	2	3	2	3	2
4	C2H4 (Ethylene)	50	13.9	**460!***	6	18	19	18	19	19	15
5	C2H6 (Ethane)	65	1.1	**58!**	0.6	1.1	1	1	1	1	1
6	CO (Carbon Monoxide)	350	143	**205!**	89	245	294	181	130	262!	182
7	CO2 (Carbon Dioxide)	2500	960	1480	430	1158	1192	810	1018	1160	1083
8	TCG [1]	720	161.2	**1172!***	98.8	270.7	325	208	159	286	202

Symbol legend: *: abnormal level, !: sharp jump

[1] Total Combustible Gases includes all gases that can burn if mixed with air in the right concentration. In the context of DGA analysis, the combustible gases are hydrogen, methane, ethane, ethylene, acetylene and carbon monoxide.

Findings for Kennedale Tx1 based on the history of DGA analysis include:

- The unit has been sampled annually, in line with current EDTI maintenance practices. The history of gas analysis up to and including 2014 indicated no signs of fault gasses in the oil.
- In 2015, a significant spike in hot metal and arcing gasses appeared, prompting an immediate internal inspection by EDTI. The inspection found signs of arcing on the support structure of the load tapchanger (LTC) reactor (Figure 2), as well as signs of overheating on the core top yoke center joint and on one of the core tie rods (Figure 3). A copper strap was added to bond the LTC reactor support and the core tie rods were tightened. Gas levels returned to normal after the repairs.
- The signs of overheating on the core top yoke center joint were relatively minor and unable to be economically addressed during the internal repair work. This may be the source of the lingering low-level Ethylene concentrations.
- Post repair oil samples indicate the transformer has a stable gas profile with overall low and acceptable concentrations of all fault gases. This indicates the major sources of the fault gases were adequately repaired and the equipment has no indication of active or incipient faults.

Figure 2
Kennedale Tx1 - Carbon build up and signs of arcing on reactor support

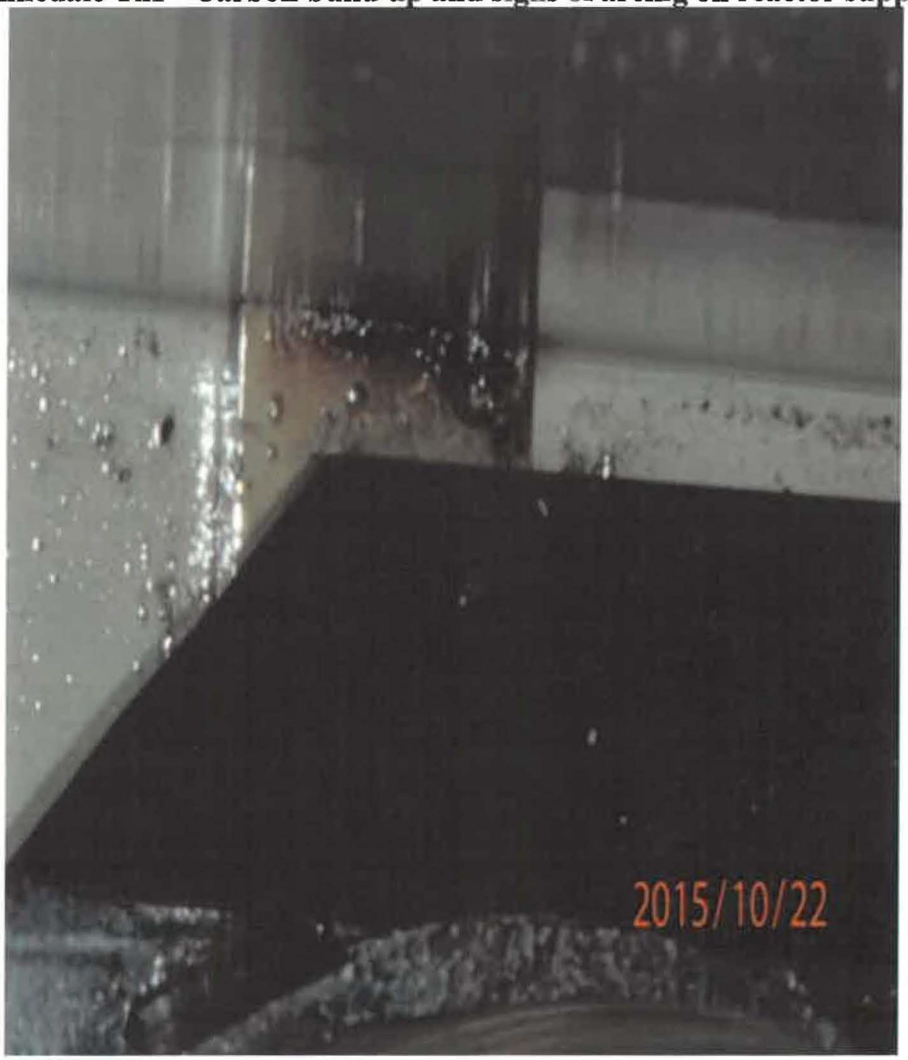


Figure 3
Kennedale Tx1 - Signs of overheating on the core top yoke (top) and tie plate (bottom)

Table 4 summarizes the overall power factor and capacitance (Doble) test results from Kennedale Tx1 for the test periods from 2005 to 2022. Table 5 summarizes the bushing Doble test results from 2007 to 2022.

The insulation systems being tested are summarized as follows

- CH: Insulation between the high voltage winding and ground
- CL: Insulation between the low voltage winding and ground
- CHL: Insulation between the high voltage winding and the low voltage winding
- C1: Bushing insulation between the center conductor and the last capacitive layer
- C2: Bushing insulation between the last capacitive layer and ground

Table 4
Kennedale Tx1 Overall Insulation Doble Test Results

Insulation System	Measurement	Test Year				
		2005	2007	2012	2017	2022
CH+CHL	Power Factor (%)	0.297	0.280	0.268	0.270	0.273
	Capacitance	12953.5	13132.6	13407.1	13405.0	13403.5
CH	Power Factor (%)	0.474	0.356	0.277	0.314	0.306
	Capacitance	5487.7	5617.3	5874.8	5873.9	5872.7
CHL	Power Factor (%)	0.277	0.207	0.240	0.235	0.253
	Capacitance	7459.0	7508.8	7530.2	7526.3	7526.5
CL+CHL	Power Factor (%)	0.415	0.336	0.361	0.345	0.346
	Capacitance	17453.4	17568.2	14632.5	17605.4	17610.2
CL	Power Factor (%)	0.533	0.435	0.429	0.426	0.417
	Capacitance	9991.8	10056.1	10101.1	10075.8	10081.2

Table 5
Kennedale Tx1 Bushing Doble Test Results

Bushing	Insulation System	Measurement	Nameplate Value	Test Year			
				2007	2012	2017	2022
H1	C1	Power Factor (%)	0.25	0.220	0.240	0.243	0.235
		Capacitance	338	336.2	335.1	335.0	334.4
	C2	Power Factor (%)	NA	0.420	0.380	0.448	0.366
		Capacitance	NA	449.2	448.1	448.1	449.3
H2	C1	Power Factor (%)	0.25	0.220	0.240	0.240	0.236
		Capacitance	340	338.8	337.4	337.8	337.0
	C2	Power Factor (%)	NA	0.410	0.360	0.377	0.333
		Capacitance	NA	435.2	436.2	434.6	434.4
H3	C1	Power Factor (%)	0.25	0.220	0.240	0.235	0.231
		Capacitance	339	337.2	335.8	336.0	335.3
	C2	Power Factor (%)	NA	0.410	0.370	0.322	0.377
		Capacitance	NA	444.7	445.0	444.1	444.0

Findings based on the history of power factor and capacitance test results include:

- Power factor of new transformers typically tests in the range of 0.2% to 0.35%, and the upper limit of insulation in good condition is 0.5%. Insulation is considered service-aged when test results are beyond 0.5% and considered critical when they're beyond 1%.
    i. Based on these limits, the power factor test results of the overall insulation, shown in Table 4, indicate that the winding insulation of Kennedale Tx1 is on the high end of what is considered to be good condition and has been moderately elevated for the majority of the transformer's life.
- The capacitance measurement of a transformer winding is an indication of the physical position and structure of the individual turns. The capacitance test results should remain relatively constant throughout the life of a transformer, any major deviation is an indication that windings or internal components have shifted relative to the winding under test.
    i. The capacitance test results of Kennedale Tx1 have been relatively consistent and there is no indication of winding movement or deformation. There is a step change in capacitance after the 2007 results, likely due to the HV bushing replacement in that year.
- Power factor and capacitance test results of a condenser-style transformer bushing should remain relatively constant throughout the service life of the bushing. Increases in power factor on a bushing can indicate the insulation is deteriorating. Similar to overall capacitance, changes to bushing capacitance may indicate a change in the structure of the capacitive layers within the bushing has occurred due to physical changes in the bushing.
    i. The original Kennedale Tx1 HV bushings were replaced with new bushings in 2007 and test results, shown in Table 5, indicate they are still in good condition.

In addition to the above assessment, the Kennedale Tx1 transformer load tapchanger (LTC) is original to the transformer and is now obsolete. There are no options for minor or major repairs as parts are not being manufactured and the original manufacturer no longer provides any support. The only source for OEM parts that are readily available is the now-removed LTC from Kennedale Tx2 which was decommissioned in 2015, discussed in further detail in Section 2.2 of this report. The only solution in the event of a failure is to retrofit the transformer with a new LTC, similar to what was installed on Kennedale Tx2, at a cost of approximately $0.5M. The duration of the Kennedale Tx2 project was approximately eight months, with an installation duration of about one month. In the event of a failure, the transformer would be out of service for this entire nine month duration as EDTI identifies a custom solution: a new tapchanger would need to be procured, manufactured, installed and tested before being able to re-energize the transformer. Extensive repairs and maintenance on older transformers are also a risk to the asset due to the age of the materials and insulation being handled throughout the work of replacing a tapchanger.

The transformer is also generally leak-free. There are points of slight weeping or sweating coming from various valves around the main tank such as the conservator shut-off valve and some of the radiator valves (Figure 4), however nothing is actively dripping or contacting the transformer pad or ground. The interface between the main tank and the tapchanger compartment also has signs of sweating along the bottom of the flange (Figure 5); this connection would be extremely expensive and labor intensive to access and repair, however at this time no action is required. In general, all noted leaks around the transformer are minor and do not require immediate attention.

Figure 4
Kennedale Tx1 - Various minor leak points

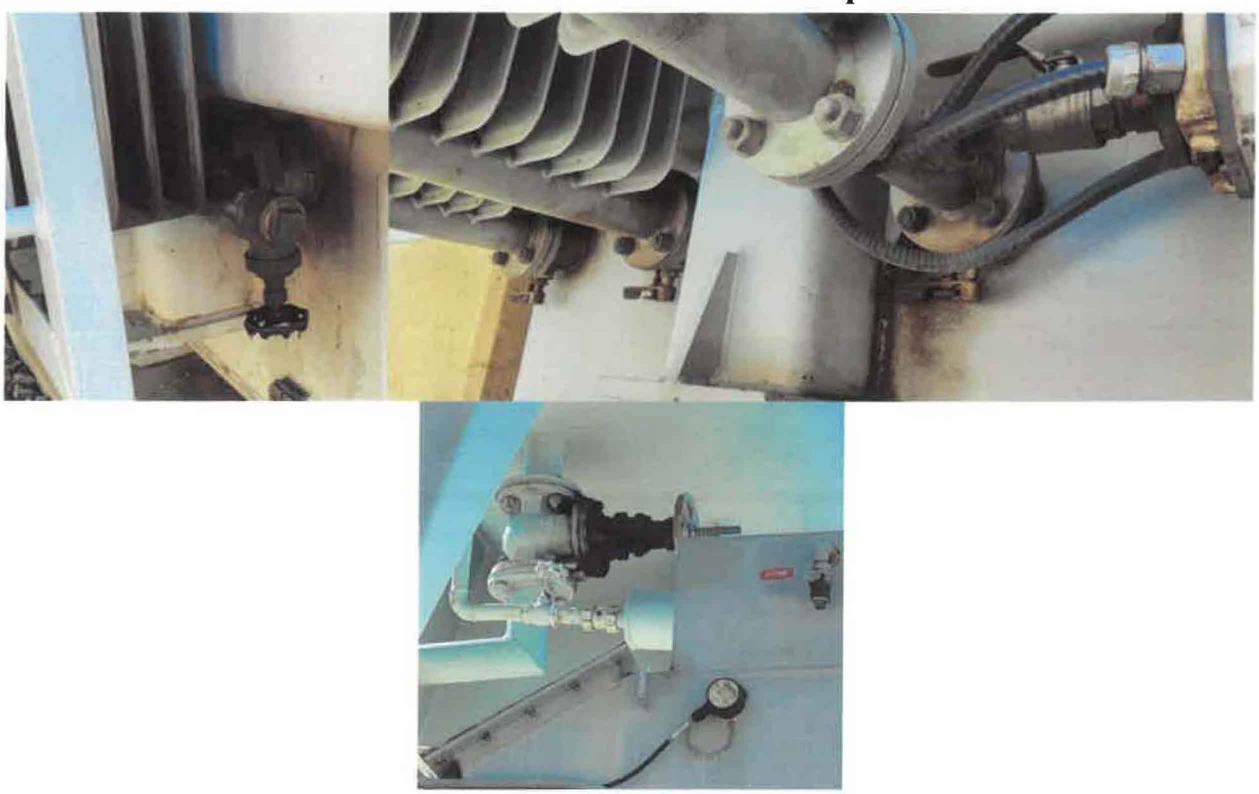


Figure 5

Kennedale Tx1 - Sweating flange between main tank and LTC compartment

Significant oil leaks can present a serious environmental hazard if the oil comes into contact with the ground. Kennedale Tx1 does not have a containment pit around the base of the transformer. In the event that any of the existing minor leaks deteriorate to major leaks, or any significant release or spill were to occur around the transformer, environmental damage could occur.

With respect to the Kennedale site, simply installing an oil containment system around the transformer is not a prudent course of action to address leak management. Oil containment systems installed within brownfield substations is a complex, costly task, given all of the existing infrastructure to work around and potential redesign required with unknown subsurface conditions. In addition, this containment would need to be redesigned and rebuilt when the transformers are eventually replaced to match the volume of oil present in the new units.

Finally, the low voltage cable connections on Kennedale Tx1 are showing signs of deterioration. The connection style is obsolete by modern practice, using small potheads[1] to enter the LV air box before connecting to bus bar and the LV bushings. Figure 6 shows the current state of the connections, with the compound in the connection nearest to the camera having already deteriorated, resulting in a gap in the insulation forming between the cable and the pothead on the cabinet. Further degradation of the connection will require the cable to be replaced. This would be a significant undertaking, requiring long outages to remove the existing cable, pull in new cable, and terminate this cable at the transformer and switchgear ends before testing and re-energizing the transformer.

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[1] A "pothead" is a cable termination. Cable terminations make physical and electrical connections between the cable and the terminal of the equipment.

Figure 6
Kennedale Tx1 - MV cables

2.2 KENNEDALE TX2

Table 6 below provides a summary of this asset, its age and conditions indicating the need for its replacement.

Table 6
Kennedale Tx2 Summary

	Asset	A Asset ID	B Age (2022)	C Asset Health Summary
1	Tx2	50MVTT7	49	- Recent DGA results show the transformer has no new indication of active or incipient faults. - Doble power factor and capacitance test results for overall insulation and HV bushings indicates both are in generally good condition. - Original tapchanger was replaced in 2015 with a vacuum type tapchanger and is in good condition - LV cables use an obsolete design for connection to the LV bushings and are deteriorating - Main tank oil PCB concentration between 2-3mg/kg - Minor oil weeping/sweating from various connections on the transformer. No significant leaks.

Table 7 summarizes the IEEE recommended DGA individual gas upper limits for normal condition (Condition 1) and also indicates the DGA values recorded from test samples taken in 2014 through 2022 from Kennedale Tx2.

Table 7
Kennedale Tx2 DGA Results and
IEEE C57.104 Guidelines for Gas Levels in Transformers
Parts per million (ppm)

Dissolved Gas in Oil		A	B	C	D	E	F	G	H	I	J
		Condition 1 (<)	2014	2015	2016	2017	2018	2019	2020	2021	2022
1	H2 (Hydrogen)	100	4	6	5	11	10	4	6	3	3
2	C2H2 (Acetylene)	1	0.2	**1.1***	**6.2!***	0	0	0	0	0	0
3	CH4 (Methane)	120	5	6	9	5.5	5	6	4	7	5
4	C2H4 (Ethylene)	50	23.9	34.3	32.4	33.2	32	30	31	30	36
5	C2H6 (Ethane)	65	2.4	2.5	3	2.9	3	3	3	3	3
6	CO (Carbon Monoxide)	350	268	**330!**	127	**306!**	**417!***	223	218	**318!**	264
7	CO2 (Carbon Dioxide)	2500	1220	1280	440	1292	1389	932	1380	1362	1520
8	TCG [1]	720	303.5	377.9	182.6	358.6	467	266	262	361	311

Symbol legend: *: abnormal level, !: sharp jump

[1] Total Combustible Gases includes all gases that can burn if mixed with air in the right concentration. In the context of DGA analysis, the combustible gases are hydrogen, methane, ethane, ethylene, acetylene and carbon monoxide.

Findings for Kennedale Tx2 based on the history of DGA analysis include:

- The long term gas profile of Kennedale Tx2 has been relatively consistent, with stable, low gas concentrations that are low.
- The onset of Acetylene in 2015 and 2016 was noted, however gas concentrations returned to normal levels without intervention. EDTI believes a transient event was the root cause and no permanent negative conditions exist in the transformer.

Table 8 summarizes the overall power factor and capacitance (Doble) test results from Kennedale Tx2 for the test periods from 2005 to 2022. Table 9 summarizes the bushing Doble test results from 2007 to 2022.

Table 8

Kennedale Tx2 Overall Insulation Doble Test Results

Insulation System	Measurement	Test Year				
		2001	2004	2009	2015	2019
CH+CHL	Power Factor (%)	NA	NA	0.353	0.306	0.306
	Capacitance	13172.0	13192.9	13541.0	13370.3	13324.7
CH	Power Factor (%)	0.309	0.319	0.105	0.284	0.338
	Capacitance	5466.0	5470.9	5382.1	5657.5	5638.4
CHL	Power Factor (%)	0.299	0.299	0.516	0.323	0.288
	Capacitance	7704.0	7719.4	8158.9	7712.8	7682.0
CL+CHL	Power Factor (%)	NA	NA	0.348	0.395	0.39
	Capacitance	17498.0	17429.9	16534.0	17399.5	17322.8
CL	Power Factor (%)	0.438	0.428	0.472	0.453	0.470
	Capacitance	9792.0	9708.8	9442.9	9689.4	9638.5

Table 9

Kennedale Tx2 Bushing Doble Test Results

Bushing	Insulation System	Measurement	Nameplate Value	Test Year			
				2004	2009	2015	2019
H1	C1	Power Factor (%)	0.26	0.231	0.223	0.226	0.213
		Capacitance	335	332.4	332.7	331.2	332.2
	C2	Power Factor (%)	NA	0.250	0.341	0.461	0.414
		Capacitance	NA	452.9	451.2	459.6	452.1
H2	C1	Power Factor (%)	0.26	0.236	0.236	0.236	0.236
		Capacitance	351	349.0	349.1	347.1	348.5
	C2	Power Factor (%)	NA	0.220	0.314	0.369	0.395
		Capacitance	NA	415.3	414.0	423.8	415.2
H3	C1	Power Factor (%)	0.26	0.231	0.231	0.237	0.233
		Capacitance	346	343.9	344.0	342.3	343.2
	C2	Power Factor (%)	NA	0.260	0.328	0.332	0.449
		Capacitance	NA	432.8	429.3	441.3	429.5

Findings based on the history of power factor and capacitance test results include:

- The power factor test results of the overall insulation indicates it is generally still in good condition. The CL power factor results, indicating the condition of the low voltage winding, are near the 0.5% upper limit and this winding has historically been above 0.4% for the majority of the transformer's life.
- The capacitance test results of Kennedale Tx2 have been relatively consistent and there is no indication of winding movement or deformation. There is a step change

between the 2004 and 2009 results, likely due to the replacement of the HV bushings in 2004.

- The original Kennedale Tx2 HV bushings were replaced with new bushings in 2004 and test results indicate they are still in good condition.

Kennedale Tx2 is also generally leak-free. There are signs of minor sweating from various valves around the main tank, radiators, and the conservator tank (Figure 7). None of the leaks are actively dripping, and there are no signs of oil coming into contact with the ground at this time.

Figure 7
Kennedale Tx2 - Minor sweating from valves

Kennedale Tx2 main tank oil volume also has concentrations of Polychlorinated Biphenyls (PCB's), confirmed by oil test results shown in Table 10. Under the current legislation from Environment Canada, transformers with known PCB concentrations less than 50ppm can continue to operate under special conditions:

- A spill of oil with greater than 1g of PCB from an in-service asset is considered a PCB spill and is a reportable event to Environment Canada
- If the oil is removed from the transformer (i.e. for maintenance or internal inspection) then that oil cannot be put back into the transformer

- The oil must be handled and disposed of properly by trained, qualified personnel

PCB concentrations at this level, alone, are not a driver for replacement of the transformer. However, any maintenance or repair activities that involve exposing personnel to the oil, oil handling, or oil removal, present a greater risk to personnel and the environment, while simultaneously increasing the cost and complexity of the repairs and maintenance.

Table 10
Kennedale Tx2 main tank oil PCB analysis

Lab Report Number	6773-1	5029322	5006329	E00-38115-01	
Sample date	2015-09-11	2009-08-20	2004-06-29	2000-08-08	
Sample temp	23	22	36		°C
Total PCB	2.4	2.9	4.4	8.0	mg/kg

Significant oil leaks can present a serious environmental hazard if the oil comes into contact with the ground. Kennedale Tx2 does not have a containment pit around the base of the transformer. In the event that any of the existing minor leaks deteriorate to major leaks, or any significant release or spill were to occur around the transformer, environmental damage could occur. Installing oil containment retroactively on Kennedale Tx2 is not feasible for the same reasons discussed above.

In addition to the above, the LV cables utilize the same obsolete design for connection to the LV bushings as Kennedale Tx1. One of the connections on a Tx2 LV cable has already failed to the point of needing replacement and necessitated a completely new cable to be pulled through the ducts with a new cable termination, shown in Figure 8. Replacing the remaining 11 cables would be a cost and labor intensive project with a prolonged outage on the transformer.

Figure 8
Kennedale Tx2 - Failed secondary cable connection and the retrofit solution

EDTI forecasts that the Kennedale transformers will be due for life cycle replacement in the 2027 to 2028 timeframe. The overall timelines associated with longer transformer procurement times has caused a shift in the forecasted replacement years than what was anticipated previously.

2.3 Kennedale Dry Type Reactors

Kennedale Tx1 and Tx2 each have a bank of dry type reactors connected in series to the low voltage terminals, seen in Figure 9. These dry type reactors are original to the substation, manufactured in 1973 and aged 49 years as of 2022. The manufacturer expected lifespan of a dry type reactor is 25 years at rated current. Due to the limitations of design accuracy in the era, these reactors were manufactured, inherent to the use of hand calculations rather than computer models such as those used in present-day design, design margins were considerably larger than they are currently, and seeing dry type reactors of this era exceed the expected lifespan is not uncommon. Despite this, the recommended lifespan from the manufacturer remains at 25 years, regardless of the year of manufacture.

Figure 9
Kennedale Tx1 (Top) and Tx2 (Bottom) Dry Type Reactors

The design and installation of dry type reactors is such that their condition cannot be assessed by electrical tests in the field. Condition assessment of the winding insulation is limited to physical inspection for damage, fouling, or deterioration. Minor damage and deterioration can be repaired in the field to an extent, and fouling can be cleaned, if routine inspections detect the deficiency soon enough. Thorough inspection of the reactors while energized is extremely difficult since the interior-facing surface of the reactor windings cannot be seen from the outside, and the exterior-facing surface is obscured by the safety fence which also limits the approach distance to the reactors. Taking routine outages for thorough inspection is not feasible due to resource requirements and the significant burden placed on the system for outage coordination of all the dry type reactors in service at Kennedale and other substations.

The severity of a reactor failure is heightened due to the proximity to the transformers, and the lack of protection offered by the fence. Increasing protection around the reactors would make any inspection completely impossible and would significantly increase the risk of a deteriorating condition going unnoticed by routing inspection.

Given the reasons discussed above such as the age of the reactors, the lack of ability to test the winding insulation condition, the difficulties to properly inspect the reactors while energized, and the consequences of a catastrophic failure, EDTI believes it would be prudent to replace the dry type reactors at the same time as the transformers.

3.0 MEDIUM VOLTAGE SWITCHGEAR

EDTI's 15 kV Medium Voltage (MV) Switchgear at Kennedale substation is comprised of the following equipment: electrical buses, cable terminations, disconnects, fuses, protective relays and circuit breakers used to isolate electrical equipment. Switchgear is used to de-energize equipment so that it can be worked on and to clear faults downstream.

The design life of 15 kV switchgear is typically between 40 and 50 years, based on industry experience and consensus.

As switchgear and its associated components approach the end of their useful lives, they are more susceptible to an increasing probability of failure. Catastrophic failures are infrequent events but have the potential to cause significant impacts, including environmental contamination, collateral damage to adjacent equipment, major fires, and injury to EDTI personnel. Switchgear failures can also result in prolonged forced outage times for customers.

EDTI has identified various issues associated with the 15 kV MV Switchgear at the Kennedale substation. These issues necessitate the replacement of the 15 kV MV Switchgear at Kennedale:

- The age and design of the circuit breakers;
- The condition of the circuit breakers;
- The condition and design of the cables and terminations; and

- Operational and safety concerns.

3.1.1 Circuit Breaker Design Issues

The MV circuit breakers in operation at Kennedale are the ABB ITE-15HK-500 air magnetic, at various vintages from 1973-1978.

EDTI has identified several issues associated with the design of these circuit breakers which increases the likelihood that they will fail:

- The arc chutes absorb moisture, and are prone to carbon buildup which reduces the interrupting capability of the circuit breaker;
- The puffer mechanism can allow arcing to create a parallel path to the blow-out coils;
- The contact pressure is lost over time due to the springs losing tension due to heating, which results in the contacts vibrating and welding;
- The breaker mechanism is gumming-up due to lack of operation and lubrication and the mechanism design has high mechanical forces which accelerate the wearing of parts;
- The auxiliary contacts become loose over time and misalign; and
- The contact clusters become loose over time due to the spring losing its tension.

3.1.2 Circuit Breaker Condition Issues

Condition analysis has identified the following concerns with regard to the Kennedale MV circuit breakers:

- The switchgear line-up has suffered a past violent failure. This failure was caused by a pothead termination failing inside of cell K42 in 2007. During this failure, damage was sustained by the rear panel of the cell, but the switchgear bus was largely unaffected.
- Racking out of the pioneer Electric circuit breakers puts the operators at risk if the circuit breaker accidently does not trip due to interlock failure;

The conclusion of the circuit breaker condition assessment is that either a total overhaul or replacement is required in order to maintain safe and reliable operation.

3.1.3 PILC Cable Terminations Condition and Design Issues

EDTI has identified the following issues associated with the Paper Insulated Lead Covered ("PILC") cable terminations at Kennedale:

- System Sustainability and Equipment Assessment Study ("SEAS"), which EDTI completed with its consultant Quanta Technologies, LLC ("Quanta") in 2013, identified that the design life of fluid filled cables is 40-45 years. Kennedale switchgear has PILC cable terminations which are approximately 50 years old and are past their design lives and therefore need to be replaced.
- At EDTI's Kennedale substation the distribution cables, including PILC cables, are installed in a vertical position prior to entering the switchgear and pressure differences in this orientation can cause oil to drain from the top of a cable to the bottom, causing the cable to swell due to the increased oil volume. This, in turn, can lead to leaks in the lead exterior and cable failures. EDTI has experienced such leaks and failures in PILC cables elsewhere in the electrical system as shown in Figures 10 and 11, below. EDTI has been able to address some leaking equipment by replacing the gaskets and by tightening bolts, however, these are temporary fixes as heat cycling causes the leaks to reappear a short time later (i.e. within a few months). Further, the equipment is at risk of failure due to oil starvation. If the gaskets have been replaced, the bolts have been tightened and the cable leaks again, the only viable solution is to replace the PILC cable. The replacement of PILC cables with XLPE cables, which do not use oil, will avoid similar issues from arising in the future.

Figure 10
Leaking Switchgear Cable (outside of cell)

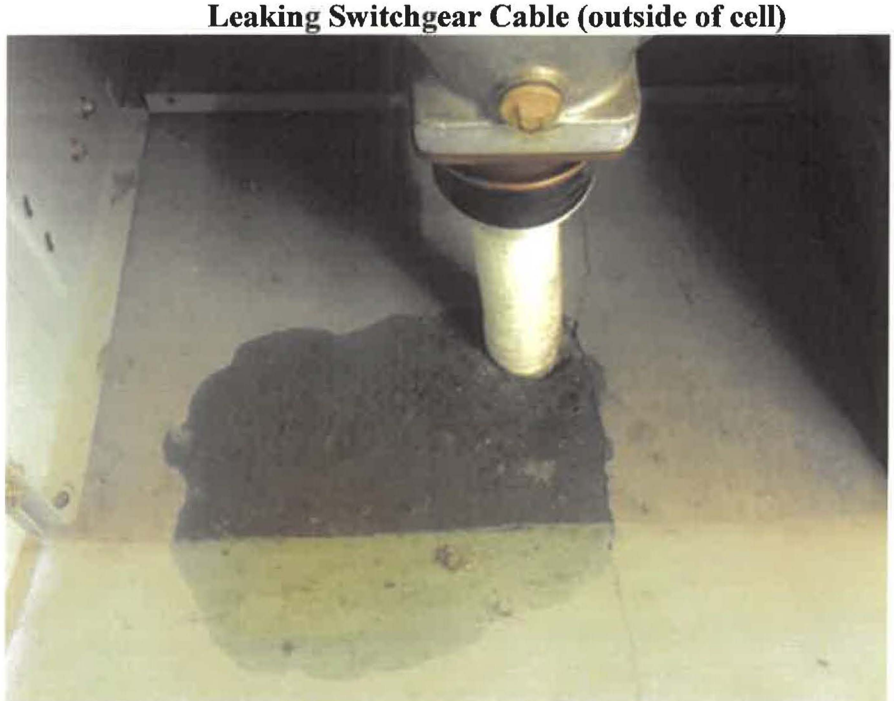


Figure 11
Leaking PILC Cables

- The cable terminations at Kennedale are filled with a petroleum based compound which is used as insulation. Due to poor sealing and cracks in the cable and pothead, EDTI has experienced failures as the petroleum based compound has leaked out of the cable (see Figure 12 below from Kennedale). In addition, this compound can dry up if it penetrates into the paper insulation and into the conductor. Without adequate insulation it is likely that the cable will fail (as experienced by EDTI and shown in Figure 13 from Kennedale). As XLPE cables use cross-linked polyethylene as insulation, the risk of cable failure due to an inadequate amount of insulation is reduced. Further, repairing PILC cables requires specialized skills and typically costs 5 to 10 times more than repairing XLPE cables, in EDTI's experience.

Figure 12
Pothead Leaking Insulation Compound (Kennedale)

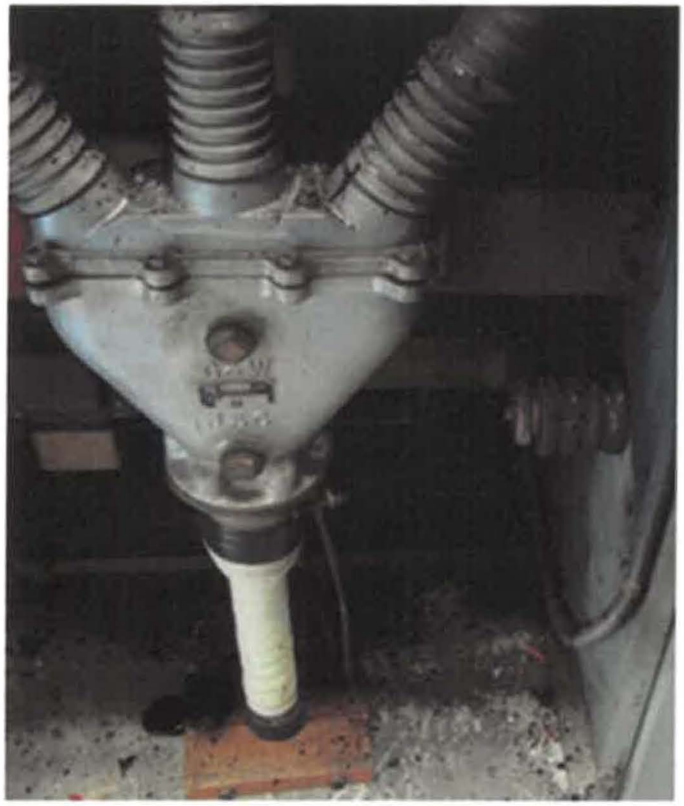


Figure 13
Failure of Pothead due to Insulation Compound Leak (Kennedale)

3.1.4 Operational & Safety Issues

EDTI has identified four safety-related issues with regard to the MV switchgear at Kennedale:

(a) The design of the existing 15kV MV Switchgear is not arc resistant;
(b) The racking of circuit breakers puts EDTI's staff at potential risk;
(c) Using test and ground devices puts EDTI's staff at potential risk; and
(d) The ABB ITE air magnetic circuit breakers in operation at EDTI's Kennedale substation contain asbestos materials.

These safety issues are further described below.

(a) Non Arc Resistant Design

The IEEE defines an arc flash hazard or an arc fault as a dangerous condition associated with the release of energy caused by an electric arc. A high arc energy fault causes a rapid rise in the temperature of the surrounding air and rapid rise in pressure inside an enclosure.

Conventional medium voltage metal-clad and metal-enclosed switchgear built to comply with EEMAC-G8-2 1972 and ANSI C37.202-1987 standards have provided safe and reliable service but are not designed and built to minimize the effects of arc faults. The probability of the occurrence of a fault on medium voltage switchgear is relatively low and, as such, a fault leading to personal injury would be rare. However, failure due to defective insulating materials, improper bus joints, incorrect protective or safety devices, human error, ingress of moisture, or abnormal service conditions cannot be ruled out.

Although the probability of the occurrence of a fault on medium voltage switchgear is relatively low, the adverse consequences of an arc flash in a non-arc-resistant switchgear are extremely high. This is due to the fact that the switchgear is not designed to withstand the energy released by the arc, and it can be partially or completely destroyed, requiring extensive and costly repairs or even replacement, and long periods of power interruptions while restoration is completed.

The switchgear installed at EDTIs Kennedale substation is conventional medium voltage metal-clad and metal-enclosed switchgear. EDTI is planning to replace this switchgear with arc-resistant medium voltage metal-clad switchgear which will minimize the impact of an arc fault if it were to occur.

(b) Racking of Circuit Breakers

In order to ensure that circuits are not live, EDTI's staff must rack (i.e., move) the circuit breakers from within their cells at its Kennedale Substation, and due to the design of this switchgear, the circuit breakers must be racked with the cell door open. If there were a breaker or switchgear malfunction while the circuit breakers were being racked, there is a risk that operators working in the vicinity could be injured. Also, the switchgear design and the wear of the cell and circuit breaker components require numerous fine adjustments during the circuit breaker insertion or extraction from the cell in order to prevent misalignment of the main or auxiliary contacts and equipment damage. This increases the time in which the cell door is open and therefore increases the safety risk to operators.

(c) Circuit Grounding

EDTI's staff must ground the circuits before they can be worked on. The insulated bus and the shutter arrangement at Kennedale make the attachment of grounding devices difficult as there is not a clear way to access suitable rated connections necessary to ground the equipment. Accordingly, Test and Ground ("T&G") devices must be used to ground the circuits. The T&G devices must be used within the switchgear cell; therefore, staff is required to work in an enclosed space, close to the load side of the breaker connection, which poses a safety risk from arc flash.

(d) Circuit Breakers Asbestos

The ABB ITE circuit breakers at Kennedale have asbestos materials in the interrupter and components (arc chutes) which could be released into the air during circuit breaker failures or maintenance. The asbestos becomes friable with age and, when disturbed, can become airborne. The airborne asbestos is a safety risk to EDTI's employees as it may cause diseases if safety procedures are not taken. New switchgear is fitted with circuit breakers that are asbestos free so that EDTI's staff are not be subjected to this safety risk.

EDTI anticipates that the switchgear will be due for life cycle replacement in the 2033 to 2036 timeframe. The complexities around the switchgear replacements currently underway at Meadowlark have caused a global shift in timelines with the implementation of switchgear replacements overall.

4.0 72KV BREAKERS

EDTI's transmission system relies on circuit breakers to disconnect transmission lines, underground transmission cables, and transformers from the interconnected electric system, thereby maintaining the operating stability of the system and reducing safety hazards for EDTI staff and the public. In addition, the proper functionality of EDTI's substation apparatus equipment is vital to EDTI's ability to comply with the Alberta Electric System Operator's ("AESO") operating requirements and Alberta Reliability Standards ("ARS").

At Kennedale, there are four 72kV, 2000A high voltage circuit breakers. Originally, air blast breakers were replaced with SF6 breakers in 1988. These breakers are now 34 years old. Expected service life of circuit breakers is 45 years. EDTI has an active program for replacing HV circuit breakers. The circuit breakers for replacement are selected using an in-house criteria which ranks all EDTI circuit breakers by assigning a weight to condition-based parameters e.g age, maintenance tests results, technical data, circuit breakers ratings, criticality, operating cost, operation issues, and health and safety concerns.

At present, the overall assessment of the Kennedale breakers indicate that there is no imminent risk of failure. If the Kennedale HV breakers were to be included in EDTI's long term replacement strategy, they would be planned for replacement sometime after 2040.

5.0 CONCLUSION

Based on the above assessments of the existing transformers, reactors, switchgear and HV breakers within the Kennedale substation, there are condition based drivers to replace these assets in the near future. The transformers currently have issues with obsolescence of the tapchangers, a past failure identified, secondary cable termination issues and minor leaks. The switchgear circuit breakers are needing replacement and the PILC termination issues are all factors for replacement. The 72kV breakers are in an acceptable condition, however, will be approaching a typical end of life age for a breaker replacement.

6.0 APPENDIX A - TRANSFORMER CONSIDERATIONS

In addition to addressing mechanical failures and issues such as excessive leaking, secondary cable termination condition, obsolete components and bushing condition, whenever possible EDTI assesses a number of specific transformer characteristics and performs a variety of tests to assess the overall condition of power transformers. EDTI takes into consideration:

Dissolved Gas Analysis

EDTI carries out Dissolved Gas in oil Analysis ("DGA") as part of its preventative power transformer maintenance program. DGA analysis provides insight into the presence of dissolved gases in the transformer insulating oil associated with the occurrence of dielectric stresses caused by thermal and electrical faults. Thermal faults are hot spots inside a transformer that have the potential to degrade the internal components of the asset. Electrical faults, including arcing, sparking and corona, also have the potential to degrade the internal components of the asset. The irreversible degradation and decomposition of the solid insulation (paper) system further leads to potential failures. Different quantities and ratios of gasses are associated with the presence of these different fault types, and varied patterns and amounts of gases are generated due to different intensities of energy dissipated by different faults, which are affected by many factors, including oil type, oil temperature, sampling method, insulation characteristics and environmental effects, such as temperature and transformer loading.

Table A1 summarizes the potential fault types associated with dissolved gas concentrations which exceed the normal condition levels recommended by the Institute of Electrical and Electronics Engineers (IEEE).

Table A1
Potential Fault Types Associated with
Key Gas Levels Exceeding Normal Condition Concentrations

	Gas Description	A Normal Condition (ppm)	B Potential Fault Type
1	Hydrogen (H2)	< 100	Thermal and Electrical – corona, partial discharges
2	Acetylene (C2H2)	< 1	Electrical – arcing
3	Methane (CH4)	< 120	Thermal – sparking
4	Ethylene (C2H4)	< 50	Thermal – severe overheating
5	Ethane (C2H6)	< 65	Thermal – local overheating
6	Carbon Monoxide (CO)	< 350	Solid Insulation Decomposition – severe overheating

To aid in the interpretation of dissolved gas level results, the Duval Triangle method is an effective tool commonly used by the electrical industry. Developed by the International Electrotechnical

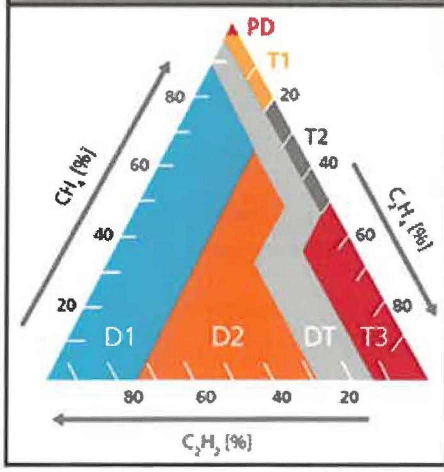
Commission (IEC), the triangle charts the intersection of measured key gas ratios against potential fault zones covering partial discharges, electrical faults (arcing high and low energy), and thermal faults (over various temperature ranges), plus a DT zone (mixture of thermal and electrical faults).

Generally, electrical faults can be considered more severe than thermal faults. However, even low-level thermal faults will negatively impact the physical insulation in the transformer, while also increasing the rate of aging in any cellulose insulation in close proximity to the fault. If left untreated, thermal faults can degrade the insulation to a point where electrical faults develop.

Figure A1 shows the location of the potential fault type zones within the triangle and the associated fault indication.

Figure A1
Duval Triangle Method – Fault Type Zones

DUVAL TRIANGLE (IEC 60599-2007-05)



ZONE	FAULT INDICATION
T1	Thermal fault, ≤300 °C
T2	Thermal fault, >300 °C, ≤700 °C
T3	Thermal fault, >700 °C
D1	Discharges of low-energy
D2	Discharges of high-energy
DT	Combination of thermal faults and discharges
PD	Partial discharge

When EDTI receives a DGA test that shows a large change in levels, or unusual results, EDTI will take a new oil sample and repeat DGA testing at a later date to confirm and verify the observed DGA test results.

In conjunction with DGA testing, EDTI also conducts relative saturation analysis on transformer insulating oil to measure the moisture content. As transformers age and deteriorate, they can develop small leaks that allow moisture to enter the closed oil systems. Oil leaks are not only harmful due to a loss of oil, but they are also a significant point of moisture ingress. Relative saturation of the transformer oil greater than 30% results in a significant reduction of the insulating strength of the oil. It also accelerates the dielectric breakdown of insulating paper and relative age of the transformer. EDTI uses silica gel canisters and conservator air cells on its transformers;

silica is a desiccant and is responsible for removing moisture from the air entering the conservator tank as the oil level in the unit changes. The conservator air cell is a barrier that limits direct contact between the oil in the conservator tank and the outside air. While periodic replacement of the silica gel is a routine task, more frequent required replacement is indicative of systemic moisture ingress above expected operating conditions. While EDTI is able to recondition oil and maintain the silica gel canisters, the damage to the insulating paper from water ingress cannot be undone.

Insulation Power Factor and Capacitance Testing

EDTI carries out insulation power factor and capacitance testing (commonly referred to as Doble testing) as part of its preventative power transformer maintenance program. Doble test results provide insight into the effectiveness of the overall insulation system and into potential changes in the internal geometry of a power transformer. A change in power factor in a Doble test result typically represents degradation in the insulation systems, while a change in the capacitance of the Doble test result represents a change in geometry. More specifically:

- The degradation of the insulation systems is often a precursor of potential equipment failure because insulation (i.e. its dielectric withstand strength) prevents the transformer from faulting electrically.
- Changes in geometry (such as distorted conductor in a winding, or shifts in a winding's position relative to other parts of the transformer) can occur in severe circumstances including: through faults, degradation of internal equipment, or loosening of internal supports caused by excessive external force or insulation shrinking with age. A change in geometry can be detrimental due altered clearances inside the transformer and to damage caused to the insulation systems when internal components move relative to each other, which can result in electrical voltage stresses and internal faults.

Oil Quality Testing

Oil quality test results provide insight into the physical and dielectric properties and characteristics of the oil used in power transformers for electrical insulation and cooling purposes. Oil degrades due to deteriorating conditions in the transformer over time. Reclamation (i.e. cleaning and regenerating) of deteriorated oil is a condition-based maintenance activity which cannot reverse any deterioration of the transformer that has already occurred. Rather, reclaiming oil at appropriate times during a transformer's life maximizes the likelihood that the transformer will be able to reliably and safely remain in service to at least its intended operating life. However, oil reclamation is a costly labour intensive process, and can decrease in effectiveness with aged transformers.

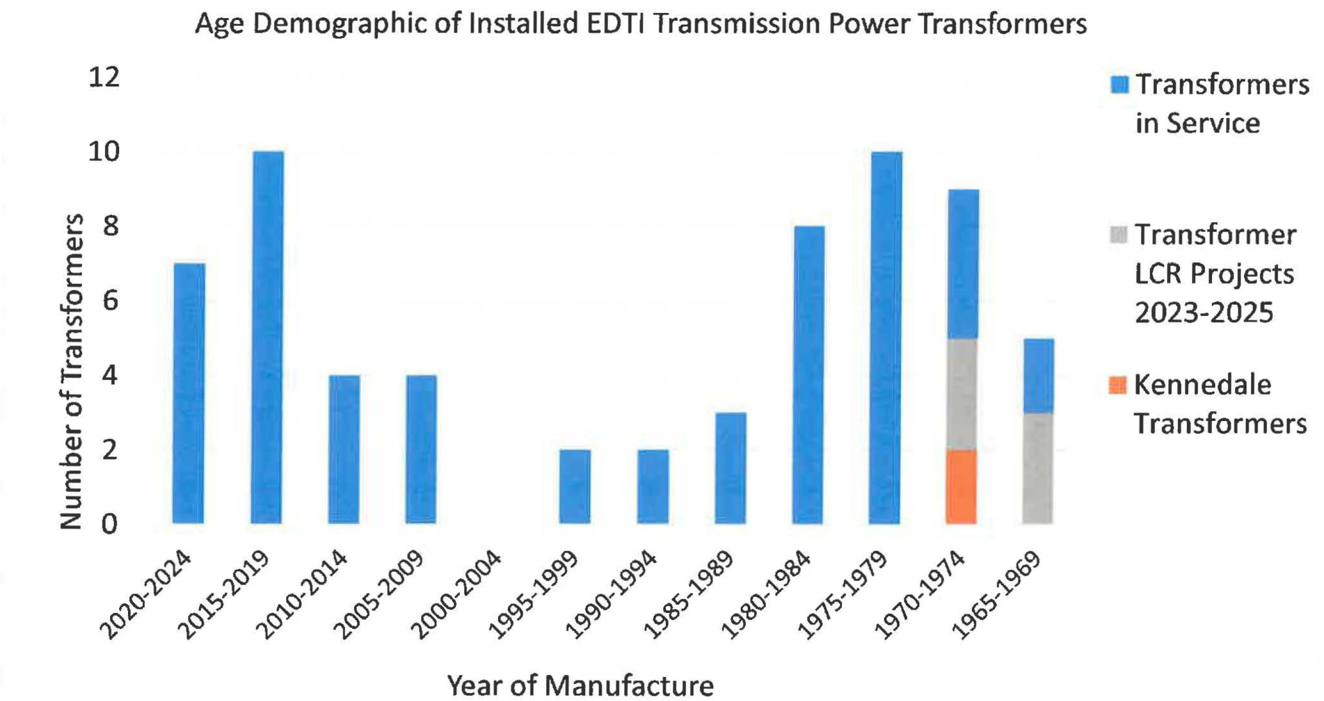
Thermographic Testing

Thermographic (infrared) test results provide insight into the degradation of the current carrying components of power transformers and regulators (e.g., bushings, connectors, OLTCs, arresters); oil cooling radiator fans and pumps; and instrument and control wiring. Infrared inspections observe hot spots typically caused by defects in connections and components by identifying locations where excessive heat is being generated. This is often a sign of component degradation and is a leading indicator of potential equipment failure.

Age

The age of a power transformer provides an indication of the accumulation of slow acting factors that typically can degrade a transformer asset over its service life, including factors such as: heat; moisture; mechanical component wear; electrical stress; through faults; and overvoltage events. While age alone is not a determinative indicator of condition, the on-going stresses and factors described lead to equipment deterioration over time, and eventually replacement is required. Figure A2 illustrates EDTI's power transformer age demographics generally and highlights the power transformers EDTI proposes to replace under lifecycle replacement during the period from 2023-2025 as well as the Kennedale transformers.

Figure A2
Power Transformer Age Demographic



Note 1: the above figure depicts the current state of EDTI's power transformer fleet as of completion of 2022 planned work

As shown in the figure, EDTI has aging transmission power transformer infrastructure. The average age of the six substation power transformers EDTI proposes to replace as part of this life cycle replacement program in the 2023-2025 Test Period, which includes Kennedale Tx1 & Tx2, is 52 years. Over the last decade, in its previous applications, EDTI has described its aging infrastructure and its anticipation that increased capital and operating expenditures will be required in future years to address its aging substation power transformer fleet.

PROVIDING MORE EPCOR

Appendix B1:

Underground Transmission Assessment Summary Report

72CK12 & 72CK13

Technical Summary Report

Revision History

Version No.	Date	Drafted By	Reviewed By	Approved By	Description of Revision
0	2021-11-15	Christopher Grodzinski Sean Langford Jennifer Wharton	Christopher Grodzinski Sean Langford Jennifer Wharton Kirstine Hull	Sean Langford Jennifer Wharton	Initial Version
1	2023-01-25	Mike Wong	Daniel Lotfizadeh Sean Langford	Daniel Lotfizadeh Sean Langford	Added section re: fault history of CK12 and CK13; minor edits; Final for Issuance
2	2023-04-05	Mike Wong	Daniel Lotfizadeh Sean Langford	Daniel Lotfizadeh Sean Langford	Revised wording in Section 3.8.

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The Association of Professional Engineers and Geoscientists of Alberta (APEGA)

PROFESSIONAL ENGINEER ALBERTA
DANIEL LOTFIZADEH
ID 260417
April 5, 2023

Table of Contents

1 Executive Summary

This summary report focuses on the review and analysis specific to the asset condition, cable system considerations and recommended lifecycle replacement timing for underground transmission Oil Filled Pipe Type ("OFPT") circuits 72CK12 and 72CK13 that provide power from the Clover Bar substation to the Kennedale substation in east Edmonton.

In 2011, Quanta Technology, LLC ("Quanta"), was engaged by EDTI to conduct a systematic review of EDTI's transmission assets to determine their overall condition and capability, having regard for their current condition and their remaining useful lives, and to assess their capability to meet future operating, system loading and forecast transmission system requirements. The full assessment is referred to as the System Sustainability and Equipment Assessment Study ("SEAS Report") and was issued in June 2013.

In 2013, the SEAS Report recommended replacement of all five 72 kV underground transmission circuits exiting the Clover Bar substation, including 72CK12 and 72CK13, within 10 years. In 2021, EDTI engaged one of the original co-authors of the SEAS Report to conduct an updated review of the Clover Bar 72 kV circuits taking into account EDTI maintenance and diagnostic testing for the subsequent years from 2012 to 2021. The culmination of this review lead to the following report. This report is a continuation and update of the 2013 SEAS Report and should be considered the present analysis.

Table 1-1 shows the condition and recommended life cycle replacement timing specific to 72CK12 and 72CK13.

Table 1-1

72CK12 and 72CK13 – Condition and Life Cycle Replacement ("LCR") Recommended Timing

Cable	Age (2022)	Condition	Recommended LCR Timing
72CK12	49	High risk, Serious and deteriorating	2020-2025
72CK13	49	High risk, Serious and deteriorating	2020-2025

The risk assessment and recommendations presented in sections 7.3.4-7.3.5 (for 72CK12) and 7.4.4-7.4.5 (for 72CK13) of the SEAS Report have been reinforced by further fluid sampling and laboratory analysis carried out in the subsequent period. Results indicate the high risk characteristics identified in the 2013 report for 72CK12 and 72CK13 have continued with negative trends.

The considerations, identified in Section 3, support a conclusion that replacement of circuits 72CK12 and 72CK13 should be prioritized in the interests of system reliability and potential negative environmental impacts.

Specifically, the 72CK12 and 72CK13 circuits show elevated concentrations of acetylene in all splice locations, indicating electrical arcing events within the pipes. Acetylene is the most important diagnostic gas, as acetylene is only produced by high energy arcing events. Along with the acetylene, the high hydrogen concentration, amongst the other gasses, indicates undesirable electrical or chemical activities inside the pipe. Since the fluid is circulated through both circuits it is impossible to pinpoint the source of the gas by fluid sampling.

Considering the continued degradation since 2013 and that lead time of a replacement transmission line is in the range of 3-5 years, immediate initiation for circuit replacement is recommended.

2 General Introduction

Several factors are evaluated when it comes to asset condition including diagnostic tests (i.e. paper insulation tests, dissolved gas analysis), and operational history (i.e. major failures, major maintenance and load history).

Cable condition is largely assessed through the measurement of cable insulation characteristics. These characteristics are measured in laboratory settings on paper samples extracted from the cables. The condition of cable insulating paper is a key indicator of cable condition.

The ranges and indicators of the paper test are presented in Table 2-1 below. The numeric values of the tests are represented by three different colours (green, yellow and red) that show the severity of the paper condition. This is described further in Section 3.2.

Obtaining a paper sample is considered invasive testing as the insulation must be physically cut (and subsequently repaired) to obtain a sample, disturbing the existing physical structure and potentially introducing new issues. This operation adds significant costs to the maintenance expenditures due to required outages, pipe fluid freezing with liquid nitogen for the duration of the work, followed by vacuum testing and electrical soaking times; and as such, it is usually performed when the circuit conditions require upgrade or repair.

Table 2-1

Ranges and Indicators for Paper Test Results

	Acceptable	Caution	Danger
Dissipation factor	<0.3%	0.3 – 0.6%	>0.6%
AC breakdown	40 kV/mm	20 - 40 kV/mm	<20 kV/mm
Moisture	<0.8%	0.8 – 3%	>3%
Degree of Polymerization	>800	600 - 800	<600

Additionally, the conditions inside the pipe are correlated (i.e. the paper absorbs moisture leading to increased dielectric losses (increased dissipation factor) and further increased cable temperature. The increased cable temperature accelerates paper decomposition that can lead to producing carbon monoxide. Carbon monoxide has the lowest saturation level of all gasses produced inside the pipe so it may create bubbles that lead to partial discharges ("PD") and hydrogen production. In addition to increased losses the insulation breakdown strength of insulation is also reduced when moisture is present.

To analyze phenomena, either electical or chemical, appearing inside the pipe the Dissolved Gas Analysis ("DGA") is used. The evaluation presented in this report is based on the EPRI paper: "*Guidelines for the Interpretation of Dissolved Gas Analysis (DGA) for Paper-Insulated Underground Transmission Cable Systems*" (TP1000275). DGA is a non-invasive procedure that relies on obtaining small amounts of insulating fluid from the pipe and testing it for the amount and ratio of dissolved gasses produced during cable operation. The gasses are indicative of chemical changes caused by thermal decomposition or electrical activities or stress. The trending of the gases' concentration and ratios is an engineering tool to establish the severity of electric phenomena or establish the rate of circuit aging and conditions of the cable internal components.

The load history for these circuits show a trend of actual circuit loads surpassing the SEAS Report recommended loads due to the configuration of EDTI's system; increasing operating temperatures and decreasing the effective service life of the cables. A rise in conductor temperature above the maximum permissible continuous operating conductor temperature reduces the life expectancy of the insulation.

3 Analysis - Circuits 72CK12 & 72CK13

3.1 Introduction

This report includes a summary of the key findings resulting from review of the tests and observations for the period from 2012 to 2021.

3.2 Paper insulation

Insulation test results for 72CK12 and 72CK13 are provided in Table 3.2.1 and 3.2.2 below.

3.2.1 72CK12

The test results for 72CK12 cable insulation:

Table 3.2.1

72CK12 – Paper Insulation Evaluation

Cct designation	Test date	Paper type	Sample location	Dissipation factor	Breakdown strength	Moisture content	DP
72CK12 CHK1A	May-07	Kraft	cable	Danger	Caution	OK	Caution
72CK12 CHK1	Dec-10	Kraft	joint	Danger	Caution	Caution	Caution

No tests have been completed since 2010; however EDTI assumesthat the paper has continued to degrade due purely to continued operation, however, trending cannot be definitely established without further data and assessment.

3.2.2 72CK13

The most recent tests for 72CK13 insulation were done in 2013 on samples taken from the splice CK1.

The test results for 72CK13 paper insulation:

Table 3.2.2

72CK13 Paper Insulation Evaluation

Cct designation	Test date	Paper type	Sample location	Dissipation factor	Breakdown strength	Moisture content	DP
72CK13 CK1A	May - 07	Kraft	cable	Caution	Caution	OK	Danger
72CK13 CK1	Jan - 12	Kraft / crepe	joint	Danger	Caution	OK	Caution
72CK13 CK1	May - 13	N/A	joint	Danger	N/A	OK	Aged

The dissipation factor exceeds normal acceptable values in these tests.

3.3 Dissolved Gas Analysis Tests & Results

72CK12 and 72CK13 are hydraulically connected and insulation fluid is slowly, and continuously, circulated through their lengths. This operating condition is non-standard as the system was originally designed as a static system. Circulating the fluid dissipates heat generated from "hot spots", but disturbs trending patterns that would be visible in circuits with static pressure, as fluid movement distributes and dilutes dissolved gases to all locations along the pipe length. As such, the gas concentration limits of concerned gases used for the analysis of circulating systems are lower than for static fluid systems as suggested by EPRI guidance. This limitation does not apply to the terminations that are not included in the flow.

Traces of acetylene were found in all splices of both 72CK12 and 72CK13 circuits. Since the fluid is circulated, it is impossible to establish the location of the source of this gas. The presence of acetylene, as well as the ratio of ethylene to ethane, indicate that electrical discharges, either temporary or permanent, have occured.

It is very important to note that amongst the changes in gas levels over time; all but one result from the 2021 review show gas levels have increased over the ten year period – in some cases significantly.

3.3.1 72CK12

Table 3.3.1

72CK12 – DGA Summary table

Location	Samples Taken (Year)	Trend 2007 to 2021	2011 DGA result per EPRI Guideline (SEAS G-13)	2021 DGA result per EPRI Guideline
MH CHK1A	2009; 2011; 2015; 2017; 2019; 2021	Rising hydrogen; stable level of all other gases	"Acceptable" levels for all gasses	Acetylene detected; "Acceptable" levels for all gases

MH CHK1	2007; 2008; 2009; 2010; 2011; 2013; 2015; 2017; 2019; 2021	Rising hydrogen; variable carbon dioxide and methane values; stable level of other gases	"Acceptable" levels for all gasses	Acetylene appears in the last four tests; "Acceptable" levels for all other gases
MH CHK2	2007; 2009; 2011; 2013; 2015; 2017; 2019; 2021	Rising hydrogen; stable level of all other gases	"Acceptable" levels for all gasses	Acetylene appears in the last four tests, the 2019 test indicated serious rise. "Acceptable" levels for all other gases
Clover Bar Terminations	2011; 2013; 2015; 2017; 2021	Stable level of all gasses	"Concern" level for hydrogen; "acceptable" levels for all other gases	"Concern" level for hydrogen; "acceptable" levels for all other gases
Kennedale Terminations	2011; 2013; 2015; 2017; 2021	Stable level of all gasses	"Concern" level for hydrogen; "acceptable" levels for all other gases	"Concern" level for hydrogen; "acceptable" levels for all other gases

3.3.2 72CK13

Table 3.3.2

72CK13 – DGA Summary table

Location	Samples Taken (Year)	Trend 2007 to 2021	2011 DGA result per EPRI Guideline (SEAS G-13)	2021 DGA result per EPRI Guideline
MH CK1A	2008; 2009; 2011; 2013; 2015; 2017; 2019; 2021	Increasing hydrogen and acetylene. stable level of all other gases	"Acceptable" levels for all gasses	"Danger" level for hydrogen, "Concern" level of acetylene; "Acceptable" levels for all other gases
MH CK1	2007; 2009; 2011; 2013; 2015; 2017; 2019; 2021	Increasing hydrogen and acetylene. stable level of all other gases	"Acceptable" levels for all gasses	"Danger" level for hydrogen, "Concern" level of acetylene; "Acceptable" levels for all other gases
MH CK2	2007; 2009; 2011; 2013; 2015; 2017; 2019; 2021	Rising hydrogen; reducing carbon dioxide; stable level of all other gases	"Acceptable" levels for all gasses	"Danger" level for hydrogen, "Acceptable" levels for all other gases

Clover Bar Terminations	2011; 2013; 2015; 2017; 2021	Stable level of all gasses	Two of three samples above "concern" threshold for hydrogen; all other gasses at "acceptable"	"Concern" level of hydrogen: all other gasses are either normal or "Acceptable"
Kennedale Terminations	2011; 2013; 2015; 2017; 2021	Acetylene should be monitored; stable level of all other gases	Three samples above "concern" threshold for hydrogen; all other gasses at "acceptable"	"Concern" level of hydrogen: all other gasses are either normal or "Acceptable"

3.4 Load

During the 2013 SEAS Report's first evaluation of Edmonton's grid, due to asset condition and cable system considerations, EDTI circuits steady state loads were recalculated and new recommended values were presented in the report. It has to be noted that 72CK12 and 72CK13 circuits are running in parallel to three additional 72kV circuits and each cable load mutually heats the others; creating thermal stress on the circuits. Reviewing the load from 2013 to present.it is noted that the circuits have been occasionally loaded above the recommended ampacities to accommodate system constraints.

Table 3.4.1

72CK12 & 72CK13 Recommended Loading

Circuit	Recommended Circuit Load	
	Normal Operation*	If 72CK13 is NOT loaded
72CK12	385A	479A
	Normal Operation*	If 72CK12 is NOT loaded
72CK13	385A	479A

*NOTE: Other Clover Bar connected circuits in operation

3.5 Cathodic protection

Upon inspection of the cable pipe cathodic protection system, there are indications that there are some deficiencies in Clover Bar's electrical isolation; including some signs of external wear such as pipe coating and link belt damage. As the pipes are approaching 50 years of service, the corrosion protection should be closely monitored while the cables are in service, as this deterioration increases the probability of a cable fluid spill event.

3.6 North Saskatchewan River Crossing

The pipes are located within the North Saskatchewan river bed. As such, they pose a major environmental risk involving the potential spill of pressurized oil should the structural integrity of the system be compromised or fail. EDTI has identified the consequences of OFPT failure in the river valley as one of its highest risk scenarios.

3.7 Fault History

Since their installation in 1973, 72CK12 and 72CK13 have experienced a number of major maintenance events, and in the case of 72CK12, multiple faults, resulting in environmental and operational impacts. These faults were taken into consideration and as a result, the circuits were derated from their initial design ratings. See Table 3.7.1 for a summary.

Table 3.7.1 - CK Cable Events Since Installation

	Date	Cable Affected	Work/Failure Description and Impact
1	June-1975	72CK12	Cable failure with pipe rupture due to overheating – 6,300L of oil escaped
2	Aug-1975	72CK12	Cable failure with pipe rupture due to overheating – 2,300L of oil escaped
3	Sep-1975	72CK12	Cable failure with pipe rupture due to overheating – 3,600L of oil escaped
4	Mar-1977	72CK12	Cable failure with pipe rupture due to overheating – 5,700L of oil spilled
5	1978	72CK12	Circuit de-rated to 80% and backfill replaced between Hooke Rd and 34th Street
6	2010	72CK12	Joint rebuilt
1	1978	72CK13	Circuit de-rated to 80% and backfill replaced between Hooke Rd and 34th Street
2	2005	72CK13	Barrier joint installed
3	2009	72CK13	Splice rebuild
4	2010	72CK13	Splice rebuild

With regard to maintenance and repair activities, EDTI utilizes activities that primarily focus on non-invasive work such as degasification and other temporary mitigation actions. Paper and splice testing, while potentially more informative with regards to data gathering and health assessment, are inherently invasive in nature, making them costlier financially and operationally.

3.8 Conclusions and Recommendations:

Taking into consideration the previous catastrophic failures on 72CK12 (see Section 3.7), the steady increase in the level of hydrogen, and last sudden increase in the acetylene level, it can be inferred that the circuit condition has continued to degrade since the original SEAS Report, and should be replaced with high priority

It is difficult to evaluate the 72CK13 circuit to the same degree of detail, as the paper test sample provided for the 2012 analysis is of unknown location within the cable; however, given the increasing hydrogen levels, and consideration that both circuits are of the same vintage and working within a connected fluid system under constant circulation, it must be treated with the same consideration and priority as 72CK12.

Further, it is noted that the daily average load on both circuits has been increasing compared to the previous study period. The maximum load regularly exceeds previously recommended values. As such, the cable temperature likely rises above those recommended by cable manufacturers and standards. As noted above, operating the transmission line above its thermal limit reduces the life expectancy of the insulation in the line itself.

The considerations taken above support the conclusion that replacement of circuits 72CK12 and 72CK13 should be prioritized in the interests of system reliability and environmental risk. Considering that lead time of a new transmission line is in the range of 3-5 years, immediate initiation of circuit replacement is required.

In the interim, while the circuits remain in service, the following actions should be taken to monitor, detect and mitigate evolving or emergent failure conditions:

- Continue to conduct DGA testing and prompt analysis;
- If required, and feasible, circulate fluid with high levels of combustible gases through a degasser and Fuller's Earth (to remove gases and impurities), to maintain safe operation until the circuits can be retired from service;
- Continue maintenance and address deficiencies in the auxiliary supporting, monitoring and protective systems (including cathodic protection);
- Monitor circuit loading as there are five circuits in close proximity and are subject to mutual heating, and
- Develop and maintain operational contingency plans to be implemented in the event of failure.

