REFERENCE:

Appendix 7.7 p. 9 of 18

PREAMBLE TO IR (IF ANY):

Appendix 7.7 (p. 9): "A comprehensive condition assessment on Bipole I and II valves and controls was completed in 2019 and shows that Bipole II valves have passed their expected lifespan, are in poor condition, and should be replaced as soon as possible."

QUESTION:

Please file the 2019 comprehensive condition assessment on the Bipole I and II valves and controls referenced in Appendix 7.7 (p. 9, lines 10-12).

RESPONSE:

Please see the Attachment to this response for the report titled "Nelson River Bipoles I and II – Condition Assessment of Thyristor Valves and Controls" dated November 6, 2019.

Manitoba Hydro

TRANSMISSION PLANNING & DESIGN DIVISION

TRANSMISSION ASSET MANAGEMENT DEPARTMENT

REPORT ON

NELSON RIVER BIPOLES I AND II — CONDITION ASSESSMENT OF THYRISTOR VALVES AND CONTROLS

PREPARED BY: Xin Li, Ph.D., P.Eng.

REVIEWED BY: Kelvin Kent, P.Eng.

APPROVED BY: Maria Neufeld, P.Eng., Manager

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ACRONYMS AND DEFINITIONS

For convenience and to avoid unnecessary confusion in this report, the following acronyms and definitions are introduced:

B2B	Back-To-Back.
BP1, BP2 and BP3	Bipole 1, Bipole 2 and Bipole 3.
CEF	Capital Expenditure Forecast.
C&P	Control & Protection.
Controls	HVDC controls and protection are highly integrated, and always installed and replaced together. For the purpose of condition assessment, no distinction needs to be made among the terms “controls”, “controls and protection” and “C&P system”.
EPLD	Erasable Programmable Logic Device.
EOL	End-Of-Life.
EPROM	Erasable Programmable Read-Only Memory.
ETT	Electrically Triggered Thyristor.
FC	Valve Firing Control.
HVDC	High Voltage Direct Current.
IC	Integrated Circuit.
ISD	In-Service Date.
LTT	Light Triggered Thyristor.
MH	Manitoba Hydro.
OEM	Original Equipment Manufacturer.
P1, P2, P3 and P4	Pole 1, Pole 2, Pole 3 and Pole 4.
PCB	Printed Circuit Board.
PLC	Programmable Logic Controller.
SAB Card	Thyristor electronics, including S-card, A-card and B-card.
TA	Thermal Analogue in the Pole 1 VG controls provided by Alstom.
TAM	Transmission Asset Management.
Technology	A type of control system or equipment that was designed and installed by a particular manufacturer at a particular time (e.g. 48 year old control technology in Bipole 1, 27 year old control technology in Pole 1, etc.).
TFM	Thyristor Fault Monitor.
TFR	Transient Fault Recorder.
Valves and Controls	Thyristor valves and associated HVDC controls (e.g. pole and VG controls).
UV EPROM	Ultraviolet Erasable Programmable Read-Only Memory.
Valve	Mercury-arc valve or thyristor valve.
VBE	Valve Base Electronics.
VG	Valve Group.

EXECUTIVE SUMMARY

This report presents the findings of the recent condition assessment of the thyristor valves and their associated HVDC Control & Protection (C&P) systems (e.g. pole and VG C&P systems) in Bipole 1 (BP1) and Bipole 2 (BP2), which will be used as a major reference for System Planning and Transmission Asset Management (TAM) to prepare a system planning report on the refurbishment/improvement of BP1 and BP2.

The condition assessment involves four aspects: ages vs. expected lifetimes (see Section 2), conditions and issues (see Sections 3 to 5), maintenance and training needs (see Section 6), and upgrade options (see Section 7).

For convenience, the term “controls and protection” or “C&P system” is also referred to as “controls” in this report.

BP1 consists of Pole 1 (P1) and Pole 2 (P2). It was started in 1971 and completed in 1976 as a mercury-arc valve based HVDC scheme [1]. Although P2 was completed in later years, the pole controls were installed in 1971 [1]. The mercury-arc valves in P1 and P2 were upgraded to thyristor valves in 1992 and 2004, respectively. Only the original VG controls in P1 were replaced along with the valves in 1992.

BP2 consists of Pole 3 (P3) and Pole 4 (P4). Each pole has two Valve Groups (VGs) that were installed in two stages. The stage 1 VGs (VG31 and VG41) were installed in 1978 and stage 2 VGs (VG32 and VG42) in 1984/1985. The pole controls were installed in 1978. No major upgrade has ever been done for the HVDC equipment inside the converter building.

Thus, BP1 and BP2 ended up having three different thyristor valve and control technologies, respectively, which are summarized as follows:

Equipment/technology	Supplier	Year installed	Age	Age in 2028	Expected lifetime*
P1 thyristor valves (ETT)	Alstom	1992	27	36	32
P1 pole controls (analog)	English Electric	1971	48	57	29
P1 VG controls (analog-digital)	Alstom	1992	27	36	25
P2 thyristor valves (LTT)	Siemens	2004	15	24	32
P2 pole controls (analog)	English Electric	1971	48	57	29
P2 VG controls (analog)	English Electric	Before 1976	> 43	> 52	29
BP1 master controls (analog)	English Electric	1971	48	57	29
BP2 thyristor valves (ETT)*	AEG, BBC & Siemens	1978/1984/ 1985	41/35/34	50/44/43	32
BP2 pole controls (analog)	AEG, BBC & Siemens	1978	41	50	29
BP2 VG controls (analog)	AEG, BBC & Siemens	1978/1984/ 1985	41/35/34	50/44/43	29

Note: *The thyristor valves were designed for 35 years of operation, but earlier valve replacement has occurred in many other projects around the world. The expected lifetime of thyristor valves and controls are given in Section 2.*

A review of the EPRI and CIGRE life extension guidelines of existing HVDC projects and the upgrade history of HVDC projects installed during 1970 to 1995 around the world, especially those similar to ours, indicates that the thyristor valves and controls in BP2, the original controls in BP1, and the VG controls in P1 have all passed the ends of their expected lifetimes (see the above table and Section 2). Particularly, the 48 year old control technology in BP1 is the oldest in the world, and the 41 year old BP2 is the oldest among the large HVDC projects (≥1000MW) whose thyristor valves and controls have never been upgraded.

By 2028, all of the valves and controls in BP1 and BP2 except the valves in P1 will be 36 to 57 years old, 4 to 28 years beyond their expected lifetimes as shown in the above table.

The detailed assessment performed recently on the thyristor valves and controls as well as the associated maintenance and training needs is presented in Sections 3 to 6. Some of the common issues identified are summarized below:

Issue	Description	Associated equipment
Lack of spare parts	Support from the original equipment suppliers or from the industry is no longer available and it is difficult to acquire new spare/replacement parts to replace the failed, failing or aging components.	All thyristor valves and controls in BP1 and BP2 except for the valves in P2 and original analog controls in BP1. All BP2 test equipment.
Lack of control redundancy	Lack of control redundancy makes BP1 and BP2 prone to pole and VG outages due to C&P system faults and also makes them difficult to access for troubleshooting and training purposes.	All C&P systems in BP1 and BP2.
Difficult and time-consuming to troubleshoot	Complexity, lack of redundancy & self-monitoring, lack of detailed alarm information, etc. make the controls difficult and time-consuming to troubleshoot.	All C&P systems in BP1 and BP2.
Difficult to train staff	It would take many years to train staff, especially plant engineers, for the 3 types of C&P systems and associated equipment such as thyristor valves, etc.	All C&P systems in BP1 and BP2.
Risk of EOL failures	Components are aging. There is a good possibility that their End-Of-Life (EOL) component failures would occur, which can cause frequent pole/VG outages. Aging equipment combined with lack of spare parts and/or loss of knowledge would result in the EOL of the equipment.	C&P systems in BP1 and BP2. BP2 test equipment. Thyristor valves in BP2.

Some of the major equipment-specific issues are summarized below (but not necessarily limited to):

- 41 year old thyristor valves in BP2:
    - The valves are inherently prone to fire. Since the late 1990s, more than 30 valve hall fire incidents have occurred due to the failures of various aging valve components, resulting in VG outages ranging from 6 hours to 4 weeks (see Section 3.1.8). Two of the fire incidents even caused partial destruction of the associated valve towers (see Section 3.1.1). The risks of fires associated with various components are identified in Section 3.1.8, which are expected to increase as the aging of valve components continues.
    - Most of the valve components such as SAB cards (i.e. thyristor electronics), fiber optic light guides in VG31 and VG41, reactor modules, BBC and AEG thyristors, etc. have severely deteriorated and are facing an increasing risk of EOL failures (see Section 3.1).

- There is a lack of spares for all types of valve components except for fiber optic light guides, thyristors and cooling circuit components.
- The VBE test equipment has severely deteriorated. If the test equipment at either end fails beyond repair or become unrepairable due to lack of spare parts or staff expertise, it will be difficult to maintain any of the 4 VGs (see Section 3.2.2).

- 27 year old Alstom thyristor valves and VG controls in P1:
  - There is a lack of spares for some types of critical valve components such as saturable reactors (see Section 4.1).
  - The analog-digital controls have passed the end of their expected lifetime of 25 years, noting that the similar Alstom controls in the McNeil B2B and Haenam-Cheju HVDC schemes were replaced at the age of 25 and 23 years, respectively (see Section 2.2 to 2.4).
  - There is a lack of spare digital components and it is difficult to get new ones due to technical obsolescence (see Section 4.2).
  - The Thermal Analogue (TA) & Firing Control (FC) panel is very difficult to troubleshoot due to lack of accessibility to the digital signals in the panel as well as lack of knowledge, experience and support available, both internally and externally (see Section 4.2.3).
  - The risk of data corruption in the memory chips is a major concern, which is not easy to address (4.2.3).
- 48 year old original analog controls in BP1:
  - The characteristics of the electric/electronic components could drift due to aging, thus resulting in the deteriorating performance or even malfunction of the controls and protection (see Section 5.1).
  - The electric/electronic components will not last forever. They have varying life expectancies. Their EOL failures will result in frequent pole and VG outages. This combined with other factors such as difficulties in troubleshooting, knowledge loss, uncertainties in staffing, etc. would make the controls increasingly difficult to maintain (see Section 5.1).
  - The quality of the original equipment manuals and drawings have significantly deteriorated due to various equipment upgrades over the past few decades (see Section 5.1). Some of the drawings are not even legible (see Appendix C). This has made the associated maintenance and training more difficult.

In view of the ages of the valves and controls in BP1 and BP2 vs. their expected lifetimes as well as their aging conditions and various associated issues, it is concluded that all of them except the 15 year old valves in P2 should be replaced as soon as practically possible.

The technically feasible options for replacing the valves and controls in BP1 and BP2 are identified and discussed in Section 7. Other aging equipment may also need to be replaced along with the valves and controls. The final plan for BP1 and BP2 refurbishment will be proposed in the system planning report.

To delay the replacement of the valves and controls in question entails various risks, some of which are highlighted below:

- EOL of one or multiple VGs in BP2 (see Sections 3.5 and 3.6).
- Loss of one VG in P1 due to lack of spare parts for the valves and controls (see Section 4.3).
- Deterioration of the availability and reliability of BP1 due to the aging analog controls and knowledge loss (see Section 5.1).
- Deterioration of the knowledge base required for maintaining so many types of complex old C&P systems due to various issues as identified in Section 6 and ongoing staffing issues.

It is expected that these risks will be evaluated and addressed in the system planning report.

1. INTRODUCTION

The Nelson River HVDC system has three bipolar schemes/projects: Bipole 1 (BP1), Bipole 2 (BP2) and recently commissioned Bipole 3 (BP3). BP1 consist of Pole 1 (P1) and Pole 2 (P2), and BP2 consists of Pole 3 (P3) and Pole 4 (P4).

BP1 was originally installed as a mercury-arc valve based HVDC scheme. P1 was completed in 1971 and P2 in 1976 [1]. The pole controls were installed for both poles in 1971 [1]. The mercury-arc valves in P1 and P2 were replaced with thyristor valves in 1992/1993 and 2004, respectively. The original HVDC controls are still in service except that the P1 valve group (VG) controls were replaced along with the mercury-arc valves in 1992.

BP2 was installed in two stages. The stage 1 VGs (VG31 and VG41) were commissioned in 1978, and stage 2 VGs (VG32 and VG42) in 1984/1985.[1] The pole controls were installed for both poles in 1978. No major upgrade has been done for the HVDC equipment inside the converter building.

Thus, BP1 and BP2 ended up having three different thyristor valve and control technologies, respectively, as summarized in Table 1.1 and Figures 1.1 and 1.2. Now, all of the thyristor valves and controls in BP2 and the HVDC controls in BP1 have passed the ends of their expected lifetimes (see Section 2 for details). The thyristor valves in P1 are approaching the ends of their 32 year expected lifetime by 2024 (see Section 2). By 2028, all of the valves and controls in BP1 and BP2 except the P2 valves will be 36 to 57 years old.

Table 1.1. Summary of the different types of thyristor valves and controls in BP1 and BP2.

Equipment/technology		Supplier	Year installed	Age	Age in 2028
P1	Thyristor valves (ETT)	Alstom	1992	27	36
	Pole controls (analog)	English Electric	1971	48	57
	VG controls (analog-digital)	Alstom	1992	27	36
P2	Thyristor valves (LTT)	Siemens	2004	15	24
	Pole controls (analog)	English Electric	1971	48	57
	VG controls (analog)	English Electric	Before 1976	> 43	> 52
BP1	Master controls	English Electric	1971	48	57
P3 & P4	Thyristor valves (ETT)	AEG, BBC & Siemens	1978/1984/1985	41/35/34	50/44/43
	Pole controls (analog)	AEG, BBC & Siemens	1978	41	50
	VG controls (analog)	AEG, BBC & Siemens	1978/1984/1985	41/35/34	50/44/43

The previous condition assessment report on the BP2 thyristor valves was prepared in 2009 and issued in January 2010 [2]. That report is now outdated as many things have changed over the past 10 years, including the valve conditions. In addition, no detailed condition assessment has ever been done for the valves and controls in BP1. This warrants a new condition assessment for the valves and controls in both BP1 and BP2.

1 Stage 2 is referred to as Stages 2 and 3 in some related documents because VG42 was commissioned in November 1984 and VG32 in June 1985.

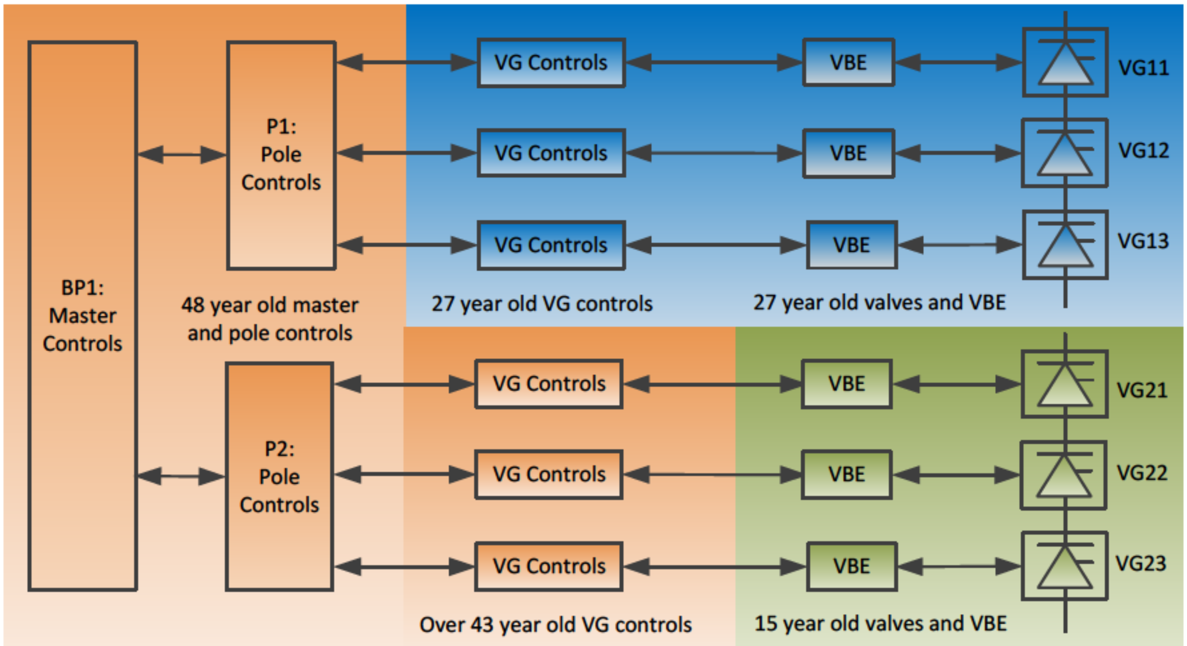


Figure 1.1. Thyristor valve and control technologies in BP1. The VG controls in P2 were built using the same analog technology as the pole controls.

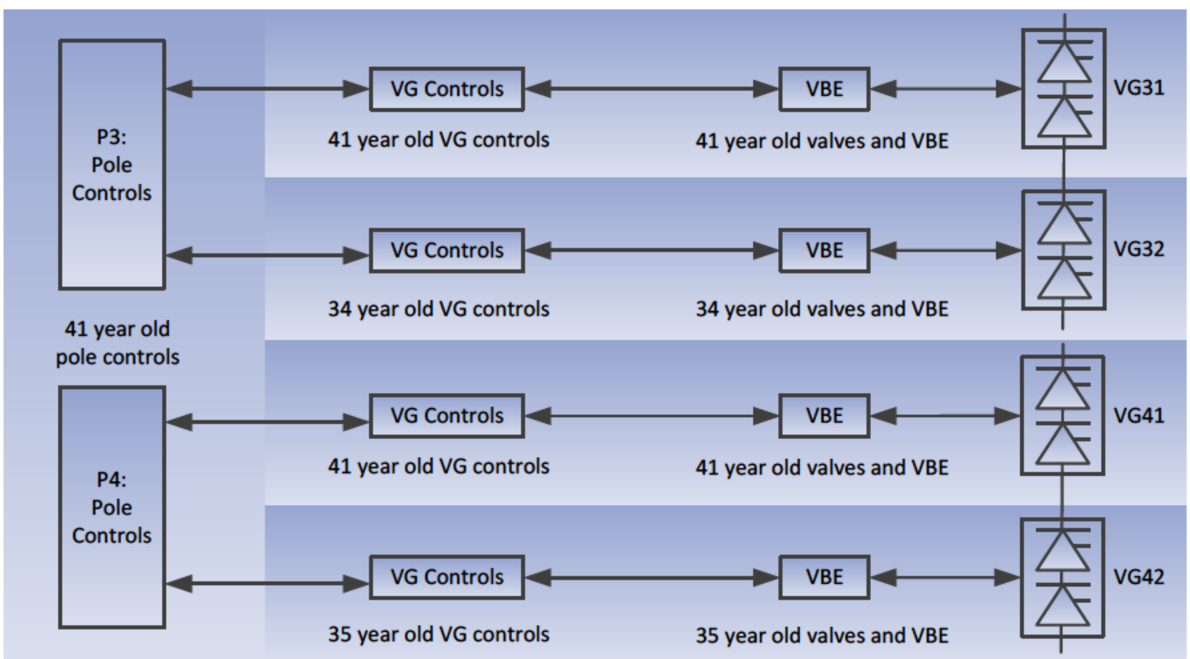


Figure 1.2. Thyristor valve and control technologies in BP2. All the 4 VGs have the same design and are in similar condition although VG42 and VG32 were installed 6 to 7 years later.

The new condition assessment includes the following 4 parts:

- Determining the state of the valves and controls in BP1 and BP2 in terms of age through a review of the ERPI and CIGRE HVDC life extension guidelines [4, 5] and the published information on the upgrades of HVDC systems around the world (see Section 2).

- Assessing the thyristor valves and controls in detail or at the component level whenever practically possible (see Sections 3 to 5).
- Assessing the associated maintenance and training needs (see Section 6).
- Identifying and discussing the technically feasible options for upgrading the valves and controls in BP1 and BP2 (see Section 7).

This condition assessment report will be used as a major reference by System Planning and TAM to develop a long-term capital plan for upgrading/improving BP1 and BP2. This report, unlike the previous one [2], does not involve cost estimation and economic analysis as it will be part of the planning study. In addition, a quantitative risk analysis is expected to be conducted by System Planning.

2. STATE OF THYRISTOR VALVES AND CONTROLS IN BP1 AND BP2 IN TERMS OF AGE

This section is to look at the state of valves and controls in BP1 and BP2 in terms of age, as compared to those in other HVDC projects around the world. The detailed condition assessment for them will be presented in Sections 3 to 6.

2.1. AGES OF THYRISTOR VALVES AND CONTROLS VS. EXPECTED LIFETIMES

The expected lifetimes of valves and controls are presented in Table 2.1, which are taken from the EPRI and CIGRE life extension guidelines of existing HVDC systems [4, 5].

Table 2.1. Expected lifetimes (years) of valves and controls stated in the EPRI and CIGRE life extension guidelines of existing HVDC systems [4, 5].

Component	EPRI [4]	CIGRE [5]
Thyristor valves	30	35
Analog controls	25	35*
Digital controls	15	12* to 15

Note: *The 12 year expected lifetime of digital controls doesn't seem to be realistic. The 35 year expected lifetime of analog controls appears to be based partly on the MH's experience.*

The ages of valves and controls in BP1 and BP2 are compared with their expected lifetimes in Table 2.2. It is seen that all the valves and controls in BP2 and the original analog controls in BP1 have passed the ends of their expected lifetimes. The thyristor valves in P1 are approaching the end of their expected lifetime.

The VG controls in P1 are analog systems built using a huge number of digital (i.e. programmable) components. Such analog-digital systems should have a shorter lifetime than the purely analog system as in P2 and BP2, which will be explored in Sections 2.2 and 2.3.

