28 January 2011

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Dear Todd,

Holyrood Thermal Generating Station (Holyrood) Condition Assessment & Life Extension Study, - Final Report

As per our Agreement, we have completed the Holyrood Thermal Generating Station Condition Assessment & Life Extension Study Report. I trust that the report satisfies your needs.

Thank you for the opportunity to work on this very interesting project.

Yours truly,

Blair Seckington

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Holyrood Thermal Generating Station

Condition Assessment & Life Extension Study

January 28, 2011

Holyrood Thermal Generating Station Condition Assessment & Life Extension Study

Blair Seckington ____________________
Prepared by: Date

Ian Leach ____________________
Checked by: Date

Bob Livet ____________________
Approved by: Date

Rev.	Description	Prepared By:	Checked:	Approved	Date
A	Draft Report	Blair Seckington			28 Jun 10
0	Final Report	Blair Seckington	Ian Leach		28 Jan 11

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APPENDICES

Significant detailed technical information on equipment and systems was initially developed as input to this report. This information is documented in Appendices 4 through 34. The additional detailed information in these Appendices is intended primarily for the reference use of Hydro engineering and plant technical specialists. These appendices should be considered as "Working Papers".

Executive Summary

HOLYROOD THERMAL GENERATING STATION CONDITION ASSESSMENT AND LIFE EXTENSION STUDY

EXECUTIVE SUMMARY

Introduction

Holyrood Thermal Generating Station (Holyrood) is a three unit, nominally 500 MW, heavy oil fired, steam cycle fossil generating station. It is located on the south shore of Conception Bay in the province of Newfoundland and Labrador, between the towns of Holyrood and Conception Bay South. Holyrood was constructed in two stages - Units 1 and 2 in the late 1960's and Unit 3 in 1977.

When all three units are in operation at full MCR (maximum continuous rating), Holyrood is capable of supplying approximately 33% of the Newfoundland and Labrador electricity demand. Typically, the units operate during the late fall to spring peak period and supply a minimum load of between 80 MW and 150 MW. The Unit 3 generator is also capable of synchronous condenser operation for grid voltage control.

Units 1 and 2 were built in the late 1960's as #6 fuel oil fired 150 MW units. Unit 1 entered service in September 1970 and Unit 2 in April 1971. These two units were modified in 1987 to increase their capacity to 175 MW. Unit 3 is a 150 MW unit and was built in 1979 and came online in February 1980.

Holyrood Phase 1 Condition Assessment Study

AMEC Americas Limited (AMEC) was contracted by Newfoundland and Labrador Hydro (Hydro), a NALCOR Energy Company, to conduct Phase 1 of a Condition Assessment and Life Extension Study for the Holyrood Generating Station.

The basis for the study was essentially:

- 2010 to 2015 Electricity Generation – similar to recent historical operation;
- 2015 to 2020 Electricity Generation - as-required, primarily "Standby" basis; and
- 2015 to 2041 Synchronous Condensing Operation – Units 1 and 2 converted to synchronous condensing capable in 2014/15 and all Units operating primarily in synchronous condensing mode to support system stability.

AMEC was to perform an initial condition assessment, generally referred in the electric utility industry as a "Level 1" assessment. This involved:

i. The review of existing maintenance and inspections information and plans, equipment and systems reviews with maintenance and operational staff, and independent visual walk-about inspections as appropriate.
ii. The development of equipment and systems assessments for:
    a. condition;
    b. action plans;
    c. technical and safety risk;
    d. life cycle status;
    e. level 2 inspection requirements; and
    f. capital investment timing.
iii. The development of key conclusions and recommendations.

The primary focus of the review was on the major equipment and systems that would be required for synchronous condensing mode operation to 2041 (i.e. generators, transformers, switchyard systems, electrical systems), but those systems required only for electricity generation to 2020 (i.e. boiler, steam turbine, fuel systems) were addressed with the 2020 end of life date as context.

Overall Plant Assessment

Holyrood is considered to be a relatively modern design plant and in good condition.

Holyrood is expected to be able to meet either the 2015 or 2020 dates for the end of its electricity generation role with capital refurbishments and replacements primarily due to typical mid-life refurbishment requirements, old age effects, and obsolescence. These are detailed later in the body of the report, but examples would include many of the breakers and motor control centres, the waste water treatment basin building structure and ventilation system, the plant elevator, and equipment such as vacuum pumps, emergency diesels and air compressors. To minimize a decrease in reliability, additional spares such as a spare 4 kV motor for each boiler feed pump, a forced draft fan, and a circulating water pump are recommended. A complete overhaul or replacement of the gas turbine generator and balance of plant would also be recommended, given its importance in a return to operation in the event of a system failure and its use as a system emergency power source.

Holyrood is also expected to be able to meet its 2041 end of life date for operation in a synchronous condensing mode, but will require some further substantial equipment refurbishments and replacements specific to that role. These are identified later in the report, but examples of these would include generator rewinds, powerhouse and pump house roof replacements, switchyard breakers and motorized switches refurbishments/replacements, and synchronous condensing conversions.

Holyrood Units 1 2, and 3 are approximately 41, 40, and 31 years of age respectively. However, given their historical seasonal based, lightly loaded service, the operational age for the majority of its equipment and systems is more like 20, 19, and 16 years, respectively. The plant has been well managed and maintained. The units have also seen minimum service at either their maximum continuous rating (let alone over-pressure/over-temperature) or at extreme minimum load. The units tend to operate between 70 and 140 MW (40% and 80% load) and most often around 110 to 125 MW (65-70%). Unit 3 has seen modest synchronous condensing operation since its retrofit in 1986.

As mentioned previously, Units 1 and 2 were uprated from 150 to 175 MW in 1987. The components that were modified or replaced during the unit upgrade have a longer life as compared to the original equipment. These support a longer life expectation for the station as a whole.

The boiler and its major elements were one of the plant’s major reliability and life issues. The original high sulphur (2.5%) and high vanadium fuel oil caused significant corrosion and fouling problems that led to upgrades to some of the boiler heat transfer surfaces. In 2009, the change to a higher quality, lower sulphur (0.7%) fuel oil has significantly improved boiler reliability and efficiency and is expected to have a positive impact on the life of boiler systems.

As indicated above, there is no reason why the plant cannot continue to generate electricity reliably to the year 2020 as identified. Similarly, if and when Units 1 and 2 are converted to synchronous condensers (current plan is conversion in 2014) to provide system support, the units and the plant should be able to fulfill that role to 2041. There are several pre-requisites to this, including continued and enhanced inspection and maintenance programs, planned major equipment refurbishment such as generator stator and rotor rewinds, controls and alarms upgrades, and switchgear and breaker refurbishments and replacements.

A key to extending plant life will be the generators, transformers, and switchgear. Units 1, 2, and 3 have major generator inspections scheduled for 2012, 2014, and 2016 respectively. They also have reliability issues that may require a near term need for stator and/or rotor rewinds and possibly later in their life core or rotor replacement. Transformers are at the point in their lifecycle where significant degradation also occurs. More frequent or continuous monitoring of their condition is required to forewarn of any problems arising. Existing switchgear is in many cases at or near end of life and refurbishment and replacement is required.

Several other key issues with single contingency systems, given age and failure history also raise red flags and include:

- The single contingency failure risk of the fresh/raw water supply from Quarry Brook Pond;
- The single contingency failure risk of the clarifier failure, at least until 2020; and
- The 42 year age and condition of the black start gas turbine – reliability, parts obsolescence make a detailed evaluation critical; especially as the island interconnected system has indicated a potential need for it as an emergency power source.

The black start gas turbine generator and its balance of plant is in need of a major overhaul, as well as refurbishment and replacement of its stack and air intake systems. In addition, it is likely that its fuel receiving and feeding system will need a major overhaul as soon as practical within the next two years.

If Hydro addresses the key issues and maintains a vigorous maintenance and inspection program, there is no technical reason that the plant cannot reach its 2020 generation end of life and 2041 synchronous condensing end of life targets.

Phase 2 Condition Assessments (Level 2 Inspections)

Following the Condition Assessment process (detailed in Section 3 of the report), AMEC identified several areas of the plant that had inadequate available information to develop a reasonable, definitive position on whether those areas/equipment could reach their desired end of life or where decisions on run or repair/replace could be taken with certainty. These areas under the Condition Assessment process should undergo a Level 2 inspection.

A summary of the recommended Level 2 inspections and their costs are presented in Section 12 of the report. More details are provided for specific units and systems/equipment in Sections 8 to 11 of the body of the report. It should be noted that the costs include the costs for the enhanced inspection/overhauls for the steam turbine and generator for Units 1, 2, and 3 in 2012, 2014, and 2016 respectively. The priorities (identified as Priority 1 through 4, with 1 being the highest) are somewhat subjective, based on the experience and expertise of AMEC staff.

Table ES-1 is a summary of Level 2 costs by priorities by year.

TABLE ES -1 LEVEL 2 ACTIVITIES SUMMARY BY PRIORITY LEVEL BY YEAR

	Total k$	2010	2011	2012	2013	2014	2015	2016	2017
Priority 1	$17,547	$392	$1,600	$4,615	$44	$6,195	$13	$4,687	$0
Priority 2	$4,811	$0	$773	$1,879	$1,929	$229	$0	$0	$0
Priority 3	$222	$0	$217	$0	$0	$5	$0	$0	$0
Priority 4	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total	$22,580	$392	$2,590	$6,494	$1,973	$6,429	$13	$4,687	$0

Table ES-2 is a summary of Level 2 costs by priority level by year for the major plant areas. These plant areas are broken down into synchronous condensing required plant equipment (Synch Cond); steam turbine and auxiliaries (Stm Turb) plant equipment required only for electricity generation; boiler and auxiliaries (Blr Stm) plant equipment required only for electricity generation; switchyard and transformer (Switchy & TS) equipment required for both synchronous condensing and electricity generation; and black start gas turbine and auxiliaries (GTG) equipment and facilities.

TABLE ES-2 LEVEL 2 ACTIVITIES PRIORITIZED SUMMARY BY PLANT AREA BY PRIORITY AND YEAR

	Total k$	2010	2011	2012	2013	2014	2015	2016	2017
Synch Cond Priority 1	$7,894	$73	$1,494	$2,286	$0	$1,961	$0	$2,081	$0
Synch Cond Priority 2	$594	$0	$594	$0	$0	$0	$0	$0	$0
Synch Cond Priority 3	$207	$0	$202	$0	$0	$5	$0	$0	$0
Synch Cond Priority 4	$0	$0	$0	$0	$0	$0	$0	$0	$0
Stm Turb Priority 1	$7,463	$0	$100	$2,311	$0	$2,451	$0	$2,601	$0
Stm Turb Priority 2	$147	$0	$147	$0	$0	$0	$0	$0	$0
Stm Turb Priority 3	$15	$0	$15	$0	$0	$0	$0	$0	$0
Stm Turb Priority 4	$0	$0	$0	$0	$0	$0	$0	$0	$0
Blr Stm Prioirity 1	$1,758	$0	$0	$0	$0	$1,758	$0	$0	$0
Blr Stm Prioirity 2	$4,070	$0	$33	$1,879	$1,929	$229	$0	$0	$0
Blr Stm Prioirity 3	$0	$0	$0	$0	$0	$0	$0	$0	$0
Blr Stm Prioirity 4	$0	$0	$0	$0	$0	$0	$0	$0	$0
Switchy & TS Priority 1	$228	$116	$6	$18	$44	$25	$13	$6	$0
Switchy & TS Priority 2	$0	$0	$0	$0	$0	$0	$0	$0	$0
Switchy & TS Priority 3	$0	$0	$0	$0	$0	$0	$0	$0	$0
Switchy & TS Priority 4	$0	$0	$0	$0	$0	$0	$0	$0	$0
GTG Priority 1	$203	$203	$0	$0	$0	$0	$0	$0	$0
GTG Priority 2	$0	$0	$0	$0	$0	$0	$0	$0	$0
GTG Priority 3	$0	$0	$0	$0	$0	$0	$0	$0	$0
GTG Priority 4	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total	$22,580	$392	$2,590	$6,494	$1,973	$6,429	$13	$4,687	$0

Conclusions & Recommendations

The study conclusions and recommendations are summarized in Section 14 and Section 15 of the report respectively. They are organized into:

Overall and Station Wide

Site Conditions

Common Facilities

Unit 1

Unit 2

Unit 3

Black Start Gas Turbine

Switchyard

Facility Management

Sections 14 and 15 should be referred to for this information.

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APPENDICES

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GLOSSARY

°F or oF	Degree Fahrenheit
°C or oC	Degree Celsius
BTU	British Thermal Unit
CO2	Carbon dioxide
CRO	Control Room Operator
CRO1	Control Room Operator Unit 1 (or 2 or 3)
CW	Circulating or cooling water
Gen	Generator (Only)
H2 or H_2	Hydrogen
HP	High Pressure
kV	Kilovolt
kVAR	Kilovolt ampere reactive
kW	Kilowatt
kWh	Kilowatthour
LP	Low pressure
Max	Maximum
MCC	Motor control centre
MCR	Maximum continuous rating
mm	Millimetres
Mg	Megagrams
mg	Milligrams
MOT	Main output transformer
MVA	Megavoltampere
MVAR	Megavolt ampere reactive
MW/MWg/MWn	Megawatt /megawatt gross/megawatt net
MWh/MWhg/MWhn	Megawatt hour/ megawatthour gross megawatthour net
Min	Minute
O2 or O_2	Oxygen
psig or psi_g	Pound per hour pounds per square inch gauge
psia or psi_a	Pounds per square inch absolute
ppmvd or ppm_{vd}	Parts per million (dry volume basis)
%	Percentage
rpm	Revolutions per minute
SC	Synchronous condenser
scfh	Standard cubic feet per hour
SCO	Shift control operator
SH	Super heat
ST	Steam turbine
STG	Steam turbine generator
T7	Transformer #7
TGS	Thermal generating station
TWh	Terawatthours (1,000,000 MWh)
VAR	Vars
V	Volts
W	“Warm” start
WO	Work order
WTP	Water treatment plant
yds	Yards
Yr (or a)	Year

HOLYROOD THERMAL GENERATING STATION
CONDITION ASSESSMENT AND LIFE EXTENSION STUDY

1 INTRODUCTION

1.1 General Description of Holyrood Thermal Generating Station

Holyrood Thermal Generating Station (Holyrood) is a three unit, nominally 500 MW, heavy oil fired, steam cycle fossil generating station. It is located on the south shore of Conception Bay in the province of Newfoundland and Labrador, between the towns of Holyrood and Conception Bay South. Holyrood was constructed in two stages - Units 1 and 2 in the late 1960's and Unit 3 in 1977.

When all three units are in operation at full MCR (maximum continuous rating), Holyrood is capable of supplying approximately 33% of the Newfoundland and Labrador electricity demand. Typically, the units operate during the late fall to spring peak period and supply a minimum load of between 80 MW and 150 MW. The Unit 3 generator is also capable of synchronous condenser operation for grid voltage control.

Units 1 and 2

Units 1 and 2 were built in the late 1960's as #6 fuel oil fired 150 MW units. Unit 1 entered service in September 1970 and Unit 2 in April 1971. These two units were modified in 1987 to increase their capacity to 175 MW.

Furnaces/Boilers: Units 1 and 2 are equipped with Combustion Engineering (now Alstom) tangentially fired natural circulation boilers. The boilers have twelve burners, four on each of three levels, designed to fire a 2.5% sulphur residual crude oil. In January 2009, Holyrood's fuel was changed to a 0.7% sulphur oil to reduce sulphur dioxide emissions, as well as particulate and sulphur trioxide.

The units are neither equipped with low NOx burners nor Overfire air for low NOx operations, nor any particulate capture devices. They were originally equipped with flue gas recirculation for reheat temperature control which was removed early in their service. The furnace is a pressurized furnace design with a forced draft fan, but no induced draft fan. As a consequence, in recent years, considerable effort has gone into assuring minimal furnace leakage into the plant.

The Units 1 and 2 boilers each has two x 50% forced draft (FD) fans driven by 4.16 kV induction motors. And two x 50% Lungstrum regenerative rotary air preheaters. The fan ducts are interconnected downstream of their outlet dampers and upstream of the air preheaters to allow single fan use, and also downstream of the air preheaters.

Upstream of the Lungstrum air preheaters, there are two steam coil air heaters. They are controlled to maintain the cold end metal temperature of the air preheater above the acid dewpoint temperature to reduce corrosion and plugging. They are typically designed to enable suitable operation down to -5 °C (20 °F) at 70% MCR.

Steam Turbine Generators: The Unit 1 and 2 steam turbine generators are General Electric (GE) three cylinder HP/IP/double flow LP 3600 rpm tandem compound turbines with GE hydrogen cooled generators. The units were modified by GE in 1987 to increase their capability to 175 MW. The HP turbines' throttle pressure was increased to 13.1 MPa at a superheat temperature of 538 °C. Units 1 and 2 turbines are somewhat unique in that they are not equipped with a main turbine shaft driven oil pump but have chain driven turning gear motors in the front of the unit, which in recent years have had some reliability issues.

The GE hydrogen cooled generator feeds its own unit exciter transformer which powers a DC static exciter. The exciter supplies a DC field voltage through a carbon brushgear slip ring assembly located on the outboard end of the generator. The normal hydrogen gas pressure in the generator casing is 310 kPa.

Condensers: The condenser is a Foster Wheeler design with 1842 m^2 (65,025 ft^2) of surface area. It is serviced by two x 100% duty vacuum pumps to maintain a 3.4 kPa (1" hg) pressure at maximum continuous rating (MCR).

Cooling Water System: The cooling water (CW) system feeding the condenser for each unit receives seawater cooling from two x 50% cooling water pump systems located in the Stage 1 pumphouse. Each pump can provide approximately 2250 L/s (35,700 USGPM) depending on tide) or about 3785 L/s (60,000 USGPM) operating together. Prior to entry into the CW pumps, water flows through two X 100% 1893 L/s (30,000 USGPM) Link Belt double entry traveling screens. The travelling screens function to remove debris from the cooling water prior to entering the pump system.

Feedwater System: The feedwater system for each unit consists of six stages of feedwater heating, a reserve feedwater storage tank system, and two feedwater pumps. The six stages of feedwater heating includes two low pressure (LP) heaters, one deaerator feedwater heater and three high pressure (HP) heaters after the feedwater pump.

Deaerator and HP Feedwater System: The deaerator for each unit is in effect an LP heater. It includes a deaerator storage tank of approximately 81,650 kg (180,000 lbs) – enough water to supply the boiler feed pumps for about 10 minutes at MCR. The elevation of the deaerator is designed to provide the necessary net positive suction head (NPSH) for the boiler feedwater pumps. Two x 50% boiler feedwater pumps are provided and either can operate and maintain up to a 90 MW load on the unit. They are double case, horizontal construction pumps rated at 75 L/s (1185 USPGM) at a head of 1829 m (6000 ft). Each pump is driven by a 3550 rpm, 3000 HP 4.16 kV, three-phase induction motor. There is no variable frequency drive (VFD) or fluid coupling as is common at other larger units. The three HP feedwater heaters (HP4, HP5, and HP6) are used to raise the feedwater temperature to the necessary economizer inlet temperature. There is no redundancy. HP 4 and HP5 must be bypassed as a set (for example in the event of a high condensate level trip). HP6 can be bypassed individually if necessary.

Condensate System: The condensate system for each unit consists of two x 100% condensate extraction pumps to remove condensate from the condenser, a gland steam condenser and one 100% flow condensate polishing system. The condensate extraction pump is a vertical canister pump that circulates condensate water through the gland steam condensers, the LP heaters, and then into the deaerator. The pumps are controlled to keep approximately 56 cm (22 inches) of water in the hotwell (approximately 33,566 kg or 74,000 lbs). The hotwell control, in parallel with the reserve storage tanks, manages variations in feedwater flow. The reserve feedwater storage tank system is designed to provide for surge and emergency requirements and consists of one high level tank and one low level tank, including a second high level tank originally intended for Unit 4, as well as associated piping, transfer pumps, and valving. Each tank has a capacity of approximately 90,850 L (24,000 USG). The transfer pumps have a capacity of 18.9 L/s (300 USGPM) at a head of 105 m (345 ft) and can transfer water between units and can also be used for boiler filling and washing.

Unit 3

Unit 3 is a 150 MW unit and was built in 1979 and came online in February 1980.

Furnace/Boiler: Unit 3 has a #6 fuel oil fired Babcock and Wilcox front wall-fired, natural circulation boiler. It has nine burners on three levels. It was designed to produce about 135 kg/s (1,072,000 lbs/hour) of steam at 13,030 kPa (1890 psig) at a superheated temperature of 541.6 °C (1005+/-10 °F), and 125.1 kg/s (993,000 Ls/hr) of reheat steam at 3716 kPa (539 psig), 541.6 °C (1005 °F).

The unit is neither equipped with low NOx burners nor Overfire air for low NOx operations, nor any particulate capture devices. The furnace is a pressurized furnace design with a forced draft fan, but no induced draft fan. As a consequence, in recent years, considerable effort has gone into assuring minimal furnace leakage into the plant.

The boiler has two x 50% forced draft (FD) fans driven by 1500 HP, 4.16 kV induction motors. Each FD fan servicing Unit 3 produces about 139.5 m^3/s (295,200 ACFM) at 8.8 kPa (35.23" w.g.) at 35 °C (95 °F). It has two x 50% Lungstrum regenerative rotary air preheaters. The fan ducts are interconnected downstream of their outlet dampers and upstream of the air preheaters to allow single fan use, and also downstream of the air preheaters.

Upstream of the Lungstrum air preheaters, there are two steam coil air heaters. They are controlled to maintain the cold end metal temperature of the air preheater above the acid dewpoint temperature to reduce corrosion and plugging. They are typically designed to enable suitable operation down to -5 °C (20 °F) at 70% MCR.

Steam Turbine Generator: The Unit 3 steam turbine generator is a Hitachi three cylinder HP/IP double flow LP 3600 rpm tandem compound turbine and a Hitachi hydrogen cooled generator. Unit 3 HP throttle pressure is 12.4 MPa at a superheated temperature of 538 °C. Its main steam flow is rated at 121 kg/s (960,644 lbs/hr) and up to 135 kg/s (1,072,000 lbs/hr) at valves wide open (VWO).

The Unit 3 turbine generator, unlike Units 1 and 2, has an internal shaft driven oil pump in the front standard, which supplies lubricating oil to the bearings, power oil (relay oil) to drive the east and west main steam stop valves, the control valves, and the east and west combined reheat intercept stop valves and other various valves associated with the unit.

Condensers: The condenser is a Foster Wheeler design with 1842 m^2 (65,025 ft^2) of surface area. It is serviced by two x 100% duty vacuum pumps to maintain a pressure of 3.4 kPa (1 inch hg) at MCR.

Cooling Water System: The cooling water system feeding the condenser receives seawater from two x 50% cooling water pump systems located in the Stage 2 Pumphouse. Each pump can provide approximately 2250 L/s (35,700 USGPM depending on tide) or about 3,785 L/s (60,000 USGPM) operating together. Prior to entry into the CW pumps, water flows through two X 100%, 1893 L/s (30,000 USGPM) Link Belt double entry traveling screens. The travelling screens function to remove debris from the cooling water prior to entering the pump system.

Feedwater System: The feedwater system consists of six stages of feedwater heating, a reserve feedwater storage tank system, and two feedwater pumps. The six stages of feedwater heating include two LP heaters, one deaerator feedwater heater and three HP heaters after the feedwater pump.

Deaerator and HP Feedwater System: The deaerator is in effect an LP heater. It includes a deaerator storage tank of approximately 81650 kg (180,000 lbs) – enough water to supply the boiler feed pumps for about 10 minutes at MCR. The elevation of the deaerator is designed to provide the necessary NPSH for the boiler feedwater pumps. Two x 50% boiler feedwater pumps are provided and either can run to maintain up to 90 MW load on the unit. They are double case, horizontal construction pumps rated at 75 L/s (1185 USPGM) at a head of 1829 m (6000 ft). Each is driven by a 3550 rpm, 3000 HP, 4.16 kV, 3 phase induction motor. There is no VFD or fluid coupling, as is common at other larger units. Three HP feedwater heaters (HP4, HP5, and HP6) are used to raise the feedwater temperature to the necessary economizer inlet temperature. There is no redundancy. HP 4 and HP5 must be bypassed as a set (for example in the event of a high condensate level trip). HP6 can be bypassed individually if necessary.

Condensate System: The condensate system consists of two x 100% condensate extraction pumps to remove boiler water from the condenser, a gland steam condenser, and one 100% flow condensate polishing system. The condensate extraction pump is a vertical canister pump which circulates condenser water through the gland steam condensers, the LP heaters, and into the deaerator. The pumps are controlled to keep approximately 56 cm (22 inches) of water in the hotwell (about 33,566 kg or 74,000 lbs). The hotwell control, in parallel with the reserve storage tanks, manages variations in feedwater flow. The reserve feedwater storage tank system is designed to provide for surge and emergency requirements and consists of one high level tank and one low level tank. It also includes a second high level tank, originally intended for Unit 4, as well as associated piping, transfer pumps, and valving. Each tank has a capacity of approximately 90,850 L (24,000 USG). The transfer pumps can transfer water between units and can be used for boiler filling and boiler washing. The pumps can provide up to 18.9 L/s (300 USGPM) at a head of 105 m (345 ft).

<u>Fuel Oil Storage & Delivery</u>

Fuel oil is delivered by tanker to the unloading docks and from there is delivered by an electrically heat traced pipeline to the fuel oil storage tank farm. The tank farm consists of four 33,710 m^3 (212,000 USG) tanks. Each tank has two suction heaters for temperature control of the oil discharge, as well as two immersion heaters that are supplied by auxiliary steam. Condensate is discharged via steam traps to a drainage system. From the tank farm, the fuel oil supplies a day tank located on the northeast side of the powerhouse via an 18 inch steam heat traced supply header by gravity flow.

The heavy oil day tank was replaced when Unit 3 was installed. The tank provides gravity flow to the supply pumps on each individual unit. For example, Unit 3 has a maximum flowrate requirement of 10.08 kg/s (80,000 lb/hr) supplied by two x 100% positive displacement pumps through two x 100% fuel oil steam heaters providing 99 °C (210 °F) oil to the units. If required, there is a bypass around the day tank from the main tank farm.

A light oil system is used for the initial start-up of the boilers during a cold start when atomizing steam is not available for firing with #6 oil. The oil system consists of storage tanks that are connected to two X 100% positive displacement pumps via a header complete with a recirculation system back to the tanks from the burner front header. The pumps have a discharge pressure of approximately 1034 kPa (150 psi). During start-up, light oil is fired into the boilers in the bottom level of burners. Atomizing air is provided for burner firing and for burner purging during boiler shutdown.

Compressed Air: Compressed air systems are provided for both Stage 1 and Stage 2. The air compressors for Stage 1 have been replaced, but the service air pressure vessels and instrument air pressure vessels are original equipment and are scheduled for replacement. Stage 2 originally had two X two-stage water cooled rotary screw Atlas Copco compressors providing compressed air to the service air system. A new replacement VFD air compressor was installed in 2008. A portion of compressed air is extracted from the service air receivers and is then filtered and dried for use as instrument air. Cooling water is provided from the general service water system for the cooler and aftercooler requirements for the air compressors.

Gas Turbines

The gas turbine generator system serves as a black start unit for the station and is occasionally used for system support.

As the power source for the 13.5 MW packaged generating unit, the gas generator employs a Rolls-Royce AVON 1533-70L (#37029) aeroderivative gas turbine used by Associated Electrical Industries (AEI) of Manchester, England. Manufacture of this type of generating unit commenced in the mid 1960's.

The unit was supplied to the Newfoundland and Labrador Power Commission in 1966 and was considered to be a development model. The generator unit itself is comprised of a number of components: inlet plenum, AVON 1533-70L power turbine, exhaust system, gearbox, generator, fuel oil system, governor/fuel control and lubricating oil system. It receives ambient air from the inlet plenum. To significantly boost the air pressure, this air is compressed via a 17- stage axial flow compressor in the forward section of the AVON 1533-70L. Fuel is supplied to an eight burner combustion section to facilitate a rapid increase in the temperature and velocity of the axial air flow. A three-stage turbine in the back end of the AVON 1533-70L uses a portion of the axial air flow to increase compressor rotational speed and to boost delivery. The high temperature, high velocity gas is used to drive the power turbine and generator through a gearbox. The engine has its own on-board lubrication system complete with circulating pumps and a reservoir.

The unit has had significant overhauls/repairs in 1978, 1986, 1991, and 2007.

Buildings

Main Buildings: The main buildings on site are:

- Main Powerhouse (Boiler House, Steam Turbine Hall, Administration Building, Water Treatment Plant)
- Waste Water Treatment Process Building
- Waste Water Treatment Basin Building
- Stage 1 Pumphouse Building
- Stage 2 Pumphouse Building

These are generally steel clad buildings with concrete foundations. The powerhouse roofing is primarily flat asphalt roofing with some clad steel roofs on some of the administration and water treatment parts. The other buildings have insulated, steel clad roofing.

Peripheral Buildings: The peripheral buildings include the following smaller buildings:

- Training Centre
- Guardhouse
- H2 and CO2 Storage Building
- Shawmont building
- Main Warehouse
- Pipe Shop
- Emergency Response Building
- Gas Turbine Building
- Chemical Storage Building

The buildings are either pre-engineered steel buildings or traditional steel buildings sitting on concrete foundations.

Powerhouse Heating and Ventilation: Steam type unit heaters are provided throughout the building, as well as access door heaters. For Stage 1, there are 69 operational unit heaters (including door heaters). For Stage 2, there are 25 unit heaters and five door heaters. Unit heaters are typically 19,870 kJ/min (1,130,000 BTU/hr) and door heaters typically 19,870 kJ/min (1,130,000 BTU/hr).

Combustion air requirements are drawn through the FD fan intake ducts which can draw air from either inside or outside of the powerhouse, depending on the outdoor temperature. The powerhouse ventilation system is designed to balance the combustion air needs against excessively cold or warm temperatures, drafts, and negative pressures in the powerhouse. For Stage 2, there are two roof vents and six horizontal wall vents.

A warm air make-up system was installed in 1992 in an attempt to ensure that plant pressure and air temperature were maintained at satisfactory levels. It included vent rooms with steam coil heaters on both the north and south walls of the plant. There have been issues with automated control under some circumstances that have resulted in freezing issues with nearby water lines inside the plant. The plant intends to put these systems into a manual control mode.

Pumphouse Heating and Ventilation: Twelve steam type unit heaters are provided in the Stage 1 pumphouse (2286 kJ/min – 130,000 BTU/hr) and one door heater. Four steam type unit heaters are provided in the Stage 2 pumphouse and one door heater. The unit heaters are typically 19,870 kJ/min (1,130,000 BTU/hr) and the door heaters 19,870 kJ/min (1,130,000 BTU/hr). The buildings also have roof ventilating fans.

2 PROJECT DESCRIPTION & SCOPE

AMEC Americas Limited (AMEC) was contracted by NL Hydro, a NALCOR Energy Company, to conduct Phase 1 of a Condition Assessment and Life Extension Study for the Holyrood Generating Station.

2.1 Study Basis

The basis for the study is as follows:

- 2010 to 2015 Generation Life
    1. Annual Capacity Factor (ACF)/pattern: ACF between 30% and 75% until 2015
    2. Reliability: high, similar to current
    3. Condition Assessment and Life Extension Schedule:
        - Phase I -2010
        - Phase 2 – 2011
        - Implementation – 2012 and beyond
- 2015-2020 Generation Standby
    1. Capacity required
    2. Operating pattern likely
    3. Hot/cold standby – time for return to service, and
    4. Reliability/availability of generation
- Synchronous Condensing 2015-2041
    1. Capability (generator, transformers) – similar to Unit 3
    2. Operating pattern and requirements
- Gas Turbine Operation
    1. Capacity required
    2. Operating pattern likely
    3. Reliability/availability of generation
    4. Life: 2020
- Subsequent equipment condition analyses

2.2 Study Focus

The study focuses on the following key assets:

1. Generators
2. Switch gear and switchyard
3. Transformers
4. Control system associated with generators
5. Station auxiliary systems
6. Buildings and building M and E system
7. Cooling water system associated with generators
8. Gas turbine generator and diesel gensets
9. Hydrogen and carbon dioxide
10. Compressed air
11. Generator lube oil

Nevertheless the other “Lower Priority Systems/Equipment” addressed include:

1. Fuel Systems (light and heavy oil);
2. Boiler System:
    a. Boilers
    b. Feed water system
    c. Heat exchangers
    d. Condensers
    e. Deaerators
    f. FD fans
    g. Air preheaters
    h. Stacks and breaching
    i. DCS associated with steam systems
    j. Electrical & instrumentation associated with steam systems
3. Turbines
4. Cooling water system associated with steam systems
5. Waste water treatment facility
6. Water treatment system

The study scope excludes consideration of the Holyrood marine terminal.

3 METHODOLOGY

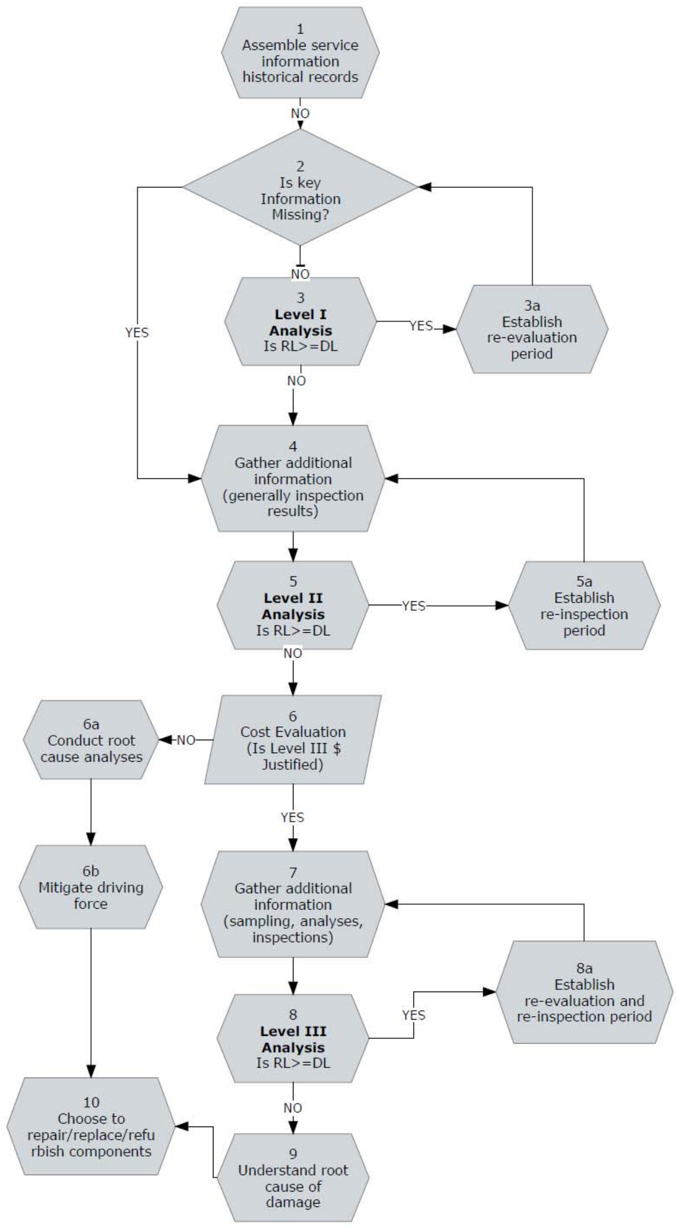
The study methodology included the following steps:

- Initial kick-off meeting and site visit
- Development of Asset Register & Flow Chart
- Site review and equipment/facility inspections
- Review the Holyrood Plant Maintenance Program – review existing information/background data and staff interviews
- Review and analysis of information and data obtained through:
    1. Existing studies on condition assessment, life expectancy, previous studies of life extension, and the associated costs (capital and O & M) of such programs
    2. Previously noted physical inspection reports of equipment
    3. Equipment lost time analysis data
    4. Interviews and discussions with NL Hydro management
    5. Interviews and discussions with Holyrood Operations and Maintenance personnel
    6. Analysis of power demands vs Holyrood generation capabilities
- Analysis of the impact and value of capital upgrades and operational and maintenance improvements
    1. Determination of remaining equipment and facility life – using existing information, experience, and OEM consultations as required to develop life cycle curves for major critical equipment and facilities; and
    2. Conduct equipment risk of failure analysis for major plant components, equipment, systems, and the entire facility. Identify any components or systems that require further investigation; and make recommendations for work that will be required to extend the plant's useful life into the future with the same high degree of reliability as experienced in the past.

To the extent practical, the approach followed the intent of the EPRI Condition Assessment Level 1 process or a reasonable alternative approach as determined by individual technology experts. The basic approach consistent with the EPRI Level 1 approach is:

- Examine only design or overall service parameters
- Compare, using conservative considerations, the residual life to the anticipated extended service period (or the interval to the next inspection whichever is less)
- Incorporate service and measurement information where practical, available and useful including:
    1. Unit running hours
    2. Numbers of starts and stops – hot, warm, cold, trips, ramp rates
    3. Unit load records
    4. Failure history and analyses reports
    5. Maintenance activities
    6. Specifics of past component repairs and replacements
    7. Materials of construction composition checks
    8. Dimensional checks
    9. Steam temperature histories
    10. Design parameters

The generic EPRI condition assessment methodology is illustrated in Figure 3-1. This chart includes step numbers used in the report to identify where in the process various systems and equipment are considered to be.



NOTE: Remaining Life (RL) is the estimated reliable remaining life of a piece of equipment or system based on available inspection and equipment data. Desired Life (DL) is the desired life of the component, but for decision making is the earlier of the desired end of life (EOL) date or the next inspection that can yield date for life assessment purposes.

FIGURE 3-1 GENERIC EPRI CONDITION ASSESSMENT METHODOLOGY

For mechanical systems, it considers aspects such as:

Feature	Level I	Level II	Level III
Failure History	Plant records	Plant records	Plant records
Dimensions	Design or nominal	Measured or nominal	Measured
Condition	Records or nominal	Inspection	Detailed inspection
Temperature and pressure	Design or operational	Operational or measured	Measured
Stresses	Design or operational	Simple calculation	Refined analysis
Material properties	Minimum	Minimum	Actual material
Material samples required?	No	No	Yes

More rigorous assessment →

More accurate operation data required →

More accurate estimate of equipment RL →

FIGURE 3-2 EPRI METHODOLOGY – INFORMATION REQUIREMENTS

The Level 1 analysis considers several issues, such as:

- Has the unit component operation exceeded its design parameters (i.e. temperature, pressure) for significant periods of time or by significant amounts?
- Will the required future service requirement exceed significant design parameters (i.e. cycling, two-shifting capacity) without suitable modification?
- Has unit maintenance and reliability shown that the design philosophy and materials have not been conservative since the units was operational?
- Has the failure history been excessive?

The following figures illustrate some more detailed, specific considerations within the generic approach for high temperature steam headers:

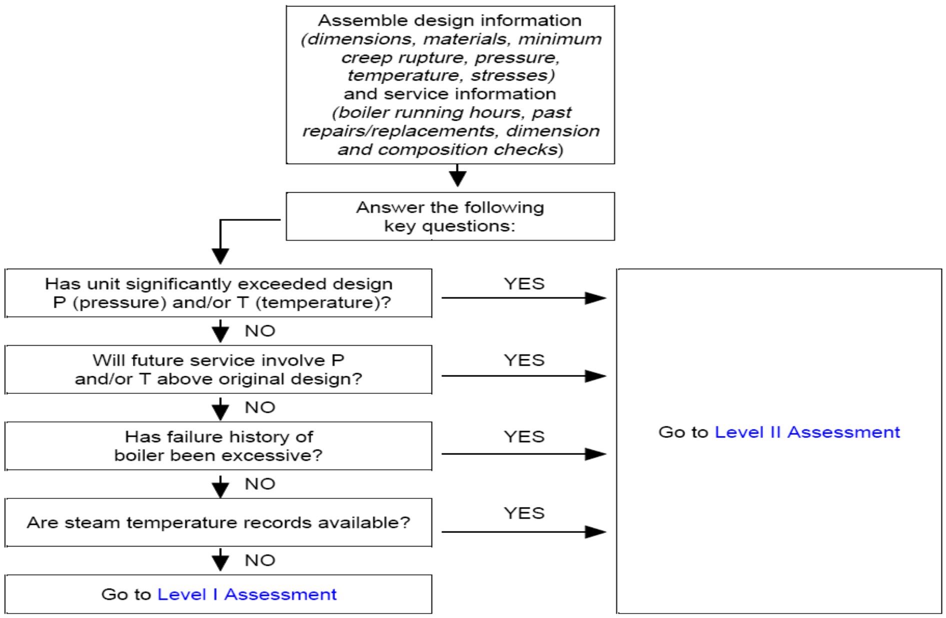


FIGURE 3-3 GENERAL ROADMAP FOR HIGH TEMPERATURE STEAM HEADERS

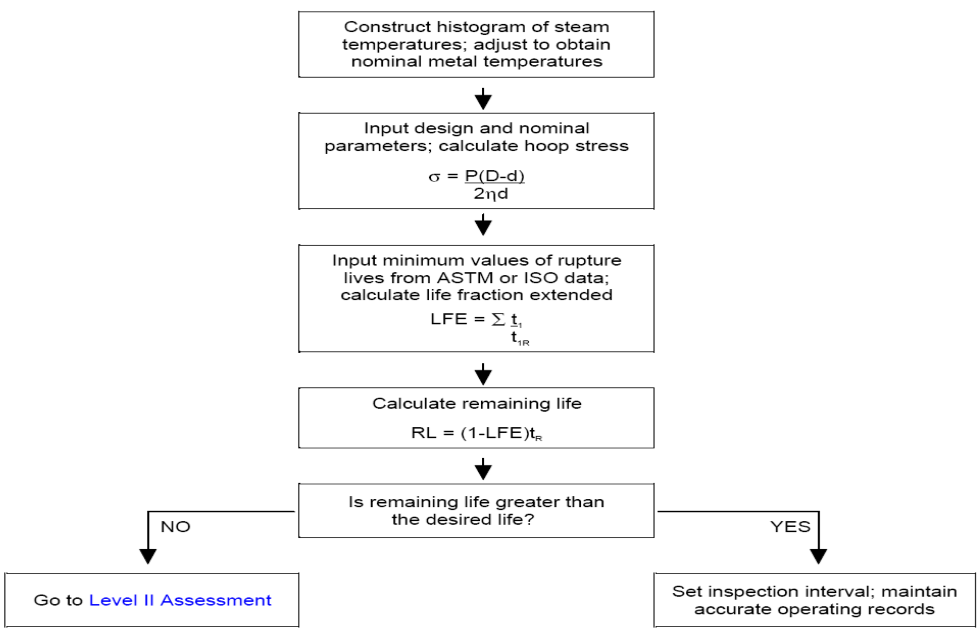


FIGURE 3-4 LEVEL I ASSESSMENT: HIGH TEMPERATURE HEADERS

The intent in moving from Level 1 to Level 2 is to address items with insufficient information to make decisions going forward. For example in the chart below, Level 1 allows selection of a number of components to replace, repair or refurbish, but leaves the majority as uncertain.

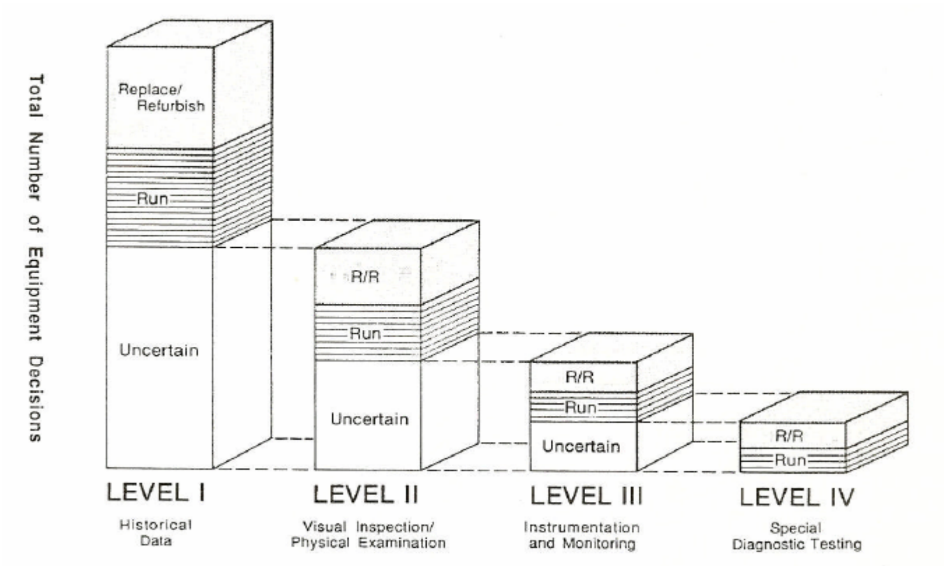


FIGURE 3-5 FOUR-LEVEL ELECTRICAL COMPONENT LIFE ASSESSMENT

For electrical systems, the same basic steps as the generic flowsheet in Figure 3-1 are used for this study. Figure 3-6 presents a more detailed perspective of the considerations in the process.

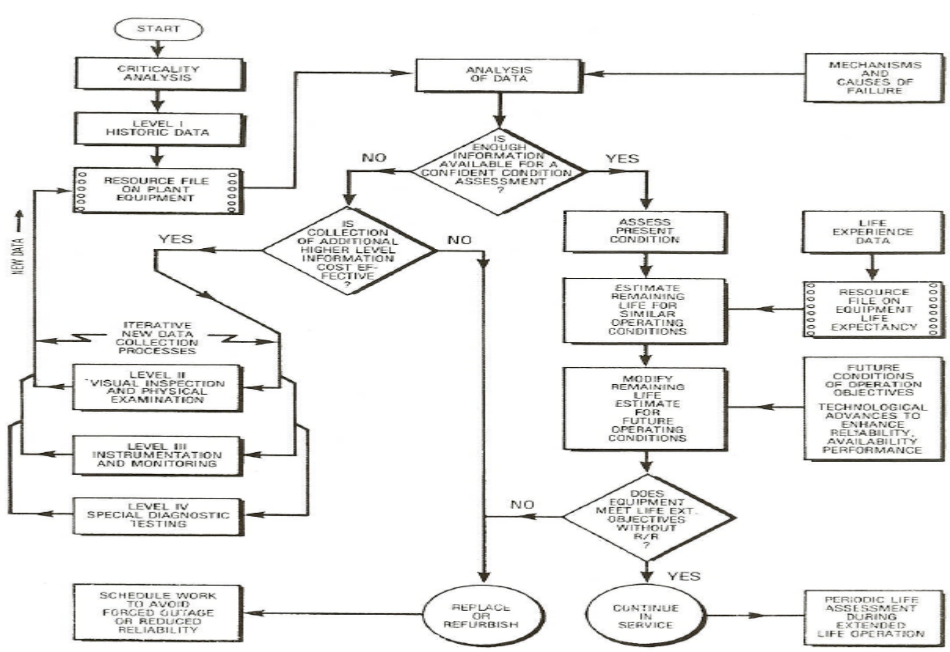


FIGURE 3-6 GENERAL LIFE ASSESSMENT PROCESS: ELECTRICAL EQUIPMENT

3.1 Background Information and Studies

The key background information and studies included the following:

- Identification of key equipment;
- Identification of recent improvements/changes – fuel, major modifications, etc.;
- Vendor consultation;
- Current/planned station budgets and plans;
- Timing of changes – likelihood;
- Staffing, Operating, Maintenance and Administration (OMA) plans;
- Criteria for operation and operating parameters;
- Major equipment to be considered;
- Present design and operating data – e.g. temperatures, vibration data, cooling water and oil temperatures, etc. at typical load points;
- Facility drawings as required, preferably on CAD;
- Maintenance data for each major piece of equipment, especially from the last major maintenance outage. Details of known limitations, and operating concerns; and
- Details of major repairs performed on major equipment.

3.2 Field Investigation

It was agreed that the scope and results of field investigative work, analyses undertaken, variables examined, and operational considerations would address:

- Station operating hrs and cold/warm/hot starts by unit and year since start up
- Station operating hrs and cold/warm/hot starts by unit and month from January 2007 to present
- Major station outages and associated reports (planned, major maintenance) by unit particularly those since 2000
- Major plant equipment and system changes (i.e. major fuel change, equipment change-out, major boiler upgrades, steam turbine modifications and generator modifications) since in-service (particularly in last 10 years) including the scope and timing of the changes
- Major inspections (and associated reports) on key equipment and systems since 1997 – including timing of the inspections and scope
- Unit performance – capacity, heat rate, availability since 2000
- Current budget and business plan information details
- Occurrences where the actual operating conditions exceeded the equipment design conditions including:
    1. High pressure and temperature steam and/or water
    2. Superheat and reheat steam systems
    3. Boiler feedwater and boiler tube systems
    4. Steam turbine components
    5. Higher than design flue gas temperatures (associated with boiler systems)
    6. Vibration
    7. Hydrogen pressure or temperature (in generator)

A list of the initial documentation provided by NL Hydro is presented in Appendix 1.

3.3 Scope, Key Features and Parameters of Study

The study scope was discussed with NL Hydro during an initial kick-off meeting and it was agreed that:

- AMEC would use the Holyrood asset register as the primary index, highlighting the equipment and systems that would be addressed and the level to which they would be assessed. The green areas indicate the equipment and systems that would be addressed and the level of the assessment – i.e. system, sub-system, and equipment. The marked up list is attached as Appendix 1.
- The generic EPRI Condition Assessment approach illustrated in Figure 3-1 is the methodology employed. The boiler analyses followed the specific approach in Figures 3-3 and 3-4 for high temperature headers. The more generic approach, using industry and individual expert experience, taking into account Holyrood specific information, was applied in most other cases.
- The intent is to provide an assessment of Level 2 requirements including schedule and cost. Given the stage of and eventual scope of the work, as well as the economic environment, an accuracy of +/-10-15% is a target at best, typically achieved during detailed quotes on actual work, and the overall costs are practically speaking more of a +10/-25% quality, typical of this stage of the work.

The following key features of the study were identified:

- No new detailed information was to be developed. The assessment was to be based on existing information obtained through existing documents and studies, plant interviews, and readily undertaken visual inspections (walk-downs).
- The findings of existing studies, even to the extent of MCC findings of obsolescence should be taken into account.
- The timing of planned equipment inspections and overhauls should be taken into account. The intent of the EPRI Level 1 methodology is to determine whether a piece of equipment or system can either reach its intended planned life or reach its next major inspection and overhaul. If it is determined that the equipment cannot reach its planned life or next major inspection/overall, then a Level 2 condition assessment is necessary.
- The study will focus primarily on key equipment systems required for synchronous condensing operation up to 2041, beyond the generation plans for 2010 to 2020.

3.4 Cost Estimating and Schedule - Phase 2 of a Condition Assessment Program

In considering the requirements for a Phase 2 study that includes a Level 2 Condition Assessment, it was agreed that AMEC would provide a cost estimate and schedule to complete a Phase 2 study, including quarterly cost and cash flows for 2011.

The Phase 2 study plan would include the assumptions made and basis used for preparation of the cost estimate. Where practical, the cost estimate will target an accuracy range of +/- 10%. It was identified and agreed that this would not be practical in many cases given the stage of work and the labour and materials marketplace and any key considerations pertinent to completing Phase 2 of a condition assessment program relating to the cost estimate and schedule provided. A fairly conservative approach was taken such that the overall costs are practically speaking of a +10/-25% quality, typical of this stage of the work.

3.5 Site Visits

AMEC staff visited Holyrood several times from January through May of 2010. These included:

- Two one-week visits by Ian Leach and Blair Seckington in January and May 2010;
- A one-week visit by three members of AMEC Nuclear Safety Solutions (NSS) in February 2010 and an additional one week visit by a single member of NSS in March 2010;
- A one-week visit by Blair Seckington in April 2010 to address balance of plant issues and project updates; and
- Several day visits by AMEC St John's staff to address civil, structural, gas turbine, and balance of plant issues between January and May 2010

In the course of these visits, meetings and interviews included the following staff:

- Plant management team as a whole – kick-off, scope, areas of responsibility, general information sharing, and NSS work scope;
- Terry LeDrew (Plant Manager) – key plant issues and asset history;
- Jeff Vincent (Manager-Long Term Asset Planning) – various plant asset conditions, capital plans, Instrumentation and Controls (I&C), Electrical, and organization;
- Wayne Rice (Manager-Work Execution) – various equipment and system conditions and plant staffing;
- Sean Mullowney (Plant Electrical Engineer) – various technical issues and programs regarding electrical systems, instrumentation, and controls;
- Paul Woodford (Maintenance Contracts Engineer) – NDE and test program results;
- Christian Thangasamy (Plant Mechanical Engineer) – various technical issues and programs related to condensers, boilers, synchronous condenser, steam turbine generator, motors, and pumps;
- Mike Flynn (Mechanical Maintenance Supervisor) – crane maintenance and the balance of plant (BOP) systems;
- Mike Manuel (Manager-Environment, Health and Safety) – water treatment plant, performance, plant future as a generating facility, and reliability;
- Ed Finn (Plant Chemist) – water treatment plant, waste water treatment plant, water and steam chemistry conditions, water system, and condensate polishing systems;
- Alonso Pollard (Performance Specialist) – performance data (reliability and availability), condenser performance and modifications, and cooling water pipe conditions;
- Gerard Cochrane (Manager - Operations) – plant and equipment performance issues, plant operations issues, and operational labour issues;
- Plant Shift Supervisors and Operators (various) – plant operations issues and performance;
- Ron LeDrew (Emergency Response Coordinator) – Emergency Response Team (ERT) activities;
- Bob Coish (Retiree, former Holyrood Plant Asset Manager, Co-Lead on Holyrood Asset Maintenance Review) – past major projects, asset conditions, and changes;
- John Adams (Alstom Technical Director) – boiler pressure parts, , air and gas side conditions, information, overhaul , inspection, and design information for Units 1,2, and 3;
- Brandon Berlin (GE Technical Director) - Steam turbine and generator information, condition assessments, overhaul, inspection, and design information for Units 1, 2, and 3;

- Jerry Goulding (Retiree, former Shift Supervisor, Asset Specialist, and Co-Lead on Holyrood Asset Maintenance Review) –past major projects, asset conditions, and changes; and
- Bob Garland – (Asset Specialist) – Controls and condensate polishers.

In addition, the following meetings were held at Hydro Place located in St John's:

January

- Project Kick Off;
- Assess base information availability; and
- Clarify project scope

April

- Update on project status; and
- Review asset register with respect to equipment status and history

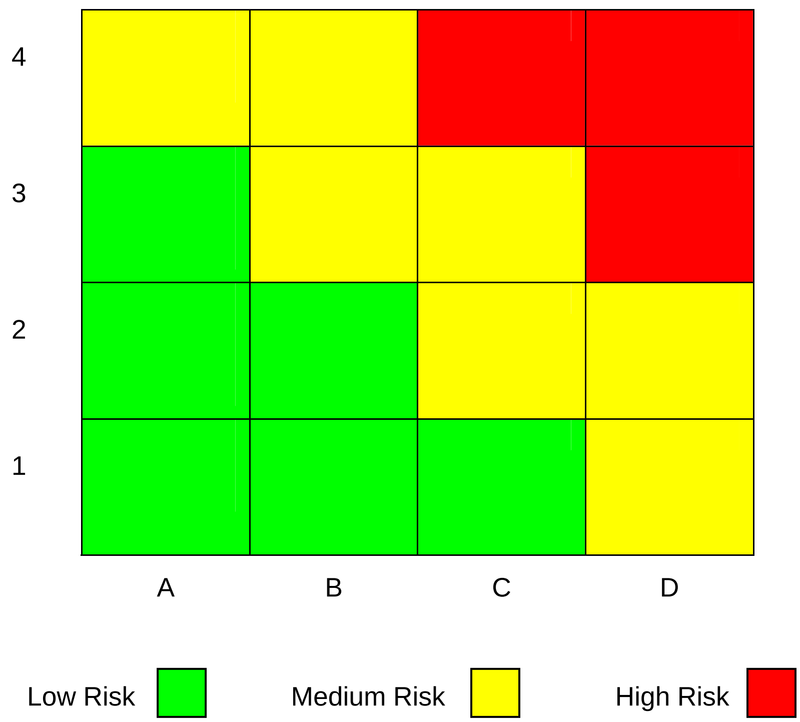
May

- Review maintenance history

3.6 Technological Risk of Failure Analysis

The risk assessment model has been developed based on methods proposed by the American Petroleum Institute (API RP 580), in lieu of a model specific to the power utility industry. The basic concept consists of a 4 x 4 matrix with the consequence measured in cost terms on the base or horizontal axis and the likelihood or frequency of the event on the vertical axis. The study risk of failure analysis was performed using the model illustrated below in Table 3-1.

TABLE 3-1 TECHNOLOGICAL RISK OF FAILURE ANALYSIS MODEL



Likelihood of Failure Event:

1. Greater than 10 years
2. 5 to 10 years
3. 1 to 5 years
4. Immanent (< 1 year)

Consequence of Failure Event:

A. Minor ($10k-$100k or derating/1 day outage)
B. Significant ($100k-$1m or 2-14 days outage)
C. Serious ($1m-$10m or 15-30 days outage)
D. Major (>$10m or >1 month outage)

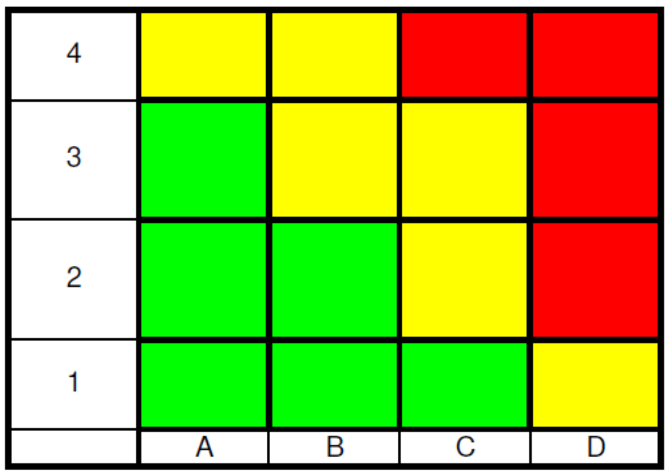
Actions:

- Items that do not apply are not ranked
- Low Risk: Monitor long term (within 5 years)
- Medium Risk: Investigate and monitor short term. Take action where beneficial
- High Risk: Corrective action required short term

3.6.1 Safety Risk Failure Analysis

In addition to the technological risk of failure analysis, a preliminary safety risk of failure analysis was undertaken at NL Hydro's request. Its basic format is based on that of the technological risk assessment model above and is somewhat of a hybrid of the more complex "Real Hazard Index" model used by the US Department of Defense. The modified model is presented below in Table 3-2.

TABLE 3-2 SAFETY RISK FAILURE ANALYSIS MODEL



Low Risk Medium Risk High Risk

<u>Likelihood of Safety Incident Event:</u>

1. Improbable – so that it can be assumed not to occur
2. Unlikely to occur during life of specific item/process
3. Will occur once during life of specific item/process
4. Likely to occur frequently

<u>Consequence of Safety Incident Event:</u>

A. Minor - will not result in injury, or illness
B. Marginal - may cause minor injury, or illness
C. Critical - may cause severe injury, or illness
D. Catastrophic - may cause death

<u>Actions</u>:

- Items that do not apply are not ranked;
- Low Risk: Monitor, take action where beneficial;
- Medium Risk: Investigate and monitor short term. Take action where beneficial; and
- High Risk: Unacceptable. Corrective action required short term

3.7 Priority Rating

A numbered priority was assigned to the various “Recommended Actions”, “Level 2 Inspections”, and “Capital Enhancements” throughout Sections 8 to 11 of this report. The scale used was from “1” to “4”. A “1” is the highest priority and essentially means that this activity should definitely be undertaken and where practical in or about the timing identified. A “4” is the lowest priority and essentially means that the item is essentially low risk and low impact and may be much more readily delayed or undertaken in some other fashion. The priority ranking is a subjective relative ranking by AMEC, meant to be an aid to Hydro in allocating resources and assessing trade-offs and program delays.

The priority ranking is not based on a rigorous process, but does take into consideration a number of aspects such as:

1. The impact (likely and worst case) of the item under consideration on achieving the end of life (EOL) goal, on plant operation health and safety, and on environmental and regulatory requirements;
2. The urgency of the need for action on the item under consideration;
3. The degree of certainty of the requirement for the item under consideration;
4. The experience at Holyrood and in the broader industry context with the item;
5. The ability to mitigate or address the issue in other ways;
6. The timing of the recommended response to the item under consideration;
7. The cost of the item under consideration relative to others; and
8. The ability of existing and planned or ongoing actions to address the item in a timely and successful manner.

The priority value of any item should be read in the context of its recommended timing. An item can be a “1”, but be scheduled for a later date if it is deemed that sufficient information exists to be confident of the minimal likely impact of the deferral (usually to tie in with a planned major activity such as an overhaul).

4 HOLYROOD ASSET REGISTER

One task of the project was to develop an asset register for the plant.

Initially the plan was to use a system based on the CEA/Monenco/OPG Thermal Subject Index (TSI)/System Classification Index (SCI) that is very plant/system user-friendly and uses the same "asset numbers" with a different prefix for equipment serving the same purpose on similar units and even across stations.

NL Hydro currently has a financial system based asset register for Holyrood. At the direction of NL Hydro, this system was used for the study. It was agreed with the Holyrood Plant Manager which assets would be addressed during the study. These are highlighted in green in Appendix 1.

5 HOLYROOD PLANT MAINTENANCE PROGRAM REVIEW

As input to the overall condition assessment and life extension study of the plant, AMEC reviewed the Holyrood plant maintenance program using existing information, background data, and staff interviews. AMEC is aware that the plant preventative maintenance (PM) program is currently undergoing a major review by NLH and is scheduled to be completed by the end of 2010. AMEC is also aware that the plant is currently re-organizing to better define its long term asset management role and its shorter term maintenance role.

The review consisted of observations of the role of the maintenance programs, past and present, as well as a focused review during the week of May 10, 2010. Reviews were undertaken with Wayne Rice, Bob Coish, Jerry Goulding, Jeff Vincent, Todd Collins, as well as several of the plant maintenance and operations staff. The discussions also included the new NL Hydro corporate asset maintenance review strategy.

5.1 Maintenance Strategy

The maintenance strategy presently in effect at Holyrood is basically a “Best Practices” approach, implemented through a combination of in-house resources for work performance and/or management. It also includes external resources for major equipment technical support, overhauls, and external contracting for specialized services. It uses the long term asset management and short term maintenance implementation model to ensure that both long term goals and short term needs are both addressed.

From AMEC’s perspective, in most areas of the operation, the maintenance strategy and the asset management program at Holyrood are well implemented and consistent with other thermal generating stations across North America.

5.1.1 Maintenance Implementation

As mentioned above, Holyrood maintenance is implemented through a combination of in-house resources for work performance and/or management and external resources for major equipment support, overhauls, and external contracting for specialized services.

For the major critical components such as boilers and boiler auxiliary systems, steam turbines, generators, and auxiliary systems, NL Hydro uses multi-year maintenance contracts. The boiler contract is currently in place with Alstom Power and the steam turbine generator contract is with GE. Under these contracts, the service contractors provide the majority of the boiler, turbine and generator maintenance, including major and/or minor overhauls. Alstom and GE have technical directors on site ensuring that Holyrood’s needs are met.

The plant also has approximately 20 – 25 smaller contracts such as winter snow plowing, garbage and waste disposal, drinking water supply, pressure washing and vacuum truck requirements, etc. Specialized areas such as Non Destructive Evaluations (NDE), high energy pump maintenance, and elevator servicing are also contracted because of the limited number of times these services are normally required.

Maintenance activities on the remainder of the plant are completed by the maintenance department under the direction of the plant’s supervisory staff. If required, technical representatives from either the equipment supplier directly or a qualified representative from contracted technical resource companies will aid in dismantling and rebuilding specific equipment.

The use of contractors and external technical resources ensures consistent quality and efficient utilization of maintenance budgets. It is extremely difficult and expensive to maintain every specialized skill set required within a thermal generating station and the use of external resources is cost effective.

5.2 Staffing

Figure 5-1 below provides an overview of the basic plant staffing configuration as of August 2010.

The long term asset planning department is responsible for monitoring and updating the 20 year plan, asset register, critical spares database, maintenance programs, and capital program. The department consists of the engineering support staff as shown in the Figure 5-1. The work execution department is - well organized and in line with conventional disciplines. The department includes:

- Mechanical Maintenance – 21 positions
- Electrical Maintenance – 6 positions
- Instrumentation & Control Maintenance – 7 positions
- Planning – 4 positions

The operations department consists of a manager, operations specialist, performance specialist, and thirty six operations support staff.

The safety, health, and environment department consists of a manager, safety coordinator, environmental technologist, chemical technologists, and emergency response technicians.

The plant support services department consists of a team lead, three administrative staff, and four warehouse staff to support all plant departments.

In 2010, AMEC compared the staffing requirements of the six x 150 MW Burrard Thermal Generating Station (TGS) (BC Hydro, seasonal peaking station) against the Lennox TGS (four x 500 MW oil and gas fired station) located in Ontario (OPG, peaking station) and the two x 175 MW and one x 150 MW oil fired Holyrood TGS (NL Hydro, seasonal capacity and base/intermediate). The details of the comparison are illustrated below in Table 5-1.

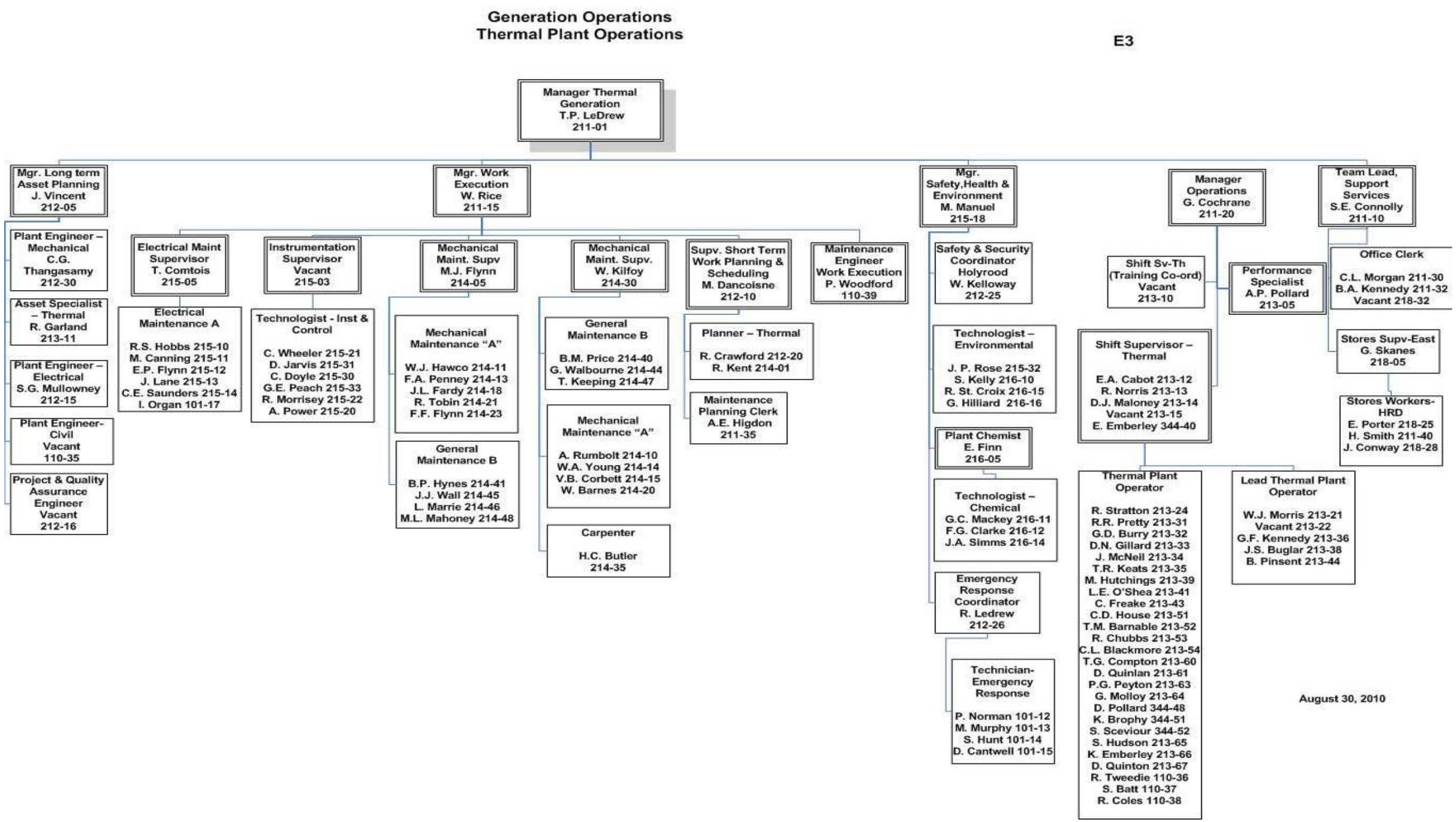


FIGURE 5-1 BASIC STAFFING CONFIGURATION – AUGUST 2010

TABLE 5-1 STAFF COMPARISON TABLE BETWEEN BURRARD TGS/HOLYROOD/LENNOX GS

Station	Burrard 6 x 150 MW	Holyrood 2x 175, 1 x 150 MW	Lennox 4 x 500 MW
Position	Plan Scenario (Seasonal Base)		
Station Manager	1	1	1
Maintenance/ Engineering / Asset Section			
Maintenance Mgr./ Asset Mgr.	1	2	2
Maintenance Management Supervisors	1	4	3
Engineering Supervisors/ Asset & Mechanical	1	0	4
Engineers Asset / Maintenance	4	6	4
Mechanical Trades & Supervisors	11	9	21
Electrical & Instrument Trades & Supervisors	16	12	23
Communication Protection & Control	2	Corp	Corp
General Trades & Supervisors	6	7	11
Operations Section			
Operations Manager	1	1	1
Operations Management Supervisors		1	2
Supervising Shift Engineers	5	5	0
Hands on Operators	35	31	62
Environment and Performance Manager (Safety, Health & Envir.)	0	1	0
Environmental Advisor (management)	1 PT	0	1
Chemist or Chem. Group Leader	1	1	1
Chemical / Environment Technicians	5	7	8
Thermal Technical Specialist	1	1	0
Office Administration			
Administrator / Support Services Coordinator	1	1	1 Corp
Clerical Staff	4.5	3	2
Corporate Finance	0		3 -Lnx only
Planning			
Manager or Leader	1	1	1
Schedulers/ Planning Technicians	3	3	2
Stores	2	4	7
Safety (+ Emerg. Response Team)	1	1 (+5)	1 Corp
Total	103	107	162+

Notes: PT = Part Time, Corp= Corporate

Each of these facilities has adopted similar maintenance strategies. However, the numbers in the table indicate that Holyrood may require some additional electrical/instrumentation support and likely more administrative support, as well as the currently planned civil engineering support.

5.2.1 Staff Training

Holyrood operates as a seasonal base loaded plant between November and April and tends to be either on or off and generally operates between 70 and 130 MW. It has few starts per unit per year, typically less than twelve. As a result, the plant operators see a fair bit of operating time and at least some starts and stops as a component of their on the job training. The station also runs training programs periodically on issues that may arise during operation. It is thought that some "what do you do if this happens", and "why is it done that way" scenario training might be useful. Otherwise, the training program for all plant staff seems consistent with other thermal generating facilities.

5.3 Predictive and Preventative Maintenance Programs

Holyrood has a very active computer-based PM program. The program is currently being revised on a corporate basis in order to make it more practical, including the development of additional predictive approaches. This is seen as a very positive step for Holyrood, given its resources, role, and maintenance approach.

The system can be somewhat difficult to use effectively as a resource in parallel with the outage reporting system. Generally, the issue tends to be the format in which documentation is produced and a more user-friendly system would be useful.

5.4 Inspections – Regulatory and Other

NL Hydro has a strong commitment to align with regulatory requirements, insurance requirements, and industry practices. Holyrood is generally very thorough in its implementation of preventative maintenance programs, inspections, overhauls, and replacement of equipment.

Holyrood has a comprehensive maintenance inspection program. However, there have been some interruptions in the last few years related to some of the systems, primarily those considered less critical or less susceptible to a modest delay. One concern is that more should be done in the areas of high pressure piping inspections and boiler hanger inspections. A second is in the area of inspections associated with steam turbines and generators. The period between major steam turbine and generator inspections has been increased from six years to nine years, primarily based on the assessment of Hartford Steam Boiler Consulting, a company that was contracted by NL Hydro to review the frequency of the steam turbine and generator preventative maintenance inspection at Holyrood. Based on industry experience associated with similar equipment and the recent results of inspections and the condition of plant monitoring equipment, it is AMEC's position that the duration between major inspections and overhauls of the steam turbines can reasonably remain at nine years subject to the findings of each overhaul, but for the generators should be reduced back to six years.

5.5 Work Management Improvements

As mentioned previously, AMEC believes the maintenance strategy and the asset management program at Holyrood are well implemented in most areas of the operation and, for the most part, are consistent with other TGS's across North America.

One significant potential maintenance system improvement opportunity relates to the fact that some Holyrood employees still use hand written Work Orders (WO's) submitted for equipment deficiencies to the Holyrood planning office, which then transfer these to a computer program (duplication of effort). A number of other generating facilities now have all employees submitting WO's electronically. After being notified, that person will then be able to review the completed WO list generated by planning. Planning, in consultation with operations and maintenance personnel, schedules the work and then the work is delegated to either a contractor or Holyrood staff.

A second improvement, and one that applies generally to the facility, is in the area of records management. This includes management of historical design information, operations and maintenance history, and management of current information. It was apparent during this study that while Holyrood is very good at inspections, maintenance, and overhauls, a document control system should be implemented.

5.6 Capital Improvements

Capital improvements completed over the last five to ten years at Holyrood should be commended. Replacing the water treatment plant systems and controls, installing a new air compressor, installing a new diesel generator set used for safe shutdown of the facility, boiler superheater replacements, and the installation of a new boiler chemical injection system increased the reliability and overall life of the plant. A listing of significant capital improvements has been included below in Table 5-2.

ITEM	UPGRADE DESCRIPTION	YEAR
A.	Uprate Generation Units 1 and 2 (150 MW to 175 MW)	1987
B.	Upgrade Unit 3 to operate as a synchronous condenser	1986
C.	Major Turbine/Generator Disassembly, Overhaul and Repair	every 9 yrs
D.	Turbine/Generator Valves Disassembly, Inspection and Repair	every 3 yrs
E.	Boilers Internal Cleaning, Inspection and Minor Repairs	Annually
F.	Construct New Water Treatment Plant	1992
G.	Construct New Wastewater Treatment Plant	1994
H.	Replace Unit 1 Boiler Stack Liner	2000
I.	Replace Unit 2 Boiler Stack Liner	2001
J.	Upgrade Unit 1 Exciter	2000
K.	Upgrade Unit 2 Exciter	1999
L.	Upgrade Unit 1 Governor Controls	2003
M.	Upgrade Unit 2 Governor Controls	1999
N.	Replace Uninterrupted Power System	2000
O.	Replace Boilers Breeching	1990
P.	Upgrade Units 1, 2 Controls System	1988 & 2004
Q.	Upgrade Units 3 Controls System	1994 & 2005
R.	Install Warm Air Make-up System	1992
S.	Construct New Security Building	2004
T.	Plant Asbestos Removal Program (3 year project)	2003-2006
U.	Replace Boiler No. 2 Superheater	2007
V.	Replace Boiler No. 1 Superheater	2008
W.	Replace Roof and Upgrade Siding	1990-2000
X.	Replace Boiler No. 2 Partial Water Wall	2006
Y.	Install Boiler Soot Blower	1995
Z.	Upgrade Boiler Air Pre-heater Steam Heat Exchanger	1990
AA.	Install Continuous Emissions Monitoring System (shared)	2003
BB.	Construct five Ambient Air Monitoring Stations	1993
CC.	Replace Heating, Ventilation & Air Conditioning Units	2002-2005
DD.	Install Cooper Ion Injection System	2007
EE.	Replace Unit 2 Boiler Stop Valve	2008
FF.	High Pressure Feedwater Heater No.5 Replacement, Unit 2	2009
GG.	Install Unit 2 Cold Reheat Drain Pots	2009
HH.	Refurbishment Unit 2 East & West Air Preheaters Cold End	2009
II.	Upgrade Tank Farm Phase 1	2009
JJ.	Upgrade Fire Sprinkler System	2008
KK.	Gas Turbine PLC Replacement	2009
LL.	Install Marine Terminal Capsan Lifting Frames	2009
MM.	Unit 3 Steam Seal Regulator Replacement	2009
NN.	Unit 1 Emergency Hydrogen Venting	2009

FIGURE 5-2 SIGNIFICANT CAPITAL IMPROVEMENTS

Several additional programs have been initiated in 2010 that are not shown in the figure including: the Steam Seal Regulator (SSR) obsolescence for Unit 1 currently underway (Unit 2 SSR is recommended to be undertaken in 2011/2012); and the switchyard air compressor piping replacement started in 2010 and carrying through 2011.

As a result of the Lower Churchill Project and the HVDC line to the island, capital improvements at Holyrood will be more difficult to justify by the uncertainty going forward as a generating facility. There is no question that Holyrood continues to need capital improvements, largely in the electrical switchgear and motor control centers and protections. Some of these, however, are dedicated to the generation/steam side of the plant which, under the terms of this study, need only last until sometime between 2015 and 2020.

Some capital improvements that may be required are outside of the plant's jurisdiction such as the power transformers and switchyard equipment.

5.7 Maintenance Review Conclusions

NL Hydro is committed to meeting their regulatory, insurance, and safety requirements through ongoing inspections, maintenance, fire safety, and capital programs.

Holyrood is transitioning to its new PM program. The new program will increase the number of systems using a strategy that employs preventive and/or predictive methods to determine when the need for maintenance exists, given Holyrood's operating pattern. It will also update the maintenance requirements and detailed practices for plant systems.

The new Maintenance Program is believed to significantly improve an already good program, while optimizing costs. It should prevent some equipment from being under-resourced, such as the black start gas turbine which generally is only required when emergencies occur and thus deemed to have a lower priority in the larger scheme of work scheduling. It will also address and update several systems such as high pressure piping and pipe hangers that have received insufficient attention in recent times.

6 HOLYROOD OPERATING HISTORY & FUTURE ASSUMPTIONS

The following tables illustrate both the historical and assumed case operating regimes for the facility. The historical data includes the period to 2009 (2009 is highlighted). For the period beyond 2009, several scenarios were examined (Generation: 40% to 70% annual capacity factor (ACF) to 2015; 10% to 2020; Synchronous Condensing: as shown).

TABLE 6-1 UNIT 1 - OPTION 1-1 - MODERATE GENERATION ACF TO 2015 LOW TO 2020

Generation to 2015 ACF=	40%	2016 to2020 ACF=	10%	
Operating Factor =	55%	Operating Factor=	20%	
Syncronous Condensing in 2015	4740	Hrs/Yr	(1500 av to date + 6 mos x 30 days x7d/wk + 75% of time)	

Year	ACF	MWh/Yr	Operating Factor %	Starts Per Year	Generation OP Hrs Cumulative Lifetime	Synch Cond OP Hrs Per Year	Synch Cond OP Hrs Cum	Total OP Hrs Cum Lifetime SC+Gen
2041	0.0%	0	0.0%	5	203925	4740	124740	328665
2040	0.0%	0	0.0%	5	203925	4740	120000	323925
2039	0.0%	0	0.0%	5	203925	4740	115260	319185
2038	0.0%	0	0.0%	5	203925	4740	110520	314445
2037	0.0%	0	0.0%	5	203925	4740	105780	309705
2036	0.0%	0	0.0%	5	203925	4740	101040	304965
2035	0.0%	0	0.0%	5	203925	4740	96300	300225
2034	0.0%	0	0.0%	5	203925	4740	91560	295485
2033	0.0%	0	0.0%	5	203925	4740	86820	290745
2032	0.0%	0	0.0%	5	203925	4740	82080	286005
2031	0.0%	0	0.0%	5	203925	4740	77340	281265
2030	0.0%	0	0.0%	5	203925	4740	72600	276525
2029	0.0%	0	0.0%	5	203925	4740	67860	271785
2028	0.0%	0	0.0%	5	203925	4740	63120	267045
2027	0.0%	0	0.0%	5	203925	4740	58380	262305
2026	0.0%	0	0.0%	5	203925	4740	53640	257565
2025	0.0%	0	0.0%	5	203925	4740	48900	252825
2024	0.0%	0	0.0%	5	203925	4740	44160	248085
2023	0.0%	0	0.0%	5	203925	4740	39420	243345
2022	0.0%	0	0.0%	5	203925	4740	34680	238605
2021	0.0%	0	0.0%	5	203925	4740	29940	233865
2020	10.0%	148920	20.0%	12	203925	4740	25200	229125
2019	10.0%	148920	20.0%	12	202173	4740	20460	222633
2018	10.0%	148920	20.0%	12	200421	4740	15720	216141
2017	10.0%	148920	20.0%	12	198669	4740	10980	209649
2016	10.0%	148920	20.0%	12	196917	4740	6240	203157
2015	40.0%	595680	55.0%	12	195165	1500	1500	196665
2014	40.0%	595680	55.0%	12	190347	0	0	190347
2013	40.0%	595680	55.0%	12	185529	0	0	185529
2012	40.0%	595680	55.0%	12	180711	0	0	180711
2011	40.0%	595680	55.0%	12	175893	0	0	175893
2010	40.0%	595680	55.0%	12	171075	0	0	171075
2009	23.5%	360410	51.6%	12	166257	0	0	166257
2008	19.1%		39.7%	13	161737			
2007	25.5%		64.3%	21	158261			
2006	20.5%		46.5%	19	152632			
2005	28.4%		47.0%	6	148555			
2004	42.2%		61.7%	12	144438			
2003	44.3%		56.9%	7	139034			
2002	55.3%		65.9%	13	134050			
2001	50.2%		74.9%	16	128275			
2000	29.2%		59.5%	11	121715			
1999	25.8%		55.0%	9	116501			
1998	35.4%		53.9%	9	111687			
1997	36.1%		54.2%	7	106970			
1996	35.7%		50.9%	11	102226			
1995	47.3%		63.0%	8	97771			
1994	18.4%		39.0%	9	92250			
1993	48.4%		75.0%	14	88832			
1992	46.3%		55.2%	22	82258			
1991	49.6%		80.2%	13	77420			
1990	48.5%		69.3%	13	70396			
1989	71.9%		102.9%	13	64322			
1988	28.9%		41.3%	13	55311			
1987	49.2%		70.4%	13	51689			
1986	55.9%		80.0%	13	45522			
1985	30.3%		43.4%	13	38512			
1984	20.2%		28.9%	12	34710			
1983	17.4%		24.9%	12	32174			
1982	33.2%		47.4%	13	29994			
1981	10.8%		15.5%	12	25839			
1980	42.2%		60.4%	13	24486			
1979	43.1%		61.7%	13	19193			
1978	30.3%		43.3%	13	13786			
1977	15.4%		22.0%	12	9994			
1976	15.3%		21.9%	12	8070			
1975	15.3%		21.9%	12	6149			
1974	11.4%		16.3%	12	4233			
1973	8.6%		12.4%	12	2805			
1972	2.7%		3.9%	12	1723			
1971	11.0%		15.7%	12	1378			
1970	1.7%		0.0%		0			
1969	0.0%		0.0%					

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TABLE 6-2 UNIT 1 - OPTION 2-1 - HIGH GENERATION ACF TO 2015, LOW TO 2020

Generation to 2015 ACF=	70%	2016 to2020 ACF=	70%	
Operating Factor =	85%	Operating Factor=	20%	
Syncronous Condensing in 2015	4740	Hrs/Yr	(1500 av to date + 6 mos x 30 days x7d/wk + 75% of time)	

Year	ACF	MWh/Yr	Operating Factor %	Starts Per Year	Generation OP Hrs Cumulative Lifetime	Synch Cond OP Hrs Per Year	Synch Cond OP Hrs Cum	Total OP Hrs Cum Lifetime SC+Gen
2041	0.0%	0	0.0%	5	219693	4740	124740	344433
2040	0.0%	0	0.0%	5	219693	4740	120000	339693
2039	0.0%	0	0.0%	5	219693	4740	115260	334953
2038	0.0%	0	0.0%	5	219693	4740	110520	330213
2037	0.0%	0	0.0%	5	219693	4740	105780	325473
2036	0.0%	0	0.0%	5	219693	4740	101040	320733
2035	0.0%	0	0.0%	5	219693	4740	96300	315993
2034	0.0%	0	0.0%	5	219693	4740	91560	311253
2033	0.0%	0	0.0%	5	219693	4740	86820	306513
2032	0.0%	0	0.0%	5	219693	4740	82080	301773
2031	0.0%	0	0.0%	5	219693	4740	77340	297033
2030	0.0%	0	0.0%	5	219693	4740	72600	292293
2029	0.0%	0	0.0%	5	219693	4740	67860	287553
2028	0.0%	0	0.0%	5	219693	4740	63120	282813
2027	0.0%	0	0.0%	5	219693	4740	58380	278073
2026	0.0%	0	0.0%	5	219693	4740	53640	273333
2025	0.0%	0	0.0%	5	219693	4740	48900	268593
2024	0.0%	0	0.0%	5	219693	4740	44160	263853
2023	0.0%	0	0.0%	5	219693	4740	39420	259113
2022	0.0%	0	0.0%	5	219693	4740	34680	254373
2021	0.0%	0	0.0%	5	219693	4740	29940	249633
2020	10.0%	148920	20.0%	12	219693	4740	25200	244893
2019	10.0%	148920	20.0%	12	217941	4740	20460	238401
2018	10.0%	148920	20.0%	12	216189	4740	15720	231909
2017	10.0%	148920	20.0%	12	214437	4740	10980	225417
2016	10.0%	148920	20.0%	12	212685	4740	6240	218925
2015	70.0%	1042440	85.0%	12	210933	1500	1500	212433
2014	70.0%	1042440	85.0%	12	203487	0	0	203487
2013	70.0%	1042440	85.0%	12	196041	0	0	196041
2012	70.0%	1042440	85.0%	12	188595	0	0	188595
2011	70.0%	1042440	85.0%	12	181149	0	0	181149
2010	70.0%	1042440	85.0%	12	173703	0	0	173703
2009	23.5%	360410	51.6%	12	166257	0	0	166257
2008	19.1%		39.7%	13	161737			
2007	25.5%		64.3%	21	158261			
2006	20.5%		46.5%	19	152632			
2005	28.4%		47.0%	6	148555			
2004	42.2%		61.7%	12	144436			
2003	44.3%		56.9%	7	139034			
2002	55.3%		65.9%	13	134050			
2001	50.2%		74.9%	16	128275			
2000	29.2%		59.5%	11	121715			
1999	25.8%		55.0%	9	116501			
1998	35.4%		53.9%	9	111687			
1997	36.1%		54.2%	7	106970			
1996	35.7%		50.9%	11	102226			
1995	47.3%		63.0%	8	97771			
1994	18.4%		39.0%	9	92250			
1993	48.4%		75.0%	14	88832			
1992	46.3%		55.2%	22	82258			
1991	49.6%		80.2%	13	77420			
1990	48.5%		69.3%	13	70396			
1989	71.9%		102.9%	13	64322			
1988	28.9%		41.3%	13	55311			
1987	49.2%		70.4%	13	51689			
1986	55.9%		80.0%	13	45522			
1985	30.3%		43.4%	13	38512			
1984	20.2%		28.9%	12	34710			
1983	17.4%		24.9%	12	32174			
1982	33.2%		47.4%	13	29994			
1981	10.8%		15.5%	12	25839			
1980	42.2%		60.4%	13	24486			
1979	43.1%		61.7%	13	19193			
1978	30.3%		43.3%	13	13786			
1977	15.4%		22.0%	12	9994			
1976	15.3%		21.9%	12	8070			
1975	15.3%		21.9%	12	6149			
1974	11.4%		16.3%	12	4233			
1973	8.6%		12.4%	12	2805			
1972	2.7%		3.9%	12	1723			
1971	11.0%		15.7%	12	1378			
1970	1.7%		0.0%		0			
1969	0.0%		0.0%					

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TABLE 6-3 UNIT 2 - OPTION 1-1 - MODERATE GENERAL ACF TO 2015, LOW TO 2020

Generation to 2015 ACF=	40%	2016 to2020 ACF=	10%	
Operating Factor =	55%	Operating Factor=	20%	
Syncronous Condensing in 2015	4740 Hrs/Yr	(1500 av to date + 6 mos x 30 days x7d/wk + 75% of time)		

Year	ACF	MWh/Yr	Operating Factor %	Starts Per Year	Generation OP Hrs Cumulative Lifetime	Synch Cond OP Hrs Per Year	Synch Cond OP Hrs Cum	Total OP Hrs Cum Lifetime SC+Gen
2041	0.0%	0	0.0%	5	195957	4740	124740	320697
2040	0.0%	0	0.0%	5	195957	4740	120000	315957
2039	0.0%	0	0.0%	5	195957	4740	115260	311217
2038	0.0%	0	0.0%	5	195957	4740	110520	306477
2037	0.0%	0	0.0%	5	195957	4740	105780	301737
2036	0.0%	0	0.0%	5	195957	4740	101040	296997
2035	0.0%	0	0.0%	5	195957	4740	96300	292257
2034	0.0%	0	0.0%	5	195957	4740	91560	287517
2033	0.0%	0	0.0%	5	195957	4740	86820	282777
2032	0.0%	0	0.0%	5	195957	4740	82080	278037
2031	0.0%	0	0.0%	5	195957	4740	77340	273297
2030	0.0%	0	0.0%	5	195957	4740	72600	268557
2029	0.0%	0	0.0%	5	195957	4740	67860	263817
2028	0.0%	0	0.0%	5	195957	4740	63120	259077
2027	0.0%	0	0.0%	5	195957	4740	58380	254337
2026	0.0%	0	0.0%	5	195957	4740	53640	249597
2025	0.0%	0	0.0%	5	195957	4740	48900	244857
2024	0.0%	0	0.0%	5	195957	4740	44160	240117
2023	0.0%	0	0.0%	5	195957	4740	39420	235377
2022	0.0%	0	0.0%	5	195957	4740	34680	230637
2021	0.0%	0	0.0%	5	195957	4740	29940	225897
2020	10.0%	148920	20.0%	12	195957	4740	25200	221157
2019	10.0%	148920	20.0%	12	194205	4740	20460	214665
2018	10.0%	148920	20.0%	12	192453	4740	15720	208173
2017	10.0%	148920	20.0%	12	190701	4740	10980	201681
2016	10.0%	148920	20.0%	12	188949	4740	6240	195189
2015	40.0%	595680	55.0%	12	187197	1500	1500	188697
2014	40.0%	595680	55.0%	12	182379	0	0	182379
2013	40.0%	595680	55.0%	12	177561	0	0	177561
2012	40.0%	595680	55.0%	12	172743	0	0	172743
2011	40.0%	595680	55.0%	12	167925	0	0	167925
2010	40.0%	595680	55.0%	12	163107	0	0	163107
2009	25.7%	394200	56.2%	6	158289	0	0	158289
2008	35.8%		56.9%	8	153367			
2007	36.7%		58.3%	9	148386			
2006	10.5%		28.4%	7	143279			
2005	30.7%		52.6%	13	140789			
2004	33.2%		50.0%	12	136186			
2003	48.6%		69.5%	14	131805			
2002	58.3%		69.3%	13	125721			
2001	57.8%		78.6%	10	119655			
2000	27.5%		61.6%	11	112771			
1999	16.7%		43.4%	12	107373			
1998	32.8%		52.4%	9	103573			
1997	41.2%		59.4%	8	98987			
1996	37.2%		58.0%	21	93783			
1995	33.0%		45.7%	14	88702			
1994	21.0%		49.1%	7	84696			
1993	30.0%		45.6%	17	80400			
1992	35.2%		53.5%	15	76408			
1991	25.6%		38.4%	11	71720			
1990	44.6%		66.9%	13	68352			
1989	18.9%		28.3%	11	62489			
1988	44.7%		67.0%	13	60009			
1987	64.6%		96.9%	14	54136			
1986	31.0%		46.5%	12	45647			
1985	52.4%		78.6%	13	41576			
1984	11.8%		17.7%	10	34694			
1983	17.8%		26.7%	11	33144			
1982	35.6%		53.4%	12	30804			
1981	2.4%		3.6%	9	26129			
1980	34.7%		52.0%	12	25811			
1979	48.6%		72.8%	13	21253			
1978	33.8%		50.8%	12	14872			
1977	13.8%		20.6%	10	10426			
1976	11.4%		17.0%	10	8618			
1975	8.9%		13.4%	10	7125			
1974	16.1%		24.1%	10	5951			
1973	10.2%		15.4%	10	3838			
1972	12.6%		18.8%	10	2493			
1971	6.4%		9.6%	10	844			
1970	0.0%		0.0%		0			
1969	0.0%		0.0%					

TABLE 6-4 UNIT 2 - OPTION 2-1 - HIGH GENERATION ACF TO 2015, LOW TO 2020

Generation to 2015 ACF=	70%	2016 to2020	ACF=	70%
Operating Factor –	85%		Operating Factor–	20%
Syncronous Condensing in 2015	4740	Hrs/Yr	(1500 av to date + 6 mos x 30 days x7d/wk + 75% of time)	

Year	ACF	MWh/Yr	Operating Factor %	Starts Per Year	Generation OP Hrs Cumulative Lifetime	Synch Cond OP Hrs Per Year	Synch Cond OP Hrs Cum	Total OP Hrs Cum Lifetime SC+Gen
2041	0.0%	0	0.0%	5	211725	4740	124740	336465
2040	0.0%	0	0.0%	5	211725	4740	120000	331725
2039	0.0%	0	0.0%	5	211725	4740	115260	326985
2038	0.0%	0	0.0%	5	211725	4740	110520	322245
2037	0.0%	0	0.0%	5	211725	4740	105780	317505
2036	0.0%	0	0.0%	5	211725	4740	101040	312765
2035	0.0%	0	0.0%	5	211725	4740	96300	308025
2034	0.0%	0	0.0%	5	211725	4740	91560	303285
2033	0.0%	0	0.0%	5	211725	4740	86820	298545
2032	0.0%	0	0.0%	5	211725	4740	82080	293805
2031	0.0%	0	0.0%	5	211725	4740	77340	289065
2030	0.0%	0	0.0%	5	211725	4740	72600	284325
2029	0.0%	0	0.0%	5	211725	4740	67860	279585
2028	0.0%	0	0.0%	5	211725	4740	63120	274845
2027	0.0%	0	0.0%	5	211725	4740	58380	270105
2026	0.0%	0	0.0%	5	211725	4740	53640	265365
2025	0.0%	0	0.0%	5	211725	4740	48900	260625
2024	0.0%	0	0.0%	5	211725	4740	44160	255885
2023	0.0%	0	0.0%	5	211725	4740	39420	251145
2022	0.0%	0	0.0%	5	211725	4740	34680	246405
2021	0.0%	0	0.0%	5	211725	4740	29940	241665
2020	10.0%	148920	20.0%	12	211725	4740	25200	236925
2019	10.0%	148920	20.0%	12	209973	4740	20460	230433
2018	10.0%	148920	20.0%	12	208221	4740	15720	223941
2017	10.0%	148920	20.0%	12	206469	4740	10980	217449
2016	10.0%	148920	20.0%	12	204717	4740	6240	210957
2015	70.0%	1042440	85.0%	12	202965	1500	1500	204465
2014	70.0%	1042440	85.0%	12	195519	0	0	195519
2013	70.0%	1042440	85.0%	12	188073	0	0	188073
2012	70.0%	1042440	85.0%	12	180627	0	0	180627
2011	70.0%	1042440	85.0%	12	173181	0	0	173181
2010	70.0%	1042440	85.0%	12	165735	0	0	165735
2009	25.7%	394200	56.2%	6	158289	0	0	158289
2008	35.8%		56.9%	8	153367			
2007	36.7%		58.3%	9	148386			
2006	10.5%		28.4%	7	143279			
2005	30.7%		52.6%	13	140789			
2004	33.2%		50.0%	12	136186			
2003	48.6%		69.5%	14	131805			
2002	58.3%		69.3%	13	125721			
2001	57.8%		78.6%	10	119655			
2000	27.5%		61.6%	11	112771			
1999	16.7%		43.4%	12	107373			
1998	32.8%		52.4%	9	103573			
1997	41.2%		59.4%	8	98987			
1996	37.2%		58.0%	21	93783			
1995	33.0%		45.7%	14	88702			
1994	21.0%		49.1%	7	84696			
1993	30.0%		45.6%	17	80400			
1992	35.2%		53.5%	15	76408			
1991	25.6%		38.4%	11	71720			
1990	44.6%		66.9%	13	68352			
1989	18.9%		28.3%	11	62489			
1988	44.7%		67.0%	13	60009			
1987	64.6%		96.9%	14	54136			
1986	31.0%		46.5%	12	45647			
1985	52.4%		78.6%	13	41576			
1984	11.8%		17.7%	10	34694			
1983	17.8%		26.7%	11	33144			
1982	35.6%		53.4%	12	30804			
1981	2.4%		3.6%	9	26129			
1980	34.7%		52.0%	12	25811			
1979	48.6%		72.8%	13	21253			
1978	33.8%		50.8%	12	14872			
1977	13.8%		20.6%	10	10426			
1976	11.4%		17.0%	10	8618			
1975	8.9%		13.4%	10	7125			
1974	16.1%		24.1%	10	5951			
1973	10.2%		15.4%	10	3838			
1972	12.6%		18.8%	10	2493			
1971	6.4%		9.6%	10	844			
1970	0.0%		0.0%		0			
1969	0.0%		0.0%					

TABLE 6-5 UNIT 3 - OPTION 1-1 - MODERATE GENERATION ACF TO 2015, LOW TO 2020

Generation to 2015 ACF–	40%	2016 to2020	ACF–	10%
Operating Factor –	55%		Operating Factor–	20%
Syncronous Condensing in 2016+	4740	Hrs/Yr	(1500 av to date + 6 mos x 30 days x7d/wk + 75% of time)	
Syncronous Condensing in 2011-201	1500	Hrs/Yr		

Year	ACF	MWh/Yr	Operating Factor %	Starts Per Year	Generation OP Hrs Cumulative Lifetime	Synch Cond OP Hrs Per Year	Synch Cond OP Hrs Cum	Total OP Hrs Cum Lifetime SC+Gen
2041	0.0%	0	0.0%	5	163331	4740	167313	330644
2040	0.0%	0	0.0%	5	163331	4740	162573	325904
2039	0.0%	0	0.0%	5	163331	4740	157833	321164
2038	0.0%	0	0.0%	5	163331	4740	153093	316424
2037	0.0%	0	0.0%	5	163331	4740	148353	311684
2036	0.0%	0	0.0%	5	163331	4740	143613	306944
2035	0.0%	0	0.0%	5	163331	4740	138873	302204
2034	0.0%	0	0.0%	5	163331	4740	134133	297464
2033	0.0%	0	0.0%	5	163331	4740	129393	292724
2032	0.0%	0	0.0%	5	163331	4740	124653	287984
2031	0.0%	0	0.0%	5	163331	4740	119913	283244
2030	0.0%	0	0.0%	5	163331	4740	115173	278504
2029	0.0%	0	0.0%	5	163331	4740	110433	273764
2028	0.0%	0	0.0%	5	163331	4740	105693	269024
2027	0.0%	0	0.0%	5	163331	4740	100953	264284
2026	0.0%	0	0.0%	5	163331	4740	96213	259544
2025	0.0%	0	0.0%	5	163331	4740	91473	254804
2024	0.0%	0	0.0%	5	163331	4740	86733	250064
2023	0.0%	0	0.0%	5	163331	4740	81993	245324
2022	0.0%	0	0.0%	5	163331	4740	77253	240584
2021	0.0%	0	0.0%	5	163331	4740	72513	235844
2020	10.0%	131400	20.0%	12	163331	4740	67773	231104
2019	10.0%	131400	20.0%	12	161579	4740	63033	224612
2018	10.0%	131400	20.0%	12	159827	4740	58293	218120
2017	10.0%	131400	20.0%	12	158075	4740	53553	211628
2016	10.0%	131400	20.0%	12	156323	4740	48813	205136
2015	40.0%	525600	55.0%	12	154571	1500	44073	198644
2014	40.0%	525600	55.0%	12	149753	1500	42573	192326
2013	40.0%	525600	55.0%	12	144935	1500	41073	186008
2012	40.0%	525600	55.0%	12	140117	1500	39573	179690
2011	40.0%	525600	55.0%	12	135299	1500	38073	173372
2010	40.0%	525600	55.0%	12	130481	1500	36573	167054
2009	19.1%	251130	33.6%	4	125663	35073	35073	160736
2008	23.6%		35.1%	5	122717	30956		
2007	29.4%		49.3%	11	119643	26656		
2006	24.7%		53.6%	9	115322	25904		
2005	38.7%		59.0%	14	110627	23204		
2004	44.8%		59.2%	9	105455	22076		
2003	48.4%		60.2%	12	100272	20922		
2002	58.6%		65.3%	15	94998	19622		
2001	42.8%		59.8%	11	89282	18468		
2000	13.0%		26.5%	4	84043	17314		
1999	26.0%		59.2%	6	81726	16159		
1998	22.6%		28.3%	4	76541	15005		
1997	33.6%		49.3%	10	74066	13851		
1996	28.6%		42.1%	9	69745	12697		
1995	30.1%		41.3%	20	66058	11542		
1994	18.3%		34.0%	21	62436	10388		
1993	35.0%		55.1%	13	59461	9234		
1992	42.8%		73.3%	12	54633	8080		
1991	28.2%		44.8%	8	48216	6925		
1990	39.5%		52.3%	12	44294	5771		
1989	56.5%		74.7%	15	39717	4617		
1988	39.9%		52.8%	12	33174	3463		
1987	61.8%		81.6%	16	28552	2308		
1986	14.6%		19.2%	8	21402	1154		
1985	56.0%		73.9%	15	19716			
1984	29.6%		39.1%	10	13240			
1983	11.5%		15.2%	8	9814			
1982	21.2%		28.0%	9	8481			
1981	20.8%		27.5%	9	6028			
1980	31.1%		41.0%	11	3623			
1979	0.2%		0.3%	6	29			
1978	0.0%		0.0%		0			
1977	0.0%		0.0%		0			
1976	0.0%		0.0%		0			
1975	0.0%		0.0%		0			
1974	0.0%		0.0%		0			
1973	0.0%		0.0%		0			
1972	0.0%		0.0%		0			
1971	0.0%		0.0%		0			
1970	0.0%		0.0%		0			
1969			0.0%					

TABLE 6-6 UNIT 3 - OPTION 2-1 - HIGH GENERATION ACF TO 2015, LOW TO 2020

Generation to 2015 ACF–	70%	2016 to2020	ACF–	70%
Operating Factor –	85%		Operating Factor–	20%
Syncronous Condensing in 2016+	4740	Hrs/Yr	(1500 av to date + 6 mos x 30 days x7d/wk + 75% of time)	
Syncronous Condensing in 2011-20	1500	Hrs/Yr		

Year	ACF	MWh/Yr	Operating Factor %	Starts Per Year	Generation OP Hrs Cumulative Lifetime	Synch Cond OP Hrs Per Year	Synch Cond OP Hrs Cum	Total OP Hrs Cum Lifetime SC+Gen
2041	0.0%	0	0.0%	5	179099	4740	167313	346412
2040	0.0%	0	0.0%	5	179099	4740	162573	341672
2039	0.0%	0	0.0%	5	179099	4740	157833	336932
2038	0.0%	0	0.0%	5	179099	4740	153093	332192
2037	0.0%	0	0.0%	5	179099	4740	148353	327452
2036	0.0%	0	0.0%	5	179099	4740	143613	322712
2035	0.0%	0	0.0%	5	179099	4740	138873	317972
2034	0.0%	0	0.0%	5	179099	4740	134133	313232
2033	0.0%	0	0.0%	5	179099	4740	129393	308492
2032	0.0%	0	0.0%	5	179099	4740	124653	303752
2031	0.0%	0	0.0%	5	179099	4740	119913	299012
2030	0.0%	0	0.0%	5	179099	4740	115173	294272
2029	0.0%	0	0.0%	5	179099	4740	110433	289532
2028	0.0%	0	0.0%	5	179099	4740	105693	284792
2027	0.0%	0	0.0%	5	179099	4740	100953	280052
2026	0.0%	0	0.0%	5	179099	4740	96213	275312
2025	0.0%	0	0.0%	5	179099	4740	91473	270572
2024	0.0%	0	0.0%	5	179099	4740	86733	265832
2023	0.0%	0	0.0%	5	179099	4740	81993	261092
2022	0.0%	0	0.0%	5	179099	4740	77253	256352
2021	0.0%	0	0.0%	5	179099	4740	72513	251612
2020	10.0%	131400	20.0%	12	179099	4740	67773	246872
2019	10.0%	131400	20.0%	12	177347	4740	63033	240380
2018	10.0%	131400	20.0%	12	175595	4740	58293	233888
2017	10.0%	131400	20.0%	12	173843	4740	53553	227396
2016	10.0%	131400	20.0%	12	172091	4740	48813	220904
2015	70.0%	919800	85.0%	12	170339	1500	44073	214412
2014	70.0%	919800	85.0%	12	162893	1500	42573	205466
2013	70.0%	919800	85.0%	12	155447	1500	41073	196520
2012	70.0%	919800	85.0%	12	148001	1500	39573	187574
2011	70.0%	919800	85.0%	12	140555	1500	38073	178628
2010	70.0%	919800	85.0%	12	133109	1500	36573	169682
2009	19.1%	251130	33.6%	4	125663	35073	35073	160736
2008	23.6%		35.1%	5	122717	30956		
2007	29.4%		49.3%	11	119643	26656		
2006	24.7%		53.6%	9	115322	25904		
2005	38.7%		59.0%	14	110627	23204		
2004	44.8%		59.2%	9	105455	22076		
2003	48.4%		60.2%	12	100272	20922		
2002	58.6%		65.3%	15	94998	19622		
2001	42.8%		59.8%	11	89282	18468		
2000	13.0%		26.5%	4	84043	17314		
1999	26.0%		59.2%	6	81726	16159		
1998	22.6%		28.3%	4	76541	15005		
1997	33.6%		49.3%	10	74066	13851		
1996	28.6%		42.1%	9	69745	12697		
1995	30.1%		41.3%	20	66058	11542		
1994	18.3%		34.0%	21	62436	10388		
1993	35.0%		55.1%	13	59461	9234		
1992	42.8%		73.3%	12	54633	8080		
1991	28.2%		44.8%	8	48216	6925		
1990	39.5%		52.3%	12	44294	5771		
1989	56.5%		74.7%	15	39717	4617		
1988	39.9%		52.8%	12	33174	3463		
1987	61.8%		81.6%	16	28552	2308		
1986	14.6%		19.2%	8	21402	1154		
1985	56.0%		73.9%	15	19716			
1984	29.6%		39.1%	10	13240			
1983	11.5%		15.2%	8	9814			
1982	21.2%		28.0%	9	8481			
1981	20.8%		27.5%	9	6028			
1980	31.1%		41.0%	11	3623			
1979	0.2%		0.3%	6	29			
1978	0.0%		0.0%		0			
1977	0.0%		0.0%		0			
1976	0.0%		0.0%		0			
1975	0.0%		0.0%		0			
1974	0.0%		0.0%		0			
1973	0.0%		0.0%		0			
1972	0.0%		0.0%		0			
1971	0.0%		0.0%		0			
1970	0.0%		0.0%		0			
1969			0.0%					

For the gas turbine generator, the NL Hydro operating data provided is:

Hours Actual - Operation to Dec 2005 (Estimated from 2005 to 2010)

- 1978 – 1,749 operating hrs since new (+85,000 idle hours)
- 1985 – 2,139 operating hrs since new (+170,000 idle hours)
- 1995 – 3,475 operating hrs since new (+256,000 idle hours)
- 2005 – 3,807 operating hrs since new (+343,000 idle hours)
- 2010 – 4,717 operating hrs since new (+381,000 idle hours)

The starts identified (including actuals to Dec 2005 and estimated to 2010) are:

- 1978 – 611 starts, since new
- 1985 – 796 starts, since new
- 1995 – 1,440 starts, since new
- 2005 – 2,025 starts, since new
- 2010 – 2,548 starts since new

Given that the combustor and the PT volute have been replaced or refurbished, AMEC have estimated the maximum hours of operation that the components may have experienced to an end date of 2020 (Assuming 4717 hours in 2010) to be:

- Combustor: 1,100 to 2,200 operating hours
- PT Volute: 2,600 to 4,700 operating hours
- Balance: 5,700 to 6,8400 operating hours

(NOTE: reduce or add about 100 to 200 operating hours per year for any difference in end date.)

Similarly, AMEC have estimated the maximum number of starts that the components may have experienced to an end date of 2020 (assuming 2,548 starts in 2010) to be:

- Combustor: 1,300 starts
- PT Volute: 2,100 starts
- Balance: 2,900 starts

(NOTE: reduce or add about 35 starts per year for any difference in end date.)

7 OVERALL PLANT CONDITION ASSESSMENT

Holyrood is considered to be a relatively modern design plant and in good condition.

Holyrood is expected to be able to meet either the 2015 or 2020 dates for the end of its electricity generation role with capital refurbishments and replacements primarily due to typical mid-life refurbishment requirements, old age effects and obsolescence. Some may also be impacted by the ambient humid, seaside environment. These are detailed later in the body of the report, but examples of would include many of the breakers and motor control centres, the waste water treatment basin building structure and ventilation system, the plant elevator, and equipment such as vacuum pumps, emergency diesels and air compressors. To minimize a decrease in reliability, additional spares such as a spare 4 kV motor for each of a boiler feed pump, a forced draft fan, and a circulating water pump are recommended. A complete overhaul or replacement of the gas turbine generator and balance of plant would also be recommended given its importance in a return to operation in the event of a system failure and its use as a system emergency power source.

Holyrood is also expected to be able to meet its 2041 synchronous condenser end of life, but will require some further substantial equipment refurbishments and replacements specific to that role that are identified later in the report. Examples of these would include generator rewinds, powerhouse and pump house roof replacements, switchyard breakers and motorized switches, synchronous condensing conversions.

Fossil plants of the same era as Holyrood were designed with an economic life of 30 years. For practical purposes, this meant at least a 40 year technical life. However, many plants in the United States are still in active service and quite functional at over 60 years of age.

Holyrood Units 1 2, and 3 are approximately 41, 40, and 31 years of age respectively. However, given their historical seasonal based, lightly loaded service, the operational age for the majority of its equipment and systems is more like 20, 19, and 16 years, respectively. The plant has been well managed and maintained. The units have also seen minimum service at either their maximum continuous rating (let alone over-pressure/over-temperature) or at extreme minimum load. The units tend to operate between 70 and 140 MW (40% and 80% load) and most often around 110 to 125 MW (65-70%). Unit 3 has seen modest synchronous condensing operation since its retrofit in 1986.

As mentioned previously, Units 1 and 2 were uprated from 150 to 175 MW in 1987. The components that were modified or replaced during the unit upgrade have a longer life as compared to the original equipment. These support a longer life expectation for the station as a whole.

The boiler and its major elements were one of the plant's major reliability and life issues. The original high sulphur (2.5%) and high vanadium fuel oil caused significant corrosion and fouling problems that led to upgrades to some of the boiler heat transfer surfaces. In 2009, the change to a higher quality, lower sulphur (0.7%) fuel oil has significantly improved boiler reliability and efficiency and is expected to have a positive impact on the life of boiler systems.

As indicated above, there is no reason why the plant cannot continue to generate electricity reliably to the year 2020 as identified. Similarly, if and when Units 1 and 2 are converted to synchronous condensers (current plan is conversion in 2014) to provide system support, the units and the plant should be able to fulfill that role to 2041. There are several pre-requisites to this, including continued and enhanced inspection and maintenance programs, planned major equipment refurbishment such as generator stator and rotor rewinds, controls and alarms upgrades, and switchgear and breaker refurbishments and replacements.

A key to extending plant life will be the generators, transformers, and switchgear. Units 1, 2, and 3 have major generator inspections scheduled for 2012, 2014, and 2016 respectively. They also have reliability issues that may require a near term need for stator and/or rotor rewinds and possibly core or rotor replacement. Transformers are at the point in their lifecycle where significant degradation also occurs. More frequent or continuous monitoring of their condition is required to forewarn of any problems arising. Existing switchgear is in many cases at or near end of life and refurbishment and replacement is required.

Several other key issues with single contingency systems, given age and failure history also raise red flags and include:

- The single contingency failure risk of the fresh/raw water supply from Quarry Brook Pond;
- The single contingency failure risk of the clarifier failure, at least until 2020; and
- The 42 year age and condition of the black start gas turbine – reliability, parts obsolescence make a detailed evaluation critical; especially as the island interconnected system has indicated a potential need for it as an emergency power source.

If Hydro addresses the key issues and maintains a vigorous maintenance and inspection program, there is no technical reason that the plant cannot reach its 2020 generation end of life and 2041 synchronous condensing end of life targets.

The gas turbine generator and balance of plant is in need of a major overhaul, as well as refurbishment and replacement of its stack and air intake systems. In addition, it is likely that it's fuel receiving and feeding system will need a major overhaul as soon as practical within the next two years.

8 UNIT 1

8.1 Unit 1 - Key Systems

8.1.1 Asset 6696 – Unit 1 Generator

(Detailed Technical Assessment in Working Papers, Appendix 4)

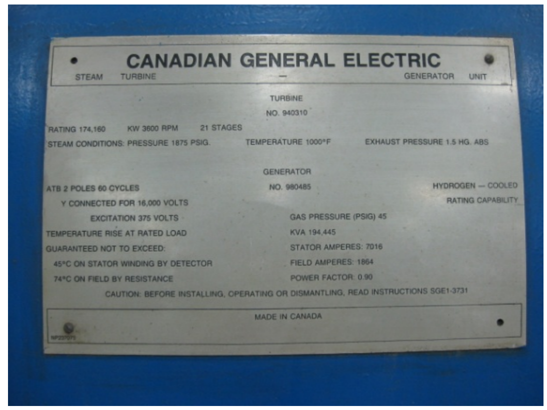

FIGURE 8-1 UNIT 1 GENERATOR

Equipment/components covered in this report are:

Unit #:	1
Asset Class #	BU 1296 - Assets Generations
SCI & System:	6691 #1 Turbine & Generator
Sub-Systems:	6696 #1 Generator Assembly
Components:	6839 #1 Generator Rotor
	6840 #1 Generator Stator
	6849 #1 Excitation System
	6850 #1 Hydrogen System

8.1.1.1 Description

Unit 1 generator, supplied by Canadian General Electric, Peterborough, is hydrogen-cooled and rated at 194,445 KVA. It went into service in 1969 and the last major inspection was in 2003. The 2003 outage inspection report is the base reference for this assessment.

The stator core and windings are flexibly-mounted in the stator frame, which contains four vertical hydrogen coolers. The stator windings operate at 16.0 KV and are indirectly cooled by hydrogen. The hydrogen is circulated throughout the generator in a closed system, at a pressure of 310 kPag (45 psig) by an axial fan mounted on each end of the rotor. An isolated phase bus delivers the power from the generator to the unit transformer.