PROVIDING MORE EPCOR

Appendix B2:

Underground Transmission Assessment Summary Report

72CN10

Technical Summary Report

Revision History

Version No.	Date	Drafted By	Reviewed By	Approved By	Description of Revision
0	2022-10-25	Mike Wong			Issued for internal review.
1	2023-01-25	Mike Wong	Daniel Lotfizadeh Sean Langford	Daniel Lotfizadeh Sean Langford	Final for Issuance
2	2023-04-05	Mike Wong	Daniel Lotfizadeh Sean Langford	Daniel Lotfizadeh Sean Langford	Timing consistency; Conclusion wording

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RM APEGA ID #: 57974
DATE: APRIL 5/23
PERMIT NUMBER: P007061
The Association of Professional Engineers and Geoscientists of Alberta (APEGA)

PROFESSIONAL ENGINEER ALBERTA
DANIEL LOTFIZADEH
ID 260417
April 5, 2023

Table of Contents

1 Executive Summary

This summary report focuses on the review and analysis specific to the asset condition, cable system considerations and recommended lifecycle replacement timing for underground transmission Oil Filled Pipe Type ("OFPT") circuit 72CN10 that provides power from the Clover Bar substation to the Namao substation in east Edmonton.

In 2011, Quanta Technology, LLC ("Quanta"), was engaged by EDTI to conduct a systematic review of EDTI's transmission assets to determine their overall condition and capability, having regard for their current condition and their remaining useful lives, and to assess their capability to meet future operating, system loading and forecast transmission system requirements. The full assessment is referred to as the System Sustainability and Equipment Assessment Study ("SEAS Report") and was issued in June 2013.

In 2013, the SEAS Report recommended replacement of all five 72 kV underground transmission circuits exiting the Clover Bar substation, including 72CN10, within 10 years. In 2021, EDTI engaged one of the original co-authors of the SEAS Report to conduct an updated review of the Clover Bar 72 kV circuits taking into account EDTI maintenance and diagnostic testing for the subsequent years from 2012 to 2021. The culmination of this review led to the following report. This report is a continuation and update of the 2013 SEAS Report and should be considered the present analysis.

Table 1-1 shows the condition and recommended life cycle replacement timing specific to 72CN10.

Table 1-1

72CN10 – Condition and Life Cycle Replacement ("LCR") Recommended Timing

Cable	Age (2022)	Condition	Recommended LCR Timing
72CN10	52	High risk and deteriorating	2022-2027

The risk assessment and recommendations presented in sections 7.5.4-7.5.5 (for 72CN10) of the SEAS Report have been reinforced by paper sampling and laboratory analysis carried out in the subsequent period. Results indicate the suboptimal characteristics identified in the SEAS Report for 72CN10 have continued with negative trends.

The considerations, identified in Section 3 support a conclusion that replacement of circuit 72CN10 should be prioritized in the interests of system reliability.

Specifically, the 72CN10 circuit shows continual deterioration of the insulation in the paper, based on the dissipation factor results taken previously. This is also coupled with high concentrations of hydrogen which are present in all accessories (e.g. splices, terminations). The negative impacts of paper deterioration and higher concentrations of hydrogen are discussed in detail below in Section 2.

Considering the continued degradation and that lead time of a replacement transmission line is in the range of 3-5 years, the replacement is to be completed in the 2022-2027 timeframe.

2 General Introduction

Cable condition is largely assessed through the measurement of cable insulation characteristics. These characteristics are measured in laboratory settings on paper samples extracted from the cables. The condition of cable insulating paper is a key indicator of cable condition.

The ranges and indicators of the paper test results are presented in Table 2-1 below. The numeric values of the tests are represented by three different colours (green, yellow and red) that show severity of the paper condition. This is described further in Section 3.2.

Obtaining a paper sample is considered invasive testing as the insulation must be physically cut (and subsequently repaired) to obtain a sample, disturbing the existing physical structure and potentially introducing new issues. This operation adds significant costs to the maintenance expenditures due to required outages, pipe fluid freezing with liquid nitrogen for the duration of the work, followed by vacuum testing and electrical soaking times; and, as such, it is usually performed when the circuit conditions require upgrade or repair.

Table 2-1

Ranges and Indicators for Paper Test Results

Rating Legend	Acceptable	Caution	Danger
Dissipation factor	<0.3%	0.3 – 0.6%	>0.6%
AC breakdown	>40 kV/mm	20 - 40 kV/mm	<20 kV/mm
Moisture	<0.8%	0.8 – 3%	>3%
Degree of Polymerization	>800	600 - 800	<600

Additionally, the conditions inside the pipe are correlated (i.e. the paper absorbs moisture, leading to increased dielectric losses (increased dissipation factor) and further increased cable temperature). The increased cable temperature accelerates paper decomposition that can lead to producing carbon monoxide. Carbon monoxide has the lowest saturation level of all gases produced inside the pipe so it may create bubbles that lead to partial discharges ("PD") and hydrogen production. In addition to increased losses, the insulation breakdown strength is also reduced when moisture is present, increasing the risk of PD or fault conditions.

To analyze phenomena appearing inside the pipe, either electrical or chemical, Dissolved Gas Analysis ("DGA") is used. The evaluation presented in this report is based on the EPRI paper: *Guideline for the Interpretation of Dissolved Gas Analysis (DGA) for Paper-Insulated Underground Transmission Cable Systems* (TP1000275). DGA is a non-invasive procedure that relies on obtaining small amounts of insulating fluid from the pipe and testing it for the amount and ratio of dissolved gases produced during cable operation. These gases are indicative of chemical changes caused by thermal decomposition or electrical activities or stress. The trending of the gases' concentration and ratios is an engineering tool to establish the severity of electric phenomena or establish the rate of circuit aging and conditions of the cable internal components.

3 Analysis - Circuit 72CN10

3.1 Introduction

This report includes a summary of the key findings resulting from review of the tests and observations for the period from 2007 to 2021.

During a prolonged cable outage in 2018, the 72CN10 cable retracted to the point of needing major works to reconnect it to the terminations. The cable pulled back from the mechanical stud connection within the termination. This was likely caused by movement of the cable within the pipe itself. An x-ray was taken of the termination, showing that the cable retracted from the stud approximately 150-200mm. Although the termination was replaced in 2019, the impact of the cable movement was not fully determined. Movement of the cable within the pipe strains the skid wires around the cable. This could lead to the skid wires breaking (which could arc due to transients). Alternatively, the skid wires could constrict around the paper cables, mechanically damaging the paper insulation.

3.2 Paper insulation

Insulation test results for 72CN10 are provided in Table 3.2-1 below.

Table 3.2-1

72CN10 – Paper Insulation Evaluation

Cct Designation	Test Date	Paper Type	Sample Location	Dissipation Factor	Breakdown Strength	Moisture Content	DP
72CN10 CNH1A	May-07	Kraft	Cable	Danger	Caution	Caution	Acceptable
72CN10 CN4	Dec-11	Kraft	Cable	Caution	Caution	Acceptable	Acceptable
		Kraft	Joint	Caution	Caution	Acceptable	Acceptable
72CN10 Namao	Sep-19	Kraft	Term	Danger	Acceptable	Caution	Acceptable
		Crepe	Term	Danger	Caution	Caution	Acceptable
72CN10 CN6	Sep-19	Kraft	Joint	Danger	Acceptable	Caution	Acceptable
		Crepe	Joint	Danger	Caution	Caution	Acceptable

The test results taken in 2019 above show that the dissipation factor exceeds many times the value that is considered normal for new paper insulation. The results of these paper tests show significant aging. As described in Section 2 above, a high dissipation factor can lead to the production of carbon monoxide that can lead to PD and hydrogen production. The presence of hydrogen production in high concentrations, combined with the presence of other gases such as acetylene, can be an identifier for unusual electrical and/or thermal activity, causing localized overheating, internal arcing, corona, and cellulose decomposition from the paper insulation.

3.3 Dissolved Gas Analysis Tests & Results

After reviewing all the DGA results from the circuit it is evident that the circuit operation has not caused any noticeable increase in the dissolved gases concentration. Hydrogen concentration remains high. Other gases in every location remain at normal or acceptable levels. The only exception is the Namao trifurcator, where the 2017 test revealed significant increase in hydrogen concentration as shown on the table below.

The 2017 sample from the Namao trifurcator shows a significant jump in the concentration of hydrogen. This generation could come either from electrical sources (low energy discharges or overall cable heating) or chemical reaction (aging paper). The test results do not show the contents of water that, in the presence of oxygen, can produce hydrogen. However, low level electrical activities cannot be excluded. The 2019 sampling at the trifurcator showed a significant drop in hydrogen concentration. This reduction could be attributed to the work on the nearby potheads[1] performed in the same year. EDTI has eliminated this data point from its trend analysis given the isolated occurrence.

Table 3.2-1

72CN10 – DGA Summary table

Location	Samples Taken	Trends	2011 DGA result per EPRI Guideline (SEAS G-13)	2021 DGA result per EPRI Guideline
MH CNH1A	2007; 2009; 2011; 2013; 2015; 2017; 2019; 2021	High concentration of hydrogen and carbon dioxide; normal and stable values for all other gases	**"Concern" level for hydrogen;** "acceptable" level for all other gases	**"Action" level for hydrogen;** "Acceptable" level for all other gases
MH CNH1	2001; 2003; 2007; 2009; 2011; 2013; 2015; 2017; 2019; 2021	Rising hydrogen; reducing carbon dioxide; stable values for all other gases	Acceptable level for all gases	**"Action" level for hydrogen.** "Acceptable" level for all gases
MH CN4	2013; 2015; 2017; 2021	Hydrogen high, other gases at normal level and stable		**"Concern"** - High value of hydrogen but stable
MH CN6	2021	No trend can be obtained	N/A	**"Concern" level** - Hydrogen elevated, other gases at normal level.
Clover Bar Terminations	2011; 2013; 2015; 2017; 2021	Hydrogen fluctuates	**"Action" level for hydrogen;** "acceptable" level for all other gases	**"Action" level for hydrogen**; "Acceptable" level for all other gases
Namao Trifurcator	2003; 2013; 2017; 2019	Hydrogen rising to "Action" level.	**"Concern" level for hydrogen**; "acceptable" level for all other gases	**"Action" level for hydrogen**; "Acceptable" level for all other gases
Namao Terminations	2011; 2013; 2015; 2017; 2021	CO_2/CO ratio falling.	N/A	**Hydrogen above "Action" level;** other gases are within "Acceptable" level.

[1] A "pothead" is a cable termination. Cable terminations make physical and electrical connections between the cable and the terminal of the equipment.

3.4 Manhole Inspections

Manhole inspection conducted in 2019 revealed damaged pipe and joint casing coatings, as well as light rust on the joint casing in CNH2 manhole, further indicating current cathodic protection needs to be reviewed and possibly upgraded.

3.5 Cathodic protection

While no flaws were found during the latest round of tests, there are recommendations that should be followed as there are some deteriorations of the pipes and their coverings. The recommendation to isolate the circuit risers from the site structures should be implemented.

3.6 North Saskatchewan River Crossing

The pipes are located on the North Saskatchewan river bed. As such, they pose a major environmental risk involving the potential spill of pressurized oil should the structural integrity of the system be compromised or fail. EDTI has identified the consequence of OFPT failure in the river valley as one of its highest risk scenarios .

3.7 Conclusions and Recommendations:

The dissipation factor results from the 2019 paper tests suggest a deterioration since the previous sampling. High dissipation factor values produce increased dielectric losses in the cable.

It is recommended to:

- Continue sampling and testing of papers from terminations and joints.
- If samples cannot be taken from the cable, an alternative approach was suggested. PD testing and cable dissipation factor measurement of the entire circuit are recommended on an urgent basis. Detailed analysis of the test results may provide a basis for a decision on possible cable replacement. However, it should be noted that PD does not necessarly identify the source of the problem. Moreover, multiple PD testing will be needed over the course of time to monitor the trend which is noticeably costly. As a result, EDTI is not following through with this at this time.
- In regards to the trifurcator on CN10, EDTI has been monitoring the CN10 terminations and has been satisfied that gas concentrations have stabilized. If the gas concentrations level changes in the CN10 terminations, EDTI will monitor DGA samples at the trifurcator, accordingly.
- Deficiencies in the manhole CNH2 should continue to be monitored. It is currently on the tapecoating repair program to be addressed in the near future.

EDTI will implement all of the recommendations made above in order to continue the maintenance and operation of the 72CN10 cable, but given the deteriorating condition and indicators for this cable, as well as giving consideration to all the other factors and drivers with respect to OFPT technology (see General OFPT Cables – LCR Assessment) and the SEAS Report (Appendix A), EDTI Asset Management is recommending the completion of the replacement of 72CN10 within the 2022-2027 timeframe.

EPCOR SEAS Project

Underground Transmission Assessment

Final Report

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Contents

1 Executive summary

Results of the EPCOR high voltage cable maintenance and diagnostic inspection program are reviewed. These are supplemented by observations gathered from EPCOR staff. Findings on cable condition based on the program results are discussed and related to utility industry experience at other locations where similar cables are being operated. This review has not produced any findings of critical deterioration that would be indicative of imminent cable failure. However, conditions at a number of cable circuits are identified for further work. This includes intensive remedial action for removal of hydrogen from several cables and a focused monitoring program.

Present circuit ratings and past cable loadings were reviewed. The circuits' ratings were recalculated using new soil thermal characteristics obtained during this project. The report contains a recommendation for further investigation of the cable backfill properties as well as installation of monitoring devices for more accurate real-time dynamic circuit ratings.

The report suggests that further examination of the cable insulation as well as fluid sampling should be continued. The sample locations are not identified as they have to be chosen based on all available information and accessibility to a specific part of a circuit.

It was indicated in this report that the lead time for a new transmission underground circuit is 3-4 years. Suggestion was made to initiate the circuits' replacement program as soon as practicable.

2 Introduction

The EPCOR EDTI power grid includes twenty underground transmission circuits. Seventeen of these operate at 72kV and three at 240kV. Their role is to transmit power to substations in the City of Edmonton. Nineteen of the cable circuits are High Pressure Fluid Filled (HPFF) cables installed between 1957 and the mid 1980s. HPFF cable ages in the EPCOR system range in age from 32 years to 56 years with an average of approximately 43 years. The service life of underground cables is highly dependent upon operating cables within the parameters specified by the cable manufacturer. There is industry experience that in certain circumstances an average age of oil cables can reach 60 years.

The cable industry estimate of cable minimum life expectancy was developed from testing done on the paper insulation aging process and the effects of thermo-mechanical cycling of the insulated cables. Cables with paper insulation that are operated continuously at the specified maximum conductor temperature of 85 °C have a design life expectancy of approximately 40-45 years. This can be higher if the operating conditions (i.e. cable insulation temperature) are less stressful. Conversely, events such as electrical faults, conductor overheating because of extended emergency or cable movement inside the carrier pipe can shorten the cable life. There is consensus among cable engineers and scientists that the rate of paper insulation deterioration doubles with each 10 °C increase in operating temperature above the manufacturers' specification (IEEE 1425 Guide for Evaluation of Remaining Life, Section 4.2).

There is no universally accepted remaining life assessment procedure for UG pipe type cables. In our opinion an assessment based on the cable temperature and dissipation factor (DF, tan δ) trending over a long period of time is the best method for this purpose. Such an assessment can be made when the performance of the thermal environment of the cable carrier pipe is known.

Typically, the end of life for fluid impregnated transmission cables is determined when one or more of the following factors are present:

1. The load rating of the cable is no longer adequate for the projected operational requirements;
2. The cable suffers a catastrophic electrical failure;
3. The cable suffers a catastrophic pressurization system failure;
4. The cable has a history of chronic leaks that expose the utility to regulatory censure and adverse publicity;
5. The maintenance and repair costs necessary to maintain the cable in a sound operating condition are excessive.
6. The deterioration of the insulation parameters warrants it.

The years of operation of the EPCOR circuits have required repairs and other works that included cutting into the carrier pipe. When the carrier pipes were opened, abnormal conditions were noted on several separate occasions. These observations included skid wires isolated from their bonding connections, damaged cable shielding tapes and skid wire surfaces, metal filings inside joint casings and cables in a position that stressed the paper insulating tapes. On some occasions burnt insulation paper was found in locations that did not exhibit any sign of cable failures or even severe deterioration. Many of these conditions could be attributed to cable movement caused by thermal expansion and contraction, but some could only be the result of installation methods and workmanship that were commonly used at the time of installation or failures. Installation methods today are more tightly specified as operational history of HPFF systems over 50 years have provided information on the importance of careful installation.

EPCOR has had an ongoing program of replacing joints for some time. The program is intended to replace joints that are considered suspect, and in so doing, restore the circuit to a reliable condition. However, a program of joint replacement does not address questions relating to the aging of the cables. While the joint replacement program can be beneficial to the system health the method of deciding which particular joint should be replaced is based sometimes on limited information. The dissolved gas analysis, external joint casing conditions and sometimes X-ray were used in joint replacement selection program. We strongly recommend partial discharge (PD) tests before any decision is made. The additional test may confirm a choice or indicate another location that electrical conditions are more severe. In some cases indicated in this report, the joint replacement did not bring expected results.

Replacement of cable terminations has also been done on the EPCOR system over time. The need for termination replacement can be based on DGA tests results and evaluation. This is the method currently used by EPCOR.

3 High Pressure Fluid Filled Cable Systems

HPFF cable systems typically consist of four major sub-systems. These are:

- the steel carrier pipe which provides a robust containment extending from termination to termination;
- the cable trench containing one or more carrier pipes;
- three insulated conductors which have been pulled into each carrier pipe, with the individual cable lengths jointed and terminated;
- auxiliary systems such as pressurizing pumping plants and control systems;

Following cable installation, jointing and terminating, the carrier pipe is always evacuated (vacuum drawn to remove traces of gasses and moisture), filled with degassed fluid and pressurized from a pumping plant. The carrier pipe, which is always protected from corrosion by an outer coating, is usually provided with secondary corrosion protection through an impressed current cathodic protection system.

In addition to the standard pressurization system, some HPFF cables also have dynamic secondary systems for circulating the dielectric fluid inside the pipes. Heavily loaded HPFF cables may also be equipped with refrigeration systems for forced cooling of the dielectric fluid. A system of this type has been installed on the EDTI grid in RV2, RV4 and RV6 circuits.

3.1 Cable System Design

Design of oil-filled pipe type cable systems incorporates many different design elements. These include soil parameters, cable attributes including insulation and ratings, cathodic protection, carrier pipe and insulating fluid to name the primary elements. This section discusses each of these elements, the operating characteristics and issues associated with each, and some examples specific to EPCOR.

3.1.1 Soil Parameters

The electrical characteristics of both the cables and the steel pipe have always been tightly specified for this type of cable system. Unfortunately, this rigor has not always been applied to the cable trench construction. As underground power transmission performance depends on the transfer of heat away from the cable, it is extremely important to have a properly engineered cable trench backfill to provide a thermal environment to facilitate heat transfer. Typically, if a cable is operated at its design load, a 10% decrease in the thermal conductivity of the soil results in 50% reduction in the cable life expectancy.

At the time when many of the early HPFF cable systems were installed, it was common to use sand as a trench backfill material. This was based on the conventional practice of providing a bedding material for underground pipes. As a result, many cable ratings which were based on assumed nominal soil characteristics were overly optimistic. During normal grid operations, these optimistic cable ratings would not be apparent unless the cables were frequently operated near the full design load. Early loading to design levels would typically occur only at generating station output cable circuits. An example of this phenomenon was experienced on the EDTI system near the Clover Bar Station in early 1970s. Circuits 72CK12 & 72CK13, 72CH9 & 72CH11, 72CN10 experienced “thermal runaway" or failure due to overheating. After exchanging the backfill surrounding the cables with thermally uniform composition backfill between Hooke Rd and 34th St., temperature sensors were installed in many places to monitor the pipe temperature. New ratings for those circuits were calculated and applied in operation.

At the time of this report, soil thermal resistivity tests are being conducted on the EPCOR system and partial data from those tests are available. The circuit ratings have been reviewed based on the test results.

3.1.2 Cable Ratings

Underground power transmission in Canada can be traced to mid 1950s. In those early days, the nominal text book values of the soil thermal resistivity were often used in the circuit load rating calculations. It was also not uncommon for conductor sizes to be selected based on nominal cable design depths. As a result, the cable ratings were often optimistic. Since EPCOR pioneered in transmission installations the circuits installed at that time may have been calculated in a simplified way. It has to be noted that the currently used calculation method is based on Neher–McGrath paper that was published in. AIEE Transactions, Part III, Volume 76, pp 752–772, October, 1957.

Other utility crossings can also critically affect cable ampacity, particularly if they are heat producing. Proximity to other transmission and distribution circuits, steam pipes, or other infrastructure can greatly affect the operating temperature and condition of an underground circuit. The additional heat generated by other utilities can change the thermal conditions of the transmission circuit by drying the surrounding soil and increasing its thermal resistance. Large trees and changes of the surface above the cables have similar influence on the cable operating conditions.

Cables supplied by different manufacturers also have an impact on the overall circuit ratings. Cables specified for 75°C maximum operating temperature can be a limiting element if other portions of the circuit are rated for 85°C operation. Overloading of the circuit is not the risk so much as early deterioration of cable insulation due to higher than specified temperatures. The operation risk by operating cables above their maximum temperature was mentioned in Section 2 - Introduction.

3.1.3 Cable Insulation

Cable aging is generally attributed to the degradation of cable insulation characteristics. These parameters can usually be measured in laboratory settings only. There is no widely accepted method of measuring remaining cable life; however condition of cable insulating paper is a key indicator of cable condition. It is also extremely difficult to monitor precisely all of the cable operating conditions along the entire route. In the past, the analysis of the insulation condition has been based on dissection of samples removed from the cable. These samples may not be representative to the condition of the entire cable unless they have been taken from the location where the most stressful factors have been present. In current practice, new testing equipment can evaluate the partial discharges and average dissipation factor in a short period of time.

3.1.4 Carrier Pipe

Integrity of the fluid or gas pressure pipe is critical to maintaining adequate pressure in the system. Deterioration of the pipe from corrosion can be a life-limiting factor of the overall system. Pipe corrosion can be either galvanic or electrolytic. Most severe examples of corrosion occur in cities where DC transit systems are in close proximity to the cable systems. Pipe corrosion is also known to occur from road salts in areas subject to severe winter weather conditions.

As stated previously, the electrical characteristics of both cable and carrier pipe have been tightly specified in the design of HPFF systems. Construction of the carrier pipe system, however, is also extremely important and is often subject to the variances that may occur in field construction. Installation methods used when installing conductor in the pipe can result in unintended damage if extreme care and attention to specification is not followed. Any stress on the conductor during installation in the carrier pipe can result in damage to insulation paper or to the internal coating of the pipe. While this may seem insignificant at the time, the internal pipe damage would cause paint flakes and other small particles to be present in the pipe filling fluid. If suspended, these particles would become discharge sites during system transients. Additionally, exposed steel on the pipe interior would, in the presence of water, produce rusting and be a source of hydrogen (IEEE 1406).

Excessive corrosion of the steel carrier pipe is inhibited by a cathodic protection (CP) system. Integrity of the CP system is a critical element to the long term health of the steel pipe. Regular inspection and maintenance of the CP components is important in ensuring the overall integrity of the carrier pipe, which as noted previously can be a life-limiting factor of the overall HPFF system.

3.2 EPCOR Observations

This section presents some experiences and examples of the impacts of these design elements on operation of the EPCOR cable system.

3.2.1 Soil Parameters

The thermal failures referenced in Section 3.1.1. prompted “in situ” tests to determine soil thermal resistivity values. The test results showed that the soil properties in this area varied significantly from location to location and were higher than the values used in the original circuit design. Those locations that were tested in the past (i.e. 72CK13 circuit route) revealed that the soil thermal resistivity values were in the 0.5 to 2.1 $[\frac{K\times m}{W}]$ range. These results were obtained from in situ tests and reflected the natural moisture levels present at the time of testing. Since the heat generated by cable loading causes moisture depletion and increased thermal resistivity, it is expected that the actual operational values would be substantially higher.

During the course of this project, it was found that many of the EPCOR rating calculations were based on a thermal resistivity of 0.8 $[\frac{K\times m}{W}]$, which is more optimistic than many of the in-situ values measured along the cable routes. The remedy is to test the soil over the entire circuit length, analyze the results and exchange the soil where its characteristics are unfavorable. Such a process is justified when continued long-term operation of the circuit is anticipated.

At the time of this report, soil tests are being conducted to determine thermal resistivity values of selected circuits. Once the test data is available, cable rating calculations will be performed and the overall cable assessments will be updated accordingly.

3.2.2 Cable Rating

We assumed that the calculations done by the cable manufacturer at the time of installation have been used in everyday operation. A number of ampacity calculations were performed in later years, but the inputs to these calculations were not recorded. While it is believed that these calculations were correctly performed, it is difficult to assess their operational value when the input values have not been defined and the values of thermal resistivity have not been validated through the comprehensive laboratory testing of native soil and backfill samples.

Another element affecting cable rating is the depth of installation. Knowledge of changes to the depth of the cables and the nature of the surface above the cable route is important in understanding and quantifying the thermal environment in which the cable operates. EPCOR's cable plan and profile drawings relate only to the conditions at the time of initial installation and there are indications that some of the cables are now deeper than when initially installed. The additional depth is the result of roadway changes and other construction that has resulted in additional cover on the original circuit route. The impact is that natural replenishment of trench moisture levels might now be less effective due to surface changes above the cable route.

An additional element impacting cable ratings is the proximity of the UG circuits to other transmission and distribution circuits as well as other underground utility infrastructure. Distribution cable heat sources can have a significant negative influence on the performance of the transmission circuits, and vice versa. It was recognized throughout the course of this project that at least two of the transmission circuits are in the vicinity of other heat sources. Circuit MG16 crosses the University of Alberta “utilidor” containing steam pipes, some distribution cables and secondary ducts but closer inspection did not raise any concern. Circuit VN21 is routed through a building cellar together with distribution circuits. It is not known if this location was taken into account when the transmission cable rating values were calculated. The locations where there is close proximity between transmission and distribution circuits should have the soil samples taken and a drying curve established.

During review of available information from the original contracts it was noted that some cables supplied by Northern Electric were supplied with a specified maximum conductor temperature of 75°C. These cables are now part of the circuits 72VN21, 72RV2, 72RS5, 72RG1 and 72MG16. It is not known if this specified maximum temperature was used for calculating the ratings of these “hybrid” circuits.

In 2012, several soil samples were taken from locations close to the cables. The samples thermal parameters were tested by Geotherm Inc. The soil thermal resistivity is the most influential parameter in calculating electrical circuit performance. Based on recent soil thermal condition tests conducted by EPCOR the new rating calculations were conducted. The soil tests results were provided by GEOTHERM, the only company specializes in soil tests for the electrical industry. While in-situ tests can indicate the soil characteristic, a full laboratory test should be performed and its results in the form of “Thermal Resistivity vs. Moisture” curve should be used as an input in the calculations.

The attempts in 1970s to provide soil thermal characteristics were limited to the site tests only. They indicated on the route of the circuits originating at Clover Bar substation that the soil along the way is far from uniformity. The results in the archives show the thermal resistivity ranging from 0.8 to over 2.5 [K*m/W] in its native state. One can expect that if laboratory tested, the later soil can produce results in the range of 4.0 [K*m/W] or higher in the dry state.

The second round of tests on the 105St, West of Jasper, conducted by the City of Edmonton in 2002 generally confirmed that the soil thermal condition in Edmonton can be classified as thermally unstable. It is unknown if the tests were performed to the same standards as the latest tests.

The latest test results provided by GEOTHERM for samples taken from different parts of the city in 2012 were used as inputs in the calculations. Since the test results are in many ways similar, they were used in establishing ratings for the circuits that samples were not obtained. It has to be noted that the samples were taken based on randomly chosen location. They may not represent the most severe conditions. It is recommended that for any detailed calculations, including new circuits, the soil samples shall be taken and tested every approximate 300-500m for any given circuit or more often if unusually high thermal resistivity is suspected.

The cable environment must be considered as dynamic. The soil conditions change with seasons and annually. The City of Edmonton is one of the driest areas in Canada with annual precipitations of 477mm while i.e. Toronto receives almost 790mm per year.

For this report two results were calculated for most circuits. One for a year that the amount of precipitation is below average marked as “pessimistic” the other “optimistic” for normal precipitation where the soil moisture is within 3-5% minimum. Since the thermal soil resistivity depends heavily on the moisture in the soil installation of few moisture monitoring devices at the standard installation depth should be considered. The locations should be monitored periodically and their reading used in calculations to revise ratings for more accuracy.

The circuit 72RV2, 72RV4 and 72RV6 loads were calculated at the worst conditions when the Forced Oil Cooling System, known as FOCS, is not operating. A more detailed loading study should be undertaken using non-conventional calculation methods and tests to establish nominal loading ratings associated with the cooling fluid temperature and speed of flow.

Ampacity calculations conditions

The circuits’ ampacity analysis was conducted with maximum load in mind but taking into consideration their age, conditions, history and environment. For this purpose the soil thermal conditions were tested. In many standards and papers as well as utility requirement there is a requirement for summer and winter ratings. Since the cable system time constant is significant it is very difficult to provide a date that would allow for applying such ratings. This is applicable to the cable depth that experiences the seasonal temperature variations. In bigger depth which it is usually bottleneck for the cable loads the temperature changes are minimal. Because of these phenomena the report gives one rating only.

The cable environment is dynamic and changes of the conditions are not limited to the soil temperature exclusively. The soil moisture has sometimes more influence than the soil temperature and is independent of a season. The lack of moisture in winter can be more significant than in summer. The moisture migrated from the cable region may freeze above and further increase the soil resistivity. To retain a moisture conditions or to allow for replenishing moisture in case of drought the external cable temperature or pipe, in the case of HPFF cables, should be maintained below 55°C. This was the temperature limit used in calculating circuits' ratings.

Taking the above into consideration, the circuits that are running close to each other in such a distance that their mutual heating has to be included in the rating calculations are even more prone to be overheated because of soil drying between them. They heat such a big volume of earth that even if one of the circuits is disconnected the soil temperature drop is not immediate. This occurrence is especially applicable to the circuits originating in Clover Bar substation. There are five circuits installed in parallel in close proximity to each other. It is very unlikely that disconnecting one circuit will allow for immediate increasing load in the remaining other circuits.

Similar conditions but to the lesser extent are applicable to the circuits RG1 and RG7 as well as JM18 and JW19.

The calculation results and inputs used are presented in the Appendix 6. However, because of the soil characteristics and seasonal conditions mentioned above the actual circuit load availability should be calculated every time based on real-time inputs.

3.2.3 Cable Insulation

The EPCOR transmission cable system consists of different conductor sizes, supplied by several different manufacturers. Some of the cables have copper conductors and some have aluminum conductors. There are a number of locations where different sized cables have been joined together. At the joints between cables having different diameters, the joints are asymmetrical. At such points, complex voltage standing waves may occur during system transients. A number of different styles of joint design have also been used throughout the system. The different styles of joints have limited impact on the cable conditions but it will have significant impact on number of spare parts that should be kept for unexpected events.

It also has to be stressed that the replaced joints do not stop the cable insulation aging. We assumed that the cable samples taken from the joint locations are actually samples of the cable insulation. As such if the tests indicated deteriorated insulation, any joint replacements that have been done were not taken into consideration when the cable conditions were assessed.

3.2.4 Carrier Pipe

Most of the EDTI 72kV cables are installed in 5" diameter steel pipe. According to the original records the pipe was specified properly to accommodate the cables. However, industry practices employed at the time these cables were installed were less stringent than practices used today. It is possible that due to the field bending methods, the pipe bends may have been oval, resulting in increased pulling tensions and excessive sidewall pressures. This situation would most likely have resulted in damage to the pipe internal coating, the interior pipe face and disturbance of the shielding and external paper layers of the cables. Installation records from the original construction are extremely limited but there is anecdotal evidence that situations as described, resulting from original installation, exist in the EDTI system. The external pipe coating at initial installation was field applied "coal tar impregnated asbestos pipe line felt" with heavy Kraft paper as an additional protection. While this is an effective and accepted method of pipe protection, it can also create a significant thermal barrier. The coating thickness was not specified and its thermal resistance would be substantial but can be approximated only. It should be noted that as asbestos is a designated hazardous material, any removal of these circuits would require special procedures and could cause a significant delay for a new installation on the same right-of -way.

In many places the pipe was covered with "GUNITE", a concrete base mixture applied with an air gun. The composition and thickness of the material used is unknown. This mixture was applied as a coating reinforcement at street or railway track crossings. This is not a conventional HPFF installation practice and would have a negative influence on the cable thermal performance by restricting the heat flow. There is no evidence that this arrangement has been taken into consideration when the circuit parameters were calculated. During the discussions with engineers who were employed at that time the opinion was that the covering thickness was very significant, exceeding 25mm in some instances. The composition of the "GUNITE" covering and its thickness may have a detrimental effect on the cable if not taken into account during the designing stage because usually this part of the circuit is installed at a significant depth.

3.2.5 Cathodic Protection

The effectiveness of cathodic protection systems have been tested annually over the past several years. However, it is known that the pipes on the EDTI system are severely corroded in many places. This knowledge was obtained from the crews working on the circuit rehabilitation. EDTI has annual corrosion inspections performed and pipe corrosion is suggested by the measurements in the annual corrosion system reports. Practically, this is an unavoidable occurrence that has to be dealt with as there is no access to the buried pipes. Also, locating spots of the pipe where the protective covering is damaged is very difficult.

It was also reported during annual inspections that some rectifiers frequently experienced blown fuses. These occurrences were reported particularly at Rossdale and Victoria substations earlier and Strathcona in 2011. Since this appears to have occurred frequently, the cause should be investigated. During the period that the rectifier is unavailable the pipe is vulnerable at any point where the coating is damaged.

EDTI has installed isolators/surge protectors (ISPs) as part of an ongoing effort to improve cathodic protection and address pipe corrosion. The ISP cells are serviced annually; however, they should also be checked after each serious disturbance in the grid. The ISP is designed for a specific rating of the short circuit current. However, the ISP is a fail-safe device. It is designed so that if the device fails because of current flow exceeding its rating, the failure mode will be as a short circuit so as to ground the structure.

Parts of the CP systems were installed in the late 1950s or 60s (as listed in the CorrPro reports). These rectifiers are over 50 years old and their replacement and installing additional protection system is strongly recommended. The replacement or upgrade decision of the ISPs should be evaluated in conjunction with replacement date of a particular circuit. If a circuit replacement date is remote the corrosion protection should be upgraded as soon as practicable. Actions of this type are being taken by EDTI as part of ongoing HPFF system maintenance. There are proposed capital projects for improvement of cathodic protection which this assessment believes is appropriate and in fact required to maintain the integrity of the carrier pipe and the overall HPFF system as it presently exists.

Pictures taken during joint replacement and maintenance in 2008 are shown in Figure 2-1. Some of them indicated severe corrosion of the joint casings in many manholes. Similar findings were also noted in the cathodic protection system annual reports. In our opinion, cleaning and recoating of exposed portions of the piping system should be done as a regular maintenance on continuous basis. Since the parts of the circuit are manufactured of carbon steel they are subject to severe corrosion when exposed to salty environment during winter months. It is not known if stray ground current is prevalent in the City of Edmonton. This phenomenon is frequently found where dc traction systems operate. It is probable that other underground pipes such as gas and water lines are cathodically protected. At the crossing points of cathodically protected pipes it is vital that the protection voltages are coordinated. Otherwise the dominant pipe can accelerate corrosion of the less protected pipe. A close attention should also be paid to the locations where the carrier pipe is protected with steel protective casing pipe. There is an indication that some perforation of carrier pipe may occur in that region if the protective coating is damaged.

Figure 3-1

Photographs from 72kV circuit VN21 taken in 2008

4 Industry standards

Guidelines, standards and research projects in the electric power industry that address the use of fluid filled pipe type cables are produced by several organizations. The most prominent are IEEE, IEC, EPRI, and CIGRE.

The guidelines and standards that are applicable to the HPFF cables were produced predominantly in North America. The guidelines and standards considered most important and some of them used as references in this project assessment are:

EPRI

TR 1001924	Guide on Selection, Handling and Maintenance of Cable Fluids
TR 1000275	Guidelines for the Interpretation of DGA for Paper-Insulated Underground Transmission Cable Systems
TR 1000458	Guide for Operation and Maintenance of Paper-Insulated Transmission Cables
TR 1014840	Underground Transmission Systems Reference Book
TR 111712	Transmission Cable Life Evaluation and Management

CIGRE

TB 358	Remaining Life Management
TB 409	DGA Monitors
TB 444	Guide for Unconventional Partial Discharge Measurements

IEC

60599	Mineral Oil-Impregnated Equipment in Service – Guide to the Interpretation of Dissolved and Free Gases Analysis, March 1999
60141-4	Oil Impregnated Paper-Insulated High Pressure Oil-Filled Pipe-Type Cables and Accessories for Alternating Voltages up to 275kV

IEEE

1425	Guide for Evaluation of the Remaining Life of Impregnated Paper-Insulated Transmission Cable Systems
1406	Guide to the Use of Gas-In-Fluid Analysis for Electric Power Cable Systems

AEIC

G3	Guide for Installation of Pipe Type Cable Systems
CS2	Specification for impregnated paper and laminated paper polypropylene insulated cable high-pressure pipe-type,

ASTM

A523	Pipe for HPPT cables
D1816	Oil Test
D5334	Thermal resistivity
D3612	Dissolved Gas Analysis

The information and guidelines can also be found in papers and articles of other organizations. Some examples are:

AIEE/IEEE
AIEE Committee Report, “Soil thermal characteristics in relation to underground power cables,” *Transactions AIEE*, vol. 79, Part III, pp. 792–856, 1960

CEATI
Mitigation of Stray Currents on Underground Transmission Systems
Cable Health Index Software

Publications:
AIEE Transactions, Part III, Volume 76, pp 752–772, October, 1957. The Calculation of the Temperature Rise and Load Capability of Cable Systems, J. H. Neher and M. H. McGrath

IEEE Committee Report, ICC Task Group on Pipe Coatings, “Guide for selecting coatings for pipes of pipe-type cable systems,” *IEEE Transactions on Power Apparatus and Systems*, vol. PAS-84, pp. 783–794, Aug. 1964

Electrical Engineering in Japan, Vol. 178, No. 1, 2012, Thermal Degradation Characteristics of Oil-Filled Cable Joint with Extremely Degraded tanδ Oil – K. Ide, M. Nakade, T. Takahashi, T. Nakajima

Jicable 07 proceedings, US Experience on Condition Assessment of Various Types of Cable Systems by DGA – N. Singh, S. Singh, R. Reyes, O. Morel, W. Zenger

It has to be noted that the standards do not provide data on aged cables. Some of the guidelines provide information that could be used in assessing the cable conditions. There is no universally accepted level below which the equipment should be considered as “unusable”.

5 Diagnostic Testing

Since visual inspections of underground cables are of limited value in condition assessment, diagnostic data gathering is necessary for a better understanding of the cable condition. Diagnostic testing consists of two primary practices, laboratory testing of insulating paper removed from in-service cables or from cable sections that have been taken out of service and dissolved gas analysis of the insulating fluid. These tests are both local tests in that the samples tested are from specific cable locations and the results are therefore limited to those locations. The tests are, however, indicators of conditions in the cable system.

Other on site cable tests include partial discharge (PD) testing and tan δ testing. These are non-destructive diagnostic tests that provide information on the condition of the entire length of cables and are the most effective at identifying cable defects, voids, tracking and other cable conditions that represent risk of cable failure. These are considered predictive and trendable tests.

Since about 1980, several cable system operators have incorporated fluid sampling and dissolved gas analysis into their routine cable maintenance program as a means of objectively monitoring changes in cable insulation condition. These programs were expected to provide insight into the condition of the impregnated paper dielectric through monitoring changes in the concentration of several dissolved gases. Similar programs have been successfully applied to power transformers. Partial discharge testing has not considered a routine maintenance test and is generally done only when comprehensive cable analysis is needed as result of suspected cable deterioration. This was partly due to the large size of the testing equipment. Since the development of the power electronics the test equipment size and methodology has changed and the partial discharge testers are being more accepted as periodical tester to establish trends in PD development and power factor deterioration.

The decision by a utility about the partial discharge testing should be supported by a detailed analysis which takes into account technical and economical conditions of a given circuit. The need for technical evaluation should be reviewed in combination with possible costs of circuit overhauling and future replacement. The consequences of a circuit failure because of lack of sufficient information should also be taken into consideration.

5.1 Insulation

Insulation tests are invasive and cannot be done frequently. Usually a sample of the cable insulation is taken after faults or during system upgrading. The following list includes the tests that are traditionally performed on cable samples and used in assessment of the cable condition. Several of these tests have been performed as part of the EPCOR cable assessment program. This is not a listing of all of the possible tests that could be done, and it should be noted that isolated measurements of specific characteristics are often not significant in themselves. Precise limits on the acceptable range of many of the characteristics of aging cable materials are not well understood. Individual measurements are usually most significant when compared with previous results and used as a basis for establishing trends if the samplings are done at the same location.

1. Radial Dissipation Factor (DF), otherwise known as tan delta (tan δ) or power factor, measured on paper samples obtained from different layers of the cable.
   - DF of a new paper insulation is in 0.003 ~ 0.0035 range.
   - Any measured value above 0.004 would indicate significant aging and should be identified for further monitoring.
   - Any aged cable having a dissipation factor exceeding 0.008 should be thoroughly tested and the initiation of preliminary planning for replacement would be advisable.
2. Partial discharge on long cable samples that have been removed from a cable circuit.
   - The results may vary and are often not conclusive when viewed in isolation. These have to be assessed in conjunction with the results of other tests and observations of the sample condition.
3. Radial AC Breakdown (ACBD) test on samples obtained from different layers of the insulation.
   - The electrical withstand (ACBD) of new paper insulation is in the range of 45~55 kV/mm

- If a measured value lower than 25kV/mm is found, the cable insulation and fluid should be thoroughly tested.

4. Degree of Polymerization (DP) that indicates the level of the breakdown of the paper molecules.
   - The DP of new paper is in the range of 1000 – 1200
   - Any value below 600 indicates severe aging.
   - Any value below 400 should be a reason for serious concern and if widespread would provide a strong justification for planning a cable replacement.
   - It has been observed that there is a correlation between the degree of polymerization (DP) and the physical condition of the paper. In samples where the measured DP value approached 200, the paper condition could be seen and felt to be deteriorated.
5. Mechanical strength of the paper insulation.
   - Tensile strength of the paper samples can be monitored and trended. Reduced tensile strength is associated with decreased DP. In conjunction with the DP test results, reduced tensile strength may suggest severe aging and approach to "end-of-life" of the paper.
   - The results of a Folding Endurance test can also be an indicator of reduction in paper mechanical strength.
6. Moisture content of the paper insulation.
   - According to many studies on paper insulation, moisture content has the most detrimental effect on the physical parameters. Water in the insulation can be the byproduct of paper decomposition. It is generally accepted in the cable industry that the moisture content should not exceed 2-3%.
7. Visual examination.
   - This includes checking for evidence of:
     - Discoloration
     - Contamination
     - Signs of wax deposits
     - Evidence of mechanical stress or damage
     - Electrical tracking, scorching or burning

In the recent years, technological development and miniaturization have led to the design of new test equipment suitable for "in-situ" non-destructive testing of entire circuits. These tests can give insight into the electrical processes occurring inside the cable and identify deterioration of the dielectric characteristics of the cable insulation.

Normal operating conditions eventually cause some degradation in most of the individual physical characteristics. A comprehensive analysis is necessary to indicate which of the changes are consistent with the normal aging process and which might be caused by the influence of abnormal conditions. This is best achieved through an ongoing testing program that provides data for trending of the most critical values.
It has to be stressed that all the above tests are done on a sample obtained from one location that may or may not represent the condition of the entire circuit. However, for the purpose of evaluation of the cable

condition the tested sample which displayed the worst parameters were taken into account. The detailed pages show the part of the cable insulation the samples were taken from.

The chemical test (DP) performed on cable insulation obtained from 72RG7 circuit by two different reputable laboratories produced significant different results. The second test witnessed by the EDTI representative is taken into account when assessing the cable results. Since the difference between two labs was significant it is Quanta's opinion that in such case a third laboratory should be employed to confirm results presented by one of the former.

According to the latest additions to the test results conducted by PowerTech the DP tests were not always conducted to the full extent of the governing standard (ASTM D 4243-99 "Standard Test Method for Measurement of Average Viscometric Degree of Polymerization of New and Aged Electrical Papers and Boards"). The samples, if available, should be sent to another lab if any doubt exists. The insulation test should be repeated as often as practicable on as many sampling locations. Because of the controversy with degree of polymerization tests the mechanical withstand test should be considered on all future paper samples.

Apart from the DP testing the other test performed by the same lab in 2012 indicate that remaining parameters of the paper insulation are exceeding the normal values significantly. The moisture content in cable Kraft paper of the circuit 72RG7 is 4% in a few cases. The moisture in paper sometimes indicates the deterioration of the paper as mentioned earlier. Because of these findings the insulation deterioration should be considered even if the polymerization factor tests are inconclusive.

The sampling locations are not suggested. Since this is an invading operation and the circuits are buried it cannot be performed at any location. Usually, the samples are taken at the failure location or during the preventative re-works such as the joint rehabilitation program conducted currently by EDTI. The rehabilitation work locations are decided on information that warrants paper samplings.

5.2 Insulating Fluid

Dissolved gas sampling (DGA) is a well established technique for detecting incipient fault conditions developing in the winding insulation of power transformers. During the late 1970s it was felt that this type of analysis could serve a similar purpose for transmission cables with impregnated paper insulation. Much data from transmission cable systems has since been collected, but the analysis of this data has proved to be more complex than initially expected. This is partly due to the construction of impregnated paper insulated transmission cables having limited similarities to power transformers and partly due to the much higher electrical stresses in cable insulation. As a result, conclusions based on transformer experience have little relevance in transmission cable DGA interpretation. IEEE developed a Trial Use Guide for Gas in Fluid Analysis for Electric Power Cable Systems in the 1990s. There is a discussion in this document of the "fundamentals of gas generation in cellulose and dielectric fluids". There is no discussion of gas generation due to processes other than cable insulation degradation. The values identified in this standard for "normal" and abnormal results were largely based on an Insulated Conductors Conference (ICC) database established in 1984. This was in the very early stages of DGA investigation as a diagnostic tool for fluid filled cables. It appears that the database may have contained a relatively small number of DGA results submitted by very few utilities. As a result, the DGA results were not representative of a broad utility experience and unfortunately that database has since been lost without any surviving record of its content.

It is probable that most of the results used by the ICC (Insulated Conductor Committee of IEEE) working group were obtained from samples collected at cable terminations. This was a typical practice for the utilities collecting DGA samples at that time. Power cables typically extend over several kilometers with much of the dielectric fluid volume inaccessible for sampling since it is contained within the paper insulation. Fluid samples from HPFF cables can be obtained only at specific locations such as the terminations, joints and trifurcators. Samples obtained at these accessories are representative of the conditions at those components, but they provide only a limited insight into the condition of the fluid beyond the sample point. There is relatively little longitudinal movement of the fluid unless the system has been designed with a capability for oil circulation. In HPFF cables, a large proportion of the overall fluid volume is contained in the interior of the pipe in the space that is not occupied by the shielded cables. There is not a significant exchange between the insulation interior and pipe fluid because of both the position of the shielding tapes and the viscosity of the impregnating fluid. As a result, it will only be after major gas generation has occurred inside the insulation that there will there be traces evident in the pipe fluid.

Another factor that must be considered in HPFF cable fluid sampling is the widely differing diffusion rates for individual gases. IEEE 1406 notes that hydrogen diffuses about 3 times faster than other gases. This precludes assessment of the condition of an entire cable based on results from isolated sampling points. Accurate analysis of the condition underlying gas generation requires that the individual components and their relative proportions be known. The concentrations of acetylene, hydrogen, methane, ethylene, ethane, carbon dioxide and carbon monoxide are important clues to the root cause of any gassing situation. For HPFF cables this is hampered by the inability to obtain samples at all points along the cable route.

At the same time as the IEEE Trial Use Guide was being formalized, EPRI initiated a contract to carry out research on the same subject. In 2000, EPRI published Guidelines for the Interpretation of Dissolved Gas Analysis (DGA) for Paper Insulated Underground Transmission Cable Systems. This document was based on broader experience than the IEEE Trial Use Guide and contained several different threshold levels for concern due to the concentrations of individual gases. The major difference between the results of the EPRI and the IEEE standard was recognition of differences in the significance of hydrogen levels at the terminations and elsewhere in the system. A comparison between guideline values in the two documents for static HPFF systems is shown in the following table:

Table 5-1

Static HPFF cable system DGA threshold values in IEEE 1406 & EPRI Guideline

	IEEE 1406 Trial Use Guide		EPRI Guidelines for Terminations		EPRI Guidelines for Cable and Joints	
Gas	**Moderate concern**	**Severe concern**	**Concern Level**	**Action Level**	**Concern Level**	**Action Level**
Nitrogen	>120,000ppm	>200,000ppm	No levels listed	No levels listed	No levels listed	No levels listed
Oxygen	>3,000ppm	>5,000ppm	No levels listed	No levels listed	No levels listed	No levels listed
Carbon Dioxide	>1,000ppm	>5,000ppm	>5,000 ppm	>10,0000 ppm	>5,000 ppm	>10,000 ppm
Carbon Monoxide	>500ppm	>1,000ppm	>300 ppm	>2,000 ppm	>500 ppm	>1,000 ppm
Hydrogen	>1,000ppm	>5,000ppm	>1,500 ppm	>10,000 ppm	>10,000 ppm	>40,000 ppm
Methane	>500ppm	>1,000ppm	>1,000 ppm	>4,000 ppm	>1,000 ppm	>4,000 ppm
Ethane	>1,000ppm	>1,500ppm	>500 ppm	>1,000 ppm	>500 ppm	>1,000 ppm
Ethylene	>200ppm	>1,000ppm	>200 ppm	>500ppm	>200 ppm	>500 ppm
Acetylene	>20ppm	>50ppm	>30 ppm	>150ppm	>1 ppm	>5 ppm
Total Combus-tible Gas	>3,000ppm	>8,000ppm	No levels listed	No levels listed	No levels listed	No levels listed

Throughout the power utility industry the most common observation in suspect HPFF dielectric fluid samples is one of elevated hydrogen concentrations. In the past as a practical guideline, HPFF cable hydrogen levels of 600 ppm or less would have generally been considered satisfactory. Once values above that level were observed, additional monitoring would usually have been done. It has been observed that even in solution, this gas is relatively mobile. Elevated levels of hydrogen are often observed from HPFF samples at significant distances from the site of generation. Observations of elevated concentrations of the other significant dissolved gases remote from the site of production are less common. The other gases including methane, ethane, ethylene and acetylene are most commonly detected only when samples are taken close to the site of gas production. When only an elevated hydrogen level is apparent in a sample result, unanswered questions remain as to whether elevated levels of the other significant gases would be found if it were possible to sample the fluid throughout the cable length. As a result, the optimum method of assessing the overall DGA profile of the pipe fluid is to completely flush the cable while frequently sampling the fluid at its exit point.

Butt gaps between adjoining tapes are always present in the HV cable insulation formed from impregnated paper tapes. Under conditions of high electric stress, partial discharges can occur at those sites and some small amounts of hydrogen are continuously produced. As long as the rate at which the gas can be absorbed by the fluid is not exceeded, this is not harmful. It is for this reason that one of the characteristics of cable fluid most highly valued by the transmission cable industry is the fluid's ability to absorb gas. In situations where gas production in the paper insulation is continuous, the concentrations of dissolved gas eventually reach saturation point and small pockets of free gas develop. Gas pockets in an electric field become sites for further discharges that contribute to an increased rate of gas generation. This can therefore become a self-sustaining process. The risk factor for a transmission cable containing gaseous voids within the laminated paper insulation is a reduced ability to withstand surges and transients, since the cable BIL value is reduced by gaseous voids.

It has generally been believed that excess levels of dissolved gas in well-maintained HPFF cable systems must be the result of either cable overheating or electrical discharges occurring inside the laminated insulation. The most worrisome conditions associated with this would be:

- Conductor overheating caused by cable overloading. This may be as a result of operating changes or increases in the thermal resistivity of the cable trench backfill material. Changes in cable thermal conditions may result from changes in the cable environment that have occurred since the original installation, or may be the result of a natural cycle of extreme dryness within the cable trench. Gases produced as a result of thermal stress will usually contain elevated hydrogen, methane, carbon dioxide and carbon monoxide levels and ethane. If the temperature is sufficiently high, there may also be elevated ethylene levels as well.

- Partial discharges occurring in the gaps in the laminated insulation resulting from permanent changes in the paper tape geometry. These discharges most commonly occur during times of heightened electric stress at points where the geometry of the paper tape insulation has been disturbed. For HPFF cables, conductor movement during cable expansion and contraction cycles can lead to repeated small radius bending of the taped insulation and produce changes in the geometry of the tape gaps. This condition is known as thermo mechanical bending (TMB). It has typically been found at the joints of cables that have been subjected to heavy loading cycles. Hydrogen is always associated with partial discharge activity. It depends on the intensity of the discharges whether or not thermal stress is also present. If there is thermal stress at the discharge site, methane, carbon monoxide, carbon dioxide ethane and ethylene may also be found at varying elevated values.

Within the North American power utility industry, there have been reported cases of HPFF cables with very high hydrogen concentrations in the pipe filling fluid. Typically, concentrations of the other combustible gases have not been significantly elevated. In many cases where elevated hydrogen concentrations have been found at the terminations, they have tended to be lower than the values obtained in samples taken at manholes close to the terminal ends. A number of cable installations with these findings have continued to operate satisfactorily over many years. This reliability is contrary to initial expectations that a paper-insulated cable with very high DGA values would be vulnerable to electrical failure during transient overvoltage events. The number of DGA results from HPFF cable installations with a high hydrogen characteristic has led to a realization that other gas production processes may be present in these cables. It has been suggested that many of the elevated hydrogen DGA results may be the result of low intensity partial discharges between the cable shielding/skid wire assembly and the pipe interior. The EPRI DGA Guidelines, published in 2000, include a comment that “Compared to transformers where hydrogen seldom exceeds 2000ppm, HPFF cable systems yield large concentrations of hydrogen. It should be noted that extraordinarily large hydrogen concentrations of the order of 100,000ppm have been observed for cable runs and splices of HPFF cable systems in some cases. Although the generation of hydrogen is attributed to low level partial discharges in fluid resulting in large hydrogen concentrations, such an activity apparently does not impact the cable life."

One of the challenges when high DGA results are discovered is to determine whether or not the results are an indication of deterioration in the quality of the cable insulation. It is self evident that if DGA values are the result of degradation of the Kraft paper or the impregnant, they have very serious implications for system reliability. Cables with degraded insulation can no longer meet the system BIL specification and could compromise the system reliability. High DGA results that are generated entirely within the pipe filling fluid do not affect the cable BIL capability. This type of gassing is typically characterized by the presence of elevated hydrogen concentrations without significant increases in the other gases. Due to the very different diffusion rates of the combustible gases found in fluid impregnated paper insulated cables, it would not be prudent to rely on single point sampling when results containing very elevated hydrogen values only are found. Flushing the system while continuously sampling allows a profile of the distribution of all the gases to be built up. This can reveal whether or not increased concentrations of gases other than hydrogen are present. Where the results confirm that the fluid contains very elevated values of hydrogen only, it would be prudent to completely flush the system to reduce the hydrogen content. This avoids serious problems with implementing emergency repair or maintenance procedures. The emergency repair procedures that would be compromised by very high dissolved gas levels include pipe freezing, joint casing welding, pipe drilling, pumping plant pressure reduction and termination insulator removal.

6 General Assessment of EPCOR HPFF Circuits

The EPCOR HPFF cables range in age from 32 to 56 years. These cables have generally had a good record of reliability, but the diagnostic testing program has identified changes in a number of the cable characteristics. Most notably, deterioration has been found in the cable insulation paper and the quality of the pipe filling fluid. Concentrations of dissolved combustible gas in the cable fluid have been close to an order of magnitude above levels considered satisfactory in industry standards. A significantly increased level of maintenance intervention is required to control the quality of the pipe filling fluid and to monitor changes in insulation paper quality.

Even with increased maintenance program intervention; the changes in insulation quality are irreversible and the original cable insulation quality cannot be restored. The best that can be expected would be a stabilization of the insulation properties at their present condition. Any deterioration in cable insulation quality eventually results in reduced system reliability through a decline in the cables ability to withstand system transients.

The lead-time for installation of a new transmission circuit is 3 to 4 years, Given the present age and condition of these cables, it is recommended that planning be initiated now for replacement of any cables from this group that are considered most critical to system reliability. In addition to the technical parameters, economic considerations must be evaluated. The cost of increased maintenance including possible periodical insulating fluid degassing, additional spares that must be kept, skilled crew capable of immediate repair in case of failure as well as emergency plan for rerouting the power flow should be offset by a new circuit cost. The determination of end of life of a cable will ultimately be an informed judgment that, with the exception of cable failure, will be made as both an engineering and business decision. Until the replacement is in place the monitoring and upgrade program should continue.

The thermal properties of the cable backfill should be assessed by a comprehensive program of field-testing and laboratory analysis in order to validate the cable load ratings. The program that is required to cover all circuits could be extensive and costly. Some samplings were requested for the purpose of this report and are presented in the appendix.

It cannot be over-emphasized that soil thermal properties tests, insulation paper sampling and DGA tests are all location specific and therefore conclusions based on these results may not be representative for conditions at other points in the cable circuit.

There were also four termination failures at Hardisty and two at Clover Bar substations in 1969/70. The lack of information does not allow for identification of those events. The Hardisty failure was recognized as RH7 and Clover Bar as CH9 as there were no other circuits at that time at these two substations.

In 2001, EPCOR adopted a program of fluid sampling. Since then an impressive volume of data on dissolved gas concentrations has been collected from the 72kV and 240kV HPFF cables. The thoroughness and persistence of the collection efforts attest to the importance of the underground transmission cables in the Edmonton power system.

In general, the EPCOR data shows a pattern of extremely high levels of hydrogen with the highest results approximately two to three times higher than the "Action Level" of the EPRI Guideline. Typically, only elevated hydrogen values have been observed in these samples. The many occurrences of significantly elevated hydrogen in the EPCOR database were initially believed to be due to deterioration in the dielectric of the cable or accessories, but in the eleven years since sampling was started, the cables have continued to perform reliably. It is also notable that the concentrations of hydrogen measured in 2001 were already extremely high. It is therefore likely that the gassing had been ongoing for many years before the sampling program commenced.

It has been observed that the patterns of hydrogen buildup in samples from manholes are very similar for both the newer 240kV cable circuits and the older 72kV cables. Fluid with high dissolved gas content in an HPFF system has adverse implications for maintenance and repair procedures and for worker safety. Flushing the entire fluid volume in a circuit is an effective but expensive method of managing the risks associated with high dissolved gas concentrations. Partial flushing of the cable fluid is generally not as effective, unless precise steps are taken to ensure that all of the fluid with elevated gas concentrations has been processed and not redistributed within the cable.

Fluid flushing does not address the underlying cause of the gassing. EPCOR's sampling program has demonstrated that following flushing, gas production (generally hydrogen) resumes from a new lower starting point. This has also been observed following some of the joint replacements.

While the joint replacement program can be beneficial to system health, it appears that the method of selecting joints for replacement has been largely based on the hydrogen concentrations found during fluid sampling as the condition of internal components and deterioration of the cable carrier pipe. In some cases an X-ray evaluation led to the joint replacement. Unless characteristic patterns of the other critical combustible gases are also detected, we strongly recommend that joint internal components replacement decisions not be based on elevated hydrogen values alone. Instead, additional PD testing should be undertaken to determine if electrical discharges are occurring in the insulation at any suspect joint. Termination replacements have generally been carried out following detection of significant acetylene values during DGA sampling. This is a satisfactory use of DGA sampling since acetylene is only produced by high energy arcing. No further electrical testing is required to validate a decision to replace the inner components of the termination in such circumstances.

This is further encouragement that the observed gassing condition is not a fatal one. While it is probable that relatively large concentrations of hydrogen in HPFF cable fluid may not be indicative of deteriorating cable insulation, it is important to recognize that in the design of HPFF cables, high hydrogen concentrations were never intended to be present. With such cables, the detection of abnormal gas concentrations makes it prudent that an active condition management program be applied to mitigate the negative effects. The adverse consequences of this condition include:

- The integrity of fluid freeze plugs, required for hydraulic isolation during repairs, can be compromised by gas coming out of solution producing lengthy gas spaces inside the pipe;
- There is a risk of fire and heightened personnel hazard during pipe cutting or drilling if there is free combustible gas inside the pipe;
- The potential consequences of an electrical fault with sufficient energy to puncture the HPFF pipe are greater if high levels of combustible gases are present in the expelled fluid;
- An accumulation of gas inside the cable termination will cause a significant reduction in the termination BIL;
- If an electrical failure occurs in a termination where the fluid has been displaced by combustible gas, porcelain shrapnel may be propelled over a very wide area;

The operational concerns due to concentrations of free gas in the insulating fluid have significant operational, environmental and safety implications. Management of the fluid condition of HPFF cables with high dissolved gas concentrations can be costly and disruptive. In extreme cases, the impacts on system availability, maintenance program costs, environmental risk and worker safety can be sufficient justification for initiating cable replacement.

6.1 Interpretation of EPCOR DGA Results by EPRI Guidelines

Analysis of DGA results is complex. Gases such as hydrogen can be produced by very different processes and may be present in varying proportions, in combination with lower concentrations of other gases. It is therefore necessary to compare the absolute concentrations of all of the gases found in a sample, as well as comparative rates of change between different samples. The condition assessment of these systems is both art and science and requires significant experience and knowledge to effectively assess all the available data to develop an accurate assessment of the activities occurring inside a cable system.

The results interpretation takes into account the maintenance done on the circuits. Any fluid flushing, degassing or joint replacement alters the trending that has to be restarted. In those cases there is insufficient data to draw a conclusion. In addition to the maintenance, a severe drop in the system pressure releases gasses from the fluid that can be interpreted in later tests can as erratic behavior or anomaly.

The EPRI Report "Guidelines for the Interpretation of Dissolved Gas Analysis for Paper Insulated Underground Transmission Cable Systems" describes threshold values for different cable situations.

EPRI Interpretation of DGA Data Ranges

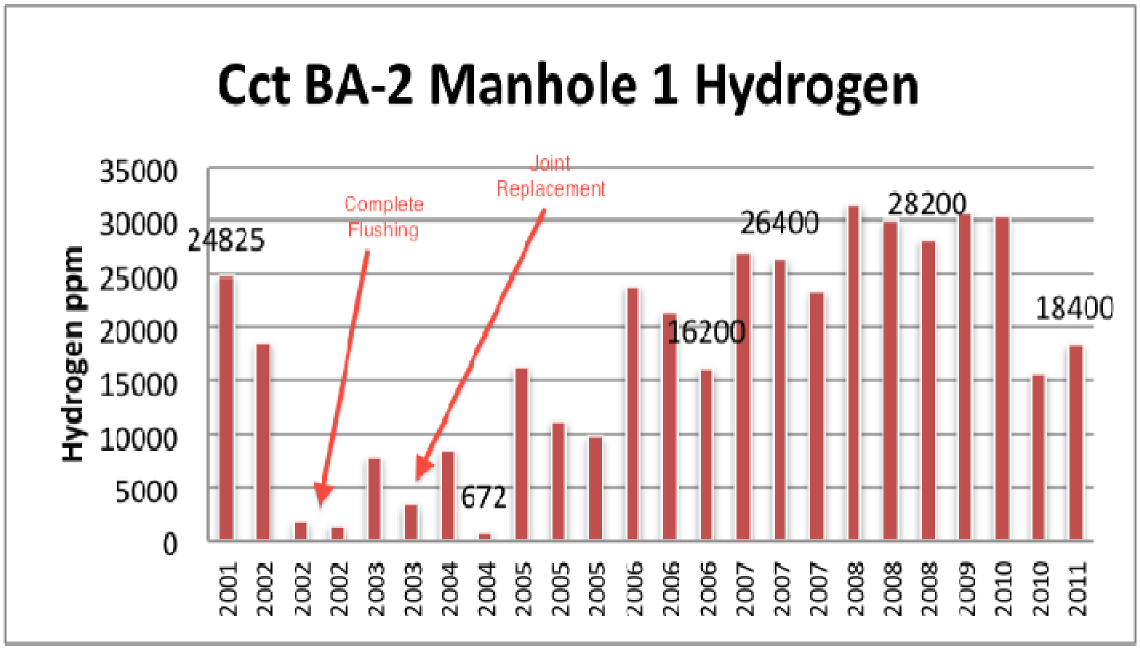
	Acceptable Range ppm			**Concern Range ppm**	**Action Level ppm**
DGA & Location	Static HPFF	Termns	Forced Cooled		
Hydrogen in Static HPFF Cables	<10,000			10,000 – 40,000	>40,000
Hydrogen in Terminations		<1,500		1,500 – 10,000	>10,000
Hydrogen in Forced Cooled HPFF Cables			<1,500	1,500 – 3,000	>3,000
Acetylene in Static HPFF Cables	<1			1 - 5	>5
Acetylene in Terminations		<30		30 - 150	>150
Acetylene in Forced Cooled HPFF Cables			<2	2 - 10	>10
Carbon Monoxide in Static HPFF Cables	<500			500 – 1,000	>1,000
Carbon Monoxide in Terminations		<300		300 – 2,000	>2,000
Carbon Monoxide in Forced Cooled HPFF Cables			<300	300 - 500	>500
Carbon Dioxide in Static HPFF Cables	<5,000			5,000 – 10,000	>10,000
Carbon Dioxide in Terminations		<5,000		5,000 – 10,000	>10,000
Carbon Dioxide in Forced Cooled HPFF Cables			<1,000	1,000 – 5,000	>5,000
Methane in Static HPFF Cables	<1,000			1,000 – 4,000	>4,000

Methane in Terminations		<1,000		1,000 – 4,000	>4,000
Methane in Forced Cooled Cables			<500	500 – 1,000	>1,000
Ethane in Static HPFF Cables	<500			500 – 1,000	>1,000
Ethane in Terminations		<500		500 – 1,000	>1,000
Ethane in Forced Cooled HPFF Cables			<500	500 – 1,000	>1,000
Ethylene in Static HPFF Cables	<200			200 - 500	>500
Ethylene in Terminations		<200		200 - 500	>500
Ethylene in Forced Cooled HPFF Cables			<100	100 - 500	>500

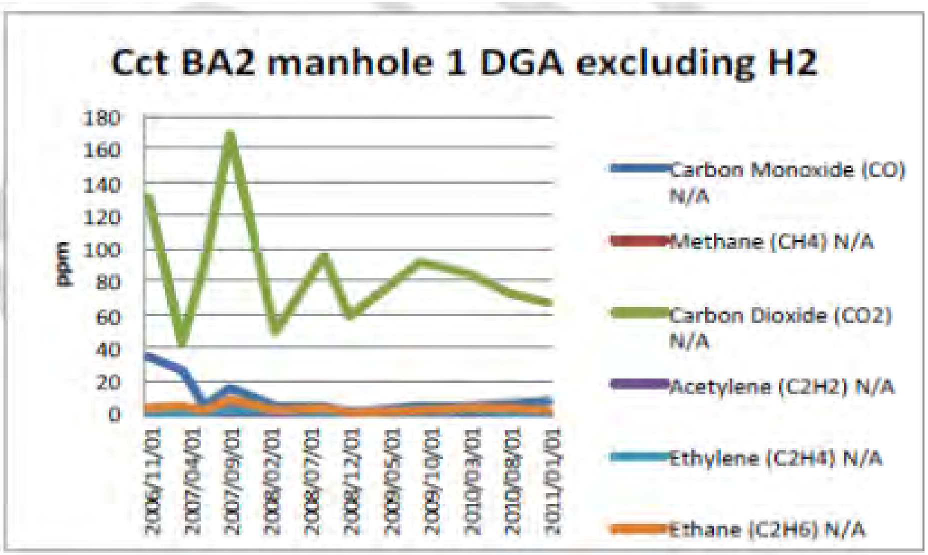
6.2 Hydrogen Concentrations

The EPCOR DGA results obtained since 2001 have consistently shown extremely high levels of hydrogen. Although the consistency of DGA sampling varies considerably from circuit to circuit, virtually all of the Edmonton HPFF cables have at some time produced samples with hydrogen levels above the EPRI "normal" range. Some other Canadian and US electric utilities have made similar observations with their HPFF sampling programs. Significantly in many of these cases, the concentrations of gases such as methane, ethane, ethylene, carbon monoxide and carbon dioxide have remained in a range that would be considered "normal" for service-aged cables. Despite initial misgivings and the adoption of increased monitoring programs, many North American utilities have now concluded that elevated hydrogen results without high values of other telltale gases are not a sign of developing dielectric deterioration. Although moving slowly, the thinking within the industry has evolved since the original IEEE standard 1406 was prepared. There is now a growing appreciation that HPFF cable fluid sampling interpretation is not based on a one dimensional "cause and effect" relationship. The prevalence of high hydrogen level results in many North American utilities from otherwise reliable HPFF cables is a powerful argument for such a reassessment. (Note: IEEE 1406 was originally developed as a "trial guideline" for gas-in-oil analysis and interpretation. It was originally intended that it would be rewritten upon collection of additional data from utility companies. The original guide was issued in 1998, reaffirmed in 2004, but failed reaffirmation in a more recent review. An ICC working group is established to review and rewrite the guideline).