Table 2.2. Comparison of the ages of valves and controls in BP1 and BP2 with their expected lifetimes.

Equipment	Age	Expected lifetime	
		EPRI [4]	CIGRE [5]
P1 VG controls (analog-digital)	27	Not available	Not available
BP1 pole controls (analog)	48	25	35
P2 VG controls (analog)	> 43		
BP2 pole controls (analog)	41		
BP2 VG controls (analog)	41/35/34		
P1 thyristor valves	27	30	35
P2 thyristor valves	15		
BP2 thyristor valves	41/35/34		

2.2. UPGRADE HISTORY OF HVDC PROJECTS AROUND THE WORLD

We have recently reviewed the published information about the upgrades of HVDC projects commissioned during 1970 to 1995 in the world. The findings are summarized in Table 2.3.

Table 2.3. The upgrade histories of HVDC projects (>100MW) installed during 1970 to 1995 throughout the world, not including BP1 and BP2.

Scheme	Capacity (MW)	Year com-missioned	Year of upgrade	Supplier	Lifetime of C&P	Lifetime of valves	Age of C&P in service	Age of valves in service	Note
C.U.	1000	1979	2004/2019	ABB	25	40			
Cahora Bassa (at Apollo)	1920	1977-1979	2008	ABB	31	31			(1)
Cahora Bassa (at Songo)	1920	1977-1979	1995/2021	ABB	45	45			
Coal Creak	1172	1978	2019		41	41			
Chateauguay	1000	1984	2009	ABB	25			35	
Cross Channel BP1&2	2000	1986	2011-2012	Alstom	26	26			
Gezhouba-Shanghai	1200	1989-1990					30	30	
Quebec – New England	2250	1991	2016	ABB	25			28	
Intermountain	1920	1986	2010	ABB	24			33	
Itaipu 1	3150	1984					35	35	
Itaipu 2	3150	1987					32	32	
Pacific Intertie - Celilo	400	1984	2016	ABB	34	34			(2)
	1100	1989	2016	ABB	29	29			
	1440	2004	2016	ABB	12	12			
Pacific Intertie - Sylmar	400	1984	2004	ABB	20	20			(3)
	1100	1989	2004	ABB	15	15			
	1440		2004	ABB					
Quebec-New England	2000	1990-1992	2016	ABB	26			29	
Rihand-Delhi	1500	1990	2019	ABB	29	29			
Vyborg	1065	1981-1984	2001	ABB	20			38	
Blackwater	200	1985	2009	ABB	24			34	
Baltic Cable	600	1994	2019	ABB	25			25	
Eddy County	200	1983					36	36	
Eel River	320	1972	2014	ABB	**42**	**42**			
Fenno-Skan 1	500	1989	2013	ABB	24			30	
Gotland 2 & 3	260	1983-1987	2018	ABB	35			36	
Highgate	200	1985	2012	ABB	27	27			
Hokkaido-Honshu 1	300	1979-1980					40	40	
Inga-Kolwezi	560	1982	2014	ABB	32	32			
Inter-Island P2	700	1992	2013	ABB	21			27	
Konti-Skan 2	300	1988	2020	ABB	32			31	(4)
Kontek	600	1995	2016	ABB	21			24	
Madawaska	350	1985	2016	ABB	31	31			
McNeill	150	1989	2013	Alstom	24			30	
New Zealand P2	700	1992	2013		21			27	
Oklaunion	220	1985	2014	ABB	29	29			
Sacoi (Mercury)	200	1968	1992	ABB	24				
Sakuma	300	1993					26	26	
Shin-Shinano 2	300	1992					27	27	
Shin-Shinano 1	300	1977	2008	ABB	31	31			
Sileru-Barsoor	400	1989	2014	ABB	25	25			(5)
Skagerrak 1&2	500	1976-1977	2007	ABB	31			43	
Skagerrak 3	500	1993	2014	ABB	21			26	
Square Butte	500	1977	2004	ABB	27			42	
Sakuma (Mercury)	300	1965	1993	ABB	28				
Vancouver Island 2	370	1978					41	41	
Vindhyachal	500	1989	2021	Siemens	32	32			(6)
Virginia	200	1987					32	32	
Welsh	600	1994	2017	Siemens	23			25	

(1) See Section 2.3.1 for more details.
(2) See Section 2.3.3 for more details.
(3) 1440MW mercury-arc valves were upgraded to thyristor valves in 2004, and controls and older thyristor valves were also replaced. The contract for C&P upgrade was awarded in 2018.
(4) Contract for C&P replacement was awarded in 2017, which is assumed to be completed in 2020.
(5) This project was not in use for a long time and decommissioned in 2014 because it became redundant.
(6) Valves and C&P to be upgraded by 2021.

The actual lifetimes of valves and controls that have been replaced or are being replaced are summarized in Tables 2.4 and 2.5, where the Songo and Sylmar converter stations are excluded due to their unique histories. Note that the thyristor valves and controls at the 320MW Eel River

B2B system in Canada, the first thyristor valve scheme commissioned for commercial service [6], were replaced at the age of 42 years.

Table 2.4. Summary of the lifetimes of thyristor valves replaced or being replaced in other HVDC projects.

HVDC projects	Number of projects in which valves have been replaced or are being replaced	Lifetime		
		Minimum	Average	Maximum
44 projects built during 1970 to 1995	15	25	32	42
14 large projects (≥1000MW)	6	26	33	41

Table 2.5. Summary of the lifetimes of HVDC C&P systems replaced or being replaced in other HVDC projects.

HVDC projects	Number of projects in which C&P systems have been replaced or are being replaced	Lifetime		
		Minimum	Average	Maximum
44 projects built during 1970 to 1995	35	20	28	42
14 large projects (≥1000MW)	11	20	27	41
27 projects built before 1989	21	20	29	42
17 projects built during 1989-1995	14	21	25	32

From Tables 2.2 to 2.5, the following observations can be made:

- The thyristor valves in 15 of the 44 projects have been replaced or are being replaced at the average age of 32 years.
- The C&P systems in 21 of the 27 projects installed before 1989 have been replaced or are being replaced at the average age of 29 years, which are representative of the analog controls in P2 and BP2.
- The C&P systems in 14 of the 17 projects installed during 1989 to 1995 have been replaced or are being replaced at the average age of 25 years, which are representative of the analog-digital VG controls in P1. The C&P systems in 11 of the 14 projects were replaced after 21 to 26 years of service.
- In only 3 of the 14 large projects (≥1000MW), the thyristor valves and controls have never been or not being upgraded, which are the Itaipu 1, Itaipu 2 and Gezhouba-Shanghai HVDC projects that are 30 to 35 years old, 6 to 11 years newer than BP2.
- There are two other projects (i.e. Hokkaido-Honshu Pole 1 and Vancouver Island Pole 2) that have a similar age as BP2 and still retain their original valves and controls, but they are much smaller in capacity.

Regarding BP1 and BP2 specifically, we can make the following observations:

- Among the oldest large HVDC projects (≥1000MW), BP2 is the only one where both thyristor valves and controls have never been replaced.
- The 48 year old analog controls in BP1 are the oldest in the world.

In the 2019 Long Term Transmission Plan , the BP2 thyristor valves and controls were scheduled to be replaced by October 2026, i.e. at the age of 48 years. This project is identified but the dollars are currently uncommitted.

2.3. COMPARISON OF BP1 AND BP2 WITH SIMILAR HVDC SCHEMES

For the purpose of comparison, this section presents three HVDC projects that similar to BP2, P1 VGs, and BP1&BP2.

2.3.1. BP2 vs. Cahora Bassa HVDC scheme

The Cahora Bassa HVDC scheme is similar to our BP2. It was first commissioned in 1977 by the same working group (AEG, BBC & Siemens) as BP2. It is rated at 1920MW/±533kV, transmitting power from the Songo converter station in Cahora Bassa, Mozambique to the Apollo converter station near Johannesburg, South Africa through 1400km DC lines. The major difference is that the thyristor valves in the Cahora Bassa project are oil-cooled, whereas those in BP2 are water-cooled. The Cahora Bassa project was put into service a year before BP2, but it has experienced many major upgrades. The Songo and Apollo converter stations of the HVDC system are owned by Hidroelectrica de Cahora Bassa and Eskom, respectively.

At the Songo converter station, the original DC controls (not HVDC controls) as described in Section 3.4 were completely replaced with PLCs during 1992 to 1994.

The valves and controls at the Songo converter station are 42 years old, one year older than those in BP2. The Cahora Bassa system, however, was taken out of service for 12 years (during 1985 to 1997) due to the civil war in that region, and therefore the remaining useful life of the valves at the Songo station should be approximately 11 years longer than the BP2 valves. A green-field project for replacing the Songo converter station with a new one is currently underway.

It is worthwhile to mention that it has been very difficult to retain qualified engineers to learn the old HVDC controls at the Songo station. The unexpected loss of the most knowledgeable plant engineer a few years ago has made the control maintenance and associated training more difficult. As a result, the Songo station has to seek external help through Manitoba Hydro International.

The Apollo converter station was refurbished by ABB in 2008, after 31 years in operation [7]. The refurbishment includes thyristor valves, HVDC controls, AC filters, and all other essential equipment of the system. Why was the Apollo station refurbished 12 to 14 years earlier than the Songo station? Loss of skills and knowledge was one of the main drivers [7].

In contrast, no major upgrade has ever been done for the BP2 HVDC equipment inside the converter building.

2.3.2. P1 valve group vs. McNeil back-to-back HVDC system

The VG controls in P1 were installed by Alstom in 1992. They were analog based but built with approximately 3000 digital (or programmable) components (e.g. UV EPROMs, EPLDs, microprocessors, etc.). Such analog-digital controls are prone to technical obsolescence as digital controls.

The expected lifetime of digital HVDC controls is typically 15 years according to the EPRI and CIGRE HVDC life extension guidelines (see Table 2.1). Apparently, the lifetime of the analog-digital VG controls in P1 is much longer than that of the purely digital controls. So we have to look at the HVDC projects of similar vintages. There are 17 HVDC projects installed around 1992/1993, i.e. during 1989 to 1995. Fourteen (14) of them were refurbished with new controls at the average age of 25 years and 11 of the 14 projects were refurbished at the age of 21 to 26 years.

Among these 17 projects, the McNeill B2B system is of particular interest since it was built by Alstom in 1989 using a similar control technology as in the P1 VGs. The HVDC controls of this project were replaced after 25 years in service, although they had been very reliable based on a report shared with MH [26]. Below are the main drivers for the replacement:

- Troubleshooting was difficult and time-consuming.
- It was difficult to acquire spare parts as about 20% of the IC components were obsolete.
- Maintaining the control system may become impossible due to diminishing external knowledge and support combined with difficulty finding spare parts.

It has just been learned that the valves and controls in the Haenam-Cheju HVDC project (300MW, ±189kV) installed by Alstom in 1996 using the same technology as in P1 were upgraded early this year, i.e. at the age of only 23 years.

The above facts suggest that the expected lifetime of analog-digital VG controls is 25 years. There is no evidence that would lead us to believe that such analog-digital HVDC controls can survive many years longer than those at McNeill and other retired HVDC controls of similar vintages.

Due to the various issues identified in Section 4.2, there is a good possibility that we would have to shut down one VG permanently due to lack of spare parts.

Another major concern about the P1 VG controls is the possible data corruption in the memory chips (e.g. UV EPROMs). If the memory chips start to lose data and cannot be reprogrammed and tested properly, which is possible as discussed in Section 4.2.3, it would be very difficult, if not impossible, to operate any of the P1 valve groups. It is noted that the risk of data corruption was not identified for the McNeil HVDC controls and actually it should not be a concern at McNeil as the controls were replaced at the age of 25 years.

Therefore, to push the VG controls in P1 well beyond their 25 year expected lifetime will force us to deal with a lot of unknowns, which would consequently expose the corporation to extended outages to parts of the HVDC system.

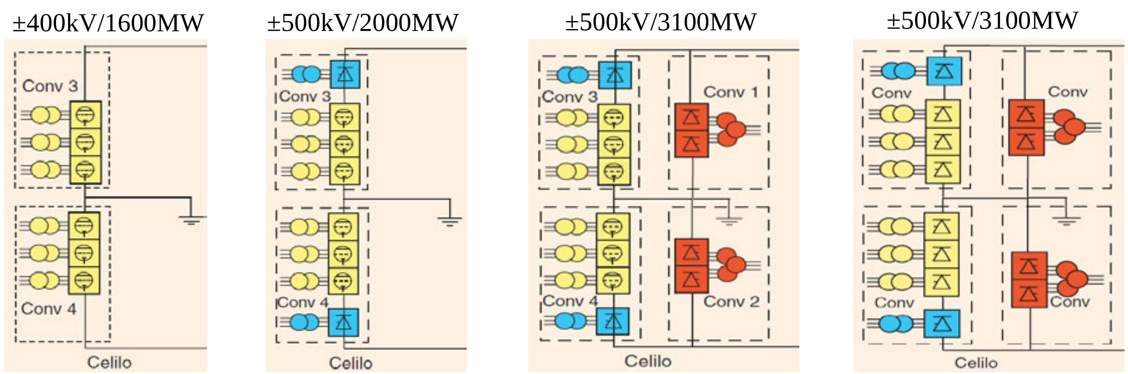
2.3.3. Nelson River HVDC system vs. Pacific HVDC Intertie

The Pacific HVDC Intertie (PDCI) mercury-arc valve scheme was put into service in 1970. Its original rating was ±400kV/1800A/1440MW and raised to 2000A/1600MW a few years later. The northern converter station of the PDCI is located at Celilo, The Dalles, Oregon, and the southern one at Sylmar, California. The Celilo station is owned by the Federal Authorities, Bonneville Power Administration (BPA), whereas the Sylmar station is owned by different entities.

The PDCI has undergone a number of major upgrades since 1970 [29, 30]. Figure 2.1 shows the evolution of the PDCI at Celilo up to 2004 [29]. After the 2004 valve replacement, the Celilo station became very complicated, as complicated as BP1 and BP2 combined. It consisted of three different thyristor valve and control technologies, respectively, which were of similar vintages as those in BP1 and BP2. One of them is the original ASEA C&P system, which was built using the same generation of control technology as the one in our BP1.

A feasibility study was conducted in 2009, where two alternatives were compared [30]. One is to retain the existing converter architecture and replace the obsolete/aging equipment to extend the life of the station. The other is to replace all the existing converters with a typical bipolar scheme to simplify the station, thus making its operation and maintenance much easier. This alternative also afforded BPA a good opportunity to increase the capacity of the station. In 2011, the BPA executive management approved the complete replacement alternative [30]. In 2012, ABB was awarded the contract to make a complete upgrade of the Celilo station. Part of the existing infrastructure (i.e. valve halls built in 1989 and part of the switchyard) was reused. The project was completed by 2016. All the 6 Siemens thyristor converters (i.e. VGs) installed in 2004, as shown in Figure 2.1(d), were decommissioned at the age of only 12 years.

The Celilo upgrade project spanned 7 years from planning to completion.



(a) As of 1977. ***(b)*** As of 1985. ***(c)*** As of 1989. ***(d)*** As of 2004.

Figure 2.1. History of PDCI upgrades [29]: (a) the capacity was raised to 1600MW in 1977; (b) upgraded to ±500kV/2000MW by 1985; (c) upgraded to ±500kV/3100MW by 1989; (d) the mercury-arc valves were replaced with thyristor valves, but the existing controls were not.

In early December 2018, we visited the Celilo converter station with intent to purchase the retired Siemens thyristor valves that can be used to extend the life of our P2 thyristor valves installed by Siemens in the same year (i.e. 2004). That gave us an opportunity to learn more about the Celilo station. The situation at Celilo prior to 2016 is briefly described below:

- Like Manitoba Hydro, BPA/Celilo used to have a very knowledgeable HVDC workforce. For that reason, modifications and additions were made multiple times to the analog HVDC controls, mostly done in house, in order to accommodate the upgrades shown in Figure 2.1. This is similar to what has been done at the BP1 converter stations.
- The Celilo station is located on the top of a hill overlooking Columbia River, less than 10km to the city center of The Dalles – a very beautiful place to work and live. In spite of that, BPA/Celilo still had difficulty recruiting and retaining younger engineers to work on the old/obsolete HVDC controls.

- As of 2018, the Celilo station had only three plant engineers: one extremely knowledgeable senior plant engineer and two younger ones having a few years of experience at the station.

The above described situation is a main driver for the BPA's decision to modernize and simplify the complex Celilo station.

BPA got a 4 year warranty on the new HVDC project. This combined with a few years of involvement with the design, installation and commissioning of the project will allow BPA/Celilo to develop sufficient staff expertise to maintain the station.

The Celilo's past situation is similar to the present situation at the BP1/BP2 converter stations. Actually, the diminishing staff expertise for the old generation of HVDC technologies is not unique to BPA and MH. It is a common factor that drives the refurbishment/replacement of the old HVDC stations throughout the world.

2.4. SUMMARY

The lifetimes of thyristor valves and controls, as found from the EPRI and CIGRE HVDC life extension guides [4, 5] and the upgrade histories of HVDC projects installed during 1970 and 1995 throughout the world, are summarized in Table 2.6.

Table 2.6. Summary of the lifetimes (in years) of valves and controls.

Component	Actual lifetime (years)		Lifetime (years) assigned by EPRI/CIGRE	Applicable to
	Average	Range		
Thyristor valves	32	25 to 42	30/35	All thyristor valves
HVDC controls installed before 1989	29	20 to 42	25/35	HVDC controls in P2 and BP2
HVDC controls installed during 1989 to 1995	25	21 to 32		VG controls in P1

These numbers should be respected when developing the refurbishment plan(s) for BP1 and BP2 because behind them lie the knowledge and experience of all other HVDC owners and experts throughout the world.

The Cahora Bassa HVDC system was commissioned in 1977 to 1979, which is similar to our BP2. Both of them were installed by the same working group (i.e. AEG, BBC & Siemens) using the same control technology. The thyristor valves and controls in the Cahora Bassa HVDC system at the Apollo converter station were replaced in 2008 at the age of 31 years, and replacement of all equipment at the Songo converter station, as a green-field project, is currently underway.

The valves and controls in the McNeill HVDC system and the VG controls in P1 were installed by Alstom in 1989 and 1992, respectively, using similar valve and control technologies. The HVDC controls in the McNeill system were replaced in 2014 at the age of 25 years, although they had been very reliable [26]. In addition, the valves and controls in the Haenam-Cheju

HVDC project (300MW, ±189kV) installed by Alstom in 1996 using the same technology as in P1 were upgraded at the age of only 23 years.

The Pacific HVDC Intertie (PDCI) is one of the earliest mercury-arc valve schemes, commissioned one year earlier than our BP1. The PDCI has undergone a number of major upgrades since commissioning, which had made it as complicated as BP1 and BP2 combined. Until not long ago, the PDCI had three different control technologies of similar vintages as those in BP1 and BP2. One of them is the original C&P system built in the late 1960's, similar to the one in our BP1. The PDCI at the Celilo converter station was completely replaced with a two converter bipolar scheme by 2016 in order to simplify the station and make its operation and maintenance easier. The situation at Celilo in the past is what we are currently facing – super complex HVDC controls vs. the declining workforce.

Based on the above, it can be concluded that the 41 year old valves and analog controls in BP2, 48 year old analog controls in P2, and 27 year old analog-digital VG controls in P1 have long passed the ends of their expected lifetimes. To further push such old equipment will force ourselves to deal with various issues and risks, known or unknown, that other utilities or HVDC owners may have never experienced.

3. BP2 THYRISTOR VALVES AND CONTROLS

BP2 is rated at 2000MW/±500kV. It was built by an HVDC Working Group formed by AEG, BBC and Siemens in two stages. The stage 1 VGs (VG31 & VG41) were completed in 1978, and stage 2 VGs (VG32 & VG42) during 1984 to 1985. This system is among the earliest thyristor-based HVDC schemes in the world.

The BP2 converter equipment has experienced various issues/problems since 1993. This section presents the issues identified in the related technical memo and report issued 9 years ago [2, 8], and those identified recently.

3.1. THYRISTOR VALVES

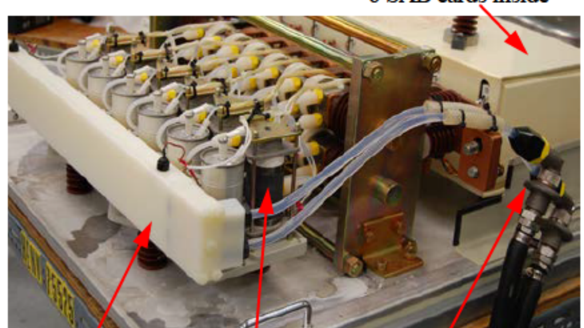
The BP2 thyristor valves had been almost trouble free for the first 15 years in service. Since 1993, they have experienced numerous aging related component failures, resulting in many forced VG outages and deferred outages required to repair/refurbish the aging components such as valve cooling components and SAB cards (i.e. thyristor electronics).

3.1.1. De-ionized water leak problems

De-Ionized Water (DIW) was used as a cooling medium in the valve cooling circuits. What needs to be cooled by DIW includes reactor and thyristor modules. Each of them can be easily connected to or disconnected from the main tower cooling pipes through quick couplers as shown in Figure 3.1(b). Each quick coupler has a 12/10mm plastic connector.

In the thyristor modules, two types of components are water-cooled, which are thyristors and grading (or snubber) resistors (see Figure 3.1). DIW is distributed to the grading resistor and thyristor at each thyristor level through a manifold header. The thyristor modules in each VG have more than 4600 plastic tubes and 9200 plastic connectors. The existence of so many components in the cooling circuits makes the BP2 thyristor valves inherently prone to water leaks.

(a) Stage 1 thyristor module



(b) Stage 2 thyristor module

Figure 3.1. Cooling components in a thyristor module.

Tubing refurbishment

In 1993, the DIW tubing, which includes all plastic/rubber parts (tubes, connectors, O-rings, etc.), started to fail, resulting in a significant number of forced outages. Replacement of all tubing components except for the thyristor module manifolds took place after the mid-nineties. Most of the tubing replacement work was carried out over the period of 1997 to 2001.