The generator rotor is directly-coupled to the turbine, and is supported on bearings located in the end-shields of the stator frame. Hydrogen seals prevent hydrogen from escaping around the rotating shaft. The seals are pressurised by oil and are located inboard of the bearings. The field windings are directly-cooled by hydrogen, fed via axial sub-slots and radial gas passages in the copper winding. The field windings are supported by retaining rings shrunk onto the ends of the rotor body. The field current is supplied to the field windings via collector rings and brush gear, outboard of the main bearing – there is no steady bearing. There is an unused thrust bearing collar at the turbine end of the generator shaft, for future synchronous condenser use.

The excitation to the field is now supplied by an ABB Unitrol static thyristor excitation system, with a fast response automatic voltage regulator to control the field current and MVAR output from the generator. The excitation has a high ceiling voltage capability to enable the generator to help the power system recover from faults and disturbances.

The auxiliary systems include:

- A static thyristor controlled exciter fed from the generator terminals, with field flashing for initial energization;
- A seal oil system, with a differential pressure controller to keep the hydrogen contained within the generator;
- A closed-loop distilled water cooling system and temperature controller to remove the heat from the generator;
- A hydrogen pressure control valve to provide automatic make-up from the bulk hydrogen supply, (at increased hydrogen pressure if overload is required);
- A scavenging system to remove the hydrogen that becomes entrained in the bearing oil and the seal oil;
- Potential transformers (PT’s), located below the isolated phase bus, measure the generator voltage; current transformers (CT’s) mounted over the generator lead bushings measure the generator current. These devices provide signals to measure the generator output, and for the electro-mechanical protection relays;
- A vibration monitoring system continuously monitors the vibration amplitudes at each turbine generator bearing in the control room, and alerts the operator to increasing vibration, especially during run-up, load changes and shut-down. It uses two proximity probes at 45° to the vertical to measure the shaft vibration level; and
- A digital multi-functional generator protection relay has been added, but at present it is primarily used for extra ground fault protection of the stator windings (which are in poor condition - see next item). It also provides supplementary alarms and sequence-of-events monitoring.

8.1.1.2 History

The history and requirements for the Unit 1 generator are as follows:

Manufactured/Delivered	1969
In-Service Date	Sep 1970
Generation Base Load End Date	Dec 2015
Generation Peak/Emerg Gen End Date	Dec 2020
Synchronous Condensing Start Date	Jan 2015
Synchronous Condensing End Date	Dec 2041
Last Major Inspection	2003
Next Major Overhaul/Inspection	2012

The thousands of hours associated with the analyses, and the number of starts per year are:

	Generation (Gen)	Synchronous Condensing (SC)
Hours Actual - Ops to Dec 2009	166	0
Hours - Ops to Gen End Date Dec 2015	210	1.5
Hours - Ops to Gen End Date Dec 2020	219	25
Hours – Ops to SC End Date Dec 2040	219	120
Starts Actual - Ops to Dec 2009	482	0
Starts - Ops to Gen End Date Dec 2015	554	5
Starts - Ops to Gen End Date Dec 2020	614	30
Starts – Ops to SC End Date Dec 2040	714	130

8.1.1.3 Inspection and Repair History

Post-2003 Improvements

- Fast dump of generator hydrogen added to supplement water sprays on bearings;
- Generator hydrogen dryer replaced;
- Hydrogen purity meter replaced; and
- Improved stator winding ground fault protection installed.

2003 Overhaul

- Full replacement of the stator slot wedges with top ripple springs;
- Stator end-winding support system cleaned and re-tightened;
- Defective RTD repaired. Accuracy of others is poor, (but they can only be replaced during replacement of the stator windings);
- Digital multi-functional generator protection relay installed, (for improved winding ground protection, alarms connected, and sequence of events monitoring). Electro-mechanical protection relays retained;
- Installed 4 new cold gas RTD's in stator;
- Damaged epoxy dowels of fibre inner end-shields – repaired with oversize dowels. Realigned hydrogen seal housing;
- Repaired leak in bushing box horizontal joint with RTV sealant. Joint needs a new gasket;
- Hydrogen coolers cleaned, and pressure tested. OK;

- Rotor shaft line realigned. Stator frame re-aligned to match rotor shaft, locking keys re-welded in frame base;
- Replaced improper flanges and gaskets and piping at liquid leak detector;
- Replaced and machined teeth of bearing oil deflectors (excessive clearances, chipped); and
- Repaired leak in horizontal joint of CE hydrogen seal with epoxy.

1997 Overhaul

- New 18%Mn/18%Cr retaining rings fitted to rotor;
- The end-portions of the field windings would be inspected while the rings were off, but no report was available. It is not known whether the rotor dovetails were NDE inspected for fatigue cracks;
- GE static exciter replaced by ABB Unitrol static exciter and Automotive Voltage Regulator (AVR) (In-service 2001); and
- Partial discharge monitoring system installed in stator windings.

8.1.1.4 Condition Assessment

The generator and its auxiliary systems are in reasonable good condition for their age.

- Stator core: satisfactory, based on El-cid results;
- Stator Windings: Poor, based on Megger test and DC hipot test;
- Rotor Forging: Not known (appears not checked in past 20 years); and
- Field Winding: Satisfactory, but few details available (concerns are based on repairs made to similar GE rotors).

Details of the sub-systems are presented in Table 8-1 below and in more detail in Appendix 4.

TABLE 8-1 CONDITION ASSESSMENT – UNIT 1 GENERATOR

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset Level 2	Asset Level 3	Description	Detail	Condition Summary ID #	Append #	Condition	EPRI Identifier	Original Life (Base Load) Ops Hrs (Yrs)	Current Expected Minimum Remaining Life Years (Subject to Test)	End of Life (EOL) Required	Next Regular Inspection	Next Planned Overhaul or Major Inspection	Capability to Reach Next Overhaul	Capability to Reach EOL	In Service
1296	6690	6691	0	0	0	1	#1 TURBINE & GENERATOR	TURBINE & GENERATOR	TURBINE & GENERATOR	N/A	1	4	Overhaul required in 2012	4	200000 (30)	5	2041	2012	2012	Yes	No	1970
1296	6690	6691	6696	0	0	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	GENERATOR ASSEMBLY		2	4	Stator: core - satisfactory; Windings: Poor Rotor: Forging: Not known, likely satisfactory; Winding: Satisfactory, but limited information Overhaul required in 2012	4	200000 (30)	5	2041	2012	2012	Yes	No	1970
1296	6690	6691	6696	6839	0	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	GENERATOR ROTOR	CORE	3	4	Forging: Not known, likely satisfactory	4	200000 (40)	15	2041	2012	2012	Yes	No	1970
1296	6690	6691	6696	6839	0	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	GENERATOR ROTOR	WINDINGS	4	4	Field Winding: Satisfactory, but little information. The field current is not credible: much too low. The field winding temperature is not monitored. No on-line monitoring for shorted field turns (most common indication the rotor needs to be re-wound) is in place. Partial discharge monitoring is not working. The shaft voltage and the shaft ground current are not monitored in operation for harmful currents through the bearing or hydrogen seal. The retaining rings, the rotor forging, and slot wedges do not appear to have been NDE checked for defects 1997.	4	200000 (30)	10	2041	2012	2012	Yes	No	1970
1296	6690	6691	6696	6840	0	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	GENERATOR STATOR	CORE	5	4	Core - satisfactory. The stator core and frame are reported to be in good condition, with no looseness or fretting damage at the bore, or at the outside flexible mounting. GE reported that El-cid readings taken before and after the re-wedging of the stator bars in 2003 show no significant core deterioration, and the stator core is fit to be re-wound. The stator winding and core RTD's do not read credible values: too low	4	200000 (40)	(5+)	2041	2012	2012	Yes	No	1970
1296	6690	6691	6696	6840	0	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	GENERATOR STATOR	WINDINGS	6	4	Windings: Poor, requiring rewind. Reported in 2003 major outage to be in very poor condition with two of three phases significantly weaker and insulation weakness (or wetness). It is anticipated that more extensive loosening, fretting, and greasing of the end-windings will be found at the next inspection. Stator winding RTD's do not read credible values: too low	4	200000 (30)	(2/8)	2041	2012	2012	Yes	No	1970
1296	6690	6691	6696	6840	7345	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	GEN. STANDOFF INSULATORS	N/A	7	4	Excessive greasing of the stand-off insulators and of the flexible line leads to the potential transformers in the past required their replacement. 2003 stator re-alignment is expected to have reduced the vibration and stress on these components. Assess in overhaul.	4	(30)	20	2041	2012	2012	Yes	No	1970
1296	6690	6691	6696	6849	271310	1	#1 TURBINE & GENERATOR	GENERATOR EXCITATION SYSTEM	EXCITER	N/A	8	4,6	Replaced in 2000, due to difficulties in obtaining replacement parts and service, by an ABB Unitrol static excitation system which is working well.	10	200000 (30)	20	2041	2012	2012	Yes	No	1999
1296	6690	6691	6696	6849	271310	1	#1 TURBINE & GENERATOR	GENERATOR EXCITATION SYSTEM	EXCITER	Controls	9	4,6	Replaced in 2000 as part of exciter Controls. Review identified reported difficulties with protective relays calibration drift, and malfunctions and the field flashing maloperation. Subsequently identified as resolved by station.	10	200000 (30)	(2)	2041	2012	2012	Yes	No	1999
1296	6690	6691	6696	6849	271311	1	#1 TURBINE & GENERATOR	GENERATOR EXCITATION SYSTEM	EXCITATION TRANSFORMER	N/A	10	4,6	Replace with zero PCB when regulations require (2013?)	10	200000 (30)	3	2041	2012	2012	Yes	No	1988
1296	6690	6691	6696	6849	271312	1	#1 TURBINE & GENERATOR	GENERATOR EXCITATION SYSTEM	EXCITER FIELD BREAKER	N/A	11	4,6	Replaced with exciter	3a	200000 (30)	10	2041	2012	2012	Yes	No	1999
1296	6690	6691	6696	6849	271311	1	#1 TURBINE & GENERATOR	GENERATOR EXCITATION SYSTEM	RT1 RECTIFYING TRANSFORMER	N/A	12	5,6	Installed in 1969, the unit has a relatively high level of risk due to its age. No details on testing were identified. The units was originally an Askarel oil filled unit but was changed in 2004 to Perchloroethylene with below 50mg/kg PCB's. Tests in 2005 identified satisfactory results. The current PCB Regulation SOR/2008-273, posted in the CEPA Environmental Registry, includes practice for the better management of PCB's in use.	4	(45)	5	2041	2013		Yes	No	1970
1296	6690	6691	6696	6850	0	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	GEN. HYDROGEN GAS SYSTEM	N/A	13	4	Hydrogen cooler, hydrogen dryer, and hydrogen purity meter working well. The hydrogen scavenging system (removing entrained hydrogen from the seal oil) appears less effective than the Unit 3 vacuum system. The hydrogen pressure is low, probably due to hydrogen leaks (causes extra heating of the generator core and windings). Consumption is not recorded. The cold gas temperature is low at 30 °C versus GE minimum 35 °C.	3a	200000 (30)	(10)	2041	2010	2012	Yes	No	1970
1296	6690	6691	6696	6850	6806	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	GENERATOR SEAL OIL SYSTEM	N/A	14	4	The horizontal joint of the hydrogen seal assembly was epoxied, to prevent hydrogen/oil leakage into the generator, but the risk is high that the hydrogen sealing system has not been successful in preventing oil entering the generator and contaminating the end-windings.	4	200000 (30)	(10)	2041	2010	2012	Yes	No	1970
1296	6690	6691	6696	6850	6851	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	GEN. CO2 GAS PURGE SYSTEM	N/A	15	4	Not reviewed in detail. No issues identified except system capacity.	3a	200000 (30)	(10)	2041	2011	2012	Yes	No	2009
1296	6690	6691	6696	6850	6853	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	GENERATOR HYDROGEN COOLING	N/A	16	4	Acceptable condition.	3a	200000 (30)	10	2041	2010	2012	Yes	No	1970

Notes:

1. A "(bracketed)" value in the "Current Expected Remaining Life" column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as "(X/Y)" has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

2. The "Next Regular Inspection" column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The "Next Planned Overhaul or Major Inspection" column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a "Desired Life" stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or are not known by AMEC.

8.1.1.5 Actions

The following table highlights a number of the basic issues/defects found and the actions recommended to address them.

TABLE 8-2 RECOMMENDED ACTIONS - 6840 #1 GENERATOR STATOR

Issues	Recommended Actions
1. There is oil leaking into the stator, reducing the effectiveness of the winding support. Oil and grease has been found on the end-windings at each past inspection, and on other similar GE generators. A leak in the horizontal joint of the seal assembly was found at the last outage and a temporary repair was made – is it still effective 7 years later?	1. Keep the differential seal oil/hydrogen differential pressure constant and between 27 – 40 kPa (4 and 6 psi). 2. Check the oil level in the de-training tank is not high, and the flow in the seal oil drain lines is not excessive or foaming, which increases the risk of oil backing up and leaking into the generator 3. Monitor the partial discharge activity every 3 months for signs of increased partial discharge activity. If the end-winding partial discharge activity exceeds 30 mV on any of the phases, plan an early intervention for repair of the stator end-winding looseness. 4. Check the hydrogen consumption and seal oil consumption for leakage.
2. The stator core appears to be in satisfactory condition, but the GE El-Cid test report is incomplete. (It is important to confirm the condition of the core is sound, before ordering a replacement stator winding for installation in 2012, see next item).	1. Plan for an El-cid test and a high flux test of the stator core, during the next major inspection. Check the stepped end packets, and record the highest defect values in each slot. 2. Repeat the measurements in the highest three slots and note the positions, for boroscope inspection. Take infra-red photos of the core and note the hot spots (areas greater than 3 °C above the surrounding areas).
3. The GE tests showed the right phase of the stator winding was in very weak condition in 2003. A rewind was recommended. An update on the winding condition should be obtained at the 2012 inspection (preferably from a second source). The tests should only be done on the winding after it has been carefully cleaned and re-tightened, and is known to be clean and dry.	1. At the next major inspection, repeat the 10 KV Megger test, and the DC hipot test at 34 KV. (Check whether the poor insulation condition was due to the high moisture or to the insulation deteriorating during the re-wedging – this is useful information for Unit 3). 2. Also test the bushings and the PT's, and carry out ratio tests on the CT's. 3. Decide whether the windings will last until 2015, or whether they should be replaced during the 2012 outage. 4. Draft a specification now, for the manufacture, test and installation of a replacement winding, together with new RTD's, and bushing and terminal plate flange seals. Also include options for new bushings and CT's, in case they are necessary. This will reduce the outage time, if a winding failure should occur during the next two years. 5. At the next major inspection, have the OEM (or potential rewind Contractors) take the stator slot and winding dimensions. 6. Consider taking advance delivery of the winding and store it at the plant until needed (make sure the new winding will fit either Unit1 or Unit 2, or identify why this is not possible).

Issues	Recommended Actions
4. The end-winding support structure is not able to withstand the operating and system stresses. It loosens and allows the insulation to erode and form grease. An improved end-winding support system is required.	1. Ask the OEM for an improved end-winding support system to be supplied with the new stator winding (modern techniques are available to allow the supports to slide when hot, rather than develop internal stress that loosens them). 2. Have the effectiveness of the new winding installation checked with the "bump" test, and additional support provided where it is found necessary
5. Top ripple springs were installed to increase the time between re-wedging the stator slots. Check that the top ripple springs are still holding the slot parts of the windings firmly in place, and no loosening of the wedges/windings has occurred.	1. Carry out a wedge tap survey, to check for loose wedges, (and find out whether Unit 2 is likely to require re-wedging at its next major outage). Visually inspect the core teeth for signs of fretting dust or "grease".
6. Further information is desirable regarding the deterioration of the stator winding in operation, and the possible need for more frequent maintenance.	1. Take Doble test measurements every 2 years, during the summer outage (it is necessary to disconnect the neutral bar – make sure it is replaced carefully, and check the joint resistance with a low resistance meter ("ductor").
7. A hydrogen seal leak was found at the bushings and at the terminal plate seals. It was sealed temporarily from the inside with RTV. GE recommended the area be checked annually for leaks, but it is not known if this was done.	1. Replace the bushing seals and the terminal plate seals. This is a difficult and expensive repair that is best done during a stator rewind. RTV sealing of the inside is satisfactory for a short time, but the deteriorated seal usually leaks elsewhere. GE uses viscaseal and a dam to identify a leak, but Hitachi repairs the leak with "titeseal" which is better.
A. Operation	
1. The stator winding and core RTD's do not read credible values. They are too low.	1. Using the GE calibration from the last outage, monitor the most accurate RTD of each phase, and the hottest core RTD, on the DCS display.
2. The partial discharge monitoring is not working. The GE test report shows the stator windings are in very poor condition, so the partial discharge levels in operation should be monitored carefully, to minimize the risk of a winding failure – see also item 2 above)	1. Contact IRIS service dept, to obtain advice on how to get it working. Record the values every 3 months and watch for an increase of >20 % in the readings of the highest 3 sensors. Bring forward the planned outage if necessary.
3. During the two month summer outage and the major inspection outages, moisture collects on the stator and rotor windings. Corrosion of the collector distributor bolts was found on Units 1 and 2 at the last outage. It greatly affects the Megger and DC hipot test results.	1. When the generator is out of service and de-gassed, blow warm dry instrument air through the generator. When the rotor is out, install heaters in the stator ends, and a tarp over the ends to keep it warm and reduce dust ingress. 2. Consider fitting pad heaters to the lower outer surface of the stator ends, with a switch to turn the heat on when the unit is off-line. 3. The rotor should be kept in a clean conditions "tent" and air heaters installed to keep the windings warm and dry.

Issues	Recommended Actions
4. Four of the stator (winding) slot temperatures are monitored on the "turbine generator" screen, but the stator core temperature is not monitored in operation. During high over-excited load the centre of the stator becomes the hottest, but during under-excited operation the core end temperatures are the highest. This is particularly important during synchronous condenser operation.	1. Use three of the lines for the hottest winding temperature in each phase, and label them phase A, phase B and phase C. Use the fourth line to monitor the hottest stator core-end temperature. Add a fifth line to show the hottest core temperature at the centre of the stator.

TABLE 8-3 RECOMMENDED ACTIONS - 6839 #1 GENERATOR ROTOR

Issues	Recommended Actions
1. The retaining rings and the rotor forging, and slot wedges do not appear to have been NDE checked for defects since they were installed in 1997. (Defects have been found in other similar rotors after less than 30 years operation).	1. Remove the retaining rings and the slot wedges 2. Carry out a detailed visual and NDE inspection for defects and fatigue cracks developing, in the dovetails, wedge ends, rotor bore, retaining rings, etc. Remove any crack-like defects. Check the shrink fit areas for fretting, and contact of end-wedges with the retaining rings.
2. The condition of the end-windings is not known, and some deformation of the turns in the coil stacks is expected, especially at the series connections between longer coils and at the lead connections to the winding. The packing blocks are expected to be fretted and dust will have collected under the retaining ring insulation that should be removed.	1. Check the end-windings for fretting, fatigue cracks in the top turns under the retaining rings, any distortion or cracking of the flexible connections.
3. The turn insulation may be damaged, or the packing blocks broken, fretted or displaced, and the ends of the slot cells may be abraded, overheated, or crushed by the retaining rings.	1. Check the insulation blocks and re-place or re-tighten as necessary. (note the dust found probably contains asbestos).
4. The ventilation system of the rotor slots uses sub-slots and radial ventilation ducts. It is prone to axial elongation (creep of the copper and restriction of the ventilation holes.	1. Check the radial holes near the ends of the rotor body for restrictions, and record the restrictions, for future (the rotor should be re-wound when the restriction exceeds 25 % of the hole area).heck the sub-slots for oil, dirt and accumulated debris. Vacuum/blow out as much of the dirt as possible.
5. The turbine generator shaft line has been realigned at each major inspection. The adjustment seems to be too much to be due to bearing wear, and it appears that the foundation is settling over time.	1. Trend the bearing vibration levels over time, and record the changes. Try to relate them to the MVAR load, as well as the MW load. 2. If the vibration level is high put the readings on a polar plot (Bode) and compromise balance it with marked weights. 3. Re-align and re-balance the rotor after the shaft line has been corrected, at the major inspection.

Issues	Recommended Actions
6. There is no record of the generator bearings being re-metalled, but GE recommended sending out the generator bearings for refurbishment at the next major overhaul. Other rotors have found uneven wear, poor Babbitt bond, and electrical damage. The #5 bearing insulation was found defective.	1. Re-furbish both generator bearings. 2. NDE the bearing Babbitt for good bond with the shell. 3. Check the surface for even wear 4. Check the insulation resistance of #5 bearing and hydrogen seal, and inspect visually. 5. Replace if defective. Replace oil deflectors.
7. GE recommended that spare bearing thermocouples be held in stock in case the installed thermocouples fail in service.	1. The bearing thermocouples are old, and in dubious condition. New thermocouples should be installed at the next major outage.
8. A week was spent working on the hydrogen seals, and numerous problems were encountered. The hydrogen seal clearances on the hydrogen side were reduced to the low end of the clearance, in an attempt to prevent oil leaking into the generator. An oil leak from the horizontal joint of the hydrogen seal was found at the CE and repaired temporarily with epoxy	1. Replace the insulation plates of the CE seals. Check the titeseal groove at the upper and lower CE end-shield for leaks. Air-test the generator for leaks, and fix them properly at the next major inspection. A new hydrogen seal assembly should be considered for the CE end.
A. Operation	
1. The field current is not credible, it is much too low.	1. Check the source and calibrate the DCCT, or use the field current value shown on the exciter.
2. The field winding temperature is not monitored. (During overexcited synchronous condenser operation the field current will be higher, and there is an increased risk of overheating the field winding insulation).	1. Install a mean field winding temperature simulator(if one does not already exist in the static excitation system), or - obtain an algorithm for the mean field winding temperature, based on the field current, cold resistance and the cold gas temperature. Show the mean field winding temperature on the control room display.
3. There is no on-line monitoring for shorted field turns (this is the most common indication the rotor needs to be re-wound).	1. Install a flux probe in the stator bore at the next major outage, when the rotor is out of the stator core.
4. The shaft voltage and the shaft ground current are not monitored or checked in operation. A harmful current could flow through the bearing or hydrogen seal. (the risk of damage increases when the starting package is added at the collector end, for synchronous condenser operation).	1. Upgrade the shaft grounding brushes with a constant-tension spring brush box, and replace the other with a copper braid, to clean the shaft. 2. Fit a shaft voltage monitoring brush at the outer end of the shaft, so the shaft voltage can be checked safely in operation, or 3. Install a Shore grounding brush and shaft current and voltage monitoring system.

Issues	Recommended Actions
5. During the two month summer outage and the major inspection outages, moisture collects on the stator and rotor windings. Corrosion of the collector distributor bolts was found on Units 1 and 2 at the last outage. It greatly affects the Megger and DC hipot test results.	1. When the generator is out of service and de-gassed, blow warm dry instrument air through the generator. When the rotor is out, install heaters in the stator ends, and a tarp over the ends to keep it warm and reduce dust ingress. 2. Consider fitting pad heaters to the lower outer surface of the stator ends, with a switch to turn the heat on when the unit is off-line. The rotor should be kept in a clean conditions "tent" and air heaters installed to keep the windings warm and dry.

TABLE 8-4 RECOMMENDED ACTIONS – 6850 #1 HYDROGEN SYSTEM

Issues	Recommended Actions
1. Several problems were found with the float trap of the middle de-training tank of the seal oil system. The valve disc had hardened, the level control was incorrect, and the valve was installed backwards.	1. Replace the seals, and viton disk, and gaskets, and check the operating level in the tank at both 207 and 310 kPa (30 and 45 psi) hydrogen pressures. 2. GE recommends the seal oil supply piping be flushed annually, to prevent dirt in the emergency by-pass line entering the system.
2. The seal oil vacuum pump is a high maintenance item. It has a rotary valve that needs to be replaced at each inspection.	1. Purchase a spare rotary seal and install it at the next major inspection. Carry out preventive maintenance on the pump
3. The hydrogen coolers were leak tested and found satisfactory, but GE recommended the gaskets be replaced at each major inspection.	1. Replace the gaskets and seals, and leak test at every major inspection. Check cold parts for green slime (operating temp too low!)
4. The liquid leak detector valve had incorrect flanges and gaskets and is prone to failure.	1. Check the operation of the liquid leak detector relay, and service the parts.
5. Hydrogen dryer. The replacement hydrogen dryer is of small capacity and will require frequent regeneration. Oil from the leaking hydrogen seals reduces its effectiveness. A pipe blockage can burn out the heater.	1. Carry out preventive maintenance on the hydrogen dryer, replace the desiccant, check the regeneration operation, and check for hydrogen leaks, especially at the purity meter and sampling valves.
6. The hydrogen pressure is automatically controlled by a valve, but this generator operates at low pressure. Is the valve not in service or is it broken? Keeping the pressure constant reduces the risk of oil ingress into the generator.	1. Service the hydrogen pressure control valve. Locate and repair hydrogen leaks ASAP.
A. Operation	
1. The hydrogen pressure is low, probably due to hydrogen leaks, resulting in extra heating of the generator core and windings.	1. Locate and repair the hydrogen leaks. 2. Increase the hydrogen pressure to 207 kPa (30 psi).

Issues	Recommended Actions
2. The hydrogen consumption of each generator is not recorded.	1. Fit a totalizer in the hydrogen supply line, so the daily hydrogen consumption of each generator can be recorded.
3. The cold gas temperature is low at 30 °C, GE usually recommend a minimum of 35 °C to avoid algae forming on the windings and the increased risk of brittle fracture in the rotor forging.	1. Ask GE to confirm the rotor forging is water-quenched, not air-quenched. 2. Increase the cold gas temperature setting to 35 °C, especially if the forging is air-quenched.
4. The hot gas temperatures are not recorded, so it is not possible to check the temperature rise across each cooler, i.e. whether the hydrogen coolers are balanced. Sometimes a cooler leak occurs, or a plug of the vent pipe after return to service, that should be detected.	1. Every month check the temperature rise across each cooler, to ensure they are balanced, and no gas lock, plugged vent, or cooler leak has occurred, which will unbalance the temperatures across the generator, and result in undesirable overheating.
5. The hydrogen pressure is automatically controlled by a valve, but this generator operates at low pressure. Is the valve not in service or is it broken? Keeping the pressure constant reduces the risk of oil ingress into the generator.	1. Service the hydrogen pressure control valve. 2. Locate and repair hydrogen leaks ASAP.

TABLE 8-5 RECOMMENDED ACTIONS - 6849 #1 EXCITATION SYSTEM

Issues	Recommended Actions
1. The ABB static excitation system is reported to be operating satisfactorily. However, the controls and protective relays are prone to calibration drift, and malfunctions. The field flashing can maloperate	1. Check the operation of the excitation system controls, limiters and protection relays. 2. Check the field breaker contacts and operation. 3. Check the thyristors and heat sinks, and snubbers, for signs of overheating,
2. The excitation system is expected to have a V/f limiter to protect the generator against over-fluxing, -the risk of generator damage is highest during initial energization on AVR control.	1. Connect the V/f element of the multi-functional generator protection relay to trip the excitation when off-line, if over-fluxing occurs.

8.1.1.6 Actions - Unit 1 Generator

The following table highlights a number of the basic issues/defects found and the actions recommended to address them.

TABLE 8-6 RECOMMENDED ACTIONS – UNIT 1 GENERATOR

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Unit	Asset 2/3	Asset 3/4	Description	Detail	Action #	App #	Action	Year	Priority
1296	6690	6691	6696	0	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	GENERATOR ASSEMBLY	N/A	1	4	Reduce operating intervals between major outages to 6 years.	2010	1
1296	6690	6691	6696	6839	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	GENERATOR ROTOR	N/A	2	4	NDE inspection of the rotor high-stress areas should be done in 2012 - cover the retaining rings, changes in cross section of the rotor (journals and coupling etc), the rotor tooth dovetails, the slot wedges and the lead wedges for fretting fatigue cracks, the rotor core (bore sonic inspection), the bearing shells for babbitt bond, the fans for fatigue cracks. The rotor dovetails with short steel wedges should be checked carefully, due to the higher risk of a fatigue crack developing under the high cyclic bending stress.	2012	1
1296	6690	6691	6696	6839	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	GENERATOR ROTOR	N/A	3	4	Remove the retaining rings and the slot wedges to permit a closer inspection. Surface defects may be found in the retaining rings, a fatigue crack may exist in the dovetails, spitting damage may be found at the wedge ends, due to negative sequence current.	2012	1
1296	6690	6691	6696	6839	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	GENERATOR ROTOR	N/A	4	4	Install a rotor flux probe near the turbine end of the stator bore wired out through the existing IRIS penetration and junction box to detect the presence of shorted field turns. Usually precedes development of a rotor ground fault and that the field winding has suffered extensive copper deformation and weakening of the turn insulation, and is close to the end of its useful life.	2012	1
1296	6690	6691	6696	6839	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	GENERATOR ROTOR	N/A	5	4	Make a visual check of the extent of restrictions of the radial gas cooling passages, and of any displaced turn insulation. Any accumulated debris in the radial ventilation ducts, the sub-slots, and in the end-windings should be blown or vacuumed out.	2012	1
1296	6690	6691	6696	6839	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	GENERATOR ROTOR	N/A	6	4	Monitor the shaft ground current, or the shaft voltage at the outboard end of the generator - replace the original equipment with on-line monitoring capability. The risk of a shaft current flowing through the bearing or hydrogen seal increases during synchronous condenser operation.	2012	1
1296	6690	6691	6696	6839	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	GENERATOR ROTOR	N/A	7	4	Perform annual 500 volt megger checks on the rotor, to confirm that there is no major deterioration of the ground insulation (below 3 Gig-ohms).	2010	1
1296	6690	6691	6696	6839	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	GENERATOR ROTOR	N/A	8	4	Install a field winding temperature indicator in control room.	2010	1
1296	6690	6691	6696	6840	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	GENERATOR STATOR	N/A	9	4	Repair hydrogen leak in the bushing box horizontal joint of the cover plate holding the bushings bushing seals. Difficult as it necessitates breaking the main connections, dropping the bushings, installing the gaskets, and re-installing the bushings. May be necessary to remove the whole bushing box. An alternative repair of poorer integrity is to seal the inside joint flanges around the bushings and terminal plates with RTV sealant.	2012	1
1296	6690	6691	6696	6840	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	GENERATOR STATOR	N/A	10	4	Install a hydrogen consumption “totalizer” in each hydrogen supply line for recording daily and checked for leaks.	2012	1
1296	6690	6691	6696	6840	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	GENERATOR STATOR	N/A	11	4	Maintain hydrogen pressure steady at the rated value of 310 KPag to simplify differential pressure controller operation and help to ensure a constant and appropriate oil flow through the hydrogen seals, reducing the risk of a seal oil spill into the generator. Also reduces the risk of the sealant at the stator end shields cracking and permitting a hydrogen leak. It will also avoid a change in the bearing height and alignment of the rotor, which can increase the bearing vibration levels.	2011	1
1296	6690	6691	6696	6840	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	GENERATOR STATOR	N/A	12	4	Before implementing a stator rewind, perform a flux loop test and thermal imaging of the core to detect any hot spots and repair them before installing the new winding.	2012	1
1296	6690	6691	6696	6840	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	GENERATOR STATOR	N/A	13	4	Perform a minor inspection and Doble test after 4 or 5 years, and carefully monitor the on-line partial discharge monitoring.	2016	2

Table 8-6 Cont’d

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Unit	Asset 2/3	Asset 3/4	Description	Detail	Action #	App #	Action	Year	Priority
1296	6690	6691	6696	6840	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	GENERATOR STATOR	N/A	14	4	Take partial discharge activity readings in the slot portion of the windings and in the end-winding portion during normal service conditions. Work with IRIS on a priority basis to repair so that the results are available in time to consider replacing the windings during the 2012 outage. Detect de-lamination of the insulation tapes, deterioration in the low-resistivity paint at the outer surface (ground wall) in the slots, and discharges in the end-windings.	2010	1
1296	6690	6691	6696	6840	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	GENERATOR STATOR	N/A	15	4	Repeat the DC hipot test at the next major inspection, taking extra care to ensure the insulation is dry before the test.	2012	1
1296	6690	6691	6696	6840	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	GENERATOR STATOR	N/A	16	4	Perform an intermediate inspection of the stator end-windings after 4 years to establish the presence of oil and grease on the end-windings to better establish the timing of the next major inspection.	2016	1
1296	6690	6691	6696	6840	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	GENERATOR STATOR	N/A	17	4	Proceed with planning work for a rewind now - typically requires 9 to 12 months to plan and carry out a stator rewind, plus site work of 4-6 months.	2010	1
1296	6690	6691	6696	6840	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	GENERATOR STATOR	N/A	18	4	Proceed with the installation of a new stator winding at the next major outage in 2012.	2011	1
1296	6690	6691	6696	6849	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	EXCITER	N/A	19	4,6	Upgrade static exciter controls compatible with the latest Unitrol 6000 system.	2013	1
1296	6690	6691	6696	6850	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	GEN. HYDROGEN GAS SYSTEM	N/A	20	4	Install a hydrogen consumption “totalizer” in each hydrogen supply line, for recording daily and checked for leaks.	2011	1
1296	6690	6691	6696	6850	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	GENERATOR SEAL OIL SYSTEM	N/A	21	4	Maintain hydrogen pressure steady at the rated value of 310 KPag to simplify differential pressure controller operation and help to ensure a constant and appropriate oil flow through the hydrogen seals, reducing the risk of a seal oil spill into the generator. Also reduces the risk of the sealant at the stator end shields cracking and permitting a hydrogen leak. It will also avoid a change in the bearing height, and alignment of the rotor, which can increase the bearing vibration levels.	2011	1
1296	6690	6691	6696	6850	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	GEN. CO2 GAS PURGE SYSTEM	N/A	22	4	No action recommended.		
1296	6690	6691	6696	6850	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	GENERATOR HYDROGEN COOLING	N/A	23	4	Maintain hydrogen pressure steady at the rated value of 310 KPag to simplify differential pressure controller operation and help to ensure a constant and appropriate oil flow through the hydrogen seals, reducing the risk of a seal oil spill into the generator. Also reduces the risk of the sealant at the stator end shields cracking and permitting a hydrogen leak. It will also avoid a change in the bearing height, and alignment of the rotor, which can increase the bearing vibration levels.	2011	1

8.1.1.7 Risk Assessment

Table 8-7 below illustrates the risk assessment for the Unit 1 generator, both from a technological perspective and a safety perspective using the models presented in Section 3.

TABLE 8-7 RISK ASSESSMENT – UNIT 1 GENERATOR

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Component	Risk Assess #	Appendix #	Major Issues	Remaining Life Years (Insufficient Info - Inspection Required Within (x) Years)	Remaining Life Comments	TECHNO-ECO RISK ASSESS MODEL			SAFETY RISK ASSESS MODEL			Possible Failure Event	Mitigation
																Likeli-hood	Conse-quence	Risk Level	Likeli-hood	Conse-quence	Safety Risk		
1296	6690	6691	6696	0	0	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	GENERATOR ASSEMBLY	N/A	5		See details below.		None								
1296	6690	6691	6696	6839	0	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	GENERATOR ROTOR	Rotor Forging and Field Windings	6	4	Electrical Failure - EOL.	10+	None	2	D	Medium	2	D	High	Loss of unit generator and SC capability. Potential life threatening.	Plan for a rotor rewind by 2020. Evaluate techno-economic values of early implementation in 2015 as part of synchronous condenser conversion.
1296	6690	6691	6696	6839	0	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	GENERATOR ROTOR	Rotor Forging and Field Windings	7	4	Mechanical failure retaining rings.	10+	None	2	D	Medium	2	D	High	Loss of unit generator and SC capability. Potential life threatening.	Removal of the retaining rings and inspection in 2012.
1296	6690	6691	6696	6840	0	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	GENERATOR STATOR	Stator Core and Frame	8	4	Electrical - sustained over-fluxing off–line (e.g. if the PT has one phase open or a blown fuse).	15	None	3	C	Medium	3	C	High	Loss of unit generator and SC capability. Potential serious injury situation	V/f element of the new generator multi-functional relay be set up to provide back-up V/f protection beyond standard protection against over-fluxing by the volts/hertz relay.
1296	6690	6691	6696	6840	0	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	GENERATOR STATOR	Stator Core and Frame	9	4	Mechanical damage - inspection related.	15	None	2	B	Low	2	B	Low	Damage is local	Repair during outage.
1296	6690	6691	6696	6840	0	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	GENERATOR STATOR	Stator Core and Frame	10	4	Mechanical - Loose plates vibrating in the magnetic field then break off and damage the stator winding.	(5)	None	3	C	Medium	3	B	Medium	Loose plates break off and damage the stator winding.	Check for signs of red iron oxide dust in the stator bore and confirm by pushing a paint scraper between the plates. Loose areas can usually be treated with penetrating epoxy and re-tightened by driving tapered wedges into the loose packets of iron.
1296	6690	6691	6696	6840	0	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	GENERATOR STATOR	Stator Core and Frame	11	4	Electrical - failures of the stator winding, and/or poor stator winding ground protection.	(10)	None	3	D	High	3	C	High	Damage to stator core	2012 Inspection and repairs - stator rewind.
1296	6690	6691	6696	6840	0	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	GENERATOR STATOR	Stator Windings	12	4	Electrical - insulation/winding failure - system over-voltage transients.	(2/8)	None	3	D	High	3	C	High	Stator winding failure - possible stator core effects. GE contention that the insulation is at high risk of failing, and cannot be considered to be reliable.	Rewind of stator in 2012. Evaluate techno-economic risk of deferral to 2018 as soon as possible. (Currently relying upon the lightning and surge arrestors fitted at the generator terminals to attenuate surges, or upon the statistical unlikelihood of the worst over-voltage situation occurring.
1296	6690	6691	6696	6840	0	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	GENERATOR STATOR	Stator Windings	13	4	Mechanical/electrical - glued layers of mica flake insulation open	(2/8)	None	3	D	High	3	B	Medium	Stator winding failure - possible stator core effects. GE contention that the insulation is at high risk of failing, and cannot be considered to be reliable.	Rewind of stator in 2012. Evaluate techno-economic risk of deferral to 2018 at next recommended overhaul. Very important to control the mechanical stresses that can open up the glued layers of insulation and lead to mechanical breakdown of the mica flakes, especially if re-wedging required.
1296	6690	6691	6696	6840	0	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	GENERATOR STATOR	Stator Windings	14	4	Mechanical/electrical - end-windings loosen. Line-end coils & phase leads distort and fail during system fault condition.	(2/8)	None	2	D	Medium	2	B	Low	The line-end coils and phase leads are at most risk, of distortion, and could fail during a severe or a sustained system fault condition.	Wedge tightening and/or re-wedging. Repair line-end coils and phase leads during overhaul. Stator rewind.
1296	6690	6691	6696	6840	7345	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	GEN. STANDOFF INSULATORS	N/A	15	4	Mechanical vibration & electrical fault greasing.	20	None	2	D	Medium	2	B	Low	Loss of unit generator and SC capability. Potential serious injury situation	Replacement. Reduce stator vibration.
1296	6690	6691	6696	6849	271310	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	EXCITER	Static Exciter	16	4,6	Electrical fault, mechanical fatigue, controls fault, ops error.	20	None	2	C	Medium	2	B	Low	Loss 1 unit generation. Damage to Unit	Inspect and Test per current maintenance program.
1296	6690	6691	6696	6849	271310	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	EXCITER	Static Exciter Controls	17	4,6	Electrical fault, mechanical fatigue, controls fault, ops error.	(2)	None	2	C	Medium	3	A	Low	Loss 1 unit generation. Damage to Unit	Upgrade controls for compatibility by 2013.
1296	6690	6691	6696	6849	271311	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	EXCITATION TRANSFORMER	N/A	18	4,6	Regulatory PCB.	3	None	3	C	Medium	2	B	Low	Oil spill/PCB contamination	Replace per regulations when required.
1296	6690	6691	6696	6849	271312	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	EXCITER FIELD BREAKER	N/A	19	4,6	Electrical fault, mechanical fatigue, controls fault, ops error.	20	None	1	C	Medium	2	B	Low	Loss 1 unit generation. Damage to Unit	Inspect and Test per current maintenance program.
1296	6690	6691	6696	6850	0	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	GEN. HYDROGEN GAS SYSTEM	Auxiliaries - Hydrogen Pressure Control	20	4	Mechanical/electrical fire.	2	None	3	C	Medium	3	D	High	Seal Leak, Hydrogen Fire/Expl - oil leaks into the stator if the flow rate is too high, and overheating and failure of the hydrogen seals if the flow rate is too low.	New hydrogen seals and totalizer.

Table 8-7 Cont'd

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Component	Risk Assess #	Appendix #	Major Issues	Remaining Life Years (Insufficient Info - Inspection Required Within (x) Years)	Remaining Life Comments	TECHNO-ECO RISK ASSESS MODEL			SAFETY RISK ASSESS MODEL			Possible Failure Event	Mitigation
																Likeli-hood	Conse-quence	Risk Level	Likeli-hood	Conse-quence	Safety Risk		
1296	6690	6691	6696	6850	0	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	GEN. HYDROGEN GAS SYSTEM	Auxiliaries - Hydrogen System - Purity meter and Dryer	21	4	Electrical/fire	2	None	1	C	Low	1	D	High	Hydrogen Fire/Explosion	Recent replacement - monitor condition and maintain.
1296	6690	6691	6696	6850	6806	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	GENERATOR SEAL OIL SYSTEM		22	4	Mech - loss, spill - hydrogen leak.	10	None	1	C	Low	2	C	Medium	Hydrogen Fire/Explosion	Inspect and Test per current maintenance program.
1296	6690	6691	6696	6850	6851	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	GEN. CO2 GAS PURGE SYSTEM	CO2 Supply, Purge System	23	4	Mech failure.	30	None	1	C	Low	2	C	Medium	Hydrogen Fire/Explosion	Inspect and Test per current maintenance program
1296	6690	6691	6696	6850	6853	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	GENERATOR HYDROGEN COOLING	Auxiliaries - Hydrogen Coolers	24	4	Electrical/fire.	10	None	1	C	Low	1	C	Medium	Hydrogen Fire/Explosion	Monitor condition and maintain.

8.1.1.8 Life Cycle Curve and Remaining Life

Figures 8-2 and 8-3 below, illustrate the life cycle curve for the Unit 1 generator system. It is broken into two parts – the generator and the exciter. Differences in the scenarios in Section 6 do not materially affect the curve. The curves are plots of current and projected operating hours (generation plus synchronous condensing mode) on the y-axis versus calendar year on the x-axis. Vertical lines represent bands of nominal years of normal base loaded life (typically thirty years and 200,000 to 240,000 operating hours to forty years and 280,000 to 320,000 operating hours). Horizontal lines represent the ranges of equipment life based on current and historical information and expert opinion. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view.

The generator figure below shows the operating hours as an electricity generator, in synchronous condensing mode (beginning in 2015), as well as the sum of the two. Only one set of curves is required, given that the major elements of the generator (stator and rotor windings and core) and much of the hydrogen system are the same age. The new parts of the hydrogen system are not identified due to their shorter time in-service. One vertical line illustrates the timing of the next generator overhaul in 2012. The lowest two horizontal lines represent the ranges of expected generator life for Holyrood Unit 1 based on current and historical information and expert opinion. The “Rewind Unit 1 Recommended” line is based on the recommended estimated remaining reliable stator winding life of five years at current generation levels. The two upper lines also represent an assessment of a longer 10 + year of the lower reliability, higher failure risk, remaining life of the rotor winding as well as a maximum 20 years likely for the stator and rotor cores.

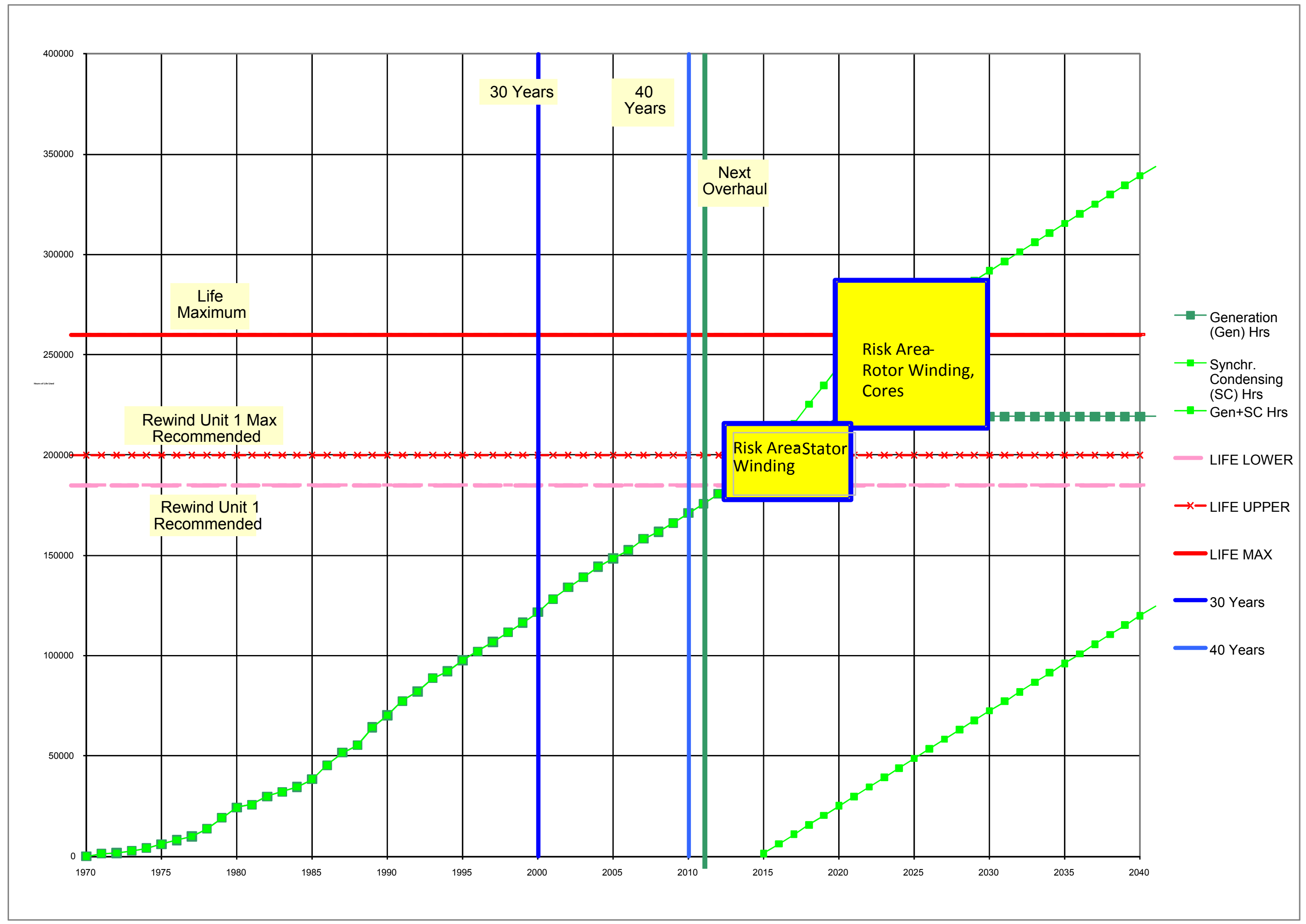

FIGURE 8-2 LIFE CYCLE CURVE – UNIT 1 GENERATOR

The exciter figure shows only the total operating hours as an electricity generator plus in synchronous condensing mode (beginning in 2015). It has two curves for any remaining original equipment as well as for the upgrades to the system made in 2001.

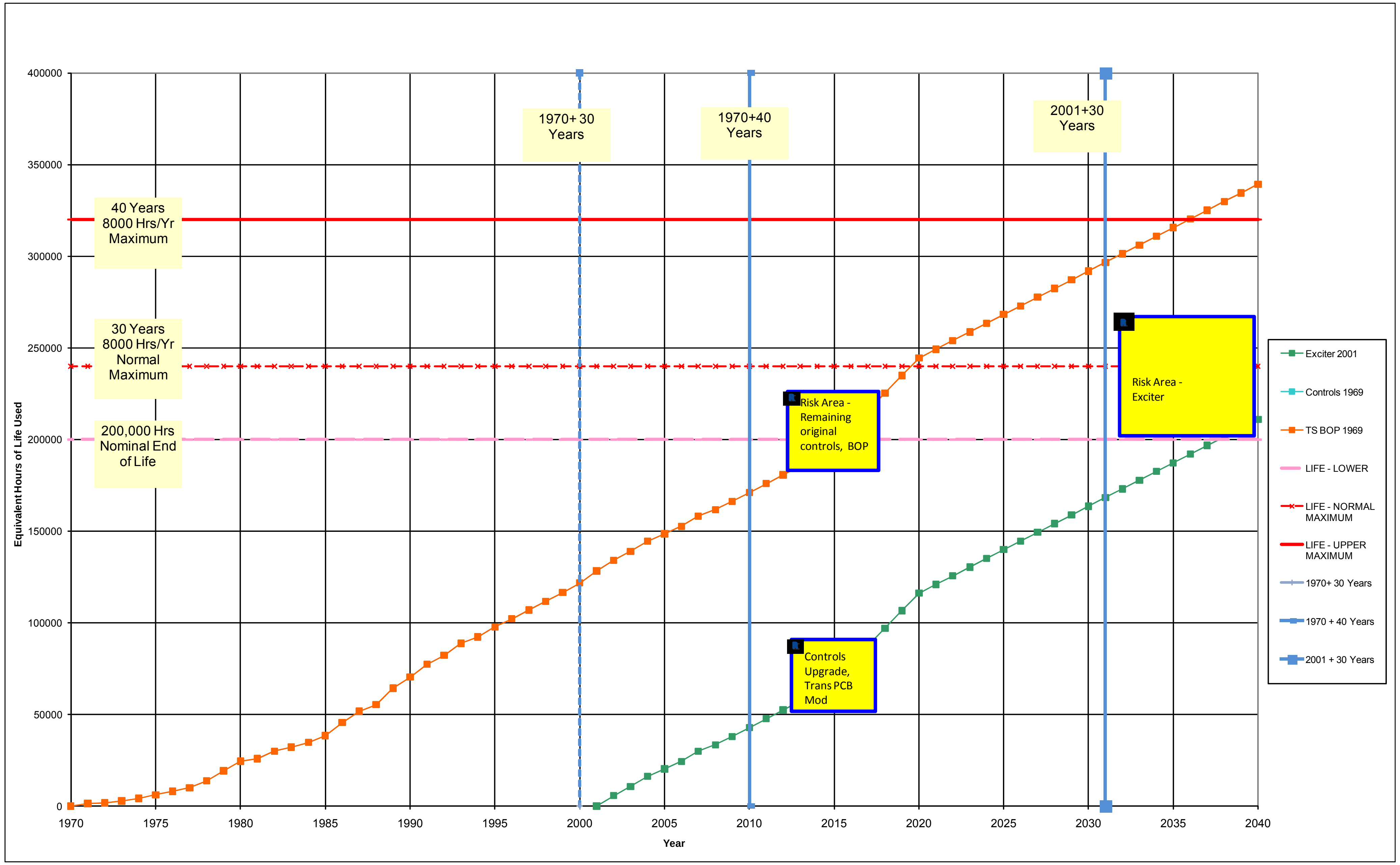

FIGURE 8-3 LIFE CYCLE CURVE – UNIT 1 GENERATOR - EXCITER

The curves indicate that the remaining life (RL) of the Unit 1 generator exceeds the desired life (DL) which is the lesser of the time to its next major planned overhaul/inspection (2012) or to the desired End of Life (EOL) date of 2041. Thus no specific dedicated Level 2 is required, but sufficient inspection and testing will be required in the 2012 overhaul to demonstrate the ability to meet the 2041 EOL date. The exciter should for the most part be able to meet an EOL of 2020, and with periodic refurbishment may meet 2041.The highlighted nearer term risk areas include the stator winding, exciter controls (upgrade only), the rectifying transformer, and some original BOP components. These systems are candidates for replacement or refurbishment – addressed in later sections. The curve also suggests that a nine year time between generator overhauls is impractical at this time in the generator's life and should be a six year cycle.

8.1.1.9 Level 2 Inspections – Unit 1 Generator

No Level 2 analyses are specifically required given their current condition and their ability to make their next major outage/overhauls. This is provided that the plant maintains their current maintenance and inspection programs and addresses the issues identified in the Issues and Actions list. The current overhaul interval was increased from 6 years to 9 years based on a recent (2005) assessment by the Hartford Steam Boiler Consulting, a company that was contracted by NL Hydro to review the frequency of steam turbine and generator inspections. This nine year interval between major overhauls is considered excessive, given the age and condition of the generators. A return to a six year interval is considered necessary.

TABLE 8-8 LEVEL 2 INSPECTIONS – UNIT 1 GENERATOR

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Sub System Comment	L2#	Appendix #	Level 2 Work	Year	Priority	Cost k$
1296	6690	6691	6696	0	0	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	GENERATOR ASSEMBLY	None	0	4	Level 2 "Pre-Major Outage Inspection" Work Allowance.	2011	1	$100
1296	6690	6691	6696	0	0	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	GENERATOR ASSEMBLY	None	1	4	No Level 2 work required before the next inspection/overhaul. Work required to scope and be ready for the next planned inspection/overhaul includes: - Review generator drawings, contract information, and operating manual to clarify design details. - Stator core: Core loop test and thermal image of core for hot spots, before the stator is re-wound. - Stator Winding: Obtain Doble test data and on-line partial discharge measurements.	2012	1	$1,849
1296	6690	6691	6696	6839	0	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	GENERATOR ROTOR	None	2	4	Included above. No Level 2 required prior to overhaul.	2012		
1296	6690	6691	6696	6840	0	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	GENERATOR STATOR	None	3	4	Included above. No Level 2 required prior to overhaul.	2012		
1296	6690	6691	6696	6840	7345	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	GEN. STANDOFF INSULATORS	None	4	4	Included above. No Level 2 required prior to overhaul.	2012		
1296	6690	6691	6696	6849	271310	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	EXCITER	None	5	4	Included above. No Level 2 required prior to overhaul.	2012		
1296	6690	6691	6696	6849	271311	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	EXCITATION TRANSFORMER	None	6	4	Included above. No Level 2 required prior to overhaul.	2012		
1296	6690	6691	6696	6849	271312	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	EXCITER FIELD BREAKER	None	7	4	Included above. No Level 2 required prior to overhaul.	2012		
1296	6690	6691	6696	6850	0	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	GEN. HYDROGEN GAS SYSTEM	None	8	4	Included above. No Level 2 required prior to overhaul.	2012		
1296	6690	6691	6696	6850	6806	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	GENERATOR SEAL OIL SYSTEM	None	9	4	Included above. No Level 2 required prior to overhaul.	2012		
1296	6690	6691	6696	6850	6851	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	GEN. CO2 GAS PURGE SYSTEM	None	10	4	Included above. No Level 2 required prior to overhaul.	2012		
1296	6690	6691	6696	6850	6853	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	GENERATOR HYDROGEN COOLING	None	11	4	Included above. No Level 2 required prior to overhaul.	2012		

8.1.1.10 2011 Level 2 Inspection Requirements and Costs – Hydro Request

As part of the effort to optimize the requirements of the 2012, 2014, and 2016 Generator Outages, Hydro staff asked for an assessment of testing and inspections (Level 2) that could be performed in 2011 with the generator rotor in place. AMEC provided the following generic initial preliminary listing, with an allowance of $200,000 per unit. Given the major overhaul in 2012, AMEC recommends that those items that would assist in better preparing for the 2012 overhaul be undertaken and that an allowance of $100,000 per unit be set aside pending further detailed review.

The following are the tests that could be considered, with the scope adjusted as appropriate within the $100K/unit allowance suggested. It must be recognized that the list appears much more all-encompassing than it is. It is a generic checklist and will not and cannot address much of what needs to be addressed in the major outage in 2012 when the rotor is removed from the stator. There are several safety related issues that would have to be addressed when considering the scope.

INSPECTIONS

Inspections – External Components: The following external component items could be inspected:

- Frame footing and bolts – torque for tightness, damage (likely not an issue – no vibration issue);
- Generator foundation – free from cracks other structural damage; footing grouting cracking/spalling;
- Grounding cables – tightness, condition (corrosion, overheating, fraying, cracking), current flow (unexpected);
- Piping & connections – condition, grounding, gasket and o-ring conditions, tightness, oil-free;
- Generator end brackets (end doors) – seal damage, cleaning/replacement of seal material, hydrogen leaks (NDE surface penetrant if leaking);
- Bearing Insulation & pedestals – grounding and bearing insulation device condition; bearing and journal pitting, insulation carbon contamination, insulation resistance (>Million ohm range);
- RTD, Thermocouple and Misc devices, Instrument Panel - hydrogen leak test, gaskets/O-ring check, wiring to external device – condition, operational check.

Inspection – Stator Internal Components: The following stator internal component items may be able to be inspected with the rotor in:

- Frame & support structure - compression bolts – greasing (oil/dust indicating loose bolts/core/nut lock device vibration), surge ring supports – cracking/looseness; fingerplates – cracked/bent fingers – likely very limited access; stator core – looseness, mechanical damage; stator windings – looseness, cracking, greasing;
- RTD and TC wiring and monitoring devices – visually inspect wiring to and from stator RTD and TC devices as possible – tightly secured. Damaged ones that are accessible may be replaced, others left for major overhaul/rewind;
- Winding TC's – inspect and check for function.

Inspection – Stator Core: The following stator core items could be inspected with the Stator Core (Rotor In) to the Extent Possible

- Core back – partial through cooler openings;
- Core Compression plates – inspect at turbine end (difficult at generator end due to phase leads) for looseness and condition;

- Core End Flux Screens and Flux Shunts – overheating, insulation resistance and thermal and distortion damage; and
- Frame to Core Compression Bands – check through cooler openings. No stator casing underbelly inspection ports so unlikely to tighten if required – stator vibration does not appear to be an issue so likely unnecessary.

Inspection – Stator Windings: The following stator windings could be inspected with the Stator Core (Rotor In) to the Extent Possible. If the inner end shields can be moved out of way, up to about 50% of turbine end and 25% of the generator end (phase lead interference) can be checked.

- End winding blocking and roving – inspect condition of blocking, roving, ties – looseness, greasing, dryness, powder, abrasion, cracked painting, missing bits;
- Surge rings - inspect condition of blocking, roving, ties – looseness, greasing, dryness, powder, abrasion, cracked painting, missing bits;
- Surge ring insulation - inspect (mirrors) integrity of insulation, especially beneath ties;
- End winding support structures - inspect (mirrors/other) condition – looseness, loose parts, missing/loose bolts/nuts, cracked supports (solid insulation material), greasing bolts, cracked/loose welding; retighten carefully and if possible; check retightening system condition (if exists);
- Tape separation/Girth cracking – inspect for near ends;
- Insulation galling/necking beyond slot – inspect for lack of insulation or cracking/separation;
- Corona discharge: End windings – white or brownish powder on end bars, dark brown burn marks; and
- End Wedge Migration Out of Slot – inspection by eye or mirror (likely difficult to see (may not be applicable – locking mechanism);

Inspection – Phase Bus Connectors and Terminals: The following could be inspected with the Stator Core (Rotor In) to **the** Extent Possible. Access is very tight and may not be possible from a safety perspective. Lower part may be more accessible through bussing box.

- Phase Bus Circumferential Bus Insulation: fretting, greasing, cracking insulation/paint, cracks in connectors/support ties;
- Phase Bus Phase Droppers: greasing, cracking insulation;
- High Voltage Bushings: Cracks, oil leakage (if applicable), looseness, dirt, tracking residues, Vent clogging (if applicable);
- Stand-off Insulators: Cracks, oil leakage (if applicable), looseness, dirt, tracking residues;
- Bushing Well (If Applicable) Insulators & Hydrogen Sealant Condition: sealant condition, gasket condition; and
- Generator Current Transformers (CT's): visual if in bushing box (IPB less accessible) - cracks, leaking resin, discolouration.

Inspection - Hydrogen Coolers: The hydrogen coolers could be inspected with the Rotor, assuming the coolers can be readily removed, in to the Extent Practical

- Tube clogging: visual inspection and descale;
- Tube leaks: hydrogen sensors, water inside casing, pressure test; and
- Tube thinning: eddy current tests.

Inspection – Rotor: The following rotor item could be inspected with the Rotor in to the Extent Practical

- Rotor cleanliness: copper dust (dc field coils on turning gear), copper dust in vent holes in winding slot wedges (shorted turns/ground faults) – short turn testing; copper dust in rotor end winding – blocking, insulation; "megger" to check insulation resistance; inspect before and after cleaning;
- Fan Rings/Hubs: Cracks in shrink area – visual if possible, NDE if fans removed; cracks/snugness at fan blade attachment to hub – NDE as appropriate;
- Bearings & Journals: (if bearing dismantled) journals, Babbitt materials, oil-baffle labyrinth, oil-seal ring clearance, bearing clearance; used oil condition (including tiny rounded electrical pits); bearing insulation and grounding brush integrity;
- End Wedges (using boroscope): discoloration, electric pitting between wedges and slot; different wedges, wedges and retaining ring;
- C-Channel Subslot (if applicable): physical damage - boroscope examination through slot under retaining ring may be possible but very difficult;
- Collector Rings: condition, insulation condition, collector thickness/groove depth, spring condition;
- Shaft Voltage Discharge Brushes: visual inspection, monitor system (applicable?);
- Rotor Winding main Lead Hydrogen Sealing: Pressure test, visual not practical;
- Couplings and Coupling Bolts: chafing, fretting, thread condition;
- Bearing insulation: inspect grounding devices, insulation, electric pitting of Babbitt, insulation carbon dust, electrical testing – megger; and
- Hydrogen Seals: Requires hydrogen seals be dismantled. Seals: inspect Babbitt and steel shell, seal rings, seal housing, wipers, springs/pressure components, gaskets/O-rings, NDE – Liquid Penetrant inspection (LPI) for cracks, Ultrasonics (UT) for Babbitt bonding to shell, Insulation resistance – megger seal insulation to ground.

Inspection – Auxiliaries: The following systems could undergo inspections as part of overall generator program, but specific details to be developed:

- Lube oil system – pre-shutdown detailed system readings, tank condition/cleanliness, piping looseness defects, valve operation, oil coolers condition (possible leak test), filters, switches, gauges, pump bearings, monitoring instrumentation check, purifier/centrifuge check;
- Hydrogen Cooling System: general condition and functionality – dryers and control, bulk supply, controls and instruments, desiccant condition;
- Seal Oil System: general condition and functionality – coolers condition (possible leak test), filters, reservoirs condition/cleanliness, hydrogen detraining, piping looseness defects, switches, gauges, pump bearings, monitoring instrumentation check; and
- Exciters: Electrical and Mechanical systems.

TESTS

Test – Stator: The tests to be further evaluated for the Stator with the rotor in could include:

- Stator Winding Electrical Tests – dry, phase isolation
  - Insulation Resistance: Megger - ohmic resistance between conductors in each phase and ground (stator core) – gross insulation issues so that further hi-voltage testing can be carried out safely;
  - Polarization Index (PI) – Megger - change in IR in first minutes (IR minute 10/IR minute 1) = function of insulation condition, contamination, moisture;

  - A Doble test can be done to measure the insulation power factor and tip-up of the stator winding, with the rotor in place. (all the stator coils are raised in steps, up to rated phase voltage, during this test, and each phase is energized separately);
  - DC Hi Pot: high voltage to winding (each phase separately or all) – done in hydrogen;
  - Series Winding Resistance: ohmic resistance of copper in each phase – shorted windings, bad connections, wrong/open connections;
  - Dielectric Absorption during DC voltage Application: measures aging of resin binder in ground wall insulation – time dependent current flow. Affected by voids in insulation;
  - DC leakage or Ramped Voltage: leakage current versus applied voltage applied increasingly over time – warns of impending insulation breakdown; and
  - Dissipation/Power Factor Tip-Up Testing: measures the void content of insulation, also other ionizing losses (PD or slot discharges).

Test – Rotor: The tests to be further evaluated for the rotor with the rotor in could include:

- Mechanical Testing
  - Rotor Vibration: typically on-line measurements, detailed testing (using on-line device connections – characterize magnitude, phase relation, frequency spectrum .
- Test – Rotor Electrical Testing
  - Rotor Winding Resistance Tests: Megger - ohmic resistance of total copper winding shorter turns, bad connections, wrong/open connections;
  - Insulation Resistance: Megger - ohmic resistance between conductors in each phase and ground (rotor forging) – gross insulation issues so that further hi-voltage testing can be carried out safely;
  - Polarization Index (PI) – Megger - change in IR in first minutes (IR minute 10/IR minute 1) = function of insulation condition, contamination, moisture;
  - Shorted turns Detection;
  - Off-Line Testing: winding impedance measurement during acceleration and deceleration for comparison with past tests (Low Voltage DC – Volt Drop Shorted Turn Test likely preferred otherwise);
  - Hydrogen Seals: NDE - Megger seal insulation; and
  - Bearings: Megger bearing insulation.

8.1.1.11 Capital Program Suggestions

Table 8-9 below shows the suggested typical capital enhancements that should be considered for the Unit 1 generators:

TABLE 8-9 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – UNIT 1 GENERATOR

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Detail	CAP#	Appendix #	Capital Item	Date	Priority
1296	6690	6691	6696	0	0	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	GENERATOR ASSEMBLY	N/A	1	4	See details below.	2012	1
1296	6690	6691	6696	6839	0	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	GENERATOR ROTOR	N/A	2	4	No capital required.		
1296	6690	6691	6696	6840	0	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	GENERATOR STATOR	N/A	3	4	Recommend ordering Stator windings in 2011 for rewinding Stator in 2012. Installation in 2012 subject to techno-economic optimization results.	2011	1
1296	6690	6691	6696	6840	7345	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	GEN. STANDOFF INSULATORS	N/A	4	4	No capital required.		
1296	6690	6691	6696	6849	271310	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	EXCITER	N/A	5	4,6	Upgrade Static Exciter controls compatible with the latest Unitrol 6000 system.	2013	1
1296	6690	6691	6696	6849	271311	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	EXCITATION TRANSFORMER	N/A	6	4,5	Replace rectifying transformer.	2013	1
1296	6690	6691	6696	6849	271312	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	EXCITER FIELD BREAKER	N/A	7		No capital required.		
1296	6690	6691	6696	6850	0	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	GEN. HYDROGEN GAS SYSTEM	N/A	8	4	Install hydrogen consumption “totalizer” in each hydrogen supply line.	2011	1
1296	6690	6691	6696	6850	6806	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	GENERATOR SEAL OIL SYSTEM	N/A	9	18	Replace/overhaul seal oil skids required for SC operation.	2015	1
1296	6690	6691	6696	6850	6851	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	GEN. CO2 GAS PURGE SYSTEM	N/A	10		No capital required.		
1296	6690	6691	6696	6850	6853	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	GENERATOR HYDROGEN COOLING	N/A	11	4	No capital required.		

8.1.2 Asset 6805 – Unit 1 Generator Lube Oil System

(Detailed Technical Assessment in Working Papers, Appendix 9)

Unit 1:	1
Asset Class #	BU 1296 - Assets Generations
SCI & System:	6691 #1 Turbine & Generator
Sub-Systems:	6805 #1 Turbine Lubricating Oil 6807 #1Turbine Hydraulic Oil Systems
Components:	6803 #1 Tank & Equipment 6804 #1 Purification 6829 #1 Pump South 6830 #1 Pump North 6833 #1 DC Pump 6835 #1 Hydraulic Oil Pump North 6838 #1 Hydraulic Oil Pump South

8.1.2.1 Description

The generator lube oil system is integrated into the steam turbine system. It consists of a storage system, AC and DC pumping systems, filtration, and heat exchangers. The lube oil tank holds approximately 98400 L (2600 US gallons) of Turboflo R&O 32 lubricating oil. Within the lube oil tank, there are three pumping units (two 100% AC motor driven and one 100% DC motor driven) and three 100% duty lube oil heat exchangers. The system supplies 35-45 °C oil to the turbine/generator lubrication and hydrogen seal oil systems. Pump discharge pressures at 275 – 300 kPa would be normal.

Lubricating oil heat exchanger cooling water heads can be isolated and removed for easy cleaning. An oil purifier is connected to the oil tank through a separate piping arrangement and is used primarily to remove water from the oil which accumulates because of the condensation throughout the process. The system is fitted with two 100% duty oil filters insuring heavy particles in the oil are removed and do not reach the bearings during lubrication.

Two 100% positive displacement hydraulic oil pumps are used to operate the emergency stop valve, the combined intercept reheat stop valves, the control valves and other miscellaneous valves on the steam turbine. The pumps operate at a pressure of 15.5 MPa to counteract the large springs which normally hold the valves closed. The hydraulic oil system has its own network of high pressure piping external to the lubricating oil system which makes it somewhat easier to maintain if problems occur.

8.1.2.2 History

Manufactured/Delivered	1969
In-Service Date	Sep 1970
Generation Base Load End Date	Dec 2015
Generation Peak/Emerg Gen End Date	Dec 2020
Synchronous Condensing Start Date	Jan 2015
Synchronous Condensing End Date	Dec 2041
Next Major Overhaul/Inspection	2012

The thousands of hours associated with the analyses, and the number of starts per year are:

	Generation (Gen)	Synchronous Condensing (SC)
Hours Actual - Ops to Dec 2009	166	0
Hours - Ops to Gen End Date Dec 2015	210	1.5
Hours - Ops to Gen End Date Dec 2020	219	25
Hours – Ops to SC End Date Dec 2040	219	120
Starts Actual - Ops to Dec 2009	482	0
Starts - Ops to Gen End Date Dec 2015	554	5
Starts - Ops to Gen End Date Dec 2020	614	30
Starts – Ops to SC End Date Dec 2040	714	130

8.1.2.3 Inspection and Repair History

The system was examined extensively as part of a plant fire protection system evaluation. It is in very good condition as part of the plant's normal maintenance and inspection program and is examined as well during major generator inspections.

8.1.2.4 Condition Assessment

This system has been in service since the unit was placed in service in 1970. Although the lubrication system is critical to the operation of the steam turbine/generator and may cause a short unit shutdown in the event of a failure, a longer shutdown may occur due to a failure of the lubricating oil piping system which cannot be inspected easily because the supply piping is installed inside of the oil return piping which is connected to the oil storage tank.

The oil storage tank appears externally to be in good condition. Internal inspection reports were not available at this time. Failures of any of the oil pumps or the oil purifier are easily repaired and, barring no hidden problems, this system should continue to operate for the time frame required. If this unit is required to support synchronous condenser operation after generation mode, this system will be required to operate at all times and should not present any major issue.

All parts of the generator lube oil system are expected to be able to make their next inspection date. All are expected to undergo more rigorous evaluation at that time. Most will be able, with maintenance and replacement, to meet the generation end date of 2020. None are expected to be able to make their 2041 synchronous condensing end date without a major refurbishment and replacement program.

TABLE 8-10 CONDITION ASSESSMENT – UNIT 1 GENERATOR LUBE OIL SYSTEM

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset Level 2	Asset Level 3	Description	Detail	Condition Summary ID #	Append #	Condition	EPRI Identifier	Original Life (Base Load) Ops Hrs (Yrs)	Current Expected Minimum Remaining Life Years (Subject to Test)	End of Life (EOL) Required	Next Regular Inspection	Next Planned Overhaul or Major Inspection	Capability to Reach Next Overhaul	Capability to Reach EOL	In Service
1296	6690	6691	271309	6695	0	1	#1 TURBINE & GENERATOR	TURBINE	TURBINE OIL SYSTEMS	N/A	27	18	Generally good condition.	3a	200000 (30)	10	2041	2011	2012	Yes	Yes	1970
1296	6690	6691	271309	6695	6805	1	#1 TURBINE & GENERATOR	TURBINE	TURBINE LUBE OIL SYSTEM	N/A	28	18	Lube oil system is in good condition. No NDE of piping was obtained and reviewed, but interviews indicated no issues. Failures of any of the oil pumps or the oil purifier are easily repaired.	3a	200000 (30)	10	2041	2011	2012	Yes	Yes	1970
1296	6690	6691	271309	6695	6805	1	#1 TURBINE & GENERATOR	TURBINE	TURB LUBE OIL TANK & EQUIP	N/A	29	18	Lube oil tank appears to be in good condition. Internal inspection reports were not available.	4	200000 (30)	(10)	2041	2012	2012	Yes	No	1970
1296	6690	6691	271309	6695	6805	1	#1 TURBINE & GENERATOR	TURBINE	TURB. LUBE OIL PURIFICATION	N/A	30	18	Lube oil purification system is relatively new and in good condition.	3a	200000 (30)	10	2041	2011	2012	Yes	Yes	2001

Notes:

1. A “(bracketed)” value in the “Current Expected Remaining Life” column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as “(X/Y)” has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

2. The “Next Regular Inspection” column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The “Next Planned Overhaul or Major Inspection” column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a “Desired Life” stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or are not known by AMEC.

8.1.2.5 Actions

Based on the condition assessment, the following actions are recommended for the Unit 1 lube oil system.

TABLE 8-11 RECOMMENDED ACTIONS – UNIT 1 GENERATOR LUBE OIL SYSTEM

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Unit	Asset 2/3	Asset 3/4	Description	Detail	Action #	App #	Action	Year	Priority
1296	6690	6691	271309	6695	1	#1 TURBINE & GENERATOR	TURBINE	TURBINE OIL SYSTEMS	N/A	55	9	Flush lube oil, seal oil and seal oil bypass lines prior to the seasonal restart of the unit every year.	2010	1
1296	6690	6691	271309	6695	1	#1 TURBINE & GENERATOR	TURBINE	TURBINE LUBE OIL SYSTEM	N/A	56	9	Flush lube oil, seal oil and seal oil bypass lines prior to the seasonal restart of the unit every year.	2010	1
1296	6690	6691	271309	6695	1	#1 TURBINE & GENERATOR	TURBINE	TURB LUBE OIL TANK & EQUIP	N/A	57	9	Perform Level II inspections on oil storage tanks and internals.	2011	1
1296	6690	6691	271309	6695	1	#1 TURBINE & GENERATOR	TURBINE	TURB. LUBE OIL PURIFICATION	N/A	58	9	No action recommended.		

8.1.2.6 Risk Assessment

Table 8-12 below illustrates the risk assessment for the system, both from a technological perspective and a safety perspective using the models presented in Section 3.

TABLE 8-12 RISK ASSESSMENT – UNIT 1 GENERATOR LUBE OIL SYSTEM

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Component	Risk Assess #	Appendix #	Major Issues	Remaining Life Years (Insufficient Info - Inspection Required Within (x) Years)	Remaining Life Comments	TECHNO-ECO RISK ASSESS MODEL			SAFETY RISK ASSESS MODEL			Possible Failure Event	Mitigation
																Likeli-hood	Conse-quence	Risk Level	Likeli-hood	Conse-quence	Safety Risk		
1296	6690	6691	271309	6695	6805	1	#1 TURBINE & GENERATOR	TURBINE	TURB LUBE OIL TANK & EQUIP	Lube Oil Tanks	50	9	Corrosion, erosion.	10+	None	1	A	Low	1	A	Low	Oil leak – containment overflow.	Inspect and maintain.
1296	6690	6691	271309	6695	6805	1	#1 TURBINE & GENERATOR	TURBINE	TURB LUBE OIL TANK & EQUIP	Lube Oil Pumps & Motors	51	9	Mechanical and/or electrical failure.	10	None	1	A	Low	1	A	Low	Unit shutdown – multiple systems.	Inspect and maintain.
1296	6690	6691	271309	6695	6805	1	#1 TURBINE & GENERATOR	TURBINE	TURB LUBE OIL TANK & EQUIP	Lube Oil Pumps & Motors	52	9	Bearing Damage - duty on the starting equipment, during synchronous condenser operation	10	None	1	A	Low	1	C	Low	Unit shutdown – multiple systems.	Maintain and inspect full-flow filter and by-pass to reduce the risk of bearing damage.
1296	6690	6691	271309	6695	6805	1	#1 TURBINE & GENERATOR	TURBINE	TURB LUBE OIL TANK & EQUIP	Lube Oil Coolers	53	9	Mechanical failure/leaks.	10	None	1	A	Low	1	A	Low	Unit shutdown for repairs.	Inspect and maintain.
1296	6690	6691	271309	6695	6805	1	#1 TURBINE & GENERATOR	TURBINE	TURB. LUBE OIL PURIFICATION	Lube Oil Filters	54	9	Mechanical and/or pluggage failure - water and particulate	10	None	1	A	Low	1	A	Low	Unit shutdown for repairs.	Inspect and maintain.

Notes: 1. The risk assessment for the lube oil pumps is based on the lube oil pump controls being added to the control room as per the recommendations of the 2009 Emergency Shutdown Procedure study.

8.1.2.7 Life Cycle Curve and Remaining Life

Figure 8-4 below illustrates the life cycle curve for the Unit 1 generator lube oil system. Two curves are required given that the upgraded purification system entered service in 2001, while other major elements of the lube oil system are largely of the same age. There is insufficient information to develop specific accurate curves for the storage tank, and coolers. Further detailed examination during the 2012 turbine overhaul should provide the basis going forward. The life curve is a plot of current and projected operating hours (generation plus synchronous condensing model on the y-axis versus calendar year on the x-axis. Vertical lines represent bands of nominal years of normal base loaded life (typically 200,000 operating hours, thirty years and 200,000 to 240,000 operating hours, and forty years, and 280,000 to 320,000 operating hours). Horizontal lines represent the ranges of equipment life based on current and historical information and expert opinion. The risk area box provides an indication of the timing of potential issues either from an age or equivalent operating hours view.

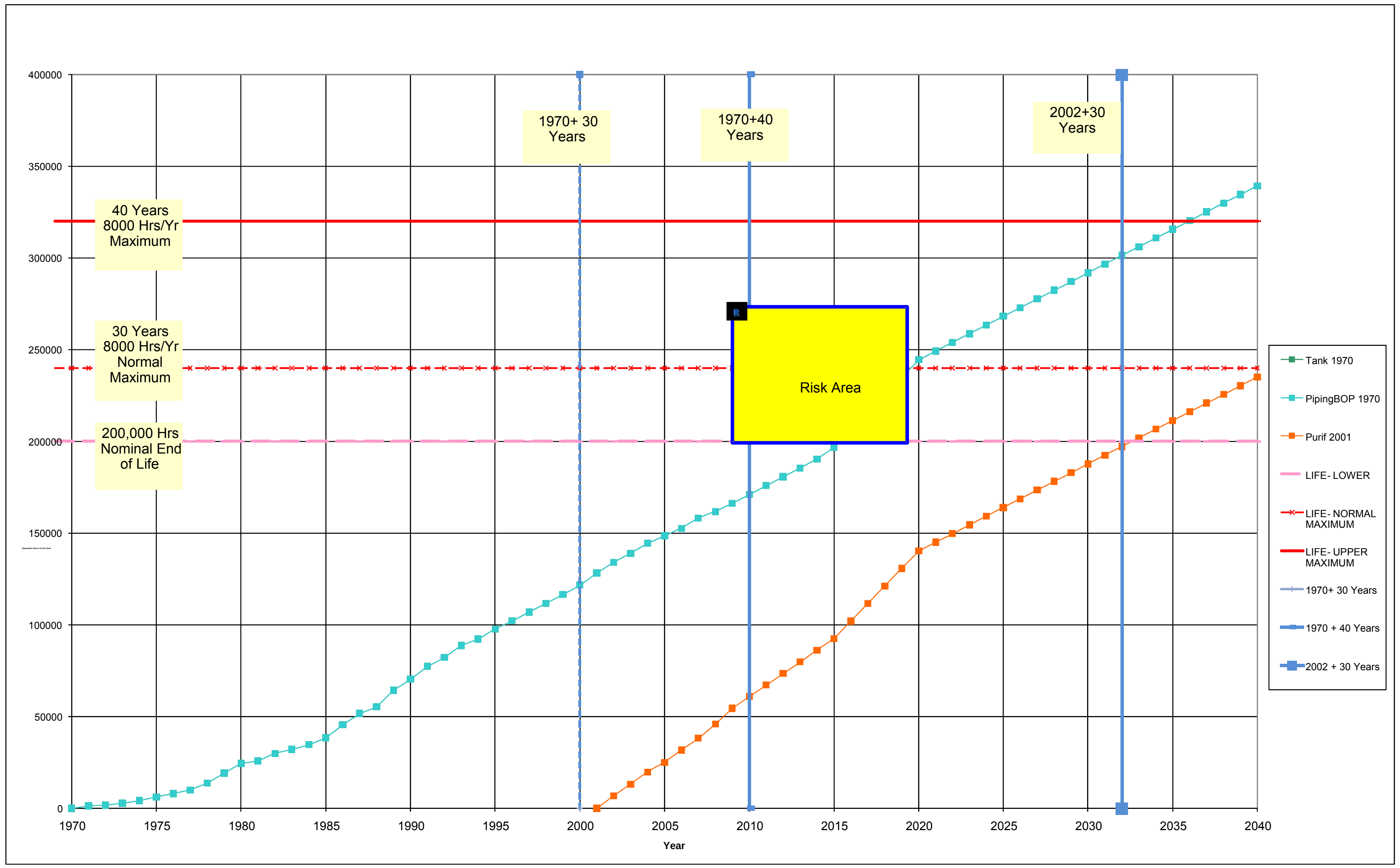

FIGURE 8-4 LIFE CYCLE CURVE – UNIT 1 GENERATOR LUBE OIL SYSTEM

The curves indicate that the remaining life (RL) of the Unit 1 generator lube oil system exceeds the desired life (DL) which is the lesser of the time to its next major planned overhaul/inspection (2012) or to the desired end of life (EOL) date of 2041. Thus no specific dedicated Level 2 is required of the system as a whole, but sufficient inspection and testing will be required in 2012 steam turbine generator overhaul to demonstrate the ability to meet the EOL date. The exception is the storage tank for which information was considered inadequate to form a firm conclusion and level 2 testing is recommended in 2011, albeit of a modest level and lower priority. The figure's highlighted risk areas is primarily operating hours driven and likely to shift further out in time after the 2012 turbine generator overhaul. The 2012 overhaul/inspection is a fundamental element in changing the current assessment.

8.1.2.8 Level 2 Inspections – Unit 1 Generator Lube Oil System

Given the condition historical data reviewed, a Level 2 analysis of the lube oil storage tank is recommended. No other Level 2 analyses is required, provided the current inspection and maintenance program for the system is maintained and a more detailed inspection is performed at the turbine overhaul.

TABLE 8-13 LEVEL 2 INSPECTIONS – UNIT 1 GENERATOR LUBE OIL SYSTEM

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Sub System Comment	L2#	Appendix #	Level 2 Work	Year	Priority	Cost k$
1296	6690	6691	271309	6695	0	1	#1 TURBINE & GENERATOR	TURBINE	TURBINE OIL SYSTEMS	None	38	9	See details below.			
1296	6690	6691	271309	6695	6805	1	#1 TURBINE & GENERATOR	TURBINE	TURBINE LUBE OIL SYSTEM	None	39	9	No Level 2 required.			
1296	6690	6691	271309	6695	6805	1	#1 TURBINE & GENERATOR	TURBINE	TURB LUBE OIL TANK & EQUIP	None	40	9	NDE inspection and visual inspections of lube oil tanks and internals.	2011	2	$6
1296	6690	6691	271309	6695	6805	1	#1 TURBINE & GENERATOR	TURBINE	TURB. LUBE OIL PURIFICATION	None	41	9	No Level 2 required.			

8.1.2.9 Capital Projects

The suggested capital enhancements include:

TABLE 8-14 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – UNIT 1 GENERATOR LUBE OIL SYSTEM

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Detail	CAP#	Appendix #	Capital Item	Date	Priority
1296	6690	6691	271309	6695	0	1	#1 TURBINE & GENERATOR	TURBINE	TURBINE OIL SYSTEMS	N/A	22	9	No capital required.		
1296	6690	6691	271309	6695	6805	1	#1 TURBINE & GENERATOR	TURBINE	TURB LUBE OIL TANK & EQUIP	N/A	24	9	No capital required.		
1296	6690	6691	271309	6695	6805	1	#1 TURBINE & GENERATOR	TURBINE	TURB. LUBE OIL PURIFICATION	N/A	25	9	Replace turbine lube oil conditioners.	2013	1

8.1.3 Asset 6723 – Unit 1 Electrical and Control Systems Associated with Generators

(Detailed Technical Assessment in Working Papers, Appendix 6)

The requirements for the electrical and control systems associated with Unit 1 are as follows:

Unit #:	1
Asset Class #	BU 1296 - Assets Generation
SCI & System:	6723 #1 Electrical & System & Controls
Sub-Systems:	6723 #1 Electrical & System & Controls
Components:	6721 #1 Relay Room Protection & Control 6722 #1 Main Controls 6724 #1 Generator Bus-Duct and Connections 6728 #1 Battery Chargers 7184/7186/7187 MCC's, C2, C3, C4 7193 #1 UPS1 Inverter 270151 #1Turbine Supervisory System 270295 #1Switchgear, 4160V/600V 7182 #1 Power Centre "A" UAB1, (600V) 291668 #1 DCS **COMMON SYSTEMS** 270297 Control Cables 270298, Power Cables 600V Metric Plugs

8.1.3.1 Description

Asset 6721 Unit 1 Relay Room Protection & Control

Generator G1, Transformer T1 and Auxiliaries P&C Panels, were manufactured by Canadian General Electric, and installed in 1969.

Generator 1 and Transformer T1 Protection Panels: These panels utilize GE electro-mechanical relays and blocking switches. In addition, they show annunciation and T1/UST1 gas and winding temperature trips and indications.

Unit 1 Protection Auxiliary Panel: This panel shows DC buses indications and blocking switches.

Unit 1 Metering Panel: This panel shows Generator 1 and Static Exciter 1 WHR's, runtime, flexitests and stator ground fault protection added in 2008. (Schweitzer SEL 300G multi-function relay and AREVA MML G01 test plugs.)

The rear of the panels show the original GE and Brown Boveri Control relays, Agastat timers and transducers.

Station Service Transformers UT1 and UT2 Protection Panels and Gas Turbine Metering and Protection Panels: These panels utilize GE electro-mechanical relays and blocking switches. In addition they show annunciation and SST1/SST2 gas and winding temperature trip indications.

Unit 1 Services Protection Panel: This panel shows UT1/SST/UT2 MWatts, WHR's, DC buses indications, voltages and blocking switches.

Gas Turbine Metering and Protection Panel: This panel includes relaying for differential, WHR, neutral over-current, annunciation and blocking switches.

Asset 6722 Unit 1 Main Controls

The original Unit 1 Main Controls were console mounted and utilized, typically GE SBM type switches, incandescent indications, analog instruments, and Panalarm annunciation. Modifications have been made to adapt the generator, turbine and boiler controls to the Distributed Control System (DCS) and to replace some of the original controls, indications and annunciation. In addition, a newly commissioned auto-synchronizing system has been added for automatically synchronizing Unit 1 to the Island Grid via the GE Speedtronic Mark V turbine control system. This allows the operator to select the U1 breaker and activate the Mark V synch. control, which incorporates a 25C synch. check function to permit placement of U1 on the grid.

G1, MW, Amps, MVA's, kV, Field Volts, Speed Load Position, Load Limit position and Balance, are shown on the original analog instruments above the console, and are also indicated on the screens via the DCS.

Screens and keyboards are provided to include control, indications, and annunciation of unit functions with boiler purge to be included in Sept. 2010.

Original controls, located in the console desk include the following. Circulating pumps, cooling water pumps and valves, thermo probe, AC and DC oil pumps, extraction and hydraulic pumps, Vacuum pumps, speed load and load limit, AVR set-point and selection.

Unit 1 trip and raise/lower volts and Unit 1 Turbine Trip pushbutton.

One screen and keyboard is provided for common indications.

The original manually operated switches and indications remain for synchronizing and operation of breakers B1B11 and B1L17. See auto synch. modifications above.

Original common analog instruments, for Unit 1 and Unit 2, (Stage 1), indicate incoming and running volts, incoming and running frequencies, and synchronizing.

Unit 1 relaying and transducers are situated in the Unit 1 logic cubicles behind Unit 1 control room. Relays are Struthers & Dunne with Agastat timers.

Other Information: Common screens and keyboards are provided to monitor and control the 4160/600V bus system via the DCS, and indicate, station service current alarms, D1 and D2 diesels control and indications, system frequency and the 4160/600V bussing, including gas turbine.

Asset 6724 Unit 1 Generator Bus-Duct and Connections

The generator bus-duct is a 3 phase Isolated Phase Bus complete with PT's and Neutral Cubicle manufactured by ITE and installed in 1969.

Asset 6728 Unit 1 Battery Chargers

Units 1/2, 129VDC Battery Charger 1, manufactured by Primax Technologies Inc. and installed in 2006. Charger 1 is a type P4500F-3-125-60, 575V Input, 129VDC Output, max. charger output rated 60A.

Units 1/2, 129VDC Battery Charger 2, manufactured by Staticon and installed in 1969.

Charger is original. A new Primax Charger was installed in 2010(Similar to Charger 1 above).

Unit 1, 258VDC Battery Charger, manufactured by CIGENTEC Inc. and installed in 2001. Charger is a type C3-250-200PAF3BHRGCUOD3S2X9, 600V Input, 258VDC Output, max. 200A Charger rated maximum output.

Reference Holyrood Plant Charger Database. Last equipment check 04 Feb 2010.

Other information:

Unit 1, 258VDC Panel was manufactured by Westinghouse, installed in 1969, and is a type CDP, complete with Westinghouse breakers.

Assets 7184/7186/7187, MCC's, C2, C3, C4

Reference the Stantec Report – Holyrood Generating Station MCC Assessment, dated January 15, 2009, for details regarding the MCC's.

Asset 7193 Unit 1, UPS1 Inverter

Inverter UPS1 was manufactured by Eaton Powerware, Series 9315 and installed in 1997. Battery manufactured by C&D Technologies, Inc. (UPS Dynasty batteries), 600V input (transformer 600V:480V into Inverter), 120/208V output, 30kVA rated power, 93Ah @ 20 hour rate to 1.75V per cell @ 77°F (25°C).

Other Information: The 120/208V, 3 phase Distribution Panel-boards fed from UPS1 inverter, via Distribution Splitter are as follows:

- Unit 1 UPS Panel No.1 at Col L10, El 24'-2", fed via 125A fused disconnect, Siemens, Type NLAB, 3 phase, 4W, 225A, 42 circuit, branch breakers type BQ, and was installed in 1998.
- Unit 1 UPS Panel No.1/A at Col L10, El 24'-2", fed from Panel No.1. Siemens, Type P1, 3 phase, 4W, 250A, 42 circuit, branch breakers type BL, and was installed in 1998.
- Unit 1 WDPF Panel,DP-1 relay room, fed via 125A fused disconnect, Siemens, Type NLAB, 3 phase, 4W, 225A, 42 circuit, branch breakers type BQ, and was installed in 1998.

Asset 270151 Unit 1 Turbine Supervisory System

The turbine supervisory system was manufactured by Bently Nevada and installed in 1990. It is a type 3300 System, complete with TDXnet Transient Data Interface and Delta Manager.

The functionality of the Bently Nevada system has been partially transferred to the GE Speedtronic Mark V Turbine Governor System. There is a link to the DCS. Data acquisition is still part of the Bently Nevada, and is transferred via a DDX link to the instrument shop. Machine protection is provided by the Mark V using information from the Bently Nevada, and is part of the Unit 1 mechanical protection.

Asset 270295 Unit 1 Switchgear 4160V/600V

Unit Board UB1 (4160V) was manufactured by ITE and installed in 1968. The 4160V switchgear, utilizes original draw-out power, air-magnetic breakers, Type 5HK, 1200A and 2000A. All protection, synch, and control relays are original CGE electro-mechanical. Schweitzer 701, Motor Protection Relaying is used on U1 Circulating Water Pumps and North and South Condensate Extraction Pumps. All other loads utilize the original P&B Golds relays.

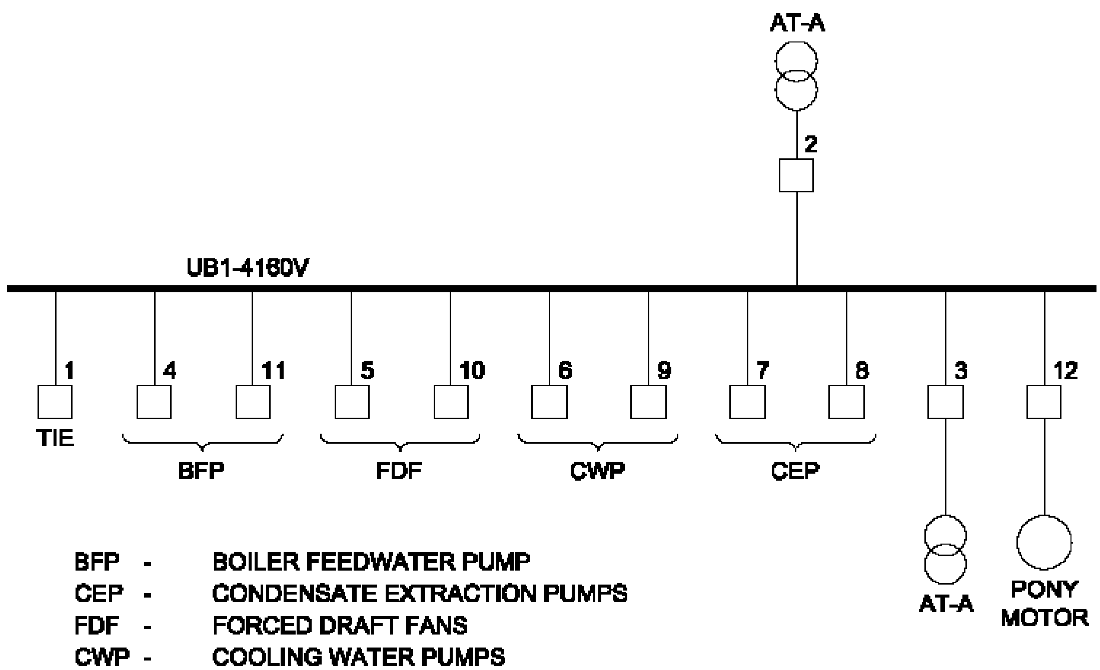

FIGURE 8-5 UNIT 1 UB1 SWITCHGEAR

Asset 7182 Power Centre "A" UAB1, (600V)

The unit was manufactured by CGE and installed in 1968. The switchboard utilizes CGE AK-50 Incoming/ Tie Breakers, and CGE AK-25 Feeder air-circuit breakers. The Unit Aux. Transformer, AT-A, is a Westinghouse, 1500kVA, 4160V:600/347V, complete with primary taps.

Asset 291668 Unit 1, DCS

The DCS was manufactured by Foxboro, and is an Invensys system installed in 2004.

The Westinghouse panels housing the DCS were installed in the late 1990's, and new cabling installed at that time. Original system was hard-wired, but later updated to a Westinghouse system. Westinghouse could not support the system which was then updated to Foxboro in 2004. The process CPU → ZCP is set-up in the original enclosures, (Westinghouse Migration Cards). All I/O is tied-in to these for analog and digital functions.

The following system and programs being used are:

- IA series – Version 8.4.2;
- IACC, Version 2.3.1 (Configuration Program); and
- FoxView Version 10.2. Sept. 30, 2008 (Graphics Program).

Reference: Foxboro Drawing D545390-SA-001 in station files for system configuration.

8.1.3.2 History

Manufactured/Delivered	1969
In-Service Date	Sep 1970
Replaced (DCS)	2004
Replaced Exciter	2000
Generation Base Load End Date	Dec 2015
Generation Peak/Emerg Gen End Date	Dec 2020
Synchronous Condensing Start Date	Jan 2015
Synchronous Condensing End Date	Dec 2041

8.1.3.3 Inspection and Repair History

Inspections and refurbishments are done on an ongoing basis and identified in Section 8.1.3.1 Description and in 8.1.3.4 Condition Assessment.

8.1.3.4 Condition Assessment

The basic DCS, protections, alarms associated with generators and auxiliaries are in good shape, but will over the next fifteen years need to be re-examined about every five years or so. The areas of most concern are the exciter controls and protection and motor controls, which have in fact been identified by the plant as an area in need of upgrade in the very short term. Some auxiliary systems such as hydrogen monitoring and generator temperature monitoring needs replacement or refurbishing. The condition assessment for the various systems is presented in the following table.

TABLE 8-15 CONDITION ASSESSMENT - UNIT 1 ELECTRICAL AND CONTROL SYSTEMS ASSOCIATED WITH GENERATORS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset Level 2	Asset Level 3	Description	Detail	Condition Summary ID #	Append #	Condition	EPRI Identifier	Original Life (Base Load) Ops Hrs (Yrs)	Current Expected Minimum Remaining Life Years (Subject to Test)	End of Life (EOL) Required	Next Regular Inspection	Next Planned Overhaul or Major Inspection	Capability to Reach Next Overhaul	Capability to Reach EOL	In Service
1296	6690	6723	0	0	0	1	#1 UNIT GENERATION SERVICES	ELEC & CONTROLS SYSTEM	ELEC & CONTROLS SYSTEM	N/A	276	6	N/A									
1296	6690	6723	6721	0	0	1	#1 UNIT GENERATION SERVICES	RELAY RM PROTECTN & CONTROL	RELAY RM PROTECTN & CONTROL	N/A	280	6	Generator & Transformer & Auxiliary Protection and Metering Panels tests in 2005 were satisfactory. Some ingress of dust and foreign material. Testing is on a 6 year cycle (2011, 2017, 2023, etc.).	10	(40)	10	2041	2011		No	No	1970
1296	6690	6723	6721	0	0	1	#1 UNIT GENERATION SERVICES	RELAY RM PROTECTN & CONTROL	RELAY RM PROTECTN & CONTROL	N/A	281	6	Station Service UT1 and UT2 Protection and Gas Turbine Metering and Protection Panels and Unit 1 Services Protection Panel tests in 2006 were satisfactory Some ingress of dust and foreign material. Testing conducted on a 6 year cycle *(2012, 2018, 2024, etc). Gas Turbine Metering and Protection Panel tests (GT Protection, Transformer T9 Protection and GT Sync) in 2008 were satisfactory. Some ingress of dust and foreign material. Testing on a 6 year cycle (2014, 2020, 2026, etc.).	10	(30)	10	2041	2014		No	No	1970
1296	6690	6723	270295	0	0	1	#1 UNIT GENERATION SERVICES	SWITCHGEAR 4160/600V	SWITCHGEAR 4160/600V	N/A	282	6	Breaker overhauls have been carried out, between 1995 and 2007 (See Appendix). All 4160V switchgear is applied within ratings. Overhauls due. Past normal life, extended by overhauls/maintenance.	10	(25-30)	5	2041			No	No	1970
1296	6690	6723	6722	0	0	1	#1 UNIT GENERATION SERVICES	MAIN CONTROLS	MAIN CONTROLS	N/A	283	6	There are age and spares problems with the relaying system.	4	(30)	10	2041			No	No	1970
1296	6690	6723	291668	0	0	1	#1 UNIT GENERATION SERVICES	DCS	DCS	N/A	284	6	Installed in 2004 - state of the art.	3a	(20)	10	2041			Yes	No	2004
1296	6690	6723	6724	0	0	1	#1 UNIT GENERATION SERVICES	GENERATOR BUS DUCT & CONNS	GENERATOR BUS DUCT & CONNS	N/A	285	6	A partial maintenance inspection in May 2009 using a 5kV Meggar indicated good insulation test readings. No testing was indicated of Section 1 (A-toward generator and B-toward main transformer).	4	200000 (30)	(10)	2041	2012	2012	Yes	No	1970
1296	6690	6723	6726	0	0	1	#1 UNIT GENERATION SERVICES	UNIT SERVICE POWER SYSTEM	UNIT SERVICE POWER SYSTEM	N/A	286	6	See details below.	3a	(30)	10	2041			No	No	1970
1296	6690	6723	6726	7181	0	1	#1 UNIT GENERATION SERVICES	UNIT SERVICE POWER SYSTEM	UNIT BOARD UB-1	N/A	287	6	Unit Board UB1 Protection 2005 are satisfactory. Relays and cases required cleaning due to ingress of dust and foreign material.	3a	(25)	10	2041			No	No	1970
1296	6690	6723	6726	7182	0	1	#1 UNIT GENERATION SERVICES	UNIT SERVICE POWER SYSTEM	POWER CENTRE A	N/A	288	6	PM performed between 1992 and 1997. Externally refurbished, and the protection relay changed on some breakers. All 600V switchgear is applied within their ratings.	3a	(30)	10	2041			No	No	1970
1296	6690	6723	6726	7183	0	1	#1 UNIT GENERATION SERVICES	UNIT SERVICE POWER SYSTEM	TURBINE & BOILER AREA MCC A1	N/A	289	6	Aging. Selective refurbishment required over time to maintain service.	10	(25)	5	2041			No	No	1970
1296	6690	6723	6728	0	0	1	#1 UNIT GENERATION SERVICES	BATTERY CHARGERS	BATTERY CHARGERS	N/A	290	6	Last equipment check 04 Feb 2010. 129VDC Battery Charger 2 (1969) to be replaced in 2010.	3a	(20)	20	2041		2010	Yes	No	2010
1296	6690	6723	6728	99043229	0	1	#1 UNIT GENERATION SERVICES	BATTERY CHARGERS	250 VOLT DC BATTERY BANK	N/A	291	6	Installed 1998. Replacement date 2023. Last equipment maintenance check was 04 Feb. 2010.	3a	(25)	15	2041	2011		Yes	No	1998
1296	6690	6723	6728	99043230	0	1	#1 UNIT GENERATION SERVICES	BATTERY CHARGERS	250 VOLT DC BATTERY CHARGE	N/A	292	6	End of Life. Plan to replace in 2010.	3a	(25)	10	2041		2010	Yes	Yes	2010
1296	6690	6723	7184	0	0	1	#1 UNIT GENERATION SERVICES	TURBINE & BOILER AREA MCC C2	TURBINE & BOILER AREA MCC C2	N/A	295	6	MCC's C1, C2, C3, E1 (GE) and GPB34, SDB34 (Siemens) available fault currents exceed the rating of the short circuit protection devices within the individual wrappers.	3a	(25)	3	2041			No	No	1970
1296	6690	6723	7186	0	0	1	#1 UNIT GENERATION SERVICES	TURBINE & BOILER AREA MCC C3	TURBINE & BOILER AREA MCC C3	N/A	296	6	MCC's C1, C2, C3, E1 (GE) and GPB34, SDB34 (Siemens) available fault currents exceed the rating of the short circuit protection devices within the individual wrappers.	3a	(25)	3	2041			No	No	1970
1296	6690	6723	7193	0	0	1	#1 UNIT GENERATION SERVICES	UPS INVERTER	UPS INVERTER	N/A	297	6	Batteries changed at 7 years and tested every 4 weeks. Maintenance performed 04 Feb. 2010.	3a	(25)	10	2041			No	No	1997
1296	6690	6723	270296	0	0	1	#1 UNIT GENERATION SERVICES	CABLE RACEWAYS	CABLE RACEWAYS	N/A	298	6	Normal inspections and PM every 10 years have not been done since 1995. Some contamination of trays in the boiler areas due to asbestos and heavy metal-dust. Some cables, power and control, are "thrown" into trays that have been convenient in the routings associated with the new installations.	4	(50)	(30)	2041			Yes	No	1970
1296	6690	6723	270297	0	0	1	#1 UNIT GENERATION SERVICES	CONTROL CABLES	CONTROL CABLES	N/A	299	6	No recent testing.	4	(50)	(10)	2041			No	No	1970
1296	6690	6723	270298	0	0	1	#1 UNIT GENERATION SERVICES	POWER CABLES	POWER CABLES	N/A	300	6	No recent testing.	4	(50)	(10)	2041			No	No	1970
1296	6690	6723	309894	0	0	1	#1 UNIT GENERATION SERVICES	600 V METRIC PLUGS	600 V METRIC PLUGS	N/A	301	6	New.	3a	(30)	30	2041			Yes	Yes	2009

Notes:

1. A "(bracketed)" value in the "Current Expected Remaining Life" column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as "(X/Y)" has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

2. The "Next Regular Inspection" column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The "Next Planned Overhaul or Major Inspection" column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a "Desired Life" stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or are not known by AMEC.

8.1.3.5 Actions – Unit 1 Electrical and Control Systems

Where a system is fully or partially required for synchronous condensing, it is included here. The following actions are recommended for the Unit 1 electrical and control systems:

TABLE 8-16 ACTIONS – UNIT 1 ELECTRICAL AND CONTROL SYSTEMS ASSOCIATED WITH GENERATORS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Unit	Asset 2/3	Asset 3/4	Description	Detail	Action #	App #	Action	Year	Priority
1296	6690	6723	6721	0	1	#1 UNIT GENERATION SERVICES	RELAY RM PROTECTION & CONTROL	RELAY RM PROTECTION & CONTROL	N/A	191	6	Test Generator G1, Transformer T1 and Auxiliaries P&C Panels - next tests planned for 2011, 2017, 2023, etc.	2011	1
1296	6690	6723	6721	0	1	#1 UNIT GENERATION SERVICES	RELAY RM PROTECTION & CONTROL	RELAY RM PROTECTION & CONTROL	N/A	192	6	Test Station Service Transformers UT1 and UT2 Protection Panels - next tests planned for 2012, 2018, 2024, etc.	2012	1
1296	6690	6723	6721	0	1	#1 UNIT GENERATION SERVICES	RELAY RM PROTECTION & CONTROL	RELAY RM PROTECTION & CONTROL	N/A	193	6	Conduct a modernization study - refurbishing the old GE electro-magnetic relays versus multi-function relaying for periods to 2015, to 2020 then to 2041. Extend scope of existing Schweitzer SEL 300G from present ground fault monitoring to include all unit protection. Assess similar multi-function relay for back-up protection and consider for control, indication and annunciation functions an ABB Combiflex system.	2011	1
1296	6690	6723	6722	0	1	#1 UNIT GENERATION SERVICES	MAIN CONTROLS	MAIN CONTROLS	N/A	194	6	Assess migrating Governor System and Burner Management to DCS - remove existing control relaying and transducers, re-direct field cabling to the DCS and re-configure the software.	2011	1
1296	6690	6723	291668	0	1	#1 UNIT GENERATION SERVICES	DISTRIBUTED CONTROL SYSTEM (DCS)	DCS	N/A	195	6	Maintain DCS system current through existing Foxboro replacement service agreement.	2014	1
1296	6690	6723	6724	0	1	#1 UNIT GENERATION SERVICES	GENERATOR BUS DUCT & CONNS	GENERATOR BUS DUCT & CONNS	N/A	196	6	Conduct generator bus-duct inspection tests using Holyrood Bus-Duct PM Inspection sheet extended to also record the low resistance tests and comments on the condition of sectional gaskets, sectional grounding straps and condition of all grounding points. Tests are as follows: Low Resistance Test : Measure the resistance of bolted connections using a low-resistance ohmmeter (Ductor). Compare resistance readings between similar bolted connections. There must not be any difference greater than 50% between resistance readings. Check the resistance values are below the manufacturer's recommended maximum value. Insulation Resistance Test: Measure the phase-to-phase and phase-to-ground insulation resistance, which must be at least 100Mohm per 1000 ft. of bus-duct.	2011	1
1296	6690	6723	6726	0	1	#1 UNIT GENERATION SERVICES	UNIT SERVICE POWER SYSTEM	UNIT SERVICE POWER SYSTEM	N/A	197	6	See details below.		
1296	6690	6723	6726	7181	1	#1 UNIT GENERATION SERVICES	UNIT SERVICE POWER SYSTEM	UNIT BOARD UB-1	N/A	198	6	No action recommended.		
1296	6690	6723	6726	7182	1	#1 UNIT GENERATION SERVICES	UNIT SERVICE POWER SYSTEM	POWER CENTRE A	Power Centre "A" UAB1, (600V)	199	6	Change all Power Centre "A" UAB1, (600V) protection setting to improve arc-flash ratings, unless already completed, including: - Protection settings adjustment on breaker A1, secondary of transformer AT-A - Replacement of trip unit on breaker A3, Lighting Transformer LT-A feeder.	2011	1
1296	6690	6723	6726	7182	1	#1 UNIT GENERATION SERVICES	UNIT SERVICE POWER SYSTEM	POWER CENTRE A	Power Centre "A" UAB1, (600V)	200	6	Inspect and test transformer AT-A and the individual AK-50 / AK-25 air circuit breakers, and the bussing checked - turns ratio, power and dissipation factor, winding resistance, movement of coils, core grounds, taps and general condition and cleanliness. If the plant three year thermal scan program has not included this equipment then bus-bar bolts should be checked and re-torqued.	2011	1
1296	6690	6723	6726	7182	1	#1 UNIT GENERATION SERVICES	UNIT SERVICE POWER SYSTEM	POWER CENTRE A	Power Centre "A" UAB1, (600V)	201	6	Overhaul to an "as new condition" or replace the switchgear, including cubicles and breaker elements, extending the life expectancy of the existing switchgear for a further 15-20 years. Consider the availability of spare breaker elements to allow a program can be set up to overhaul each breaker off site with essentially no interruption to plant requirements.	2012	1
1296	6690	6723	6726	7183	1	#1 UNIT GENERATION SERVICES	UNIT SERVICE POWER SYSTEM	TURBINE & BOILER AREA MCC A1		202	6	Not reviewed.		
1296	6690	6723	6728	0	1	#1 UNIT GENERATION SERVICES	BATTERY CHARGERS	BATTERY CHARGERS	Battery Chargers	203	6	Continue Planned Maintenance on newer units	2011	2
1296	6690	6723	6728	0	1	#1 UNIT GENERATION SERVICES	BATTERY CHARGERS	BATTERY CHARGERS	Battery Chargers	204	6	Replace Units 1/2, 129VDC Battery Charger 2 with a new Primax Charger alongside in 2010.	2010	1
1296	6690	6723	6728	0	1	#1 UNIT GENERATION SERVICES	BATTERY CHARGERS	BATTERY CHARGERS	Battery Chargers	205	6	Replace Unit 1, 258VDC Panel and breakers installed in 1969	2010	1

Table 8-16 Cont'd

Newfoundland and Labrador Hydro a NALCOR Energy Co.
Holyrood Thermal Generating Station
Condition Assessment & Life Extension Study

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Unit	Asset 2/3	Asset 3/4	Description	Detail	Action #	App #	Action	Year	Priority
1296	6690	6723	6728	99043229	1	#1 UNIT GENERATION SERVICES	BATTERY CHARGERS	250 VOLT DC BATTERY BANK	N/A	206	6	No action recommended.		
1296	6690	6723	6728	99043230	1	#1 UNIT GENERATION SERVICES	BATTERY CHARGERS	250 VOLT DC BATTERY CHARGE	N/A	207	6	No action recommended.		
1296	6690	6723	7184	0	1	#1 UNIT GENERATION SERVICES	TURBINE & BOILER AREA MCC C2	TURBINE & BOILER AREA MCC C2	MCC's, C2, C3, C4	208	6	Conduct a study of how the distribution system (4160V, 600V, MCC's, cabling, etc.) is impacted by changes between 2010 and 2020, and before the start of the suggested Condition Evaluation Report addressed in other sections.	2011	1
1296	6690	6723	7186	0	1	#1 UNIT GENERATION SERVICES	TURBINE & BOILER AREA MCC C3	TURBINE & BOILER AREA MCC C3	MCC's, C2, C3, C4	211	6	Address issues of MCC's C1, C2, C3, E1 (GE) and GPB34, SDB34 (Siemens) available fault currents exceeding the rating of the short circuit protection devices within the individual wrappers of each MCC (Reference the Stantec Report – Holyrood Generating Station MCC Assessment, dated January 15, 2009).	2011	1
1296	6690	6723	7193	0	1	#1 UNIT GENERATION SERVICES	UPS INVERTER	UPS INVERTER	UPS1 Inverter	212	6	Overhaul/upgrade unit to extend the life expectancy to at least 2020.	2012	2
1296	6690	6723	7193	0	1	#1 UNIT GENERATION SERVICES	UPS INVERTER	UPS INVERTER	UPS1 Inverter	213	6	Optimize in conjunction with UPS2, UPS3 and UPS4 the possible replacement of the four units with two parallel units for requirement for inverters from 2020 to 2041.	2012	2
1296	6690	6723	7193	0	1	#1 UNIT GENERATION SERVICES	UPS INVERTER	UPS INVERTER	UPS1 Inverter	214	6	Maintain PM program for the 120/208V, 3ph Distribution Panel-boards panels and breakers fed from UPS1 inverter, via Distribution Splitter.	2011	2
1296	6690	6723	270295	0	1	#1 UNIT GENERATION SERVICES	SWITCHGEAR 4160/600V	SWITCHGEAR 4160/600V	Switchgear, 4160V/600V	215	6	Assess Switchgear, 4160V/600V relaying in UB1modernization study for the protection relays. Consider that the remaining P&B Golds relays remain and not be replaced by Schweitzer 701 MPR's. As of 2015 the breakers utilizing these will become standby and as of 2020 will become spare.	2011	1
1296	6690	6723	270295	0	1	#1 UNIT GENERATION SERVICES	SWITCHGEAR 4160/600V	SWITCHGEAR 4160/600V	N/A	216	6	Overhaul all 4160V switchgear breakers. Consider with the availability of spare breaker elements a program to overhaul breakers 4,5,6,7,8,9,10,11 off site if necessary, with essentially no interruption to plant requirements recognizing that these will be in standby mode from 2015-2020 and as of 2020 will become "spare" but in good condition.	2011	2
1296	6690	6723	270295	0	1	#1 UNIT GENERATION SERVICES	SWITCHGEAR 4160/600V	SWITCHGEAR 4160/600V	N/A	217	6	Replace existing breakers 1, 2 and 3 during the complete overhaul with Eaton Electrical VR-Series breakers for a life expectancy to at least 2041. Use spare cubicle (UB1-12) for the new U1 Synchronous Condenser Start Pony Motor breaker 12 using a new Eaton Electrical VR-Series type direct replacements for ITE, 4160V, Type 5HK). Consider the Eaton Electrical Remote racking device (RPR2) to allow remote racking of breaker from up to 50ft away, and is programmable for other types of breakers. One RPR2 would service U1 and U2 needs.	2012	1
1296	6690	6723	270296	0	1	#1 UNIT GENERATION SERVICES	CABLE RACEWAYS	CABLE RACEWAYS	N/A	218	6	Clean raceways, trays and cables to be tested by a crew of specialized hazardous area cleaners before any inspections or tests are carried out.	2011	3
1296	6690	6723	270297	0	1	#1 UNIT GENERATION SERVICES	CONTROL CABLES	CONTROL CABLES	N/A	219	6	Test selected control cables selected based on how the distribution will be affected post SC conversion, especially if the cables are required to be re-run. Low Resistance Test: Measure the resistance of bolted connections using a low-resistance ohmmeter (Ductor). Compare resistance readings between similar bolted connections. There must not be any difference greater than 50% between resistance readings. Check the resistance values are below the manufacturer's recommended maximum value.	2011	3
1296	6690	6723	270298	0	1	#1 UNIT GENERATION SERVICES	POWER CABLES	POWER CABLES	N/A	220	6	Test selected power cables - 4160V, 600V cables selected based on how the distribution will be affected post SC conversion, especially if the cables are required to be re-run. Low Resistance Test: Measure the resistance of bolted connections using a low-resistance ohmmeter (Ductor). Compare resistance readings between similar bolted connections. There must not be any difference greater than 50% between resistance readings. Check the resistance values are below the manufacturer's recommended maximum value. Insulation Resistance Test: Apply a test voltage of 5kV for cable used for 4160V, 1000V for cable rated at 600V, and 500V for cable rated at 300V. Record phase-to-phase and phase-to-ground insulation resistance tests, which must be at least 100Mohm per 1000 ft. of cable.	2011	3
1296	6690	6723	309894	0	1	#1 UNIT GENERATION SERVICES	600 V MELTRIC PLUGS	600 V MELTRIC PLUGS	N/A	221	6	No recommended action. Complete install.		