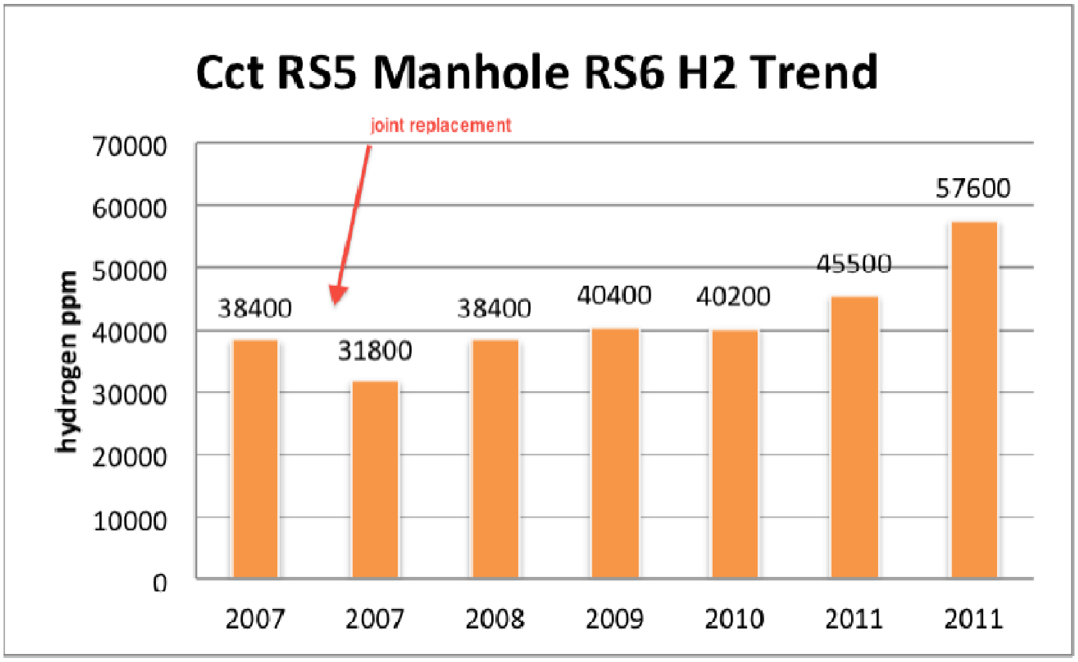
The following graph for circuit BA-2 at manhole #1 shows the trend in hydrogen over an eleven-year period. The fluid in this cable was completely flushed in 2002 / 2003. The cable joint was replaced in 2003. It is understood that some partial flushing of the fluid was carried out in 2010, although the full scope of that work is not clear from the available records.



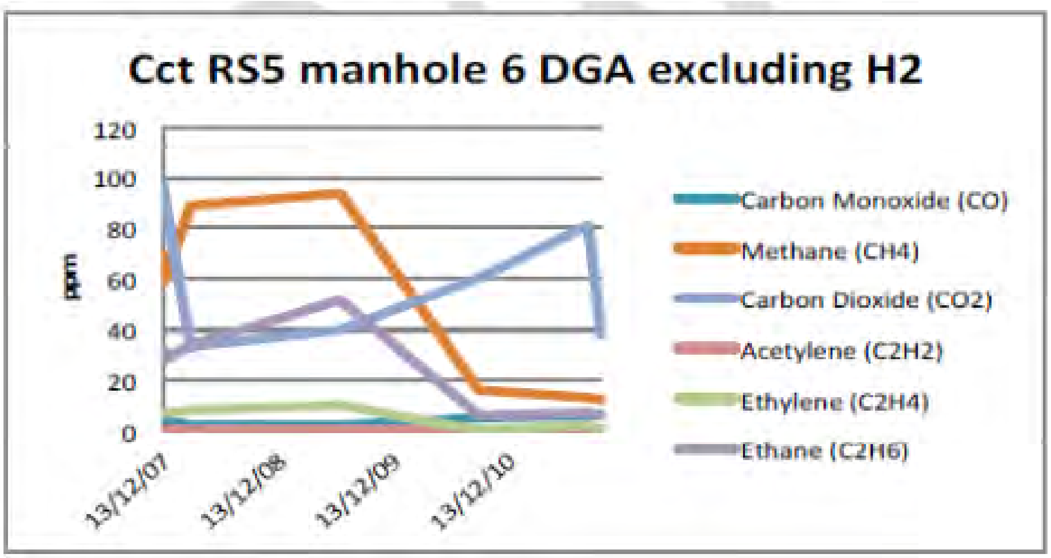
The following graph shows the DGA results for gases other than hydrogen at manhole 1 of circuit BA-2. It can be seen that at the same time as the hydrogen results at this manhole were climbing, all of the other gases continued to be within a range considered to be "normal" for a cable of this age.



All of the joints of cable circuit RS5 were replaced in late 2007 and early 2008. When that work was undertaken it was found that the manhole with the highest concentration of hydrogen was manhole RS6. The following graph shows the variation in hydrogen levels since December 2007.



The following graph shows the DGA results for gases other than hydrogen at manhole RS6 of circuit RS-5. It can be seen that at the same time as the hydrogen results at this manhole were climbing, all of the other gases were within a range considered to be "normal" for a cable of this age.



The graphs from circuits BA2 and RS5 demonstrate that the processes responsible for hydrogen production have continued in these cables despite the joint remedial work and, in the case of circuit BA2, fluid flushing. Furthermore, the DGA results demonstrate that the combustible gases other than hydrogen have been within a "normal" range and have not shown a tendency to increase. These observations appear to validate the guidance in the EPRI Guideline that hydrogen can be produced in HPFF cables in the space between the shielded cables and the pipe wall. Such a process would not involve the cable insulation unless increasing values of gases such as methane, ethane, carbon monoxide, carbon dioxide and ethylene are also found.

6.3 Acetylene Concentration

The production of acetylene provides one example of a cable specific gassing process that differs completely from transformer experience. With HPFF cable terminations if acetylene is detected, frequent monitoring is recommended, but the need for urgent corrective action may not be compelling as with transformers, unless the concentrations are already at a high level or are rising rapidly. The reason for this is because, unlike power transformers, the cable primary insulation is not involved in the production of acetylene. In impregnated paper transmission cables, acetylene is most commonly produced at the outside of the stress cone shielding inside the base of the cable termination. If the surge impedance of the bonding connections between the stress cone shielding wires and close proximity metallic components is high, arcing can occur during system transients. The resulting short duration intense arcing produces acetylene. It should be noted that at power frequencies, all of these components appear to be satisfactorily bonded electrically. Many power utilities with underground transmission cables have observed acetylene in some of their cable termination samples.

If significant acetylene is found in DGA samples, it indicates that localized high temperatures have occurred in the dielectric fluid. The source of the gas production would be close to the sampling point. The abnormally high temperatures involved in this process can seriously degrade the quality of the paper insulation at that location.

Detection of acetylene in HPFF termination samples is usually an indication of:

- The stress cone shielding connections have been disturbed as a result of mechanical stresses associated with normal cable operation;
- The original stress cone shielding was poorly installed;
- Unauthorized termination modifications have been made subsequent to the original installation.

Identification of acetylene as a gas generated outside the cable dielectric in such circumstances is noted in the "historical background" section of IEEE 1406. While observations of acetylene at HPFF terminations are not indicative of insulation deterioration, action should be taken for findings of 100 ppm or more, as high acetylene concentrations are frequently accompanied by soot deposits in the dielectric fluid. These deposits greatly degrade the quality of the fluid in the termination. Occurrences of acetylene in cable termination fluid are generally successfully resolved when the termination stress cone shielding is removed and carefully replaced. Following replacement, periodic sampling is recommended to confirm the effectiveness of the corrective action.

The 240kV cable terminations at Argyll for both BA2 and BA3 contained mid level concentrations of acetylene when they were first sampled in 2001. With the exception of an isolated re-occurrence at a BA2 Argyll termination in 2010, the acetylene levels have since diminished to almost zero. The EPCOR 72kV HPFF cables have experienced acetylene in varying concentrations at a relatively small number of cable terminations. These have included circuit KN23 at Namao, circuit JM18 at Jasper and circuit JW19 at

Jasper. The DGA spreadsheet demonstrates that that all of the conditions have been satisfactorily managed, presumably by replacing the internal components of the terminations.

6.4 Carbon Dioxide and Carbon Monoxide Concentrations

Both carbon dioxide and carbon monoxide are produced when paper decomposition occurs. In general, when this happens, the volume of carbon dioxide is much greater than that of carbon monoxide. However, when very high temperatures are involved, the proportion of carbon monoxide increases. In extreme cases the volume of carbon monoxide may approach that of the carbon dioxide. Reductions in the ratio of carbon dioxide to carbon monoxide are an indication of high temperature decomposition. The results of research carried out by EPRI led to the conclusion that an increase in the proportion of carbon monoxide relative to carbon dioxide was indicative of electrical discharges. This condition would most likely to be found in samples taken from joints that are experiencing thermal mechanical bending (TMB).

DGA results from the EPCOR spreadsheets show generally satisfactory levels of both gases with few demonstrated causes for any concern relating to thermally induced paper decomposition.

6.5 Methane Concentrations

The normal aging process of paper insulation can produce some increases in methane concentration. In an older, but healthy, HPFF cable the methane concentrations are typically less than 30ppm. Concentrations above 50ppm are of considerable interest. The ratio of hydrogen to methane is an important indicator of the underlying process if both gases are found to be at elevated levels.

Thermal decomposition of paper or fluid tends to produce both hydrogen and methane at appreciable rates. Higher temperatures tend to increase the relative volumes of methane. Sustained electrical discharges are the most frequent source for significant temperature rises in the insulation of HPFF cables. These situations are characterized by increasing methane volumes and a reduction in the hydrogen to methane ratio. Ratios of less than four to one are considered significant indicators of thermal decomposition occurring.

Lower temperature partial discharge activity (ionization) would produce hydrogen and little methane. In this situation, the ratio of hydrogen to methane would be very large.

The EPCOR DGA obtained since 2001 results have consistently shown extremely high levels of hydrogen and low methane levels. This suggests that thermal decomposition is not occurring at the points where the DGA samples for these cables were taken.

6.6 Ethane and Ethylene Concentrations

DGA results containing less than 10ppm for ethylene and 40ppm for ethane gas are normal. If high temperature partial discharges occur within a cable, ethane will be produced in combination with hydrogen and methane. At even higher temperatures, such as found when high energy arcing occurs, significant volumes of ethylene are produced. In samples where acetylene has been found, it is common to also find elevated ethylene concentrations which exceed the ethane values. It has been noted in an Ontario

Hydro investigation of elevated gassing rates in oil paper insulated high voltage cables, that elevated concentrations of ethane and lesser volumes of ethylene can be found if continuous discharges occur causing moderately overheated paper and oil.

DGA results from the EPCOR spreadsheet show generally satisfactory levels of both ethane and ethylene with no significant areas for concern.

6.7 Saturated Hydrocarbons & Isobutylene

HPFF cables were utilized in the US decades before their introduction into Canada. Early American HPFF often contained high concentrations of saturated hydrocarbons. Accordingly, the EPRI Guideline includes values for saturated hydrocarbons and isobutylene. This category was included to differentiate between sample results from early and late vintage US cables. Few Canadian include this data in their DGA programs.

Data for this category were not available for the majority of the EPCOR sampling results.

6.8 General Conclusions

The DGA results show levels of hydrogen that are elevated relative to all industry standards. Although some of the trends are erratic, in general the hydrogen levels appear to be rising. These results are broadly similar to those found in several other North American utilities with HPFF cables of similar vintage and system design. It is likely that this is the result of ionization occurring inside the HPFF pipe during system transients.

HPFF cables of a similar age to those in Edmonton have been reported throughout North America exhibiting similar results. It is almost certain that the cable insulation is not the source of the dissolved gases, however, inevitably some exchange between the oil in the pipe and that in the paper insulation must occur. Therefore some degradation of the insulation properties will eventually occur if the pipe filling oil has a high DGA level. The hydrogen values found throughout this cable system are not unique and the methane and acetylene values are relatively low for cables of this age and design. Some of EPCOR's HPFF cables are close to sixty years old and in general the DGA results display the effects of a long service life.

6.9 General recommendations

- We strongly recommend that all circuits are tested for the presence of the partial discharges. The same equipment provides the average dissipation factor measurement which would give more information about the system aging. Since EPCOR has engaged in a program of joint rehabilitation based primarily on DGA results, PD measurements would provide a second opinion and this test is complementary to DGA on the need to replace some of the joints. In addition, if the same test is repeated in the future it may provide data for the trend analysis.
- It is recommended that regular DGA sampling be carried out at the same sample points on circuits where significantly increase dissolved gas activity has been noted. These cable circuits are identified in the following section.

* It is recommended that fluid flushing and filtering to improve the quality of the pipe fluid be carried out for circuits displaying significantly elevated hydrogen values. During flushing, frequent samples should be taken to determine the complete DGA profile along the cable length. These cable circuits are identified in the following section.

7 Detailed Circuit Assessment

This section of the report provides detailed assessments of each individual cable circuit on the EPCOR system. The information reviewed includes the basic cable information (age, type, design ratings), significant operational events over the service life of the cable, loading history, and diagnostic test results. All of the available information on each circuit has been evaluated using the CEATI Cable Health Index program and this section includes the summary results of that evaluation. Finally, the operating risk of each circuit is presented as well as recommendations for future actions.

Cable ratings
The Circuit Ratings (amperes) listed within the table for each cable circuit are EPCOR's existing operating ratings. The original circuit rating listed below the table is the rating specified in the original cable specification. The recommended rating is the rating that Quanta have recommended based on Quanta review of available information.

Paper insulation tests
Since the paper samples are difficult to obtain the test can be done occasionally. Since limited number of tests is available the test with the worst parameters is used as a representative for the quality of insulation for the entire length of the circuit.

Dissolved gas analysis
Where the levels of any combustible gas are above the “action” threshold in the EPRI Guideline it is recommended that DGA sampling be performed at six month intervals. For DGA values that are elevated, but still within the “concern” range we recommend annual sampling. DGA results that are within the acceptable ranges can be re-sampled at longer intervals.

Recommendations
The recommendation of additional tests included in the individual cable assessments, PD in particular, should be preceded by a detailed analysis of costs associated with the various tests and the expected benefit of the information provided by the tests. While partial discharge test gives an inside look into the circuit that is not available by using any other method, the cost of partial discharge testing is significant. Before a decision is taken the thorough review of the circuit conditions, power outage and crew availability should be justified by the economical assessment, risk, and grid future planning.

CEATI Cable Health Index

CEATI International has developed and offers the industry a Cable Health Asset Index Software program that is designed to assist asset managers in evaluating condition and risk of specific assets, in this case underground cable. The software application accepts inputs of various cable parameters and based on weightings applied by the user for each parameter, calculates scores for Total Health Rating, Total Risk Rating, and an overall Total Rating. Each of the individual circuit assessments that follow in this section include the detailed report page from the program showing the specific inputs used in the assessment of the circuit.

The input value in the program called “Standing” is a value base assigned to specific conditions or operating history of the cable. For example, item 3.8 in Health Factors is Paper Insulation Condition – HPFF & LPFF. In the software program drop down boxes for every assessment offer the user a selection of values based on known factors or measurements. For example, severe DP test results produce a “Standing” of 10 in the program, less severe DP scores result in lower standing value. The “Weighting” value in the program is directly entered by users based on the importance of the specific topic to the overall health of the asset. This value was assigned by the investigator based on his knowledge of the EDTI grid. The “sub-total” score is the product of standing and weighting. The advice on the specific item was collected in the software manual.

For each of the EPCOR cable circuits presented in this section, the CEATI Health Rating, Risk Rating and Total Rating will be shown, in addition to the detailed report page from the program. These scores offer a relative ranking of the health and risk of each circuit based on the inputs which were jointly provided by EHV Power/Quanta personnel and EPCOR personnel. As HPFF cable condition assessment is a very subjective process, additional quantification of condition and risk factors only aid in the overall data collection and evaluation upon which a cable condition is ultimately based.

A summary table of all circuits is provided in Appendix 1. That table displays the Health Factor, Risk Factor, and Total Rating of the EPCOR circuits. The detailed forms that include the inputs used in calculation were added at the end of each circuit evaluation. (Note: there are slight variances in the Total Rating number shown on the individual circuit detailed reports and the Appendix 1 Summary Report. Review of this variance has shown that it is caused by a feature in the CEATI program that is beyond the ability of the user to adjust. The variances are in the range of 5 to 10 points and do not impact the overall assessment of the circuit.)

7.1 Cable Circuit 72CH9

CH9 is a 72kV circuit between Clover Bar and Hardisty substations. Specific characteristics of this cable are as follows:

Circuit Name	Length (m)	Yr of Install	Conductor Size (kcmil) & Type	Cable Mfr	Circuit Ratings (Amperes)			
					Summer Continuous	Summer Emergency	Winter Continuous	Winter Emergency
72CH9	8,629	1970	950 Al	Northern	320	320	320	320
	586		1500 Cu	Pirelli				

The original circuit rating was 610A @ 0.77 load factor

Recommended ratings: 350A (conditioned by loads of other Clover Bar connected circuits; details in Appendix #6)

7.1.1 Operational History

1. **Major failures:**

1974 - Cable failure including pipe rupture, presumably due to overheating
1998 - Hardisty pothead failure because loss of pressure

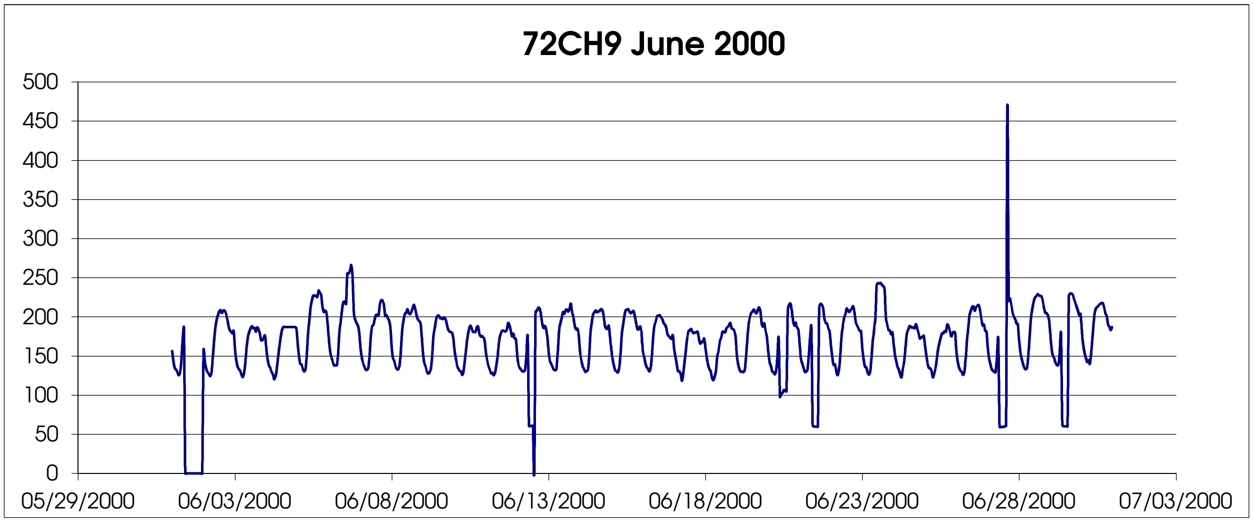
2. **Major maintenance:**

1978 - Circuit de-rated approx. 50% and backfill replaced on Hooke Rd from Hooke Rd to 34th St.
2007 – Termination, phase 2 repaired at Hardisty
2010 - Splice was rebuilt in manhole CNH1

3. **Load History**

This circuit experienced a fault in 1974 that was later attributed to improper backfill and insulation overheating. The remedial action of replacing part of the backfill and reducing the maximum allowable cable load reduced the risk of further failures. The extent of the cable overheating due to this overloading is not known. It is almost certain that this occurrence has shortened the remaining lifetime of each of the cables that were involved.

The load history was provided by EPCOR from 1999 to the present. There is no sign of circuit overloading. The maximum daily circuit load is within 50-60% of the cable rating. The chart below shows a typical pattern with one short duration load spike caused by switch tripping.



4. Major improvements

The native backfill soil was replaced with thermally uniform composition backfill between Hooke Rd and 34th St. The detailed thermal characteristics of the new backfill are unknown at the time of this report.

The analysis of gases inside the pipe and accessories was the cause of rebuilding termination at Hardisty substation and joint in CNH1.

Since the circuit crosses the North Saskatchewan River (NSR), barrier stop joints were installed on each side of the river to reduce possibility of a major fluid spill.

2005 - Barrier stop joint installed in manhole 1A
2007 - Barrier stop joints installed at CH4A and CH5A

7.1.2 Diagnostic Tests

For the purpose of circuit assessment the following tests have been done:

1. Insulation testing

The paper insulation tested in May 2007 was from the barrier splice work undertaken in 2005. The location of tapes was from the Hermitage Park Barrier Splice installation.

And again in October 2008 on samples taken at

a. Intersection of 51St and Ada Blvd .
b. Intersection of 50St and 109A Ave.

While the earlier test revealed reduced breakdown strength, only the later test shows that DF and breakdown strength of the cable insulation and moisture contents exhibit deterioration. The degree of polymerization results are within acceptable range. In addition to the tests, some contaminants of unknown origin were found on the samples.

Circuit	Test Date	Paper Type	Sample Location	Dissipation Factor	Breakdown Strength	Moisture Content	DP
72CH9	May-07	Kraft	cable	Caution	Danger	OK	OK
	Oct-08	Kraft	cable	Danger	Danger	Danger	OK

2. Dissolved Gas Analysis

Location	Samples Taken	Trends	Most recent DGA result per EPRI Guideline
MH CNH1A	2007; 2009; 2011	Rising hydrogen; other gases stable	"Concern" level for hydrogen; "acceptable" level for all other gases
MH CNH1	2001; 2007; 2009; 2011	Stable values for all gases	"Concern" level for hydrogen; "acceptable" level for all other gases
MH CNH2	No samples	N/A	N/A
MH CH3	No samples	N/A	N/A
MH CH4	2008; 2009; 2011	Rising hydrogen; other gases stable	"Acceptable" level for all gases
MH CH4A	2007	N/A	"Acceptable" level for all gases
MH CH5	No samples	N/A	N/A
MH CH5A	2008; 2009; 2011	Rising hydrogen; other gases stable	"Acceptable" level for all gases
MH CH6	No samples	N/A	N/A
Cloverbar Trifurcator	No samples	N/A	N/A
Cloverbar Terminations	2011	N/A	Two samples at "concern" level for hydrogen, remaining sample at "acceptable" level; "acceptable" level for all other gases
Cloverbar Risers	No samples	N/A	N/A
Hardisty Trifurcator	No samples	N/A	N/A
Hardisty Terminations	2011	N/A	One sample at "action" level for hydrogen, remaining samples at "concern" level; "acceptable" level for all other gases
Hardisty Risers	No samples	N/A	N/A

Observations

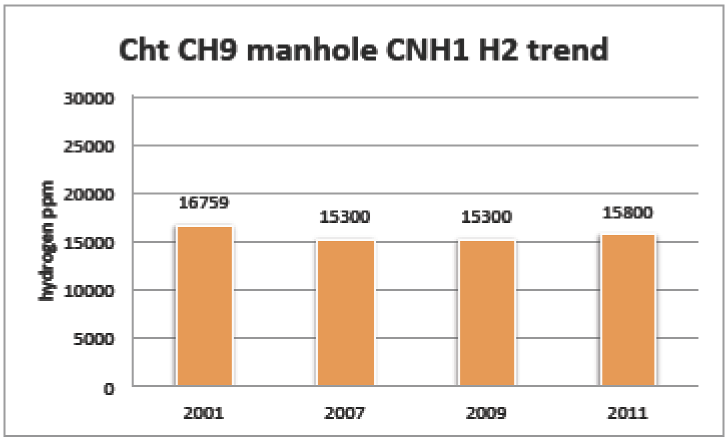
Manholes

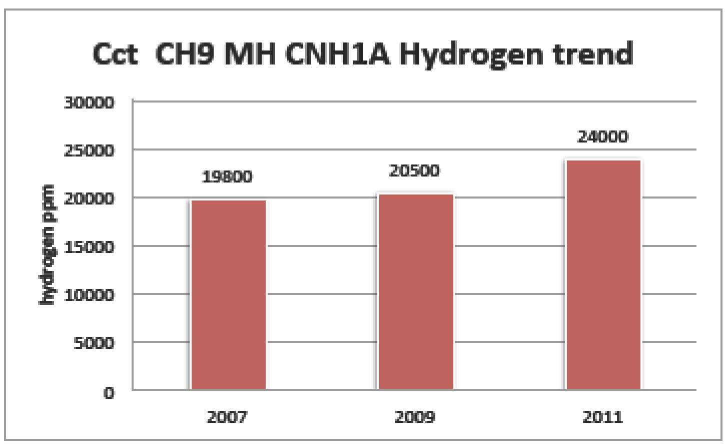
This circuit contains moderately high hydrogen levels that are generally within the "concern" range of the EPRI Guidelines. None of the manhole samples approaches the upper end of the EPRI range for the "concern" category. Concentrations of the other telltale gases have been stable at the manholes.

Terminal Ends

A sample taken in 2011 at one of the Hardisty terminations was marginally above the "concern" upper level for hydrogen. The other two termination samples were at slightly lower values. Concentrations of the other telltale gases have been stable at the terminations.

<u>Circuit 72CH9 Trends</u>





7.1.3 Cable Health Index

CEATI Health Index ratings:

Health Factor: 559
Risk Factor: 248
Total Factor: 847

7.1.4 Risk Assessment

This 42 years old circuit experienced severe overheating problem in the past. The failure that occurred in 1974 was a result of this phenomenon. The failure was repaired but the locations outside of the failed areas have reduced parameters that can lead to another failure. The insulation tests done in 2008 indicated that major parameters are outside of the normal range (see Appendix2). This circuit is considered critical risk and should be a priority for replacement. Ongoing temperature monitoring and DGA, PD and tan δ testing are recommended while it remains in service.

7.1.5 Recommendations

- The circuit insulation should be monitored closely. The PD and dissipation factor test for the entire circuit should be performed as soon as possible and repeated after approximate one year to establish a trend. The subsequent tests frequency should be scheduled by analyzing the previous tests.
- Annual DGA sampling should be carried out at the joints and terminations of this circuit;
- There are temperature monitoring points installed several years ago. If these points are available and sensors are operational the temperature should be obtained and analyzed with the cable load at different seasons of a year.
- There are other areas on the south side of the NSR between the river and substation where the soil conditions may be worse than in the tested area. More detailed studies are recommended.

Table 7.1

Cable Health Index - Detailed Report

Cable Details

Circuit Name	72CH9	Cable Installation Date	1969-10-15
Circuit Section		Cable Length	8523m
Cable Type	HPFF	Conductor Material	Aluminium
Cable Voltage	69	Insulation Material	Paper
Conductor Size	950MCM		

3.0 Health Factor

	Standing	WF	Sub-Total
3.1 Electrical History	7	10	70
3.2 Physical Age	8	10	80
3.3 Outage Records	4	8	32
3.4 Loading History	10	5	50
3.5 System Cable Design Issue	10	10	100
3.6 System Maintenance History	10	7	70
3.7a Oil Testing - HPFF & LPFF	10	6	60
3.7b Oil Testing LPLF	0	6	0
3.8 Paper InsulationCondition - HPFF & LPFF	1	10	10
3.9 Insulation Condition - XLPE	0	7	0
3.10 Accessorry Condition	1	10	10
3.11 Hydraulic History	1	4	4
3.12 Installation Conditions	10	5	50
3.13 Civil Structure Condition	3	3	9
3.14 Stray Current Presence	1	7	7
3.15a Corrosion Protection Condition - HPFF	1	7	7
3.15b Corrosion Protection Condition - LPFF & XLPE	0	7	0

Health Factor Rating: 559

4.0 Risk Factors

	Standing	WF	Sub-Total
4.1 Environmental Impact	10	5	50
4.2 Potential Oil Spill	10	5	50
4.3 Regulatory Requirements	2	5	10
4.4 Safety	5	10	50
4.5 Short Circuit Level	5	4	20
4.6 Obsolescence	5	10	50
4.7 Importance of Circuit	3	6	18

Risk Factor Rating: 248

5.0 Maintenance Cost Factor

	Standing	WF	Sub-Total
5.1 Maintenance & Replacement Costs	10	5	50

5.2 Other Details

Maintenance Cost Factor Rating: 50

Summary - Total Values

Health Factor Rating:	559
Risk Factor Rating:	248
Maintenance Cost Factor Rating:	50

Total Rating: 857

Number of Known Factors: 22

Number of Unknown Factors: 3

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7.2 Cable Circuit 72CH11

CH11 is a 72kV circuit between Clover Bar and Hardisty substations. Specific characteristics of this cable are as follows:

Circuit Name	Length (m)	Yr of Install	Conductor Size (kcmil) & Type	Cable Mfr	Circuit Ratings (Amperes)			
					Summer Continuous	Summer Emergency	Winter Continuous	Winter Emergency
72CH11	8,740	1971	950 Al	Northern Electric	320	320	320	320
	586		1500 Cu	Pirelli				

The original circuit rating was 681A @ 0.77 load factor

Recommended ratings: 290A (conditioned by loads of other Clover Bar connected circuits; details in Appendix #6)

7.2.1 Operational History

1. **Major failures:**

05.1975 – cable failure with pipe rupture, possible cause – overheating, over 10,000l of oil escaped
07.1975 – cable failure with pipe rupture, possible cause – overheating, approx. 1,500l of oil spilled
09.1975 - cable failure, possible cause – poor workmanship of earlier repair,

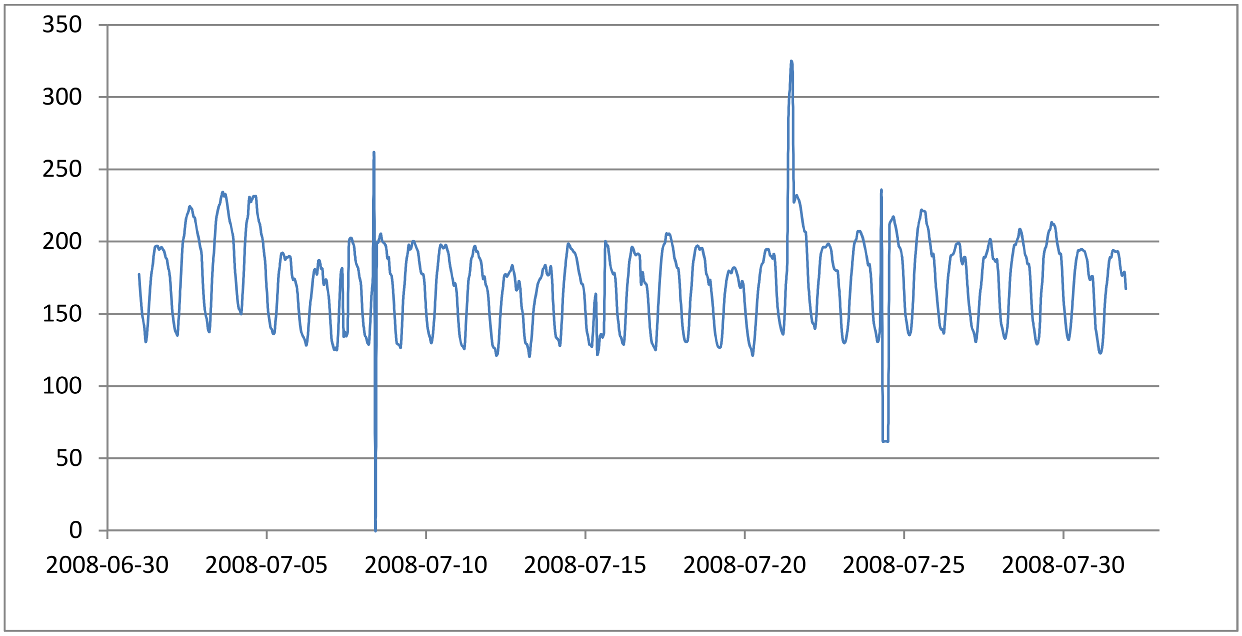
2. **Major maintenance :**

The circuit de-rated approx. 50% and backfill replaced on Hooke Rd from Hooke Rd to 34th St.

2010 – joint rebuilt

3. **Load history:**

This circuit experienced three faults in 1975 that were attributed to improper backfill. The remedial action of replacing part of the backfill and lowering the maximum allowable cable load from 681A to 320A reduced the risk of further failures.
The load history was provided by EPCOR from 1999 to the present. There is no sign of circuit overloading. The maximum daily circuit load is within 50-60% of the cable rating. The chart below shows a typical pattern with one short duration load spike.



4. Major improvement

The native backfill soil was replaced with thermally uniform composition backfill between Hooke Rd and 34th St. The detailed thermal characteristics of the new backfill are unknown at the time of this report.

2005 – barrier joint installed

2007 – two barrier joints installed

7.2.2 Diagnostic Tests

1. Insulation testing

The paper insulation tested in May 2007 was from the barrier splice work undertaken in 2005. The location of tapes was from the Hermitage Park Barrier Splice installation.

And again in October 2008 on samples taken at:

a. Intersection of 51St and Ada Blvd.
b. Intersection of 50St and 109A Ave.

These circuits experienced three faults in the past. The latest insulation tests indicated reduced dissipation factor and ACBD and normal moisture level. The dissipation factor increased from slightly elevated but typical for aged paper to the dangerous level.

Circuit designation	Test date	Paper type	Sample location	Dissipation factor	Breakdown strength	Moisture content	DP
72CH11	May-07	Kraft	cable	Caution	Danger	OK	OK
	Oct-08	Kraft	cable	Danger	Danger	Caution	OK

2. Dissolved Gas Analysis

Circuit 72CH11 Cloverbar x Hardisty SS - 38 Samples

Location	Samples Taken	Trends	Most recent DGA result per EPRI Guideline
MH CHK1	2001; 2008; 2009; 2010; 2011	Rising hydrogen; stable methane and ethane, reducing carbon dioxide and ethylene	"Concern" level for hydrogen; "acceptable" level for all other gases
MH CHK1A	2007; 2009; 2011	Inconsistent changes in hydrogen and carbon dioxide levels, stable values for all other gases	"Concern" level for hydrogen; "acceptable" level for all other gases
MH CHK2	2001; 2007; 2009; 2011	Rising hydrogen; inconsistent changes in methane and carbon dioxide, stable values for other gases	"Concern" level for hydrogen; "acceptable" level for all other gases
MH CH3	2001; 2007; 2009; 2011	Inconsistent changes in hydrogen levels, stable values for all other gases	"Concern" level for hydrogen; "acceptable" level for all other gases
MH CH4	2001; 2011	Reduced hydrogen level; stable values for other gases	"Acceptable" levels for all gases
MH CH4A	2008; 2009; 2011	Increasing hydrogen level; stable values for other gases	"Concern" level for hydrogen; "acceptable" level for all other gases
MH CH5	2001; 2007; 2009; 2011	Rising hydrogen; reducing carbon dioxide, all other gases stable	"Action" level for hydrogen; "acceptable" level for all other gases
MH CH5A	2008; 2009; 2011	Rising hydrogen; all other gases stable	"Acceptable" levels for all gases
MH CH6	2001; 2007; 2009; 2011;	Rising hydrogen; inconsistent changes in carbon dioxide, all other gases stable	"Acceptable" levels for all gases
Cloverbar Trifurcator	No samples	N/A	N/A
Cloverbar Terminations	2011	N/A	"Concern" level for hydrogen; "acceptable" level for all other gases
Cloverbar Risers	No samples	N/A	N/A

Hardisty Trifurcator	No samples	N/A	N/A
Hardisty Terminations	2011;	N/A	One result at "Alarm" level for hydrogen with the other two slightly lower at the upper end of the the "concern" range; "acceptable" level for all other gases
Hardisty Risers	No samples	N/A	N/A

Observations

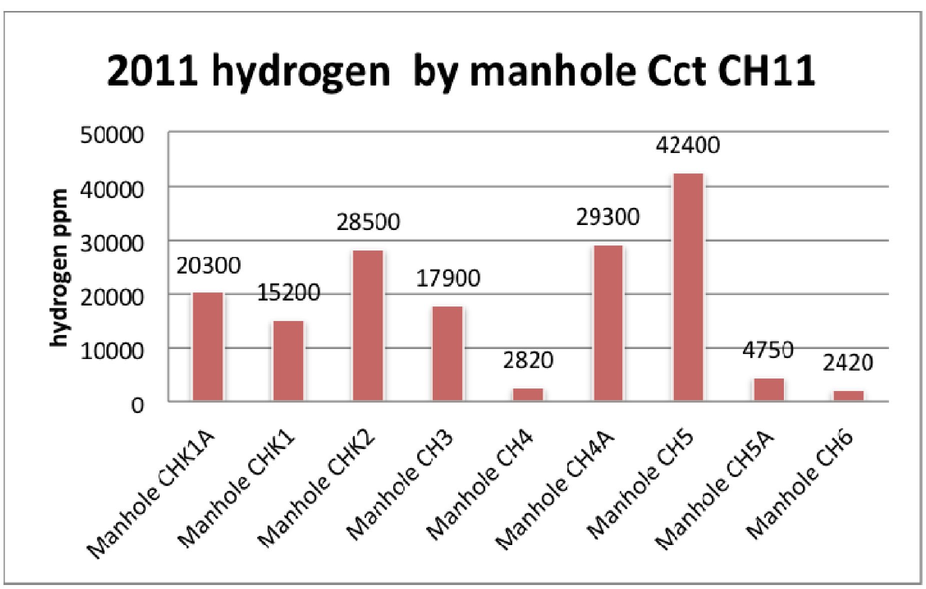
Manholes

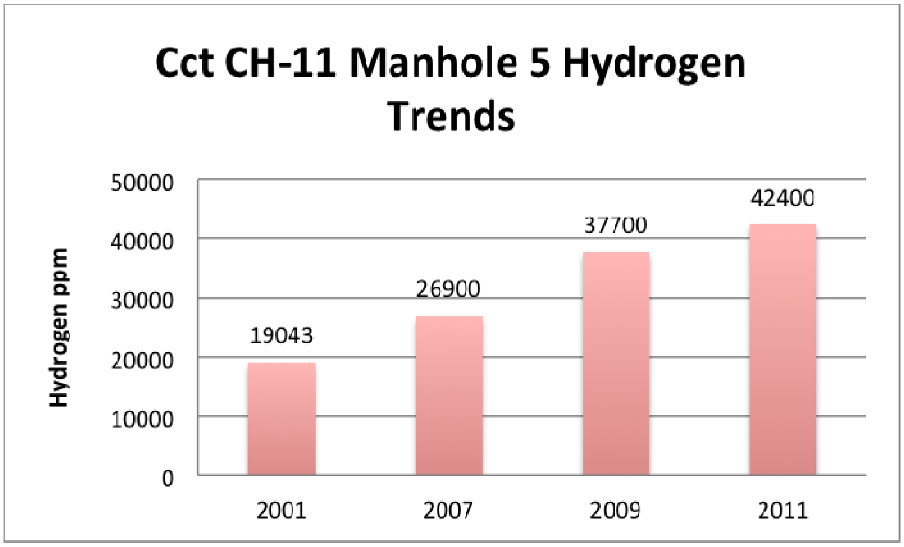
The hydrogen levels at manhole CH5 have continued to rise and the 2011 results have exceeded the "action level" of the EPRI Guidelines. The carbon dioxide levels at this manhole are relatively high but have reduced considerably since the first sample was taken in 2001 and appear to be legacy effects. The methane levels at manholes CHK1 and CHK2 are within the EPRI acceptable range, but are higher than those found elsewhere in the EPCOR HPFF system. The values are stable and have changed very little since 2001. It is therefore likely that these elevated methane values are legacy effects from operating conditions before the start of the DGA program.

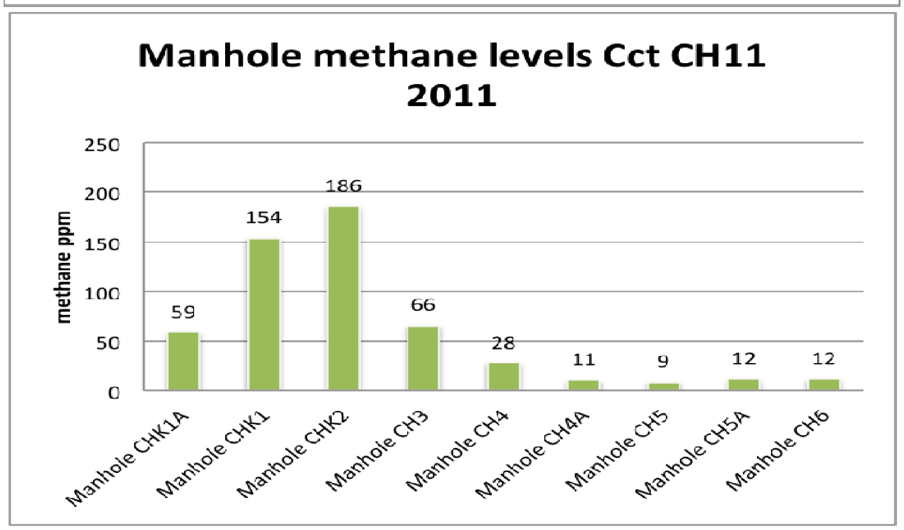
Terminal Ends

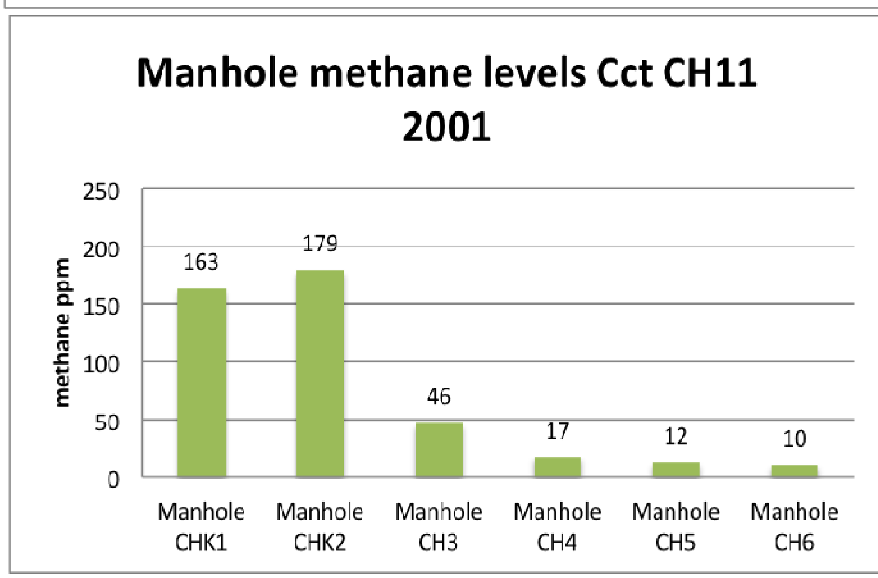
The hydrogen levels at the Cloverbar and Hardisty terminations are in the EPRI "concern" level with the exception of one termination at Hardisty where the hydrogen level is just above the "action" threshold. All other gases at these terminations are within the EPRI acceptable ranges.

<u>Circuit 72CH11Trends</u>




Cct CH-11 Manhole 5 Hydrogen Trends
Hydrogen ppm
50000
40000
30000
20000
10000
0
19043
26900
37700
42400
2001
2007
2009
2011


Manhole methane levels Cct CH11 2011
methane ppm
250
200
150
100
50
0
59
154
186
66
28
11
9
12
12
Manhole CHK1A
Manhole CHK1
Manhole CHK2
Manhole CH3
Manhole CH4
Manhole CH4A
Manhole CH5
Manhole CH5A
Manhole CH6


Manhole methane levels Cct CH11 2001
methane ppm
250
200
150
100
50
0
163
179
46
17
12
10
Manhole CHK1
Manhole CHK2
Manhole CH3
Manhole CH4
Manhole CH5
Manhole CH6

7.2.3 Cable Health Index

CEATI Health Index ratings:

Health Factor:	677
Risk Factor:	269
Total Factor:	986

7.2.4 Risk Assessment

The risk associated with this circuit is similar to the 72CH9 as both circuit parameters indicate a reduced level of electrical integrity (the electrical parameters outside their ranges) as indicated above. This circuit risk is considered to be critical because of the past failures and it should be a priority for replacement.

7.2.5 Recommendations

- Flush all the fluid from this circuit through a filter and degasser while monitoring DGA levels.
- Continue flushing until the hydrogen concentrations have been reduced to a consistent value of less than 10, 000 ppm at manholes and 5,000ppm at terminations.
- Following fluid degassing, DGA should be monitored by sampling at all joints and terminations at six-month intervals;
- Another paper sample should be taken at the first opportunity from a location where the backfill was replaced.
- The PD and dissipation factor test for the entire circuit should be performed now and repeated after one year to establish a trend;
- There are other areas on the south side of the NSR between the river and substation where the soil conditions may be worse than in the tested area. More detailed studies are recommended;

Table 7.2

Cable Health Index - Detailed Report

Cable Details

Circuit Name	72CH11	Cable Installation Date	1971-10-15
Circuit Section		Cable Length	8612m
Cable Type	HPFF	Conductor Material	Aluminium
Cable Voltage	69	Insulation Material	Paper
Conductor Size	950MCM		

3.0 Health Factor

	Standing	WF	Sub-Total
3.1 Electrical History	10	10	100
3.2 Physical Age	8	10	80
3.3 Outage Records	10	8	80
3.4 Loading History	10	5	50
3.5 System Cable Design Issue	10	10	100
3.6 System Maintenance History	10	7	70
3.7a Oil Testing - HPFF & LPFF	10	6	60
3.7b Oil Testing LPLF	0	6	0
3.8 Paper InsulationCondition - HPFF & LPFF	1	10	10
3.9 Insulation Condition - XLPE	0	7	0
3.10 Accessorry Condition	5	10	50
3.11 Hydraulic History	1	4	4
3.12 Installation Conditions	10	5	50
3.13 Civil Structure Condition	3	3	9
3.14 Stray Current Presence	1	7	7
3.15a Corrosion Protection Condition - HPFF	1	7	7
3.15b Corrosion Protection Condition - LPFF & XLPE	0	7	0

Health Factor Rating: 677

4.0 Risk Factors

	Standing	WF	Sub-Total
4.1 Environmental Impact	10	5	50
4.2 Potential Oil Spill	10	5	50
4.3 Regulatory Requirements	3	5	15
4.4 Safety	5	10	50
4.5 Short Circuit Level	9	4	36
4.6 Obsolescence	5	10	50
4.7 Importance of Circuit	3	6	18

Risk Factor Rating: 269

5.0 Maintenance Cost Factor

	Standing	WF	Sub-Total
5.1 Maintenance & Replacement Costs	10	5	50

5.2 Other Details

Maintenance Cost Factor Rating: 50

Summary - Total Values

Health Factor Rating:	677
Risk Factor Rating:	269
Maintenance Cost Factor Rating:	50

Total Rating: 996

Number of Known Factors: 22

Number of Unknown Factors: 3

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7.3 Cable Circuit 72CK12

CK12 is a 72kV circuit between Clover Bar and Kennedale substations. Specific characteristics of this cable are as follows:

Circuit Name	Length (m)	Yr of Install	Conductor Size (kcmil) & Type	Cable Mfr	Circuit Ratings (Amperes)			
					Summer Continuous	Summer Emergency	Winter Continuous	Winter Emergency
72CK12	3,950	1973	950 Al	Canada Wire	385	433	449	489

The original circuit rating was 482A, no load factor available.

Recommended ratings: **310A (conditioned by loads of other Clover Bar connected circuits; details in Appendix #6)**
380A if 72CK13 is not loaded (details in Appendix #6)

7.3.1 Operational History

1. **Major failures**

06.1975 - cable failure with pipe rupture, possible cause – overheating, approx 6,300 l of oil escaped
08.1975 - cable failure with pipe rupture, possible cause – overheating, approx. 2,300 l of oil escaped
09.1975 - cable failure with pipe rupture, possible cause – overheating,
03.1977 - cable failure with pipe rupture, possible cause – overheating, approx. 5,700 l of oil spilled

2. **Major maintenance**

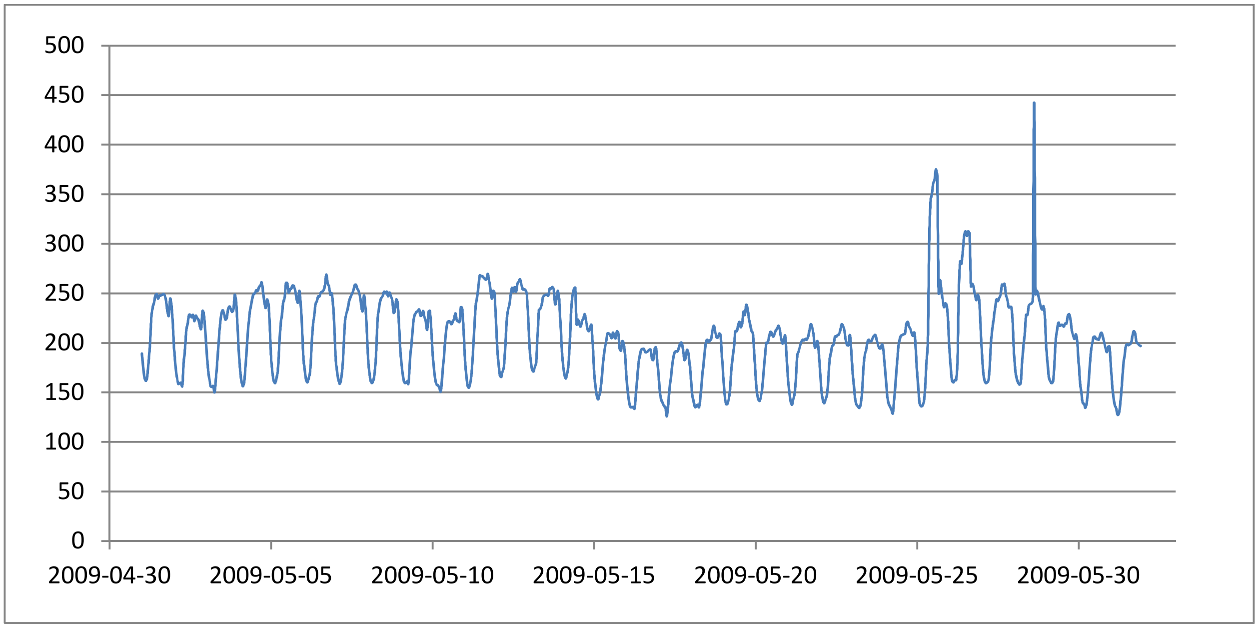
Circuit de-rated and backfill replaced on Hooke Rd from Hooke Rd to 34th St. The detailed thermal characteristics of the new backfill are unknown at the time of this report.

2010 – joint rebuilt

3. **Load History**

This circuit experienced severe faults in the past that were attributed to improper backfill. The remedial action of replacing part of the backfill and lowering the maximum allowable cable load reduced the risk of further failures.

The load history was provided by EPCOR from Jan. 1999 to the present. Reviewing this circuit did not reveal any sign of circuit overloading. The maximum daily circuit load is within 50-60% of the cable rating. The chart below shows a typical pattern with one short duration load spike.



4. Major improvements

The native backfill soil was replaced with thermally uniform composition backfill between Hooke Rd and 34th St. The detailed thermal characteristics of the new backfill are unknown at the time of this report.

2005 – barrier stop joint installed

7.3.2 Diagnostic Tests

1. Insulation test:

The paper insulation tested in May 2007 was from the barrier splice work undertaken in 2005. The location of tapes was from the Hermitage Park Barrier Splice installation.

These circuits experienced multiple faults in the past. The only one insulation test indicated reduced dissipation factor, degree of polymerization and ACBD but normal moisture level. The dissipation factor increased from normal 0.300% for a new insulation to the dangerous level of 0.670%. The polymerization factor indicates accelerated aging in comparison to other cables of the same vintage. This process cause can be attributed to the repeating cable failures in 1975.

Cct designation	Test date	Paper type	Sample location	Dissipation factor	Breakdown strength	Moisture content	DP
72CK12	May-07	Kraft	cable	Danger	Caution	OK	Caution

2. Dissolved Gas Analysis

<u>Circuit 72CK12 Cloverbar x Kennedale SS - 16 Samples</u>

Location	Samples Taken	Trends	2011 DGA result per EPRI Guideline
MH CHK1A	2009; 2011;	Reducing hydrogen; stable values of all other gases	"Acceptable" levels for all gases
MH CHK1	2007; 2008; 2009; 2010; 2011	Rising hydrogen; variable carbon dioxide and methane values; stable values for other gases	"Acceptable" levels for all gases
MH CHK2	2007; 2009; 2011	Rising hydrogen; stable values of all other gases	"Acceptable" levels for all gases
Cloverbar Trifurcator	No samples	N/A	N/A
Cloverbar Terminations	2011	N/A	"Concern" level for hydrogen; "acceptable" levels for all other gases
Cloverbar Risers	No samples	N/A	N/A
Kennedale Trifurcator	No samples	N/A	N/A
Kennedale Terminations	2011	N/A	"Concern" level for hydrogen; "acceptable" levels for all other gases
Kennedale Risers	No samples	N/A	N/A

Observations

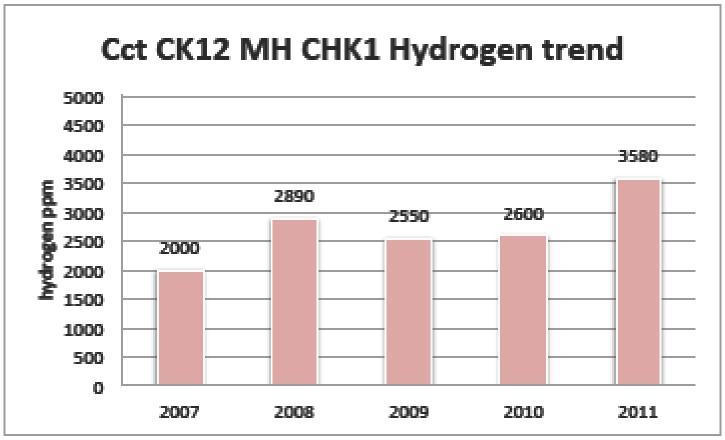
Manholes

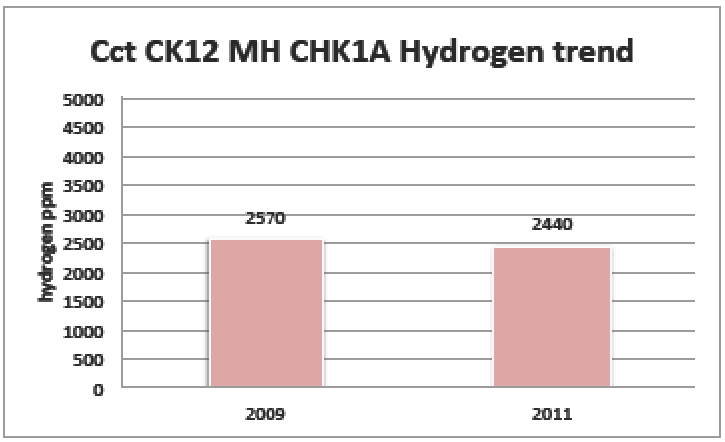
The hydrogen levels for circuit CK12 are relatively low when compared to most of the other EPCOR HPFF cables. All of the other gases are relatively stable at levels that are considered satisfactory given the age of the cable.

Terminal Ends

The hydrogen concentrations at all of the CK12 terminations are at the "concern" level in the EPRI Guidelines. All of the other gases are relatively stable at satisfactory levels given the age of the system.

Circuit 72CK12 Trends





7.3.3 Cable Health Index

CEATI Health Index ratings:

Health Factor: 646
Risk Factor: 243
Total Factor: 929

7.3.4 Risk Assessment

Because of repeated failures as well as electrical and mechanical parameters shown above that are beyond the limits that could be considered as normal aging this is the most vulnerable circuit if all available information is taken into consideration. This is reflected in the Health Index above. It should be scheduled for replacement with priority.

7.3.5 Recommendations

- A program of annual DGA sampling should be carried out at each of the manholes and terminations;
- Perform PD and dissipation factor tests at the first available opportunity;

- If the opportunity permits another paper sample from the originally installed cable should be obtained and tested to verify that the above normal aging conditions discovered in the previous test has not accelerated. The analysis of the trend can be used in more accurate prediction of the future circuit performance.
- There are other areas on the south side of the NSR between the river and substation where the soil conditions may be worse than in the tested area. More detailed studies are recommended.

Table 7.3

Cable Health Index - Detailed Report

Cable Details

Circuit Name	72CK12
Circuit Section	
Cable Type	HPFF
Cable Voltage	69
Conductor Size	950MCM
Cable Installation Date	1973-10-15
Cable Length	3931m
Conductor Material	Aluminium
Insulation Material	Paper

3.0 Health Factor

	Standing	WF	Sub-Total
3.1 Electrical History	10	10	100
3.2 Physical Age	7	10	70
3.3 Outage Records	8	8	64
3.4 Loading History	10	5	50
3.5 System Cable Design Issue	10	10	100
3.6 System Maintenance History	5	7	35
3.7a Oil Testing - HPFF & LPFF	10	6	60
3.7b Oil Testing LPLF	0	6	0
3.8 Paper InsulationCondition - HPFF & LPFF	4	10	40
3.9 Insulation Condition - XLPE	0	7	0
3.10 Accessorry Condition	5	10	50
3.11 Hydraulic History	1	4	4
3.12 Installation Conditions	10	5	50
3.13 Civil Structure Condition	3	3	9
3.14 Stray Current Presence	1	7	7
3.15a Corrosion Protection Condition - HPFF	1	7	7
3.15b Corrosion Protection Condition - LPFF & XLPE	0	7	0

Health Factor Rating: 646

4.0 Risk Factors

	Standing	WF	Sub-Total
4.1 Environmental Impact	10	5	50
4.2 Potential Oil Spill	10	5	50
4.3 Regulatory Requirements	1	5	5
4.4 Safety	5	10	50
4.5 Short Circuit Level	5	4	20
4.6 Obsolescence	5	10	50
4.7 Importance of Circuit	3	6	18

Risk Factor Rating: 243

5.0 Maintenance Cost Factor

	Standing	WF	Sub-Total
5.1 Maintenance & Replacement Costs	10	5	50

5.2 Other Details

Maintenance Cost Factor Rating: 50

Summary - Total Values

Health Factor Rating:	646
Risk Factor Rating:	243
Maintenance Cost Factor Rating:	50

Total Rating: 939

Number of Known Factors: 22

Number of Unknown Factors: 3

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7.4 Cable Circuit 72CK13

CK13 is a 72kV circuit between Clover Bar and Kennedale substations. Specific characteristics of this cable are as follows:

Circuit Name	Length (m)	Yr of Install	Conductor Size (kcmil) & Type	Cable Mfr	Circuit Ratings (Amperes)			
					Summer Continuous	Summer Emergency	Winter Continuous	Winter Emergency
72CK13	3,981	1973	950 Al	Canada Wire	385	433	449	489

The original circuit rating was 482A, no load factor available.

Recommended ratings: **390A (conditioned by loads of other Clover Bar connected circuits; details in Appendix #6)**
430A if 72CK12 is not loaded (details in Appendix #6)

7.4.1 Operational History

1. **Major failures:**

None recorded

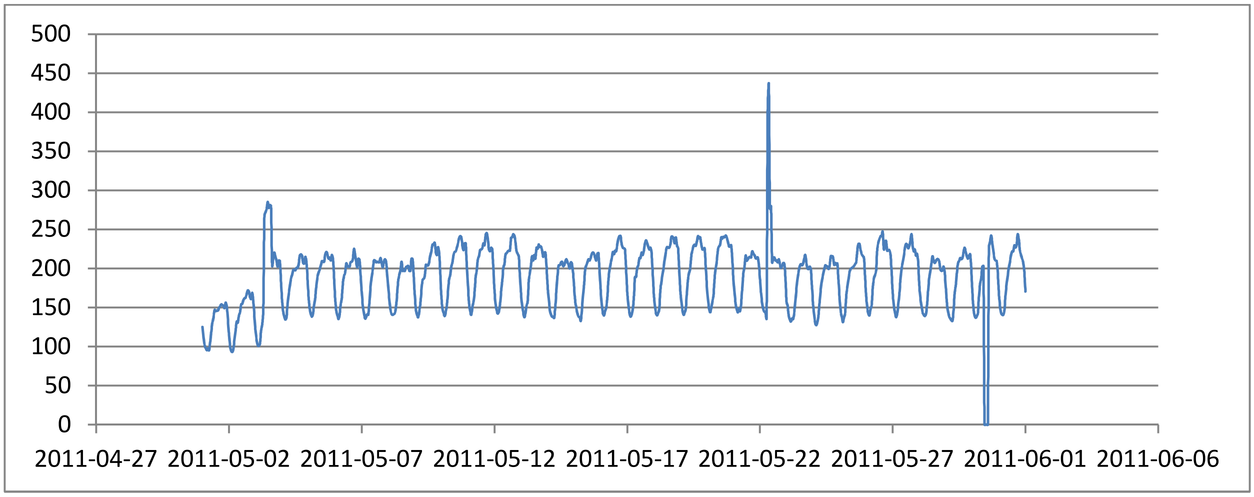
2. **Major maintenance:**

1978 - Circuit de-rated and backfill replaced on Hooke Rd from Hooke Rd to 34th St.
2009 – splice rebuilt
2010 – splice rebuilt

3. **Loading pattern and history**

This circuit experienced no fault in the past but it was installed in improper backfill. The remedial action of replacing part of the backfill and lowering the maximum allowable cable load reduced the risk of failures.

The load history was provided by EPCOR from Jan. 1999 to the present. There is no sign of circuit overloading. The maximum daily circuit load is within 60-70% of the cable rating. The chart below shows a typical pattern with one short duration load spike.



4. Major improvement

The native backfill soil was replaced with thermally uniform composition backfill between Hooke Rd and 34th St.
2005 – barrier joint installed

7.4.2 Diagnostic Tests

1. Insulation tests

The paper insulation tested in May 2007 was from the barrier splice work undertaken in 2005. The location of tapes was from the Hermitage Park Barrier Splice installation.

This circuit running parallel to the 72CK12 did not experience faults in the past. There is no information about the location that the sample was obtained but we assumed that the place was the same as for sample obtained from the 72CK12 cct. In comparison to the 72CK12 this circuit shows degree of polymerization results that are much worse and have to be taken seriously. The value of DP = 464 indicates the insulation paper that is considered at the end of its life for the purpose of cable insulation. Another paper sample should be extracted and tested by a different laboratory to confirm the paper conditions.

The one insulation test indicated reduced dissipation factor and ACBD but normal moisture level. The dissipation factor increased from normal 0.300% for a new insulation to the cautious level of 0.486%. The polymerization factor indicates severe accelerated aging in some places within the cable insulation.