As shown in [2], over the course of the tubing refurbishment, the forced VG outages had decreased gradually. However, shortly after most of the tubing refurbishment was completed in 2001, the forced VG outages started to increase quickly at an exponential rate over the following years. One of the major contributing factors was still the tubing failures leading to DIW leaks.

Thus, the second round of tubing refurbishment had to be conducted, which started in 2009 (see "BP2 Thyristor Cooling Refurbishment" in CEF08-1). The refurbishment covered all thyristor module tubing components, including the manifold headers that were not replaced in the first round of tubing refurbishment. In addition, other tubing components (e.g. 12/10mm connectors) started to fail and had to be replaced.

The second valve tubing refurbishment program, like the first one, had to be spread over several years considering system operating restrictions, staff availability and other scheduled work.

Flashover/fire caused by DIW leak

In addition to numerous forced outages, DIW leaks also caused two catastrophic flashover incidents. The first incident occurred on January 14, 2009. A DIW leak due to a broken 12/10mm plastic connector (see Figure 3.2) caused a flashover in a valve tower in VG42 at Henday and blew up a light-guide channel and damaged the fiber optic light guides inside (see Figure 3.3). Fortunately, the flashover did not cause fire and smoke damage. Discoloration of the connector is an obvious sign of ageing as shown in Figure 3.2. The second incident occurred in VG32 at Henday on December 04, 2011 also due to a 12/10mm connector failure, but its consequence was much more severe as shown in Figure 3.4 (see [9] for more details). The resulting fire/arc burnt half of a light guide channel and 50% of the light guides inside. The thyristor pairs in three modules were short-circuited. The resulting smoke and debris did not only severely contaminate the valve tower where the flashover took place, but also contaminated other valve hall components. It took 13 days to clean and repair the damaged/contaminated valves. We barely managed to repair the damaged light guide channel with deviations from the original installation due to a shortage of spare parts and materials.

The damage in these two incidents could be much worse. In the Itaipu HVDC system for example, an entire quadrivalve was destroyed by fire. The affected VG was forced out of service for 14 months. It has to be pointed out that the fire incident occurred shortly after the project was commissioned and all the support was available from the supplier. If such an incident happens to our BP2 valves, the affected VG will be out of service permanently for a couple of reasons. First, repair will not be possible due to the lack of spare/replacement parts and support from the supplier. Second, it is impractical to just replace one VG given the age of all BP2 equipment.

Figure 3.2. Broken 12/10 mm double-sided plastic connector as a result of aging.

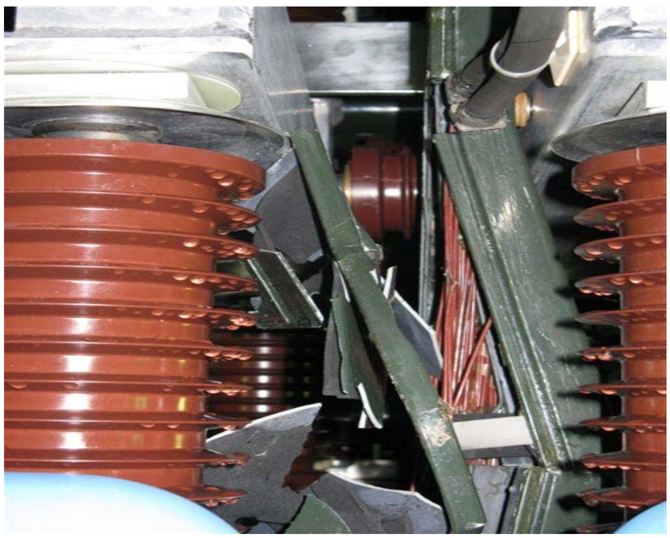


Figure 3.3. Damage caused by flashover due to a water leak in VG42 at Henday on January 14, 2009.

Figure 3.4. Damage caused by flashover due to a water leak in VG32 at Henday on December 04, 2011.

Lifetime of tubing components

The valve tubing refurbishment history indicates that the average lifetime of tubing in BP2 is approximately 15 years. Some of the tubing components installed during the second round of tubing refurbishment have reached or are approaching the ends of their expected lifetimes. The frequency of forced VG outages due to DIW leaks are expected to increase. Whether another round of tubing refurbishment is required depends on how long we plan to keep the existing valves in service. The 12/10mm plastic connectors are less than 10 years old. A random sample of them have been inspected recently and no sign of aging has been observed.

Summary

The BP2 valves are inherently prone to water leaks due to the existence of a huge number of plastic/rubber tubing components such as tubes, connectors, seals and O-rings. The failures of tubing components have not only caused numerous forced outages, but also flashover/fire that has the potential to destroy an entire valve tower or valve hall. Some of the tubing components installed during the second round of cooling refurbishment have reached or are approaching the ends of their expected lifetimes. Whether another round of tubing refurbishment is required depends on how long we plan to keep the existing valves in service.

3.1.2. SAB card failures

There are a total of 1536 thyristor modules in service in BP2. Each module consists of 6 parallel-connected thyristor pairs. Each thyristor pair functions as a single thyristor. The gate electronics unit for each thyristor pair is called SAB card, which includes three components: power supply board (S-card), logic board (A-card) and light transmitter & receiver (B-card) (see Figure 3.5). Totally, there are 9216 SAB cards in service in BP2.

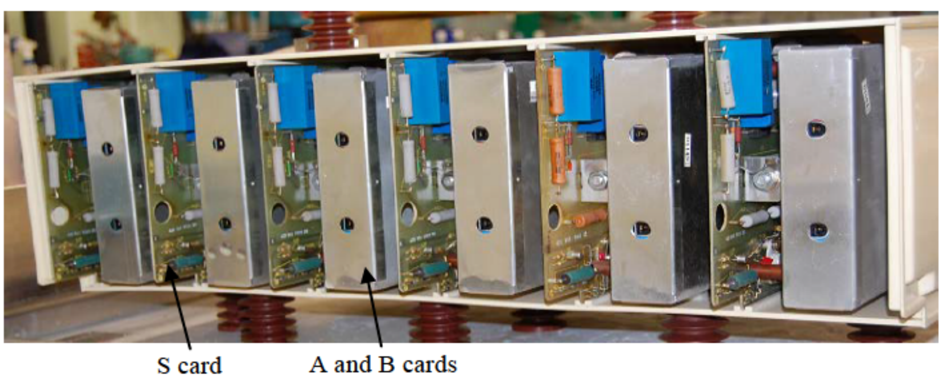


Figure 3.5. Six SAB cards in a thyristor module.

Fire incidents due to SAB card failures

Starting from 1998, fire incidents frequently occurred in the valve hall as a result of SAB card failures. At least 23 fire incidents have happened over the past two decades. Some of the burnt cards are shown in Figures 3.6 and 3.7. In the initial incidents, fires always started in close proximity of the power inputs of S-cards.

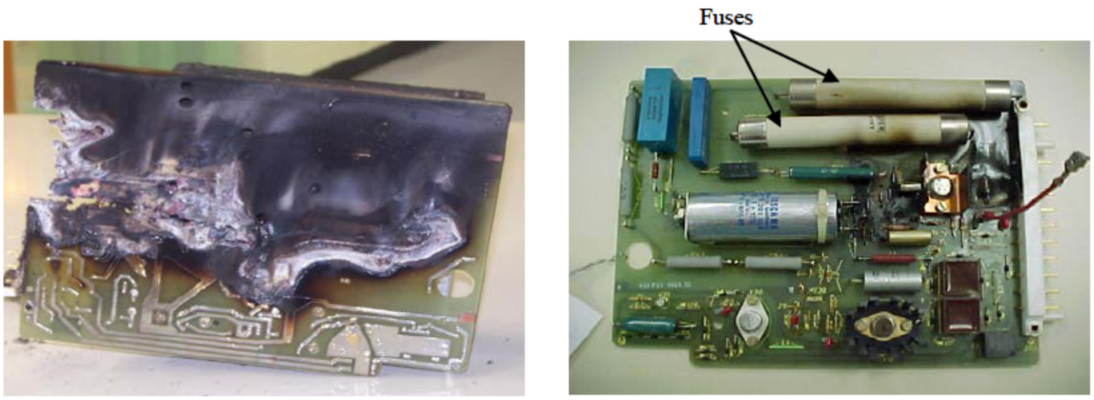


Figure 3.6. S-cards damaged by fires.

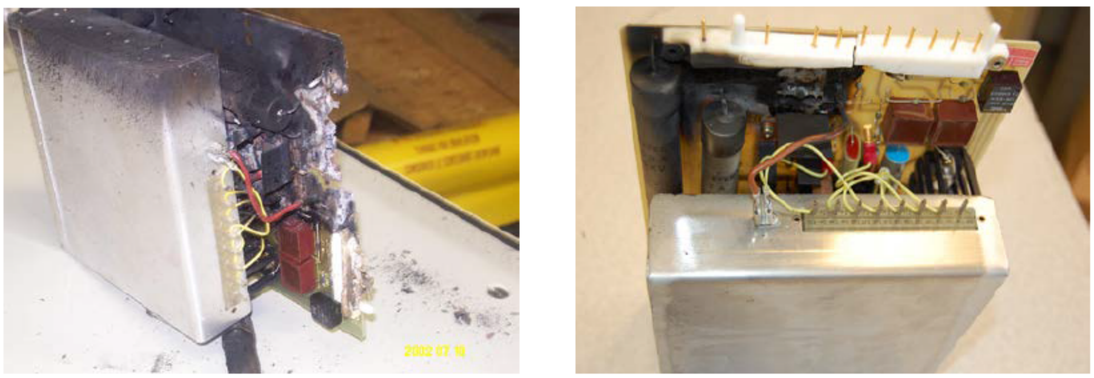


Figure 3.7. SAB cards damaged by fires.

A detailed investigation was carried out with the supplier's help. It was determined that the root cause of the fires was solder joint failure due to aging and vibration. Over the next 4 years, the joints near the power inputs of all S-cards were re-soldered (see A1 in Figure 3.8). Each VG had to be taken out of service for 2 weeks to complete the re-soldering work.

Figure 3.9 shows 11 burnt S-cards at Henday. Fires started in area A1 on cards 1 to 6, areas A1 and A2 on cards 7 to 10, and area A2 on card 11. Re-soldering has reduced S-card failures, but not eliminated them. On cards 5 to 7 for example, fires also started in area A1 where re-soldering had been done before.

Now the majority of the Printed Circuit Boards (PCB) of S-cards in service have shown a varying degree of discoloration (see Figure 3.8) resulting from some overheated solder joints.

Recently, during SAB card repairs, it was found that an increasing number of SAB card faults have been caused by blown capacitors in A-cards.

As the SAB cards continue to deteriorate, the rate of SAB card failures and resultant risk of fires are expected to increase (see Section 3.1.8).

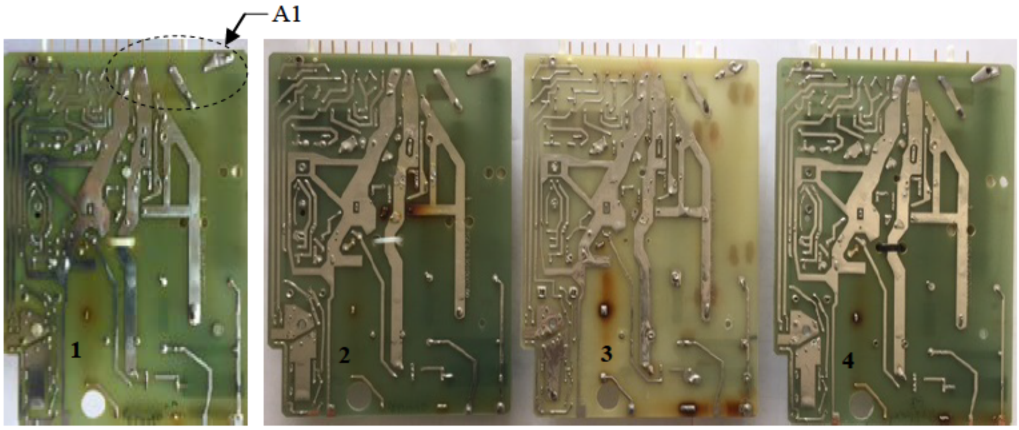


Figure 3.8. Aging S-cards. Card 1 is functioning. Cards 2 to 4 failed beyond repair.

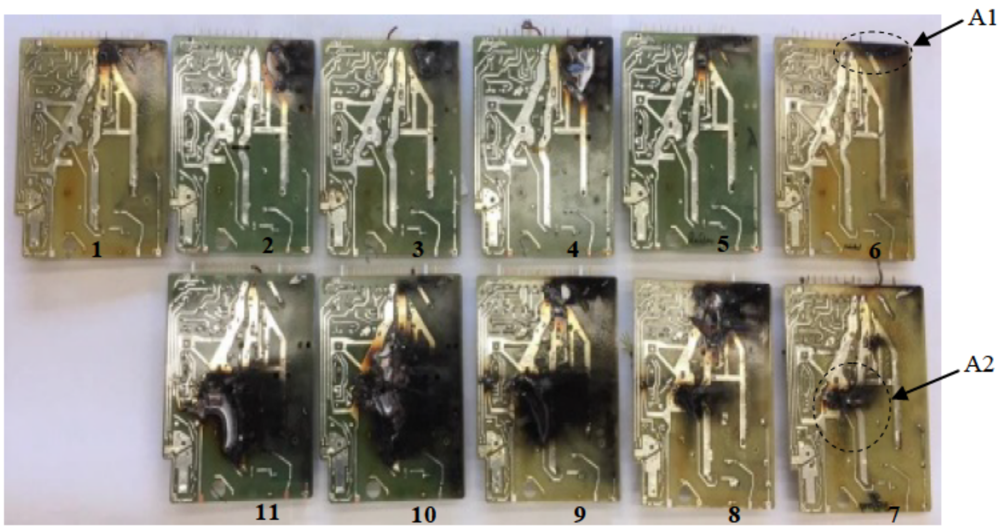


Figure 3.9. Burnt S-cards at Henday. Fires started in area A1 on cards 1 to 6, areas A1 and A2 on cards 7 to 10, and area A2 on card 11. S-cards were re-soldered only in area A1. Fires occurred on cards 5 to 7 that had been re-soldered.

Concerns on spare parts for SAB card repairs

There has been a shortage of some types of spare parts for SAB card repairs because they were custom designed for this particular equipment and can no longer be obtained from any sources including the original suppliers. Sometimes, spare parts have to be obtained from the cards that have failed beyond repair.

Currently, there are a total of approximately 470 spare SAB cards at the two stations, including those in the 32 spare thyristor modules and those waiting for repair in the shops. There seems to be no immediate concern about the shortage of SAB cards, but the situation could change anytime. The SAB cards are located at the thyristor level and being continuously subjected to abusive operating condition such as heat and vibration. They are not expected to last as long as the electronics in a typical control system environment. Thus, there is a good possibility that the failures of SAB cards would start to happen at a rapidly increasing rate due to aging. Should that happen, the spare SAB cards would be used up quickly.

Summary

There should be no concern about the availability of spare SAB cards if one VG is permanently shut down. However, the SAB cards that are in severely deteriorated state would not be reliable spares. Deterioration of the SAB cards will continue and could also accelerate. Thus, the risk of valve hall fires due to S-card failures could increase.

3.1.3. Aging fiber optic light guides and associated channels

There are more than 21000 glass-fibre Light Guides (LG) in the BP2 valve groups, which are placed in four LG channels (cable trays) in each valve tower (quadrivalve). These light guides are used to transmit firing and monitoring signals between the Valve Base Electronics (VBE) and thyristor levels. All the light guides and LG channels are original.

Conditions of light guides and LG channels as of 2009

In January and May of 2009, some of the LG channels in the BP2 valve groups were inspected at Dorsey and Henday. The inspection results are presented in Report HVDC 09-14E [14]. The inspection results at Dorsey were also sent to Siemens for assessment [15].

It was found that the light guides in the 250kV valve groups (VG31 & VG41) had deteriorated to such a degree that their insulation jackets had cracked and broken off, leaving numerous sections of glass-fibre without protection as shown in Figures 3.10(a) and (b). The associated LG channels have also severely deteriorated and suffered varying degrees of damage due to partial discharge and electrical tracking activities as shown in Figure 3.11. It seems that the damage had been done quite some time prior to 2009.

During the repair of the damage in the two flashover incidents described in Section 3.1.1, it was found that the light guides in the stage 2 VGs (VG32 and VG42) were in much better condition (see Figure 3.3). Their insulation jackets appear to be made from different material. The light guides in VG32 were inspected at Henday in 2009 and they all appeared to be in good condition at that time [14]. The light guides in two LG channels of VG42 were recently inspected at Dorsey and Henday, respectively. They appear to be in decent condition (see Figure 3.12).

Figure 3.10(a). Severely deteriorated LG insulation jackets at Henday.

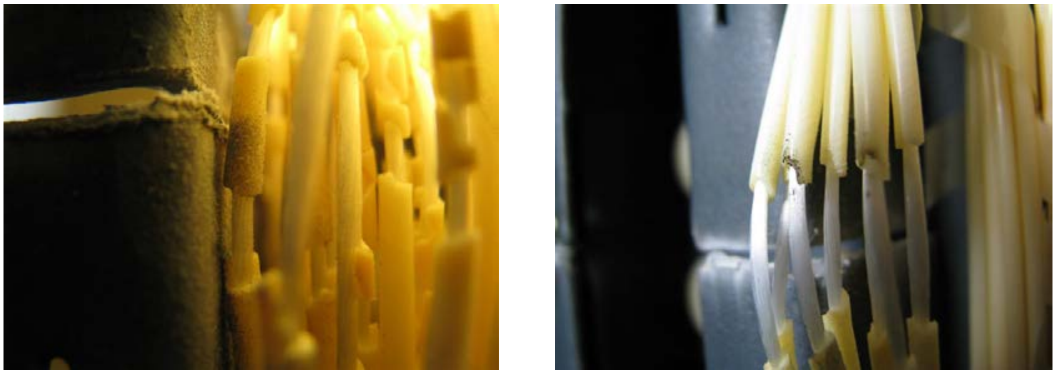


Figure 3.10(b). Severely deteriorated LG insulation jacket at Dorsey.

Figure 3.11. Damages caused by electrical tracking and partial discharge activities inside the LG channel.

Figure 3.12. Light guides in VG42 as of May 2019.

Shortage of parts and materials for LG channels as of 2009

There was a shortage of spare parts and materials for LG channels as of 2009. The valve technicians at Henday and Dorsey had checked the available parts and materials in the stores for

LG channels and found that there were not enough spare parts available to replace even one LG channel [9].

The LG channels were designed with special requirements for use in the high voltage environment and cannot be replaced simply with common plastic cable trays.

Current status of spare light guides and LG channels

Eight years ago, HVDC Engineering (now part of TAM) started to look for the original supplier of the LG channels. With the help of Siemens, HVDC Engineering was able to get the replacement light guide cables and channel parts sufficient for one 250kV tower and one 500kV tower. If one of the stage 1 VGs (i.e. VG31 and VG41) is shut down permanently, its light guides cannot be used as spares for other VGs, but if one of the stage 2 VGs (i.e. VG32 and VG42) retires, its light guides would likely be usable in other VGs.

Risk of fire

The aging light guides and dirty LG channels pose a risk of fire hazards in the valves if moisture or water gets inside according to Siemens [15]. It was reported that, in one HVDC scheme, the degradation of plastic optical fiber protection had led to a few pole outage and later caused a flashover/fire incident that destroyed 24 thyristors [16]. Such an incident had also occurred in a different HVDC project [16].

Therefore, the risk of VG outages or fire due to the deteriorated and dirty light guides as shown in Figures 3.10(a) and (b) cannot be ruled out.

Difficulty in replacing failed light guides in VG31 and VG41

It would be hard to replace a failed light guide in VG31 and VG41 without the risk of damaging others due to their severely deteriorated conditions as shown in Figures 3.10(a) and (b). Once the light guides start to fail, VG31 and VG41 could be forced out of service permanently.

Summary

The spare fiber optic light guides and light guide cannel parts on hand are sufficient for one 250kV tower and one 500kV tower. The existing light guides in the stage 1 VGs will become useless if they are removed from the valves, whereas those removed from the stage 2 VGs would likely be usable as spares for other VGs.

The light guides in the stage 1 VGs (i.e. VG31 and VG41) are in severely deteriorated condition. They have the potential to cause VG outages or flashover/fire. If the light guides fail, they cannot be replaced without the risk of damaging others. In other words, these light guides cannot be touched unless they are all replaced. Therefore, once the light guides start to malfunction/fail, VG31 and VG41 would be forced out of service permanently due to lack of replacement light guides.

3.1.4. Reactor module failures

Each BP2 valve tower has 32 water-cooled reactor modules. There are a total of 768 reactor modules in BP2.

Original reactor modules

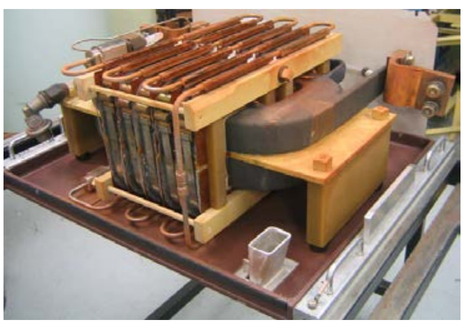
The reactor modules started to show a sign of severe deterioration/aging after 29 years in service. In April 27, 2007, during maintenance, red dust was found on 14 reactor modules at Dorsey as shown in Figure 3.13(a). One of them was disassembled and inspected in the maintenance workshop at Dorsey, which was witnessed by Siemens [17].

Analysis by Siemens led to a conclusion that the red dust mainly consisted of iron particles. It was also concluded that the red dust resulted from the core delamination that could lead to extensive destruction of the iron core layers (see Figure 3.14) [17]. Siemens recommended that such reactors should be replaced.