8.1.3.6 Risk Assessment

Where a system is fully or partially required for synchronous condensing, it is included here. Table 8-17 below illustrates the risk assessment for the Unit 1 electrical and control systems associated with generators, both from a technological perspective and a safety perspective using the models presented in Section 3.

TABLE 8-17 RISK ASSESSMENT – UNIT 1 ELECTRICAL AND CONTROL SYSTEMS ASSOCIATED WITH GENERATORS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Component	Risk Assess #	Appendix #	Major Issues	Remaining Life Years (Insufficient Info - Inspection Required Within (x) Years)	Remaining Life Comments	TECHNO-ECO RISK ASSESS MODEL			SAFETY RISK ASSESS MODEL			Possible Failure Event	Mitigation
																Likeli-hood	Conse-quence	Risk Level	Likeli-hood	Conse-quence	Safety Risk		
1296	6690	6723	0	0	0	1	#1 UNIT GENERATION SERVICES	ELEC & CONTROLS SYSTEM	ELEC & CONTROLS SYSTEM	N/A	181		See details below.		None								
1296	6690	6723	6721	0	0	1	#1 UNIT GENERATION SERVICES	RELAY RM PROTECTN & CONTROL	RELAY RM PROTECTN & CONTROL	Relay Room Protection & Control	182	6	Electrical fault, mechanical fault, ops error.	10	None	2	C-D	Medium	2	C-D	Medium	Loss 1 unit generation, damage to unit or equipment. Safety	Current inspection and maintain.
1296	6690	6723	270295	0	0	1	#1 UNIT GENERATION SERVICES	SWITCHGEAR 4160/600V	SWITCHGEAR 4160/600V	Switchgear, 4160V/600V	183	6	Electrical fault, mechanical fatigue, ops error.	5	None	3	B-C	Medium	3	B-C	Medium	Loss up to 1 unit generation. Damage to equipment.	Refurbish or replace.
1296	6690	6723	6722	0	0	1	#1 UNIT GENERATION SERVICES	MAIN CONTROLS	MAIN CONTROLS	Main Controls	184	6	Electrical fault, mechanical fatigue, ops error.	10	None	1	C	Low	1	C	Low	Loss of unit. Safety	Current inspection and maintain.
1296	6690	6723	291668	0	0	1	#1 UNIT GENERATION SERVICES	DISTRIBUTED CONTROL SYSTEM (DCS)	DCS	DCS	185	6	Electrical fault, ops error.	10	None	1	C	Low	1	C	Low	Loss 1 unit generation. Damage to unit	Maintain.
1296	6690	6723	6724	0	0	1	#1 UNIT GENERATION SERVICES	GENERATOR BUS DUCT & CONNS	GENERATOR BUS DUCT & CONNS	Generator Bus-Duct and Connections	186	6	Electrical fault.	(10)	None	3	C-D	Medium/ High	3	C-D	High	Loss 1 unit generation, damage to unit Safety	Current inspection and maintain.
1296	6690	6723	6726	0	0	1	#1 UNIT GENERATION SERVICES	UNIT SERVICE POWER SYSTEM	UNIT SERVICE POWER SYSTEM		187		See details below.	10	None								
1296	6690	6723	6726	7181	0	1	#1 UNIT GENERATION SERVICES	UNIT SERVICE POWER SYSTEM	UNIT BOARD UB-1		188		Electrical fault, mechanical fatigue, ops error.	10	None	3	B	Medium	3	B	Medium	Loss of part of 1 unit generation. Damage to equipment.	Refurbish or replace.
1296	6690	6723	6726	7182	0	1	#1 UNIT GENERATION SERVICES	UNIT SERVICE POWER SYSTEM	POWER CENTRE A	Power Centre (600V)	189	6	Electrical fault, mechanical fatigue, ops error.	10	None	3	B	Medium	3	B	Medium	Loss of part of 1 unit generation. Damage to equipment.	Refurbish or replace.
1296	6690	6723	6726	7183	0	1	#1 UNIT GENERATION SERVICES	UNIT SERVICE POWER SYSTEM	TURBINE & BOILER AREA MCC A1	N/A	190		Mech/elect failure.	5	None	3	B	Medium	3	A	Low	Loss of part of 1 unit generation. Damage to equipment.	Refurbish or replace.
1296	6690	6723	6728	0	0	1	#1 UNIT GENERATION SERVICES	BATTERY CHARGERS	BATTERY CHARGERS	Battery Chargers	191	6	Electrical or chemical fault.	20	None	1	B	Low	1	B	Low	Unit damage on fail to safe shutdown	Refurbish or replace.
1296	6690	6723	6728	99043229	0	1	#1 UNIT GENERATION SERVICES	BATTERY CHARGERS	250 VOLT DC BATTERY BANK	N/A	192		Electric failure.	15	None	1	B	Low	1	B	Low	Unit damage on fail to safe shutdown	Refurbish or replace.
1296	6690	6723	6728	99043230	0	1	#1 UNIT GENERATION SERVICES	BATTERY CHARGERS	250 VOLT DC BATTERY CHARGE	N/A	193		Electric failure.	10	None	1	B	Low	1	B	Low	Unit damage on fail to safe shutdown	Refurbish or replace.
1296	6690	6723	7184	0	0	1	#1 UNIT GENERATION SERVICES	TURBINE & BOILER AREA MCC C2	TURBINE & BOILER AREA MCC C2	MCC's, C2, C3, C4	194	6	Electrical fault, mechanical fatigue, ops error.	3	None	3	C	Medium	3	C	High	Loss 1 unit generation, damage to equipment	Refurbish or replace.
1296	6690	6723	7186	0	0	1	#1 UNIT GENERATION SERVICES	TURBINE & BOILER AREA MCC C3	TURBINE & BOILER AREA MCC C3	MCC's, C2, C3, C4	195	6	Electrical fault, mechanical fatigue, ops error.	3	None	3	C	Medium	3	C	High	Loss 1 unit generation, damage to equipment	Refurbish or replace.
1296	6690	6723	7193	0	0	1	#1 UNIT GENERATION SERVICES	UPS INVERTER	UPS INVERTER	UPS Inverter 1,2,3,4	196	6	Electrical fault.	10	None	3,1	B	Medium, Low	1	B	Low	Unit damage on fail to safe shutdown	Refurbish or replace.
1296	6690	6723	270296	0	0	1	#1 UNIT GENERATION SERVICES	CABLE RACEWAYS	CABLE RACEWAYS	N/A	197		Electrical fault.	(30)	None	1	C	Low	1	B	Low	Loss up to 1 unit generation. Damage to equipment.	Clean and re-organize.
1296	6690	6723	270297	0	0	1	#1 UNIT GENERATION SERVICES	CONTROL CABLES	CONTROL CABLES	Cables	198	6	Electrical fault.	(10)	None	2	B-C	Low	2	B-C	Low	Loss of up to 1 unit generation. Equipment/unit damage	Test indicative number.
1296	6690	6723	270298	0	0	1	#1 UNIT GENERATION SERVICES	POWER CABLES	POWER CABLES	Cables	199	6	Electrical fault.	(10)	None	2	B-C	Low	2	B-C	Low	Loss of up to 1 unit generation. Equipment/unit damage	Test indicative number.
1296	6690	6723	309894	0	0	1	#1 UNIT GENERATION SERVICES	600 V MELTRIC PLUGS	600 V MELTRIC PLUGS	N/A	200		Not addressed in detail.	30	None	1	C	Low	1	C	Low		

8.1.3.7 Life Cycle Curve and Remaining Life

Figures 8-6 and 8-7 below, illustrate the life cycle curves for the Unit 1 electrical and control systems associated with generators. Several curves are required to represent the various elements. They have been broken into two parts – the electrical and control systems (MCC's, relays, breakers, TSI, DCS) and those primarily associated with batteries and chargers. The curves are plots of current and projected years in service on the y-axis versus calendar year on the x-axis. Age in-service due to either aging or obsolescence is more an issue than unit operating hours. Vertical lines represent bands of nominal years of in-service life for different in service dates. Horizontal lines represent the ranges of equipment life based on current and historical information and expert opinion. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view.

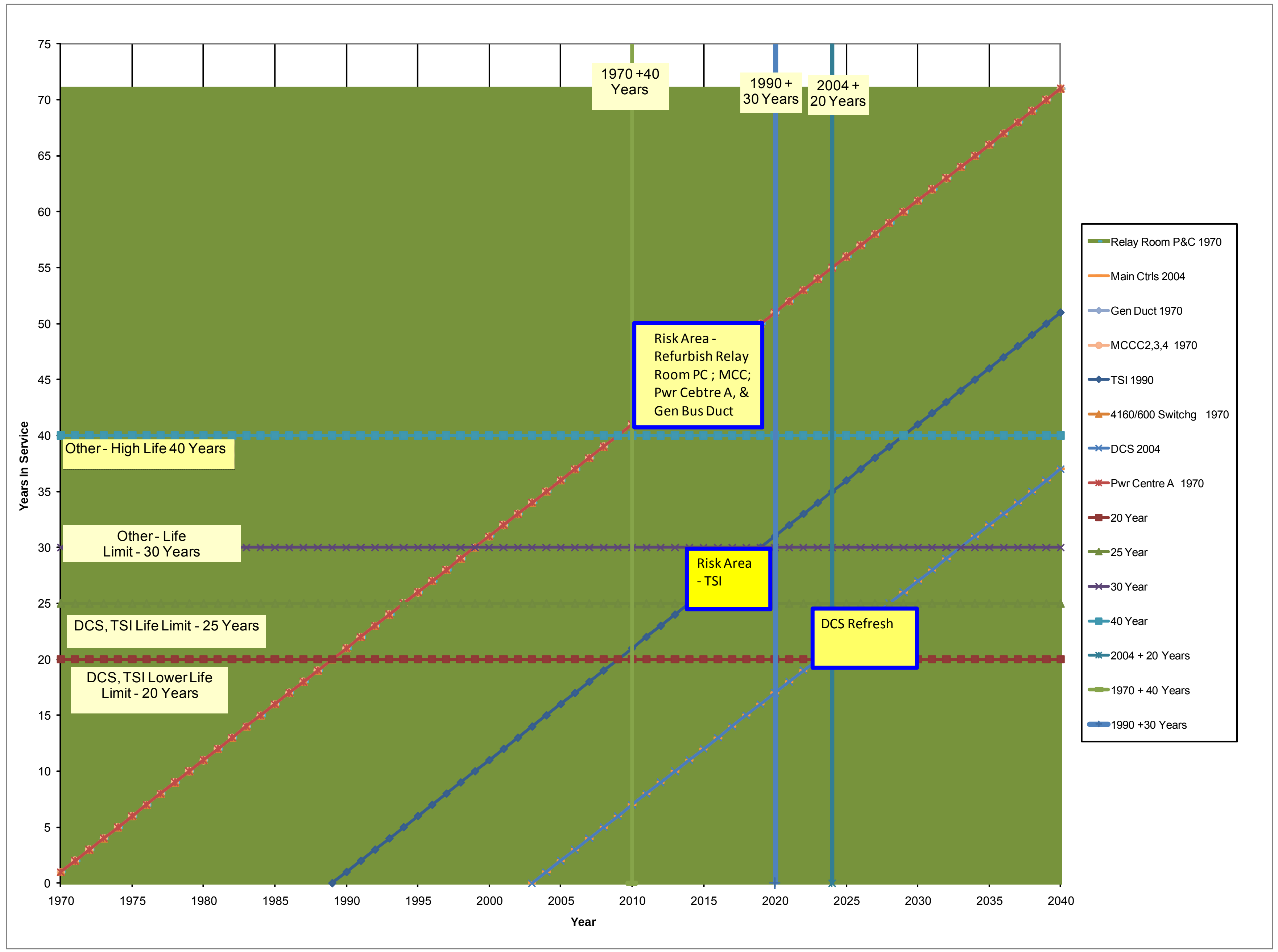

FIGURE 8-6 LIFE CYCLE CURVE – UNIT 1 ELECTRICAL AND CONTROL SYSTEMS ASSOCIATED WITH GENERATORS (MCC'S, RELAYS, BREAKERS, TSI, DCS)

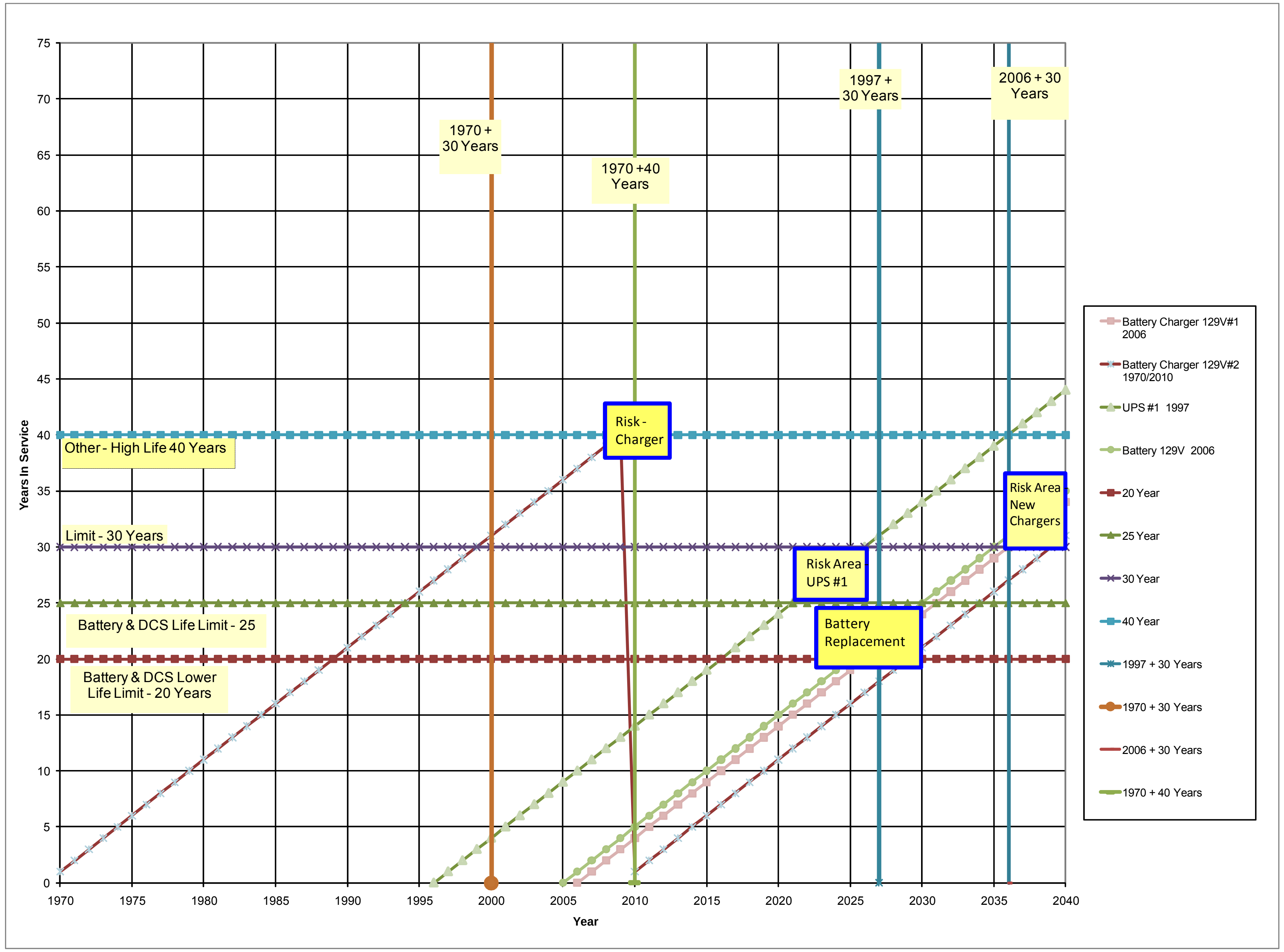

FIGURE 8-7 LIFE CYCLE CURVE – UNIT 1 ELECTRICAL AND CONTROL SYSTEMS ASSOCIATED WITH GENERATORS (BATTERIES AND CHARGERS)

The curves indicate that the remaining life (RL) of much of the equipment does not exceed the desired life (DL) for generation of 2020 and for synchronous condensing of 2041, without extensive refurbishment or replacement. This is well illustrated by the highlighted risk areas which highlights that many original MCC's and relays as well as the TSI are in need or replacement or extensive refurbishment in the very near term. The risk figures also illustrate that most of the rest of the equipment (DCS, batteries, and chargers) will require replacement or refurbishment in the 2020+ period.

8.1.3.8 Level 2 Inspections – Unit 1 Electrical and Control Systems Associated with Generators

Where a system is fully or partially required for synchronous condensing, it is included here. Recommended Level 2 analyses are identified in the Table 8-18.

TABLE 8-18 LEVEL 2 INSPECTIONS– UNIT 1 ELECTRICAL AND CONTROL SYSTEMS ASSOCIATED WITH GENERATORS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Sub System Comment	L2#	Appendix #	Level 2 Work	Year	Priority	Cost k$
1296	6690	6723	0	0	0	1	#1 UNIT GENERATION SERVICES	ELEC & CONTROLS SYSTEM	ELEC & CONTROLS SYSTEM	None	169	6	No Level 2 required.			
1296	6690	6723	6721	0	0	1	#1 UNIT GENERATION SERVICES	RELAY RM PROTECTN & CONTROL	RELAY RM PROTECTN & CONTROL	None	170	6	No Level 2 required.			
1296	6690	6723	270295	0	0	1	#1 UNIT GENERATION SERVICES	SWITCHGEAR 4160/600V	SWITCHGEAR 4160/600V	None	171	6	No Level 2 required.			
1296	6690	6723	6722	0	0	1	#1 UNIT GENERATION SERVICES	MAIN CONTROLS	MAIN CONTROLS	None	172	6	No Level 2 required.			
1296	6690	6723	291668	0	0	1	#1 UNIT GENERATION SERVICES	DISTRIBUTED CONTROL SYSTEM (DCS)	DCS	None	173	6	No Level 2 required.			
1296	6690	6723	6724	0	0	1	#1 UNIT GENERATION SERVICES	GENERATOR BUS DUCT & CONNS	GENERATOR BUS DUCT & CONNS	Generator Bus-Duct and Connections	174	6	Conduct in 2011 a complete generator bus-duct partial maintenance inspection and tests on the U1 bus-duct: Low Resistance Test : Measure the resistance of bolted connections using a low-resistance ohmmeter (Ductor). Compare resistance readings between similar bolted connections. There must not be any difference greater than 50% between resistance readings. Check the resistance values are below the manufacturer's recommended maximum value. Insulation Resistance Test: Measure the phase-to-phase and phase-to-ground insulation resistance, which must be at least 100Mohm per 1000 ft. of bus-duct.	2011	1	$15
1296	6690	6723	6726	0	0	1	#1 UNIT GENERATION SERVICES	UNIT SERVICE POWER SYSTEM	UNIT SERVICE POWER SYSTEM	None	175	6	No Level 2 required.			
1296	6690	6723	6726	7181	0	1	#1 UNIT GENERATION SERVICES	UNIT SERVICE POWER SYSTEM	UNIT BOARD UB-1	None	176	6	No Level 2 required.			
1296	6690	6723	6726	7182	0	1	#1 UNIT GENERATION SERVICES	UNIT SERVICE POWER SYSTEM	POWER CENTRE A	Power Centre "A" UAB1, (600	177	6	Inspection and testing of transformer AT-A and the individual AK-50 / AK-25 air circuit breakers, and the bussing checked. If the plant three year thermal scan program has not included this equipment then bus-bar bolts should be checked and re-torqued. Inspection and testing of the transformer should include turns ratio, power and dissipation factor, winding resistance, movement of coils, core grounds, taps and general condition and cleanliness.	2011	2	$6
1296	6690	6723	6726	7183	0	1	#1 UNIT GENERATION SERVICES	UNIT SERVICE POWER SYSTEM	TURBINE & BOILER AREA MCC A1	None	178	6	No Level 2 required.			
1296	6690	6723	6728	0	0	1	#1 UNIT GENERATION SERVICES	BATTERY CHARGERS	BATTERY CHARGERS	None	179	6	No Level 2 required.			
1296	6690	6723	6728	99043229	0	1	#1 UNIT GENERATION SERVICES	BATTERY CHARGERS	250 VOLT DC BATTERY BANK	None	180	6	No Level 2 required.			
1296	6690	6723	6728	99043230	0	1	#1 UNIT GENERATION SERVICES	BATTERY CHARGERS	250 VOLT DC BATTERY CHARGE	None	181	6	No Level 2 required.			
1296	6690	6723	7184	0	0	1	#1 UNIT GENERATION SERVICES	TURBINE & BOILER AREA MCC C2	TURBINE & BOILER AREA MCC C2	None	182	6	No Level 2 required.			
1296	6690	6723	7186	0	0	1	#1 UNIT GENERATION SERVICES	TURBINE & BOILER AREA MCC C3	TURBINE & BOILER AREA MCC C3	None	183	6	No Level 2 required.			
1296	6690	6723	7193	0	0	1	#1 UNIT GENERATION SERVICES	UPS INVERTER	UPS INVERTER	None	184	6	No Level 2 required.			
1296	6690	6723	270296	0	0	1	#1 UNIT GENERATION SERVICES	CABLE RACEWAYS	CABLE RACEWAYS	Units 1, 2, 3 Cable Raceways, Control Cables, Power Cables	185	6	No Level 2 required.		2	

Table 8-18 Cont'd

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Sub System Comment	L2#	Appendix #	Level 2 Work	Year	Priority	Cost k$
1296	6690	6723	270297	0	0	1	#1 UNIT GENERATION SERVICES	CONTROL CABLES	CONTROL CABLES	Units 1, 2, 3 Cable Raceways, Control Cables, Power Cables	186	6	Inspection and test selected control cables (especially if the cables are required to be re-run to different equipment): - Low Resistance Test: Measure the resistance of bolted connections using a low-resistance ohmmeter (Ductor). Compare resistance readings between similar bolted connections. There must not be any difference greater than 50% between resistance readings. Check the resistance values are below the manufacturer's recommended maximum value.	2011	2	$7
1296	6690	6723	270298	0	0	1	#1 UNIT GENERATION SERVICES	POWER CABLES	POWER CABLES	Units 1, 2, 3 Cable Raceways, Control Cables, Power Cables	187	6	Inspection and test selected power (4160V, 600V) cables (especially if the cables are required to be re-run to different equipment): - Low Resistance Test: Measure the resistance of bolted connections using a low-resistance ohmmeter (Ductor). Compare resistance readings between similar bolted connections. Check the resistance values are below the manufacturer's recommended maximum value. - Insulation Resistance Test: Apply a test voltage of 5kV for cable used for 4160V, 1000V for cable rated at 600V, and 500V for cable rated at 300V. Record phase-to-phase and phase-to-ground insulation resistance tests, which must be at least 100Mohm per 1000 ft. of cable.	2011	2	$10
1296	6690	6723	309894	0	0	1	#1 UNIT GENERATION SERVICES	600 V METRIC PLUGS	600 V METRIC PLUGS	None	188	6	No Level 2 required.			

8.1.3.9 Capital Projects

Where a system is fully or partially required for synchronous condensing, it is included here. The suggested typical capital enhancements include:

TABLE 8-19 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – UNIT 1 ELECTRICAL AND CONTROL SYSTEMS ASSOCIATED WITH GENERATORS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Detail	CAP#	Appendix #	Capital Item	Date	Priority
1296	6690	6723	0	0	0	1	#1 UNIT GENERATION SERVICES	ELEC & CONTROLS SYSTEM	ELEC & CONTROLS SYSTEM	N/A	136		No capital required.		
1296	6690	6723	6721	0	0	1	#1 UNIT GENERATION SERVICES	RELAY RM PROTECTN & CONTROL	RELAY RM PROTECTN & CONTROL	N/A	137	6	Implement modernization study re: appraise the cost of refurbishing the old GE electro-magnetic relays against the cost of multi-function relaying.	2014	1
1296	6690	6723	6722	0	0	1	#1 UNIT GENERATION SERVICES	MAIN CONTROLS	MAIN CONTROLS	N/A	138	6	Implement study to migrate Governor System and Burner Management to DCS - remove existing control relaying and transducers, re-direct field cabling to the DCS and re-configure the software.	2014	2
1296	6690	6723	6724	0	0	1	#1 UNIT GENERATION SERVICES	GENERATOR BUS DUCT & CONNS	GENERATOR BUS DUCT & CONNS	N/A	139	6	None planned, but may result from inspection and tests.		
1296	6690	6723	6726	0	0	1	#1 UNIT GENERATION SERVICES	UNIT SERVICE POWER SYSTEM	UNIT SERVICE POWER SYSTEM	N/A	140	6	No capital required.		
1296	6690	6723	6726	7181	0	1	#1 UNIT GENERATION SERVICES	UNIT SERVICE POWER SYSTEM	UNIT BOARD UB-1	N/A	141	6	No capital required.		
1296	6690	6723	6726	7182	0	1	#1 UNIT GENERATION SERVICES	UNIT SERVICE POWER SYSTEM	POWER CENTRE A	N/A	142	6	Change all protection setting to improve arc-flash ratings, unless already completed, including: - Protection settings adjustment on breaker A1, secondary of transformer AT-A. - Replacement of trip unit on breaker A3, Lighting Transformer LT-A feeder.	2011	1
1296	6690	6723	6726	7182	0	1	#1 UNIT GENERATION SERVICES	UNIT SERVICE POWER SYSTEM	POWER CENTRE A	N/A	143	6	Conduct a complete overhaul to an "as new condition" or replacement of the switchgear, including cubicles and breaker elements, extending the life expectancy of the existing switchgear for a further 15-20 years. Use spare breaker elements to allow a program can be set up to overhaul each breaker off site with essentially no interruption to plant requirements.	2012	1
1296	6690	6723	6726	7183	0	1	#1 UNIT GENERATION SERVICES	UNIT SERVICE POWER SYSTEM	TURBINE & BOILER AREA MCC A1	N/A	144		No capital required.		
1296	6690	6723	6728	0	0	1	#1 UNIT GENERATION SERVICES	BATTERY CHARGERS	BATTERY CHARGERS	N/A	145		No capital required.		
1296	6690	6723	6728	99043229	0	1	#1 UNIT GENERATION SERVICES	BATTERY CHARGERS	250 VOLT DC BATTERY BANK	N/A	146	6	Replace Units 1/2, 129VDC Battery Charger 2 with a new Primax Charger alongside in 2010.	2010	2
1296	6690	6723	6728	99043230	0	1	#1 UNIT GENERATION SERVICES	BATTERY CHARGERS	250 VOLT DC BATTERY CHARGE	N/A	147	6	Replace Unit 1, 258VDC Panel and breakers.	2010	2
1296	6690	6723	7184	0	0	1	#1 UNIT GENERATION SERVICES	TURBINE & BOILER AREA MCC C2	TURBINE & BOILER AREA MCC C2	N/A	150	6	Address issues of MCC's C1, C2, C3, E1 (GE) and GPB34, SDB34 (Siemens) available fault currents exceeding the rating of the short circuit protection devices within the individual wrappers of each MCC.	2012	1
1296	6690	6723	7186	0	0	1	#1 UNIT GENERATION SERVICES	TURBINE & BOILER AREA MCC C3	TURBINE & BOILER AREA MCC C3	N/A	151	6	Address issues of MCC's C1, C2, C3, E1 (GE) and GPB34, SDB34 (Siemens) available fault currents exceeding the rating of the short circuit protection devices within the individual wrappers of each MCC.	2012	1

Table 8-19 Cont'd

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Detail	CAP#	Appendix #	Capital Item	Date	Priority
1296	6690	6723	7193	0	0	1	#1 UNIT GENERATION SERVICES	UPS INVERTER #1	UPS INVERTER	N/A	152	6	Overhaul/upgrade unit to extend the life expectancy to at least 2020.	2012	1
1296	6690	6723	7193	0	0	1	#1 UNIT GENERATION SERVICES	UPS INVERTER #1	UPS INVERTER	N/A	153	6	Implement optimization study in conjunction with UPS2, UPS3 and UPS4 replacement.	2012	2
1296	6690	6723	270295	0	0	1	#1 UNIT GENERATION SERVICES	SWITCHGEAR 4160/600V	SWITCHGEAR 4160/600V	N/A	154	6	Implement changes to this Switchgear, 4160V/600V relaying in UB1modernization study (5.3.2.2 IV) for the protection relays. Consider that the remaining P&B Golds relays remain and not be replaced by Schweitzer 701 MPR's. As of 2015 the breakers utilizing these will become standby and as of 2020 will become spare.	2012	2
1296	6690	6723	270295	0	0	1	#1 UNIT GENERATION SERVICES	SWITCHGEAR 4160/600V	SWITCHGEAR 4160/600V	N/A	155	6	Overhaul all 4160V switchgear breakers. Use spare breaker elements to overhaul breakers 4,5,6,7,8,9,10,11 off site if necessary with essentially no interruption to plant requirements recognizing that these will be in standby mode from 2015-2020 and as of 2020 will become "spare" but in good condition.	2012	2
1296	6690	6723	270295	0	0	1	#1 UNIT GENERATION SERVICES	SWITCHGEAR 4160/600V	SWITCHGEAR 4160/600V	N/A	156	6	Replace existing breakers 1, 2 and 3 during the complete overhaul with Eaton Electrical VR-Series breakers for a life expectancy to at least 2041. Use spare cubicle (UB1-12) can be for the new U1 Synchronous Condenser Start Pony Motor breaker 12 using a new Eaton Electrical VR-Series type direct replacements for ITE, 4160V, Type 5HK). Consideration should be given to the Eaton Electrical Remote racking device (RPR2), which allows remote racking of a breaker from up to 50ft away, and is programmable for other types of breaker that might be used. One RPR2 would service U1 and U2 needs.	2012	1
1296	6690	6723	270295	0	0	1	#1 UNIT GENERATION SERVICES	SWITCHGEAR 4160/600V	SWITCHGEAR 4160/600V	N/A	157	6	Implement changes to this Switchgear, 4160V/600V relaying in UB1modernization study (5.3.2.2 IV) for the protection relays. Consider that the remaining P&B Golds relays remain and not be replaced by Schweitzer 701 MPR's. As of 2015 the breakers utilizing these will become standby and as of 2020 will become spare.	2012	2
1296	6690	6723	270295	0	0	1	#1 UNIT GENERATION SERVICES	SWITCHGEAR 4160/600V	SWITCHGEAR 4160/600V	N/A	158	6	No capital required.		
1296	6690	6723	270296	0	0	1	#1 UNIT GENERATION SERVICES	CABLE RACEWAYS	CABLE RACEWAYS	N/A	159	6	Install new cable installations on new tray, and in accordance with the applicable Codes.	2011	1
1296	6690	6723	270297	0	0	1	#1 UNIT GENERATION SERVICES	CONTROL CABLES	CONTROL CABLES	N/A	160	6	Install new cable installations on new tray, and in accordance with the applicable Codes.	2011	1
1296	6690	6723	270298	0	0	1	#1 UNIT GENERATION SERVICES	POWER CABLES	POWER CABLES	N/A	161	6	Install any new cable installations on new tray, and in accordance with the applicable Codes.	2011	1
1296	6690	6723	291668	0	0	1	#1 UNIT GENERATION SERVICES	DISTRIBUTED CONTROL SYSTEM	DCS	N/A	162	6	No capital required.		
1296	6690	6723	309894	0	0	1	#1 UNIT GENERATION SERVICES	600 V METRIC PLUGS	600 V METRIC PLUGS	N/A	163	6	Complete the NLH program of 600V, 3ph, plugs and receptacles on the four Pump feeders left to modify, two on Unit 1 and two on Unit 2 to the LP Drains Pumps.	2010	3

8.1.4 Asset 280182 - Unit 1 Cooling Water Systems Associated with Generators

(Detailed Technical Assessment in Working Papers, Appendices 8 and 11)

The requirements for the cooling water systems associated with generators for Holyrood are as follows:

Unit #:	1
Asset Class #	BU 1296 - Assets Generations
SCI & System:	8715 #1 Unit Generation Services
Sub-Systems:	270182 #1 CW System
Components:	7137 #1 CW Travelling Screens East
	7138 #1 CW Travelling Screens West
	7146 #1 CW Pump East
	7147 #1 CW Pump West
	7134 #1 CW Intake
	7138 #1 CW Discharge to Outfall
	6719 #1 General Service Water
	6782 #1 Turbine Generator Cooling Water

8.1.4.1 Description

The items examined were limited to those required to achieve the 2041 synchronous condensing end date:

- The main pumphouse sea water intake, traveling screens, and general service water system;
- Sea water heat exchanger system;
- Seawater discharge system; and
- Electrical and control requirements.

Circulating Water (CW) Pump & Screen Systems: Circulating water (CW) systems servicing Unit 1 consist of two 50% CW vertical turbine pumps driven by 4 kV motors and auxiliary systems. The pump drive motors are original. Two travelling screen systems are used to remove debris from the cooling water prior to entering the pumps. The primary function of the CW system is to provide condenser cooling water, but also cooling water for other closed loop systems. It is necessary that the CW system operate efficiently in order to maintain optimal plant thermal efficiency by minimizing steam turbine condenser backpressures.

Turbine Generator (TG) Auxiliary Cooling Water System: Sea water cooling is required for the TG Auxiliary Cooling Water system required for synchronous condensing operation. For Unit 3, it can currently be supplied by a sump pump and dedicated line from the Stage 2 pumphouse (Unit 4 CW pump pit), from the water take-off from the Stage 2 pumphouse cooling water pumps, and from an interconnection with the Units 1 and 2 cooling water system. Typically when only Unit 3 is running as synchronous condenser, the smaller sump pump and dedicated line from the Stage 2 pumphouse is used.

For the purpose of long term synchronous generation operation to 2041 of all three units, the intent is to supply seawater from a small, permanent pump arrangement similar to Unit 3. It may come from the one pumphouse or in the form of two separate, but interconnected systems.

FIGURE 8-8 DEDICATED SEAWATER COOLING WATER LINE FOR UNIT 3 SYNCHRONOUS CONDENSING TG AUXILIARY COOLING WATER

8.1.4.2 History

Manufactured/Delivered	1969
In-Service Date	Sep 1970
Generation Base Load End Date	Dec 2015
Generation Peak/Emerg Gen End Date	Dec 2020
Synchronous Condensing Start Date	Jan 2015
Synchronous Condensing End Date	Dec 2041
Last Major Overhaul/Inspection	Not identified
Next Major Overhaul/Inspection	Not Identified

The thousands of hours associated with the analyses, and the number of starts per year are:

	Generation (Gen)	Synchronous Condensing (SC)
Hours Actual - Ops to Dec 2009	166	0
Hours - Ops to Gen End Date Dec 2015	210	1.5
Hours - Ops to Gen End Date Dec 2020	219	25
Hours – Ops to SC End Date Dec 2040	219	120
Starts Actual - Ops to Dec 2009	482	0
Starts - Ops to Gen End Date Dec 2015	554	5
Starts - Ops to Gen End Date Dec 2020	614	30
Starts – Ops to SC End Date Dec 2040	714	130

8.1.4.3 Inspection and Repair History

CW Travelling Screens: Travelling screen internals have been replaced on Unit 1 in the last 5 to 10 years. Interviews suggest that no recent issues have been experienced with these units. Visual examination confirms that generally the Unit 1 screens appear to be in good shape.

The external casings have some corroded parts, but nothing that appears to impair current or short term performance.

CW Wash Water Pumps and Motors: An external inspection of the pumps and motors indicated that they have extensive corrosion but were running at the time of the visual inspection. They are considered to be a minor maintenance issue and not addressed as a part of this assessment.

CW Pumps: CW pumps are performing fairly well. No reports were available on the condition of the pumps, but interviews suggest that regular maintenance has been ongoing and the units should be able to meet 2015 and 2020 timelines with continued maintenance. Major pump overhauls are scheduled on a twelve year cycle as indicated in Table 8-20 below.

TABLE 8-20 MAJOR PUMP OVERHAULS

Annual Asset Maintenance																		
Pumps	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
1 CW Pump East			X												83,000.00			
1 CW Pump West											75,000.00							
2 CW Pump East	X				X												87,000.00	
2 CW Pump West												77,000.00						
3 CW Pump East		X									75,000.00							
3 CW Pump West						10,000.00												89,000.00

It is understood that a temporary CW pump is being used in the existing Unit 4 intake to supply smaller quantities of cooling water to Unit 3 for Synchronous Condensing duty. Further the system has been designed to supply all three units if and when converted. In addition, there are interconnections between Units 1 to 3 CW systems to allow them to provide back-up for this purpose if necessary.

CW Pump Motors: The CW Pumps are driven by 4 kV motors. The motors are the original equipment and are tested electrically every year in accordance with the plant PM process. They are in good condition, but beyond their normal physical life expectation.

CW Pump Outlet Piping, Valves & Fittings: Outlet piping, valves, and fittings from the CW pump discharge to the inlet of the 162 cm (64 inch) concrete piping that goes underground to the Unit 1 condenser has generally experienced significant corrosion and some patching of the system has been done. It requires a Level 2 inspection and possibly a complete replacement.

Cooling Water System Intake & Discharge: The 91 cm (36 inch) and 162 cm (64 inch) CW intake and discharge concrete piping that is installed underground to the unit condenser has periodically been dewatered and inspected by plant staff. No specific corrosion, spalling, cracks or fractures were identified, and no patching of the system has been done. There have been no obvious issues with the systems, but no detailed engineering evaluations and NDE work has been undertaken.

PM inspections are planned going forward on a three year cycle as per schedule below in Table 8-21.

TABLE 8-21 PM INSPECTIONS

Annual Asset Maintenance																	
CW Inspection		2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Unit 1													25,625.00			26,625.00	
Unit 2														25,625.00			26,625.00
Unit 3												25,000.00			25,625.00		

8.1.4.4 Condition Assessment

The condition assessment of the Unit 1 cooling water systems associated with generators is illustrated below in Table 8-22.

TABLE 8-22 CONDITION ASSESSMENT – UNIT 1 COOLING WATER SYSTEMS ASSOCIATED WITH GENERATORS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset Level 2	Asset Level 3	Description	Detail	Condition Summary ID #	Append #	Condition	EPRI Identifier	Original Life (Base Load) Ops Hrs (Yrs)	Current Expected Minimum Remaining Life Years (Subject to Test)	End of Life (EOL) Required	Next Regular Inspection	Next Planned Overhaul or Major Inspection	Capability to Reach Next Overhaul	Capability to Reach EOL	In Service
1296	6690	6715	6719	0	0	1	#1 UNIT GENERATION SERVICES	GENERAL SERVICE COOLING	GENERAL SERVICE COOLING	N/A	255	12	PVC piping can have lifetimes of up to 100 years. The current pipe is less than 20 years old. No difficulties identified or expected.	4	(50)	30	2041	2011		Yes	Yes	1990
1296	6690	6715	6782	0	0	1	#1 UNIT GENERATION SERVICES	TURB/GEN COOLING SYSTEM	TURB/GEN COOLING SYSTEM	N/A	256	11,15	Piping, pumps, and heat exchangers appear in good condition. Heat exchangers are cleaned and checked for leaks annually, and are cathodically protected and a closed cooling system corrosion inhibitor used. No issues had been encountered with the heat exchangers. No inspection or maintenance data was available.	4	200000 (30)	10	2041	2011		Yes	No	1970
1296	6690	6715	6782	0	0	1	#1 UNIT GENERATION SERVICES	TURB/GEN COOLING SYSTEM	TURB/GEN COOLING SYSTEM	Sea Water Piping	257	11,15	Sea Water piping 18" lines and associated valving is original equipment for all units. No condition data but no significant issues identified. Piping and valves have external corrosion and pitting, but rate seems not to be rapid.	3a	200000 (30)	(10)	2041	2011		Yes	No	1970
1296	6690	6715	270182	7134	0	1	#1 UNIT GENERATION SERVICES	CW SYSTEM	C.W. INTAKE	Intake structure and foreay	269	11	No recent underwater inspections of intake structures or bay, but surface visual check looked good. There is no reason to expect any kind of aggressive attack.	4	(60)	(20)	2041		2011	No	No	1970
1296	6690	6715	270182	7135	0	1	#1 UNIT GENERATION SERVICES	CW SYSTEM	C.W. DISCHARGE TO OUTFALL	Pit, Stoplogs and Discharge	270	11	No recent underwater inspections of pit, stoplogs or outfall structures.	4	(60)	(20)	2041		2011	No	No	1970
1296	6690	6715	270182	7137	0	1	#1 UNIT GENERATION SERVICES	CW SYSTEM	C.W.TRAVELLING SCREENS EAST	N/A	271	11	Internals in good condition after major upgrade within the last five to ten years. External casings and auxiliaries have some corrosion.	4	(20)	(10)	2041	2011		No	No	2000
1296	6690	6715	270182	7138	0	1	#1 UNIT GENERATION SERVICES	CW SYSTEM	C.W.TRAVELLING SCREENS WEST	N/A	272	11	Internals in good condition after major upgrade within the last five to ten years. External casings and auxiliaries have some corrosion.	4	(20)	(10)	2041	2011		No	No	2000
1296	6690	6715	270182	8819	0	1	#1 UNIT GENERATION SERVICES	CW SYSTEM	C.W. SCREEN WASH SYSTEM	N/A	273	11	Significant corrosion. Likely near end of life.	4	(30)	5	2041			No	No	1970

Notes:

1. A "(bracketed)" value in the "Current Expected Remaining Life" column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as "(X/Y)" has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

2. The "Next Regular Inspection" column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The "Next Planned Overhaul or Major Inspection" column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a "Desired Life" stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or are not known by AMEC.

8.1.4.5 Actions

Based on the condition assessment, the following actions are recommended for the Unit 1 cooling water system associated with generators:

TABLE 8-23 RECOMMENDED ACTIONS – UNIT 1 COOLING WATER SYSTEMS ASSOCIATED WITH GENERATORS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Unit	Asset 2/3	Asset 3/4	Description	Detail	Action #	App #	Action	Year	Priority
1296	6690	6715	0	0	1	#1 UNIT GENERATION SERVICES	UNIT GENERATION SERVICES	UNIT GENERATION SERVICES	N/A	162	12	Continue current condition monitoring and heat exchanger servicing.	2011	2
1296	6690	6715	6719	0	1	#1 UNIT GENERATION SERVICES	GENERAL SERVICE COOLING	GENERAL SERVICE COOLING	N/A	163	12	Continue current inspection and maintenance activities.	2011	2
1296	6690	6715	6782	0	1	#1 UNIT GENERATION SERVICES	TURB/GEN COOLING SYSTEM	TURB/GEN COOLING SYSTEM	N/A	164	8	Continue current condition monitoring and heat exchanger servicing.	2011	2
1296	6690	6715	6782	0	1	#1 UNIT GENERATION SERVICES	TURB/GEN COOLING SYSTEM	TURB/GEN COOLING SYSTEM	N/A	165	8	Clean and coat remaining Auxiliary Cooling water piping.	2011	2
1296	6690	6715	6782	0	1	#1 UNIT GENERATION SERVICES	TURB/GEN COOLING SYSTEM	TURB/GEN COOLING SYSTEM	N/A	166	8	Perform representative Level II pipe thickness checks on seawater intake and discharge piping.	2011	2
1296	6690	6715	6782	0	1	#1 UNIT GENERATION SERVICES	TURB/GEN COOLING SYSTEM	TURB/GEN COOLING SYSTEM	N/A	167	8	Perform Level 2 inspection on Aux Cooling Pipes during next five years.	2011	2
1296	6690	6715	6782	0	1	#1 UNIT GENERATION SERVICES	TURB/GEN COOLING SYSTEM	TURB/GEN COOLING SYSTEM	N/A	168	8	See details below.		
1296	6690	6715	6782	9592	1	#1 UNIT GENERATION SERVICES	T/G COOLING PUMP SOUTH	T/G COOLING PUMP SOUTH	N/A	169	8	Continue current condition monitoring and heat exchanger servicing.	2011	2
1296	6690	6715	6782	9593	1	#1 UNIT GENERATION SERVICES	T/G COOLING PUMP NORTH	T/G COOLING PUMP NORTH	N/A	170	8	Continue current condition monitoring and heat exchanger servicing.	2011	2
1296	6690	6715	270182	0	1	#1 UNIT GENERATION SERVICES	CW SYSTEM	CW SYSTEM	N/A	182	11	Maintain current program of ongoing inspections and overhauls. Procure a spare motor be maintained to service all three units, in the event of a failure of an existing unit.	2011	2
1296	6690	6715	270182	7134	1	#1 UNIT GENERATION SERVICES	CW SYSTEM	C.W. INTAKE	Intake	183	11	Perform an underwater inspection of intake and outfall structures - including areas such as stoplogs.	2011	2
1296	6690	6715	270182	7135	1	#1 UNIT GENERATION SERVICES	CW SYSTEM	C.W. DISCHARGE TO OUTFALL	Outfall	184	11	Perform an underwater inspection of intake and outfall structures - including areas such as stoplogs.	2011	2
1296	6690	6715	270182	7137	1	#1 UNIT GENERATION SERVICES	CW SYSTEM	C.W.TRAVELLING SCREENS EAST	N/A	185	11	Continue current condition monitoring and heat exchanger servicing.	2011	2
1296	6690	6715	270182	7138	1	#1 UNIT GENERATION SERVICES	CW SYSTEM	C.W.TRAVELLING SCREENS WEST	N/A	186	11	Continue current condition monitoring and heat exchanger servicing.	2011	2
1296	6690	6715	270182	8819	1	#1 UNIT GENERATION SERVICES	CW SYSTEM	C.W. SCREEN WASH SYSTEM	N/A	187	11	Refurbish pump/motor.	2011	3

8.1.4.6 Risk Assessment

Table 8-24 below illustrates the risk assessment for the cooling water systems associated with generators, both from a technological perspective and a safety perspective using the models presented in Section 3.

TABLE 8-24 RISK ASSESSMENT – UNIT 1 COOLING WATER SYSTEMS ASSOCIATED WITH GENERATORS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Component	Risk Assess #	Appendix #	Major Issues	Remaining Life Years (Insufficient Info - Inspection Required Within (x) Years)	Remaining Life Comments	TECHNO-ECO RISK ASSESS MODEL			SAFETY RISK ASSESS MODEL			Possible Failure Event	Mitigation
																Likeli-hood	Conse-quence	Risk Level	Likeli-hood	Conse-quence	Safety Risk		
1296	6690	6715	0	0	0	1	#1 UNIT GENERATION SERVICES	UNIT GENERATION SERVICES	UNIT GENERATION SERVICES	N/A	156		See details below.		None								
1296	6690	6715	6719	0	0	1	#1 UNIT GENERATION SERVICES	GENERAL SERVICE COOLING	GENERAL SERVICE COOLING	GSW Pump/Motor Failure	157	12	Mechanical or electrical failure.	10	None	1	A	Low	1	A	Low	Minimum	Current inspection and maintain.
1296	6690	6715	6719	0	0	1	#1 UNIT GENERATION SERVICES	GENERAL SERVICE COOLING	GENERAL SERVICE COOLING	GSW Ht Exch Failure	158	12	Mechanical failure/pluggage.	10	None	1	A	Low	1	A	Low	Seawater contamination (unlikely)	Inspect and maintain.
1296	6690	6715	6719	0	0	1	#1 UNIT GENERATION SERVICES	GENERAL SERVICE COOLING	GENERAL SERVICE COOLING	GSW Piping Failure	159	12	Mechanical failure.	10	None	1	A	Low	1	A	Low	Leak and short duration impact	Inspect and maintain.
1296	6690	6715	6782	0	0	1	#1 UNIT GENERATION SERVICES	TURB/GEN COOLING SYSTEM	TURB/GEN COOLING SYSTEM	Units 1&2 ACW Piping	160	8	Corrosion, mechanical failure.	10	None	1	A	Low	1	A	Low	Leak and short duration impact	Inspect and maintain.
1296	6690	6715	6782	0	0	1	#1 UNIT GENERATION SERVICES	TURB/GEN COOLING SYSTEM	TURB/GEN COOLING SYSTEM	Units 1 & 2 Seawater Piping	161	8	Corrosion, mechanical failure.	(10)	None	1	A	Low	1	A	Low	Leak and short duration impact	Inspect and maintain.
1296	6690	6715	6782	9592	0	1	#1 UNIT GENERATION SERVICES	T/G COOLING PUMP SOUTH	T/G COOLING PUMP SOUTH	Units 1&2 ACW Pump/Motor	162	8	Mechanical or electrical failure.	10	None	1	A	Low	1	A	Low	Sparing, minimal	Current inspection and maintain.
1296	6690	6715	6782	9593	0	1	#1 UNIT GENERATION SERVICES	T/G COOLING PUMP NORTH	T/G COOLING PUMP NORTH	Units 1&2 ACW Pump/Motor	163	8	Mechanical or electrical failure.	10	None	1	A	Low	1	A	Low	Sparing, minimal	Current inspection and maintain.
1296	6690	6715	270182	7135	0	1	#1 UNIT GENERATION SERVICES	CW SYSTEM	C.W. DISCHARGE TO OUTFALL	Unit #1 CW Outfall Piping	175	11	Concrete cracking.	(20)	None	1	B	Low	1	A	Low	Cracking or failure – major leak requiring repair	Inspect and maintain.
1296	6690	6715	270182	7137	0	1	#1 UNIT GENERATION SERVICES	CW SYSTEM	C.W.TRAVELLING SCREENS EAST	Travelling Screens	176	11	Corrosion- Internal/Ext.	(10)	None	2	B	Low	2	A	Low	Condenser plugging	Current inspection and maintain.
1296	6690	6715	270182	7138	0	1	#1 UNIT GENERATION SERVICES	CW SYSTEM	C.W.TRAVELLING SCREENS WEST	Travelling Screens	177	11	Corrosion- Internal/Ext.	(10)	None	2	B	Low	2	A	Low	Condenser plugging	Current inspection and maintain.
1296	6690	6715	270182	8819	0	1	#1 UNIT GENERATION SERVICES	CW SYSTEM	C.W. SCREEN WASH SYSTEM	Pumps\ & Motors	178	11	Corrosion- Internal/Ext.	(5)	None	3	A	Low	2	A	Low	Major leak and repair/patch	Inspect and maintain.

8.1.4.7 Life Cycle Curve and Remaining Life

Figure 8-9 below, illustrates the life cycle curves for the major elements of the Unit 1 cooling water systems associated with generators. The life curves are plots of current and projected operating hours (generation plus synchronous condensing mode) on the y-axis versus calendar year on the x-axis. The figure has vertical lines representing differing representative nominal age limits for various components. It has horizontal lines that represent a range of practical equivalent base loaded operating hour life limits. Data specific to the intake and outfall structures were not sufficient to include them at this time, but they are not expected to be an issue (perhaps the condition of some operational equipment such as stoplogs or their supports). Data specific to the pumps and motors for the general service cooling water and the turbine generator cooling water are also not presented as they are relatively new and/or modest equipment elements. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view.

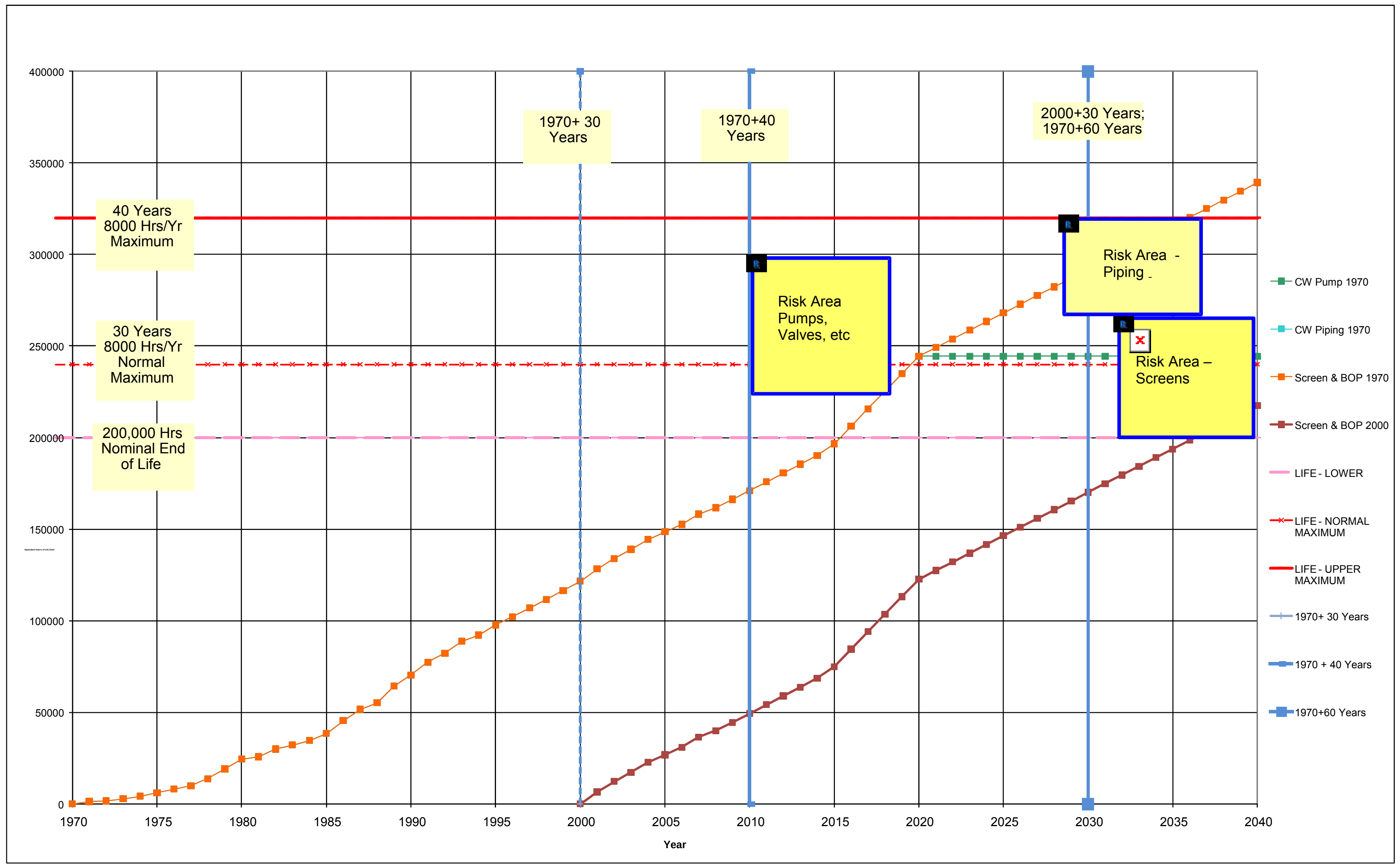

Figure 8-9 Life Cycle Curve – Unit 1 Cooling Water Systems Associated with Generators

The curve indicates that the remaining life (RL) of most elements of the Unit 1 cooling water systems associated with generators is sufficient to reach the end date of 2020 for generation, but not necessarily the 2041 end date for synchronous condensing. The CW pumps and associated equipment are the primary nearer term issues highlighted by the risk boxes. The actual end date and remaining life will become clearer through the series of ongoing routine inspections that forms part of the plant's PM program and the Level 2 inspections recommended in the report. Curves for the intake and outfall structures and associated sub-components should be added subsequent to the undertaking of a Level 2 inspection.

8.1.4.8 Level 2 Inspections – Unit 1 Cooling Water Systems Associated with Generators

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 8-25 below, assuming that the current plant inspection and maintenance program is maintained or improved.

TABLE 8-25 LEVEL 2 INSPECTIONS – UNIT 1 COOLING WATER SYSTEMS ASSOCIATED WITH GENERATORS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Sub System Comment	L2#	Appendix #	Level 2 Work	Year	Priority	Cost k$
1296	6690	6715	0	0	0	1	#1 UNIT GENERATION SERVICES	UNIT GENERATION SERVICES	UNIT GENERATION SERVICES	None	147	N/A	No Level 2 required.			
1296	6690	6715	6719	0	0	1	#1 UNIT GENERATION SERVICES	GENERAL SERVICE COOLING	GENERAL SERVICE COOLING	None	148	12	No Level 2 required.			
1296	6690	6715	6782	0	0	1	#1 UNIT GENERATION SERVICES	TURB/GEN COOLING SYSTEM	TURB/GEN COOLING SYSTEM	Seawater intake and discharge piping	149	8	Perform representative Level 2 pipe thickness checks.	2011	2	$6
1296	6690	6715	6782	0	0	1	#1 UNIT GENERATION SERVICES	TURB/GEN COOLING SYSTEM	TURB/GEN COOLING SYSTEM	AC Water piping	150	8	Thickness spot checks within 5 years.	2011	2	$6
1296	6690	6715	6782	0	0	1	#1 UNIT GENERATION SERVICES	TURB/GEN COOLING SYSTEM	TURB/GEN COOLING SYSTEM	None	151	8	AC Water Ht Exchangers shell and tubes within 5 years.	2011	2	$6
1296	6690	6715	6782	9592	0	1	#1 UNIT GENERATION SERVICES	T/G COOLING PUMP SOUTH	T/G COOLING PUMP SOUTH	None	152	8	No Level 2 required.			
1296	6690	6715	6782	9593	0	1	#1 UNIT GENERATION SERVICES	T/G COOLING PUMP NORTH	T/G COOLING PUMP NORTH	None	153	8	No Level 2 required.			
1296	6690	6715	270182	7134	0	1	#1 UNIT GENERATION SERVICES	CW SYSTEM	C.W. INTAKE	CW intake and discharge structures and piping	162	11	Inspections – diver visual inspection within 2 to 4 years.	2011	2	$30
1296	6690	6715	270182	7135	0	1	#1 UNIT GENERATION SERVICES	CW SYSTEM	C.W. DISCHARGE TO OUTFALL	CW intake and discharge structures and piping	163	11	Inspections – diver visual inspection within 2 to 4 years.	2011	2	$30
1296	6690	6715	270182	7137	0	1	#1 UNIT GENERATION SERVICES	CW SYSTEM	C.W.TRAVELLING SCREENS EAST	None	164	11	No Level 2 required.			
1296	6690	6715	270182	7138	0	1	#1 UNIT GENERATION SERVICES	CW SYSTEM	C.W.TRAVELLING SCREENS WEST	None	165	11	No Level 2 required.			
1296	6690	6715	270182	8819	0	1	#1 UNIT GENERATION SERVICES	CW SYSTEM	C.W. SCREEN WASH SYSTEM	None	166	11	No Level 2 required.			

8.1.4.9 Capital Projects

Table 8-26 below shows the suggested typical capital enhancements that should be considered for the Unit 1 cooling water systems associated with generators:

TABLE 8-26 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – UNIT 1 COOLING WATER SYSTEMS ASSOCIATED WITH GENERATORS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Detail	CAP#	Appendix #	Capital Item	Date	Priority
1296	6690	6715	6719	0	0	1	#1 UNIT GENERATION SERVICES	GENERAL SERVICE COOLING	GENERAL SERVICE COOLING	N/A	115	12	No capital required.		
1296	6690	6715	6782	0	0	1	#1 UNIT GENERATION SERVICES	TURB/GEN COOLING SYSTEM	TURB/GEN COOLING SYSTEM	N/A	116	8	Clean and coat AC Water pipes.	2012	2
1296	6690	6715	6782	0	0	1	#1 UNIT GENERATION SERVICES	TURB/GEN COOLING SYSTEM	TURB/GEN COOLING SYSTEM	N/A	117	8	No capital required.		
1296	6690	6715	6782	9592	0	1	#1 UNIT GENERATION SERVICES	T/G COOLING PUMP SOUTH	T/G COOLING PUMP SOUTH	N/A	118	8	No capital required.		
1296	6690	6715	6782	9593	0	1	#1 UNIT GENERATION SERVICES	T/G COOLING PUMP NORTH	T/G COOLING PUMP NORTH	N/A	119	8	No capital required.		
1296	6690	6715	270182	7134	0	1	#1 UNIT GENERATION SERVICES	CW SYSTEM	C.W. INTAKE	Intake structure and foreay	129	11	Add system for synchronous condensing similar to Unit 3.	2014	1
1296	6690	6715	270182	7135	0	1	#1 UNIT GENERATION SERVICES	CW SYSTEM	C.W. DISCHARGE TO OUTFALL	Pit, Stoplogs and Discharge	130	11	No capital required.		
1296	6690	6715	270182	7137	0	1	#1 UNIT GENERATION SERVICES	CW SYSTEM	C.W.TRAVELLING SCREENS EAST	N/A	131	11	No capital required.		
1296	6690	6715	270182	7138	0	1	#1 UNIT GENERATION SERVICES	CW SYSTEM	C.W.TRAVELLING SCREENS WEST	N/A	132	11	No capital required.		
1296	6690	6715	270182	8819	0	1	#1 UNIT GENERATION SERVICES	CW SYSTEM	C.W. SCREEN WASH SYSTEM	N/A	133	11	No capital required.		

8.2 Unit 1 – Lower Priority Systems

8.2.1 Asset 6699 Unit 1 Boiler System

(Detailed Technical Assessment in Working Papers, Appendices 29, 30 and 34)

The equipment associated with the Unit 1 boiler system is listed below:

Unit #:	1
Asset Class #	BU 1296 - Assets Generations
SCI & System:	6899 #1 Boiler Plant
Sub-Systems:	6700 #1 Boiler Structure
	6701 #1 Boiler F.W. & Sat. Steam
	6702 #1 Boiler Superheater and Reheater
Components:	6869 #1 Economizer, tubing and headers
	6871 #1 Linking piping (boiler internal)
	6871 #1 Furnace water circuit 6870 #1 Steam drum, 6871 #1 Downcomers and feeder piping 6871 #1 Lower Waterwall headers 6871 #1 Waterwall tubing 6871 #1 Upper Waterwall headers, and riser piping
	6873/6878 #1Superheater,headers and tubing
	6878 #1 Reheater, headers and tubing
	6871 #1 Safety Valves
	6876 #1 Boiler Main Steam lines
	6902 #1 Boiler Stop Valve
	6700 #1 Furnace structural, hangers and casing
	6706 #1 Boiler Blowdown Tank

8.2.1.1 Description

Unit 1 boiler is a Combustion Engineering (now supported by ALSTOM), natural circulation, single reheat, pressurized unit. The boiler was originally designed in 1968 for an output of 150 MW with a maximum steam flow of 127 kg/s (1,050,000 lbs/hr), at 12.41 MPag (1800 psig) and 538 °C (1000 °F) with an inlet feedwater temperature of 240 °C (464 °F). The reheat steam flow was designed for 116 kg/s (921,000 lbs/hr) with an inlet temperature of 365 °C (690 °F) and an outlet temperature of 541 °C (1005 °F). HTGS Stage I (Units 1 & 2) was commissioned in 1969/1970.

Unit 1 was uprated to nominal output of 175 MW in 1988/1889. The boiler was analyzed to determine if this increased load could be accommodated by raising the superheat steam flow approximately 11% to 141 kg/s (1,167,200 lb/hr) and the reheat steam flow approximately 13% to 126 kg/s (1,044,630 lb/hr). Associated boiler pressure part modifications were evaluated such that the boiler design pressure of 15.2 MPa (2205 psig) could be maintained with the increased steam outlet pressure. All the pressure parts were analyzed for ASME Code compliance and optimized operation. In order to reduce anticipated attemperator spray water in the superheater section, heating surface was removed from the primary superheater sections. Additional modifications were made to the boiler non-pressure part equipment. After uprating, the boiler is rated at a maximum steam flow of 141 kg/s (1,167,000 lbs/hr), at 13.58 MPag (1970 psig) and 541 °C (1005 °F) with an inlet feedwater temperature of 240 °C (464 °F)353 °C (667 °F) and an outlet temperature of 541 °C (1005 °F).

The system includes:

- Economizer, tubing and headers;
- Linking piping (boiler internal);
- Furnace water circuit;
  - Steam drum,
  - Downcomers and feeder piping as required
  - Lower Waterwall headers
  - Waterwall tubing
  - Upper Waterwall headers, and riser piping as required
- Superheater; headers and tubing;
- Reheater; headers and tubing;
- Safety valves;
- Furnace combustion systems; burners, fans, air heaters;
- Furnace structural, hangers and casing; and
- Boiler Main Steam lines
- Boiler Stop Valve
- Boiler blow down tank.

Boiler #1 had superheater sections replaced in 2007. Boiler sootblowers were added in 1995. Unit 1 was upgraded in 1988 to 175 MW from 150 MW.

8.2.1.2 History

Manufactured/Delivered	1969
In-Service Date	Sep 1970
Generation Base Load End Date	Dec 2015
Generation Peak/Emerg Gen End Date	Dec 2020
Major Inspection/Maintenance Repair	Annual May to Sep on all units

The hours associated with the analyses are:

Hours Generation Actual - Ops to Dec 2009	166
Max Hours Generation Ops – to Dec 2015	210
Max Hrs Gen Ops to Gen End Date Dec 2020	219
Max Hours Ops – 1986 to Dec 2009	121
Max Hrs - 1986 to Dec 2015	165
Max Hrs – 1986 to Gen End Date Dec 2020	174
Max Hours Ops – 2007/8 to Dec 2009	8
Max Hrs – 2007/8 to Dec 2015	54
Max Hrs – 2007/8 to Gen End Date Dec 2020	174

8.2.1.3 Inspection and Repair History

Asset 6869 Economizer

As per part of routine non destructive evaluation (NDE) inspections, ultrasonic thickness (UT) measurement readings are taken at specified locations on the economizer inlet and outlet headers (inspection results were not available). The following discussion summarizes the significant inspections and repairs completed on the economizer section servicing Unit 1.

During the 2002 outage, a thermocouple was installed on the economizer inlet header near the inlet pipe. Also, the economizer inlet and outlet headers were opened for debris removal and internal inspection. Loose debris was found in the inlet header and was removed.

There was a failure in the economizer inlet header stub tube in November 2003. A small circumferential crack was observed on the top side of the horizontal element at a location less than 2.5 cm (1 inch) from the economizer inlet header, in the bottom row of economizer assembly #1 (counting left to right). When the tube sample was split longitudinally, deep circumferential cracking was observed on both the top and bottom sides of the horizontal element at the leak site. The destructive examination of the sample established that the section of economizer nipple tubing had suffered extensive internal damage and that this internal damage was the direct cause of the leak. It was concluded that the damage was due to combination of thermal fatigue and corrosion-fatigue cracking related mechanisms. The fact that the cracking was concentrated on the top and bottom sides of the tube in the failure area may indicate the influence of a bending load during service. It was further noted that the internal damage had been substantially augmented by significant external wastage due to low temperature corrosion related to condensation. The failed tube section was removed and replaced with available tube material.

During the 2004 outage, an inspection of the selected tube stubs at both ends and middle of the inlet header (visual and angle beam UT) found no indication of damage similar to the failure that occurred in the fall of 2003 discussed above. The inlet header supports were exposed and found to be in good condition. However, the sootblower pipe supports were removed from the header to eliminate any external loads.

Asset 6871 Waterwall Headers, Downcomers, and Lower and Upper Feeder Tubes

Exterior visual inspections of the lower and upper waterwall headers are carried out during the boiler outage inspections. Lower waterwall headers were opened a number of times for debris removal after boiler repairs. Apart from the repair debris, pipe stubs were also found in the header. The stubs were about 23 cm (9.5 inch) long by 6.3 cm (2.5 inch) outside diameter (OD) and were threaded at one end. It is believed that these pipe stubs were used for the initial fit-up and welding of the sidewalls. There were no internal inspections to check for ligament cracking or cracking at other locations.

UT measurements were taken on the waterwall circuit feeder and riser tubes and some of the riser tubes were found in contact with each other but no damage was noted.

Asset 6870 Steam Drum

All the accessible internal seam and nozzle welds are inspected using the Wet Fluorescent Magnetic Particle Examination (WFMT) method during every outage. A varying degree of magnetite layer was observed during outage inspections. Although slight pitting was observed but not active, it is not considered a pressure integrity issue for the steam drum.

Asset 6871 High Temperature Headers and Piping

During annual maintenance outages, Magnetic Particle Inspection (MPI) is carried out on selective tube to header welds on the superheater and reheater section headers subject to accessibility. There has been no abnormality observed to date. Also, UT measurements were taken on the headers next to MPI locations. No significant header wall thinning was noted.

The superheater five (SH5) and superheater six (SH6) headers were opened and cleaned as part of the superheater work during the 2008 maintenance outage. Significant cracking was found in the handhole bore on the SH6 header located on the east side. These cracks were removed and repaired. There has been no internal inspection carried out for ligament cracking on any of the headers in the superheater section.

A visual inspection of the header supports is performed during every maintenance outage. During the 2008 outage, it was observed that all hangers appeared to be bearing load except for 2, 3 and 4 from the east and 2 and 3 from the west under SH3 and number 2 from each side under SH4. These hangers should normally support the casing floor under the headers.

During every maintenance outage, MPI on the selective tube to header welds is carried out on all the reheat section headers (RH1 and RH2) subject to accessibility. There has been no abnormality observed to date. Also, UT measurements are taken on the headers next to MPI location. No significant header wall thinning was observed.

A visual inspection of the superheater link piping is carried out during outage inspections.

Asset 6873 Superheater Link Piping and Attemperator

A visual inspection of the superheater link piping is carried out during every outage. There was no internal inspection carried out on superheater attemperators during the 2001-2009 period.

Asset 6869 Economizer Tubes

In November 2003, there was a failure in the economizer inlet header stub tube. It was documented during 2005 outage inspection that the third tube from the west side previously failed and was removed from service and plugged at the headers. The cause of this failure is unknown. This was the same location of a tube failure on Unit 2 in April 2005 due to corrosion fatigue at a mill defect in the tube. The Unit 2 tube alignment was reported to have been in good condition.

During 2009 outage, some of the baffle plates were found to be dislocated. This was repaired and the plates secured. As per part of routine NDE inspection, UT measurements are taken at specified locations on the economizer tube bends.

Asset 6871 Waterwall Tubes

During 2007 outage, a boiler chemical cleaning was performed. The tube damage apparent after the cleaning of the waterwalls for the 2006 thickness survey was repaired. Two viewports were rebuilt due to their deteriorating condition. A thermocouple was installed on each side waterwall as requested by the Department of Government Services. A LFET was completed on the waterwall tubes in 2007 and the tubes in the high heat zone of the furnace were found to be in good shape.

During the 2008 outage, an internal boroscope inspection was completed on six front wall tubes and ten baffle wall tubes over the full length of each tube. No significant problems were observed. Extensive pitting was observed around many of the burners and significant corrosion was noted in the lower furnace on the south side as observed during previous outages. Two observation ports were selected for replacement based on inspections of the refractory completed during the previous year. The sealboxes were found in good condition. It is not mentioned in the 2008 outage report whether a furnace floor tubes thickness survey was completed. (NOTE: A LFET was completed on the water wall tubes in 2007 and the tubes in the high heat zone of the furnace were found to be in good shape.)

Asset 6873/6878 Superheater and Reheater Tubes

The anti-vibration baffles were noted to be in very poor condition. There are minor tube alignment issues as some tubes had drifted laterally. However, the alignment did not appear to be worsening at that time. No significant tube thickness loss was discovered during the UT inspections performed at selective locations on the Unit 1 superheater and reheater sections during the 2008 outage. The tubes were well above the minimum wall thickness required. No tube sample analysis has been performed on the lower secondary superheater section on Unit 1. Also, recent tube thickness data is not available for the lower section.

During the 2005 outage, a tube spread and thickness survey was completed in the secondary superheater section to document tube thinning and alignment. The results indicated extensive thinning in the upper stainless steel section between the 7th and 8th floor cavities where the metal temperatures are the highest and the conditions most conducive for liquid ash corrosion.

A partial replacement of the Unit 1 secondary superheater was completed during the 2008 annual maintenance outage. Thirty one upper superheater assemblies (SA-213-EP-321H) were replaced because of severe thinning caused by OD corrosion and forced outages as a result of six tube failures from 2005 to 2008. The new assemblies were fabricated from 347H stainless steel tubes. This was an upgrade from the original 321H tubes. The assemblies were supplied with T22 (2-¼ chrome) safe-ends for welding to the T22 tube ends in the boiler and vestibule. Hence, the old DMWs (Dissimilar Metal Welds) were removed and replaced with new DMWs that were completed in the shop. In addition, one lower superheater assembly was replaced as well, which had been removed from service (plugged) during a forced outage repair completed in February of 2008.

Asset 6878 Reheater

There is a history of failure of spacer bars due to long term exposure to high temperatures causing a slight misalignment of the reheater tubes. The problem areas identified have been repaired and 309 grade stainless steel material has been used for all new spacers. Additional problem areas are likely to be identified during inspections. Although hanger tubes have bowed and touch each other at certain locations since 2001, the alignment of the reheater is not adversely affected. During the 2005 outage, extensive thinning in the bottom loop (stainless steel section) was noted.

During the 2008 outage, physical damage was discovered directly above the 7th superheater assembly from the east side due to previous catastrophic failures of that assembly. Thickness measurements were taken in the remaining reheater section. The results indicated little or no change since 2005 and no further tube failures have been observed in the reheater section.

Asset 6871/6700 Safety Valves, Casings, & Structure/Hangers

Safety relief valves (SRVs) are inspected and maintained as per the plant SRV testing and overhaul program. The program is considered adequate to maintain the SRVs for the 2020 desired life.

Casing: The casing has a history of failures of both fabric and metallic expansion joints. These are repaired and replaced as required. Failures of both fabric and metallic expansion joints are an ongoing issue. During the AMEC field walkdown, some boiler expansion joints were found leaking.

Steel structure and hangers - corrosion in the boiler penthouse areas was identified in walkdowns of the unit. The condition of the boiler refractory is uncertain.

Asset 6706/7014 Boiler Blow Down Tank

The unit is inspected annually, except in 2009 and 2010. In 2009, the unit was inspected externally only due to access and isolation issues. Deterioration of internals and corrosion have been continuing issues, but safety concerns with access, isolation, and cramped spaces are primary concerns.

8.2.1.4 Condition Assessment

The condition assessment of the Unit 1 boiler system is illustrated below in Table 8-27.

TABLE 8-27 CONDITION ASSESSMENT – UNIT 1 BOILER SYSTEM

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset Level 2	Asset Level 3	Description	Detail	Condition Summary ID #	Append #	Condition	EPRI Identifier	Original Life (Base Load) Ops Hrs (Yrs)	Current Expected Minimum Remaining Life Years (Subject to Test)	End of Life (EOL) Required	Next Regular Inspection	Next Planned Overhaul or Major Inspection	Capability to Reach Next Overhaul	Capability to Reach EOL	In Service
1296	6690	6699	0	0	0	1	#1 BOILER PLANT	BOILER PLANT	BOILER PLANT	N/A	52	30	No active high energy piping management program. High temperature piping constant support hanger monitoring program discontinued after 2001. A few skewed hangers, topped or bottomed up constant spring support, and interference problem for main steam, hot reheat and cold reheat lines.	4	200000 (30)	(10+)	2020	2011	2012	Yes	Yes	1970
1296	6690	6699	6701	0	0	1	#1 BOILER PLANT	BOILER F.W. & SAT'D STEAM	BOILER F.W. & SAT'D STEAM	N/A	53	30	No information on recent inspections of the sample of the upper waterwall headers flat end welds.	4	200000 (30)	(10)	2020	2011	2012	Yes	Yes	1970
1296	6690	6699	6701	0	0	1	#1 BOILER PLANT	BOILER F.W. & SAT'D STEAM	BOILER F.W. & SAT'D STEAM	N/A	54	30	High heat flux and challenging chemistry are related to numerous damage mechanisms on interior and exterior surfaces of waterwall tubing. No information on recent destructive testing reports of waterwall tubes that were removed in 2006.	4	200000 (30)	(10)	2020	2011	2012	Yes	Yes	1970
1296	6690	6699	6701	6869	0	1	#1 BOILER PLANT	BOILER F.W. & SAT'D STEAM	BOILER ECONOMIZER	Headers & link Piping	55	30	Outlet headers or link piping to the steam drum in good condition. Thermal/corrosion fatigue related failure experienced in the inlet headers stub tubes. Only partial internal and stub tube inspections in 2004 outage.	4	200000 (30)	(10)	2020	2011	2012	Yes	Yes	1970
1296	6690	6699	6701	6869	0	1	#1 BOILER PLANT	BOILER F.W. & SAT'D STEAM	BOILER ECONOMIZER	Tubing	56	30	Insufficient inspections to assess condition Wall thickness review inconclusive -some 2009 readings decreased and some increased vs 2004.	4	200000 (30)	(10)	2020	2011	2012	Yes	Yes	1970
1296	6690	6699	6701	6870	0	1	#1 BOILER PLANT	BOILER F.W. & SAT'D STEAM	BOILER STEAM DRUM	N/A	57	30	No major life limiting issues observed during previous limited steam drum inspections. Design assessed as having no significant concerns. Inspections were focused at visible areas only and many of the susceptible locations have not been inspected.	4	200000 (30)	10+	2020	2011	2012	Yes	Yes	1970
1296	6690	6699	6702	6873	0	1	#1 BOILER PLANT	BLR SUPERHEAT& REHEAT ASS'Y	BOILER PRIMARY SUPERHEATER	Tubes	60	30	No significant life limiting issue has been observed in the primary superheater section tubes.	4	200000 (30)	10	2020	2011	2012	Yes	Yes	1970
1296	6690	6699	6702	6874	0	1	#1 BOILER PLANT	BLR SUPERHEAT& REHEAT ASS'Y	BOILER SUPERHEATER ATTEMP.	N/A	61	30	Design calculations for combination creep and fatigue damage from thermal fatigue raises concern with attemporators. No internal inspections of the attemporaters and link piping done to confirm the absence of thermal fatigue damage.	4	200000 (30)	(10)	2020	2011	2012	Yes	Yes	1970
1296	6690	6699	6702	6877	0	1	#1 BOILER PLANT	BLR SUPERHEAT& REHEAT ASS'Y	BOILER REHEATER ATTEMPERATOR	N/A	62	30	Design calculations for combination creep and fatigue damage from thermal fatigue raises concern with attemporators. No internal inspections of the attemporaters and link piping done to confirm the absence of thermal fatigue damage.	4	200000 (30)	(5)	2020	2011	2012	Yes	Yes	1970
1296	6690	6699	6702	6878	0	1	#1 BOILER PLANT	BLR SUPERHEAT& REHEAT ASS'Y	BOILER REHEATER	Piping	63	30	Previous metallographic examinations of hot reheat piping discovered partially degraded microstructure but no evidence of creep. No NDE or metallographic examination after 2002.	4	200000 (30)	(10)	2020	2011	2012	Yes	Yes	1970
1296	6690	6699	6702	6878	0	1	#1 BOILER PLANT	BLR SUPERHEAT& REHEAT ASS'Y	BOILER REHEATER	Headers & link Piping	64	30	Design creep life calculations for reheater outlet headers suggest concern.	4	200000 (30)	(10)	2020	2011	2012	Yes	Yes	1970
1296	6690	6699	6702	6878	0	1	#1 BOILER PLANT	BLR SUPERHEAT& REHEAT ASS'Y	BOILER REHEATER	Tubing	65	30	No inspections, including destructive tube sample analysis, done assessing the extent of damage due to creep, sagging, OD liquid ash corrosion and ID high temperature corrosion.	4	200000 (30)	(10)	2020	2011	2012	Yes	Yes	1970
1296	6690	6699	6702	322990	0	1	#1 BOILER PLANT	BLR SUPERHEAT& REHEAT ASS'Y	SECONDARY SUPERHEATER	Headers & link Piping	66	30	Design creep life calculations for secondary superheater outlet headers suggest concern.	4	200000 (30)	(10)	2020	2011	2012	Yes	Yes	1970
1296	6690	6699	6702	322990	0	1	#1 BOILER PLANT	BLR SUPERHEAT& REHEAT ASS'Y	SECONDARY SUPERHEATER	Tubes	67	30	Partial replacement with upgraded materials of the secondary superheater sections in 2008 - expected to operate without failure up to the desired life. Destructive tube sample analysis is required for the lower secondary superheater section not replaced.	4	200000 (30)	(10)	2020	2011	2012	Yes	Yes	1970
1296	6690	6699	6701	6701	0	1	#1 BOILER PLANT	BOILER F.W. & SAT'D STEAM	BOILER BLOWDOWN TANK	N/A	68	30	Thinning, corrosion. Sefety issues - isolation and access	10	200000 (30)	(2)	2020	2011	2011	Yes	No	1970
1296	6690	6699	6702	6876	0	1	#1 BOILER PLANT	BLR SUPERHEAT& REHEAT ASS'Y	BOILER MAIN STEAM LINES	Piping	69	30	Previous metallographic examinations of main steam piping discovered partially degraded microstructure but no evidence of creep. No NDE or metallographic examination after 2002.	4	200000 (30)	(10)	2020		2011	Yes	Yes	1970
1296	6690	6699	6702	6876	6902	1	#1 BOILER PLANT	BLR SUPERHEAT& REHEAT ASS'Y	BOILER STOP VALVE	N/A	70	30	No recent information review.	4	200000 (30)	(10)	2020	2011	2011	Yes	No	1970

Notes:

1. A "(bracketed)" value in the "Current Expected Remaining Life" column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as "(X/Y)" has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

2. The "Next Regular Inspection" column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The "Next Planned Overhaul or Major Inspection" column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a "Desired Life" stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or are not known by AMEC.

8.2.1.5 Actions

Based on the condition assessment, the following actions are recommended for the Unit 1 boiler system:

TABLE 8-28 RECOMMENDED ACTIONS – UNIT 1 BOILER SYSTEM

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Unit	Asset 2/3	Asset 3/4	Description	Detail	Action #	App #	Action	Year	Priority
1296	6690	6699	0	0	1	#1 BOILER PLANT	BOILER PLANT	BOILER PLANT	N/A	61	30	See details below.		
1296	6690	6699	6701	0	1	#1 BOILER PLANT	BOILER F.W. & SAT'D STEAM	BOILER F.W. & SAT'D STEAM	N/A	62	30	Monitor pitting on the tubes adjacent to the burners.	2011	2
1296	6690	6699	6701	0	1	#1 BOILER PLANT	BOILER F.W. & SAT'D STEAM	BOILER F.W. & SAT'D STEAM	N/A	63	30	Monitor pitting on the waterwall slope under the economizer.	2011	2
1296	6690	6699	6701	0	1	#1 BOILER PLANT	BOILER F.W. & SAT'D STEAM	BOILER F.W. & SAT'D STEAM	N/A	64	30	Monitor wall thinning on the south side waterwall floor tubes.	2012	2
1296	6690	6699	6701	0	1	#1 BOILER PLANT	BOILER F.W. & SAT'D STEAM	BOILER F.W. & SAT'D STEAM	N/A	65	30	Review the destructive testing 2006 report of waterwall tubes to evaluate the findings.	2011	2
1296	6690	6699	6701	0	1	#1 BOILER PLANT	BOILER F.W. & SAT'D STEAM	BOILER F.W. & SAT'D STEAM	N/A	66	30	Inspect selective flat end welds of the upper waterwall headers.	2012	2
1296	6690	6699	6701	0	1	#1 BOILER PLANT	BOILER F.W. & SAT'D STEAM	BOILER F.W. & SAT'D STEAM	N/A	67	30	Inspect the selective feeder and riser tubes for corrosion fatigue damage.	2012	2
1296	6690	6699	6701	0	1	#1 BOILER PLANT	BOILER F.W. & SAT'D STEAM	BOILER F.W. & SAT'D STEAM	N/A	68	30	Perform preliminary internal inspection of the lower waterwall headers at the locations of the degradation mechanisms identified for the steam drum, using boroscope; inspection of selective flat end welds, feeder tube attachment welds and downcomers connection welds.	2012	2
1296	6690	6699	6701	0	1	#1 BOILER PLANT	BOILER F.W. & SAT'D STEAM	BOILER F.W. & SAT'D STEAM	N/A	69	30	Perform preliminary inspection of superheater and reheater headers support locations on the downcomers for thermal/mechanical fatigue.	2012	2
1296	6690	6699	6701	6869	1	#1 BOILER PLANT	BOILER F.W. & SAT'D STEAM	BOILER ECONOMIZER	N/A	70	30	Perform inspection including sample tube removal and ultrasonic sonic testing survey at the accessible locations to assess the potential corrosion fatigue damage due to mill defects that had caused a failure in the economizer tube in Unit 2 in 2005.	2012	2
1296	6690	6699	6701	6869	1	#1 BOILER PLANT	BOILER F.W. & SAT'D STEAM	BOILER ECONOMIZER	N/A	71	30	Modify start-up procedures to include monitoring of the thermocouple temperature and using the continuous feed during start-ups.	2012	2
1296	6690	6699	6701	6869	1	#1 BOILER PLANT	BOILER F.W. & SAT'D STEAM	BOILER ECONOMIZER	N/A	72	30	Perform Level 2 inspections of the economizer inlet header: i. ID visual inspection of bore holes, girth welds and tee welds. If cracking is identified, depth must be assessed. ii. UT inspection of stub tubes. iii. Stub tube sample to assess evidence of FAC.	2012	2
1296	6690	6699	6701	6869	1	#1 BOILER PLANT	BOILER F.W. & SAT'D STEAM	BOILER ECONOMIZER	N/A	73	30	Visually inspect the economizer outlet headers and supports and the economizer link piping during annual outages to ensure there is no change in the state and/or abnormal movement.	2012	2
1296	6690	6699	6701	6870	1	#1 BOILER PLANT	BOILER F.W. & SAT'D STEAM	BOILER STEAM DRUM	N/A	74	30	Remove the drum furniture and a section of the liner to inspect seam welds, nozzle welds, ligaments, downcomers and feedwater inlet pipe.	2012	2
1296	6690	6699	6701	6870	1	#1 BOILER PLANT	BOILER F.W. & SAT'D STEAM	BOILER STEAM DRUM	N/A	75	30	Perform external inspection of feeder tube welds.	2012	2
1296	6690	6699	6701	6870	1	#1 BOILER PLANT	BOILER F.W. & SAT'D STEAM	BOILER STEAM DRUM	N/A	76	30	Manage steam drum target life with appropriate operational control and routine inspection and maintenance.	2012	2
1296	6690	6699	6701	6871	1	#1 BOILER PLANT	BOILER F.W. & SAT'D STEAM	FURNACE	N/A	77	30	See details below.		
1296	6690	6699	6702	0	1	#1 BOILER PLANT	BLR SUPERHEAT& REHEAT ASS'Y	BLR SUPERHEAT& REHEAT ASS'Y	N/A	78	30	Inspect SH-5, SH-6 and RH-2 for creep and creep fatigue damage including internal boroscopic, for external visual, dimensional on body spool pieces, UT inspections on welds and stub tubes and replica inspection.	2012	2
1296	6690	6699	6702	0	1	#1 BOILER PLANT	BLR SUPERHEAT& REHEAT ASS'Y	BLR SUPERHEAT& REHEAT ASS'Y	N/A	79	30	Investigate the condition that SH3 and SH4 hanger's not bearing load to identify cause and adverse affects.	2012	2
1296	6690	6699	6702	6873	1	#1 BOILER PLANT	BLR SUPERHEAT& REHEAT ASS'Y	BOILER PRIMARY SUPERHEATER	N/A	80	30	Inspect for the presence of inside pitting and scaling	2012	2
1296	6690	6699	6702	6873	1	#1 BOILER PLANT	BLR SUPERHEAT& REHEAT ASS'Y	BOILER PRIMARY SUPERHEATER	N/A	81	30	Enhance the present inspection and maintenance program to monitor and control the tubes alignment issues and failures of AVBs.	2012	2
1296	6690	6699	6702	6874	1	#1 BOILER PLANT	BLR SUPERHEAT& REHEAT ASS'Y	BOILER SUPERHEATER ATTEMP.	N/A	82	30	Inspect attemperator and ID of the link piping for evidence of thermal fatigue.	2012	2
1296	6690	6699	6702	6877	1	#1 BOILER PLANT	BLR SUPERHEAT& REHEAT ASS'Y	BOILER REHEATER ATTEMP.	N/A	83	30	Inspect attemperator and ID of the link piping for evidence of thermal fatigue.	2012	2
1296	6690	6699	6702	6878	1	#1 BOILER PLANT	BLR SUPERHEAT& REHEAT ASS'Y	BOILER REHEATER	N/A	84	30	Inspect to check the presence of inside pitting and scaling.	2012	2
1296	6690	6699	6702	6878	1	#1 BOILER PLANT	BLR SUPERHEAT& REHEAT ASS'Y	BOILER REHEATER	N/A	85	30	Enhance the present inspection and maintenance program to monitor and control the tubes alignment issues.	2012	2

Table 8-28 Cont'd

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Unit	Asset 2/3	Asset 3/4	Description	Detail	Action #	App #	Action	Year	Priority
1296	6690	6699	6702	6878	1	#1 BOILER PLANT	BLR SUPERHEAT& REHEAT ASS'Y	BOILER REHEATER	N/A	86	30	Perform destructive tube sample analysis to assess the extent of the damage due to creep, sagging, OD liquid ash corrosion, ID high temperature corrosion and DMWs.	2012	2
1296	6690	6699	6702	6878	1	#1 BOILER PLANT	BLR SUPERHEAT& REHEAT ASS'Y	BOILER REHEATER	N/A	87	30	Enhance the present inspection and maintenance program to monitor and control failures of tube saddle supports and other alignment issues. .	2012	2
1296	6690	6699	6702	6878	1	#1 BOILER PLANT	BLR SUPERHEAT& REHEAT ASS'Y	BOILER REHEATER	N/A	88	30	As economically justified assess and implement the addition of reheater surface for reheat temperature and efficiency.	2012	2
1296	6690	6699	6702	322990	1	#1 BOILER PLANT	BLR SUPERHEAT& REHEAT ASS'Y	SECONDARY SUPERHEATER	N/A	89	30	Perform destructive tube sample analysis on the lower secondary superheater section that is not replaced so far, to assess the extent of the damage due to creep, sagging, OD liquid ash corrosion and ID high temperature corrosion.	2012	2
1296	6690	6699	6702	322990	1	#1 BOILER PLANT	BLR SUPERHEAT& REHEAT ASS'Y	SECONDARY SUPERHEATER	N/A	90	30	Enhance the present inspection and maintenance program to monitor and control failures of tube saddle supports and other alignment issues.	2012	2
1296	6690	6699	6702	322990	1	#1 BOILER PLANT	BLR SUPERHEAT& REHEAT ASS'Y	SECONDARY SUPERHEATER	N/A	91	30	Refurbish and use the furnace exit thermoprobe during start-up activities.	2011	2
1296	6690	6699	6701	6701	1	#1 BOILER PLANT	BOILER F.W. & SAT'D STEAM	BOILER BLOWDOWN TANK	N/A	92	30	Replace tank	2011	1
1296	6690	6699	6702	6876	1	#1 BOILER PLANT	BLR SUPERHEAT& REHEAT ASS'Y	BOILER MAIN STEAM LINES	N/A	93	30	Implement an active high energy piping management program including NDE testing at key locations and an high temperature piping constant support hanger monitoring program.	2011	2
1296	6690	6699	6702	6876	1	#1 BOILER PLANT	BLR SUPERHEAT& REHEAT ASS'Y	BOILER STOP VALVE	N/A	94	30	Inspect and refurbish/replace during next major boiler outage.	2012	2

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8.2.1.6 Risk Assessment

Table 8-29 below illustrates the risk assessment for the Unit 1 boiler system, both from a technological perspective and a safety perspective using the models presented in Section 3.

TABLE 8-29 RISK ASSESSMENT – UNIT 1 BOILER SYSTEM

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Component	Risk Assess #	Appendix #	Major Issues	Remaining Life Years (Insufficient Info - Inspection Required Within (x) Years)	Remaining Life Comments	TECHNO-ECO RISK ASSESS MODEL			SAFETY RISK ASSESS MODEL			Possible Failure Event	Mitigation
																Likeli-hood	Conse-quence	Risk Level	Likeli-hood	Conse-quence	Safety Risk		
1296	6690	6699	6701	0	0	1	#1 BOILER PLANT	BOILER F.W. & SAT'D STEAM	BOILER F.W. & SAT'D STEAM	Upper WW Headers	58	30	Thermal fatigue cracking, corrosion-fatigue cracking in flat end welds. Corrosion.	10	Could meet the desired life with routine inspections.	2	B	Low	2	C	Medium	Flat end weld cracking. Wall thinning due to corrosion.	Inspect and maintain.
1296	6690	6699	6701	0	0	1	#1 BOILER PLANT	BOILER F.W. & SAT'D STEAM	BOILER F.W. & SAT'D STEAM	Riser Tubes	59	30	Corrosion, corrosion fatigue.	(10)	Inspections are required to assess the remaining life.	3	B	Med	2	C	Medium	Corrosion fatigue cracking - forced outage.	Inspections are required to assess remaining life.
1296	6690	6699	6701	0	0	1	#1 BOILER PLANT	BOILER F.W. & SAT'D STEAM	BOILER F.W. & SAT'D STEAM	Lower WW Headers	60	30	Thermal fatigue cracking, corrosion-fatigue cracking. corrosion.	(10)	No real life limiting issue. Additional inspections required.	3	B	Med	3	B	Medium	Ligament cracking and weld cracking. - forced outage.	Additional inspections required.
1296	6690	6699	6701	0	0	1	#1 BOILER PLANT	BOILER F.W. & SAT'D STEAM	BOILER F.W. & SAT'D STEAM	Feeder Tubes	61	30	Corrosion, corrosion fatigue.	(10)	Inspections are required to assess the remaining life.	3	B	Med	3	B	Medium	Corrosion fatigue cracking and wall thinning due to corrosion related mechanism - Forced outage for repair.	Inspections are required to assess remaining life.
1296	6690	6699	6701	0	0	1	#1 BOILER PLANT	BOILER F.W. & SAT'D STEAM	BOILER F.W. & SAT'D STEAM	Downcomers	62	30	Thermal/mechanical fatigue cracking at the header support locations.	(10)	Inspections are required to assess the remaining life.	3	B	Med	3	B	Medium	Thermal/Mechanical Fatigue Cracking at the header support locations - forced outage for repair.	Inspections are required to assess remaining life.
1296	6690	6699	6701	0	0	1	#1 BOILER PLANT	BOILER F.W. & SAT'D STEAM	BOILER F.W. & SAT'D STEAM	Waterwall Tubes	63	30	Corrosion fatigue, thermal/mechanical fatigue, water side under-deposit corrosion, short-term overheat, fireside corrosion.	(10)	Some sections of floor tubes and pitting in some areas require attention, other than that no major life limiting issue observed.	3	B	Med	3	B	Medium	Tube wall thinning due to falling slag erosion on the floor tubes. Extensive pitting leading to tube failure. Tube leak/ forced outage for repair	Some sections of floor tubes and pitting in some areas require attention.
1296	6690	6699	6701	6869	0	1	#1 BOILER PLANT	BOILER F.W. & SAT'D STEAM	BOILER ECONOMIZER	Economizer Inlet Headers	64	30	Thermal/Mechanical Fatigue Cracking, Corrosion-Fatigue Cracking, Corrosion, FAC.	(10)	No real issue as per inspection to date. Additional inspections required	3	B	Med	3	B	Medium	Ligament cracking, tube stub thinning/cracking, weld cracking. Forced outage for repair.	Additional inspections required.
1296	6690	6699	6701	6869	0	1	#1 BOILER PLANT	BOILER F.W. & SAT'D STEAM	BOILER ECONOMIZER	Economizer Outlet Headers and Link Piping	65	30	Mechanical fatigue cracking, corrosion fatigue cracking, corrosion.	10	Could meet the desired life with routine inspections.	1	B	Low	1	B	Low	Weld cracking due to support failure - forced outage for repair.	Routine inspections.
1296	6690	6699	6701	6869	0	1	#1 BOILER PLANT	BOILER F.W. & SAT'D STEAM	BOILER ECONOMIZER	Economizer Tubes	66	30	External corrosion and corrosion fatigue.	(10)	Inspections are required to assess the remaining life	1	B	Low	1	B	Low	Tube failure due to corrosion, corrosion-fatigue. Tube leak/ forced outage for repair.	Inspections are required to assess remaining life.
1296	6690	6699	6701	6870	0	1	#1 BOILER PLANT	BOILER F.W. & SAT'D STEAM	BOILER STEAM DRUM	Steam Drum	67	30	Thermal fatigue cracking, corrosion fatigue cracking.	(10)	No real issue as per inspection to date. Additional inspections required	3	C	Med	3	C	High	Ligament cracking. Weld cracking. Forced outage. Safety threat.	Additional inspections required.
1296	6690	6699	6702	6873	0	1	#1 BOILER PLANT	BLR SUPERHEAT& REHEAT ASS'Y	BOILER PRIMARY SUPERHEATER	Superheater Steam Cooled Walls Outlet Header	70	30	Thermal fatigue.	10	No real life limiting issue. Could meet the desired life with routine inspections.	1	B	Low	1	D	Medium	Thermal fatigue cracking. Forced outage. Life Safety.	Additional inspections required.
1296	6690	6699	6702	6873	0	1	#1 BOILER PLANT	BLR SUPERHEAT& REHEAT ASS'Y	BOILER PRIMARY SUPERHEATER	Superheater Rear Horizontal Spaced Inlet Header	71	30	Thermal fatigue.	10	No real life limiting issue. Could meet the desired life with routine inspections.	1	B	Low	1	D	Medium	Thermal fatigue cracking. Forced outage. Life Safety.	Additional inspections required.
1296	6690	6699	6702	6873	0	1	#1 BOILER PLANT	BLR SUPERHEAT& REHEAT ASS'Y	BOILER PRIMARY SUPERHEATER	Superheater Rear Horizontal Spaced Outlet Header	72	30	Creep and thermal fatigue.	10	No real life limiting issue. Could meet the desired life with routine inspections.	1	C	Low	1	D	Medium	Creep and thermal fatigue cracking. Forced outage. Life Safety.	Additional inspections required.
1296	6690	6699	6702	6873	0	1	#1 BOILER PLANT	BLR SUPERHEAT& REHEAT ASS'Y	BOILER PRIMARY SUPERHEATER	Superheater Front Support Tube Inlet Header	73	30	Creep and thermal fatigue.	(10)	Additional inspections required to assess the remaining life.	3	C	Med	2	D	High	Creep and thermal fatigue cracking. Forced outage. Life Safety.	Additional inspections required to assess the remaining life.
1296	6690	6699	6702	6875	0	1	#1 BOILER PLANT	BLR SUPERHEAT& REHEAT ASS'Y	BOILER PRIMARY SUPERHEATER	Superheater Front Horizontal Platen Inlet Header	74	30	Creep and thermal fatigue.	10	No real life limiting issue. Could meet the desired life with routine inspections.	1	C	Low	1	D	Medium	Creep and thermal fatigue cracking. Forced outage. Life Safety.	Additional inspections required.
1296	6690	6699	6702	6875	0	1	#1 BOILER PLANT	BLR SUPERHEAT& REHEAT ASS'Y	BOILER PRIMARY SUPERHEATER	Superheater Front Horizontal Space Outlet Header	75	30	Creep and thermal fatigue.	(10)	Additional inspections required to assess the remaining life.	3	D	High	3	D	High	Creep and thermal fatigue cracking. Forced outage. Life Safety.	Additional inspections required to assess the remaining life.
1296	6690	6699	6702	6873	0	1	#1 BOILER PLANT	BLR SUPERHEAT& REHEAT ASS'Y	BOILER PRIMARY SUPERHEATER	Primary Superheater Tubes	76	30	Fatigue, OD/ID corrosion, ID pitting.	10	No real life limiting issues; however, the presence inside pitting and scaling is not known.	1	C	Low	1	D	Medium	Tube failure due to excessive pitting and corrosion. Forced outage. Life Safety.	Additional inspections required.
1296	6690	6699	6702	6874	0	1	#1 BOILER PLANT	BLR SUPERHEAT& REHEAT ASS'Y	BOILER SUPERHEATER ATTEMP.	Superheater Link Piping and Attemperator	79	30	Thermal/mechanical fatigue, pitting corrosion.	(10)	No real issue as per external visual inspection to date. Additional inspections required	3	B	Med	1	D	Medium	Thermal/Mechanical Fatigue Cracking, Forced outage. Safety.	Additional inspections required.
1296	6690	6699	6702	6877	0	1	#1 BOILER PLANT	BLR SUPERHEAT& REHEAT ASS'Y	BOILER REHEATER ATTEMPERATOR	N/A	80	33	Not addressed in detail.	(10)	Additional inspections required to assess the remaining life.	3	B	Medium	3	C	High	Attemperator failure. Overtemperature of tubing and pipe failure	Inspection and refurbish or replace.

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Table 8-29 Cont'd

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Component	Risk Assess #	Appendix #	Major Issues	Remaining Life Years (Insufficient Info - Inspection Required Within (x) Years)	Remaining Life Comments	TECHNO-ECO RISK ASSESS MODEL			SAFETY RISK ASSESS MODEL			Possible Failure Event	Mitigation
																Likeli-hood	Conse-quence	Risk Level	Likeli-hood	Conse-quence	Safety Risk		
1296	6690	6699	6702	6878	0	1	#1 BOILER PLANT	BLR SUPERHEAT& REHEAT ASS'Y	BOILER REHEATER	Hot Reheat	81	33	Thermal/mechanical fatigue; creep, creep fatigue; corrosion.	(10)	Major issue is creep and creep fatigue. Creep life fraction expended is high (more than 60% for Units 1 & 2 and more than 25% for Unit 3 at the end of 2009). No evidence of upset or thermal fatigue. Metallographic inspections conducted in past for Units 1. No evidence of upset or thermal fatigue. Metallographic inspections conducted in past for Units 1 & 2 (1987 to 2002); carbide particles in ferrite matrix; no significant crack or damage were found.. No major damages found during walkdowns. Walkdown summary part describes specific observations.	3	C	Med	3	D	High	Pipe and/or weld failures at potentially high stress locations Forced outage. Life Safety.	Inspect hot and cold walkdowns to assess hanger condition and potential high stress locations. FOCUS Phased Array and Metallographic Inspections at key locations. Hanger/Support Inspection and monitoring. Program Level 2 assessments.
1296	6690	6699	6702	6878	0	1	#1 BOILER PLANT	BLR SUPERHEAT& REHEAT ASS'Y	BOILER REHEATER	Cold Reheat	82	33	Thermal/Mechanical Fatigue; Corrosion-Fatigue; Cracking; Corrosion	(10)	No seam-welded pipe. No NDE inspection or material testing has been done in recent past. Not possible to assess current condition or remaining life. No major damage found during walkdowns. Walkdown summary part describes specific observations.	1	B	Low	1	D	Low	Pipe and/or weld failures at potentially high stress locations Forced outage. Life Safety.	Piping Management Program. Hanger/Support Inspection and Monitoring Program. Level II assessments
1296	6690	6699	6702	6878	0	1	#1 BOILER PLANT	BLR SUPERHEAT& REHEAT ASS'Y	BOILER REHEATER	Reheater Inlet Header	83	30	Thermal fatigue.	10	Could meet the desired life with routine inspections.	1	B	Low	1	B	Low	Thermal fatigue cracking. Forced outage. Life Safety.	Inspect and maintain.
1296	6690	6699	6702	6878	0	1	#1 BOILER PLANT	BLR SUPERHEAT& REHEAT ASS'Y	BOILER REHEATER	Reheater Outlet Header	84	30	Creep and thermal fatigue.	(10)	Additional inspections required to assess the remaining life.	3	D	High	3	D	High	Creep and thermal fatigue cracking. Forced outage. Life Safety.	Inspect and maintain.
1296	6690	6699	6702	6878	0	1	#1 BOILER PLANT	BLR SUPERHEAT& REHEAT ASS'Y	BOILER REHEATER	Reheater Tubes	85	30	Creep, OD/ID corrosion, ID pitting, stress corrosion cracking and DMWs.	(10)	Inspections are required to assess the remaining life.	3	C	Med	3	D	High	Creep, fatigue and stress corrosion cracking damage, wall thinning due to corrosion and pitting and DMW failures. Unit shutdown	Inspect and maintain.
1296	6690	6699	6702	322990	0	1	#1 BOILER PLANT	BLR SUPERHEAT& REHEAT ASS'Y	SECONDARY SUPERHEATER	Secondary Superheater Tubes (Lower)	86	30	Creep, OD/ID corrosion, ID pitting and sagging.	(10)	Inspections are required to assess the remaining life.	3	C	Med	3	D	High	Tube failure due to creep and Creep, OD/ID corrosion, ID pitting. Unit shutdown	Inspect and maintain.
1296	6690	6699	6702	322990	0	1	#1 BOILER PLANT	BLR SUPERHEAT& REHEAT ASS'Y	SECONDARY SUPERHEATER	Secondary Superheater Tubes (Upper part that was replaced during the uprate in 1988/1989)	87	30	Creep, OD/ID corrosion, ID pitting and stress corrosion cracking	(10)	Inspections are required to assess the remaining life.	2	C	Med	2	D	High	Creep, fatigue and stress corrosion cracking damage, and wall thinning due to corrosion and pitting. Unit shutdown	Inspect and maintain.
1296	6690	6699	6702	322990	0	1	#1 BOILER PLANT	BLR SUPERHEAT& REHEAT ASS'Y	SECONDARY SUPERHEATER	Secondary Superheater Tubes (Upper part that was replaced during the 2008 outage)	88	30	Creep, OD/ID corrosion, ID pitting and stress corrosion cracking	10	This section is relatively new and could meet the desired life.	1	C	Low	1	D	Low	Creep, fatigue and stress corrosion cracking damage, and wall thinning due to corrosion and pitting. Unit shutdown	Inspect and maintain.
1296	6690	6699	6702	6876	0	1	#1 BOILER PLANT	BLR SUPERHEAT& REHEAT ASS'Y	BOILER MAIN STEAM LINES	N/A	89	33	Thermal/mechanical fatigue; creep, creep fatigue; corrosion.	(10)	Major issue is creep and creep fatigue. Creep life fraction expended is high (more than 60% at the end of 2009). No evidence of upset or thermal fatigue. Metallographic inspections conducted in past for Unit 1 (1987 to 2002); carbide particles in ferrite matrix; no significant crack or damage were found. No major damage found during walkdowns. Walkdown summary part describes specific observations.	3	D	High	3	D	High	Pipe and/or weld failures at potentially high stress locations Forced outage. Life Safety.	Inspect hot and cold walkdowns to assess hanger condition and potential high stress locations. Conduct inspections of welds at potentially high stress locations.
1296	6690	6699	6702	6876	6902	1	#1 BOILER PLANT	BLR SUPERHEAT& REHEAT ASS'Y	BOILER STOP VALVE	N/A	90	33	Not addressed in detail. Thermal/mechanical fatigue; creep, creep fatigue; corrosion.	(5)	Additional inspections required to assess the remaining life.	3	C	Medium	3	C	High	Steam erosion - unintended flow to turbine. Material failure and rupture.	Inspection and refurbish or replace.
1296	6690	6699	6701	6701	0	1	#1 BOILER PLANT	BOILER F.W. & SAT'D STEAM	BOILER BLOWDOWN TANK	N/A	91	33	Not addressed in detail. Thermal/mechanical fatigue; creep, creep fatigue; corrosion.	(2)	Safety issue. End of life.	2	B	Medium	3	C	High	Mechanical failure. Steam leak. Personal injury.	Replace

8.2.1.7 Life Cycle Curve and Remaining Life

The life cycle curves for the various elements of the Unit 1 boiler system is broken into three separate parts – the boiler headers and components outside the flue gas path, the high pressure and temperature steam lines (main steam, reheat steam), and the tubes exposed to the combustion process and/or flue gas within the boiler. Differences between the scenarios do not materially affect the curve.

The boiler headers and components are subject primarily to time spent under the effects of steam pressure and temperature. Their equivalent expended life presented in figure below is primarily related to the material properties and the steam conditions. As a result, several curves are required to represent the range of the various elements of the system. Details are included in Appendix 30. The life curves are plots on the y-axis of current and projected consumed equivalent life hours based on the theoretical metallurgical assessments. This differs from other sections that use nominal operating hours of usage on the y-axis versus calendar year on the x-axis. The figure has several vertical lines representing differing representative nominal age limits for various components. It also has several horizontal lines that represent a range of practical equipment equivalent base loaded operating hour life limits. The figure also includes two highlighted boxes. The risk box is representative of typical life expectations. The second identified as the “Level 2 Test” box identifies where EPRI recommends an initial Level 2 analyses or equivalent for these sorts of components (consumed life = 10% of expected or design life).

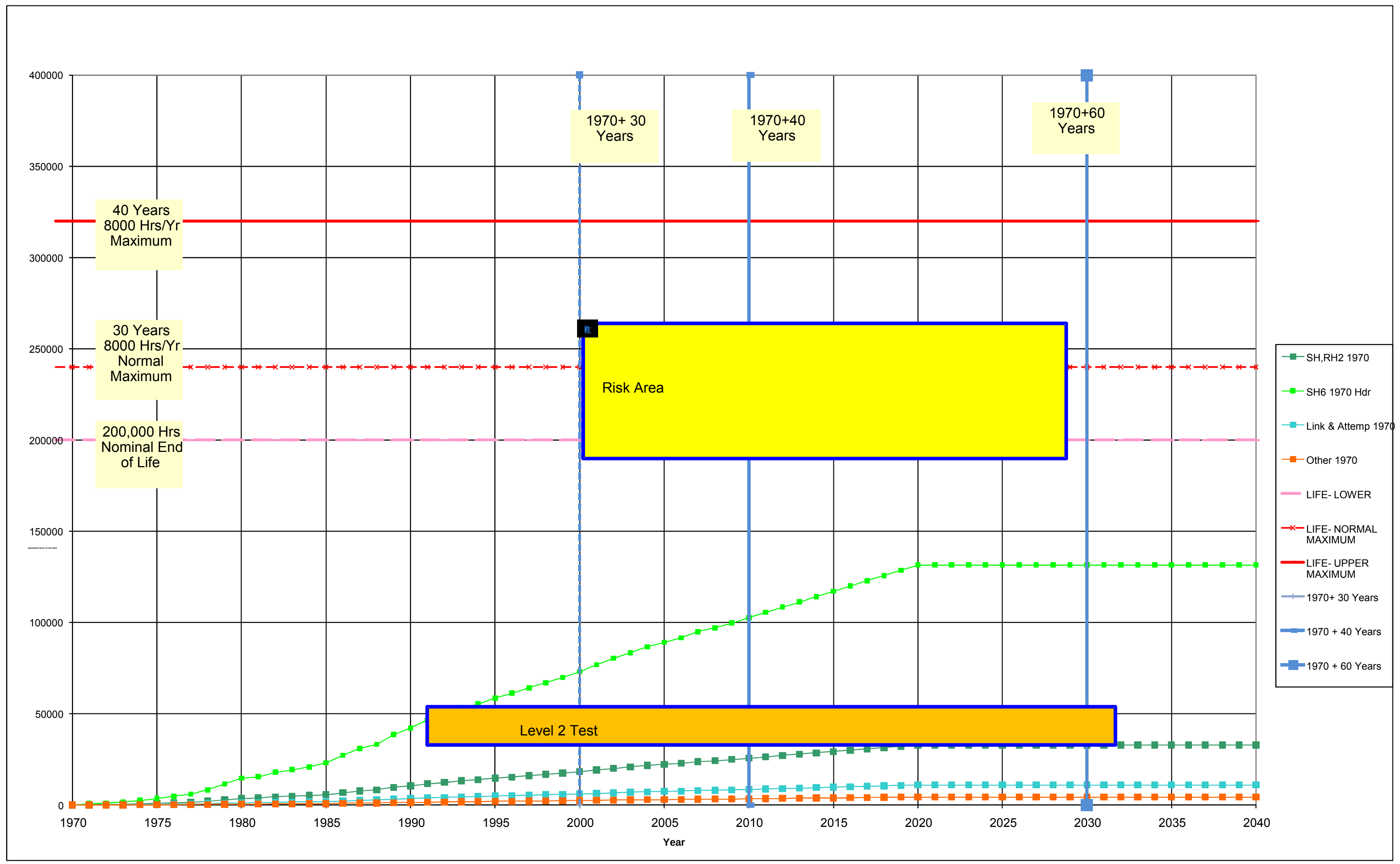

FIGURE 8-10 LIFE CYCLE CURVE –UNIT 1 BOILER SYSTEM (BOILER HEADERS AND COMPONENTS OUTSIDE THE FLUE GAS PATH)

The header life curves indicate that the remaining life (RL) of the Unit 1 boiler headers and associated components is expected to exceed the desired life (DL) which is the generation end of life in 2020. Nevertheless, it also identifies that some of higher temperature components should undergo a Level 2 inspection (identified later in this section of the report) if not already planned or undertaken.

Three curves represent the high pressure, high temperature steam lines (main steam, hot reheat, and cold reheat). Their life expenditure (illustrated in figure below) is primarily related to the time spent under the effects of steam pressure and temperature, similar to the boiler headers, and to the material properties of the steam lines. Details are included in Appendix 33.The life curves are plots on the y-axis of current and projected "consumed equivalent life hours" based on the theoretical metallurgical assessments. The figure has three vertical lines representing differing representative nominal age limits. It also has several horizontal lines that represent a range of practical equipment equivalent base loaded operating hour life limits. The figure also included two highlighted boxes. The risk box is representative of typical life expectations. The second identified as the "Level 2 Test" box identifies where an initial Level 2 analyses or equivalent is likely required (consumed life = 10% of expected life).