Cct designation	Test date	Paper type	Sample location	Dissipation factor	Breakdown strength	Moisture content	DP
72CK13	May-07	Kraft	cable	Caution	Caution	OK	Danger

2. Dissolved Gases Analysis

Circuit 72CK13 Cloverbar x Kennedale SS - 15 Samples

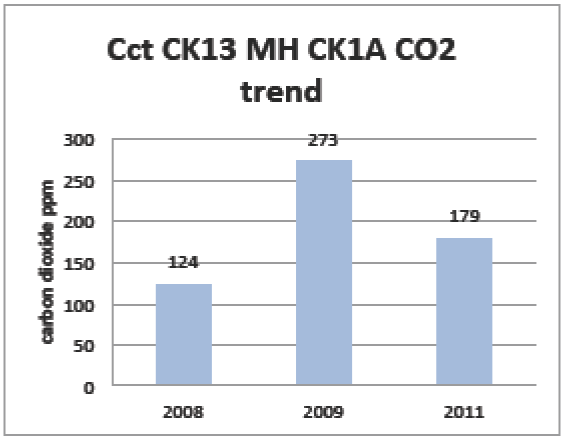
Location	Samples Taken	Trends	Most recent DGA result per EPRI Guideline
MH CK1A	2008; 2009; 2011	Inconsistent hydrogen and carbon dioxide values; all other gases stable	"Acceptable" levels for all gases
MH CK1	2007; 2009; 2011;	Rising hydrogen and carbon dioxide; all other gases stable	"Acceptable" levels for all gases
MH CK2	2007; 2009; 2011	Rising hydrogen; reducing carbon dioxide; all other gases stable	"Acceptable" levels for all gases
Cloverbar Trifurcator	No samples	N/A	N/A
Cloverbar Terminations	2011	N/A	Two of three samples just above "concern" threshold for hydrogen; all other gases at "acceptable" values
Cloverbar Risers	No samples	N/A	N/A
Kennedale Trifurcator	No samples	N/A	N/A
Kennedale Terminations	2011;	N/A	Three samples above "concern" threshold for hydrogen; all other gases at "acceptable" values
Kennedale Risers	No samples	N/A	N/A

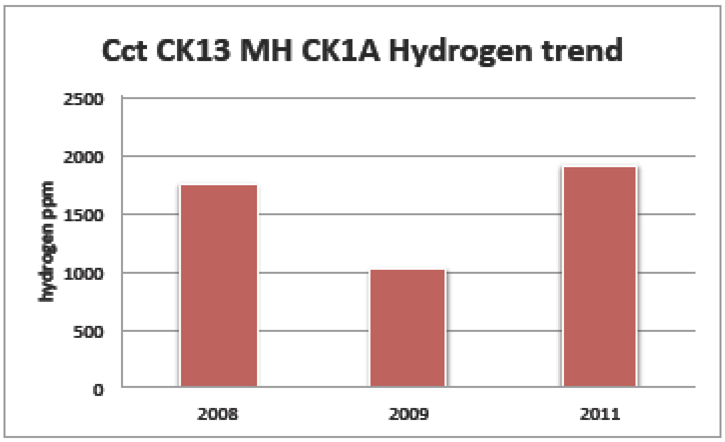
Observations

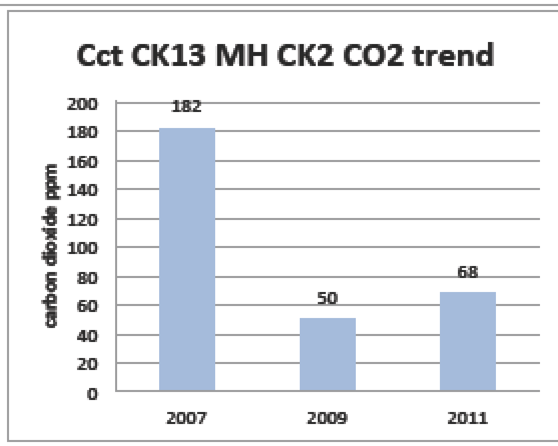
Manholes
The hydrogen levels for circuit CK13 are relatively low when compared to most of the other EPCOR HPFF cables. All of the other gases are stable at satisfactory levels.

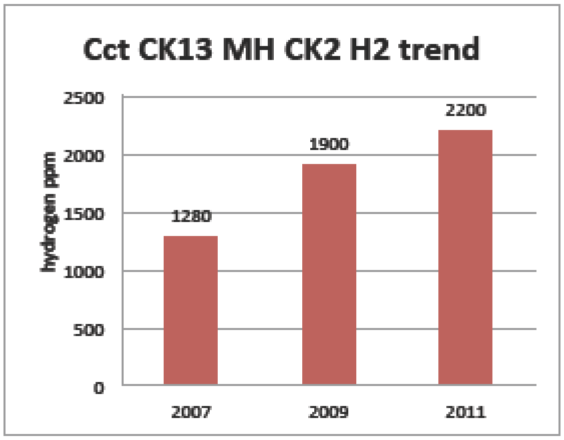
Terminal Ends
The hydrogen concentrations at all of the terminations are at, or close to, the "concern" level of the EPRI Guidelines.

<u>**Circuit 72CK13 Trends**</u>









7.4.3 Cable Health Index

CEATI Health Index ratings:

Health Factor:	514
Risk Factor:	251
Total Factor:	805

7.4.4 Risk Assessment

The cables appeared to be losing mechanical integrity as evaluated in 2007. The DP factor was at the level that is considered as severe aging or even deterioration. Since then, we can assume that the cable aged further to the point that it should be considered for replacement at the first available option unless repeated test proves otherwise.

7.4.5 Recommendations

- A program of annual DGA sampling should be carried out at each of the manholes and terminations;
- A paper sample should be obtained as soon as practicable and evaluate the circuit further.
- Until the sample is tested and evaluated the cable should be loaded at maximum of 50% of current rating and any change of the load should be reduced to minimum to reduce the risk of mechanical damage of the insulation caused by excessive cable thermo-mechanical bending.
- There are other areas on the south side of the NSR between the river and substation where the soil conditions may be worse than in the tested area. More detailed studies are recommended.

Table 7.4

Cable Health Index - Detailed Report

Cable Details

Circuit Name	72CK13	*Cable Installation Date*	1973-10-15
Circuit Section		*Cable Length*	3876m
Cable Type	HPFF	*Conductor Material*	Aluminium
Cable Voltage	69	*Insulation Material*	Paper
Conductor Size	950MCM		

3.0 Health Factor

	Standing	WF	Sub-Total
3.1 Electrical History	1	10	10
3.2 Physical Age	7	10	70
3.3 Outage Records	4	8	32
3.4 Loading History	10	5	50
3.5 System Cable Design Issue	5	10	50
3.6 System Maintenance History	5	7	35
3.7a Oil Testing - HPFF & LPFF	10	6	60
3.7b Oil Testing LPLF	0	6	0
3.8 Paper InsulationCondition - HPFF & LPFF	8	10	80
3.9 Insulation Condition - XLPE	0	7	0
3.10 Accessorry Condition	5	10	50
3.11 Hydraulic History	1	4	4
3.12 Installation Conditions	10	5	50
3.13 Civil Structure Condition	3	3	9
3.14 Stray Current Presence	1	7	7
3.15a Corrosion Protection Condition - HPFF	1	7	7
3.15b Corrosion Protection Condition - LPFF & XLPE	0	7	0

Health Factor Rating: 514

4.0 Risk Factors

	Standing	WF	Sub-Total
4.1 Environmental Impact	10	5	50
4.2 Potential Oil Spill	10	5	50
4.3 Regulatory Requirements	1	5	5
4.4 Safety	5	10	50
4.5 Short Circuit Level	7	4	28
4.6 Obsolescence	5	10	50
4.7 Importance of Circuit	3	6	18

Risk Factor Rating: 251

5.0 Maintenance Cost Factor

	Standing	WF	Sub-Total
5.1 Maintenance & Replacement Costs	10	5	50

5.2 Other Details

Maintenance Cost Factor Rating: 50

Summary - Total Values

Health Factor Rating:	514
Risk Factor Rating:	251
Maintenance Cost Factor Rating:	50

Total Rating: 815

Number of Known Factors: 22

Number of Unknown Factors: 3

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7.5 Cable Circuit 72CN10

CN10 is a 72kV circuit between Clover Bar and Namao substations. Specific characteristics of this cable are as follows:

Circuit Name	Length (m)	Yr of Install	Conductor Size (kcmil) & Type	Cable Mfr	Circuit Ratings (Amperes)			
					Summer Continuous	Summer Emergency	Winter Continuous	Winter Emergency
72CN10	9,178	1970	950 Al	Northern Electric	480	480	480	480

The original circuit rating was 610A @ 0.77 load factor

Recommended ratings: 300A (conditioned by loads of other Clover Bar connected circuits; details in Appendix #6)

7.5.1 Operational History

1. **Major failures:**

None recorded

2. **Major maintenance:**

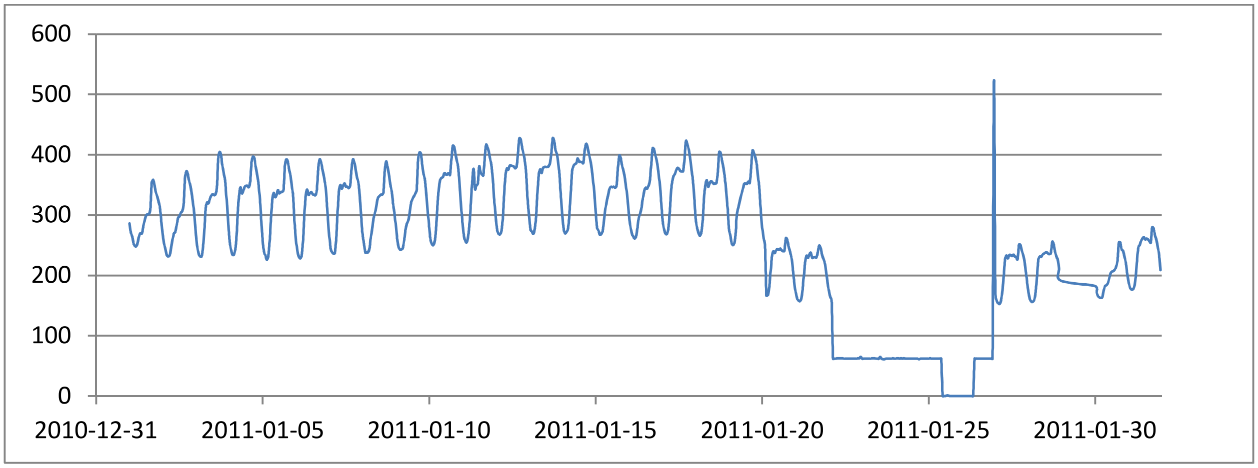
Circuit de-rated and backfill replaced on Hooke Rd from Hooke Rd to 34th St.
2010 – splice rebuilt
2011 – splice rebuilt

3. **Loading pattern and history**

This circuit experienced no fault in the past but it was installed in improper backfill. The remedial action of replacing part of the backfill and lowering the maximum allowable cable load reduced the risk of failures.

The load history was provided by EPCOR from Jan. 1999 to the present. There is no sign of circuit overheating. The maximum daily circuit load is within 60-80% of EPCOR's existing operating cable ratings. The chart below shows a typical pattern with one short duration load spike which exceeds the emergency rating.

If compared to the recommended ratings the load seems to exceed them. However, to establish the cable temperature the cable loads of the other circuits originating at the Clover Bar substation should be taken into consideration at the same time.



4. Major improvements

The native backfill soil was replaced with thermally uniform composition backfill between Hooke Rd and 34th St.
2005 – barrier joint installed to limit potential fluid spill

7.5.2 Diagnostic Tests

1. Insulation tests:

The paper insulation tested in May 2007 was from the barrier splice work undertaken in 2005. The location of tapes was from the Hermitage Park Barrier Splice installation.

This circuit did not experience any fault in the past. The only one insulation test indicated reduced dissipation factor, moisture level and ACBD but normal degree of polymerization. The dissipation factor increased from normal 0.300% for a new insulation to the dangerous level of 0.649%. The polymerization factor does not indicate aging in comparison to other cables of the same vintage. If possible to obtain another paper sample the DP test should be complemented with paper endurance test.

The paper insulation was tested in May 2007 on samples taken at:
CN4 joint

The test did not show any severe deterioration. The dissipation factor is elevated but it can be expected for the aged cable. The moisture content display a pattern that is similar to other cables (72RG7). The highest moisture content was found in the samples taken close to the cable conductor. The DP factor does not indicate aging but the moisture should be taken into consideration.

Cct designation	Test date	Paper type	Sample location	Dissipation factor	Breakdown strength	Moisture content	DP
72CN10	May-07	Kraft	cable	Danger	Caution	Caution	OK
	Oct-12	Kraft	cable	Caution	Caution	Caution	OK
		Kraft	joint	Caution	Caution	Caution	OK

2. Dissolved Gas Analysis

Circuit 72CN10 Cloverbar x Namao SS - 13 Samples

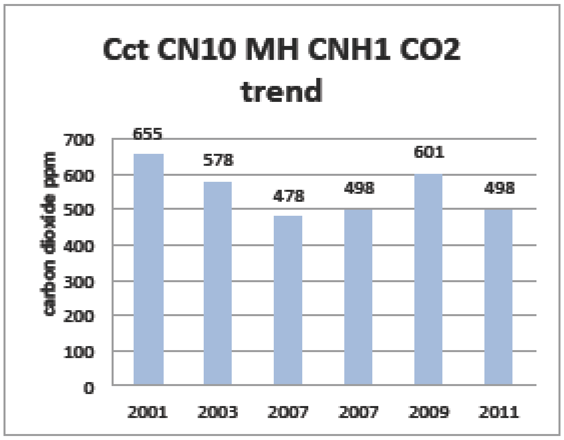
Location	Samples Taken	Trends	Most recent DGA result per EPRI Guideline
MH CNH1A	2007; 2009; 2011	Rising hydrogen and carbon dioxide; stable values for all other gases	"Concern" level for hydrogen; "acceptable" level for all other gases
MH CNH1	2001;2003; 2007; 2009; 2011;	Rising hydrogen; reducing carbon dioxide; stable values for all other gases	Acceptable level for all gases
MH CNH2	No samples	N/A	N/A
MH CN3	No samples	N/A	N/A
MH CN4	No samples	N/A	N/A
MH CH5	No samples	N/A	N/A
MH CN6	No samples	N/A	N/A
Cloverbar Trifurcator	No samples	N/A	N/A
Cloverbar Terminations	2011	N/A	"Action" level for hydrogen; "acceptable" level for all other gases
Cloverbar Risers	No samples	N/A	N/A
Namao Trifurcator	2003;	N/A	"Concern" level for hydrogen; "acceptable" level for all other gases
Namao Terminations	No samples	N/A	N/A
Namao Risers	No samples	N/A	N/A

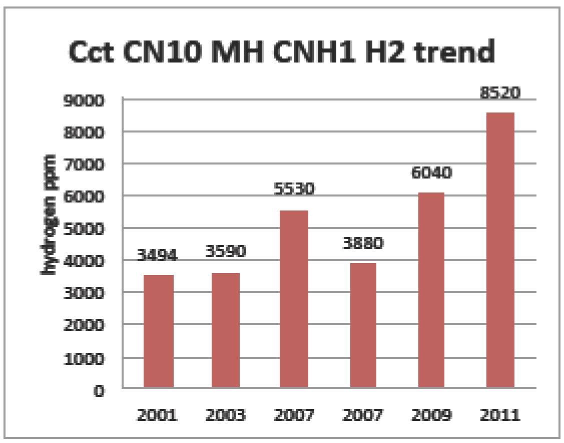
Observations

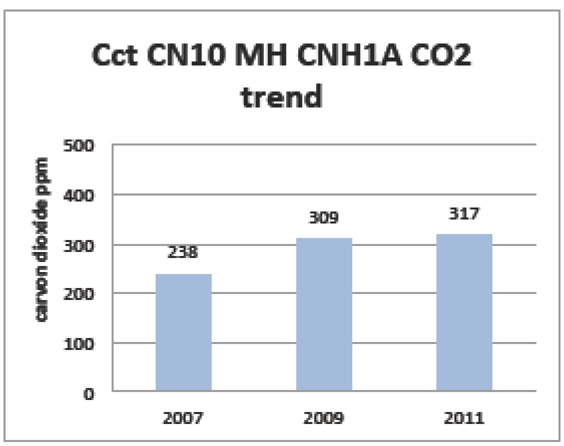
General

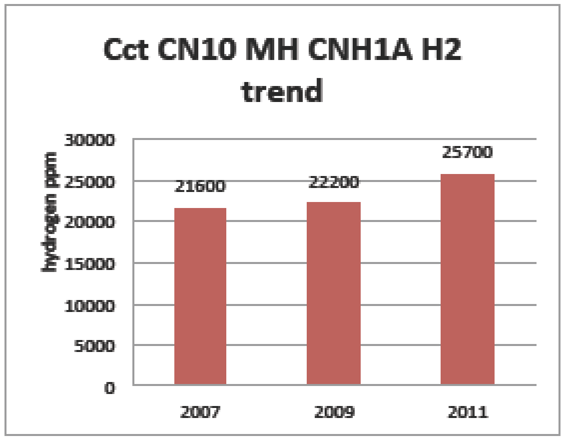
This circuit contains moderately high hydrogen levels that appear to be clustered at sample points close to the circuit ends. The DGA values at the Cloverbar terminations are within the "action" range of the EPRI Guidelines. A sample taken in 2003 at the Namao trifurcator was at a level midway through the "concern" level. Samples taken in 2011 at manhole CNH1A were at similar level. Fluid sampling at the terminations in Namao Substation would be helpful in assessing the current condition of the circuit.

Circuit 72CN10 Trends









7.5.3 Cable Health Index

CEATI Health Index ratings:

Health Factor:	386
Risk Factor:	268
Total Factor:	694

7.5.4 Risk Assessment

The tests done five years ago suggested that the insulation is losing its electrical integrity. Since that time the cable aged further and another test is strongly recommended. Because of high dissipation factor and low breakdown level in spite of low moisture contents the risk assessment of this circuit is high. If obtaining a sample is not possible this circuit should be considered for replacement even if the Health Index does not indicate that.

The later tests did not show such severe deterioration. However, the moisture increase in the layers closer to the cable conductor may indicate that the cable was running in elevated temperature and the paper starts de-composing.

7.5.5 Recommendations

- A program of annual DGA sampling at all manholes and terminations should be carried out;
- The hydrogen levels at the Clover Bar terminations should be closely monitored and if necessary, flushing performed to reduce the levels to less than 5,000ppm;
- Paper insulation test should be a priority on this circuit to assess if the electrical deterioration has not reached dangerous level. There are other areas on the south side of the NSR between the river and substation where the soil conditions may be worse than in the tested area. More detailed studies are recommended.
- There are other areas on the south side of the NSR between the river and substation where the soil conditions may be worse than in the tested area. More detailed studies are recommended.

QUANTA TECHNOLOGY

Is not Table 7.5

Cable Health Index - Detailed Report

Cable Details

Circuit Name	72CN10	*Cable Installation Date*	1969-10-15
Circuit Section		*Cable Length*	9113m
Cable Type	HPFF	*Conductor Material*	Aluminium
Cable Voltage	69	*Insulation Material*	Paper
Conductor Size	950MCM		

3.0 Health Factor

	Standing	WF	Sub-Total
3.1 Electrical History	1	10	10
3.2 Physical Age	8	10	80
3.3 Outage Records	4	8	32
3.4 Loading History	10	5	50
3.5 System Cable Design Issue	1	10	10
3.6 System Maintenance History	1	7	7
3.7a Oil Testing - HPFF & LPFF	10	6	60
3.7b Oil Testing LPLF	0	6	0
3.8 Paper Insulation Condition - HPFF & LPFF	1	10	10
3.9 Insulation Condition - XLPE	0	7	0
3.10 Accessorry Condition	5	10	50
3.11 Hydraulic History	1	4	4
3.12 Installation Conditions	10	5	50
3.13 Civil Structure Condition	3	3	9
3.14 Stray Current Presence	1	7	7
3.15a Corrosion Protection Condition - HPFF	1	7	7
3.15b Corrosion Protection Condition - LPFF & XLPE	0	7	0

Health Factor Rating: 386

4.0 Risk Factors

	Standing	WF	Sub-Total
4.1 Environmental Impact	10	5	50
4.2 Potential Oil Spill	10	5	50
4.3 Regulatory Requirements	6	5	30
4.4 Safety	5	10	50
4.5 Short Circuit Level	5	4	20
4.6 Obsolescence	5	10	50
4.7 Importance of Circuit	3	6	18

Risk Factor Rating: 268

5.0 Maintenance Cost Factor

	Standing	WF	Sub-Total
5.1 Maintenance & Replacement Costs	10	5	50

5.2 Other Details

Maintenance Cost Factor Rating: 50

Summary - Total Values

Health Factor Rating:	386
Risk Factor Rating:	268
Maintenance Cost Factor Rating:	50

Total Rating: 704

Number of Known Factors 22

Number of Unknown Factors 3

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7.6 Cable Circuit 72JM18

JM18 is a 72kV circuit between Jasper and Meadowlark substations. Specific characteristics of this cable are as follows:

Circuit Name	Length (m)	Yr of Install	Conductor Size (kcmil) & Type	Cable Mfr	Circuit Ratings (Amperes)			
					Summer Continuous	Summer Emergency	Winter Continuous	Winter Emergency
72JM18	6,200	1975	950 Al	Canada Wire	480	525	525	577

The original circuit load continuous rating was 482A. The emergency rating was 642A limited to two hours during each 24 hours period.

Recommended ratings: 320A (evaluated together with 72JW19)
390A if 72JW19 is not loaded

7.6.1 Operational History

1. **Major maintenance:**

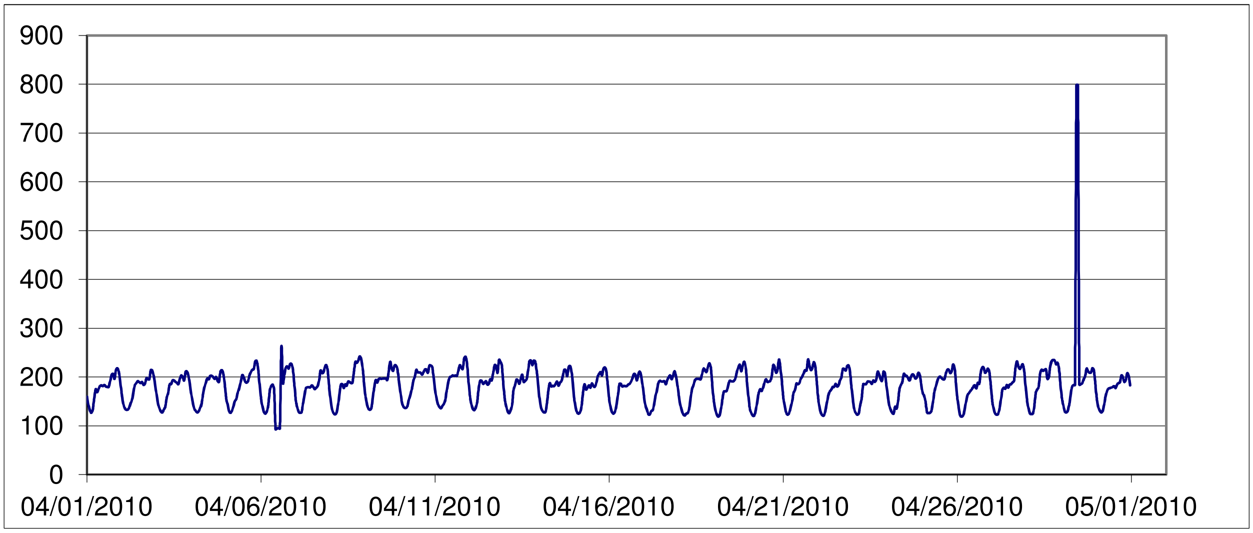
2004 – terminations at Jasper TS rebuilt
2005 – three joints rebuilt
2010 – terminations at Jasper TS degassed

2. **Major maintenance**

No information available

3. **Loading pattern and history**

The load history was provided by EPCOR from Jan. 1999 to the present. In comparison to the rating in affect at the time there is no sign of circuit overloading. The maximum daily circuit does not exceed the circuit continuous rating except the spike shown on the chart. It happened in Jan 17, 2008 and again April 29, 2010. Such sudden increase of the cable load may have severe detrimental effect on the cable conditions.



4. Major improvements

Pressurization pumping plant replaced at Jasper TS.

7.6.2 Diagnostic Tests

1. Insulation tests:

The paper insulation was tested in:

July 2005 on samples taken at:
Jasper TS from the terminations stress cones only one sample was taken from the cable insulation. Since the termination stress cones were replaced the test results are not longer valid.

January 2005 on samples taken from:
Manhole JM18-1
Manhole JM18-2
Manhole JM18-3

The test results of the dissipation factor tested at 90°C were alarming as their value on samples taken from the outer layers exceeded 2.0% while new cable should be less than 0.8%. If compared with other tests this value can be attributed to the moisture level which approaches to the limit that can be considered as dangerous.

Cct designation	Test date	Paper type	Sample location	Dissipation factor	Breakdown strength	Moisture content	DP
72JM18	Jul-05	Kraft	termination	Caution	OK	OK	OK
	Jan-05	Kraft	Joint #1	Danger	OK	Caution	OK
			Joint #2	Danger	OK	Caution	OK
			Joint #3	Danger	OK	Caution	OK

2. DGA tests

<u>Circuit 72JM-18 Jasper x Meadowlark SS -</u> <u>78 Samples</u>

Location	Samples Taken	Trends	Most recent DGA result per EPRI Guideline
MH JWM1	2003; 2005; 2007; 2008; 2009	Inconsistent changes in hydrogen; generally stable values for other gases; an unexplained sharp reduction in all values including hydrogen for the most recent result	"Acceptable" range (but all prior hydrogen results were at mid level of "concern" range)
MH JWM2	2001; 2003; 2005; 2007; 2008	Some inconsistent changes in hydrogen despite a generally rising trend; rising trend in carbon dioxide; generally stable values for other gases	"Concern" range for hydrogen; "acceptable" range for all other gases
MH JM3	2001; 2003; 2005; 2008;	Some inconsistent changes in hydrogen despite a generally rising trend; rising trend in carbon dioxide; generally stable values for other gases	"Concern" range for hydrogen; "acceptable" range for all other gases
MH JM4	2001; 2003; 2005; 2008; 2009	Rising trend in hydrogen, carbon dioxide and carbon monoxide; generally stable values for other gases	"Concern" range for hydrogen; "acceptable" range for all other gases
MH JM5	2001; 2003; 2005; 2008; 2009;	Some inconsistent changes in hydrogen and carbon dioxide; generally stable values for other gases	"Concern" range for hydrogen; "acceptable" range for all other gases
Jasper Trifurcator	No samples	N/A	N/A
Jasper Terminations	2003; 2004; 2005; 2008; 2011	Generally high hydrogen levels; high acetylene levels occurred in the earliest samples and despite remedial work traces of this gas remain in the termination samples; reducing carbon dioxide; stable values for all other gases	Action level for hydrogen, "concern" level for acetylene; "acceptable" level for other gases
Jasper Risers	2001; 2003; 2004; 2005; 2008; 2011	Generally high hydrogen levels; high acetylene and moderate ethylene levels occurred in several samples and traces of these gases remain in the later samples; inconsistent changes in carbon dioxide levels; stable values for all other gases	"Action" level for hydrogen, traces of acetylene in the "acceptable" and "concern" ranges; all other gases in "acceptable" range
Meadowlark Trifurcator	2003; 2005	Rising hydrogen and carbon dioxide levels; stable values for other gases	"Concern" level for hydrogen; "acceptable" range for other gases
Meadowlark	2003; 2005	Rising hydrogen and carbon dioxide	Upper end of "acceptable" range

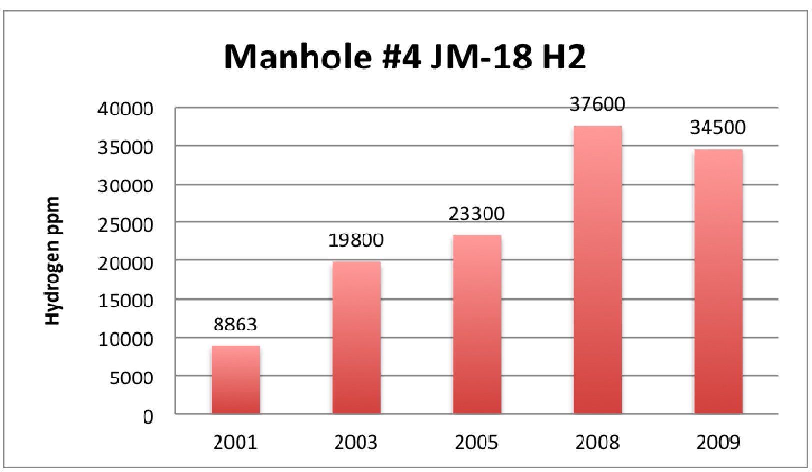
Terminations		levels; stable values for other gases	and lower end of "concern" range for hydrogen; "acceptable" range for other gases
Meadowlark Risers	2001; 2003; 2005;	Rising hydrogen, carbon dioxide and ethane levels; stable values for other gases	Upper end of "acceptable" range and lower end of "concern" range for hydrogen; "acceptable" range for other gases

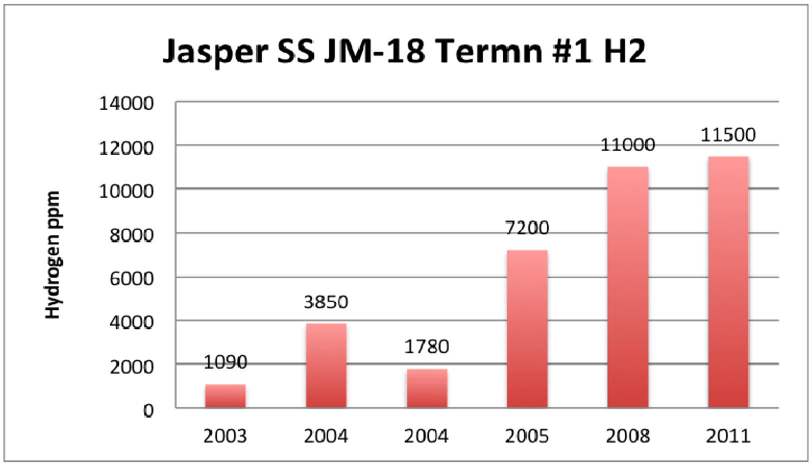
Observations

Manholes
The hydrogen concentrations from samples at manhole JM4 are close to the "action" level of the EPRI Guidelines. The reasons for the observed increases and decreases in some of the hydrogen and carbon dioxide concentrations are not obvious. It is possible that the trends were influenced by fluid movement associated with joint replacements carried out in 2005.

Terminal Ends
It is presumed that the reduction in hydrogen concentrations in 2004 at the Jasper terminations was the result of replacement of the fluid during the termination rebuilding. It is noteworthy that the rising hydrogen trend resumed in subsequent samples. Benefits resulting from the reported degassing of the Jasper terminations in the fall of 2010 could not be seen in the 2011 DGA results. These results therefore remain inside the EPRI "action" level.

<u>Circuit 72JM18 Trends</u>





7.6.3 Cable Health Index

CEATI Health Index ratings:

Health Factor:	399
Risk Factor:	251
Total Factor:	690

7.6.4 Risk Assessment

When the circuit was analyzed during the course of this project after the new ratings were calculated it was noticed that overheating might have occurred on several occasions in the last ten years. This is only discoverable when the circuit JM18 and JW19 are analyzed together within boundaries of a limited location (see Appendix #6). Since the conditions in this location are unknown more tests are recommended.

If the DGA semi-annual monitoring indicates an increasing trend there is evidence that the system conditions are deteriorating. Current assessment of this circuit is a medium risk; however, regular monitoring is required.

7.6.5 Recommendations

- Flush all the fluid from this circuit through a filter and degasser while monitoring DGA levels.
- Continue flushing until the hydrogen concentrations have been reduced to less than 10,000 ppm at manholes and 5,000ppm at terminations.
- Following fluid degassing, DGA should be monitored by sampling at all joints at six-month intervals and terminations every three months.
- A cable insulation sample should be obtained at the first available opportunity and subjected to the regular tests including mechanical tensile and folding endurance tests. The location between the Jasper terminations and the first manhole is of a particular concern.

Table 7.6

Cable Health Index - Detailed Report

Cable Details

Circuit Name	72JM18	Cable Installation Date	1976-08-01
Circuit Section		Cable Length	6190m
Cable Type	HPFF	Conductor Material	Aluminium
Cable Voltage	69	Insulation Material	Paper
Conductor Size	950MCM		

3.0 Health Factor

	Standing	WF	Sub-Total
3.1 Electrical History	1	10	10
3.2 Physical Age	7	10	70
3.3 Outage Records	4	8	32
3.4 Loading History	10	5	50
3.5 System Cable Design Issues	1	10	10
3.6 System Maintenance History	5	7	35
3.7a Oil Testing - HPFF & LPFF	10	6	60
3.7b Oil Testing LPLF	0	6	0
3.8 Paper InsulationCondition - HPFF & LPFF	1	10	10
3.9 Insulation Condition - XLPE	0	7	0
3.10 Accessorry Condition	5	10	50
3.11 Hydraulic History	1	4	4
3.12 Installation Conditions	9	5	45
3.13 Civil Structure Condition	3	3	9
3.14 Stray Current Presence	1	7	7
3.15a Corrosion Protection Condition - HPFF	1	7	7
3.15b Corrosion Protection Condition - LPFF & XLPE	0	7	0

Health Factor Rating: 399

4.0 Risk Factors

	Standing	WF	Sub-Total
4.1 Environmental Impact	7	5	35
4.2 Potential Oil Spill	10	5	50
4.3 Regulatory Requirements	2	5	10
4.4 Safety	5	10	50
4.5 Short Circuit Level	5	4	20
4.6 Obsolescence	5	10	50
4.7 Importance of Circuit	6	6	36

Risk Factor Rating: 251

5.0 Maintenance Cost Factors

	Standing	WF	Sub-Total
5.1 Maintenance & Replacement Costs	7	5	35
5.2 Other Details			

Maintenance Cost Factor Rating: 35

Summary - Total Values

Health Factor Rating:	399
Risk Factor Rating:	251
Maintenance Cost Factor Rating:	35

Total Rating: 685

Number of Known Factors: 22

Number of Unknown Factors: 3

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7.7 Cable Circuit 72JW19

JW19 is a 72kV circuit between Jasper and Woodcroft substations. Specific characteristics of this cable are as follows:

Circuit Name	Length (m)	Yr of Install	Conductor Size (kcmil) & Type	Cable Mfr	Circuit Ratings (Amperes)			
					Summer Continuous	Summer Emergency	Winter Continuous	Winter Emergency
72JW19	6,379	1976	950 Al	Canada Wire	480	525	525	577

The original circuit rating was 482A, no load factor available.

Recommended ratings: 320A (evaluated together with 72JM18)
390A if 72JM18 is not loaded

7.7.1 Operational History

1. **Major failures:**

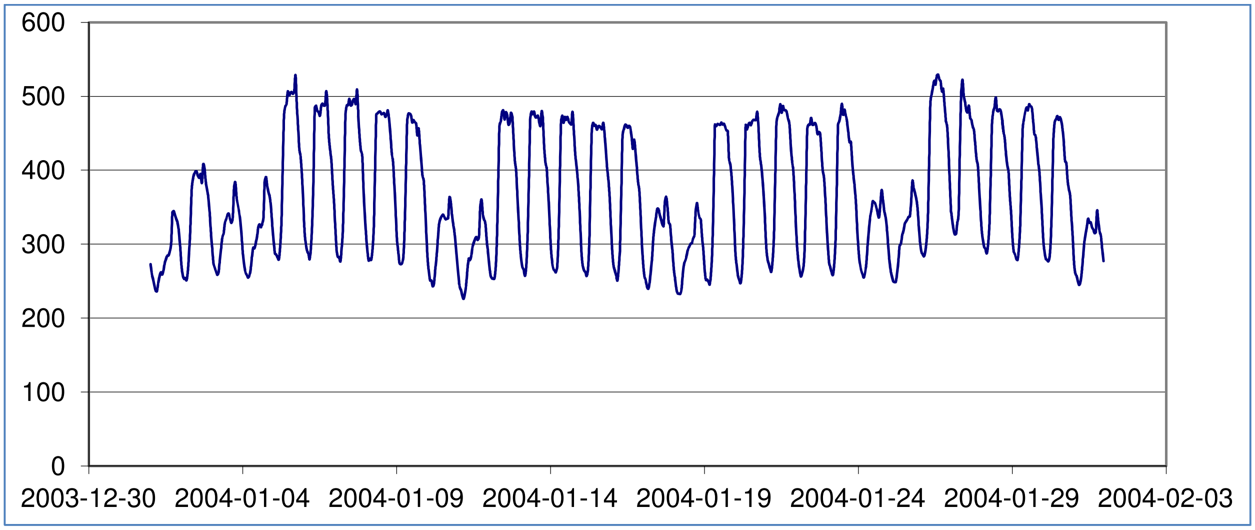
None recorded

2. **Major maintenance:**

2004 – terminations at Jasper TS rebuilt
2006 – terminations at Woodcroft SS rebuilt
2006 – three joints rebuilt
2010 – terminations at Jasper TS degassed

3. **Loading pattern and history**

The load history was provided by EPCOR from Jan. 1999 to the present. There is no sign of circuit severe overloading according to the ratings applicable at the time. The maximum daily circuit load exceeds sometimes the circuit continuous rating. If those overloading occurred in the unfavorable conditions the cable overheating may be a reality. The frequency of the emergency load should not exceed the conditions described in the AEIC CS2-97 standard.



4. Major improvements

Pressurization pumping plant replaced.

7.7.2 Diagnostic Tests

1. Insulation tests

The paper insulation was tested in:

July 2005 on samples taken at:

Jasper TS from the terminations stress cones. Only one sample was taken from the cable insulation. Since the termination stress cones were replaced the test results are not longer valid.

In addition to the electrical and mechanical tests the visual observations revealed a significant sign of carbon on the surface of the paper.

October 2006 on samples taken at:

Manhole JW19-1 (crepe paper)
Manhole JW19-2 (crepe paper)
Manhole JW19-3 (crepe paper)
Terminations at Woodcroft SS – Kraft paper

Since the crepe paper at the joints was replaced when the joints were rebuilt the test results are of a little value for these joints. However, it may indicate the conditions of the three remaining joints that should be scheduled for maintenance if the DGA warrants such an action.

The Kraft paper was taken from the terminations stress cones that were replaced. Since both sides of the circuit have the termination replaced the test could be of a little value.

It has to be stressed that except for on test on outer layer of the cable insulation conducted in 2005 there is no other results that could be taken into consideration for the purpose of the cable condition evaluation.

Cct designation	Test date	Paper type	Sample location	Dissipation factor	Breakdown strength	Moisture content	DP
72JW19	Jul-05	Kraft	termination	Caution	Caution	OK	OK
	Oct-06	crepe	joints	Danger	Danger	OK	OK
	Oct-06	Kraft	Termination Stress cones	Danger	OK	OK	OK

2. DGA tests

<u>Circuit 72JW19 Jasper x Woodcroft SS -</u> <u>83 Samples</u>

Location	Samples Taken	Trends	Most recent DGA result per EPRI Guideline
MH JMW1	2003; 2005; 2007; 2008; 2009; 2011;	Rising hydrogen and ethane levels; stable values for other gases	"Action" level for hydrogen; "acceptable" level for all other gases
MH JMW2	2001; 2003; 2005; 2007; 2008; 2011;	Rising hydrogen and ethane levels; stable values for other gases	"Action" level for hydrogen; "acceptable" level for all other gases
MH JW3	2003; 2005; 2006; 2008; 2009; 2011;	Inconsistent changes in hydrogen levels; stable values for other gases	"Concern" level for hydrogen; "acceptable" level for all other gases
MH JW4	2001; 2003; 2005; 2008; 2009;	Rising hydrogen levels; stable values for all other gases	"Action" level for hydrogen; "acceptable" level for all other gases
MH JW5	2003; 2005; 2009; 2011	Rising hydrogen levels; sharp rise in carbon dioxide in 2011; stable values for all other gases	"Action" level for hydrogen; "acceptable" level for all other gases
MH JW6	No samples	N/A	N/A
Jasper Trifurcator	No samples	N/A	N/A
Jasper Terminations	2003; 2004; 2005; 2008; 2011;	Erratic changes in hydrogen levels; some high acetylene levels occurred in the earliest samples but have been largely eliminated; stable values for other gases	"Action" level for hydrogen; "acceptable" level for all other gases

Jasper Risers	2001; 2003; 2004; 2005; 2008; 2011;	Rising hydrogen levels; some high acetylene levels occurred in the earliest samples but have been largely eliminated; stable values for other gases	"Action" level for hydrogen; "acceptable" level for all other gases
Woodcroft Trifurcator	2003;	N/A	"Concern" level for hydrogen; "acceptable" level for all other gases
Woodcroft Terminations	2003; 2004; 2005; 2006	Rising hydrogen levels; some trace acetylene levels seen in some samples; stable values for other gases	"Action" level for hydrogen; "acceptable" level for all other
Woodcroft Risers	2003; 2005;	Relatively stable hydrogen levels; some trace acetylene levels seen in some samples; stable values for other gases	"Action" level for hydrogen; "acceptable" level for all other

Observations

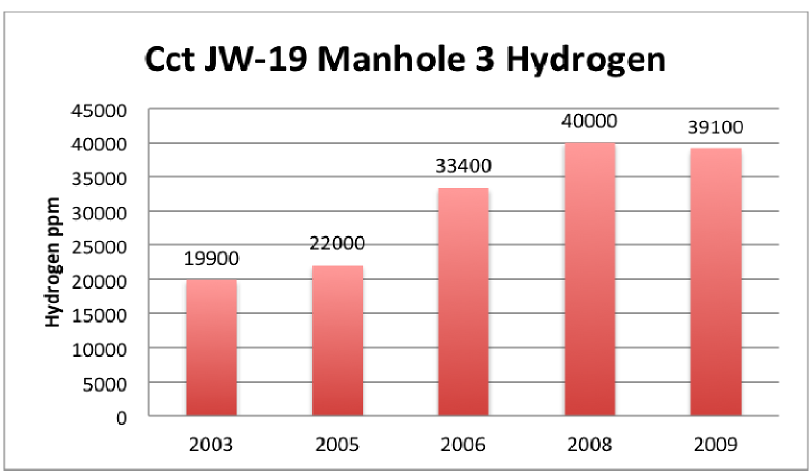
Manholes

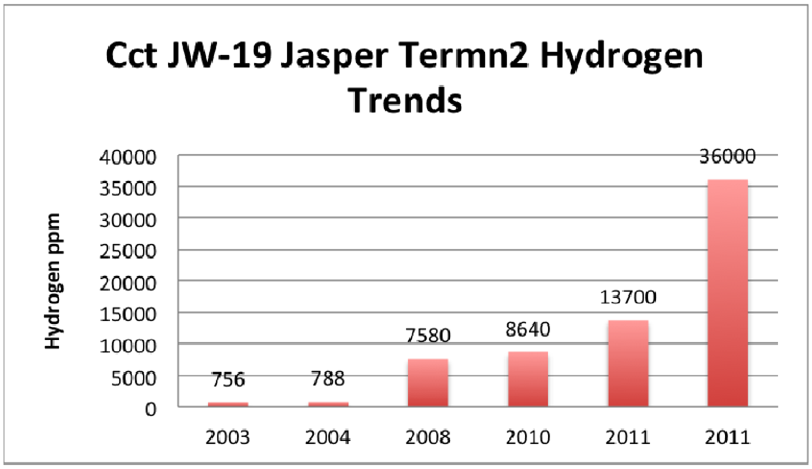
A rising trend in hydrogen is evident in the manhole sample results. Most of these are "action" range of the EPRI Guideline.

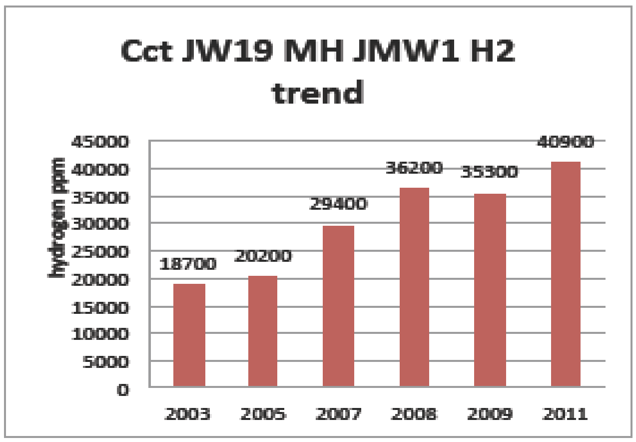
Terminal ends

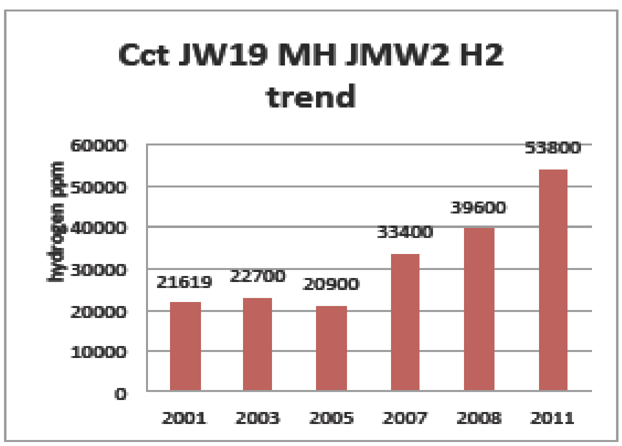
The termination hydrogen levels are well into the "action" range of the EPRI Guideline. A rising trend in termination hydrogen is evident at the Jasper end of the circuit. . Despite the reported degassing in 2010, the Jasper hydrogen concentrations from 2011 appear higher than they were in the prior period. The last samples from the Woodcroft terminal end were taken in 2005, further sampling is recommended.

<u>Circuit 72JW19 Trends</u>









7.7.3 Cable Health Index

CEATI Health Index ratings:

Health Factor:	389
Risk Factor:	228
Total Factor:	657

7.7.4 Risk Assessment

When the circuit was analyzed during the course of this project after the new ratings were calculated it was noticed that overheating might have occurred on several occasions in the last ten years. This is only discoverable when the circuits JM18 and JW19 are analyzed together within boundaries of a limited location (see Appendix #6). Since the conditions at this location are unknown more tests and detailed analysis are recommended.

All insulation tests on samples obtained from different parts of the circuit indicated increased dissipation factor (DF). The increased dissipation factor that is in fact reduced dielectric strength of the cable insulation. The steadily increasing hydrogen trend should be a reason for further investigation. The circuit is currently considered medium risk but requires close monitoring.

7.7.5 Recommendations

- Flush all the fluid from this circuit through a filter and degasser while monitoring DGA levels.
- Continue flushing until the hydrogen concentrations have been reduced to less than 10,000 ppm at all manholes and 5,000 ppm at the terminations.
- Following fluid degassing, DGA should be monitored by sampling at all joints and terminations at six-month intervals. The location between the Jasper terminations and the first manhole is a particular importance.
- All remaining joints should be examined. If warranted by DGA or indication of partial discharges they should be opened and paper samples obtained for testing.

Table 7.7

Cable Health Index - Detailed Report

Cable Details

Circuit Name	72JW19	Cable Installation Date	1976-09-01
Circuit Section		Cable Length	6468m
Cable Type	HPFF	Conductor Material	Aluminium
Cable Voltage	69	Insulation Material	Paper
Conductor Size	950MCM		

3.0 Health Factor

	Standing	WF	Sub-Total
3.1 Electrical History	1	10	10
3.2 Physical Age	6	10	60
3.3 Outage Records	4	8	32
3.4 Loading History	10	5	50
3.5 System Cable Design Issues	1	10	10
3.6 System Maintenance History	5	7	35
3.7a Oil Testing - HPFF & LPFF	10	6	60
3.7b Oil Testing LPLF	0	6	0
3.8 Paper InsulationCondition - HPFF & LPFF	1	10	10
3.9 Insulation Condition - XLPE	0	7	0
3.10 Accessorry Condition	5	10	50
3.11 Hydraulic History	1	4	4
3.12 Installation Conditions	9	5	45
3.13 Civil Structure Condition	3	3	9
3.14 Stray Current Presence	1	7	7
3.15a Corrosion Protection Condition - HPFF	1	7	7
3.15b Corrosion Protection Condition - LPFF & XLPE	0	7	0

Health Factor Rating: 389

4.0 Risk Factors

	Standing	WF	Sub-Total
4.1 Environmental Impact	7	5	35
4.2 Potential Oil Spill	10	5	50
4.3 Regulatory Requirements	1	5	5
4.4 Safety	5	10	50
4.5 Short Circuit Level	5	4	20
4.6 Obsolescence	5	10	50
4.7 Importance of Circuit	3	6	18

Risk Factor Rating: 228

5.0 Maintenance Cost Factors

	Standing	WF	Sub-Total
5.1 Maintenance & Replacement Costs	7	5	35

5.2 Other Details

Maintenance Cost Factor Rating: 35

Summary - Total Values

Health Factor Rating:	389
Risk Factor Rating:	228
Maintenance Cost Factor Rating:	35

Total Rating: 652

Number of Known Factors: 22

Number of Unknown Factors: 3

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7.8 Cable Circuit 72KN23

KN23 is a 72kV circuit between Kennedale and Namao substations. Specific characteristics of this cable are as follows:

Circuit Name	Length (m)	Yr of Install	Conductor Size (kcmil) & Type	Cable Mfr	Circuit Ratings (Amperes)			
					Summer Continuous	Summer Emergency	Winter Continuous	Winter Emergency
72KN23	5,243	1974	950 Al	Canada Wire	480	480	480	480

The original circuit rating was 482A, no load factor available.
Recommended ratings: 460A (evaluated together with CN10)

7.8.1 Operational History

1. **Major failures**

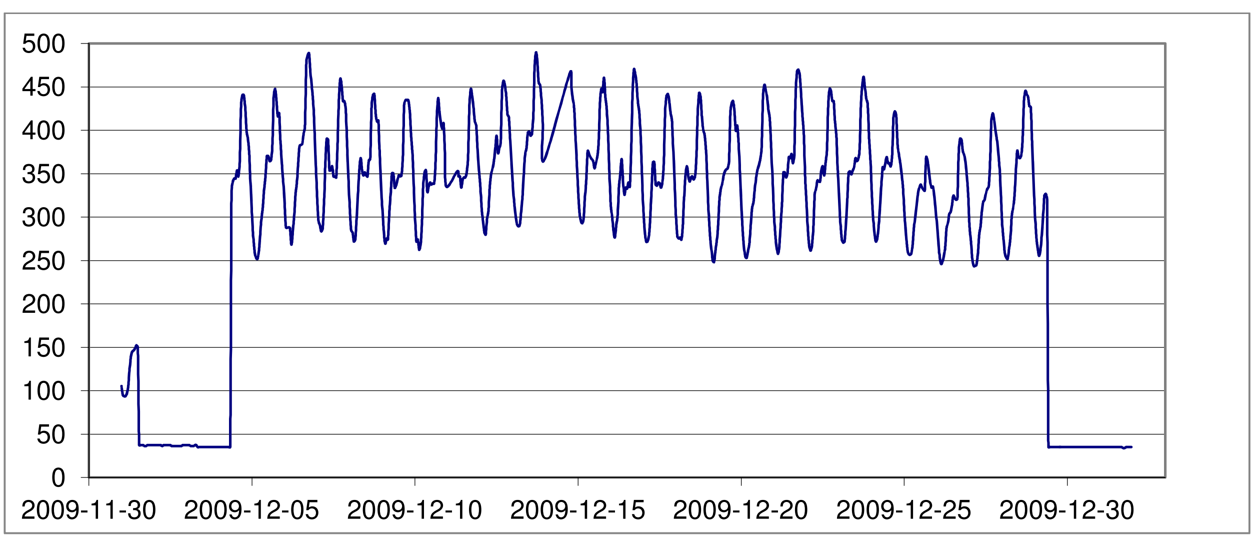
None recorded

2. **Major maintenance:**

2011 - splice in manhole 1 was rebuilt
2012 - Namao termination rebuilt

3. **Loading pattern and history**

The load history was provided by EPCOR from 2007 to the present. There is no sign of circuit overloading. The maximum daily circuit load is within 90-100% of the continuous rating.



4. Major improvements

No information available.

7.8.2 Diagnostic Tests

1. Insulations tests

There is no record of the full test of the insulation. The test done by DTE laboratory in Detroit MI, one of the most recognized laboratories within electrical cable industry in North America, covers only moisture contents and DP.
The samples were taken from:
Joint – KN23KN1 and terminations at Namao and Kennedale
The dissipation factor is at elevated level at the terminations.
The tests done by PowerTech covered all standard tests. The DP and moisture test results were similar.

Cct designation	Test date	Paper type	Sample location	Dissipation factor	Breakdown strength	Moisture content	DP
72KN23	2012	Kraft	Joint			OK	OK
		Kraft	Termination N	Caution		OK	OK
		Kraft	Termination K	Caution		OK	OK

2. Dissolved Gas Analysis

Circuit 72KN23 Kennedale x Namao SS - 18 Samples

Location	Samples Taken	Trends	2011 DGA result per EPRI Guideline
MH KN1	2001; 2006; 2009; 2011	Rising hydrogen levels; all other gases stable	“Acceptable” range for all gases
MH KN2	2001; 2006; 2009; 2011	Increasing hydrogen but unexplained drop between the 2009 & 2011 samples; generally higher than usual methane values up to 2009; stable values for gases other than hydrogen up to 2009; all gases displayed same reduction in 2011 sample results	“Acceptable” range for hydrogen, (but not consistent with prior results which were all in the “concern” range); “Acceptable” range for all other gases
MH KN3	2001; 2006;	Reducing hydrogen levels; stable values of all other gases	“Acceptable” range for all gases
Kennedale Trifurcator	No samples	N/A	N/A
Kennedale Terminations	2011;	N/A	“Concern” level for hydrogen; “Acceptable” range for all other gases

Kennedale Risers	No samples	N/A	N/A
Namao Trifurcator	2006	N/A	"Acceptable" range for all gases
Namao Terminations	2011	N/A	Two samples at "action" level, one at "concern" level for hydrogen; three samples at "action" level for acetylene, ethylene, methane, carbon monoxide, carbon dioxide are in "acceptable" range but higher than commonly seen in EPCOR DGA results.
Namao Risers	No samples	N/A	N/A

Observations

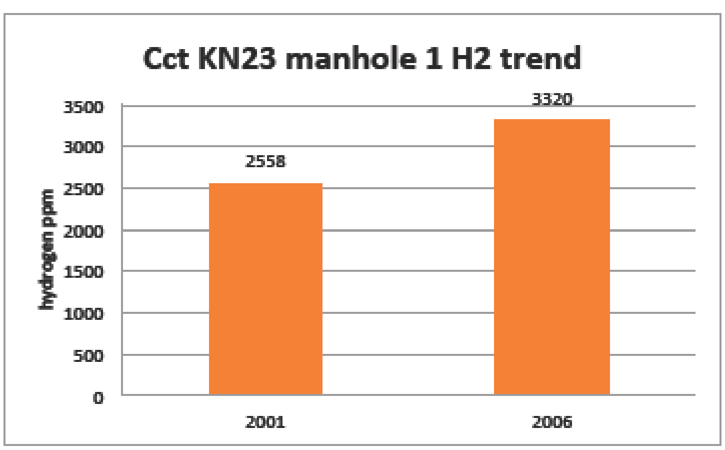
Manholes

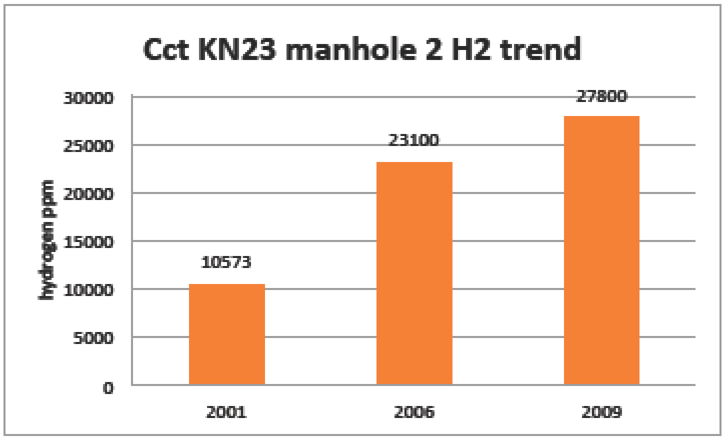
The 2011 hydrogen results from manhole KN2 are not consistent with the results obtained between 2001 and 2009. Fresh testing would be advisable. The earlier test results suggested some thermal decomposition as they contained higher than normal levels of carbon monoxide, carbon dioxide and methane. There were also slightly elevated levels of ethylene and ethane.

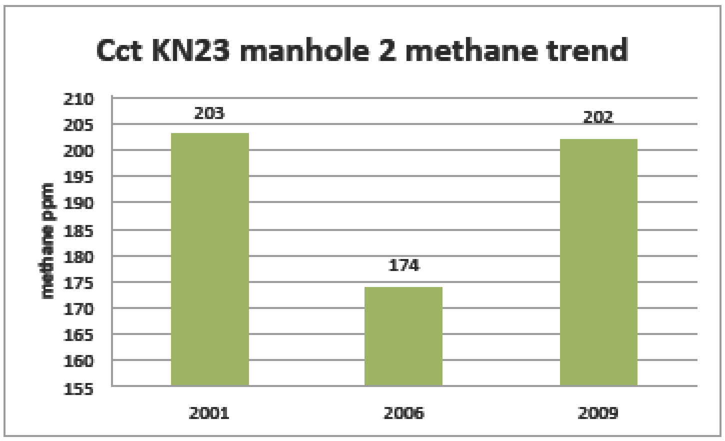
Terminal Ends

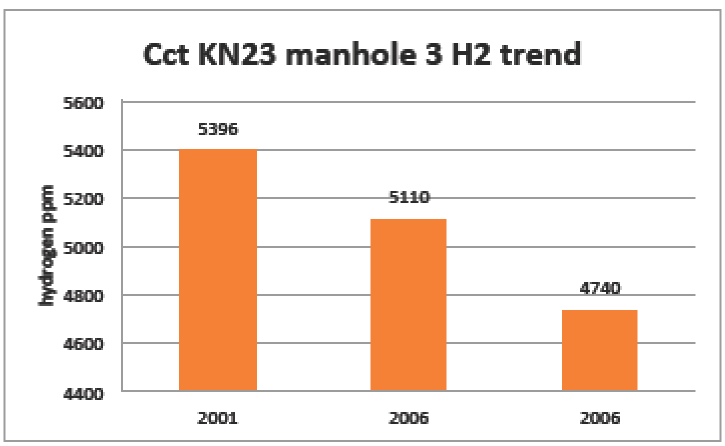
Two of the 2011 Namao termination results are at the "action" level for hydrogen while all three samples are at "action" level for acetylene. Ethylene, methane, carbon monoxide and carbon dioxide are in "acceptable" range but higher than commonly seen in EPCOR DGA results. The results from the Kennedale terminations are in the "concern" range for hydrogen, but are much lower than at the Namao terminations.

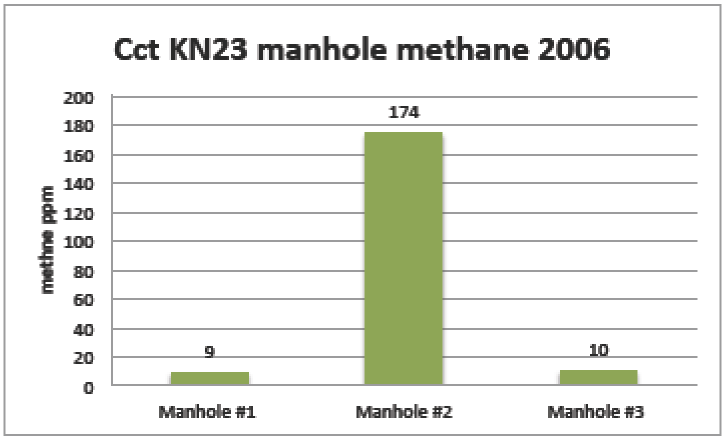
<u>Circuit 72KN23 Trends</u>




Cct KN23 manhole 2 H2 trend
hydrogen ppm
30000
25000
20000
15000
10000
5000
0
10573
23100
27800
2001
2006
2009


Cct KN23 manhole 2 methane trend
methane ppm
210
205
200
195
190
185
180
175
170
165
160
155
203
174
202
2001
2006
2009


Cct KN23 manhole 3 H2 trend
hydrogen ppm
5600
5400
5200
5000
4800
4600
4400
5396
5110
4740
2001
2006
2006



7.8.3 Cable Health Index

CEATI Health Index ratings:

Health Factor: 411
Risk Factor: 243
Total Factor: 694
NOTE: the factors are based on assumed soil parameters. They will be adjusted when soil testing are finalized.

7.8.4 Risk Assessment

Since there is no record of the insulation tests and the fact that the circuit is 38 years old, loaded heavily and terminations at Namao contained excessive amount of acetylene there is a risk that the circuit and accessories conditions are exceeding the normal aging. This circuit is considered medium risk and close monitoring is required and recommended.

7.8.5 Recommendations

- Insulation paper test to be done as soon as possible;
- The fluid at the Namao terminal end should be flushed with degassed fluid until a hydrogen concentration of 5,000ppm or less has been established;;
- Annual DGA sampling at all manholes and terminations should be carried out.

Table 7.8

Cable Health Index - Detailed Report

Cable Details

Circuit Name	72KN23	Cable Installation Date	1973-10-15
Circuit Section		Cable Length	5234m
Cable Type	HPFF	Conductor Material	Aluminium
Cable Voltage	69	Insulation Material	Paper
Conductor Size	950MCM		

3.0 Health Factor

	Standing	WF	Sub-Total
3.1 Electrical History	1	10	10
3.2 Physical Age	7	10	70
3.3 Outage Records	3	8	24
3.4 Loading History	5	5	25
3.5 System Cable Design Issue	1	10	10
3.6 System Maintenance History	5	7	35
3.7a Oil Testing - HPFF & LPFF	10	6	60
3.7b Oil Testing LPLF	0	6	0
3.8 Paper Insulation Condition - HPFF & LPFF	6	10	60
3.9 Insulation Condition - XLPE	0	7	0
3.10 Accessorry Condition	5	10	50
3.11 Hydraulic History	1	4	4
3.12 Installation Conditions	8	5	40
3.13 Civil Structure Condition	3	3	9
3.14 Stray Current Presence	1	7	7
3.15a Corrosion Protection Condition - HPFF	1	7	7
3.15b Corrosion Protection Condition - LPFF & XLPE	0	7	0

Health Factor Rating: 411

4.0 Risk Factors

	Standing	WF	Sub-Total
4.1 Environmental Impact	10	5	50
4.2 Potential Oil Spill	10	5	50
4.3 Regulatory Requirements	1	5	5
4.4 Safety	5	10	50
4.5 Short Circuit Level	5	4	20
4.6 Obsolescence	5	10	50
4.7 Importance of Circuit	3	6	18

Risk Factor Rating: 243

5.0 Maintenance Cost Factor

	Standing	WF	Sub-Total
5.1 Maintenance & Replacement Costs	10	5	50

5.2 Other Details: no papper test found

Maintenance Cost Factor Rating: 50

Summary - Total Values

Health Factor Rating:	411
Risk Factor Rating:	243
Maintenance Cost Factor Rating:	50

Total Rating: 704

Number of Known Factors: 22

Number of Unknown Factors: 3

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7.9 Cable Circuit 72MG16

MG16 is a 72kV circuit between Meadowlark and Garneau substations. Specific characteristics of this cable are as follows:

Circuit Name	Length (m)	Yr of Install	Conductor Size (kcmil) & Type	Cable Mfr	Circuit Ratings (Amperes)			
					Summer Continuous	Summer Emergency	Winter Continuous	Winter Emergency
72MG16	4,581	1969	950 Al	Hitachi	480	525	525	640
	1,042		1750 Cu	Pirelli				

The original circuit rating was 482A, no calculations results available.
Recommended ratings: 460A

7.9.1 Operational History

1. **Major failures:**

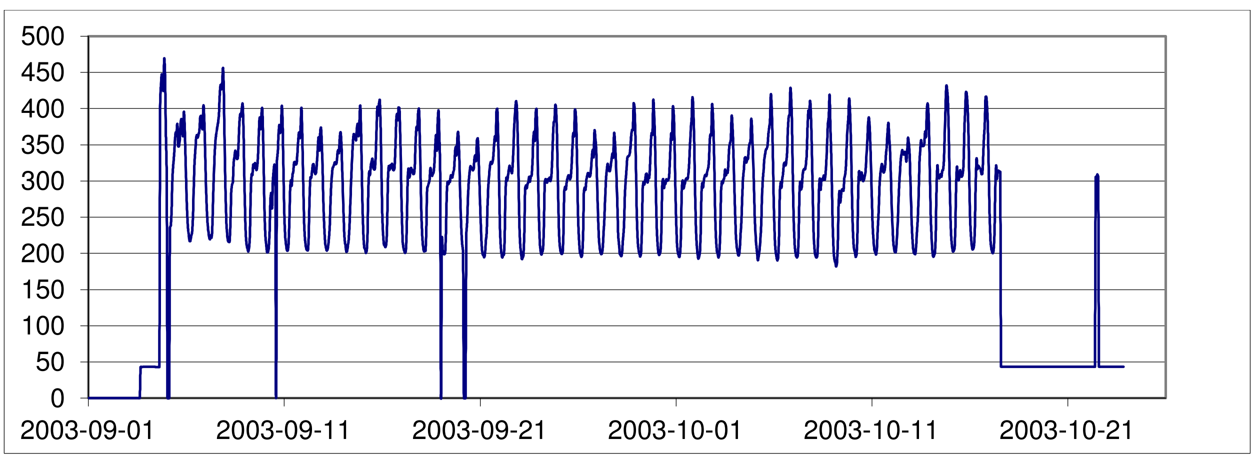
None recorded

2. **Major maintenance:**

No information available

3. **Loading pattern and history**

The load history was provided by EPCOR from Jan. 2007 to the present. There is no sign of circuit over-loading. The maximum daily circuit load is within 80-90% of the continuous rating.