From Figure 3.13(b), it is seen that the epoxy resin film bonding the iron layers had severely deteriorated. Such a condition was caused not only by thermal aging but also by mechanical aging as the core was continuously subjected to a cyclic mechanic stress resulting from magnetic field. The aging bounding material and cyclic mechanic stress led to the core delamination.

Since all the epoxy resin films have the same lifetime and are subjected to the same operating condition, it is expected that a similar condition would be observed for other reactors if they are disassembled.

The above facts indicate that the reactor modules in BP2 have a lifetime of approximately 30 years and all of them are in the wear-out state.



(a) Reactor module with red dust.

(b) Delaminated core parts.

Figure 3.13. Failed reactor module originally installed.

Visual inspection has been performed this year for all the reactor modules in service. Totally 14 fretting reactor modules were identified during the inspection, 10 at Dorsey and 4 at Henday. All of them have been removed from service except that 4 are waiting to be replaced at Dorsey.

Replacement reactor modules

Concerned about the shortage of spare reactor modules, MH ordered 24 replacement reactor modules from Siemens. They were delivered in 2009 [18].


Figure 3.14. Failure of a replacement reactor module at Henday.

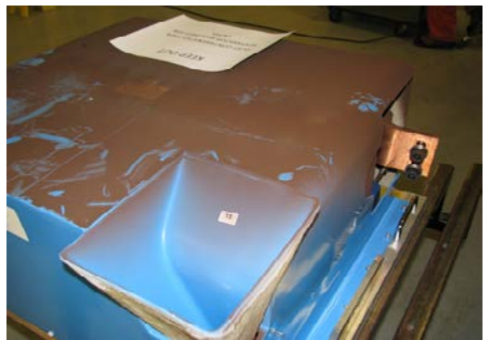



Figure 3.15. Failure of a replacement reactor module at Dorsey.

Twenty three (23) of them were installed in the BP2 valves in 2012, but failed only one year after being put in trial operation. On May 7, 2012, 11 of them were installed in VG31 at Henday. On April 23, 2013, VG31 was tripped on fire detection. It was found that one of them completely failed (see Figure 3.14). Other reactor modules were also starting to show a similar sign of failure. All of them were then removed from service. Twelve (12) replacement reactor modules installed at Dorsey also showed a similar sign of failure. i.e., red/brown dust on the module (see Figure 3.15). Analysis by Siemens indicates that the root cause of the failure was core delamination similar to the failure of the original reactor modules.

In addition, each replacement reactor module has 40 plastic tubing connectors, whereas each original one has only a few. This makes the replacement modules much more prone to water leaks. Water and red dust could lead to flashover.

Twelve (12) of the failed replacement modules were later repaired by Siemens. Four (4) of them were installed at Dorsey two years ago. They have not shown any sign of failure so far.

<u>Risk of running out of spare reactor modules soon</u>

There were 32 original spare reactor modules coming with the valves, 16 for each station. Twenty four (24) replacement modules were purchased from Siemens in 2009, but they failed approximately one year after being put in service. Twelve (12) of the replacement modules were later repaired by Siemens.

A total of 36 reactor modules have failed, including the 14 fretting ones identified this year. All of them have been replaced except that 4 fretting ones are waiting to be replaced.

The spare reactor modules currently in stock are summarized in Table 3.1. After the 4 fretting modules are replaced, there will be only 8 spare modules left. Thus, the spare reactor modules would likely be used up sooner than previously expected.

Table 3.1. Stock of usable spare Reactor Modules (RMs) as of September 2019.

Station(s)	Original spare RMs	Replacement spare RMs	Fretting RMs waiting to be replaced	All spare RMs after fretting one are replaced
Dorsey	0	2	4	-2
Henday	4	6	0	10
Dorsey & Henday	4	8	4	8

Risk of catastrophic fire

The failure of a reactor module can damage the water tubes inside the module or in its close proximity, which can cause a massive water leak leading to catastrophic flashover/fire.

3.1.5. Thyristor leakage problem

There are a total number of 18432 thyristors (or 9216 thyristor pairs) in service in the BP2 valves. The original thyristors were made by three suppliers (i.e. AEG, BBC and Siemens), each providing approximately one third of them. Approximately 470 of them have been replaced with the spare thyristors purchased from Bharat Heavy Electricals Limited (BHEL), an India based thyristor manufacturer.

Now 50% of the original thyristors are 41 years old and the rest of them are 35 years old. Have they reached their expected lifetimes? If yes, what should be done? This section is intended to answer these questions.

Pole 1 thyristor leakage problem

There is no consensus about the lifetime of thyristors. Some suppliers claim 30 years and some claim 50 years. The design of thyristor valves has been based on a long-standing belief that thyristors do not age or deteriorate within the lifetime of the valves [11]. For this reason, periodically checking thyristor conditions had never been part of our thyristor valve maintenance practice until a serious thyristor leakage problem was discovered over the course of investigating a thyristor related problem in two P1 VGs (i.e. VG11 and VG12) [10, 11]. Approximately 70% of the thyristors in these two VGs at Radisson and Dorsey were found to be leaky (i.e. exhibiting increased leakage currents) to various degrees, and all of them were replaced in 2014 after 22 years of service. Apparently, these thyristors had a much short lifetime than what has been claimed by the industry.

The increased thyristor leakage currents were caused by the deteriorated performance of their silicon wafer/passivation dielectric materials due to aging [11]. The existence of a large number of seriously leaky thyristors in each valve in VG11 and VG12 had resulted in an extremely unbalanced voltage distribution in the valve and exposed it to a great risk of cascading thyristor failures that will result in the short-circuiting of all the thyristor levels in the valve and can also cause flashover that could be more destructive. Such valve failure has happened in the Vancouver Island Pole 2 and Gezhouba converter stations [11, 12, 13].

Leaky thyristors in BP2 valves

The thyristor leakage problem has happened in the P1 valves. It could also happen in BP2. For this reason, we started to perform leakage current measurements in August of 2017 at Henday and Dorsey. So far 285 and 159 thyristor modules have been completed at Henday and Dorsey, respectively, which account for approximately 29% of the 1536 thyristor modules in BP2. The reverse and forward leakage currents of thyristor pairs were measured at 400V DC within 10 hours after the associated VGs were blocked.

The major observations from the leakage current readings, which are not temperature-adjusted, are summarized as follows:

- The Siemens and BHEL thyristors are very healthy in terms of leakage currents. The average and median leakage currents of the Siemens thyristor pairs are 0.049mA and 0.04mA, respectively. Their average and median leakage resistances are approximately 8.1MΩ and 10.0MΩ, respectively, more than 36 times higher than the dc grading resistance of 220kΩ (or 0.22MΩ). The BHEL thyristor pairs have similar leakage currents and resistances.
- The majority of AEG and BBC thyristor pairs are leaky such that they have a leakage current above 0.4mA which is approximately 10 times higher than that of the Siemens thyristor pairs (see Table 3.2).
- About 37% to 48% of the BBC thyristor pairs and 45% to 59% of the AEG ones are seriously leaky such that their leakage resistances are below the dc grading resistance of 220kΩ (see Table 3.3).
- The BBC and AEG thyristors, whether installed in 1978 or later, are equally bad in terms of increased leakage currents (see Tables 3.2 and 3.3).

Table 3.4 shows 184 failed thyristors removed from the BP2 valves. It is seen that 84% of them are BBC thyristors. In addition, the repair records of the Henday thyristor modules for the period of 2011 to 2013 show that 21 thyristors failed during emergency firing tests and all of them are BBC thyristors. The above facts clearly suggest that the BBC thyristors are not only leaky, but also have a reduced voltage withstand capability.

Table 3.2. Summary of leaky thyristor pairs with a leakage current larger than 0.4mA.

Type of thyristor	**Henday**			**Dorsey**		
	Thyristor pairs measured	**Leaky thyristor pairs**		**Thyristor pairs measured**	**Leaky thyristor pairs**	
Stage 1 BBC	304	242	79.6%	120	85	70.8%
Stage 2 BBC	209	150	71.8%	168	103	61.3%
Stage 1&2 BBC	513	392	76.4%	288	188	65.3%
Stage 1 AEG	257	171	66.5%	160	135	84.4%
Stage 2 AEG	277	182	65.7%	156	137	87.8%
Stage 1&2 AEG	534	353	66.1%	316	272	86.1%

Table 3.3. Summary of seriously leaky thyristor pairs (i.e. those having a leakage resistance lower than the dc grading resistance of 220kΩ).

Type of thyristor	Henday			Dorsey		
	Thyristor pairs measured	Leaky thyristor pairs		Thyristor pairs measured	Leaky thyristor pairs	
Stage 1 BBC	304	147	48.4%	120	45	37.5%
Stage 2 BBC	209	101	48.3%	168	60	35.7%
Stage 1&2 BBC	513	248	48.3%	288	105	36.5%
Stage 1 AEG	257	124	48.2%	160	87	54.4%
Stage 2 AEG	277	116	41.2%	156	98	62.8%
Stage 1&2 AEG	534	240	44.9%	316	185	58.5%

Table 3.4. A sample of failed thyristors removed from the BP2 valves.*

Type of thyristor	Henday	Dorsey	Radisson & Dorsey	%
BBC	88	56	144	84
AEG	9	1	10	6
Siemens	15	8	23	13
BHEL	6	1	7	4
Total	118	66	184	100

***Note:** *Thyristors always fail to a short-circuit mode. Approximately 470 of the original thyristors have been replaced with the BHEL thyristors.*

The AEG leaky thyristors might have a reduced voltage withstand capability due to aging, which is yet to be found by voltage withstand tests. As the tests are destructive in nature, we will not perform the tests now due to a limited stock of spare thyristors. After the 1150MW loading restriction on BP3 is lifted, we may perform a screening test on each of the BBC and AEG thyristors. All the thyristor with a reduced voltage withstand capability should be removed from service permanently.

Based on the above facts, we can conclude that the BBC and AEG thyristors have reached or passed the ends of their lifetimes, whereas the Siemens thyristors are still healthy.

In order to reduce the risk of valve failure or cascading thyristor failures, we may need to replace the seriously leaky thyristors, especially those having a leakage resistance much smaller than 220kΩ. Note that BHEL can still provide thyristors for BP2 at an acceptable price. How many new thyristors need to be purchased will be determined after more thyristors are assessed and the final plan for upgrading the BP2 valves is approved.

Summary

Approximately 2/3 of the BP2 thyristors are BBC and AEG thyristors. The majority of them have reached or passed the ends of their life expectancies, as evidenced by significantly increased leakage currents. A thyristor valve with a large number of leaky thyristors has unbalanced voltage distribution and reduced voltage withstand capability [11]. In addition, 84% of the failed thyristors (i.e. shorted thyristors) are BBC thyristors, indicating that their voltage withstand capability has reduced significantly due to aging.

In order to restore the valve voltage withstand capability and avoid valve failure, the severely aging/leaky thyristors may need to be replaced as what has been done in the P1 thyristor valves [10, 11]. Note that the replacement thyristors can still be purchased from a thyristor manufacturer in India (i.e. BHEL) at an acceptable price. How many new thyristors need to be purchased will be determined after more thyristors are assessed and the final plan for upgrading the BP2 valves is approved.

3.1.6. Aging grading capacitors and resistors

Each thyristor level has a grading (or snubber) capacitor and resistor. BP2 has a total of 9216 grading capacitors and resistors, respectively. The capacitors are oil filled. The stage 1 and 2 resistors have different designs as shown in Figure 3.1.

Grading capacitors

The failure rate of capacitors is very low. At Henday for example, only one grading capacitor has failed over the past 10 years to our knowledge.

In December 2016, capacitance and electrical leakage measurements were taken at the room temperature for 114 grading capacitors at Dorsey. Below are the findings:

- 9% of them had a capacitance slightly beyond the specified tolerance of ±5%.
- 7% of them exhibited measurable electrical leakage (i.e. between 5 and 85μA).

The grading capacitors are not of concern in the terms of capacitance. The heat generated by the leakage currents is much less than 0.2W, which would unlikely cause any damage to the capacitors. The other effect of the leakage currents, if any, is unknown at this point.

Figure 3.16. Comparison of original and possible replacement grading capacitors.

The failure of an oil filled grading capacitor may result in catastrophic fire. It may be prudent to replace the capacitors exhibiting significant leakage currents. Effort has been made at Dorsey to find compatible replacement capacitors. Shown in Figure 3.16 is one of the possible replacement capacitors recently purchased from Siemens (P.O. 194757). They have a different physical style than the original ones, but can be installed with minor modifications.

Grading resistors

The grading resistors have rarely failed. For instance, only two of them have failed over the past 10 years at Henday to our knowledge.

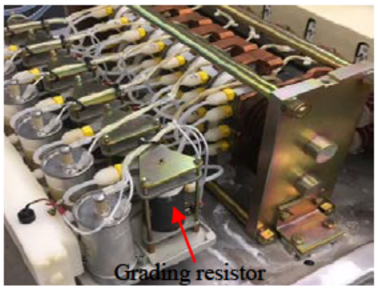


Figure 3.17. Stage 2 grading capacitor and resistor.

The plastic inserts of the stage 2 grading resistors were found to have severely deteriorated as evidenced by discoloration shown in Figure 3.17. The concern is that they would deteriorate to a degree such that they break apart and block the associated DIW cooling circuits, which could cause damage to the associated thyristor module components and even cause fire.

Dorsey has purchased sufficient replacement inserts for all the stage 2 grading resistors at both stations. As a test, 6 grading resistors at Dorsey were refurbished with new inserts and put back in service in 2017. The thermal labels installed on the heatsinks of the grading resistors indicate that the replacement resistor inserts perform as the original ones.

Refurbishment of all the stage 2 grading resistors can be done in conjunction with other work such as thyristor replacement.

Summary

Approximately 7% of the grading capacitors have exhibited measureable leakage currents. The effect of the electrical leakage is unknown at this point, but it may be prudent to replace them. The replacement capacitors that have been found so far have a different physical style, but can be installed with minor modifications.

The plastic inserts of the stage 2 grading resistors need to be replaced, which can be done along with other work such as thyristor replacement.

3.1.7. Compensating capacitor modules

BP2 has 384 compensating capacitor modules at each station, i.e. 32 per valve tower. They are used to ensure even voltage distribution under fast transient conditions. Their capacitances have recently been checked at both ends, and no issue has been identified.

3.1.8. Valve hall fires

Old HVDC thyristor valves contain a large amount of flammable materials and are prone to fires [19]. This section is to provide an overview of the valve hall fire incidents in the HVDC projects around the world, including BP2 and to quickly assess the risk of catastrophic fires in the BP2 valve halls.

Valve hall fire incidents in HVDC projects around the world

According to a survey conducted by CIGRE WG 14.01, over 29 valve hall incidents had occurred before 1994 in the different HVDC projects throughout the world (see CIGRE TB136 [20]). The results of the survey are briefly summarized in Appendix B. The fires were caused by the failures of various valve components (e.g. cooling circuit components, damping/grading resistor & capacitors, thyristor electronics, connections between components, etc.).

Three of these fire incidents destroyed a complete quadrivalve in the Itaipu and Rihand-Delhi HVDC projects [19, 20] and all valves in one valve hall at the Sylmar converter station in the Pacific HVDC Intertie [20, 29]. The affected converter equipment was forced out of service for 14 to 15 months. Another catastrophic fire destroyed a VBE panel in the Chateauguay B2B station. The damage took 4 months to repair. It should be noted that all these four HVDC projects were less than 5 years old when the fire incidents occurred. If a similar fire incident were to happen today, the affected converter equipment would be out of service permanently because no repair could be possible due to lack of spare/replacement parts and support from the original suppliers.

Valve hall fire incidents in BP2 valves

The BP2 thyristor valves, like those in other old HVDC projects, are prone to fire. Since 1993, more than 30 fire incidents have occurred in the BP2 valve halls as shown in Table 3.5. The majority of fire incidents were caused by aging valve components. One of them was catastrophic as shown in Figure 3.4.

Table 3.5. Fire incidents in the BP2 valve halls.

Number of fire incidents	Outage duration	Cause	Year of incident
> 23	< 24 hours	SAB card failures.	1993 to present
1	13 DAYS	Flashover/fire due to a DIW leak caused extensive damage (see Figure 3.4).	2011
1	6 hours	Partial blocking of DIW to a reactor module.	1992
1	< 24 hours	Damping resistor failure. The associated S-card was also burnt.	2008
1	< 24 hours	Disconnected water line (human error).	2012
1	4 weeks	Failure of an oil-filled wall bushing due to flashover led to explosion and fire at Dorsey.	1987
1	< 24 hours	Failure of a replacement reactor module purchased in 2009.	2013
2	< 24 hours	Incorrect connections between reactor modules and compensating capacitor modules (human error)	Nov. 8 & 13, 2005

It was fortunate that those fires were detected in time so that they were unable to spread to the entire quadrivalve (or valve tower) or the oil-filled capacitors. The risk of valve hall fires is expected to increase as the aging of valve components continues.

The above described fire incidents would unlikely happen in the modern thyristor valves because of improved designs that include use of fire-retarding/non-flammable materials, fire barriers, fire-sensing devices, etc. [21].

<u>Risk of catastrophic fires in BP2 valve halls</u>

From Appendix B, it is known that loose connections and various component failures can cause valve hall fires. Each of the fire incidents will cause a forced VG outage, and some of them have the potential to destroy a valve or VG. The potential consequences of the valve hall fires are summarized below:

- Fire due to loose connections. A loose connection in the valve can cause valve hall fire that has the potential to destroy a valve or VG. Sometimes it is caused by human error (see Table 3.5 and Appendix B). More frequent repairs and less experience could lead to more human error.
- Fire due to SAB card failures. The failures of SAB cards have caused many fire incidents, but the resulting damage was all limited to the failed SAB cards and their neighboring cards. This is because the SAB cards are completely covered and physically isolated from other part of the thyristor module (see Figures 3.1 and 3.5). Therefore, an SAB card failure has a low probability of causing extensive damage (e.g. destroying part of a valve or VG).
- Fire due to DIW leaks. Fire due to DIW leaks has the potential to destroy a valve or VG. Such a risk can be mitigated through tubing refurbishment. The failure of a reactor module can also damage the cooling tubes and cause DIW leaks. This kind of risk is expected to increase as the reactor modules continue to deteriorate.
- Fire due to grading resistors. The failure of a grading resistor can cause fire. This kind of risk should be low after the aging resistor inserts are replaced.
- Fire due to grading capacitors. The failure of an oil-filled capacitor has the potential to cause fire. This kind of risk will be minimized by inspecting all the capacitors and replacing them when needed.
- Fire due to aging thyristors. The aging thyristor can cause cascading thyristor failures and flashover/fire. This kind of risk will be eliminated by replacing all the aging/leaky thyristors.
- Fire due to deteriorated light guides in the stage 1 VGs (i.e. VG31 and VG41). The deteriorated/dirty light guides and LG channels can cause flashover or fire (see Section 3.1.3). This kind of risk can only be reduced by replacing them. Note that the dirty/aging light guides and LG channels cannot be cleaned without the risk of damaging the light guides (see Figure 3.10).

3.2. TEST EQUIPMENT

There are two sets of identical test equipment for BP2 valve maintenance, one at each end. The test equipment includes the SAB card test set, thyristor module test bench, VBE test set and TFM test set. The test equipment has been used extensively due to frequent repairs and is in a severely deteriorated state.

3.2.1. SAB card test sets

Some of the components used in the test sets are not commonly available. There is a possibility that the failed SAB cards could no longer be repaired at one station at some point when the test set itself is not repairable due to lack of spare parts or staff expertise.

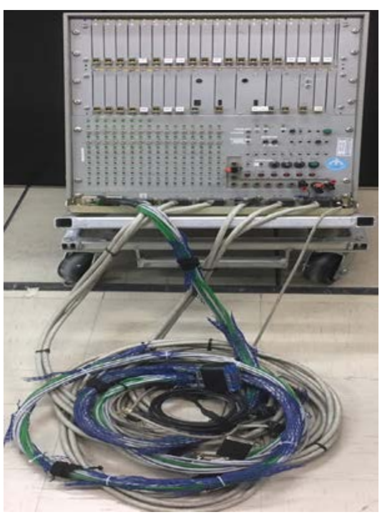
In such a situation, we will have to use the parts from one test set to repair the other, preferably at Dorsey because Dorsey always has more skilled staff than Henday. All the faulty SAB cards will have to be shipped to Dorsey for repair. It wouldn't be cost prohibitive to do so since the SAB cards are relatively small and can be easily shipped by air with little risk of being damaged.

3.2.2. VBE and TFM test equipment

Each BP2 station has only one set of test equipment for the VBE and TFMs as shown in Figure 3.18, which has been used extensively for maintenance, troubleshooting and training purposes. The test equipment is 41 years old and in severely deteriorated condition.

If the VBE test equipment at either end fails beyond repair or becomes unrepairable due to lack of spare parts or staff expertise, it will be difficult to maintain and troubleshoot the VBE, which would result in the EOL of all BP2 VGs.

One may wonder if it is possible for the two stations to share the VBE test equipment. It is possible, but not practical for a couple of reasons. First, the test equipment is not a small/light item that can easily be shipped by air. It will be at high risk of being damaged during shipment. Second, to ship the equipment from one station to the other would take two days or much longer depending on the weather condition and the method of shipment.



(a) VBE test equipment

(b) TFM test equipment

Figure 3.18. BP2 test equipment for the VBE and TFMs.

3.2.3. Thyristor module test bench

The test equipment, especially the one at Henday, has severely deteriorated and is no longer able to perform all the manufacturer's recommended tests properly.

If the test equipment fails beyond repair, it will still be possible to troubleshoot and repair thyristor modules based on the TFM records.

3.2.4. Safety concern

Frequent access to the deteriorating thyristor module test equipment has raised a safety concern. The equipment has severely deteriorated and its components such as switches, pushbuttons and relays inside the test equipment have been failing and breaking down frequently. As the equipment generates and controls high voltage, malfunction of its components can result in flashover that can not only destroy the test equipment itself but also cause severe injury to the test personnel (see [8]).