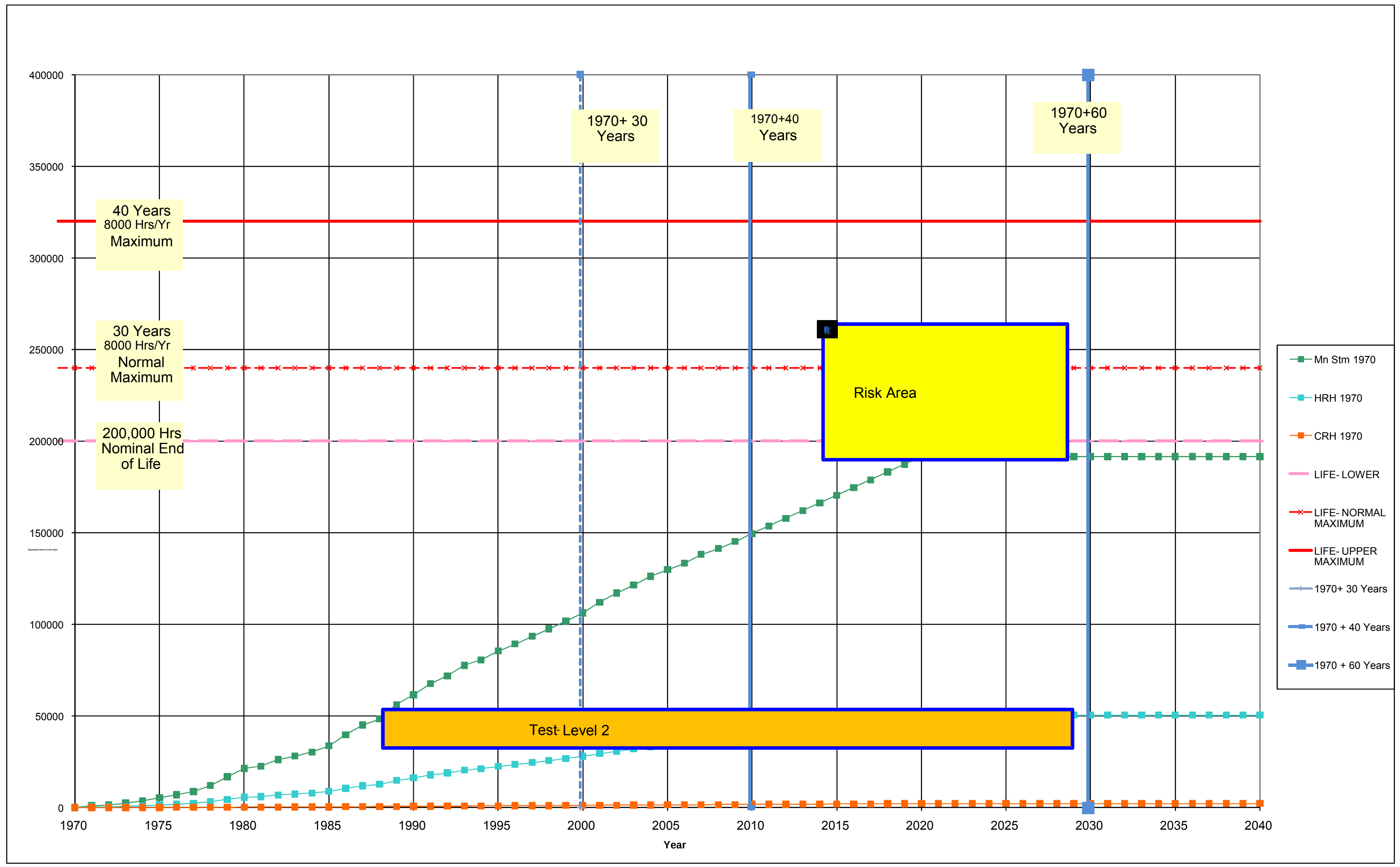

FIGURE 8-11 LIFE CYCLE CURVE –UNIT 1 BOILER SYSTEM (HIGH PRESSURE AND TEMPERATURE STEAM LINES)

The high pressure steam line life curves indicate that the remaining life (RL) of the Unit 1 steam lines and their associated components are expected to exceed the desired life (DL) which is the generation end of life in 2020. Nevertheless, it also identifies that both the main steam and hot reheat steam lines exceed EPRI's 10% consumed life guide for a Level 2 inspection of these systems. Given that they have not been tested for some time, this is considered appropriate at this time.

The Unit 1 boiler system tubes and associated components (exposed to combustion process and/or flue gas within the boiler) are subject to both internal water and/or steam intermediate temperatures and high pressures, but also externally to higher combustion temperatures, and corrosive and erosive conditions. Typically the externally conditions often are the life limiting factor. This is certainly the case for Holyrood units which were fuelled with a high sulphur, high vanadium, moderate ash heavy oil up until 2009. This is evident in the reliability statistics for the boilers, the multiple boiler outages for air preheater cleaning, economizer fouling history, and in the fairly extensive tube surface changes to 2009. The move to a lower sulphur, lower vanadium oil has effectively minimized these going forward, but some legacy effects are inevitable.

A single life cycle curve is presented beginning with the in-service date of the unit. It is meant to represent initial design goals, using nominally operating hours. It was considered impractical to accurately document or reasonably present in one curve the many changes that have occurred, and are likely to continue to occur going forward due to legacy impacts. It is shows the current status of the boiler blowdown tank, which is both a life issue and a safety issue. It uses nominal operating hours as opposed to metallurgical equivalent hours in the two previous boiler curves as a more appropriate way of expressing its normal lifetime.

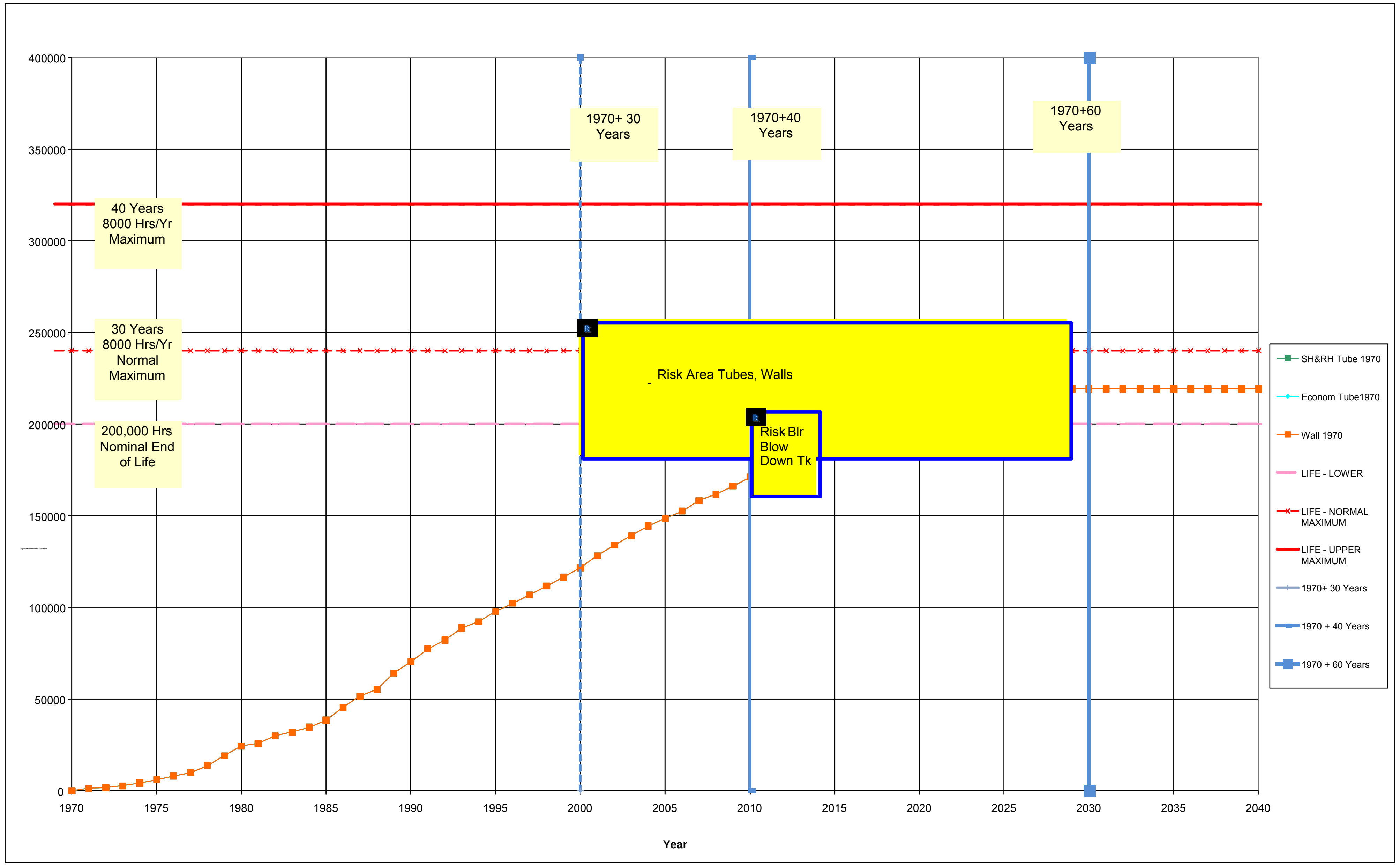

FIGURE 8-12 LIFE CYCLE CURVE –UNIT 1 BOILER SYSTEM (TUBES EXPOSED TO THE COMBUSTION PROCESS, BOILER BLOWDOWN)

The curve indicates that the boiler tubes within the furnace envelope would have been expected to be seeing some end of life component concerns with original equipment. Nevertheless, it is more likely legacy impacts that will have greater effects on component replacements and refurbishments going forward to 2020. With ongoing inspections and refurbishments, 2020 is achievable with good reliability with the new fuel. It also shows that the boiler blowdown tank should be replaced.

8.2.1.8 Level 2 Inspections – Unit 1 Boiler System

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 8-30 below, assuming that the current plant inspection and maintenance program is maintained or improved.

TABLE 8-30 LEVEL 2 INSPECTIONS – UNIT 1 BOILER SYSTEM

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Sub System Comment	L2#	Appendix #	Level 2 Work	Year	Priority	Cost k$
1296	6690	6699	0	0	0	1	#1 BOILER PLANT	BOILER PLANT	BOILER PLANT	None	44	30	Costs consolidated here. See boiler section for details.	2012	2	$1,433
1296	6690	6699	6701	0	0	1	#1 BOILER PLANT	BOILER F.W. & SAT'D STEAM	BOILER F.W. & SAT'D STEAM	Upper WW Headers	45	30	Inspection of selective flat end welds. External visual and thickness measurement.	2012	3	
1296	6690	6699	6701	0	0	1	#1 BOILER PLANT	BOILER F.W. & SAT'D STEAM	BOILER F.W. & SAT'D STEAM	Riser Tubes	46	30	Inspection of selective riser tubes for corrosion fatigue cracking.	2012	2	
1296	6690	6699	6701	0	0	1	#1 BOILER PLANT	BOILER F.W. & SAT'D STEAM	BOILER F.W. & SAT'D STEAM	Lower WW Headers	47	30	Inspections of ligament cracking, selective flat end welds, body spool pieces welds, feeder tube attachment welds and downcomers connection welds.	2012	2	
1296	6690	6699	6701	0	0	1	#1 BOILER PLANT	BOILER F.W. & SAT'D STEAM	BOILER F.W. & SAT'D STEAM	Feeder Tubes	48	30	Inspection of selective feeder tubes for corrosion fatigue cracking.	2012	2	
1296	6690	6699	6701	0	0	1	#1 BOILER PLANT	BOILER F.W. & SAT'D STEAM	BOILER F.W. & SAT'D STEAM	Downcomers	49	30	Inspections of thermal/mechanical fatigue damage at the headers support locations.	2012	3	
1296	6690	6699	6701	0	0	1	#1 BOILER PLANT	BOILER F.W. & SAT'D STEAM	BOILER F.W. & SAT'D STEAM	Waterwall Tubes	50	30	Assessment of the floor tubes wall thinning. Evaluation of pitting in pitting on the tubes adjacent to burners and on the waterwall slope under the economizer.	2012	2	
1296	6690	6699	6701	6869	0	1	#1 BOILER PLANT	BOILER F.W. & SAT'D STEAM	BOILER ECONOMIZER	Economizer Inlet Headers	51	30	Inspection of internal surfaces, ligaments, major girth and seam welds and drain line penetrations. UT inspection of stub tubes and a stub tube sample removal to assess evidence of FAC.	2012	2	
1296	6690	6699	6701	6869	0	1	#1 BOILER PLANT	BOILER F.W. & SAT'D STEAM	BOILER ECONOMIZER	Economizer Outlet Headers and Link Piping	52	30	External visual inspection to ensure that there is no change in the state and/or abnormal movement.	2012	3	
1296	6690	6699	6701	6869	0	1	#1 BOILER PLANT	BOILER F.W. & SAT'D STEAM	BOILER ECONOMIZER	Economizer Tubes	53	30	Sample tubes removal and ultrasonic sonic testing survey at the accessible locations to assess the potential corrosion fatigue damage due to mill defects that had caused a failure in the Unit economizer tube in Unit 2 in 2005.	2012	3	
1296	6690	6699	6701	6870	0	1	#1 BOILER PLANT	BOILER F.W. & SAT'D STEAM	BOILER STEAM DRUM	Steam Drum	54	30	Removal of the drum furniture and a section of the liner to inspect seam welds, nozzle welds, ligaments, downcomers and feedwater inlet pipe. External inspection of feeder tube welds.	2012	2	
1296	6690	6699	6701	6871	0	1	#1 BOILER PLANT	BOILER F.W. & SAT'D STEAM	FURNACE	None	55	30	No Level 2 required.			
1296	6690	6699	6702	0	0	1	#1 BOILER PLANT	BLR SUPERHEAT& REHEAT ASS'Y	BLR SUPERHEAT& REHEAT ASS'Y	Superheater Steam Cooled Walls Outlet Header	56	30	No Level 2 required.		3	
1296	6690	6699	6702	6873	0	1	#1 BOILER PLANT	BLR SUPERHEAT& REHEAT ASS'Y	BOILER PRIMARY SUPERHEATER	Superheater Rear Horizontal Spaced Inlet Header	57	30	No Level 2 required.		3	
1296	6690	6699	6702	6873	0	1	#1 BOILER PLANT	BLR SUPERHEAT& REHEAT ASS'Y	BOILER PRIMARY SUPERHEATER	Superheater Rear Horizontal Spaced Outlet Header	58	30	No Level 2 required.		3	
1296	6690	6699	6702	6873	0	1	#1 BOILER PLANT	BLR SUPERHEAT& REHEAT ASS'Y	BOILER PRIMARY SUPERHEATER	Superheater Front Support Tube Inlet Header	59	30	Creep and creep fatigue damage including internal boroscopic, external visual, dimensional on body spool pieces, UT inspections on welds and stub tubes and replica inspection.		2	
1296	6690	6699	6702	6873	0	1	#1 BOILER PLANT	BLR SUPERHEAT& REHEAT ASS'Y	BOILER PRIMARY SUPERHEATER	Superheater Front Horizontal Platen Inlet Header	60	30	No Level 2 required.		3	

Table 8-30 Cont'd

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Sub System Comment	L2#	Appendix #	Level 2 Work	Year	Priority	Cost k$
1296	6690	6699	6702	6873	0	1	#1 BOILER PLANT	BLR SUPERHEAT& REHEAT ASS'Y	BOILER PRIMARY SUPERHEATER	Superheater Front Horizontal Space Outlet Header	61	30	Creep and creep fatigue damage including internal boroscopic, external visual, dimensional on body spool pieces, UT inspections on welds and stub tubes and replica inspection.	2012	1	
1296	6690	6699	6702	6873	0	1	#1 BOILER PLANT	BLR SUPERHEAT& REHEAT ASS'Y	BOILER PRIMARY SUPERHEATER	Superheater Link Piping and Attemperator	62	30	Inspections for assessment of damage caused by Thermal/Mechanical Fatigue Cracking, Corrosion-Fatigue Cracking and Corrosion.	2012	2	
1296	6690	6699	6702	6873	0	1	#1 BOILER PLANT	BLR SUPERHEAT& REHEAT ASS'Y	BOILER PRIMARY SUPERHEATER	Primary Superheater Tubes	63	30	Inspections to check the presence inside pitting and scaling.	2012	3	
1296	6690	6699	6702	6874	0	1	#1 BOILER PLANT	BLR SUPERHEAT& REHEAT ASS'Y	BOILER SUPERHEATER ATTEMP.	None	64	30	No Level 2 required.			
1296	6690	6699	6702	6877	0	1	#1 BOILER PLANT	BLR SUPERHEAT& REHEAT ASS'Y	BOILER REHEATER ATTEMPERATOR	None	65	30	No Level 2 required.			
1296	6690	6699	6702	6878	0	1	#1 BOILER PLANT	BLR SUPERHEAT& REHEAT ASS'Y	BOILER REHEATER	Reheater Inlet Header	66	30	No Level 2 required.		3	
1296	6690	6699	6702	6878	0	1	#1 BOILER PLANT	BLR SUPERHEAT& REHEAT ASS'Y	BOILER REHEATER	Reheater Outlet Header	67	30	Creep and creep fatigue damage including internal boroscopic, external visual, dimensional on body spool pieces, UT inspections on welds and stub tubes and replica inspection.	2012	1	
1296	6690	6699	6702	6878	0	1	#1 BOILER PLANT	BLR SUPERHEAT& REHEAT ASS'Y	BOILER REHEATER	Reheater Tubes	68	30	Inspections to assess the extent of the damage due to destructive tube sample analysis to assess the extent of the damage due to creep, OD liquid ash corrosion, ID high temperature corrosion, stress corrosion cracking and DMWs.	2012	2	
1296	6690	6699	6702	322990	0	1	#1 BOILER PLANT	BLR SUPERHEAT& REHEAT ASS'Y	SECONDARY SUPERHEATER	Secondary Superheater Tubes (Lower)	69	30	Inspections to assess the extent of the damage due to creep, sagging, OD liquid ash corrosion and ID high temperature corrosion for creep, fatigue corrosion and pitting.	2012	2	
1296	6690	6699	6702	322990	0	1	#1 BOILER PLANT	BLR SUPERHEAT& REHEAT ASS'Y	SECONDARY SUPERHEATER	Secondary Superheater Tubes (Upper part that was replaced during the uprate in 1988/1989)	70	30	Inspections for creep, fatigue, corrosion, pitting and stress corrosion cracking.	2012	2	
1296	6690	6699	6702	322990	0	1	#1 BOILER PLANT	BLR SUPERHEAT& REHEAT ASS'Y	SECONDARY SUPERHEATER	Secondary Superheater Tubes (Upper part that was replaced during the 2008 outage)	71	30	No Level 2 required.		3	
1296	6690	6699	6701	6701	0	1	#1 BOILER PLANT	BOILER F.W. & SAT'D STEAM	BOILER BLOWDOWN TANK	N/A	72	33	No Level 2 required			
1296	6690	6699	6702	6876	0	1	#1 BOILER PLANT	BLR SUPERHEAT& REHEAT ASS'Y	BOILER MAIN STEAM LINES	(Testing of Main Steam, Hot Reheat, Cold Reheat, HP feedwater)	73	33	Level 2 testing of steam and high pressure feedwater lines.	2011	1	$395
1296	6690	6699	6702	6876	6902	1	#1 BOILER PLANT	BLR SUPERHEAT& REHEAT ASS'Y	BOILER STOP VALVE	None	74	33	Level 2 Testing of boiler stop valves as part of Main Steam Lines Program.	2011	1	$30
1296	6690	6699	6700	0	0	1	#1 BOILER PLANT	BOILER STRUCTURE	BOILER STRUCTURE	None	75	17	No Level 2 required. Undertake preliminary visual inspection of inaccessible areas subject to roof leaks.	2012	2	$6

8.2.1.9 Capital Projects

Table 8-31 below shows the suggested typical capital enhancements that should be considered for the Unit 1 boiler system:

TABLE 8-31 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – UNIT 1 BOILER SYSTEM

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Detail	CAP#	Appendix #	Capital Item	Date	Priority
1296	6690	6699	0	0	0	1	#1 BOILER PLANT	BOILER PLANT	BOILER PLANT	N/A	42	30	Install nitrogen blanketing. No other pending Level 2 or next inspection.	2013	2
1296	6690	6699	6701	0	0	1	#1 BOILER PLANT	BOILER F.W. & SAT'D STEAM	BOILER F.W. & SAT'D STEAM	N/A	43	30	None , pending Level 2 or next inspection.		
1296	6690	6699	6701	6869	0	1	#1 BOILER PLANT	BOILER F.W. & SAT'D STEAM	BOILER ECONOMIZER	N/A	44	30	None, pending Level 2 or next inspection possible new recirc line.		
1296	6690	6699	6701	6870	0	1	#1 BOILER PLANT	BOILER F.W. & SAT'D STEAM	BOILER STEAM DRUM	N/A	45	30	None, pending Level 2 or next inspection.		
1296	6690	6699	6701	6871	0	1	#1 BOILER PLANT	BOILER F.W. & SAT'D STEAM	FURNACE	N/A	46	30	None, pending Level 2 or next inspection.		
1296	6690	6699	6702	0	0	1	#1 BOILER PLANT	BLR SUPERHEAT & REHEAT ASS'Y	BLR SUPERHEAT& REHEAT ASS'Y	N/A	47	30	None, pending Level 2 or next inspection.		
1296	6690	6699	6702	6873	0	1	#1 BOILER PLANT	BLR SUPERHEAT & REHEAT ASS'Y	BOILER PRIMARY SUPERHEATER	N/A	48	30	None, pending Level 2 or next inspection.		
1296	6690	6699	6702	6874	0	1	#1 BOILER PLANT	BLR SUPERHEAT & REHEAT ASS'Y	BOILER SUPERHEATER ATTEMP.	N/A	49	30	None, pending Level 2 or next inspection.		
1296	6690	6699	6702	6877	0	1	#1 BOILER PLANT	BLR SUPERHEAT & REHEAT ASS'Y	BOILER REHEATER ATTEMPERATOR	N/A	50	30	None, pending Level 2 or next inspection.		
1296	6690	6699	6702	6878	0	1	#1 BOILER PLANT	BLR SUPERHEAT & REHEAT ASS'Y	BOILER REHEATER	N/A	51	30	Implement addition of RH surface to match design temps and efficiency, subject to decision on Holyrood.	2012	2
1296	6690	6699	6702	322990	0	1	#1 BOILER PLANT	BLR SUPERHEAT & REHEAT ASS'Y	SECONDARY SUPERHEATER	N/A	52	30	None, pending Level 2 or next inspection.		
1296	6690	6699	6701	6701	0	1	#1 BOILER PLANT	BOILER F.W. & SAT'D STEAM	BOILER BLOWDOWN TANK	N/A	53	30	Replace tank	2011	1
1296	6690	6699	6702	6876	0	1	#1 BOILER PLANT	BLR SUPERHEAT & REHEAT ASS'Y	BOILER MAIN STEAM LINES	N/A	54	30	None, pending Level 2 or next inspection.		
1296	6690	6699	6702	6876	6902	1	#1 BOILER PLANT	BLR SUPERHEAT & REHEAT ASS'Y	BOILER STOP VALVE	N/A	55	30	None, pending Level 2 or next inspection.		

8.2.2 Asset 6708 – Unit 1 Feedwater System High Pressure (HP) Heat Exchangers

(Detailed Technical Assessment in Working Papers, Appendices 32 and 34)

Unit #:	1
Asset Class #	BU 1296 - Assets Generations
SCI & System:	6708 #1 Condensate & Feedwater System
Sub-Systems:	6713 #1 High Pressure Feedwater
Components:	7112 #1 HP Heater 4
	7113 #1 HP Heater 5
	7114 #1 HP Heater 6
	8835 #1 Boiler Feed Pump East
	8838 #1 Boiler Feed Pump West

8.2.2.1 Description

The high pressure (HP) feedwater system servicing Unit 1 contains three HP feedwater heat exchangers that are referred to as HP-4, HP-5 and HP-6. The primary function of the HP feedwater heat exchangers is to optimize the unit thermal efficiency by preheating the feedwater prior to entering the boilers.

Each HP feedwater heater is a horizontally mounted, 100% capacity pressure vessels of the U-tube type construction. There are two tube passes on the feedwater side and a divided flow of heating steam on the shell side of the HP feedwater heater The main components of the HP feedwater heat exchangers are shell, shell skirt, tubes, tubesheet, channel, impingement plates, tube support plates/pass partition plates/baffles, shrouds, impingement plate and channel cover. Tubesheet and channel are made from a single forging. The tubes material for all three HP feedwater heat exchangers is stainless steel SA-688-304.

There are three zones on the shell side that are commonly referred to as desuperheating, condensing, and drains subcooling zones.

1. Desuperheating Zone: This is an enclosed portion at the outlet end of the tube bundle. An impingement plate is installed below the steam inlet nozzle to prevent impingement damage to the tubes. The desuperheating zone is enveloped by a separate shroud which conducts the steam from the inlet nozzle to the condensing zone.

2. Condensing Zone: Steam exiting the desuperheating zone is condensed as it traverses through the condensing zone. Also, any drains from higher pressure heater flow into the condensing zone through the drains inlet nozzle. An impingement plate is installed just inside this nozzle to protect the tubes from these flashing drains. The condensing zone is vented continuously to remove non-condensable gases.

3. Drains Subcooling Zone: This zone is an enclosed portion of the inlet end of the tube bundle to maximize heat transfer from the shell side condensate to the incoming feedwater before the condensate exits. The condensate should be sub-cooled sufficiently to prevent flashing as the condensate leaves the HP feedwater heater shell through the drains outlet nozzle.

Two motor driven boiler feed pumps (BFP) service Unit 1. The pumps are multiple stage barrel centrifugal pumps. Each provides up to 60% of full load flow. They have been in service since 1970, with some upgrades when the unit was uprated in 1988. The pump motors are 4 kV motors, approximately 2000 kW. They directly drive the pumps. There is no variable speed device such as variable frequency drives or fluid couplings.

8.2.2.2 History

The requirements for the Unit 1 generators are as follows:

Manufactured/Delivered	1969
In-Service Date	Sep 1970
Generation Base Load End Date	Dec 2015
Generation Peak/Emerg Gen End Date	Dec 2020

The hours associated with the analyses vary for systems/equipment that has been replaced (specifically the HP5 heat exchangers) are:

Hours Generation Actual - Ops to Dec 2009	166
Max Hours Generation Ops – to Dec 2015	210
Max Hrs Gen Ops to Gen End Date Dec 2020	219

	Unit 1		
	HP-4	**HP-5**	**HP-6**
Year Installed	1985	1987	1988

8.2.2.3 Inspection and Repair History

With the exception of tube leak testing, there have been no NDE inspections carried out on the currently in service HP feedwater heat exchangers in the past. A long term commitment (life-cycle management plan) is required to diagnose and track all the failures to identify possible remedial actions so as to preclude similar future occurrences, and provides the best chance for optimizing feedwater heaters.

The original Unit 1 HP feedwater heat exchangers were replaced from the years 1985 to 1988. HP-4, HP-5 and HP-6 had about 16, 15 and 14 years of base loaded equivalent operation respectively by the end of year 2009 because the plant does not operate all year around. There would be approximately an additional 6 to 8 years of base loaded plant equivalent operation up to the end forecasted operating period of 2020 required. Hence, the feedwater heat exchangers will exceed the average life expectancy of 20 years before the year 2020. The HP-4 is more critical in terms of operating years and it was not designed for the uprated operating conditions. Level 2 inspections are required in order to assess the remaining life on all the Unit 1 HP feedwater heat exchangers.

The Unit 1 boiler feed pumps and motors are regularly maintained. The plant has a common spare pump barrel that they use to be able to refurbish all of the plant pumps on a six to seven year cycle. The 4 kV motors are tested electrically annually. No specific issues have been identified, but the BFP motors are at a stage in life where failures or lower reliability may be anticipated.

8.2.2.4 Condition Assessment

The condition assessment of the Unit 1 feedwater system – HP feedwater heat exchangers is illustrated below in Table 8-32.

TABLE 8-32 CONDITION ASSESSMENT – UNIT 1 FEEDWATER SYSTEM - HP FEEDWATER HEAT EXCHANGERS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset Level 2	Asset Level 3	Description	Detail	Condition Summary ID #	Append #	Condition	EPRI Identifier	Original Life (Base Load) Ops Hrs (Yrs)	Current Expected Minimum Remaining Life Years (Subject to Test)	End of Life (EOL) Required	Next Regular Inspection	Next Planned Overhaul or Major Inspection	Capability to Reach Next Overhaul	Capability to Reach EOL	In Service
1296	6690	6709	6712	0	0	1	#1 CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEEDWATER PUMPING	N/A	243	23	All existing feedwater pumps are original equipment, but motors replaced in 1989.	3a	200000 (30)	10	2020	2010		Yes	Yes	1970/1989
1296	6690	6709	6712	8835	0	1	#1 CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEED PUMP EAST	N/A	244	23	Pumps installed in 1969 and motors in 1989. Good condition due to pump refurbishment using spare barrel. Last pump refurbishment 2009.	3a	200000 (30)	10+	2020	2016	2016	Yes	Yes	1970/1989
1296	6690	6709	6712	8835	0	1	#1 CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEED PUMP EAST	Motor	245	23,25	Motors installed in 1989. Inspected and tested yearly.	3a	200000 (25)	(5+)	2020	2016	2016	Yes	No	1989
1296	6690	6709	6712	8836	0	1	#1 CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEED PUMP WEST	N/A	246	23	Pumps installed in 1969 and motors in 1989. Good condition due to pump refurbishment using spare barrel. Last pump refurbishment 2003, planned for 2010.	3a	200000 (30)	10+	2020	2010	2010	Yes	Yes	1970/1989
1296	6690	6709	6712	8836	0	1	#1 CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEED PUMP WEST	Motor	247	23,25	Motors installed in 1989. Inspected and tested yearly.	3a	200000 (25)	(5+)	2020	2010	2010	Yes	No	1989
1296	6690	6709	6713	0	0	1	#1 CONDENSATE & F.W. SYSTEM	HIGH PRESSURE FEEDWATER SYS	HIGH PRESSURE FEEDWATER SYS	N/A	248	32,33	No Flow Accelerated Corrosion (FAC) management program. Present water chemistry and operating conditions indicates that the feedwater system is susceptible to FAC.	4	150000 (25)	(5)	2020	2012	2012	Yes	Yes	1970
1296	6690	6709	6713	7112	0	1	#1 CONDENSATE & F.W. SYSTEM	HIGH PRESSURE FEEDWATER SYS	H.P. HEATER 4	N/A	249	32	Installed 1985. No NDE inspections carried out on the currently in service HP feedwater heaters. HP feedwater tube leaks experienced plugged in order to satisfy the short-term problem with cause uncertain. Numbers of leaks and locations not known. Uncertain if SCC tube failure degradation mechanism observed at Unit 2 HP-5 applicable to other HP feedwater heaters.	4	(25)	(10)	2020	2011	2012	Yes	Yes	1985
1296	6690	6709	6713	7113	0	1	#1 CONDENSATE & F.W. SYSTEM	HIGH PRESSURE FEEDWATER SYS	H.P. HEATER 5	N/A	250	32	Installed 1986. No NDE inspections carried out on the currently in service HP feedwater heaters. HP feedwater tube leaks experienced plugged in order to satisfy the short-term problem with cause uncertain. Numbers of leaks and locations not known. Uncertain if SCC tube failure degradation mechanism observed at Unit 2 HP-5 applicable to other HP feedwater heaters.	10	(20)	(10)	2020	2011	2012	Yes	Yes	1987
1296	6690	6709	6713	7114	0	1	#1 CONDENSATE & F.W. SYSTEM	HIGH PRESSURE FEEDWATER SYS	H.P. HEATER 6	N/A	251	32	Installed 1987. No NDE inspections carried out on the currently in service HP feedwater heaters. HP feedwater tube leaks experienced plugged in order to satisfy the short-term problem with cause uncertain. Numbers of leaks and locations not known. Uncertain if SCC tube failure degradation mechanism observed at Unit 2 HP-5 applicable to other HP feedwater heaters.	4	(25)	(10)	2020	2011	2012	Yes	Yes	1988

Notes:
1. A "(bracketed)" value in the "Current Expected Remaining Life" column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as "(X/Y)" has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.
2. The "Next Regular Inspection" column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The "Next Planned Overhaul or Major Inspection" column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a "Desired Life" stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or are not known by AMEC.

8.2.2.5 Actions

Based on the condition assessment, the following actions are recommended for the Unit 1 feedwater system – HP feedwater heat exchangers:

TABLE 8-33 RECOMMENDED ACTIONS – UNIT 1 FEEDWATER SYSTEM - HP FEEDWATER HEAT EXCHANGERS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Unit	Asset 2/3	Asset 3/4	Description	Detail	Action #	App #	Action	Year	Priority
1296	6690	6709	6712	0	1	#1 CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEEDWATER PUMPING	N/A	145	23	Assess potential for variable speed control of BFW pumps.	2011	2
1296	6690	6709	6712	0	1	#1 CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEEDWATER PUMPING	N/A	146	23	Assess potential for spare BFP motor, and subsequent refurbishment/rewind of Unit 3 motors.	2011	2
1296	6690	6709	6712	8835	1	#1 CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEED PUMP EAST	N/A	147	23	Maintain current program of ongoing inspections and overhauls.	2011	2
1296	6690	6709	6712	8836	1	#1 CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEED PUMP WEST	N/A	148	23	Maintain current program of ongoing inspections and overhauls.	2011	2
1296	6690	6709	6713	0	1	#1 CONDENSATE & F.W. SYSTEM	HIGH PRESSURE FEEDWATER SYS	HIGH PRESSURE FEEDWATER SYS	N/A	149	32	See details below.		
1296	6690	6709	6713	7112	1	#1 CONDENSATE & F.W. SYSTEM	HIGH PRESSURE FEEDWATER SYS	H.P. HEATER 4	N/A	150	32	Perform Level 2 inspections.	2012	2
1296	6690	6709	6713	7113	1	#1 CONDENSATE & F.W. SYSTEM	HIGH PRESSURE FEEDWATER SYS	H.P. HEATER 5	N/A	151	32	Perform Level 2 inspections.	2012	2
1296	6690	6709	6713	7114	1	#1 CONDENSATE & F.W. SYSTEM	HIGH PRESSURE FEEDWATER SYS	H.P. HEATER 6	N/A	152	32	Perform Level 2 inspections.	2012	2

8.2.2.6 Risk Assessment

Table 8-34 below illustrates the risk assessment for the Unit 1 feedwater systems – HP feedwater heat exchangers, both from a technological perspective and a safety perspective using the models presented in Section 3.

TABLE 8-34 RISK ASSESSMENT – UNIT 1 FEEDWATER SYSTEM - HP FEEDWATER HEAT EXCHANGERS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Component	Risk Assess #	Appendix #	Major Issues	Remaining Life Years (Insufficient Info - Inspection Required Within (x) Years)	Remaining Life Comments	TECHNO-ECO RISK ASSESS MODEL			SAFETY RISK ASSESS MODEL			Possible Failure Event	Mitigation
																Likeli-hood	Conse-quence	Risk Level	Likeli-hood	Conse-quence	Safety Risk		
1296	6690	6709	6712	0	0	1	#1 CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEEDWATER PUMPING	N/A	142		See details below.		None								
1296	6690	6709	6712	8835	0	1	#1 CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEED PUMP EAST	FW Pump East	143	23	Seal, bearing, impeller failure.	10+	None	1	C	Low	1	C	Low	Pump failure; 50% capability reduction	Current inspection and maintain.
1296	6690	6709	6712	8835	0	1	#1 CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEED PUMP EAST	Unit #1 FW Pp Motor East	144	23	Electric fault.	(5+)	None	1	C	Low	1	B	Low	Pump failure; 50% capability reduction	Spare and current inspection and maintain.
1296	6690	6709	6712	8836	0	1	#1 CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEED PUMP WEST	4 kV Boiler Feed Pump Motor	145	25	Electrical fault, mechanical fatigue, ops error.	(5+)	None	1	C	Low	1	B	Low	Loss 60% unit generation for extended time	Spare and current inspection and maintain.
1296	6690	6709	6712	8835	0	1	#1 CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEED PUMP EAST	4 kV Boiler Feed Pump Motor	146	25	Electrical fault, mechanical fatigue, ops error.	(5+)	None	1	C	Low	1	B	Low	Loss 60% unit generation for extended time	Spare and current inspection and maintain.
1296	6690	6709	6712	8836	0	1	#1 CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEED PUMP WEST	FW Pump West	147	23	Seal, bearing, impeller failure.	10+	None	1	C	Low	1	C	Low	Pump failure; 50% capability reduction	Current inspection and maintain.
1296	6690	6709	6712	8836	0	1	#1 CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEED PUMP WEST	Unit #1 FW Pp Motor West	148	23	Electric fault.	(5+)	None	1	C	Low	1	C	Low	Pump failure; 50% capability reduction	Spare and current inspection and maintain.
1296	6690	6709	6713	0	0	1	#1 CONDENSATE & F.W. SYSTEM	HIGH PRESSURE FEEDWATER SYS	HIGH PRESSURE FEEDWATER SYS	Feedwater Discharge	149	33	Flow Accelerated Corrosion (FAC); thermal/mechanical fatigue cracking; corrosion-fatigue cracking; corrosion.	(10)	Major issue is FAC; No NDE inspection or material testing has been done in recent past. Not possible to assess current condition or remaining life.	3	D	High	3	D	High	Piping failure. High energy release.	Conduct sample FAC inspections using EPRI methodology.
1296	6690	6709	6713	0	0	1	#1 CONDENSATE & F.W. SYSTEM	HIGH PRESSURE FEEDWATER SYS	HIGH PRESSURE FEEDWATER SYS	All HP Feedwater Heaters	150	32	SCC, Thermal/ mechanical fatigue.	(10)	Life management program is required.	1	C	Low	2	B	Low	Excessive tube failure event resulting in Turbine water induction.	Inspect and maintain.
1296	6690	6709	6713	7112	0	1	#1 CONDENSATE & F.W. SYSTEM	HIGH PRESSURE FEEDWATER SYS	H.P. HEATER 4	Unit #1 HP Feedwater Heater #4	151	32	SCC, FAC, thermal/ mechanical fatigue, corrosion fatigue.	(10)	Inspections are required to assess the remaining life.	3	B	Medium	2	B	Low	Tube failures, internal hardware failure and shell wall thinning due FAC and weld cracking. Safety	Inspect and maintain.
1296	6690	6709	6713	7113	0	1	#1 CONDENSATE & F.W. SYSTEM	HIGH PRESSURE FEEDWATER SYS	H.P. HEATER 5	Unit #1 HP Feedwater Heater #5	152	32	SCC, FAC, thermal/ mechanical fatigue, corrosion fatigue.	(10)	Inspections are required to assess the remaining life.	3	B	Medium	2	B	Low	Tube failures, internal hardware failure and shell wall thinning due FAC and weld cracking. Safety threat.	Inspect and maintain.
1296	6690	6709	6713	7114	0	1	#1 CONDENSATE & F.W. SYSTEM	HIGH PRESSURE FEEDWATER SYS	H.P. HEATER 6	Unit #1 HP Feedwater Heater #6	153	32	SCC, FAC, thermal/ mechanical fatigue, corrosion fatigue.	(10)	Inspections are required to assess the remaining life.	3	B	Medium	2	B	Low	Tube failures, internal hardware failure and shell wall thinning due FAC and weld cracking. Safety threat.	Inspect and maintain.

8.2.2.7 Life Cycle Curve and Remaining Life

The life cycle curves for the Unit 1 feedwater system - HP heat exchangers and Unit 1 boiler feed pumps are illustrated below. The life curves are plots of current and projected operating hours (generation mode only) on the y-axis versus calendar year on the x-axis. The figure has several vertical lines representing differing representative nominal age limits for various components. It also has several horizontal lines that represent a range of practical equipment equivalent base loaded operating hour life limits. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view.

For the Unit 1 feedwater system HP heat exchangers, individual curves represent the three heat exchangers and components, as well as a curve to represent any balance of plant that is original equipment.

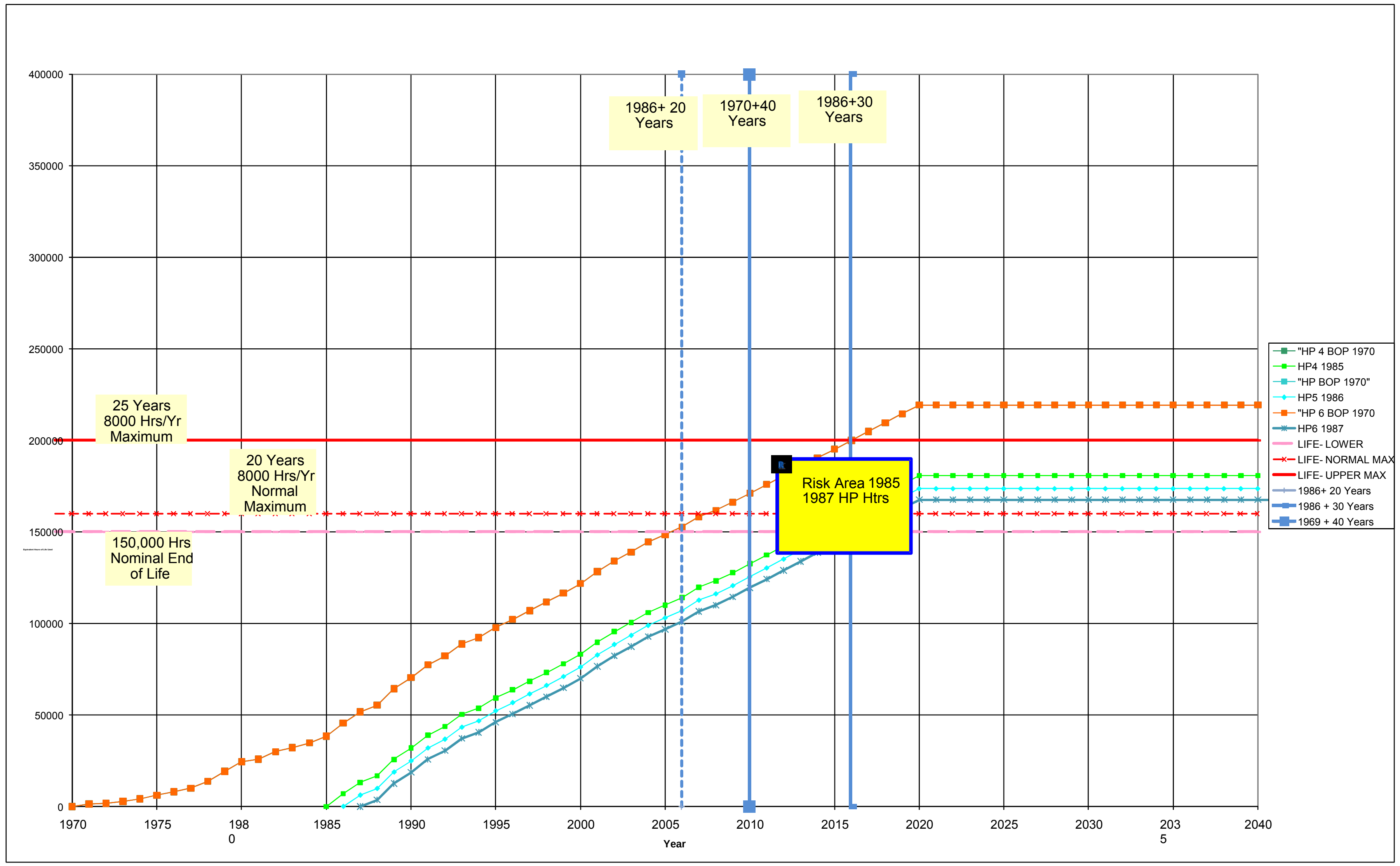

FIGURE 8-13 LIFE CYCLE CURVE – UNIT 1 FEEDWATER SYSTEM - HP FEEDWATER HEAT EXCHANGERS

The curves indicate that the remaining life (RL) of the Unit 1 HP heat exchangers (and the associated feedwater systems) may be able to reach the desired life (DL) 2020 end date for generation. Nevertheless, given that no detailed NDE information has been obtained on the HP heat exchangers for some time, a detailed Level 2 inspection is recommended for 2012.

For the Unit 1 Boiler Feed Pumps, a single curve represents each of the two boiler feed pumps dating back to their original installation. While indicative of expected life with good maintenance practice, the pumps have been and continue to be refurbished on a six year cycle using a spare pump section. Their actual condition is therefore substantially better than might otherwise be expected.

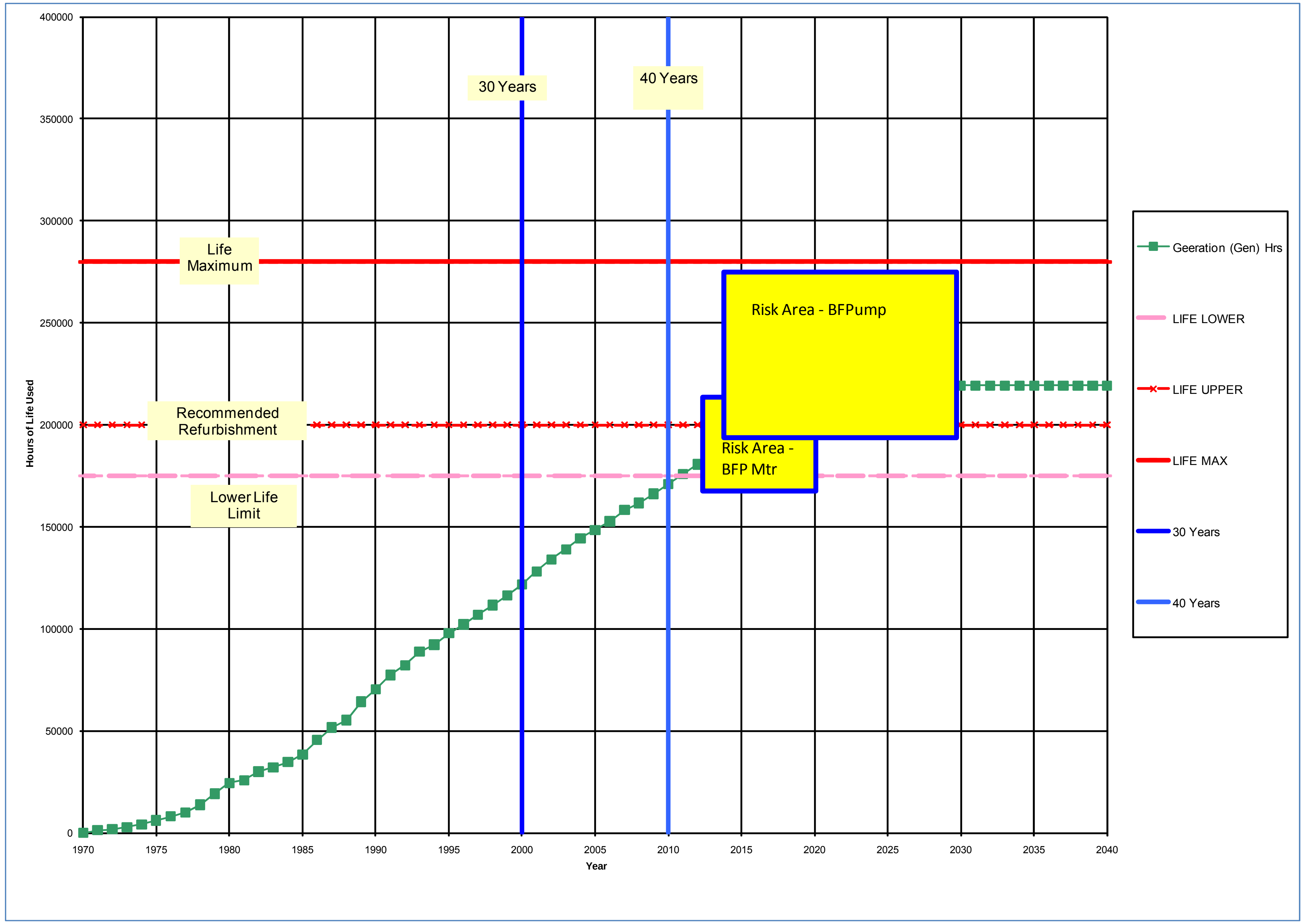

FIGURE 8-14 LIFE CYCLE CURVE – UNIT 1 FEEDWATER SYSTEM - HP BOILER FEED PUMPS

The curve indicates that the remaining life (RL) of the Unit 1 HP boiler feed pumps is likely able to reach desired end date which is the 2020 end date for generation. Given their six year refurbishment cycle and a spare pump section, they are expected to continue to perform reliably well past the 2020 end date for generation. The BFP motors are approaching older age and entering areas where reliability and unexpected failure may become more an issue than expected life.

8.2.2.8 Level 2 Inspections – Unit 1 Feedwater System HP Heat Exchangers

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 8-35 below, assuming that the current plant inspection and maintenance program is maintained or improved.

TABLE 8-35 LEVEL 2 INSPECTIONS – UNIT 1 FEEDWATER SYSTEM - HP FEEDWATER HEAT EXCHANGERS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Sub System Comment	L2#	Appendix #	Level 2 Work	Year	Priority	Cost k$
1296	6690	6709	6712	0	0	1	#1 CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEEDWATER PUMPING	None	129	23	No Level 2 inspections required at this time. Continue program of regular tests and overhauls.			
1296	6690	6709	6712	8835	0	1	#1 CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEED PUMP EAST	None	130	23	No Level 2 inspections required at this time. Continue program of regular tests and overhauls.			
1296	6690	6709	6712	8836	0	1	#1 CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEED PUMP WEST	None	131	23	No Level 2 inspections required at this time. Continue program of regular tests and overhauls.			
1296	6690	6709	6713	0	0	1	#1 CONDENSATE & F.W. SYSTEM	HIGH PRESSURE FEEDWATER SYS	HIGH PRESSURE FEEDWATER SYS	None	132	32	Level 2 of high pressure feedwater heaters summarized here. Level 2 testing of high pressure feedwater lines is included within the costs of the Main Steam Line Item.	2012	2	$225
1296	6690	6709	6713	7112	0	1	#1 CONDENSATE & F.W. SYSTEM	HIGH PRESSURE FEEDWATER SYS	H.P. HEATER 4	None	133	32	Shell side inspections and channel side for the degradation mechanisms.	2012	2	
1296	6690	6709	6713	7112	0	1	#1 CONDENSATE & F.W. SYSTEM	HIGH PRESSURE FEEDWATER SYS	H.P. HEATER 4	None	134	32	Assessment of the tube plug map.	2012	2	
1296	6690	6709	6713	7112	0	1	#1 CONDENSATE & F.W. SYSTEM	HIGH PRESSURE FEEDWATER SYS	H.P. HEATER 4	None	135	32	ET inspection of tubes to assess the present condition (metallurgical evaluation may also be required depending upon the condition of the tubes).	2012	2	
1296	6690	6709	6713	7112	0	1	#1 CONDENSATE & F.W. SYSTEM	HIGH PRESSURE FEEDWATER SYS	H.P. HEATER 4	None	136	32	NDE inspection the major welds (seam, supports and nozzle welds) for the degradation mechanisms. PT or Magnetic particle testing (MT) or Conventional UT or Phased array (focused) can be used depending upon location.	2012	2	
1296	6690	6709	6713	7113	0	1	#1 CONDENSATE & F.W. SYSTEM	HIGH PRESSURE FEEDWATER SYS	H.P. HEATER 5	None	137	32	Shell side inspections and channel side for the degradation mechanisms.	2012	2	
1296	6690	6709	6713	7113	0	1	#1 CONDENSATE & F.W. SYSTEM	HIGH PRESSURE FEEDWATER SYS	H.P. HEATER 5	None	138	32	Assessment of the tube plug map.	2012	2	
1296	6690	6709	6713	7113	0	1	#1 CONDENSATE & F.W. SYSTEM	HIGH PRESSURE FEEDWATER SYS	H.P. HEATER 5	None	139	32	ET inspection of tubes to assess the present condition (metallurgical evaluation may also be required depending upon the condition of the tubes).	2012	2	
1296	6690	6709	6713	7113	0	1	#1 CONDENSATE & F.W. SYSTEM	HIGH PRESSURE FEEDWATER SYS	H.P. HEATER 5	None	140	32	NDE inspection the major welds (seam, supports and nozzle welds) for the degradation mechanisms. PT or Magnetic particle testing (MT) or Conventional UT or Phased array (focused) can be used depending upon location.	2012	2	
1296	6690	6709	6713	7114	0	1	#1 CONDENSATE & F.W. SYSTEM	HIGH PRESSURE FEEDWATER SYS	H.P. HEATER 6	None	141	32	Shell side inspections and channel side for the degradation mechanisms.	2012	2	
1296	6690	6709	6713	7114	0	1	#1 CONDENSATE & F.W. SYSTEM	HIGH PRESSURE FEEDWATER SYS	H.P. HEATER 6	None	142	32	Assessment of the tube plug map.	2012	2	
1296	6690	6709	6713	7114	0	1	#1 CONDENSATE & F.W. SYSTEM	HIGH PRESSURE FEEDWATER SYS	H.P. HEATER 6	None	143	32	ET inspection of tubes to assess the present condition (metallurgical evaluation may also be required depending upon the condition of the tubes).	2012	2	
1296	6690	6709	6713	7114	0	1	#1 CONDENSATE & F.W. SYSTEM	HIGH PRESSURE FEEDWATER SYS	H.P. HEATER 6	None	144	32	NDE inspection the major welds (seam, supports and nozzle welds) for the degradation mechanisms. PT or Magnetic particle testing (MT) or Conventional UT or Phased array (focused) can be used depending upon location.	2012	2	

8.2.2.9 Capital Projects

Table 8-36 below shows the suggested typical capital enhancements that should be considered for the Unit 1 feedwater system – HP feedwater heat exchangers:

TABLE 8-36 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – UNIT 1 FEEDWATER SYSTEM - HP FEEDWATER HEAT EXCHANGERS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Detail	CAP#	Appendix #	Capital Item	Date	Priority
1296	6690	6709	6712	0	0	1	#1 CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEEDWATER PUMPING	N/A	101	23	No capital required.		
1296	6690	6709	6712	8835	0	1	#1 CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEED PUMP EAST	N/A	102	23	Retrofit of variable speed control – fluid couplings or variable speed drives to reduce energy consumption and improve efficiency.	2013	2
1296	6690	6709	6712	8835	0	1	#1 CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEED PUMP EAST	N/A	103	23	Procure a spare 4 kV motor, to allow rewind of Units 1 and 2 and if practical Unit 3 motors as required.	2012	1
1296	6690	6709	6712	8835	0	1	#1 CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEED PUMP EAST	N/A	104	23	Install vibration monitoring.	2012	1
1296	6690	6709	6712	8836	0	1	#1 CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEED PUMP WEST	N/A	105	23	Retrofit of variable speed control – fluid couplings or variable speed drives to reduce energy consumption and improve efficiency.	2013	2
1296	6690	6709	6712	8836	0	1	#1 CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEED PUMP WEST	N/A	106	23	Procure a spare 4 kV motor, to allow rewind of Units 1 and 2 and if practical Unit 3 motors as required.	2012	1
1296	6690	6709	6712	8836	0	1	#1 CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEED PUMP WEST	N/A	107	23	Install vibration monitoring.	2012	1
1296	6690	6709	6713	0	0	1	#1 CONDENSATE & F.W. SYSTEM	HIGH PRESSURE FEEDWATER SYS	HIGH PRESSURE FEEDWATER SYS	N/A	108	32	No capital required.		
1296	6690	6709	6713	7112	0	1	#1 CONDENSATE & F.W. SYSTEM	HIGH PRESSURE FEEDWATER SYS	H.P. HEATER 4	N/A	109	32	No capital required.		
1296	6690	6709	6713	7113	0	1	#1 CONDENSATE & F.W. SYSTEM	HIGH PRESSURE FEEDWATER SYS	H.P. HEATER 5	N/A	110	32	Replace HP #5 Heater.	2013	1
1296	6690	6709	6713	7114	0	1	#1 CONDENSATE & F.W. SYSTEM	HIGH PRESSURE FEEDWATER SYS	H.P. HEATER 6	N/A	111	32	No capital required.		

8.2.3 Asset 7053 – Unit 1 Feedwater System - Deaerator

(Detailed Technical Assessment in Working Papers, Appendices 31 and 34)

Unit #:	1
Asset Class #	BU 1296 - Assets Generations
SCI & System:	6708 #1 Condensate & Feedwater System
Sub-Systems:	6711 #1 Low Pressure Feedwater System
Components:	7053 #1 Deaerator System (Deaerator and Deaerator Storage Tank)

8.2.3.1 Description

The deaerator system consists of two vessels, a heater (deaerator) and a storage tank (deaerator storage tank). The Unit 1 deaerator is a horizontal spray type, with the deaerator mounted on the horizontal deaerator storage tank. The deaerator and deaerator storage tank vessels are of welded construction using carbon steel with some of the deaerator internal hardware fabricated from stainless steel. The vessels are designed as per American Society of Mechanical Engineers (ASME) Boilers and Pressure Vessels Code Section VIII, Div. 1. There is one safety valve on the top of the deaerator.

The function of the deaerator is to remove oxygen and other dissolved gases in the feedwater in order to lower the potential for corrosion in the steam/water cycle. Condensate is sprayed over a cascading series of trays to maximize the surface area of the water. Bleed steam is used as a main source of steam to strip the oxygen and other non-condensable gases from the condensate. Pegging steam is provided from the auxiliary steam system. The steam and gases are vented from the top of the deaerator vessel.

The deaerated water is collected in the storage tank where steam coil heaters maintain water temperatures during off-line periods. The deaerator storage tank is the suction tank for the boiler feedwater pumps (BFP's). High pressure (HP) feedwater heater drains are fed to the deaerator. The BFP recirculation is fed back to the storage tank.

The deaerator storage tank is provided with two cradle type supports. One end is anchored and the other support is free to allow thermal expansion.

8.2.3.2 History

Manufactured/Delivered	1969
In-Service Date	Sep 1970
Generation Base Load End Date	Dec 2015
Generation Peak/Emerg Gen End Date	Dec 2020

The hours associated with the analyses are:

Hours Generation Actual - Ops to Dec 2009	166
Max Hours Generation Ops – to Dec 2015	210
Max Hrs Gen Ops to Gen End Date Dec 2020	219

8.2.3.3 Inspection and Repair History

The deaerator and deaerator storage tank vessel internal visual inspections and NDE of selective welds were carried out in accordance with the plant annual outage inspection plan. The inspections were mostly focused on the accessible areas. There were very limited inspections carried out on the deaerator vessel as there is no real access to the shell without removing the trays. The following is a summary of the inspection findings that were reported in the ALSTOM outage reports from year 2001 to 2009:

Deaerator

- Cracks in the stainless steel liner;
- Warped stainless liner causing sealing issues for spray nozzles;
- Loose trays;
- Circumferential ridges in the deaerator shell on both the north and south sides; Minor corrosion, pitting, and wall thinning possibly due to flow accelerated corrosion in the bottom of the shell was noted when a section of trays was removed in 2007; and
- No evidence of cracking in the accessible shell seam welds during limited inspections.

Deaerator Storage Tank

- Corrosion fatigue was found in the storage tank on the inside surface of the shell around the saddle support locations during the 2003 inspection. All damage was removed and the thickness of the tank was restored by pad welding. A semi-circle was cut in the centre gusset plates in the saddles to increase flexibility. Also, the stitch weld between the vessel shell and saddle plate was removed at the centre gusset plate location. Corrosion fatigue was not observed during subsequent inspections at these locations.
- Light pitting has been observed on the inside surfaces in general and especially around the weld seams and in the bottom of shell.
- The manway gasket seating surface was noted to be in poor condition.
- Significant undercut was noted in the first can to can girth weld from the east side during the 2004 outage. The undercut was at a repair weld that was done some time in the past - possibly during fabrication and runs along the bottom one third to one quarter of the shell.
- It was noted in the 2004 outage report that the hot feedwater inlet nozzle to shell attachment welds appeared to be in poor condition. These have not been repaired.

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8.2.3.4 Condition Assessment

The condition assessment of the Unit 1 feedwater system - deaerator is illustrated below in Table 8-37.

TABLE 8-37 CONDITION ASSESSMENT – UNIT 1 FEEDWATER SYSTEM – DEAERATOR

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset Level 2	Asset Level 3	Description	Detail	Condition Summary ID #	Append #	Condition	EPRI Identifier	Original Life (Base Load) Ops Hrs (Yrs)	Current Expected Minimum Remaining Life Years (Subject to Test)	End of Life (EOL) Required	Next Regular Inspection	Next Planned Overhaul or Major Inspection	Capability to Reach Next Overhaul	Capability to Reach EOL	In Service
1296	6690	6709	6711	7053	0	1	#1 CONDENSATE & F.W. SYSTEM	CONDENSATE & F.W. SYSTEM	DEAERATOR SYSTEM	N/A	240	31	No major life limiting issue observed during the past limited deaerator and deaerator storage tank inspections. Many susceptible locations have not been inspected. The corrosion fatigue issues experienced in the past are not re-occurring. Some pitting in the both deaerator and deaerator storage tank vessels observed. Wall thinning observed in the bottom of the deaerator shells. Ridges observed may be due to erosion. Undercut observed in storage tank.	4	200000 (30)	(10)	2020	2011	2012	Yes	Yes	1970

Notes: 1. A “(bracketed)” value in the “Current Expected Remaining Life” column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as “(X/Y)” has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

2. The “Next Regular Inspection” column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The “Next Planned Overhaul or Major Inspection” column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a “Desired Life” stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or are not known by AMEC.

8.2.3.5 Actions

Based on the condition assessment, the following actions are recommended for the Unit 1 feedwater system - deaerator.

TABLE 8-38 RECOMMENDED ACTIONS – UNIT 1 FEEDWATER SYSTEM – DEAERATOR

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Unit	Asset 2/3	Asset 3/4	Description	Detail	Action #	App #	Action	Year	Priority
1296	6690	6709	6711	7053	1	#1 CONDENSATE & F.W. SYSTEM	CONDENSATE & F.W. SYSTEM	DEAERATOR SYSTEM	N/A	135	31	Perform Level 2 inspections.	2012	2
1296	6690	6709	6711	7053	1	#1 CONDENSATE & F.W. SYSTEM	CONDENSATE & F.W. SYSTEM	DEAERATOR SYSTEM	N/A	136	31	Implement ongoing inspections and performance testing based on industry practices.	2012	3
1296	6690	6709	6711	7053	1	#1 CONDENSATE & F.W. SYSTEM	CONDENSATE & F.W. SYSTEM	DEAERATOR SYSTEM	N/A	137	31	Repair the feedwater recirculation inlet nozzles at the deaerator storage tank from inside.	2012	1
1296	6690	6709	6711	7053	1	#1 CONDENSATE & F.W. SYSTEM	CONDENSATE & F.W. SYSTEM	DEAERATOR SYSTEM	N/A	138	31	Refurbish manway seating surfaces that are in poor condition.	2012	2
1296	6690	6709	6711	7053	1	#1 CONDENSATE & F.W. SYSTEM	CONDENSATE & F.W. SYSTEM	DEAERATOR SYSTEM	N/A	139	31	Monitor pitting corrosion in the deaerator and deaerator storage tank vessels and wall thinning in the bottom of the deaerator.	2012	2
1296	6690	6709	6711	7053	1	#1 CONDENSATE & F.W. SYSTEM	CONDENSATE & F.W. SYSTEM	DEAERATOR SYSTEM	N/A	140	31	Investigate the root cause of the ridges observed in the deaerator.	2012	2
1296	6690	6709	6711	7053	1	#1 CONDENSATE & F.W. SYSTEM	CONDENSATE & F.W. SYSTEM	DEAERATOR SYSTEM	N/A	141	31	Assess the significance of weld undercut that was observed in Unit 1 deaerator storage tank.	2012	2
1296	6690	6709	6711	7053	1	#1 CONDENSATE & F.W. SYSTEM	CONDENSATE & F.W. SYSTEM	DEAERATOR SYSTEM	N/A	142	31	Evaluate condition of spray nozzles that were observed eroding in Unit 3.	2012	2

8.2.3.6 Risk Assessment

The risk assessment associated with the Unit 1 feedwater system - deaerator, both from a technological perspective and a safety perspective, is illustrated below in Table 8-39.

TABLE 8-39 RISK ASSESSMENT - UNIT 1 FEEDWATER SYSTEM – DEAERATOR

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Component	Risk Assess #	Appendix #	Major Issues	Remaining Life Years (Insufficient Info - Inspection Required Within (x) Years)	Remaining Life Comments	TECHNO-ECO RISK ASSESS MODEL			SAFETY RISK ASSESS MODEL			Possible Failure Event	Mitigation
																Likeli-hood	Conse-quence	Risk Level	Likeli-hood	Conse-quence	Safety Risk		
1296	6690	6709	6711	7053	0	1	#1 CONDENSATE & F.W. SYSTEM	CONDENSATE & F.W. SYSTEM	DEAERATOR SYSTEM	Deaerators	138	31	Corrosion fatigue, thermal fatigue, corrosion & FAC.	(10)	No real life limiting issue as per inspection to date. Additional inspections required.	3	B	Medium	3	B	Medium	Weld cracking, corrosion fatigue, wall thinning due FAC and internal hardware failure leading to functional failure. Forced outage. Life Safety.	Inspect and maintain.
1296	6690	6709	6711	7053	0	1	#1 CONDENSATE & F.W. SYSTEM	CONDENSATE & F.W. SYSTEM	DEAERATOR SYSTEM	Deaerators/ Storage Tanks	139	31	Corrosion fatigue, thermal fatigue, corrosion & FAC.	10	No evidence of susceptibly during limited inspection to date. Ongoing monitoring required.	1	D	Medium	2	D	Low	Forced outage. Life Safety.	Inspect and maintain.

8.2.3.7 Life Cycle Curve and Remaining Life

Figure 8-15 below illustrates the life cycle curve for the Unit 1 Unit 1 feedwater system – deaerator. One curve is used as the major elements of the deaerator are largely of the same age and condition. The life curve is a plot of current and projected operating hours in generation mode only on the y-axis versus calendar year on the x-axis. The figure has several vertical lines representing differing representative nominal age limits for various components. It also has several horizontal lines that represent a range of practical equipment equivalent base loaded operating hour life limits. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view.

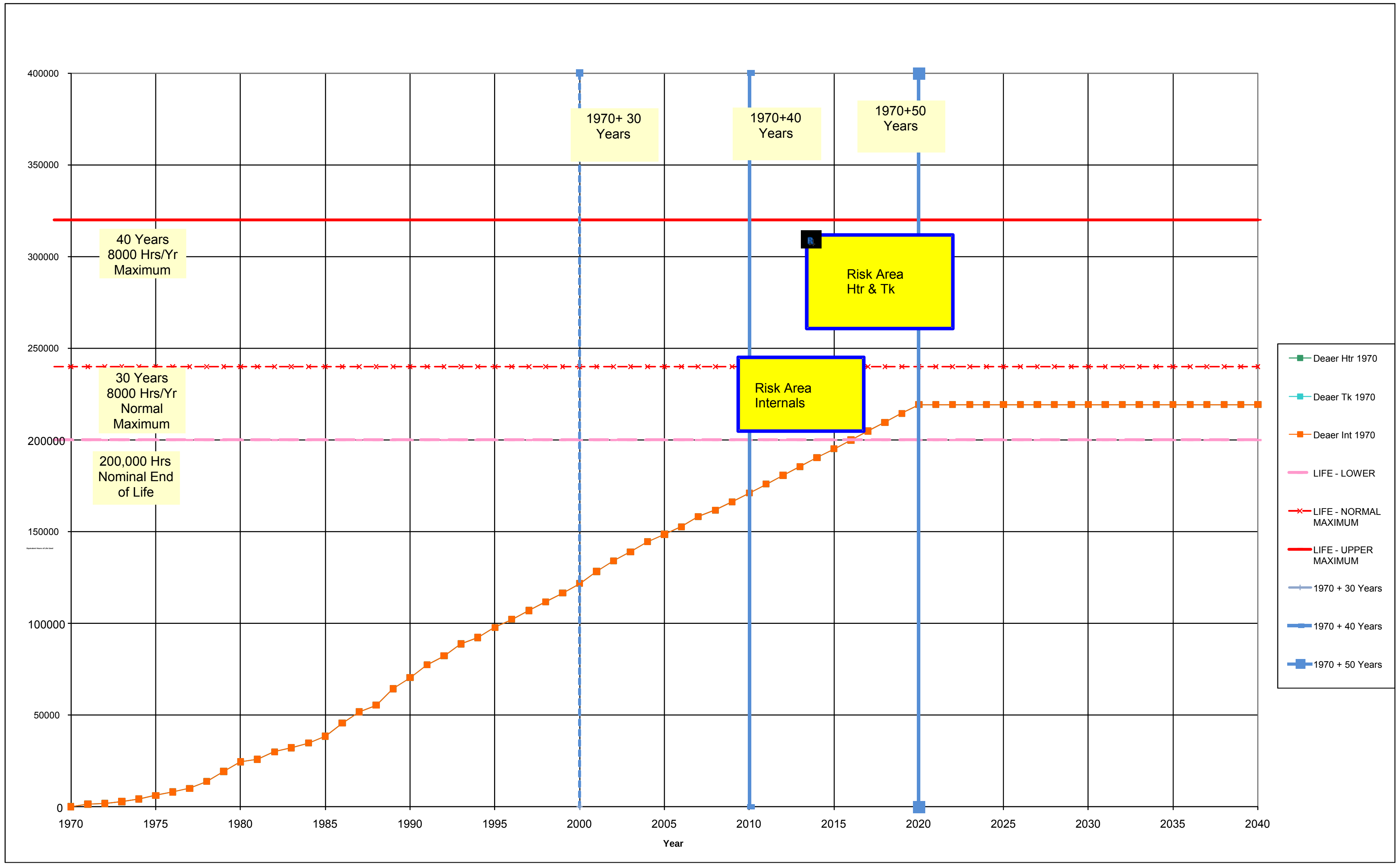

FIGURE 8-15 LIFE CYCLE CURVE – UNIT 1 FEEDWATER SYSTEM - DEAERATOR

The curve indicates that the remaining life (RL) of the Unit 1 feedwater system - deaerator exceeds the desired life (DL) which is end date for generation of 2020, with the potential though unlikely exception of some deaerator internals. The plant inspections form an excellent base of condition information supporting the ability of the deaerator as a whole to meet the EOL date. There is however insufficient detailed inspection information of some of the difficult to reach internals to fully assess their condition. A detailed Level 2 inspection in 2012 is recommended to provide information for that assessment.

8.2.3.8 Level 2 Inspections – Unit 1 Feedwater System - Deaerator

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 8-40 below, assuming that the current plant inspection and maintenance program is maintained or improved.

TABLE 8-40 LEVEL 2 INSPECTIONS – UNIT 1 FEEDWATER SYSTEM – DEAERATOR

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Sub System Comment	L2#	Appendix #	Level 2 Work	Year	Priority	Cost k$
1296	6690	6709	6711	7053	0	1	#1 CONDENSATE & F.W. SYSTEM	CONDENSATE & F.W. SYSTEM	DEAERATOR SYSTEM	None	121	31	NDE inspection of the areas that were not inspected is required.	2012	2	$216
1296	6690	6709	6711	7053	0	1	#1 CONDENSATE & F.W. SYSTEM	CONDENSATE & F.W. SYSTEM	DEAERATOR SYSTEM	None	122	31	Visual inspection for FAC damage (shiny black surface) of the susceptible areas. UT thickness measurement to be carried out if FAC damage is evident.	2012	2	
1296	6690	6709	6711	7053	0	1	#1 CONDENSATE & F.W. SYSTEM	CONDENSATE & F.W. SYSTEM	DEAERATOR SYSTEM	None	123	31	Inspection of all accessible shell and head surfaces for pitting, and for water streaks or signs of erosion (erosion will normally appear as a clean, pitted surface).	2012	2	
1296	6690	6709	6711	7053	0	1	#1 CONDENSATE & F.W. SYSTEM	CONDENSATE & F.W. SYSTEM	DEAERATOR SYSTEM	None	124	31	Inspection of the tray stack.	2012	2	
1296	6690	6709	6711	7053	0	1	#1 CONDENSATE & F.W. SYSTEM	CONDENSATE & F.W. SYSTEM	DEAERATOR SYSTEM	None	125	31	Inspection of the spray valves.	2012	2	
1296	6690	6709	6711	7053	0	1	#1 CONDENSATE & F.W. SYSTEM	CONDENSATE & F.W. SYSTEM	DEAERATOR SYSTEM	None	126	31	Inspections for cracking Re-inspection intervals to be based on operating/inspection/repair history as per NACE recommendations and local regulations.	2012	2	

8.2.3.9 Capital Projects

Table 8-41 below shows the suggested typical capital enhancements that should be considered for the Unit 1 feedwater system –deaerator:

TABLE 8-41 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – UNIT 1 FEEDWATER SYSTEM – DEAERATOR

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Detail	CAP#	Appendix #	Capital Item	Date	Priority
1296	6690	6709	6711	7053	0	1	#1 CONDENSATE & F.W. SYSTEM	CONDENSATE & F.W. SYSTEM	DEAERATOR SYSTEM	N/A	98	31	No capital required.		

8.2.4 Asset 6711 – Unit 1 Feedwater System - Low Pressure (LP) Feedwater Heat Exchangers

(Detailed Technical Assessment in Working Papers, Appendix 24)

Unit #:	1
Asset Class #	BU 1296 - Assets Generations
SCI & System:	6708 #1 Condensate & Feedwater System
Sub-Systems:	6711 #1 Low Pressure Feedwater
Components:	7059 #1 LP Heater 1
	7066 #1 LP Heater 2
	7058 #1 LP FW Reserve
	8799 #1 Condensate Extraction System

8.2.4.1 Description

The low pressure (LP) feedwater system servicing Unit 1 contains two LP feedwater heat exchangers that are referred to as LP-1 and LP-2. The primary function of the LP feedwater heat exchangers is to increase plant thermal efficiency by preheating the boiler feedwater prior entering to the deaerators.

The LP feedwater heat exchangers are horizontally mounted, 100% capacity pressure vessels of the U-tube type construction. There are two tube passes on the feedwater side and a divided flow of heating steam on the shell side of each heater.

The main components of the LP feedwater heat exchangers are shell, shell skirt, tubes, tubesheet, channel, impingement plates, tube support plates/pass partition plates/baffles, shrouds, impingement plate and channel cover. The tubesheet and channel are made from a single forging. The heat exchangers are designed according to ASME Boiler and Pressure Vessel Code Section VIII Div. 1, Heat Exchanger Institute standard for closed feedwater heat exchangers.

Two condensate extraction pumps serve Unit 1, driven by 4 kV electric motors. The pumps are original equipment and the motors installed with the unit upgrade in 1989. The pumps draw condensate from the condenser and circulate it to the low pressure feedwater heaters and deaerator. The system also includes condensate make-up and a low pressure feedwater reserve tank system to enable the unit to manage high and low water levels throughout the condensate and feedwater system.

8.2.4.2 History

Manufactured/Delivered	1969
In-Service Date	Sep 1970
Generation Base Load End Date	Dec 2015
Generation Peak/Emerg Gen End Date	Dec 2020

The hours associated with the analyses are:

Hours Generation Actual - Ops to Dec 2009	166
Max Hours Generation Ops – to Dec 2015	210
Max Hrs Gen Ops to Gen End Date Dec 2020	219

8.2.4.3 Inspection and Repair History

Leak tests are generally performed on the LP feedwater heat exchangers during annual outages, but records of these tests were not available. Leaking tubes are plugged when identified during a leak test. In addition, tube plugging maps and history were not available. During interviews with plant operations staff, it was noted that there were no performance issues associated with the LP feedwater heat exchangers servicing Unit 1.

The condensate extraction system is regularly inspected as part of the plant PM program. No significant issues have been identified with the pumps or motors. The motors are electrically checked annually and appear to be in reasonable condition for their age. The motors are however at an age where reliability and failure may be issues in the future. The condensate extraction piping is experiencing some external corrosion, but no leaks or failures were identified.

No internal inspections of the reserve tanks have been undertaken recently, primarily due to concerns associated with enclosed space requirements. Externally, minor surface pitting was evident but no significant problems or leaks were noted.

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8.2.4.4 Condition Assessment

The condition assessment of the Unit 1 feedwater system – LP feedwater heat exchangers (and associated condensate extraction system) components is illustrated below in Table 8-42.

TABLE 8-42 CONDITION ASSESSMENT – UNIT 1 FEEDWATER SYSTEM - LP FEEDWATER HEAT EXCHANGERS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset Level 2	Asset Level 3	Description	Detail	Condition Summary ID #	Append #	Condition	EPRI Identifier	Original Life (Base Load) Ops Hrs (Yrs)	Current Expected Minimum Remaining Life Years (Subject to Test)	End of Life (EOL) Required	Next Regular Inspection	Next Planned Overhaul or Major Inspection	Capability to Reach Next Overhaul	Capability to Reach EOL	In Service
1296	6690	6709	7040	0	0	1	#1 CONDENSATE & F.W. SYSTEM	CONDENSATE MAKE UP SYSTEM	CONDENSATE MAKE UP SYSTEM	N/A	146	21	Not reviewed.	3a	200000 (30)	10	2020	2011		Yes	Yes	1970
1296	6690	6709	8799	0	0	1	#1 CONDENSATE & F.W. SYSTEM	CONDENSATE EXTRACTION SYSTEM	CONDENSATE EXTRACTION SYSTEM	N/A	147	20	Limited review. No issues identified.	3a	(30)	10	2020	2011		Yes	Yes	1970
1296	6690	6709	8799	7045	0	1	#1 CONDENSATE & F.W. SYSTEM	CONDENSATE EXTRACTION SYSTEM	COND EXTRACTION PUMP NORTH	N/A	148	20	Pump installed in 1969 and motor in 1989. No issue identified.	3a	(30)	10	2020	2012		Yes	Yes	1970/1989
1296	6690	6709	8799	7049	0	1	#1 CONDENSATE & F.W. SYSTEM	CONDENSATE EXTRACTION SYSTEM	COND EXTRACTION PUMP SOUTH	N/A	231	20	Pump installed in 1969 and motor in 1989. No issue identified.	3a	(30)	10	2020	2012		Yes	Yes	1970/1989
1296	6690	6709	6711	0	0	1	#1 CONDENSATE & F.W. SYSTEM	CONDENSATE & F.W. SYSTEM	LOW PRESSURE FEEDWATER SYS	N/A	234	24,26	Not reviewed in detail. No issues identified.	4	200000 (30)	10	2020	2011	2011	Yes	Yes	1970
1296	6690	6709	6711	7056	0	1	#1 CONDENSATE & F.W. SYSTEM	CONDENSATE & F.W. SYSTEM	LOW PRESSURE FW RESERVE	N/A	235	26	No internal visual inspections recently. Minor external pitting corrosion. Relatively minor internal corrosion identified during interviews. No recent NDE inspections.	4	(60)	(20)	2020	2011	2011	Yes	Yes	1970
1296	6690	6709	6711	7059	0	1	#1 CONDENSATE & F.W. SYSTEM	#1 CONDENSATE & F.W. SYSTEM	LOW PRESSURE HEATER 1	N/A	236	26	No NDE inspections done. Annual cleaning and tube leak testing. Two heaters on the units may have been replaced, but no records or other interviews could confirm.	4	(30)	(10)	2020	2011	2011	Yes	Yes	1970
1296	6690	6709	6711	7066	0	1	#1 CONDENSATE & F.W. SYSTEM	#1 CONDENSATE & F.W. SYSTEM	LOW PRESSURE HEATER 2	N/A	237	26	No NDE inspections done. Annual cleaning and tube leak testing. Two heaters on the units may have been replaced, but no records or other interviews could confirm..	4	(30)	(10)	2020	2011	2011	Yes	Yes	1970

Notes:
1. A "(bracketed)" value in the "Current Expected Remaining Life" column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as "(X/Y)" has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.
2. The "Next Regular Inspection" column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The "Next Planned Overhaul or Major Inspection" column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a "Desired Life" stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or are not known by AMEC.

8.2.4.5 Actions

Based on the condition assessment, the following actions are recommended for the Unit 1 feedwater system (and associated condensate extraction system) components - LP feedwater heat exchangers.

TABLE 8-43 RECOMMENDED ACTIONS – UNIT 1 FEEDWATER SYSTEM - LP FEEDWATER HEAT EXCHANGERS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Unit	Asset 2/3	Asset 3/4	Description	Detail	Action #	App #	Action	Year	Priority
1296	6690	6709	0	0	1	#1 CONDENSATE & F.W. SYSTEM	CONDENSATE & F.W. SYSTEM	CONDENSATE & F.W. SYSTEM	N/A	127	20	See details below.		
1296	6690	6709	6711	0	1	#1 CONDENSATE & F.W. SYSTEM	CONDENSATE & F.W. SYSTEM	LOW PRESSURE FEEDWATER SYS	N/A	128	24	Implement ongoing inspections and performance testing based on industry practices.	2011	2
1296	6690	6709	6711	7056	1	#1 CONDENSATE & F.W. SYSTEM	CONDENSATE & F.W. SYSTEM	LOW PRESSURE FW RESERVE	N/A	129	24	Perform Level 2 inspections on tanks – thickness checks and internals inspections.	2011	2
1296	6690	6709	6711	7056	1	#1 CONDENSATE & F.W. SYSTEM	CONDENSATE & F.W. SYSTEM	LOW PRESSURE FW RESERVE	N/A	130	24	Continue a program of ongoing inspections and compare against industry practices.	2011	2
1296	6690	6709	6711	7059	1	#1 CONDENSATE & F.W. SYSTEM	#1 CONDENSATE & F.W. SYSTEM	LOW PRESSURE HEATER 1	N/A	131	24	Perform Level 2 inspections.	2011	3
1296	6690	6709	6711	7066	1	#1 CONDENSATE & F.W. SYSTEM	#1 CONDENSATE & F.W. SYSTEM	LOW PRESSURE HEATER 2	N/A	132	24	Perform Level 2 inspections.	2011	3
1296	6690	6709	7040	0	1	#1 CONDENSATE & F.W. SYSTEM	CONDENSATE MAKE UP SYSTEM	CONDENSATE MAKE UP SYSTEM	N/A	155	21	See WTP and Polishers.		
1296	6690	6709	8799	0	1	#1 CONDENSATE & F.W. SYSTEM	CONDENSATE EXTRACTION SYSTEM	CONDENSATE EXTRACTION SYSTEM	N/A	156	20	Spot check likely critical parts of piping and valving – thickness and corrosion.	2011	2
1296	6690	6709	8799	0	1	#1 CONDENSATE & F.W. SYSTEM	CONDENSATE EXTRACTION SYSTEM	CONDENSATE EXTRACTION SYSTEM	N/A	157	20	Maintain current program of ongoing inspections and overhauls. Procure a spare motor to service all three units, in the event of a failure of an existing unit.	2011	2
1296	6690	6709	8799	7045	1	#1 CONDENSATE & F.W. SYSTEM	CONDENSATE EXTRACTION SYSTEM	COND EXTRACTION PUMP NORTH	N/A	158	20	Procure a spare condensate extraction motor, primarily for Units 1 & 2 but compatible with Unit 3. Continue current inspection and maintenance activities.	2012	1
1296	6690	6709	8799	7049	1	#1 CONDENSATE & F.W. SYSTEM	CONDENSATE EXTRACTION SYSTEM	COND EXTRACTION PUMP SOUTH	N/A	159	20	Procure a spare condensate extraction motor, primarily for Units 1 & 2 but compatible with Unit 3. Continue current inspection and maintenance activities.	2012	1

8.2.4.6 Risk Assessment

Table 8-44 below illustrates the risk assessment for the Unit 1 feedwater system – LP feedwater heat exchangers (and associated condensate extraction system) components, both from a technological perspective and a safety perspective using the models presented in Section 3.

TABLE 8-44 RISK ASSESSMENT – UNIT 1 FEEDWATER SYSTEM - LP FEEDWATER HEAT EXCHANGERS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Component	Risk Assess #	Appendix #	Major Issues	Remaining Life Years (Insufficient Info - Inspection Required Within (x) Years)	Remaining Life Comments	TECHNO-ECO RISK ASSESS MODEL			SAFETY RISK ASSESS MODEL			Possible Failure Event	Mitigation
																Likeli-hood	Conse-quence	Risk Level	Likeli-hood	Conse-quence	Safety Risk		
1296	6690	6709	0	0	0	1	#1 CONDENSATE & F.W. SYSTEM	CONDENSATE & F.W. SYSTEM	CONDENSATE & F.W. SYSTEM	N/A	123		See details below.	(5)	None								
1296	6690	6709	7040	0	0	1	#1 CONDENSATE & F.W. SYSTEM	CONDENSATE MAKE UP SYSTEM	CONDENSATE MAKE UP SYSTEM	N/A	124		Not addressed. Mechanical collapse.		None								
1296	6690	6709	8799	0	0	1	#1 CONDENSATE & F.W. SYSTEM	CONDENSATE EXTRACTION SYSTEM	CONDENSATE EXTRACTION SYSTEM	CE Piping/Valves	125	20	Weld failure, rupture.	10	None	1	A	Low	1	B	Low	Piping leak; short duration shutdown for repair	Inspect and maintain.
1296	6690	6709	8799	7045	0	1	#1 CONDENSATE & F.W. SYSTEM	CONDENSATE EXTRACTION SYSTEM	COND EXTRACTION PUMP NORTH	CE Pumps	126	20	Seal, bearing, impeller failure.	10	None	1	A	Low	1	B	Low	Pump failure; 0% capability reduction due to redundancy	Current inspection and maintain.
1296	6690	6709	8799	7045	0	1	#1 CONDENSATE & F.W. SYSTEM	CONDENSATE EXTRACTION SYSTEM	COND EXTRACTION PUMP NORTH	4 kV Condensate Extraction Pump Motor - A, B	127	25	Electrical fault, mechanical fatigue, ops error.	10	None	1	A	Low	1	B	Low	Loss 60% unit generation	Spare and current inspection and maintain.
1296	6690	6709	8799	7049	0	1	#1 CONDENSATE & F.W. SYSTEM	CONDENSATE EXTRACTION SYSTEM	COND EXTRACTION PUMP SOUTH	CE Pumps	128	20	Seal, bearing, impeller failure.	10	None	1	A	Low	1	B	Low	Pump failure; 0% capability reduction due to redundancy	Current inspection and maintain.
1296	6690	6709	8799	7049	0	1	#1 CONDENSATE & F.W. SYSTEM	CONDENSATE EXTRACTION SYSTEM	COND EXTRACTION PUMP SOUTH	4 kV Condensate Extraction Pump Motor - A, B	129	25	Electrical fault, mechanical fatigue, ops error.	10	None	1	A	Low	1	B	Low	Loss 60% unit generation	Spare and current inspection and maintain.
1296	6690	6709	6711	0	0	1	#1 CONDENSATE & F.W. SYSTEM	CONDENSATE & F.W. SYSTEM	LOW PRESSURE FEEDWATER SYS	All LP Feedwater Heaters	132	24	SCC, thermal/ mechanical fatigue.	(10)	Life management program is required	1	C	Low	1	B	Low	Excessive tube failure event resulting in Turbine water induction.	Inspect and maintain.
1296	6690	6709	6711	7056	0	1	#1 CONDENSATE & F.W. SYSTEM	CONDENSATE & F.W. SYSTEM	LOW PRESSURE FW RESERVE	LP Feedwater Reserve Tanks	133	26	Corrosion, impingement.	(20)	>10 Years. Inspections are required to confirm	1	A	Low	1	A	Low	Major Leak, loss condensate	Inspect and maintain.
1296	6690	6709	6711	7059	0	1	#1 CONDENSATE & F.W. SYSTEM	#1 CONDENSATE & F.W. SYSTEM	LOW PRESSURE HEATER 1	LP Feedwater Heater #1	134	24	SCC, FAC, thermal/ mechanical fatigue, corrosion fatigue.	(10)	Inspections are required to assess the remaining life.	1	B	Low	1	B	Low	Tube failures, internal hardware failure and shell wall thinning due FAC and weld cracking. Unit shutdown/htr bypass	Inspect and maintain.
1296	6690	6709	6711	7066	0	1	#1 CONDENSATE & F.W. SYSTEM	#1 CONDENSATE & F.W. SYSTEM	LOW PRESSURE HEATER 2	LP Feedwater Heater #2	135	24	SCC, FAC, thermal/ mechanical fatigue, corrosion fatigue.	(10)	Inspections are required to assess the remaining life	1	B	Low	1	B	Low	Tube failures, internal hardware failure and shell wall thinning due FAC and weld cracking. Unit shutdown/htr bypass	Inspect and maintain.

8.2.4.7 Life Cycle Curve and Remaining Life

The life cycle curve for the Unit 1 feedwater system - LP feedwater heat exchangers is illustrated below. One curve represents both of the low pressure heat exchangers which are original equipment. The life curve is a plot of current and projected operating hours (generation mode only) on the y-axis versus calendar year on the x-axis. The figure has several vertical lines representing differing representative nominal age limits for various components. It also has several horizontal lines that represent a range of practical equipment equivalent base loaded operating hour life limits. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view.

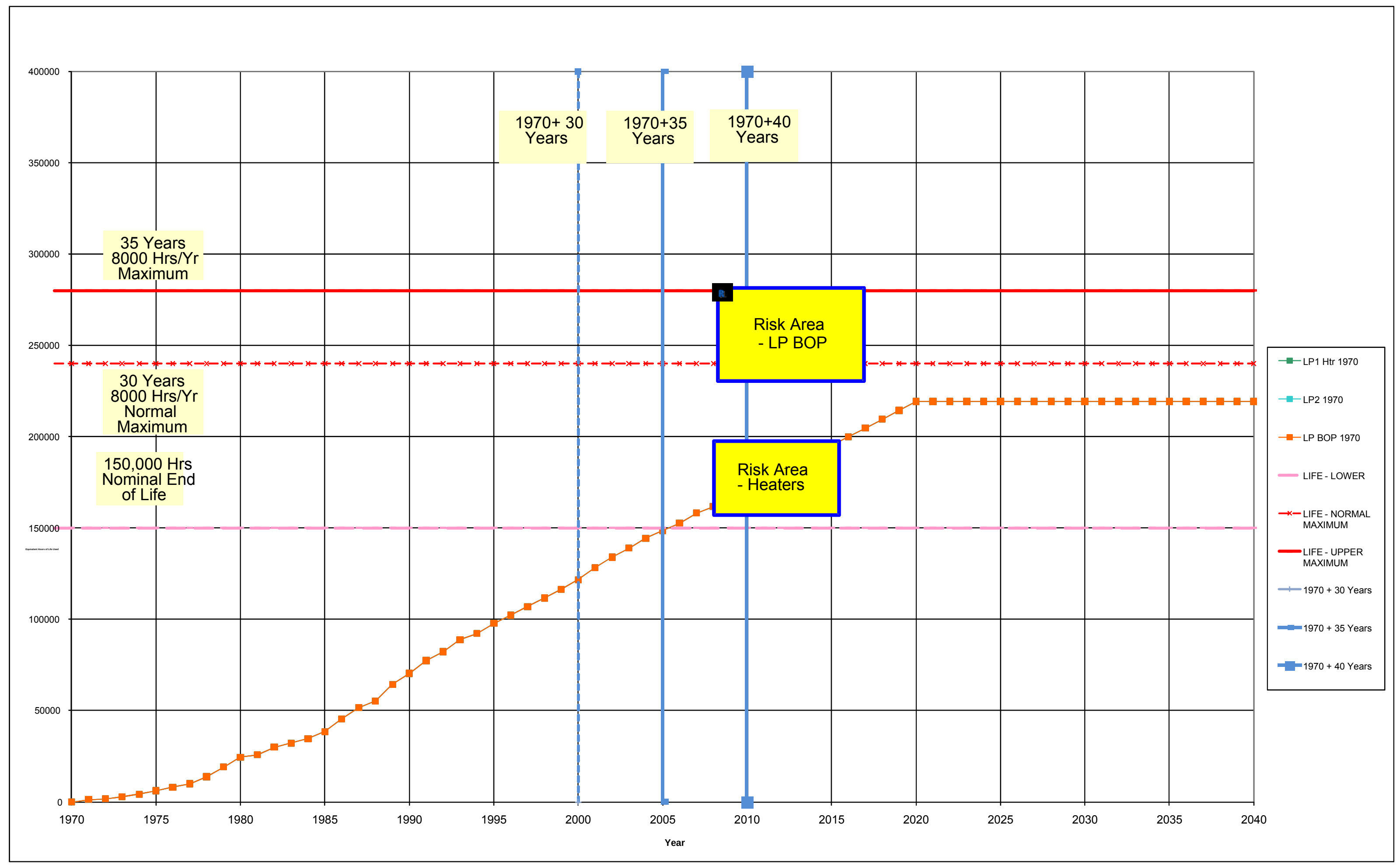

FIGURE 8-16 LIFE CYCLE CURVE – UNIT 1 FEEDWATER SYSTEM - LP FEEDWATER HEAT EXCHANGERS

The curves indicate that the remaining life (RL) of the feedwater system LP heat exchangers may not be able to reach the desired life (DL) 2020 end date for generation. Given that no detailed NDE information has been obtained on the LP heat exchangers, a detailed Level 2 inspection is recommended for 2011.

The life cycle curve for the Unit 1 condensate extraction pumps and motors is illustrated below. Two curves are used to represent the original equipment pump and the pump motor (upgraded in 1989). The life curve is a plot of current and projected operating hours (generation mode only) on the y-axis versus calendar year on the x-axis. The figure has several vertical lines representing differing representative nominal age limits for various components. It also has several horizontal lines that represent a range of practical equipment equivalent base loaded operating hour life limits. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view.

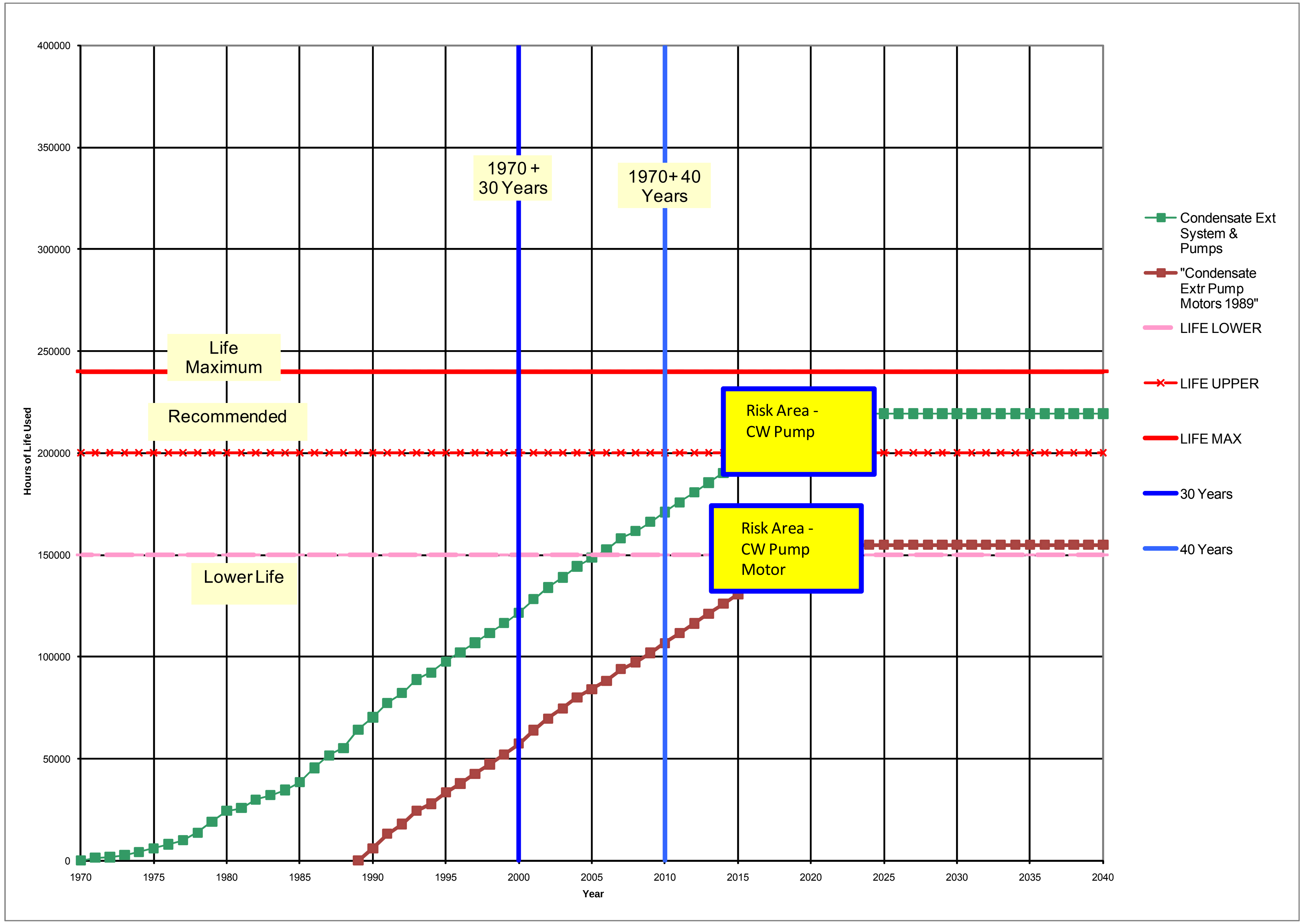

Figure 8-17 Life Cycle Curve – Unit 1 Feedwater System – Condensate Extraction Pumps and Motors

The curves indicate that the remaining life (RL) of the condenser condensate extraction pumps and motors can likely be able to reach the desired life (DL) 2020 end date for generation. The condensate extraction pump motors are expected however to be entering a period of higher unreliability.

8.2.4.8 Level 2 Inspections – Unit 1 Feedwater System - LP Feedwater Heat Exchangers

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 8-45 below, assuming that the current plant inspection and maintenance program is maintained or improved.

TABLE 8-45 LEVEL 2 INSPECTIONS – UNIT 1 FEEDWATER SYSTEM - LP FEEDWATER HEAT EXCHANGERS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Sub System Comment	L2#	Appendix #	Level 2 Work
1296	6690	6709	0	0	0	1	#1 CONDENSATE & F.W. SYSTEM	CONDENSATE & F.W. SYSTEM	CONDENSATE & F.W. SYSTEM	None	102	24	No Level 2 required.
1296	6690	6709	7040	0	0	1	#1 CONDENSATE & F.W. SYSTEM	CONDENSATE MAKE UP SYSTEM	CONDENSATE MAKE UP SYSTEM	None	103	20	No Level 2 required.
1296	6690	6709	8799	0	0	1	#1 CONDENSATE & F.W. SYSTEM	CONDENSATE EXTRACTION SYSTEM	CONDENSATE EXTRACTION SYSTEM	None	104	20	No Level 2 inspections required at this time. Continue program of regular inspections and overhauls.
1296	6690	6709	8799	7045	0	1	#1 CONDENSATE & F.W. SYSTEM	CONDENSATE EXTRACTION SYSTEM	COND EXTRACTION PUMP NORTH	None	105	20	No Level 2 inspections required at this time. Continue program of regular inspections and overhauls.
1296	6690	6709	8799	7049	0	1	#1 CONDENSATE & F.W. SYSTEM	CONDENSATE EXTRACTION SYSTEM	COND EXTRACTION PUMP SOUTH	None	106	20	No Level 2 inspections required at this time. Continue program of regular inspections and overhauls.
1296	6690	6709	6711	0	0	1	#1 CONDENSATE & F.W. SYSTEM	CONDENSATE & F.W. SYSTEM	LOW PRESSURE FEEDWATER SYS	None	107	24	
1296	6690	6709	6711	7056	0	1	#1 CONDENSATE & F.W. SYSTEM	CONDENSATE & F.W. SYSTEM	LOW PRESSURE FW RESERVE	None	110	26	Inspections of interior wall inspections and thickness measurements of walls and impaired major welds. Internals visual inspection.
1296	6690	6709	6711	7059	0	1	#1 CONDENSATE & F.W. SYSTEM	#1 CONDENSATE & F.W. SYSTEM	LOW PRESSURE HEATER 1	None	111	24	Shell side inspections and channel side for the degradation mechanisms.
1296	6690	6709	6711	7059	0	1	#1 CONDENSATE & F.W. SYSTEM	#1 CONDENSATE & F.W. SYSTEM	LOW PRESSURE HEATER 1	None	112	24	Assessment of the tube plug map.
1296	6690	6709	6711	7059	0	1	#1 CONDENSATE & F.W. SYSTEM	#1 CONDENSATE & F.W. SYSTEM	LOW PRESSURE HEATER 1	None	113	24	ET inspection of tubes to assess the present condition (metallurgical evaluation may also be required depending upon the condition of the tubes).
1296	6690	6709	6711	7059	0	1	#1 CONDENSATE & F.W. SYSTEM	#1 CONDENSATE & F.W. SYSTEM	LOW PRESSURE HEATER 1	None	114	24	NDE inspection the major welds (seam, supports and nozzle welds) for the degradation mechanisms. PT or Magnetic particle testing (MT) or Conventional UT or Phased array (focused) can be used depending upon location.
1296	6690	6709	6711	7066	0	1	#1 CONDENSATE & F.W. SYSTEM	#1 CONDENSATE & F.W. SYSTEM	LOW PRESSURE HEATER 2	None	115	24	Shell side inspections and channel side for the degradation mechanisms.
1296	6690	6709	6711	7066	0	1	#1 CONDENSATE & F.W. SYSTEM	#1 CONDENSATE & F.W. SYSTEM	LOW PRESSURE HEATER 2	None	116	24	Assessment of the tube plug map.
1296	6690	6709	6711	7066	0	1	#1 CONDENSATE & F.W. SYSTEM	#1 CONDENSATE & F.W. SYSTEM	LOW PRESSURE HEATER 2	None	117	24	ET inspection of tubes to assess the present condition (metallurgical evaluation may also be required depending upon the condition of the tubes).
1296	6690	6709	6711	7066	0	1	#1 CONDENSATE & F.W. SYSTEM	#1 CONDENSATE & F.W. SYSTEM	LOW PRESSURE HEATER 2	None	118	24	NDE inspection the major welds (seam, supports and nozzle welds) for the degradation mechanisms. PT or Magnetic particle testing (MT) or Conventional UT or Phased array (focused) can be used depending upon location.

8.2.4.9 Capital Projects

Table 8-46 below shows the suggested typical capital enhancements that should be considered for the Unit 1 feedwater system – LP feedwater heat exchangers (and associated condensate extraction system) components:

TABLE 8-46 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – UNIT 1 FEEDWATER SYSTEM - LP FEEDWATER HEAT EXCHANGERS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Detail	CAP#	Appendix #	Capital Item	Date	Priority
1296	6690	6709	0	0	0	1	#1 CONDENSATE & F.W. SYSTEM	CONDENSATE & F.W. SYSTEM	CONDENSATE & F.W. SYSTEM	N/A	85		No capital required.		
1296	6690	6709	7040	0	0	1	#1 CONDENSATE & F.W. SYSTEM	CONDENSATE MAKE UP SYSTEM	CONDENSATE MAKE UP SYSTEM	N/A	86		No capital required.		
1296	6690	6709	8799	0	0	1	#1 CONDENSATE & F.W. SYSTEM	CONDENSATE EXTRACTION SYSTEM	CONDENSATE EXTRACTION SYSTEM	N/A	87	20	No capital required.		
1296	6690	6709	8799	7045	0	1	#1 CONDENSATE & F.W. SYSTEM	CONDENSATE EXTRACTION SYSTEM	COND EXTRACTION PUMP NORTH	N/A	88	20	Replace as required per current inspection and overhaul findings.	2013	3
1296	6690	6709	8799	7049	0	1	#1 CONDENSATE & F.W. SYSTEM	CONDENSATE EXTRACTION SYSTEM	COND EXTRACTION PUMP SOUTH	N/A	89	20	Replace as required per current inspection and overhaul findings.	2013	3
1296	6690	6709	6711	0	0	1	#1 CONDENSATE & F.W. SYSTEM	CONDENSATE & F.W. SYSTEM	LOW PRESSURE FEEDWATER SYS	N/A	92	26	No capital required.		
1296	6690	6709	6711	7056	0	1	#1 CONDENSATE & F.W. SYSTEM	CONDENSATE & F.W. SYSTEM	LOW PRESSURE FW RESERVE	N/A	93	26	No capital required.		
1296	6690	6709	6711	7059	0	1	#1 CONDENSATE & F.W. SYSTEM	#1 CONDENSATE & F.W. SYSTEM	LOW PRESSURE HEATER 1	N/A	94	24	No capital required.		
1296	6690	6709	6711	7066	0	1	#1 CONDENSATE & F.W. SYSTEM	#1 CONDENSATE & F.W. SYSTEM	LOW PRESSURE HEATER 2	N/A	95	24	No capital required.		

8.2.5 Asset 271316 – Unit 1 Condenser

(Detailed Technical Assessment in Working Papers, Appendix 22)

Unit #:	1
Asset Class #	BU 1296 - Assets Generations
SCI & System:	6691 #1 Turbine & Generator
Sub-Systems:	6739 # 1 Turbine & Condenser
Components:	271316 #1 Condenser
	6895 #2 Condenser Air Extraction

8.2.5.1 Description

The Unit 1 condenser is shell and tube type heat exchanger with two passes. There are two tube bundles in a single shell. The inlet and the outlet waterboxes are divided. Each tube bundle has an air removing zone (ARZ) in the middle of the bundle. There are 2 x 100% liquid ring vacuum pumps to remove the air and non condensable gases from the condenser shell. The pumps are sized to allow the unit to run at full vacuum with only one pump operating. Each pump is equipped with a nominally 70 kW, 600 V motor. The condenser also has a stainless steel metal bellow joint between the condenser shell and the turbine lower exhaust casing to compensate for turbine and condenser expansion.

The condenser cooling water is a combination of sea water and fresh water. The carbon steel waterbox material is protected by an epoxy coating and a sacrificial anodic system. The condenser waterboxes are equipped with a back wash system for cleaning the tubes internally while the unit is in operation. Nylon brushes are used to clean the tubes prior to the condenser lay-up.

The condenser was designed, fabricated and supplied Foster Wheeler in 1969/70.

8.2.5.2 History

Manufactured/Delivered	1969
In-Service Date	Sep 1970
Generation Base Load End Date	Dec 2015
Generation Peak/Emerg Gen End Date	Dec 2020
Next Major Overhaul/Inspection	2012

The hours associated with the analyses vary from element to element are:

Hours Generation Actual - Ops to Dec 2009	166
Max Hours Generation Ops – to Dec 2015	210
Max Hrs Gen Ops to Gen End Date Dec 2020	219

8.2.5.3 Inspection and Repair History

Unit 1 condenser is in good shape for its age. The number of plugged tubes is quite low, and the rate of increase in plugging has remained steadily low. The condition is monitored, but no aggressive inspection program is either in place or seems to be required.

A recent tube plug survey completed in 2010 indicated that 5.7% of the condenser tubes are plugged. The 2001 survey indicated that 5.3% of the tubes were plugged at that time. Based on this result, the in-service tube degradation rate of 0.4% over 9 years is very slow. This is also supported by the eddy current testing that was completed in 1998 when 70% of the total condenser tubes were inspected. Results show that 85% of the tubes tested had a wall loss of less than 25%. This is very close to the tube nominal wall thickness and the accuracy of the eddy current testing. These results indicate that the tubes have minimal degradation.

Inspections also confirm that there is no condensate grooving on the tube outside diameter (OD) in the air removing zone of the tube bundle. With the exception of minor wear, the waterboxes and the condenser shell are in good condition.

According to station staff, the steel piping at the inlet and outlet between the condenser and the underground concrete pipes has been replaced but the date was unknown. Some patching is evident on some units.

Shell & Hotwell: A review of the 2003 and 2008 inspection reports confirm that both the shell and hotwell are in good condition.

Waterboxes: The 2003 report indicated that the water boxes and the epoxy lining were in good condition. However, the condition of the water boxes was not mentioned in the 2008 inspection report.

Vacuum Pumps: The two condenser air extraction vacuum pumps and system are original equipment and approaching their expected end of life. No major issues were identified when achieving the required condenser back pressure at turbine full load or during unit start up. The pumps and motors are serviced yearly under the plant PM program. The plant is modifying the existing vent system to enable venting externally in order to eliminate the exhaust of its moisture into the powerhouse.

8.2.5.4 Condition Assessment

The condition assessment of the Unit 1 condenser is illustrated below in Table 8-47.

TABLE 8-47 CONDITION ASSESSMENT – UNIT 1 CONDENSER

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset Level 2	Asset Level 3	Description	Detail	Condition Summary ID #	Append #	Condition	EPRI Identifier	Original Life (Base Load) Ops Hrs (Yrs)	Current Expected Minimum Remaining Life Years (Subject to Test)	End of Life (EOL) Required	Next Regular Inspection	Next Planned Overhaul or Major Inspection	Capability to Reach Next Overhaul	Capability to Reach EOL	In Service
1296	6690	6691	6733	0	0	1	#1 TURBINE & GENERATOR	TURBINE CONDENSER SYSTEM	TURBINE CONDENSER SYSTEM	N/A	19	22	Good condition.	3a	200000 (40)	10	2020	2011	2012	Yes	Yes	1970
1296	6690	6691	6733	6780	0	1	#1 TURBINE & GENERATOR	TURBINE CONDENSER SYSTEM	CONDENSER AIR EXTRACTION	N/A	20	22	System in good condition. External venting needed.	10	150000 (30)	5	2020	2011	2012	Yes	No	1970
1296	6690	6691	6733	6780	8876	1	#1 TURBINE & GENERATOR	TURBINE CONDENSER SYSTEM	CONDENSER VACUUM PUMP NORTH	N/A	21	22	Near end of life.	10	150000 (30)	(2)	2020	2011	2012	Yes	No	1970
1296	6690	6691	6733	6780	8877	1	#1 TURBINE & GENERATOR	TURBINE CONDENSER SYSTEM	CONDENSER VACUUM PUMP SOUTH	N/A	22	22	Near end of life.	10	150000 (30)	(2)	2020	2011	2012	Yes	No	1970
1296	6690	6691	6733	271316	0	1	#1 TURBINE & GENERATOR	TURBINE CONDENSER SYSTEM	TURBINE CONDENSER	N/A	23	22	Condition is very good. 2010 tubes plug survey shows 5.7 % of tubes plugged vs 5.3% in 2001. No condensate grooving on the tube OD in the air removing zone. Minor wear and tear of waterboxes and condenser shell. The condenser steel piping at inlet and outlet has some patching evident on some units	3a	300000 (50)	20	2020	2011	2012	Yes	Yes	1970

Notes:
1. A "(bracketed)" value in the "Current Expected Remaining Life" column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as "(X/Y)" has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.
2. The "Next Regular Inspection" column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The "Next Planned Overhaul or Major Inspection" column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a "Desired Life" stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or are not known by AMEC.

8.2.5.5 Actions

Based on the condition assessment, the following actions are recommended for the Unit 1 condenser:

TABLE 8-48 RECOMMENDED ACTIONS – UNIT 1 CONDENSER

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Unit	Asset 2/3	Asset 3/4	Description	Detail	Action #	App #	Action	Year	Priority
1296	6690	6691	6733	0	1	#1 TURBINE & GENERATOR	TURBINE CONDENSER SYSTEM	TURBINE CONDENSER SYSTEM	N/A	26	22	Develop a ongoing program of monitoring CW inlet/outlet pipe conditions	2011	2
1296	6690	6691	6733	6780	1	#1 TURBINE & GENERATOR	TURBINE CONDENSER SYSTEM	CONDENSER AIR EXTRACTION	N/A	27	22	Perform Level II inspections on waterboxes for Unit 2 at a practical time.	2011	2
1296	6690	6691	6733	6780	1	#1 TURBINE & GENERATOR	TURBINE CONDENSER SYSTEM	CONDENSER VACUUM PUMP NORTH	N/A	28	22	Inspect CW Vacuum pump and refurbish or replace motor and pump	2011	3
1296	6690	6691	6733	6780	1	#1 TURBINE & GENERATOR	TURBINE CONDENSER SYSTEM	CONDENSER VACUUM PUMP SOUTH	N/A	29	22	Inspect CW Vacuum pump and refurbish or replace motor and pump	2011	3
1296	6690	6691	6733	271316	1	#1 TURBINE & GENERATOR	TURBINE CONDENSER SYSTEM	TURBINE CONDENSER	N/A	30	22	No action recommended.		

8.2.5.6 Risk Assessment

Table 8-49 below illustrates the risk assessment for the Unit 1 condenser, both from a technological perspective and a safety perspective using the models presented in Section 3.

TABLE 8-49 RISK ASSESSMENT – UNIT 1 CONDENSER

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Component	Risk Assess #	Appendix #	Major Issues	Remaining Life Years (Insufficient Info - Inspection Required Within (x) Years)	Remaining Life Comments	TECHNO-ECO RISK ASSESS MODEL			SAFETY RISK ASSESS MODEL			Possible Failure Event	Mitigation
																Likeli-hood	Conse-quence	Risk Level	Likeli-hood	Conse-quence	Safety Risk		
1296	6690	6691	6733	0	0	1	#1 TURBINE & GENERATOR	TURBINE CONDENSER SYSTEM	TURBINE CONDENSER SYSTEM	N/A	27		See details below.		None								
1296	6690	6691	6733	6780	0	1	#1 TURBINE & GENERATOR	TURBINE CONDENSER SYSTEM	CONDENSER AIR EXTRACTION	N/A	28		See details below.	10	None								
1296	6690	6691	6733	6780	8876	1	#1 TURBINE & GENERATOR	TURBINE CONDENSER SYSTEM	CONDENSER VACUUM PUMP NORTH	Condenser Vacuum Pumps & System	29	22	Mechanical failure/leaks.	2	None	1	A	Low	1	A	Low	Derate/Eff Decrease while replaced	Maintain, refurbish or replace as required.
1296	6690	6691	6733	6780	8877	1	#1 TURBINE & GENERATOR	TURBINE CONDENSER SYSTEM	CONDENSER VACUUM PUMP SOUTH	Condenser Vacuum Pumps & System	30	22	Mechanical failure/leaks.	2	None	1	A	Low	1	A	Low	Derate/Eff Decrease while replaced	Maintain, refurbish or replace as required.
1296	6690	6691	6733	271316	0	1	#1 TURBINE & GENERATOR	TURBINE CONDENSER SYSTEM	TURBINE CONDENSER	Condenser	31	22	Corrosion, erosion.	20	None	2	B	Low	2	A	Low	Major seawater leak to condenser - unit shutdown.. Water cleanup	Inspect and repair. Track history.

8.2.5.7 Life Cycle Curve and Remaining Life

The life cycle curve for the Unit 1 condenser is illustrated below. Only one curve is used as the major elements of the condenser are of the same age and condition. The life curve is a plot of current and projected operating hours (generation mode only) on the y-axis versus calendar year on the x-axis. The figure has several vertical lines representing differing representative nominal age limits for various components. It also has several horizontal lines that represent a range of practical equipment equivalent base loaded operating hour life limits. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view.