4. **Major improvements**

2003 - New river crossing from manhole 3 to manhole 4 via 3A replaced part of the circuit

7.9.2 Diagnostic Tests

1. **Insulation test**

The test conducted in November 2003 on a 9 metre section of three phase pipe-type cable that was removed from circuit 72GM16 at a point adjacent to a splice located in manhole 4 at the junction of Groat Road and 87th Avenue.

The test on paper obtained from Manhole 4 was conducted in April 2004. The paper was contaminated in transit and some test results can be of doubtful value. Since there has been no other test done on this cable the results have to be taken into consideration.

Cct designation	Test date	Paper type	Sample location	Dissipation factor	Breakdown strength	Moisture content	DP
72MG16	Nov-03	Kraft	cable	Caution	OK	No test	No test
	Apr-04	Kraft	joints	Danger	Caution	Danger	OK

2. **Dissolved Gas Analysis**

Circuit 72MG16 Meadowlark x Garneau Substation - 75 Samples

Location	Samples Taken	Trend	Most recent DGA result per EPRI Guideline
MH MG1	2001; 2003; 2007; 2008;2009; 2011;	Variable moderate hydrogen levels;	"Acceptable" range for all gases
MH MG2	2001; 2003; 2007; 2008; 2009; 2011;	Stable moderate hydrogen levels;	"Acceptable" range for all gases
MH MG3	2001; 2003; 2007; 2008; 2009; 2011;	Stable moderate hydrogen levels; Small but steady increases in carbon monoxide, carbon dioxide, methane, ethane and ethylene levels since 2007;	"Acceptable" range for all gases, with increases noted in carbon monoxide, carbon dioxide, methane, ethane and ethylene levels
MH MG3A	2007; 2008; 2009; 2011;	Stable moderate hydrogen levels; Small but steady increases in carbon monoxide, carbon dioxide, methane, ethane and ethylene levels since 2007;	"Acceptable" range for all gases, with increases noted in carbon monoxide, carbon dioxide, methane, ethane and ethylene levels
MH MG4	2001; 2003; 2007; 2008; 2009; 2011;	Initial high hydrogen levels followed by stable moderate levels; (the reduction is thought to be due to the river crossing relocation in 2003) Small but noticeable increases in carbon monoxide, carbon dioxide, methane, ethane and ethylene levels since 2007;	"Acceptable" range for all gases, although increases have been noted in carbon monoxide, carbon dioxide, methane, ethane and ethylene levels

MH MG5	2001; 2003; 2007; 2008; 2009; 2011	Rising hydrogen levels; all other gases stable at low levels	“Acceptable” range for all gases
Bypass manhole RG4	2009	N/A	“Acceptable” range for all gases
Meadowlark Trifurcator	No samples	N/A	N/A
Meadowlark Terminations	2001; 2011;	Stable moderate hydrogen levels;	“Concern” range for hydrogen, “acceptable” range for other gases
Meadowlark Risers	2011;	Stable moderate hydrogen levels;	“Concern” range for hydrogen, “acceptable” range for other gases
Garneau Trifurcator	No samples;	N/A	N/A
Garneau Terminations	2001; 2003; 2008; 2010;	Stable low values for all gases	“Acceptable” range for all gases
Garneau Risers	2003; 2008; 2010;	Stable low values for all gases	“Acceptable” range for all gases

Observations

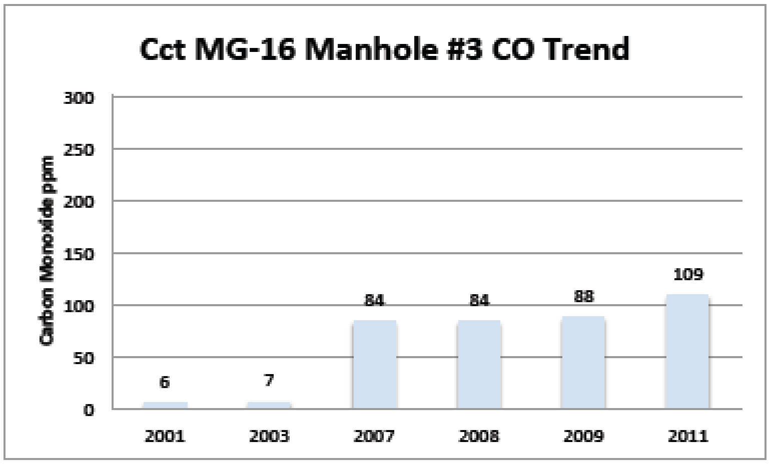
Manholes

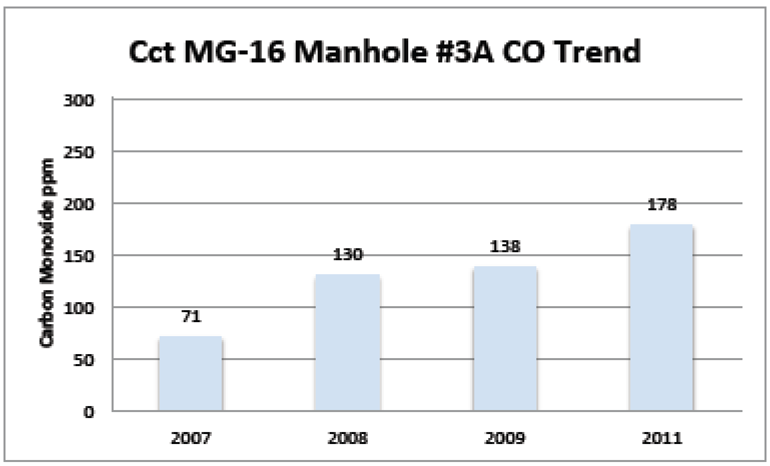
The results from this circuit are generally characterized by moderate levels of hydrogen at manholes. The overall increases in carbon monoxide, carbon dioxide, methane, ethylene and ethane levels found at manholes MG3, MG3A and MG4 suggest a need for further investigation.

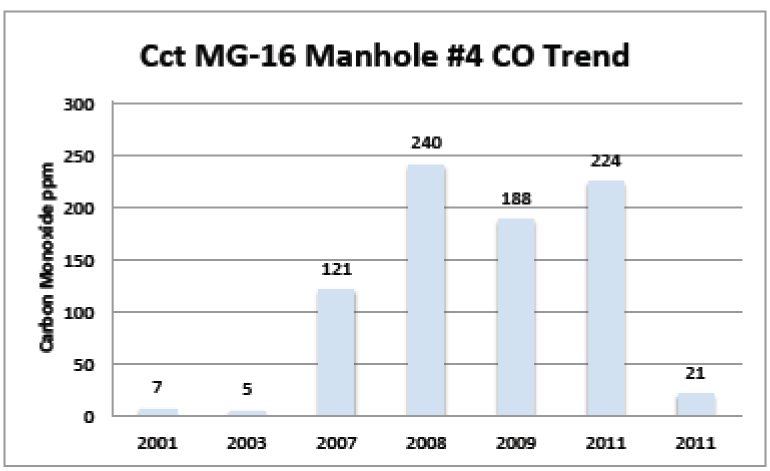
Terminal ends

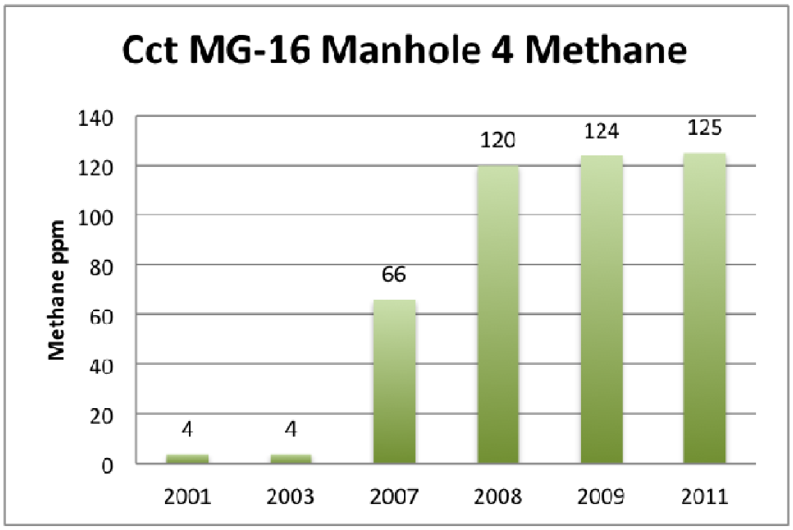
The hydrogen levels at the Meadowlark terminations are at the “concern” level. Higher than typical levels of methane, carbon monoxide, carbon dioxide, ethylene and ethane were noted at the phase 2 Meadowlark termination, although they were still within the “acceptable” range. Lesser values were seen in the other two Meadowlark terminations sampled at the same time.

Trends


Cct MG-16 Manhole #3 CO Trend
Carbon Monoxide ppm
300
250
200
150
100
50
0
6
7
84
84
88
109
2001
2003
2007
2008
2009
2011


Cct MG-16 Manhole #3A CO Trend
Carbon Monoxide ppm
300
250
200
150
100
50
0
71
130
138
178
2007
2008
2009
2011


Cct MG-16 Manhole #4 CO Trend
Carbon Monoxide ppm
300
250
200
150
100
50
0
7
5
121
240
188
224
21
2001
2003
2007
2008
2009
2011
2011



7.9.3 Cable Health Index

CEATI Health Index ratings:

Health Factor:	330
Risk Factor:	274
Total Factor:	644

7.9.4 Risk Assessment

This is heavily loaded circuit. The CO found in some manholes is a reason for concern. Because other factors used in health index such as maintenance, hydraulic problems or outage records do not indicate any problem, the overall risk assessment is low.

7.9.5 Recommendations

- Insulation paper test to be done as soon as possible
- Annual DGA sampling at all manholes and terminations should be carried out.
- The hydraulic connections shall be reviewed.

Table 7.9

Cable Health Index - Detailed Report

Cable Details

Circuit Name	72GM16
Circuit Section	
Cable Type	HPFF
Cable Voltage	69
Conductor Size	950MCM/1750MCM
Cable Installation Date	1968-11-04
Cable Length	5499m
Conductor Material	Aluminium
Insulation Material	Paper

3.0 Health Factor

	Standing	WF	Sub-Total
3.1 Electrical History	1	10	10
3.2 Physical Age	7	10	70
3.3 Outage Records	2	8	16
3.4 Loading History	5	5	25
3.5 System Cable Design Issue	1	10	10
3.6 System Maintenance History	1	7	7
3.7a Oil Testing - HPFF & LPFF	10	6	60
3.7b Oil Testing LPLF	0	6	0
3.8 Paper Insulation Condition - HPFF & LPFF	1	10	10
3.9 Insulation Condition - XLPE	0	7	0
3.10 Accessorry Condition	5	10	50
3.11 Hydraulic History	1	4	4
3.12 Installation Conditions	9	5	45
3.13 Civil Structure Condition	3	3	9
3.14 Stray Current Presence	1	7	7
3.15a Corrosion Protection Condition - HPFF	1	7	7
3.15b Corrosion Protection Condition - LPFF & XLPE	0	7	0

Health Factor Rating: 330

4.0 Risk Factors

	Standing	WF	Sub-Total
4.1 Environmental Impact	10	5	50
4.2 Potential Oil Spill	10	5	50
4.3 Regulatory Requirements	2	5	10
4.4 Safety	5	10	50
4.5 Short Circuit Level	7	4	28
4.6 Obsolescence	5	10	50
4.7 Importance of Circuit	6	6	36

Risk Factor Rating: 274

5.0 Maintenance Cost Factor

	Standing	WF	Sub-Total
5.1 Maintenance & Replacement Costs	10	5	50

5.2 Other Details

Maintenance Cost Factor Rating: 50

Summary - Total Values

Health Factor Rating:	330
Risk Factor Rating:	274
Maintenance Cost Factor Rating:	50

Total Rating: 654

Number of Known Factors: 22

Number of Unknown Factors: 3

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7.10 Cable Circuit 72RG1

RG1 is a 72kV circuit between Rossdale and Garneau substations. Specific characteristics of this cable are as follows:

Circuit Name	Length (m)	Yr of Install	Conductor Size (kcmil) & Type	Cable Mfr	Circuit Ratings (Amperes)			
					Summer Continuous	Summer Emergency	Winter Continuous	Winter Emergency
72RG1	1,945	1969	950 Al	Hitachi	480	525	525	640

The original circuit rating was 482A, no calculations results available.
Recommended ratings: 340A if the 72RG7 circuit is loaded 600A

7.10.1 Operational History

1. **Major failures:**

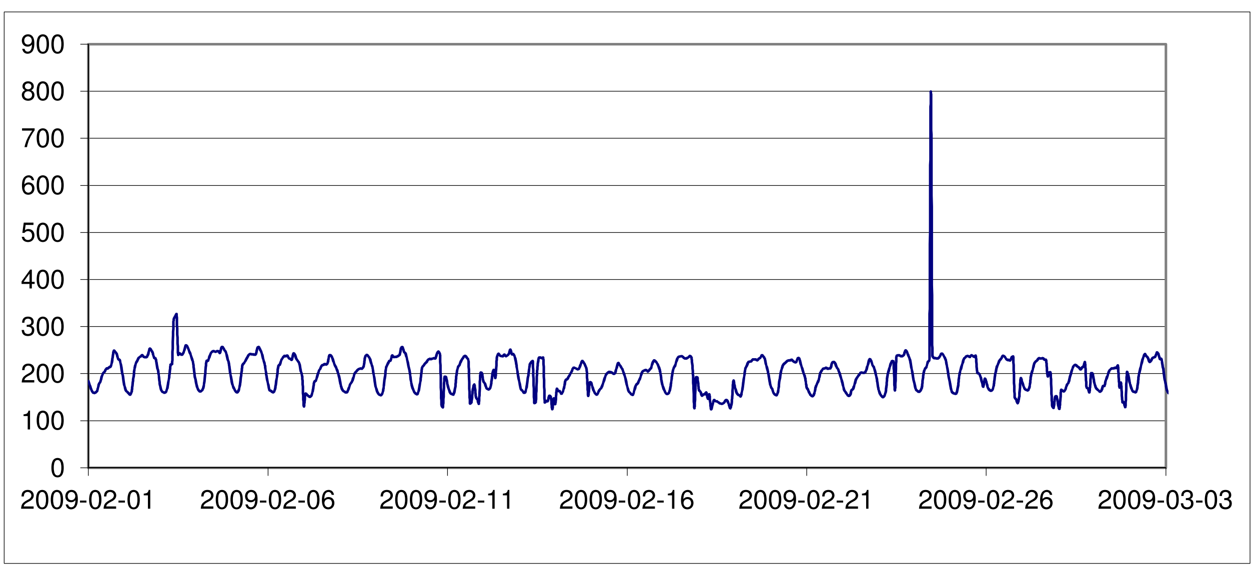
None recorded

2. **Major maintenance:**

No information available

3. **Loading pattern and history**

The load history was provided by EPCOR from Jan. 1999 to the present. There is no sign of circuit overloading. The maximum daily circuit load is within 50-60% of the continuous rating. The visible sudden increase of the load occurred on Feb 24, 2009 and reached 799A – reason unknown. Such sudden increase of the cable load above its maximum emergency rating is detrimental to the cable conditions.



4. **Major improvements**

2008 - barrier splice were installed in manhole 6

7.10.2 Diagnostic Tests

1. **Insulation tests**

The test samples were obtained at the location of the barrier splice installation.

The paper test results indicate the normal level for the age of these cables. The elevated dissipation fastor and reduced breakdown withstand can be attributed to the circuit aging.

Circuit designation	Test date	Paper type	Sample location	Dissipation factor	Breakdown strength	Moisture content	DP
72RG1	Nov-08	Kraft	joints	Caution	Caution	OK	OK

2. **Dissolved Gas Analysis**

Circuit 72RG1 Rossdale x Garneau Substation - 30 Samples

Location	**Samples Taken**	**Trend**	**Most recent DGA result per EPRI Guideline**
MH RG1	2001; 2003; 2008	Rising hydrogen levels; all other gases stable	Acceptable range for all gases
MH RG6	2009	N/A	Acceptable range for all gases
Bypass manhole RG4	2008; 2010; 2011	Rising hydrogen; inconsistent changes in carbon monoxide; all other gases stable	"Concern" level for hydrogen, all other gases in "acceptable" range
Rossdale Trifurcator	No samples	N/A	N/A
Rossdale Terminations	No samples	N/A	N/A
Rossdale Risers	No samples	N/A	N/A
Garneau Trifurcator	No samples	N/A	N/A
Garneau Terminations	2001; 2003; 2008; 2010; 2011	Low stable values for all gases	"Acceptable" ranges for all gases
Garneau Risers	2003; 2008; 2010; 2011	Low stable values for all gases	"Acceptable" ranges for all gases

Observations

General

The results from this circuit are generally characterized by moderate levels of hydrogen at manholes with no significantly elevated methane values. DGA sampling at the Rossdale terminal ends would be highly recommended.

7.10.3 Cable Health Index

CEATI Health Index ratings:

Health Factor: 376
Risk Factor: 256
Total Factor: 672

7.10.4 Risk Assessment

The test results do not indicate excessive aging. The elevated CO level discovered in 2010 test has to be monitored closely. This circuit is considered low risk at this time.

7.10.5 Recommendations

- Annual DGA sampling should be carried out at the joints and terminations of this circuit.

.

Table 7.10

Cable Health Index - Detailed Report

Cable Details

Circuit Name	72RG1	*Cable Installation Date*	1968-11-04
Circuit Section		*Cable Length*	2063m
Cable Type	HPFF	*Conductor Material*	Aluminium
Cable Voltage	69	*Insulation Material*	Paper
Conductor Size	950MCM		

3.0 Health Factor

	Standing	WF	Sub-Total
3.1 Electrical History	1	10	10
3.2 Physical Age	8	10	80
3.3 Outage Records	2	8	16
3.4 Loading History	10	5	50
3.5 System Cable Design Issues	1	10	10
3.6 System Maintenance History	1	7	7
3.7a Oil Testing - HPFF & LPFF	10	6	60
3.7b Oil Testing LPLF	0	6	0

	Standing	WF	Sub-Total
3.8 Paper InsulationCondition - HPFF & LPFF	1	10	10
3.9 Insulation Condition - XLPE	0	7	0
3.10 Accessorry Condition	5	10	50
3.11 Hydraulic History	1	4	4
3.12 Installation Conditions	10	5	50
3.13 Civil Structure Condition	5	3	15
3.14 Stray Current Presence	1	7	7
3.15a Corrosion Protection Condition - HPFF	1	7	7
3.15b Corrosion Protection Condition - LPFF & XLPE	0	7	0

Health Factor Rating: 376

4.0 Risk Factors

	Standing	WF	Sub-Total
4.1 Environmental Impact	10	5	50
4.2 Potential Oil Spill	10	5	50
4.3 Regulatory Requirements	2	5	10
4.4 Safety	5	10	50
4.5 Short Circuit Level	7	4	28
4.6 Obsolescence	5	10	50
4.7 Importance of Circuit	3	6	18

Risk Factor Rating: 256

5.0 Maintenance Cost Factors

	Standing	WF	Sub-Total
5.1 Maintenance & Replacement Costs	10	5	50

5.2 Other Details

Maintenance Cost Factor Rating: 50

Summary - Total Values

Health Factor Rating:	376
Risk Factor Rating:	256
Maintenance Cost Factor Rating:	50

Number of Known Factors: 22

Number of Unknown Factors: 3

Total Rating: 682

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7.11 Cable Circuit 72RG7

RG7 is a 72kV circuit between Rossdale and Garneau substations. Specific characteristics of this cable are as follows:

Circuit Name	Length (m)	Yr of Install	Conductor Size (kcmil) & Type	Cable Mfr	Circuit Ratings (Amperes)			
					Summer Continuous	Summer Emergency	Winter Continuous	Winter Emergency
72RG7	2,256	1981	1500 Cu	Pirelli	640	720	720	800

The original circuit rating specified by the cable manufacturer was 100MW, calculations are not available. The original rating can be converted to 844A at rated voltage of 72kV and cos φ=0.95;

The contract specified that the cable should perform satisfactorily at the following conditions:

Continuous rating 720A at the load factor 1.0 if the 72RG1 circuit is loaded 480A

Recommended ratings: 600A if the 72RG1 circuit is loaded 340A

7.11.1 Operational History

1. **Major failures;**

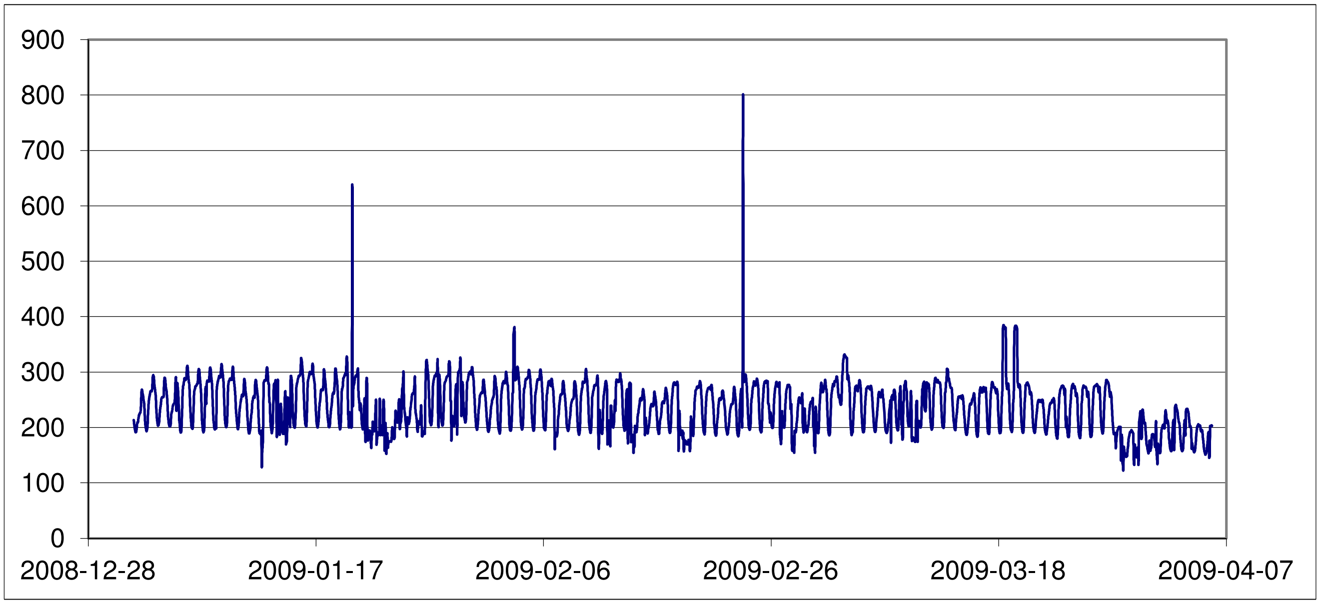
None recorded

2. **Major maintenance:**

2011 - joint in manhole 2 was rebuilt

3. **Loading pattern and history**

The load history was provided by EPCOR from Jan. 1999 to the present. There is no sign of circuit overloading. The maximum daily circuit load is within 40-50% of the continuous rating. The visible sudden increase of the load occurred on Feb 24, 2009 and reached 799A – reason unknown. It does not exceed the specified circuit emergency rating but such sudden increase in the cable load is detrimental to the cable conditions.



4. Major improvements:

2008 - new barrier joint was installed in manhole 5

7.11.2 Diagnostic Tests

1. Insulation tests

Evidence of paper mechanical deterioration of the 72RG7 circuit was reported when the barrier splices were installed on this circuit. There were also reported some visual observations during the sampling that have to be taken into consideration – unusual fluid smell during sampling and colour.

The degree of polymerization tests of a sample taken from the cable insulation done by two laboratories produced significantly different results. The results after the initial test produced DP value in the range of 336 – 450 while the new test results were in the range of 642 – 850.

The most recent results of the DP parameter have been accepted by EDTI as valid due to close monitoring of the test procedure. Apart from the test evaluation lab, the both results indicate the severely aged circuit in comparison to other older circuits in the same grid. The moisture content varies significantly from 0.3% to 6.3%. It is not known if such difference in moisture saturation in these samples was caused by long time that elapsed from sampling or it was a result of improper handling.

The test results by PowerTech #80020476-12-REP1 submitted on 12 October 2012 show that moisture content in the 72RG7cable insulation has a distinct pattern. The moisture increases with the depth of the insulation. The higher moisture content was found in the paper closest to the conductor. Since the moisture in paper can indicate paper deterioration this finding should be taken seriously until other parameters exclude this.

The same tests show also that the paper used in joint insulation has much lower AC breakdown level but the dissipation factor is much higher than the cable insulation while moisture is not excessively high.

Cct designation	Test date	Paper type	Sample location	Dissipation factor	Breakdown strength	Moisture content	DP
72RG7	Nov-08	Kraft	joints	Caution	Caution	OK	Danger
	Mar-12	Kraft	cable			Caution	Caution

2. Dissolved Gas Analysis

Circuit 72RG-7 Rossdale x Garneau Substation - 48 Samples

Location	**Samples Taken**	**Trend**	**Most recent DGA result per EPRI Guideline**
MH RG2	2001; 2003; 2008; 2009; 2010; 2011	Rising hydrogen and carbon dioxide; very small increases in other gases	"Action" level for hydrogen; "acceptable" levels for all other gases
MH RG3	2001; 2003; 2008; 2009; 2011;	Inconsistent changes in hydrogen level; increase in carbon monoxide; all other gases stable	"Concern" level for hydrogen; "acceptable" levels for all other gases
MH RG5	2009; 2010	Stable values for all gases	"Acceptable" level for all gases
MH RG4 bypass	2008; 2009; 2010; 2011	Inconsistent changes in hydrogen and carbon dioxide levels; all other gas levels stable	"Acceptable" level for all gases
Rossdale Trifurcator	No samples	N/A	N/A
Rossdale Terminations	2003; 2011	Reduction in hydrogen levels; inconsistent changes in carbon dioxide levels; other gases stable	"Concern" level for hydrogen; "acceptable" levels for all other gases
Rossdale Risers	2003; 2011;	Reduction in hydrogen levels; inconsistent changes in carbon dioxide levels; other gases stable	"Concern" level for hydrogen; "acceptable" levels for all other gases
Garneau Trifurcator	No samples	N/A	N/A
Garneau Terminations	2001; 2003; 2008; 2010; 2011	Stable low values for all gases	"Acceptable" level for all gases
Garneau Risers	2003; 2008; 2010; 2011;	Stable low values for all gases	"Acceptable" level for all gases

Observations

Manholes

The results from this circuit are generally characterized by significant levels of hydrogen at manholes without significantly elevated methane values.

Terminal ends

The DGA values at the Garneau terminations are very satisfactory while the Rossdale terminations have shown a marked decrease in hydrogen concentration since the values recorded in 2003. There is no obvious explanation for this reduction or for the differences in the hydrogen values at the three Rossdale terminations.

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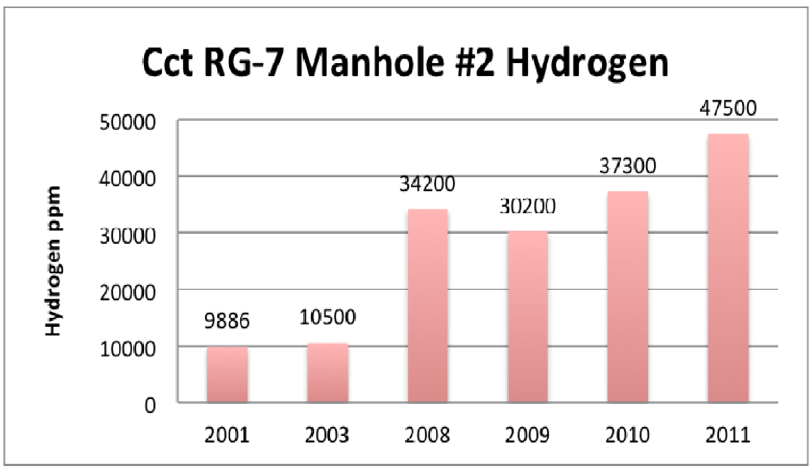
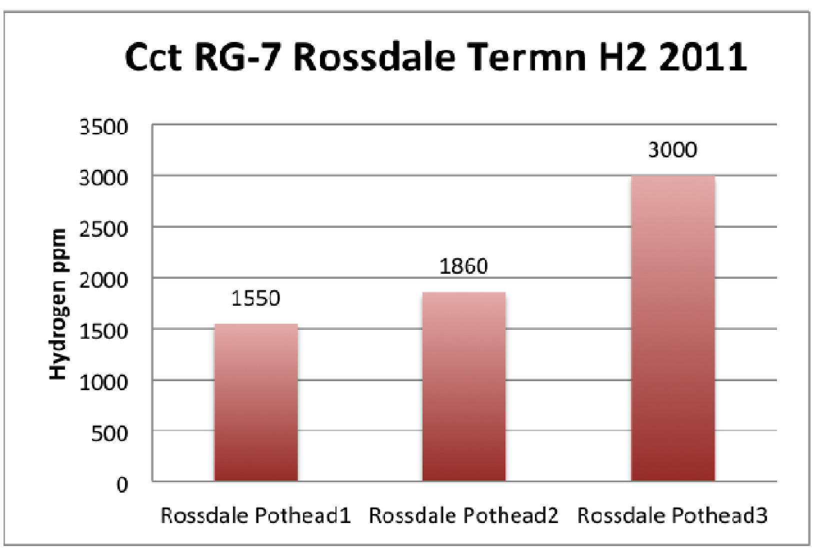
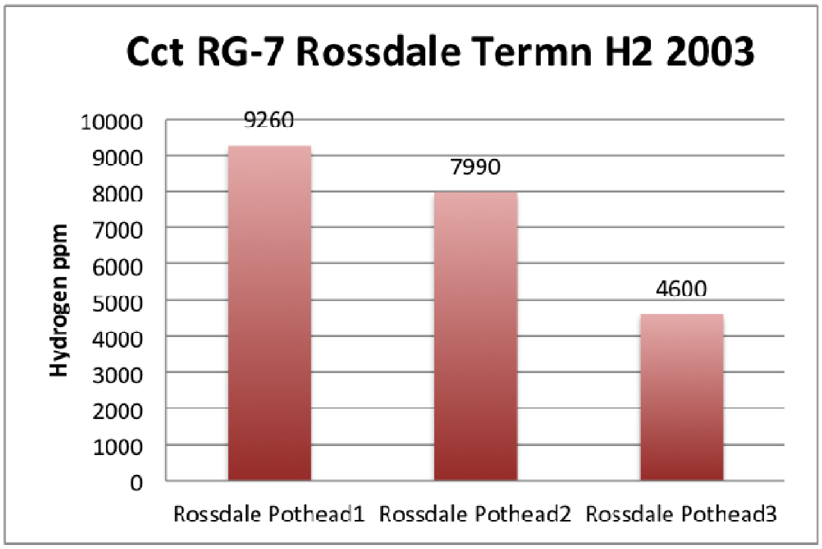
Trends







7.11.3 Cable Health Index

CEATI Health Index ratings:

Health Factor:	323
Risk Factor:	301
Total Factor:	664

The health index input parameter for the quality of the cable insulation used in this rating was from the latest test of the DP made by Kinectrics in 2012.

7.11.4 Risk Assessment

The paper samples tested at two laboratories produced different results in the DP tests. The results from 2012 tests were accepted as the results obtained by using monitored testing procedure. To remove the uncertainty of the quality of the insulation another sample from a different location should be tested. Based on latest information, this circuit is considered low risk. However, the former test results for the dissipation factor and breakdown voltage were at the level that can be considered as excessive aging.

The test results from two labs should be reconciled to remove uncertainty.

7.11.5 Recommendations

- Flush all the fluid from this circuit through a filter and degasser while monitoring DGA levels.
- Continue flushing until the hydrogen concentrations have been reduced to less than 10,000 ppm at manholes and less than 5,000ppm at the terminal ends.
- Following fluid degassing, DGA should be monitored by sampling at all joints and terminations at six-month intervals.
- Another paper sample should be obtained from the cable insulation at the first opportunity at any available location and tested by a lab specialized in this type of testing.

Table 7.11

Cable Health Index - Detailed Report

Cable Details

Circuit Name	72RG7
Circuit Section	
Cable Type	HPFF
Cable Voltage	69
Conductor Size	1500MCM
Cable Installation Date	1981-10-15
Cable Length	2264m
Conductor Material	Copper
Insulation Material	Paper

3.0 Health Factor

	Standing	WF	Sub-Total
3.1 Electrical History	1	10	10
3.2 Physical Age	5	10	50
3.3 Outage Records	1	8	8
3.4 Loading History	5	5	25
3.5 System Cable Design Issue	1	10	10
3.6 System Maintenance History	1	7	7
3.7a Oil Testing - HPFF & LPFF	10	6	60
3.7b Oil Testing LPLF	0	6	0
3.8 Paper InsulationCondition - HPFF & LPFF	6	10	60
3.9 Insulation Condition - XLPE	0	7	0
3.10 Accessorry Condition	1	10	10
3.11 Hydraulic History	1	4	4
3.12 Installation Conditions	10	5	50
3.13 Civil Structure Condition	5	3	15
3.14 Stray Current Presence	1	7	7
3.15a Corrosion Protection Condition - HPFF	1	7	7
3.15b Corrosion Protection Condition - LPFF & XLPE	0	7	0

Health Factor Rating: 323

4.0 Risk Factors

	Standing	WF	Sub-Total
4.1 Environmental Impact	10	5	50
4.2 Potential Oil Spill	10	5	50
4.3 Regulatory Requirements	1	5	5
4.4 Safety	5	10	50
4.5 Short Circuit Level	9	4	36
4.6 Obsolescence	5	10	50
4.7 Importance of Circuit	10	6	60

Risk Factor Rating: 301

5.0 Maintenance Cost Factor

	Standing	WF	Sub-Total
5.1 Maintenance & Replacement Costs	10	5	50

5.2 Other Details the DP value can be questionable

Maintenance Cost Factor Rating: 50

Summary - Total Values

Health Factor Rating:	323
Risk Factor Rating:	301
Maintenance Cost Factor Rating:	50

Total Rating: 674

Number of Known Factors: 22

Number of Unknown Factors: 3

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7.12 Cable Circuit 72RS5

RS5 is a 72kV circuit between Rossdale and Strathcona substations. Specific characteristics of this cable are as follows:

Circuit Name	Length (m)	Yr of Install	Conductor Size (kcmil) & Type	Cable Mfr	Circuit Ratings (Amperes)			
					Summer Continuous	Summer Emergency	Winter Continuous	Winter Emergency
72RS5	4,832	1958	650 Cu	Northern Electric	480	525	525	640
	655		1750 Cu	Pirelli				

The original circuit rating was 482A, no calculations results available.

Recommended ratings: 470A

7.12.1 Operational History

1. **Major failures:**

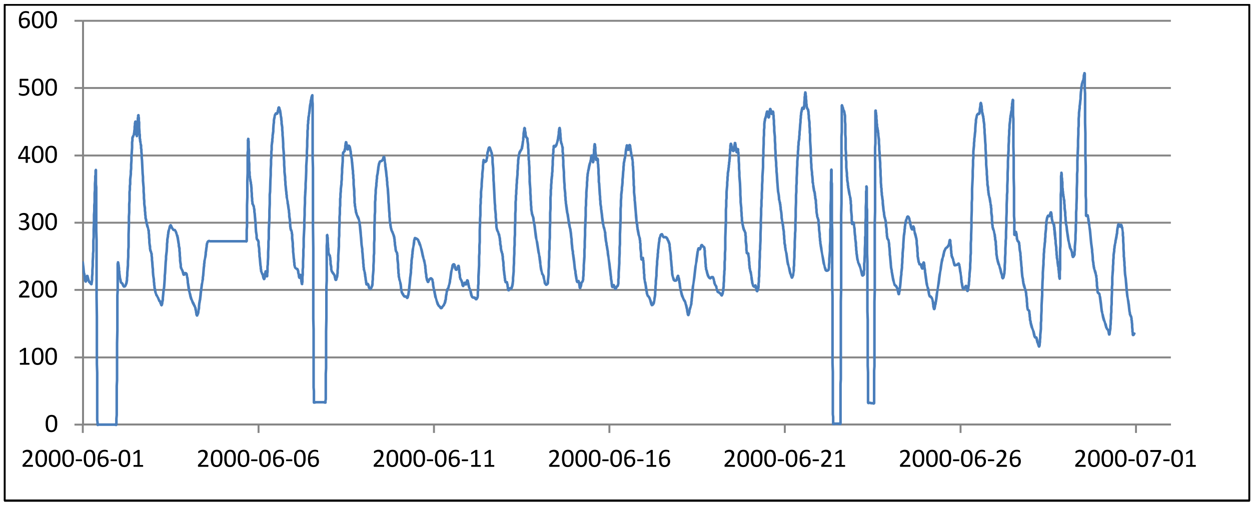
01.1970 – termination failure at Strathcona - reason unknown
12.1970 – termination failure, possible cause - excessive pressure.
12.1972 – termination failure, possible cause - extreme cold

2. **Major maintenance:**

2008 - splices rebuilt from manhole 2 to 6 because of excessive gasses.
2010 - RS5 was degassed from Strathcona terminations to manhole 2

3. **Loading pattern and history:**

The load history was provided by EPCOR from Jan. 1999 to the present. There is no sign of circuit overloading. However, the maximum daily circuit load is within 80-100% range of the continuous rating. In the recent years, the load on this circuit is applied intermittently with cable being idle for a week or more.



4. Major improvements

2004 - new river crossing from Rossdale site to manhole RS1

7.12.2 Diagnostic Tests

1. Insulation tests

The tests were performed on samples obtained from the following locations:
September 204:
Crepe paper taken from joint RS5

December 2004
9m cable adjusted to the manhole RS5

October 2008
Crepe paper from joints RS2 – RS6

The crepe paper test results obtained from the joints indicate severe aging. These joints were replaced and the condition of the joints should guarantee their proper working conditions. Because of the joint replacement these test results should not be taken into consideration when condition assessment is conducted. If the conditions warrant a new samples should be obtained and tested.

However, the Kraft paper condition of the cable insulation is unknown since the test was performed over 8 years ago. At that time, the only parameter that was of concern was the dissipation factor; the degree of polymerization and moisture contents were not tested.

Because of difficulties to obtain samples the partial discharge test should be performed at the first opportunity.

Cct designation	Test date	Paper type	Sample location	Dissipation factor	Breakdown strength	Moisture content	DP
72RS5	Sep-04	crepe	joints	Danger	**Danger !!!**	OK	OK
	Dec-04	Kraft	cable	Caution	OK		
	Oct-08	crepe	joints	Danger	Danger	Caution	OK

2. Dissolved Gas Analysis

Circuit 72RS5 Rossdale x Strathcona SS – 25 Samples

Location	Samples Taken	Trend	2011 DGA result per EPRI Guideline
MH RS1	2007; 2011	Reducing level of hydrogen; other gases stable	"Concern" level for hydrogen; "acceptable" for all other gases
MH RS2	2001; 2003; 2006; 2007	Increasing hydrogen; other gases stable	"Concern" level for hydrogen; "acceptable" for all other gases
MH RS3	2009	N/A	"Concern" level for hydrogen; "acceptable" for all other gases
MH RS4	2001; 2003; 2006; 2007; 2009	Increasing hydrogen; other gases stable	"Concern" level for hydrogen; "acceptable" for all other gases
MH RS5	2010; 2011	Increasing hydrogen; some fluctuation in methane, carbon di-oxide, and ethane	"Action" level for hydrogen; "acceptable" for all other gases
MH RS6	2007; 2008; 2009; 2010; 2011	Increasing hydrogen; some fluctuation in methane, carbon di-oxide, and ethane	"Action" level for hydrogen; "acceptable" for all other gases
Rossdale Trifurcator	No samples	N/A	N/A
Rossdale Terminations	No samples	N/A	N/A
Rossdale Risers	No samples	N/A	N/A
Strathcona Trifurcator	2001; 2003; 2006; 2007	Reducing hydrogen; rising acetylene; slight increases in carbon dioxide, ethylene and ethane; stable values for me-thane and carbon monoxide	"Action" level for acetylene; "acceptable" for all other gases
Strathcona Terminations	No samples	N/A	N/A
Strathcona Risers	No samples	N/A	N/A

Observations

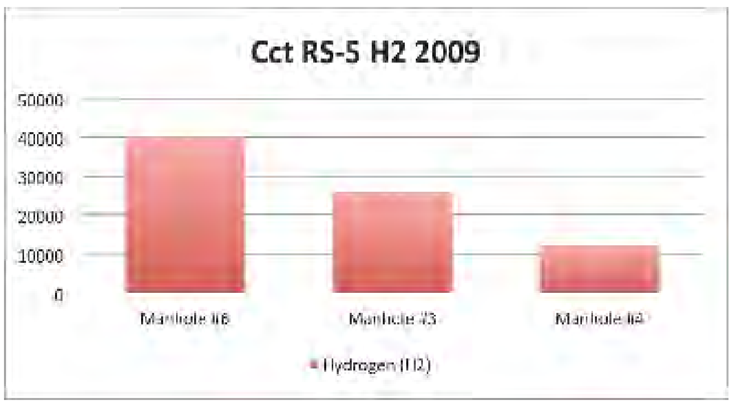
Manholes

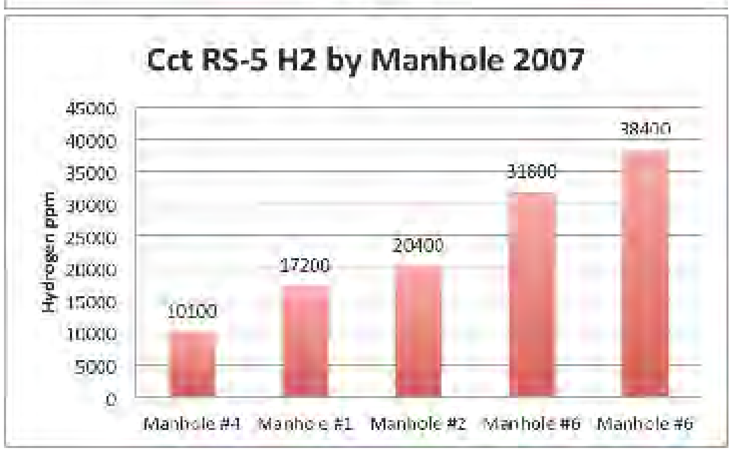
There has been no decline in the rate of production of hydrogen since the replacement of the cable joints in 2007/2008. It is notable that acetylene was detected at the trifurcator at Strathcona Substation in 2003, 2006 and 2007. No record of remedial work at the trifurcator or further DGA sampling was found. The partial flushing of the cable carried out in 2010 was probably responsible for temporary spike in methane levels at manhole RS5 in that year. The methane level at manhole RS6 has continued at a satisfactory low level since the 2010 flushing. This suggests that the joint replacement work in 2007/2008 was successful in improving the conditions responsible for generating gases other than hydrogen.

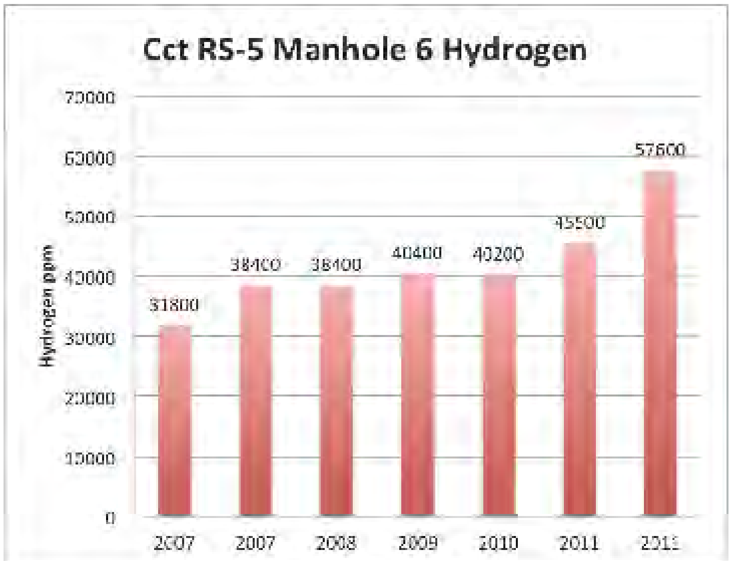
Terminations

No termination sample results for this circuit have been found in the database. It is highly advisable to carry out regular DGA sampling at the Strathcona and Rossdale terminal ends.

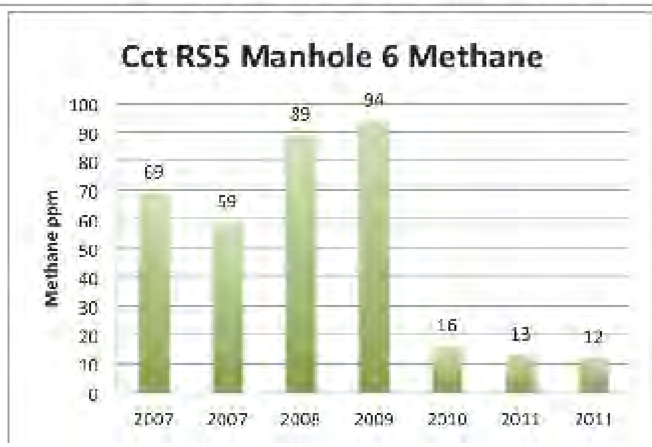
<u>Circuit 72RS5 Trends</u>



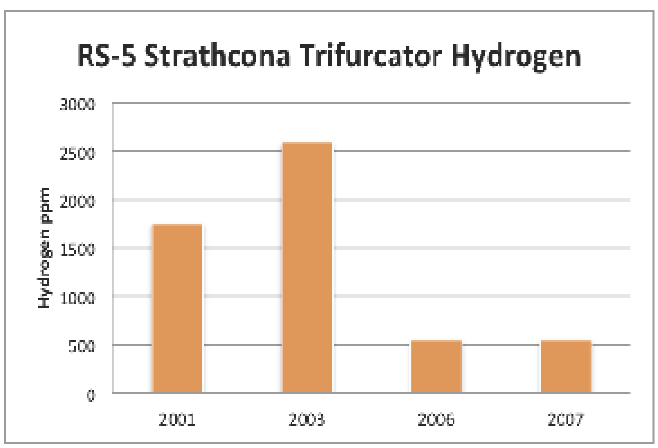




Cct RS-5 Manhole 6 Hydrogen
Hydrogen ppm
70000
60000
50000
40000
30000
20000
10000
0
31800
38400
38400
40400
40200
45500
57600
2007
2007
2008
2009
2010
2011



Cct RS5 Manhole 6 Methane
Methane ppm
100
90
80
70
60
50
40
30
20
10
0
69
59
89
94
16
13
12
2007
2007
2008
2009
2010
2011
2011



RS-5 Strathcona Trifurcator Hydrogen
Hydrogen ppm
3000
2500
2000
1500
1000
500
0
2001
2003
2006
2007

7.12.3 Cable Health Index

CEATI Health Index ratings:

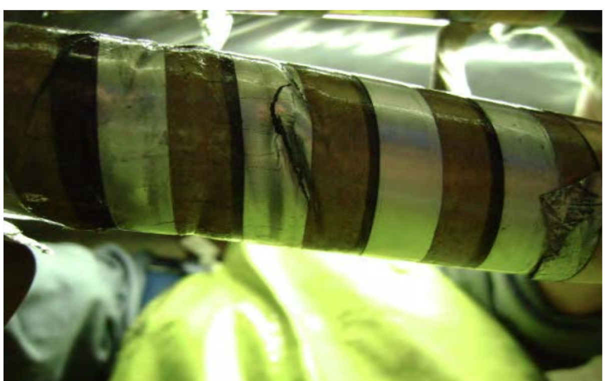
Health Factor:	548
Risk Factor:	295
Total Factor:	883

7.12.4 Risk Assessment

This is one of the oldest circuits in the EPCOR's grid. It is one of only two 72kV connections that feed the Strathcona substation.

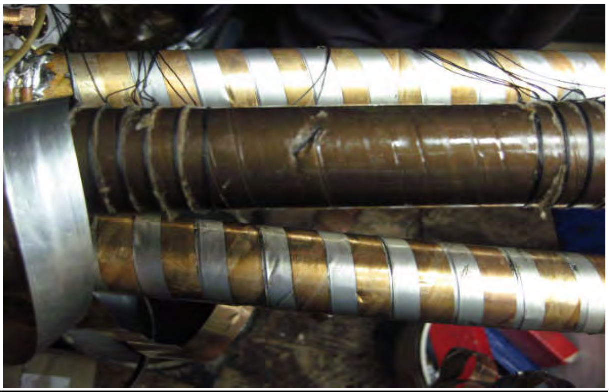
Circuit 72RS5 is known to have had bonding defects at some of the cable joints. These were found and corrected in late 2007 and early 2008 during a program of cable joint replacement. The continuing trends suggest that hydrogen generation has continued unabated in the period since that work was performed. No flushing of the cable fluid was performed at that time. The significant drop in methane concentration at manhole RS6 occurred after the 2010 flushing and it appears that the methane levels at this manhole have since remained stable at the low values. The conditions of the joints before the joint rebuilding are shown in the following pictures at the end of this section.

Photographs from 72kV circuit RS5 Manholes 2, 5 and S6 in 2007 & 2008.

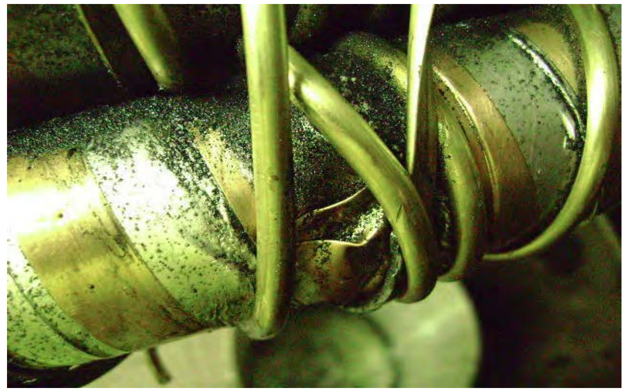


Cable shielding damage Manhole #5

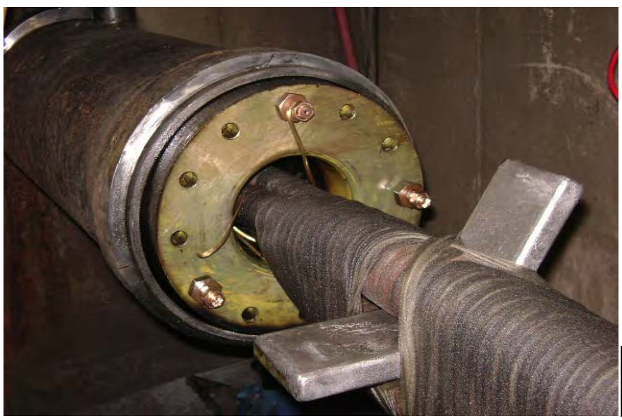
Twisted skid wire and damaged shielding tapes, Manhole #2



Damaged outer insulation layers, Manhole #2



Metal filings and loose skid wires, Manhole #5



Two skid wire ends not connected to flange of joint casing. Manhole #S6

The joint rehabilitation program revealed that the cable in the vicinity of the joints is in poor mechanical conditions. The first tests on crepe paper performed over 8 years ago showed dangerous level of the insulation electrical conditions. Because of the damages discovered during the joint replacement and high dissipation factor revealed on same samples in 2004 this circuit risk is assessed as critical and it should be on the priority list for replacement.

7.12.5 Recommendations

- Replace the circuit at the first opportunity;
- Sample the fluid at the Strathcona trifurcator;
- Flush all the fluid from this circuit through a filter and degasser while monitoring DGA levels;
- Continue flushing until the hydrogen concentrations have been reduced to less than 10,000 ppm at manholes and less than 5,000 ppm at the terminations;
- Following fluid degassing, DGA should be monitored by sampling at all joints and terminations at six-month intervals;
- Perform PD and tan δ tests to identify any needs for immediate repairs. The PD test was recommended on the previous insulation test reports.

Table 7.12

Cable Health Index - Detailed Report

Cable Details

Circuit Name	72RS5
Circuit Section	
Cable Type	HPFF
Cable Voltage	69
Conductor Size	650MCM
Cable Installation Date	1958-09-01
Cable Length	5454m
Conductor Material	Copper
Insulation Material	Paper

3.0 Health Factor

	Standing	WF	Sub-Total
3.1 Electrical History	1	10	10
3.2 Physical Age	10	10	100
3.3 Outage Records	6	8	48
3.4 Loading History	10	5	50
3.5 System Cable Design Issues	5	10	50
3.6 System Maintenance History	10	7	70
3.7a Oil Testing - HPFF & LPFF	10	6	60
3.7b Oil Testing LPLF	0	6	0
3.8 Paper InsulationCondition - HPFF & LPFF	1	10	10
3.9 Insulation Condition - XLPE	0	7	0
3.10 Accessorry Condition	5	10	50
3.11 Hydraulic History	8	4	32
3.12 Installation Conditions	9	5	45
3.13 Civil Structure Condition	3	3	9
3.14 Stray Current Presence	1	7	7
3.15a Corrosion Protection Condition - HPFF	1	7	7
3.15b Corrosion Protection Condition - LPFF & XLPE	0	7	0

Health Factor Rating: 548

4.0 Risk Factors

	Standing	WF	Sub-Total
4.1 Environmental Impact	10	5	50
4.2 Potential Oil Spill	10	5	50
4.3 Regulatory Requirements	3	5	15
4.4 Safety	5	10	50
4.5 Short Circuit Level	5	4	20
4.6 Obsolescence	5	10	50
4.7 Importance of Circuit	10	6	60

Risk Factor Rating: 295

5.0 Maintenance Cost Factors

	Standing	WF	Sub-Total
5.1 Maintenance & Replacement Costs	10	5	50

5.2 Other Details

Maintenance Cost Factor Rating: 50

Summary - Total Values

Health Factor Rating:	548
Risk Factor Rating:	295
Maintenance Cost Factor Rating:	50

Total Rating: 893

Number of Known Factors: 22

Number of Unknown Factors: 3

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7.13 Cable Circuit 72RV2

RV2 is a 72kV circuit between Rossdale and Victoria substations. Specific characteristics of this cable are as follows:

<table>
<tr><th rowspan="2">Circuit Name</th><th rowspan="2">Length (m)</th><th rowspan="2">Yr of installation</th><th rowspan="2">Conductor Size (kcmil) & Type</th><th rowspan="2">Cable Mfr</th><th colspan="4">Circuit Ratings (Amperes)</th></tr>
<tr><th>Summer Continuous</th><th>Summer Emergency</th><th>Winter Continuous</th><th>Winter Emergency</th></tr>
<tr><td rowspan="2">72RV2</td><td>2,109</td><td rowspan="2">1957</td><td>650 Cu</td><td>Northern Electric</td><td colspan="4" rowspan="2">See Note Below</td></tr>
<tr><td>580</td><td>1250 Cu</td><td>Okonite</td></tr>
</table>

The original circuit rating was 482A, no calculations results available. Since the cable was the first installed in the Edmonton's grid its allowable rating was calculated for the cable without any additional heat source that could affect the cable ratings. Since then two circuits RV4 and RV6 were installed and the limitation was introduced as below.

This circuit's hydraulic system together with RV4 & RV6 was redesigned to allow for oil circulation for cooling purposes in 1990. Their steady state ampacity ratings were established to be 200MVA @ 72kV with 2 or 3 circuits in service. However, the RV4/RV6 crossing at the Rossdale sub limits load to 160MVA on these two circuits without oil circulation.

Recommended ratings without fluid circulation: 420A (evaluated together with 72RV4 & 72RV6)

7.13.1 Operational History

1. **Major failures:**

09.1973 – termination failure, possible cause – moisture
10.1979 – cable failure with pipe rupture, possible cause - lack of electrical coordination between pipe and casing, approx. 2,000 liters of oil spilled
1992 - joint failure because of loss of pressure

2. **Major maintenance:**

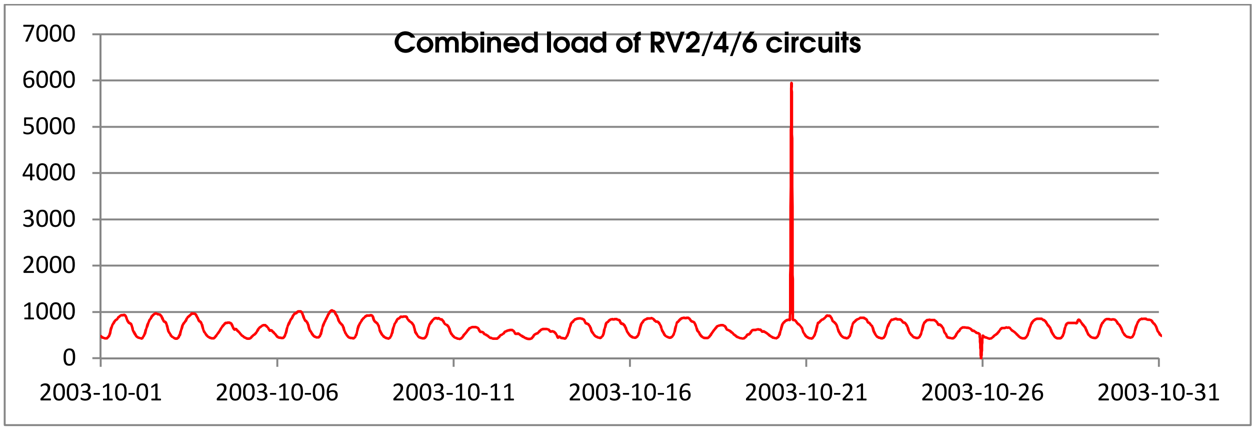
In 1990s a forced fluid circulation system (FOCS) was installed. The insulating fluid is being circulated with speed of approximate 6 l/s. If any of those three circuits exhibits deterioration and produce gasses they will be moved by pumps to the other two circuits and localization of any change in the cable conditions will severely limited.

2011 – part of the circuit was relocated, new joint and terminations were installed at Victoria sub (NLRT), section of cable conductor changed to 1250 kcmil.

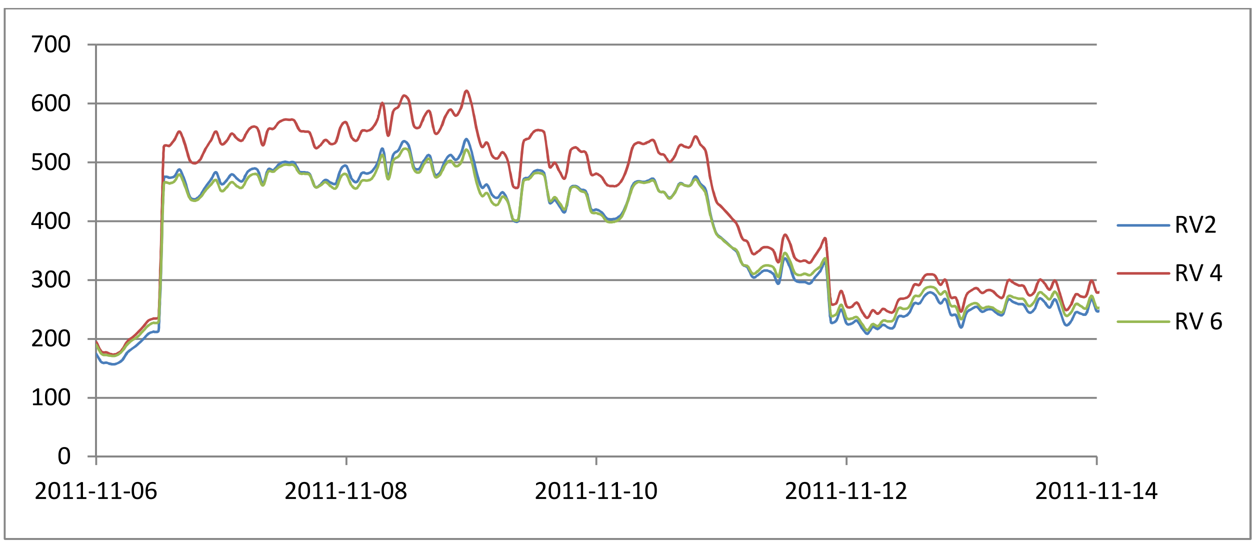
The circuit has been divided in the past (RN2 split for RV2 and VN21) and relocated for the purpose of LRT construction. The relocation caused that it now consists of two different conductor sizes.

3. **Load history:**

The load history was provided by EPCOR from Jan. 1999 to the present. The maximum combined load of all three circuits is shown below. The maximum load totaled to approx. 5,948A. The load was evenly distributed over all three circuits carrying 742MVA for a short period of time. The RV2 circuit load was 1,972A.



It was also found that the RV2 circuit was loaded over prolonged period of time as shown below. It shows that the cable combined load of three circuits exceeds the recommended 200MVA for four days:



4. **Major improvements:**

No information available

7.13.2 Diagnostic Tests

1. **Insulation test**

October 1993 test – 9m long cable was taken from the location adjacent to the cable failure.

March 2012 test – the sample was taken from the manhole RV5

Insulation test done almost 20 years ago on 650kcmil part did not indicate any problem, except ACBD level was lower than the new cables. The recent test revealed the aging that some of the cable parameters are typical for the age of the cable except dissipation factor that exceeded over twice the normal value.

Cct designation	Test date	Paper type	Sample location	Dissipation factor	Breakdown strength	Moisture content	DP
72RV2	Oct-93	Kraft	cable	OK	Caution		
	Mar-12	Kraft	cable	Danger	Caution	Caution	OK

2. Dissolved Gas Analysis

The DGA tests and results are common for all three circuits RV2, RV4, RV6 that are connected hydraulically at FOCS.

Circuit 72RV2 Rossdale x Victoria Substation - 8 Samples

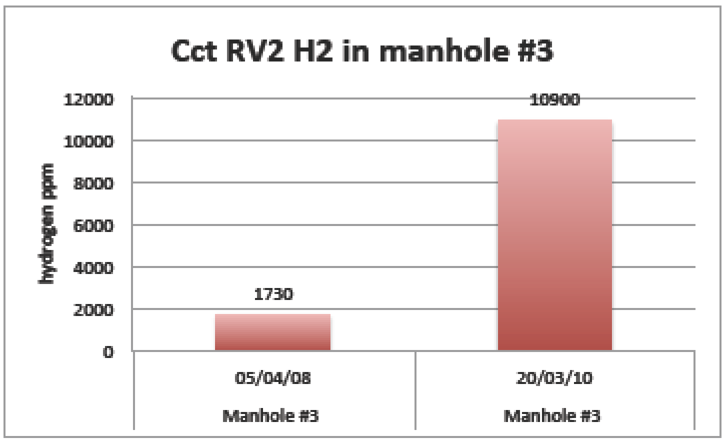
Location	**Samples Taken**	**Trend**	**Most DGA result per EPRI Guideline**
MH RV1	2008; 2009	Stable hydrogen and all other gases	"Action" level for hydrogen; "concern" level for acetylene; all other gases within "acceptable" range
MH RV2	2008	N/A	"Action" level for hydrogen; "concern" level for acetylene; all other gases within "acceptable" range
MH RV3	2008; 2010	Increasing hydrogen, acetylene, methane, ethylene and ethane values; stable carbon monoxide and carbon dioxide values	"Action" level for hydrogen; "concern" level for acetylene; all other gases within "acceptable" range
Rossdale Trifurcator	No samples	N/A	N/A
Rossdale Terminations	2002	N/A	"Acceptable" levels for all gases
Rossdale Risers	No samples	N/A	N/A
Victoria Trifurcator	No samples	N/A	N/A
Victoria Terminations	No samples	N/A	N/A
Victoria Risers	No samples	N/A	N/A

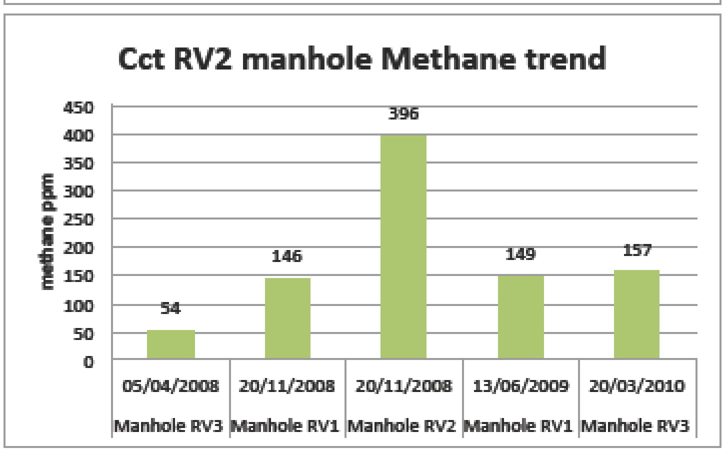
Observations

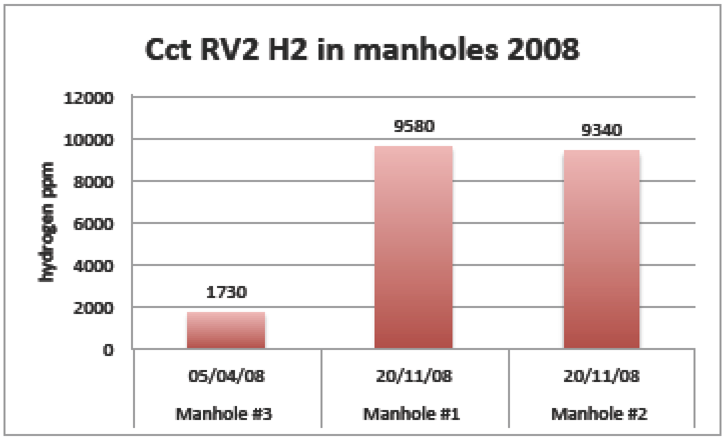
General

The 2008 DGA results from the three manholes suggest that hydrogen generation is occurring at significant levels in this forced cooled circuit. The generally lower gas levels from the 2008 sample at manhole RV3 were likely to have been influenced by major construction activities that occurred at Victoria Substation. Despite the dilution effect of fluid circulation the methane values generally appear higher than for other EPCOR HPFF circuits. This suggests some thermally induced decomposition may have occurred in one or more of these circuits. A DGA sample in 2007 from the main tank of FOCS displayed similar levels of hydrogen and methane to those found at the manholes.