3.2.5. Summary

The test equipment is 41 years old and in severely deteriorated condition. At a certain point, we may not be able to repair the test equipment due to lack of spare parts or staff expertise.

The most critical test equipment is the one for the VBE. Without this test equipment, it will be difficult to maintain and troubleshoot the VBE, which would result in the EOL of all BP2 VGs.

3.3. ANALOG ELECTRONIC SYSTEMS

The analog electronic systems in BP2 are complex and highly customized. They include the HVDC controls & protection, VBE and TFMs, DC filter protection, AC filter protection, etc.

A common factor that drives the replacement of old analog systems in all other HVDC projects is either lack of spare parts or lack of staff expertise or both [4, 5]. The 41 year old analog systems in BP2 are, of course, no exception.

Due to the complexity of analog systems consisting of a huge number of electric/electronic components, it is impractical to assess the availability of any spare parts and to predict at which point they would no longer be available, either on hand or from the market. In other words, the analog electronic systems cannot be assessed the same way as the thyristor valves.

The 41 year old analog systems in BP2 have long passed the end of their expected lifetime of 29 years (see Table 2.6). The analog systems in the Cahora Bassa project were built by the same working group (AEG, BBC and Siemens) using the same technology as in BP2, but they were replaced at the age of 31 years at the Apollo station and will be replaced at the Songo station within 3 to 4 years. When similar systems in other HVDC projects have been replaced (see Section 2), there is no technical ground to support the expectation that all the analog systems in BP2 can be maintained for many more years to come.

3.4. DC CONTROLS

The DC controls include the control equipment for valve group switching sequences and other programmed switching sequences of the DC switchyard. Part of the DC control system is the interlocking system which permits operation only when it is safe.

The DC control equipment is relayed-based. It is no longer reliable due to aging. It often takes some extra effort to complete the switching sequences for the isolation and restoration of a pole or VG. For this reason, the outage for station equipment repair or maintenance is usually scheduled longer than actually required in order to avoid forced extension of the outage. Thus, the performance of the DC controls is not reflected in the historic outage data.

3.5. RISK OF END-OF-LIFE

The End-Of-Life (EOL) of equipment is understood as a situation where it can no longer be repaired due to lack of spare/replacement parts or can no longer be maintained at an acceptable level of availability and reliability due to aging components or diminishing staff expertise.

Based on the condition assessment results presented in the previous sections, it is expected that BP2 will experience an increasing risk of EOL of one or multiple VGs, as described below:

- If we run out of spares for any type of parts/components such as reactor modules due to EOL component failures or catastrophic events (e.g. fire/flashover and valve failure), we would have to shut down one VG for spares to keep other 3 VGs going.
- Once the light guides start to malfunction/fail, the two stage 1 VGs (i.e. VG31 and VG41) would be forced out of service indefinitely due to lack of replacement light guides (see Section 3.1.3).
- If the VBE test equipment at either station fails beyond repair or becomes unrepairable due to lack of spare parts or staff expertise, it will be difficult to maintain and troubleshoot the VBE, which would result in the EOL of all BP2 VGs (see Section 3.2.2).

There is not much that can be done to reduce/eliminate the risks of EOL except the following:

- The risk of valve failure can be reduced by restoring the valve voltage withstand capability. This can be achieved by replacing the severely aging/leaky thyristors.
- It is possible to refurbish/rebuild the VBE test equipment in order to avoid the resulting EOL of all BP2 VGs.

With the benefit of additional capacity from the newly commissioned BP3, it is possible that the minimum HVDC capacity requirement could be met by maintaining 1000MW reliable capacity in BP2 (see Appendix E). The reliability of each individual VG would deteriorate, but 3 VGs would be able to offer 1000MW transmission capacity at an acceptable level of availability and reliability.

If the 2000MW transmission capacity of BP2 needs to be maintained until 2026 and beyond, all the VGs need to be replaced as soon as practically possible.

3.6. SUMMARY

Most of the major valve components in BP2 are in severely deteriorated condition, which include thyristors, reactor modules, SAB cards (i.e. thyristor electronics), fiber optic light guides, etc.

Lack of spares is an issue for all types of valve components except for fiber optic light guides, thyristors and cooling circuit components.

Thirty six (36) reactor modules have failed, including the 14 fretting ones identified this year. All of them have been replaced except that 4 fretting ones are waiting to be replaced. After the 4 fretting modules are replaced, there will be only 8 spare modules left. Thus, the spare reactor modules would likely be used up sooner than previously expected.

The BBC and AEG thyristor pairs account for approximately 2/3 of the 9216 thyristor pairs in BP2. Most of them are found to be leaky to various degrees. The seriously leaky thyristors, especially those having a leakage resistance much smaller than the dc grading resistance of 220kΩ, may need to be replaced in order to reduce the risk of cascading thyristor failures as what has been done in the P1 thyristor valves [10, 11]. Note that the replacement thyristors can still be made by a thyristor manufacturer in India (i.e. BHEL) at an acceptable cost.

The 41 year old VBE test equipment is in severely deteriorated condition. If the test equipment at either station fails beyond repair or becomes unrepairable due to lack of spare parts or staff expertise, it will be difficult to maintain, troubleshoot and repair the VBE, which would result in the EOL of all BP2 VGs.

The light guides in the stage 1 VGs (i.e. VG31 and VG41) are in severely deteriorated condition. They have the potential to cause VG outages or flashover/fire. If the light guides fail, they cannot be replaced without the risk of damaging others. In other words, these light guides cannot be touched unless they are all replaced. Therefore, once the light guides start to malfunction/fail, VG31 and VG41 would be forced out of service indefinitely due to lack of replacement light guides.

More than 30 fire incidents have occurred in the BP2 valve halls. Most of them were caused by the failures of aging valve components and a few by human error. Some of the valve hall fires have the potential to destroy a valve tower or VG. The risk of fire is expected to increase as the valve components continue to deteriorate.

Based on the above, it is expected that BP2 will suffer an increasing risk of EOL of one or multiple VGs as described in Section 3.5. The measures that can be taken to reduce/eliminate the risk of EOL is limited, but it is possible that 3 VGs could be maintained until 2026 assuming that the concern on the VBE test equipment can be fully addressed.

If the 2000MW transmission capacity of BP2 needs to be maintained until 2026 and beyond, all the VGs should be replaced as soon as practically possible.

4. P1 THYRISTOR VALVES AND CONTROLS

The mercury-arc valves in Pole 1 (P1) were upgraded to thyristor valves by Alstom during 1992 to 1993. The VG controls were replaced along with the valves, but the original pole controls were not. Thus, P1 ended up having two completely different HVDC control technologies (see Figure 1.1).

In this section, focus is placed only on the thyristor valves and VG controls. The 48 year old pole controls, the same as in P2, will be assessed in Section 5.

4.1. THYRISTOR VALVE COMPONENTS

The thyristor valves in P1 were constructed with 100mm Electrically Triggered Thyristors (ETT). Each valve has 42 and 40 thyristor banded-pair assemblies (i.e. thyristor modules) at Radisson and Dorsey, respectively. Each banded-pair has two thyristor levels as shown in Figure 4.1. There are a total of 2952 thyristors in service in the P1 valves at Radisson and Dorsey combined.

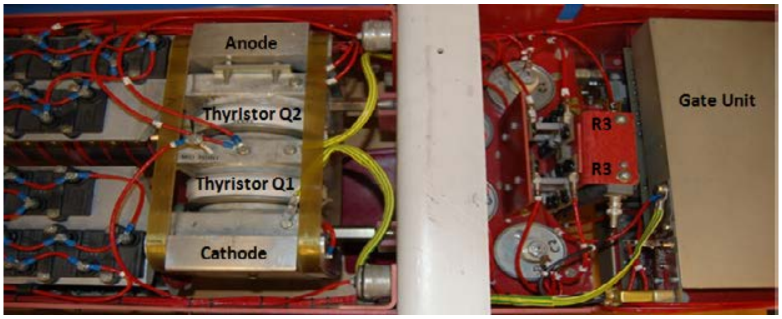


Figure 4.1. Pole 1 thyristor banded-pair assembly (or thyristor module).

4.1.1. Thyristors

In 2013, near 70% of the thyristors in VG11 and VG12 at both stations (Radisson and Dorsey) were found to be leaky (i.e. exhibiting significantly increased leakage currents) to various degrees. This problem has been resolved by replacing all the leaky thyristors in VG11 and VG12 in 2014.

The thyristors in VG13 are still original. The majority of them were still in good condition as of 2015, but might become leaky in years to come. So we will have to check them for increased leakage currents periodically.

If we plan to keep the thyristor valves in service for 15 to 20 more years, we would likely need to purchase more thyristors. The number of thyristors to be purchased will depend on the results of future thyristor assessment for VG13.

4.1.2. Thyristor gate units and BOD cards

The thyristor gate units (i.e. gate electronics unit) in the P1 valves have not shown any sign of aging (see Figure 4.2).

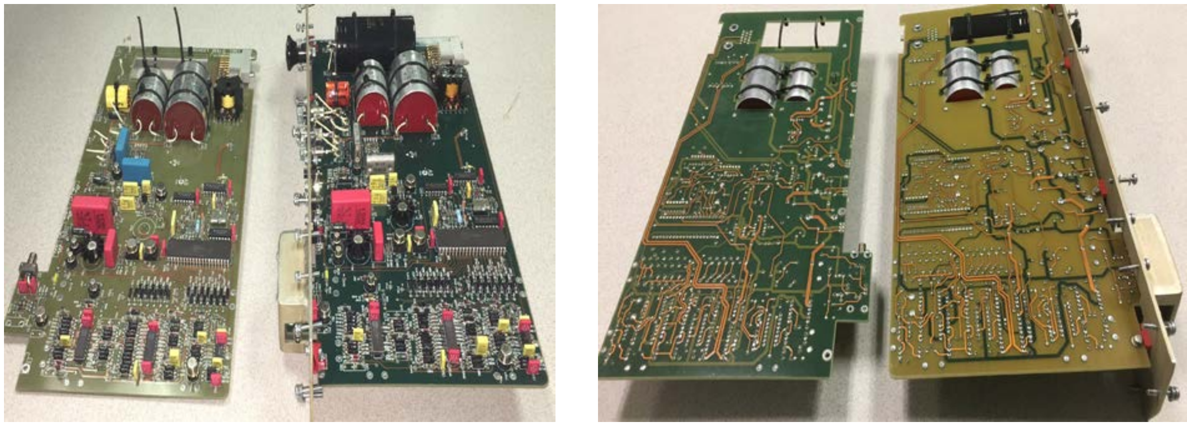


Figure 4.2. Two gate electronics units (PCB 1561). One is scrapped and other has been repaired. They exhibit no sign of aging.

There is no field programmable device in the gate units. The logic of the gate unit is in the gate array A4G24036GDC, which is an application specific IC chip fabricated by MEDL. They have been very reliable. So far, only a few of them have failed at the two stations. We do not have spares for these chips other than those on the spare gate units (PCB 1561).

There were a total of 146 spare gate units at the two stations as of 2016. Their consumption rate is less than 1 per year at each station over the past 27 years. There is no concern about the spare gate units.

Each thyristor level has a Break-Over Diode (BOD) card as shown in Figure 4.3. It is connected to the gate unit via a backplane (PCB1562). The BOD card consists of 7 BODs connected in series and other simple electrical components such as resistors and capacitors.

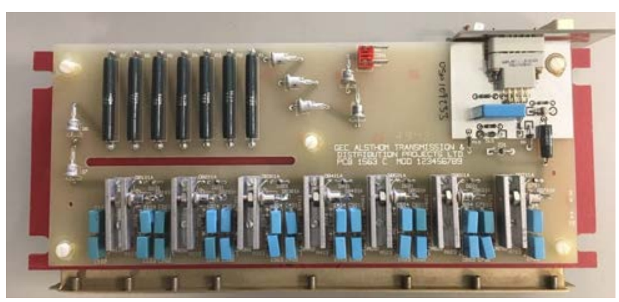


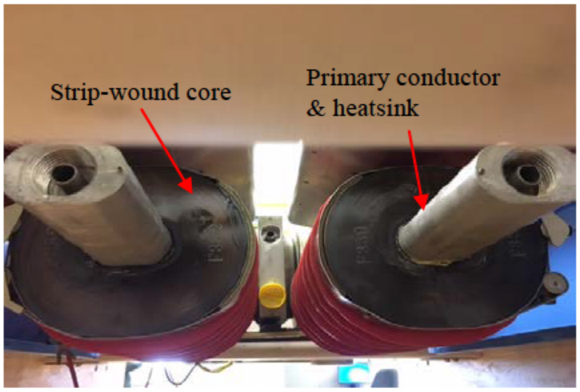
Figure 4.3. BOD card (PCB 1563).

The BOD cards have been very reliable and rarely needed repairs. Like the gate units, the BOD cards have not shown an apparent sign of aging/deterioration. There are more spare BOD cards than spare gate units. Therefore, there is no concern about the spare BOD cards as well.

4.1.3. Saturable reactors

Each thyristor level has a saturable reactor that consists of 8 separate strip-wound cores as shown in Figure 4.4. There are 3 types of cores in each set: 1 of L2 cores, 5 of L3 cores and 2 of L4 cores. They are separated by silicone rubber washers.

There are 1440 and 1512 saturable reactors at Dorsey and Radisson, respectively, but there are only two spare reactors (or 16 strip-wound cores) at each station, which are being used in the thyristor test modules (i.e. banded pair assemblies).



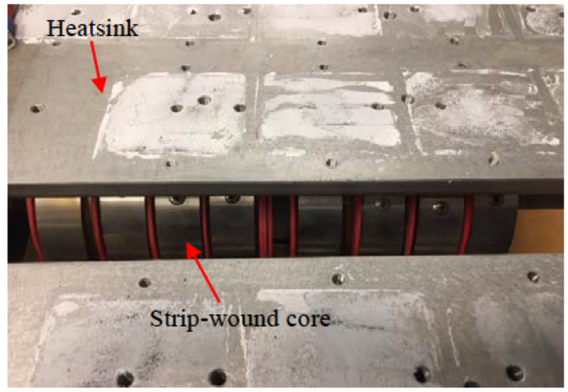


Figure 4.4. P1 thyristor level saturable reactors.

The expected lifetime of reactors is 30 years as stated in the CIGRE HVDC life extension guides [5], which is the case with the BP2 reactor modules. The P1 saturable reactors have been trouble-free since commissioning in 1992/1993 and not yet exhibited an apparent sign of deterioration.

Owing to their simple design, the strip-wound cores are expected to have a lower failure rate than the BP2 reactor modules. Also, because they are separated from one another, they would most likely fail individually. In spite of that, there is still a concern about the shortage of spare reactors for the P1 valves. Once the P1 reactor cores start to fail, there is a risk that we would run out of spare cores quickly at both stations.

4.1.4. Valve cooling

Each thyristor banded pair assembly has three heatsinks, a smaller one and two bigger ones. They provide cooling for thyristors, damping resistors and saturable reactors. The heatsinks are connected via cross-linked polyethylene (PEX) pipes/tubes of the same diameter (see Figure 4.5). There are no tiny tubing components (tubes and connectors) like those in the BP2 thyristor modules (see Figures 3.1). For this reason, the P1 thyristor valves are much less prone to water leaks.

Figure 4.5 shows the condition of the P1 valve cooling tubing after 21 years of service. The tubing nut exhibited a clear sign of aging/degradation in the form of discoloration, whereas the PEX pipe still looks good. In 2014, two PEX pipes were evaluated by Polymer Engineering Company Ltd., BC. In the evaluation report [28], no conclusion was reached regarding the tubing life span, but it was pointed out that "potential failure of nuts during service or during removal of pipes associated with maintenance work may become a problem before PEX tubing failure occurs".

Because of the special tubing design as shown in Figure 4.5, the PEX tubes would unlikely break away even if their tubing nuts become cracked. In other words, the aging tubing nuts would unlikely cause a massive coolant leak and catastrophic flashover/fire as what has been caused by the aging tubing connectors in the BP2 valves (see Figures 3.2 to 3.4).

The rubber O-rings have lost their elasticity due to aging and no longer been able to seal water effectively, thus causing heatsink corrosion at some thyristor levels. Figure 4.6 shows corrosion observed in a few heatsinks at Dorsey. The deepest corrosion is about 1mm. At Radisson, one-third of the O-rings seals have been replaced, but no apparent sign of heatsink corrosion has been observed during O-ring replacement. It is still not clear as to how many heatsinks have experienced corrosion at the two stations.

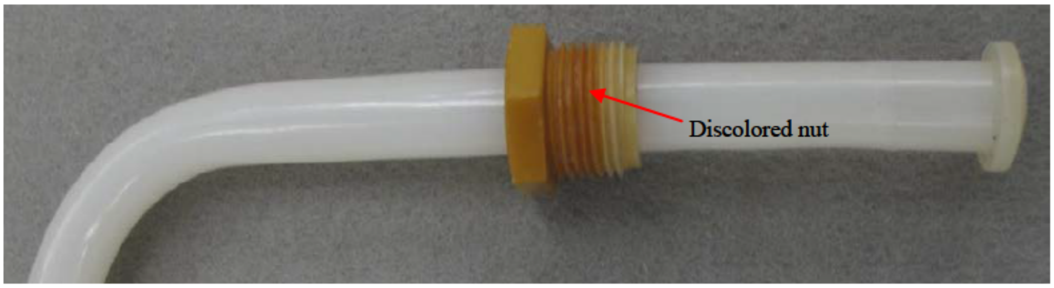


Figure 4.5. PEX tube and discolored nut.

Figure 4.6. Corrosion of aluminum heatsink.

Heatsink corrosion is a serious concern. If allowed to continue, it might eventually cause heatsink failure. There is no information on how to repair heatsinks in the P1 maintenance manuals. In additional, there is essentially no spare heatsink available for replacement at either station.

The aging cooling circuit components, especially the O-rings, should be replaced as soon as practically possible in order to address the concern on heatsink corrosion.

4.1.5. Other thyristor level components

Other thyristor level components include:

- Grading capacitors C1, C2 and C3.
- 125kΩ DC grading resistors.
- Damping resistors R1 and R2.
- MOV assemblies.

- dv/dt current transformers.
- GRP tension bands/straps.

These components have been very reliable and are still in good condition. None or very few of the original spare parts for the valves have been consumed over the past 27 years.

The spare part inventory for the P1 thyristor valves is shown in Table 4.1. There is no immediate concern about the spare valve components other than spare saturable reactors, heatsinks and GRP tension bands.

Table 4.1. P1 thyristor valve spare part inventory as of 2016.

Valve components	Quantity at Dorsey & Radisson
MOV assembly	314
Damping resistor (22Ω)	640
Damping resistor (88Ω)	1300
DC grading resistor (125kΩ)	65
Grading capacitor C1/C2 (0.75µF)	78
Fast grading capacitor C3 (0.075µF)	399
GRP tension band/strap pair	8
dv/dt current transformer	94
Saturable reactor (on the two test thyristor modules)	4
Gate unit	146
BOD card	> 146

4.1.6. Test equipment for thyristor valves

There are two types of test equipment for the P1 thyristor valves at each station: Gate Unit Test equipment (GUTE) and Valve Test Equipment (VTE).

Gate unit test equipment

There is one piece of GUTE at each station, which has been used routinely for gate unit tests and repairs. The GUTE is still in decent shape.

In the distant future, there is a possibility that the GUTE itself becomes unrepairable due to lack of spare parts. If that happens, the test and repair work can be done at one station, either Dorsey or Radisson.

Valve test equipment

The Valve Test Equipment (VTE) is high voltage test equipment. It was intended for use to perform functional and integrity tests after component replacement at the thyristor levels, but the maintenance history shows that the VTE is not necessarily required for routine valve troubleshooting and repair work.

We used to use the VTE once at Radisson during the investigation of the P1 thyristor leakage problem, but it did not give any useful test results. The thyristor valves can be maintained without necessarily using the VTE.

4.1.7. Risk of fire

In the BP2 thyristor valves, most of the fire incidents have been caused by the failures of SAB cards, but the P1 valves have never had any burnt gate electronics units.

The P1 valves are not prone to coolant leaks as the BP2 valves and the associated risk of flashover/fire is low.

A damping resistor in VG12 was burnt due to a disconnected wire. The damage was limited to the resistor itself only. There is little chance for the fire to spread to the oil filled capacitors as shown in Figure 4.1.

4.2. VG CONTROLS

The VG controls in P1 were installed by Alstom in 1992 along with the thyristor valves. The original English Electric pole controls are still in service, which will be discussed in Section 5.

4.2.1. Brief description

The VG controls are essentially analog electronics, but contain a huge number of digital (or programmable) components. Based on our assessment conducted in 2016, the P1 VGs have a total of approximately 3000 digital components (UV EPROMs, EEPROMs, EPLDs and microprocessors). Approximately 87% and 9% of them are UV EPROMs and EPLDs, respectively. About 68% of the digital components are in the C&P systems and 32% in the VBE.

The VG controls have a complex Thermal Analogue (TA) as shown in Appendix D. Its principal function is to calculate the thyristor junction temperature for each valve, enabling optimum utilization of the thyristor ratings. More than 210 UV EPROMs are used by the TA in each VG at each station (Radisson or Dorsey). The TA makes the controls very complicated. There is no TA or anything similar in P2, BP2 and BP3.

There are 13 types of digital components (IC chips): 9 types of UV EPROMs, 1 type of EEPROM, 1 type of EPLD and 1 type of 8-bit microprocessor. They were made by six different manufacturers.

The programmable elements in the EPLDs are also EPROMs. The UV EPROMs are used to store firmware and data, and EPLDs to perform logic/control functions (e.g. blocking control, switch supervision, etc.).