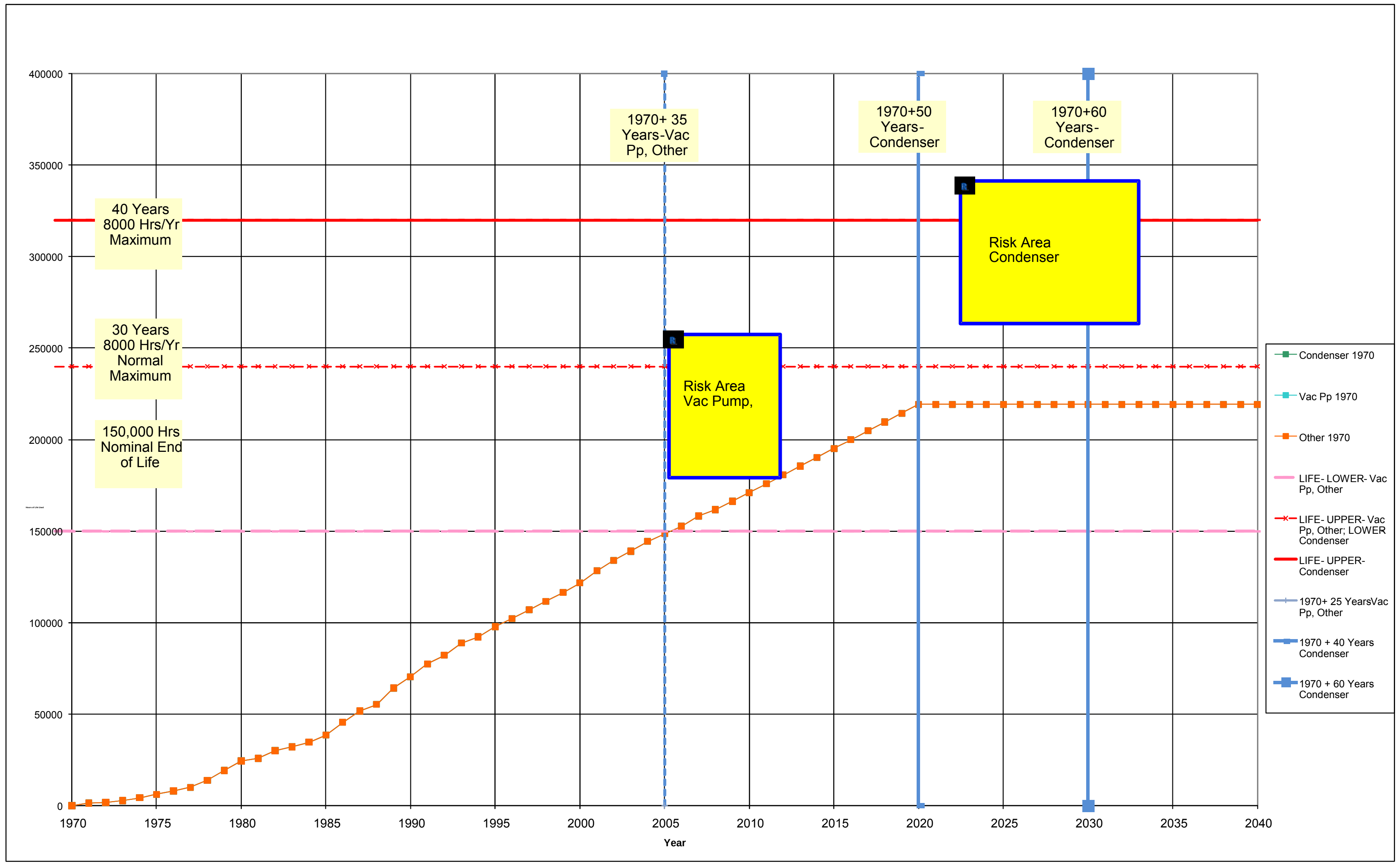

FIGURE 8-18 LIFE CYCLE CURVE – UNIT 1 CONDENSER

The curves indicate that the remaining life (RL) of the Unit 1 condenser can easily reach the desired life (DL) 2020 end date for generation. The exception to this, as illustrated by the risk boxes, is the vacuum pumps. These are original equipment, and likely at or near end of life.

8.2.5.8 Level 2 Inspections – Unit 1 Condenser

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 8-50 below, assuming that the current plant inspection and maintenance program is maintained or improved.

TABLE 8-50 LEVEL 2 INSPECTIONS – UNIT 1 CONDENSER

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Sub System Comment	L2#	Appendix #	Level 2 Work	Year	Priority	Cost k$
1296	6690	6691	6733	0	0	1	#1 TURBINE & GENERATOR	TURBINE CONDENSER SYSTEM	TURBINE CONDENSER SYSTEM	None	14	22	NDE spot check inspection of major inlet and outlet pipes. Continue condensers ongoing mtce and inspection.	2011	2	$4
1296	6690	6691	6733	0	0	1	#1 TURBINE & GENERATOR	TURBINE CONDENSER SYSTEM	TURBINE CONDENSER SYSTEM	None	15	22	At next turbine and valve overhaul in 2012: - Leak test and update of the tubesheet maps for both the waterboxes. - Check the inlet waterboxes for tubes with water erosion at the tube inlets. Where required, install 10'' plastic inserts into the tubes to protect them - Inspect condenser hotwell internal piping and supports for steam and water erosion. Investigate and repair as necessary - Inspect hotwell drip drains for eroded or missing baffle plates. Replace if eroded or missing	2011	2	$0
1296	6690	6691	6733	6780	0	1	#1 TURBINE & GENERATOR	TURBINE CONDENSER SYSTEM	CONDENSER AIR EXTRACTION	None	16	22	No Level 2 required.			
1296	6690	6691	6733	6780	8876	1	#1 TURBINE & GENERATOR	TURBINE CONDENSER SYSTEM	CONDENSER VACUUM PUMP NORTH	None	17	22	No Level 2 required.			
1296	6690	6691	6733	6780	8877	1	#1 TURBINE & GENERATOR	TURBINE CONDENSER SYSTEM	CONDENSER VACUUM PUMP SOUTH	None	18	22	No Level 2 required.			
1296	6690	6691	6733	271316	0	1	#1 TURBINE & GENERATOR	TURBINE CONDENSER SYSTEM	TURBINE CONDENSER	None	19	22	No Level 2 required.			

8.2.5.9 Capital Projects

Table 8-51 below shows the suggested typical capital enhancements that should be considered for the Unit 1 condenser:

TABLE 8-51 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – UNIT 1 CONDENSER

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Detail	CAP#	Appendix #	Capital Item	Date	Priority
1296	6690	6691	6733	0	0	1	#1 TURBINE & GENERATOR	TURBINE CONDENSER SYSTEM	TURBINE CONDENSER SYSTEM	N/A	14	22	See details below.		
1296	6690	6691	6733	6780	0	1	#1 TURBINE & GENERATOR	TURBINE CONDENSER SYSTEM	CONDENSER AIR EXTRACTION	N/A	15	22	Procure spare vacuum pump and motor for Units 1 & 2 (and 3 as practical).	2012	2
1296	6690	6691	6733	6780	8876	1	#1 TURBINE & GENERATOR	TURBINE CONDENSER SYSTEM	CONDENSER VACUUM PUMP NORTH	N/A	16	22	Refurbish/Replace vacuum pumps and motors as required.	2012	2
1296	6690	6691	6733	6780	8877	1	#1 TURBINE & GENERATOR	TURBINE CONDENSER SYSTEM	CONDENSER VACUUM PUMP SOUTH	N/A	17	22	Refurbish/Replace vacuum pumps and motors as required.	2012	2
1296	6690	6691	6733	271316	0	1	#1 TURBINE & GENERATOR	TURBINE CONDENSER SYSTEM	TURBINE CONDENSER	N/A	18	22	No capital required.		

8.2.6 Asset 8777 – Unit 1 FD Fans (and System)

(Detailed Technical Assessment in Working Papers, Appendix 19)

Unit #:	1
Asset Class #	BU 1296 - Assets Generations
SCI & System:	6699 #1 Boiler Plant
Sub-Systems:	6703 #1 Boiler Air System
	6704 #1 Boiler Gas System
	6705 #1 Boiler Fuel Firing System
	6987 #1 Bir Heavy Oil System
	6990 #1 Boiler Light Oil
Components:	8777 #1 Boiler FD Fan System 6943 #1 Boiler FD Fan East 6944 #1 Boiler FD Fan West 6954 #1 Boiler Steam Air Heater East 6955 #1 Boiler Steam Air Heater West 6914 #1 Boiler Main Air Heater East 6915 #1 Boiler Main Air Heater West
	6917 #1 Boiler Gas Passes 6920 #1 Boiler Sootblowing System 6933 #1 Retractable Sootblowers 6934 #1 Rotary Sootblowers 8789 #1 Air Heater Sootblowers
	6988 #1 Boiler Heavy Oil Pump East 6994 #1 Boiler Heavy Oil Pump West 6995 #1 Boiler Heavy Oil Pump steam, valves and pipe 6998 #1 Boiler Heavy Oil Firing 6999 #1 Boiler Light Oil Pump West 8976 #1 Boiler Light Oil Pump East 8977 #1 Boiler Light Oil Pump West
	6979 #1 Boiler Air Supply Seal Air 6982 #1 Boiler Scanner Air System

8.2.6.1 Description

The Unit 1 Combustion Engineering (CE) boiler has two 50% duty 4KV AC constant speed motor driven Howden Forced Draft Fans (East/West) which supply the combustion air for both the heavy #6 residual oil and the lighter #2 ignition oil. These fans are centrifugal in design and draw air from the top of the boiler house through ducts specifically connected to each fan inlet.

The air flow required for combustion is regulated by the use of variable inlet vanes which allow the required amount of air into the boiler furnace to ensure that the fuel oil is completely burned. The FD fan inlet vanes are controlled automatically either by the plant DCS system or manually by the operator if required.

In addition, each FD fan has set of steam coil air heaters and a rotating Ljungstrom air heater to heat the air used in the combustion process. The combustion air is heated prior to being admitted to the furnace windbox in order to improve fuel firing and also to reduce back end corrosion. Before using the steam coil air heater to heat the combustion air, at least one boiler in the plant must be generating sufficient steam for this function.

8.2.6.2 History

Manufactured/Delivered	1969
In-Service Date	Sep 1970
Generation Base Load End Date	Dec 2015
Generation Peak/Emerg Gen End Date	Dec 2020

The hours associated with the analyses are:

Hours Generation Actual - Ops to Dec 2009	166
Max Hours Generation Ops – to Dec 2015	210
Max Hrs Gen Ops to Gen End Date Dec 2020	219
Max Hours Ops – 1986 to Dec 2009	121
Max Hrs - 1986 to Dec 2015	165
Max Hrs – 1986 to Gen End Date Dec 2020	174

8.2.6.3 Inspection and Repair History

The FD fans, Ljungstrom air heaters, and steam coil air heaters were installed when the unit was constructed in the late 1960's. They are checked annually as part of the boiler inspection program. Generally, all are in reasonable condition considering their age. Issues such as fan component cracking and air heater corrosion are addressed as required. The steam coil air heater was upgraded in 1990 to include a second row of steam coils.

On March 3rd, 2007, the West FD fan self destructed during operation. As a result of the failure, the components that required refurbishment included the fan rotating element, the fan casing, the variable inlet vanes (VIV), and bearing support pedestals. As well, new bearings, sole plates, and alignment shims were installed. The root cause of the forced outage was a vibration related dorsal fin failure. The dorsal fins were re-designed so that they would not be susceptible to a vibration induced failure. During the 2007 outage, the Unit 1 East FD fan dorsal fins were also modified to reflect changes that Howden (the fan OEM) had recommended to the dorsal fin arrangement on the West FD fan. The flow induced vibration still exists on the Unit 1 FD fan system. A change to the ductwork geometry has been identified as being required to reduce or eliminate the turbulence causing the flow induced vibration.

The last outage report completed in 2009 indicates that detailed inspections of this equipment were carried out with minor repairs made to cracks in the ductwork, seals replaced in the Ljungstrom air heaters, some gap discrepancies rectified and an observation that some fins on the steam coil air heater had bent during operation.

The continued use of the much lower sulphur residual fuel oil (0.7% Sulphur) may reduce the corrosion levels noted, especially in the air heaters, and may reduce the maintenance requirements performed by Alstom, depending on a series of operating parameters. The steam coils are pressure tested every year, although no data sheets were reviewed and the inspection dates were not marked on the tubes as had been done previously.

The unit has experienced significant forced draft system vibration, as a consequence of the original ductwork design. Flow induced turbulence in ductwork causing vibration has the potential to result in significant damage to forced draft fans and in cracks in the ductwork. The plant has plans to modify the ductwork system in an effort to reduce vibration levels caused by air flow turbulence and also to improve overall noise and efficiency. These changes are strongly supported.

Asset 6704 Boilers Flue Gas System, Sootblowers

The Unit 1 back end flue gas ductwork is original and was installed in 1969. During yearly plant outages, the accessible ductwork has been inspected by Alstom. Reports obtained from the plant indicate that due diligence has been carried out to ensure the structural integrity of the ductwork is maintained and any repairs were completed at the time of inspection. Structural supports were inspected and all have been identified to be in good condition and will last for the foreseeable future.

With regards to the sootblowing system, minor maintenance is carried out during normal operation. Any major work requires a unit shutdown. Boiler fouling and opacity excursions were observed and changes were implemented to improve the sootblowing sequences. With the use of a lower sulphur fuel oil, the implementation of an Intelligent Sootblowing Control system should be considered so that sootblowing is only carried out when needed.

Asset 6705 Fuel Oil Firing

Reports at plant regarding the condition of the light and heavy oil systems were not available. However, they appear to have been properly maintained. Although these two systems are critical to unit operation, replacement parts or systems will typically be available for the life of a plant and therefore not considered to be life limiting.

Asset 6789 Boiler Air Supply Seal Air and Scanner Air

These two auxiliary systems are totally external to the main boiler and have limited control circuitry to ensure they operate correctly. Any piping or hose leaks can be repaired at minimum costs as long as proper maintenance activity is carried out. Replacement of flame scanner heads is the single most costly expenditure if the system fails. Both of these systems appear to be well maintained as noted during AMEC's inspection.

8.2.6.4 Condition Assessment

The condition assessment of the Unit 1 FD fans and system is illustrated below in Table 8-52.

TABLE 8-52 CONDITION ASSESSMENT – UNIT 1 FD FANS (AND SYSTEM)

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset Level 2	Asset Level 3	Description	Detail	Condition Summary ID #	Append #	Condition	EPRI Identifier	Original Life (Base Load) Ops Hrs (Yrs)	Current Expected Minimum Remaining Life Years (Subject to Test)	End of Life (EOL) Required	Next Regular Inspection	Next Planned Overhaul or Major Inspection	Capability to Reach Next Overhaul	Capability to Reach EOL	In Service
1296	6690	6699	6703	0	0	1	#1 BOILER PLANT	BOILER AIR SYSTEM	BOILER AIR SYSTEM	N/A	72	19, 30	Inspected yearly and repairs completed.	3a	200000 (40)	10	2020	2011		Yes	Yes	1970
1296	6690	6699	6703	6879	0	1	#1 BOILER PLANT	BOILER AIR SYSTEM	BOILER AIR SUPPLY (A/H TO	N/A	73	19, 30	Inspected yearly and repairs completed.	3a	200000 (40)	10	2020	2011		Yes	Yes	1970
1296	6690	6699	6703	6879	6979	1	#1 BOILER PLANT	BOILER AIR SYSTEM	BOILER SEAL AIR FAN	N/A	74	19, 30	Inspected yearly and repairs completed.	3a	200000 (30)	10	2020	2011		Yes	Yes	1970
1296	6690	6699	6703	6879	6982	1	#1 BOILER PLANT	BOILER AIR SYSTEM	BOILER SCANNER AIR SYSTEM	N/A	75	19, 30	Inspected yearly and repairs completed.	3a	200000 (30)	10	2020	2011		Yes	Yes	1970
1296	6690	6699	6703	6880	0	1	#1 BOILER PLANT	BOILER AIR SYSTEM	BOILER WINDBOX	N/A	76	19, 30	Inspected yearly and repairs completed.	3a	200000 (40)	10	2020	2011		Yes	Yes	1970
1296	6690	6699	6703	8777	0	1	#1 BOILER PLANT	BOILER AIR SYSTEM	BOILER F.D. FAN SYSTEM	N/A	77	19, 30	Inspected yearly and repairs completed.	3a	200000 (40)	10	2020	2011		Yes	Yes	1970
1296	6690	6699	6703	8777	6943	1	#1 BOILER PLANT	BOILER AIR SYSTEM	BOILER F.D. FAN EAST	N/A	78	19, 30	Inspected yearly and repairs completed as required. Modified dorsal fin arrangement.	3a	200000 (40)	10	2020	2011		Yes	Yes	1970
1296	6690	6699	6703	8777	6944	1	#1 BOILER PLANT	BOILER AIR SYSTEM	BOILER F.D. FAN WEST	N/A	79	19, 30	West fan rotating element, the fan casing, a new dorsal fin arrangement on the air inlet duct, the VIV west ring along with new bearings, a new FD fan motor, new sole plates and shims replaced in 2007. Inspected yearly and repairs completed.	3a	200000 (40)	20	2020	2011		Yes	Yes	2007
1296	6690	6699	6703	8777	6943	1	#1 BOILER PLANT	BOILER AIR SYSTEM	BOILER F.D. FAN EAST	Motor	80	25	Inspected yearly and repairs completed as required. Flow induced turbulence in ductwork causing vibration with potential for damage to FD fans and cracks in ductwork.	3a	(30)	(5)	2020	2011		Yes	No	1988
1296	6690	6699	6703	8777	6944	1	#1 BOILER PLANT	BOILER AIR SYSTEM	BOILER F.D. FAN WEST	Motor	81	25	A new FD fan motor, new sole plates and shims replaced in 2007. Inspected yearly and repairs completed. Flow induced turbulence in ductwork causing vibration with potential for damage to FD fans and cracks in ductwork.	3a	(30)	20	2020	2011		Yes	Yes	2007
1296	6690	6699	6703	8783	0	1	#1 BOILER PLANT	BOILER AIR SYSTEM	BOILER STEAM AIR HEATER	N/A	82	19, 30	In 2008 a large number of the fins were bent possibly creating a higher FD fan differential pressure across these coils - status uncertain.	3a	200000 (30)	10	2020	2011		Yes	Yes	1990
1296	6690	6699	6703	8783	6954	1	#1 BOILER PLANT	BOILER AIR SYSTEM	#1BOILER STEAM AIR HEATER EAST	N/A	83	19, 30	In 2008 a large number of the fins were bent possibly creating a higher FD fan differential pressure across these coils - status uncertain.	3a	200000 (30)	10	2020	2011		Yes	Yes	1990
1296	6690	6699	6703	8783	6955	1	#1 BOILER PLANT	BOILER AIR SYSTEM	#1BOILER STEAM AIR HEATER WEST	N/A	84	19, 30	In 2008 a large number of the fins were bent possibly creating a higher FD fan differential pressure across these coils - status uncertain.	3a	200000 (30)	10	2020	2011		Yes	Yes	1990
1296	6690	6699	6703	8784	0	1	#1 BOILER PLANT	BOILER AIR SYSTEM	BOILER MAIN AIR HEATER	N/A	85	19, 30	Inspected yearly and repairs completed as required.	3a	200000 (30)	10	2020	2011		Yes	Yes	1970
1296	6690	6699	6703	8784	6914	1	#1 BOILER PLANT	BOILER AIR SYSTEM	BOILER MAIN AIR HEATER EAST	N/A	86	19, 30	Inspected yearly and repairs completed as required.	3a	200000 (30)	10	2020	2011		Yes	Yes	1970
1296	6690	6699	6703	8784	6915	1	#1 BOILER PLANT	BOILER AIR SYSTEM	BOILER MAIN AIR HEATER WEST	N/A	87	19, 30	Inspected yearly and repairs completed as required.	3a	200000 (30)	10	2020	2011		Yes	Yes	1970
1296	6690	6699	6704	0	0	1	#1 BOILER PLANT	BOILER GAS SYSTEM	BOILER GAS SYSTEM	N/A	88	19, 30	Inspected yearly and repairs completed.	3a	200000 (40)	10	2020	2011		Yes	Yes	1970
1296	6690	6699	6704	6920	0	1	#1 BOILER PLANT	BOILER GAS SYSTEM	BOILER SOOTBLOWING SYSTEM	N/A	89	19	Installed about 1979, with yearly major or minor overhauls.	3a	200000 (30)	10	2020	2011		No	Yes	1970
1296	6690	6699	6705	0	0	1	#1 BOILER PLANT	BOILER FUEL FIRING SYSTEM	BOILER FUEL FIRING SYSTEM	N/A	90	19	Inspected yearly and repairs completed as required.	3a	200000 (30)	10	2020	2011		No	Yes	1970
1296	6690	6699	6705	6990	0	1	#1 BOILER PLANT	BOILER FUEL FIRING SYSTEM	BOILER LIGHT OIL	N/A	135	19	Inspected yearly and repairs completed as required.	3a	200000 (30)	10	2020	2011		No	Yes	1970
1296	6690	6699	6707	0	0	1	#1 BOILER PLANT	BLR AUX STM & COND SYSTEM	BLR AUX STM & COND SYSTEM	N/A	136		Not reviewed in detail - primarily unit heaters from good to poor condition. New source needed after close of generation.	4	200000 (30)	(5)	2041	2011		No	No	1970
1296	6690	6699	6700	0	0	1	#1 BOILER PLANT	BOILER STRUCTURE	BOILER STRUCTURE	N/A	137	17	SH3 and SH4 hangers found not bearing any load.	4	200000 (30)	30	2041	2011	2011	Yes	Yes	1970

Notes:

1. A "(bracketed)" value in the "Current Expected Remaining Life" column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as "(X/Y)" has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

2. The "Next Regular Inspection" column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The "Next Planned Overhaul or Major Inspection" column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a "Desired Life" stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or are not known by AMEC.

3. The ability of the east and west FD fans to meet a 2020 EOL may be affected if the planned duct reconfiguration is not undertaken.

8.2.6.5 Actions

Based on the condition assessment, the following actions are recommended for the Unit 1 FD fans (and system):

TABLE 8-53 RECOMMENDED ACTIONS – UNIT 1 FD FANS (AND SYSTEM)

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Unit	Asset 2/3	Asset 3/4	Description	Detail	Action #	App #	Action	Year	Priority
1296	6690	6699	6703	0	1	#1 BOILER PLANT	BOILER AIR SYSTEM	BOILER AIR SYSTEM	N/A	96	19,30	Continue routine inspection, maintenance and overhaul - evaluating air heater hot end baskets; connecting installed FD fans vibration probes to online monitoring system; refurbish and use the furnace exit thermoprobe during start-up activities to avoid distortion and overheating of the secondary superheater and reheater sections tubes	2010	1
1296	6690	6699	6703	6879	1	#1 BOILER PLANT	BOILER AIR SYSTEM	BOILER AIR SUPPLY (A/H TO	N/A	97	19,30	No action recommended.	2010	2
1296	6690	6699	6703	6879	1	#1 BOILER PLANT	BOILER AIR SYSTEM	BOILER SEAL AIR FAN	N/A	98	19,30	No action recommended.	2010	2
1296	6690	6699	6703	6879	1	#1 BOILER PLANT	BOILER AIR SYSTEM	BOILER SCANNER AIR SYSTEM	N/A	99	19,30	No action recommended.	2010	2
1296	6690	6699	6703	6880	1	#1 BOILER PLANT	BOILER AIR SYSTEM	BOILER WINDBOX	N/A	100	19,30	No action recommended.	2010	2
1296	6690	6699	6703	8777	1	#1 BOILER PLANT	BOILER AIR SYSTEM	BOILER F.D. FAN SYSTEM	N/A	101	19,30	Maintain ongoing inspection and maintenance programs. Maintain a spare motor be maintained to service all three units, in the event of a failure of an existing unit.	2010	2
1296	6690	6699	6703	8777	1	#1 BOILER PLANT	BOILER AIR SYSTEM	BOILER F.D. FAN EAST	N/A	102	19,30	No action recommended.	2010	2
1296	6690	6699	6703	8777	1	#1 BOILER PLANT	BOILER AIR SYSTEM	BOILER F.D. FAN WEST	N/A	103	19,30	No action recommended.	2010	2
1296	6690	6699	6703	8783	1	#1 BOILER PLANT	BOILER AIR SYSTEM	BOILER STEAM AIR HEATER	N/A	104	19,30	Continue current inspection and maintenance activities.	2010	2
1296	6690	6699	6703	8783	1	#1 BOILER PLANT	BOILER AIR SYSTEM	#1BOILER STEAM AIR HEATER EAST	N/A	105	19,30	Continue current inspection and maintenance activities.	2010	2
1296	6690	6699	6703	8783	1	#1 BOILER PLANT	BOILER AIR SYSTEM	#1BOILER STEAM AIR HEATER WEST	N/A	106	19,30	Continue current inspection and maintenance activities.	2010	2
1296	6690	6699	6703	8784	1	#1 BOILER PLANT	BOILER AIR SYSTEM	BOILER MAIN AIR HEATER	N/A	107	19,30	Continue current inspection and maintenance activities.	2010	2
1296	6690	6699	6703	8784	1	#1 BOILER PLANT	BOILER AIR SYSTEM	BOILER MAIN AIR HEATER EAST	N/A	108	19,30	Continue current inspection and maintenance activities.	2010	2
1296	6690	6699	6703	8784	1	#1 BOILER PLANT	BOILER AIR SYSTEM	BOILER MAIN AIR HEATER WEST	N/A	109	19,30	Continue current inspection and maintenance activities.	2010	2
1296	6690	6699	6704	6920	1	#1 BOILER PLANT	BOILER GAS SYSTEM	BOILER SOOTBLOWING SYSTEM	N/A	111	19	Update obsolete controls as appropriate. Evaluate/implement Intelligent Sootblowing (ISB) to reduce sootblowing energy consumption and mechanical damage impacts.	2012	2
1296	6690	6699	6704	6920	1	#1 BOILER PLANT	BOILER GAS SYSTEM	BOILER SOOTBLOWING SYSTEM	N/A	112	19	Continue yearly inspections and repair work.	2011	2
1296	6690	6699	6705	0	1	#1 BOILER PLANT	BOILER FUEL FIRING SYSTEM	BOILER FUEL FIRING SYSTEM	N/A	113	19	Continue yearly inspections and repair work.	2011	3
1296	6690	6699	6705	6990	1	#1 BOILER PLANT	BOILER FUEL FIRING SYSTEM	BOILER LIGHT OIL	N/A	114	19	Continue yearly inspections and repair work.	2011	3
1296	6690	6699	6707	0	1	#1 BOILER PLANT	BLR AUX STM & COND SYSTEM	BLR AUX STM & COND SYSTEM	N/A	115		Refurbish and replace unit heaters as required.	2012	3
1296	6690	6699	6700	0	1	#1 BOILER PLANT	BOILER STRUCTURE	BOILER STRUCTURE	N/A	116	17	Visually inspect difficult to access areas.		
1296	6690	6699	6700	0	1	#1 BOILER PLANT	BOILER STRUCTURE	BOILER STRUCTURE	N/A	117	30	Continue present inspection and maintenance program. Evaluate a preventive replacement of the boiler expansion joints.	2011	2
1296	6690	6699	6700	0	1	#1 BOILER PLANT	BOILER STRUCTURE	BOILER STRUCTURE	N/A	118	30	Evaluate corrosion on the steel structure and hangers in the boilers penthouse areas during the boiler routine maintenance and inspection activities. Review condition of the boiler refractory to assess the requirement for replacement during the boiler routine maintenance and inspection activities.	2011	2

8.2.6.6 Risk Assessment

Table 8-54 below illustrates the risk assessment for the Unit 1 FD fans (and system), both from a technological perspective and a safety perspective using the models presented in Section 3.

TABLE 8-54 RISK ASSESSMENT – UNIT 1 FD FANS (AND SYSTEM)

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Component	Risk Assess #	Appendix #	Major Issues	Remaining Life Years (Insufficient Info - Inspection Required Within (x) Years)	Remaining Life Comments	TECHNO-ECO RISK ASSESS MODEL			SAFETY RISK ASSESS MODEL			Possible Failure Event	Mitigation
																Likeli-hood	Conse-quence	Risk Level	Likeli-hood	Conse-quence	Safety Risk		
1296	6690	6699	6703	0	0	1	#1 BOILER PLANT	BOILER AIR SYSTEM	BOILER AIR SYSTEM	N/A	93		See details below.		None								
1296	6690	6699	6703	6879	0	1	#1 BOILER PLANT	BOILER AIR SYSTEM	BOILER AIR SUPPLY (A/H TO	N/A	94		See details below.		None								
1296	6690	6699	6703	6879	6979	1	#1 BOILER PLANT	BOILER AIR SYSTEM	BOILER SEAL AIR FAN	Scanner & Seal Air	95	19	Mechanical fatigue, corrosion, ops error.	10	None	1	A	Low	1	A	Low	Worst case - Short duration shutdown for repair. Safety	Current inspection and maintain.
1296	6690	6699	6703	6879	6982	1	#1 BOILER PLANT	BOILER AIR SYSTEM	BOILER SCANNER AIR SYSTEM	Scanner & Seal Air	96	19	Mechanical fatigue, corrosion, ops error.	10	None	1	A	Low	1	A	Low	Worst case - Short duration shutdown for repair. Safety	Current inspection and maintain.
1296	6690	6699	6703	6880	0	1	#1 BOILER PLANT	BOILER AIR SYSTEM	BOILER WINDBOX	N/A	97		Not Addressed. Mechanical collapse.	10	None								
1296	6690	6699	6703	8777	0	1	#1 BOILER PLANT	BOILER AIR SYSTEM	BOILER F.D. FAN SYSTEM		98		See details below.		None								
1296	6690	6699	6703	8777	6943	1	#1 BOILER PLANT	BOILER AIR SYSTEM	BOILER F.D. FAN EAST	Unit #1 LP FD Fan	99	19	Mechanical fatigue, corrosion, ops error.	10	None	1	B	Low	1	B	Low	Derate by 50% for short period. Consider spare motor	Current inspection and maintain.
1296	6690	6699	6703	8777	6944	1	#1 BOILER PLANT	BOILER AIR SYSTEM	BOILER F.D. FAN WEST	Unit #1 LP FD Fan	100	19	Mechanical fatigue, corrosion, ops error.	10	None	1	B	Low	1	B	Low	Derate by 50% for short period. Consider spare motor	Current inspection and maintain.
1296	6690	6699	6703	8777	6943	1	#1 BOILER PLANT	BOILER AIR SYSTEM	BOILER F.D. FAN EAST	4 kV Forced Draft Fan Motor	101	25	Electrical fault, mechanical fatigue, ops error.	5+	None	1	C	Low	1	B	Low	Loss 60% of 1 unit generation + damages	Spare and current inspection and maintain.
1296	6690	6699	6703	8777	6944	1	#1 BOILER PLANT	BOILER AIR SYSTEM	BOILER F.D. FAN WEST	5 kV Forced Draft Fan Motor	102	25	Electrical fault, mechanical fatigue, ops error.	5+	None	1	C	Low	1	B	Low	Loss 60% of 1 unit generation + damages	Spare and Current Inspection and maintain.
1296	6690	6699	6703	8783	0	1	#1 BOILER PLANT	BOILER AIR SYSTEM	BOILER STEAM AIR HEATER	N/A	103		See details below.		None								
1296	6690	6699	6703	8783	6954	1	#1 BOILER PLANT	BOILER AIR SYSTEM	#1BOILER STEAM AIR HEATER EAST	Unit #1 Steam Preheat Coils	104	19	Corrosion, erosion, mech distortion.	10	None	1	A	Low	1	B	Low	Short term shutdown for repairs, derated or run at increased impact	Current inspection and maintain.
1296	6690	6699	6703	8783	6955	1	#1 BOILER PLANT	BOILER AIR SYSTEM	#1BOILER STEAM AIR HEATER WEST	Unit #1 Steam Preheat Coils	105	19	Corrosion, Erosion, Mech distortion	10	None	1	A	Low	1	B	Low	Short term shutdown for repairs, derated or run at increased impact	Current inspection and maintain.
1296	6690	6699	6703	8784	0	1	#1 BOILER PLANT	BOILER AIR SYSTEM	BOILER MAIN AIR HEATER	APH Ductwork – Gas & Air	106	19	Corrosion, erosion thinning.	10	None	2	A	Low	1	B		Short duration shutdown for repair/patch	Current inspection and maintain.
1296	6690	6699	6703	8784	6914	1	#1 BOILER PLANT	BOILER AIR SYSTEM	BOILER MAIN AIR HEATER EAST	Unit #1 APH	107	19	Corrosion, mech failure.	10	None	1	A	Low	1	B	Low	50% shutdown for mtce and repairs	Current inspection and maintain.
1296	6690	6699	6703	8784	6915	1	#1 BOILER PLANT	BOILER AIR SYSTEM	BOILER MAIN AIR HEATER WEST	Unit #1 APH	108	19	Corrosion, mech failure.	10	None	1	B	Low	1	A	Low	50% shutdown for mtce and repairs	Current inspection and maintain.
1296	6690	6699	6704	0	0	1	#1 BOILER PLANT	BOILER GAS SYSTEM	BOILER GAS SYSTEM	N/A	109		See details below.		None								
1296	6690	6699	6704	6920	0	1	#1 BOILER PLANT	BOILER GAS SYSTEM	BOILER SOOTBLOWING SYSTEM	N/A	110		Mechanical failure.	10	None	2	B	Low	2	B	Low	Steam leak. Tube erosion	Current inspection and maintain.
1296	6690	6699	6705	0	0	1	#1 BOILER PLANT	BOILER FUEL FIRING SYSTEM	BOILER FUEL FIRING SYSTEM	Fuel Feed System	111	19	Mechanical fatigue, corrosion, ops error.	10	None	1	A	Low	1	C	Medium	Derate for short period. Safety	Current inspection and maintain.
1296	6690	6699	6705	6990	0	1	#1 BOILER PLANT	BOILER FUEL FIRING SYSTEM	BOILER LIGHT OIL	N/A	112		Mechanical failure, leak.	10	None	3	A	Low	3	B	Medium	Oil spill (hot)	Current inspection and maintain.
1296	6690	6699	6707	0	0	1	#1 BOILER PLANT	BLR AUX STM & COND SYSTEM	BLR AUX STM & COND SYSTEM	N/A	113		Mechanical failure.	(5)	None	3	A	Low	3	B	Medium	Steam leak	Current inspection and maintain.

8.2.6.7 Life Cycle Curve and Remaining Life

The life cycle curve for the Unit 1 FD fans (and system) is illustrated below. Several curves are required to represent the various elements given their different in-service dates and operation history. The life curves are plots of current and projected operating hours (generation mode only) on the y-axis versus calendar year on the x-axis. The figure has several vertical lines representing differing representative nominal age limits for various components. It also has several horizontal lines that represent a range of practical equipment equivalent base loaded operating hour life limits. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view.

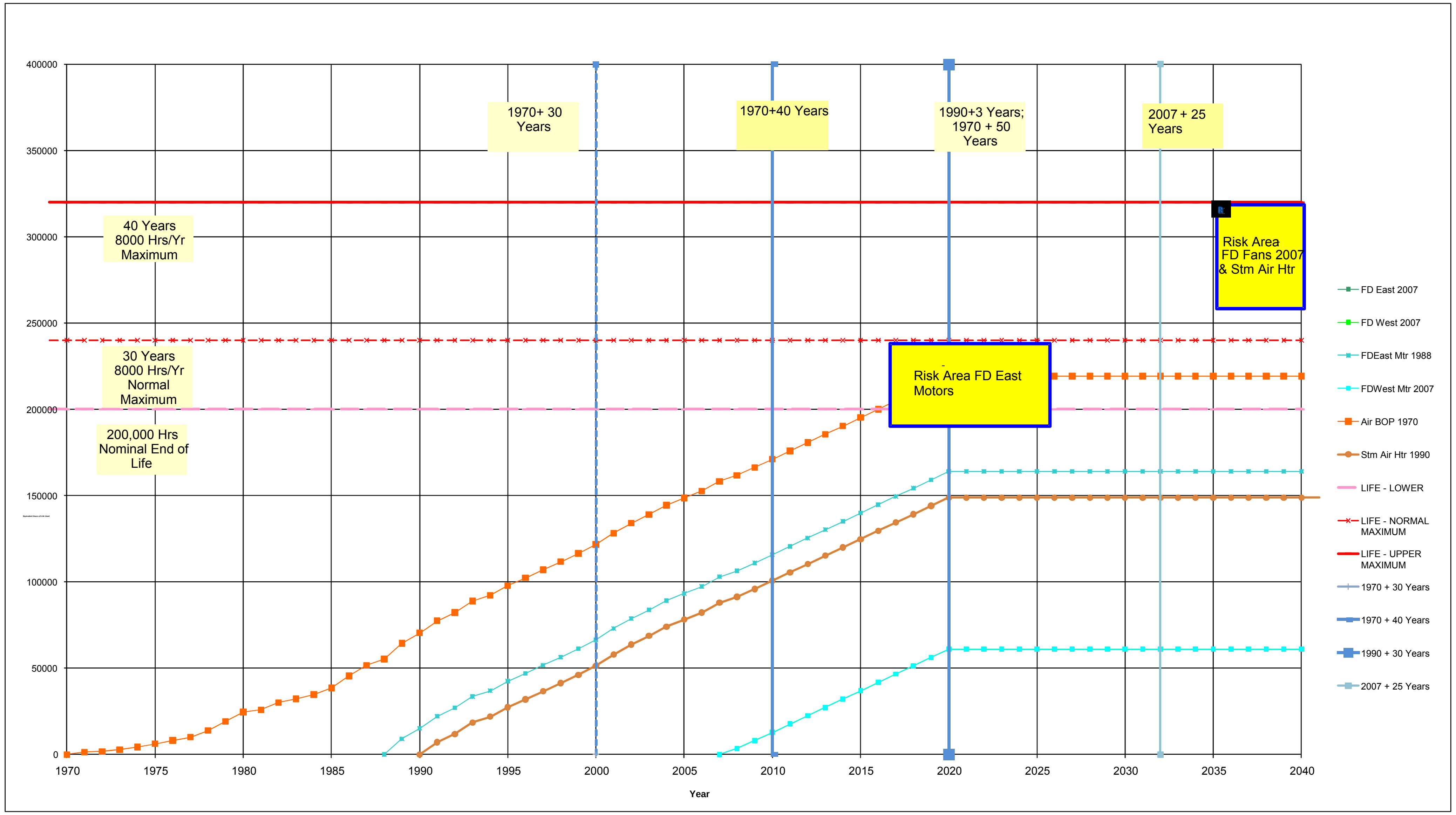

FIGURE 8-19 LIFE CYCLE CURVE – UNIT 1 FD FANS (AND SYSTEM)

The curves indicate that the remaining life (RL) of the Unit 1 FD fans (and system) is expected to meet or exceed the desired life (DL) 2020 end date for generation. The age of the large 4 kV motors makes them a logical cost-effective candidate for sparing to ensure reliability, although plant testing/monitoring programs are effectively monitoring their status.

8.2.6.8 Level 2 Inspections – Unit 1 FD Fans (and System)

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 8-55 below, assuming that the current plant inspection and maintenance program is maintained or improved.

TABLE 8-55 LEVEL 2 INSPECTIONS – UNIT 1 FD FANS (AND SYSTEM)

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Sub System Comment	L2#	Appendix #	Level 2 Work	Year	Priority	Cost k$
1296	6690	6699	6703	0	0	1	#1 BOILER PLANT	BOILER AIR SYSTEM	BOILER AIR SYSTEM		77	19	Level 2 inspections or testing of duct thickness.	2011	3	$0
1296	6690	6699	6703	6879	0	1	#1 BOILER PLANT	BOILER AIR SYSTEM	BOILER AIR SUPPLY (A/H TO	None	78	19	No Level 2 inspections or testing is required.			
1296	6690	6699	6703	6879	6979	1	#1 BOILER PLANT	BOILER AIR SYSTEM	BOILER SEAL AIR FAN	None	79	19	No Level 2 inspections or testing is required.			
1296	6690	6699	6703	6879	6982	1	#1 BOILER PLANT	BOILER AIR SYSTEM	BOILER SCANNER AIR SYSTEM	None	80	19	No Level 2 inspections or testing is required.			
1296	6690	6699	6703	6880	0	1	#1 BOILER PLANT	BOILER AIR SYSTEM	BOILER WINDBOX	None	81	19	No Level 2 inspections or testing is required.			
1296	6690	6699	6703	8777	0	1	#1 BOILER PLANT	BOILER AIR SYSTEM	BOILER F.D. FAN SYSTEM	None	82	19	No Level 2 inspections or testing is required.			
1296	6690	6699	6703	8777	6943	1	#1 BOILER PLANT	BOILER AIR SYSTEM	BOILER F.D. FAN EAST	None	83	19	No Level 2 inspections or testing is required on fan or 4 kV Motors, provided the current inspection and maintenance program is maintained. Assumes FD turbulence upgrades undertaken.			
1296	6690	6699	6703	8777	6944	1	#1 BOILER PLANT	BOILER AIR SYSTEM	BOILER F.D. FAN WEST	None	84	19	No Level 2 inspections or testing is required on fan or 4 kV Motors, provided the current inspection and maintenance program is maintained. Assumes FD turbulence upgrades undertaken.			
1296	6690	6699	6703	8783	0	1	#1 BOILER PLANT	BOILER AIR SYSTEM	BOILER STEAM AIR HEATER	None	85	19	No Level 2 inspections or testing is required.			
1296	6690	6699	6703	8783	6954	1	#1 BOILER PLANT	BOILER AIR SYSTEM	#1BOILER STEAM AIR HEATER EAST	None	86	19	No Level 2 inspections or testing is required.			
1296	6690	6699	6703	8783	6955	1	#1 BOILER PLANT	BOILER AIR SYSTEM	#1BOILER STEAM AIR HEATER WEST	None	87	19	No Level 2 inspections or testing is required.			
1296	6690	6699	6703	8784	0	1	#1 BOILER PLANT	BOILER AIR SYSTEM	BOILER MAIN AIR HEATER	None	88	19	No Level 2 inspections or testing is required.			
1296	6690	6699	6703	8784	6914	1	#1 BOILER PLANT	BOILER AIR SYSTEM	BOILER MAIN AIR HEATER EAST	None	89	19	No Level 2 inspections or testing is required.			
1296	6690	6699	6703	8784	6915	1	#1 BOILER PLANT	BOILER AIR SYSTEM	BOILER MAIN AIR HEATER WEST	None	90	19	No Level 2 inspections or testing is required.			
1296	6690	6699	6704	0	0	1	#1 BOILER PLANT	BOILER GAS SYSTEM	BOILER GAS SYSTEM	None	91	19	No Level 2 inspections or testing is required.	2011	3	$0
1296	6690	6699	6704	6920	0	1	#1 BOILER PLANT	BOILER GAS SYSTEM	BOILER SOOTBLOWING SYSTEM	None	92	19	No Level 2 inspections or testing is required.			
1296	6690	6699	6705	0	0	1	#1 BOILER PLANT	BOILER FUEL FIRING SYSTEM	BOILER FUEL FIRING SYSTEM	None	93	19	No Level 2 inspections or testing is required.	2011	3	$0
1296	6690	6699	6705	6990	0	1	#1 BOILER PLANT	BOILER FUEL FIRING SYSTEM	BOILER LIGHT OIL	None	94	19	No Level 2 inspections or testing is required.			
1296	6690	6699	6707	0	0	1	#1 BOILER PLANT	BLR AUX STM & COND SYSTEM	BLR AUX STM & COND SYSTEM	None	95	N/A	Not examined. No Level 2 required.	2011	3	$0

8.2.6.9 Capital Projects

Table 8-56 below shows the suggested typical capital enhancements that should be considered for the Unit 1 FD fans (and system):

TABLE 8-56 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – UNIT 1 FD FANS (AND SYSTEM)

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Detail	CAP#	Appendix #	Capital Item	Date	Priority
1296	6690	6699	6703	0	0	1	#1 BOILER PLANT	BOILER AIR SYSTEM	BOILER AIR SYSTEM	N/A	57	19	Upgrade air ducts to reduce vibration, improve efficiency.	2012	2
1296	6690	6699	6703	6879	0	1	#1 BOILER PLANT	BOILER AIR SYSTEM	BOILER AIR SUPPLY (A/H TO	N/A	58	19	No capital required.		
1296	6690	6699	6703	6879	6979	1	#1 BOILER PLANT	BOILER AIR SYSTEM	BOILER SEAL AIR FAN	N/A	59	19	No capital required.		
1296	6690	6699	6703	6879	6982	1	#1 BOILER PLANT	BOILER AIR SYSTEM	BOILER SCANNER AIR SYSTEM	N/A	60	19	No capital required.		
1296	6690	6699	6703	6880	0	1	#1 BOILER PLANT	BOILER AIR SYSTEM	BOILER WINDBOX	N/A	61	19	No capital required.		
1296	6690	6699	6703	8777	0	1	#1 BOILER PLANT	BOILER AIR SYSTEM	BOILER F.D. FAN SYSTEM	N/A	62	25	Procure spare motor - common to Units 1 & 2; adaptable Unit 3 to extent practical.	2012	1
1296	6690	6699	6703	8777	0	1	#1 BOILER PLANT	BOILER AIR SYSTEM	BOILER F.D. FAN SYSTEM	N/A	63	19	Assess fluid coupling/VFD for BFWP and FDF.	2011	2
1296	6690	6699	6703	8777	0	1	#1 BOILER PLANT	BOILER AIR SYSTEM	BOILER F.D. FAN SYSTEM	N/A	64	19	See details below.		
1296	6690	6699	6703	8777	6943	1	#1 BOILER PLANT	BOILER AIR SYSTEM	BOILER F.D. FAN EAST	N/A	65	19	Install vibration monitoring.	2012	2
1296	6690	6699	6703	8777	6944	1	#1 BOILER PLANT	BOILER AIR SYSTEM	BOILER F.D. FAN WEST	N/A	66	19	Install vibration monitoring.	2012	2
1296	6690	6699	6703	8783	0	1	#1 BOILER PLANT	BOILER AIR SYSTEM	BOILER STEAM AIR HEATER	N/A	67	19	No capital required.		
1296	6690	6699	6703	8783	6954	1	#1 BOILER PLANT	BOILER AIR SYSTEM	BOILER STEAM AIR HEATER EAST	N/A	68	19	No capital required.		
1296	6690	6699	6703	8783	6955	1	#1 BOILER PLANT	BOILER AIR SYSTEM	BOILER STEAM AIR HEATER WEST	N/A	69	19	No capital required.		
1296	6690	6699	6703	8784	0	1	#1 BOILER PLANT	BOILER AIR SYSTEM	BOILER MAIN AIR HEATER	N/A	70	19	No capital required.		
1296	6690	6699	6703	8784	6914	1	#1 BOILER PLANT	BOILER AIR SYSTEM	BOILER MAIN AIR HEATER EAST	N/A	71	19	No capital required.		
1296	6690	6699	6703	8784	6915	1	#1 BOILER PLANT	BOILER AIR SYSTEM	BOILER MAIN AIR HEATER WEST	N/A	72	19	No capital required.		
1296	6690	6699	6704	0	0	1	#1 BOILER PLANT	BOILER GAS SYSTEM	BOILER GAS SYSTEM	N/A	73	19	No capital required.		
1296	6690	6699	6704	6920	0	1	#1 BOILER PLANT	BOILER GAS SYSTEM	BOILER SOOTBLOWING SYSTEM	N/A	74	19	FD fan ductwork modifications.	2011	3
1296	6690	6699	6705	0	0	1	#1 BOILER PLANT	BOILER FUEL FIRING SYSTEM	BOILER FUEL FIRING SYSTEM	N/A	75	19	No capital required.		
1296	6690	6699	6705	6990	0	1	#1 BOILER PLANT	BOILER FUEL FIRING SYSTEM	BOILER LIGHT OIL	N/A	76	19	No capital required.		
1296	6690	6699	6707	0	0	1	#1 BOILER PLANT	BLR AUX STM & COND SYSTEM	BLR AUX STM & COND SYSTEM	N/A	77		New building heating system	2015-2020	2
1296	6690	6699	6700	0	0	1	#1 BOILER PLANT	BOILER STRUCTURE	BOILER STRUCTURE	N/A	78		No capital required.		

8.2.7 Asset 6919 – Unit 1 Stack and Breeching

(Detailed Technical Assessment in Working Papers, Appendix 17)

Unit #:	1
Asset Class #	BU 1296 - Assets Generations
SCI & System:	6899 #1 Boiler Plant
Sub-Systems:	6714 #1 Boiler Gas System
Components:	6919 #1 Boiler Stack 270294 #1 Stack Breeching

8.2.7.1 Description

The Unit 1 stack was constructed in 1969 from reinforced concrete and contains a steel liner with some sections constructed from stainless steel and the remaining sections constructed from carbon steel. The stack breeching is the insulated steel ductwork that conveys the hot flue gas from the boiler air preheater to the stack.

Description	Stack Calendar Life	Operating hours/Equiv Op Yrs since Installation to 2009	Operating hours/Equiv Op Yrs to 2015/2020
Unit 1 Stack	44	166,000 (20)	210,000/220,000 (27)

The hours are based on 70% ACF/85% operating factor (OF) to 2015 (where the OF is equal to the actual running hours at any load in a year divided by 8760) and 10% ACF/20% OF from 2015-2020. The hours for 2015 and 2020 would be about 16,000 hours less if plant runs closer to historical 40% ACF up to 2015.

Manufactured/Delivered	1969
In-Service Date	Sep 1970
Generation Base Load End Date	Dec 2015
Generation Peak/Emerg Gen End Date	Dec 2020

The hours associated with the analyses are:

Hours Generation Actual - Ops to Dec 2009	166
Max Hours Generation Ops – to Dec 2015	210
Max Hrs Gen Ops to Gen End Date Dec 2020	219
Max Hours Ops – 1986 to Dec 2009	121
Max Hrs - 1986 to Dec 2015	165
Max Hrs – 1986 to Gen End Date Dec 2020	174
Max Hours Ops – 2007/8 to Dec 2009	8
Max Hrs – 2007/8 to Dec 2015	54
Max Hrs – 2007/8 to Gen End Date Dec 2020	174

8.2.7.2 Inspection and Repair History

The Unit 1 stack was built in 1966. Since the original construction, the plant has performed regular PM inspections and completed the suggested repairs. Previous stack inspection reports indicate that there has been no major cracking or structural issues. There is some small cracking in portions of the stack and some water infiltration around construction joints. The carbon steel portions of the liners have localized areas of heavy corrosion as well as areas with minimal corrosion. The condition of the current linings and cap seem to suggest that Unit 1 has not been operating below the sulfuric acid dew point. The recent change to a much lower sulphur fuel oil has also reduced the acid dew point, thereby allowing the plant to operate at a lower stack exit temperature to improve efficiency.

The life of the steel liners will vary depending on the materials of construction, the flue gas constituents, and the flue gas exit temperature. The upper liner sections of the stack are made of stainless steel to address the higher likelihood of acid attack as the flue gas cools going up the stack to levels approaching the acid dew point (local cooling could be below the dew point). The lower section of the liner is carbon steel which is adequate, provided the temperature in that zone does not frequently fall below the acid dew point of the stack. The design life of the liners should have been at least 30 years for the design fuels and operating conditions. Unit 1 carbon steel liner was replaced in 2000. The inspections also suggest that life should not be an issue for the liner for the next ten years, despite the fact that portions of the liner are in excess of 43 years of age. Unit 1 stack has seen approximately 20 years of operation over the period and therefore should be in reasonable shape. An additional 6 to 8 years of equivalent operation life may require some more careful examination. It is suggested during the next stack inspection that some NDE thickness measurements be taken at strategic points on both the stainless steel and carbon steel liners.

The Unit 1 stack breeching, referred to as the East and West stack breeching, is connected to the outlet of each air pre-heater and conveys the hot flue gas to the boiler exhaust stack. The original Unit 1 stack breeching was installed in 1969 and had a rectangular cross section that was constructed from carbon steel plate. It was insulated externally with water tight insulation and metal cladding. The original breeching had a life span of approximately twenty years. During operation, there were numerous problems associated with corrosion that led to a complete replacement in 1989.

The existing Unit 1 stack breeching installed in 1989 also has a rectangular cross section that is constructed from carbon steel plate but is insulated internally on the sides and top with borosilicate (glass) block. The breeching sections are also coated externally with a protective film to inhibit corrosion. In addition, the breeching sections also have a silicate concrete floor.

Early into the Unit 1 operation following the upgrade in 1989, problems associated with cracking of the breeching internal insulating liner and concrete floor began develop. The concrete floor began to crack and the insulation blocks began to fall off the breeching, allowing the flue gas to penetrate the breeching plate where it would then cool and form sulphuric acid condensation causing localized corrosion necessitating plate repairs. As a result, the internal insulation liner and breeching plate has required frequent repairs and relatively high maintenance cost during scheduled Unit 1 annual outages.

Hydro completed thickness scanning on Unit 1 stack breeching steel casing in August 2010. The scan indicated that the casing was generally in good condition but localized areas required steel plate replacement due to corrosion. The current plan is to refurbish the steel casing based on the results of the plate thickness scan, replace the expansion joints and the corroded support structure, and insulate the breeching externally complete with water tight cladding and flashing. Ice protection shelters will also be constructed above the replacement breeching in order to protect the external insulation from damage caused by ice falling from the stack and the plant power house. The upgrade will be completed in 2011. Following the upgrade, the stack breeching is expected to be able to make the 2020 generation end date without additional major refurbishment or replacement.

8.2.7.3 Condition Assessment

The condition assessment of the Unit 1 stack and breeching is illustrated below in Table 8-57.

TABLE 8-57 CONDITION ASSESSMENT – UNIT 1 STACK AND BREECHING

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset Level 2	Asset Level 3	Description	Detail	Condition Summary ID #	Append #	Condition	EPRI Identifier	Original Life (Base Load) Ops Hrs (Yrs)	Current Expected Minimum Remaining Life Years (Subject to Test)	End of Life (EOL) Required	Next Regular Inspection	Next Planned Overhaul or Major Inspection	Capability to Reach Next Overhaul	Capability to Reach EOL	In Service
1296	6690	6699	6704	6919	0	1	#1 BOILER PLANT	BOILER GAS SYSTEM	BOILER STACK	N/A	140	17	The concrete stacks are in good condition, inspected every three years.	3a	(60/30)	30	2041	2011		Yes	Yes	1970
1296	6690	6699	6704	6919	0	1	#1 BOILER PLANT	BOILER GAS SYSTEM	BOILER STACK	Liner	141	17	The carbon steel portions of the liners have localized areas of heavy corrosion as well as areas with minimal corrosion. Unit 1 carbon steel liner was replaced in 2000.	3a	(60/30)	10+	2041	2011		Yes	Yes	1970/2000
1296	6690	6699	6704	6919	270294	1	#1 BOILER PLANT	BOILER GAS SYSTEM	BOILER STACK BREECHING	N/A	142	17	Installed in 1990. The current refractory brick lining in the breeching is cracked, which caused localized corrosion. It is planned to refurbish the breeching and replace the brick refractory with an insulated steel lined duct.	10	(30)	3	2020	2011	2011	Yes	No	1989/2011

Notes:
1. A "(bracketed)" value in the "Current Expected Remaining Life" column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as "(X/Y)" has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.
2. The "Next Regular Inspection" column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The "Next Planned Overhaul or Major Inspection" column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a "Desired Life" stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or are not known by AMEC.
3. The ability of the stack breeching to meet the EOL date of 2020 will be affected if planned refurbishments in 2011 are not undertaken.
4. The stack end of life is identified as 2041, assuming that it would not be demolished before the plant itself is closed.

8.2.7.4 Actions

Based on the condition assessment, the following actions are recommended for the Unit 1 stack and breeching:

TABLE 8-58 RECOMMENDED ACTIONS – UNIT 1 STACK AND BREECHING

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Unit	Asset 2/3	Asset 3/4	Description	Detail	Action #	App #	Action	Year	Priority
1296	6690	6699	6704	6919	1	#1 BOILER PLANT	BOILER GAS SYSTEM	BOILER STACK	N/A	121	17	Paint stack, at least top portions, within next five years.	2013	2
1296	6690	6699	6704	6919	1	#1 BOILER PLANT	BOILER GAS SYSTEM	BOILER STACK	N/A	122	17	Continue current stack inspections every 3 years and monitor degradation of concrete stacks and steel liners.	2012	1
1296	6690	6699	6704	6919	1	#1 BOILER PLANT	BOILER GAS SYSTEM	BOILER STACK	N/A	123	17	Continue to make all necessary repairs to deficiencies found in inspection reports.	2012	1
1296	6690	6699	6704	6919	1	#1 BOILER PLANT	BOILER GAS SYSTEM	BOILER STACK BREECHING	N/A	124	17	Undertake current stack breeching refurbishment, including patching the steel liner, installing external insulation, replacing the corroded support structure and installing an ice protection shelter to protect the new external insulation from falling ice.	2011	1

8.2.7.5 Risk Assessment

Table 8-59 below illustrates the risk assessment for the Unit 1 stack and breech, both from a technological perspective and a safety perspective using the models presented in Section 3.

TABLE 8-59 RISK ASSESSMENT – UNIT 1 STACK AND BREECHING

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Component	Risk Assess #	Appendix #	Major Issues	Remaining Life Years (Insufficient Info - Inspection Required Within (x) Years)	Remaining Life Comments	TECHNO-ECO RISK ASSESS MODEL			SAFETY RISK ASSESS MODEL			Possible Failure Event	Mitigation
																Likeli-hood	Conse-quence	Risk Level	Likeli-hood	Conse-quence	Safety Risk		
1296	6690	6699	6704	6919	0	1	#1 BOILER PLANT	BOILER GAS SYSTEM	BOILER STACK	Unit #1 Concrete Shell	116	17	Structural cracking.	30	None	1	D	Medium	1	D	Medium	Structural failure requiring shutdown and Unit outage.	Current inspection and maintain.
1296	6690	6699	6704	6919	0	1	#1 BOILER PLANT	BOILER GAS SYSTEM	BOILER STACK	Unit #1 Stainless Steel Liner	117	17	Corrosion/failure.	(10)	None	1	B	Low	1	C	Low	Corrosion causing major leak or failure – major leak requiring repair and Unit outage.	Current inspection and maintain.
1296	6690	6699	6704	6919	0	1	#1 BOILER PLANT	BOILER GAS SYSTEM	BOILER STACK	Unit #1 Carbon Steel Liner	118	17	Corrosion/failure.	(10)	None	3	B	Medium	3	C	Medium	Corrosion causing major leak or failure – major leak requiring repair	Current inspection and maintain.
1296	6690	6699	6704	6919	270294	1	#1 BOILER PLANT	BOILER GAS SYSTEM	BOILER STACK BREECHING	Unit #1 Stack Breeching	119	17	Corrosion/failure.	3	None	3	D	High	2	B	Low	Corrosion causing major leak or failure – major leak requiring repair and Unit outage.	Repair and maintain.
1296	6690	6699	6700	0	0	1	#1 BOILER PLANT	BOILER STRUCTURE	BOILER STRUCTURE	N/A	120	17	Mechanical failure.	30	None	1	D	Medium	1	D	Low	Building collapse	Inspect and maintain.

8.2.7.6 Life Cycle Curve and Remaining Life

The life cycle curve for the Unit 1 stack and breeching system is illustrated below. Four curves represent the stack, the stack breeching, and the stack liners based on their in-service dates. The life curves are plots of current and projected operating hours (generation mode only) on the y-axis versus calendar year on the x-axis. The figure has several vertical lines representing differing representative nominal age limits for various components. It also has several horizontal lines that represent a range of practical equivalent base loaded operating hour life limits. Several risk areas reflect also the differing normal lives of the components. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view.

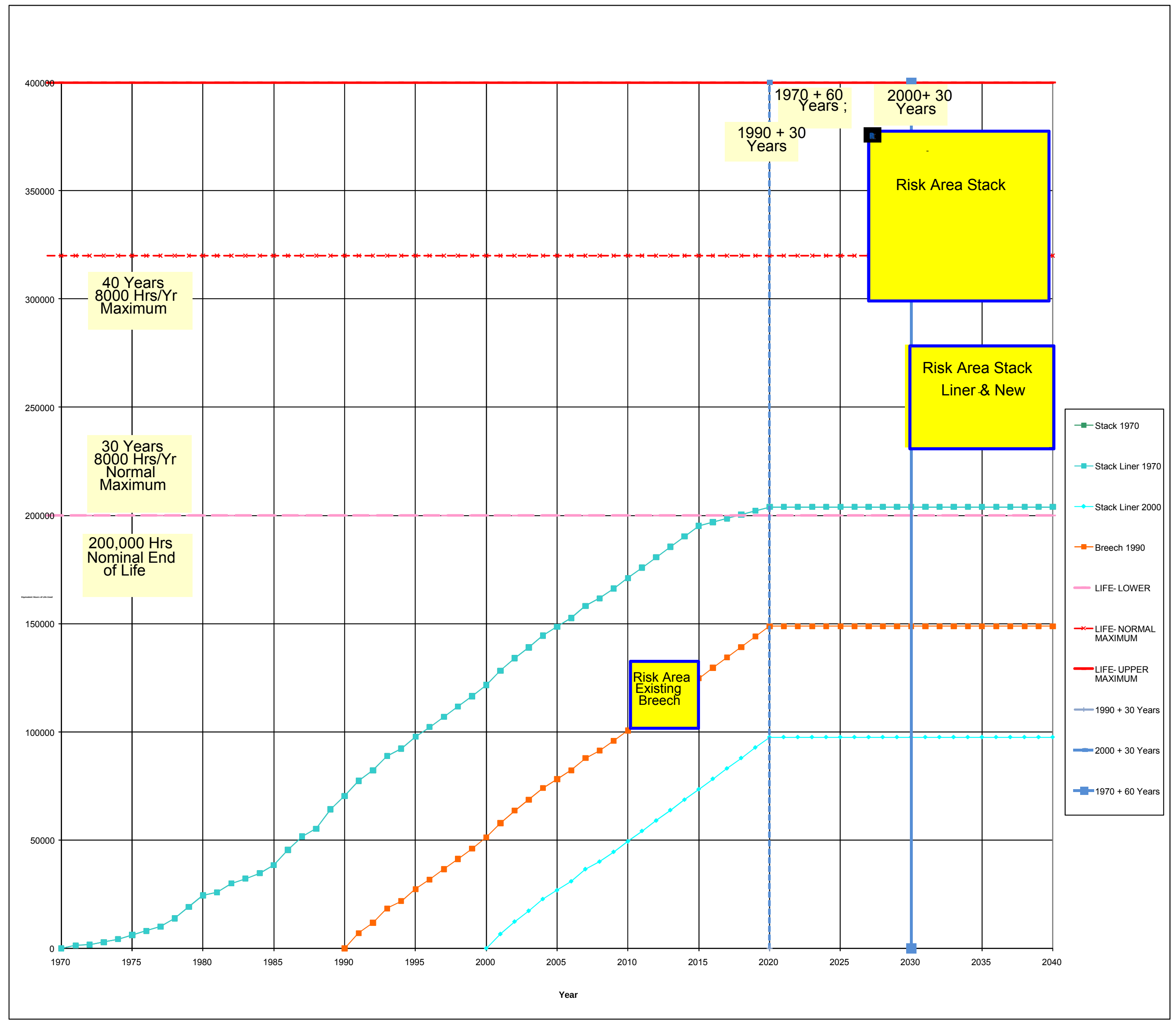

FIGURE 8-20 LIFE CYCLE CURVE – UNIT 1 STACK AND BREECHING

The curves indicate that the remaining life (RL) of the Unit 1 stack is may be able to reach the desired life (DL) 2020 end date for generation, as well as the end date of 2040 for synchronous condensing/plant life. It does show that the stack breeching is in need of immediate repair. The breeching requirement is not a normal life issue, but one of poor design. Other elements can achieve the 2020 end date for generation with the ongoing plant maintenance program.

8.2.7.7 Level 2 Inspections – Unit 1 Stack and Breeching

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 8-60 below, assuming that the current plant inspection and maintenance program is maintained or improved.

TABLE 8-60 LEVEL 2 INSPECTIONS – UNIT 1 STACK AND BREECHING

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Sub System Comment	L2#	Appendix #	Level 2 Work	Year	Priority	Cost k$
1296	6690	6699	6704	6919	0	1	#1 BOILER PLANT	BOILER GAS SYSTEM	BOILER STACK	Stacks	98	17	No Level 2 inspections. Continue inspections every 3 years and monitor degradation of concrete stacks and steel liners.	2011		$0
1296	6690	6699	6704	6919	270294	1	#1 BOILER PLANT	BOILER GAS SYSTEM	BOILER STACK BREECHING	None	99	17	No Level 2 required. (Assumes breeching refurbishment undertaken in 2011.)			

8.2.7.8 Capital Projects

Table 8-61 below shows the suggested typical capital enhancements that should be considered for the Unit 1 stack and breeching:

TABLE 8-61 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – UNIT 1 STACK AND BREECHING

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Detail	CAP#	Appendix #	Capital Item	Date	Priority
1296	6690	6699	6704	6919	0	1	#1 BOILER PLANT	BOILER GAS SYSTEM	BOILER STACK	N/A	81	17	See details below.		
1296	6690	6699	6704	6919	270294	1	#1 BOILER PLANT	BOILER GAS SYSTEM	BOILER STACK BREECHING	N/A	82	17	Refurbish stack breeching.	2011	1

8.2.8 Asset 6723 - Unit 1 Electrical and Control Systems (including DCS) Associated with Steam Systems

(Detailed Technical Assessment in Working Papers, Appendix 6)

The assets listed below include only those identified as exclusive to plant steam systems.

Unit #:	1
Asset Class #	BU 1296 - Assets Generation
SCI & System:	6723 # 1 Electrical & System & Controls
Sub-Systems:	6723 # 1 Electrical & System & Controls
Components:	6693 #1 Turbine Governor System 270151 #1 Turbine Supervisory System 7173 #1 Burner Management 309897 #1 Boiler Protection & Control

8.2.8.1 Description

The following information covers the Unit 1 electrical and control systems within the plant and its associated buildings.

Asset 6693 Unit 1 Turbine Governor System

The system is comprised of an electronic speed governor (GE SpeedTronic Mark V), manufactured by General Electric, and installed in 2003. The governor is complete with protection and monitors speed, metal temperatures, vibration, and steam valve positions into the turbine. A human machine interface (HMI), for operator use, is provided in the control room.

Asset 7173 Unit 1 Burner Management

The present burner management system is comprised of a Modicon PLC and Operator Control (HMI), and was installed in 1995. Field wiring in the bottom of the PLC cabinets is the original and was installed in 1969.

The PLC hardware is a Modicon 984 CPU with 800 series I/O and uses Schneider Electric ProWorx software. HMI hardware is a PC with Factory Link Version 6.5 software.

The system controls the operation of the burners and provides start-up and shut-down of the burner and protection of the fuel and air systems.

In 1995, a major upgrade was completed and the Combustion Engineering Cygnus operator consoles were removed and replaced with a PC based HMI console. At this time, the Windows based Factory Link Version 6.5 was installed in the console. During the upgrade, the original Modicon 884 processor was replaced with a 984 processor. The original 800 series I/O modules remained and today these are 25 years old.

Asset 291668 Unit 1, DCS

The DCS and auxiliaries related to the steam systems was manufactured by Foxboro, and is an Invensys system installed in 2004 and is considered "state-of-the-art". The processes transferred to the DCS included condensate polishing, water treatment plant, waste water treatment plant, burner management, and boiler P&C. Turbine governor control would likely require upgrades and changes, and the plant has no plans to do so. The Westinghouse panels housing the DCS were installed in the late 1980's, and new cabling was installed at that time. The original system was hard-wired but was later upgraded to a Westinghouse system.

Asset 309897 Unit 1, Boiler Protection & Control

The boiler protection and control system provides safety of personnel, protection of the boiler and its equipment, and control of the boiler processes.

During initial migration from the original Bailey system to Westinghouse WDPF, field equipment, (switches and transmitters), were eliminated where possible or upgraded to more modern design. Typically, -10 to +10V was replaced by 4-20mA analog, plus the boiler control was upgraded to the current design at that time.

In 2004, the DCS system was again upgraded from the Westinghouse WDPF to the present Foxboro DCS system and control algorithms again were revisited. The Foxboro DCS equipment was mounted within the original Westinghouse WDPF enclosures, where it presently remains.

8.2.8.2 History

The requirements for the electrical and control systems associated with the steam system for Holyrood are as follows:

Manufactured/Delivered	1969
In-Service Date	Sep 1970
Generation Base Load End Date	Dec 2015
Generation Peak/Emerg Gen End Date	Dec 2020
Last Controls Upgrade	2004

8.2.8.3 Inspection and Repair History

Foxboro technical support is provided a number of times per year under a support agreement. Upgrades have been and will be carried out as required. Field adjustments and modifications will continue as necessary.

8.2.8.4 Condition Assessment

The condition assessment of the Unit 1 electrical and control systems (including DCS) associated with steam systems is illustrated below in Table 8-62.

TABLE 8-62 CONDITION ASSESSMENT – UNIT 1 ELECTRICAL AND CONTROL SYSTEMS (INCLUDING DCS) ASSOCIATED WITH STEAM SYSTEMS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset Level 2	Asset Level 3	Description	Detail	Condition Summary ID #	Append #	Condition	EPRI Identifier	Original Life (Base Load) Ops Hrs (Yrs)	Current Expected Minimum Remaining Life Years (Subject to Test)	End of Life (EOL) Required	Next Regular Inspection	Next Planned Overhaul or Major Inspection	Capability to Reach Next Overhaul	Capability to Reach EOL	In Service
1296	6690	6723	6721	0	0	1	#1 UNIT GENERATION SERVICES	RELAY RM PROTECTN & CONTROL	RELAY RM PROTECTN & CONTROL	N/A	305	6	Generator & Transformer & Auxiliary Protection and Metering Panels tests in 2005 were satisfactory. Some ingress of dust and foreign material. Testing is on a 6 year cycle (2011, 2017, 2023, etc.).	10	(40)	10	2041	2011		No	No	1970
1296	6690	6723	270295	0	0	1	#1 UNIT GENERATION SERVICES	SWITCHGEAR 4160/600V	SWITCHGEAR 4160/600V	N/A	306	6	Breaker overhauls have been carried out, between 1995 and 2007 (See Appendix). All 4160V switchgear is applied within ratings. Overhauls due. Past normal life, extended by overhauls/maintenance.	10	(25-30)	5	2041			No	No	1970
1296	6690	6723	6722	0	0	1	#1 UNIT GENERATION SERVICES	MAIN CONTROLS	MAIN CONTROLS	N/A	307	6	There are age and spares problems with the relaying system.	4	(30)	10	2041			No	No	1970
1296	6690	6723	6693	0	0	1	#1 UNIT GENERATION SERVICES	TURBINE GOVERNOR SYSTEM	TURBINE GOVERNOR SYSTEM	N/A	277	6	Maintenance (PM) and corrective actions (CA) are performed as required. Servos are checked annually, due to problems with "dirty" hydraulic lines resulting in blocked pilot strainers. From an electrical and controls point of view, the system is operating well. GE support until 2012-2013 with no guarantee of spares.	3a	(30)	(10)	2020	2012		Yes	No	2003
1296	6690	6723	270151	0	0	1	#1 UNIT GENERATION SERVICES	TURBINE SUPERVISORY SYSTEM	TURBINE SUPERVISORY SYSTEM	N/A	308	6	Operating well, with numerous spares. In 2010 will progress toward Phase 5 (Obsolescence) status at some indeterminate time.	10	(25)	2	2020			No	No	1990
1296	6690	6723	291668	0	0	1	#1 UNIT GENERATION SERVICES	DISTRIBUTED CONTROL SYSTEM (DCS)	DCS	N/A	309	6	Installed in 2004 - state of the art.	3a	(20)	10	2041			Yes	No	2004
1296	6690	6723	7173	0	0	1	#1 UNIT GENERATION SERVICES	BURNER MANAGEMENT	BURNER MANAGEMENT	N/A	310	6	Major upgrade in 1995 with HMI operator consoles and processor. Original 800 series I/O modules remained. Minor failures only. Annual maintenance inspections and repairs.	3a	(25)	10	2020	2011		Yes	Yes	1995
1296	6690	6723	309897	0	0	1	#1 UNIT GENERATION SERVICES	BOILER PROTECTION & CONTROL	BOILER PROTECTION & CONTROL	N/A	311	6	Maintenance on an unscheduled basis a number of times per year under a support agreement. Upgrades carried out as required.	3a	200000 (30)	15	2020			Yes	Yes	2004

Notes:

1. A "(bracketed)" value in the "Current Expected Remaining Life" column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as "(X/Y)" has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

2. The "Next Regular Inspection" column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The "Next Planned Overhaul or Major Inspection" column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a "Desired Life" stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or are not known by AMEC.

8.2.8.5 Actions

Based on the condition assessment, the following actions are recommended for the Unit 1 electrical and control systems (including DCS) associated with steam systems.

TABLE 8-63 RECOMMENDED ACTIONS – UNIT 1 ELECTRICAL AND CONTROL SYSTEMS (INCLUDING DCS) ASSOCIATED WITH STEAM SYSTEMS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Unit	Asset 2/3	Asset 3/4	Description	Detail	Action #	App #	Action	Year	Priority
1296	6690	6723	0	0	1	#1 UNIT GENERATION SERVICES	ELEC & CONTROLS SYSTEM	ELEC & CONTROLS SYSTEM	N/A	224	6	See details below.		
1296	6690	6723	0	0	1	#1 UNIT GENERATION SERVICES	ELEC & CONTROLS SYSTEM	ELEC & CONTROLS SYSTEM	N/A	225	6	See details below.		
1296	6690	6723	6722	0	1	#1 UNIT GENERATION SERVICES	MAIN CONTROLS	MAIN CONTROLS	N/A	226	6	Assess migrating Governor System and Burner Management to DCS - remove existing control relaying and transducers, re-direct field cabling to the DCS and re-configure the software.	2011	1
1296	6690	6723	291668	0	1	#1 UNIT GENERATION SERVICES	DISTRIBUTED CONTROL SYSTEM (DCS)	DCS	N/A	227	6	Maintain DCS system current through existing Foxboro replacement service agreement.	2014	1
1296	6690	6723	6721	0	1	#1 UNIT GENERATION SERVICES	RELAY RM PROTECTN & CONTROL	RELAY RM PROTECTION & CONTROL	N/A	228	6	Test Generator G1, Transformer T1 and Auxiliaries P&C Panels - next tests planned for 2011, 2017, 2023, etc.	2011	1
1296	6690	6723	270295	0	1	#1 UNIT GENERATION SERVICES	SWITCHGEAR 4160/600V	SWITCHGEAR 4160/600V	N/A	229	6	Assess Switchgear, 4160V/600V relaying in UB1 modernization study for the protection relays. Consider that the remaining P&B Golds relays remain and not be replaced by Schweitzer 701 MPR's. As of 2015 the breakers utilizing these will become standby and as of 2020 will become spare.	2011	1
1296	6690	6723	6693	0	1	#1 UNIT GENERATION SERVICES	TURBINE GOVERNOR SYSTEM	TURBINE GOVERNOR SYSTEM	N/A	230	6	See details below.		2
1296	6690	6723	6693	333928	1	#1 UNIT GENERATION SERVICES	TURBINE GOVERNOR SYSTEM	HOLYROOD MARK V AUTO SYNC	N/A	231	6	Assess and implement GE migration of the Turbine Governor System Mark V to the Mark Ve system.	2012	2
1296	6690	6723	270151	0	1	#1 UNIT GENERATION SERVICES	TURBINE SUPERVISORY SYSTEM (TSI)	TURBINE SUPERVISORY SYSTEM	N/A	232	6	Assess Turbine Supervisory System replacement options (vendor, GE 3500 Series Monitoring System, other GE options) that might be available in 2010-2011.	2011	1
1296	6690	6723	7173	0	1	#1 UNIT GENERATION SERVICES	BURNER MANAGEMENT	BURNER MANAGEMENT	N/A	234	6	Transfer Burner Management system from PLC system to DCS. Replace any existing field mounted pressure switches by analog transducers to provide continuous status monitoring. Flame Scanners will remain unchanged from its present state.	2012	2
1296	6690	6723	309897	0	1	#1 UNIT GENERATION SERVICES	BOILER PROTECTION & CONTROL	BOILER PROTECTION & CONTROL	N/A	235	6	Maintain the Boiler Protection and Control System current through existing Foxboro migration process infinitum.T16	2014	1

8.2.8.6 Risk Assessment

Table 8-64 below illustrates the risk assessment for the Unit 1 electrical and control systems (including DCS) associated with steam systems, both from a technological perspective and a safety perspective using the models presented in Section 3.

TABLE 8-64 RISK ASSESSMENT – UNIT 1 ELECTRICAL AND CONTROL SYSTEMS (INCLUDING DCS) ASSOCIATED WITH STEAM SYSTEMS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Component	Risk Assess #	Appendix #	Major Issues	Remaining Life Years (Insufficient Info - Inspection Required Within (x) Years)	Remaining Life Comments	TECHNO-ECO RISK ASSESS MODEL			SAFETY RISK ASSESS MODEL			Possible Failure Event	Mitigation
																Likeli-hood	Conse-quence	Risk Level	Likeli-hood	Conse-quence	Safety Risk		
1296	6690	6723	270295	0	0	1	#1 UNIT GENERATION SERVICES	SWITCHGEAR 4160/600V	SWITCHGEAR 4160/600V	Switchgear, 4160V/600V	204	6	Electrical fault, mechanical fatigue, ops error.	5	None	3	B-C	Medium	3	B-C	Medium	Loss up to 1 unit generation. Damage to equipment.	Refurbish or replace.
1296	6690	6723	6721	0	0	1	#1 UNIT GENERATION SERVICES	RELAY RM PROTECTION & CONTROL	RELAY RM PROTECTION & CONTROL	Relay Room Protection & Control	205	6	Electrical fault, mechanical fatigue, ops error.	10	None	2	C-D	Medium	2	C-D	Medium	Loss 1 unit generation, damage to unit or equipment. Safety	Current inspection and maintain.
1296	6690	6723	6722	0	0	1	#1 UNIT GENERATION SERVICES	MAIN CONTROLS	MAIN CONTROLS	Main Controls	206	6	Electrical fault, mechanical fatigue, ops error.	10	None	1	C	Low	1	C	Low	Loss of unit. Safety	Current inspection and maintain.
1296	6690	6723	291668	0	0	1	#1 UNIT GENERATION SERVICES	DISTRIBUTED CONTROL SYSTEM (DCS)	DCS	DCS	207	6	Electrical fault, ops error.	10	None	1	C	Low	1	C	Low	Loss 1 unit generation. Damage to unit	Maintain.
1296	6690	6723	6693	0	0	1	#1 UNIT GENERATION SERVICES	TURBINE GOVERNOR SYSTEM	TURBINE GOVERNOR SYSTEM	Turbine Governor System	208	6	Electrical fault, mechanical failure ops error.	(10)	None	1	C-D	Low	1	C	Low	Loss 1 unit generation, damage to unit. Safety	Upgrade governor system.
1296	6690	6723	6693	333928	0	1	#1 UNIT GENERATION SERVICES	TURBINE GOVERNOR SYSTEM	MARK V AUTO SYNC		209		Not addressed.		None								
1296	6690	6723	270151	0	0	1	#1 UNIT GENERATION SERVICES	TURBINE SUPERVISORY SYSTEM	TURBINE SUPERVISORY SYSTEM	Turbine Supervisory System	210	6	Electrical fault, mechanical fatigue, ops error.	2	None	3	C	Medium	3	C	Medium	Loss 1 unit generation, damage to unit	Refurbish or replace.
1296	6690	6723	6693	99000260	0	1	#1 UNIT GENERATION SERVICES	#1 UNIT GENERATION SERVICES	INSTALL GOVENOR UNIT 1 - MFG C		211		Not addressed.		None								
1296	6690	6723	7173	0	0	1	#1 UNIT GENERATION SERVICES	BURNER MANAGEMENT	BURNER MANAGEMENT	Burner Management	212	6	Electrical fault, mechanical fatigue, ops error.	10	None	1	C	Medium, Low	1	C	Low	Loss 1 unit generation, equipment damage	Refurbish or replace.
1296	6690	6723	309897	0	0	1	#1 UNIT GENERATION SERVICES	BOILER PROTECTION & CONTROL	BOILER PROTECTION & CONTROL	Boiler Protection & Control	213	6	Electrical fault, mechanical fatigue, ops error.	15	None	1	B	Low	1	B	Low	Loss of part of 1 unit generation, equipment damage	Maintain.

8.2.8.7 Life Cycle Curve and Remaining Life

The life cycle curve for the Unit 1 electrical and control systems (including DCS) associated with steam systems is illustrated below. Several curves are required to represent the various elements of and their operational timing. The life curves are plots of current and projected operating hours (generation mode only) on the y-axis versus calendar year on the x-axis. The figure has several vertical lines representing differing representative nominal age limits for various components. It also has several horizontal lines that represent a range of practical equipment equivalent base loaded operating hour life limits. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view.

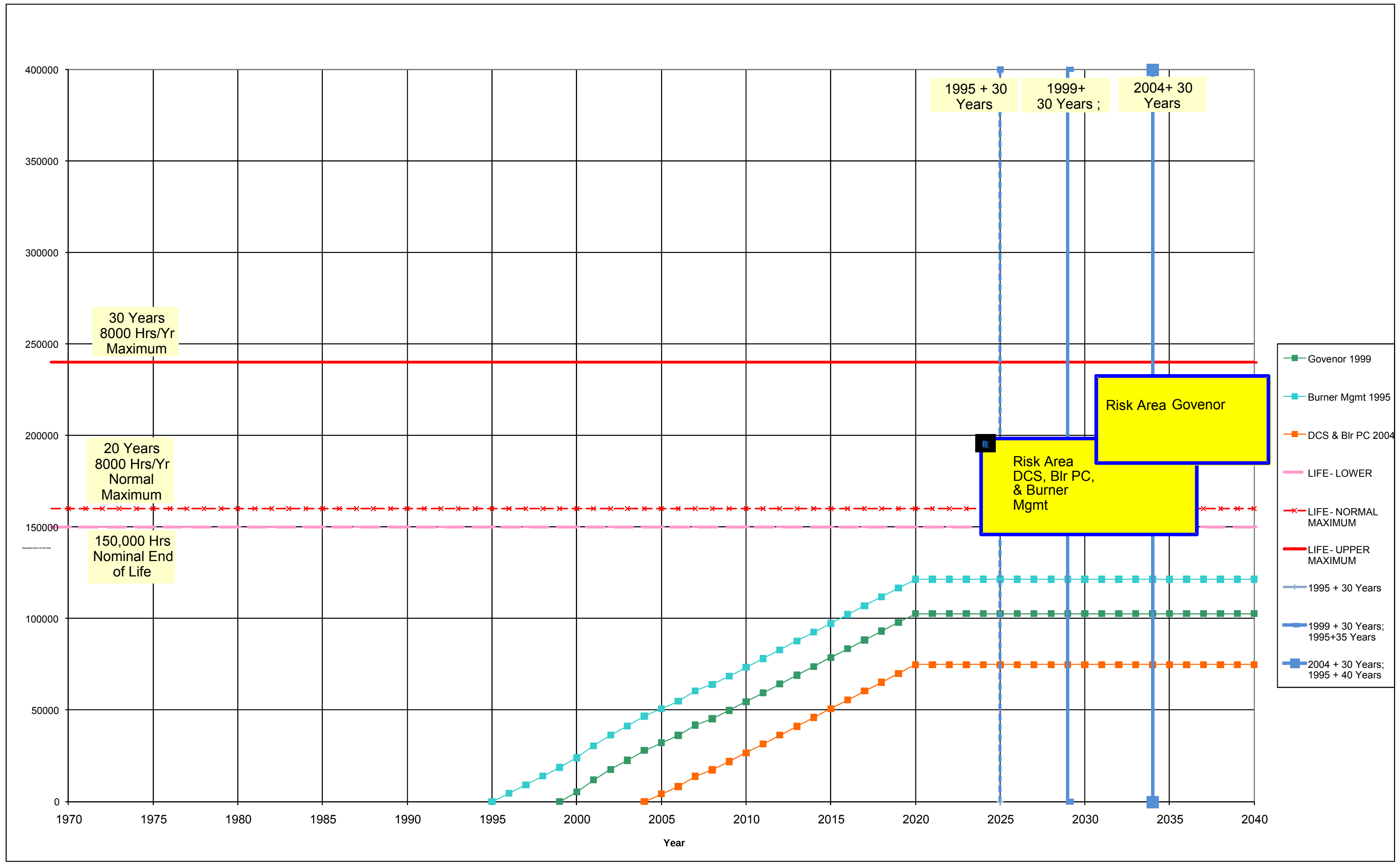

FIGURE 8-21 LIFE CYCLE CURVE – UNIT 1 ELECTRICAL AND CONTROL SYSTEMS (INCLUDING DCS) ASSOCIATED WITH STEAM SYSTEMS

The curves indicate that the remaining life (RL) of the Unit 1 control systems (including DCS) associated with steam systems can readily reach the desired life (DL) 2020 end date for generation, provided regular inspection and service as per the station PM plan is maintained. The electrical systems, particularly breakers and motor controls are addressed in more detail as part of Section 8.1.3. It is clear that in order to meet the end date for generation service, some components must be replaced, or in some cases refurbished.

8.2.8.8 Level 2 Inspections – Unit 1 Electrical and Control Systems (including DCS) Associated with Steam Systems

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 8-65 below, assuming that the current plant inspection and maintenance program is maintained or improved.

TABLE 8-65 LEVEL 2 INSPECTIONS – UNIT 1 ELECTRICAL AND CONTROL SYSTEMS (INCLUDING DCS) ASSOCIATED WITH STEAM SYSTEMS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Sub System Comment	L2#	Appendix #	Level 2 Work	Year	Priority	Cost k$
1296	6690	6723	6721	0	0	1	#1 UNIT GENERATION SERVICES	RELAY RM PROTECTN & CONTROL	RELAY RM PROTECTN & CONTROL	None	191	6	No Level 2 required.			
1296	6690	6723	270295	0	0	1	#1 UNIT GENERATION SERVICES	SWITCHGEAR 4160/600V	SWITCHGEAR 4160/600V	None	192	6	No Level 2 required.			
1296	6690	6723	6693	0	0	1	#1 UNIT GENERATION SERVICES	TURBINE GOVERNOR SYSTEM	TURBINE GOVERNOR SYSTEM	None	193	6	No Level 2 required.			
1296	6690	6723	6693	333928	0	1	#1 UNIT GENERATION SERVICES	TURBINE GOVERNOR SYSTEM	Holyrood Mark V Auto Sync	None	194	6	No Level 2 required.			
1296	6690	6723	6693	99000260	0	1	#1 UNIT GENERATION SERVICES	#1 UNIT GENERATION SERVICES	INSTALL GOVENOR UNIT 1 - MFG C	None	195	6	No Level 2 required.			
1296	6690	6723	270151	0	0	1	#1 UNIT GENERATION SERVICES	TURBINE SUPERVISORY SYSTEM	TURBINE SUPERVISORY SYSTEM	None	196	6	No Level 2 required.			
1296	6690	6723	6722	0	0	1	#1 UNIT GENERATION SERVICES	MAIN CONTROLS	MAIN CONTROLS	None	197	6	No Level 2 required.			
1296	6690	6723	291668	0	0	1	#1 UNIT GENERATION SERVICES	DISTRIBUTED CONTROL SYSTEM (DCS)	DCS	None	198	6	No Level 2 required.			
1296	6690	6723	7173	0	0	1	#1 UNIT GENERATION SERVICES	BURNER MANAGEMENT	BURNER MANAGEMENT	None	199	6	No Level 2 required.			
1296	6690	6723	309897	0	0	1	#1 UNIT GENERATION SERVICES	BOILER PROTECTION & CONTROL	BOILER PROTECTION & CONTROL	None	200	6	No Level 2 required.			

8.2.8.9 Capital Projects

Table 8-66 below shows the suggested typical capital enhancements that should be considered for the electrical and control systems (including DCS) associated with steam systems:

TABLE 8-66 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – UNIT 1 ELECTRICAL AND CONTROL SYSTEMS (INCLUDING DCS) ASSOCIATED WITH STEAM SYSTEMS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Detail	CAP#	Appendix #	Capital Item	Date	Priority
1296	6690	6723	0	0	0	1	#1 UNIT GENERATION SERVICES	ELEC & CONTROLS SYSTEM	ELEC & CONTROLS SYSTEM	N/A	166	6	See details below.		
1296	6690	6723	6721	0	0	1	#1 UNIT GENERATION SERVICES	RELAY RM PROTECTN & CONTROL	RELAY RM PROTECTN & CONTROL	N/A	167	6	Implement modernization study re: appraise the cost of refurbishing the old GE electro-magnetic relays against the cost of multi-function relaying.	2014	1
1296	6690	6723	270295	0	0	1	#1 UNIT GENERATION SERVICES	SWITCHGEAR 4160/600V	SWITCHGEAR 4160/600V	N/A	168	6	No capital required.		
1296	6690	6723	6722	0	0	1	#1 UNIT GENERATION SERVICES	MAIN CONTROLS	MAIN CONTROLS	N/A	169	6	Implement study to migrate Governor System and Burner Management to DCS - remove existing control relaying and transducers, re-direct field cabling to the DCS and re-configure the software.	2014	2
1296	6690	6723	291668	0	0	1	#1 UNIT GENERATION SERVICES	DISTRIBUTED CONTROL SYSTEM (DCS)	DCS	N/A	170	6	No capital required.		
1296	6690	6723	270151	0	0	1	#1 UNIT GENERATION SERVICES	TURBINE SUPERVISORY SYSTEM	TURBINE SUPERVISORY SYSTEM	N/A	171	6	No capital required.		
1296	6690	6723	6693	0	0	1	#1 UNIT GENERATION SERVICES	TURBINE GOVERNOR SYSTEM	TURBINE GOVERNOR SYSTEM	N/A	172	6	Assess and implement GE migration of the Mark V to the Mark Ve system. Replace existing 196 processor and modernize operator and maintenance stations. Field wiring and devices remain the same.	2013	1
1296	6690	6723	7173	0	0	1	#1 UNIT GENERATION SERVICES	BURNER MANAGEMENT	BURNER MANAGEMENT	N/A	175	6	Transfer Burner Management system from PLC system to DCS. Replace any existing field mounted pressure switches by analog transducers. Flame Scanners remain unchanged.	2011	1
1296	6690	6723	309897	0	0	1	#1 UNIT GENERATION SERVICES	BOILER PROTECTION & CONTROL	BOILER PROTECTION & CONTROL	N/A	176	6	No capital required.		

8.2.9 Asset 271309 – Unit 1 Steam Turbine

(Detailed Technical Assessment in Working Papers, Appendix 18)

Unit #:	1
Asset Class #	BU 1296 - Assets Generations
SCI & System:	6691 #1 Turbine & Generator
Sub-Systems:	271309 #1 Steam turbine
Components:	6729 #1 Main Steam Chest
	6730 #1 HP Turbine
	6731 #1 IP Turbine
	6732 #1 LP Turbine
	6734 #1 Front Standard

Note: High energy piping and hangers are addressed within the Boiler Section (Section 8.2.1) under heading Boiler Main Steam Lines (Asset Code 6876). The scope is assumed to include piping and hangers up to the steam turbine.

8.2.9.1 Description

The Unit 1 turbine went into service in 1970. It was originally a 150 MW turbine supplied by General Electrical (GE). The original turbine was a 1970 vintage Lynn D3 model. The turbine is rated to operate at a main steam inlet pressure of 13.0 MPag (1890 psig) and steam temperature of 538 °C (1,000 °F). The reheat steam inlet temperature is 538 °C (1,000 °F). The turbine rotating speed is 3,600 RPM.

The unit consists of one combined high pressure (HP) and intermediate pressure (IP) turbine and one double flow low pressure (LP) turbine. The HP/IP and LP rotors are integral with the blade wheels. There is no centerline bore through the rotors. The turbine rotors are supported by three journal bearings. The trust bearing and the turning gear are located in the HP front standard.

The generator rotor is directly-coupled to the turbine. It is supported by two journal bearings located at the stator end-shields. In 1989, the unit was upgraded to produce 175 MW by replacing the HP/IP rotor and the HP/IP steam path components including the HP nozzle block. No changes were made to the LP turbine or the auxiliary equipment.

Unit 1 turbine has an upgraded Mk 5 Electro-Hydraulic Controlled (EHC) governor system with a partial arc steam admission system through 6 control valves. Unit 1 also has one main stop valve (MSV) with an internal pilot valve to control the run up of the turbine to full speed. There are two combined casing reheat stop and intercept valves.

The steam seal regulator (SSR) is the key component of the steam turbine gland steam sealing system. The SSR controls the flow of steam to and from all of the turbine shaft seals. The seals minimize the leakage of process steam along the rotor shaft from the turbine casing. There SSR must be able to respond differently at low and high loads.

The turbine auxiliaries considered in this report included:

- The lube oil system;
- The gland steam sealing system, including steam seal regulator;
- The control oil system;
- Steam blow down valve; and
- Power assisted extraction steam non return valves (NRV).

8.2.9.2 History

Manufactured/Delivered	1969
In-Service Date	Sep 1970
Units 1 and 2 Upgrade	1987
Units 1 and 2 Governor Valves	2003
Units 1 and 2 HP Nozzle Block Replacement	2008
Generation Base Load End Date	Dec 2015
Generation Peak/Emerg Gen End Date	Dec 2020
Last Major Overhaul	2003
Last Valve (Minor) Overhaul	2006/2009
Next Major Overhaul/Inspection	2012
Next Valve (Minor) Overhaul	2015/2018

The hours associated with the analyses are:

Hours Generation Actual - Ops to Dec 2009	166
Max Hours Generation Ops – to Dec 2015	210
Max Hrs Gen Ops to Gen End Date Dec 2020	219

8.2.9.3 Inspection and Repair History

The turbine major overhauls have been completed on six year frequency. As of the year 2003, the overhauls were scheduled to be done every 9 years with the next overhaul scheduled for the year 2012.

The turbine valves overhaul frequency of 3 years was not changed. The last valve overhaul was completed in the year 2009 including a replacement of the HP turbine section nozzle block. The next valve overhaul is scheduled for 2012.

The Unit 1 steam seal regulator is obsolete and in recent years, replacement components have been fabricated locally by copying the original parts. There are issues with the SSR controller binding and sticking during operation. Failure to address the SSR could result in premature deterioration of the steam turbine generator bearings.

The reports indicate that the overhaul work has been done by GE since the year 1999.

2009 Valve Overhaul

This was a scheduled valve overhaul. A boroscope inspection of the nozzle block was done at the start of the valve overhaul to check the condition of the partition plates. The inspection confirmed some partition separation and deformation. Based on the Unit 2 2007 incident, and since there was a concern that some partitions could liberate and do a damage to the turbine steam path, the HP/IP turbine was opened to replace the nozzle block. The following work was performed during the overhaul:

- Installed a new HP nozzle block;
- Dressed out first three HP stage blades. The blades had significant foreign object damage (FOD), possibly by welding slag carried over from the boiler superheater replacement;
- First two HP stage diaphragms were weld repaired and the partition surfaces were built up using the Inconel 82 wire;
- Four out of six control valve (CV) stems and two cross heads were replaced. Stem #4 was cut to allow for valve disassembly. Inconel Stems #2 and #5 were worn beyond allowable tolerances. Inconel Stem #3 was bent beyond specification;
- New Inconel Stems were installed in the #2 and #5 positions;
- The Main Steam Valve (MSV) stem was replaced;
- Both reheat stop valves stems were replaced;
- Fourteen MSV screen rivets that were badly damaged by weld slag from the boiler were replaced; and
- A 2.2 cm (7/8 inch) deep crack in the left combined reheat intercept valve was successfully repaired using a temper bead weld process. This crack was not seen during the last 2006 valve overhaul.

2006 Turbine Valve Overhaul

- Replaced various turbine valves stems, seats, and bushings that were damaged, bent, worn out or had excessive run out. CV stem # 4 and #6 were replaced with original material. CV stem #5 was replaced with an Inconel material. (Note that Inconel stems were also installed on CV #3 in 2004 and CV #2 in 2005); and
- A crack in the left reheat valve anti-swirl dam was grinded out and weld repaired. If the proper weld procedure was not followed, the crack could restart in the weld repair area or the weld heat affected zone (HAZ). There may be a connection between this repair and the new large crack found during the 2009 overhaul that was not discovered during this 2006 overhaul (see 2009 overhaul below above).

2005 Maintenance Upgrade

Installed the duplex full flow in-line filters in the lube oil system.

2003 Major Turbine & Valve Overhaul

- Upgraded the turbine control system to Mark 5 and installed a 60 tooth wheel with 6 speed pickups for turbine control and over speed protection;
- Installed two new proximity probes in bearing #1 and metal thermocouples in bearings 1, 2, and 3;
- Removed eight crack indications in the HP turbine lower outer casing. Grinding was less than 6.3 mm (1/4 inch);
- Removed sixteen crack indications in the HP turbine upper outer casing. Grinding was less than 6.3 mm (1/4 inch);
- Minor grinding to remove few indications in the HP turbine lower and upper inner casings;
- Minor grinding to remove indications in the LP turbine lower and upper inner casings;
- Re-brazed LP turbine 4th stage tie wire;
- Repaired some reinforcement struts in the LP turbine lower and upper outer casings;

- Replaced various turbine valves stem, seats, and bushings that were damaged, bent, worn out or had run out beyond the allowable limits. CV stems #4 and #5 were replaced due to excessive run out. Stem #3 was broken. Stems #1 and #6 had to be cut out to service the valve; and.
- Replaced bearings in the emergency oil pump, lube oil pump, and turning gear unit.

1989 HP/IP Turbine Upgrade

The unit was uprated to produce 175 MW. The following components were replaced:

- New HP/IP rotor with some stages removed;
- Inner casing steam path was changed for both the HP and IP turbine sections; and

The upgrade report was not submitted and has not been reviewed. It is assumed that the inner and outer casings of the HP and IP turbines were not replaced. It is also assumed that the casing joint studs were not replaced.

8.2.9.4 Condition Assessment

The condition assessment of the Unit 1 steam turbine is illustrated below in Table 8-67.

TABLE 8-67 CONDITION ASSESSMENT – UNIT 1 STEAM TURBINE

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset Level 2	Asset Level 3	Description	Detail	Condition Summary ID #	Append #	Condition	EPRI Identifier	Original Life (Base Load) Ops Hrs (Yrs)	Current Expected Minimum Remaining Life Years (Subject to Test)	End of Life (EOL) Required	Next Regular Inspection	Next Planned Overhaul or Major Inspection	Capability to Reach Next Overhaul	Capability to Reach EOL	In Service
1296	6690	6691	271309	0	0	1	#1 TURBINE & GENERATOR	TURBINE	TURBINE	N/A	33	18	Generally good for age. See details below.	4								
1296	6690	6691	271309	6729	0	1	#1 TURBINE & GENERATOR	TURBINE	TURBINE MAIN STEAM CHEST	N/A	34	18	Many control valve stem failures and the wear/tear of various stem bushes. High temperature studs and the valves are the original equipment.	4	200000 (30)	2/5	2020	2012	2012	Yes	No	1970
1296	6690	6691	271309	6730	0	1	#1 TURBINE & GENERATOR	TURBINE	H.P. TURBINE	N/A	35	18	Generally turbine and valves in good shape. Extensive foreign object damage (FOD). Turbine casing, high temperature studs and valves are original equipment. HP rotor and HP steam paths that sees the high pressure and temperature service replaced in 1989. Lot of studs with excessive over projection in the HP inner and outer casings	4	200000 (30)	(10)	2020	2012	2012	Yes	No	1970/1988
1296	6690	6691	271309	6731	0	1	#1 TURBINE & GENERATOR	TURBINE	I.P. TURBINE	N/A	36	18	Generally turbine in good shape. LP rotor, LP turbine casings are the original equipment.	4	200000 (30)	10	2020	2012	2012	Yes	Yes	1970/1988
1296	6690	6691	271309	6732	0	1	#1 TURBINE & GENERATOR	TURBINE	L.P. TURBINE	N/A	37	18	Generally turbine in good shape. LP rotor, LP turbine casings are the original equipment.	4	200000 (30)	10	2020	2012	2012	Yes	Yes	1970
1296	6690	6691	271309	6734	0	1	#1 TURBINE & GENERATOR	TURBINE	TURBINE FRONT STANDARD	N/A	38	18	High temperature studs and the valves are the original equipment. Generally HP valves in good shape.	4	200000 (30)	10	2020	2012	2012	Yes	Yes	1970
1296	6690	6691	271309	6766	0	1	#1 TURBINE & GENERATOR	TURBINE	TURBINE RH/IP STEAM CHEST	N/A	39	18	Many control valve stem failures and the wear/tear of various stem bushes. High temperature studs and the valves are the original equipment.	4	200000 (30)	2/5	2020	2012	2012	Yes	No	1970
1296	6690	6691	271309	6777	0	1	#1 TURBINE & GENERATOR	TURBINE	TURBINE GLAND STEAM SYSTEM	N/A	40	18	Original equipment, acceptable condition.	3a	(30)	10	2020	2012	2012	Yes	Yes	1970
1296	6690	6691	271309	6777	0	1	#1 TURBINE & GENERATOR	TURBINE	TURBINE GLAND STEAM SYSTEM	Steam Seal Regulator	40a	18	Original equipment. The Steam seal regulator 's many moving parts and wear points result in frequent binding and sticking requiring manual intervention. Parts are very difficult to obtain and the system should be considered obsolete. Failure to address could result in premature deterioration of the steam turbine generator bearings.	10	(30)	(2)	2020	2011	2011	Yes	No	1970
1296	6690	6691	271309	6778	0	1	#1 TURBINE & GENERATOR	TURBINE	TURBINE PRE-WARMING SYSTEM	N/A	41	18	Original equipment. Not reviewed.	3a	(30)	10	2020	2012	2012	Yes	Yes	1970
1296	6690	6691	271309	6779	0	1	#1 TURBINE & GENERATOR	TURBINE	TURBINE TURNING GEAR	N/A	42	18	Original equipment. Chain disengagement occurs. Needs refurbishment.	10	(30)	(2)	2020	2012	2012	Yes	No	1970
1296	6690	6691	271309	6781	0	1	#1 TURBINE & GENERATOR	TURBINE	TURBINE DRAINS SYSTEMS	N/A	43	18	Original equipment. Not reviewed in detail. No issues identified.	4	(30)	5	2020	2011	2012	Yes	No	1970
1296	6690	6691	271309	270125	0	1	#1 TURBINE & GENERATOR	TURBINE	TURBINE BLED STEAM SYSTEM	N/A	49	18	Original equipment. Two of seven pneumatic actuators for extraction steam NRVs were seized. There was substantial rust in the cylinders.	4	(30)	5	2020		2012	Yes	No	1970

Notes:

1. A “(bracketed)” value in the “Current Expected Remaining Life” column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as “(X/Y)” has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

2. The “Next Regular Inspection” column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The “Next Planned Overhaul or Major Inspection” column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a “Desired Life” stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or are not known by AMEC.

3. The ability of the steam seal regulator (SSR) to meet its next overhaul date and the EOL date of 2020 is conditional on its replacement as planned in 2010/2011

8.2.9.5 Actions

Based on the condition assessment, the following actions are recommended for the Unit 1 steam turbine:

TABLE 8-68 RECOMMENDED ACTIONS - UNIT 1 STEAM TURBINE

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Unit	Asset 2/3	Asset 3/4	Description	Detail	Action #	App #	Action	Year	Priority
1296	6690	6691	271309	0	1	#1 TURBINE & GENERATOR	TURBINE	TURBINE	N/A	33	18	Replace only studs that have mechanical damage, thread deformation or thread wear, irrespective of the temperature service or stud location.	2012	1
1296	6690	6691	271309	0	1	#1 TURBINE & GENERATOR	TURBINE	TURBINE	N/A	34	18	Maintain records on stud replacements - why, date and location. Mark all high temperature studs and install at the same location during every stud change out.	2010	1
1296	6690	6691	271309	0	1	#1 TURBINE & GENERATOR	TURBINE	TURBINE	N/A	35	18	Evaluate and resolve the many control valve stem failures. The change of the stem material to Inconel will not solve this problem. Contact Bill Dumbleton (former Saskpower - turbtech@telusnet.net).	2010	1
1296	6690	6691	271309	0	1	#1 TURBINE & GENERATOR	TURBINE	TURBINE	N/A	36	18	Increase extraction steam NRV inspection from 3 years to 6 years. Top heater NRV need not be checked as there is no danger of over speed damage if the valve does not function. Check pneumatic actuator every 3 years. Ensure dry air is supplied to the cylinders. Check NRV valve operation on the seasonal restart every year.	2010	1
1296	6690	6691	271309	0	1	#1 TURBINE & GENERATOR	TURBINE	TURBINE	N/A	37	18	Follow GE recommended use of N7000 heavy duty metal free anti-seize compound for all turbine casing and valve threaded components.	2011	2
1296	6690	6691	271309	0	1	#1 TURBINE & GENERATOR	TURBINE	TURBINE	N/A	38	18	Implement procedures and temporary filters necessary to reduce/eliminate foreign object impact damage.	2010	1
1296	6690	6691	271309	6729	1	#1 TURBINE & GENERATOR	TURBINE	TURBINE MAIN STEAM CHEST	N/A	39	18	Work with vendor to identify and resolve key valve issues. Undertake thorough inspection for cracks in both the RH/LH main steam stop valve.	2012	1
1296	6690	6691	271309	6730	1	#1 TURBINE & GENERATOR	TURBINE	H.P. TURBINE	N/A	40	18	Carry out in 2012 Major Overhaul and the 2015 valve only overhaul the following work and inspections: 1. Replace the HP diaphragm and spill strip if NL Hydro wants to improve the unit efficiency. 2. Inspect the dressed up first 3 HP stage blade surfaces for cracks, wear and tear. Blade replacement is not recommended for relatively minor efficiency loss if unit is operated above 75% MCR. 3. Inspect repaired HP diaphragm partition trailing edges (built up using Inconel 82 TIG wire) to check if the Inconel is washing or wearing out. Repair minor damage using Inconel 82, but for extensive damage be prepared to repair the partition off site with 410SS filler material (including stress relief and post weld heat treatment).	2012	1
1296	6690	6691	271309	6730	1	#1 TURBINE & GENERATOR	TURBINE	H.P. TURBINE	N/A	41	18	Estimate HP inner casing studs close to the nozzle block studs that operate above 850 ◦F that may have reached or are close to the end of their predicted creep life (GE to identify studs that operate close to and above 850 °F and supply their engineering article on their recommended practice for the high temperature stud replacement) Replace studs close to the end of their creep life. Typically per past GE stud creep life evaluation, turbine half casing studs have a life of around 250,000 to 300,00 hrs.	2011	1
1296	6690	6691	271309	6730	1	#1 TURBINE & GENERATOR	TURBINE	H.P. TURBINE	N/A	42	18	Turn in the HP outer and inner casing studs that have a projection over the allowable limits. Machine seized studs that do not move. Clean, re-tape holes and re-install studs that are not damaged. Asses stud supply options - OEM or other.	2012	1
1296	6690	6691	271309	6731	1	#1 TURBINE & GENERATOR	TURBINE	I.P. TURBINE	N/A	43	18	Estimate IP inner casing studs close to the nozzle block studs that operate above 850○F that may have reached or are close to the end of their predicted creep life (GE to identify studs that operate close to and above 850○F and supply their engineering article on their recommended practice for the high temperature stud replacement) Replace studs close to the end of their creep life. Typically per past GE stud creep life evaluation, turbine half casing studs have a life of around 250,000 to 300,00 hrs.	2011	1
1296	6690	6691	271309	6732	1	#1 TURBINE & GENERATOR	TURBINE	L.P. TURBINE	N/A	44	18	Perform if possible bore scope inspection of LP L0 blades once a year through the LP turbine inspection door. This should be done after the unit is shut down after the seasonal operation.	2010	1

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Table 8.68 Cont'd

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Unit	Asset 2/3	Asset 3/4	Description	Detail	Action #	App #	Action	Year	Priority
1296	6690	6691	271309	6732	1	#1 TURBINE & GENERATOR	TURBINE	L.P. TURBINE	N/A	45	18	Carry out in 2012 Major Overhaul and the 2015 valve only overhaul the following work and inspections: 1. Inspect and braze broken tie wires on any LP blades to ensure that the designed blade damping condition is maintained. 2. Inspect, where possible, L0 and L-1 blade root and wheel steeple surfaces. Repair and replace blade as required. 3. Inspect L0 and L-1 blades for water erosion and report. Past reports did not comment on the condition of the blades. Take pictures of the blade surfaces with water wear.	2012	1
1296	6690	6691	271309	6734	1	#1 TURBINE & GENERATOR	TURBINE	TURBINE FRONT STANDARD	N/A	46	18	Undertake normal major inspection checks.	2012	1
1296	6690	6691	271309	6766	1	#1 TURBINE & GENERATOR	TURBINE	TURBINE RH/IP STEAM CHEST	N/A	47	18	Inspect for cracks in the RH/LH reheat valves and for crack reinitiation in left hand combined reheat intercept valve body previously repaired. Estimate MSV/CV/RSV and ICV casing studs close to the nozzle block studs that operate above 850○F - see HP a IP inner casings. Since the turbine valves are opened more often and operated at 1000oF, their operating creep life will be shorter. They are also more liable to be damaged and are subjected to wear and tear during the valve 3 year disassemble. Replace all if the other majority of the studs in a valve body are being replaced due to mechanical, wear or tear damage.	2011	1
1296	6690	6691	271309	6777	1	#1 TURBINE & GENERATOR	TURBINE	TURBINE GLAND STEAM SYSTEM	N/A	48	18	No specific recommended actions, beyond normal major overhaul work.	2012	2
1296	6690	6691	271309	6777	1	#1 TURBINE & GENERATOR	TURBINE	TURBINE GLAND STEAM SYSTEM	Steam Seal Regulator	48a	18	Replace obsolete SSR in 2010/11.	2011	1
1296	6690	6691	271309	6778	1	#1 TURBINE & GENERATOR	TURBINE	TURBINE PRE-WARMING SYSTEM	N/A	49	18	No specific recommended actions, beyond normal major overhaul work.	2012	2
1296	6690	6691	271309	6779	1	#1 TURBINE & GENERATOR	TURBINE	TURBINE TURNING GEAR	N/A	50	18	No specific recommended actions, beyond normal major overhaul work.	2012	2
1296	6690	6691	271309	6781	1	#1 TURBINE & GENERATOR	TURBINE	TURBINE DRAINS SYSTEMS	N/A	51	18	No specific recommended actions, beyond normal major overhaul work.	2012	2
1296	6690	6691	271309	270125	1	#1 TURBINE & GENERATOR	TURBINE	TURBINE BLED STEAM SYSTEM	N/A	52	18	No specific recommended actions, beyond normal major overhaul work.	2012	2

8.2.9.6 Risk Assessment

Table 8-69 below illustrates the risk assessment for the Unit 1 steam turbine, both from a technological perspective and a safety perspective using the models presented in Section 3.

TABLE 8-69 RISK ASSESSMENT – UNIT 1 STEAM TURBINE

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Component	Risk Assess #	Appendix #	Major Issues	Remaining Life Years (Insufficient Info - Inspection Required Within (x) Years)	Remaining Life Comments	TECHNO-ECO RISK ASSESS MODEL			SAFETY RISK ASSESS MODEL			Possible Failure Event	Mitigation
																Likeli-hood	Conse-quence	Risk Level	Likeli-hood	Conse-quence	Safety Risk		
1296	6690	6691	271309	0	0	1	#1 TURBINE & GENERATOR	TURBINE	TURBINE	N/A	34		See details below.		None	2	B	Low	2	A	Low	Major seawater leak to condenser - unit shutdown.. Water cleanup	Inspect and repair. Track history.
1296	6690	6691	271309	6729	0	1	#1 TURBINE & GENERATOR	TURBINE	TURBINE MAIN STEAM CHEST	Valves	35		Valve mechanical failure.	(2)	None	2	C	Medium	2	C	Medium	Turbine shutdown, overspeed failure	Inspect and maintain. Identify long term solution.
1296	6690	6691	271309	6730	0	1	#1 TURBINE & GENERATOR	TURBINE	H.P. TURBINE	High Pressure Turbine diaphragms, nozzle partition plates and turbine blades.	36	18	Mechanical failure - relative higher risk from erosion and Foreign Object Damage (FOD).	10	None	2	B	Low	2	A	Low	Turbine lost generation, efficiency, capacity	New nozzle block and some partitions replaced in 2009. Inspect and maintain. Eliminate FOD
1296	6690	6691	271309	6731	0	1	#1 TURBINE & GENERATOR	TURBINE	I.P. TURBINE	Intermediate Pressure Turbine diaphragms, and first stage turbine blades.	37	18	Mechanical failure - SPE and erosion from Foreign Object Damage (FOD).	10	None	2	B	Low	2	A	Low	Turbine lost generation, efficiency, capacity	The diaphragms have been repaired. The blades cannot be repaired. No current condition assessment of the blades. Check condition of the first stage RH blades in 2012 overhaul. Eliminate SP and FOD.
1296	6690	6691	271309	6732	0	1	#1 TURBINE & GENERATOR	TURBINE	L.P. TURBINE	Low Pressure (LP) Turbine	38	18	Chemical/Mechanical failure - LP monoblock integral discs - SCC failure.	10	None	1	B	Low	1	B	Low	Turbine lost generation, efficiency, capacity	Manage the condensate and feedwater chemistry within the ASME guidelines.
1296	6690	6691	271309	6734	0	1	#1 TURBINE & GENERATOR	TURBINE	TURBINE FRONT STANDARD	Governor, Overspeed systems etc.	39	18	Not addressed in detail. Mechanical or electronics failure.	10	None	2	C	Medium	2	C	Medium	Turbine shutdown, overspeed failure	Inspect and maintain. Identify long term solution.
1296	6690	6691	271309	6766	0	1	#1 TURBINE & GENERATOR	TURBINE	TURBINE RH/IP STEAM CHEST	Valves	40	18	Valve mechanical failure.	(2)	None	2	C	Medium	2	C	Medium	Turbine shutdown, overspeed failure	Inspect and maintain. Identify long term solution.
1296	6690	6691	271309	6777	0	1	#1 TURBINE & GENERATOR	TURBINE	TURBINE GLAND STEAM SYSTEM	N/A	41		Not addressed in detail. Mechanical sealing failure.	10	None	1	C	Low	1	C	Medium	Steam leak	Inspect and maintain.
1296	6690	6691	271309	6777	0	1	#1 TURBINE & GENERATOR	TURBINE	TURBINE GLAND STEAM SYSTEM	Steam Seal Regulator	41a		Safety risk location under turbine. Condenser vacuum affected - could require trip.	-2	Obsolete parts.	3	C	Medium	3	C	Medium	Turbine shutdown, overspeed failure	Replace.
1296	6690	6691	271309	6778	0	1	#1 TURBINE & GENERATOR	TURBINE	TURBINE PRE-WARMING SYSTEM	N/A	42		Not addressed in detail.	10	None	2	A	Low	1	A	Low	Slow start up	Inspect and maintain.
1296	6690	6691	271309	6779	0	1	#1 TURBINE & GENERATOR	TURBINE	TURBINE TURNING GEAR	N/A	43	18	Not addressed in detail. Mechanical chain failure.	2	None	3	B	Medium	3	A	Low	Turbine bowing without tubing= gear on shutdown	Inspect and maintain.
1296	6690	6691	271309	6781	0	1	#1 TURBINE & GENERATOR	TURBINE	TURBINE DRAINS SYSTEMS	N/A	44		Not addressed in detail. Mechanical chain failure.	5	None	2	B	Low	2	B	Low	Shutdown	Inspect and maintain.
1296	6690	6691	271309	270125	0	1	#1 TURBINE & GENERATOR	TURBINE	TURBINE BLED STEAM SYSTEM	N/A	45		Not addressed in detail. Mechanical chain failure.	5	None	1	C	Low	1	C	Low	Shutdown. Possible water induction	Inspect and maintain.

8.2.9.7 Life Cycle Curve and Remaining Life

The life cycle curve for the Unit 1 steam turbine is illustrated below. The two curves represent either the original equipment or that upgraded in 1988 when the turbine was uprated. The unit is due to undergo a major overhaul in 2012. The life curve is a plot of current and projected operating hours (generation mode only) on the y-axis versus calendar year on the x-axis. The figure has several vertical lines representing differing representative nominal age limits for various components. It also has several horizontal lines that represent a range of practical equipment equivalent base loaded operating hour life limits. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view.