<u>Circuit 72RV2 Trends</u>







7.13.3 Cable Health Index

CEATI Health Index ratings:

Health Factor:	514
Risk Factor:	328
Total Factor:	882

7.13.4 Risk Assessment

This is the oldest circuit in the grid. It has been divided, relocated and reconnected many times. It is very difficult to assess its conditions of each circuit individually through dissolved gas analysis as the fluid is circulated through RV4 and RV6 and the gasses are averaged by the liquid movement. The paper test indicated normal aging conditions. It is considered medium risk at this time but the parameters should be monitored closely taking into account age of the cable.

7.13.5 Recommendations

- Paper tests are recommended for the old cables at every opportunity.
- Complete degassing of all of the fluid in this system (including the reservoir) would allow DGA trending to be effectively carried out without the results being influenced by past events.
- Since this circuit liquid is circulated the samples should be taken every half a year from at least one location. It is strongly recommended that DGA sampling be done at six-month intervals at manhole #2 so that the methane concentration trend can be monitored.
- PD tests are strongly recommended to detect locations exhibiting the most severe cases of partial discharges for further analysis.
- Taking into account the increased dissipation factor discovered at the recent test, a temperature sensor located between manhole RV2 and trifurcator cold be of value to monitor the circuit temperature for further load analysis.
- A new LRT line is under construction which crosses the RV2, RV4 and RV6 circuits. The influence of the DC voltage on these circuits shall be analyzed and a solution, if any, discussed with a company specializing in corrosion protection.

Table 7.13

Cable Health Index - Detailed Report

Cable Details

Circuit Name	72RV2	*Cable Installation Date*	1957-09-30
Circuit Section		*Cable Length*	2080m
Cable Type	HPFF	*Conductor Material*	Copper
Cable Voltage	69	*Insulation Material*	Paper
Conductor Size	650MCM		

3.0 Health Factor

	Standing	WF	Sub-Total
3.1 Electrical History	10	10	100
3.2 Physical Age	10	10	100
3.3 Outage Records	10	8	80
3.4 Loading History	5	5	25
3.5 System Cable Design Issue	1	10	10
3.6 System Maintenance History	1	7	7
3.7a Oil Testing - HPFF & LPFF	10	6	60
3.7b Oil Testing LPLF	0	6	0
3.8 Paper InsulationCondition - HPFF & LPFF	1	10	10
3.9 Insulation Condition - XLPE	0	7	0
3.10 Accessorry Condition	5	10	50
3.11 Hydraulic History	1	4	4
3.12 Installation Conditions	9	5	45
3.13 Civil Structure Condition	3	3	9
3.14 Stray Current Presence	1	7	7
3.15a Corrosion Protection Condition - HPFF	1	7	7
3.15b Corrosion Protection Condition - LPFF & XLPE	0	7	0

Health Factor Rating: 514

4.0 Risk Factors

	Standing	WF	Sub-Total
4.1 Environmental Impact	8	5	40
4.2 Potential Oil Spill	10	5	50
4.3 Regulatory Requirements	10	5	50
4.4 Safety	5	10	50
4.5 Short Circuit Level	7	4	28
4.6 Obsolescence	5	10	50
4.7 Importance of Circuit	10	6	60

Risk Factor Rating: 328

5.0 Maintenance Cost Factor

	Standing	WF	Sub-Total
5.1 Maintenance & Replacement Costs	8	5	40

5.2 Other Details: Circuit is a part of forced oil cooling system. No recent paper test

Maintenance Cost Factor Rating: 40

Summary - Total Values

Health Factor Rating:	514
Risk Factor Rating:	328
Maintenance Cost Factor Rating:	40

Total Rating: 882

Number of Known Factors: 22

Number of Unknown Factors: 3

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7.14 Cable Circuit 72RV4

RV4 is a 72kV circuit between Rossdale and Victoria substations. Specific characteristics of this cable are as follows:

Circuit Name	Length (m)	Yr of Install	Conductor Size (kcmil) & Type	Cable Mfr	Circuit Ratings (Amperes)			
					Summer Continuous	Summer Emergency	Winter Continuous	Winter Emergency
72RV4	1,451	1978	1500 Cu	Pirelli	See Note below			
	693		1250 Cu	Okonite				

Note: This circuit's hydraulic system together with RV2 & RV6 was redesigned to allow for oil circulation for cooling purposes. Their steady state ampacity was established to be 200MVA @ 72kV with 2 or 3 circuits in service. However, the RV4/RV6 crossing at the Rossdale sub limits load to 160MVA on these two circuits without oil circulation.

The original circuit rating is not available.

Recommended ratings without fluid circulation: 520A (evaluated together with 72RV2 & 72RV6)

7.14.1 Operational History

1. **Major failures:**

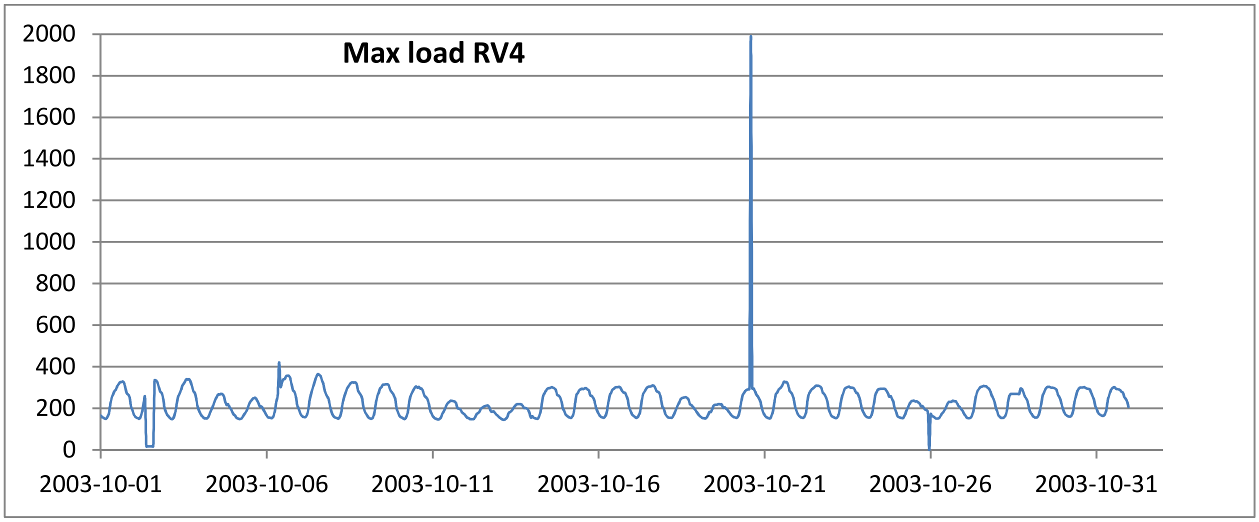
1992 - Rossdale pothead failure – cause unknown

2. **Major maintenance:**

In 1990s a forced fluid circulation system (FOCS) has been installed.
2008 – new terminations and a buried splice at Victoria were installed (DESS), cable conductor section size 1500 kcmil.
2011 – part of the circuit relocated, new joint and terminations were installed at Victoria sub (NLRT), section of cable conductor changed to 1250 kcmil.
2012 – joint rehabilitation MH#4.

3. **Load history**

The load history was provided by EPCOR from Jan. 1999 to the present. The maximum load of RV4 circuit is shown below. The maximum load totaled to approx. 5,948A. The load was evenly distributed over all three RV circuits. The RV4 circuit load was 1,972A for a short period of time.



The analysis of the load pattern does not indicate any overloading of this circuit because the conductor size is the largest out of the three circuits being cooled with one common fluid circulating system. However, the short period overload as shown on the graph has a detrimental effect on the quality of insulation.

4. Major improvements:

No information available

7.14.2 Diagnostic Tests

1. Insulation test:

November 2008 – 9m cable sample taken from close to Victoria substation during relocation for DESS project

August 2009 – 9m cable sample taken from the the location close to the Victoria substation.

March 2012 test sample was taken at MH RV5

The earlier tests indicated normal aging. The latest test revealed that the paper insulation is at the dangerous level. The dissipation factor exceeds the typical value for a new cable by factor of four and it is in 0.9 – 1.53% range. This is not likely caused by the moisture which content varies from sample to sample. In one occasion the moisture level exceeds 3%. It is very likely caused by badly deteriorated paper which polymerization factor was found to be below 600 level on one sample.

Cct designation	Test date	Paper type	Sample location	Dissipation factor	Breakdown strength	Moisture content	DP
72RV4	Nov-08	Kraft	cable	Caution	OK		
	Aug-09	Kraft	cable	Caution	OK		
	Mar-12	Kraft	cable	**Danger !!!**	OK	**Danger !!!**	Danger

2. Dissolved Gas Analysis

Circuit 72RV4 Rossdale x Victoria Substation - 7 Samples

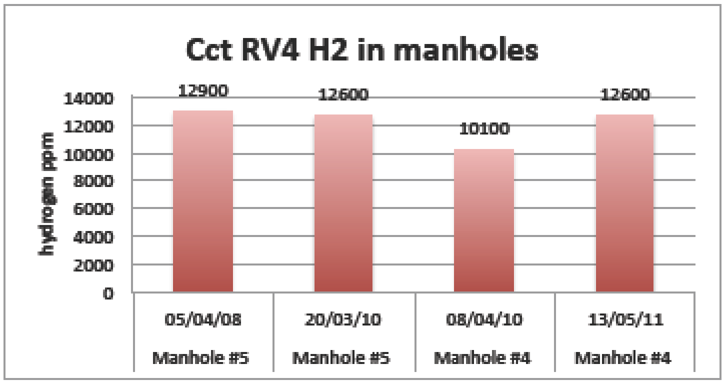
Location	**Samples Taken**	**Trend**	**Most recent DGA result per EPRI Guideline**
MH RV4	2010; 2011	Increasing hydrogen; reducing methane; all other gases stable	"Action" level for hydrogen; "concern" level for acetylene; all other gases in "acceptable" range
MH RV5	2008; 2010	Decreasing hydrogen; all other gases stable	"Action" level for hydrogen; "concern" level for acetylene; all other gases in "acceptable" range
Rossdale Trifurcator	No samples	N/A	N/A
Rossdale Terminations	2002	N/A	"Acceptable" levels for all gases
Rossdale Risers	No samples	N/A	N/A
Victoria Trifurcator	No samples	N/A	N/A
Victoria Terminations	No samples	N/A	N/A
Victoria Risers	No samples	N/A	N/A

Observations

General

The 2008, 2010 and 2011 DGA results from the two manholes suggest that hydrogen generation is occurring at significant levels in this forced cooled circuit. The methane values also appear higher than for other EPCOR HPFF circuits, particularly with the dilution effect of fluid circulation. This suggests some thermally induced decomposition may have occurred in one or more of these circuits. A DGA sample in 2007 from the main tank of FOCS displayed similar levels of hydrogen and methane as those found at the manholes of these circuits.

Circuit 72RV4 Trends



7.14.3 Cable Health Index

CEATI Health Index ratings:

Health Factor:	422
Risk Factor:	316
Total Factor:	778

7.14.4 Risk Assessment

The insulating fluid is being circulated with speed of approximate 6 l/s. If any of those three circuits exhibits deterioration and produces gasses they will be moved by pumps to the other two circuits and localization of any change in the cable conditions will be severely limited.

The recent opening of the pipe at the MH#4 joint revealed a significant amount of charred insulating paper. Since the cable was not subjected to a fault in the past the charred paper might originate at different circuit, possibly RV2. An investigation should commence promptly to find the reason of the contamination. The combination of the complementary parameters of the moisture and DP indicates that the serious aging occurred. This is considered a high risk circuit.

7.14.5 Recommendations

- Complete degassing of the fluid in this system would allow DGA trending to be effectively carried out without the results being excessively influenced by past events;
- The gas level should be monitored as a part of the hydraulic section (RV2/RV4/RV6). The details of the tests are applicable to all 72RV circuits because the oil is continuously circulated.
- The paper insulation tests shall be performed as soon as possible after opening of the new rehabilitation joint and through testing of this circuit shall be performed. The recommended PD test shall be performed before the circuit is stressed with another DC withstand test. Note that the proposed PD test can be considered also as the AC withstand test.

- Because of the recent discovery the fluid in the circuits 72RV2, 72RV4 and 72RV6 should be flushed through a filter and degasser to remove traces of burnt material after the joint rehabilitation is complete. After the filtering all filters in the hydraulic system should be replaced.
- Soil tests in the vicinity of crossing with RV6 are strongly recommended. After testing the soil samples from this location and taking into consideration the past circuits loads it will be possible to estimate the cable temperature.
- Temperature testing station with temperature sensors connected to the RV4 & RV6 pipes at the crossing location should be considered.
- PD and tan δ test is recommended.

Table 7.14

Cable Health Index - Detailed Report

Cable Details

Circuit Name	72RV4	Cable Installation Date	1978-12-15
Circuit Section		Cable Length	2120m
Cable Type	HPFF	Conductor Material	Copper
Cable Voltage	69	Insulation Material	Paper
Conductor Size	1500MCM		

3.0 Health Factor

	Standing	WF	Sub-Total
3.1 Electrical History	1	10	10
3.2 Physical Age	6	10	60
3.3 Outage Records	6	8	48
3.4 Loading History	5	5	25
3.5 System Cable Design Issue	1	10	10
3.6 System Maintenance History	1	7	7
3.7a Oil Testing - HPFF & LPFF	10	6	60
3.7b Oil Testing LPLF	0	6	0
3.8 Paper Insulation Condition - HPFF & LPFF	8	10	80
3.9 Insulation Condition - XLPE	0	7	0
3.10 Accessorry Condition	5	10	50
3.11 Hydraulic History	1	4	4
3.12 Installation Conditions	9	5	45
3.13 Civil Structure Condition	3	3	9
3.14 Stray Current Presence	1	7	7
3.15a Corrosion Protection Condition - HPFF	1	7	7
3.15b Corrosion Protection Condition - LPFF & XLPE	0	7	0

Health Factor Rating: 422

4.0 Risk Factors

	Standing	WF	Sub-Total
4.1 Environmental Impact	8	5	40
4.2 Potential Oil Spill	10	5	50
4.3 Regulatory Requirements	6	5	30
4.4 Safety	5	10	50
4.5 Short Circuit Level	9	4	36
4.6 Obsolescence	5	10	50
4.7 Importance of Circuit	10	6	60

Risk Factor Rating: 316

5.0 Maintenance Cost Factor

	Standing	WF	Sub-Total
5.1 Maintenance & Replacement Costs	8	5	40

5.2 Other Details: Circuit is a part of forced oil cooling

Maintenance Cost Factor Rating: 40

Summary - Total Values

Health Factor Rating:	422
Risk Factor Rating:	316
Maintenance Cost Factor Rating:	40

Total Rating: 778

Number of Known Factors: 22

Number of Unknown Factors: 3

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7.15 Cable Circuit 72RV6

RV6 is a 72kV circuit between Rossdale and Victoria substations. Specific characteristics of this cable are as follows:

Circuit Name	Length (m)	Yr of Install	Conductor Size (kcmil) & Type	Cable Mfr	Circuit Ratings (Amperes)			
					Summer Continuous	Summer Emergency	Winter Continuous	Winter Emergency
72RV6	1,554	1968	950 Al	Northern Electric	See Note below			
	567		1250 Cu	Okonite				
	579 replaced		1500 Cu	Pirelli				

Note: This circuit's hydraulic system together with RV4 & RV6 was redesigned to allow for oil circulation for cooling purposes. Their steady state ampacity was established to be 200MVA @ 72kV with 2 or 3 circuits in service. However, the RV4/RV6 crossing at the Rossdale sub limits load to 160MVA on these two circuits without oil circulation.

The original rating of this circuit is not available.

Recommended ratings without fluid circulation: 295A (evaluated together with 72RV2 & 72RV4)

7.15.1 Operational History

1. **Major failures:**

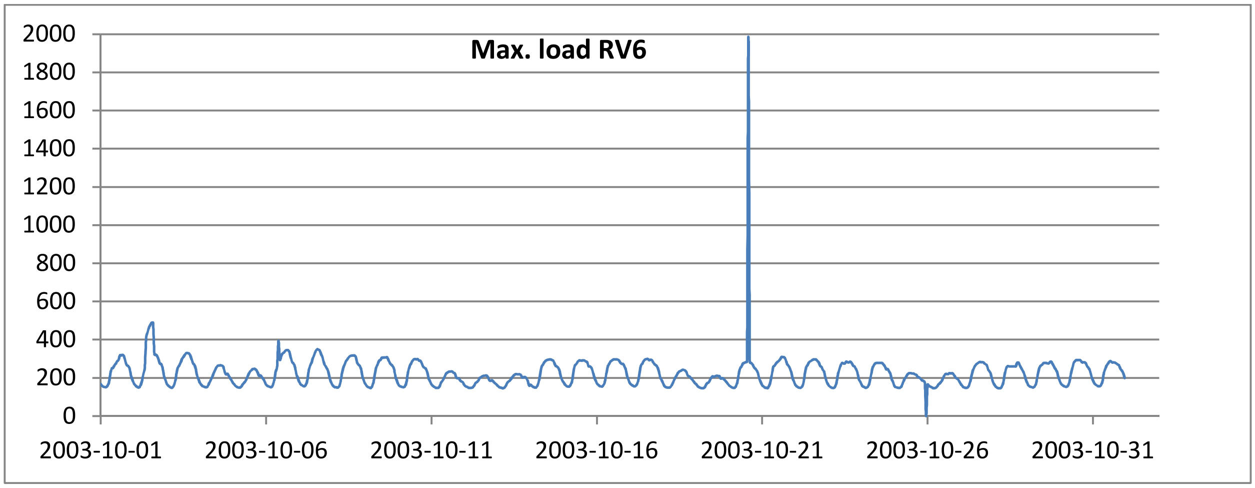
01.1984 – termination failure, possible cause - extreme cold, approx. 1,200 l of oil escaped

2. **Major maintenance:**

2011 – the circuit was relocated from manhole 3 to Victoria Sub
2011 - new terminations were installed at Victoria sub (NLRT)

3. **Load history**

The load history was provided by EPCOR from Jan. 1999 to the present. The maximum load of RV6 circuit is shown below. The maximum load totaled to approx. 5,948A. The load was evenly distributed over all three RV circuits. The RV6 circuit load was 1,972A for a short period of time.



4. **Major improvements:**

No information available

7.15.2 Diagnostic Tests

1. **Insulation test:**

March 2012 test on samples obtained from the joints at manhole RV5.

The tests indicate the normal aging.

Cct designation	Test date	Paper type	Sample location	Dissipation factor	Breakdown strength	Moisture content	DP
72RV6	Mar-12	Kraft	cable	Caution	Caution	Caution	OK

2. Dissolved Gas Analysis

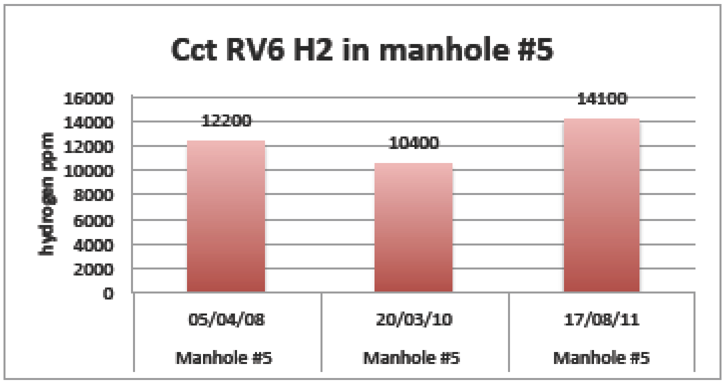
Location	Samples Taken	Trend	Most recent DGA result per EPRI Guideline
MH RV4	No samples	N/A	N/A
MH RV5	2008; 2010; 2011	Inconsistent hydrogen levels, reducing methane level; some acetylene trace amounts	"Action" level for hydrogen, "caution" level for acetylene, "acceptable" levels for all other gases
Rossdale Trifurcator	No samples	N/A	N/A
Rossdale Terminations	2002	N/A	N/A
Rossdale Risers	No samples	N/A	N/A
Victoria Trifurcator	No samples	N/A	N/A
Victoria Terminations	2011	N/A	"Concern" level for hydrogen in two terminations; all other results at "acceptable" levels
Victoria Risers	No samples	N/A	N/A

Observations

General

The 2008, 2010 and 2011 DGA results from the two manholes suggest that hydrogen generation is occurring at significant levels in this forced cooled circuit. The methane values appear higher than for other EPCOR HPFF circuits, despite the dilution effect of fluid circulation. This suggests some thermally induced decomposition may have occurred in one or more of these circuits. A DGA sample in 2007 from the main tank of FOCS displayed similar levels of hydrogen and methane as found at the manholes of these circuits. Two of the three samples taken from the Victoria terminations in 2011 had hydrogen concentrations at the "concern" level. It is presumed that the excellent DGA results at the third termination had been influenced by the major work undertaken there in 2011.

Circuit 72RV6 Trends



7.15.3 Cable Health Index

CEATI Health Index ratings:

Health Factor:	337
Risk Factor:	257
Total Factor:	634

7.15.4 Risk Assessment

This circuit has been relocated and reconnected a few times. It is very difficult to assess its conditions as the fluid is circulated through RV2 and RV4 and the gasses are averaged by the liquid movement. The paper test indicated normal aging conditions. Low risk at this time.

7.15.5 Recommendations

- Complete degassing of the fluid in this system would allow DGA trending to be effectively carried out without the results being excessively influenced by past events.
- The gas level should be monitored as a part of the hydraulic section (RV2/RV4/RV6). The details of the tests are applicable to all 72RV circuits because the oil is continuously circulated.
- The paper insulation tests shall be performed as soon as possible after opening of the new rehabilitation joint and through testing of this circuit shall be performed. The recommended PD test shall be performed before the circuit is stressed with another DC withstand test. Note that the proposed PD test can be considered also as the AC withstand test.
- Because of the recent discovery the fluid in the circuits 72RV2, 72RV4 and 72RV6 should be flushed through a filter and degasser to remove traces of burnt material after the joint rehabilitation is complete.
- PD and tan δ test is recommended.

Table 7.15

Cable Health Index - Detailed Report

Cable Details

Circuit Name	72RV6	Cable Installation Date	1978-12-15
Circuit Section		Cable Length	2130m
Cable Type	HPFF	Conductor Material	Copper
Cable Voltage	69	Insulation Material	Paper
Conductor Size	1500MCM		

3.0 Health Factor

	Standing	WF	Sub-Total
3.1 Electrical History	1	10	10
3.2 Physical Age	6	10	60
3.3 Outage Records	1	8	8
3.4 Loading History	10	5	50
3.5 System Cable Design Issues	1	10	10
3.6 System Maintenance History	1	7	7
3.7a Oil Testing - HPFF & LPFF	10	6	60
3.7b Oil Testing LPLF	0	6	0
3.8 Paper InsulationCondition - HPFF & LPFF	1	10	10
3.9 Insulation Condition - XLPE	0	7	0
3.10 Accessorry Condition	5	10	50
3.11 Hydraulic History	1	4	4
3.12 Installation Conditions	9	5	45
3.13 Civil Structure Condition	3	3	9
3.14 Stray Current Presence	1	7	7
3.15a Corrosion Protection Condition - HPFF	1	7	7
3.15b Corrosion Protection Condition - LPFF & XLPE	0	7	0

Health Factor Rating: 337

4.0 Risk Factors

	Standing	WF	Sub-Total
4.1 Environmental Impact	8	5	40
4.2 Potential Oil Spill	10	5	50
4.3 Regulatory Requirements	6	5	30
4.4 Safety	5	10	50
4.5 Short Circuit Level	9	4	36
4.6 Obsolescence	5	3	15
4.7 Importance of Circuit	6	6	36

Risk Factor Rating: 257

5.0 Maintenance Cost Factors

	Standing	WF	Sub-Total
5.1 Maintenance & Replacement Costs	8	5	40

5.2 Other Details

Maintenance Cost Factor Rating: 40

Summary - Total Values

Health Factor Rating:	337
Risk Factor Rating:	257
Maintenance Cost Factor Rating:	40

Total Rating: 634

Number of Known Factors: 22

Number of Unknown Factors: 3

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7.16 Cable Circuit 72RW3

RW3 is a 72kV circuit between Rossdale and Woodcroft substations. Specific characteristics of this cable are as follows:

Circuit Name	Length (m)	Yr of Install	Conductor Size (kcmil) & Type	Cable Mfr	Circuit Ratings (Amperes)			
					Summer Continuous	Summer Emergency	Winter Continuous	Winter Emergency
72RW3	7,833	1960	950 Al	Northern Electric	480	525	525	640

The original continuous rating is not available. The Northern Electric tender documents guaranteed the following emergency ratings:
636A at 1.0 load factor
740A at 0.6 load factor
It has to be noted that the insulation maximum temperature was specified to be 75°C

Recommended ratings: 465A

7.16.1 Operational History

1. **Major failures:**

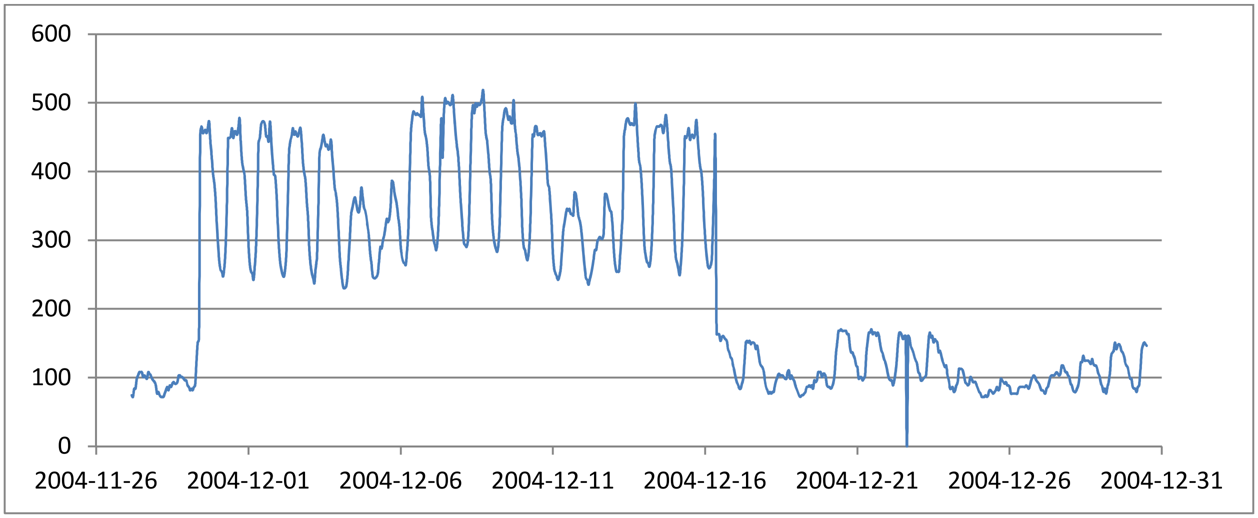
2001 - pothead phase 2 at Woodcroft failed – cause unknown

2. **Major maintenance:**

2010 – joint in manhole 7 rebuilt
2011 – joint in manhole 5 rebuilt

3. **Load history:**

The load history was provided by EPCOR from Jan. 1999 to the present. The cable runs sometimes at maximum allowed ratings. If compared the newly calculated ratings the circuit seems to be overloaded at times.



4. **Major improvements:**

No information available

7.16.2 Diagnostic Tests

1. **Insulation tests**

The tests performed in 2012 by PowerTech did not indicate any abnormal deterioration.

Cct designation	Test date	Paper type	Sample location	Dissipation factor	Breakdown strength	Moisture content	DP
72RW3	Oct-12	Kraft & joints	Joint RW5	OK	OK	OK	OK

2. **Dissolved Gas Analysis**

Circuit 72RW3 Rossdale x Woodcroft SS – 4 Samples

Location	Samples Taken	Trend	Most recent DGA result per EPRI Guideline
MH RW1	No samples	N/A	N/A
MH RW2	No samples	N/A	N/A
MH RW3	2003; 2009	Increasing hydrogen; all other gases stable	"Acceptable" levels for all gases
MH RW4	No samples	N/A	N/A
MH RW5	2003	N/A	"Concern" level for hydrogen; "acceptable" levels for all other gases
MH RW6	No samples	N/A	N/A
MH RW7	No samples	N/A	N/A

MH RW8	2003	N/A	“Acceptable” levels for all gases
Rossdale Trifurcator	No samples	N/A	N/A
Rossdale Terminations	No samples	N/A	N/A
Rossdale Risers	No samples	N/A	N/A
Woodcroft Trifurcator	No samples	N/A	N/A
Woodcroft Terminations	No samples	N/A	N/A
Woodcroft Risers	No samples	N/A	N/A

Observations

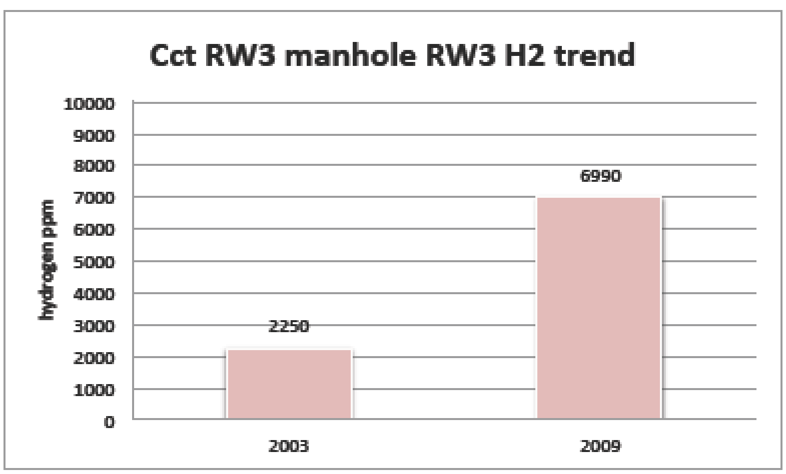
Manholes

The last DGA results are from manhole RW3 in 2009 and show that the gases other than hydrogen are at stable level; hydrogen however has increased significantly since the prior sample in 2003.

Terminal ends

No samples from the terminal ends were present in the database. It would be advisable to get DGA samples at each end of the circuit.

<u>Circuit 72RW3 Trends</u>



7.16.3 Cable Health Index

CEATI Health Index ratings:

Health Factor: 412
Risk Factor: 259
Total Factor: 711

7.16.4 Risk Assessment

The risk cannot be assessed for this circuit as there is no sufficient number of test results. The insulation test did not indicate any excessive deterioration but the DGA registered significant increase of hydrogen amount at the same location.

7.16.5 Recommendations

- Another insulation paper test should be performed by an acceptable laboratory and DP test results compared. The testing laboratory should be the one that the company is comfortable with. Since the obtaining the samples may not be possible within a short timeframe the alternative partial discharge test can be the best solution;
- Soil samples should be taken and analyzed;
- Annual DGA testing should be performed at the manholes and terminal ends;
- PD and tan δ test is strongly recommended;

Table 7.16

Cable Health Index - Detailed Report

Cable Details

Circuit Name	72RW3
Circuit Section	
Cable Type	HPFF
Cable Voltage	69
Conductor Size	950MCM
Cable Installation Date	1960-09-01
Cable Length	7836m
Conductor Material	Aluminium
Insulation Material	Paper

3.0 Health Factor

	Standing	WF	Sub-Total
3.1 Electrical History	4	10	40
3.2 Physical Age	10	10	100
3.3 Outage Records	4	8	32
3.4 Loading History	5	5	25
3.5 System Cable Design Issues	1	10	10
3.6 System Maintenance History	1	7	7
3.7a Oil Testing - HPFF & LPFF	10	6	60
3.7b Oil Testing LPLF	0	6	0
3.8 Paper InsulationCondition - HPFF & LPFF	1	10	10
3.9 Insulation Condition - XLPE	0	7	0
3.10 Accessorry Condition	5	10	50
3.11 Hydraulic History	1	4	4
3.12 Installation Conditions	9	5	45
3.13 Civil Structure Condition	5	3	15
3.14 Stray Current Presence	1	7	7
3.15a Corrosion Protection Condition - HPFF	1	7	7
3.15b Corrosion Protection Condition - LPFF & XLPE	0	7	0

Health Factor Rating: 412

4.0 Risk Factors

	Standing	WF	Sub-Total
4.1 Environmental Impact	9	5	45
4.2 Potential Oil Spill	10	5	50
4.3 Regulatory Requirements	2	5	10
4.4 Safety	5	10	50
4.5 Short Circuit Level	9	4	36
4.6 Obsolescence	5	10	50
4.7 Importance of Circuit	3	6	18

Risk Factor Rating: 259

5.0 Maintenance Cost Factors

	Standing	WF	Sub-Total
5.1 Maintenance & Replacement Costs	9	5	45
5.2 Other Details			

Maintenance Cost Factor Rating: 45

Summary - Total Values

Health Factor Rating:	412
Risk Factor Rating:	259
Maintenance Cost Factor Rating:	45

Total Rating: 716

Number of Known Factors: 22

Number of Unknown Factors: 3

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7.17 Cable Circuit 72VN21

VN21 is a 72kV circuit between Victoria and Namao substations. Specific characteristics of this cable are as follows:

Circuit Name	Length (m)	Yr of Install	Conductor Size (kcmil) & Type	Cable Mfr	Circuit Ratings (Amperes)			
					Summer Continuous	Summer Emergency	Winter Continuous	Winter Emergency
72VN21	3,865	1957	650 Cu	Northern Electric	480	525	525	640

The original circuit rating was 482A, no calculations results available.

Recommended ratings without fluid circulation: 435A

7.17.1 Operational History

1. **Major failures:**

   None recorded

2. **Major maintenance:**

This circuit is a part of the original RN circuit that was divided into 72RV2 and 72VN21.

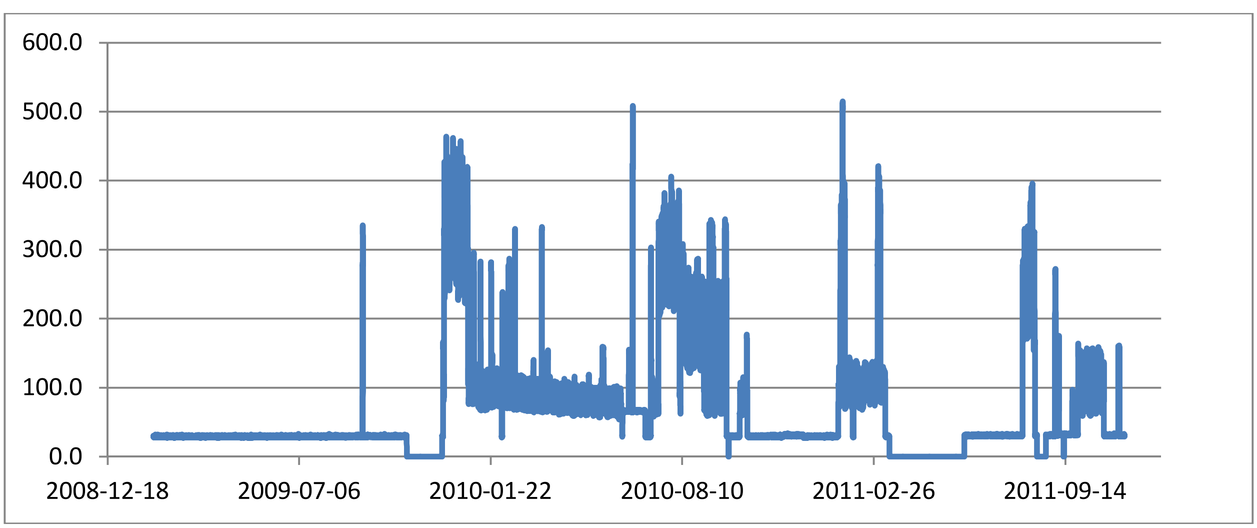
2008 - new terminations and a buried splice at Victoria were installed (DESS)

2009 - splice was rebuilt in manhole 2, 4 and 6

2011 - splice in manhole 2 was removed and manhole 1A and 2A were installed and new cable spliced in.

3. **Load history**

The load history was provided by EPCOR from January 1999 to the present.



4. Major improvements:

No information available

7.17.2 Diagnostic Tests

1. Insulation tests:

August 2009 – 9m sample extracted from the relocation area close to Victoria substation.

March 2012 – two samples were obtained from VN1 and VN2 joints

The tested cable is of the same vintage as the 72RV2 circuit. The 2009 test of the cable insulation did not discover any major degradation. Its dissipation factor and ACBD was lower but typical for the 55 years old cable.
The latest test revealed the insulation degradation, exceeding those of 72RV2, which indicates accelerated aging.

Cct designation	Test date	Paper type	Sample location	Dissipation factor	Breakdown strength	Moisture content	DP
VN21	Aug-09	Kraft	cable	Caution	Caution		
	Mar-12	Kraft	cable	Danger	Caution	Caution	Caution

2. Dissolved Gas Analysis

Circuit 72VN21 Victoria x Namao Substation - 31 Samples

Location	**Samples Taken**	**Trend**	**Most recent DGA result per EPRI Guideline**
MH NV1	2001; 2006; 2008	Increasing hydrogen, methane and ethane; stable values for carbon monoxide, carbon dioxide and ethylene; stable values for carbon monoxide and carbon dioxide	"Concern" level for hydrogen; "acceptable" levels for all other gases
MH NV2A	2001	N/A	"Concern" level for hydrogen; "acceptable" levels for all other gases
MH NV3	2001; 2006; 2008	Increasing hydrogen, methane and ethane; stable values for carbon monoxide, carbon dioxide and ethylene; stable values for carbon monoxide and carbon dioxide	"Concern" level for hydrogen; "acceptable" levels for all other gases
MH NV4	2001; 2008	Increasing hydrogen, methane, carbon monoxide, ethane and ethylene; stable carbon dioxide	"Acceptable" levels for all gases
MH NV5	2001; 2006;	Increasing hydrogen, methane,	"Concern" range for hydrogen and

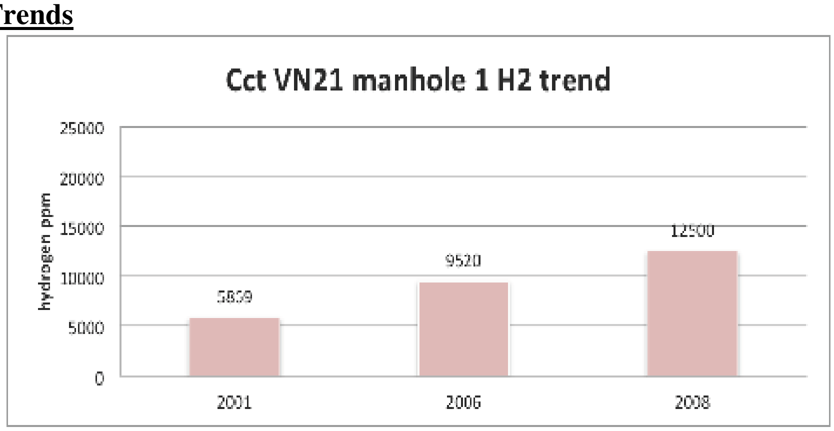
	2009; 2011	ethane, ethylene, carbon monoxide and carbon dioxide; trace amount of acetylene in the 2011 result	acetylene; "acceptable" range for all other gases
MH NV6	2001; 2006; 2009; 2011	Fluctuating hydrogen trend, stable methane, ethane and ethylene; trace amount of acetylene in the 2001 and the 2011 results	"Acceptable" range for all gases except for the one case of acetylene
Victoria Trifurcator	No samples	N/A	N/A
Victoria Terminations	2011;	N/A	"Concern" range for hydrogen, "acceptable" range for other gases (traces of acetylene were found in all three of the termination samples)
Victoria Risers	No samples	N/A	N/A
Namao Trifurcator	No samples;	N/A	N/A
Namao Terminations	2011;	N/A	"Concern" range for hydrogen, "acceptable" range for other gases (traces of acetylene were found in five of the six termination samples)
Namao Risers	No samples	N/A	N/A

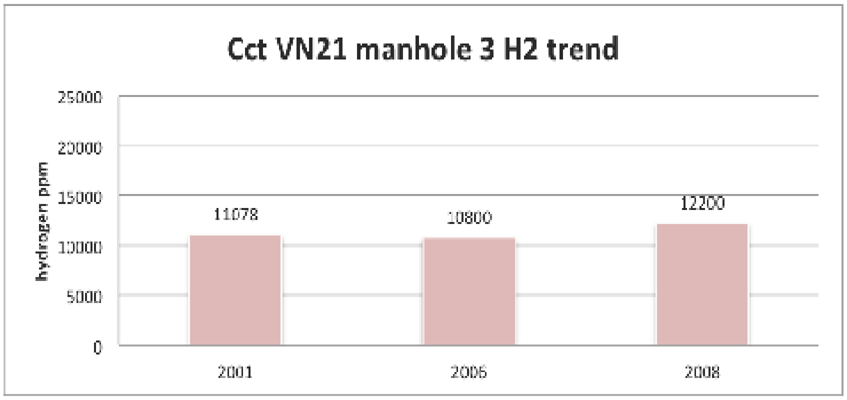
Observations

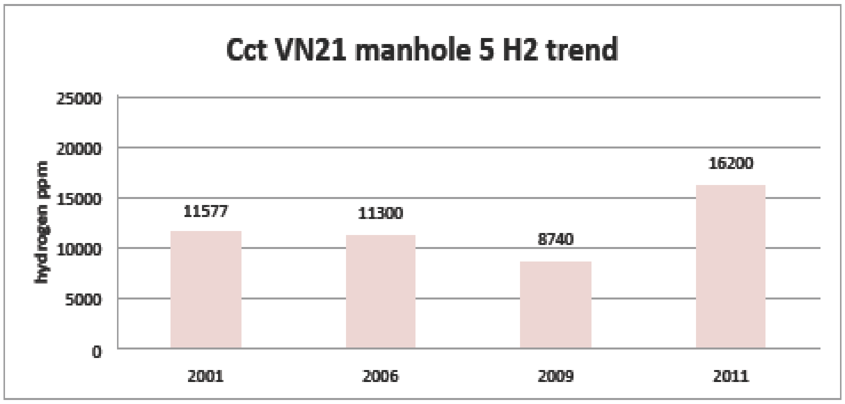
General

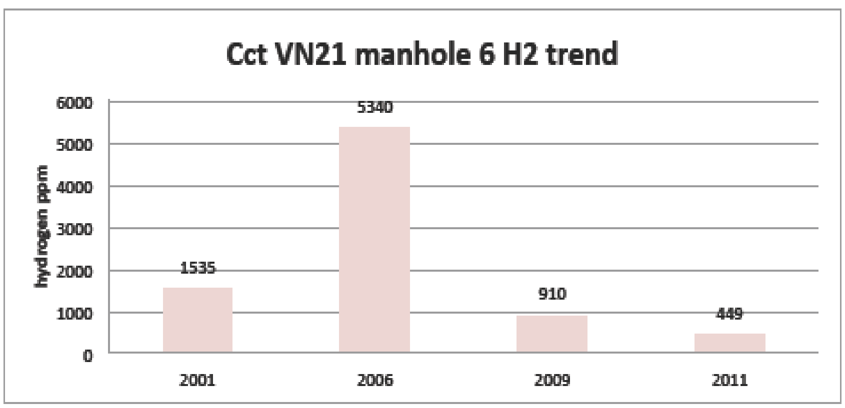
Major work was done on this circuit in 2008, 2009 and 2011. It is probable that the acetylene found in 2011 samples at manholes NV5 and NV6 may be related to fluid movement associated with this work. The increases in methane at manholes NV4 and NV5 may also be related to fluid movement and may indicate that some low-level thermal decomposition has occurred somewhere within the cable system.

Circuit 72VN21 Trends









7.17.3 Cable Health Index

CEATI Health Index ratings:

Health Factor:	423
Risk Factor:	232
Total Factor:	695

7.17.4 Risk Assessment

The latest paper tests conducted in May 2011 revealed significant deterioration of the dissipation factor. The DP factor of the layers close to the conductor in all three phases is lower than other layers that indicates thermal damage in VN1 location. It is reasonable to expect that the other locations are in similar conditions. The sample extracted in 2011 from VN2 location also generally confirmed aging. The dissipation factor at both locations is within the range of 0.93-1.51%. Since the moisture level is high, but not excessively high, we can assume that the increased dissipation factor and reduced polymerization factor are caused by severe deterioration.

The other parameters also show severe electrical and mechanical aging. Since this is the oldest circuit in EDTI grid replacing this circuit in the near future should be considered. Overall risk based on health index is considered medium.

7.17.5 Recommendations

- The circuit should be monitored very closely and a paper sample should be obtained from all three phases at other locations as soon as possible.
- DGA sampling should be done at six month intervals at manholes NV4 and NV5 so that and the overall trend of combustible gases can be monitored.
- PD and tan δ test should be done to confirm or eliminate causes of the gassing in the manholes that exhibits the concern level of the combustible gases.
- Annual DGA sampling should be done at the other manholes and terminal ends.

Table 7.17

Cable Health Index - Detailed Report

Cable Details

Circuit Name	72VN21	Cable Installation Date	1957-09-30
Circuit Section		Cable Length	3882m
Cable Type	HPFF	Conductor Material	Copper
Cable Voltage	69	Insulation Material	Paper
Conductor Size	650MCM		

3.0 Health Factor

	Standing	WF	Sub-Total
3.1 Electrical History	1	10	10
3.2 Physical Age	10	10	100
3.3 Outage Records	2	8	16
3.4 Loading History	5	5	25
3.5 System Cable Design Issues	1	10	10
3.6 System Maintenance History	5	7	35
3.7a Oil Testing - HPFF & LPFF	10	6	60
3.7b Oil Testing LPLF	0	6	0
3.8 Paper Insulation Condition - HPFF & LPFF	6	10	60
3.9 Insulation Condition - XLPE	0	7	0
3.10 Accessorry Condition	5	10	50
3.11 Hydraulic History	1	4	4
3.12 Installation Conditions	9	5	45
3.13 Civil Structure Condition	3	3	9
3.14 Stray Current Presence	1	7	7
3.15a Corrosion Protection Condition - HPFF	1	7	7
3.15b Corrosion Protection Condition - LPFF & XLPE	0	7	0

Health Factor Rating: 438

4.0 Risk Factors

	Standing	WF	Sub-Total
4.1 Environmental Impact	7	5	35
4.2 Potential Oil Spill	10	5	50
4.3 Regulatory Requirements	1	5	5
4.4 Safety	5	10	50
4.5 Short Circuit Level	9	4	36
4.6 Obsolescence	5	10	50
4.7 Importance of Circuit	1	6	6

Risk Factor Rating: 232

5.0 Maintenance Cost Factors

	Standing	WF	Sub-Total
5.1 Maintenance & Replacement Costs	7	5	35

5.2 Other Details

Maintenance Cost Factor Rating: 35

Summary - Total Values

Health Factor Rating:	438
Risk Factor Rating:	232
Maintenance Cost Factor Rating:	35

Total Rating: 705

Number of Known Factors: 22

Number of Unknown Factors: 3

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7.18 Cable Circuit 240BA2

BA2 is a 240kV circuit between Bellamy and Argyll terminal stations. Specific characteristics of this cable are as follows

Circuit Name	Length m	Yr of Install	Conductor Size (kcmil) & Type	Cable Mfr	Circuit Ratings (Amperes)			
					Summer Continuous	Summer Emergency	Winter Continuous	Winter Emergency
240BA2	4,713m	1977	2500 Cu	Prysmian	1090	1277	1284	1443
					963	1139	1152	1300

Note:

the ratings are:

first row - one cct, the other is not loaded

second row - 2 ccts working at the same time

Recommended ratings:

if 240BA3 is equally loaded: 850A

if 240BA3 is not loaded: 890A

7.18.1 Operational History

1. **Major failures:**

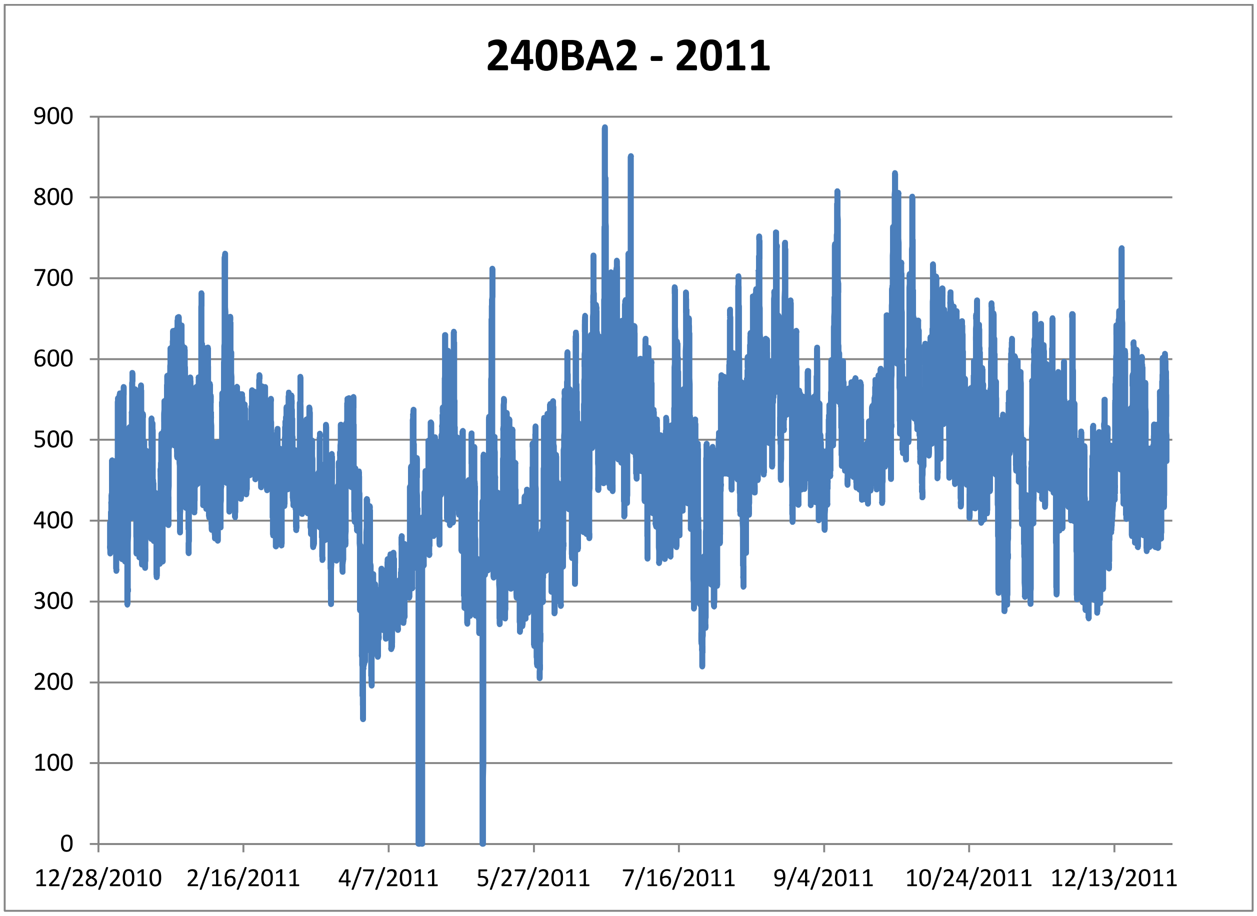
None recorded

2. **Major maintenance:**

2002 – cable terminations rebuilt at the Argyll transition station
2002 / 2003 - All fluid from the circuit flushed and degassed
2003 – joints rebuilt in manholes 1 and 2
2010 – fluid in Argyll terminations degassed
2010 - degassed fluid added between Argyll and manhole 4
2012 – fluid flushed and degassed

3. **Load history**

The load history was provided by EPCOR from Jan. 1999 to the present. A sample year is shown below.



4. Major improvement

No information available

7.18.2 Diagnostic Tests

1. Insulation tests

May 2004 test on samples obtained from joints in manholes BA1 and BA2

October 2008 test on samples obtained – no information

The tests are related to the crepe paper used in jointing. It indicates some paper deterioration that can be assumed typical for this long aging.
There is no test performed on the cable Kraft paper used in cable insulation.

Cct designation	Test date	Paper type	Sample location	Dissipation factor	Breakdown strength	Moisture content	DP
BA2	May-04	crepe	joints	Danger	Caution	OK?	OK
	Oct-08	crepe	joints		Danger		

2. Dissolved Gas Analysis

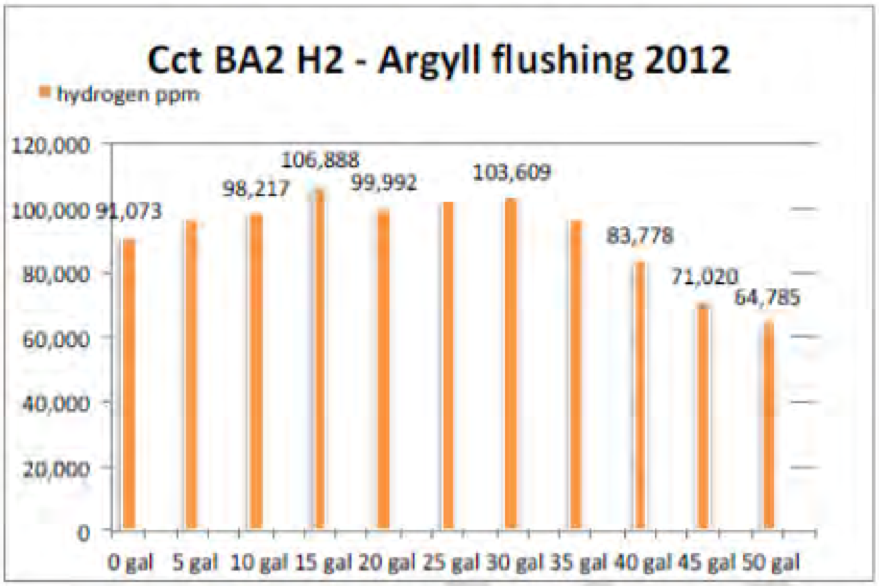
Circuit 240BA2 Bellamy x Argyll Substation – 476 samples

Location	Samples Taken	Trend	Most recent DGA per EPRI Guideline
MH #1	2001; 2002; 2003; 2004; 2005; 2006; 2007; 2008; 2009; 2010; 2011;	Rising hydrogen with occasional reversals which may be due to flushing or other work; small fluctuations in levels of other gases	"Concern" level for hydrogen; "acceptable" level for all other gases
MH #2	2001; 2002; 2003; 2004; 2005; 2006; 2007; 2008; 2009; 2010; 2011;	Rising hydrogen with occasional reversals which may be due to flushing or other work; small fluctuations in levels of other gases	"Concern" level for hydrogen; "acceptable" level for all other gases
MH #3	2001; 2002; 2003; 2004; 2005; 2006; 2007; 2008; 2009; 2010; 2011;	Rising hydrogen with occasional reversals which may be due to flushing or other work; small fluctuations in levels of other gases	"Acceptable" level for all gases
MH #4	2001; 2002; 2003; 2004; 2005; 2006; 2007; 2008; 2009; 2010; 2011;	Rising hydrogen with occasional reversals which may be due to flushing or other work; small fluctuations in levels of other gases	"Acceptable" level for all gases
MH #5	2001; 2002; 2003; 2004; 2005; 2006; 2007; 2008; 2009; 2010; 2011;	Rising hydrogen with occasional reversals which may be due to flushing or other work; small fluctuations in levels of other gases	"Concern" level for hydrogen "acceptable" level for all other gases
MH #6	2001; 2002; 2003; 2004; 2005; 2006; 2007; 2008; 2009; 2010; 2011;	Very low stable hydrogen levels with recent high values possibly caused by fluid flushing; small fluctuations in levels of other gases	"Concern" level for hydrogen "acceptable" level for all other gases
MH #7	2001; 2002; 2003; 2004; 2005; 2006; 2007; 2008; 2009; 2010; 2011;	Moderately rising hydrogen with occasional reversals which may be due to flushing or other work; small fluctuations in levels of other gases	"Acceptable" level for all gases
Argyll Terminations	2001; 2002; 2003; 2004; 2005; 2006; 2007; 2008; 2009; 2010; 2011;	Rising hydrogen with occasional reversals which may be due to flushing or other work; small fluctuations in levels of other gases	"Action" level for hydrogen; "acceptable" level for all other gases
Argyll Risers	2001; 2002; 2003; 2004; 2005; 2006; 2007; 2008; 2009; 2010; 2011;	Rising hydrogen with occasional reversals which may be due to flushing or other work; small fluctuations in levels of other gases	"Action" level for hydrogen; "acceptable" level for all other gases
Argyll	2001; 2002; 2003;	Rising hydrogen with occasional rever-	"Acceptable" level for

Trifurcator	2004; 2005; 2006; 2007; 2008; 2009; 2010; 2011;	sals which may be due to flushing or other work; small fluctuations in levels of other gases	all gases (a sharp drop from the “action” levels for hydrogen one year earlier
Bellamy Terminations	2001; 2003; 2004; 2005; 2006; 2007; 2008; 2009; 2010; 2011;	Low hydrogen levels with some moderate increases in recent samples; stable values for other gases	“Acceptable” level for all gases
Bellamy Risers	2001; 2002; 2003; 2004; 2005; 2006; 2007; 2008; 2009; 2010; 2011;	Moderately rising hydrogen with occasional reversals which may be due to flushing or other work; small fluctuations in levels of other gases	“Acceptable” level for all gases
Bellamy Trifurcator	No samples	N/A	

Observations

- The influence of the degassing in 2002/2003 is evident in the hydrogen charts for all parts of the circuit. It is equally clear however, that hydrogen production continued unabated after the degassing had been completed.
- The terminations at Argyll Substation have a much greater tendency to produce hydrogen than do the SF6 terminations at Bellamy.
- The fluid samples taken from manholes closest to Bellamy Substation have consistently shown higher hydrogen concentrations than those in the middle of the route.
- In general, the hydrogen concentrations at manholes beyond the zone of influence of either substation are relatively low.
- The overall results from the EPCOR BA2 and BA3 sampling program shows that peak values of hydrogen consistently occur at the Argyll Substation termination system and at manholes 1 and 2. These two manholes are the closest to Bellamy Substation.
- The flushing of the BA2 circuit in April 2012 revealed that the highest concentration of gasses was between bottom of Argyll terminations and MH#7. The peak values occurred after a volume of 15 to 30 gallons was flushed. This places the location of peak hydrogen quite close to the cable terminal ends. The variation in hydrogen levels during this flushing are shown in the following graph:

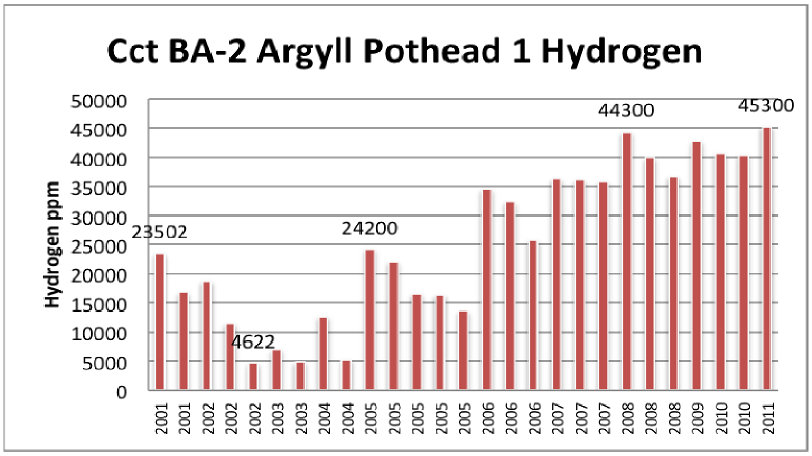


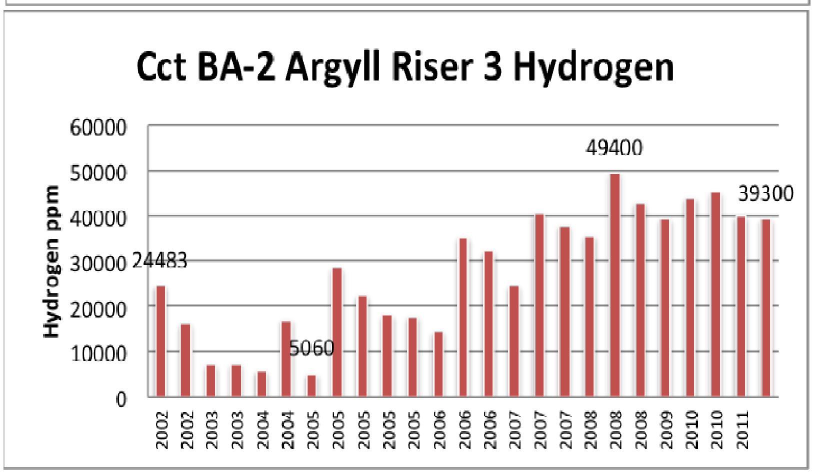
Levels of the other telltale gases during the flushing were all extremely low and stable. Maximum values are shown below:

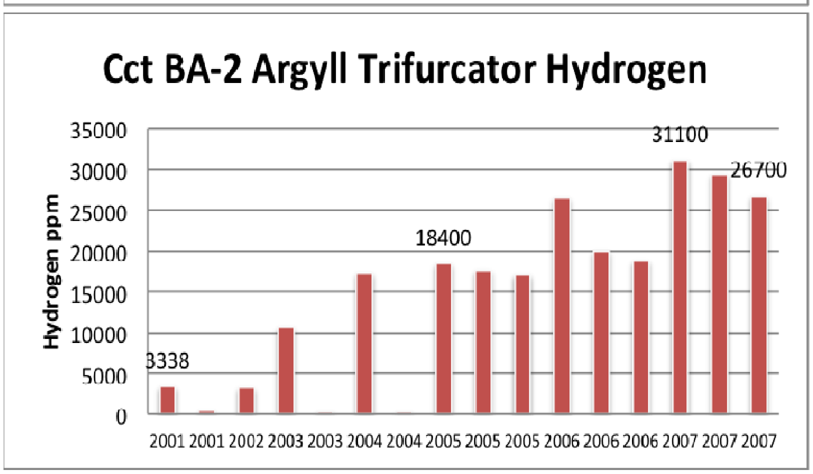
- Acetylene 4.9ppm;
- Carbon monoxide 17ppm;
- Carbon dioxide 161ppm;
- Methane 5.3ppm;
- Ethane 3.2ppm;
- Ethylene 2.4ppm;

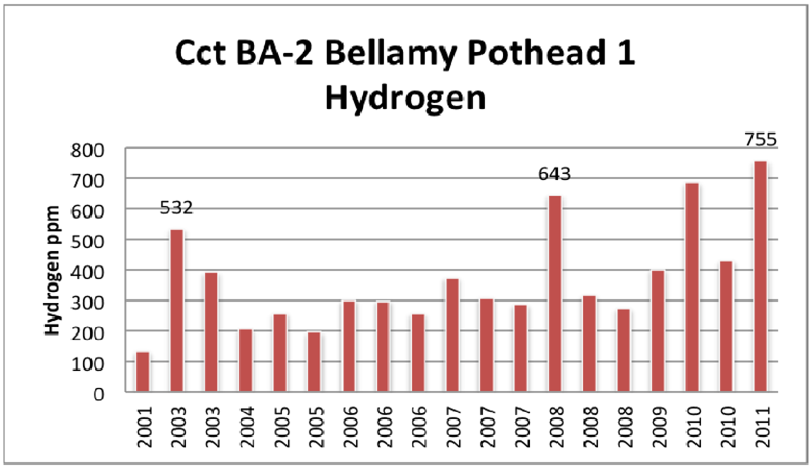
EDTI proposes to replace life cycle replacement of the BA2 cable pipe, riser, and accessories at the Argyll station beginning in 2014. Ideally, partial discharge testing would be performed on this circuit as an additional input to the decision process.