4.2.2. Inherent problem – frequent commutation failures

The simulated thyristor junction temperature from the TA is used as an input for the dv/dt protection built in each thyristor gate unit. It has been a known problem, from day one, that the P1 VG is inherently prone to commutation failures due to its unique thyristor forward recover and overvoltage protection scheme. For example, near 300 commutation failures occurred in

2017. Those commutation failures did not result in VG outages, but may be an indication of an underlying problem.

A technical note prepared by Narinder Dhaliwal provides a detailed explanation for this problem.

4.2.3. Maintenance related issues and concerns

Due to lack of redundancy and use of so many digital components without self-monitoring capability, the analog-digital C&P system is even more difficult to maintain and troubleshoot than the purely analog systems in P2 and BP2.

Difficulty in troubleshooting TA&FC panel

The TA&FC panel for each VG has triplicated firing controls, named Channels A, B and C. Each channel has 6 firing control cards for 6 thyristor valves, respectively. The firing control card for one thyristor valve in Channel A has a fault as shown in Figure 4.7. This fault can be cleared locally via the reset button on the panel, but would come back sometime later. It has been there for several years, and what has been causing it is still a mystery.

As the digital signals in the cards and between them are not accessible, troubleshooting measures for the TA&FC panel are very limited. Troubleshooting effort (e.g. such as card swapping, etc.) has been attempted several times, but nothing has been found so far.

This is an example showing how difficult it is to troubleshoot the complex analog-digital controls.

There is little knowledge, experience and support available, both internally and externally, for troubleshooting the TA&FC panel.

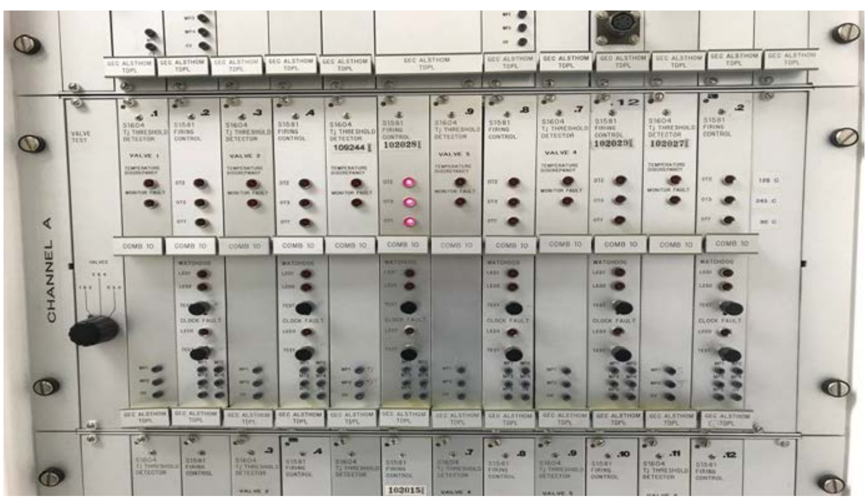


Figure 4.7. Mysterious fault in the TA&FC panel.

Technical obsolescence

The digital components have become obsolete. There is a lack of spares on hand for them, and it is difficult to acquire new spares as well.

Below are some examples:

- The DOS-based TFM computer is not repairable due to lack of spare parts, and it is also hard to be replaced by a newer computer due to various compatibility issues.
- Additional EPLDs were required for the bypass switch replacement project. Lucky, barely enough EPLDs could be found from eBay.
- Some of the parts on the TA test set at Radisson have been used as spares to repair the controls in service.
- A search on eBay on Oct. 27, 2018 for example returned few listings almost for all types of digital components.

In addition, the software for programming the EPLDs is MaxPlus II, which is only compatible with Windows XP or older version. Microsoft ended its support for Windows XP in 2014.

<u>Concern on data corruption</u>

UV EPROMs are floating gate memory devices [23]. Each EPROM consists of a large number of programmable cells. Each cell stores data (i.e. a bit) in the form of charges trapped on the floating gate in the cell. The insulation layer of each cell in the EPROM, like any other insulation material, is not perfect, i.e. it leaks. Thus EPROMs don't have unlimited data retention time. The guaranteed data retention time is more than 10 years [24] and typically specified for 20 years [25]. From the experience of many people (including ourselves) having legacy electronic systems/devices built with EPROMs, data corruption has been known to be a real issue. The programmable elements of EPLDs also have limited data retention time.

The EPROMs and EPLDs in the controls, VBE and test equipment were made by five different manufacturers. There is a good possibility that some of them would start to lose data earlier than others. Once data corruption starts, it will cause an increasing number of faults in the VG controls. This type of fault would be very difficult to locate, and the affected VGs would no longer be operable unless all the digital chips are reprogrammed as described below.

<u>Challenges in reprogramming/refreshing digital components</u>

To avoid possible data corruption, it is advisable to refresh (i.e. reprogram) the memory chips on all the spare cards (PCBs) or get ready for it. Once the memory chips are refreshed, they should be good for at least 20 more years. This work sounds easy, but not so much in practice because approximately 3000 of them have to be refreshed individually and all the associated cards (PCBs) may have to be tested. Below are some of the challenges that can be anticipated:

- During the refreshing process, there is a chance to damage the digital chips but there is a lack of spares.
- The TA test set has never worked properly and not been used in recent years. Some of its components (PCBs) at Radisson have been used as spare parts to repair the controls in service as previously mentioned.
- There is a complex test procedure for each card (PCB), which has never be tried or verified in the shop. The procedure is hard to understand because it deals with digital signals. Experience indicates that some of the test procedures might not work.

Note that the majority of UV EPROMs are used in the TA as previously mentioned.

For the same reasons as described above, the EPLDs in the VG controls and VBE should be reprogrammed as well.

4.2.4. Valve base electronics and thyristor fault monitor

The Valve Base Electronics (VBE) and Thyristor Fault Monitor (TFM) are an integrated part of the thyristor valves. They are usually replaced along with the thyristor valves not the VG controls.

<u>VBE</u>

The VBE serves as a firing interface between the VG controls and thyristor electronics (i.e. gate units) and also provides monitoring and protection for each thyristor valve. The same technology was used to build both the controls and VBE. Thus, the VBE will have the same issues as the VG controls. If the controls are replaced, however, there will be sufficient spare parts for the VBE.

The VBE is fully redundant for each valve and has been very reliable. The only issue we have experienced so far is the high failure rate of opto-receivers. We are still able to acquire replacement opto-receivers at this point in time.

<u>TFM</u>

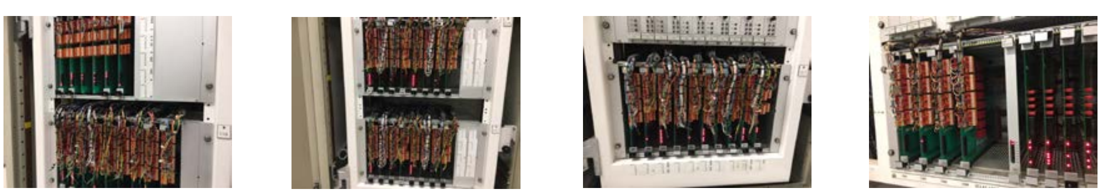
There is one TFM for all 3 VGs in P1. It communicates with the PPC-3000 microprocessors in all the VBE panels, and displays, prints and stores the information on the status of each thyristor level, which is used by the maintenance staff for valve troubleshooting and repair.

The TFM is DOS-computer based. The computer is failing and its printer has stopped working at Radisson. We have been unable to repair it due to lack of spare parts and replace it with a newer computer due to various compatibility issues as previously mentioned.

The TFM can be upgraded separately or along with the VG controls.

4.2.5. Klippon relays

There are over 250 Klippon relay cards of different types in the P1 VG controls & protection and VBE at each station (see Figure 4.8).



(a) Six-pulse controls. ***(b)*** Protection. ***(c)*** TA&FC. ***(d)*** VBE.

Figure 4.8. Klippon relay cards.

The Klippon relays seem to have reached the end of their life expectancy. A number of forced outages have occurred due to failed Klippon relays.

In addition, we are running out of spares for certain types of Klippon relays.

4.3. SUMMARY

Thyristor valves

All of the valve components appear to be in decent condition except the cooling circuit components.

There used to be a serious thyristor leakage problem in VG11 and VG12 at both ends. This problem was resolved by replacing all the leaky thyristors in 2014. Thyristors in VG13 are still original and need to be checked periodically for increased leakage currents.

There may be a need to buy additional replacement thyristors for VG13 someday down the road if all of the thyristor valves are to be kept in service for 15 more years or even longer.

No issue/concern has been identified, at this point in time, about the spares for valve components except for saturable reactors, GRP tension bands and heatsinks. No spare saturable reactors and heatsinks have been found if those on the thyristor test module at each station are not counted.

The aging cooling circuit components, especially the O-rings, in the P1 valves should be replaced as soon as practically possible in order to stop or slow down heatsink corrosion. The heatsinks should be inspected for signs of corrosion during O-ring replacement.

TAM started to contact GE Alstom in April this year, trying to acquire spare saturable reactors, heatsinks and GRP tension bands, and to seek information on how to repair/restore corroded heatsinks. Here is the final response from GE Alstom: “At this stage it is difficult for us to make a budgetary quote for these items” and “it will be difficult for us to make these parts”. In addition, Alstom has not been able to offer any useful advice or information on how to address the concern on heatsink corrosion.

Due to the difficulty of acquiring spare parts, one VG would have to be shut down to keep other VGs going once the saturable reactors start to fail.

VG controls (Alstom controls)

The issues/concerns identified about the analog-digital VG controls are as follows:

- The 27 year old VG controls have passed the end of their expected lifetime of 25 years, noting that the similar Alstom controls in the McNeil and Haenam-Cheju projects were replaced at the age of 25 and 23 years, respectively (see Section 2.3 and 2.4).
- The controls, especially the TA&FC panels, are very difficult to troubleshoot due to the fact that they were built using a huge number of digital components and the digital signals are not accessible.
- There is little knowledge, experience and support available, both internally and externally, for troubleshooting the TA&FC panels.
- Possible data corruption in the digital components is a major concern that is not easy to address.

- There is a lack of spares for various types of digital components. The technology is obsolete and it has been difficult to acquire spare parts.

To delay the control replacement entails the following risks:

- Extended VG outages due to the difficulty of troubleshooting the TA&FC panels among other factors.
- Loss of one VG due to lack of spare digital components.
- Prolonged VG outages or even loss of 3 VGs due to data corruption in the memory chips if we have trouble reprogramming them.

5. P2 THYRISTOR VALVES AND CONTROLS

The mercury-arc valves in P2 were upgraded to thyristor valves by Siemens in 2004. The master controls, pole controls in both P1 and P2, and VG controls in P2 are still the original ones installed by English Electric along with the mercury-arc valves (see Section 1).

5.1. CONTROLS AND PROTECTION

The original analog HVDC C&P system is 48 years old, the oldest in the world. It has long passed the end of its 29 year expected lifetime (see Section 2). The analog C&P system is not redundant and any component failure in the system can cause a pole or VG outage (see Section 6.2.1).

The original pole and VG controls consist of over 750 Printed Circuit Boards (PCBs) at each station, which were built using discrete components such as resistors, capacitors, diodes, transistors, relays, etc. as well as Integrated Circuit (IC) chips, as shown in Figure 5.1. The analog controls have been modified multiple times and some cards have been rebuilt to accommodate the needs for equipment improvements/upgrades (e.g. thyristor valve replacement, bypass switch replacement, etc.). It has never been an issue to get new spare/replacement parts for repairing the controls or rebuilding cards.

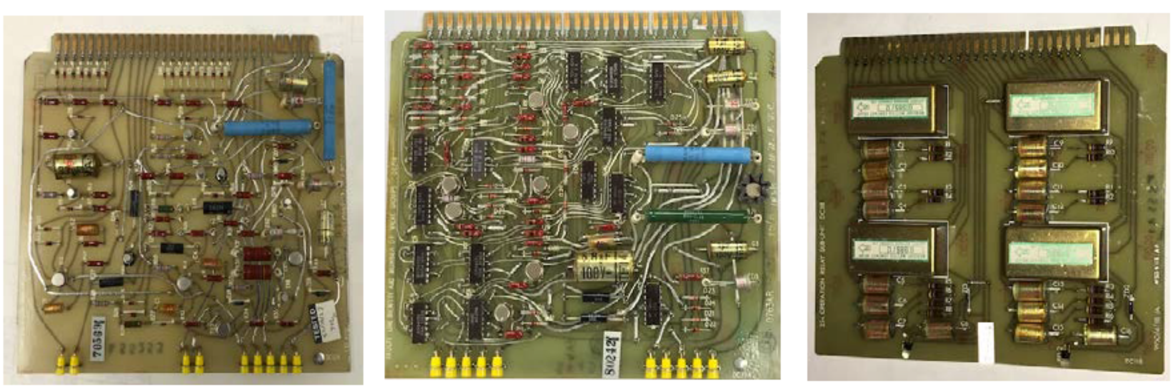


Figure 5.1. Examples of PCBs in the original analog controls in BP1.

However, the analog system is not only hard to understand and learn, but also difficult and time-consuming to troubleshoot (see Sections 6.1 and 6.2.1). For this reason, it is crucial to have a well-trained and very knowledgeable plant engineering workforce available at the site to perform troubleshooting during a control related outage. MH used to have such a workforce and that is the very reason why the analog system can be maintained for so many years. The workforce, however, has declined significantly since 2015 due to retirement. Without sufficient staff expertise, it is difficult to maintain the analog controls.

In addition, there are some other issues/concerns as described below:

- The characteristics of the electric/electronic components could drift due to aging, thus resulting in the deteriorating performance or even malfunction of the controls.
- The electric/electronic components will not last forever. They have varying life expectancies. The EOL component failures, once they start to happen, will result in

frequent pole and VG outages, thus significantly affecting the reliability and availability of BP1.

- The quality of the BP1 equipment manuals and drawings has degraded significantly due to various equipment upgrades in the past. For instance, approximately 30% and 45% of the schematic diagrams for the pole controls and the pole & line protection, respectively, are in poor quality. Some of them are not even legible (see Appendix C). This makes it difficult for O&M staff to locate, interpret and validate the data/information required for learning or troubleshooting purposes.

Although it is possible to keep the analog controls going for many years to come as far as the availability of spare parts is concerned, there will be an increasing risk that the associated poles and VGs would suffer reduced availability and reliability due to the above described issues.

5.2. THYRISTOR VALVES

The P2 thyristor valves were installed by Siemens in 2004. They were built using Light-Triggered Thyristors (LTT) and therefore have much simpler thyristor level electronics than those in P1 and BP2. Siemens made a claim that the thyristor valves were designed for maintenance free operation.

These thyristor valves have proven to be very reliable. For instance, there has been virtually no random component failure in the P2 valves at Radisson for the past 10 years. The original spare parts for the valves have rarely been used. There is no concern as to whether the P2 valves can be maintained for 35 years in service.

Currently, we are in the process of acquiring valve components retired from the BPA Celilo converter station. Note that the valves in 6 VGs at the Celilo station were also installed by Siemens in 2004 using the same technology, but decommissioned after 12 years in service as a result of the station upgrade. With the large number of spare parts, the useful life of the P2 thyristor valves could easily be extended by 20 years.

6. MAINTENANCE AND TRAINING NEEDS

The purpose of this section is to identify and discuss the issues associated with the complex C&P systems in BP1 and BP2 from the maintenance and training perspectives, which should be taken into consideration in the HVDC system planning and the associated staff planning.

6.1. ISSUES ASSOCIATED WITH STAFF TRAINING

The three types of HVDC C&P systems in BP1 and BP2 are very complex, highly customized and completely different from one another. Each of them requires a highly specialized and knowledgeable workforce to perform maintenance and troubleshooting, which is difficult and time-consuming (see Section 6.2). The skill and knowledge sets that the workforce has or needs are unique to the BP1 and BP2 converter stations, and cannot be transferred from any other locations within the corporation, including the BP3 converter stations. Any new engineering and technical staff working at the converter stations have to undertake many years of on-job training at the BP1 and BP2 stations to develop necessary technical competencies to fulfill their duties.

The early engineering and technical staff, i.e. those joined the workforce 30 to 40 years ago, were at a great advantage of learning each of the three types of C&P systems during a different period of time because these C&P systems were installed in 1971, 1978 and 1992, respectively. Also, they got the best learning opportunities during the installation and commissioning of the C&P systems.

Nowadays, the situation is completely different. New engineering or technical personnel, especially new plant engineers, do not have the luxury to learn the different types of C&P systems one by one over a long period of time. They do not only have to learn all of the complex C&P systems simultaneously along with various other types of station equipment such as thyristor valves, cooling systems, etc., but also have to face many challenges and difficulties that did not exist before, some of which are described below (but not limited to):

- The most knowledgeable senior plant engineers who used to provide training for new engineering and technical staff have retired within the last 5 years.
- The quality of the BP1 equipment manuals and drawings has degraded significantly due to various equipment upgrades over the past few decades. Some of the drawings are not even legible (see Appendix C). Particularly, over the last several years, document upgrades have not been kept up with equipment upgrades due to limited resources and high staff turnover. New or less experienced staff will have difficulty locating, interpreting and validating all the data/information they need, either for learning or troubleshooting purposes.
- Due to high utilization of the HVDC system, it has been difficult to access the C&P systems for troubleshooting and training purposes. This situation will become worse for BP1 after the Keeyask generating station is put in service due to insufficient spare transmission capacity in BP1 and limited transfer capacity from BP1 to BP2/BP3.
- The NERC CIP Compliance related work has been consuming a significant amount of engineers' and technicians' time, which was previously dedicated to learn the various types of HVDC equipment or provide training for new staff.

In the past, it would take at least 10 years for new plant engineers to get trained for all three types of analog C&P systems and various other types of station equipment such as thyristor valves, cooling systems, etc. A longer training period would be required considering all the above described factors. Many would not stay long enough to learn all the C&P systems as evidenced by the fact that 63% of the 8 plant engineers hired for BP1 and BP2 since 2000 have left after 3 to 5 years.

Similarly, it would also take many years for new staff in the C&P maintenance group to get trained for the different types of C&P systems.

6.2. Issues associated with maintenance of analog HVDC controls

This section is mainly intended to illustrate/explain why it is difficult and how difficult it is to troubleshoot the complex analog HVDC C&P systems in BP1 and BP2 as compared to the modern digital systems and thyristor valves.

6.2.1. Difficulties in troubleshooting analog HVDC controls

The analog C&P systems in BP1 and BP2, unlike their digital counterpart as described in Section 6.2.3, are not redundant. Each of them was built using a huge number of electric/electronic components and any of the components in the controls could be a single point of failure. In other words, any failed component or loose connection in the controls (e.g. pole and VG controls) has the potential to cause one or multiple forced outages of the associated pole or VG. For this reason, BP1 and BP2 are prone to control fault related outages. In 2010 for example, the C&P systems in BP2 were blamed for 20 forced outages including 7 pole outages, which accounted for 43% of the 46 forced outages at the converter stations (see 2010 CIGRE report on BP2 [22]).

The old C&P systems including those for the P1 VGs don't have self-monitoring and input signal monitoring functions as the modern digital C&P system in BP3. The TFR traces, SER alarms and status indications on the C&P panels and PCBs (e.g. control cards, relay cards, etc.) don't provide enough information that helps to pinpoint the location of the fault, which could be either inside or outside the C&P system. The controls and protection are highly integrated even if they are in separate cubicles/panels. A protection panel might show up as a control system fault or vice versa. The measurement circuit problem might look like a fault in the control or protection panels. Monitoring equipment or measurement devices are often needed for checking various signals of interest in the C&P systems. All this makes a C&P system fault difficult and time-consuming to locate. Below are some examples:

- On Nov. 29, 2005, VG31 at Dorsey had a control problem resulting in a pole outage of 40 hours.
- During Sept. 29 to Oct. 12, 2017, a failed diode in the pole/line differential protection caused the group controls of VG22 to malfunction, which forced the VG out of service for more than 12 days.
- On the weekend of Apr, 06, 2019, VG22 could not be restored back to service following a scheduled outage. After many hours of investigation in the VG controls, it was found that a problem was in the pole controls. To troubleshoot the problem, P2 needed to be taken out of service, but the pole had not been available for troubleshooting until the following weekend. VG22 was forced out of service for more than 7 days.

Sometimes, a pole or group outage occurs due to an intermit fault in the C&P system. Such a fault is even more difficult to troubleshoot because the fault usually disappears by itself before it is located. The only way to locate the fault is to restore the affected pole or group back to service with monitoring being installed, and then wait for the fault to occur again. Sometimes, the monitoring points have to be changed multiple times until the fault is located. This usually leads to multiple forced pole or group outages. Below are some examples:

- In October 2012, a defective ring counter in the group controls of VG23 at Radisson caused two forced VG outages before it was located.
- In June 2006, VG31 at Henday suffered 3 forced outages due to a defective card in the pole controls. A pole outage had to be taken to replace the card.
- In November 2009, Pole 3 suffered 3 forced outages due to an intermittent fault in the VG42 bridge controls.
- During July to November in 2010, a faulty 25V supply fuse holder in the VG42 bridge controls at Henday resulted in 5 pole outages.
- In December 2016, a fault occurred in the VG32 controls, causing a pole outage. It took half a year to locate the fault, which caused a total of 6 forced pole outages.

The VBE in BP2 is no different than the C&P systems in terms of redundancy, complexity and troubleshooting.

The AC and DC filter protection systems were built using the same analog electronics technology as the pole and VG controls. They are also complex, hard to understand, and difficult and time-consuming to troubleshoot. For instance, the 12th harmonic DC filter F401N at Henday was taken out of service on Oct. 21, 2018 due to a problem in the associated protection panel. It took near 7 months to identify and resolve the problem due to lack of staff expertise, manpower, spare parts, and reliable test sets. P4 relied only on the 12th harmonic filter at Dorsey to operate during that period. Should a problem happen to that filter, P4 would have been forced out of service.