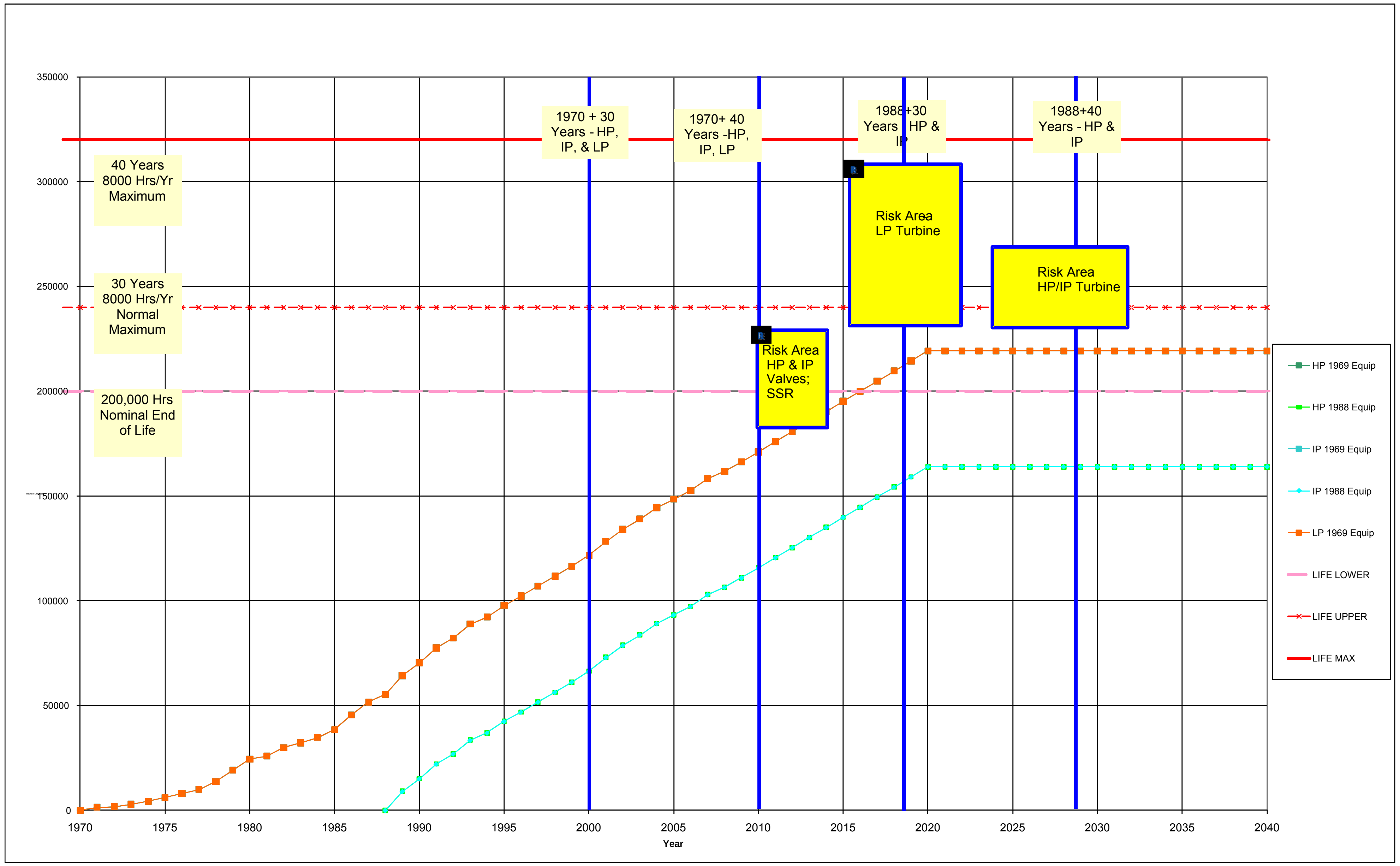

FIGURE 8-22 LIFE CYCLE CURVE – UNIT 1 STEAM TURBINE

The curves indicate that the remaining life (RL) of the various elements of the Unit 1 steam turbine exceeds the desired life (DL) which is the lesser of the time to its next major planned overhaul/inspection (2012) or to the desired End of Life (EOL) date of 2020. In fact the 2020 end date should be readily achievable. Hence, no specific dedicated Level 2 is required, but sufficient inspection and testing will be required in the 2012 overhaul to confirm the ability to meet the 2020 EOL date. The exceptions to that are the HP and IP valves which continue to have reliability and life issues, the steam seal regulator, as well potentially as high temperature stud bolts. It is clear that the current inspection schedule seems suitable.

8.2.9.8 Level 2 Inspections – Unit 1 Steam Turbine

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 8-70 below, assuming that the current plant inspection and maintenance program is maintained or improved.

TABLE 8-70 LEVEL 2 INSPECTIONS – UNIT 1 STEAM TURBINE

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Sub System Comment	L2#	Appendix #	Level 2 Work	Year	Priority	Cost k$
1296	6690	6691	271309	0	0	1	#1 TURBINE & GENERATOR	TURBINE	TURBINE	None	22	18	No Level 2 required.			
1296	6690	6691	271309	0	0	1	#1 TURBINE & GENERATOR	TURBINE	TURBINE	None	23	18	No Level 2 inspections. Actions identified fall under the norms of the overhaul scopes.	2012	1	$2,311
1296	6690	6691	271309	0	0	1	#1 TURBINE & GENERATOR	TURBINE	TURBINE	None	24	18	See details below.			
1296	6690	6691	271309	6729	0	1	#1 TURBINE & GENERATOR	TURBINE	TURBINE MAIN STEAM CHEST	None	25	18	Identify and asses studs that operate above 850 °F may have reached or are close to the end of their predicted creep life (HP MSV studs).	2011	1	$6
1296	6690	6691	271309	6730	0	1	#1 TURBINE & GENERATOR	TURBINE	H.P. TURBINE	None	26	18	Identify and asses studs that operate above 850 °F may have reached or are close to the end of their predicted creep life (HP inner casing studs close to the nozzle block)	2011	1	$6
1296	6690	6691	271309	6731	0	1	#1 TURBINE & GENERATOR	TURBINE	I.P. TURBINE	None	27	18	Identify and assess those studs that operate above 850 °F may have reached or are close to the end of their predicted creep life (IP inner casing studs).	2011	1	$6
1296	6690	6691	271309	6732	0	1	#1 TURBINE & GENERATOR	TURBINE	L.P. TURBINE	None	28	18	LP L0 blades Boroscope: If possible, do bore scope inspection of LP L0 blades once a year through the LP turbine inspection door, done after the unit is shut down after every seasonal operation.	2011	2	$6
1296	6690	6691	271309	6734	0	1	#1 TURBINE & GENERATOR	TURBINE	TURBINE FRONT STANDARD	None	29	18	No Level 2 required.			
1296	6690	6691	271309	6766	0	1	#1 TURBINE & GENERATOR	TURBINE	TURBINE RH/IP STEAM CHEST	None	30	18	Identify and asses studs that operate above 850 °F may have reached or are close to the end of their predicted creep life (CV/RSV and ICV studs).	2011	1	$6
1296	6690	6691	271309	6777	0	1	#1 TURBINE & GENERATOR	TURBINE	TURBINE GLAND STEAM SYSTEM	None	31	18	No Level 2 required.			
1296	6690	6691	271309	6777	0	1	#1 TURBINE & GENERATOR	TURBINE	TURBINE GLAND STEAM SYSTEM	Steam Seal Regulator	31a	18	No Level 2 required. (Assumes replacement in 2010/11 due to obsolecence.)			
1296	6690	6691	271309	6778	0	1	#1 TURBINE & GENERATOR	TURBINE	TURBINE PRE-WARMING SYSTEM	None	32	18	No Level 2 required.			
1296	6690	6691	271309	6779	0	1	#1 TURBINE & GENERATOR	TURBINE	TURBINE TURNING GEAR	None	33	18	No Level 2 required.			
1296	6690	6691	271309	6781	0	1	#1 TURBINE & GENERATOR	TURBINE	TURBINE DRAINS SYSTEMS	None	34	18	No Level 2 required.			
1296	6690	6691	271309	270125	0	1	#1 TURBINE & GENERATOR	TURBINE	TURBINE BLED STEAM SYSTEM	None	35	18	No Level 2 required.			

8.2.9.9 Capital Projects

Table 8-71 below shows the suggested typical capital enhancements that should be considered for the Unit 1 steam turbine:

TABLE 8-71 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – UNIT 1 STEAM TURBINE

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Detail	CAP#	Appendix #	Capital Item	Date	Priority
1296	6690	6691	271309	0	0	1	#1 TURBINE & GENERATOR	TURBINE	TURBINE	N/A	28	18	No capital required.		
1296	6690	6691	271309	6729	0	1	#1 TURBINE & GENERATOR	TURBINE	TURBINE MAIN STEAM CHEST	N/A	29	18	No capital required.		
1296	6690	6691	271309	6730	0	1	#1 TURBINE & GENERATOR	TURBINE	H.P. TURBINE	N/A	30	18	No capital required.		
1296	6690	6691	271309	6731	0	1	#1 TURBINE & GENERATOR	TURBINE	I.P. TURBINE	N/A	31	18	No capital required.		
1296	6690	6691	271309	6732	0	1	#1 TURBINE & GENERATOR	TURBINE	L.P. TURBINE	N/A	32	18	No capital required.		
1296	6690	6691	271309	6734	0	1	#1 TURBINE & GENERATOR	TURBINE	TURBINE FRONT STANDARD	N/A	33	18	No capital required.		
1296	6690	6691	271309	6766	0	1	#1 TURBINE & GENERATOR	TURBINE	TURBINE RH/IP STEAM CHEST	N/A	34	18	No capital required.		
1296	6690	6691	271309	6777	0	1	#1 TURBINE & GENERATOR	TURBINE	TURBINE GLAND STEAM SYSTEM	N/A	35	18	Replace the steam seal regulator.	2011	1
1296	6690	6691	271309	6778	0	1	#1 TURBINE & GENERATOR	TURBINE	TURBINE PRE-WARMING SYSTEM	N/A	36		No capital required.		
1296	6690	6691	271309	6779	0	1	#1 TURBINE & GENERATOR	TURBINE	TURBINE TURNING GEAR	N/A	37	18	Refurbish chain and mechanism.	2011	2
1296	6690	6691	271309	6781	0	1	#1 TURBINE & GENERATOR	TURBINE	TURBINE DRAINS SYSTEMS	N/A	38		No capital required.		
1296	6690	6691	271309	270125	0	1	#1 TURBINE & GENERATOR	TURBINE	TURBINE BLED STEAM SYSTEM	N/A	39		No capital required.		

8.2.10 Asset 270182 – Unit 1 Cooling Water System - Associated with Steam Systems

(Detailed Technical Assessment in Working Papers, Appendix 11, 25)

Unit #:	1
Asset Class #	BU 1296 - Assets Generations
SCI & System:	8715 #1 Unit Generation Services
Sub-Systems:	270182 #1 CW System
Components:	7137 #1 CW Travelling Screens East
	7138 #1 CW Travelling Screens West
	7146 #1 CW Pump East
	7147 #1 CW Pump West
	7134 #1 CW Intake
	7138 #1 CW Discharge to Outfall

8.2.10.1 Description

The circulating water (CW) systems servicing Unit 1 consist of two 50% CW vertical turbine pumps driven by 4 kV motors and auxiliary systems. The pump drive motors are original. Two travelling screen systems are used to remove debris from the cooling water prior to entering the pumps. The primary function of the CW system is to provide condenser cooling water, but also cooling water for other closed loop systems. It is necessary that the CW system operate efficiently in order to maintain optimal plant thermal efficiency by minimizing steam turbine condenser backpressures.

FIGURE 8-23 UNIT 1 CIRCULATING WATER PUMPS

FIGURE 8-24 UNIT 1 CIRCULATING WATER TRAVELLING SCREENS

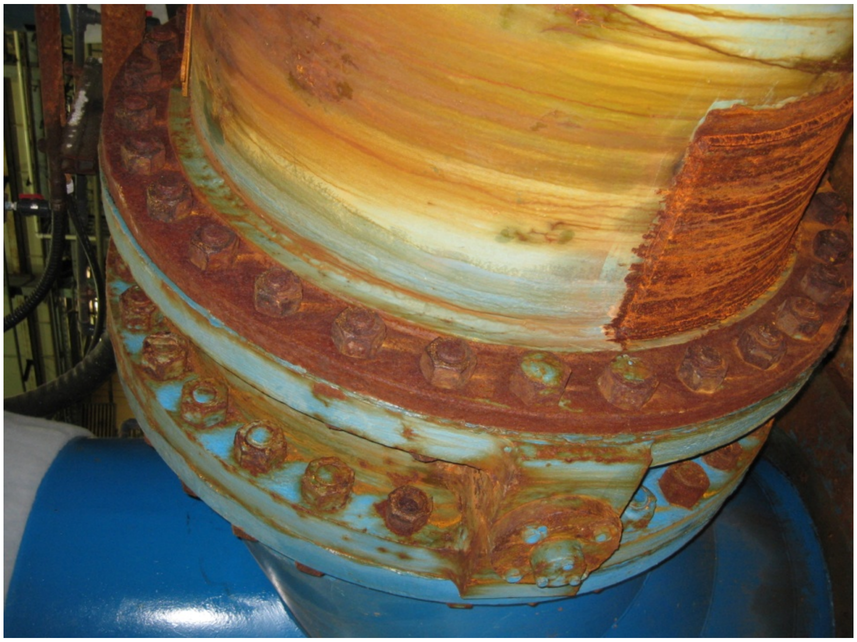

FIGURE 8-25 CIRCULATING WATER PIPE PATCH

8.2.10.2 History

The requirements for cooling water system on Unit 1 are as follows:

Manufactured/Delivered	1969
In-Service Date	Sep 1970
Generation Base Load End Date	Dec 2015
Generation Peak/Emerg Gen End Date	Dec 2020
Synchronous Condensing Start Date	Jan 2015

Synchronous Condensing End Date	Dec 2041
Next Major Overhaul/Inspection	2012

The hours associated with the analyses are:

Hours Generation Actual - Ops to Dec 2009	166
Max Hours Generation Ops – to Dec 2015	210
Max Hrs Gen Ops to Gen End Date Dec 2020	219

8.2.10.3 Inspection and Repair History

Cooling Water Pumps & Motors, Screens, and Piping Systems

CW Travelling Screens: The travelling screen internals have been replaced on Unit 1 in last 5 to 10 years. Interviews suggest that no recent issues have been experienced with this unit. Visual examination confirmed that the Unit 1 screens generally appear to be in good condition.

The external casings are in differing states, with some parts more corroded than others. None appears to impair current or short term performance.

CW Wash Water Pumps and Motors: An external inspection of the pumps and motors indicated that they have extensive corrosion but were running at the time of the visual inspection. They are considered to be a minor maintenance issue and not addressed as a part of this assessment.

CW Pumps: CW pumps on Unit 1 are performing fairly well. No reports were available on the condition of the pumps, but interviews suggest that regular maintenance has been ongoing and the unit should be able to meet 2015 and 2020 timelines with continued maintenance. Major pump overhauls are scheduled on a twelve year cycle as indicated in Table 8-72 below.

TABLE 8-72 MAJOR PUMP OVERHAULS

Annual Asset Maintenance																	
Pumps	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
1 CW Pump East			X												83,000.00			
1 CW Pump West											75,000.00							
2 CW Pump East	X				X												87,000.00	
2 CW Pump West												77,000.00						
3 CW Pump East		X									75,000.00							
3 CW Pump West						10,000.00												89,000.00

It is understood that a temporary CW pump is being used in the existing Unit 4 intake to supply smaller quantities of cooling water to Unit 3 for Synchronous Condensing duty. The system has been designed to supply all three units if and when converted. In addition, there are interconnections between Units 1 to 3 CW systems to allow them to provide back-up for this purpose if necessary.

CW Pump Motors: The CW pumps are driven by 4 kV motors. The motors are the original equipment and are tested electrically every year in accordance with the plant PM process. They are in good condition, but beyond their normal physical life expectation.

CW Pump Outlet Piping, Valves & Fittings: Outlet piping, valves, and fittings from the CW pump discharge to the inlet of the 162 cm (64 inch) concrete piping that goes underground to the Unit 1 condenser has generally experienced significant corrosion and some patching of the system has been done. It requires a Level 2 inspection and possibly a complete replacement.

Cooling Water System Intake & Discharge: The 91 cm (36 inch) and 162 cm (64 inch) CW intake and discharge concrete piping that is installed underground to the unit condenser has periodically been dewatered and inspected by plant staff. No specific corrosion, spalling, cracks or fractures were identified, and no patching of the system has been done. There have been no obvious issues with the systems, but no detailed engineering evaluations and NDE work has been undertaken.

PM inspections are planned going forward on a three year cycle as per schedule below in Table 8-73.

TABLE 8-73 PM INSPECTIONS

Annual Asset Maintenance																	
CW Inspection		2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Unit 1													25,625.00			26,625.00	
Unit 2														25,625.00			26,625.00
Unit 3												25,000.00			25,625.00		

8.2.10.4 Condition Assessment

The condition assessment of the Unit 1 CS system associated with steam systems is illustrated below in Table 8-74.

TABLE 8-74 CONDITION ASSESSMENT – UNIT 1 COOLING WATER SYSTEM - ASSOCIATED WITH STEAM SYSTEMS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset Level 2	Asset Level 3	Description	Detail	Condition Summary ID #	Append #	Condition	EPRI Identifier	Original Life (Base Load) Ops Hrs (Yrs)	Current Expected Minimum Remaining Life Years (Subject to Test)	End of Life (EOL) Required	Next Regular Inspection	Next Planned Overhaul or Major Inspection	Capability to Reach Next Overhaul	Capability to Reach EOL	In Service
1296	6690	6715	6782	9592	0	1	#1 UNIT GENERATION SERVICES	T/G COOLING PUMP SOUTH	T/G COOLING PUMP SOUTH	N/A	260	11,15	Relatively new AC pumps and motors (no date available). No issue with them.	3a	(30)	10	2041	2012		Yes	No	2000
1296	6690	6715	6782	9593	0	1	#1 UNIT GENERATION SERVICES	T/G COOLING PUMP NORTH	T/G COOLING PUMP NORTH	N/A	261	11,15	Relatively new AC pumps and motors (no date available). No issue with them.	4	(30)	10	2041	2012		Yes	No	2000
1296	6690	6715	270182	0	0	1	#1 UNIT GENERATION SERVICES	CW SYSTEM	CW SYSTEM	N/A	262	11	Generally in good condition, with significant corrosion on major steel pipes and pumps, and valves.	4	200000 (30)	(10)	2041	2011		No	No	1970
1296	6690	6715	270182	7134	0	1	#1 UNIT GENERATION SERVICES	CW SYSTEM	C.W. INTAKE	Concrete pipe from Pumps to Condenser	263	11	No recent inspections of cement pipes, but walk-downs about 5 years ago indicated that the pipe looked intact. Given the geotechnical conditions and soil, there is no reason to expect any kind of aggressive attack. A copper ion system was installed to minimize any internal mussel growth on the CW pipe.	4	(60)	(20)	2041		2011	No	No	1970
1296	6690	6715	270182	7135	0	1	#1 UNIT GENERATION SERVICES	CW SYSTEM	C.W. DISCHARGE TO OUTFALL	Concrete pipe from Condenser to outfall pit	264	11	No recent inspections of cement pipes, but walk-downs about 5 years ago indicated that the pipe looked intact. Some moderate issues with stop log structures were identified. Given the geotechnical conditions and soil, there is no reason to expect any kind of aggressive attack. A copper ion system was installed to minimize any internal mussel growth on the CW pipe.	4	(60)	(20)	2041		2011	No	No	1970
1296	6690	6715	270182	7146	0	1	#1 UNIT GENERATION SERVICES	CW SYSTEM	C.W. PUMP EAST	N/A	265	11	The CW pumps have major inspections and overhauls about every twelve years. The motors are electrically checked annually per their PM requirements. Overall the pumps and motors seem to be performing satisfactorily. Several patches are evident on the CW steel pipes and valves associated with the pumps.	3a	(30)	(10)	2020	2012		No	No	1970
1296	6690	6715	270182	7147	0	1	#1 UNIT GENERATION SERVICES	CW SYSTEM	C.W. PUMP WEST	N/A	266	11	The CW pumps have major inspections and overhauls about every twelve years. The motors are electrically checked annually per their PM requirements. Overall the pumps and motors seem to be performing satisfactorily. Several patches are evident on the CW steel pipes and valves associated with the pumps.	3a	(30)	(10)	2020	2012		No	No	1970

Notes: 1. A "(bracketed)" value in the "Current Expected Remaining Life" column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as "(X/Y)" has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

2. The "Next Regular Inspection" column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The "Next Planned Overhaul or Major Inspection" column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a "Desired Life" stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or are not known by AMEC.

8.2.10.5 Actions

Based on the condition assessment, the following actions are recommended for the Unit 1 cooling water system associated with steam systems.

TABLE 8-75 RECOMMENDED ACTIONS – UNIT 1 COOLING WATER SYSTEM ASSOCIATED WITH STEAM SYSTEMS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Unit	Asset 2/3	Asset 3/4	Description	Detail	Action #	App #	Action	Year	Priority
1296	6690	6715	270182	0	1	#1 UNIT GENERATION SERVICES	CW SYSTEM	CW SYSTEM	N/A	173	11	Maintain current program of ongoing inspections and overhauls. Procure a spare motor be maintained to service all three units, in the event of a failure of an existing unit.	2011	2
1296	6690	6715	270182	7146	1	#1 UNIT GENERATION SERVICES	CW SYSTEM	C.W. PUMP EAST	N/A	174	11	Perform planned CW pump inspections on one pump per unit in 2010 to 2012 (Level 2).	2011	2
1296	6690	6715	270182	7147	1	#1 UNIT GENERATION SERVICES	CW SYSTEM	C.W. PUMP WEST	N/A	175	11	Perform planned CW pump inspections on one pump per unit in 2010 to 2012 (Level 2).	2012	2
1296	6690	6715	270182	7146	1	#1 UNIT GENERATION SERVICES	CW SYSTEM	C.W. PUMP EAST	N/A	176	11	Clean CW steel pipe and check thickness measurements (Level 2).	2011	2
1296	6690	6715	270182	7147	1	#1 UNIT GENERATION SERVICES	CW SYSTEM	C.W. PUMP WEST	N/A	177	11	Clean CW steel pipe and check thickness measurements (Level 2).	2011	2
1296	6690	6715	270182	7134	1	#1 UNIT GENERATION SERVICES	CW SYSTEM	C.W. INTAKE	Pipe	178	11	Within the next two to four years, perform a detailed visible inspection, with some NDE spotchecks, of the concrete intake and discharge pipes.	2011	2
1296	6690	6715	270182	7135	1	#1 UNIT GENERATION SERVICES	CW SYSTEM	C.W. DISCHARGE TO OUTFALL	Pipe	179	11	Within the next two to four years, perform a detailed visible inspection, with some NDE spotchecks, of the concrete intake and discharge pipes.	2011	2

8.2.10.6 Risk Assessment

Table 8-76 below illustrates the risk assessment for the cooling water systems associated with steam systems, both from a technological perspective and a safety perspective using the models presented in Section 3.

TABLE 8-76 RISK ASSESSMENT FOR THE UNIT 1 COOLING WATER SYSTEM - ASSOCIATED WITH STEAM SYSTEMS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Component	Risk Assess #	Appendix #	Major Issues	Remaining Life Years (Insufficient Info - Inspection Required Within (x) Years)	Remaining Life Comments	TECHNO-ECO RISK ASSESS MODEL			SAFETY RISK ASSESS MODEL			Possible Failure Event	Mitigation
																Likeli-hood	Conse-quence	Risk Level	Likeli-hood	Conse-quence	Safety Risk		
1296	6690	6715	270182	0	0	1	#1 UNIT GENERATION SERVICES	CW SYSTEM	CW SYSTEM	Unit #1 CW Concrete Pipe to Condenser	166	11	Concrete racking.	(20)	None	1	B	Low	1	A	Low	Cracking or failure – major leak requiring repair	Inspect and maintain.
1296	6690	6715	270182	0	0	1	#1 UNIT GENERATION SERVICES	CW SYSTEM	CW SYSTEM	Unit #1 CW Pipe to Outfall Structure	167	11	Concrete racking.	(20)	None	1	B	Low	1	A	Low	Cracking or failure – major leak requiring repair	Inspect and maintain.
1296	6690	6715	270182	7146	0	1	#1 UNIT GENERATION SERVICES	CW SYSTEM	C.W. PUMP EAST	CW Pumps	168	11	Corrosion- Internal/Ext.	(10)	None	2	B	Low	2	A	Low	50% unit output loss while replaced with spare	Current inspection and maintain.
1296	6690	6715	270182	7147	0	1	#1 UNIT GENERATION SERVICES	CW SYSTEM	C.W. PUMP WEST	CW Pumps	169	11	Corrosion- Internal/Ext.	(10)	None	2	B	Low	2	A	Low	50% unit output loss while replaced with spare	Current inspection and maintain.
1296	6690	6715	270182	7146	0	1	#1 UNIT GENERATION SERVICES	CW SYSTEM	C.W. PUMP EAST	4 kV Cooling Water Pump Motor	170	25	Electrical fault, mechanical fatigue, ops error.	(5+)	None	1	B	Low	2	A	Low	Loss 60% of 1 unit generation	Current inspection and maintain.
1296	6690	6715	270182	7147	0	1	#1 UNIT GENERATION SERVICES	CW SYSTEM	C.W. PUMP WEST	4 kV Cooling Water Pump Motor	171	25	Electrical fault, Mechanical Fatigue, Ops error,	(5+)	None	1	B	Low	2	A	Low	Loss 60% of 1 unit generation	Current inspection and maintain.
1296	6690	6715	270182	7134	0	1	#1 UNIT GENERATION SERVICES	CW SYSTEM	C.W. INTAKE	Unit #1 Intake Structure	172	11	Structural cracking; steel corrosion.	(20)	None	1	B	Low	1	A	Low	Structural failure requiring shutdown	Inspect and maintain.

8.2.10.7 Life Cycle Curve and Remaining Life

The life cycle curve for the Unit 1 cooling water system associated with steam systems is illustrated below. One curve represents all the major elements of the system which are about the same age. No information existed on the condition of the large CW pipe to and from the condensers. Although it was not plotted here, its life would be expected to be on the order of 60 years, given no incidents to date as a result of original poor design or installation. The life curve is a plot of current and projected operating hours (generation mode only) on the y-axis versus calendar year on the x-axis. The figure has vertical lines representing differing representative nominal age limits. It also has several horizontal lines that represent a range of practical equivalent base loaded operating hour life limits. Both limits can come into play and both are extendable through maintenance refurbishment and component replacement. The risk area box provides an indication of the timing of potential issues either from an age or equivalent operating hours view.

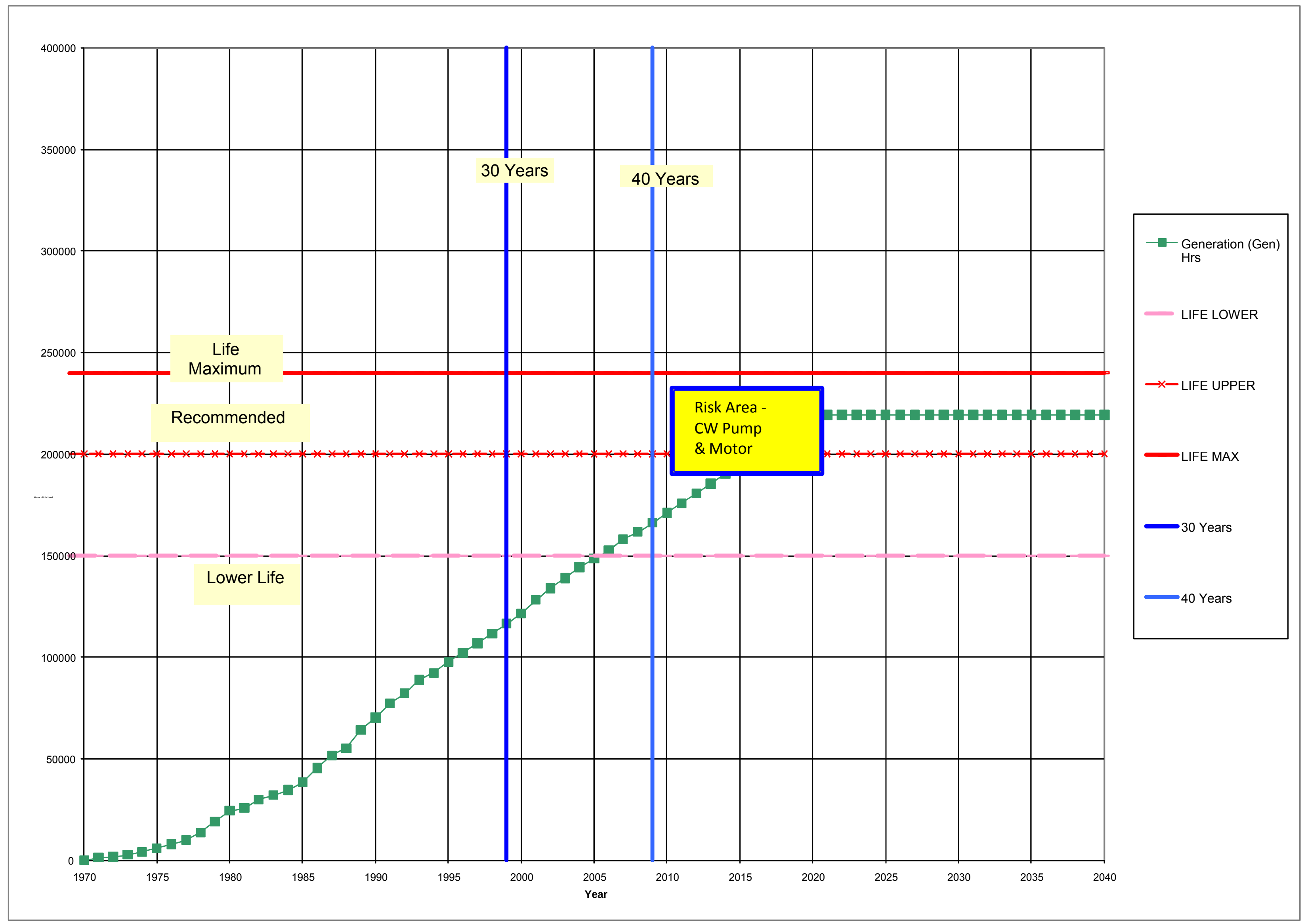

FIGURE 8-26 LIFE CYCLE CURVE – UNIT 1 COOLING WATER SYSTEM ASSOCIATED WITH STEAM SYSTEMS

The curves indicate that the remaining life (RL) of the Unit 1 cooling water system - associated with steam systems can likely reach the end date for generation of 2020, but with some reliability risk, particularly as it pertains to the 4 kV motor. It is recommended that a spare motor shared between units would be a reasonable precaution. Corrosion of the steel pipe, valves, and fittings was also evident suggesting that some maintenance on these issues is required.

8.2.10.8 Level 2 Inspections – Unit 1 Cooling Water System Associated with Steam Systems

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 8-77 below, assuming that the current plant inspection and maintenance program is maintained or improved.

TABLE 8-77 LEVEL 2 INSPECTIONS – UNIT 1 COOLING WATER SYSTEM ASSOCIATED WITH STEAM SYSTEMS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Sub System Comment	L2#	Appendix #	Level 2 Work	Year	Priority	Cost k$
1296	6690	6715	270182	0	0	1	#1 UNIT GENERATION SERVICES	CW SYSTEM	CW SYSTEM	Concrete Pipe to/from pump to condenser	156	11	Inspections - dry walk-down and NDE spotcheck.	2011	2	$6
1296	6690	6715	270182	0	0	1	#1 UNIT GENERATION SERVICES	CW SYSTEM	CW SYSTEM	Steel Pipe to/from condenser	157	11	Clean steel pipe and check thickness measurements.	2011	2	$6
1296	6690	6715	270182	7146	0	1	#1 UNIT GENERATION SERVICES	CW SYSTEM	C.W. PUMP EAST	CW Pumps	158	11	Perform planned inspections on one pump per unit in 2010 to 2012 (Level 2). No Level 2 on 4 kV motor if current maintenance program continues.	2011	2	
1296	6690	6715	270182	7147	0	1	#1 UNIT GENERATION SERVICES	CW SYSTEM	C.W. PUMP WEST	CW Pumps	159	11	Perform planned inspections on one pump per unit in 2010 to 2012 (Level 2. No Level 2 on 4 kV motor if current maintenance program continues.	2011	2	

8.2.10.9 Capital Projects

Table 8-78 below shows the suggested typical capital enhancements that should be considered for the Unit 1 cooling water system associated with steam systems:

TABLE 8-78 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – UNIT 1 COOLING WATER SYSTEM ASSOCIATED WITH STEAM SYSTEMS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Detail	CAP#	Appendix #	Capital Item	Date	Priority
1296	6690	6715	270182	0	0	1	#1 UNIT GENERATION SERVICES	CW SYSTEM	CW SYSTEM	N/A	122	11	No capital required.		
1296	6690	6715	270182	7134	0	1	#1 UNIT GENERATION SERVICES	CW SYSTEM	C.W. INTAKE	Concrete pipe from Pumps to Condenser	123	11	No capital required.		
1296	6690	6715	270182	7135	0	1	#1 UNIT GENERATION SERVICES	CW SYSTEM	C.W. DISCHARGE	Concrete pipe from Condenser to outfall pit	124	11	No capital required.		
1296	6690	6715	270182	7146	0	1	#1 UNIT GENERATION SERVICES	CW SYSTEM	C.W. PUMP EAST	N/A	125	25	Procure spare motor - common to Units 1 & 2; adaptable Unit 3 to extent practical.	2012	1
1296	6690	6715	270182	7147	0	1	#1 UNIT GENERATION SERVICES	CW SYSTEM	C.W. PUMP WEST	N/A	126	25	Procure spare motor - common to Units 1 & 2; adaptable Unit 3 to extent practical.	2012	1

9 UNIT 2

9.1 Unit 2 - Key Systems

9.1.1 Asset 7753 – Unit 2 Generator

(Detailed Technical Assessment in Working Papers, Appendix 4)

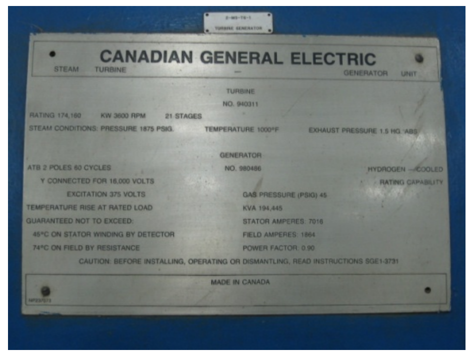

FIGURE 9-1 UNIT 2 GENERATOR

Equipment/components covered in this section include the following:

Unit #:	2
Asset Class #	BU 1296 - Assets Generations
SCI & System:	7638 - #2 Turbine & Generator
Sub-Systems:	7753 # 2 Generator Assembly
Components:	7754 #2 Generator Rotor
	7759 #2 Generator Stator
	7767 #2 Excitation System
	7768 #2 Hydrogen System

9.1.1.1 Description

The Unit 2 generator is rated at 194,445 KVA, hydrogen-cooled, supplied by Canadian General Electric, Peterborough. It went into service in 1971. The last major inspection was in 2005, after 34 years of service, and is the base reference for this assessment.

The stator core and windings are flexibly-mounted in the stator frame, which contains four vertical hydrogen coolers. The stator windings operate at 16.0 KV and are indirectly cooled by hydrogen. The hydrogen is circulated throughout the generator in a closed system, at 310 kPa (45 psi) pressure, by an axial fan mounted on each end of the rotor. Isolated phase bus delivers the power from the generator to the unit transformer.

The generator rotor is directly-coupled to the turbine, and is supported on bearings located in the end-shields of the stator frame. Hydrogen seals prevent the hydrogen from escaping around the rotating shaft. The seals are pressurised by oil and are located inboard of the bearings. The field windings are directly-cooled by hydrogen, fed via axial sub-slots and radial gas passages in the copper winding. The field windings are supported by retaining rings shrunk onto the ends of the rotor body. The field current is supplied to the field windings via collector rings and brush gear, outboard of the main bearing – there is no steady bearing. There is an unused thrust bearing collar at the turbine end of the generator shaft for future synchronous condenser use.

The excitation to the field is now supplied by an ABB Unitrol static thyristor excitation system, with a fast response automatic voltage regulator to control the field current and MVAR output from the generator. The excitation has a high ceiling voltage capability, to enable the generator to help the power system recover from faults and disturbances.

The auxiliary systems include:

- A static thyristor controlled exciter fed from the generator terminals, with field flashing for initial energization;
- A seal oil system, with a differential pressure controller to keep the hydrogen contained within the generator;
- A closed-loop distilled water cooling system and temperature controller to remove the heat from the generator;
- A hydrogen pressure control valve to provide automatic make-up from the bulk hydrogen supply, (at increased hydrogen pressure if overload is required);
- A scavenging system to remove the hydrogen that becomes entrained in the bearing oil and the seal oil;
- Potential transformers (P.T's), located below the isolated phase bus, measure the generator voltage. Current transformers (CT's) mounted over the generator lead bushings measure the generator current. These devices provide signals to measure the generator output, and for the electro-mechanical protection relays;
- A vibration monitoring system continuously monitors the vibration amplitudes at each turbine generator bearing in the control room and alerts the operator to increasing vibration, especially during run-up, load changes, and shut-down. It uses two proximity probes at 45 degrees to the vertical to measure the shaft vibration level; and
- A digital multi-functional generator protection relay has been added, but at present it is primarily used for extra ground fault protection of the stator windings (which are in poor condition - see next item). It also provides supplementary alarms and sequence-of-events monitoring.

9.1.1.2 History

The history and requirements for the Unit 2 generator are as follows:

Manufactured/Delivered	1970
In-Service Date	Apr 1971
Generation Base Load End Date	Dec 2015
Generation Peak/Emerg Gen End Date	Dec 2020
Synchronous Condensing Start Date	Jan 2015
Synchronous Condensing End Date	Dec 2041
Last Major Inspection	2005
Next Major Overhaul/Inspection	2014

The thousands of hours associated with the analyses, and the number of starts per year are:

	Generation (Gen)	**Synchronous Condensing (SC)**
Hours Actual - Ops to Dec 2009	158	0
Hours - Ops to Gen End Date Dec 2015	188	1.5
Hours - Ops to Gen End Date Dec 2020	212	25
Hours – Ops to SC End Date Dec 2040	212	120
Starts Actual - Ops to Dec 2009	442	0
Starts - Ops to Gen End Date Dec 2015	554	5
Starts - Ops to Gen End Date Dec 2020	614	30
Starts – Ops to SC End Date Dec 2040	674	130

9.1.1.3 Inspection and Repair History

Post-2005 Improvements

- Fast dump of generator hydrogen planned to be added to supplement water sprays on bearings;
- Generator hydrogen dryer replaced;
- Hydrogen purity meter replaced; and
- Plant supervisory TV screens and displays and DAS replaced – alarm settings and states can be checked readily.

2005 Overhaul

- Full replacement of the stator slot wedges with top ripple springs;
- Slot couplers re-installed;
- Stator end-winding support system cleaned and re-tightened;
- RTD's checked. 3 are broken and 4 are more than 20% inaccurate (they can only be replaced during replacement of the stator windings);
- Damaged epoxy dowels of fibre inner end-shields – repaired with oversize dowels;
- Rotor dried out and re-tested;
- Collector ring distributors corroded, removed, cleaned and put back;
- Bore seals pressure tested OK;
- Realigned hydrogen seal housing;
- Hydrogen coolers cleaned, and pressure tested OK;

- Installed 4 new cold gas RTD's in stator (GE state they are in wrong locations and will read low);
- Digital multi-functional generator protection relay installed, (for improved winding ground protection, alarms connected, and sequence of events monitoring). Electro-mechanical protection relays retained; and
- Hydrogen seal rings lapped and clearances re-set to lower limits to minimize future oil leaks.

1999 Overhaul

- Installed slot couplers for partial discharge monitoring;
- ABB excitation system installed and commissioned;
- Hydrogen seal rings found scored, segments replaced;
- Fan blades NDE checked OK;
- Hydrogen coolers cleaned and inspected – no leaks;
- Collector end hydrogen seal casing realigned to end shield, oversized dowels fitted; and
- Rotor/stator air gaps and fan tip clearances checked.

1994 Overhaul (details not known)

- Retaining rings may have been replaced;
- Expect greasing of stator end-windings necessitated re-tightening them; and
- May have re-tightened end-wedges,

1990 Overhaul

- Unit up-rated from 174.160 MVA at 207 kPa (30 psi) hydrogen pressure, to 194.445 MVA at 310 kPa (45 psi) hydrogen pressure. New hydrogen seal set installed;
- Stand-off insulators replaced, and lead tube silvered. (Greasing occurred at lead supports due to vibration and oil ingress);
- Retaining rings polished and NDE inspected in situ;
- Pyranol-filled (PCB) excitation transformer drained, cleaned and re-filled with oil (per plant staff but more likely silicon fluid?);
- Installed slot couplers for partial discharge monitoring;
- ABB excitation system installed and commissioned;
- Hydrogen seal rings found scored, segments replaced;
- Fan blades NDE checked OK;
- Hydrogen coolers cleaned and inspected – no leaks;
- Collector end hydrogen seal casing realigned to end shield, oversized dowels fitted; and
- Rotor/stator air gaps and fan tip clearances checked.

9.1.1.4 Condition Assessment

The generator and its auxiliary systems are in reasonable good condition for their age.

- Stator core: satisfactory, based on El-cid results;
- Stator Windings: Poor, based on Megger test and DC hipot test;
- Rotor Forging: Not known. (Appears not checked in past 20 years); and
- Field Winding: Satisfactory, but few details available (concerns are based on repairs made to similar GE rotors).

Details of the sub-systems are presented in the Table 9-1 and in more detail in Appendix 4.

TABLE 9-1 CONDITION ASSESSMENT – UNIT 2 GENERATOR

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset Level 2	Asset Level 3	Description	Detail	Condition Summary ID#	Append #	Condition	EPRI Identifier	Original Life (Base Load) Ops Hrs (Yrs)	Current Expected Minimum Remaining Life Years (Subject to Test)	End of Life (EOL) Required	Next Regular Inspection	Next Planned Overhaul or Major Inspection	Capability to Reach Next Overhaul	Capability to Reach EOL	In Service
1296	7635	7636	7753	0	0	2	U2 GENERATOR	GENERATOR ASSEMBLY	GENERATOR	N/A	11	4	Stator: Core - Satisfactory; Windings - Poor Rotor: Forging - Not known, likely satisfactory; Winding - Satisfactory, but limited information Overhaul required in 2014.									
1296	7635	7636	7753	7754	0	2	U2 GENERATOR	GENERATOR ASSEMBLY	GENERATOR ROTOR	Core	12	4	Forging: Not known, likely satisfactory.	4	200000 (40)	(15)	2041		2014	Yes	No	1971
1296	7635	7636	7753	7754	0	2	U2 GENERATOR	GENERATOR ASSEMBLY	GENERATOR ROTOR	Winding	13	4	Field Winding: Satisfactory, but little information. The field current is not credible - much too low. The field winding temperature is not monitored. No on-line monitoring for shorted field turns (most common indication the rotor needs to be re-wound) is in place. Partial discharge monitoring is not working. The shaft voltage and the shaft ground current are not monitored in operation for harmful currents through the bearing or hydrogen seal. The retaining rings and the rotor forging, and slot wedges do not appear to have been NDE checked for defects.	4	200000 (30)	(10)	2041		2014	Yes	No	1971
1296	7635	7636	7753	7759	0	2	U2 GENERATOR	GENERATOR ASSEMBLY	GENERATOR STATOR	Core	14	4	Core - Satisfactory. The stator core and frame are reported to be in good condition, with no looseness or fretting damage at the bore or at the outside flexible mounting. GE reported that El-cid readings taken before and after the re-wedging of the stator bars in 2005 show no significant core deterioration, and the stator core is fit to be re-wound. The stator winding and core RTD's do not read credible values - too low.	4	200000 (40)	(15)	2041		2014	Yes	No	1971
1296	7635	7636	7753	7759	0	2	U2 GENERATOR	GENERATOR ASSEMBLY	GENERATOR STATOR	Windings	15	4	Windings: Poor, requiring rewind. Reported in 2003 major outage to be in very poor condition with two of three phases significantly weaker and insulation weakness (or wetness). It is anticipated that more extensive loosening, fretting, and greasing of the end-windings will be found at the next inspection. Stator winding RTD's do not read credible values - too low.	4	200000 (30)	(10)	2041		2014	Yes	No	1971
1296	7635	7636	7753	7768	0	2	U2 GENERATOR	GENERATOR ASSEMBLY	GEN HYDROGEN GAS SYSTEM	N/A	16	4	Hydrogen cooler, hydrogen dryer, and hydrogen purity meter working well. The hydrogen scavenging system (removing entrained hydrogen from the seal oil) appears less effective than the Unit 3 vacuum system. The hydrogen pressure is low, probably due to hydrogen leaks (causes extra heating of the generator core and windings). Consumption is not recorded. The cold gas temperature is low at 30 °C versus GE minimum 35 °C.	3a	200000 (30)	(10)	2041	2011	2011	Yes	No	1971
1296	7635	7636	7753	7768	7732	2	U2 GENERATOR	GENERATOR ASSEMBLY	GENERATOR SEAL OIL SYSTEM	N/A	17	4	The horizontal joint of the hydrogen seal assembly was epoxied to prevent hydrogen/oil leakage into the generator, but the risk is high that the hydrogen sealing system has not been successful in preventing oil entering the generator and contaminating the end-windings.	4	(30)	(5)	2020	2011	2014	Yes	No	1971
1296	7635	7636	7753	7768	7732	2	U2 GENERATOR	GENERATOR ASSEMBLY	TURB AC SEAL OIL PUMP EAST	N/A	18	4	Not reviewed in detail - no issues. Aging. Include in Generator overhaul.	4	(30)	(5)	2020	2011	2014	Yes	No	1971
1296	7635	7636	7753	7768	7732	2	U2 GENERATOR	GENERATOR ASSEMBLY	GEN AC SEAL OIL PUMP WEST	N/A	19	4	Not reviewed in detail - no issues. Aging. Include in Generator overhaul.	4	200000 (30)	(5)	2041	2011	2014	Yes	No	1971
1296	7635	7636	7753	7768	7732	2	U2 GENERATOR	GENERATOR ASSEMBLY	GEN DC SEAL OIL PUMP	N/A	20	4	Not reviewed in detail - no issues. Aging. Include in Generator overhaul.	4	200000 (30)	(5)	2041	2011	2014	Yes	No	1971
1296	7635	7636	7753	7768	7732	2	U2 GENERATOR	GENERATOR ASSEMBLY	GEN SEAL OIL VACUUM PUMP	N/A	21	4	Not reviewed in detail - no issues. Aging. Include in Generator overhaul.	4	200000 (30)	(5)	2041	2011	2014	Yes	No	1971
1296	7635	7636	7753	7768	7773	2	U2 GENERATOR	GENERATOR ASSEMBLY	GEN CO2 GAS PURGE SYSTEM	N/A	22	4	Not reviewed in detail. No issues identified aside from capacity and supply concerns.	4	200000 (30)	(10)	2041	2011	2014	Yes	No	1971
1296	7635	7636	7753	7768	7776	2	U2 GENERATOR	GENERATOR ASSEMBLY	GENER COMPRESSED AIR PURGE	N/A	23	4	Not reviewed in detail. No issues identified.	4	200000 (30)	(10)	2041	2011	2014	Yes	No	1971
1296	7635	7636	7753	7768	7777	2	U2 GENERATOR	GENERATOR ASSEMBLY	GENERATOR HYDROGEN COOLING	N/A	24	4	Acceptable condition. No issues identified	3a	200000 (30)	10	2041	2011	2011	Yes	No	1971
1296	7635	7636	7753	99034724	0	2	U2 GENERATOR	GENERATOR ASSEMBLY	PARTIAL DISCHARGE ANALYSIS SYSTEM	N/A	25	4	Inoperative. Needs repair for generator assessment.	10	200000 (30)	1	2041	2010	2011	No	No	1971
1296	7635	7636	7767	0	0	2	U2 GENERATOR	GENERATOR EXCITATION SYSTEM	GENERATOR EXCITATION SYSTEM	N/A	26	4,6	See details below.	3a	200000 (30)	10	2041	2011	2014	Yes	No	1971
1296	7635	7636	7767	271322	0	2	U2 GENERATOR	GENERATOR EXCITATION SYSTEM	EXCITER	N/A	27	4,6	Replaced in 1999 (due to difficulties in obtaining replacement parts and service) by an ABB Unitrol static excitation system which is working well. The controls and protective relays are prone to calibration drift and malfunctions, and the field flashing can maloperate.	10	200000 (30)	20	2041	2011	2014	Yes	No	1999
1296	7635	7636	7767	271322	99036228	2	U2 GENERATOR	GENERATOR EXCITATION SYSTEM	EXCITER	Controls	28	4,6	Replaced in 1999 as part of exciter Controls. Review identified reported difficulties with protective relays calibration drift and malfunctions, and the field flashing maloperation. Subsequently identified as resolved by station.	10	200000 (30)	(3)	2041	2011	2014	Yes	No	1999
1296	7635	7636	7767	271324	0	2	U2 GENERATOR	GENERATOR EXCITATION SYSTEM	EXCITATION TRANSFORMER	N/A	29	4,6	Replaced with exciter	3a	200000 (30)	3	2041	2011	2014	Yes	No	1999
1296	7635	7636	7767	271324	0	2	U2 GENERATOR	GENERATOR EXCITATION SYSTEM	RECTIFYING TRANSFORMER RT2	N/A	30	5,6	Installed in 1969, the unit has a relatively high level of risk due to its age. No details on testing were identified. The unit was originally an Askarel oil filled unit but was changed in 2004 to Perchloroethylene with below 50 mg/kg PCB's. Tests in 2005 identified satisfactory results. The current PCB Regulation SOR/2008-273, posted in the CEPA Environmental Registry, includes practice for the better management of PCB's in use.	4	(45)	5	2041	2013		Yes	No	1971
1296	7635	7636	7767	271325	0	2	U2 GENERATOR	GENERATOR EXCITATION SYSTEM	EXCITER FIELD BREAKER	N/A	31	4,6	Replaced with exciter.	3a	200000 (30)	20	2041	2011	2014	Yes	No	1999

Notes:
1. A "(bracketed)" value in the "Current Expected Remaining Life" column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation, including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as "(X/Y)" has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.
2. The "Next Regular Inspection" column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The "Next Planned Overhaul or Major Inspection" column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a "Desired Life" stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or not known by AMEC.

9.1.1.5 Actions

The following table highlights a number of the basic issues/defects found and the actions recommended to address them.

TABLE 9-2 RECOMMENDED ACTIONS - 7759 #2 GENERATOR STATOR

Issues	Recommended Actions
1. There is oil leaking into the stator, reducing the effectiveness of the winding support. Oil and grease has been found on the end-windings at each past inspection, and on other similar GE generators. A leak in the horizontal joint of the seal assembly was found at the last outage and a temporary repair was made – is it still effective 7 years later?	1. Keep the differential seal oil/hydrogen differential pressure constant and between 27 and 40 kPa (4 and 6 psi). 2. Check the oil level in the de-training tank is not high, and the flow in the seal oil drain lines is not excessive or foaming, which increases the risk of oil backing up and leaking into the generator 3. Monitor the partial discharge activity every 3 months for signs of increased partial discharge activity. If the end-winding partial discharge activity exceeds 30 mV on any of the phases, plan an early intervention for repair of the stator end-winding looseness. 4. Check the hydrogen consumption and seal oil consumption for leakage.
2. The stator core appears to be in satisfactory condition, but the GE El-Cid test report is incomplete. (It is important to confirm the condition of the core is sound, before ordering a replacement stator winding for installation in 2014, see next item).	1. Plan for an El-cid test and a high flux test of the stator core, during the next major inspection. Check the stepped end packets, and record the highest defect values in each slot. 2. Repeat the measurements in the highest three slots and note the positions, for boroscope inspection. Take infra-red photos of the core and note the hot spots. (areas greater than 3 °C above the surrounding areas).
3. The GE tests showed the right phase of the stator winding was in very weak condition in 2003. A rewind was recommended. An update on the winding condition should be obtained at the 2014 inspection (preferably from a second source). The tests should only be done on the winding after it has been carefully cleaned and re-tightened, and is known to be clean and dry.	1. At the next major inspection, repeat the 10 KV Megger test, and the DC hipot test at 34 KV. (Check whether the poor insulation condition was due to the high moisture or to the insulation deteriorating during the re-wedging – this is useful information for unit 3). 2. Also test the bushings and the PT's, and carry out ratio tests on the CT's. 3. Decide whether the windings will last until 2015/2020, or whether they should be replaced during the 2014 outage. 4. Draft a specification now, for the manufacture, test and installation of a replacement winding, together with new RTD's, and bushing and terminal plate flange seals. Also include options for new bushings and CT's, in case they are necessary. This will reduce the outage time, if a winding failure should occur during the next two years.

Issues	Recommended Actions
	5. At the next major inspection, have the OEM (or potential rewind Contractors) take the stator slot and winding dimensions. 6. Consider taking advance delivery of the winding and store it at the plant until needed. (Make sure the new winding will fit either unit1 or unit 2, or identify why this is not possible.)
4. The end-winding support structure is not able to withstand the operating and system stresses. It loosens and allows the insulation to erode and form grease. An improved end-winding support system is required.	1. Ask the OEM for an improved end-winding support system to be supplied with the new stator winding. (Modern techniques are available to allow the supports to slide when hot, rather than develop internal stress that loosens them.) 2. Have the effectiveness of the new winding installation checked with the “bump” test, and additional support provided where it is found necessary
5. Top ripple springs were installed to increase the time between re-wedging the stator slots. Check that the top ripple springs are still holding the slot parts of the windings firmly in place, and no loosening of the wedges/windings has occurred.	1. Carry out a wedge tap survey, to check for loose wedges, (and find out whether unit 2 is likely to require re-wedging at its next major outage). Visually inspect the core teeth for signs of fretting dust or “grease”.
6. Further information is desirable regarding the deterioration of the stator winding in operation, and the possible need for more frequent maintenance.	1. Take Doble test measurements every 2 years, during the summer outage (it is necessary to disconnect the neutral bar – make sure it is replaced carefully, and check the joint resistance with a low resistance meter (“ductor”)
7. A hydrogen seal leak was found at the bushings and at the terminal plate seals. It was sealed temporarily from the inside with RTV. GE recommended the area be checked annually for leaks, but it is not known if this was done.	1. Replace the bushing seals and the terminal plate seals. This is a difficult and expensive repair that is best done during a stator rewind. RTV sealing of the inside is satisfactory for a short time, but the deteriorated seal usually leaks elsewhere. GE uses viscaseal and a dam to identify a leak, but Hitachi repairs the leak with “titeseal” which is better.

A. Operation	
1. The stator winding and core RTD's do not read credible values. They are too low.	1. Using the GE calibration from the last outage, monitor the most accurate RTD of each phase and the hottest core RTD, on the DCS display.
2. The partial discharge monitoring is not working. The GE test report shows the stator windings are in very poor condition, so the partial discharge levels in operation should be monitored carefully, to minimize the risk of a winding failure – see also item 2 above)	2. Contact IRIS service dept, to obtain advice on how to get it working. Record the values every 3 months and watch for an increase of >20 % in the readings of the highest 3 sensors. Bring forward the planned outage if necessary.
3. During the two month summer outage and the major inspection outages, moisture collects on the stator and rotor windings. Corrosion of the collector distributor bolts was found on units 1 and 2 at the last outage. It greatly affects the Megger and DC hipot test results.	1. When the generator is out of service and de-gassed, blow warm dry instrument air through the generator. When the rotor is out, install heaters in the stator ends, and a tarp over the ends to keep it warm and reduce dust ingress. 2. Consider fitting pad heaters to the lower outer surface of the stator ends, with a switch to turn the heat on when the unit is off-line. 3. The rotor should be kept in a clean conditions "tent" and air heaters installed to keep the windings warm and dry.
4. Four of the stator (winding) slot temperatures are monitored on the "turbine generator" screen, but the stator core temperature is not monitored in operation. During high over-excited load the centre of the stator becomes the hottest, but during under-excited operation the core end temperatures are the highest. This is particularly important during synchronous condenser operation.	1. Use three of the lines for the hottest winding temperature in each phase, and label them phase A, phase B and phase C. Use the fourth line to monitor the hottest stator core-end temperature. Add a fifth line to show the hottest core temperature at the centre of the stator.

TABLE 9-3 RECOMMENDED ACTIONS - 7754 #2 GENERATOR ROTOR

Issues	Recommended Actions
1. The retaining rings and the rotor forging, and slot wedges do not appear to have been NDE checked for defects since they were installed in 1997. (Defects have been found in other similar rotors after less than 30 years operation).	1. Remove the retaining rings and the slot wedges. 2. Carry out a detailed visual and NDE inspection for defects and fatigue cracks developing, in the dovetails, wedge ends, rotor bore, retaining rings, etc. Remove any crack-like defects. Check the shrink fit areas for fretting, and contact of end-wedges with the retaining rings.
2. The condition of the end-windings is not known, and some deformation of the turns in the coil stacks is expected, especially at the series connections between longer coils and at the lead connections to the winding. The packing blocks are expected to be fretted and dust will have collected under the retaining ring insulation that should be removed.	1. Check the end-windings for fretting, fatigue cracks in the top turns under the retaining rings, any distortion or cracking of the flexible connections.
3. The turn insulation may be damaged, or the packing blocks broken, fretted or displaced, and the ends of the slot cells may be abraded, overheated, or crushed by the retaining rings.	1. Check the insulation blocks and re-place or re-tighten as necessary. (Note the dust found probably contains asbestos).
4. The ventilation system of the rotor slots uses sub-slots and radial ventilation ducts. It is prone to axial elongation (creep of the copper and restriction of the ventilation holes.	1. Check the radial holes near the ends of the rotor body for restrictions, and record the restrictions, for future (the rotor should be re-wound when the restriction exceeds 25 % of the hole area).heck the sub-slots for oil, dirt and accumulated debris. Vacuum/blow out as much of the dirt as possible.
5. The turbine generator shaft line has been realigned at each major inspection. The adjustment seems to be too much to be due to bearing wear, and it appears that the foundation is settling over time.	1. Trend the bearing vibration levels over time, and record the changes. Try to relate them to the MVAR load, as well as the MW load. 2. If the vibration level is high put the readings on a polar plot (Bode) and compromise balance it with marked weights. 3. Re-align and re-balance the rotor after the shaft line has been corrected, at the major inspection.

Issues	Recommended Actions
6. There is no record of the generator bearings being re-metalled, but GE recommended sending out the generator bearings for refurbishment at the next major overhaul. Other rotors have found uneven wear, poor Babbitt bond, and electrical damage. The #5 bearing insulation was found defective.	1. Re-furbish both generator bearings. 2. NDE the bearing Babbitt for good bond with the shell. 3. Check the surface for even wear, 4. Check the insulation resistance of #5 bearing and hydrogen seal, and inspect visually. 5. Replace if defective. Replace oil deflectors.
7. GE recommended that spare bearing thermocouples be held in stock in case the installed thermocouples fail in service.	1. The bearing thermocouples are old, and in dubious condition. New thermocouples should be installed at the next major outage.
8. A week was spent working on the hydrogen seals, and numerous problems were encountered. The hydrogen seal clearances on the hydrogen side were reduced to the low end of the clearance, in an attempt to prevent oil leaking into the generator. An oil leak from the horizontal joint of the hydrogen seal was found at the CE and repaired temporarily with epoxy	1. Replace the insulation plates of the CE seals. Check the titeseal groove at the upper and lower CE end-shield for leaks. Air-test the generator for leaks, and fix them properly at the next major inspection. 2. A new hydrogen seal assembly should be considered for the CE end.
A. Operation	
1. The field current is not credible, it is much too low.	1. Check the source and calibrate the DCCT, or use the field current value shown on the exciter.
2. The field winding temperature is not monitored. (During overexcited synchronous condenser operation the field current will be higher, and there is an increased risk of overheating the field winding insulation).	1. Install a mean field winding temperature simulator(if one does not already exist in the static excitation system), or 2. Obtain an algorithm for the mean field winding temperature, based on the field current, cold resistance and the cold gas temperature. Show the mean field winding temperature on the control room display.
3. There is no on-line monitoring for shorted field turns (this is the most common indication the rotor needs to be re-wound).	1. Install a flux probe in the stator bore at the next major outage, when the rotor is out of the stator core.

Issues	Recommended Actions
4. The shaft voltage and the shaft ground current are not monitored or checked in operation. A harmful current could flow through the bearing or hydrogen seal. (the risk of damage increases when the starting package is added at the collector end, for synchronous condenser operation).	1. Upgrade the shaft grounding brushes with a constant-tension spring brush box, and replace the other with a copper braid, to clean the shaft. 2. Fit a shaft voltage monitoring brush at the outer end of the shaft, so the shaft voltage can be checked safely in operation, or\ 3. Install a Sohre grounding brush and shaft current and voltage monitoring system.
5. During the two month summer outage and the major inspection outages, moisture collects on the stator and rotor windings. Corrosion of the collector distributor bolts was found on units 1 and 2 at the last outage. It greatly affects the Megger and DC hipot test results.	1. When the generator is out of service and de-gassed, blow warm dry instrument air through the generator. When the rotor is out, install heaters in the stator ends, and a tarp over the ends to keep it warm and reduce dust ingress. 2. Consider fitting pad heaters to the lower outer surface of the stator ends, with a switch to turn the heat on when the unit is off-line. 3. The rotor should be kept in a clean conditions "tent" and air heaters installed to keep the windings warm and dry.

TABLE 9-4 7768 #2 HYDROGEN SYSTEM

Issues	Recommended Actions
1. Several problems were found with the float trap of the middle de-training tank of the seal oil system. The valve disc had hardened, the level control was incorrect, and the valve was installed backwards.	1. Replace the seals, and viton disk, and gaskets, and check the operating level in the tank at both 207 and 310 kPa (30 and 45 psi) hydrogen pressures. 2. GE recommends the seal oil supply piping be flushed annually, to prevent dirt in the emergency by-pass line entering the system.
2. The seal oil vacuum pump is a high maintenance item. It has a rotary valve that needs to be replaced at each inspection.	1. Purchase a spare rotary seal and install it at the next major inspection. Carry out preventive maintenance on the pump
3. The hydrogen coolers were leak tested and found satisfactory, but GE recommended the gaskets be replaced at each major inspection.	1. Replace the gaskets and seals, and leak test at every major inspection. Check cold parts for green slime (operating temp too low!)
4. The liquid leak detector valve had incorrect flanges and gaskets and is	1. Check the operation of the liquid leak detector relay, and service the parts.

Issues	Recommended Actions
prone to failure.	
5. Hydrogen dryer. The replacement hydrogen dryer is of small capacity and will require frequent regeneration. Oil from the leaking hydrogen seals reduces its effectiveness. A pipe blockage can burn out the heater.	1. Carry out preventive maintenance on the hydrogen dryer, replace the desiccant, check the regeneration operation, check for hydrogen leaks, especially at the purity meter and sampling valves.
6. The hydrogen pressure is automatically controlled by a valve, but this generator operates at low pressure. Is the valve not in service or is it broken? Keeping the pressure constant reduces the risk of oil ingress into the generator.	1. Service the hydrogen pressure control valve. 2. Locate and repair hydrogen leaks ASAP.
A. Operation	
1. The hydrogen pressure is low, probably due to hydrogen leaks, resulting in extra heating of the generator core and windings.	1. Locate and repair the hydrogen leaks. 2. Increase the hydrogen pressure to 207 kPa (30 psi).
2. The hydrogen consumption of each generator is not recorded.	1. Fit a totalizer in the hydrogen supply line, so the daily hydrogen consumption of each generator can be recorded.
3. The cold gas temperature is low at 30°C, GE usually recommend a minimum of 35°C to avoid algae forming on the windings and the increased risk of brittle fracture in the rotor forging.	1. Ask GE to confirm the rotor forging is water-quenched, not air-quenched. 2. Increase the cold gas temperature setting to 35 °C, especially if the forging is air-quenched.
4. The hot gas temperatures are not recorded, so it is not possible to check the temperature rise across each cooler, i.e. whether the hydrogen coolers are balanced. Sometimes a cooler leak occurs, or a plug of the vent pipe after return to service, that should be detected.	1. Every month check the temperature rise across each cooler, to ensure they are balanced, and no gas lock, plugged vent, or cooler leak has occurred, which will unbalance the temperatures across the generator, and result in undesirable overheating.
5. The hydrogen pressure is automatically controlled by a valve, but this generator operates at low pressure. Is the valve not in service or is it broken? Keeping the pressure constant reduces the risk of oil ingress into the generator.	1. Service the hydrogen pressure control valve. Locate and repair hydrogen leaks ASAP.

TABLE 9-5 RECOMMENDED ACTIONS - 7787 #2 EXCITATION SYSTEM

Issues	Recommended Actions
1. The ABB static excitation system is reported to be operating satisfactorily. However, the controls and protective relays are prone to calibration drift, and malfunctions. The field flashing can maloperate	1. Check the operation of the excitation system controls, limiters and protection relays. 2. Check the field breaker contacts and operation. 3. Check the thyristors and heat sinks, and snubbers, for signs of overheating,
2. The excitation system is expected to have a V/f limiter to protect the generator against over-fluxing; the risk of generator damage is highest during initial energization on AVR control.	1. Connect the V/f element of the multi-functional generator protection relay to trip the excitation when off-line, if over-fluxing occurs.

9.1.1.6 Actions - Unit 2 Generator

The following table highlights a number of the basic issues/defects found and the actions recommended to address them.

TABLE 9-6 RECOMMENDED ACTIONS – UNIT 2 GENERATOR

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Unit	Asset 2/3	Asset 3/4	Description	Detail	Action #	App #	Action	Year	Priority
1296	7635	7636	7753	0	2	U2 GENERATOR	GENERATOR ASSEMBLY	GENERATOR	General	8	4	Reduce operating intervals between major outages to 6 years.	2010	1
1296	7635	7636	7753	0	2	U2 GENERATOR	GENERATOR ASSEMBLY	GENERATOR	General	9	4	Review generator drawings, contract information, and operating manual to clarify design details.	2010	2
1296	7635	7636	7753	7754	2	U2 GENERATOR	GENERATOR ASSEMBLY	GENERATOR ROTOR	Rotor Core	10	4	NDE inspection of the rotor high-stress areas should be done in 2012 - cover the retaining rings, changes in cross section of the rotor (journals and coupling etc), the rotor tooth dovetails, the slot wedges and the lead wedges for fretting fatigue cracks, the rotor core (bore sonic inspection), the bearing shells for babbitt bond, and the fans for fatigue cracks. The rotor dovetails with short steel wedges should be checked carefully, due to the higher risk of a fatigue crack developing under the high cyclic bending stress.	2014	1
1296	7635	7636	7753	7754	2	U2 GENERATOR	GENERATOR ASSEMBLY	GENERATOR ROTOR	Rotor Core	11	4	Remove the retaining rings and the slot wedges to permit a closer inspection. Surface defects may be found in the retaining rings, a fatigue crack may exist in the dovetails, and spitting damage may be found at the wedge ends, due to negative sequence current.	2014	1
1296	7635	7636	7753	7754	2	U2 GENERATOR	GENERATOR ASSEMBLY	GENERATOR ROTOR	Rotor Core	12	4	Install a rotor flux probe near the turbine end of the stator bore, wired out through the existing IRIS penetration and junction box, to detect the presence of shorted field turns. Usually precedes development of a rotor ground fault. The field winding has suffered extensive copper deformation and weakening of the turn insulation, and is close to the end of its useful life.	2014	1
1296	7635	7636	7753	7754	2	U2 GENERATOR	GENERATOR ASSEMBLY	GENERATOR ROTOR	Rotor Core	13	4	Make a visual check of the extent of restrictions of the radial gas cooling passages, and of any displaced turn insulation. Any accumulated debris in the radial ventilation ducts, the sub-slots, and in the end-windings should be blown or vacuumed out.	2014	1
1296	7635	7636	7753	7754	2	U2 GENERATOR	GENERATOR ASSEMBLY	GENERATOR ROTOR	Rotor Core	14	4	Monitor the shaft ground current or the shaft voltage at the outboard end of the generator - replace the original equipment with on-line monitoring capability. The risk of a shaft current flowing through the bearing or hydrogen seal increases during synchronous condenser operation.	2014	1
1296	7635	7636	7753	7754	2	U2 GENERATOR	GENERATOR ASSEMBLY	GENERATOR ROTOR	Field Winding	15	4	Perform annual 500 volt megger checks on the rotor to confirm that there is no major deterioration of the ground insulation (below 3 Gig-ohms).	2010	1
1296	7635	7636	7753	7754	2	U2 GENERATOR	GENERATOR ASSEMBLY	GENERATOR ROTOR	Field Winding	16	4	Install a field winding temperature indicator in control room.	2010	1
1296	7635	7636	7753	7759	2	U2 GENERATOR	GENERATOR ASSEMBLY	GENERATOR STATOR	Stator Core	17	4	Repair hydrogen leak in the bushing box horizontal joint of the cover plate holding the bushings bushing seals. Difficult as it necessitates breaking the main connections, dropping the bushings, installing the gaskets, and re-installing the bushings. May be necessary to remove the whole bushing box. An alternative repair of poorer integrity is to seal the inside joint flanges around the bushings and terminal plates with RTV sealant.	2014	1
1296	7635	7636	7753	7759	2	U2 GENERATOR	GENERATOR ASSEMBLY	GENERATOR STATOR	Stator Core	18	4	Install a hydrogen consumption “totalizer” in each hydrogen supply line for dailing recording and check for leaks.	2014	1
1296	7635	7636	7753	7759	2	U2 GENERATOR	GENERATOR ASSEMBLY	GENERATOR STATOR	Stator Core	19	4	Maintain steady hydrogen pressure at the rated value of 310 KPag to simplify differential pressure controller operation and help to ensure a constant and appropriate oil flow through the hydrogen seals, reducing the risk of a seal oil spill into the generator. Also reduces the risk of the sealant at the stator end shields cracking and permitting a hydrogen leak. It will also avoid a change in the bearing height, and alignment of the rotor, which can increase the bearing vibration levels.	2014	1
1296	7635	7636	7753	7759	2	U2 GENERATOR	GENERATOR ASSEMBLY	GENERATOR STATOR	Stator Core	20	4	Perform, before implementing a stator rewind, a flux loop test and thermal imaging of the core to detect any hot spots and repair them before installing the new winding	2014	1
1296	7635	7636	7753	7759	2	U2 GENERATOR	GENERATOR ASSEMBLY	GENERATOR STATOR	Stator Winding	21	4	Perform a minor inspection and Doble test after 4 or 5 years, and careful monitoring of the on-line partial discharge monitoring.	2018	1

Table 9-6 Cont'd

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Unit	Asset 2/3	Asset 3/4	Description	Detail	Action #	App #	Action	Year	Priority
1296	7635	7636	7753	7759	2	U2 GENERATOR	GENERATOR ASSEMBLY	GENERATOR STATOR	Stator Winding	22	4	Take partial discharge activity readings in the slot portion of the windings and in the end-winding portion during normal service conditions. Work with IRIS to determine a repair priority so that the results are available in time to assess replacing the windings during the 2014 outage. Detect de-lamination of the insulation tapes, deterioration in the low-resistivity paint at the outer surface (ground wall) in the slots, and discharges in the end-windings.	2014	1
1296	7635	7636	7753	7759	2	U2 GENERATOR	GENERATOR ASSEMBLY	GENERATOR STATOR	Stator Winding	23	4	Repeat the DC hipot test at the next major inspection, taking extra care to ensure the insulation is dry before the test.	2014	1
1296	7635	7636	7753	7759	2	U2 GENERATOR	GENERATOR ASSEMBLY	GENERATOR STATOR	Stator Winding	24	4	Perform an intermediate inspection of the stator end-windings after 4 years to establish the presence of oil and grease on the end-windings to better establish the timing of the next major inspection	2018	1
1296	7635	7636	7753	7759	2	U2 GENERATOR	GENERATOR ASSEMBLY	GENERATOR STATOR	Stator Winding	25	4	Proceed with planning work for a rewind - typically requires 9 to 12 months to plan and carry out a stator rewind, plus site work of 4-6 months.	2012	1
1296	7635	7636	7753	7759	2	U2 GENERATOR	GENERATOR ASSEMBLY	GENERATOR STATOR	Stator Winding	26	4	Evaluate proceeding with the installation of a new stator winding at the next major outage in 2014 following overhaul of Unit 1.	2012	1
1296	7635	7636	7753	7768	2	U2 GENERATOR	GENERATOR ASSEMBLY	GEN HYDROGEN GAS SYSTEM	Hydrogen	27	4	Install a hydrogen consumption "totalizer" in each hydrogen supply line for daily recording and check for leaks.	2011	1
1296	7635	7636	7753	7768	2	U2 GENERATOR	GENERATOR ASSEMBLY	GENERATOR SEAL OIL SYSTEM	N/A	28	4	No specific recommended actions beyond normal major overhaul work.	2014	2
1296	7635	7636	7753	7768	2	U2 GENERATOR	GENERATOR ASSEMBLY	TURB AC SEAL OIL PUMP EAST	N/A	29	4	No specific recommended actions beyond normal major overhaul work.	2014	2
1296	7635	7636	7753	7768	2	U2 GENERATOR	GENERATOR ASSEMBLY	GEN AC SEAL OIL PUMP WEST	N/A	30	4	No specific recommended actions beyond normal major overhaul work.	2014	2
1296	7635	7636	7753	7768	2	U2 GENERATOR	GENERATOR ASSEMBLY	GEN DC SEAL OIL PUMP	N/A	31	4	No specific recommended actions beyond normal major overhaul work.	2014	2
1296	7635	7636	7753	7768	2	U2 GENERATOR	GENERATOR ASSEMBLY	GEN SEAL OIL VACUUM PUMP	N/A	32	4	No specific recommended actions beyond normal major overhaul work.	2014	2
1296	7635	7636	7753	7768	2	U2 GENERATOR	GENERATOR ASSEMBLY	GEN CO2 GAS PURGE SYSTEM	N/A	33	4	No specific recommended actions beyond normal major overhaul work.	2014	2
1296	7635	7636	7753	7768	2	U2 GENERATOR	GENERATOR ASSEMBLY	GENER COMPRESSED AIR PURGE	N/A	34	4	No specific recommended actions beyond normal major overhaul work.	2014	2
1296	7635	7636	7753	7768	2	U2 GENERATOR	GENERATOR ASSEMBLY	GENERATOR HYDROGEN COOLING	N/A	35	4	Maintain hydrogen pressure steady at the rated value of 310 KPag to simplify differential pressure controller operation and help to ensure a constant and appropriate oil flow through the hydrogen seals. This will reduce the risk of a seal oil spill into the generator and will also reduce the risk of the sealant at the stator end shields cracking and permitting a hydrogen leak. A change in the bearing height and alignment of the rotor, which can increase the bearing vibration levels, will also be avoided.	2011	1
1296	7635	7636	7753	99034724	2	U2 GENERATOR	GENERATOR ASSEMBLY	PARTIAL DISCHARGE ANALYSIS SYS	N/A	36	4	Repair and monitor results for generator condition analyses.	2010	1
1296	7635	7636	7767	0	2	U2 GENERATOR	GENERATOR EXCITATION SYSTEM	GENERATOR EXCITATION SYSTEM	Static Exciter	37	4,6	Upgrade Unit 2 Static Exciter controls compatible with the latest Unitrol 6000 system.	2013	1
1296	7635	7636	7767	271322	2	U2 GENERATOR	GENERATOR EXCITATION SYSTEM	EXCITER	N/A	39	4,6	No specific recommended actions, beyond normal major overhaul work.	2014	1
1296	7635	7636	7767	271324	2	U2 GENERATOR	GENERATOR EXCITATION SYSTEM	EXCITATION TRANSFORMER	N/A	40	4,6	Replace oil or transformer as per PCB regulations when required. No specific recommended actions beyond normal major overhaul work.	2014	1
1296	7635	7636	7767	271325	2	U2 GENERATOR	GENERATOR EXCITATION SYSTEM	EXCITER FIELD BREAKER	N/A	41	4,6	No specific recommended actions beyond normal major overhaul work.	2014	1

9.1.1.7 Risk Assessment

Table 9-7 below illustrates the risk assessment for the Unit 2 generator, both from a technological perspective and a safety perspective using the models presented in Section 3.

TABLE 9-7 RISK ASSESSMENT – UNIT 2 GENERATOR

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Component	Risk Assess #	Appendix #	Major Issues	Remaining Life Years	Remaining Life Comments	TECHNO-ECO RISK ASSESSMENT MODEL			SAFETY RISK ASSESSMENT MODEL			Possible Failure Event	Mitigation
														(Insufficient Info - Inspection Required Within (x) Years)		Likeli-hood	Conse-quence	Risk Level	Likeli-hood	Conse-quence	Safety Risk		
1296	7635	7636	7753	7754	0	2	U2 GENERATOR	GENERATOR ASSEMBLY	GENERATOR ROTOR	Rotor Forging and Field Windings:	13	4	Electrical failure - EOL.	(15)	None	2	D	Medium	2	D	High	Loss of unit generator and SC capability. Potential life threatening.	Assess in 2014 overhaul the need for a rotor rewind by 2020+. Evaluate techno-economic values of early implementation in 2015 as part of synchronous condenser conversion.
1296	7635	7636	7753	7754	0	2	U2 GENERATOR	GENERATOR ASSEMBLY	GENERATOR ROTOR	Rotor Forging and Field Windings:	14	4	Mechanical failure retaining rings.	(10)	None	2	D	Medium	2	D	High	Loss of unit generator and SC capability. Potential life threatening.	Removal of the retaining rings and inspection in 2014.
1296	7635	7636	7753	7759	0	2	U2 GENERATOR	GENERATOR ASSEMBLY	GENERATOR STATOR	Stator Core and Frame:	15	4	Electrical - sustained over-fluxing off–line (e.g. if the PT has one phase open or a blown fuse).	(15)	None	3	C	Medium	3	C	High	Loss of unit generator and SC capability. Potential serious injury situation.	Extra V/f protection is desirable if the generator is energized on AVR control, as core damage occurs faster because it goes to ceiling excitation (typically 160% rated flux). It should be noted that this V/f protection may not be applicable if the generator is energized on manual control. The standard protection against over-fluxing is the volts/hertz relay. It is recommended that the V/f element of the new generator multi-functional relay be set up to provide back-up protection, especially during off-line conditions. Initial energization is the time of highest risk.
1296	7635	7636	7753	7759	0	2	U2 GENERATOR	GENERATOR ASSEMBLY	GENERATOR STATOR	Stator Core and Frame:	16	4	Mechanical - loose plates vibrating in the magnetic field then break off and damage the stator winding, more prevalent at the core ends.	(4)	None	3	C	Medium	3	B	Medium	Loose plates break off and damage the stator winding.	Check for signs of red iron oxide dust in the stator bore as the standard sign of loose iron, and confirm by pushing a paint scraper between the plates. Loose areas can usually be treated with penetrating epoxy and re-tightened by driving tapered wedges into the loose packets of iron.
1296	7635	7636	7753	7759	0	2	U2 GENERATOR	GENERATOR ASSEMBLY	GENERATOR STATOR	Stator Core and Frame:	17	4	Electrical - failures of the stator winding, and/or poor stator winding ground protection.	(10)	None	3	D	High	3	C	High	Damage to stator core.	2014 Inspection and repairs/ stator rewind.
1296	7635	7636	7753	7759	0	2	U2 GENERATOR	GENERATOR ASSEMBLY	GENERATOR STATOR	Stator Windings:	18	4	Electrical - insulation/winding failure - most likely to occur during serious system over-voltage transients.	(4)	None	3	D	High	3	C	High	Stator winding failure - possible stator core effects. GE contention that the insulation is at high risk of failing and cannot be considered to be reliable.	Rewind the stator in 2014. Evaluate techno-economic risk of deferral at next recommended overhaul in 2020 based on finding of Unit 1 overhaul. The generator is currently relying upon the lightning and surge arrestors fitted at the generator terminals to attenuate the surges, or upon the statistical unlikelihood of the worst over-voltage situation occurring.
1296	7635	7636	7753	7759	0	2	U2 GENERATOR	GENERATOR ASSEMBLY	GENERATOR STATOR	Stator Windings:	19	4	Mechanical/electrical - can open up the glued layers of insulation and lead to mechanical breakdown of the mica flakes, which have poor mechanical properties.	(4)	None	3	D	High	3	B	Medium	Stator winding failure - possible stator core effects. GE contention that the insulation is at high risk of failing and cannot be considered to be reliable.	Rewind stator in 2014. Evaluate techno-economic risk of deferral to 2020 at next recommended overhaul. Very important to control the mechanical stresses that can open up the glued layers of insulation and lead to mechanical breakdown of the mica flakes, especially if re-wedging required.
1296	7635	7636	7753	7759	0	2	U2 GENERATOR	GENERATOR ASSEMBLY	GENERATOR STATOR	Stator Windings:	20	4	Mechanical/electrical - an increasing risk that the end-windings will loosen again after seven years of operation after 2003 rewedging. The line-end coils and phase leads are at most risk of distortion, and could fail during a severe or a sustained system fault condition.	(4)	None	2	D	Medium	2	B	Low	The line-end coils and phase leads are at most risk of distortion and could fail during a severe or a sustained system fault condition.	Wedge tightening and/or re-wedging. Repair line-end coils and phase leads during overhaul. Stator rewind.
1296	7635	7636	7753	7768	0	2	U2 GENERATOR	GENERATOR ASSEMBLY	GEN HYDROGEN GAS SYSTEM	Auxiliaries - Hydrogen System Pressure Control	21	4	Mechanical/electrical/fire.	2	None	3	C	Medium	3	D	High	Seal Leak, Hydrogen Fire/Expl - oil leaks into the stator if the flow rate is too high,	New hydrogen seals and totalizer.
1296	7635	7636	7753	7768	0	2	U2 GENERATOR	GENERATOR ASSEMBLY	GEN HYDROGEN GAS SYSTEM	Auxiliaries - Hydrogen System - Purity meter and	22	4	Electrical/fire.	10	None	1	C	Low	1	D	High	Hydrogen fire/explosion.	Recent replacement - monitor condition and maintain.
1296	7635	7636	7753	7768	7732	2	U2 GENERATOR	GENERATOR ASSEMBLY	GENERATOR SEAL OIL SYSTEM	N/A	23		Mech - loss, spill-hydrogen leak.	10	None	2	C	Low	2	C	Medium	Hydrogen fire.	Inspect and test per current maintenance program.
1296	7635	7636	7753	7768	7732	2	U2 GENERATOR	GENERATOR ASSEMBLY	TURB AC SEAL OIL PUMP EAST	N/A	24		Mech - loss oil seal.	5	None	2	C	Medium	2	C	Medium	Hydrogen fire or unit shutdown.	Inspect and test per current maintenance program.
1296	7635	7636	7753	7768	7732	2	U2 GENERATOR	GENERATOR ASSEMBLY	GEN AC SEAL OIL PUMP WEST	N/A	25		Mech - loss oil seal.	5	None	2	C	Medium	2	C	Medium	Hydrogen fire or unit shutdown.	Inspect and test per current maintenance program.

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Table 9-7 Cont'd

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Component	Risk Assess #	Appendix #	Major Issues	Remaining Life Years	Remaining Life Comments	TECHNO-ECO RISK ASSESSMENT MODEL			SAFETY RISK ASSESSMENT MODEL			Possible Failure Event	Mitigation
														(Insufficient Info - Inspection Required Within (x) Years)		Likeli-hood	Conse-quence	Risk Level	Likeli-hood	Conse-quence	Safety Risk		
1296	7635	7636	7753	7768	7732	2	U2 GENERATOR	GENERATOR ASSEMBLY	GEN DC SEAL OIL PUMP	N/A	26		Mech - loss oil seal.	5	None	2	C	Medium	2	C	Medium	Hydrogen fire or unit shutdown.	Inspect and test per current maintenance program.
1296	7635	7636	7753	7768	7732	2	U2 GENERATOR	GENERATOR ASSEMBLY	GEN SEAL OIL VACUUM PUMP	N/A	27		Mech - oil hydrogen issue.	5	None	2	C	Medium	2	C	Medium	Hydrogen fire or unit shutdown.	Inspect and test per current maintenance program.
1296	7635	7636	7753	7768	7773	2	U2 GENERATOR	GENERATOR ASSEMBLY	GEN CO2 GAS PURGE SYSTEM	N/A	28		Mech - fire suppress fails.	Not reviewed	None	1	C	Low	2	C	Medium	Hydrogen fire or unit shutdown.	Inspect and test per current maintenance program.
1296	7635	7636	7753	7768	7777	2	U2 GENERATOR	GENERATOR ASSEMBLY	GENERATOR HYDROGEN COOLING	Auxiliaries - Hydrogen Coolers	30	4	Electrical/fire.	10	None	1	C	Low	1	C	Medium	Hydrogen fire or unit shutdown.	Monitor condition and maintain.
1296	7635	7636	7753	99034724	0	2	U2 GENERATOR	GENERATOR ASSEMBLY	PARTIAL DISCHARGE ANALYSIS SYS	N/A	31		Measurement error.	1	None	4	D	High	4	A	Low	Missed generator problem.	Refurbish.
1296	7635	7636	7767	0	0	2	U2 GENERATOR	GENERATOR EXCITATION SYSTEM	GENERATOR EXCITATION SYSTEM	N/A	32		See details below.		None								
1296	7635	7636	7767	271322	0	2	U2 GENERATOR	GENERATOR EXCITATION SYSTEM	EXCITER	Static Exciter Controls	33	4,6	Electrical fault, mechanical fatigue, controls fault, ops error.	2	None	2	C	Medium	2	A	Low	Loss 1 unit generation. Damage to unit.	Upgrade controls for compatibility by 2013.
1296	7635	7636	7767	271322	99036228	2	U2 GENERATOR	GENERATOR EXCITATION SYSTEM	EXCITER	Static Exciter	34	4,6	Electrical fault, mechanical fatigue, controls fault, ops error.	20	None	2	C	Medium	2	B	Low	Loss 1 unit generation. Damage to unit.	Inspect and test per current maintenance program.
1296	7635	7636	7767	271322	99036228	2	U2 GENERATOR	GENERATOR EXCITATION SYSTEM	EXCITER	N/A	35	4,6	The static excitation system was replaced in 1999 and is reported to be working well. It should last the remaining life of the plant provided appropriate services and spare parts continue to be available.	20	None	2	C	Medium	2	B	Low	Loss 1 unit generation. Damage to unit.	Inspect and test per current maintenance program.
1296	7635	7636	7767	271324	0	2	U2 GENERATOR	GENERATOR EXCITATION SYSTEM	EXCITATION TRANSFORMER	N/A	38	4,6,	Regulatory PCB.	3	2013 PCB Reg Likely	3	C	Medium	2	B	Low	Oil spill/PCB contamination.	Replace per regulations when required.
1296	7635	7636	7767	271325	0	2	U2 GENERATOR	GENERATOR EXCITATION SYSTEM	EXCITER FIELD BREAKER	N/A	39	4,6	Electrical fault, mechanical fatigue, controls fault, ops error.	20	None	1	C	Medium	2	B	Low	Loss 1 unit generation. Damage to unit.	Inspect and test per current maintenance program.

9.1.1.8 Life Cycle Curve and Remaining Life

Figure 9-2 and 9-3 below illustrate the life cycle curve for the Unit 2 generator. It is broken into two parts – the generator and the exciter. Differences in the scenarios identified in Section 6do not materially affect the curve. The curves are plots of current and projected operating hours (generation plus synchronous condensing mode) on the y-axis versus calendar year on the x-axis. Vertical lines represent bands of nominal years of normal base loaded life (typically thirty years and 200,000 to 240,000 operating hours to forty years and 280,000 to 320,000 operating hours). Horizontal lines represent the ranges of equipment life based on current and historical information and expert opinion. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view.

The generator figure below shows the operating hours as an electricity generator, in synchronous condensing mode (beginning in 2015), as well as the sum of the two. Only one set of curves is required, given that the major elements of the generator (stator and rotor windings and core) and much of the hydrogen system are the same age. One vertical line illustrates the timing of the next generator overhaul in 2014. The lowest two horizontal lines represent the ranges of expected generator life for Holyrood Unit 2 based on current and historical information and expert opinion. The "Rewind Unit 2 Recommended" line is based on the recommended estimated remaining reliable stator winding life of five years at current generation levels. The other two represent longer rotor winding lives that may be achievable with decreasing reliability and higher failure risk, as well as a maximum 20 years likely for the stator and rotor cores.

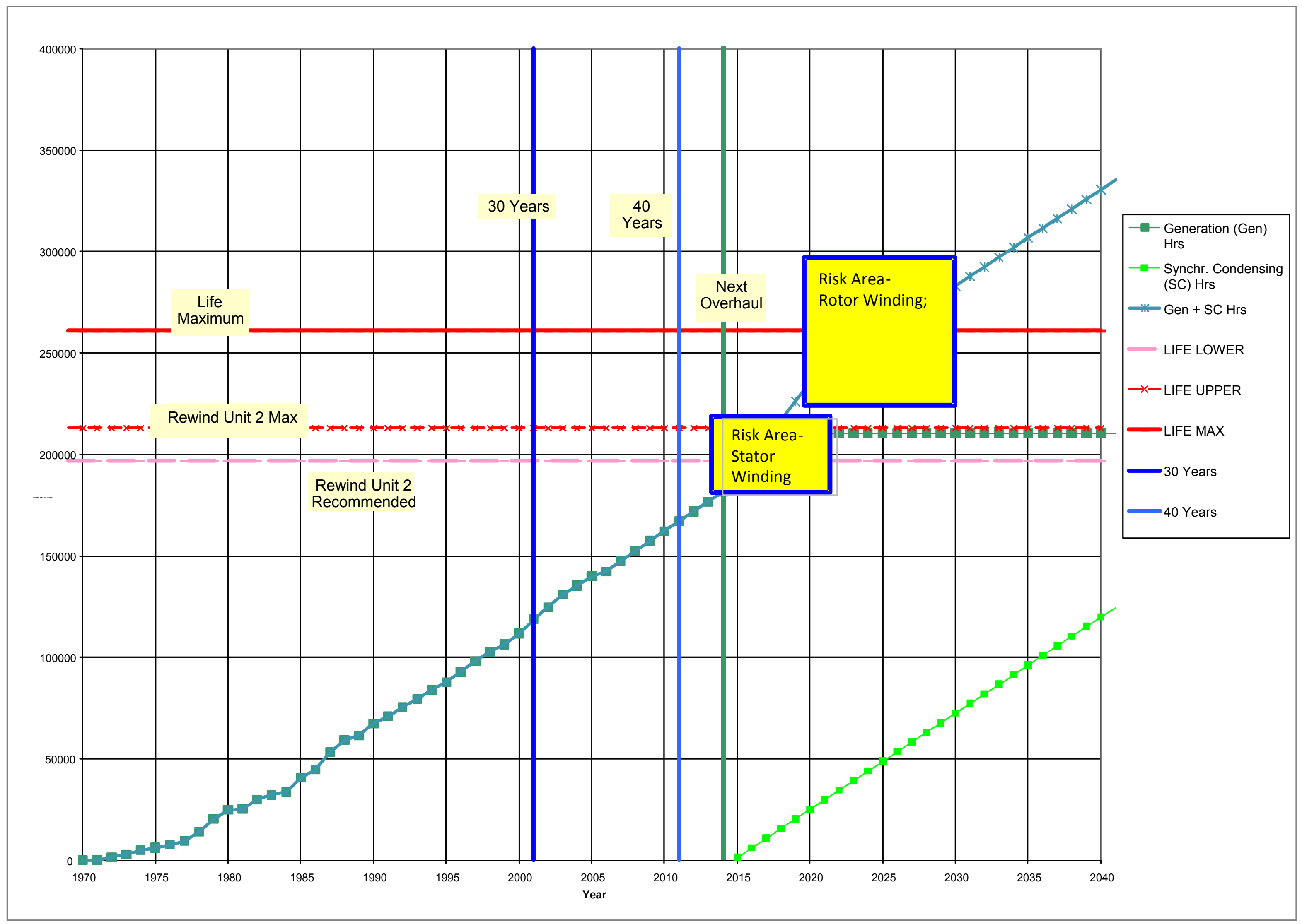

Figure 9-2 Life Cycle Curve – Unit 2 Generator

The exciter figure shows only the total operating hours as an electricity generator plus in synchronous condensing mode (beginning in 2015). It has two curves for any remaining original equipment as well as for the upgrades to the system completed in 2000.

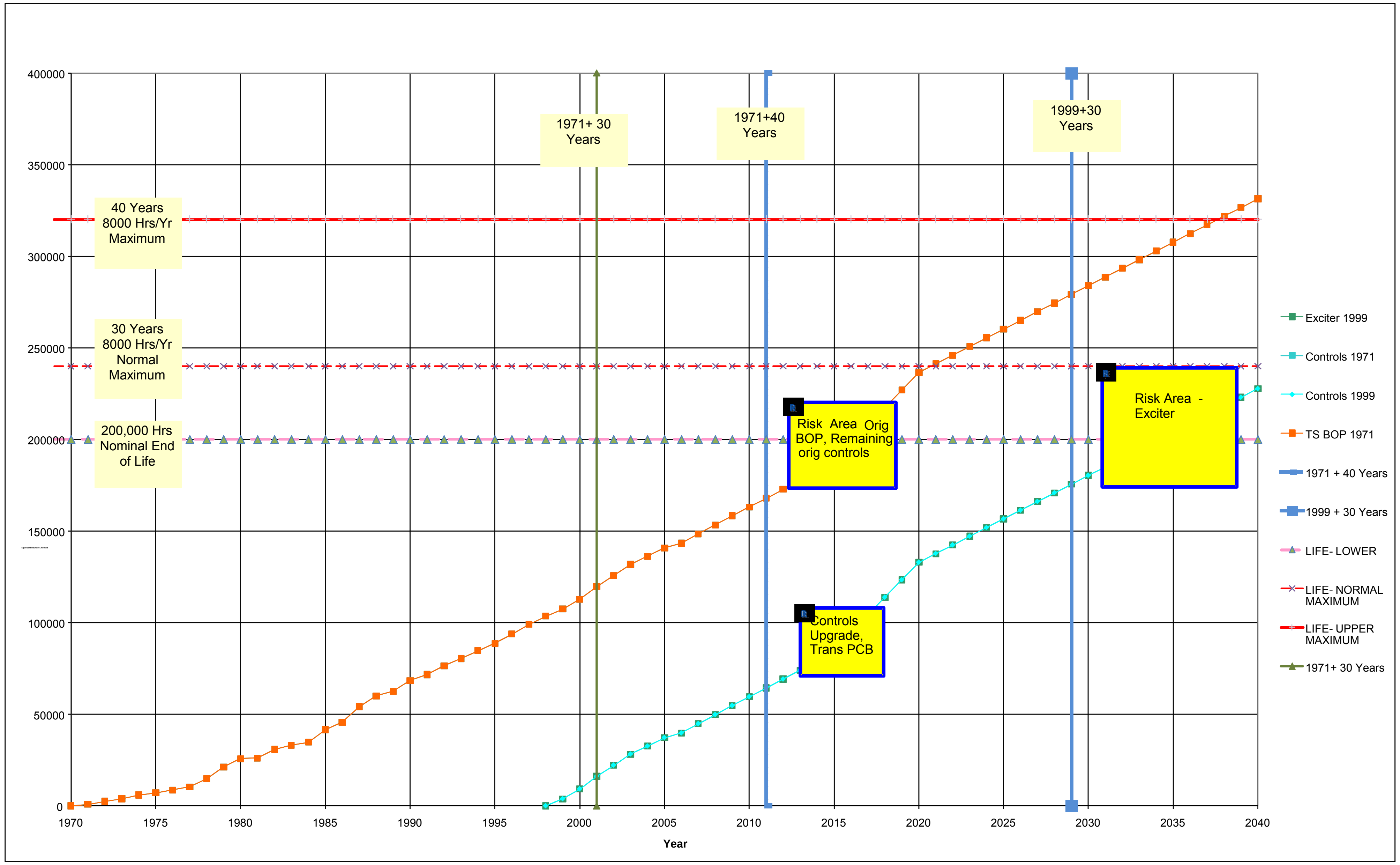

FIGURE 9-3 LIFE CYCLE CURVE – UNIT 2 GENERATOR - EXCITER

The curves indicate that the remaining life (RL) of the Unit 2 generator exceeds the desired life (DL) which is the lesser of the time to its next major planned overhaul/inspection (2014) or to the desired End of Life (EOL) date of 2041. No specific dedicated Level 2 is required, but sufficient inspection and testing will be required in the 2014 overhaul to demonstrate the ability to meet the 2041 EOL date. The exciter should for the most part be able to meet an EOL of 2020, and with periodic refurbishment may meet 2041.The highlighted nearer term risk areas include the stator winding, exciter controls (upgrade only), the rectifying transformer, and some original BOP components. These systems are candidates for replacement or refurbishment – addressed in later sections. The curve also suggests that a nine year time between generator overhauls is impractical at this time in the generator’s life and should be a six year cycle.

9.1.1.9 Level 2 Inspections – Unit 2 Generator

No Level 2 analyses are specifically required given their current condition and their ability to make their next major outage/overhauls. This is provided the plant maintains their current maintenance and inspection programs and addresses the issues identified in the Issues and Actions list. The current overhaul interval was increased from 6 years to 9 years based on a recent (2005) assessment by Hartford Steam Boiler Consulting, a company that was contracted by NL Hydro to review the frequency of steam turbine and generator inspections. This nine year interval between major overhauls is considered excessive, given the age and condition of the generators. A return to a six year interval is considered necessary.

TABLE 9-8 LEVEL 2 INSPECTIONS – UNIT 2 GENERATOR

Newfoundland and Labrador Hydro a NALCOR Energy Co.
Holyrood Thermal Generating Station
Condition Assessment & Life Extension Study

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Sub System Comment	L2#	Appendix #	Level 2 Work	Year	Priority	Cost k$
1296	7635	7636	7753	0	0	2	U2 GENERATOR	GENERATOR ASSEMBLY	GENERATOR	None	5	4	Level 2 "Pre-Major Outage Inspection Work Allowance	2011	1	$100
1296	7635	7636	7753	0	0	2	U2 GENERATOR	GENERATOR ASSEMBLY	GENERATOR	None	6	4	No Level 2 work required before the next inspection/overhaul. Work required to scope and be ready for the next planned inspection/overhaul includes: - Review generator drawings, contract information, and operating manual to clarify design details. - Stator core: Core loop test and thermal image of core for hot spots before the stator is re-wound. - Stator Winding: Obtain Doble test data and on-line partial discharge measurements.	2014	1	$1,961
1296	7635	7636	7753	7754	0	2	U2 GENERATOR	GENERATOR ASSEMBLY	GENERATOR ROTOR	None	7	4	No Level 2 required - included in generator overhaul.	2014		
1296	7635	7636	7753	7759	0	2	U2 GENERATOR	GENERATOR ASSEMBLY	GENERATOR STATOR	None	8	4	No Level 2 required - included in generator overhaul.	2014		
1296	7635	7636	7753	7768	0	2	U2 GENERATOR	GENERATOR ASSEMBLY	GEN HYDROGEN GAS SYSTEM	None	9	4	No Level 2 required - included in generator overhaul.	2014		
1296	7635	7636	7753	7768	7732	2	U2 GENERATOR	GENERATOR ASSEMBLY	GENERATOR SEAL OIL SYSTEM	None	10	4	No Level 2 required - included in generator overhaul.	2014		
1296	7635	7636	7753	7768	7732	2	U2 GENERATOR	GENERATOR ASSEMBLY	TURB AC SEAL OIL PUMP EAST	None	11	4	No Level 2 required - included in generator overhaul.	2014		
1296	7635	7636	7753	7768	7732	2	U2 GENERATOR	GENERATOR ASSEMBLY	GEN AC SEAL OIL PUMP WEST	None	12	4	No Level 2 required - included in generator overhaul.	2014		
1296	7635	7636	7753	7768	7732	2	U2 GENERATOR	GENERATOR ASSEMBLY	GEN DC SEAL OIL PUMP	None	13	4	No Level 2 required - included in generator overhaul.	2014		
1296	7635	7636	7753	7768	7732	2	U2 GENERATOR	GENERATOR ASSEMBLY	GEN SEAL OIL VACUUM PUMP	None	14	4	No Level 2 required - included in generator overhaul.	2014		
1296	7635	7636	7753	7768	7773	2	U2 GENERATOR	GENERATOR ASSEMBLY	GEN CO2 GAS PURGE SYSTEM	None	15	4	No Level 2 required - included in generator overhaul.	2014		
1296	7635	7636	7753	7768	7776	2	U2 GENERATOR	GENERATOR ASSEMBLY	GENER COMPRESSED AIR PURGE	None	16	4	No Level 2 required - included in generator overhaul.	2014		
1296	7635	7636	7753	7768	7777	2	U2 GENERATOR	GENERATOR ASSEMBLY	GENERATOR HYDROGEN COOLING	None	17	4	No Level 2 required - included in generator overhaul.	2014		
1296	7635	7636	7753	99034724	0	2	U2 GENERATOR	GENERATOR ASSEMBLY	PARTIAL DISCHARGE ANALYSIS SYS	None	18	4	Repair in 2010.			
1296	7635	7636	7767	0	0	2	U2 GENERATOR	GENERATOR EXCITATION SYSTEM	GENERATOR EXCITATION SYSTEM	None	19	4	No Level 2 required - included in generator overhaul.	2014		
1296	7635	7636	7767	271322	0	2	U2 GENERATOR	GENERATOR EXCITATION SYSTEM	EXCITER	None	20	4	No Level 2 required - included in generator overhaul.	2014		
1296	7635	7636	7767	271322	99036228	2	U2 GENERATOR	GENERATOR EXCITATION SYSTEM	EXCITER	None	21	4	No Level 2 - included in generator overhaul.	2014		
1296	7635	7636	7767	271324	0	2	U2 GENERATOR	GENERATOR EXCITATION SYSTEM	EXCITATION TRANSFORMER	None	22	4	No Level 2 - included in generator overhaul.	2014		
1296	7635	7636	7767	271325	0	2	U2 GENERATOR	GENERATOR EXCITATION SYSTEM	EXCITER FIELD BREAKER	None	23	4	No Level 2 - included in generator overhaul.	2014		

9.1.1.10 2011 Level 2 Inspection Requirements and Costs – Hydro Request

As part of the effort to optimize the requirements of the 2012, 2014, and 2016 generator outages, Hydro staff asked for an assessment of testing and inspections (Level 2) that could be performed in 2011 with the generator rotor in place. AMEC provided the following generic initial preliminary listing, with an allowance of $200,000 per unit. Given the major overhaul in 2014, AMEC recommends that those items that would assist in better preparing for the 2012 overhaul be undertaken and that an allowance of $100,000 per unit be set aside pending further detailed review.

The following are the tests that could be considered, with the scope adjusted as appropriate within the $100K/unit allowance suggested. It must be recognized that the list appears much more all-encompassing than it is. It is a generic checklist and will not and cannot address much of what needs to be addressed in the major outage in 2014 when the rotor is removed from the stator. There are several safety related issues that would have to be addressed when considering the scope.

INSPECTIONS

Inspections – External Components: The following external component items could be inspected:

- Frame footing and bolts – torque for tightness, damage (likely not an issue – no vibration issue);
- Generator foundation – free from cracks other structural damage; footing grouting cracking/spalling;
- Grounding cables – tightness, condition (corrosion, overheating, fraying, cracking), current flow (unexpected);
- Piping & connections – condition, grounding, gasket and o-ring conditions, tightness, oil-free;
- Generator end brackets (end doors) – seal damage, cleaning/replacement of seal material, hydrogen leaks (NDE surface penetrant if leaking);
- Bearing Insulation & pedestals – grounding and bearing insulation device condition; bearing and journal pitting, insulation carbon contamination, insulation resistance (>Million ohm range); and
- RTD, Thermocouple and Misc devices, Instrument Panel - hydrogen leak test, gaskets/O-ring check, wiring to external device – condition, operational check.

Inspection – Stator Internal Components: The following stator internal component items may be able to be inspected with the rotor in:

- Frame & support structure compression bolts – greasing (oil/dust indicating loose bolts/core/nut lock device vibration), surge ring supports – cracking/looseness; fingerplates – cracked/bent fingers – likely very limited access; stator core – looseness, mechanical damage; stator windings – looseness, cracking, greasing;
- RTD and TC wiring and monitoring devices – visually inspect wiring to and from stator RTD and TC devices as possible – tightly secured. Damaged ones that are accessible may be replaced, others left for major overhaul/rewind; and
- Winding TC's – inspect and check for function.

Inspection – Stator Core: The following stator core items could be inspected with the stator core (rotor in) to the extent possible

- Core back – partial through cooler openings;
- Core Compression plates – inspect at turbine end (difficult at generator end due to phase leads) for looseness and condition;

- Core End Flux Screens and Flux Shunts – overheating, insulation resistance and thermal and distortion damage; and
- Frame to Core Compression Bands – check through cooler openings. No stator casing underbelly inspection ports so unlikely to tighten if required – stator vibration does not appear to be an issue so likely unnecessary.

Inspection – Stator Windings: The following stator windings could be inspected with the Stator Core (Rotor In) to the Extent Possible. If the inner end shields can be moved out of way, up to about 50% of turbine end and 25% of the generator end (phase lead interference) can be checked.

- End winding blocking and roving – inspect condition of blocking, roving, ties – looseness, greasing, dryness, powder, abrasion, cracked painting, missing bits;
- Surge rings - inspect condition of blocking, roving, ties – looseness, greasing, dryness, powder, abrasion, cracked painting, missing bits;
- Surge ring insulation - inspect (mirrors) integrity of insulation, especially beneath ties;
- End winding support structures - inspect (mirrors/other) condition – looseness, loose parts, missing/loose bolts/nuts, cracked supports (solid insulation material), greasing bolts, cracked/loose welding; retighten carefully and if possible; check retightening system condition (if exists);
- Tape separation/Girth cracking – inspect for near ends;
- Insulation galling/necking beyond slot – inspect for lack of insulation or cracking/separation;
- Corona discharge: End windings – white or brownish powder on end bars, dark brown burn marks; and
- End Wedge Migration Out of Slot – inspection by eye or mirror (likely difficult to see (may not be applicable – locking mechanism).

Inspection – Phase Bus Connectors and Terminals: The following could be inspected with the Stator Core (Rotor In) to the Extent Possible. Access is very tight and may not be possible from a safety perspective. Lower part may be more accessible through bussing box.

- Phase Bus Circumferential Bus Insulation: fretting, greasing, cracking insulation/paint, cracks in connectors/support ties;
- Phase Bus Phase Droppers: greasing, cracking insulation;
- High Voltage Bushings: Cracks, oil leakage (if applicable), looseness, dirt, tracking residues, Vent clogging (if applicable);
- Stand-off Insulators: Cracks, oil leakage (if applicable), looseness, dirt, tracking residues;
- Bushing Well (If Applicable) Insulators & Hydrogen Sealant Condition: sealant condition, gasket condition; and
- Generator Current Transformers (CT's): visual if in bushing box (IPB less accessible) - cracks, leaking resin, discolouration.

Inspection - Hydrogen Coolers: The hydrogen coolers could be inspected with the Rotor, assuming the coolers can be readily removed, in to the Extent Practical

- Tube clogging: visual inspection and descale;
- Tube leaks: hydrogen sensors, water inside casing, pressure test; and
- Tube thinning: eddy current tests.

Inspection – Rotor: The following rotor item could be inspected with the Rotor in to the Extent Practical

- Rotor cleanliness: copper dust (dc field coils on turning gear), copper dust in vent holes in winding slot wedges (shorted turns/ground faults) – short turn testing; copper dust in rotor end winding – blocking, insulation; "megger" to check insulation resistance; inspect before and after cleaning;
- Fan Rings/Hubs: Cracks in shrink area – visual if possible, NDE if fans removed; cracks/snugness at fan blade attachment to hub – NDE as appropriate;
- Bearings & Journals: (if bearing dismantled) journals, Babbitt materials, oil-baffle labyrinth, oil-seal ring clearance, bearing clearance; used oil condition(including tiny rounded electrical pits); bearing insulation and grounding brush integrity;
- End Wedges (using boroscope): discoloration, electric pitting between wedges and slot; different wedges, wedges and retaining ring;
- C-Channel Subslot (if applicable): physical damage - boroscope examination through slot under retaining ring may be possible but very difficult;
- Collector Rings: condition, insulation condition, collector thickness/groove depth, spring condition;
- Shaft Voltage Discharge Brushes: visual inspection, monitor system (applicable?);
- Rotor Winding main Lead Hydrogen Sealing: Pressure test, visual not practical;
- Couplings and Coupling Bolts: chafing, fretting, thread condition;
- Bearing insulation: inspect grounding devices, insulation, electric pitting of Babbitt, insulation carbon dust, electrical testing – megger; and
- Hydrogen Seals: Requires hydrogen seals be dismantled. Seals: inspect Babbitt and steel shell, seal rings, seal housing, wipers, springs/pressure components, gaskets/O-rings, NDE – Liquid Penetrant inspection (LPI) for cracks, Ultrasonics (UT) for Babbitt bonding to shell, Insulation resistance – megger seal insulation to ground.

Inspection – Auxiliaries: The following systems could undergo inspections as part of overall generator program, but specific details to be developed:

- Lube oil system – pre-shutdown detailed system readings, tank condition/cleanliness, piping looseness defects, valve operation, oil coolers condition (possible leak test), filters, switches, gauges, pump bearings, monitoring instrumentation check, purifier/centrifuge check;
- Hydrogen Cooling System: general condition and functionality – dryers and control, bulk supply, controls and instruments, desiccant condition;
- Seal Oil System: general condition and functionality – coolers condition (possible leak test), filters, reservoirs condition/cleanliness, hydrogen detraining, piping looseness defects, switches, gauges, pump bearings, monitoring instrumentation check; and
- Exciters: Electrical and Mechanical systems.

TESTS

Test – Stator: The tests to be further evaluated for the Stator with the rotor in could include:

- Stator Winding Electrical Tests – dry, phase isolation
    - Insulation Resistance: Megger - ohmic resistance between conductors in each phase and ground (stator core) – gross insulation issues so that further hi-voltage testing can be carried out safely;
    - Polarization Index (PI) – Megger - change in IR in first minutes (IR minute 10/IR minute 1) = function of insulation condition, contamination, moisture;

- A Doble test can be done to measure the insulation power factor and tip-up of the stator winding, with the rotor in place. (all the stator coils are raised in steps, up to rated phase voltage, during this test, and each phase is energized separately);
- DC Hi Pot: high voltage to winding (each phase separately or all) – done in hydrogen.
- Series Winding Resistance: ohmic resistance of copper in each phase – shorted windings, bad connections, wrong/open connections;
- Dielectric Absorption during DC voltage Application: measures aging of resin binder in ground wall insulation – time dependent current flow. Affected by voids in insulation;
- DC leakage or Ramped Voltage: leakage current versus applied voltage applied increasingly over time – warns of impending insulation breakdown; and
- Dissipation/Power Factor Tip-Up Testing: measures the void content of insulation, also other ionizing losses (PD or slot discharges).

Test – Rotor: The tests to be further evaluated for the rotor with the rotor in could include:

- Mechanical Testing
  - Rotor Vibration: typically on-line measurements, detailed testing (using on-line device connections – characterize magnitude, phase relation, frequency spectrum.
- Test – Rotor Electrical Testing
  - Rotor Winding Resistance Tests: Megger - ohmic resistance of total copper winding shorter turns, bad connections, wrong/open connections;
  - Insulation Resistance: Megger - ohmic resistance between conductors in each phase and ground (rotor forging) – gross insulation issues so that further hi-voltage testing can be carried out safely;
  - Polarization Index (PI) – Megger - change in IR in first minutes (IR minute 10/IR minute 1) = function of insulation condition, contamination, moisture; and
  - Shorted turns Detection
    - Off-Line Testing: winding impedance measurement during acceleration and deceleration for comparison with past tests (Low Voltage DC – Volt Drop Shorted Turn Test likely preferred otherwise)
    - Hydrogen Seals: NDE - Megger seal insulation
    - Bearings: Megger bearing insulation.

9.1.1.11 Capital Projects

The following are the suggested typical capital enhancements that should be considered:

TABLE 9-9 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – UNIT 2 GENERATOR

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Detail	CAP#	Appendix #	Capital Item	Date	Priority
1296	7635	7636	7753	0	0	2	U2 GENERATOR	GENERATOR ASSEMBLY	GENERATOR	N/A	12	4	Install a rotor flux probe near the turbine end of the stator bore when the rotor is removed in 2014.	2014	1
1296	7635	7636	7753	7754	0	2	U2 GENERATOR	GENERATOR ASSEMBLY	GENERATOR ROTOR	N/A	13	4	No capital investment required.		
1296	7635	7636	7753	7759	0	2	U2 GENERATOR	GENERATOR ASSEMBLY	GENERATOR STATOR	N/A	14	4	Recommend ordering stator windings in 2013 for rewinding stator in 2014. Installation in 2014 subject to techno-economic optimization results.	2013	1
1296	7635	7636	7753	7768	0	2	U2 GENERATOR	GENERATOR ASSEMBLY	GEN HYDROGEN GAS SYSTEM	N/A	15	4	Install a hydrogen consumption "totalizer" in each hydrogen supply line.	2011	1
1296	7635	7636	7753	7768	7732	2	U2 GENERATOR	GENERATOR ASSEMBLY	GENERATOR SEAL OIL SYSTEM	N/A	16	4	Replace/overhaul seal oil skids required for SC operation.	2015	1
1296	7635	7636	7753	7768	7732	2	U2 GENERATOR	GENERATOR ASSEMBLY	TURB AC SEAL OIL PUMP EAST	N/A	17	4	No capital investment required.		
1296	7635	7636	7753	7768	7732	2	U2 GENERATOR	GENERATOR ASSEMBLY	GEN AC SEAL OIL PUMP WEST	N/A	18		No capital investment required.		
1296	7635	7636	7753	7768	7732	2	U2 GENERATOR	GENERATOR ASSEMBLY	GEN DC SEAL OIL PUMP	N/A	19		No capital investment required.		
1296	7635	7636	7753	7768	7732	2	U2 GENERATOR	GENERATOR ASSEMBLY	GEN SEAL OIL VACUUM PUMP	N/A	20		No capital investment required.		
1296	7635	7636	7753	7768	7773	2	U2 GENERATOR	GENERATOR ASSEMBLY	GEN CO2 GAS PURGE SYSTEM	N/A	21		No capital investment required.		
1296	7635	7636	7753	7768	7776	2	U2 GENERATOR	GENERATOR ASSEMBLY	GENERATOR COMPRESSED AIR	N/A	22		No capital investment required.		
1296	7635	7636	7753	7768	7777	2	U2 GENERATOR	GENERATOR ASSEMBLY	GENERATOR HYDROGEN COOLING	N/A	23	4	No capital investment required.		
1296	7635	7636	7753	99034724	0	2	U2 GENERATOR	GENERATOR ASSEMBLY	PARTIAL DISCHARGE ANALYSIS SYS	N/A	24	4	Repair	2010	1
1296	7635	7636	7767	0	0	2	U2 GENERATOR	GENERATOR EXCITATION SYSTEM	GENERATOR EXCITATION SYSTEM	N/A	25	4,6	No capital investment required.		
1296	7635	7636	7767	271322	0	2	U2 GENERATOR	GENERATOR EXCITATION SYSTEM	EXCITER	N/A	26	4,6	Upgrade static exciter controls compatible with the latest Unitrol 6000 system.	2013	1
1296	7635	7636	7767	271324	0	2	U2 GENERATOR	GENERATOR EXCITATION SYSTEM	EXCITATION TRANSFORMER	N/A	27	4,5	Replace rectifying transformer.	2013	1
1296	7635	7636	7767	271325	0	2	U2 GENERATOR	GENERATOR EXCITATION SYSTEM	EXCITER FIELD BREAKER	N/A	28	4,6	No capital investment required.		