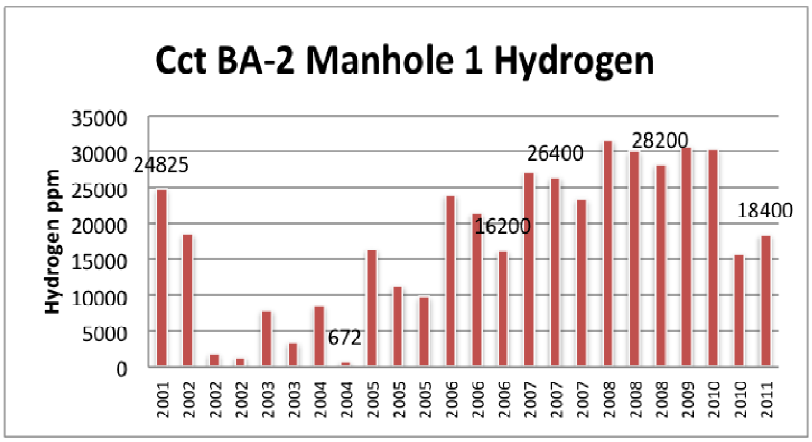
Trends


Cct BA-2 Argyll Pothead 1 Hydrogen
Hydrogen ppm
50000
45000
40000
35000
30000
25000
20000
15000
10000
5000
0
23502
4622
24200
44300
45300
2001 2001 2002 2002 2002 2003 2003 2003 2004 2004 2005 2005 2005 2005 2005 2006 2006 2006 2007 2007 2007 2008 2008 2008 2009 2010 2010 2011


Cct BA-2 Argyll Riser 3 Hydrogen
Hydrogen ppm
60000
50000
40000
30000
20000
10000
0
24483
5060
49400
39300
2002 2002 2003 2003 2004 2004 2005 2005 2005 2005 2006 2006 2006 2007 2007 2007 2008 2008 2008 2009 2010 2010 2011


Cct BA-2 Argyll Trifurcator Hydrogen
Hydrogen ppm
35000
30000
25000
20000
15000
10000
5000
0
3338
18400
31100
26700
2001 2001 2002 2003 2003 2004 2004 2005 2005 2005 2006 2006 2006 2007 2007 2007


Cct BA-2 Bellamy Pothead 1 Hydrogen
Hydrogen ppm
800
700
600
500
400
300
200
100
0
532
643
755
2001
2003
2003
2004
2005
2005
2006
2006
2006
2007
2007
2007
2008
2008
2008
2009
2010
2010
2011


Cct BA-2 Manhole 1 Hydrogen
Hydrogen ppm
35000
30000
25000
20000
15000
10000
5000
0
24825
672
16200
26400
28200
18400
2001
2002
2002
2002
2003
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2008
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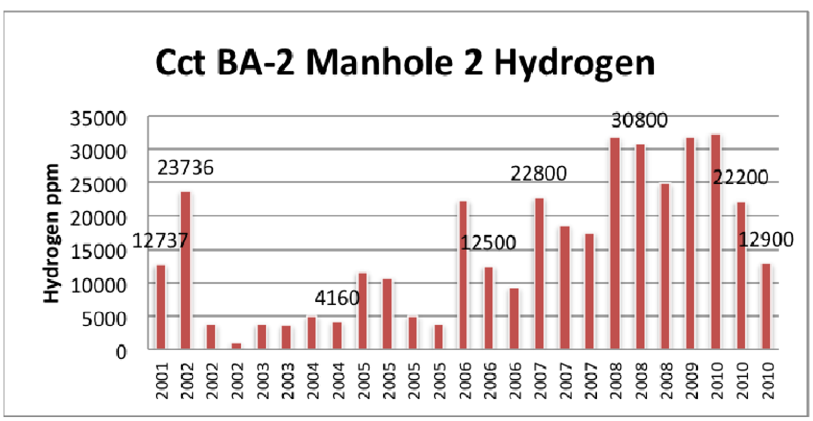
2008
2009
2010
2010
2011


Cct BA-2 Manhole 2 Hydrogen
Hydrogen ppm
35000
30000
25000
20000
15000
10000
5000
0
12737
23736
4160
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30800
22200
12900
2001
2002
2002
2002
2003
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2008
2009
2010
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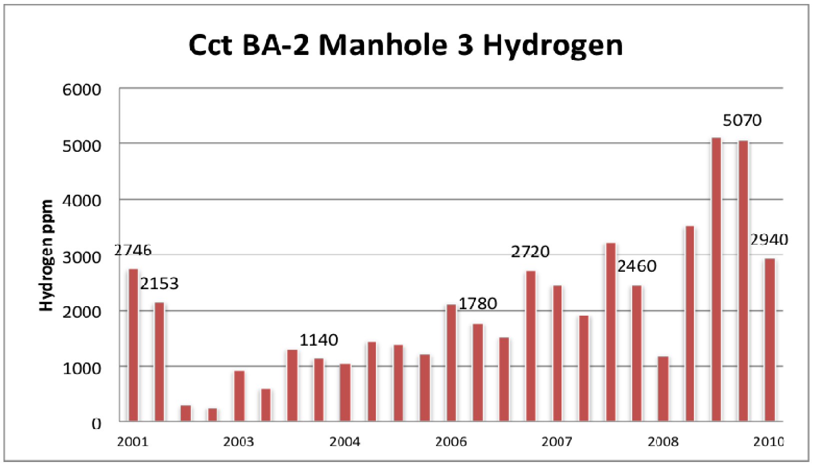
2010


Cct BA-2 Manhole 3 Hydrogen
Hydrogen ppm
6000
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4000
3000
2000
1000
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2153
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1780
2720
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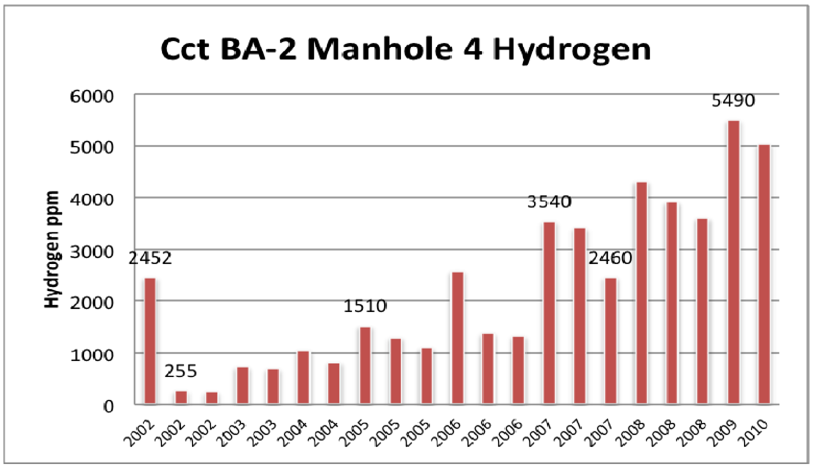
5070
2940
2001
2003
2004
2006
2007
2008
2010


Cct BA-2 Manhole 4 Hydrogen
Hydrogen ppm
6000
5000
4000
3000
2000
1000
0
2452
255
1510
3540
2460
5490
2002
2002
2002
2003
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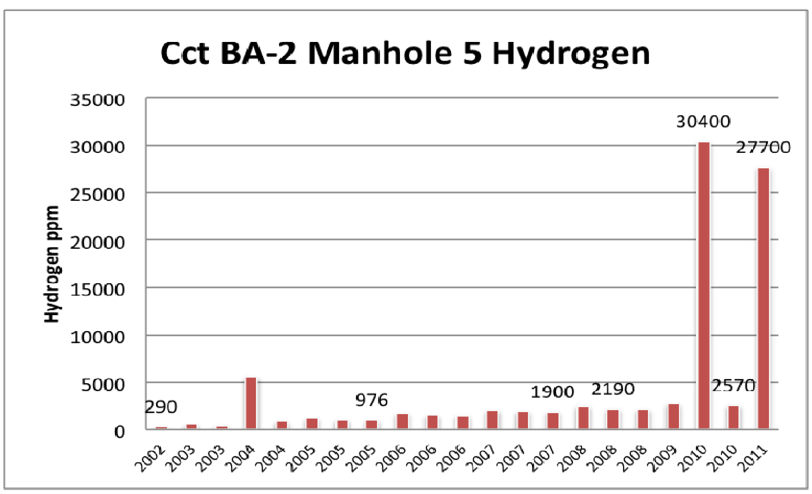
2007
2007
2008
2008
2008
2009
2010


Cct BA-2 Manhole 5 Hydrogen
Hydrogen ppm
35000
30000
25000
20000
15000
10000
5000
0
30400
27700
290
976
1900
2190
2570
2002
2003
2003
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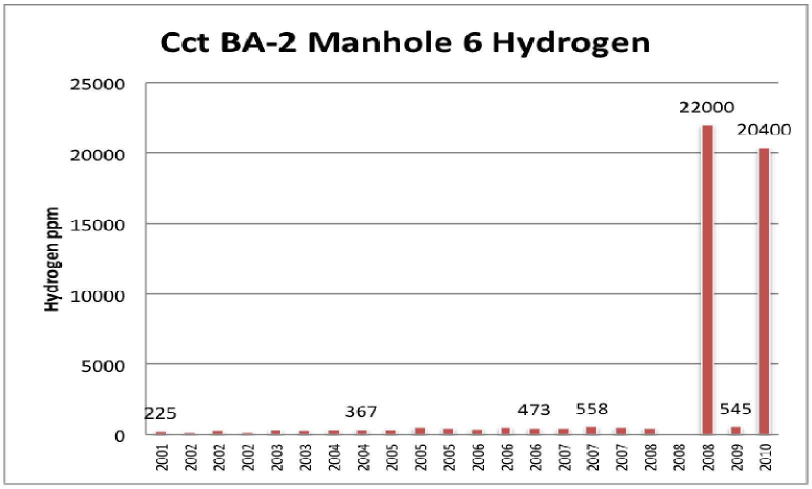
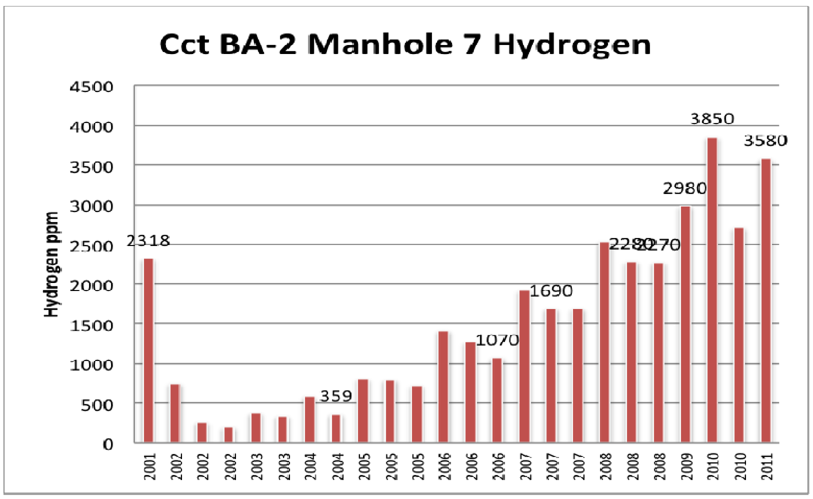
2008
2009
2010
2010
2011





7.18.3 Cable Health Index

CEATI Health Index ratings:

Health Factor:	492
Risk Factor:	285
Total Factor:	817

7.18.4 Risk Assessment

The circuit partial flushing in 2011 revealed high concentration of hydrogen between the bottom of Argyll riser and the first manhole MH#7. If the removal of gasses does not improve the circuit working conditions replacement of a certain part of the circuit could be a solution. The frequency of such action can be based on evaluation of fluid samples and trend analysis.

This action has to be dictated by the economic and organizational reasons. The evaluation of associated costs and difficulties to obtain a power outage for periodic removal of gasses can justify the replacing of a part of this circuit. Proposed remedial actions of replacing a section of the circuit may lessen operating risk and extend the life of the entire circuit.

7.18.5 Recommendations

- Flush all the fluid from this circuit through a filter and degasser while monitoring DGA levels.
- Continue flushing until the hydrogen concentrations at manholes have been reduced to less than10, 000 ppm and less than 5,000ppm at terminal ends
- Following fluid degassing, DGA level should be monitored by sampling at manholes 1, 2 and 7and the Argyll terminations at six-month intervals. If the trending indicates reappearing of gasses at an unusual rate the circuit or a part of it should be replaced.
- Kraft paper radial test is strongly recommended.
- The PD and tan δ tests are strongly recommended to establish a baseline for future circuit evaluations and to help in verifying the length of the circuit that could be replaced.

Table 7.18

Cable Health Index - Detailed Report

Cable Details

Circuit Name	240BA2	Cable Installation Date	1977-10-15
Circuit Section		Cable Length	4614m
Cable Type	HPFF	Conductor Material	Copper
Cable Voltage	230	Insulation Material	Paper
Conductor Size	2500MCM		

3.0 Health Factor

	Standing	WF	Sub-Total
3.1 Electrical History	1	10	10
3.2 Physical Age	6	10	60
3.3 Outage Records	6	8	48
3.4 Loading History	5	5	25
3.5 System Cable Design Issue	10	10	100
3.6 System Maintenance History	5	7	35
3.7a Oil Testing - HPFF & LPFF	10	6	60
3.7b Oil Testing LPLF	0	6	0
3.8 Paper InsulationCondition - HPFF & LPFF	1	10	10
3.9 Insulation Condition - XLPE	0	7	0
3.10 Accessorry Condition	5	10	50
3.11 Hydraulic History	1	4	4
3.12 Installation Conditions	9	5	45
3.13 Civil Structure Condition	1	3	3
3.14 Stray Current Presence	1	7	7
3.15a Corrosion Protection Condition - HPFF	5	7	35
3.15b Corrosion Protection Condition - LPFF & XLPE	0	7	0

Health Factor Rating: 492

4.0 Risk Factors

	Standing	WF	Sub-Total
4.1 Environmental Impact	10	5	50
4.2 Potential Oil Spill	10	5	50
4.3 Regulatory Requirements	1	5	5
4.4 Safety	5	10	50
4.5 Short Circuit Level	5	4	20
4.6 Obsolescence	5	10	50
4.7 Importance of Circuit	10	6	60

Risk Factor Rating: 285

5.0 Maintenance Cost Factor

	Standing	WF	Sub-Total
5.1 Maintenance & Replacement Costs	10	5	50

5.2 Other Details

Maintenance Cost Factor Rating: 50

Summary - Total Values

Health Factor Rating:	492
Risk Factor Rating:	285
Maintenance Cost Factor Rating:	50

Total Rating: 827

Number of Known Factors: 22

Number of Unknown Factors: 3

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7.19 Cable Circuit 240BA3

BA3 is a 240kV circuit between Bellamy and Argyll terminal stations. Specific characteristics of this cable are as follows:

Circuit Name	Length m	Yr of Install	Conductor Size (kcmil) & Type	Cable Mfr	Circuit Ratings (Amperes)			
					Summer Continuous	Summer Emergency	Winter Continuous	Winter Emergency
240BA3	4,653m	1977	2500 Cu	Prysmian	1090	1277	1284	1443
					963	1139	1152	1300

Note:
the ratings are:
first row - one cct, the other is not loaded
second row - 2 ccts working at the same time

Recommended ratings:
if 240BA2 is equally loaded: 850A
if 240BA2 is not loaded: 890A

7.19.1 Operational History

1. **Major failures:**

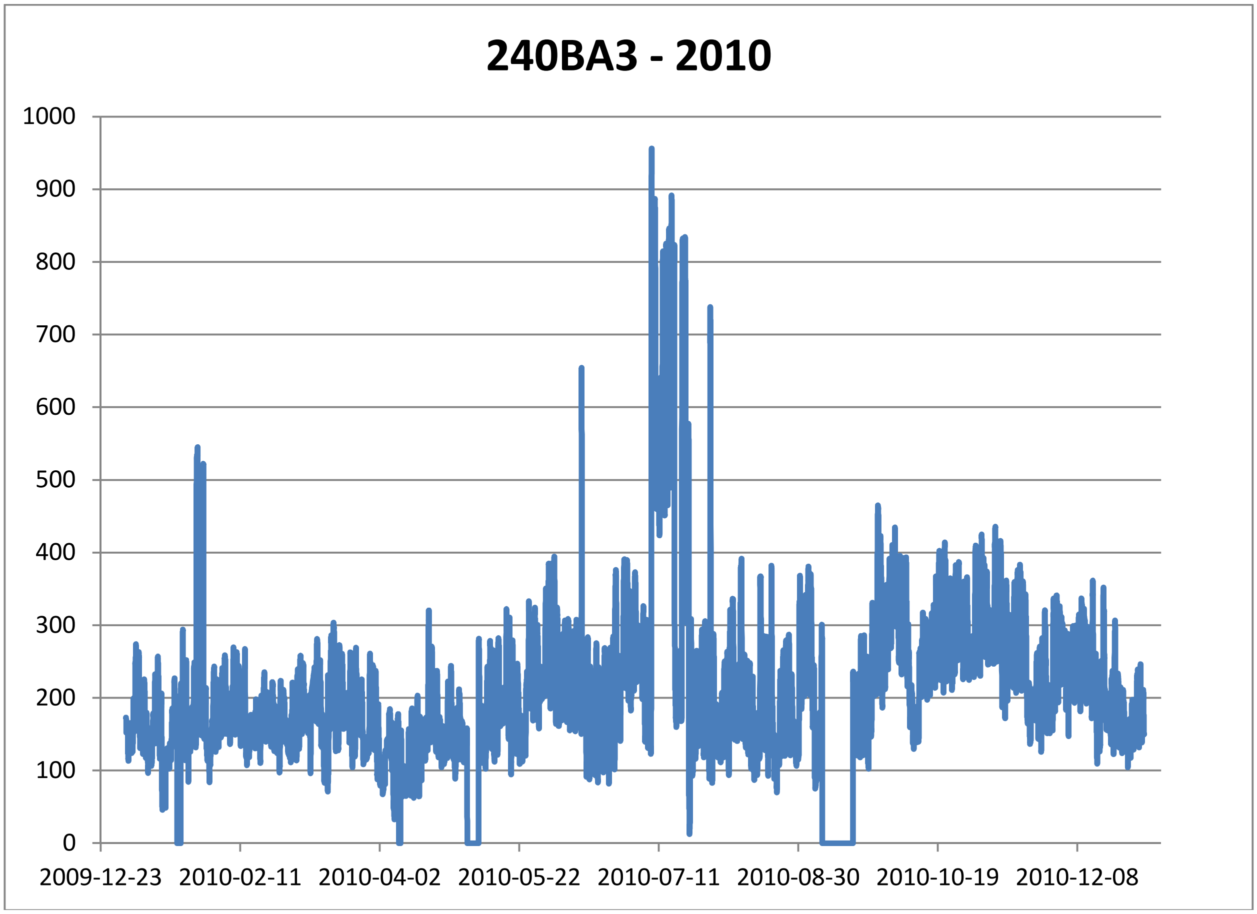
None recorded

2. **Major maintenance**

2002 – cable terminations rebuilt at Argyll Transition Station
2002/2003 – entire circuit degassed
2012 – circuit BA3 degassed from Bellamy Pumping Plant to manhole 2, potheads at Argyll TS flushed

3. **Load history**

The load history was provided by EPCOR from Jan. 1999 to the present. A sample year is shown below.



4. **Major improvement**

No information available

7.19.2 Diagnostic Tests

1. **Insulation tests:**

No paper insulation tests were performed.

Cct designation	Test date	Paper type	Sample location	Dissipation factor	Breakdown strength	Moisture content	DP
BA3	No test						

Dissolved Gas Analysis

Circuit 240BA3 Bellamy x Argyll Substation – 470 samples

Location	Samples Taken	Trend	Most recent DGA per EPRI Guideline
MH #1	2001; 2002; 2003;	Rising hydrogen with occasional re-	"Concern" level for hy-

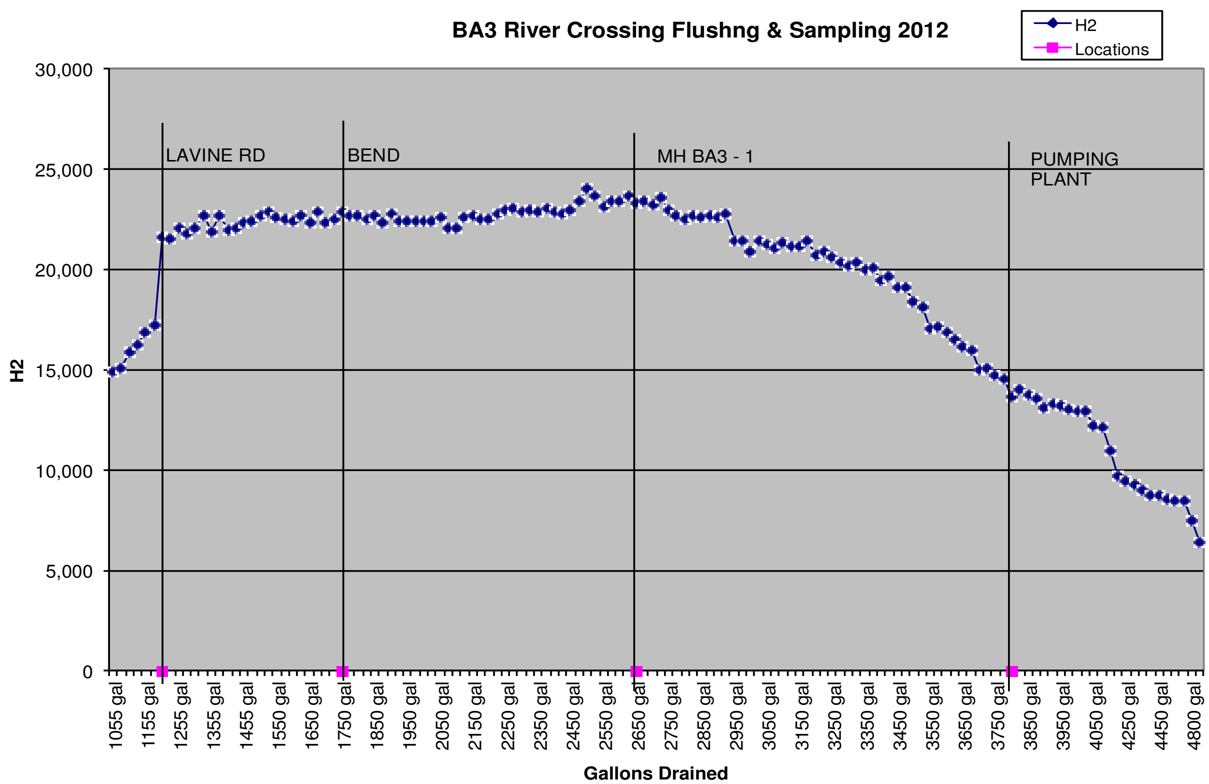
	2004; 2005; 2006; 2007; 2008; 2009; 2010; 2011;	versals which may be due to flushing or other work; small fluctuations in levels of other gases	drogen; "acceptable" level for all other gases
MH #2	2001; 2002; 2003; 2004; 2005; 2006; 2007; 2008; 2010; 2011;	Rising hydrogen with occasional reversals which may be due to flushing or other work; small fluctuations in levels of other gases	"Acceptable" level for hydrogen and all other gases
MH #3	2001; 2002; 2003; 2004; 2005; 2006; 2007; 2008; 2009; 2010; 2011;	Moderately rising hydrogen with occasional reversals which may be due to flushing or other work; small fluctuations in levels of other gases	"Acceptable" level for hydrogen and all other gases
MH #4	2001; 2002; 2003; 2004; 2005; 2006; 2007; 2008; 2010; 2011;	Moderately rising hydrogen with occasional abrupt changes which may be due to flushing or other work; small fluctuations in levels of other gases	"Concern" level for hydrogen; "acceptable" level for all other gases.
MH #5	2001; 2002; 2003; 2004; 2005; 2006; 2007; 2008; 2009; 2010; 2011;	Very slowly rising hydrogen with occasional abrupt changes which may be due to flushing or other work; small fluctuations in levels of other gases	"Acceptable" level for all gases
MH #6	2001; 2002; 2003; 2004; 2005; 2006; 2007; 2008; 2009; 2010; 2011;	Low stable hydrogen levels with occasional high values, probably caused by fluid flushing; small fluctuations in levels of other gases	"Acceptable" level for all gases
Argyll Terminations	2001; 2002; 2003; 2004; 2005; 2006; 2007; 2008; 2009; 2010; 2011;	Rising hydrogen with occasional reversals which may be due to flushing or other work; small fluctuations in levels of other gases	"Action" level for hydrogen; "acceptable" level for all other gases
Argyll Risers	2001; 2002; 2003; 2004; 2005; 2006; 2007; 2008; 2009; 2010; 2011;	Rising hydrogen with occasional reversals which may be due to flushing or other work; small fluctuations in levels of other gases	"Action" level for hydrogen; "acceptable" level for all other gases
Argyll Trifurcator	2001; 2002; 2003; 2004; 2005; 2006; 2007; 2008; 2009; 2010; 2011;	Rising hydrogen with occasional reversals which may be due to flushing or other work; small fluctuations in levels of other gases	"Acceptable" level for all gases (a sharp drop from the "action" levels for hydrogen one year earlier
Bellamy Terminations	2001; 2003; 2004; 2005; 2006; 2007; 2008; 2009; 2010; 2011;	Low hydrogen levels with some moderate increases in recent samples; stable values for other gases	"Acceptable" level for all gases
Bellamy Risers	2001; 2002; 2003; 2004; 2005; 2006; 2007; 2008; 2009; 2010; 2011;	Moderately rising hydrogen with occasional reversals which may be due to flushing or other work; small fluctuations in levels of other gases	"Acceptable" level for all gases
Bellamy Trifurcator	No samples	N/A	

Observations

The influence of the degassing in 2002/2003 is evident in the hydrogen charts for all parts of the circuit. It is equally clear that hydrogen production continued after the degassing had been completed, at rates that appear related to the sample point along the circuit length.

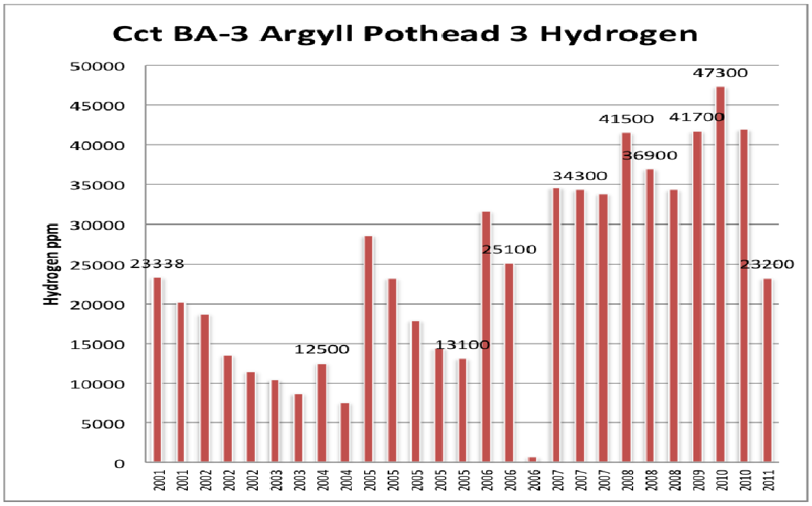
As with circuit 240BA2, the terminal ends at Argyll Substation have the greatest tendency to produce hydrogen. There is a significant contrast between the hydrogen levels at the Argyll end and the results from samples at the Bellamy SF6 terminations. Samples taken from the two manholes closest to Bellamy Substation have consistently shown the highest hydrogen concentrations from all the manholes.

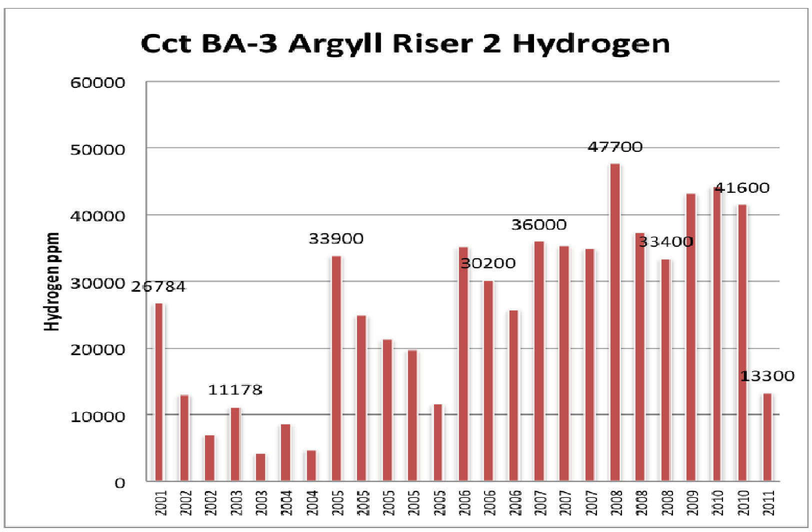
Flushing performed at manhole #1 in March 2012 showed that the peak hydrogen values near Bellamy SS to be at the river crossing. This is show in the following graph:

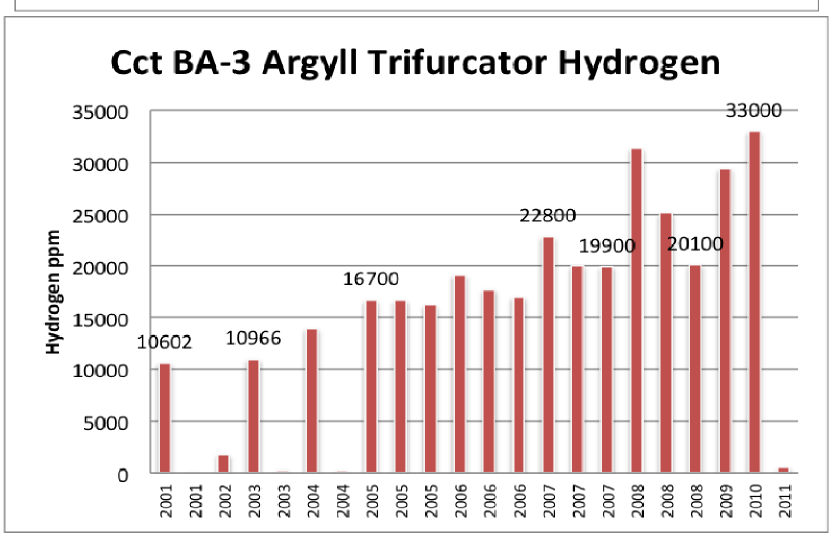


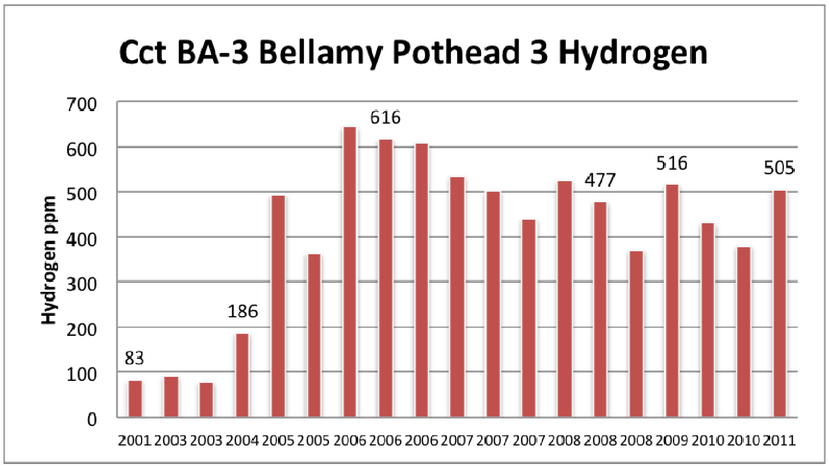
In general, the hydrogen concentrations at manholes beyond the zone of influence of either substation are relatively low. The hydrogen concentrations are somewhat high at manhole 4. These are not consistent with the trends from manholes 3 or 5. They also differ with the circuit BA2 trends at this part of the route. Ideally, partial discharge testing would be performed on this circuit as an additional input to the decision process.

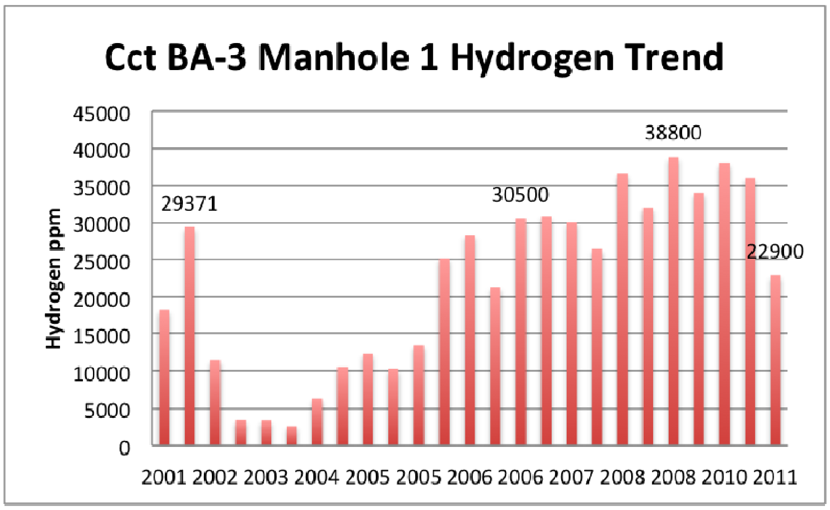
Circuit 240BA3 Trends

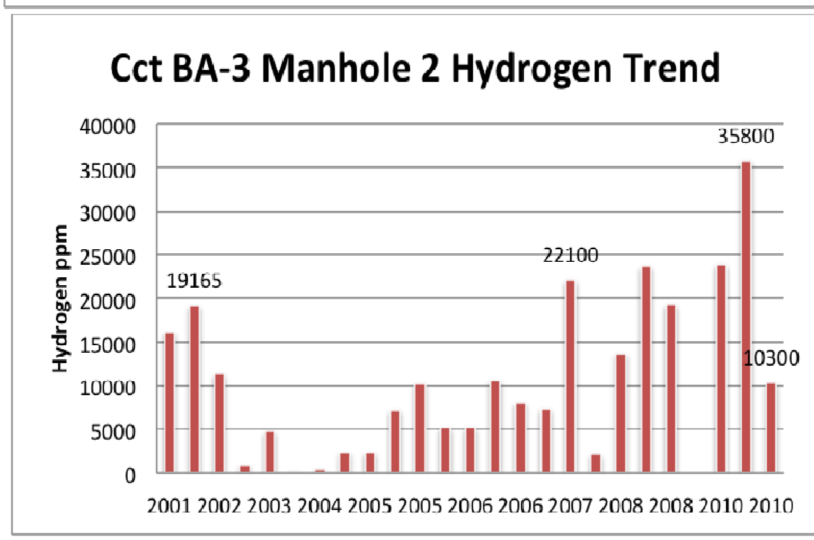


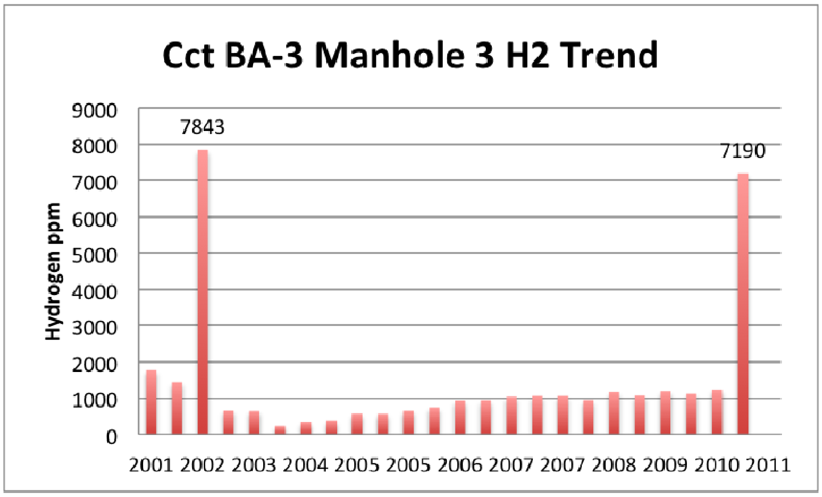


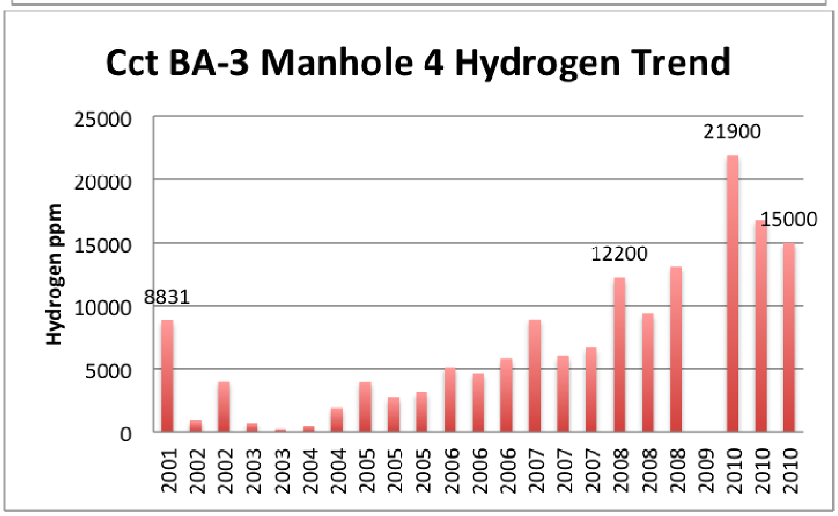


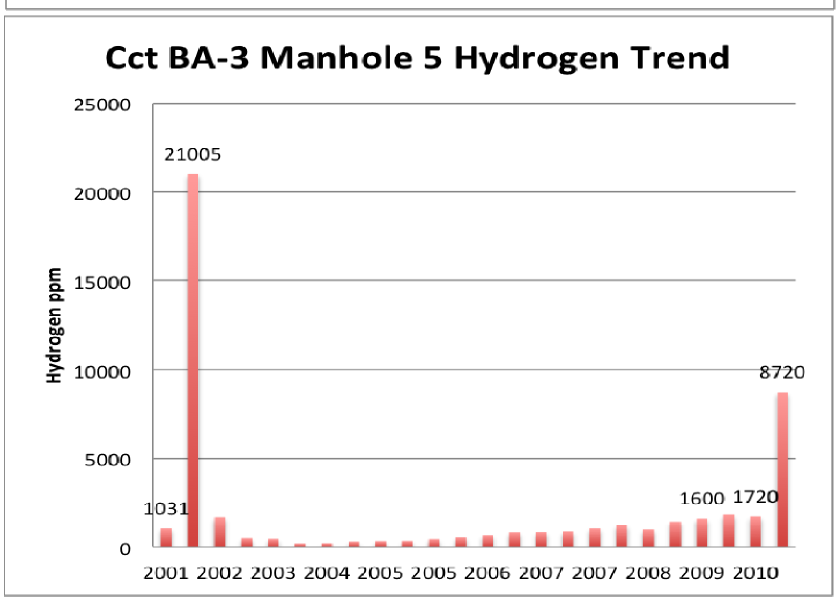

Cct BA-3 Bellamy Pothead 3 Hydrogen
Hydrogen ppm
700
600
500
400
300
200
100
0
83
186
616
477
516
505
2001 2003 2003 2004 2005 2005 2006 2006 2006 2007 2007 2007 2008 2008 2008 2009 2010 2010 2011

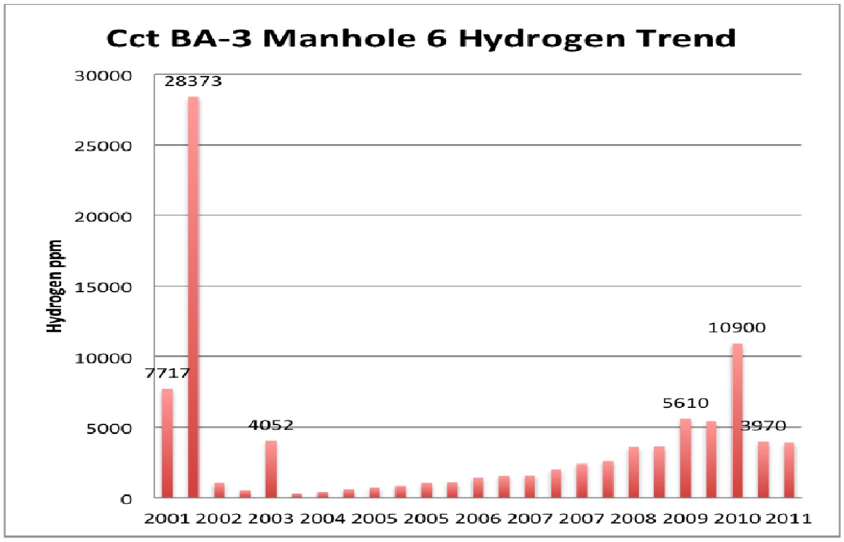

Cct BA-3 Manhole 1 Hydrogen Trend
Hydrogen ppm
45000
40000
35000
30000
25000
20000
15000
10000
5000
0
29371
30500
38800
22900
2001 2002 2003 2004 2005 2005 2006 2006 2007 2008 2008 2010 2011


Cct BA-3 Manhole 2 Hydrogen Trend
Hydrogen ppm
40000
35000
30000
25000
20000
15000
10000
5000
0
19165
22100
35800
10300
2001 2002 2003 2004 2005 2005 2006 2006 2007 2008 2008 2010 2010


Cct BA-3 Manhole 3 H2 Trend
Hydrogen ppm
9000
8000
7000
6000
5000
4000
3000
2000
1000
0
7843
7190
2001 2002 2003 2004 2005 2005 2006 2007 2007 2008 2009 2010 2011


Cct BA-3 Manhole 4 Hydrogen Trend
Hydrogen ppm
25000
20000
15000
10000
5000
0
8831
12200
21900
15000
2001 2002 2002 2003 2003 2004 2004 2005 2005 2005 2006 2006 2006 2007 2007 2007 2008 2008 2008 2009 2010 2010 2010


Cct BA-3 Manhole 5 Hydrogen Trend
Hydrogen ppm
25000
20000
15000
10000
5000
0
21005
1031
1600
1720
8720
2001 2002 2003 2004 2005 2005 2006 2007 2007 2008 2009 2010



7.19.3 Cable Health Index

CEATI Health Index ratings:

Health Factor:	471
Risk Factor:	261
Total Factor:	772

7.19.4 Risk Assessment

The partial flushing of circuit 240BA3 in 2012 revealed a pattern of extremely high hydrogen concentrations between the base of the Argyll termination and the nearest manhole. None of the other combustible gases were detected at elevated values. The presence of elevated hydrogen without other telltale gases has been identified in the EPRI Guideline as being symptomatic of low level partial discharge activity. As stated before and found in opinions of others (Nirmal Singh in particular), the presence of significantly elevated hydrogen without other key gases does not indicate a deterioration in cable or joints. However, the maintenance and safety implications of very high hydrogen concentrations are significant. These, together with the cost of managing hydrogen levels through fluid flushing and the associated effect on circuit availability can provide a sufficient reason for replacing older cable sections. Since circuits 240BA2 and BA3 are of the same age and because of lack of cable insulation test on any of them the recommendations stated for 240BA2 are applicable to the 240BA3 circuits. The section length identified with DGA profiling shall be confirmed with the PD test to ensure that it covers the most affected part of the circuit.

7.19.5 Recommendations

- The paper insulation test should be performed at the first opportunity.
- Flush all the fluid from this circuit through a filter and degasser while monitoring DGA levels.
- Continue flushing until the hydrogen concentrations have been reduced to less than10, 000 ppm.

- Following fluid degassing, DGA should be monitored by sampling at manholes 1, 2, 4 and 6 as well as the Argyll terminations. This should be done at six-month intervals. A new baseline should be established as soon as possible.
- The PD and tan δ tests are strongly recommended before replacement of a part of the circuit is decided.

Table 7.19

Cable Health Index - Detailed Report

Cable Details

Circuit Name	240BA3	Cable Installation Date	1977-10-15
Circuit Section		Cable Length	4677m
Cable Type	HPFF	Conductor Material	Copper
Cable Voltage	230	Insulation Material	Paper
Conductor Size	2500MCM		

3.0 Health Factor

	Standing	WF	Sub-Total
3.1 Electrical History	1	10	10
3.2 Physical Age	6	10	60
3.3 Outage Records	4	8	32
3.4 Loading History	5	5	25
3.5 System Cable Design Issue	1	10	10
3.6 System Maintenance History	10	7	70
3.7a Oil Testing - HPFF & LPFF	10	6	60
3.7b Oil Testing LPLF	0	6	0
3.8 Paper InsulationCondition - HPFF & LPFF	1	10	10
3.9 Insulation Condition - XLPE	0	7	0
3.10 Accessorry Condition	10	10	100
3.11 Hydraulic History	1	4	4
3.12 Installation Conditions	9	5	45
3.13 Civil Structure Condition	1	3	3
3.14 Stray Current Presence	1	7	7
3.15a Corrosion Protection Condition - HPFF	5	7	35
3.15b Corrosion Protection Condition - LPFF & XLPE	0	7	0

Health Factor Rating: 471

4.0 Risk Factors

	Standing	WF	Sub-Total
4.1 Environmental Impact	10	5	50
4.2 Potential Oil Spill	10	5	50
4.3 Regulatory Requirements	1	5	5
4.4 Safety	5	10	50
4.5 Short Circuit Level	5	4	20
4.6 Obsolescence	5	10	50
4.7 Importance of Circuit	6	6	36

Risk Factor Rating: 261

5.0 Maintenance Cost Factor

	Standing	WF	Sub-Total
5.1 Maintenance & Replacement Costs	10	5	50
5.2 Other Details			

Maintenance Cost Factor Rating: 50

Summary - Total Values

Health Factor Rating:	471
Risk Factor Rating:	261
Maintenance Cost Factor Rating:	50
Total Rating:	782
Number of Known Factors	22
Number of Unknown Factors	3

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7.20 Cable Circuit 240CV5

CV5 is a 240kV circuit between Castle Downs and Victoria stations. Specific characteristics of this cable are as follows:

Circuit Name	Length m	Yr of Install	Conductor Size (kcmil) & material	Cable Mfr	Circuit Ratings (Amperes)			
					Summer Continu-ous	Summer Emer-gency	Winter Continu-ous	Winter Emergency
240CV5	10,185m	2008	2500 Cu	Prysmian	1099	1287	1294	1455

The thermal environment for the route of 240CV5 circuit has been altered on Kingsway Ave. where a new LRT line is under construction. All rating calculations for this circuit should include load calculation performed for the post LRT construction thermal conditions at this location. A study on this location was performed by G. Anders in 2012. The study concluded that this section of the circuit does not limit the previously calculated rating except in the beginning of winter when the soil temperature has not reached its lowest limit at the depth of 3m.

7.20.1 Operational History

1. **Major failures:**

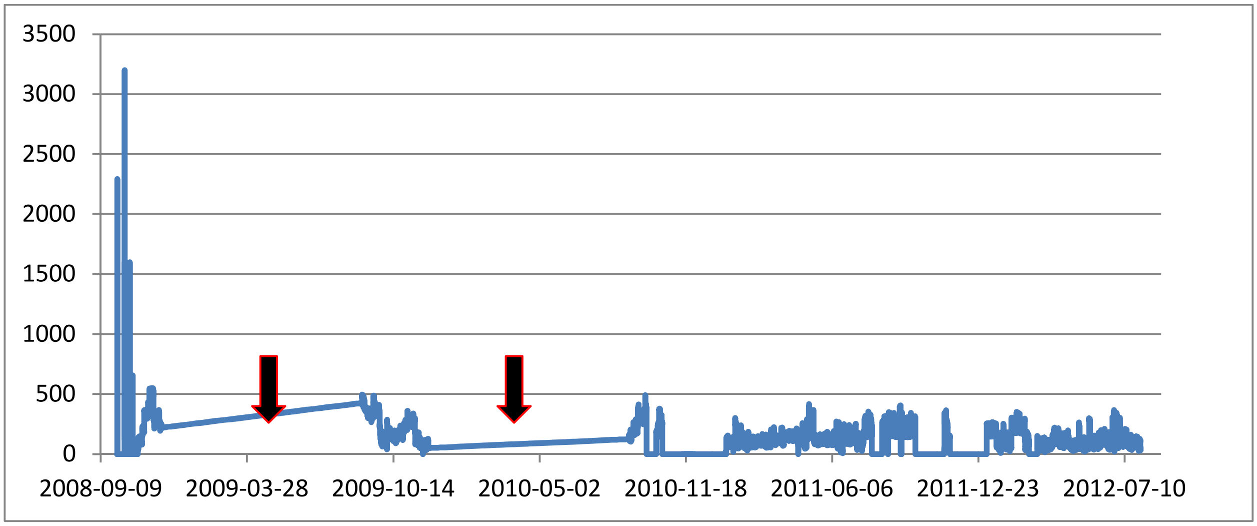
2010 - The termination #3 at Victoria substation failed and was replaced with cable section from the MH 17. The cause of failure is under investigation.

2. **Major maintenance**

2011 – Termination #2 at Victoria TS opened and checked for any sign of deterioration – nothing found. The upper part of the termination replaced.

3. **Load history**

The load history is available from the circuit commissioning. There is no indication that the circuit current exceeded its design load.



Note: the load history is not continuous. There are two periods indicated by arrows when the data is not available. The circuit was out of commission.

4. Major improvements

No information available.

7.20.2 Diagnostic Tests

The DGA tests were performed for the gas content within terminations. The test results are included as an appendix #4. These tests were done for information purposes. No standard is available at this time to evaluate the quantity of gases in the XLPE cable terminations.

After the failed termination was repaired the circuit was tested using a HV resonance tester with terminations monitored for partial discharges. The test results are contained in the report "AC High Potential and Partial Discharge Testing of Three (3) 240kV Single Conductor XLPE Insulated Cables" that is in the EDTI archives. All three phases passed the test.

The report also stated the following:
"… Evidence of Partial Discharge activity was detected on the termination within Victoria Substation of Phase 3. Due to higher levels of external corona it wasn't possible to perform a PDIV or PDEV of the source. However, an examination of the data acquired at 194kV (1.4U0) shows no evidence of PD and, therefore, it can be deduced that the PDIV of the source exceeds 1.4U0. This further suggests the source will not be present during normal on-line condition with the exception of during voltage transients of sufficiently high magnitudes…"

7.20.3 Cable Health Index

CEATI Health Index ratings:

Health Factor: 306
Risk Factor: 143
Total Factor: 459

7.20.4 Risk Assessment

This is the newest HV circuit in service on the EDTI system and is the only non-HPFF high voltage circuit. There is no evident operational risk with the circuit and a service life consistent with the cable class and construction should be anticipated. The failure of termination #3 at Victoria is still under investigation to determine root cause. Final findings of that investigation may warrant some remedial action on the circuit but that is not known at this time.

7.20.5 Recommendations

- The thermal environment for the route of 240CV5 circuit has been altered on Kingsway Ave. where a new LRT line is under construction. All rating calculations for this circuit should include load calculation performed for the post LRT construction thermal conditions at this location. It is strongly recommended that the soil moisture condition at this location be periodically checked. This would be particularly valuable at the end of a dry summer season and at any time of the year when the peak cable load is above 75% of the design rating for one week or longer. A permanent installation of a moisture sensor close to this location should also be considered.
- The circuit includes temperature monitoring system. The system should be periodically checked to confirm the cable temperature as related to the circuit load.
- The standard jacket test should continue periodically as described in the circuit manual
- The PD test should be performed in the next 3-5 years to evaluate the existence of partial discharges.

Table 7.20

Cable Health Index - Detailed Report

Cable Details

Circuit Name	240CV5	Cable Installation Date	2008-01-01
Circuit Section		Cable Length	10.7km
Cable Type	XLPE	Conductor Material	Copper
Cable Voltage	230	Insulation Material	XLPE
Conductor Size	2250		

3.0 Health Factor

	Standing	WF	Sub-Total
3.1 Electrical History	7	10	70
3.2 Physical Age	1	10	10
3.3 Outage Records	4	8	32
3.4 Loading History	2	5	10
3.5 System Cable Design Issue	5	10	50
3.6 System Maintenance History	5	7	35
3.7a Oil Testing - HPFF & LPFF	10	6	60
3.7b Oil Testing LPLF	0	6	0
3.8 Paper InsulationCondition - HPFF & LPFF	0	10	0
3.9 Insulation Condition - XLPE	1	7	7
3.10 Accessorry Condition	1	10	10
3.11 Hydraulic History	0	4	0
3.12 Installation Conditions	1	5	5
3.13 Civil Structure Condition	1	3	3
3.14 Stray Current Presence	1	7	7
3.15a Corrosion Protection Condition - HPFF	0	7	0
3.15b Corrosion Protection Condition - LPFF & XLPE	1	7	7

Health Factor Rating: 306

4.0 Risk Factors

	Standing	WF	Sub-Total
4.1 Environmental Impact	1	5	5
4.2 Potential Oil Spill	1	5	5
4.3 Regulatory Requirements	3	5	15
4.4 Safety	2	10	20
4.5 Short Circuit Level	7	4	28
4.6 Obsolescence	1	10	10
4.7 Importance of Circuit	10	6	60

Risk Factor Rating: 143

5.0 Maintenance Cost Factor

	Standing	WF	Sub-Total
5.1 Maintenance & Replacement Costs	1	5	5

5.2 Other Details

Maintenance Cost Factor Rating: 5

Summary - Total Values

Health Factor Rating:	306
Risk Factor Rating:	143
Maintenance Cost Factor Rating:	5

Total Rating: 454

Number of Known Factors: 21

Number of Unknown Factors: 4

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8 Infrastructure Assessment

In addition to review and assessment of the cable circuits, an inspection and assessment of the other infrastructure of the UG transmission system was conducted. This assessment included manholes, pumping stations, and river crossings.

8.1 Manholes and structures

The interiors of many manholes regularly fill with water. Since most of the manholes are located under city streets, this water contains road salt and other contaminants that are damaging to concrete. While this is unavoidable, implementation of an effective inspection and maintenance program can delay the rate of deterioration of the manhole condition. It is recommended that the underground vaults be periodically cleaned, inspected and any early stage concrete damage repaired. There are no obvious reasons why manholes that are inspected and repaired regularly cannot continue to be used reliably for another 15 – 20 years or more. As a minimum an annual program of power washing, debris removal and inspection should be established. Coating the interior walls with white paint has been helpful at some other power utilities in promoting a sustained improvement in manhole interior condition.

Starting in 2012 EPCOR Transmission has implemented an updated manhole inspection procedure. The plan is designed to inspect the entire system in two years. EPCOR EDTI owns and maintains 32 - 240 kV manholes and 83 - 72 kV manholes. Of the 115 manholes in the city 76 are inspected in the first year of the rotation and the remaining 39 are inspected in the second year. However the 240 kV circuits are inspected every year making a total of 71 manhole inspections in the second year of the rotation. The manhole inspection includes manhole cleaning, visual inspection of piping, splice, valves, manhole walls, neck and lid. This data is recorded and entered into the GIS system. The data is then reviewed by Transmission Engineers for repairs and future maintenance. Oil samples from manholes that contain a splice are also taken whenever a manhole is inspected.

EHV Power inspected 25 manholes that are representative to each circuit. We found that the most of the structures are in good condition. Some of them need cleaning as they were flooded with water and a few are in need for chimney repair. The details should be identified during the newly implemented manhole inspection program. Since there were randomly selected locations for inspection our opinion is the manholes are structurally sound and they could be used for many years to come. If their size allows they can be considered as elements that could accommodate future circuit joints.

Since the implementation of the manhole inspection procedure the joints casings and visible part of the pipes coating in the manholes were found in satisfactory to good conditions. The exceptions are:

- The manhole 72RG1-RG1 – "South" reducing flange coating showing a sign of excessive heat as the tape is partially melted (Figure 6-1). It is unknown if the heat was applied during the tape installation or it was caused by overheated cable. In any case, this occurrence should be investigated as soon as possible. The investigation should not be limited to the manhole RG1 but other locations on the same circuit should also be visited and checked for similar conditions.

Figure 8-1

- The manhole 72VN21-VN3 - The coating at the South and North manhole walls is in good condition. The joint sleeve and the carrier pipe on each side of the sleeve for approx. 0.6m have no tape on it. The bare metal is exposed and severely corroded. See Figure 6-2.

Figure 8-2

During the manholes inspection, it was generally observed that the pipe entrance to the manholes is not sealed with grout or concrete but stabilized in the centre of the opening with wooden wedges. It was observed that the pipe covering was disturbed in such places and the exposed pipe corroded.

8.2 Pressurization Plants

There are seven locations where pumping plants and oil panels are located. The equipment is old but well maintained with modifications incorporated to provide data connections and alarm annunciation to the SCADA system. In addition to the pumping plant monitoring, all potheads are equipped with the wireless pressure sensors to transmit changes in pothead fluid pressure into the SCADA system. The age of the pumping plants is for reference only as they have been refurbished many times in the past.

The pumping plants are inspected every two weeks by the station maintenance crews. During the inspections charts are changed and a general assessment of the plants is performed. The nitrogen pumps are checked to make sure they are operational, a log is also kept. EPCOR's long term policy of replacing the older pumping plants is to be commended but the existing maintenance program should be corrected to include the part of the fluid circuits that can be clogged by dirt and debris that are in suspended in the fluid.

8.2.1 Pressurization schematic analysis

There are 19 circuits that require continuous pressure of liquid for insulation purpose. The analysis is based on EDTI schematic drawing 72K-079-001.The 72kV circuits are hydraulically independent from 240kV circuits. The 240kV circuits' pressure system seems to be sufficiently maintained for the purpose.

The 72kV circuits are fed from six pumping plants (PP) distributed over the city. In normal operation regime the pressure on each circuit is maintained from a dedicated output of a plant. Exception is circuit 72MG16 which is being pressurized from Jasper PP through the 72JM18 circuit and 72KN23 hydraulically connected to the 72CK12 circuit. All circuits except 72VN21 have auxiliary fluid supply that can be used in case of emergency.

The 72kV hydraulic system is divided into two independent circuits. One serves 72RV circuits and 72VN21 circuit. The RV circuits are connected to a FOCS (Forced Oil Cooling System) system that allows for fluid circulation for the purposed of the cable cooling.

The remaining circuits are being fed from Jasper, Rossdale and Clover Bar pumping stations. In our opinion the system is sufficient for N-0 criteria. It allows for normal operating of the grid and performing scheduled maintenance service on any circuit.

The N-1 criteria cannot be fulfilled in all cases. The most difficult would be a cable fault on 72JM18 circuit. If the fault causes the carrier pipe rupture the fluid will escape draining both circuits (72JM18 & 72MG16) feeding Meadowlark substation. Since the Meadowlark substation has only two feeds (both underground) the station could be lost for a prolonged period of time.

The Rossdale System #2 feeds four circuits. Even more severe situation, than described above, would be if one of the 72RG7 or 72RS5 ruptures. If the valve configuration as presented on the drawing is maintained a fault causing pipe rupture on one circuit can affect all other circuits being hydraulically connected to this pumping plant.

The KN23 circuit is hydraulically connected to the Clover Bar PP System #2 via 72CK12 circuit. The cross-over manifold arrangement in Kennedale substation is similar to that in Meadowlark substation. However, it was modified that the restricted flow valves are connected to the circuit 72CK13 and through it to System #1 at Clover Bar PP. In a limited way, the System #2 Pump 1 & 2 ladders are running in parallel.

While the Rossdale system can be reconfigured without any additional extensive works, the Kennedale and Meadowlark substation may pose a problem in case of grid disturbances. One of the possible solutions could be to design a system for Meadowlark substation that would automatically reconnect the hydraulic feed from the basic (from Jasper via 72JM16) to the secondary (from Rossdale via one of 72RG) if disturbances are detected in the 72JM16 circuit. The control system can be included as a part of the company SCADA system.

One of the solutions for Kennedale substation is to install a new pumping plant and transfer hydraulic connections of the circuits 72KN23, 72CK12 and 72CK13 to this new unit. The aged System #2 at Clover Bar substation could be retired.

8.2.2 Pressurization Plants conditions review

EDTI embarked on the plan of replacing the aging pressurization plants. It is the Quanta view that the equipment that is difficult to maintain and to obtain service part should be replaced.

8.2.2.1 Jasper Pumping Plant

At Jasper Pumping Plant the old original unit is still operating but the new MAC pumping plant will be operating in approx 1 month. This new pumping plant is part of EPCOR's life cycle replacements of the older pumping plants.

8.2.2.2 Rossdale Pumping Plant

The Rossdale substation is equipped with two pressurization units and a circulation system.

Unit #1 - Perelli Jerome design fabricated by MV Mark in 1995. This unit feeds (1) 72RV2, & 72VN21 as well as (2) 72RV4 and (3) 72RV6. This unit has the original pumps and feeds the circulating unit. The ladder on this unit has some very small oil leaks, there is old absorbent blanket under the ladder and the strainers on this unit look clogged. This is an older unit that feeds the circulating system and should be replaced as part of the long term policy of replacing the older pumping plants.

Unit # 2 - MAC Products design fabricated in 2005. This unit feeds Line # 1 :- (1) 72RW3, (2) 72RG7. Line # 2 :- (1) 72RS5, (2) 72RG1 & (3) RH7 Tie. This unit is in good shape and has no visible leaks on the ladder under the control panel & no leaks on the auxiliary ladder. The annunciator panel has 3 alarms flashing; false alarms seem to be a problem with this unit and need to be addressed.

Circulating Unit: - This system is fed from unit #1. It has recently been upgraded and has 3 new looking pumps and motors, the electric valves have also been upgraded and look new, the water cooling unit looks in good shape for its age. The original strainer looks clogged and it is the only area that we have some concern about but regular maintenance would alleviate our concerns. If the strainer is contaminated with some small particles that were difficult to clean during construction or were created by the cable movement the fluid flow may be restricted and efficiency of the filter reduced.

8.2.2.3 Bellamy Pumping Plant

The Bellamy Pumping Plant is a MAC Products design fabricated in October 2002. This unit feeds Line # 1 - 240BA2, Line # 2 - 240BA3. This is a static feeding unit that feeds the 230kV system to Argyll transfer station. This unit is fairly new but needs regular maintenance. The oil absorbent blanket under the ladder needs to be changed periodically and an oil leak on the pump relief flange on Line # 2 stopped. Semi–annual maintenance, especially cleaning or replacing strainers, is required.

8.2.2.4 Cloverbar Pumping Plant

Cloverbar substation is equipped with two pressurization units.

Unit # 1 is a Jerome Underground Transmission design manufactured around 1968. This unit feeds Line #1 :- (1) 72CH9, (2) 72CN10. Line # 2 :- (1) 72CH11. This is a static unit and is the oldest in the EPCOR System. The Unit has clean absorbent blanket under the pumps and ladder, the ladder is clean and it shows recent maintenance works. This unit has performed well but its age makes it the priority candidate for replacement. EDTI proposes a capital project in 2013-2014 to replace this pump plant. Quanta concurs with this proposal for life cycle replacement of both units 1 and 2 at Clover Bar.

Unit #2 is a G.M. Gest design manufactured in 1973. This unit feeds Line #1 - (1) 72CK12, (2) 72KN23, Line #2 - (1) 72CK13, (2) 72KN23. This Unit is unique in the fact that since August 1980 Pump #2 has been in the "Hand" position pumping down line 72CK12 and returning on line 72CK12, pump #2 is also keeping pressure on line 72KN23. Pump #1 is in the "Auto" position in case Pump #2 fails. This Unit is due to be replaced next year. The new plant should have features that will take care of this circulating mode if such a mode is necessary for the fed circuits.

In general, the ladder is clean and a new looking pump is on unit #2. The strainers on this unit should be checked on a regular basis since this unit is being used to circulate.

8.2.2.5 Namao Oil Panel

At Namao Substation there is a small metal shed where the 2" pipes from the trifurcators come above the ground and are manifolded together. A few minor leaks should be stopped during scheduled maintenance.

8.2.2.6 Victoria Circulating Pumps

This circulating pumping station was manufactured in June 1986. This unit is very similar to the circulating unit in Rossdale Pumping Plant. The electric valves look new. The pumps and motors showing their age and may need to be changed sometime in the future. In general, this unit and the cooling unit are in good shape for its age but replacement should be considered, like the unit at Rossdale the strainers need to be checked on a regular basis.

8.2.2.7 Meadowlark Oil Panel

At Meadowlark Substation there is a small metal shed that houses the 2" pipes that are manifolded together. The other manifold system is in front of the termination structures. Both systems are in good operational conditions.

8.2.3 General recommendations

- An operating algorithm for the Rossdale Unit 2 pumping plant should be created that would take into account N-0 and N-1 criteria of operation. Based on the algorithm the existing hydraulic ladder should be reviewed and appropriate corrections made;
- Similar scenario for the Meadowlark substation should also be reviewed;
- For the Kennedale substation a new pumping plant should be considered in place of the Unit #2 at the Clover Bar substation.

- In addition to the existing bi-weekly inspection plan a semi-annual inspection and maintenance plan should be implemented. The plan should cover testing the plant working algorithm, condition assessment of all devices and replacement of those parts which conditions are showing signs of deterioration.
- All strainers on static pressurization units should be checked every six months
- All strainers on circulation systems should be checked more often.
- Filters should be cleaned or replaced at any sign of deposits on either static or circulating systems.
- Oil leaks should be repaired promptly.
- The leak detection systems are based on outdated equipment. Since the system is based on a proprietary algorithm it may require additional programming in addition to new hardware. The existing leak detection algorithm should also be reviewed to check if it can be connected to the operational algorithm to prevent unusual scenarios in valve operations.

8.3 North Saskatchewan River crossings

There are 14 river crossings in Edmonton. The crossing of two circuits 72RS5 and 72MG16 were replaced to minimize the influence of the river flow. The remaining 12 pipes are a reason for concern. To minimize the risk of river contamination in case of a pipe rupture all circuits have had special joints installed in the recent years.

In 2000 EPCOR asked an engineering company, Stantec, to review the crossing and to provide solution for the future. The Stantec report suggested that all river crossings should be replaced. The new depth should take into consideration the flood and scouring models.

EPCOR established an annual inspection program that provides a survey of the amount of cover above the cable pipes. A survey by a specialized company ensures that the river erosion does not threaten the mechanical integrity of the pipes.

The 2010 survey indicated that the cover of individual circuits is as measured between water edges:

Cct designation	Min cover	Max cover	Notes
240BA2	0.34m	2.3m	Could be a reason for concern if erosion continue
240BA3	0.74m	2.69m	
72CH9/72CN10	0.19m	3.52m	
72CH11/72CK12	0.0m	1.87m	There is no sign of exposed pipe
72CK13	0.6m	2.58m	
RH7	0.38m	2.48m	Hydraulic connection only
72CH9/72CH11	0.84m	3.88m	
72MG16	0.78m	1.67m	
72RG1	0.42m	2.55m	
72RG7	1.52m	2.68m	

The surveying company included a note that the measured depths could be deeper than the instruments indicate. It would be prudent to insist on a manual check of the locations where the measured depth is as highlighted above. If the manual examinations of these locations confirm the depth of the pipe an immediate action should be considered to stabilize the pipe or to replace this part of the circuit.

If the river flows raises a concern (i.e. flood or ice) in the places where the minimum cover is less than 0.5m, the survey should be repeated more often.

9 Spare parts

The variety of the cables and accessories in the EPCOR grid makes the spare parts inventory inflated. Since the grid consists of two types of cables the spare part inventory must take this into consideration. While the XLPE cable spare parts are well stocked according to the received list the HPFF part of the grid should be addressed.

It is our suggestion that the future repairs should be made with one size cable. The cable with 1250kcmil copper conductor recently applied for 72RV2/4/6 circuits seems to be a good choice. It would require ordering significantly longer spare length to cover any and all possible cases of maintenance, emergency and possible failures in the future until the circuits are replaced. The 240kV HPFF cable size should be the same as installed 2500kcmil. We do not recommend jointing cables with different conductor sizes.

The HPFF cables can be supplied protected for long storage under the condition that they are properly maintained. It has to be noted that the drawback is that this type of cable is in decline and the only manufacturer OKONITE may not be able to supply the cable on emergency basis. The cables as well as terminations, especially porcelain, are long lead items that have to be ordered several months in advance.

Based on this philosophy we created a list of major equipment that could provide basic necessities for emergency purposes. Some of the parts are on EPCOR's list the others have to be ordered. We left in the list some joints that could be used in case there is no need to replace part of the circuit. They can be used for regular maintenance or rehabilitation. It is important to keep the emergency kits in sealed packages to be sure that when the emergencies arise all parts are available without the necessity for additional inspection.