The analog C&P systems do not only make faults/problems in themselves difficult to troubleshoot, but also make those at other locations difficult to find. Below are just a few examples:

- On Oct. 31, 2018, VG41 at Dorsey was tripped by ESOF due to commutation failures, causing the VG to be out of service for 8.2 days. This could be caused by a problem either in the thyristor valves or in the associated controls or VBE. After 8 days of intensive investigation, a problem was found in one bridge arm, which seemed to be a cause, if not the cause, of the outage.
- Over the period of Mar. 04 to Sept. 19, 2019, commutation failures in VG31 at Dorsey caused 7 outages of the VG itself with a total duration of 81 days as well as 4 pole outages. The TRF traces looked similar to those associated with the above mentioned outage of VG41. After 6 months of investigation, the problem was found to be in the VBE of VG31D.
- On Dec. 26, 2015, the abnormal firing angle protection of VG12 at Radisson operated, forcing the VG out of service for 3.5 days. The problem could be either in control or

protection panels, but it was eventually traced to a failed coaxial cable connector in the bushing capacitor tap termination box of the associated converter transformer.

For the above reasons, a highly skilled and knowledgeable plant engineering workforce is necessarily required to troubleshoot a fault in the old C&P systems and restore the affected VG or pole back to service in a timely manner.

6.2.2. Increasing workload associated with aging HVDC equipment

BP1 and BP2 are 48 and 41 years old, respectively, which are among the oldest HVDC systems in the world.

No major refurbishment has been done for the HVDC equipment inside the BP2 converter building. Most of the major system components such as thyristor valves, HVDC controls (i.e. pole and VG controls), DC controls, AC and DC filter protection, etc. are still original.

A lot of system components in BP1 have been replaced or refurbished, which include mercury-arc valves, smoothing reactors, bypass switches, P1 valve cooling controls, VG interlocking controls, etc. What has not been replaced includes the analog C&P systems, pole interlocking controls, pole transductors, motor-generator (MG) sets, communication system, T-switches, AC and DC disconnects, and so on (see [1] for more details).

Now, the workforce, especially the plant engineering workforce, do not only take care of the different types of old C&P systems in BP1 and BP2, but also have to deal with various equipment aging or EOL related issues. The associated workload is expected to increase as the aging of equipment continues.

6.2.3. Quick look at modern digital HVDC controls

For the purpose of comparison, let us have a quick look at the digital C&P systems in BP3, which are representative of all modern digital HVDC control technologies.

To eliminate single points of failure and ensure uninterruptible operation, both control and protection systems in BP3 are provided with full redundancy, i.e. each of them consists of two fully functional systems (System 1 and System 2). One system is active and the other is on standby. Redundancy is also provided for the measurement circuits by using separate sensor electronics. If a fault occurs in the active system, the standby system will be switched in seamlessly. Therefore, BP3 can hardly have C&P fault related pole or VG outages. In additional, there is no need to take a pole or VG outage out of service for the purpose of replacing a defective part/component in the C&P systems.

The control and protection functions are realized with Simatic TDC systems that have comprehensive self-monitoring functions. The TDC software and powerful iba Transient Fault Recorder (TRF) allow for easy and quick online access to various digital and analog signals. All this makes the digital system much easier to troubleshoot than the old ones in BP1 and BP2.

Apparently, once the old C&P systems in BP1 and BP2 are replaced with the same digital technology (e.g. Siemens’s, Alstom’s, ABB’s, etc.), their maintenance and staffing needs will be reduced substantially.

6.2.4. Quick look at maintenance of thyristor valves

Also for the purpose of comparison, let us take a quick look at the maintenance of thyristor valves.

Each thyristor valve has a certain number of redundant thyristor levels in order to eliminate a forced outage due to random thyristor or thyristor level faults. In P1 for instance, each valve has 3 redundant thyristor levels. This allows random thyristor faults to be fixed before the redundancy in any valve is exceeded, which is usually done during opportunity outages, i.e. those scheduled for other work. Therefore, unlike C&P system faults, valve component failures do not usually cause pole or VG outages.

The status of each thyristor level in the valve is monitored by the associated VBE and TFM. This makes it easy to locate a thyristor fault. For this reason, the troubleshooting and repair work of thyristor faults are usually performed by telecontrol and electrical maintenance without support from plant engineering except in the case of a valve fault like thyristor redundancy exceeded, overcurrent, commutation failure, etc. or a major valve hall event like flashover, fire, etc.

When an unusual problem happens to thyristor valves, plant engineering is definitely required to resolve the problem. One example is the P1 thyristor leakage problem that caused numerous beaker trips in VG11 at Radisson. It took approximately 7 years for this problem to be fully resolved [10, 11].

The three types of thyristor valves in BP1 and BP2 are ranked from maintenance-intensive to maintenance-free as follows:

- The BP2 thyristor valves are maintenance-intensive because each of them consists of a large number of unreliable aging components such as thyristors, SAB cards and tubing components. The maintenance work mainly includes the replacement of thyristor modules in the valve halls and the troubleshooting and repair of thyristor modules and SAB cards in the shops.
- The P1 thyristor valves require much less maintenance than the BP2 valves. The maintenance work mainly includes replacing the failed thyristors and their associated gate units in the valve halls, and testing, troubleshooting and repairing the gate units in the shops. In addition, the thyristors in VG13 at both ends and VG11 at Radisson need to be checked periodically for increased leakage currents.
- The P2 thyristor valves have proven to be maintenance-free as Siemens claimed except that the grading electrodes in the valve cooling circuits need to be cleaned every 9 months. The thyristor failure rate has been extremely low. For instance, there has been no thyristor failure at Radisson over the last 10 years. No troubleshooting and repair work is required for the P2 valves in the shops.

The differences between thyristor valves and C&P systems in terms of maintenance are summarized as follows:

- Unlike C&P system faults, component failures in any thyristor valve do not usually cause a pole or VG outage thanks to the redundant thyristor levels in the valve.
- It is much easier to locate a failed component in the thyristor valves than in the C&P systems because every thyristor level is monitored by the associated VBE and TFM.

- Support from plant engineering is not usually required for routine troubleshooting/repair work, but required for valve related forced outages, major valve hall events (e.g. flashover, fire, etc.) and unusual problems (e.g. the P1 thyristor leakage problem, etc.).
- The thyristor valves in BP2 are maintenance-intensive due to the large number of aging components. The valves in P2 are practically maintenance-free, and those in P1 require much less maintenance than those in BP2.

In summary, a random component failure in the old C&P systems is much more difficult and time-consuming to locate than in the thyristor valves and therefore has more impact on the reliability of the HVDC system.

6.3. SUMMARY

BP1 and BP2 contain 3 types of very complex and highly customized old C&P systems which are completely different from one another. A unique skill and knowledge set is required to maintain each of the systems, which cannot be transferred from any other locations within the corporation, including the BP3 converter stations. Any new staff at the converter station, especially new plant engineers, have to learn all the 3 types of C&P systems along with various other types of station equipment such as thyristor valves, VBE and TFMs, cooling systems, etc. The past experience shows that it would take at least 10 years for a plant engineer to get trained (see Section 6.1).

The analog C&P systems are difficult and time-consuming to troubleshoot as illustrated in Section 6.2. Therefore, it is crucial to have enough fully trained plant engineers to provide 24/7 on-site engineering support in outage or emergency situations so that the related equipment can be restored in a safe and timely manner.

The workforce, especially the plant engineering workforce, do not only take care of the different types of old C&P systems in BP1 and BP2, but also have to deal with various equipment aging or EOL related issues. The associated workload is expected to increase as the aging of equipment continues.

The above described facts must be taken into consideration when planning for the HVDC system upgrades and determining the associated staffing requirements.

7. THYRISTOR VALVE AND CONTROL REPLACEMENT OPTIONS FOR BP1 AND BP2

The main purpose of this section is to identify and discuss the technically feasible options for the valve and control replacement in BP1 and BP2, aiming to address the various issues, concerns and risks identified in this report. A long-term plan for the BP1 and BP2 system upgrades is being developed jointly by System Planning and TAM considering other factors such as the possibility of improving the Northern Collector System (NCS), etc.

7.1. THYRISTOR VALVES AND CONTROLS DUE FOR REPLACEMENT

The valves and controls that need to be replaced are summarized in Table 7.1. It is seen that all three types of C&P systems in BP1 and BP2, and the thyristor valves in BP2 have passed or long passed the ends of their expected lifetimes.

The 27 year old P1 thyristor valves will reach the end of their 32 year expected lifetime in 2024 (see Section 2). If they are replaced along with the controls, there will be no waste of their useful life considering that valve replacement would take at least 5 years (from planning to commissioning).

Table 7.1. Thyristor valves and controls that need to be replaced and their ages and expected lifetimes (years).

Equipment	Age	Expected lifetime	Age in 2025	Age in 2028	Age in 2035	Reference sections in addition to 2.1 to 2.4
P1 thyristor valves	27	32	33	36	43	4.1
P2 pole and VG controls (analog)	43 to 48*	29	54	57	64	5.1
P1 pole controls (analog)	48	29	54	57	64	5.1
P1 VG controls (analog-digital)	27	25	33	36	43	4.2
BP1 master controls (analog)	48	29	54	57	64	
BP2 thyristor valves	34 to 41*	32	47	50	57	3.1
BP2 pole and VG Controls (analog)	34 to 41*	29	47	50	57	3.3 and 3.6

***Note**: See Section 1 for more details.*

The above facts combined with the various issues, concerns and risks identified in Sections 3 to 6 suggest that all the above mentioned equipment should be replaced as soon as practically possible.

7.2. BP2 VALVE AND CONTROL REPLACEMENT

As mentioned in Section 3.5, it is possible that 3 VGs could be maintained until 2026 by shutting down one VG for spare parts when needed, and also possible that only two VGs would need to be replaced to meet the minimum capacity requirement of 1000MW (see Appendix E). For the purpose of discussion, it is assumed that only two VGs would be replaced, either two VGs in one pole (Option#1) or one VG in each pole (Option#2).

It is beyond the scope of this report to discuss how much HVDC capacity, 1000MW or 2000MW, would be required to meet the minimum HVDC capacity requirement and all stakeholders' needs. If BP2 is required to transmit 2000MW until 2026 and beyond, the BP2 valve refurbishment project needs to be advanced. This is because there is no guarantee that all the VGs can be maintained until 2026 due to lack of spare parts, especially for the valves (see Section 3). The scope and budgetary costs for replacing two poles are given in the Teshmont report [32].

7.2.1. BP2Option#1 – replacement of one pole

This option is to refurbish only one pole at both stations and add metallic return switching equipment for monopolar operation so that one DC line can be connected as a metallic return (see Appendix D in [32]).

For the sake of discussion, it is assumed that P3 is selected for refurbishment.

Scope

The 41 year old converter stations have passed the age at which typical HVDC system life extension measures (e.g. refurbishment of VGs only) are no longer feasible, both technically and financially. This is because the longest lasting station components such as civil work, DC buswork, structures, etc. will reach the end of their 50 year expected lifetime by 2028 and all other station components have long passed the ends of their expected lifetimes (see Appendix A).

Therefore, all of the original system components in P3 should be replaced along with the thyristor valves.

The scope and budgetary costs of this option are given in the Teshmont report [32].

Timing

As previously mentioned, it is possible to maintain three VGs until 2026 by shutting down one VG for spare parts when needed.

Can the valve replacement project be deferred beyond 2026? The answer is yes, but it is not recommended from the planning perspective. First, all of the original station components will reach or pass the ends of their expected lifetimes by 2028 (see Appendix A). Second, the valves are in severely deteriorated condition (see Section 3). Third, there is no evidence showing that the converters and associated equipment can be maintained for more than 50 years without major refurbishment (see Section 2).

Discussion

The merits of this option are summarized as follows:

- As the two poles are controlled independently, there will be no difficulty interfacing the new controls in one pole with the existing controls in the other pole.
- P3 will be reliable for 35 years after all its aging equipment is replaced.

- It offers the flexibility to keep P4 going until it can no longer be maintained or replace P4 when more reliable transmission capacity is required.

The major issue with this option is that the workforce will have to maintain two different control technologies until P4 is shut down. This, however, will not be a major concern if the two types of old C&P systems in BP1 are replaced (see Section 7.3.4).

7.2.2. BP2Option#2 – replacement of one VG in each pole

An alternative option is to refurbish the stage 1 VGs (i.e. VG31 and VG41) at both stations. This option is expected to be more expensive and difficult to implement than BP2Option#1 for the following reasons:

- Replacement of the pole related equipment such pole controls is required for both poles.
- There will be more issues with interfacing between the new and existing controls in each pole.

Therefore, there is no point to further discuss this option in the planning study for BP1 and BP2.

7.2.3. Operation of BP2 after P3 replacement

For the sake of discussion, it is assumed that P3 would be refurbished by 2026.

Although each individual existing VG in P4 will not be as reliable as the new one, two existing VGs plus a new pole should be able to provide 1500MW reliable capacity for some years after 2026. That would be sufficient to meet the minimum HVDC capacity requirement as described in Appendix E. In addition, from the operation perspective, we wish to keep P4 going as long as possible in order to minimize the transmission losses.

A question has been asked by System Planning as to how long the aging VGs in P4 can last? It is possible to keep them going for many years beyond 2026, but various other aging system components as described in Section 3, and ongoing staffing issues may limit the remaining useful life of the aging VGs.

To keep the aging VGs going beyond 2026, the following actions/measures need to be taken:

- Have a knowledge transfer and retention plan in place to ensure that the workforce is capable of maintaining the old thyristor valves and all the associated analog electronic controls and protection.
- Refurbish or rebuild the VBE test equipment. Without the test equipment at either station, it will be difficult, if not impossible, to maintain and troubleshoot the VBE.
- Acquire additional fiber optic light guides. How many of them would be required depends on further condition assessment of the light guides in VG32 and VG42.
- Refurbish thyristor modules by replacing the their aging components such as the seriously leaky thyristors.

If there is no need to replace P4, it may be shut down permanently. Shutting down each aging VG should be carried out in a controlled and proactive manner, depending on the availability of staff expertise, risk of fire, O&M costs, etc.

7.3. BP1 VALVE AND CONTROL REPLACEMENT

Depending on whether the valves are replaced along with the controls or not, we have two options, i.e., to replace the valves and controls (Option#1) or the controls only (Option#2).

7.3.1. BP1Option#1 – replacement of BP1 controls and P1 valves

This option is to replace the BP1 controls (i.e. master, pole and VG controls) and the P1 thyristor valves at both Dorsey and Radisson.

Scope

The scope of the control replacement project is given in the Teshmont report [31], which includes the master, pole and VG controls as well as the associated aging control equipment/panels.

The Teshmont report does not include the valve replacement as part of the control replacement. Below is the reason why it should.

The 27 year old thyristor valves in P1 will reach the end of their 32 year expected lifetime in 2024 (see Section 2). The control replacement project would be at least 5 to 6 years away. For the sake of argument, it is assumed that the controls will be replaced by 2025. The thyristor valves will be 33 years old by that time. If the valves are replaced along with the controls, there will be no waste of their useful life.

It is worthwhile to note that 14 of the 19 retired thyristor valve technologies listed in Table 2.3 were replaced before/at the age of 32. For instance, at the BPA Celilo converter station, all the 6 Siemens VGs installed in 2004 were replaced by 2016 along with the controls and other thyristor valves (see Section 2.3.3).

The issues with the control only replacement option will be discussed in Section 7.3.2.

Timing

The timing of the valve and control replacement will be discussed in Section 7.3.4.

Discussion

This option has the following technical benefits, which are irrelevant to the timing of the valve and control replacement:

- The inherent commutation failure problem with the Alstom valves and controls will be eliminated.
- We don’t have to face the challenges, issues and risks as described in Section 7.3.3.
- Having the same types of valves and controls at both ends will allow us to share the engineering and technical resources between the south and north. It is one of the effective ways to address the ongoing staffing issues, especially in the north.

- The new thyristor valves will be much easier to maintain. The technical and engineering staff at both ends will have more time to look after various types of aging equipment in BP1 and BP2.

No technical disadvantage has been identified as compared to other options.

7.3.2. BP1Option#2 – replacement of BP1 controls only

This option is to replace the controls (i.e., master, pole and VG controls) in BP1 and retain the P1 valves at both ends.

Scope

The scope of this option is the same as BP1Option#1 with the following exceptions:

- The TFMs will be replaced along with the controls.
- The valves will be retained.
- The VBE will stay with the valves.

Timing

The timing of the control replacement will be discussed in Section 7.3.4.

Discussion

For the purpose of discussion, let's assume that only the BP1 controls will be replaced by 2025. If the thyristor valves are to be retained, the expectation is that they will be able to survive for 48 years or until 2040 when the new controls reach the end of their 15 year expected lifetime so that the valves and controls can be replaced at the same time.

However, such an expectation is unrealistic for a couple of reasons. First, no valve component has an expected lifetime above 35 years (see Section 1.6 of [5]). The EOL failures of some types of components are highly possible over the next 20 years. Second, there is a lack of spare saturable reactors, heatsinks and GRP tension bands (see Sections 4.1 and 4.3). Third, Alstom has long ended the support for the P1 valves, and it will be difficult to find spare/replacement components for replacing the failing or aging valve components. If we run out of spares before 2040, which is a high probability event, one of the following unwanted consequences are inevitable:

- Shutting down one VG for spare parts to keep the other VGs going. As a result, BP1 will lose one VG (or 309MW capacity) for several years.
- Replacing the P1 valves and the BP1 controls separately within an unreasonably short period of time.
- Replacing the P1 valves and BP1 controls altogether before the controls reach the end of their 15 year expected lifetime.

Another major issue is that the functionality of the Thermal Analogue (TA), which is an integrated part of the thyristor protection scheme, has to be retained in the new VG controls, which makes it difficult to replace the controls without replacing the valves (see Section 7.3.3).

No technical benefit has been identified as compared to BP1Option#1.

7.3.3. Difficulty in replacing P1 VG controls

The P1 valves and controls were installed by Alstom in 1992. Each P1 VG has a very sophisticated thyristor protection scheme that involves the thyristor gate units and the complex TA and FC system that is an integrated part of the VG controls. The function of the TA is to simulate the real-time thyristor junction temperature (Tj) (see Appendix D). The FCs combine Tj with the start/stop commands from the VG controls to form coded firing pulses that are transmitted to the VBE and then from the VBE to the thyristor valves through optical fibers. The Tj information decoded from the firing pulses is used as an input for the Tj dependent thyristor forward recovery and overvoltage protection built in each gate unit. Such a system is unique to the Alstom valves and controls. There is no TA or anything similar in P2, BP2 and BP3.

Due to the special design as above described, it is difficult to replace the VG controls without replacing the valves, or vice versa. In contrast, the valves and controls in other projects can be upgraded separately without much technically difficulty. For example, the P2 mercury-arc valves were replaced with the Siemen thyristor valves in 2004, but the existing analog VG controls were retained. What was required was merely a simple interface between the existing controls and Siemens VBE in addition to minor control modifications. The P2 valve replacement project went quickly and smoothly. Back in 1992, however, the mercury-arc valves and VG controls had to be replaced along with the Alstom valves and controls for above described technical reasons. Thus, BP1 ended up having two types of complex C&P systems.

If the Alstom valves are to be retained when upgrading the BP1 controls, we have to face the same challenges and issues, if not more, as ATCO Electric did during the process of upgrading the controls at the McNeil converter station where the valves and controls were built by Alstom using a similar technology [26]. Some of them are described below:

- The technical specifications for the control replacement will have to include a provision to retain all the functions of the TA, the proprietary property of Alstom. This provision apparently favors Alstom over other HVDC venders. For this reason, Alstom as the OEM was awarded the contract for the McNeil control replacement [26]. Thus, the option of retaining the thyristor valves would significantly affect the tendering process and limit the chance of selecting the best control technology for our HVDC system.
- Alstom may not keep detailed design information for the old project as was the case with the McNeil project. Relying on the old documents, which might be inaccurate and incomplete, to replicate the functions of the TA entails significant risks as recognized and experienced by ATCO. For this reason, ATCO conducted frequent design reviews with Alstom and participated in all the factory tests. In spite of that, there were still some design errors and issues discovered during the installation and commissioning phase, which required further design work by Alstom. Deficiencies were also discovered after the new controls were commissioned, which took almost a year to fix.

The P1 control replacement would likely happen at least 10 years after the McNeil control replacement. It is reasonable to expect that we would face more challenges and issues than ATCO. One of them, for example, is the diminishing technical resources for the Alstom control replacement.

All the above challenges, issues and risks as well as the difficulties of interfacing with the existing equipment and other risks as discussed in Section 7.3.2 will ultimately translate, directly and indirectly, to increased costs that may well offset the short-term saving from deferring the P1 valve replacement.

7.3.4. Timing of BP1 control replacement

The control replacement should be done first in BP1 and then in BP2 for the following reasons (but not necessarily limited to):

- The 27 year old analog-digital VG controls in P1 have passed the end of their expected lifetime of 25 years (see Section 2.3.2). To delay the controls replacement entails various risks as described in Section 4.3.
- The expert knowledge and support for replacement of the original HVDC control technologies in BP1 are diminishing and will no longer be available 10 years from now.
- Power from the $10 billion new Keeyask generating station and existing Kettle generation station will mainly rely on BP1 to transmit because the transfer capability from BP1 to BP2/BP3 is limited. This requires that BP1 be maintained at the same level of reliability and availability as before, if not higher, but such a requirement is very difficult to meet unless the old controls are replaced.
- For the same reason as above mentioned, access to the controls in BP1 for training and troubleshooting purposes will become more difficult after the Keeyask generating station is put in service. This combined with the poor quality of the manuals and drawings will make the associated maintenance and training more difficult (see Section 6).