9.1.2 Asset 7711 – Unit 2 Generator Lube Oil System

(Detailed Technical Assessment in Working Papers, Appendix 9)

Unit #:	2
Asset Class #	BU 1296 - Assets Generations
SCI & System:	7638 #2 Turbine & Generator
Sub-Systems:	7711 #2 Turbine Lubricating Oil System (7719) and Turbine Hydraulic Oil System (7741)
Components:	7712 #2 Tank & Equipment 7715 #2 Purification 7720 #2 Pump South 7721 #2 Pump North 7725 #2 DC Pump 7743 #2 Hydraulic Oil Pump North 7744 #2 Hydraulic Oil Pump South

9.1.2.1 Description

The generator lube oil system is integrated into the steam turbine system. It consists of a storage system, AC and DC pumping systems, filtration, and coolers/heat exchangers. The lube oil tank holds approximately 9840 L (2600 US gallons) of Turboflo R&O 32 lubricating oil. Within the lube oil tank, there are three pumping units (two 100% AC motor driven and one 100% DC motor driven) and three 100% duty lube oil heat exchangers. The system supplies 35-45 °C oil to the turbine/generator lubrication and hydrogen seal oil systems. Pump discharge pressures at 275 – 300 kPa would be normal.

Lubricating oil heat exchanger cooling water heads can be isolated and removed for easy cleaning. An oil purifier is connected to the oil tank through a separate piping arrangement and is used primarily to remove water from the oil which accumulates because of the condensation throughout the process. The system is fitted with two 100% duty oil filters ensuring heavy particles in the oil are removed and do not reach the bearings during lubrication.

Two 100% positive displacement hydraulic oil pumps are used to operate the emergency stop valve, the combined intercept reheat stop valves, the control valves and other miscellaneous valves on the steam turbine. The pumps operate at a pressure of 15.5 MPa to counteract the large springs which normally hold the valves closed. The hydraulic oil system has its own network of high pressure piping external to the lubricating oil system which makes it somewhat easier to maintain if problems occur.

9.1.2.2 History

Manufactured/Delivered	1970
In-Service Date	Apr 1971
Generation Base Load End Date	Dec 2015
Generation Peak/Emerg Gen End Date	Dec 2020
Synchronous Condensing Start Date	Jan 2015
Synchronous Condensing End Date	Dec 2041
Next Major Overhaul/Inspection	2014

The thousands of hours associated with the analyses, and the number of starts per year are:

	Generation (Gen)	**Synchronous Condensing (SC)**
Hours Actual - Ops to Dec 2009	158	0
Hours - Ops to Gen End Date Dec 2015	188	1.5
Hours - Ops to Gen End Date Dec 2020	212	25
Hours – Ops to SC End Date Dec 2040	212	120
Starts Actual - Ops to Dec 2009	442	0
Starts - Ops to Gen End Date Dec 2015	554	5
Starts - Ops to Gen End Date Dec 2020	614	30
Starts – Ops to SC End Date Dec 2040	674	130

9.1.2.3 Inspection and Repair History

The system was examined extensively as part of a plant fire protection system evaluation. It is in good condition and capable of meeting the requirements of the generator up to the year 2041, with regular maintenance and inspection during major generator inspections.

9.1.2.4 Condition Assessment

This system has been in service since Unit 2 was placed in service in 1971. Although the lubrication system is critical to the operation of the steam turbine/generator and may cause a short unit shutdown in the event of a failure, a longer shutdown may occur due to a failure of the lubricating oil piping system which cannot be inspected easily because the supply piping is installed inside of the oil returns piping which is connected to the storage tank.

The tank appears externally to be in good condition. Internal inspection reports were not available during the assessment. Failures of any of the oil pumps or the oil purifier are easily repaired and barring no hidden problems, this system should continue to operate for the time frames required. If Unit 2 is required to support synchronous condenser operation after generation mode, this system will be required to operate continuously and should not present any major issue.

All parts of the generator lube oil system are expected to be able to make their next inspection date. All are expected to require more rigorous evaluation at that time. Most will be able with maintenance and replacement to meet the generation end dates. None are expected to be able to make their 2041 synchronous condensing end date without a major refurbishment and replacement program.

TABLE 9-10 CONDITION ASSESSMENT – UNIT 2 GENERATOR LUBE OIL SYSTEM

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset Level 2	Asset Level 3	Description	Detail	Condition Summary ID#	Append #	Condition	EPRI Identifier	Original Life (Base Load) Ops Hrs (Yrs)	Current Expected Minimum Remaining Life Years (Subject to Test)	End of Life (EOL) Required	Next Regular Inspection	Next Planned Overhaul or Major Inspection	Capability to Reach Next Overhaul	Capability to Reach EOL	In Service
1296	7635	7636	271317	7711	0	2	#2 TURBINE	TURBINE	TURBINE OIL SYSTEMS	N/A	45	18	See details below.	3a	(30)	10	2041	2011	2011	Yes	No	1971
1296	7635	7636	271317	7711	7719	2	#2 TURBINE	TURBINE	TURBINE LUBE OIL SYSTEM	N/A	46	18	Lube oil system is in good condition. No NDE of piping was obtained and reviewed, but interviews indicated no issues. Failures of any of the oil pumps or the oil purifier are easily repaired.	3a	(30)	10	2041	2011	2011	Yes	No	1971
1296	7635	7636	271317	7711	7719	2	#2 TURBINE	TURBINE	TURB LUBE OIL TANK & EQUIP	N/A	47	18	Lube oil tank appears to be in good condition. Internal inspection reports were not available.	4	(30)	10	2041	2011	2011	Yes	No	1971
1296	7635	7636	271317	7711	7719	2	#2 TURBINE	TURBINE	TURB LUBE OIL PURIFICATION	N/A	48	18	Lube oil purification system is relatively new and in good condition.	3a	(30)	10	2041	2011	2011	Yes	No	2001
1296	7635	7636	271317	7711	7719	2	#2 TURBINE	TURBINE	TURB LUBE A.C. OIL P/P NORT	N/A	50	18	Lube oil pumps in good condition based on interviews. Failures readily dealt with through backups and replacements as required.	3a	(30)	10	2041	2011	2011	Yes	No	1971
1296	7635	7636	271317	7711	7719	2	#2 TURBINE	TURBINE	TURB LUBE A.C. OIL P/P SOUT	N/A	51	18	Lube oil pumps in good condition based on interviews. Failures readily dealt with through backups and replacements as required.	3a	(30)	10	2041	2011	2011	Yes	No	1971
1296	7635	7636	271317	7711	7719	2	#2 TURBINE	TURBINE	TURBINE LUBE D.C. PUMP	N/A	52	18	Lube oil pumps in good condition based on interviews. Failures readily dealt with through backups and replacements as required.	3a	(30)	10	2041	2011	2011	Yes	No	1971
1296	7635	7636	271317	7711	7741	2	#2 TURBINE	TURBINE	#2TURBINE HYDRAULIC OIL SYSTEM	N/A	53	18	In good condition based on interviews. Failures readily dealt with, backups and replacements as required.	3a	(30)	10	2041	2011	2011	Yes	No	1971
1296	7635	7636	271317	7711	7741	2	#2 TURBINE	TURBINE	TURBINE HYD. OIL PUMP NORTH	N/A	54	18	In good condition based on interviews. Failures readily dealt with, backups and replacements as required.	3a	(30)	10	2041	2011	2011	Yes	No	1971
1296	7635	7636	271317	7711	7741	2	#2 TURBINE	TURBINE	TURBINE HYD. OIL PUMP SOUTH	N/A	55	18	In good condition based on interviews. Failures readily dealt with, backups and replacements as required.	3a	(30)	10	2041	2011	2011	No	No	1971

Notes:
1. A "(bracketed)" value in the "Current Expected Remaining Life" column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation, including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as "(X/Y)" has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.
2. The "Next Regular Inspection" column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The "Next Planned Overhaul or Major Inspection" column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a "Desired Life" stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or not known by AMEC.

9.1.2.5 Actions

Based on the condition assessment, the following actions are recommended for the Unit 2 lube oil system.

TABLE 9-11 RECOMMENDED ACTIONS – UNIT 2 GENERATOR LUBE OIL SYSTEM

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Unit	Asset 2/3	Asset 3/4	Description	Detail	Action #	App #	Action	Year	Priority
1296	7635	7636	271317	7711	2	#2 TURBINE	TURBINE	TURBINE OIL SYSTEMS	N/A	70	9	No recommended action.		
1296	7635	7636	271317	7711	2	#2 TURBINE	TURBINE	TURBINE LUBE OIL SYSTEM	N/A	71	9	Flush the lube oil, the seal oil and the seal oil bypass lines prior to the seasonal restart of the unit every year.	2011	1
1296	7635	7636	271317	7711	2	#2 TURBINE	TURBINE	TURB LUBE OIL TANK & EQUIP	N/A	72	9	Perform Level 2 inspections on oil storage tanks and internals.	2011	1
1296	7635	7636	271317	7711	2	#2 TURBINE	TURBINE	TURB LUBE OIL PURIFICATION	N/A	73	9	No recommended action.		
1296	7635	7636	271317	7711	2	#2 TURBINE	TURBINE	DUPLEX FILTER FOR LUBE OIL	N/A	74	9	No recommended action.		
1296	7635	7636	271317	7711	2	#2 TURBINE	TURBINE	TURB LUBE A.C. OIL P/P NORT	N/A	75	9	No recommended action.		
1296	7635	7636	271317	7711	2	#2 TURBINE	TURBINE	TURB LUBE A.C. OIL P/P SOUT	N/A	76	9	No recommended action.		
1296	7635	7636	271317	7711	2	#2 TURBINE	TURBINE	TURBINE LUBE D.C. PUMP	N/A	77	9	No recommended action.		
1296	7635	7636	271317	7711	2	#2 TURBINE	TURBINE	#2TURBINE HYDRAULIC OIL SYSTEM	N/A	78	9	No recommended action.		
1296	7635	7636	271317	7711	2	#2 TURBINE	TURBINE	TURBINE HYD. OIL PUMP NORTH	N/A	79	9	No recommended action.		
1296	7635	7636	271317	7711	2	#2 TURBINE	TURBINE	TURBINE HYD. OIL PUMP SOUTH	N/A	80	9	No recommended action.		

9.1.2.6 Risk Assessment

Table 9-12 below illustrates the risk assessment for the Unit 2 generator lube oil system, both from a technological perspective and a safety perspective using the models presented in Section 3.

TABLE 9-12 RISK ASSESSMENT – UNIT 2 GENERATOR LUBE OIL SYSTEM

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Component	Risk Assess #	Appendix #	Major Issues	Remaining Life Years	Remaining Life Comments	TECHNO-ECO RISK ASSESSMENT MODEL			SAFETY RISK ASSESSMENT MODEL			Possible Failure Event	Mitigation
														(Insufficient Info - Inspection Required Within (x) Years)		Likeli-hood	Conse-quence	Risk Level	Likeli-hood	Conse-quence	Safety Risk		
1296	7635	7636	271317	7711	0	2	#2 TURBINE	TURBINE	TURBINE OIL SYSTEMS	N/A	51	9	See details below.	10	None								
1296	7635	7636	271317	7711	7719	2	#2 TURBINE	TURBINE	TURBINE LUBE OIL SYSTEM	N/A	52	9	See details below.	10	None								
1296	7635	7636	271317	7711	7719	2	#2 TURBINE	TURBINE	TURB LUBE OIL TANK & EQUIP	Lube Oil Tanks	53	9	Corrosion, erosion.	10	None	1	A	Low	1	A	Low	Oil leak – containment overflow. Safety.	Inspect and maintain.
1296	7635	7636	271317	7711	7719	2	#2 TURBINE	TURBINE	TURB LUBE OIL TANK & EQUIP	Lube Oil Pumps & Motors	54	9	Mechanical and/or electrical failure.	10	None	1	A	Low	1	A	Low	Unit shutdown – multiple systems.	Inspect and maintain.
1296	7635	7636	271317	7711	7719	2	#2 TURBINE	TURBINE	TURB LUBE OIL TANK & EQUIP	Lube Oil Coolers	55	9	Mechanical failure/leaks.	10	None	1	A	Low	1	A	Low	Unit shutdown for repairs.	Inspect and maintain.
1296	7635	7636	271317	7711	7719	2	#2 TURBINE	TURBINE	TURB LUBE OIL TANK & EQUIP	Lube Oil Filters	56	9	Bearing failure.	10	None	1	A	Low	1	A	Low	Unit shutdown for repairs.	Inspect and maintain.
1296	7635	7636	271317	7711	7719	2	#2 TURBINE	TURBINE	TURB LUBE OIL PURIFICATION	Lube Oil Filters	57	9	Mechanical and/or pluggage failure.	10	None	1	A	Low	1	A	Low	Water & particulate contamination.	Inspect and maintain.
1296	7635	7636	271317	7711	7719	2	#2 TURBINE	TURBINE	DUPLEX FILTER FOR LUBE OIL	N/A	58	9	Mechanical/electrical failure.	10	None	1	A	Low	1	A	Low	Unit shutdown – multiple systems.	Inspect and maintain.
1296	7635	7636	271317	7711	7719	2	#2 TURBINE	TURBINE	TURB LUBE A.C. OIL P/P NORT	N/A	59	9	Mechanical/electrical failure.	10	None	1	A	Low	1	A	Low	Unit shutdown – multiple systems.	Inspect and maintain.
1296	7635	7636	271317	7711	7719	2	#2 TURBINE	TURBINE	TURB LUBE A.C. OIL P/P SOUT	N/A	60	9	Mechanical/electrical failure.	10	None	1	A	Low	1	A	Low	Unit shutdown – multiple systems.	Inspect and maintain.
1296	7635	7636	271317	7711	7719	2	#2 TURBINE	TURBINE	TURBINE LUBE D.C. PUMP	N/A	61	9	Mechanical/electrical failure.	10	None	1	A	Low	1	A	Low	Unit shutdown – multiple systems.	Inspect and maintain.
1296	7635	7636	271317	7711	7741	2	#2 TURBINE	TURBINE	#2TURBINE HYDRAULIC OIL SYSTEM	N/A	62	9	Mechanical/electrical failure.	10	None	1	A	Low	1	A	Low	Unit shutdown – multiple systems.	Inspect and maintain.
1296	7635	7636	271317	7711	7741	2	#2 TURBINE	TURBINE	TURBINE HYD. OIL PUMP NORTH	N/A	63	9	Mechanical/electrical failure.	10	None	1	A	Low	1	A	Low	Unit shutdown – multiple systems.	Inspect and maintain.
1296	7635	7636	271317	7711	7741	2	#2 TURBINE	TURBINE	TURBINE HYD. OIL PUMP SOUTH	N/A	64	9	Mechanical/electrical failure.	10	None	1	A	Low	1	A	Low	Unit shutdown – multiple systems.	Inspect and maintain.

Notes: 1. The risk assessment for the lube oil pumps is based on the lube oil pump controls being added to the control room as per the recommendations of the 2009 Emergency Shutdown Procedure study.

9.1.2.7 Life Cycle Curve and Remaining Life

Figure 9-4 below illustrates the life cycle curve for the Unit 2 lube oil system. Two curves are required given that the purification system was upgraded while other major elements of the lube oil system are approximately the same age. There is insufficient information to develop specific accurate curves for the storage tank, and coolers. Further detailed examination during the 2014 turbine overhaul should provide the basis going forward. The life curve is a plot of current and projected operating hours (generation plus synchronous condensing mode on the y-axis versus calendar year on the x-axis. Vertical lines represent bands of nominal years of normal base loaded life (typically 200,000 operating hours, thirty years and 200,000 to 240,000 operating hours, and forty years, and 280,000 to 320,000 operating hours). Horizontal lines represent the ranges of equipment life based on current and historical information and expert opinion. The risk area box provides an indication of the timing of potential issues either from an age or equivalent operating hours view.

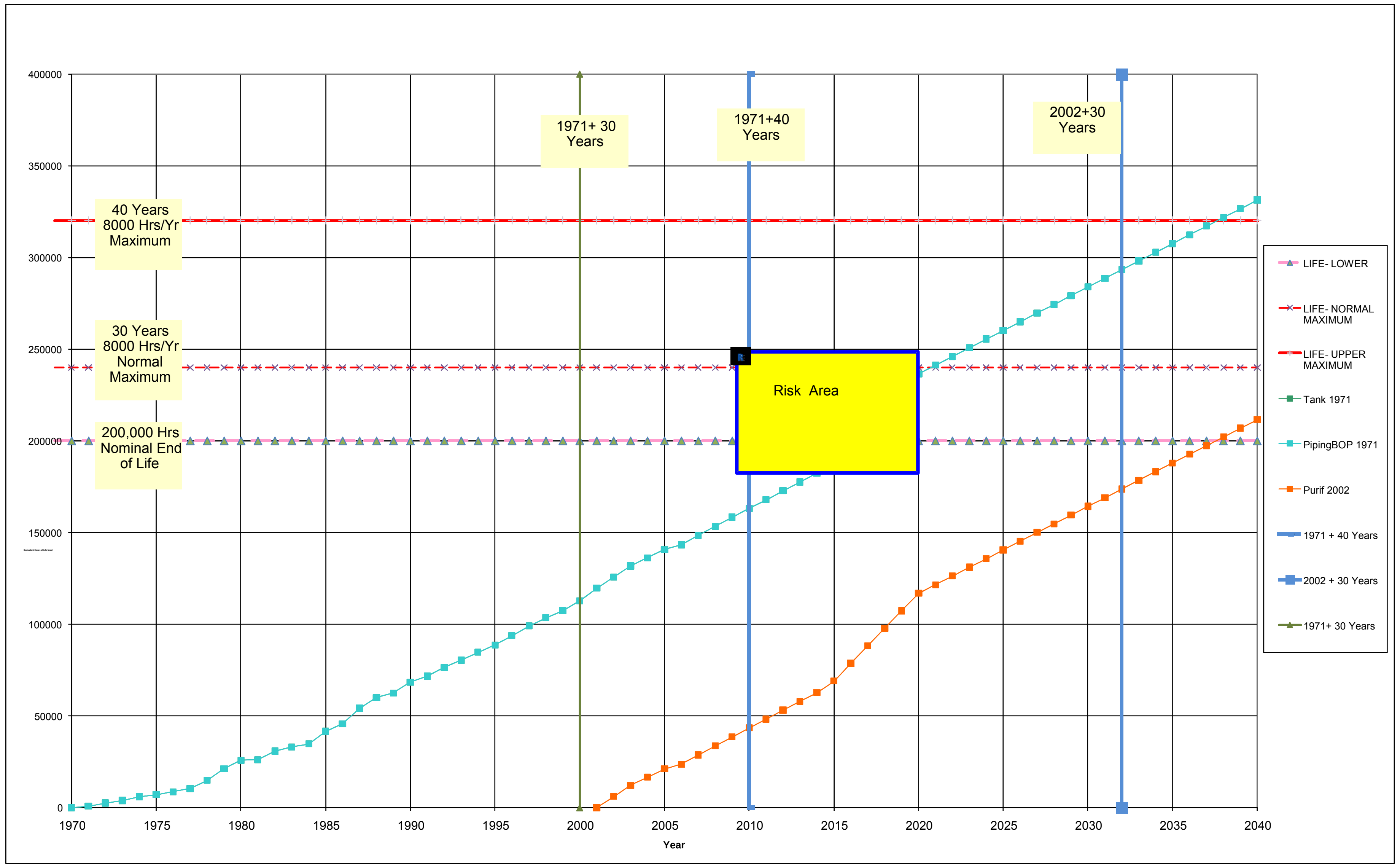

FIGURE 9-4 LIFE CYCLE CURVE – UNIT 2 GENERATOR LUBE OIL SYSTEM

The curves indicate that the remaining life (RL) of the Unit 2 generator lube oil system exceeds the desired life (DL) which is the lesser of the time to its next major planned overhaul/inspection (2014) or to the desired End of Life (EOL) date of 2041. Hence, no specific dedicated Level 2 is required of the system as a whole, but sufficient inspection and testing will be required in 2014 steam turbine generator overhaul to demonstrate the ability to meet the EOL date. The exception is the storage tank for which information was considered inadequate to form a firm conclusion and level 2 testing is recommended in 2011. The figure's highlighted risk areas is primarily operating hours driven and likely to shift further out in time after the 2014 turbine generator overhaul. The 2014 overhaul/inspection is a fundamental element in changing the current assessment.

9.1.2.8 Level 2 Inspections – Unit 2 Generator Lube Oil System

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 9-13 below, assuming that the current plant inspection and maintenance program is maintained or improved.

TABLE 9-13 LEVEL 2 INSPECTIONS – UNIT 2 GENERATOR LUBE OIL SYSTEM

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Sub System Comment	L2#	Appendix #	Level 2 Work	Year	Priority	Cost k$
1296	7635	7636	271317	7711	0	2	#2 TURBINE	TURBINE	TURBINE OIL SYSTEMS	None	36	9	No Level 2 required - included in steam turbine overhaul.	2014		
1296	7635	7636	271317	7711	7719	2	#2 TURBINE	TURBINE	TURBINE LUBE OIL SYSTEM	None	37	9	No Level 2 required - included in steam turbine overhaul.	2014		
1296	7635	7636	271317	7711	7719	2	#2 TURBINE	TURBINE	TURB LUBE OIL TANK & EQUIP	None	38	9	NDE inspection and visual inspections of lube oil tanks and internals.	2011	2	$6
1296	7635	7636	271317	7711	7719	2	#2 TURBINE	TURBINE	TURB LUBE OIL PURIFICATION	None	39	9	No Level 2 required - included in steam turbine overhaul.	2014		
1296	7635	7636	271317	7711	7719	2	#2 TURBINE	TURBINE	DUPLEX FILTER FOR LUBE OIL	None	40	9	No Level 2 required - included in steam turbine overhaul.	2014		
1296	7635	7636	271317	7711	7719	2	#2 TURBINE	TURBINE	TURB LUBE A.C. OIL P/P NORT	None	41	9	No Level 2 required - included in steam turbine overhaul.	2014		
1296	7635	7636	271317	7711	7719	2	#2 TURBINE	TURBINE	TURB LUBE A.C. OIL P/P SOUT	None	42	9	No Level 2 required - included in steam turbine overhaul.	2014		
1296	7635	7636	271317	7711	7719	2	#2 TURBINE	TURBINE	TURBINE LUBE D.C. PUMP	None	43	9	No Level 2 required - included in steam turbine overhaul.	2014		
1296	7635	7636	271317	7711	7741	2	#2 TURBINE	TURBINE	#2TURBINE HYDRAULIC OIL SYSTEM	None	44	9	No Level 2 required - included in steam turbine overhaul.	2014		
1296	7635	7636	271317	7711	7741	2	#2 TURBINE	TURBINE	TURBINE HYD. OIL PUMP NORTH	None	45	9	No Level 2 required - included in steam turbine overhaul.	2014		
1296	7635	7636	271317	7711	7741	2	#2 TURBINE	TURBINE	TURBINE HYD. OIL PUMP SOUTH	None	46	9	No Level 2 required - included in steam turbine overhaul.	2014		

9.1.2.9 Capital Projects

The suggested typical capital enhancements include:

TABLE 9-14 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – UNIT 2 GENERATOR LUBE OIL SYSTEM

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Detail	CAP#	Appendix #	Capital Item	Date	Priority
1296	7635	7636	271317	7711	0	2	#2 TURBINE	TURBINE	TURBINE OIL SYSTEMS	N/A	44	9	Provide concrete curbing around turbine lube oil tanks and seal oil tanks so as to collect any oil that leaks. Provide Isolation for generator requirements from turbine system requirements during synchronous generation operation	2012	1
1296	7635	7636	271317	7711	7719	2	#2 TURBINE	TURBINE	TURBINE LUBE OIL SYSTEM	N/A	45	9	No capital investment required.		
1296	7635	7636	271317	7711	7719	2	#2 TURBINE	TURBINE	TURB LUBE OIL TANK & EQUIP	N/A	46	9	Replace turbine lube oil conditioners.	2013	1
1296	7635	7636	271317	7711	7719	2	#2 TURBINE	TURBINE	TURB LUBE OIL PURIFICATION	N/A	47	9	No capital investment required.		
1296	7635	7636	271317	7711	7719	2	#2 TURBINE	TURBINE	DUPLEX FILTER FOR LUBE OIL	N/A	48	9	Provide mechanical level switches in full flow lube oil filter compartment to detect leaks.	2013	2
1296	7635	7636	271317	7711	7719	2	#2 TURBINE	TURBINE	TURB LUBE A.C. OIL P/P NORT	N/A	49	9	Provide electrical control (both "On" and "Off") for the lube oil pumps in parallel with the local controls in the Control Room	2012	1
1296	7635	7636	271317	7711	7719	2	#2 TURBINE	TURBINE	TURB LUBE A.C. OIL P/P SOUT	N/A	50	9	Provide electrical control (both "On" and "Off") for the lube oil pumps in parallel with the local controls in the Control Room	2012	1
1296	7635	7636	271317	7711	7719	2	#2 TURBINE	TURBINE	TURBINE LUBE D.C. PUMP	N/A	51	9	Provide paralleled electrical control for the DC Lube Oil Pump and "On" and "Off" control for all lube oil pumps in parallel with the local controls in the Control Room.	2012	1
1296	7635	7636	271317	7711	7741	2	#2 TURBINE	TURBINE	#2TURBINE HYDRAULIC OIL	N/A	52	9	No capital investment required.		
1296	7635	7636	271317	7711	7741	2	#2 TURBINE	TURBINE	TURBINE HYD. OIL PUMP NORTH	N/A	53	9	No capital investment required.		
1296	7635	7636	271317	7711	7741	2	#2 TURBINE	TURBINE	TURBINE HYD. OIL PUMP SOUTH	N/A	54	9	No capital investment required.		

9.1.3 Asset 8152 – Unit 2 Electrical and Control Systems Associated with Generators

(Detailed Technical Assessment in Working Papers, Appendix 6)

The requirements for the electrical and control systems associated with Unit 2 are as follows:

Unit #:	2
Asset Class #	BU 1296 - Assets Generation
SCI & System:	8152 #2 Electrical System & Controls
Sub-Systems:	8152 #2 Electrical System & Controls
Components:	8138 #2 Relay Room Protection & Control 8144 #2 Main Controls 8153 #2 Generator Bus-Duct and Connections 8173 #2 Battery Chargers 8174 #2 UPS2 Inverter 8186 #2 Battery Banks 271478 #2 Switchgear 4160V/600V 8162 Power Centre “B” UAB2, (600V) 271479 #2 Turbine Supervisory System 299451 #2 DCS COMMON SYSTEMS 270297 Control Cables 270298 Power Cables 600 V Metric Plugs

9.1.3.1 Description

Asset 8138 Unit 2 Relay Room Protection & Control

Generator G2, Transformer T2 and Auxiliaries P&C Panels, were manufactured by Canadian General Electric, and installed in 1969.

Generator 2 and Transformer T2 Protection Panels: These panels utilize GE electro-mechanical relays and blocking switches. In addition, they show annunciation and T2/UST2 gas and winding temperature trips and indications.

Unit 2 Protection Auxiliary Panel: This panel shows DC buses indications and blocking switches.

Unit 2 Metering Pane: This panel shows Generator 2 and Static Exciter 2 WHR's, runtime, flexitests and stator ground fault protection that was added in 2008. (Schweitzer SEL 300G multi-function relay and AREVA MML G01 test plugs.)

The rear of the panels show the original GE and Brown Boveri Control relays, Agastat timers and transducers.

Asset 8144 Unit 2 Main Controls

The original Unit 2 main controls were console mounted and utilized, typically GE SBM type switches, incandescent indications, analog instruments and Panalarm annunciation. Modifications have been made to adapt the generator, turbine and boiler controls to the Distributed Control System (DCS) and to replace some of the original controls, indications and annunciation. In addition, a newly commissioned auto-synchronizing system has been added for automatically synchronizing Unit 2 to the Island Grid via the GE Speedtronic Mark V turbine control system. This allows the operator to select the U2 breaker and activate the Mark V synch. control, which incorporates a 25C synch. check function to permit placement of U2 on the grid.

G2, MW, Amps, MVA's, kV, Field Volts, Speed Load Position, Load Limit position and Balance, are shown on the original analog instruments above the console, and are also indicated on the screens via the DCS.

Screens and keyboards are provided to include control, indications, and annunciation of unit functions.

Original controls, located in the console desk include the following. Circulating pumps, cooling water pumps and valves, thermo probe, AC and DC oil pumps, extraction and hydraulic pumps, Vacuum pumps, speed load and load limit, AVR set-point and selection, Unit 2 trip and raise/lower volts and Unit 2 Turbine Trip pushbutton.

The original manually operated switches and indications remain for synchronizing and operation of breakers B2B11 and B2L42. See auto synch modifications above.

Original common analog instruments, for Unit 1 and Unit 2, (Stage 1), indicate incoming and running volts, incoming and running frequencies, and synchronizing.

Unit 2 relaying and transducers are situated in the Unit 2 logic cubicles behind unit 2 control room. Relays are Struthers & Dunne with Agastat timers.

Asset 8153 Unit 2 Generator Bus-Duct and Connections

The generator bus-duct is a 3 phase, Isolated Phase Bus, complete with PT's and Neutral Cubicle, manufactured by ITE and installed in 1969.

Bus-duct connections were modified when T1 power transformer was up-graded.

Asset 8173 Unit 2 Battery Chargers

(Note: Units 1/2 129VDC Battery Chargers are covered under asset 6728).

Unit 2 258VDC Battery Charger was manufactured by CIGENTEC Inc. and installed in 2001. Charger 1 is a type C3-250-200PAF3BHRGCUOD3S2X9, 600V Input, 258VDC Output, with a 200A rated maximum charger output.

Reference Holyrood Plant Charger Database. Last equipment check 04 Feb 2010.

Other information:

Unit 2 258VDC Panel was manufactured by Westinghouse, installed in 1969, and is a type CDP, complete with Westinghouse breakers.

Asset 8174 Unit 2 UPS2 Inverter

Inverter UPS2 was manufactured by Eaton Powerware, Series 9315 and installed in 1998. Battery manufactured by C&D Technologies, Inc. (UPS Dynasty batteries), 600V input (transformer 600V:480V into Inverter), 120/208V output, 30kVA rated power, 93Ah @ 20 hour rate to 1.75V per cell @ 77 °F (25 °C).

Other Information: 120/208V, 3 phase Distribution Panel-boards fed from UPS2 Inverter, via Distribution Splitter are as follows:

Unit 2 UPS Panel No.2 at Col L10, El 24'-2", fed via 125A fused disconnect, Siemens, Type NLAB, 3 phase, 4W, 225A, 42 circuit, 100A main breaker, branch breakers type BQ, and was installed in 1998.

Unit 2 WDPF Panel, DP-2 relay room, fed via 125A fused disconnect, Siemens, Type NLAB, 3 phase, 4W, 225A, 42 circuit, 100A main breaker, branch breakers type BQ, and was installed in 1998.

Asset 8186 #2 Battery Banks

Unit 2, 129VDC Battery Bank, manufactured by C&D Technologies Inc. and installed July, 2006. Battery Bank is a Model KCR 11 and is Flooded Lead-calcium.

Reference Holyrood Plant Battery Bank Database for details. Replacement date 2031. Last equipment maintenance check was 04 Feb.2010.

Unit 2, 258VDC Battery Bank. Manufacturer: C&D Technologies Inc. and installed June 1998. Battery Bank is a Model KCR 11 and is Flooded Lead-calcium.

Reference Holyrood Plant Battery Bank Database for details. Replacement date 2023. Last equipment maintenance check was 04 Feb. 2010.

Asset 271478 Unit 2 Switchgear 4160V/600V

Unit Board UB2 (4160V) was manufactured by ITE and installed in 1968. The 4160V switchgear, utilizes original draw-out power breakers, Type 5HK, 1200A and 2000A. All protection, synch, and control relays are original CGE electro-mechanical. Schweitzer 701, Motor Protection Relays have been added to some feeders. All other loads utilize original P&B Golds' relays.

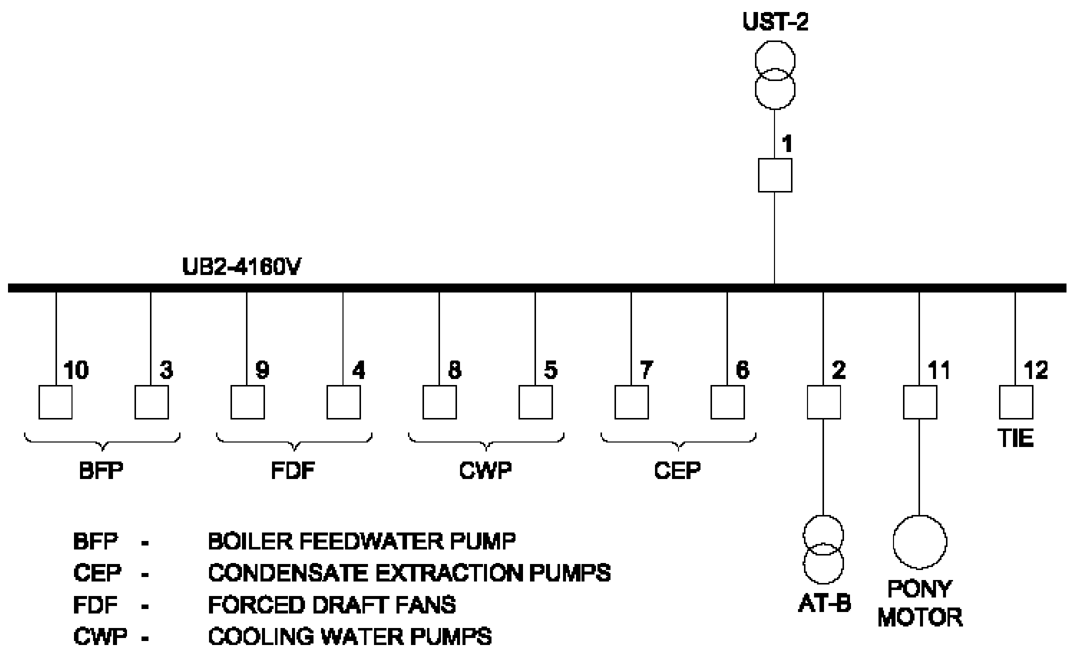

FIGURE 9-5 UB2 SWITCHGEAR

Asset 8162 Power Centre "B" UAB2, (600V), manufactured by CGE and installed in 1968.

The switchboard utilizes CGE AK-50 Incoming / Tie Breakers, and CGE AK-25 Feeder breakers.

The Unit Aux. Transformer AT-B is a Delta, type EV1. 1500kVA, 4160V:600/347V, AN, complete with primary tap-changer, +2@2.5%, -2@2.55, and was installed in 2000. The original transformer faulted.

Asset 271479 Unit 2 Turbine Supervisory System

The Turbine Supervisory System was manufactured by Bently Nevada and installed in 1990. It is a type 3300 System, complete with TDXnet Transient Data Interface and Delta Manager.

Functionality of the Bently Nevada system has been partially transferred to the GE Speedtronic Mark V Turbine Governor System. There is a link to the DCS. Data acquisition is still part of the Bently Nevada, and is transferred via a DDX link to the instrument shop. Machine protection is provided by the Mark V using information from the Bently Nevada, and is part of the Unit 2 mechanical protection.

The system is operating well, with numerous spares available at the plant, and some "boards" that might be repaired to possibly extend the system life indefinitely.

As of July 01, 2009, GE commenced the transition of the 3300 System from a Phase 2 status (Mature product) to a Phase 3 status (Spares only). This means that the product is no longer available for new installations, and that no new customer modifications are available. During Phase 3, new and some existing spares are available, as is repair and support. However, GE are suggesting that Phase 3 status will continue for approximately 12 months, i.e. until July, 2010, at which time they will move to Phase 4, (No Spares, Limited Support). Therefore, as of July, 2010 the system will progress at a Phase 4 status toward Phase 5 (Obsolescence), which will come into being at some future indeterminate time.

Asset 299451 Unit 2, DCS

The DCS, manufactured by Foxboro, is an Invensys system and was installed in 2004.

The Westinghouse panels housing the DCS were installed in the late 1990's, and new cabling was installed at that time. Original system was hard-wired, but later updated to a Westinghouse system. Westinghouse could not support the system which was then updated to Foxboro in 2004. The process CPU → ZCP is set-up in the original enclosures, (Westinghouse Migration Cards). All I/O is tied-in to these for analog and digital functions.

The following system and programs being used are:

- IA series – Version 8.4.2;
- IACC, Version 2.3.1 (Configuration Program); and
- FoxView Version 10.2. Sept. 30, 2008 (Graphics Program).

Reference Foxboro Drawing D545390-SA-001 for system configuration.

9.1.3.2 History

Manufactured/Delivered	1970
In-Service Date	Apr 1971
Replaced (DCS)	2002-2003
Generation Base Load End Date	Dec 2015
Generation Peak/Emerg Gen End Date	Dec 2020
Synchronous Condensing Start Date	Jan 2015
Synchronous Condensing End Date	Dec 2041
Next Major Overhaul/Inspection	2014

The thousands of hours associated with the analyses, and the number of starts per year are:

	Generation (Gen)	**Synchronous Condensing (SC)**
Hours Actual - Ops to Dec 2009	158	0
Hours - Ops to Gen End Date Dec 2015	188	1.5
Hours - Ops to Gen End Date Dec 2020	212	25
Hours – Ops to SC End Date Dec 2040	212	120
Starts Actual - Ops to Dec 2009	442	0
Starts - Ops to Gen End Date Dec 2015	554	5
Starts - Ops to Gen End Date Dec 2020	614	30
Starts – Ops to SC End Date Dec 2040	674	130

9.1.3.3 Inspection and Repair History

Inspections and refurbishments are done on an ongoing basis and identified in Section 9.1.3.1 Description and in 9.1.3.4 Condition Assessment.

9.1.3.4 Condition Assessment

Where a system is fully or partially required for synchronous condensing or there is uncertainty, it is included here. The basic DCS, protections, alarms associated with generators and auxiliaries are in good shape, but will over the next fifteen years need to be re-examined approximately on a 5 year frequency. The areas of most concern are the exciter controls and protection and motor controls – which have in fact been identified by the plant as an area in need of upgrade in the very short term. Some auxiliary systems such as hydrogen monitoring and generator temperature monitoring need replacement or refurbishing. The condition assessment for the various systems is presented in the following table.

TABLE 9-15 CONDITION ASSESSMENT – UNIT 2 ELECTRICAL AND CONTROL SYSTEMS ASSOCIATED WITH GENERATORS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset Level 2	Asset Level 3	Description	Detail	Condition Summary ID#	Append #	Condition	EPRI Identifier	Original Life (Base Load) Ops Hrs (Yrs)	Current Expected Minimum Remaining Life Years (Subject to Test)	End of Life (EOL) Required	Next Regular Inspection	Next Planned Overhaul or Major Inspection	Capability to Reach Next Overhaul	Capability to Reach EOL	In Service
1296	7635	8152	0	0	0	2	#2 ELECTRICAL & CONTROLS SYS	ELECTRICAL & CONTROLS SYS	ELECTRICAL & CONTROLS SYS	N/A	155	6										
1296	7635	8152	8138	0	0	2	#2 ELECTRICAL & CONTROLS SYS	RELAY RM PROTECT & CONTROL	RELAY RM PROTECT & CONTROL	N/A	156	6	Generator, Transformer and Auxiliary Protection and Metering Panels tests in 2006 were satisfactory. Some ingress of dust and foreign material. Testing is on a 6 year cycle (2012, 2018, 2024, etc.)	10	(30)	10	2041			No	No	1971
1296	7635	8152	271478	0	0	2	#2 ELECTRICAL & CONTROLS SYS	SWITCHGEAR 4160 & 600 VOLT	SWITCHGEAR 4160 & 600 VOLT	N/A	157	6	Breaker overhauls were been carried out in 2006 and 2007, except UB2-2 in 1996 (See Appendix). All 4160V switchgear is applied within ratings. Past normal life - extended by overhauls/maintenance.	10	(25)	5	2041			No	No	1971
1296	7635	8152	8144	0	0	2	#2 ELECTRICAL & CONTROLS SYS	MAIN CONTROLS	MAIN CONTROLS	N/A	158	6	There are age and spares problems with the relaying system.	4	(30)	10	2041			Yes	No	1971
1296	7635	8152	299451	0	0	2	#2 ELECTRICAL & CONTROLS SYS	DCS	DCS	N/A	159	6	Installed in 2004 - state of the art.	3a	(20)	10+	2041			Yes	No	2004
1296	7635	8152	8153	0	0	2	#2 ELECTRICAL & CONTROLS SYS	GEN. BUS DUCTS & CONN'S	GEN. BUS DUCTS & CONN'S	N/A	160	6	A partial maintenance inspection in May 2009 using a 5kV Meggar indicated good insulation test readings. No testing was indicated of Section 1 (A - toward generator and B - toward main transformer).	4	200000 (30)	(10)	2041			Yes	No	1969
1296	7635	8152	8156	0	0	2	#2 ELECTRICAL & CONTROLS SYS	UNIT SERVICE POWER SYSTEM	UNIT SERVICE POWER SYSTEM	N/A	162	6	See details below.	3a	(25)	10	2041			No	No	1971
1296	7635	8152	8156	8157	0	2	#2 ELECTRICAL & CONTROLS SYS	UNIT SERVICE POWER SYSTEM	UNIT BOARD UB-2	N/A	163	6	2006 tests were satisfactory. Some ingress of dust and foreign material.	3a	(30)	10	2041			No	No	1971
1296	7635	8152	8156	8162	0	2	#2 ELECTRICAL & CONTROLS SYS	UNIT SERVICE POWER SYSTEM	POWER CENTRE B	N/A	167	6	Last PM performed between 1992 and 1997 when breakers sent to external company for maintenance and protection relay replacement. All 600V switchgear is applied within their ratings.	3a	(25)	(10)	2041			No	No	1971
1296	7635	8152	8156	8168	0	2	#2 ELECTRICAL & CONTROLS SYS	UNIT SERVICE POWER SYSTEM	TURBINE & BOILER AREA MCC B1	N/A	168	6	MCC's C1, C2, C3, E1 (GE) and GPB34, SDB34 (Siemens) available fault currents exceed the rating of the short circuit protection devices within the individual wrappers.	4	(25)	3	2041			No	No	1971
1296	7635	8152	8173	99032478	0	2	#2 ELECTRICAL & CONTROLS SYS	BATTERY CHARGERS	250 VOLT DC BATTERY CHARGER	N/A	169	6	Installed in 2001. Last equipment check 04 Feb 2010. Good condition.	3a	(20)	15	2041			No	No	2001
1296	7635	8152	8174	0	0	2	#2 ELECTRICAL & CONTROLS SYS	UPS 2, INVERTER	UPS 2, INVERTER	N/A	170	6	New in 1998. Batteries changed at 7 years and tested every 4 weeks. Maintenance performed 04 Feb 2010.	10	(25)	10	2041			No	No	1998
1296	7635	8152	8186	0	0	2	#2 ELECTRICAL & CONTROLS SYS	BATTERY BANKS	BATTERY BANKS	N/A	171	6	Installed 2006. Replacement date 2031. Last equipment maintenance check was 04 Feb 2010.	3a	(25)	20	2041			Yes	No	2006
1296	7635	8152	8186	99032477	0	2	#2 ELECTRICAL & CONTROLS SYS	BATTERY BANKS	250 VOLT BATTERY BANK	N/A	172	6	Installed 1998. Replacement date 2023. Last equipment maintenance check was 04 Feb 2010.	3a	(25)	15	2041			No	No	1998
1296	7635	8152	8186	99032479	0	2	#2 ELECTRICAL & CONTROLS SYS	BATTERY BANKS	250 VOLT DC BATTERY CHARGER	N/A	173	6	New in 2001.	3a	(25)	15	2041			No	No	2001
1296	7635	8152	271475	0	0	2	#2 ELECTRICAL & CONTROLS SYS	CABLE RACEWAYS	CABLE RACEWAYS	N/A	174	6	Normal inspections and PM scheduled every 10 years - has not been done since 1995. Some contamination of trays in the boiler areas due to asbestos and heavy metal-dust. Some cables, power, and control are "thrown" into trays that have been convenient in the routings associated with the new installations.	3a	(50)	(30)	2041	1995		No	No	1971
1296	7635	8152	271476	0	0	2	#2 ELECTRICAL & CONTROLS SYS	CONTROL CABLES	CONTROL CABLES	N/A	175	6	Original equipment. No recent testing.	4	(50)	(10)	2041			No	No	1971
1296	7635	8152	271477	0	0	2	#2 ELECTRICAL & CONTROLS SYS	POWER CABLES	POWER CABLES	N/A	176	6	Original equipment. No recent testing.	4	(50)	(10)	2041			No	No	1971

Notes:

1. A "(bracketed)" value in the "Current Expected Remaining Life" column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation, including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as "(X/Y)" has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

2. The "Next Regular Inspection" column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The "Next Planned Overhaul or Major Inspection" column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a "Desired Life" stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or not known by AMEC.

9.1.3.5 Actions – Unit 2 Electrical and Control Systems Associated with Generators

Where a system is fully or partially required for synchronous condensing, it is included here. Based on the condition assessment, the following actions are recommended for the electrical and control systems.

TABLE 9-16 RECOMMENDED ACTIONS – UNIT 2 ELECTRICAL AND CONTROL SYSTEMS ASSOCIATED WITH GENERATORS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Unit	Asset 2/3	Asset 3/4	Description	Detail	Action #	App #	Action	Year	Priority
1296	7635	8152	8138	0	2	#2 ELECTRICAL & CONTROLS SYS	RELAY RM PROTECT & CONTROL	RELAY RM PROTECT & CONTROL	N/A	212	6	Test Generator G1, Transformer T1 and Auxiliaries P&C Panels - next tests planned for 2011, 2017, 2023, etc.	2011	1
1296	7635	8152	8138	0	2	#2 ELECTRICAL & CONTROLS SYS	RELAY RM PROTECT & CONTROL	RELAY RM PROTECT & CONTROL	N/A	213	6	Test Station Service Transformers UT1 and UT2 Protection Panels - next tests planned for 2012, 2018, 2024, etc.	2012	1
1296	7635	8152	8138	0	2	#2 ELECTRICAL & CONTROLS SYS	RELAY RM PROTECT & CONTROL	RELAY RM PROTECT & CONTROL	N/A	214	6	Conduct a modernization study - refurbishing the old GE electro-magnetic relays versus multi-function relaying for periods to 2015 to 2020 then to 2041. Extend scope of existing Schweitzer SEL 300G from present ground fault monitoring to include all unit protection. Assess similar multi-function relay for back-up protection and consider for control, indication and annunciation functions an ABB Combiflex system.	2011	1
1296	7635	8152	271478	0	2	#2 ELECTRICAL & CONTROLS SYS	SWITCHGEAR 4160 & 600 VOLT	SWITCHGEAR 4160 & 600 VOLT	Switchgear 4160V/600V	215	6	Include this Switchgear 4160V/600V relaying in UB2 modernization study (5.3.2.15 IV) for the protection relays. Consider that the remaining P&B Golds relays remain and not be replaced by Schweitzer 701 MPR's. As of 2015 the breakers utilizing these will become standby and as of 2020 will become spare.	2011	2
1296	7635	8152	271478	0	2	#2 ELECTRICAL & CONTROLS SYS	SWITCHGEAR 4160 & 600 VOLT	SWITCHGEAR 4160 & 600 VOLT	Switchgear 4160V/600V	216	6	Overhaul all 4160V switchgear breakers. With the availability of spare breaker elements, consider a program to overhaul breakers 3,4,5,6,7,8,9,10, off site if necessary. With essentially no interruption to plant requirements recognizing that these will be in standby mode from 2015-2020 and as of 2020 will become "spare" but in good condition.	2012	2
1296	7635	8152	271478	0	2	#2 ELECTRICAL & CONTROLS SYS	SWITCHGEAR 4160 & 600 VOLT	SWITCHGEAR 4160 & 600 VOLT	Switchgear 4160V/600V	217	6	During the complete overhaul, replace existing breakers 1, 2 and 12 with Eaton Electrical VR-Series breakers for a life expectancy to at least 2041. Spare cubicle (UB2-12) can be used for the new U2 Synchronous Condenser Start Pony Motor breaker 12 using a new Eaton Electrical VR-Series type direct replacement for ITE, 4160V, Type 5HK. Consideration should be given to the Eaton Electrical Remote racking device (RPR2), which allows remote racking of a breaker from up to 50 ft away, and is programmable for other types of breaker that might be used. One RPR2 would service U1 and U2 needs.	2014	1
1296	7635	8152	8144	0	2	#2 ELECTRICAL & CONTROLS SYS	MAIN CONTROLS	MAIN CONTROLS	Main Controls	218	6	Assess removing existing Main Controls control relaying and transducers, re-direct field cabling to the DCS and re-configure the software.	2011	2
1296	7635	8152	299451	0	2	#2 ELECTRICAL & CONTROLS SYS	DISTRIBUTED CONTROL SYSTEM (DCS)	DCS	DCS	219	6	Maintain DCS system current through existing Foxboro replacement service agreement.	2014	1
1296	7635	8152	8153	0	2	#2 ELECTRICAL & CONTROLS SYS	GEN. BUS DUCTS & CONN'S	GEN. BUS DUCTS & CONN'S	Generator Bus-Duct and Connections	220	6	Conduct generator bus-duct inspection tests using Holyrood Bus-Duct PM Inspection sheet extended to also record the low resistance tests and comments on the condition of sectional gaskets, sectional grounding straps and condition of all grounding points. Tests are as follows: 1. Low Resistance Test : Measure the resistance of bolted connections using a low-resistance ohmmeter (Ductor). Compare resistance readings between similar bolted connections. There must not be any difference greater than 50% between resistance readings. Check the resistance values are below the manufacturer's recommended maximum value. 2. Insulation Resistance Test: Measure the phase-to-phase and phase-to-ground insulation resistance, which must be at least 100Mohm per 1000 ft. of bus-duct.	2011	1
1296	7635	8152	8155	0	2	#2 ELECTRICAL & CONTROLS SYS	GEN. TRANSFORMER & AUXS	GEN. TRANSFORMER & AUXS	N/A	221	6	No recommended actions.		
1296	7635	8152	8156	0	2	#2 ELECTRICAL & CONTROLS SYS	UNIT SERVICE POWER SYSTEM	UNIT SERVICE POWER SYSTEM	N/A	222	6	No recommended actions.		
1296	7635	8152	8156	8157	2	#2 ELECTRICAL & CONTROLS SYS	UNIT SERVICE POWER SYSTEM	UNIT BOARD UB-2	N/A	223	6	No recommended actions.		
1296	7635	8152	8156	8162	2	#2 ELECTRICAL & CONTROLS SYS	UNIT SERVICE POWER SYSTEM	POWER CENTRE B	Power Centre "B" UAB2, (600V),	224	6	Change all Power Centre "B" UAB2, (600V) protection setting to improve arc-flash ratings, unless already completed, including: 1. Protection settings adjustment on breaker B1, secondary of transformer AT-B 2. Replacement of trip unit on breaker B43, Lighting Transformer LT-B feeder.	2011	1
1296	7635	8152	8156	8162	2	#2 ELECTRICAL & CONTROLS SYS	UNIT SERVICE POWER SYSTEM	POWER CENTRE B	Power Centre "B" UAB2, (600V),	225	6	Inspect and test transformer AT-B and the individual AK-50 / AK-25 air circuit breakers, and check the bussing - turns ratio, power and dissipation factor, winding resistance, movement of coils, core grounds, taps and general condition and cleanliness. If the plant three year thermal scan program has not included this equipment then bus-bar bolts should be checked and retorqued.	2011	1

Table 9-16 Cont'd

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Unit	Asset 2/3	Asset 3/4	Description	Detail	Action #	App #	Action	Year	Priority
1296	7635	8152	8156	8162	2	#2 ELECTRICAL & CONTROLS SYS	UNIT SERVICE POWER SYSTEM	POWER CENTRE B	Power Centre "B" UAB2, (600V),	226	6	Overhaul to an "as new condition" or replace the switchgear, including cubicles and breaker elements, extending the life expectancy of the existing switchgear for a further 15-20 years. Consider the availability of spare breaker elements to allow a program to be set up to overhaul each breaker off site with essentially no interruption to plant requirements.	2012	1
1296	7635	8152	8156	8168	2	#2 ELECTRICAL & CONTROLS SYS	UNIT SERVICE POWER SYSTEM	TURBINE & BOILER AREA MCC B1	N/A	227	6	Replace of refurbish as required given fault current exceedances.	2012	1
1296	7635	8152	8173	0	2	#2 ELECTRICAL & CONTROLS SYS	BATTERY CHARGERS	BATTERY CHARGERS	N/A	230	6	Continue planned maintenance on newer units.	2011	2
1296	7635	8152	8173	99032476	2	#2 ELECTRICAL & CONTROLS SYS	BATTERY CHARGERS	250 VOLT DC BATTERY BANK	N/A	232	6	No recommended actions.		
1296	7635	8152	8173	99032478	2	#2 ELECTRICAL & CONTROLS SYS	BATTERY CHARGERS	250 VOLT DC BATTERY CHARGER	Battery Chargers	233	6	Replace Unit 2 Battery Chargers 258VDC Panel and breakers.	2012	1
1296	7635	8152	8174	0	2	#2 ELECTRICAL & CONTROLS SYS	UPS 2, INVERTER	UPS 2, INVERTER	Inverter UPS2	234	6	Overhaul/upgrade unit to extend the life expectancy to at least 2020	2012	1
1296	7635	8152	8174	0	2	#2 ELECTRICAL & CONTROLS SYS	UPS 2, INVERTER	UPS 2, INVERTER	Inverter UPS2	235	6	Optimize in conjunction with UPS1, UPS3 and UPS4 the possible replacement of the four units with two parallel units for requirement for inverters from 2020 to 2041.	2011	2
1296	7635	8152	8186	0	2	#2 ELECTRICAL & CONTROLS SYS	BATTERY BANKS	BATTERY BANKS	Battery Banks	236	6	No action is required.		
1296	7635	8152	8186	99032477	2	#2 ELECTRICAL & CONTROLS SYS	BATTERY BANKS	250 VOLT BATTERY BANK	N/A	237	6	No action is required.		
1296	7635	8152	8186	99032479	2	#2 ELECTRICAL & CONTROLS SYS	BATTERY BANKS	250 VOLT DC BATTERY CHARGER	N/A	238	6	No action is required.		
1296	7635	8152	271475	0	2	#2 ELECTRICAL & CONTROLS SYS	CABLE RACEWAYS	CABLE RACEWAYS	N/A	239	6	Clean raceways, trays and cables to be tested by a crew of specialized hazardous area cleaners before any inspections or tests are carried out.	2011	3
1296	7635	8152	271476	0	2	#2 ELECTRICAL & CONTROLS SYS	CONTROL CABLES	CONTROL CABLES	N/A	240	6	Test selected control cables selected based on how the distribution will be affected post SC conversion, especially if the cables are required to be re-run. Low Resistance Test: Measure the resistance of bolted connections using a low-resistance ohmmeter (Ductor). Compare resistance readings between similar bolted connections. There must not be any difference greater than 50% between resistance readings. Check the resistance values are below the manufacturer's recommended maximum value.	2011	3
1296	7635	8152	271477	0	2	#2 ELECTRICAL & CONTROLS SYS	POWER CABLES	POWER CABLES	N/A	241	6	Test selected power cables - 4160V, 600V cables selected based on how the distribution will be affected post SC conversion, especially if the cables are required to be re-run. Low Resistance Test: Measure the resistance of bolted connections using a low-resistance ohmmeter (Ductor). Compare resistance readings between similar bolted connections. There must not be any difference greater than 50% between resistance readings. Check the resistance values are below the manufacturer's recommended maximum value. Insulation Resistance Test: Apply a test voltage of 5kV for cable used for 4160V, 1000V for cable rated at 600V, and 500V for cable rated at 300V. Record phase-to-phase and phase-to-ground insulation resistance tests, which must be at least 100Mohm per 1000 ft. of cable.	2011	3

9.1.3.6 Risk Assessment

Where a system is fully or partially required for synchronous condensing, it is included here. Table 9-17 below illustrates the risk assessment for the Unit 2 electrical and control systems associated with generators, both from a technological perspective and a safety perspective using the models presented in Section 3.

TABLE 9-17 RISK ASSESSMENT UNIT 2 ELECTRICAL AND CONTROL SYSTEMS ASSOCIATED WITH GENERATORS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Component	Risk Assess #	Appendix #	Major Issues	Remaining Life Years	Remaining Life Comments	TECHNO-ECO RISK ASSESSMENT MODEL			SAFETY RISK ASSESSMENT MODEL			Possible Failure Event	Mitigation
														(Insufficient Info - Inspection Required Within (x) Years)		Likeli-hood	Conse-quence	Risk Level	Likeli-hood	Conse-quence	Safety Risk		
1296	7635	8152	8138	0	0	2	#2 ELECTRICAL & CONTROLS SYS	RELAY RM PROTECT & CONTROL	RELAY RM PROTECT & CONTROL	N/A	189	6	Electrical fault, mechanical fatigue, ops error.	10	None	2	C-D	Medium	2	C-D	Medium	Loss 1 unit generation, damage to unit or equipment.	Current inspection and maintain.
1296	7635	8152	271478	0	0	2	#2 ELECTRICAL & CONTROLS SYS	SWITCHGEAR 4160 & 600 VOLT	SWITCHGEAR 4160 & 600 VOLT	N/A	190	6	Electrical fault, mechanical fatigue, ops error.	5	None	3	B-C	Medium	3	B-C	Medium	Loss up to 1 unit generation. Damage to equipment.	Refurbish or replace.
1296	7635	8152	8144	0	0	2	#2 ELECTRICAL & CONTROLS SYS	MAIN CONTROLS	MAIN CONTROLS	N/A	191	6	Electrical fault, mechanical fatigue ops error.	10	None	1	C	Low	1	C	Low	Loss 1 unit generation. Damage to unit.	Current inspection and maintain.
1296	7635	8152	299451	0	0	2	#2 ELECTRICAL & CONTROLS SYS	DISTRIBUTED CONTROL SYSTEM (DCS)	DCS	N/A	192	6	Electrical fault, ops error.	10+	None	1	C	Low	1	C	Low	Loss 1 unit generation. Damage to unit.	Maintain.
1296	7635	8152	8153	0	0	2	#2 ELECTRICAL & CONTROLS SYS	GEN. BUS DUCTS & CONN'S	GEN. BUS DUCTS & CONN'S	N/A	193	6	Electrical fault.	(10)	None	3	C-D	Medium/ High	3	C-D	High	Loss 1 unit generation. Damage to unit.	Current inspection and maintain.
1296	7635	8152	8155	0	0	2	#2 ELECTRICAL & CONTROLS SYS	GEN. TRANSFORMER & AUX'S	GEN. TRANSFORMER & AUX'S	N/A	194		Regulatory PCB.	3	2013 PCB Reg likely.	3	C	Medium	2	B	Low	Oil spill/PCB contamination.	Replace per regulations when required.
1296	7635	8152	8156	0	0	2	#2 ELECTRICAL & CONTROLS SYS	UNIT SERVICE POWER SYSTEM	UNIT SERVICE POWER SYSTEM	N/A	195		Electrical fault, mechanical fatigue, controls fault, ops error.	20	None	1	C	Medium	2	B	Low	Loss 1 unit generation. Damage to unit.	Inspect and test per current maintenance program.
1296	7635	8152	8156	8157	0	2	#2 ELECTRICAL & CONTROLS SYS	UNIT SERVICE POWER SYSTEM	UNIT BOARD UB-2	N/A	196		See details below.	5	None	3	B	Medium	3	B	Medium	Loss of part of 1 unit generation. Damage to equipment.	Refurbish or replace.
1296	7635	8152	8156	8162	0	2	#2 ELECTRICAL & CONTROLS SYS	UNIT SERVICE POWER SYSTEM	POWER CENTRE B	Power Centre (600V)	197	6	Electrical fault, mechanical fatigue, ops error.	5	None	3	B	Medium	3	B	Medium	Loss of part of 1 unit generation. Damage to equipment.	Refurbish or replace.
1296	7635	8152	8156	8168	0	2	#2 ELECTRICAL & CONTROLS SYS	UNIT SERVICE POWER SYSTEM	TURBINE & BOILER AREA MCC B1	N/A	198		Electrical fault, mechanical fatigue, ops error.	5	None	3	B	Medium	3	B	Medium	Loss of part of 1 unit generation. Damage to equipment.	Refurbish or replace.
1296	7635	8152	8173	99032476	0	2	#2 ELECTRICAL & CONTROLS SYS	BATTERY CHARGERS	250 VOLT DC BATTERY BANK	N/A	203		Electrical or chemical fault.	20	None	1	B	Low	1	A	Low	Loss 60% of 1 unit generation.	Current inspection and maintain.
1296	7635	8152	8173	99032478	0	2	#2 ELECTRICAL & CONTROLS SYS	BATTERY CHARGERS	250 VOLT DC BATTERY CHARGER	N/A	204		Electrical or chemical fault.	15	None	1	B	Low	1	A	Low	Loss 60% of 1 unit generation.	Current inspection and maintain.
1296	7635	8152	8174	0	0	2	#2 ELECTRICAL & CONTROLS SYS	UPS 2, INVERTER	UPS 2, INVERTER	N/A	205	6	Electrical fault.	10	None	3,1	B	Medium/L ow	1	B	Low	Unit damage on fail to safe shutdown.	Refurbish or replace.
1296	7635	8152	8186	0	0	2	#2 ELECTRICAL & CONTROLS SYS	BATTERY BANKS	BATTERY BANKS	N/A	206		Electrical or chemical fault.	20	None	1	B	Low	1	A	Low	Loss 60% of 1 unit generation.	Current inspection and maintain.
1296	7635	8152	8186	99032477	0	2	#2 ELECTRICAL & CONTROLS SYS	BATTERY BANKS	250 VOLT BATTERY BANK	N/A	207		Electrical or chemical fault.	15	None	1	B	Low	1	A	Low	Loss 60% of 1 unit generation.	Current inspection and maintain.
1296	7635	8152	8186	99032479	0	2	#2 ELECTRICAL & CONTROLS SYS	BATTERY BANKS	250 VOLT DC BATTERY CHARGER	N/A	208		Electrical or chemical fault.	15	None	1	B	Low	1	A	Low	Loss 60% of 1 unit generation.	Current inspection and maintain.
1296	7635	8152	271475	0	0	2	#2 ELECTRICAL & CONTROLS SYS	CABLE RACEWAYS	CABLE RACEWAYS	N/A	209		Electrical fault.	(30)	None	1	C	Low	1	B	Low	Loss up to 1 unit generation. Damage to equipment.	Clean and re-organize.
1296	7635	8152	271476	0	0	2	#2 ELECTRICAL & CONTROLS SYS	CONTROL CABLES	CONTROL CABLES	N/A	210	6	Electrical fault.	(10)	None	2	B-C	Low	2	B-C	Low	Loss of up to 1 unit generation. Equipment/unit damage.	Test indicative number.
1296	7635	8152	271477	0	0	2	#2 ELECTRICAL & CONTROLS SYS	POWER CABLES	POWER CABLES	N/A	211	6	Electrical fault.	(10)	None	2	B-C	Low	2	B-C	Low	Loss of up to 1 unit generation. Equipment/unit damage.	Test indicative number.

9.1.3.7 Life Cycle Curve and Remaining Life

Figures 9-6 and 9-7 below illustrate the life cycle curve for the Unit 2 electrical and control systems associated with generators. Several curves are required to represent the various elements. They have been broken into two parts – the electrical and control systems (MCC's, relays, breakers, TSI, DCS) and those primarily associated with batteries and chargers. The curves are plots of current and projected years in service on the y-axis versus calendar year on the x-axis. Age in-service due to either aging or obsolescence is more an issue than unit operating hours. Vertical lines represent bands of nominal years of in-service life for different in service dates. Horizontal lines represent the ranges of equipment life based on current and historical information and expert opinion. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view.

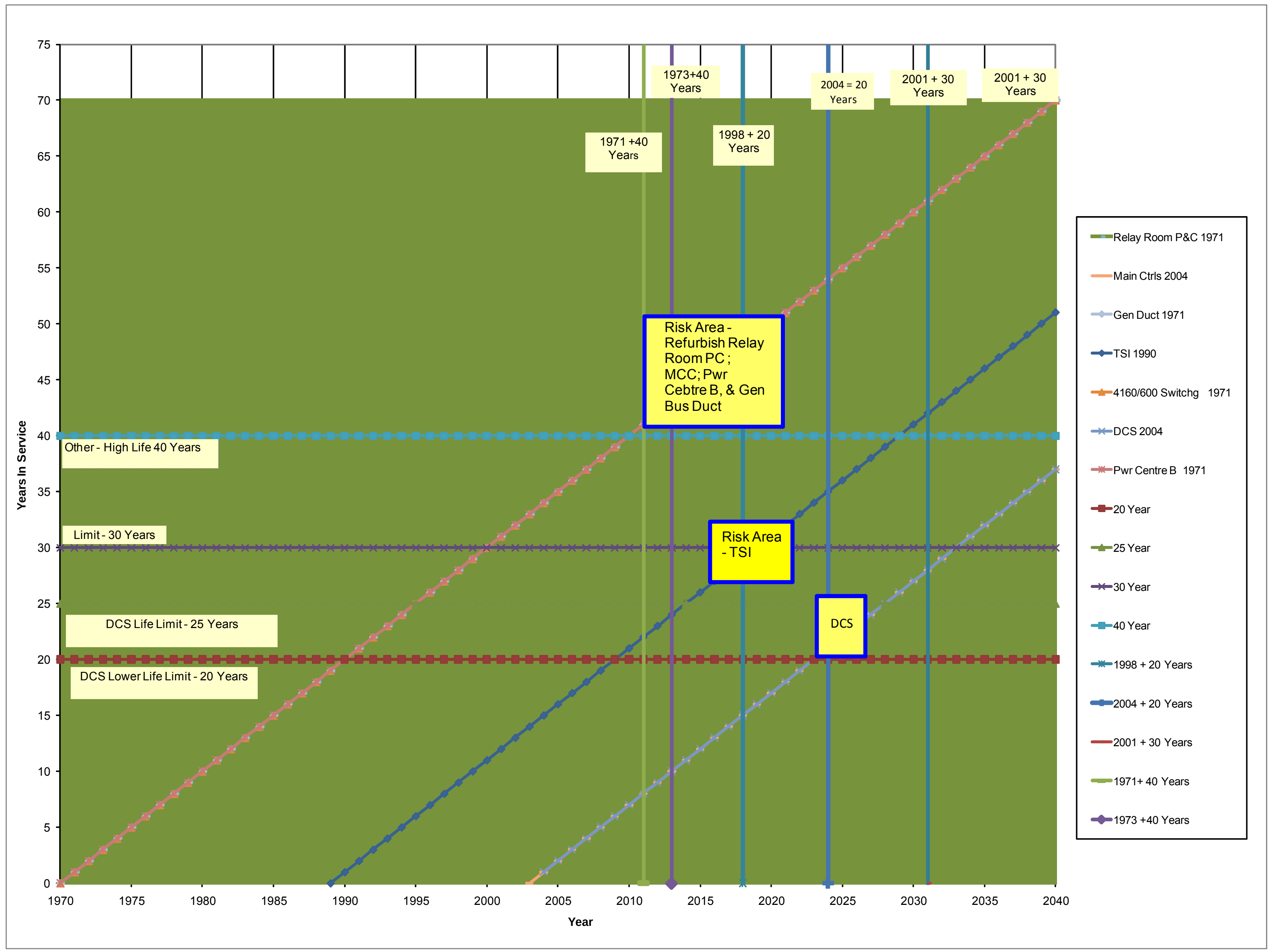

FIGURE 9-6 LIFE CYCLE CURVE – UNIT 2 ELECTRICAL AND CONTROL SYSTEMS ASSOCIATED WITH GENERATORS (MCC'S, RELAYS, BREAKERS, TSI, DCS)

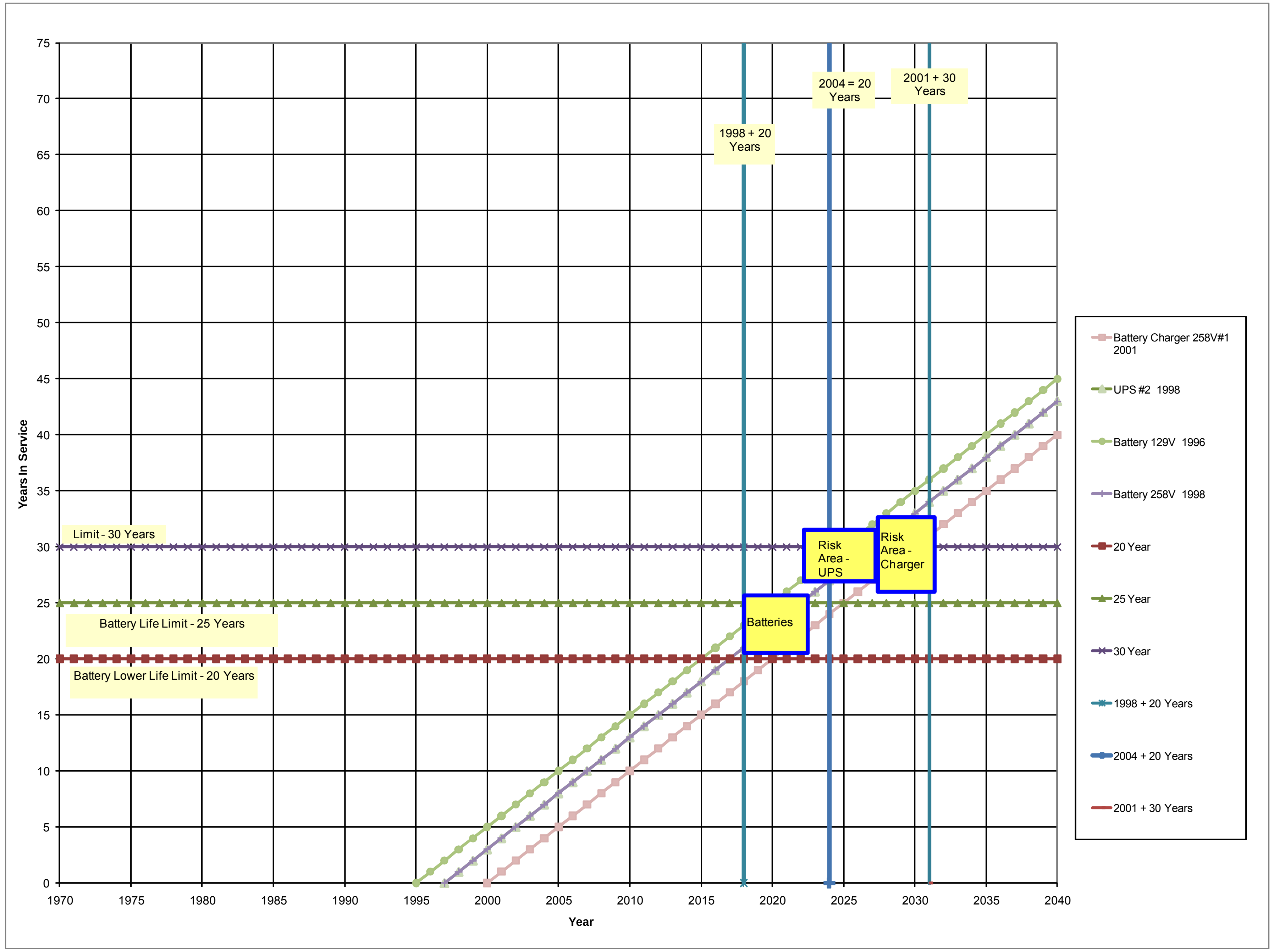

FIGURE 9-7 LIFE CYCLE CURVE – UNIT 2 ELECTRICAL AND CONTROL SYSTEMS ASSOCIATED WITH GENERATORS (BATTERIES AND CHARGERS)

The curves indicate that the remaining life (RL) of much of the equipment does not exceed the desired life (DL) for generation of 2020 and for synchronous condensing of 2041, without extensive refurbishment or replacement. This is well illustrated by the highlighted risk areas which highlights that many original MCC's and relays as well as the TSI are in need or replacement or extensive refurbishment in the very near term. The risk figures also illustrate that most of the rest of the equipment (DCS, batteries, and chargers) will require replacement or refurbishment in the 2020+ period.

9.1.3.8 Level 2 Inspections – Unit 2 Electrical and Control Systems Associated with Generators

Where a system is fully or partially required for synchronous condensing, it is included here. Recommended Level 2 analyses are identified in the Table 9-18.

TABLE 9-18 LEVEL 2 INSPECTIONS – UNIT 2 ELECTRICAL AND CONTROL SYSTEMS ASSOCIATED WITH GENERATORS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Sub System Comment	L2#	Appendix #	Level 2 Work	Year	Priority	Cost k$
1296	7635	8152	0	0	0	2	#2 ELECTRICAL & CONTROLS SYS	ELECTRICAL & CONTROLS SYS	ELECTRICAL & CONTROLS SYS	None	154	6	No Level 2 required.			
1296	7635	8152	8138	0	0	2	#2 ELECTRICAL & CONTROLS SYS	RELAY RM PROTECT & CONTROL	RELAY RM PROTECT & CONTROL	None	155	6	No Level 2 required.			
1296	7635	8152	271478	0	0	2	#2 ELECTRICAL & CONTROLS SYS	SWITCHGEAR 4160 & 600 VOLT	SWITCHGEAR 4160 & 600 VOLT	None	156	6	No Level 2 required.			
1296	7635	8152	8144	0	0	2	#2 ELECTRICAL & CONTROLS SYS	MAIN CONTROLS	MAIN CONTROLS	None	157	6	No Level 2 required.			
1296	7635	8152	299451	0	0	2	#2 ELECTRICAL & CONTROLS SYS	DCS	DCS	None	158	6	No Level 2 required.			
1296	7635	8152	8153	0	0	2	#2 ELECTRICAL & CONTROLS SYS	GEN. BUS DUCTS & CONN'S	GEN. BUS DUCTS & CONN'S	Generator Bus-Duct and Connections	159	6	Conduct complete generator bus-duct partial maintenance inspection and tests on the U1 bus-duct: - Low Resistance Test : Measure the resistance of bolted connections using a low-resistance ohmmeter (Ductor). Compare resistance readings between similar bolted connections. There must not be any difference greater than 50% between resistance readings. Check that resistance values are below the manufacturer's recommended maximum value. - Insulation Resistance Test: Measure the phase-to-phase and phase-to-ground insulation resistance, which must be at least 100Mohm per 1000 ft of bus-duct.	2011	1	$15
1296	7635	8152	8155	0	0	2	#2 ELECTRICAL & CONTROLS SYS	GEN. TRANSFORMER & AUXS	GEN. TRANSFORMER & AUXS	None	160	6	No Level 2 required.			
1296	7635	8152	8156	0	0	2	#2 ELECTRICAL & CONTROLS SYS	UNIT SERVICE POWER SYSTEM	UNIT SERVICE POWER SYSTEM	None	161	6	No Level 2 required.			
1296	7635	8152	8156	8157	0	2	#2 ELECTRICAL & CONTROLS SYS	UNIT SERVICE POWER SYSTEM	UNIT BOARD UB-2	None	162	6	No Level 2 required.			
1296	7635	8152	8156	8162	0	2	#2 ELECTRICAL & CONTROLS SYS	UNIT SERVICE POWER SYSTEM	POWER CENTRE B	Power Centre "B" UAB2, (600	163	6	Inspection and testing of transformer AT-B and the individual AK-50 / AK-25 air circuit breakers and check the bussing. If the plant three year thermal scan program has not included this equipment then bus-bar bolts should be checked and retorqued. Inspection and testing of the transformer should include turns ratio, power and dissipation factor, winding resistance, movement of coils, core grounds, taps and general condition and cleanliness.			
1296	7635	8152	8156	8168	0	2	#2 ELECTRICAL & CONTROLS SYS	UNIT SERVICE POWER SYSTEM	TURBINE & BOILER AREA MCC B1	None	164	6	No Level 2 required.			
1296	7635	8152	8173	0	0	2	#2 ELECTRICAL & CONTROLS SYS	BATTERY CHARGERS	BATTERY CHARGERS	None	165	6	No Level 2 required.			
1296	7635	8152	8173	99032476	0	2	#2 ELECTRICAL & CONTROLS SYS	BATTERY CHARGERS	250 VOLT DC BATTERY BANK	None	167	6	No Level 2 required.			
1296	7635	8152	8173	99032478	0	2	#2 ELECTRICAL & CONTROLS SYS	BATTERY CHARGERS	250 VOLT DC BATTERY CHARGER	None	168	6	No Level 2 required.			
1296	7635	8152	8174	0	0	2	#2 ELECTRICAL & CONTROLS SYS	UPS 2, INVERTER	UPS 2, INVERTER	None	169	6	No Level 2 required.			
1296	7635	8152	8186	0	0	2	#2 ELECTRICAL & CONTROLS SYS	BATTERY BANKS	BATTERY BANKS	None	170	6	No Level 2 required.			

Table 9-18 Cont'd

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Sub System Comment	L2#	Appendix #	Level 2 Work	Year	Priority	Cost k$
1296	7635	8152	8186	99032477	0	2	#2 ELECTRICAL & CONTROLS SYS	BATTERY BANKS	250 VOLT BATTERY BANK	None	171	6	No Level 2 required.			
1296	7635	8152	8186	99032479	0	2	#2 ELECTRICAL & CONTROLS SYS	BATTERY BANKS	250 VOLT DC BATTERY CHARGER	None	172	6	No Level 2 required.			
1296	7635	8152	271475	0	0	2	#2 ELECTRICAL & CONTROLS SYS	CABLE RACEWAYS	CABLE RACEWAYS	Units 1, 2, 3 Cable Raceways, Control Cables, Power Cables	173	6	No Level 2 required.		3	
1296	7635	8152	271476	0	0	2	#2 ELECTRICAL & CONTROLS SYS	CONTROL CABLES	CONTROL CABLES	Units 1, 2, 3 Cable Raceways, Control Cables, Power Cables	174	6	Inspection and test selected control cables (especially if the cables are required to be re-run to different equipment): - Low Resistance Test: Measure the resistance of bolted connections using a low-resistance ohmmeter (Ductor). Compare resistance readings between similar bolted connections. There must not be any difference greater than 50% between resistance readings. Check the resistance values are below the manufacturer's recommended maximum value.	2011	3	$7
1296	7635	8152	271477	0	0	2	#2 ELECTRICAL & CONTROLS SYS	POWER CABLES	POWER CABLES	Units 1, 2, 3 Cable Raceways, Control Cables, Power Cables	175	6	Inspection and test selected power (4160V, 600V) cables (especially if the cables are required to be re-run to different equipment): - Low Resistance Test: Measure the resistance of bolted connections using a low-resistance ohmmeter (Ductor). Compare resistance readings between similar bolted connections. Check the resistance values are below the manufacturer's recommended maximum value. - Insulation Resistance Test: Apply a test voltage of 5kV for cable used for 4160V, 1000V for cable rated at 600V, and 500V for cable rated at 300V. Record phase-to-phase and phase-to-ground insulation resistance tests, which must be at least 100Mohm per 1000 ft of cable.	2011	3	$10

9.1.3.9 Capital Projects

Where a system is fully or partially required for synchronous condensing, it is included here. The suggested typical capital enhancements include:

TABLE 9-19 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – UNIT 2 ELECTRICAL AND CONTROL SYSTEMS ASSOCIATED WITH GENERATORS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Detail	CAP#	Appendix #	Capital Item	Date	Priority
1296	7635	8152	0	0	0	2	#2 ELECTRICAL & CONTROLS SYS	ELECTRICAL & CONTROLS SYS	ELECTRICAL & CONTROLS SYS	N/A	148		No capital investment required.		
1296	7635	8152	8138	0	0	2	#2 ELECTRICAL & CONTROLS SYS	RELAY RM PROTECT & CONTROL	RELAY RM PROTECT & CONTROL	N/A	149	6	No capital investment required.		
1296	7635	8152	271478	0	0	2	#2 ELECTRICAL & CONTROLS SYS	SWITCHGEAR 4160 & 600 VOLT	SWITCHGEAR 4160 & 600 VOLT	N/A	150	6	Implement changes to this Switchgear 4160V/600V relaying in UB2 modernization study (5.3.2.15 IV) for the protection relays. Consider that the remaining P&B Golds relays remain and not be replaced by Schweitzer 701 MPR's. As of 2015 the breakers utilizing these will become standby and as of 2020 will become spare.	2013	1
1296	7635	8152	271478	0	0	2	#2 ELECTRICAL & CONTROLS SYS	SWITCHGEAR 4160 & 600 VOLT	SWITCHGEAR 4160 & 600 VOLT	N/A	151	6	Overhaul all 4160V switchgear breakers. Use spare breaker elements to overhaul breakers 3,4,5,6,7,8,9,10 off site if necessary. There will be little interruption to plant requirements, recognizing that these will be in standby mode from 2015-2020 and as of 2020 will become "spare" but in good condition.	2013	1
1296	7635	8152	271478	0	0	2	#2 ELECTRICAL & CONTROLS SYS	SWITCHGEAR 4160 & 600 VOLT	SWITCHGEAR 4160 & 600 VOLT	N/A	152	6	Replace existing breakers 1, 2 and 12 during the complete overhaul with Eaton Electrical VR-Series breakers for a life expectancy to at least 2041. Use spare cubicle (UB2-12) for the new U2 Synchronous Condenser Start Pony Motor breaker 12 using a new Eaton Electrical VR-Series type direct replacement for ITE, 4160V, Type 5HK. Consideration should be given to the Eaton Electrical Remote racking device (RPR2), which allows remote racking of a breaker from up to 50ft away, and is programmable for other types of breakers that might be used. One RPR2 would service U1 and U2 needs.	2013	1
1296	7635	8152	8144	0	0	2	#2 ELECTRICAL & CONTROLS SYS	MAIN CONTROLS	MAIN CONTROLS	N/A	153	6	No capital investment required.		
1296	7635	8152	299451	0	0	2	#2 ELECTRICAL & CONTROLS SYS	DCS	DCS	N/A	154	6	No capital investment required.		
1296	7635	8152	8153	0	0	2	#2 ELECTRICAL & CONTROLS SYS	GEN. BUS DUCTS & CONN'S	GEN. BUS DUCTS & CONN'S	N/A	155	6	None planned, but may result from tests		
1296	7635	8152	8155	0	0	2	#2 ELECTRICAL & CONTROLS SYS	GEN. TRANSFORMER & AUX'S	GEN. TRANSFORMER & AUX'S	N/A	156		No capital investment required.		
1296	7635	8152	8156	0	0	2	#2 ELECTRICAL & CONTROLS SYS	UNIT SERVICE POWER SYSTEM	UNIT SERVICE POWER SYSTEM	N/A	157	6	No capital investment required.		
1296	7635	8152	8156	8157	0	2	#2 ELECTRICAL & CONTROLS SYS	UNIT SERVICE POWER SYSTEM	UNIT BOARD UB-2	N/A	158	6	No capital investment required.		
1296	7635	8152	8156	8162	0	2	#2 ELECTRICAL & CONTROLS SYS	UNIT SERVICE POWER SYSTEM	POWER CENTRE B	N/A	159	6	Change all protection setting to improve arc-flash ratings, unless already completed, including: - Protection settings adjustment on breaker B1, secondary of transformer AT-B. - Replacement of trip unit on breaker B43, Lighting Transformer LT-B feeder.	2011	1

Table 9-19 Cont'd

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Detail	CAP#	Appendix #	Capital Item	Date	Priority
1296	7635	8152	8156	8162	0	2	#2 ELECTRICAL & CONTROLS SYS	UNIT SERVICE POWER SYSTEM	POWER CENTRE B	N/A	160	6	Conduct a complete overhaul to an "as new condition" or replacement of the switchgear, including cubicles and breaker elements, extending the life expectancy of the existing switchgear for a further 15-20 years. Consider the availability of spare breaker elements to allow a program can be set up to overhaul each breaker off site with essentially no interruption to plant requirements.	2013	1
1296	7635	8152	8156	8168	0	2	#2 ELECTRICAL & CONTROLS SYS	UNIT SERVICE POWER SYSTEM	TURBINE & BOILER AREA MCC B!	N/A	161	6	Replace as required per current inspection and overhaul findings.	2012	1
1296	7635	8152	8173	0	0	2	#2 ELECTRICAL & CONTROLS SYS	BATTERY CHARGERS	BATTERY CHARGERS	N/A	162	6	Replace Unit 2 Battery Chargers 258VDC Panel and breakers	2013	1
1296	7635	8152	8173	99032476	0	2	#2 ELECTRICAL & CONTROLS SYS	BATTERY CHARGERS	250 VOLT DC BATTERY BANK	N/A	164	6	No capital investment required.		
1296	7635	8152	8173	99032478	0	2	#2 ELECTRICAL & CONTROLS SYS	BATTERY CHARGERS	250 VOLT DC BATTERY CHARGER	N/A	167	6	No capital investment required.		
1296	7635	8152	8174	0	0	2	#2 ELECTRICAL & CONTROLS SYS	UPS 2, INVERTER	UPS 2, INVERTER	N/A	168	6	Overhaul/upgrade unit to extend the life expectancy to at least 2020.	2012	1
1296	7635	8152	8174	0	0	2	#2 ELECTRICAL & CONTROLS SYS	UPS 2, INVERTER	UPS 2, INVERTER	N/A	169	6	Implement optimization study in conjunction with UPS2, UPS3 and UPS4 replacement.	2012	2
1296	7635	8152	8186	0	0	2	#2 ELECTRICAL & CONTROLS SYS	BATTERY BANKS	BATTERY BANKS	N/A	170	6	No capital investment required.		
1296	7635	8152	8186	99032477	0	2	#2 ELECTRICAL & CONTROLS SYS	BATTERY BANKS	250 VOLT BATTERY BANK	N/A	171	6	No capital investment required.		
1296	7635	8152	8186	99032479	0	2	#2 ELECTRICAL & CONTROLS SYS	BATTERY BANKS	250 VOLT DC BATTERY CHARGER	N/A	172	6	No capital investment required.		
1296	7635	8152	271475	0	0	2	#2 ELECTRICAL & CONTROLS SYS	CABLE RACEWAYS	CABLE RACEWAYS	N/A	173	6	Install any new cable installations on new tray, and in accordance with the applicable Codes.	2011	1
1296	7635	8152	271476	0	0	2	#2 ELECTRICAL & CONTROLS SYS	CONTROL CABLES	CONTROL CABLES	N/A	174	6	Install any new cable installations on new tray, and in accordance with the applicable Codes.	2011	1
1296	7635	8152	271477	0	0	2	#2 ELECTRICAL & CONTROLS SYS	POWER CABLES	POWER CABLES	N/A	175	6	Install any new cable installations on new tray, and in accordance with the applicable Codes.	2011	1

9.1.4 Asset 271486 – Unit 2 Cooling Water Systems Associated with Generation

(Detailed Technical Assessment in Working Papers, Appendices 11, 8)

Unit #:	2
Asset Class #	BU 1296 - Assets Generations
SCI & System:	8093 #2 Unit Generation Services
Sub-Systems:	271486 #2 CW System
Components:	8097 #2 CW Travelling Screens East
	8098 #2 CW Travelling Screens West
	8106 #2 CW Pump East
	8107 #2 CW Pump West
	8095 #2 CW Intake
	8120 #2 CW Discharge to Outfall
	8132 #2 General Service Water
	7703 #2 Turbine Generator Cooling Water

9.1.4.1 Description

The items examined were limited to those required to achieve the 2041 synchronous condensing end date:

- The main pumphouses sea water intakes, traveling screens, and general service water system;
- Sea water heat exchanger system;
- Seawater discharge system; and
- Electrical and control requirements.

Circulating Water (CW) Pump & Screens Systems: Circulating water (CW) systems servicing Unit 2 consists of two 50% CW vertical turbine pumps driven by 4 kV motors and auxiliary systems. The pump drive motors are original. Two travelling screen systems are used to remove debris from the cooling water prior to entering the pumps. The primary function of the CW system is to provide condenser cooling water, but also cooling water for other closed loop systems. It is necessary that the CW system operate efficiently in order to maintain optimal plant thermal efficiency by minimizing steam turbine condenser backpressures.

Turbine Generator (TG) Auxiliary Cooling Water System: Sea water cooling is required for the TG auxiliary cooling water system required for synchronous condensing operation. Unit 3 is currently supplied by a sump pump and dedicated line from the Stage 2 pumphouse (Unit 4 CW pump pit), from the water take-off from the Stage 2 pumphouse cooling water pumps, and from an interconnection with the Units 1 and 2 cooling water system. Typically, when only Unit 3 is running as synchronous condenser, the smaller sump pump and dedicated line from the Stage 2 pumphouse is used.

For the purpose of long term synchronous condensing operation to 2041 for all three units, the intent is to supply seawater from a small, permanent pump arrangement similar to Unit 3 as shown in Section 8.1.4.1. It may come from one pumphouse or in the form of two separate, but interconnected systems.

FIGURE 9-8 DEDICATED SEAWATER COOLING WATER LINE FOR UNIT 3 SYNCHRONOUS CONDENSING GT AUXILIARY COOLING WATER

9.1.4.2 History

Manufactured/Delivered	1970
In-Service Date	Apr 1971
Generation Base Load End Date	Dec 2015
Generation Peak/Emerg Gen End Date	Dec 2020
Synchronous Condensing Start Date	Jan 2015
Synchronous Condensing End Date	Dec 2041
Last Major Overhaul/Inspection	Not identified
Next Major Overhaul/Inspection	Not Identified

The thousands of hours associated with the analyses, and the number of starts per year are:

	Generation (Gen)	**Synchronous Condensing (SC)**
Hours Actual - Ops to Dec 2009	158	0
Hours - Ops to Gen End Date Dec 2015	188	1.5
Hours - Ops to Gen End Date Dec 2020	212	25
Hours – Ops to SC End Date Dec 2040	212	120
Starts Actual - Ops to Dec 2009	442	0
Starts - Ops to Gen End Date Dec 2015	554	5
Starts - Ops to Gen End Date Dec 2020	614	30
Starts – Ops to SC End Date Dec 2040	674	130

9.1.4.3 Inspection and Repair History

CW Travelling Screens: Travelling screen internals have been replaced on Unit 2 in last 5 to 10 years. Interviews suggest that no recent issues have been experienced with this unit. Visual examination confirms that the Unit 2 screens generally appear to be in good shape.

The external casings have some corroded parts, but nothing that appears to impair current or short term performance.

CW Wash Water Pumps and Motors: An external inspection of the pumps and motors indicated that they have extensive corrosion but were running at the time of the visual inspection. They are considered to be a minor maintenance issue and not addressed as a part of this assessment.

CW Pumps: CW pumps on all units are performing fairly well. No reports were available on the condition of the pumps, but interviews suggest that regular maintenance has been ongoing and the units should be able to meet 2015 and 2020 timelines with continued maintenance. Major pump overhauls are scheduled on a twelve year cycle as indicated in Table 9-20 below.

TABLE 9-20 SCHEDULED MAJOR PUMP OVERHAULS

Annual Asset Maintenance																		
Pumps	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
1 CW Pump East			X												83,000.00			
1 CW Pump West											75,000.00							
2 CW Pump East	X				X												87,000.00	
2 CW Pump West												77,000.00						
3 CW Pump East		X									75,000.00							
3 CW Pump West						10,000.00												89,000.00

It is understood that a temporary CW pump is being used in the existing Unit 4 intake to supply smaller quantities of cooling water to Unit 3 for synchronous condensing duty. The system has been designed to supply all three units if and when converted. In addition, there are interconnections between Units 1 to 3 CW systems to allow them to provide back-up for this purpose if necessary.

CW Pump Motors: In accordance with the plant PM process, motors are tested electrically every year..

CW Pump Outlet Piping, Valves & Fittings: Outlet piping, valves and fittings from the CW pump discharge to the inlet of the 162 cm (64 inch) concrete piping that is installed underground to the Unit 2 condensers has generally experienced significant corrosion and some patching of the system has been done. It requires a Level 2 inspection and possibly a complete replacement.

Cooling Water System Intake & Discharge: The 91 cm (36 inch) and 162 cm (64 inch) CW intake and discharge concrete piping that is installed underground to the unit condensers has periodically been pumped, dewatered, and inspected by plant staff. No specific corrosion, spalling, cracks or fractures were identified and no patching of the system has been done. There have been no obvious issues with the systems, but no detailed engineering evaluations and NDE work has been undertaken.

PM inspections are planned going forward on a three year cycle as per the schedule below shown in Table 9-21.

TABLE 9-21 PM INSPECTIONS

Annual Asset Maintenance																	
CW Inspection		2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Unit 1													25,625.00			26,625.00	
Unit 2														25,625.00			26,625.00
Unit 3												25,000.00			25,625.00		

9.1.4.4 Condition Assessment

The condition assessment of the Unit 2 cooling water systems associated with generators is illustrated below in Table 9-22:

TABLE 9-22 CONDITION ASSESSMENT – UNIT 2 COOLING WATER SYSTEMS ASSOCIATED WITH GENERATORS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset Level 2	Asset Level 3	Description	Detail	Condition Summary ID#	Append #	Condition	EPRI Identifier	Original Life (Base Load) Ops Hrs (Yrs)	Current Expected Minimum Remaining Life Years (Subject to Test)	End of Life (EOL) Required	Next Regular Inspection	Next Planned Overhaul or Major Inspection	Capability to Reach Next Overhaul	Capability to Reach EOL	In Service
1296	7635	8093	7703	0	0	2	#2 UNIT GENERATION SERVICES	TURB/GEN COOLING SYSTEM	TURB/GEN COOLING SYSTEM	N/A	131	12	Piping, pumps, and heat exchangers appear in good condition. Heat exchangers are cleaned and checked for leaks annually, and are cathodically protected and a closed cooling system corrosion inhibitor used. No issues had been encountered with the heat exchangers. No inspection or maintenance data was available.	4	200000 (30)	10	2041	2011		No	No	1971
1296	7635	8093	7703	0	0	2	#2 UNIT GENERATION SERVICES	TURB/GEN COOLING SYSTEM	TURB/GEN COOLING SYSTEM	Sea water piping	132	11,15	Sea Water piping 18" lines and associated valving is original equipment for all units. No condition data but no significant issues identified. Piping and valves have external corrosion and pitting, but rate seems not to be rapid.	4	(30)	(10)	2041	2011		No	No	1971
1296	7635	8093	7703	9622	0	2	#2 UNIT GENERATION SERVICES	TURB/GEN COOLING SYSTEM	T/G COOLING PUMP SOUTH	N/A	133	11,15	Relatively new AC pumps and motors (no date available). No issue with them.	4	(30)	(10)	2041	2012		No	No	2000
1296	7635	8093	7703	9624	0	2	#2 UNIT GENERATION SERVICES	TURB/GEN COOLING SYSTEM	T/G COOLING PUMP NORTH	N/A	134	11,15	Relatively new AC pumps and motors (no date available). No issue with them.	4	(30)	(10)	2041	2012		No	No	2000
1296	7635	8093	7703	299550	0	2	#2 UNIT GENERATION SERVICES	TURB/GEN COOLING SYSTEM	CW TRAVELLING STRUCTURE	N/A	135	11,15	Internals in good condition after major upgrade within the last five to ten years. External casings and auxiliaries have some corrosion.	4	(20)	10	2041			No	No	2000
1296	7635	8093	7703	299551	0	2	#2 UNIT GENERATION SERVICES	TURB/GEN COOLING SYSTEM	CW TRAVELLING STRUCTURE	N/A	136	11,15	Internals in good condition after major upgrade within the last five to ten years. External casings and auxiliaries have some corrosion.	4	(20)	10	2041			No	No	2000
1296	7635	8093	8132	0	0	2	#2 UNIT GENERATION SERVICES	GENERAL SERVICE COOLING	GENERAL SERVICE COOLING	N/A	137	11,15	PVC piping can have lifetimes of up to 100 years. The current pipe is less than 20 years old. No difficulties identified or expected	4	(50)	10	2041			Yes	No	1990
1296	7635	8093	271486	0	0	2	#2 UNIT GENERATION SERVICES	CW SYSTEM	CW SYSTEM	N/A	147	11	Generally in good condition, however significant corrosion on major steel pipes, pumps, and valves.	4	200000 (30)	10+	2041			No	No	1971
1296	7635	8093	271486	8095	0	2	#2 UNIT GENERATION SERVICES	CW SYSTEM	CW INTAKE SYSTEM	Intake structure and foreay	148	11	No recent underwater inspections of intake structures or bay, but surface visual check looked good. There is no reason to expect any kind of aggressive attack.	4	(60)	(20)	2041		2011	Yes	Yes	2000
1296	7635	8093	271486	8120	0	2	#2 UNIT GENERATION SERVICES	CW SYSTEM	CW DISCHARGE TO OUTFALL	Pit, stoplogs and discharge	149	11	No recent underwater inspections of pit, stoplogs or outfall structures.	4	(60)	(20)	2041		2011	Yes	Yes	1971
1296	7635	8093	271486	8097	0	2	#2 UNIT GENERATION SERVICES	CW SYSTEM	CWTRAVELLING SCREENS EAST	N/A	150	11	Internals in good condition after major upgrade within the last five to ten years. External casings and auxiliaries have some corrosion.	4	(20)	(10)	2041	2012		Yes	No	2000
1296	7635	8093	271486	8098	0	2	#2 UNIT GENERATION SERVICES	CW SYSTEM	CWTRAVELLING SCREENS WEST	N/A	151	11	Internals in good condition after major upgrade within the last five to ten years. External casings and auxiliaries have some corrosion.	4	(20)	(10)	2041	2012		Yes	No	1971
1296	7635	8093	271486	8821	0	2	#2 UNIT GENERATION SERVICES	CW SYSTEM	CW SCREEN WASH SYSTEM	N/A	152	11	Significant corrosion. Likely near end of life.	3a	(30)	(5)	2041			No	No	1971

Notes: 1. A "(bracketed)" value in the "Current Expected Remaining Life" column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation, including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as "(X/Y)" has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

1. The "Next Regular Inspection" column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The "Next Planned Overhaul or Major Inspection" column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a "Desired Life" stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or not known by AMEC.

9.1.4.5 Actions

Based on the condition assessment, the following actions are recommended for the Unit 2 cooling water systems associated with generators:

TABLE 9-23 RECOMMENDED ACTIONS – UNIT 2 COOLING WATER SYSTEMS ASSOCIATED WITH GENERATORS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Unit	Asset 2/3	Asset 3/4	Description	Detail	Action #	App #	Action	Year	Priority
1296	7635	8093	7703	0	2	#2 UNIT GENERATION SERVICES	TURB/GEN COOLING SYSTEM	TURB/GEN COOLING SYSTEM	Aux Cooling Water Piping/Hexch	181	8	Continue current condition monitoring and heat exchanger servicing.	2011	2
1296	7635	8093	7703	0	2	#2 UNIT GENERATION SERVICES	TURB/GEN COOLING SYSTEM	TURB/GEN COOLING SYSTEM	TG Piping	182	8	Clean and coat remaining auxiliary cooling water piping.	2011	2
1296	7635	8093	7703	0	2	#2 UNIT GENERATION SERVICES	TURB/GEN COOLING SYSTEM	TURB/GEN COOLING SYSTEM	Aux Cooling Water Piping	183	8	Perform representative Level 2 pipe thickness checks on seawater intake and discharge piping.	2011	2
1296	7635	8093	7703	0	2	#2 UNIT GENERATION SERVICES	TURB/GEN COOLING SYSTEM	TURB/GEN COOLING SYSTEM	Aux Cooling Water Pipes	184	8	Perform Level 2 on auxiliary cooling pipes.	2011	2
1296	7635	8093	7703	0	2	#2 UNIT GENERATION SERVICES	TURB/GEN COOLING SYSTEM	TURB/GEN COOLING SYSTEM	Aux CW Ht Exch	186	8	Perform Level 2 on auxiliary cooling heat exchangers.	2011	2
1296	7635	8093	7703	9622	2	#2 UNIT GENERATION SERVICES	TURB/GEN COOLING SYSTEM	T/G COOLING PUMP SOUTH	TG Piping	187	8	Continue current condition monitoring and heat exchanger servicing.	2011	2
1296	7635	8093	7703	9624	2	#2 UNIT GENERATION SERVICES	TURB/GEN COOLING SYSTEM	T/G COOLING PUMP NORTH	N/A	188	8	Continue current condition monitoring and heat exchanger servicing.	2011	2
1296	7635	8093	7703	299550	2	#2 UNIT GENERATION SERVICES	TURB/GEN COOLING SYSTEM	CW TRAVELLING STRUCTURE	N/A	189	11	Continue current condition monitoring.	2011	2
1296	7635	8093	8132	0	2	#2 UNIT GENERATION SERVICES	GENERAL SERVICE COOLING	GENERAL SERVICE COOLING	N/A	191	12	Continue current inspection and maintenance activities.	2011	2
1296	7635	8093	271486	0	2	#2 UNIT GENERATION SERVICES	CW SYSTEM	CW SYSTEM	N/A	203	11	Maintain current program of ongoing inspections and overhauls. Procure a spare motor be maintained to service all three units, in the event of a failure of an existing unit.	2011	2
1296	7635	8093	271486	8095	2	#2 UNIT GENERATION SERVICES	CW SYSTEM	CW INTAKE SYSTEM	N/A	204	11	Perform an underwater inspection of intake and outfall structures - including areas such as stoplog.	2011	2
1296	7635	8093	271486	8097	2	#2 UNIT GENERATION SERVICES	CW SYSTEM	CWTRAVELLING SCREENS EAST	N/A	205	11	Continue current condition monitoring.	2011	2
1296	7635	8093	271486	8098	2	#2 UNIT GENERATION SERVICES	CW SYSTEM	CWTRAVELLING SCREENS WEST	N/A	206	1	Continue current condition monitoring.	2011	2
1296	7635	8093	271486	8120	2	#2 UNIT GENERATION SERVICES	CW SYSTEM	CW DISCHARGE TO OUTFALL	N/A	207	11	Perform an underwater inspection of intake and outfall structures - including areas such as stoplog.	2011	2
1296	7635	8093	271486	8821	2	#2 UNIT GENERATION SERVICES	CW SYSTEM	CW SCREEN WASH SYSTEM	N/A	208	11	Refurbish or replace.	2011	2

9.1.4.6 Risk Assessment

Table 9-24 below illustrates the risk assessment for the Unit 2 cooling water systems associated with generators, both from a technological perspective and a safety perspective using the models presented in Section 3.

TABLE 9-24 RISK ASSESSMENT – UNIT 2 COOLING WATER SYSTEMS ASSOCIATED WITH GENERATORS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Component	Risk Assess #	Appendix #	Major Issues	Remaining Life Years	Remaining Life Comments	TECHNO-ECO RISK ASSESSMENT MODEL			SAFETY RISK ASSESSMENT MODEL			Possible Failure Event	Mitigation
														(Insufficient Info - Inspection Required Within (x) Years)		Likeli-hood	Conse-quence	Risk Level	Likeli-hood	Conse-quence	Safety Risk		
1296	7635	8093	7703	0	0	2	#2 UNIT GENERATION SERVICES	TURB/GEN COOLING SYSTEM	TURB/GEN COOLING SYSTEM	ACW Piping	160	8	Corrosion, mechanical failure.	10	None	1	A	Low	1	A	Low	Leak and short duration impact.	Inspect and maintain.
1296	7635	8093	7703	0	0	2	#2 UNIT GENERATION SERVICES	TURB/GEN COOLING SYSTEM	TURB/GEN COOLING SYSTEM	Seawater Piping	161	8	Corrosion, mechanical failure.	(10)	None	1	A	Low	1	A	Low	Leak and short duration impact.	Inspect and maintain.
1296	7635	8093	7703	9622	0	2	#2 UNIT GENERATION SERVICES	TURB/GEN COOLING SYSTEM	T/G COOLING PUMP SOUTH	ACW Pump/Motor	162	8	Mechanical or electrical failure.	(10)	None	1	A	Low	1	A	Low	Sparing, minimal.	Current inspection and maintain.
1296	7635	8093	7703	9624	0	2	#2 UNIT GENERATION SERVICES	TURB/GEN COOLING SYSTEM	T/G COOLING PUMP NORTH	ACW Pump/Motor	163	8	Mechanical or electrical failure.	(10)	None	1	A	Low	1	A	Low	Sparing, minimal.	Current inspection and maintain.
1296	7635	8093	7703	299550	0	2	#2 UNIT GENERATION SERVICES	TURB/GEN COOLING SYSTEM	CW TRAVELLING SCREENS	N/A	164	11	Corrosion - internal/external.	(10)	None	2	B	Low	2	A	Low	ACW Cooling plugging	Current inspection and maintain.
1296	7635	8093	7703	299551	0	2	#2 UNIT GENERATION SERVICES	TURB/GEN COOLING SYSTEM	CW TRAVELLING SCREENS	N/A	165	11	Corrosion - internal/external.	(10)	None	2	B	Low	2	A	Low	ACW Cooling plugging	Current inspection and maintain.
1296	7635	8093	8132	0	0	2	#2 UNIT GENERATION SERVICES	GENERAL SERVICE COOLING	GENERAL SERVICE COOLING	GSW Pump/Motor Failure	166	12	Mechanical or electrical failure.	10	None	1	A	Low	1	A	Low	Minimum	Current inspection and maintain.
1296	7635	8093	8132	0	0	2	#2 UNIT GENERATION SERVICES	GENERAL SERVICE COOLING	GENERAL SERVICE COOLING	GSW Ht Exch Failure	167	12	Mechanical failure/pluggage.	10	None	1	A	Low	1	A	Low	Seawater contamination (unlikely).	Inspect and maintain.
1296	7635	8093	8132	0	0	2	#2 UNIT GENERATION SERVICES	GENERAL SERVICE COOLING	GENERAL SERVICE COOLING	GSW Piping Failure	168	12	Mechanical failure.	10	None	1	A	Low	1	A	Low	Leak and short duration impact.	Inspect and maintain.
1296	7635	8093	271486	8095	0	2	#2 UNIT GENERATION SERVICES	CW SYSTEM	CW INTAKE SYSTEM	Intake Structure	181	11	Structural cracking; steel corrosion.	(20)	None	1	B	Low	1	A	Low	Structural failure requiring shutdown.	Inspect and maintain.
1296	7635	8093	271486	8097	0	2	#2 UNIT GENERATION SERVICES	CW SYSTEM	CWTRAVELLING SCREENS EAST	N/A	182	11	Corrosion - internal/external.	(10)	None	2	B	Low	2	A	Low	Condenser plugging.	Current inspection and maintain.
1296	7635	8093	271486	8098	0	2	#2 UNIT GENERATION SERVICES	CW SYSTEM	CWTRAVELLING SCREENS WEST	N/A	183	11	Corrosion - internal/external.	(10)	None	2	B	Low	2	A	Low	Condenser plugging.	Current inspection and maintain.
1296	7635	8093	271486	8120	0	2	#2 UNIT GENERATION SERVICES	CW SYSTEM	CW DISCHARGE TO OUTFALL	CW Outfall Piping	184	11	Concrete cracking.	(20)	None	1	B	Low	1	A	Low	Cracking or failure – major leak requiring repair.	Inspect and maintain.
1296	7635	8093	271486	8821	0	2	#2 UNIT GENERATION SERVICES	CW SYSTEM	CW SCREEN WASH SYSTEM	N/A	185	11	Corrosion, failure.	5	None	2	A	Low	3	A	Low	Screen pressure drop/load reduction.	Refurbish/replace.

9.1.4.7 Life Cycle Curve and Remaining Life

Figure 9-9 below illustrates the life cycle curve for the Unit 2 cooling water systems associated with generators. The life curves are plots of current and projected operating hours (generation plus synchronous condensing mode) on the y-axis versus calendar year on the x-axis. The figure has vertical lines representing differing representative nominal age limits for various components. It has horizontal lines that represent a range of practical equivalent base loaded operating hour life limits. Data specific to the intake and outfall structures were not sufficient to include them at this time, but they are not expected to be an issue (perhaps the condition of some operational equipment such as stoplogs or their supports). Data specific to the pumps and motors for the general service cooling water and the turbine generator cooling water are also not presented as they are relatively new and/or modest equipment elements. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view.

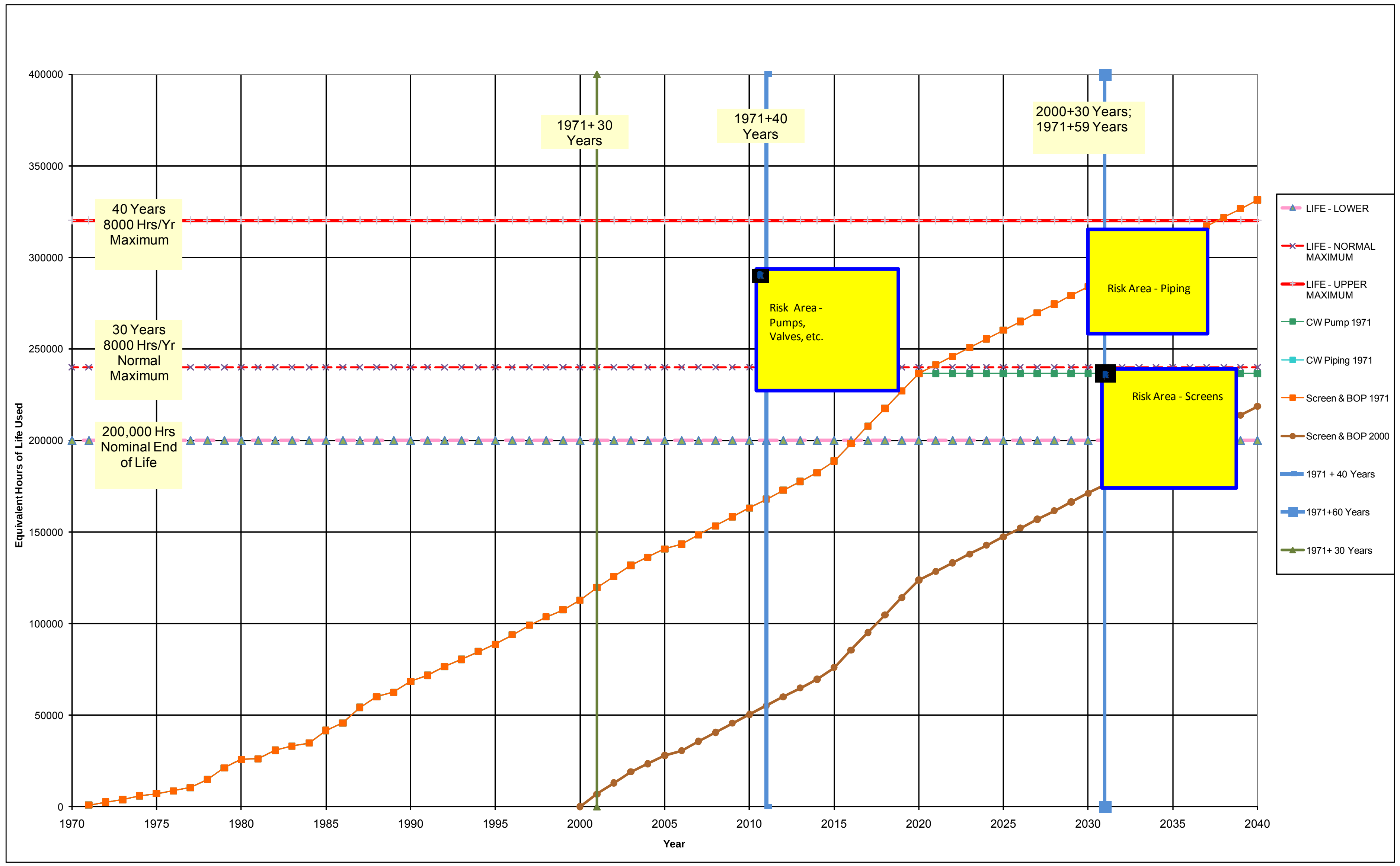

FIGURE 9-9 LIFE CYCLE CURVE – UNIT 2 COOLING WATER SYSTEMS ASSOCIATED WITH GENERATORS

The curve indicates that the remaining life (RL) of most elements of the Unit 2 cooling water systems associated with generators is sufficient to reach the end date of 2020 for generation, but not necessarily the 2041 desired life (DL) end date for synchronous condensing. The CW pumps and associated equipment are the primary nearer term issues highlighted by the risk boxes. The actual end date and remaining life will become clearer through the series of ongoing routine inspections that forms part of the plant's PM program and the Level 2 inspections recommended in the report. The intake and outfall structures and associated sub-components should be added as a result of a Level 2 inspection.

9.1.4.8 Level 2 Inspections – Unit 2 Cooling Water Systems Associated with Generators

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 9-25 below, assuming that the current plant inspection and maintenance program is maintained or improved.