There are also many parts that are in inventory that are remaining from the previous projects or repairs. It has to be remembered that some parts have limited shelf life. The whole inventory should be reviewed. The parts that are of unknown vintage or with expired dates should be removed for disposal of. This is especially important for the parts that are made of synthetic materials. In case of incomplete kits the remaining parts that are usable should be kept separate from the emergency parts to be drawn on when needed for maintenance. If, at any time, a kit is opened and parts removed it should be kept in maintenance section. Any paper should be in a closed and sealed container. If a seal is broken or there is sign of rust or oxidization on the outside of packages such part should be disposed of. In any case if the storage exceeds 5 years the paper and fluid that the paper is immersed should be tested for electrical properties. Any parts found exceeding the dielectric properties should be discarded.

The review of the shelf life is of particular importance for the XLPE spare parts. The shelf life range is generally from 2 to 10 years. The synthetic parts of paper cables are also within this category. Note that these are general statements. In every case the storage should follow manufacturer procedures and conditions.

10 Summary

The EDTI 72kV and 240kV underground transmission system continues to provide reliable service as it has for many years. In some cases, circuits have been in service for over 50 years. The attention to inspection and maintenance by EDTI to ensure continuous operation of the system is commendable. Like many other North American utility companies, however, the need for replacement and/or refurbishment of the system is becoming a more critical issue as system loads grow and the infrastructure continues to age.

The science of condition assessment of UG HPFF cables is an evolving one. Many "experts" struggle with inconsistent diagnostic test data and interpretations of the data. There is no single industry accepted method or indicator that one can use to determine the end of life of an UG cable or other assets of other classes. Ideally, major electric power infrastructure assets would be replaced the day before they would naturally fail. This is however an unrealistic manner in which to operate a power system as no one knows when that day will occur. When the lead times for design, engineering, right of way acquisition and manner other components of UG cable system replacement are considered, prudent management plans for replacement of assets based on the best available information and industry experience, to the extent there is a reasonable history.

Two drivers are the primary reasons for cable replacement planning for the EDTI system. The first is the age and condition of the assets, as reviewed in detail in this report. The second is the load serving capability of the system as the economy of the City grows and creates greater demand on the power infrastructure. These drivers demand a well planned and scheduled approach to upgrading the infrastructure to ensure the utility meets its load serving obligation while being good stewards of the investments required to do so.

EDTI continues to diligently monitor and maintain the UG transmission infrastructure and has ongoing capital programs to ensure the system is reliable. The proposed capital projects for the BA2 and BA3 circuits were discussed in Section 6. The ongoing program of splice replacements was highlighted in the discussion of DGA as a necessary activity when test results indicate an emerging problem. The ongoing capital replacement of fluid pressurization plants was discussed in Section 7. The pump plant replacement project is one part of a broader initiative to upgrade cathodic protection, replace the oil leak monitoring system, and replace the heat exchanger of the forced oil cooling system. These are all life cycle replacement projects that are based on the condition and reliability concerns of existing plant and, as indicated throughout this report, part of the necessary life cycle upgrades required to maintain the HPFF system. While the long term asset strategy may be to replace the HPFF system, it will require the reliable operation of all ancillary systems until the entire HPFF plant is retired. These efforts should continue as part of management of the assets..

The assessment of the underground transmission system at EPCOR and the associated infrastructure results in summary evaluation of the UG system and an estimated time frame in which each circuit should be addressed. The evaluation is based on information available at this time and will be updated and revised based on the results on currently ongoing soil thermal resistivity tests. With that data, actual cable rating calculations will be done which may alter the current recommendations. It is anticipated, however, that those results would only accelerate the need to address some circuits.

The following Table 10-1 provides a summary of the assessment of all EDTI circuits.

Table 10-1

Circuit	CEATI Health Index	Risk Assessment (critical, high, med., low)	Recommended Replacement Timing	Driver for Replacement
72CH9	847	C	<10 yrs	Previous cable overheating & apparent insulation breakdown
72CH11	986	C	<10 yrs	Previous cable overheating & apparent insulation breakdown
72CK12	929	H	<10 yrs	Insulation breakdown & previous failure (overheating).
72CK13	805	H	<10 yrs	Apparent loss of mechanical strength due to TMB; derated.
72CN10	694	H	<10 yrs	Insulation breakdown and aging
72JM18	690	M	15 - 20 yrs	No immediate risk. Monitor and test regularly. Replace for age and condition as needed.
72JW19	657	M	15 - 20 yrs	No immediate risk. Monitor and test regularly. Replace for age and condition as needed.
72KN23	694	M	10 - 15 yrs	Risk of accelerated aging due to loading. Terminations showing high acetylene levels.
72MG16	644	L	15 - 20 yrs	No immediate risk. Heavily loaded circuit to be monitored regularly.
72RG1	672	L	15 - 20 yrs	No immediate risk. Heavily loaded circuit to be monitored regularly.
72RG7	664	L	15 - 20 yrs	Based on latest paper sample tests, no immediate risk.
72RS5	883	C	<5 yrs	Cable is at end of life due to mechanical and electrical breakdown. One of the oldest circuits currently in service (~54 yrs).
72RV2	882	M	10 - 15 yrs	Oldest circuit in service (~55 yrs). Diagnostics do not indicate immediate risk, however circuit should be monitored closely and scheduled for replacement.
72RV4	778	H	< 10 yrs	More detailed testing and evaluation is recommended. Cable integrity is questionable.
72RV6	634	L	15 - 20 yrs	No immediate risk. Monitor and test regularly. Replace for age and condition as needed.
72RW3	771	N/A	15 - 20 yrs	No test data available. Monitor and test regularly. Replace for age and condition as needed.
72VN21	710	M	10 - 15 yrs	No immediate risk. Monitor and test regularly. Replace for age and condition as needed.
240BA2	817	M	15 - 20 yrs	Replacement of cable section and terminations scheduled for 2013-2014. Once completed, close monitoring required but continued service is expected.
240BA3	772	L	15 - 20 yrs	No immediate risk. Monitor and test regularly. Replace for age and condition as needed.
240CV5	459	L	> 40 yrs	No immediate risk. Monitor and test regularly. Replace for age and condition as needed.

NOTE:

1. The assessment and inputs to this table are based on limited and incomplete data. The table should be evaluated when more information is available.
2. Recommended replacement timing is based on combination of factors not calculations. The replacement timing is intended to assist prioritization of circuit replacement if replacements are made on a standalone basis. The same priority considerations are given for the broader Transmission Planning Options (TO1 – TO4) however the timing for each circuit changes as part of a broader network solution instead of a standalone replacement. For comparison the replacement timing in this table aligns most closely with the recommended TO-4 option.

Appendix 1 - CEATI Health Index Summary Report

Cable Health Index - Summary Report - Sorted by Total Rating

Circuit Name	Circuit Section	Cable Type	Total Health	Total Risk	Total Cost	Total Rating	Known Factors	Unknown Factors
72CH11		HPFF	677	269	40	986	22	3
72CK12		HPFF	646	243	40	929	22	3
72RS5		HPFF	548	295	40	883	22	3
72RV2		HPFF	514	328	40	882	22	3
72CH9		HPFF	559	248	40	847	22	3
240BA2		HPFF	492	285	40	817	22	3
72CK13		HPFF	514	251	40	805	22	3
72RV4		HPFF	422	316	40	778	22	3
240BA3		HPFF	471	261	40	772	22	3
72RW3		HPFF	412	259	40	711	22	3
72VN21		HPFF	438	232	40	710	22	3
72CN10		HPFF	386	268	40	694	22	3
72KN23		HPFF	411	243	40	694	22	3
72JM18		HPFF	399	251	40	690	22	3
72RG1		HPFF	376	256	40	672	22	3
72RG7		HPFF	323	301	40	664	22	3
72JW19		HPFF	389	228	40	657	22	3
72GM16		HPFF	330	274	40	644	22	3
72RV6		HPFF	337	257	40	634	22	3
240CV5		XLPE	306	143	10	459	21	4

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The CEATI designed Health Index is based on several parameters that describe the cable age, conditions, environment as well as maintenance. Most of the inputs were obtained from archives. However, the environment inputs as well as cable conditions are not always available. The important input from the engineering point of view - Paper Insulation Conditions is difficult to obtain and therefore the entry to the system may not reflect the current conditions. On few occasions, the main insulation has not been tested. The paper that is used as a part of a joint was tested instead. The maintenance cost input was assumed as no data was available.

The index should be evaluated on continuous base every time a new input is available.

Appendix 2 - Insulation test results evaluation level (legend)

1. Dissipation Factor

New cable value 0.0025 – 0.003

	no data	
OK	within limits	< 0.003
Caution	exceeds limits	0.003 – 0.006
Danger	danger zone	> 0.006

2. AC voltage breakdown strength

New cable value >45kV/mm

	no data	
OK	within limits	> 40 kV/mm
Caution	exceeds limits	20 – 40 kV/mm
Danger	danger zone	< 20 kV/mm

3. Moisture contents

New cable value <0.1%

	no data	
OK	within limits	< 0.8%
Caution	exceeds limits	0.8 – 2.0%
Danger	danger zone	> 2.0%

4. Degree of polymerization

New cable value 1000 - 1200

	no data	
OK	within limits	> 800
Caution	exceeds limits	800 - 600
Danger	danger zone	< 600

Danger !!!	exceeding above limits, immediate attention may be required

Note:

The above values should not be considered as firm.
They are based on many standards, papers, and professional judgment.
They may indicate normal aging or excessive degradation.
Any decision based on these numbers should be evaluated in conjunction with other observations and documents.

Appendix 3 – On site cable electrical tests description

The following standardized tests can be used in evaluating transmission cable conditions. The tests' brief descriptions, values and advantages were collected below. In addition the reader can find more information in IEEE 400 set if standards and in IEC 60270.

1. HV withstand test

All of the withstand tests are "off line" tests. There are four different testers to check if complete circuit insulation can survive increased voltage that can appear during the circuit life. There are two methodology used in this type of testing: dc and ac.

Main insulation tests

DC test. Most commonly used tester in case of paper insulated cables. Applied voltage stress is up to 3 x U_0. The test can be destructive with no warning before failure. There is no data that can be obtained from this test other than "fail/pass". The test will damage the weak points in insulation of cable, joints or terminations. The test was standardized many years ago when the ac testers were not available for "on site" tests because of their significant size and weight.

AC tests. There are three different testers in this group.

AC resonance tester – the equipment that supplies AC voltage to stress the insulation similar to the DC tester but using ac with frequency range of 20 – 300Hz.The voltage and frequency produced by the tester depends on cable length and feeding impedance. There is no data produced by the test alone other "pass/fail". The test can damage the weak points in the cable insulation of any origin prior to service failure. The test can be combined with partial discharge testers if the connection points are available. The combination of resonance testers with PD equipment is the best suited for single conductor cables (either XLPE or paper insulated). The system requires heavy trucks and significant amount of power.

VLF tester – very low frequency tester with test frequency of 0.1Hz. The outcome is the same as in case of resonance tester. Little proven in case of paper insulated cables.

DAC – damped oscillation tester. The newest equipment to test the cables during commissioning or in case of condition evaluation. The equipment uses naturally occurring oscillations when the cable charge is discharged through an inductance. The tester is equipped with TDR (time domain reflectometry) that can record partial discharges and their locations without any additional testers. Based on damping oscillations the system can calculate also average value of the dissipation factor (tanδ). The tester can be used on either paper or XLPE insulated cables and can be used as "pass-fail" tester or in combination with PD as conditions evaluation equipment. If carefully observed partial discharges appear the operator can prevent insulation damage by terminating the test. If the test is terminated the collected data provide guidance to the locations of the insulation where the partial discharges are concentrated. The DAC testers are portable and require regular power outlet. This tester is suitable for any cables that have single phases shielded cables (XLPE, LPOF or HPFF). This equipment can be used on long cables. In addition to the evaluating condition in real time it will help to monitor cable deterioration by trending the development of partial discharges and the increase of the dissipation factor.

Jacket tests

Applicable to mostly single conductor cables that jacket is a part of the sheath bonding scheme. This dc type “pass/fail” test only. This test is applicable to circuit 240CV5 only at this time.

2. Measuring and data collecting tests

On-site testing and diagnosis of transmission power cables consists of voltage testing, partial discharge detection and dissipation factor measurements. Applying AC voltages for this purpose has become in last years a common use in Europe and Asia. In addition to continuous AC energizing more and more the use of damped AC (DAC) energizing is applied.

The sinusoidal damped AC voltages have been proposed 20 years ago as a complementary and/or alternative method to sinusoidal continuous AC voltages. The DAC method has become accepted in the last years for on-site testing including standardized PD measurements and dissipation factor (tan delta) measurements of all types and length of power cables.

During the application of high (over) voltage to the test object several diagnostic parameters are measured. Real-time registration of PD inception voltage (PDIV), PD extinction voltage (PDEV), PD-patterns is crucial for the execution of the on-site tests. Moreover the dielectric losses behavior on different test voltage levels can be evaluated to obtain an integral ageing characteristic of the cable circuit.

During the increment of the test voltage a sudden increase of PD activity may be present which can be used to identify and real-time localize serious discharging defects. The obtained PD mapping based on the TDR (Time Domain Reflectometry) analysis indicates the PD levels and PD concentrations along the power cable length in function of the applied test voltages.

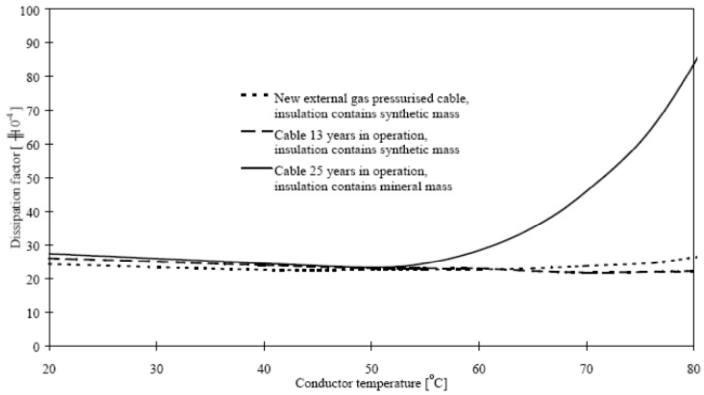
Oil-impregnated cables (LPOF, HPPT, PILC, EGP) are the oldest cable types in operation. Thermal and electrical overstressing through an extended period of time is likely to cause damage to the insulation. The insulation degradation over the years depends strongly on the cable age and operational history. An increase in the dissipation factor (tan δ) value as well as the presence of local discharging defects during operation may be indicators of the degradation of oil-impregnated paper insulation. On-site diagnosis through dissipation factor and partial discharges can be done at a constant cable temperature on a disconnected cable circuit, with the possibility to vary test voltage levels (e.g. 0.1Uo up to 2Uo). Such diagnostic test can provide information to determine the life consumption of oil-impregnated paper insulation. In combination with the past and expected future load data, as well as the soil temperature, are the most dominant factors for insulation life expectancy.

For all types of oil-impregnated cable circuits, Damped AC (DAC) voltage on-site testing, partial discharge measurements and dissipation factor measurements can be performed at HV conditions and within the recommended power frequency testing range (20Hz-300Hz)
(pic. testing at TenneT B.V. in the Netherlands)

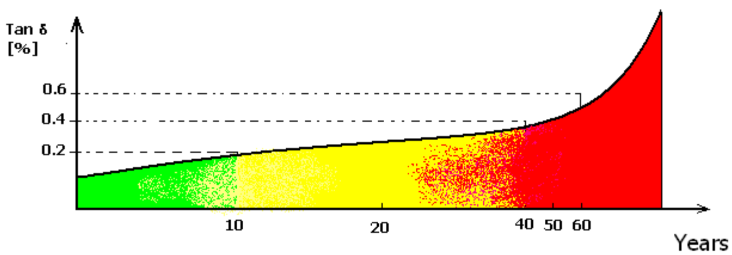
The dissipation factor of the integral cable insulation is obtained through the use of sinusoidal damped AC (DAC) voltages. Based on the resulting resonant frequency, the cable capacitance can be calculated and the dissipation factor is derived from the decay characteristics of the damped sinusoidal voltage wave. In combination to sensitive standardized PD detection, DAC technology makes it possible to obtain the dissipation factor at different voltage levels to assess the aging conditions of the insulation.

Condition assessment	Type of diagnosis	Important parameters
Insulation voltage withstand	Over-voltage application	• Max. test voltage • Criteria: Pass / Fail
Insulation weak-spots detection	Detection, location and measurement of partial discharges	• PDIV / PDEV • PD magnitudes in [pC] in function of the test voltage (e.g. up to 2.5xU0) • PD site location, PD phase-resolved patterns • Criteria: PD level
Insulation integral condition	Estimation of dielectric losses	• Dissipation factor in [%] in function of the test voltage (e.g. up to 2.5 xU0) • Criteria: $\tan\delta$, $\Delta\tan\delta$ values

The dissipation factor measurement (tan delta) can be used for the determination of the loss factor of cable insulation materials. Due to the fact that this factor increases during the aging process of the cable, the tan delta measurement can be used as a diagnostic measurement. The obtained measurement values can be compared to a known reference value for the specific type of dielectric being diagnosed. A judgment is then made regarding how much the dielectric losses differ. In addition to the absolute value of tan delta, the increment of tan delta (Δ tan delta or tip-up) measured at two designated voltages can be used for condition assessment.

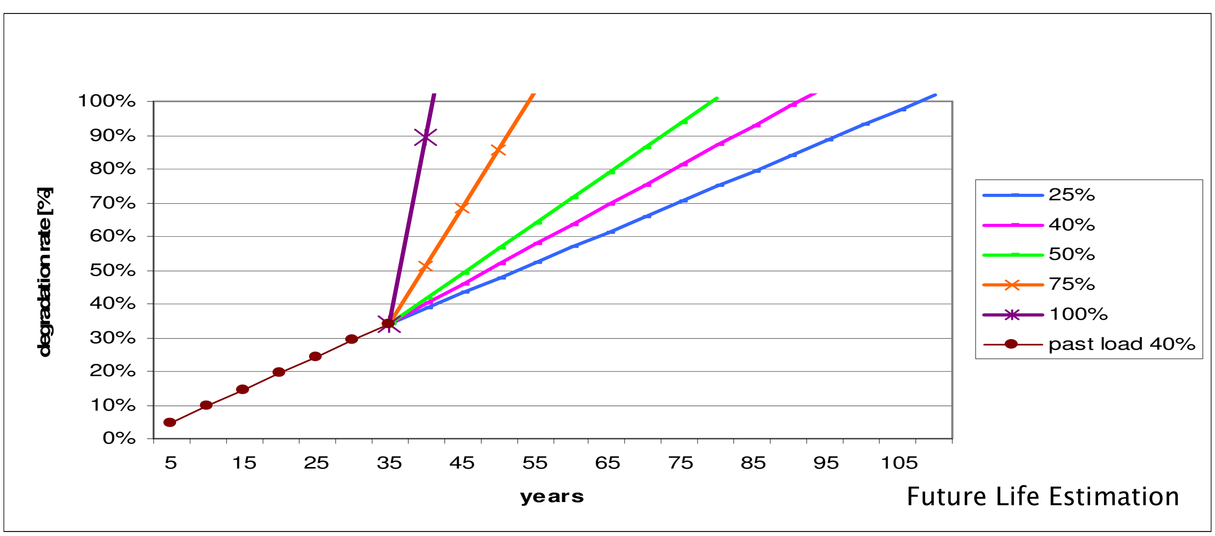


Thermal stability depends on the dissipation factor



Dissipation factor increases with the service age

For the overall condition assessment of the cable insulation several general considerations for the insulation degradation can be given. The thermal effects of past and future operation conditions (e.g. short term over-loading) are of importance for the life expectancy of oil-filled cables. Furthermore the thermal and mechanical degradation are major aging mechanisms of oil-impregnated insulation (partial discharges can accelerate this process). The electrical stresses, such as switching surges or lightning may result in physical erosion throughout the paper structure. The present deterioration effects such as the increase of paper porosity, moisture presence and dissolved gasses may increase the conductivity in the oil-impregnated paper insulation.



Example shown of the insulation life consumption estimated based on relative tan δ values in combination with the operational life consumption calculation based on thermal aging and past load provides the future life estimation calculation based on thermal aging of the expected future load.

Note: all the "on-site" data collecting tests are the best suitable for evaluation purposes. They can be used in trending of the irregularities within cable insulation.

Appendix 4 – CV5, DGA results at Extruded Terminations

Sample Date	12-16-2010			12-17-2010					
Feeder	Phase 1 (Victoria)			Phase 2 (Victoria)			Phase 3 (Castle Down)		
Vial No.	xd057741 62226	xd057641 92246	xd058341 42242	xd059041 72264	xd058142 02220	xd057942 32231	xd058437 72283	xd057337 42206	xd058138 02200
Methane	246,100	245,600	252,700	289,900	273,500	279,200	207,800	206,400	201,000
Ethane	960	1,001	1,014	1,029	1,003	1,012	793	776	759
Ethylene	9.3	9.9	9.7	22	21	21	14	13	13
Acetylene	0.0	0.0	0.0	2.5	2.3	2.5	1.4	1.5	1.3
Propane	130	131	128	128	125	127	112	112	112
Propylene	36	38	37	49	50	50	44	44	43
Isobutene	196	202	197	204	203	204	216	216	215
n-butane	65	67	64	63	63	64	56	54	55
t-2-butene	30	32	31	32	32	32	28	27	26
1-butene	69	71	70	66	70	69	60	58	57
Isobutyl-ene	9,043	9,359	9,280	9,711	9,711	9,718	11,879	11,886	11,910
Hydrogen	192	212	173	146	153	162	126	141	156
C. Monox-ide	31	32	35	26	25	24	23	22	24
C. dioxide	1,102	1,210	1,034	1,005	918	927	872	913	865
Nitrogen	45,316	48,832	46,146	41,627	41,430	41,689	42,410	46,614	48,274
Oxygen	2,614	3,076	2,484	2,631	2,120	2,036	2,912	2,386	2,882

NOTE: the above are the test results conducted by DTE.

Appendix 5 – Proposed minimum spare parts inventory for emergency purposes

	Item	Proposed Quantity	Units
A	**Cable**		
1	HPFF 240kV, 2500kcmil Cu conductor	300	m
2	HPFF 72kV,1250kcmil Cu conductor	2000	m
3	XLPE 240kV, 2250kcmil Cu conductor	760	m
4	XLPE 240kV, 2500kcmil Cu conductor	1450	m
B	**Terminations**		
1	HPFF 240kV, o/d 2500kcmil Cu (complete)	1	ea
2	HPFF 240kV, GIS 2500kcmil Cu (complete)	1	ea
3	HPFF 72kV, o/d 950kcmil Al	1	ea
4	HPFF 72kV, GIS 950kcmil Al	1	ea
5	HPFF 72kV, o/d 650kcmil Cu	1	ea
6	HPFF 72kV, o/d 1500kcmil Cu	1	ea
7	HPFF 72kV, GIS 1500kcmil Cu	1	ea
8	HPFF 72kV, o/d 1250kcmil Cu	4	ea
9	HPFF 72kV, o/d 1750kcmil Cu	1	ea
10	72kV o/d termination insulator	4	ea
11	72kV GIS cone	2	ea
12	XLPE 240kV, o/d 2250kcmil Cu (complete)	1	ea
13	XLPE 240kV, 2250kcmil Cu, stress cone	1	ea
14	XLPE 240kV, 2250kcmil Cu, top plate	1	ea
15	Termination connector o/d 950kcmil Al (comp)	1	ea
16	Termination connector GIS 950kcmil Al (comp)	1	ea
C	**Joints (HPFF-3ph, XLPE-1ph)**		
1	HPFF 240kV, 2500kcmil Cu	2	ea
2	HPFF 72kV, 950kcmil Al-950kcmil Al (conc)	2	ea
3	HPFF 72kV, 650kcmil Cu-650kcmil Cu	2	ea
4	HPFF 72kV, 650kcmil Cu-1250kcmil Cu	4	ea

5	HPFF 72kV, 1500kcmil Cu-1250kcmil Cu	2	ea
6	HPFF 72kV, 1250kcmil Cu-950kcmil Al (conc)	6	ea
7	XLPE 240kV, 2250/2250kcmil Cu	4	ea
8	XLPE 240kV, 2250/2500kcmil Cu	2	ea
9	Joint casing 72kV HPFF	2	ea
10	Joint casing 240kV HPFF	1	ea
11	Joint connector 950kcmil Al-950kcmil Al (conc/comp)	2	ea
12	Joint connector 1250kcmil Cu–950kcmil Al (comp)	6	ea
D	**Fluid**		
1	DF 100	5,000	l
2	Polybutene fluid for XLPE 240kV terminations	400	l
E	**Miscellaneous**		
1	5" carrier pipe (40' length), HDPE coated	400	ft
2	8" carrier pipe HDPE coated	100	ft
3	Chill rings 5"	12	ea
4	Chill rings 8"	6	ea
5	Emergency freezing kit	4	ea
6	Heat-shrink tubes for 72kV joints and pipe	40	ea
7	Heat-shrink tubes for 240kV joints and pipe	12	ea
8	SVLs for X-bonding system of 240CV5	6	ea

Note:
The joints and termination designed for 950kcmil Al conductor shall have two connectors for two different conductor construction. The remaining parts of the joints and terminations should be the same.

Appendix 6 - Cable rating calculations results

Common assumptions used in calculations:

1. All calculations utilize load factor of 0.85 as common for the City of Edmonton. It is suggested that for all future rating evaluations an average loss factor should be calculated separately for each circuit.
2. The calculations were performed for two scenarios:
   a. Pessimistic – the worst possible conditions when the soil thermal resistivity is the highest. It may happen in a dry summer.
   b. Optimistic – when the soil conditions are to be "normal" for most of the time.
3. For cable depth over 3m soil moisture 3% can be expected if the external component temperature of the carrier pipe does not exceed 55°C;
4. For the cable depth over 5m soil moisture of 5% was used as a close water table at this depth can be expected; The cable external components temperature cannot exceed 55°C;
5. For cable depth at standard 1.5m under the significant length asphalt soil moisture 0% is used;
6. If 0% moisture content was used the conductor temperature assumed to be at maximum allowable level provided by the cable manufacturers. The maximum conductor temperature was used:
   a. For cables manufactured by Northern Electric - 75°C
   b. For others - 85°C
7. Temperatures at the depth used for calculations were obtained from the borehole #GT450 monitored by the Natural Resources Canada;
   a. Max summer temperature at standard 1.5m depth used in calculations is 15°C;
   b. Max summer temperature at the depth of 3m and below used in calculations is 10°C;
   c. In some cases inside the Edmonton's downtown the 18°C was used.

72CH9 / 72CH11 / 72CK12 / 72CK13 / 72CN10

Recommended ratings:

CH9 – 350A
CH11 - 290A
CK12 - 310A
CK13 - 390A
CN10 - 300A

The evaluation was conducted for the Hermitage Park because of park location (organic soil), depth of circuit and vicinity of cliff. The prediction of the location was right as the obtained soil samples revealed presence of organic material. The soil test results confirmed very high thermal resistivity of 3.2[K*m/W] in dry state. In addition to the organic soil, the vegetation (trees and bushes) has also detrimental effect on the soil moisture.

Because of mutual heating effect of all circuits the calculations were performed to minimize such influence. The pessimistic scenario is not very likely to happen as the park location and open space will replenish any moisture that evaporates in the natural way. However, periodically the drought may occur. Installation and monitoring of a moisture sensor is strongly advised in this location. The calculations were performed for two scenarios for 15% moisture and reduced to 5% after prolonged period of lack of precipitations. The calculations results for “Normal operating” (high moisture contents) reflect conditions in which the external parts of the circuits will not exceed the temperature considered as a borderline for driving the moisture away from the cables. As noted in the general discussion the area close to the Clover Bar substation may demonstrate worse soil conditions that found on the other side of the NSR. Taking a soil sample and testing is strongly advised.

In calculating the ratings for these circuits it was taken into consideration that any cable should be loaded to the point that its external temperature remains below the 55°C.

Depth - 2.17 m
Circuits’ separation - as per Edmonton Power drawing #1 showing section view at this location;

<u>Pessimistic - during and after period of limited precipitations</u>
Soil thermal resistivity - 1.7 [K*m/W] @ 5% moisture contents
Circuit:

72CK13 - continuous rating 343A
Conductor temperature: 63.0 °C
Pipe covering temperature: 54.0 °C

72CK12 - continuous rating 274A
Conductor temperature: 61.0 °C
Pipe covering temperature: 54.9 °C

72CH11 - continuous rating 238A
Conductor temperature: 59.0 °C
Pipe covering temperature: 53.8 °C

72CN10 - continuous rating 250A
Conductor temperature: 59.0 °C
Pipe covering temperature: 53.4 °C

72CH9 - continuous rating 295A
Conductor temperature: 61 °C
Pipe covering temperature: 53.7 °C

<u>Optimistic</u>
Soil thermal resistivity - 1.3 [K*m/W] @ >15% moisture contents
Circuit:

72CK13 - continuous rating 390A
Conductor temperature: 63.5 °C
Pipe covering temperature: 52.2 °C

72CK12	- continuous rating		310A
	Conductor temperature: 60.6 °C		
	Pipe covering temperature:	53.1 °C	
72CH11	- continuous rating		290A
	Conductor temperature: 60.4 °C		
	Pipe covering temperature:	53.3 °C	
72CN10	- continuous rating		300A
	Conductor temperature: 60.8 °C		
	Pipe covering temperature:	53.3 °C	
72CH9	- continuous rating		350A
	Conductor temperature: 63.5 °C		
	Pipe covering temperature:	53.6 °C	

Additional calculations

In addition to the calculations when all circuits are loaded to the maximum the following scenario is applicable if one of the circuits 72CK12 or 72CK13 is not loaded:

#1	72CK13	-	not loaded	
	72CK12	-	continuous rating	380A
	72CH11	-	continuous rating	290A
	72CH9	-	continuous rating	350A
	72CN10	-	continuous rating	300A
#2	72CK13	-	continuous rating	430A
	72CK12	-	not loaded	
	72CH11	-	continuous rating	290A (it can be increased to 350A)
	72CH9	-	continuous rating	350A
	72CN10	-	continuous rating	300A

72JM18 / 72JW19

Recommended ratings:

JM18 - 335A

JW19 - 335A

Both circuits are running parallel to each other at a distance of 0.76m. The roads they crossing between Jasper Substation and Mayfield Rd are wide and covered with asphalt. These are very difficult conditions for those circuits.

In addition to the circuits loaded concurrently the calculations were provided for the scenario when only one circuit is loaded.

Inputs:

Depth - 2.1 m
Circuits' separation - 0.76 m
Soil thermal resistivity - 2.6 [K*m/W] @ 0% moisture contents

JM18	-	continuous rating	335A
		Conductor temperature:	85.0 °C
		Pipe covering temperature:	76.4 °C
JW19	-	continuous rating:	335A
		Conductor temperature:	85.0 °C
		Pipe covering temperature:	76.4 °C

One circuit energized

If one circuit is de-energized the other one can be loaded 430A when the conditions specified above are the same:

Soil thermal resistivity - 2.6 [K*m/W] @ 0% moisture contents

JM18 or JW19	-	continuous rating	390A
		Conductor temperature:	85.0 °C
		Pipe covering temperature:	73.9 °C

72KN23 – recommended rating: 460A

The worst conditions are expected where the KN23 crosses CN10, east of Namao substation. The vertical separation was established to be 0.45m. The soil thermal resistivity was assumed. The CN10 load was calculated for five circuits running parallel in Hermitage Park and used as constant in calculation of KN23 rating.

Inputs:

Depth - 1.4 m
Soil ambient temperature - 15°C

Pessimistic

Soil thermal resistivity - 2.0 [K*m/W] assumed @ 0% moisture;

CN10	-	Circuit continuous rating:	300A
		Conductor temperature:	71.6°C
		Pipe covering temperature:	64.2°C
KN23	-	Circuit continuous rating:	393A
		Conductor temperature:	85.0°C
		Pipe covering temperature:	73.6°C

Optimistic

Soil thermal resistivity - 1.1 [K*m/W] assumed @ 3% moisture;

CN10	-	Circuit continuous rating:	300A
		Conductor temperature:	52.4°C
		Pipe covering temperature:	44.7°C

KN23 -	Circuit continuous rating:	461A
	Conductor temperature:	69.0°C
	Pipe covering temperature:	53.5°C

72MG16 – recommended rating 460A

Pessimistic

Depth - 1.5m

Soil thermal resistivity - 2.35 [K*m/W] @ 0% moisture contents

Circuit continuous rating:	392A
Conductor temperature:	75.0 °C
Pipe covering temperature:	63.6 °C

Optimistic

Depth – 1.5 m

Soil thermal resistivity - 1.35 [K*m/W] @ 3% moisture contents

Circuit continuous rating:	460A
Conductor temperature:	69.4 °C
Pipe covering temperature:	53.1 °C

72RG1 / 72RG7

Recommended rating:

RG1 – 340A,

RG7 – 600A

Two locations were evaluated: RG1 at the crossing on 85Ave between 109 and 110 St because of significant depth and RG1 & RG7 in front of Garneau Sub. on 85Ave. where they are in close proximity to each other that the mutual heating is in effect. The later calculations were reflecting the maximum load on the 72RG1 circuit as the one that has a smaller conductor but not exceeding the 55°C on the external covering. In addition to the conditions described above, the large mature trees with deep extended roots covering the 85 Ave. NW reduce the soil moisture in addition to the heat produced by the cables.

RG1 at the crossing on 85Ave between 109 and 110 St

Pessimistic:

Depth - 8.9 m

Soil thermal resistivity - 1.2 [K*m/W] @ 3% moisture contents,

Circuit continuous rating:	486A
Conductor temperature:	75.8°C
Pipe covering temperature:	60.1°C

RG1 & RG7 in front of Garneau Sub. on 85Ave.

Pessimistic:

Depth - 1.5m

Circuits' separation - 1.5m

Soil thermal resistivity - 3.97 [K*m/W] @ 0% moisture contents

Circuit:

RG1	-	continuous rating	296A
		Conductor temperature:	85.0 °C
		Pipe covering temperature:	78.2 °C
RG7	-	continuous rating:	510A
		Conductor temperature:	85.0 °C
		Pipe covering temperature:	79.0 °C

Optimistic:

Depth - 1.5m

Circuits' separation - 1.5m

Soil thermal resistivity - 1.9 [K*m/W] @ 5% moisture contents

Circuit:

RG1	-	continuous rating	340A
		Conductor temperature:	60.0 °C
		Pipe covering temperature:	51.3 °C
RG7	-	continuous rating:	600A
		Conductor temperature:	63.0 °C
		Pipe covering temperature:	54.7 °C

72RS5 – recommended rating 470A

Pessimistic

Depth - 1.5m

Soil thermal resistivity - 2.8 [K*m/W] @ 0% moisture contents

Circuit continuous rating: 374A

Conductor temperature: 75.0 °C

Pipe covering temperature: 64.4 °C

Optimistic

Depth – 1.5 m

Soil thermal resistivity - 1.5 [K*m/W] @ 5% moisture contents

Circuit continuous rating: 470A

Conductor temperature: 70.5 °C

Pipe covering temperature: 54.2 °C

Depth – 1.5 m

Soil thermal resistivity - 1.4 [K*m/W] @ 3% moisture contents

Circuit continuous rating: 481A

Conductor temperature: 70.0 °C

Pipe covering temperature: 53.8 °C

72RV2 / 72RV4 / 72RV6
Recommended ratings:

RV2	**-**	**420A**
RV4	**-**	**520A**
RV6	**-**	**295A**

Three locations were analyzed:

Horizontal directional drilling between 105 St and 104 St
North of Jasper Ave under asphalt on 104 St
Crossing RV4 & RV6 at Rossdale Sub.

The limiting location seems to be on 104 St because the cables between 105 and 104 St in spite of deeper section where cables have been replaced with lager size conductors during relocation for the purpose of NLRT extension. The replaced cables have copper conductor size 1250kcmil (approx 630mm^2) that do not pose limitations for those circuits.

The RV4 and RV6 are crossing each other at the depth approximate 3.2m close to intersection of 104St and 95Ave. The vertical separation between these two circuits is 0.3m. Such close separation has significant impact on the RV4 circuit.

If the FOCS (Forced Oil Cooling System) is not operating the following is the maximum rating of these circuits.

Circuits' location - 104St and 103Ave
Installation of temperature and moisture sensors at this location is advised.

Inputs:
Depth - 1.5 m
Circuits' separation - as per Edmonton Power drawing #72K-086-002
Soil thermal resistivity - 2.1 [K*m/W] @ 0% moisture contents (the asphalt layer not taken into consideration). The street surface coverage does not allow for moisture penetration during precipitations.
Soil ambient temperature - 18°C

Circuit:

72RV2 -	continuous rating	419A
	Conductor temperature:	75 °C
	Pipe covering temperature:	62 °C
72RV4 -	continuous rating	663A
	Conductor temperature:	85 °C
	Pipe covering temperature:	75.7 °C
72RV6 -	continuous rating	294A
	Conductor temperature:	75 °C
	Pipe covering temperature:	67.9 °C

104St and 95Ave - RV4 & RV6 crossing

Depth - 3.2 m
Vertical separation - 0.3m
Circuits' separation - as per Edmonton Power drawing #72K-086-001

Soil thermal resistivity -	1.3 [K*m/W] @ 3% moisture contents (the asphalt layer not taken into consideration)
Soil ambient temperature -	10°C

72RV4 -	continuous rating	520A
	conductor temperature:	60.6 °C
	Pipe covering temperature:	49.9 °C
72RV6 -	continuous rating	300A
	Conductor temperature:	61.2 °C
	Pipe covering temperature:	53.3 °C

72RW3 – recommended rating 465A

In the absence of the soil test for this circuit the soil thermal resistivity is assumed based on soil samples obtained from different parts of the city. At the Groat Ravine Rd. a distribution duct 3x3 with one lightly loaded cable installed is crossing at approx depth of 1.2m, assumed duct temp = 20 °C was chosen. The 72RW3 circuit depth at this location is assumed as the profile drawing does not show elevation at this point.

Pessimistic:

Depth: - 3 m (Groat Ravine Rd bridge)

Soil thermal resistivity -	2.35 [K*m/W] @ 1% moisture contents,	
	Circuit continuous rating:	398A
	Conductor temperature:	75°C
	Pipe covering temperature:	63.9°C

Depth: - 1.5 m

Soil thermal resistivity -	2.3 [K*m/W] @ 0% moisture contents	
	Circuit continuous rating:	403A
	Conductor temperature:	75°C
	Pipe covering temperature:	64.8°C

Optimistic

Depth: - 3 m (Groat Ravine Rd bridge)

Soil thermal resistivity -	1.4 [K*m/W] @ 3% moisture contents;	
	Circuit continuous rating:	465A
	Conductor temperature:	68°C
	Pipe covering temperature:	54.1°C

72VN21 - Recommended ratings: 435A

The circuit runs parallel to a distribution duct bank at the intersection of 102St and 117Ave. The separation distance between these two plants is 0.6m according to the plan drawing. The duct bank temperature was assumed to be 40°C. The thermal resistivity at this location was assumed as there is no tested soil in close vicinity.

Depth - 1.2m
Soil ambient temperature - 18 °C

Pessimistic:

Soil thermal resistivity	-	2.3 [K*m/W] @ 0% moisture contents	
		Continuous rating:	360A
		Conductor temperature:	75.0 °C
		Pipe covering temperature:	65.1 °C

Optimistic:

Soil thermal resistivity	-	1.1 [K*m/W] @ 3% moisture contents	
		Continuous rating:	437A
		Conductor temperature:	67.0 °C
		Pipe covering temperature:	52.7 °C

240BA2 / 240BA3

Recommended ratings:

240BA2 - 850A
240BA3 - 850A

240BA2 or 240BA3 - 890A if other cct is not loaded

The worst conditions are assumed at the crossing of 63Ave. This is a congested intersection with other utilities and heat producing distribution duct banks. It is expected that the moisture will be at the lower end of the scale. As such, 3% is used in calculations as the most optimistic occurrence. In order to provide more accurate rating installation of the temperature and moisture sensors is advisable in addition to the testing of a soil sample taken from this location.

Circuit depth - 1.2 m
Circuits' separation - 3m
Soil Ambient temperature - 18 °C

Pessimistic:

Soil thermal resistivity -		2.3 [K*m/W] assumed @ 0% moisture;	
BA2 & BA3	-	Circuit continuous rating:	732A
		Conductor temperature:	85.0°C
		Pipe covering temperature:	73.9°C

Optimistic:

Soil thermal resistivity -		1.2 [K*m/W] assumed @ 3% moisture;	
BA2 & BA3	-	Circuit continuous rating:	850A
		Conductor temperature:	68.6°C
		Pipe covering temperature:	54.3°C

One circuit energized

During power outage of one circuit the other can be loaded 890A when the conditions specified for the optimistic ratings are the same:

Soil thermal resistivity	-	1.2 [K*m/W] assumed @ 3% moisture;	
BA2 or BA3	-	Circuit continuous rating:	890A
		Conductor temperature:	70.2°C
		Pipe covering temperature:	54.8°C

Appendix 7 - Loss of Life

The loss of life calculations were conducted based on EPRI document TR-111712. The document suggested that daily load should be obtained as data for calculating loss of life inputs. It has to be noted that the document and formulas contained in it are based on controlled laboratory conditions with access to the conductor temperature on continuous basis. In the real world the conductor temperature, if not measured, is calculated based on locations randomly chosen for testing the cable environment. These location conditions may or may not be the most severe from the cable standpoint.

The calculation followed the method described in the Chapters 5-7 of the referenced EPRI document.

Cable temperature

As the amount of load data collected over the last 10 years and available for calculations was enormous while at the same time it was lacking of information for the preceding years, it was decided that the calculations would be simplified. Each circuit was analyzed separately and divided into three groups based on the graphs showing the load vs. time. For each group an average load magnitude and its duration in terms of a part of a year were assigned. This assigned pattern was later applied to the entire operating life of a circuit thereby covering the time when the load data was not available. It has to be noted that any period that the circuit was idle was also taken into consideration.

For each group the cable conductor temperature was calculated and used as an input in the loss of life calculations using the following equation:

$$Loss\ of\ Life = t\ A_{\mathrm{T}}\ e^{\frac{-B}{Tc+273}}\ K_{\mathrm{m}}$$

Where: T_c - conductor calculated temperature in °C
t - time in days at temperature T_c
B - Arrhenius rate constant = 10003 K
$A_{\mathrm{T}} = \frac{1}{e^{\frac{-B}{Tmax+273}}}$
T_{max} – maximum continuous operating temperature provided by the cable manufacturer
K_m – thermo-mechanical bending factor (value between 1 – 1.33)

The conductor temperature was calculated based on the information used in calculation of each circuit ampacity. This includes the newest soil parameters which were obtained during the course of this project. The total loss of life is a sum of loss of life calculated for each group.

It can be assumed that the daily and seasonal load patterns 40 years ago were different that it is now but lack of information does not allow for adjustment. By analyzing the load pattern one can notice that the cables were operated with significant load fluctuation. This, in turn, causes that the conductor temperature changes had significant impact on the cable termo-mechanical bending. These conditions were included in the loss of life calculations. The calculated minimum life is estimated to be 21.43 years for circuits with considerable thermo-mechanical bending caused by the daily load fluctuations and peak load at maximum design temperature. For the cables that their daily load factor is approaching 1.0 with minimum bending, the minimum life estimate is 28.5 years.

The circuits that are installed in close proximity to each other such as the circuits originating in i.e. Clover Bar or Jasper substations as well as those which crossing each other had to be evaluated together. Their conductor temperature calculations were done the same way as calculating the rated load in Appendix 6.

Taking the above assumptions under consideration, evaluation of the circuits originating in Clover Bar substation did not produce reasonable results. The load pattern in the last 10 years indicated that the circuits were only lightly loaded; hence, their temperature was significantly below the maximum. When the loads were used in calculation of the cables temperatures they produced the results of the cables that have many future years of service. This is contrary to the evidence that the cables were overheated in the past to the point that they failed many times. Because of difficulties to obtain reasonable results the attempt to calculation of those circuits' loss of life was aborted.

The same difficulties were faced in evaluation of the circuits between Rossdale and Victoria substations. These circuits are equipped with cooling system (FOCS) installed in 1990s. Calculation of such circuits' ampacities is not standardized. To obtain the conductor temperature in these conditions requires significant studies using mathematical theory known as Finite Element Method. Using this method a study should be performed as suggested in the Appendix #6. The circuits' loads for the time before the FOCS installation were not available.

Degree of Polymerization

The deterioration of the material used as the cable insulation is a function of its temperature and time. The degree of deterioration can be used to assess the insulation conditions. The degree of degradation is expressed in reduction of the degree of polymerization that can be a result of laboratory tests.

It is possible to estimate the degree of polymerization from aging models and kinetics parameters (EPRI). The condition of such evaluation lays in the proper testing procedure of the lab. The tests done in the past have not always produced the reliable results that can be trusted as inputs in the evaluation. However, because of difficulties to obtain other samples it was decided to use the information on the basis "as is".

It was assumed that the initial degree of polymerization was $DP_i = 1200$ for all cables. By using the numbers provided by the laboratories the "Retained DP" was calculated which is the ratio of aged DP_a to unaged DP_u. The retained DP was used in the loss-of-life calculation based on the following formula:

$$Loss\ of\ Life = \frac{\ln(DP_r)}{A_T\, e^{\frac{-B}{Tc+273}}}$$

Where: $DP_r = \frac{DP_a}{DP_u}$ - retained degree of polymerization

T_c - conductor calculated temperature in °C

B - Arrhenius rate constant = 10003 K

In calculation of the remaining life we have not taken into consideration that the test results are dated. Some of the results are 6-8 years old and it is prudent to say that the insulation has aged further. Since the aging depends on the cable temperature, the daily load fluctuation and lack of information on the paper tape temperature make calculation of the deterioration difficult if not impossible at this time.

The remaining life column shows the amount of time that the cable will age to the point that its further operation becoming uncertain. It is calculated on the basis that the cable conductor temperature remains at or below the maximum operation temperature provided by the cable manufacturer. In most cases the maximum recommended temperature is 85°C except for the cables manufactured by the Northern Electric Company which recommended 75°C as the "maximum safe recommended conductor temperature".

The table below should be updated every time the new DP data is available to make it more accurate.

Circuit designation	**Year of installation**	**Rating [A]**	**Loss of life [years]**		**Remaining life [years]**	
			Temp	**DP**	**Temp**	**DP**
72VN21	1957	435	11.7	7.8	9.8	13.8
72RW3	1960	465	1.9	2.3	20.0	19.3
72RG7	1981	600	0.6	10.0	20.0	11.5
72RG1	1969	340	1.8	2.3	19.0	19.4
72RS5	1958	470	19.0	2.3	3.8	19.4
72MG16	1969	460	1.3	2.7	20.4	18.9
72JM18	1975	320	21.7	3.3	1.1	18.3
72JW19	1976	320	21.9	3.3	0.9	18.3
72KN23	1974	460	1.7	6.9	19.7	14.7
240BA2	1977	850	2.2	-	19.3	-
240BA3	1977	850	2.7	-	19.8	-

The numbers in the Temp and DP columns are calculated on two totally different principles. The DP loss of life is based on the insulation test in the laboratory. These tests measure changes in the chemical structures of the material (paper). The degree of changes reflects the aging of the insulation. If the initial number representing the degree of polymerization at the time of the cable manufacturing is taken as accurate the remaining life of the insulation can also be considered as dependable information. However, it has to be noted that the lab insulation tests were not always performed on samples taken from the most aged part of the cable. As such may not represent the worst condition of the circuit.

The remaining/loss of life based on the cable temperature are calculated on a different principle. There is no measured data – the input data for calculation are based on interpretation of the available information. The only firm data is the circuit load at a certain time of the cable life. The remaining data necessary for calculation of the cable temperature were evaluated and assigned by an engineer. The environmental conditions changes over time with respect to surface conditions as well as from season to season. All of those have a significant influence on the loss of life calculation.

The results are different since the DP samples are never taken from the location that is considered as the worst environmental circuit conditions. Taking in the consideration that the DP "Loss of Life" calculations results are based on more tangible inputs they should take priority over the calculations based on the cable temperature.

e cable temperature.

EDTI
Summary Life Cycle Assessment Report

Underground Oil Filled Pipe Type Cables

Revision: 1.0

Date: January 25, 2023

Revision History

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0	2022-10-25	Mike Wong			Internal circulation
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Contents

1 Executive Summary:

EDTI continually inspects and assesses the condition of its underground transmission circuits and uses analytical tools to evaluate the level of maintenance and repair required to ensure the ongoing performance of its cable system assets. In addition to other factors, EDTI uses these assessments to determine whether it is more cost effective to continue to operate, maintain and repair an asset, or to replace it with a new asset.

In 2013, as part of EDTI's role as a Transmission Facility Owner ("TFO"), EDTI conducted a detailed review of the maintenance records, repairs, test results and loading of its Oil Filled Pipe Type ("OFPT") cable. This "2013 System Sustainability and Equipment Assessment Study" ("SEAS Report") was conducted by Quanta Technology, LLC ("Quanta"), and assessed the capability of EDTI's transmission infrastructure to meet future operating, system loading, and forecast transmission system growth requirements.

On the basis of a number of technical, social, environmental and economic factors, EDTI has determined that it should replace its OFPT transmission lines as opportunities arise. These opportunities would include transmission system growth projects, end-of-life assessments, and other major capital projects on or near these assets.

This report summarizes the background, drivers and conclusions which support EDTI's strategy to replace its OFPT transmission lines. There are three relevant appendices associated with this document:

- Appendix A is a copy of the original 2013 SEAS Report;
- Appendix B1 is a Technical Summary of the condition of CK12 and CK13 transmission lines; and
- Appendix B2 is a Technical Summary of the condition of CN10 transmission line.

2 Background:

The EDTI Transmission system is made up of a mixture of aerial and underground transmission lines between its high voltage substations. The underground transmission system can be further segregated into OFPT and cross-linked polyethylene ("XLPE") type lines. In total, there are currently 18 OFPT lines in service at 72 or 240 kV voltage levels. These lines transmit power between the substations making up EDTI's interconnected electrical system. The substations then provide this power to the electric distribution system and ultimately to the customers within the City of Edmonton.

As a TFO, EDTI is obligated under section 39(1) of the *Electric Utilities Act* to maintain its transmission facilities in a manner that is consistent with the safe, reliable and economic operation of the interconnected electric system.

EDTI's approach to the operation and management of its transmission infrastructure is to actively monitor the condition of its assets, perform condition-based maintenance and refurbish equipment, and only replace deteriorating assets when further refurbishment is no longer technically and/or economically feasible. Although EDTI extends the life of its transmission assets as long as reliably and economically possible through effective condition monitoring and maintenance programs, these assets nevertheless deteriorate with time and use and need to be replaced.

As OFPT[1] underground power cables approach the end of their useful lives, they are susceptible to an increased probability of oil leaks and cable faults. Underground power cable faults are infrequent events but have the potential for significant impacts. OFPT cable faults typically require lengthy repair outage times needing specially trained personnel and equipment to partake in repairs if the fault is significant. This would negatively affect EDTI's ability to provide reliable electrical transmission service to the Alberta Interconnected Electric System ("AIES"). OFPT cable faults also pose a potential risk to the environment and to the safety of EDTI staff and the public. High energy cable faults can rupture the OFPT cable pipe, resulting in an uncontrolled release of dielectric fluid (oil). Furthermore, several of these OFPT cables cross underneath the North Saskatchewan River at multiple locations which makes both the cost to repair and environmental impacts of a release, higher.

As part of the SEAS Report noted above, EDTI engaged Quanta to conduct a systematic review of EDTI's transmission assets to determine their overall condition and capability, within which a detailed analysis of EDTI's underground Transmission system was conducted. This Underground Transmission ("UGT") Assessment forms part of the reasoning by EDTI, calling for the replacement of the OFPT underground power cables.

The SEAS Report (Appendix A) provides extensive information on OFPT technology, testing methodologies and diagnoses, risks, and meaningful considerations to be made in a Life Cycle Replacement assessment. Key points will be highlighted in the review below; however, it is not the intention of this report to reiterate all of the information contained within the SEAS Report, which remains relevant and foundational.

Appendix B provides technical condition-based assessments of the OFPT cables of interest.

3 Drivers:

EDTI notes that the following drivers support the immediate replacement of its OFPT underground transmission lines:

[1] HPFF ("High Pressure Fluid Filled") is used as an equivalent term to OFPT

3.1 Age

The age of an underground cable and the age of the supporting ancillary systems, provide an indication of the accumulation of slow acting factors that degrade such assets over their service life, such as heat and physical stress or degradation. While age alone is not a determinative indicator of condition, the on-going operational stresses cause equipment deterioration over time.

As OFPT underground power cables approach the end of their useful lives, they are susceptible to an increasing probability of oil leaks and cable faults. Underground power cable faults are infrequent events but have the potential for significant impacts.

3.2 Thermal Considerations and Ratings

The thermal environment around underground cables is a significant factor in the ampacity rating and long-term health of the cables. Cable ratings are primarily determined by the amount of current they can carry on a continuous basis at a design temperature that will not degrade the cable insulation. As load increases, conductor temperatures increase and ground temperatures adjacent to the cable pipe increase. As temperatures rise, the surrounding in-situ materials dry out radially from the pipe and the backfill material becomes less and less efficient at dissipating heat. This can eventually lead to a condition known as "thermal runaway" where heat can no longer be dissipated. In this condition, the heat causes the cable insulating papers to become damaged and weaken, leading to cable faults and potential pipe rupture. To reduce the probability of this scenario, backfill materials are now engineered to mitigate these thermal conditions.

3.3 Asset Condition

EDTI completes regular testing of its OFPT infrastructure. These tests provide some guidance on the condition of the asset in general. The following sections describe the various asset condition assessments that EDTI undertakes.

3.3.1 Paper Insulation

Cable degradation or "aging" is generally attributed to the degradation of cable insulation characteristics. These parameters are measured in laboratory settings on paper samples extracted from the cables; the condition of cable insulating paper is a key indicator of cable condition.

Obtaining a paper sample is considered destructive testing as the cable and insulation must be physically cut (and subsequently repaired) to obtain a sample, disturbing the existing physical structure and potentially introducing new issues, such as moisture or contaminants. This operation adds significant costs to the maintenance expenditures due to required outages, pipe fluid freezing with liquid nitrogen for the duration of the work, followed by vacuum testing and electrical soaking times. As such, it is usually performed when the circuit conditions require upgrade or repair.

EDTI will typically obtain samples of the paper insulation during times of termination or splice replacements. The execution of these types of projects is already invasive, so taking paper samples at this time is reasonable. The results of these samples will be utilized in the overall assessment of the cable in general.

Detailed paper results for the cables of interest can be found in Appendix B.

3.3.2 Dissolved Gas Analysis ("DGA")

EDTI completes regular DGA testing on its OFPT cables in areas where valves are present to take an oil sample. This is typically done at splice locations found in manholes and cable terminations found at substations. Similar to Transformer DGA, Cable DGA can provide some clues on the integrity of the insulating paper, the thermal condition of the conductors and the condition of the oil. A change in the DGA concentrations over multiple samples gives further indication of changing conditions in those sections.

Typical gases being analyzed are carbon dioxide, hydrogen and acetylene (to name a few). As these concentrations change with samples, conclusions can be derived to determine the condition of the cable at that location. Challenges can occur in those cables where there are circulations imparted on the oil. See Section 7.1 for more information.

Detailed DGA results for the cables of interest can be found in Appendix B.

3.3.3 Load Considerations

The historical loading on an OFPT cable has an impact on the cable's life expectancy. Overloading and consistently high loading of the circuit causes heating within the cable which leads to accelerated deterioration of the cable insulation. This, in turn, increases the probability of an electrical fault.

The SEAS Report evaluated the circuits' steady state loads used by EDTI and subsequently recalculated new, recommended values (Appendix A, pdf page 182 of 194). Reviewing the load from 2013 to present as part of the study, it is noted that the circuits have been occasionally loaded above the recommended ampacities to accommodate system constraints.

3.4 Fault & Maintenance History

Since their installation, EDTI has experienced some thermal failures on its OFPT lines. The fault and maintenance history are important considerations when calculating the life expectancy of cables. These details are addressed further in Appendix A and Appendix B.

With regard to maintenance and repair, EDTI utilizes activities that primarily focus on non-invasive work such as degasification and other temporary mitigation actions. Paper and splice testing, while potentially more informative with regards to data gathering and health assessment, are inherently invasive in nature, making them costlier financially and operationally.

It should also be noted that repairing a portion or subset of an OFPT cable system will not resolve underlying conditions on/in the remaining portions of the OFPT circuits. Due to a lack of visibility with regards to testing, the untouched portions will continue to be subject to increased risk of failure due to their age and use. Since EDTI can only access the existing cable at the end termination points and splice joints in the manholes (approximately 1-2% of the total cable lengths) it is unable to accurately assess all portions of the underground circuits. EDTI cannot be certain that all deteriorated portions of the cable and pipe can be identified for repair without complete or major replacement of the assets.

EDTI will continue to regularly monitor these circuits through non-invasive means (e.g., DGA, temperature monitoring, etc.) to ensure emergent indications of rapid degradation are found and addressed prior to major failures.

3.5 Route Characteristics

The physical cable or circuit route is an important factor of the health and longevity of an underground transmission circuit. There are two major considerations where route characteristics directly impact the life of the OFPT circuit.

First, consideration of the thermal environment that includes the avoidance of external heat sources, depth of burial and soil/ground conditions in the vicinity of the asset. These external heat sources typically occur from crossings with other underground services, including but not limited to transmission cables, distribution cables and other concrete duct work for gas or water lines. Several lines share right of ways and alignments which have a contributory effect on each other from a heating perspective, as well as reducing capacity due to this thermal consideration. These heat sources ultimately impact the life expectancy of the insulating papers within the OFPT cable.

Second is the protection of the asset from either direct physical contact or stress or mechanical damage and indirect damage from vibrations or corrosion. A common mode of failure for an OFPT system is from the outside-in; meaning that most cable failures are a result of damage to the steel pipe itself, from such impacts as external contact or shearing, corrosion, and vibration, and not from the conductors within. For example, an OFPT line located within a shared Right of Way (in relation to which EDTI has no ability to limit access) may be visually located numerous times via hydrovacing. Exposing the pipe coating to excessive hydrovac pressures could severely damage the coating, increasing the risk of corrosion on the pipe and potentially causing oil leaks.

3.6 OFPT Technology – Obsolescence

EDTI does not consider OFPT cable to be a viable technology for the future; a summary of the reasons follows:

- With industry's transition away from the use of OFPT systems to other insulating technology (i.e., cross-linked polyethylene ("XLPE") or ethylene propylene rubber ("EPR") cable in duct bank), the market is now left with only one paper insulated transmission cable manufacturer in North America. Given the lack of competition and manufacturing, long lead times for products have been experienced and this trend is expected to continue.
- Due to this transition and market demand, this technology is not well supported, with the majority of experts in the field slowly retiring, which limits the technical recourse for further maintenance and upgrades. EDTI maintains a base level of competency in the repair and maintenance of these cables, but major repairs are contracted out to specialist firms. There are few firms remaining with the skill set to work on OFPT cables. Most are based out of the United States, and engaging these firms for major repairs is very costly and difficult to arrange.
- Current supply chain issues as a whole are exacerbated by only having a single source supplier for the cable materials and the limited numbers of specialized construction firms that have experience with this technology.
- It is becoming increasingly uneconomic to maintain and refurbish these existing assets because of a lack of availability of manufacturers and contractors to supply, maintain or repair OFPT cables.
- OFPT cable faults typically require lengthy response times, repair outage times, higher potential environmental impacts and a larger excavation to accommodate the repair (for freeze pits, splice pits, etc.).
- Due to the use of pressurized oil in the system, complicated ancillary systems with additional mechanical and electrical components including valves, motors and pump plants require maintenance, adding to the complexity and costs of the system. This is covered in more detail below.

3.7 Supporting Infrastructure and Systems

OFPT cable systems require many ancillary systems and continuous monitoring/attention to ensure proper operation. For example, specialized pumping plants to maintain fluid pressure, cathodic protection systems to protect the steel cable pipes, pressure sensors to monitor fluid pressure within pipe and terminations, and cooling systems are just some of the vital and costly components of OFPT systems that are not required with other systems.

As transmission cable ancillary equipment ages and approaches the end of its useful life, EDTI anticipates that an increasing number of ancillary equipment assets will require increased maintenance or immediate replacement due to failure in order to maintain the safe and reliable operating condition of these systems.

In all of these supporting systems, the expected life cycle of the systems and the cable itself are not aligned, making it difficult to optimize replacements with end of life assessments for all the infrastructure required to operate OFPT systems

3.7.1 Pump Plants and Oil System

OFPT circuits require a complicated pressurization system to maintain oil pressure within the pipe. These systems are made up of a mechanical pump plant and oil tanks / reservoirs. OFPT cables require a constant pressure be applied to them (around 200 psi) to account for volumetric fluctuations caused by load variations and ambient temperatures changes. Upon demand, the pump plant will draw oil from the low pressure tank, raise its pressure and supply it to the cable. During times of high load, the oil will flow back into the reservoir tank via a cable relief valve. This constant pressurization allows the OFPT cable to have a very high level of electrical insulation, allowing for minimal phase spacing between conductors within the pipe.

Some circuits within EDTI's OFPT cables use the pressurization system to circulate the oil within the pipe. This allows for mitigation against potential hot spots in the cable (i.e., at splices or other areas of insulation breakdown) and / or to allow additional capacity in the cable. Circulating the oil within the pipe transfers the heat over a greater area.

In these cases, the fluid moves continuously through the system, which also moves dissolved gases from their point of origin to all points of the system. This creates difficulty in interpreting DGA analysis, as mentioned above, as the gas concentration limits appear lower than they would in a static system. The gases of concern become dispersed, creating difficulty in finding the true location of the source problem, ultimately masking a larger problem.

3.7.2 Cathodic Protection

EDTI uses cathodic protection systems to reduce and mitigate the effects of natural corrosion activities on steel pipes containing the power cables. This system is made up of an impressed current rectifier at either end of the OFPT cable to continuously place a current on the pipe and resist oxidation of the pipe. This system works in conjunction with the exterior coatings on the pipe. However, EDTI has noted over time that there are areas of significant corrosion on certain pipes, discovered during maintenance and inspection. These corrosion spots indicate potential deficiencies in the electrical isolation with regards to the cathodic protection system. As these pipes are approaching 50 years of age, EDTI will continue to carefully monitor, maintain and repair the supporting infrastructure, while also trying to avoid significant capital investment in light of the dwindling service life of these assets.

3.7.3 Pressure Sensors

EDTI uses pressure sensors at the OFPT line terminations within the substations. These pressure sensors provide valuable real-time data on the pressure of the insulating oil at the termination. These systems are monitored constantly by control operators with crews being dispatched when pressure levels are at actionable levels.

3.8 Environmental Risks and North Saskatchewan River Crossings

As mentioned in the route characteristics section, a major environmental risk involves the potential spill of pressurized oil should the structural integrity of the system be compromised or fail. This risk is heightened for the circuits that cross the bottom of the North Saskatchewan River. The OFPT technology inherently contains oil as an insulating medium and therefore presents a greater risk of contaminating the environment in the event of a pipe failure. High-energy cable faults can rupture the OFPT cable pipe, resulting in an uncontrolled release of dielectric insulating fluid.

The North Saskatchewan River Valley ("River Valley") is an environmentally sensitive and protected area within Edmonton city limits and beyond, with a number of migratory seasons for different bird and animal species over the course of the year. It is subject to regulation and permitting due to municipal bylaws (City of Edmonton River Valley Bylaw), and Federal Acts such as the Migratory Birds Convention Act and the Canadian Navigable Waters Act.

Several of EDTI's OFPT cables are not buried beneath the river bed, but lie on the surface of the river bed and are provided additional mechanical protection through the use of specialty coverings. The river is not deep, and in high-flow conditions such as spring thaw or during a high-water event, where there is increased debris in the river, the cables may be subject to impact or shear through dragging by this debris. EDTI has safeguards in place to mitigate against a pipe breach, in the form of erosion protection, oil-leak-management systems and barrier splices on either side of a river crossing to decrease the potential for or impact of oil spills, but the consequence of failure in the River Valley is one of the highest risk scenarios EDTI has identified

3.9 Consequence of Failure

Although listed last in the drivers for life-cycle-replacement, the consequence of failure is a primary consideration for EDTI. EDTI strives to maintain its transmission facilities in a manner that is consistent with the safe, reliable and economic operation of the interconnected electric system.

Regardless of the probability of failure, the impact of failure of the OFPT cables has a domino effect. This is due to a number of factors including: the impact from losing the primary sources to substations, the lengthy system outages to repair or replace cables, economic impacts stemming directly from the repairs required as well as schedule (outages) impact to other capital and maintenance work to prioritize repair efforts and the potential massive environmental impact of thousands of litres of insulating oil being released into a sensitive wildlife and fisheries area.

From an operational service perspective, EDTI operates a highly interconnected and interdependent system. EDTI's ability to maintain the current level of service in the areas supplied by these OFPT cables is highly dependent on a number of factors including: time of year, current loading and demand at the substations, the state of other interconnected substations and circuits, the impact of thermal overloading from long term operation of maintaining the entire load of a given substation on alternate circuits and thermal considerations if the piping configuration had to be modified due to a failure on other cables.

The loss of one or more of these cables would, in all likelihood, put the other cables or lines near or beyond the maximum normal operating rating. It would also prevent any maintenance activities on the other parts of the system in operation until such time that restoration of the affected cables were possible. Given the lead times for equipment and replacement for these assets, this could result in a state of system instability for weeks to months.

4 Conclusion

Through its sound inspection, maintenance and repair practices, EDTI has been able to keep its OFPT circuits in operation beyond expected service life and by the time a replacement is fully constructed and energized, beyond the original recommendation of the SEAS Report. However, as demonstrated above (and with the Appendices), it is now time to replace these assets and more broadly, this technology.

Considering the lead-time of a replacement transmission line, aerial or underground, is in the range of 3-5 years, immediate initiation for circuit replacement is necessary. EDTI expects increased maintenance expenditures to keep the circuits in operational condition to meet its obligations as a Transmission Facility Owner but is actively planning to replace these systems.