If BP1 is refurbished with new controls before BP2, the following benefits will be realized (but not limited to):

- The two types of complex old C&P systems will be eliminated. The workforce will then be capable of maintaining just one type of analog control technology in BP2, and the impact of retirement and ongoing staffing issues will be minimized.
- Significant engineering and maintenance resources will be freed up to look after the various types of aging equipment in BP1 and BP2.
- It is possible to refurbish BP2 using the same type of control technology as suggested in [1]. The skills and knowledge gained from the installation and commissioning of the new BP1 controls can be directly used for the BP2 refurbishment.
- Training of engineering and technical staff will become much easier for the following reasons:
    - They can be trained more effectively during the installation and commissioning of new controls.
    - The 1000MW extra capacity (or two extra VGs) in BP2 will make it much easier to access the various types of equipment for troubleshooting and training purposes.
    - The BP2 manuals and drawings are well organized and still in good quality.
- It will be much easier to recruit and retain younger staff to learn and work on the modern digital controls.

The above underscores the importance and necessity of refurbishing BP1 with new controls before BP2. No opposite decision should be made unless:

- MH can manage to secure the necessary engineering and technical resources for maintaining the three types of old C&P systems in BP1 and BP2 until 2026 and an additional type afterwards assuming that the BP2 refurbishment will be completed by 2026.
- The decision is supported by a detailed planning study where the major issues and risks identified in Sections 4 and 5, especially the risk of losing one P1 VG due to lack of spare parts for the Alstom valves or controls, are properly addressed.

7.3.5. Partial control replacement for BP1

The partial control replacement (i.e. piecemeal approach) is to replace the controls in one pole only, either in P1 or in P2.

The option to replace the controls only in P1 can be justified if the Alstom controls are the only ones that need to be replaced. This is apparently not the case because the 48 year old controls in P2 also need to be replaced. Moreover, if this option is implemented, BP1 and BP2 will end up having 4 different control technologies after one pole in BP2 is replaced. This will make the associated maintenance and training much more difficult.

The option to replace the controls only in P2 seems to serve no technical purpose but to cause additional problems, as described below:

- The parts retired from the controls in P2 can be used as spares for the pole controls in P1, but they are not necessarily needed simply because it has never been an issue to get new spare/replacement parts for repairing the original analog controls or rebuilding cards.
- The issues and risks associated with the two types of C&P systems in BP1 will remain unaddressed.
- A new control technology will be added to BP1. After one pole is replaced in BP2, there will be 5 different types of complex C&P systems in BP1 and BP2, 3 in BP1 and 2 in BP2. This will make the associated maintenance and training extremely difficult, if not nearly impossible.

In addition to the above, there are various issues/problems inherently associated with the piecemeal approach as discussed in Section 4.3 of the previous condition assessment report [2].

The piecemeal approach shall not be adopted for the BP1 control replacement unless it can be justified through a detailed lifecycle cost analysis that takes into account all the above mentioned issues and risks.

It should be noted that it is not a piecemeal approach to replace only one pole in BP2 if it meets the HVDC capacity requirement and other stakeholders' needs.

8. CONCLUDING SUMMARY

A review of the EPRI and CIGRE HVDC life extension guides [4, 5] and the upgrade history of HVDC projects installed during 1970 to 1995 in the world, especially those similar to ours, indicates that the thyristor valves and controls in BP2, the controls in BP1 and the analog-digital VG controls in P1 have all passed the ends of their expected lifetimes (see Section 2). By 2028, all of the valves and controls will be 36 to 57 years old (see Tables 1.1 and 7.1), and should be replaced before 2028 or as soon as practically possible.

The above conclusions are reinforced by the need to address the various key issues identified via the condition assessment presented in Sections 3 to 6.

The technically feasible options for replacing the valves and controls in BP1 and BP2 are identified and discussed in Section 7.

To delay the control and valve replacement entails various risks, some of which are highlighted below:

- EOL of one or multiple VGs in BP2 (see Sections 3.5 and 3.6).
- Loss of one VG in P1 due to lack of spare parts for the valves and controls (see Section 4.3).
- Deterioration of the availability and reliability of BP1 due to the aging analog controls and knowledge loss (see Section 5.1).
- Deterioration of the knowledge base required for maintaining so many types of complex old C&P systems due to various issues as identified in Section 6 and ongoing staffing issues.

It is expected that these risks will be evaluated and addressed in the related planning study.

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APPENDIX A: COMPONENT LIFETIMES OF HVDC CONVERTER STATION

Listed below in Table A-1 are the component lifetimes provided in the EPRI Life Extension Guidelines of Existing HVDC Systems, Report 1013976. Similar information is also available in the CIGRE Life Extension Guidelines of Existing HVDC Systems, TB 649.

Table A-1. Component lifetimes of HVDC converter station.

Component	Expected lifetime (years)
[redacted]	[redacted]

2b

**It should be noted there are many converter transformers and thyristor valves that have experienced early failures and have much shorter lifetimes.*

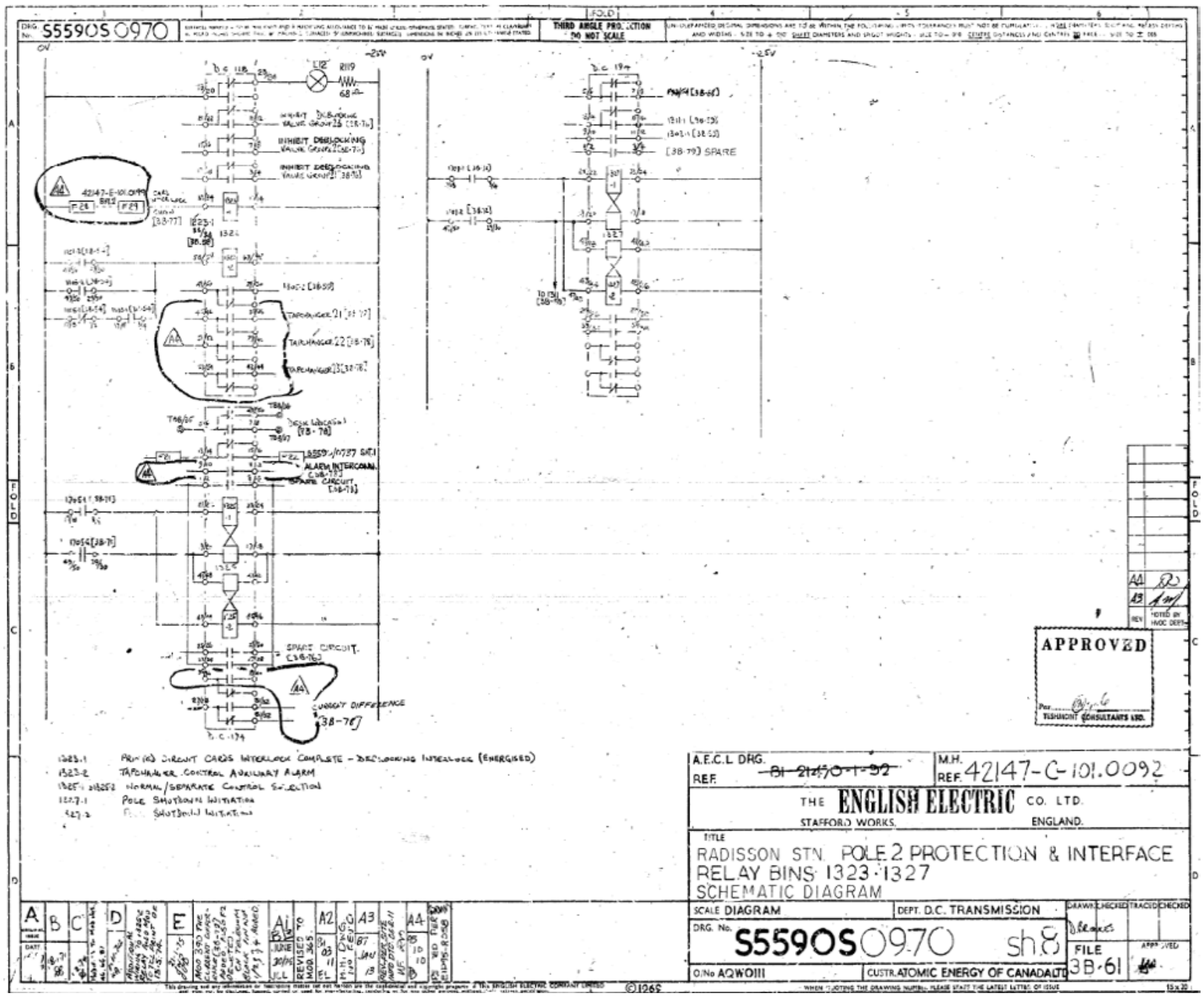
APPENDIX B: CIGRE SURVEY OF VALVE HALL FIRES AS OF 1999

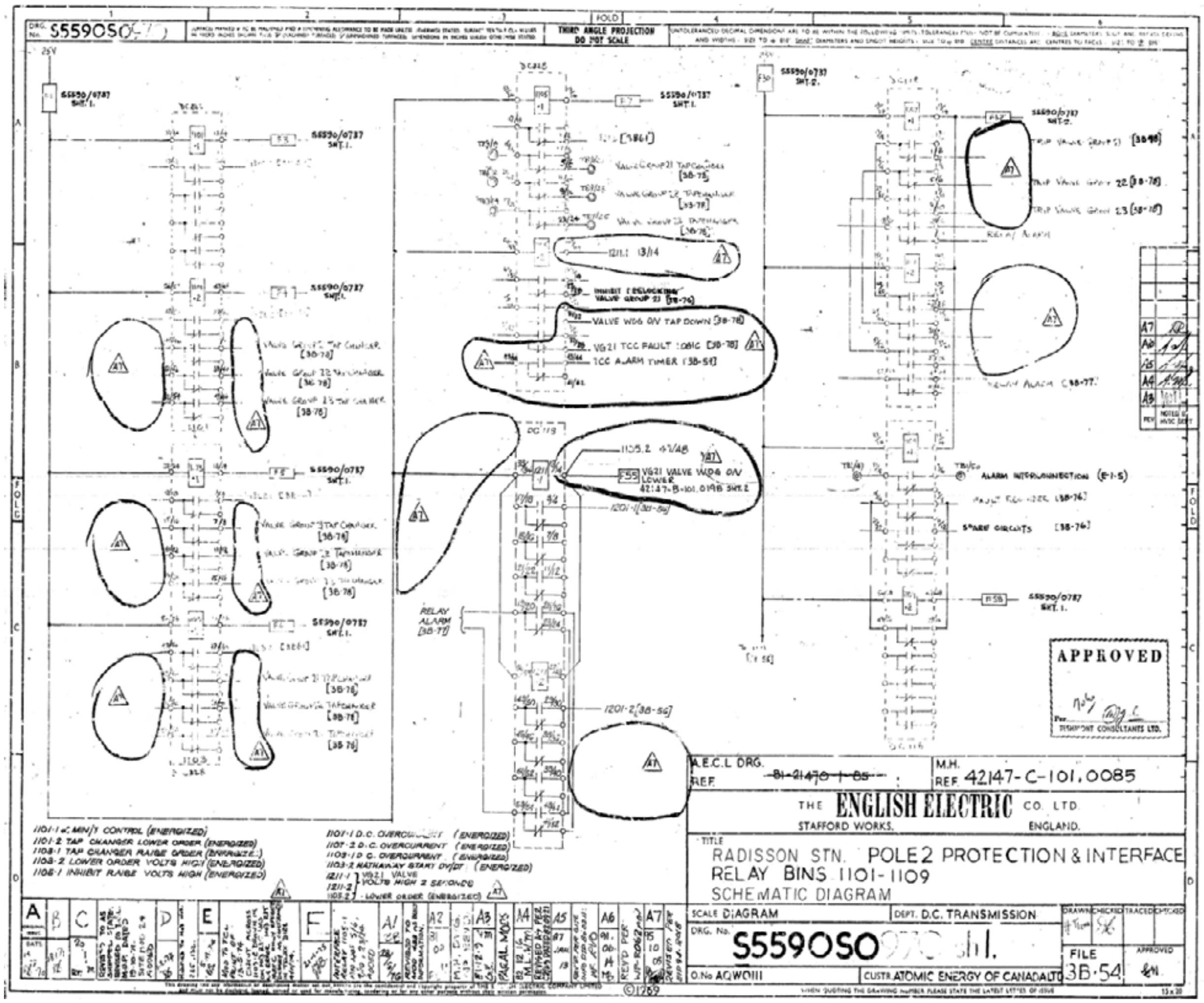
According to a survey conducted by CIGRE WG 14.01, over 29 valve hall incidents had occurred before 1994 in the different HVDC projects throughout the world (see CIGRE TB136 [20]). The results of the survey are briefly summarized below in Table B-1.

Table B-1. CIGRE survey of valve hall fire incidents as of 1999.

Scheme	Outage duration	Cause	Year of incident
Nelson River BP2	6 hours	Partial blocking of DIW to a reactor module.	???
Itaipu	4 days	Failure of a reactor.	1992
Hydro Quebec-New England	6 hours	Damping resistor failure.	1991
Nelson River P2	0 hour	Gate electronic board was partially burnt. Discovered during maintenance.	1993
Intermountain	4 & 1 hours	Two incidents due to the oil leaks of thyristor grading capacitors.	1987 & 1990
Gezhouba-Shanghai	< 7 days	A date electronic card failure. Six cards and four light guides were destroyed.	1991
Chateauguay B2B	4 months	Loose connection causing fire in a cable trench which led to the destruction of the VBE.	1984
CU	2 days	Loose connection causing fire/arc which damaged several oil-filled capacitors.	1985
Eel River	4 days	Loose connection causing fire that resulted in the melting of some thyristor heatsinks.	1972
Vancouver Island P2	1 hour	Loose connection causing minor damage.	1984
Gezhouba-Shanghai	47 days	Poor connection to reactor resulting arc. This led to the melting of metal, burning of reactor, and partial flashover.	1994
CU	< 1 day	Loose connection resulted in damage of a damping capacitor, causing smoke damage.	1986
Intermountain	1 day	Fire resulted from loose connection to dc grading resistor.	1990
Rihand-Delhi	15 months	Fire destroyed one quadrivalve and caused extensive damage to other valves. Possible cause was loose connection to DC grading resistor.	1990
Eel River B2B	< 7 days	Loose connection in a resistive voltage divider created arc. The voltage divider was destroyed.	unknown
Indian National HVDC Experimental	4 months	Loose connector in thyristor level circuit caused fire leading to damage of thyristors, light guides, and cooling water pipes.	1989
Intermountain	1 hour	Loose connection to DC grading resistor.	1989
Itaipu	14 months	Water leak resulted flashover/fire. A quadrivalve was destroyed.	1989
Nelson River BP2	7 weeks	Failure of oil-filled wall bushing due to flashover led to explosion and fire at Dorsey.	1987
Pacific Intertie	< 7 days	Water leak caused flashover. Some grading resistors & resistors, and light guides were destroyed.	1989, 1990, 1990
Vancouver Island P2	< 4 weeks	High humidity caused flashover leaking smoke damage.	1990
Vancouver Island P2	14 weeks	Tracking due to humidity caused smoke damage.	1990
Gezhouba-Shanghai	1 day	Water leak caused flashover which destroyed a reactor.	1991
Inga-Shaba HVDC Intertie	< 6 months	Fire destroyed 66 thyristors out of 258 per valve. Cause was not identified. Likely by water leak.	1992
Vancouver Island P2	29 days	Flashover caused failures of 66 thyristor levels and damage to valve structure. Cause not accurately identified.	1994
Pacific Intertie	> 15 months	All valve in one pole at Sylmar were destroyed by fire. Caused not reported.	1993

APPENDIX C: EXAMPLES OF POOR QUALITY DRAWINGS OF POLE 2




S559OSO
THIRD ANGLE PROJECTION DO NOT SCALE
APPROVED
A.E.C.L. DRG. REF.
M.H. REF 42147-C-101,0085
THE ENGLISH ELECTRIC CO. LTD.
STAFFORD WORKS. ENGLAND.
RADISSON STN. POLE 2 PROTECTION & INTERFACE
RELAY BINS 1101-1109
SCHEMATIC DIAGRAM
SCALE DIAGRAM
DEPT. D.C. TRANSMISSION
O.No AQW0111
CUSTR ATOMIC ENERGY OF CANADA LTD
FILE 3B-54
©1969

APPENDIX D: BLOCK DIAGRAM OF P1 VG THERMAL ANALOGUE

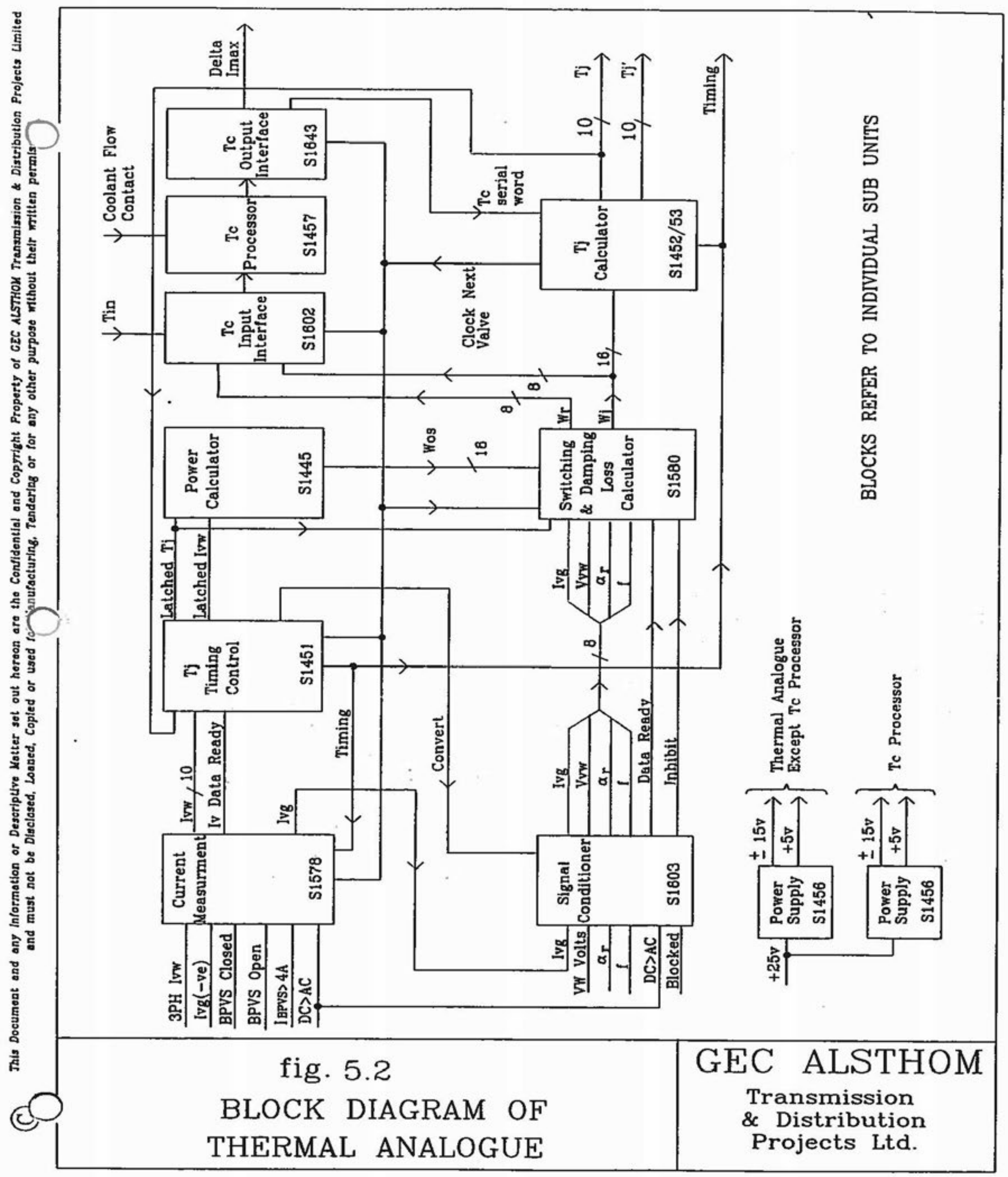


fig. 5.2
BLOCK DIAGRAM OF THERMAL ANALOGUE

APPENDIX E: HVDC CAPACITY REQUIREMENTS

The minimum capacity requirement for the Nelson River HVDC system is stated in [E1] as "The MH High Voltage Direct Current (HVDC) System is planned, designed and constructed such that the minimum total HVDC Facility rating is equal to the total amount of NETWORK INTEGRATION TRANSMISSION SERVICE from all GENERATOR FACILITY(IES) connected to the NORTHERN COLLECTOR SYSTEM plus 500 MW (largest HVDC valve group rating)" (see Item 2.27 on Page 34 of [E.1]). **6**

The total firm northern collector system generation will be 4184MW, including the 630MW from Keeyask scheduled to be in-service by 2021. Bipole 3 was primarily intended to address the inadequacy of HVDC capability during catastrophic HVDC outages, but offers a de facto benefit to provide additional HVDC capacity. With the aging of the existing HVDC system, retirement of some of the existing Bipole 2 (BP2) capacity has become possible.

However, to meet the above described planning requirement, the minimum total HVDC capacity shall be at least 4684MW (i.e. 4184MW + 500MW spare). As shown in the table below, this means a minimum reliable capacity of 1000MW for BP2. Additional capacity of BP2 may be justified due to the considerations of other factors and are being evaluated.

1. NCS Generation (MW)		MW
1.1	Kettle	1224
1.2	Limestone	1350
1.3	Long Spruce	980
1.4	Keeyask	630
	Subtotal (MW)	4184
2. HVDC VG spare (MW)		500
3. HVDC minimum capacity required (MW)		4684
3. HVDC capacity (MW)		Winter/summer
3.1	Bipole 1	1854/1668
3.2	Bipole 2	1000/1000
3.3	Bipole 3	2000/2000
	Subtotal (MW)	4854/4668*

***Note:** *1000MW in BP2 meets the HVDC capacity requirement with the consideration of NCS loss.*

References:

[E1] "Manitoba Hydro Transmission System Interconnection Requirements", version 4, July 2016 (http://www.oasis.oati.com/MHEB/index html).