TABLE 9-25 LEVEL 2 INSPECTIONS – UNIT 2 COOLING WATER SYSTEMS ASSOCIATED WITH GENERATORS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Sub System Comment	L2#	Appendix #	Level 2 Work	Year	Cost k$
1296	7635	8093	0	0	0	2	#2 UNIT GENERATION SERVICES	UNIT GENERATION SERVICES	UNIT GENERATION SERVICES	None	134	N/A	No Level 2 required.		
1296	7635	8093	7703	0	0	2	#2 UNIT GENERATION SERVICES	TURB/GEN COOLING SYSTEM	TURB/GEN COOLING SYSTEM	seawater intake and discharge piping	135	8	Perform representative Level II pipe thickness checks.	2011	$6
1296	7635	8093	7703	0	0	2	#2 UNIT GENERATION SERVICES	TURB/GEN COOLING SYSTEM	TURB/GEN COOLING SYSTEM	AC Water piping	136	8	Thickness spot checks.	2011	$6
1296	7635	8093	7703	0	0	2	#2 UNIT GENERATION SERVICES	TURB/GEN COOLING SYSTEM	TURB/GEN COOLING SYSTEM	Ht Exch	137	8	AC Water Ht Exchangers shell and tubes.	2011	$6
1296	7635	8093	7703	9622	0	2	#2 UNIT GENERATION SERVICES	TURB/GEN COOLING SYSTEM	T/G COOLING PUMP SOUTH	CW Pumps	138	11	Perform planned inspections on one pump per unit in 2010 to 2012 (similar to Level 2).	2011	
1296	7635	8093	7703	9624	0	2	#2 UNIT GENERATION SERVICES	TURB/GEN COOLING SYSTEM	T/G COOLING PUMP NORTH	CW Pumps	139	11	Perform planned inspections on one pump per unit in 2010 to 2012 (similar to Level 2).	2011	
1296	7635	8093	8132	0	0	2	#2 UNIT GENERATION SERVICES	GENERAL SERVICE COOLING	GENERAL SERVICE COOLING	None	140	12	No Level 2 required.		
1296	7635	8093	8132	0	0	2	#2 UNIT GENERATION SERVICES	GENERAL SERVICE COOLING	GENERAL SERVICE COOLING	None	141	11	No Level 2 required.		
1296	7635	8093	8132	0	0	2	#2 UNIT GENERATION SERVICES	GENERAL SERVICE COOLING	GENERAL SERVICE COOLING	None	142	11	No Level 2 required.		
1296	7635	8093	271486	8095	0	2	#2 UNIT GENERATION SERVICES	CW SYSTEM	CW INTAKE SYSTEM	CW intake and discharge structures and piping	147	11	Inspections – diver visual inspection.	2011	$30
1296	7635	8093	271486	8097	0	2	#2 UNIT GENERATION SERVICES	CW SYSTEM	CWTRAVELLING SCREENS EAST	CW intake and discharge structures and piping	148	11	No Level 2 required.		
1296	7635	8093	271486	8098	0	2	#2 UNIT GENERATION SERVICES	CW SYSTEM	CWTRAVELLING SCREENS WEST	None	149	11	No Level 2 required.		
1296	7635	8093	7703	299550	0	2	#2 UNIT GENERATION SERVICES	TURB/GEN COOLING SYSTEM	CW TRAVELLING STRUCTURE	None	150	11	No Level 2 required.		
1296	7635	8093	7703	299551	0	2	#2 UNIT GENERATION SERVICES	TURB/GEN COOLING SYSTEM	CW TRAVELLING STRUCTURE	None	151	11	No Level 2 required.		
1296	7635	8093	271486	8120	0	2	#2 UNIT GENERATION SERVICES	CW SYSTEM	CW DISCHARGE TO OUTFALL	None	152	11	Inspections – diver visual inspection within 2 to 4 years.	2011	$30
1296	7635	8093	271486	8821	0	2	#2 UNIT GENERATION SERVICES	CW SYSTEM	CW SCREEN WASH SYSTEM	None	153	11	No Level 2 required.		

9.1.4.9 Capital Projects

The suggested typical capital enhancements include:

TABLE 9-26 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – UNIT 2 COOLING WATER SYSTEMS ASSOCIATED WITH GENERATORS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Detail	CAP#	Appendix #	Capital Item	Date	Priority
1296	7635	8093	7703	0	0	2	#2 UNIT GENERATION SERVICES	TURB/GEN COOLING SYSTEM	TURB/GEN COOLING SYSTEM	N/A	126	8	Clean and coat AC Water pipes.	2012	2
1296	7635	8093	7703	9622	0	2	#2 UNIT GENERATION SERVICES	TURB/GEN COOLING SYSTEM	T/G COOLING PUMP SOUTH	N/A	127	8	No capital investment required.		
1296	7635	8093	7703	9624	0	2	#2 UNIT GENERATION SERVICES	TURB/GEN COOLING SYSTEM	T/G COOLING PUMP NORTH	N/A	128	8	No capital investment required.		
1296	7635	8093	7703	299550	0	2	#2 UNIT GENERATION SERVICES	TURB/GEN COOLING SYSTEM	CW TRAVELLING SCREENS	N/A	129	11	No capital investment required.		
1296	7635	8093	7703	299551	0	2	#2 UNIT GENERATION SERVICES	TURB/GEN COOLING SYSTEM	CW TRAVELLING SCREENS	N/A	130	11	No capital investment required.		
1296	7635	8093	8132	0	0	2	#2 UNIT GENERATION SERVICES	GENERAL SERVICE COOLING	GENERAL SERVICE COOLING	N/A	131	12	None		
1296	7635	8093	271486	8095	0	2	#2 UNIT GENERATION SERVICES	CW SYSTEM	CW INTAKE SYSTEM	Intake structure and pit	141	11	No capital investment required.		
1296	7635	8093	271486	8097	0	2	#2 UNIT GENERATION SERVICES	CW SYSTEM	CWTRAVELLING SCREENS EAST	N/A	142	11	No capital investment required.		
1296	7635	8093	271486	8098	0	2	#2 UNIT GENERATION SERVICES	CW SYSTEM	CWTRAVELLING SCREENS WEST	N/A	143	11	No capital investment required.		
1296	7635	8093	271486	8120	0	2	#2 UNIT GENERATION SERVICES	CW SYSTEM	CW DISCHARGE TO OUTFALL	Outfall structure, pit, stoplogs	144	11	No capital investment required.		
1296	7635	8093	271486	8821	0	2	#2 UNIT GENERATION SERVICES	CW SYSTEM	CW SCREEN WASH SYSTEM	N/A	145	11	No capital investment required.		

9.2 Unit 2 – Lower Priority Systems

9.2.1 Asset 7786 Unit 2 Boiler System

(Detailed Technical Assessment in Working Papers, Appendices 29, 30, and 34)

The requirements for the boiler system servicing Unit 2 is as follows:

Unit #:	2
Asset Class #	BU 1296 - Assets Generations
SCI & System:	7786 #2 Boiler Plant
Sub-Systems:	7787 #2 Boiler Structure
	7789 #2 Boiler F.W. & Sat. Steam
	7810 #2 Boiler Superheater and Reheater
Components:	7790 #2 Economizer, tubing and headers
	7789 #2 Linking piping (boiler internal)
	7789 #2 Furnace water circuit 7794 #2 Steam drum, 7789 #2 Downcomers and feeder piping as required 7789 #2 Lower Waterwall headers 7789 #2 Waterwall Tubing 7789 #2 Upper Waterwall headers, and riser piping as re
	7811 #2 Superheater; headers and tubing
	7835 #2 Reheater; headers and tubing
	7789 #2 Safety Valves
	7823 #2 Boiler Main Steam lines
	7824 #2 Boiler Stop Valve
	7787 #2 Furnace structural, hangers and casing
	7945 #2 Boiler Blowdown Tank

9.2.1.1 Description

The Unit 2 boiler is a Combustion Engineering (now supported by ALSTOM), natural circulation, single reheat, pressurized unit. The boiler was originally designed in 1968 for an output of 150 MW with a maximum steam flow of 132.4 kg/s (1,050,000 lbs/hr), at 227 MPag (1800 psig) and 538 °C (1000 °F) with an inlet feedwater temperature of 240 °C (464 °F). The reheat steam flow was designed for 126 kg/s (921,000 lbs/hr) with an inlet temperature of 366 °C (690 °F) and an outlet temperature of 541 °C (1005°F). Unit 2 was commissioned in 1970.

Unit 2 was uprated to nominal output of 175 MW in 1988/1889. The boiler was analyzed to determine if this increased load could be accommodated by raising the superheat steam flow approximately 11% to 1,167,200 lb/hr and the reheat steam flow approximately 13% to 131 kg/s (1,044,630 lb/hr). Associated boiler pressure part modifications were evaluated such that the boiler design pressure of 15.2 MPag (2205 psig) could be maintained with the increased steam outlet pressure. All the pressure parts were analyzed for ASME Code compliance and optimized operation. In order to reduce anticipated attemperator spray water in the superheater section, heating surface was removed from the primary superheater sections. Additional modifications were made to the boiler non-pressure part equipment. After uprating, the boilers are rated at a maximum steam flow of 147 kg/s (1,167,000 lbs/hr), at 13.6 MPag (1970 psig) and 541 °C (1005 °F) with an inlet feedwater temperature of 240 °C (464 °F). The reheat steam flow was designed for 13.1 kg/s (104,500 lbs/hr) with an inlet temperature of 353 °C (667 °F) and an outlet temperature of 541 °C (1005 °F).

The system includes:

- Economizer, tubing and headers;
- Linking piping (boiler internal;
- Furnace water circuit;
    - Steam drum,
    - Downcomers and feeder piping as required
    - Lower Waterwall headers
    - Waterwall tubing
    - Upper Waterwall headers, and riser piping as required
- Superheater; headers and tubing;
- Reheater; headers and tubing ;
- Safety valves;
- Furnace structural, hangers and casing; and
- Boiler Main Steam lines
- Boiler Stop Valve
- Boiler blow down tank.

Boiler #2 had superheater sections replaced in 2008. Boiler sootblowers were added in 1995. Unit 2 was upgraded in 1988 to 175 MW from 150 MW.

9.2.1.2 History

Manufactured/Delivered	1970
In-Service Date	Apr 1971
Generation Base Load End Date	Dec 2015
Generation Peak/Emerg Gen End Date	Dec 2020
Major Inspection/Maintenance Repair	Annual May to Sep on all units

The hours associated with the analyses are:

Hours Generation Actual - Ops to Dec 2009	158
Max Hours Generation Ops – to Dec 2015	188
Max Hrs Gen Ops to Gen End Date Dec 2020	212
Max Hours Ops – 1986 to Dec 2009	113
Max Hrs - 1986 to Dec 2015	142
Max Hrs – 1986 to Gen End Date Dec 2020	164
Max Hours Ops – 2007/8 to Dec 2009	5
Max Hrs – 2007/8 to Dec 2015	35
Max Hrs – 2007/8 to Gen End Date Dec 2020	59

9.2.1.3 Inspection and Repair History

As a component of routine non destructive evaluation (NDE) inspections, ultrasonic thickness (UT) measurement readings are taken at specified locations on the economizer inlet and outlet headers (inspection results were not available). The following discussion summarizes the significant inspections and repairs completed on the economizer section servicing Unit 2:

Asset 7790 Economizer

During the 2002 outage, the economizer inlet header was opened for debris removal and internal visual inspection.

During the 2003 outage, a thermocouple was installed on economizer inlet header near inlet pipe.

During the 2004 outage, three rows of tube stubs from the economiser inlet header were exposed for inspection using shear wave UT inspection, starting with the second row from the west to find internal corrosion fatigue cracking similar to what caused the tube failure on Unit 1 in 2003. No evidence of damage was found. In addition, a visual internal inspection was done using a boroscope. The first two tube rows were inspected from the east handhole cap. This included an inspection of the first couple of inches inside the tubes and associated ligament areas. No defect could be seen. Also, the sootblower pipe supports were relocated from the header to the buckstay to eliminate expansion issues and any unnecessary loads on the header.

During October 2009, a tube leak was found in the economizer inlet header top west stub tube approximately 1 inch from the header on the top side of the tube. It was concluded that the failure was due to corrosion fatigue cracking similar to the incident that was observed on Unit 1 during 2003. The failed section of the tube was removed and replaced with available tube material (T11).

Asset 7789 Waterwall Headers, Downcomers, and Lower and Upper Feeder Tubes

Exterior visual inspections of the lower and upper waterwall headers are carried out during the boiler outage inspections. Lower waterwall headers were opened a number of times for debris removal after boiler repairs. There were no internal inspections done for checking for ligament cracking or cracking at other locations. During 2007 outage, two upper waterwall headers (H3R and H4) were opened to determine if there was any blockage that could impact the circulation - particularly on the east side where the previous waterwall failures were concentrated. No problems were found. A couple of ligaments could be seen in H4 and there was no indication of any cracking. UT thickness measurement is taken on the waterwall circuit feeder and riser tubes. Some of the riser tubes were found in contact with each other during outage inspection, however no damage was noted.

Asset 7794 Steam Drum

All the accessible internal seam and nozzle welds are inspected using the Wet Fluorescent Magnetic Particle Examination (WFMT) method during every outage. A varying degree of magnetite layer was observed during outage inspections. Although a slight pitting was observed, but not active, it is not considered a pressure integrity issue for the steam drums. During the Unit 2 2005 outage, all the separators were removed for a detailed inspection of the internals and the shell. However, the baffles were not removed.

Asset 7789 High Temperature Headers and Piping

During annual maintenance outages, Magnetic Particle Inspection (MPI) is carried out on the selective tube to header welds on the superheater and reheater section headers, subject to accessibility. There has been no abnormality observed to date. Also, UT measurements were taken on the headers next to MPI locations. No significant header wall thinning was noted.

During 2007 outage, SH5 and SH6 were opened on the east side for cleaning and inspection as part of the superheater work. During a boroscopic inspection of the superheater outlet header, significant scale was noted and there were sections where exfoliation had apparently occurred.

Asset 7811 Superheater Link Piping and Attemperator

A visual inspection of the superheater link piping is carried out during every outage. There was no internal inspection carried out on superheater attemperators during the 2001-2009 period.

Asset 7790 Economizer Tubes

In April of 2005, a tube leak was found in the second tube down from top in the third row from west side during the plant operation. It was a longitudinal crack approximately 9 cm (3.5 inches) long in the tube located at the support. Destructive examination of the tube sample established that the failure in the tube originated from one of two diametrically opposed cracks on the inside diameter (ID) surface of the seamless tube that were shown by metallurgical examination to be mill defects and failure mechanism was corrosion fatigue.

In October 2009, a tube leak was found in the economizer inlet header top west stub tube approximately 2.5 cm (1 inch) from the header on the top side of the tube. The section of the tube was replaced with T11 material. The leak was similar to the leak observed in Unit 1 in 2003.

Asset 7789 Waterwall Tubes

During April 2006, an NDE inspection of the furnace walls was completed in the burner zone between elevations 12.8 m (42 feet) and 19.8 m (65 feet) on the north, south and west walls and 2.4 m (8 feet) slope section of the roof, in order to check for internal tube damage. In addition, approximately 85.3 m (280 linear feet) of the east wall was scanned from the cold side. The Low Frequency Electromagnetic Technique (LFET) was used, with confirmation by UT. No defect was found in the slope roof tubes and cold side of the east wall. However, some indications were found on the north, south and west walls. The east wall, from the second floor to the fourth floor, was replaced due to thinning, hydrogen damage and blistering caused by the internal fireside deposits that had caused number of tube failures. Also, tubes on the north, south and west walls that had shown damage during LFET inspection were replaced. Moreover, a boiler chemical clean was performed during the outage.

During the 2009 outage, two tube samples were removed from the high heat flux area at approximately top burner elevation. Also, a boroscope inspection was carried out through the tubes and those were found to be clean.

Asset 7811, 7835 Superheater and Reheater Tubes

The anti-vibration baffles were noted to be in very poor condition. There are minor tube alignment issues as some tubes had drifted laterally. However, the alignment did not appear to be worsening at that time. No significant tube thickness loss was discovered during the 2008 outage UT inspections at the selective locations on Unit 2. The tubes were well above the minimum wall thickness required. No tube sample analysis has been performed on the lower secondary superheater section on Unit 2. Also, tube thickness measurement data was not available for the lower section.

Asset 7811 Secondary Superheater

During the 2006 outage, surface replication was performed on the three tubes of lower secondary superheater section that had been found bowed up to 15 cm (6 inches) in the middle span to determine if there were any metallurgical concerns. There were no creep voids, cracks, or microfissures observed at any of the tube locations examined. During 2007, a partial replacement of the Unit 2 secondary superheater was carried out. A total of 30 of the 31 final superheater assemblies (except 7^{th} platen), that were made of SA-213-TP-321H material were replaced because of severe thinning caused by OD corrosion. The new assemblies were fabricated from SA-213-347H stainless steel tubes with nominal wall thickness of 6.4 mm (0.2 inches). This was an upgrade from the original 321H tubes having nominal wall thickness ranging from 4.2 mm (0.165 inches) to 5.6 mm (0.220 inches). The assemblies were supplied with T22 (2¼ chrome) safe-ends for welding to the T22 tube ends in the boiler and vestibule. Thus the old DMWs (Dissimilar Metal Welds) were removed and replaced with new DMWs that were completed in the shop.

Broken welds were found in the saddle attachment welds between the hanger tubes and the superheater tubes during the 2009 outage. Only one had tube damage from failure and the others were broken in the weld. Most of them were repaired. During the 2009 outage it was observed that some superheater tubes had sagged down considerably.

Asset 7835 Reheater

Some tube wall thinning was observed in the reheater section. However, all measurements were above the ASME calculated thickness. There has been no tube failures observed in the reheater section. The DMWs were inspected at random locations to check for potential cracking using Liquid Penetrant Inspection (LPI) method.

Asset 7789 Safety Valves, Casings, & Structure/Hangers

Safety relief valves (SRVs) are inspected and maintained as per the plant SRV testing and overhaul program. The program is considered adequate to maintain the SRVs for the desired life to 2020.

Casing: The casing has a history of failures at both fabric and metallic expansion joints. These are repaired and replaced as required. Failures of both fabric and metallic expansion joints are an ongoing issue. During the AMEC field walkdown, some boiler expansion joints were found leaking.

Steel structure and hangers - corrosion in the boilers penthouse areas was identified in walkdowns of the unit. The condition of the boiler refractory is uncertain.

Asset 7945/7948 Boiler Blow Down Tank

The unit is inspected annually, except in 2009 and 2010. In 2009 the unit was inspected externally only due to access and isolation issues. Deterioration of internals and corrosion have been continuing issues, but safety concerns with access, isolation, and cramped spaces are primary concerns.

9.2.1.4 Condition Assessment

The condition assessment of the Unit 2 boiler system is illustrated below in Table 9-27:

TABLE 9-27 CONDITION ASSESSMENT – UNIT 2 BOILER SYSTEM

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset Level 2	Asset Level 3	Description	Detail	Condition Summary ID#	Append #	Condition	EPRI Identifier	Original Life (Base Load) Ops Hrs (Yrs)	Current Expected Minimum Remaining Life Years (Subject to Test)	End of Life (EOL) Required	Next Regular Inspection	Next Planned Overhaul or Major Inspection	Capability to Reach Next Overhaul	Capability to Reach EOL	In Service
1296	7635	7786	0	0	0	2	#2 BOILER PLANT	BOILER PLANT	BOILER PLANT	N/A	58	30	No active high energy piping management program. High temperature piping constant support hanger monitoring program discontinued after 2001. A few skewed hangers, topped or bottomed up constant spring support, and interference problem for main steam, hot reheat and cold reheat lines.	4	200000 (30)	(10)	2020	2011	2013	Yes	Yes	1971
1296	7635	7786	7789	0	0	2	#2 BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER FW & SAT'D STEAM SYS	N/A	59	30	No information on recent inspections of the sample of the upper waterwall headers flat end welds	4	200000 (30)	(10)	2020	2011	2013	Yes	Yes	1971
1296	7635	7786	7789	0	0	2	#2 BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER FW & SAT'D STEAM SYS	N/A	60	30	High heat flux and challenging chemistry are related to numerous damage mechanisms on interior and exterior surfaces of waterwall tubing. No information on recent destructive testing reports of waterwall tubes that were removed in 2009.	4	200000 (30)	(10)	2020	2011	2013	Yes	Yes	1971
1296	7635	7786	7789	7790	0	2	#2 BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER ECONOMIZER	Headers & link Piping	61	30	Economizer outlet headers or link piping to the steam drum in good condition. Thermal/corrosion fatigue related failure experienced in the economizer inlet headers stub tubes. Only partial internal and stub tube inspections on Unit 2 during 2004 outage. Failure in the outlet tube of Unit 2 economizer inlet header in 2009.	4	200000 (30)	(10)	2020	2011	2013	Yes	Yes	1971
1296	7635	7786	7789	7790	0	2	#2 BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER ECONOMIZER	Tubing	62	30	Insufficient inspections to assess condition. Wall thickness review inconclusive - some 2009 readings decreased and some increased vs 2004. Corrosion fatigue failure of economizer tube in 2005 due to a manufacturing defect.	4	200000 (30)	(10)	2020	2011	2013	Yes	Yes	1971
1296	7635	7786	7789	7794	0	2	#2 BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER STEAM DRUM	N/A	63	30	No major life limiting issues observed during previous limited steam drum inspections. Design assessed as having no significant concerns. Inspections were focused at visible areas only and many of the susceptible locations have not been inspected.	4	200000 (30)	10	2020	2011	2013	Yes	Yes	1971
1296	7635	7786	7789	7801	0	2	#2 BOILER PLANT	BOILER FW & SAT'D STEAM SYS	FURNACE	N/A	64	30	See details below.									
1296	7635	7786	7810	0	0	2	#2 BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER SUPERHEATER & REHEAT	N/A	65	30	See details below.									
1296	7635	7786	7810	7811	0	2	#2 BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER PRIMARY SUPERHEATER	N/A	66	30	Design creep life calculations for secondary superheater outlet headers suggest concern. Internal scale noted in superheater outlet header during previous outage inspections.	4	200000 (30)	(10)	2020	2011	2013	Yes	Yes	1971
1296	7635	7786	7810	7811	0	2	#2 BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER PRIMARY SUPERHEATER	Tubes	67	30	Insufficient inspections to assess damage. Wall thickness review inconclusive - some 2009 readings decreased and some increased vs 2004. Corrosion fatigue failure of economizer tube in 2005 due to a manufacturing defect.	4	200000 (30)	(10)	2020	2011	2013	Yes	Yes	1971
1296	7635	7786	7810	7811	0	2	#2 BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER SECONDARY SUPERHEATER	Tubes	68	30	Partial replacement with upgraded materials of the secondary superheater sections in 2007 - expected to operate without failure up to the desired life. Destructive tube sample analysis is required for the lower secondary superheater section that was not replaced. Surface replication performed on three tubes lower secondary superheater section and no creep damage observed.	4	200000 (30)	(10)	2020	2011	2013	Yes	Yes	1971
1296	7635	7786	7810	7813	0	2	#2 BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER SUPERHEATER ATTEMP'R	N/A	69	30	Design calculations for combination creep and fatigue damage from thermal fatigue raises concern with attemperators.	4	200000 (30)	(10)	2020	2011	2013	Yes	Yes	1971
1296	7635	7786	7810	7830	0	2	#2 BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER REHEATER ATTEMPERATOR	N/A	70	30	Design calculations for combination creep and fatigue damage from thermal fatigue raises concern with attemperators.	4	200000 (30)	(10)	2020	2011	2013	Yes	Yes	1971
1296	7635	7786	7810	7835	0	2	#2 BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER REHEATER	Headers & link Piping	71	30	Design creep life calculations for reheater outlet headers suggest concern.	4	200000 (30)	(10)	2020	2011	2013	Yes	Yes	1971
1296	7635	7786	7810	7835	0	2	#2 BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER REHEATER	Tubes	72	30	No inspections done (including destructive tube sample analysis) assessing the extent of damage due to creep, sagging, OD liquid ash corrosion and ID high temperature corrosion.	4	200000 (30)	(10)	2020	2011	2013	Yes	Yes	1971
1296	7635	7786	7789	7789	0	2	#2 BOILER PLANT	BLR BLOWDOWN DRAINS	BOILER BLOWDOWN TANK	N/A	73	30	Thinning, corrosion. Sefety issues - isolation and access	10	200000 (30)	(3)	2020	2012	2012	Yes	No	1971
1296	7635	7786	7810	7823	0	2	#2 BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER MAIN STEAM LINES	N/A	74	30	No active high energy piping management program. High temperature piping constant support hanger monitoring program discontinued after 2001. A few skewed hangers, topped or bottomed up constant spring support, and interference problem (only Unit 3) for main steam, hot reheat and cold reheat lines.	4	200000 (30)	(10)	2020		2011	Yes	Yes	1971
1296	7635	7786	7810	7823	322451	2	#2 BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER STOP VALVE	N/A	75	30	Reasonable condition. No detailed review.	3a	200000 (30)	(10)	2020	2011	2011	Yes	No	2008

Notes:

1. A "(bracketed)" value in the "Current Expected Remaining Life" column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation, including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as "(X/Y)" has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

2. The "Next Regular Inspection" column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The "Next Planned Overhaul or Major Inspection" column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a "Desired Life" stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or not known by AMEC.

9.2.1.5 Actions

Based on the condition assessment, the following actions are recommended for the Unit 2 boiler system.

TABLE 9-28 RECOMMENDED ACTIONS – UNIT 2 BOILER SYSTEM

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Unit	Asset 2/3	Asset 3/4	Description	Detail	Action #	App #	Action	Year	Priority
1296	7635	7786	0	0	2	#2 BOILER PLANT	BOILER PLANT	BOILER PLANT	N/A	83	30	See details below.		
1296	7635	7786	7789	0	2	#2 BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER FW & SAT'D STEAM SYS	N/A	84	30	Monitor pitting on the tubes adjacent to the burners.	2011	2
1296	7635	7786	7789	0	2	#2 BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER FW & SAT'D STEAM SYS	N/A	85	30	Review the destructive testing 2009 report of waterwall tubes to evaluate the findings.	2011	2
1296	7635	7786	7789	0	2	#2 BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER FW & SAT'D STEAM SYS	N/A	86	30	Inspect selective flat end welds of the upper waterwall headers.	2013	2
1296	7635	7786	7789	0	2	#2 BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER FW & SAT'D STEAM SYS	N/A	87	30	Inspect the selective feeder and riser tubes for corrosion fatigue damage.	2013	2
1296	7635	7786	7789	0	2	#2 BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER FW & SAT'D STEAM SYS	N/A	88	30	Perform preliminary internal inspection of lower waterwall headers at the locations of the degradation mechanisms identified for steam drum using boroscope; inspection of selective flat end welds, feeder tube attachment welds and downcomers connection welds.	2013	2
1296	7635	7786	7789	0	2	#2 BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER FW & SAT'D STEAM SYS	N/A	89	30	Perform preliminary inspection of superheater and reheater headers support locations on the downcomers for thermal/mechanical fatigue.	2013	2
1296	7635	7786	7789	7790	2	#2 BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER ECONOMIZER	N/A	90	30	Perform inspection including sample tube removal and ultrasonic sonic testing survey at the accessible locations to assess the potential corrosion fatigue damage due to mill defects that had caused a failure in the economizer tube in Unit 2 in 2005.	2013	2
1296	7635	7786	7789	7790	2	#2 BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER ECONOMIZER	N/A	91	30	Modify start-up procedures to include monitoring of the thermocouple temperature and using the continuous feed during start-ups.	2011	2
1296	7635	7786	7789	7790	2	#2 BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER ECONOMIZER	N/A	92	30	Perform Level 2 inspections of the economizer inlet header: 1. ID visual inspection of bore holes, girth welds and tee welds. If cracking is identified, depth must be assessed. 2. UT inspection of stub tubes. 3. Sample stub tube to assess evidence of FAC.	2013	2
1296	7635	7786	7789	7790	2	#2 BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER ECONOMIZER	N/A	93	30	During annual outages, visually inspect the economizer outlet headers and supports, and the economizer link piping to ensure there is no change in the state and/or abnormal movement.	2013	2
1296	7635	7786	7789	7794	2	#2 BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER STEAM DRUM	N/A	94	30	Remove the drum furniture and a section of the liner to inspect seam welds, nozzle welds, ligaments, downcomers and feedwater inlet pipe.	2013	2
1296	7635	7786	7789	7794	2	#2 BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER STEAM DRUM	N/A	95	30	Perform external inspection of feeder tube welds.	2013	2
1296	7635	7786	7789	7794	2	#2 BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER STEAM DRUM	N/A	96	30	Manage steam drum target life with appropriate operational control and routine inspection and maintenance.	2013	2
1296	7635	7786	7810	0	2	#2 BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER SUPERHEATER & REHEAT	N/A	98	30	Inspect SH-4, SH-6 and RH-2 for creep and creep fatigue damage including internal boroscopic, external visual, dimensional on body spool pieces, UT inspections on welds and stub tubes and replica inspection.	2013	2
1296	7635	7786	7810	7811	2	#2 BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER PRIMARY SUPERHEATER	N/A	99	30	Inspect the presence of inside pitting and scaling.	2013	2
1296	7635	7786	7810	7811	2	#2 BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER PRIMARY SUPERHEATER	N/A	100	30	Enhance the present inspection and maintenance program to monitor and control the tubes alignment issues and failures of AVBs.	2013	2

Table 9-28 Cont'd

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Unit	Asset 2/3	Asset 3/4	Description	Detail	Action #	App #	Action	Year	Priority
1296	7635	7786	7810	7811	2	#2 BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER SECONDARY SUPERHEATER	N/A	101	30	Perform destructive tube sample analysis on the lower secondary superheater section that is not replaced to assess the extent of the damage due to creep, sagging, OD liquid ash corrosion and ID high temperature corrosion. Similar confirmatory inspection is required for the part of upper superheater tubes that were replaced during Units 2 uprate in 1988/1989.	2013	1
1296	7635	7786	7810	7811	2	#2 BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER SECONDARY SUPERHEATER	N/A	102	30	Continue the present inspection and maintenance program to monitor and control failures of tube saddle supports and other alignment issues.	2013	2
1296	7635	7786	7810	7811	2	#2 BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER SECONDARY SUPERHEATER	N/A	103	30	Refurbish the furnace exit thermoprobe and use during start-up activities.	2013	2
1296	7635	7786	7810	7813	2	#2 BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER SUPERHEATER ATTEMP'R	N/A	104	30	Inspect attemperator and ID the link piping for evidence of thermal fatigue.	2013	2
1296	7635	7786	7810	7830	2	#2 BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER REHEATER ATTEMPERATOR	N/A	105	30	Inspect attemperator and ID the link piping for evidence of thermal fatigue.	2013	2
1296	7635	7786	7810	7835	2	#2 BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER REHEATER	N/A	106	30	Inspect to check the presence of inside pitting and scaling.	2013	2
1296	7635	7786	7810	7835	2	#2 BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER REHEATER	N/A	107	30	Enhance the present inspection and maintenance program to monitor and control the tubes alignment issues.	2013	2
1296	7635	7786	7810	7835	2	#2 BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER REHEATER	N/A	108	30	Perform destructive tube sample analysis to assess the extent of the damage due to creep, sagging, OD liquid ash corrosion, ID high temperature corrosion and DMWs.	2013	2
1296	7635	7786	7810	7835	2	#2 BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER REHEATER	N/A	109	30	Enhance the present inspection and maintenance program to monitor and control failures of tube saddle supports and other alignment issues.	2013	2
1296	7635	7786	7810	7835	2	#2 BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER REHEATER	N/A	110	30	Assess and implement as economically justified, the addition of reheater surface for reheat temperature and efficiency.	2013	2
1296	7635	7786	7810	7823	2	#2 BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER MAIN STEAM LINES	N/A	111	30	Implement an active high energy piping management program including NDE testing at key locations and a high temperature piping constant support hanger monitoring program.	2011	2
1296	7635	7786	7789	7789	2	#2 BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER BLOWDOWN TANK	N/A	112	30	Replace tank	2012	1
1296	7635	7786	7810	7823	2	#2 BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER STOP VALVES	N/A	113	30	Inspect and refurbish/replace during next major boiler outage.	2011	2

9.2.1.6 Risk Assessment

Table 9-29 below illustrates the risk assessment for the Unit 2 boiler system, both from a technological perspective and a safety perspective using the models presented in Section 3.

TABLE 9-29 RISK ASSESSMENT – UNIT 2 BOILER SYSTEM

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Component	Risk Assess #	Appendix #	Major Issues	Remaining Life Years	Remaining Life Comments	TECHNO-ECO RISK ASSESSMENT MODEL			SAFETY RISK ASSESSMENT MODEL			Possible Failure Event	Mitigation
														(Insufficient Info - Inspection Required Within (x) Years)		Likeli-hood	Conse-quence	Risk Level	Likeli-hood	Conse-quence	Safety Risk		
1296	7635	7786	7789	0	0	2	#2 BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER FW & SAT'D STEAM SYS	Upper WW Headers	68	30	Thermal fatigue cracking, corrosion-fatigue cracking in flat end welds, corrosion.	10	Could meet the desired life with routine inspections.	2	B	Low	2	C	Medium	Flat end weld cracking. Wall thinning due to corrosion. Unit outage. Safety.	Routine inspections.
1296	7635	7786	7789	0	0	2	#2 BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER FW & SAT'D STEAM SYS	Riser Tubes	69	30	Corrosion, corrosion fatigue.	(10)	Inspections are required to assess the remaining life.	3	B	Med	2	C	Medium	Wall thinning due to corrosion. Unit outage. Safety.	Inspections are required to assess remaining life.
1296	7635	7786	7789	0	0	2	#2 BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER FW & SAT'D STEAM SYS	Lower WW Headers	70	30	Thermal fatigue cracking, corrosion-fatigue cracking, corrosion.	(10)	No real life limiting issue. Additional inspections required.	3	B	Med	3	B	Medium	Ligament cracking and weld cracking. Unit outage.	Additional inspections required.
1296	7635	7786	7789	0	0	2	#2 BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER FW & SAT'D STEAM SYS	Feeder Tubes	71	30	Corrosion, corrosion fatigue.	(10)	Inspections are required to assess the remaining life.	3	B	Med	3	B	Medium	Corrosion fatigue cracking and wall thinning due to corrosion related mechanism. Unit outage.	Inspections are required to assess remaining life.
1296	7635	7786	7789	0	0	2	#2 BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER FW & SAT'D STEAM SYS	Downcomers	72	30	Thermal/mechanical fatigue cracking at the header support locations.	(10)	Inspections are required to assess the remaining life.	3	B	Med	3	B	Medium	Thermal/Mechanical Fatigue Cracking at the header support locations. Unit outage. Safety.	Inspections are required to assess remaining life.
1296	7635	7786	7789	0	0	2	#2 BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER FW & SAT'D STEAM SYS	Waterwall Tubes	73	30	Corrosion fatigue, thermal/mechanical fatigue, water side under-deposit corrosion, short-term overheat, fireside corrosion.	10	Pitting in some areas require attention, other than that no major life limiting issue observed.	3	B	Med	3	B	Medium	Extensive pitting leading to tube failure. Unit derate/outage.	Some sections of floor tubes and pitting in some areas require attention.
1296	7635	7786	7789	7790	0	2	#2 BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER ECONOMIZER	Economizer Inlet Headers	74	30	Thermal/mechanical fatigue cracking, corrosion fatigue cracking, corrosion, FAC.	(10)	No real issue as per inspection to date. Additional inspections required.	3	B	Med	3	B	Medium	Ligament cracking, tube stub thinning/cracking, weld cracking. Unit derate/outage.	Additional inspections required.
1296	7635	7786	7789	7790	0	2	#2 BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER ECONOMIZER	Economizer Outlet Headers and Link Piping	75	30	Mechanical fatigue cracking, corrosion fatigue cracking, corrosion.	10	Could meet the desired life with routine inspections.	1	B	Low	1	B	Low	Weld cracking due to support failure. Unit derate/outage.	Routine inspections.
1296	7635	7786	7789	7790	0	2	#2 BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER ECONOMIZER	Economizer Tubes	76	30	External corrosion and corrosion fatigue.	(10)	Inspections are required to assess the remaining life.	1	B	Low	1	B	Low	Tube failure due to corrosion, corrosion-fatigue. Unit derate.	Inspections are required to assess remaining life.
1296	7635	7786	7789	7794	0	2	#2 BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER STEAM DRUM	Steam Drum	77	30	Thermal fatigue cracking, corrosion-fatigue cracking.	10	No real issue as per inspection to date. Additional inspections required.	3	C	Med	3	C	High	Ligament cracking. Weld cracking. Unit outage and life safety.	Additional inspections required.
1296	7635	7786	7810	0	0	2	#2 BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER SUPERHEATER & REHEAT	Secondary Superheater Tubes (Lower)	79	30	Creep, OD/ID corrosion, ID pitting and sagging.	(10)	Inspections are required to assess the remaining life.	3	C	Med	3	C	High	Tube failure due to creep and creep fatigue, OD/ID corrosion, ID pitting. Outage and life safety.	Additional inspections required.
1296	7635	7786	7810	0	0	2	#2 BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER SUPERHEATER & REHEAT	Secondary Superheater Tubes (Upper part that was replaced during the uprate in 1988/1989)	80	30	Creep, OD/ID corrosion, ID pitting and stress corrosion cracking.	(10)	Inspections are required to assess the remaining life.	2	C	Med	2	C	Medium	Creep, fatigue and stress corrosion, cracking damage, and wall thinning due to corrosion and pitting. Unit outage and life safety.	Additional inspections required.
1296	7635	7786	7810	0	0	2	#2 BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER SUPERHEATER & REHEAT	Secondary Superheater Tubes (Upper part that was replaced during the 2008 outage)	81	30	Creep, OD/ID corrosion, ID pitting and stress corrosion cracking.	10	This section is relatively new and could meet the desired life.	1	C	Low	1	C	Low	Creep, fatigue and stress corrosion, cracking damage, and wall thinning due to corrosion and pitting. Unit outage and life safety.	Additional inspections required.
1296	7635	7786	7810	7811	0	2	#2 BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER PRIMARY SUPERHEATER	Superheater Steam Cooled Walls Outlet Header	82	30	Thermal fatigue.	10	No real life limiting issue. Could meet the desired life with routine inspections.	1	B	Low	1	D	Medium	Thermal fatigue cracking. Unit outage and life safety.	Additional inspections required.
1296	7635	7786	7810	7811	0	2	#2 BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER PRIMARY SUPERHEATER	Superheater Rear Horizontal Spaced Inlet	83	30	Thermal fatigue.	10	No real life limiting issue. Could meet the desired life with routine inspections.	1	B	Low	1	D	Medium	Thermal fatigue cracking. Outage and life safety.	Additional inspections required.
1296	7635	7786	7810	7811	0	2	#2 BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER PRIMARY SUPERHEATER	Superheater Rear Horizontal Spaced Outlet	84	30	Creep and thermal fatigue.	10	No real life limiting issue. Could meet the desired life with routine inspections.	1	C	Low	1	D	Medium	Creep and thermal fatigue cracking. Outage and life safety.	Additional inspections required.
1296	7635	7786	7810	7811	0	2	#2 BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER PRIMARY SUPERHEATER	Superheater Front Support Tube Inlet Header	85	30	Creep and thermal fatigue.	(10)	Additional inspections required to assess the remaining life.	3	C	Med	2	D	Medium	Creep and thermal fatigue cracking. Outage and life safety.	Additional inspections required to assess the remaining life.
1296	7635	7786	7810	7811	0	2	#2 BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER PRIMARY SUPERHEATER	Superheater Front Horizontal Platen Inlet	86	30	Creep and thermal fatigue.	10	No real life limiting issue. Could meet the desired life with routine inspections.	1	C	Low	1	D	Medium	Creep and thermal fatigue cracking. Outage and life safety.	Additional inspections required.
1296	7635	7786	7810	7811	0	2	#2 BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER PRIMARY SUPERHEATER	Superheater Front Horizontal Space Outlet	87	30	Creep and thermal fatigue.	(10)	Additional inspections required to assess the remaining life.	3	D	High	3	D	High	Creep and thermal fatigue cracking. Outage and life safety.	Additional inspections required to assess the remaining life.
1296	7635	7786	7810	7811	0	2	#2 BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER PRIMARY SUPERHEATER	Primary Superheater Tubes	88	30	Fatigue, OD/ID corrosion, ID pitting.	10	No real life limiting issues; however, the presence inside pitting and scaling is not known.	1	C	Low	1	D	Low	Tube failure due to excessive pitting and corrosion. Unit outage.	Additional inspections required.
1296	7635	7786	7810	7813	0	2	#2 BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER SUPERHEATER ATTEMP'R	Superheater Link Piping and Attemperator	89	30	Thermal/mechanical fatigue, corrosion fatigue, corrosion.	(10)	No real issue as per external visual inspection to date. Additional inspections required.	1	C	Low	1	D	Medium	Thermal/mechanical fatigue cracking, corrosion-fatigue cracking, wall thinning due to corrosion related mechanisms.	Additional inspections required.
1296	7635	7786	7810	7830	0	2	#2 BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER REHEATER ATTEMPERATOR	N/A	90	33	Not Addressed in detail. Mechanical failure.	(10)	Additional inspections required to assess the remaining life.	3	B	Medium	3	C	High	Inspection and refurbish or replace.	
1296	7635	7786	7810	7835	0	2	#2 BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER REHEATER	Hot Reheat	91	33	Thermal/mechanical fatigue, creep, creep fatigue, corrosion.	(10)	Major issue is creep and creep fatigue. Creep life fraction expended is high (more than 60% for Units 1 & 2 and more than 25% for Unit 3 at the end of 2009). No evidence of upset or thermal fatigue. Metallographic inspections conducted in past for Units 1 & 2 (1987 to 2002); carbide particles in ferrite matrix; no significant crack or damage were found. No major damage found during walkdowns. Walkdown summary part describes specific observations.	3	C	Med	3	D	High	Pipe and/or weld failures at potentially high stress locations. Outage and life safety.	Inspect hot and cold walkdowns to assess hanger condition and potential high stress locations. FOCUS Phased Array and Metallographic Inspections at key locations. Hanger/Support Inspection and Monitoring Program. Level 2 assessments.

Table 9-29 Cont'd

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Component	Risk Assess #	Appendix #	Major Issues	Remaining Life Years	Remaining Life Comments	TECHNO-ECO RISK ASSESSMENT MODEL			SAFETY RISK ASSESSMENT MODEL			Possible Failure Event	Mitigation
														(Insufficient Info - Inspection Required Within (x) Years)		Likeli-hood	Conse-quence	Risk Level	Likeli-hood	Conse-quence	Safety Risk		
1296	7635	7786	7810	7835	0	2	#2 BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER REHEATER	Cold Reheat	92	33	Thermal/mechanical fatigue, corrosion fatigue, cracking, corrosion.	(10)	No seam-welded pipe. No NDE inspection or material testing has been done in recent past. Not possible to assess current condition or remaining life. No major damage found during walkdowns. Walkdown summary part describes specific observations.	1	B	Low	1	D	Low	Pipe and/or weld failures at potentially high stress locations Outage and life safety.	Piping Management Program. Hanger/Support Inspection and Monitoring Program. Level 2 assessments
1296	7635	7786	7810	7835	0	2	#2 BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER REHEATER	Reheater Inlet Header	93	30	Thermal fatigue.	10	Could meet the desired life with routine inspections.	1	B	Low	1	B	Low	Thermal fatigue cracking. Outage and life safety.	Inspect and maintain.
1296	7635	7786	7810	7835	0	2	#2 BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER REHEATER	Reheater Outlet Header	94	30	Creep and thermal fatigue.	(10)	Additional inspections required to assess the remaining life.	3	D	High	3	D	High	Creep and thermal fatigue cracking. Outage and life safety.	Inspect and maintain.
1296	7635	7786	7810	7835	0	2	#2 BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER REHEATER	Reheater Tubes	95	30	Creep, OD/ID corrosion, ID pitting, stress corrosion cracking and DMWs.	(10)	Inspections are required to assess the remaining life.	3	C	Med	3	D	High	Creep, fatigue and stress corrosion, cracking damage, wall thinning due to corrosion and pitting and DMW failures. Unit outage.	Inspect and maintain.
1296	7635	7786	7789	7789	0	2	#2 BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER BLOWDOWN TANK	N/A	95	33	Not addressed in detail. Thermal/mechanical fatigue.	(2)	Safety issue. End of life.	2	B	Medium	3	C	High	Mechanical failure. Steam leak. Personal injury.	Replace
1296	7635	7786	7810	7823	0	2	#2 BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER MAIN STEAM LINES	Main Steam	96	33	Thermal/mechanical fatigue, creep, creep fatigue, corrosion.	(10)	Major issue is creep and creep fatigue. Creep life fraction expended is high (more than 60% for Units 1 & 2 and more than 25% for Unit 3 at the end of 2009). No evidence of upset or thermal fatigue. Metallographic inspections conducted in past for Units 1 & 2 (1987 to 2002); carbide particles in ferrite matrix; no significant crack or damage were found. No major damage found during walkdowns. Walkdown summary part describes specific observations.	3	D	High	3	D	High	Inspect hot and cold walkdowns to assess hanger condition and potential high stress locations. Conduct inspections of welds at potentially high stress locations. Outage and life safety.	Inspect hot and cold walkdowns to assess hanger condition and potential high stress locations. Conduct inspections of welds at potentially high stress locations.
1296	7635	7786	7810	7823	322451	2	#2 BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER STOP VALVE	N/A	97	33	Thermal/mechanical fatigue, creep, creep fatigue, corrosion.	(5)	Additional inspections required to assess the remaining life.	3	C	Medium	3	C	High	Inspection and refurbish or replace.	

9.2.1.7 Life Cycle Curve and Remaining Life

The life cycle curves for the various elements of the Unit 2 boiler system is broken into three separate parts – the boiler headers and components outside the flue gas path, the high pressure and temperature steam lines (main steam, reheat steam), and the tubes exposed to the combustion process and/or flue gas within the boiler. Differences between the scenarios do not materially affect the curve.

The boiler headers and components are subject primarily to time spent under the effects of steam pressure and temperature. Their equivalent expended life presented in figure below is primarily related to the material properties and the steam conditions. As a result several curves are required to represent the range of the various elements of the system. Details are included in Appendix 30.The life curves are plots on the y-axis of current and projected consumed equivalent life hours based on the theoretical metallurgical assessments. This differs from other sections that use nominal operating hours of usage on the y-axis versus calendar year on the x-axis. The figure has several vertical lines representing differing representative nominal age limits for various components. It also has several horizontal lines that represent a range of practical equipment equivalent base loaded operating hour life limits. The figure also included two highlighted boxes. The risk box is representative of typical life expectations. The second identified as the “Level 2 Test” box identifies where EPRI recommends an initial Level 2 analyses or equivalent for these sorts of components (consumed life = 10% of expected or design life).

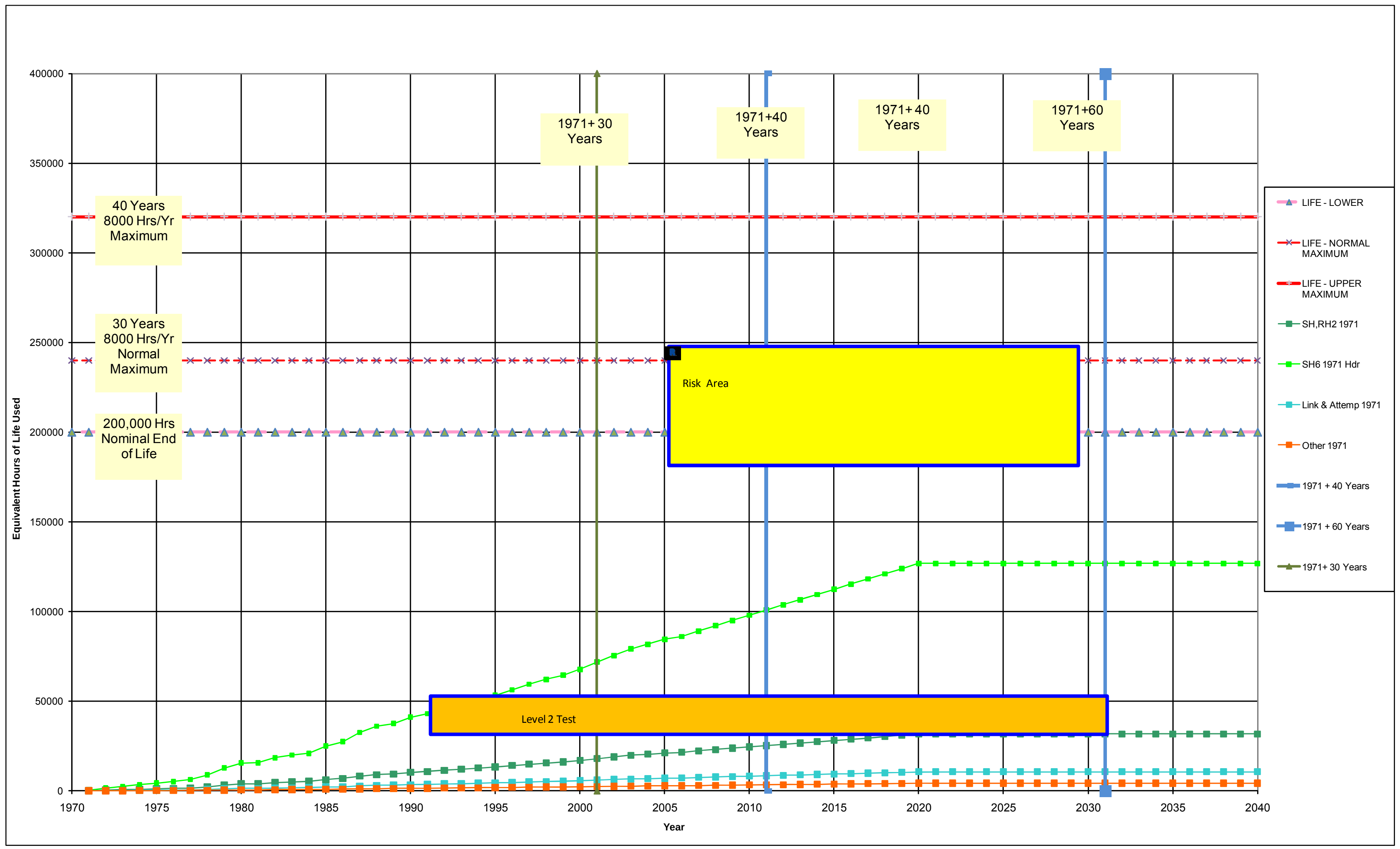

FIGURE 9-10 LIFE CYCLE CURVE – UNIT 2 BOILER SYSTEM – BOILER HEADERS

The header life curves indicate that the remaining life (RL) of the Unit 2 boiler headers and associated components is expected to exceed the desired life (DL) which is the generation end of life in 2020. Nevertheless, it also identifies that some of higher temperature components should undergo a Level 2 inspection (identified later in this section of the report) if not already planned or undertaken.

Three curves represent the high pressure, high temperature steam lines (main steam, hot reheat, and cold reheat). Their life expenditure (illustrated in figure below) is primarily related to the time spent under the effects of steam pressure and temperature (similar to the boiler headers) and to the material properties of the steam lines. Details are included in Appendix 33.The life curves are plots on the y-axis of current and projected "consumed equivalent life hours" based on the theoretical metallurgical assessments. The figure has three vertical lines representing differing representative nominal age limits. It also has several horizontal lines that represent a range of practical equipment equivalent base loaded operating hour life limits. The figure also included two highlighted boxes. The risk box is representative of typical life expectations. The second identified as the "Level 2 Test" box identifies where an initial Level 2 analyses or equivalent is likely required (consumed life = 10% of expected life). The main steam life consumption is higher because it operates at both high temperature and high pressure. The hot reheat lines operates at comparable temperatures, but at lower pressures. The cold reheat line operates at both lower temperature and pressure. All values take into consideration the pipe materials used.

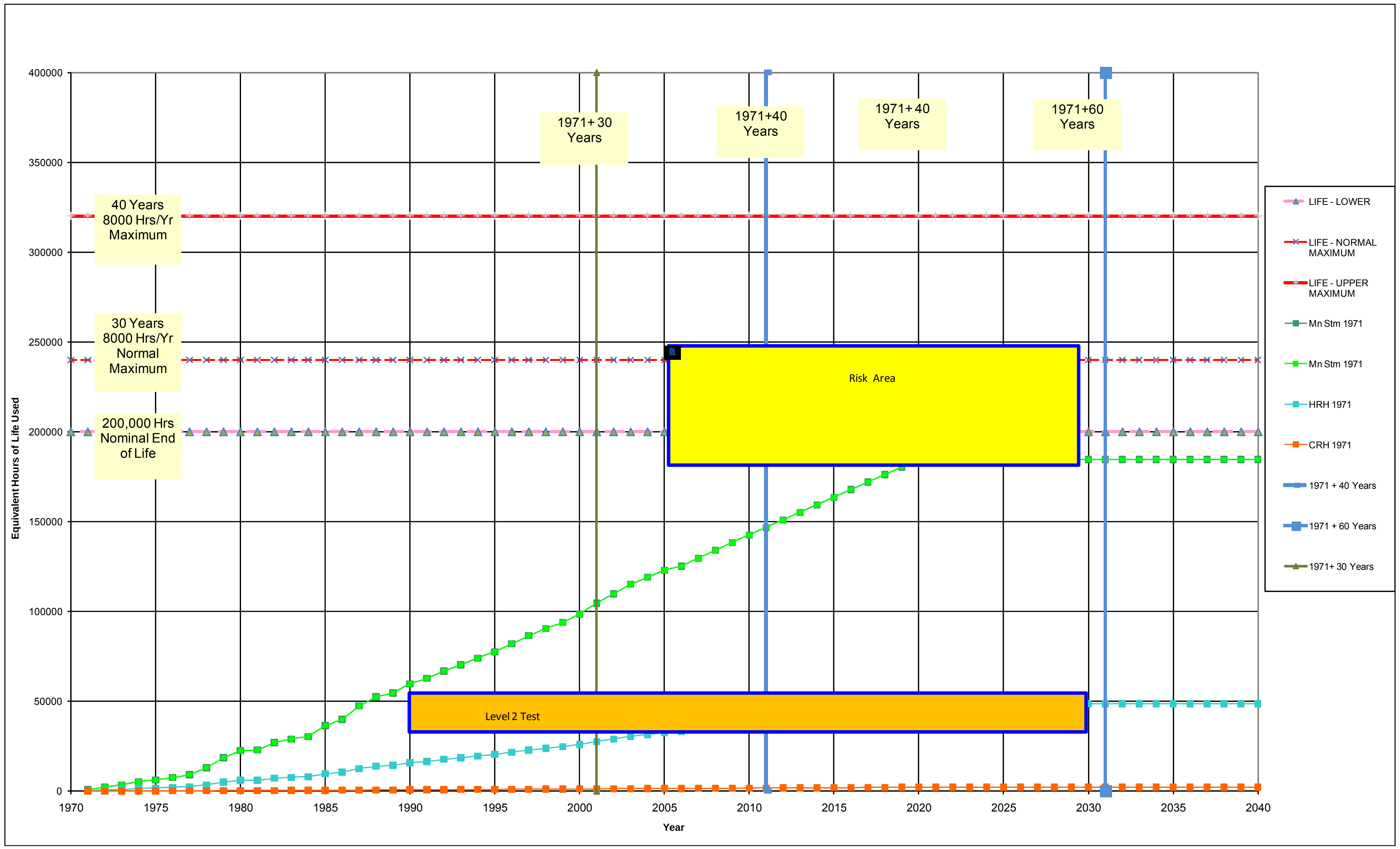

FIGURE 9-11 LIFE CYCLE CURVE – UNIT 2 BOILER SYSTEM – HIGH PRESSURE AND TEMPERATURE STEAM LINES

The high pressure steam line life curves indicate that the remaining life (RL) of the Unit 2 steam lines and their associated components are expected to exceed the desired life (DL) which is the generation end of life in 2020. Nevertheless it also identifies that both the main steam and hot reheat steam lines exceed EPRI's 10% consumed life guide for a Level 2 inspection of these systems. Given that they have not been tested for some time, this is considered appropriate at this time.

The Unit 2 boiler system tubes and associated components (exposed to combustion process and/or flue gas within the boiler) are subject to both internal water and/or steam intermediate temperatures and high pressures, but also externally to higher combustion temperatures, and corrosive and erosive conditions. Typically the externally conditions often are the life limiting factor. This is certainly the case for Holyrood units which were fuelled with a high sulphur, high vanadium, moderate ash heavy oil up until 2009. This is evident in the reliability statistics for the boilers, the multiple boiler outages for air preheater cleaning, economizer fouling history, and in the fairly extensive tube surface changes to 2009. The move to a lower sulphur, lower vanadium oil has effectively minimized these going forward, but some legacy effects are inevitable.

A single life cycle curve is presented beginning with the in-service date of the unit. It is meant to represent initial design goals, using nominally operating hours. It was considered impractical to accurately document or reasonably present in one curve the many changes that have occurred, and are likely to continue to occur going forward due to legacy impacts. It uses nominal operating hours as opposed to metallurgical equivalent hours in the two previous boiler curves as a more appropriate way of expressing its normal lifetime.

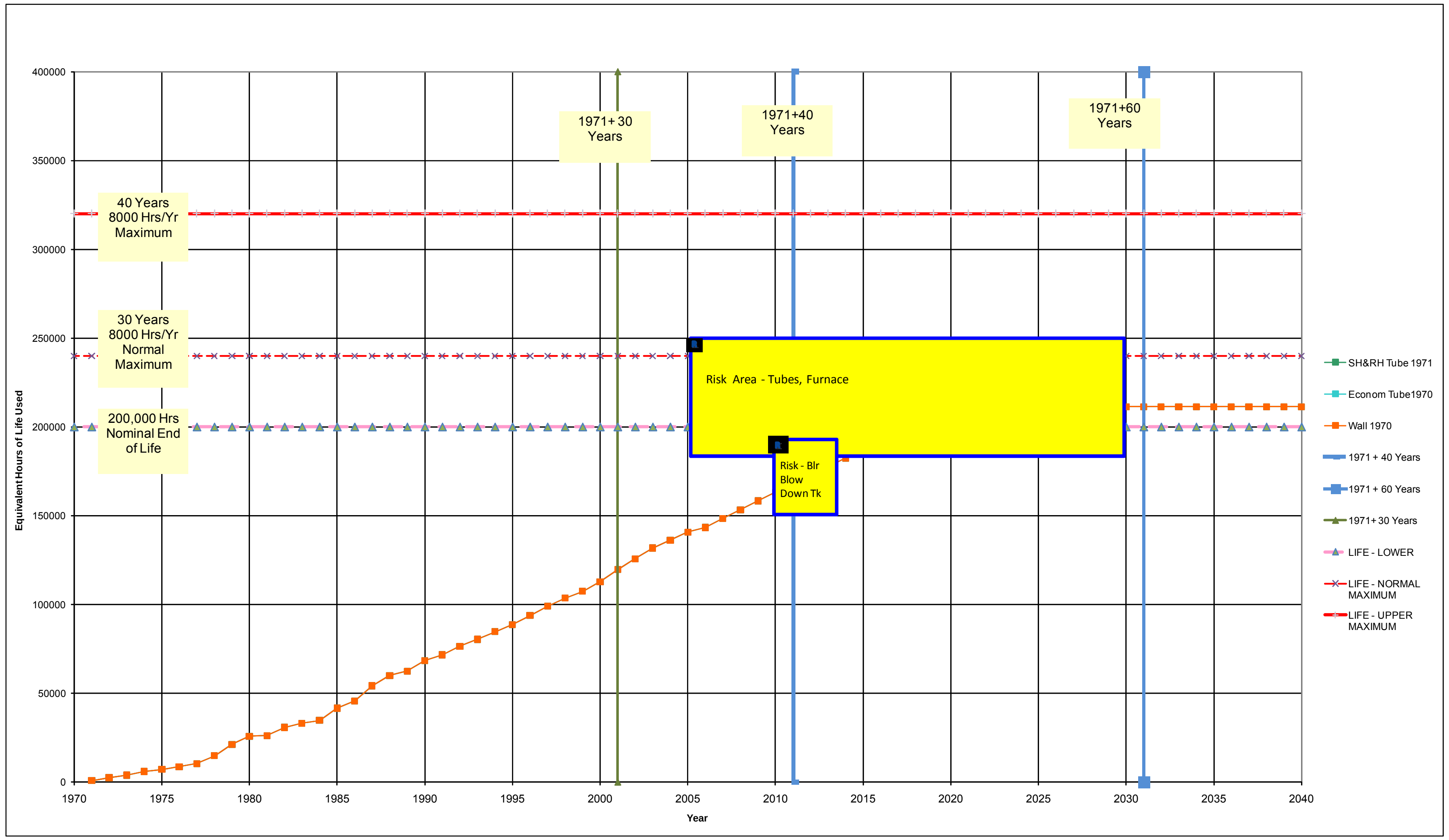

FIGURE 9-12 LIFE CYCLE CURVE – UNIT 2 BOILER SYSTEM (TUBES EXPOSED TO THE COMBUSTION PROCESS, BOILER BLOWDOWN)

The curve indicates that the boiler tubes within the furnace envelope would have been expected to be seeing some end of life component concerns with original equipment. Nevertheless, it is more likely legacy impacts that will have greater effects on component replacements and refurbishments going forward to 2020. With ongoing inspections and refurbishments, 2020 is achievable with good reliability with the new fuel. It also shows that the boiler blowdown tank should be replaced.

9.2.1.8 Level 2 Inspections – Unit 2 Boiler System

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 9-30 below, assuming that the current plant inspection and maintenance program is maintained or improved.

TABLE 9-30 LEVEL 2 INSPECTIONS – UNIT 2 BOILER SYSTEM

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Sub System Comment	L2#	Appendix #	Level 2 Work	Year	Priority	Cost k$
1296	7635	7786	0	0	0	2	#2 BOILER PLANT	BOILER PLANT	BOILER PLANT	N/A	47	30	Level 2 - Covers all boiler pressure part system costs - economizer, reheat, superheat, drum. See individual items for technical details.	2013	2	$1,476
1296	7635	7786	7789	0	0	2	#2 BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER FW & SAT'D STEAM SYS	Upper WW Headers	48	30	Inspections of ligament cracking, selective flat end welds, body spool pieces welds, feeder tube attachment welds and downcomers connection welds.	2013	3	
1296	7635	7786	7789	0	0	2	#2 BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER FW & SAT'D STEAM SYS	Riser Tubes	49	30	Inspection of selective riser tubes for corrosion fatigue cracking.	2013	2	
1296	7635	7786	7789	0	0	2	#2 BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER FW & SAT'D STEAM SYS	Lower WW Headers	50	30	Inspections of ligament cracking, selective flat end welds, body spool pieces welds, feeder tube attachment welds and downcomers connection welds.	2013	2	
1296	7635	7786	7789	0	0	2	#2 BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER FW & SAT'D STEAM SYS	Feeder Tubes	51	30	Inspection of selective feeder tubes for corrosion fatigue cracking.	2013	2	
1296	7635	7786	7789	0	0	2	#2 BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER FW & SAT'D STEAM SYS	Downcomers	52	30	Inspections of thermal/mechanical fatigue damage at the headers support locations.	2013	2	
1296	7635	7786	7789	0	0	2	#2 BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER FW & SAT'D STEAM SYS	Waterwall Tubes	53	30	Assessment of the floor tubes wall thinning. Evaluation of pitting on the tubes adjacent to burners and on the waterwall slope under the economizer.	2013	2	
1296	7635	7786	7789	7790	0	2	#2 BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER ECONOMIZER	Economizer Inlet Headers	54	30	Inspection of internal surfaces, ligaments, major girth and seam welds and drain line penetrations. UT inspection of stub tubes and a stub tube sample removal to assess evidence of FAC.	2013	2	
1296	7635	7786	7789	7790	0	2	#2 BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER ECONOMIZER	Economizer Outlet Headers and Link Piping	55	30	External visual inspection to ensure that there is no change in the state and/or abnormal movement.	2013	3	
1296	7635	7786	7789	7790	0	2	#2 BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER ECONOMIZER	Economizer Tubes	56	30	Sample tubes removal and ultrasonic sonic testing survey at the accessible locations to assess the potential corrosion fatigue damage due to mill defects that had caused a failure in the unit economizer tube in Unit 2 in 2005.	2013	3	
1296	7635	7786	7789	7794	0	2	#2 BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER STEAM DRUM	Steam Drum	57	30	Removal of the drum furniture and a section of the liner to inspect seam welds, nozzle welds, ligaments, downcomers and feedwater inlet pipe. External inspection of feeder tube welds.	2013	2	
1296	7635	7786	7810	7811	0	2	#2 BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER PRIMARY SUPERHEATER	Superheater Steam Cooled Walls Outlet Header	60	30	No Level 2 required.		3	
1296	7635	7786	7810	7811	0	2	#2 BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER PRIMARY SUPERHEATER	Superheater Rear Horizontal Spaced Inlet Header	61	30	No Level 2 required.		3	
1296	7635	7786	7810	7811	0	2	#2 BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER PRIMARY SUPERHEATER	Superheater Rear Horizontal Spaced Outlet Header	62	30	No Level 2 required.		3	

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Table 9-30 Cont'd

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Sub System Comment	L2#	Appendix #	Level 2 Work	Year	Cost k$
1296	7635	7786	7810	7811	0	2	#2 BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER PRIMARY SUPERHEATER	Superheater Front Support Tube Inlet Header	63	30	Internal boroscopic, external visual, dimensional on body spool pieces for creep and creep fatigue damage; UT inspections on welds and stub tubes and replica inspection.	2013	
1296	7635	7786	7810	7811	0	2	#2 BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER PRIMARY SUPERHEATER	Superheater Front Horizontal Platen Inlet Header	64	30	No Level 2 required.		
1296	7635	7786	7810	7811	0	2	#2 BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER PRIMARY SUPERHEATER	Superheater Front Horizontal Space Outlet Header	65	30	Internal boroscopic, external visual, dimensional on body spool pieces for creep and creep fatigue damage; UT inspections on welds and stub tubes and replica inspection.	2013	
1296	7635	7786	7810	7811	0	2	#2 BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER PRIMARY SUPERHEATER	Superheater Link Piping and Attemperator	66	30	Inspections for assessment of damage caused by thermal/mechanical fatigue cracking, corrosion fatigue cracking and corrosion.	2013	
1296	7635	7786	7810	7811	0	2	#2 BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER PRIMARY SUPERHEATER	Primary Superheater Tubes	67	30	Inspections to check the presence of inside pitting and scaling.	2013	
1296	7635	7786	7810	7813	0	2	#2 BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER SUPERHEATER ATTEMPR	None	68	30	No Level 2 required.		
1296	7635	7786	7810	7830	0	2	#2 BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER REHEATER ATTEMPERATOR	Reheater Inlet Header	69	30	No Level 2 required.		
1296	7635	7786	7810	7830	0	2	#2 BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER REHEATER ATTEMPERATOR	Reheater Outlet Header	70	30	Internal boroscopic, external visual, dimensional on body spool pieces for creep and creep fatigue damage; UT inspections on welds and stub tubes and replica inspection.	2013	
1296	7635	7786	7810	7830	0	2	#2 BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER REHEATER ATTEMPERATOR	Reheater Tubes	71	30	Destructive tube sample analysis to assess the extent of the damage due to creep. ID liquid ash corrosion, ID high temperature corrosion, stress corrosion cracking and DMW's.	2013	
1296	7635	7786	7810	7835	0	2	#2 BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER SECONDARY SUPERHEATER	Secondary Superheater Tubes (Lower)	72	30	Inspections to assess the extent of the damage due to creep, sagging, ID liquid ash corrosion and ID high temperature corrosion for creep, fatigue corrosion and pitting.	2013	
1296	7635	7786	7810	7835	0	2	#2 BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER SECONDARY SUPERHEATER	Secondary Superheater Tubes (Upper part that was replaced during the uprate in 1988/1989)	73	30	Inspections for creep, fatigue, corrosion, pitting and stress corrosion cracking.	2013	
1296	7635	7786	7810	7835	0	2	#2 BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER SECONDARY SUPERHEATER	Secondary Superheater Tubes (Upper part that was replaced during the 2008 outage)	74	30	No Level 2 required.		
1296	7635	7786	7789	7789	0	2	#2 BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER BLOWDOWN TANK		74a	33	No Level 2 required.		
1296	7635	7786	7810	7823	0	2	#2 BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER MAIN STEAM LINES	(Testing of Main Steam , Hot Reheat, Cold Reheat, HP feedwater	75	33	Level 2 testing of steam and high pressure feedwater lines.	2011	$395
1296	7635	7786	7810	7823	322451	2	#2 BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER STIOP VALVES	None	76	33	Level 2 testing of boiler stop valves as part of Main Steam Lines Program.	2011	$30
1296	7635	7786	7787	0	0	2	#2 BOILER PLANT	BOILER STRUCTURE	BOILER STRUCTURE		77	17	No Level 2 required.		

9.2.1.9 Capital Projects

The suggested typical capital enhancements for the system include:

TABLE 9-31 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – UNIT 2 BOILER SYSTEM

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Detail	CAP#	Appendix #	Capital Item	Date	Priority
1296	7635	7786	0	0	0	2	#2 BOILER PLANT	BOILER PLANT	BOILER PLANT	N/A	57	30	Install nitrogen blanketing. No other capital investment, pending Level 2 or next inspection.	2013	2
1296	7635	7786	7789	0	0	2	#2 BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER FW & SAT'D STEAM SYS	N/A	58	30	None, pending Level 2 or next inspection.		
1296	7635	7786	7789	7790	0	2	#2 BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER ECONOMIZER	N/A	59	30	None, pending Level 2 or next inspection. Possible new recirculation line.		
1296	7635	7786	7789	7794	0	2	#2 BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER STEAM DRUM	N/A	60	30	None, pending Level 2 or next inspection.		
1296	7635	7786	7789	7801	0	2	#2 BOILER PLANT	BOILER FW & SAT'D STEAM SYS	FURNACE	N/A	61	30	None, pending Level 2 or next inspection.		
1296	7635	7786	7810	0	0	2	#2 BOILER PLANT	BOILER SUPERHEATER &	BOILER SUPERHEATER &	N/A	62	30	None, pending Level 2 or next inspection.		
1296	7635	7786	7810	7811	0	2	#2 BOILER PLANT	BOILER SUPERHEATER &	BOILER PRIMARY SUPERHEATER	N/A	63	30	None, pending Level 2 or next inspection.		
1296	7635	7786	7810	7813	0	2	#2 BOILER PLANT	BOILER SUPERHEATER &	BOILER SUPERHEATER	N/A	64	30	None, pending Level 2 or next inspection.		
1296	7635	7786	7810	7830	0	2	#2 BOILER PLANT	BOILER SUPERHEATER &	BOILER REHEATER ATTEMPERATOR	N/A	65	30	None, pending Level 2 or next inspection.		
1296	7635	7786	7810	7835	0	2	#2 BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER REHEATER	N/A	66	30	Implement addition of RH surface to match design temperatures and efficiency, subject to decision on Holyrood.	2014	2
1296	7635	7786	7789	7789	0	2	#2 BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER BLOWDOWN TANK	N/A	67	30	Replace tank	2012	1
1296	7635	7786	7810	7823	0	2	#2 BOILER PLANT	BOILER SUPERHEATER &	BOILER MAIN STEAM LINES	N/A	68	30	None, pending Level 2 or next inspection.		
1296	7635	7786	7810	7823	322451	2	#2 BOILER PLANT	BOILER SUPERHEATER &	BOILER STOP VALVE	N/A	69	30	None, pending Level 2 or next inspection.		

9.2.2 Asset 7978 – Unit 2 Feedwater System High Pressure (HP) Heat Exchangers

(Detailed Technical Assessment in Working Papers, Appendices 32 and 34)

Unit #:	2
Asset Class #	BU 1296 - Assets Generations
SCI & System:	7976 #2 Condensate & Feedwater System
Sub-Systems:	8059 #2 High Pressure Feedwater
Components:	8066 #2 H.P. Heater 4
	8067 #2 H.P. Heater 5
	8068 #2 H.P. Heater 6
	8859 #2 Boiler Feed Pump East
	8860 #2 Boiler Feed Pump West

9.2.2.1 Description

The high pressure (HP) feedwater systems servicing Unit 2 contains three HP feedwater heat exchangers that are referred to as HP-4, HP-5 and HP-6. The primary function of the HP feedwater heat exchangers is to optimize the unit thermal efficiency by preheating the feedwater prior to entering the boilers.

Each HP feedwater heater is a horizontally mounted, 100% capacity pressure vessel of U-tube type construction. There are two tube passes on the feedwater side and a divided flow of heating steam on the shell side of the HP feedwater heater. The main components of the HP feedwater heat exchangers are shell, shell skirt, tubes, tubesheet, channel, impingement plates, tub support plates/pass partition plates/baffles, shrouds, impingement plate and channel cover. The tubesheet and channel are made from a single forging. The tube material for all three HP feedwater heat exchangers is stainless steel SA-688.

There are three zones on the shell side that are commonly referred to as desuperheating, condensing, and drains subcooling.

1. Desuperheating Zone: This is an enclosed portion at the outlet end of the tube bundle. An impingement plate is installed below the steam inlet nozzle to prevent impingement damage to the tubes. The desuperheating zone is enveloped by a separate shroud which conducts steam from the inlet nozzle to the condensing zone.

2. Condensing Zone: Steam exiting the desuperheating zone is condensed as it traverses through the condensing zone. Also, any drains from higher pressure heater flow into the condensing zone through the drains inlet nozzle. An impingement plate is installed just inside this nozzle to protect the tubes from these flashing drains. The condensing zone is vented continuously to remove non-condensable gases.

3. Drains Subcooling Zone: This zone is an enclosed portion of the inlet end of the tube bundle to maximize heat transfer from the shell side condensate to the incoming feedwater before the condensate exits. The condensate should be sub-cooled sufficiently to prevent flashing as the condensate leaves the HP feedwater heater shell through the drains outlet nozzle.

Two motor driven boiler feed pumps (BFP) service Unit 2. The pumps are multiple stage barrel centrifugal pumps. Each can provide up to 60% of the full load requirement. They have been in service since 1971, with some upgrades when the unit was uprated in 1989. The pump motors are 4 kV with a power rating of approximately 2000 kW. They directly drive the pumps. There is no variable speed device such as variable frequency drives or fluid couplings.

9.2.2.2 History

The requirements for the Unit 2 generators are as follows:

Manufactured/Delivered	1970
In-Service Date	Apr 1971
Generation Base Load End Date	Dec 2015
Generation Peak/Emerg Gen End Date	Dec 2020

The hours associated with the analyses vary for systems/equipment that has been replaced (specifically the HP5 heat exchangers) are:

Hours Generation Actual - Ops to Dec 2009	158
Max Hours Generation Ops – to Dec 2015	188
Max Hrs Gen Ops to Gen End Date Dec 2020	212

	Unit 2		
	HP-4	HP-5	HP-6
Year Installed	1988	2009	1988

9.2.2.3 Inspection and Repair History

There have been no NDE inspections carried out on the currently in service HP feedwater heat exchangers in the past apart from tube leak testing. Other than yearly leak checks, no NDE has been performed on LP heat exchangers either. A long term commitment (life-cycle management plan) is required to diagnose and track all the failures to identify possible remedial actions so as to preclude similar future occurrences and provides the best chance for optimizing feedwater heater.

The Unit 2 HP feedwater heat exchangers HP-4 and HP-5 have the same operating life as the feedwater heater HP-5 that was replaced in 2009 due to excessive tube failures due to Stress Corrosion Cracking (SCC). The HP feedwater heater HP-5 is exposed to higher temperature than HP-4 and HP-6; otherwise HP-4 and HP-6 would have been exposed to the similar environment as HP-5. Hence, Level 2 inspections are required in order to assess the remaining life on Unit 2 HP-4 and HP-6 feedwater heat exchangers.

The Unit 2 boiler feed pumps and motors are regularly maintained. The plant has a common spare pump barrel that they use to be able to refurbish all of the plant pumps on a six to seven year cycle. The 4 kV motors are tested electrically annually. No specific issues have been identified, but the motors are at a stage in life where failures may be anticipated.

9.2.2.4 Condition Assessment

The condition assessment of the Unit 2 feedwater system – HP feedwater heat exchangers is illustrated below in Table 9-32:

TABLE 9-32 CONDITION ASSESSMENT – UNIT 2 FEEDWATER SYSTEM - HP FEEDWATER HEAT EXCHANGERS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset Level 2	Asset Level 3	Description	Detail	Condition Summary ID#	Append #	Condition	EPRI Identifier	Original Life (Base Load) Ops Hrs (Yrs)	Current Expected Minimum Remaining Life Years (Subject to Test)	End of Life (EOL) Required	Next Regular Inspection	Next Planned Overhaul or Major Inspection	Capability to Reach Next Overhaul	Capability to Reach EOL	In Service
1296	7635	7978	8037	0	0	2	#2 CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEEDWATER PUMPING	N/A	119	23	4160V Motor annual tests. On-line bearing and winding temperature monitoring and system alarms based on motor current levels. Pumps, using a spare barrel, are refurbished approximately every seven to years.	3a	200000 (30)	10	2020	2012	2012	Yes	No	1971/1989
1296	7635	7978	8037	8847	0	2	#2 CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEED PUMP WEST	N/A	120	23	Pumps installed in 1969 and motors in 1989. Good condition due to pump refurbishment using spare barrel. Last pump refurbishment 2002 - next planned for 2011.	3a	200000 (30)	10+	2020	2011	2012	Yes	Yes	1971/1989
1296	7635	7978	8037	8847	0	2	#2 CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEED PUMP WEST	Motors	121	23	Motors installed in 1989.	3a	(25)	(5+)	2020	2011	2012	Yes	No	1989
1296	7635	7978	8037	8848	0	2	#2 CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEED PUMP EAST	N/A	122	23	Pumps installed in 1969 and motors in 1989. Good condition due to pump refurbishment using spare barrel. Last pump refurbishment 2004, next planned for 2012.	3a	200000 (30)	10+	2020	2012	2012	Yes	Yes	1971/1989
1296	7635	7978	8037	8848	0	2	#2 CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEED PUMP EAST	Motors	123	23	Motors installed in 1989.	3a	(25)	(5+)	2020	2012	2012	Yes	No	1989
1296	7635	7978	8059	0	0	2	#2 CONDENSATE & F.W. SYSTEM	H.P. FEEDWATER SYSTEM	H.P. FEEDWATER SYSTEM	N/A	124	32,33	No Flow Accelerated Corrosion (FAC) management program. Present water chemistry and operating conditions indicates that the feedwater system is susceptible to FAC.	4	150000 (20)	(5)	2020	2012	2013	Yes	Yes	1971
1296	7635	7978	8059	8066	0	2	#2 CONDENSATE & F.W. SYSTEM	H.P. FEEDWATER SYSTEM	H.P. HEATER 4	N/A	125	32	Installed 1985. No NDE inspections carried out on the currently in service HP feedwater heaters. HP feedwater tube leaks experienced. Plugged in order to satisfy the short-term problem. Cause uncertain. Numbers of leaks and locations not known. Uncertain if SCC tube failure degradation mechanism observed at Unit 2 HP-5 applicable to other HP feedwater heaters.	4	(25)	(10)	2020	2012	2013	Yes	Yes	1988
1296	7635	7978	8059	8067	0	2	#2 CONDENSATE & F.W. SYSTEM	H.P. FEEDWATER SYSTEM	H.P. HEATER 5	N/A	126	32	Replaced in 2009.	4	(20)	20	2020	2012	2013	Yes	Yes	2009
1296	7635	7978	8059	8068	0	2	#2 CONDENSATE & F.W. SYSTEM	H.P. FEEDWATER SYSTEM	H.P. HEATER 6	N/A	127	32	Installed 1988. No NDE inspections carried out on the currently in service HP feedwater heaters. HP feedwater tube leaks experienced. Plugged in order to satisfy the short-term problem. Cause uncertain. Numbers of leaks and locations not known. Uncertain if SCC tube failure degradation mechanism observed at Unit 2 HP-5 applicable to other HP feedwater heaters.	4	(25)	(10)	2020	2012	2013	Yes	Yes	1988

Notes:

1. A "(bracketed)" value in the "Current Expected Remaining Life" column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation, including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as "(X/Y)" has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

2. The "Next Regular Inspection" column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The "Next Planned Overhaul or Major Inspection" column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a "Desired Life" stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or not known by AMEC.

9.2.2.5 Actions

Based on the condition assessment, the following actions are recommended for the Unit 2 feedwater system – HP feedwater heat exchangers:

TABLE 9-33 RECOMMENDED ACTIONS – UNIT 2 FEEDWATER SYSTEM - HP FEEDWATER HEAT EXCHANGERS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Unit	Asset 2/3	Asset 3/4	Description	Detail	Action #	App #	Action	Year	Priority
1296	7635	7978	8037	0	2	#2 CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEEDWATER PUMPING	N/A	170	23	Assess potential for variable speed control of BFW pumps.	2011	2
1296	7635	7978	8037	0	2	#2 CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEEDWATER PUMPING	N/A	171	23	Assess potential for spare BFP motor and subsequent refurbishment/rewind of Unit 3 motors.	2011	2
1296	7635	7978	8037	8847	2	#2 CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEED PUMP WEST	N/A	172	23	Maintain current program of ongoing inspections and overhauls	2011	2
1296	7635	7978	8037	8848	2	#2 CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEED PUMP EAST	N/A	173	23	Maintain current program of ongoing inspections and overhauls	2011	2
1296	7635	7978	8059	0	2	#2 CONDENSATE & F.W. SYSTEM	H.P. FEEDWATER SYSTEM	H.P. FEEDWATER SYSTEM	N/A	174	32	See details below.		
1296	7635	7978	8059	8066	2	#2 CONDENSATE & F.W. SYSTEM	H.P. FEEDWATER SYSTEM	H.P. HEATER 4	N/A	175	32	Perform Level 2 inspections.	2013	2
1296	7635	7978	8059	8067	2	#2 CONDENSATE & F.W. SYSTEM	H.P. FEEDWATER SYSTEM	H.P. HEATER 5	N/A	176	32	Perform Level 2 inspections.	2013	2
1296	7635	7978	8059	8068	2	#2 CONDENSATE & F.W. SYSTEM	H.P. FEEDWATER SYSTEM	H.P. HEATER 6	N/A	177	32	Perform Level 2 inspections.	2013	2

9.2.2.6 Risk Assessment

Table 9-34 below illustrates the risk assessment for the Unit 2 feedwater system – HP feedwater heat exchangers, both from a technological perspective and a safety perspective using the models presented in Section 3.

TABLE 9-34 RISK ASSESSMENT – UNIT 2 FEEDWATER SYSTEM - HP FEEDWATER HEAT EXCHANGERS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Component	Risk Assess #	Appendix #	Major Issues	Remaining Life Years	Remaining Life Comments	TECHNO-ECO RISK ASSESSMENT MODEL			SAFETY RISK ASSESSMENT MODEL			Possible Failure Event	Mitigation
														(Insufficient Info - Inspection Required Within (x) Years)		Likeli-hood	Conse-quence	Risk Level	Likeli-hood	Conse-quence	Safety Risk		
1296	7635	7978	8037	0	0	2	#2 CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEEDWATER PUMPING	Feedwater Discharge	148	33	Flow Accelerated Corrosion (FAC), thermal/mechanical fatigue cracking, corrosion-fatigue cracking; corrosion.	10	Major issue is FAC; No NDE inspection or material testing has been done in recent past. Not possible to assess current condition or remaining life.	3	D	High	3	D	High	Conduct sample FAC inspections using EPRI methodology.	Inspect and maintain.
1296	7635	7978	8037	8847	0	2	#2 CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEED PUMP WEST	FW Pump East	149	23	Seal, bearing, impeller failure.	10+	Could meet the desired life; continued inspections/overhauls required .	1	C	Low	1	C	Low	Pump failure; 50% capability reduction.	Current inspection and maintain.
1296	7635	7978	8037	8847	0	2	#2 CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEED PUMP WEST	4 kV Boiler Feed Pump Motor	150	25	Electrical fault, mechanical fatigue, ops error.	(5+)	>2020 with regular inspection, maintenance.	1	C	Low	1	B	Low	Loss 60% unit generation for extended time.	Spare and current inspection and maintain.
1296	7635	7978	8037	8848	0	2	#2 CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEED PUMP EAST	FW Pump West	151	23	Seal, bearing, impeller failure.	10+	Could meet the desired life; continued inspections/overhauls required.	1	C	Low	1	C	Low	Pump failure; 50% capability reduction.	Current inspection and maintain.
1296	7635	7978	8037	8848	0	2	#2 CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEED PUMP EAST	4 kV Boiler Feed Pump Motor	152	25	Electrical fault, mechanical fatigue, ops error.	(5+)	>2020 with regular inspection, maintenance.	1	C	Low	1	B	Low	Loss 60% unit generation for extended time.	Spare and current inspection and maintain.
1296	7635	7978	8059	0	0	2	#2 CONDENSATE & F.W. SYSTEM	H.P. FEEDWATER SYSTEM	H.P. FEEDWATER SYSTEM	All HP Feedwater Heaters	153	32	SCC, thermal/ mechanical fatigue.	(10)	Life management program is required.	1	C	Low	2	B	Low	Excessive tube failure event resulting in Turbine water induction.	Inspect and maintain.
1296	7635	7978	8059	8066	0	2	#2 CONDENSATE & F.W. SYSTEM	H.P. FEEDWATER SYSTEM	H.P. HEATER 4	Unit #2 HP Feedwater Heater #4	154	32	SCC, FAC, thermal/ mechanical fatigue, corrosion fatigue.	(10)	Inspections are required to assess the remaining life.	3	B	Medium	2	B	Medium	Tube failures, internal hardware failure and shell wall thinning due FAC and weld cracking.	Inspect and maintain.
1296	7635	7978	8059	8067	0	2	#2 CONDENSATE & F.W. SYSTEM	H.P. FEEDWATER SYSTEM	H.P. HEATER 5	Unit #2 HP Feedwater Heater #5	155	32	SCC, FAC, thermal/ mechanical fatigue, corrosion fatigue.	(10)	Brand new Heater can meet the desired life with routine inspections.	1	B	Low	2	B	Low	Tube failures, internal hardware failure and shell wall thinning due FAC and weld cracking.	Inspect and maintain.
1296	7635	7978	8059	8068	0	2	#2 CONDENSATE & F.W. SYSTEM	H.P. FEEDWATER SYSTEM	H.P. HEATER 6	Unit #2 HP Feedwater Heater #6	156	32	SCC, FAC, thermal/ mechanical fatigue, corrosion fatigue.	(10)	Inspections are required to assess the remaining life.	3	B	Medium	2	B	Low	Tube failures, internal hardware failure and shell wall thinning due FAC and weld cracking.	Inspect and maintain.

9.2.2.7 Life Cycle Curve and Remaining Life

The life cycle curves for the Unit 2 feedwater system - HP feedwater heat exchangers and Unit 2 boiler feed pumps are illustrated below. The life curves are plots of current and projected operating hours (generation mode only) on the y-axis versus calendar year on the x-axis. The figure has several vertical lines representing differing representative nominal age limits for various components. It also has several horizontal lines that represent a range of practical equipment equivalent base loaded operating hour life limits. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view.

For the Unit 2 feedwater system - HP feedwater heat exchangers, individual curves represent the three heat exchangers and components, as well as a curve to represent any balance of plant that is original equipment.

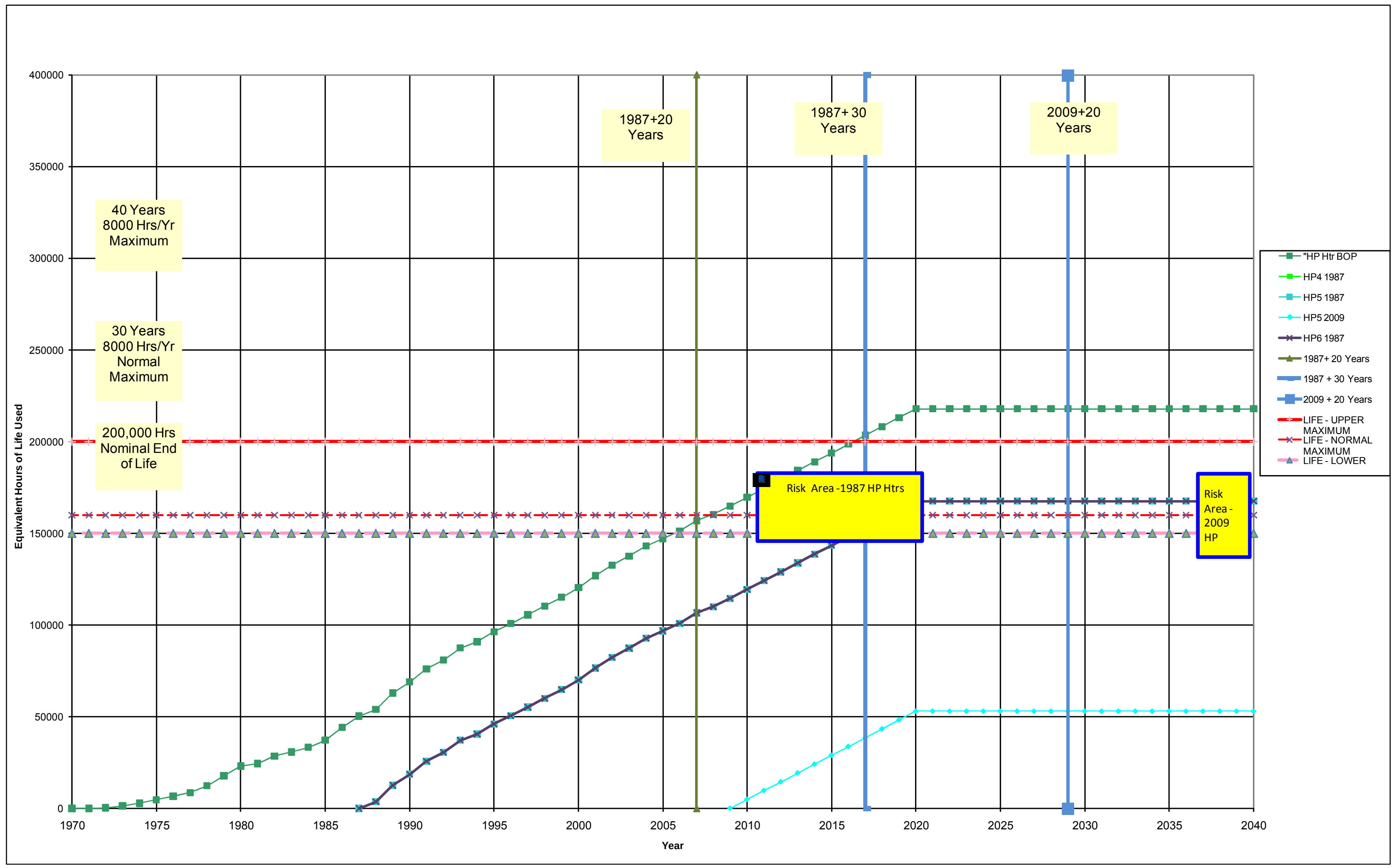

FIGURE 9-13 LIFE CYCLE CURVE – UNIT 2 FEEDWATER SYSTEM - HP FEEDWATER HEAT EXCHANGERS -

The curves indicate that the remaining life (RL) of the Unit 2 HP feedwater heat exchangers (and the associated feedwater systems) may be able to reach the desired life (DL) 2020 end date for generation. Nevertheless, given that no detailed NDE information has been obtained on the HP heat exchangers for some time, a detailed Level 2 inspection is recommended for 2013.

For the Unit 2 boiler feed pumps, a single curve represents each of the two boiler feed pumps dating back to their original installation. While indicative of expected life with good maintenance practice, the pumps have been and continue to be refurbished on a six year cycle using a spare pump section. Their actual condition is therefore substantially better than might otherwise be expected.

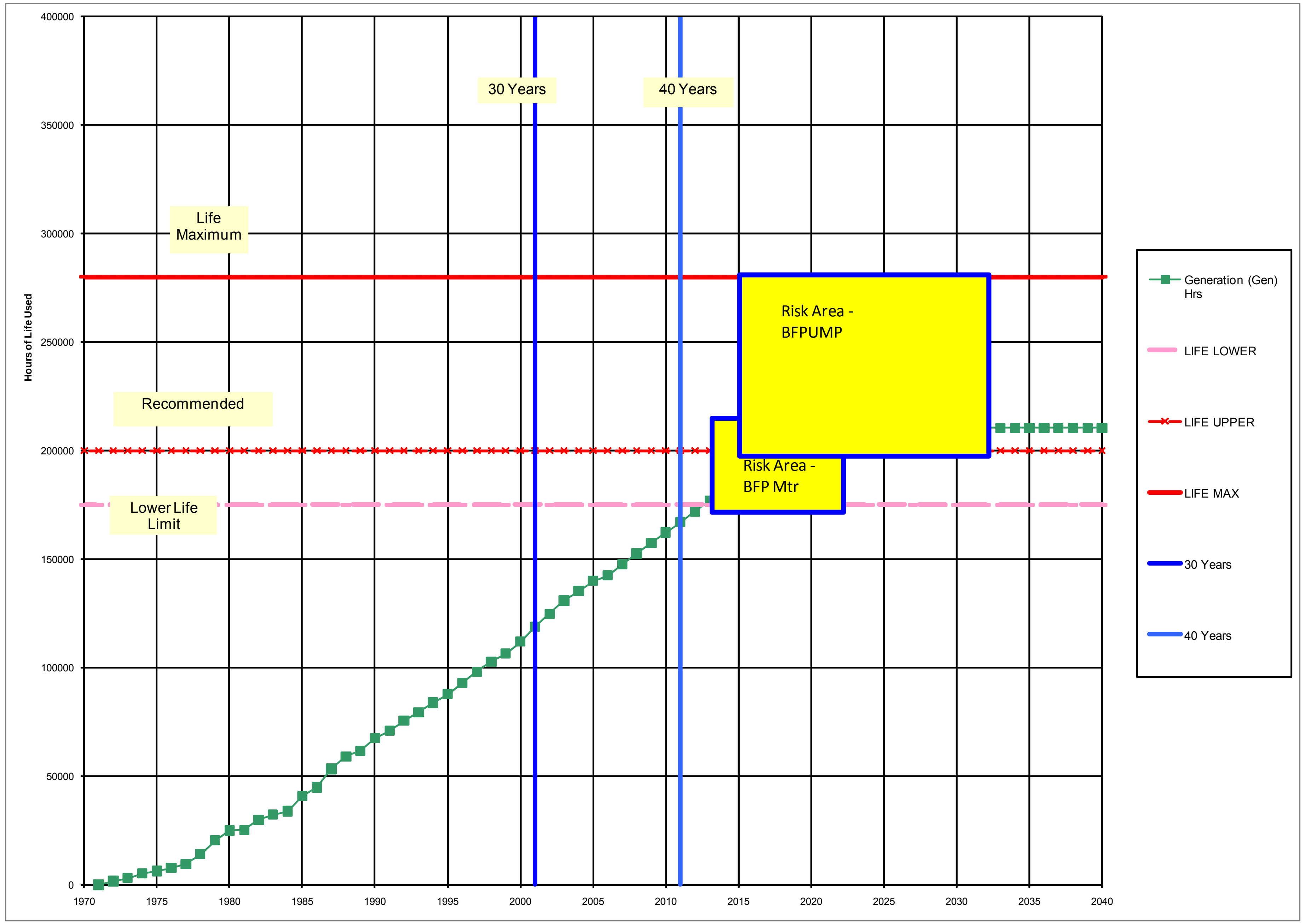

FIGURE 9-14 LIFE CYCLE CURVE – UNIT 2 FEEDWATER SYSTEM - BOILER FEED PUMPS

The curve indicates that the remaining life (RL) of the Unit 2 HP boiler feed pumps is likely able to reach desired end date which is the 2020 end date for generation. Given their six year refurbishment cycle and a spare pump section, they are expected to continue to perform reliably well past the 2020 end date for generation. The BFP motors are approaching older age and entering areas where reliability and unexpected failure may become more an issue than expected life.

9.2.2.8 Level 2 Inspections – Unit 2 Feedwater System - HP Feedwater Heat Exchangers

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 9-35 below, assuming that the current plant inspection and maintenance program is maintained or improved.

TABLE 9-35 LEVEL 2 INSPECTIONS – UNIT 2 FEEDWATER SYSTEM - HP FEEDWATER HEAT EXCHANGERS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Sub System Comment	L2#	Appendix #	Level 2 Work	Year	Priority	Cost k$
1296	7635	7978	8059	8066	0	2	#2 CONDENSATE & F.W. SYSTEM	H.P. FEEDWATER SYSTEM	H.P. HEATER 4	None	122	32	Shell side inspections and channel side for the degradation mechanisms.	2013	2	
1296	7635	7978	8059	8066	0	2	#2 CONDENSATE & F.W. SYSTEM	H.P. FEEDWATER SYSTEM	H.P. HEATER 4	None	123	32	Assessment of the tube plug map.	2013	2	
1296	7635	7978	8059	8066	0	2	#2 CONDENSATE & F.W. SYSTEM	H.P. FEEDWATER SYSTEM	H.P. HEATER 4	None	124	32	ET inspection of tubes to assess the present condition (metallurgical evaluation may also be required depending upon the condition of the tubes).	2013	2	
1296	7635	7978	8059	8066	0	2	#2 CONDENSATE & F.W. SYSTEM	H.P. FEEDWATER SYSTEM	H.P. HEATER 4	None	125	32	NDE inspection the major welds (seam, supports and nozzle welds) for the degradation mechanisms. PT or Magnetic particle testing (MT) or Conventional UT or Phased array (focused) can be used depending upon location.	2013	2	
1296	7635	7978	8059	8067	0	2	#2 CONDENSATE & F.W. SYSTEM	H.P. FEEDWATER SYSTEM	H.P. HEATER 5	None	126	32	Shell side inspections and channel side for the degradation mechanisms.	2013	2	
1296	7635	7978	8059	8067	0	2	#2 CONDENSATE & F.W. SYSTEM	H.P. FEEDWATER SYSTEM	H.P. HEATER 5	None	127	32	Assessment of the tube plug map.	2013	2	
1296	7635	7978	8059	8067	0	2	#2 CONDENSATE & F.W. SYSTEM	H.P. FEEDWATER SYSTEM	H.P. HEATER 5	None	128	32	ET inspection of tubes to assess the present condition (metallurgical evaluation may also be required depending upon the condition of the tubes).	2013	2	
1296	7635	7978	8059	8067	0	2	#2 CONDENSATE & F.W. SYSTEM	H.P. FEEDWATER SYSTEM	H.P. HEATER 5	None	129	32	NDE inspection the major welds (seam, supports and nozzle welds) for the degradation mechanisms. PT or Magnetic particle testing (MT) or Conventional UT or Phased array (focused) can be used depending upon location.	2013	2	
1296	7635	7978	8059	8068	0	2	#2 CONDENSATE & F.W. SYSTEM	H.P. FEEDWATER SYSTEM	H.P. HEATER 6	None	130	32	Shell side inspections and channel side for the degradation mechanisms.	2013	2	
1296	7635	7978	8059	8068	0	2	#2 CONDENSATE & F.W. SYSTEM	H.P. FEEDWATER SYSTEM	H.P. HEATER 6	None	131	32	Assessment of the tube plug map.	2013	2	
1296	7635	7978	8059	8068	0	2	#2 CONDENSATE & F.W. SYSTEM	H.P. FEEDWATER SYSTEM	H.P. HEATER 6	None	132	32	ET inspection of tubes to assess the present condition (metallurgical evaluation may also be required depending upon the condition of the tubes).	2013	2	
1296	7635	7978	8059	8068	0	2	#2 CONDENSATE & F.W. SYSTEM	H.P. FEEDWATER SYSTEM	H.P. HEATER 6	None	133	32	NDE inspection the major welds (seam, supports and nozzle welds) for the degradation mechanisms. PT or Magnetic particle testing (MT) or Conventional UT or Phased array (focused) can be used depending upon location.	2013	2	

9.2.2.9 Capital Projects

The suggested typical capital enhancements for the system include:

TABLE 9-36 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – UNIT 2 FEEDWATER SYSTEM – HP FEEDWATER HEAT EXCHANGERS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Detail	CAP#	Appendix #	Capital Item	Date	Priority
1296	7635	7978	8037	0	0	2	#2 CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEEDWATER PUMPING	N/A	112		No capital investment required.		
1296	7635	7978	8037	8847	0	2	#2 CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEED PUMP WEST	N/A	113	23	Retrofit of variable speed control – fluid couplings or variable speed drives to reduce energy consumption and improve efficiency.	2013	3
1296	7635	7978	8037	8847	0	2	#2 CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEED PUMP WEST	N/A	114	23	Procure a spare 4 kV motor, to allow rewind of Units 1 and 2 and, if practical, Unit 3 motors as required.	2012	1
1296	7635	7978	8037	8847	0	2	#2 CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEED PUMP WEST	N/A	115	23	Install vibration monitoring.	2012	1
1296	7635	7978	8037	8848	0	2	#2 CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEED PUMP EAST	N/A	116	23	Retrofit of variable speed control – fluid couplings or variable speed drives to reduce energy consumption and improve efficiency.	2013	3
1296	7635	7978	8037	8848	0	2	#2 CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEED PUMP EAST	N/A	117	23	Procure a spare 4 kV motor, to allow rewind of Units 1 and 2 and if practical Unit 3 motors as required.	2012	1
1296	7635	7978	8037	8848	0	2	#2 CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEED PUMP EAST	N/A	118	23	Install vibration monitoring.	2012	1
1296	7635	7978	8059	0	0	2	#2 CONDENSATE & F.W. SYSTEM	H.P. FEEDWATER SYSTEM	H.P. FEEDWATER SYSTEM	N/A	119	32	No capital investment required.		
1296	7635	7978	8059	8066	0	2	#2 CONDENSATE & F.W. SYSTEM	H.P. FEEDWATER SYSTEM	H.P. HEATER 4	N/A	120	32	None, pending Level 2 or next inspection.		
1296	7635	7978	8059	8067	0	2	#2 CONDENSATE & F.W. SYSTEM	H.P. FEEDWATER SYSTEM	H.P. HEATER 5	N/A	121	32	Replace HP Htr 5 - similar to Unit 1.	2013	1
1296	7635	7978	8059	8068	0	2	#2 CONDENSATE & F.W. SYSTEM	H.P. FEEDWATER SYSTEM	H.P. HEATER 6	N/A	122	32	None, pending Level 2 or next inspection.		

9.2.3 Asset 8017 – Unit 2 Feedwater System - Deaerator

(Detailed Technical Assessment in Working Papers, Appendices 31 and 34)

Unit #:	2
Asset Class #	BU 1296 - Assets Generations
SCI & System:	7976 #2 Condensate & Feedwater System
Sub-Systems:	7992 #2 Low Pressure Feedwater System
Components:	8017 #2 Deaerator System (Deaerator and Deaerator Storage Tank)

9.2.3.1 Description

Deaerator systems consist of two vessels, a heater (deaerator) and a storage tank (deaerator storage tank). The Unit 2 deaerator is a horizontal spray type, with the deaerator mounted on the horizontal deaerator storage tank.

The deaerator and deaerator storage tank vessels are of welded construction using carbon steel with some of the deaerator internal hardware fabricated from stainless steel. The vessels are designed as per American Society of Mechanical Engineers (ASME) Boilers and Pressure Vessels Code Section VIII, Div. 1. There is one safety valve on the top of the each deaerator vessel.

The function of the deaerator is to remove oxygen and other dissolved gases in the feedwater to lower the potential for corrosion in the steam/water cycle. Condensate is sprayed over a cascading series of trays to maximize the surface area of the water. Bleed steam is used as a main source of steam to strip the oxygen and other non-condensable gases from the condensate. Pegging steam is provided from the auxiliary steam system. The steam and gases are vented from the top of the deaerator vessel.

The deaerated water is collected in the storage tank where steam coil heaters maintain water temperatures during off-line periods.

The deaerator storage tank is the suction tank for the boiler feedwater pumps (BFP's). High pressure (HP) feedwater heater drains are fed to the deaerator. The BFP recirculation is fed back to the storage tank.

The deaerator storage tank is provided with two cradle type supports. One end is anchored and the other support is free to allow thermal expansion.

9.2.3.2 History

Manufactured/Delivered	1970
In-Service Date	Apr 1971
Generation Base Load End Date	Dec 2015
Generation Peak/Emerg Gen End Date	Dec 2020

The hours associated with the analyses are:

Hours Generation Actual - Ops to Dec 2009	158
Max Hours Generation Ops – to Dec 2015	188
Max Hrs Gen Ops to Gen End Date Dec 2020	212

9.2.3.3 Inspection and Repair History

The deaerator and deaerator storage tank vessels internal visual inspections and NDE of the selective welds were carried out in accordance with the plant annual inspection plan. The inspections were mostly focused on the accessible areas. There were very limited inspections carried out on the deaerator vessels as there is no real access to the shell without removing the trays. The following is a summary of the inspection findings that were reported in the ALSTOM outage reports from years 2001 to 2009.

Deaerator

- Cracks in the stainless steel liner;
- Warped stainless liner causing sealing issues for spray nozzles;
- Loose trays;
- Circumferential ridges in the deaerator shells on both the north and south sides;
- Minor corrosion, pitting and wall thinning, possibly due to flow accelerated corrosion in the bottom of the shells, was noted when a section of trays was removed in 2005; and
- No evidence of cracking in the accessible shell seam welds during limited inspections.

Deaerator Storage Tank

- Corrosion fatigue was found in the storage tank on the inside surface of the shell around the saddle support locations during the 2003 inspections. All damage was removed and the thickness of the tank was restored by pad welding. A semi-circle was cut in the centre gusset plates in the saddles to increase flexibility. Also, the stitch weld between the vessel shell and saddle plate was removed at the centre gusset plate location. Corrosion fatigue was not observed during subsequent inspections at these locations; and
- Light pitting has been observed on the inside surfaces in general and especially around the weld seams and in the bottom of shells.

9.2.3.4 Condition Assessment

The condition assessment of the Unit 2 feedwater system - deaerator is illustrated below in Table 9-37:

TABLE 9-37 CONDITION ASSESSMENT– UNIT 2 FEEDWATER SYSTEM - DEAERATOR

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset Level 2	Asset Level 3	Description	Detail	Condition Summary ID#	Append #	Condition	EPRI Identifier	Original Life (Base Load) Ops Hrs (Yrs)	Current Expected Minimum Remaining Life Years (Subject to Test)	End of Life (EOL) Required	Next Regular Inspection	Next Planned Overhaul or Major Inspection	Capability to Reach Next Overhaul	Capability to Reach EOL	In Service
1296	7635	7978	7992	8017	0	2	#2 CONDENSATE & F.W. SYSTEM	L P FEEDWATER SYSTEM	DEAERATOR SYSTEM	N/A	116	31	No major life limiting issue observed during the past limited deaerator and deaerator storage tank inspections. Many susceptible locations have not been inspected. The corrosion fatigue issues experienced in the past are not re-occurring. Some pitting in the both deaerator and deaerator storage tank vessels observed. Wall thinning observed in the bottom of the deaerator shells. Ridges observed may be due to erosion.	4	200000 (30)	(10)	2020	2011	2013	Yes	Yes	1971

Notes:

1. A "(bracketed)" value in the "Current Expected Remaining Life" column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation, including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as "(X/Y)" has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

2. The "Next Regular Inspection" column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The "Next Planned Overhaul or Major Inspection" column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a "Desired Life" stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or not known by AMEC.

9.2.3.5 Actions

Based on the condition assessment, the following actions are recommended for the Unit 2 feedwater system - deaerator.

TABLE 9-38 RECOMMENDED ACTIONS – UNIT 2 FEEDWATER SYSTEM - DEAERATOR

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Unit	Asset 2/3	Asset 3/4	Description	Detail	Action #	App #	Action	Year	Priority
1296	7635	7978	7992	8017	2	#2 CONDENSATE & F.W. SYSTEM	L P FEEDWATER SYSTEM	DEAERATOR SYSTEM	N/A	159	31	See details below.		
1296	7635	7978	7992	8017	2	#2 CONDENSATE & F.W. SYSTEM	L P FEEDWATER SYSTEM	DEAERATOR SYSTEM	N/A	160	31	Perform Level 2 inspections.	2013	2
1296	7635	7978	7992	8017	2	#2 CONDENSATE & F.W. SYSTEM	L P FEEDWATER SYSTEM	DEAERATOR SYSTEM	N/A	161	31	Implement ongoing inspections and performance testing based on industry practices.	2013	3
1296	7635	7978	7992	8017	2	#2 CONDENSATE & F.W. SYSTEM	L P FEEDWATER SYSTEM	DEAERATOR SYSTEM	N/A	162	31	Repair the feedwater recirculation inlet nozzles at the deaerator storage tank from inside if not repaired yet.	2013	3
1296	7635	7978	7992	8017	2	#2 CONDENSATE & F.W. SYSTEM	L P FEEDWATER SYSTEM	DEAERATOR SYSTEM	N/A	163	31	Refurbish manway seating surfaces that are in poor condition.	2013	2
1296	7635	7978	7992	8017	2	#2 CONDENSATE & F.W. SYSTEM	L P FEEDWATER SYSTEM	DEAERATOR SYSTEM	N/A	164	31	Monitor pitting corrosion in the deaerator and deaerator storage tank vessels and wall thinning in the bottom of the deaerator.	2013	2
1296	7635	7978	7992	8017	2	#2 CONDENSATE & F.W. SYSTEM	L P FEEDWATER SYSTEM	DEAERATOR SYSTEM	N/A	165	31	Investigate the root cause of the ridges observed in deaerator vessels.	2013	2
1296	7635	7978	7992	8017	2	#2 CONDENSATE & F.W. SYSTEM	L P FEEDWATER SYSTEM	DEAERATOR SYSTEM	N/A	166	31	Assess the significance of weld undercut that was observed in Unit 1 deaerator storage tank.	2013	2
1296	7635	7978	7992	8017	2	#2 CONDENSATE & F.W. SYSTEM	L P FEEDWATER SYSTEM	DEAERATOR SYSTEM	N/A	167	31	Evaluate condition of spray nozzles that were observed eroding in Unit 3.	2013	2

9.2.3.6 Risk Assessment

Table 9-39 below illustrates the risk assessment for the Unit 2 feedwater system - deaerator, both from a technological perspective and a safety perspective using the models presented in Section 3.

TABLE 9-39 RISK ASSESSMENT – UNIT 2 FEEDWATER SYSTEM – DEAERATOR

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Component	Risk Assess #	Appendix #	Major Issues	Remaining Life Years	Remaining Life Comments	TECHNO-ECO RISK ASSESSMENT MODEL			SAFETY RISK ASSESSMENT MODEL			Possible Failure Event	Mitigation
														(Insufficient Info - Inspection Required Within (x) Years)		Likeli-hood	Conse-quence	Risk Level	Likeli-hood	Conse-quence	Safety Risk		
1296	7635	7978	7992	8017	0	2	#2 CONDENSATE & F.W. SYSTEM	L P FEEDWATER SYSTEM	DEAERATOR SYSTEM	Deaerators	143	31	Corrosion-fatigue, thermal fatigue, corrosion and FAC.	(10)	No real life limiting issue as per inspection to date. Additional inspections required.	3	B	Medium	3	B	Medium	Weld cracking, corrosion fatigue, wall thinning due FAC and internal hardware failure leading to functional failure.	Inspect and maintain.
1296	7635	7978	7992	8017	0	2	#2 CONDENSATE & F.W. SYSTEM	L P FEEDWATER SYSTEM	DEAERATOR SYSTEM	Deaerator Storage Tanks	144	31	Corrosion-fatigue, thermal fatigue, corrosion and FAC.	(10)	No real life limiting issue as per inspection to date. Additional inspections required.	2	B	Low	2	B	Low	Weld cracking, corrosion fatigue cracking, pitting corrosion cracking and support failure.	Inspect and maintain.
1296	7635	7978	7992	8017	0	2	#2 CONDENSATE & F.W. SYSTEM	L P FEEDWATER SYSTEM	DEAERATOR SYSTEM	Deaerators/ Storage Tanks	145	31	Corrosion fatigue and thermal fatigue.	(10)	No evidence of susceptibly during limited inspection to date. Ongoing monitoring required.	1	D	Medium	1	D	Low	Catastrophic failure at seam weld.	Inspect and maintain.

9.2.3.7 Life Cycle Curve and Remaining Life

The life cycle curve for the Unit 2 feedwater system - deaerator is illustrated below. One curve is used as the major elements of the deaerator are largely of the same age and condition. The life curve is a plot of current and projected operating hours in generation mode only on the y-axis versus calendar year on the x-axis. The figure has several vertical lines representing differing representative nominal age limits for various components. It also has several horizontal lines that represent a range of practical equipment equivalent base loaded operating hour life limits. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view.

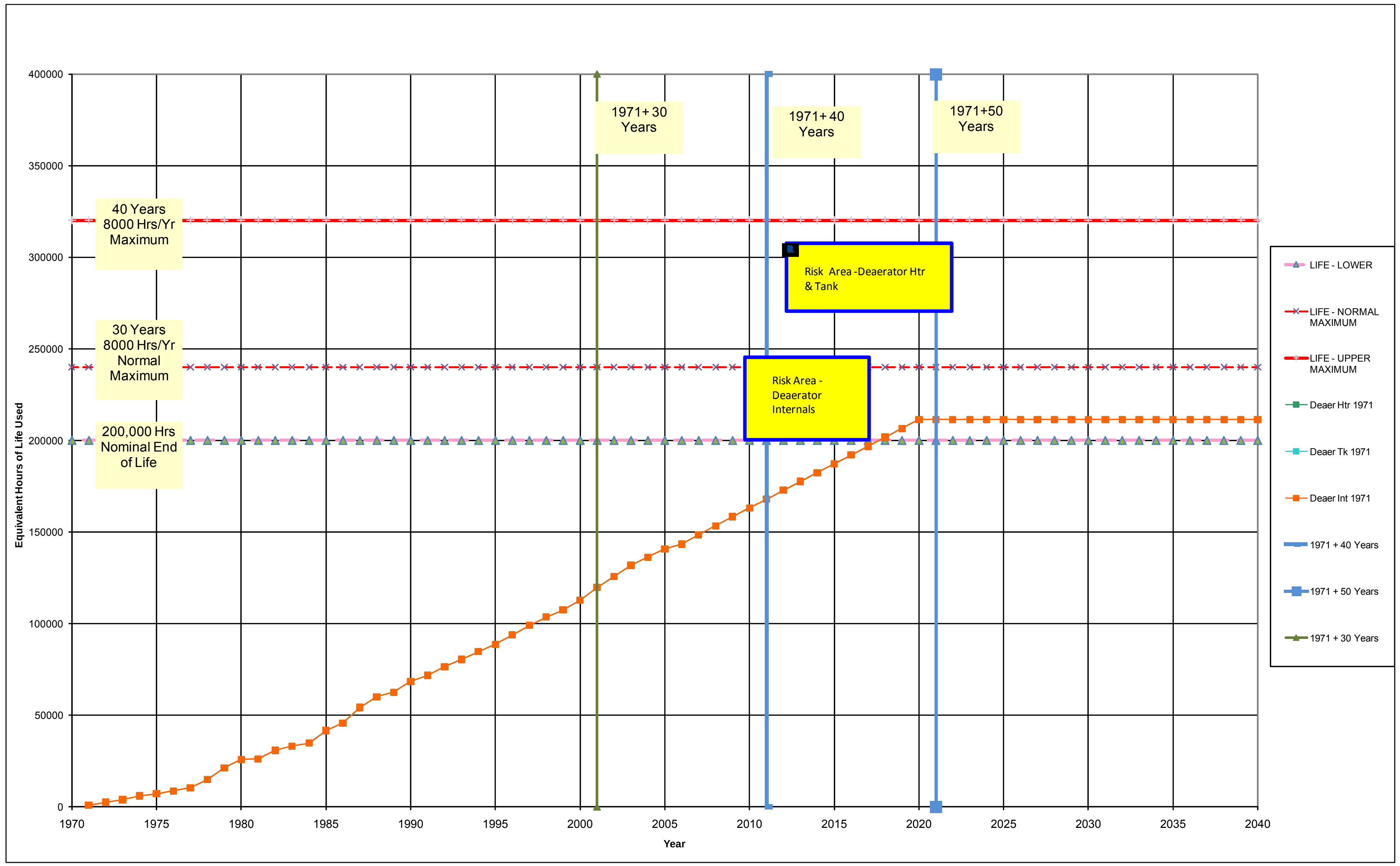

FIGURE 9-15 LIFE CYCLE CURVE – UNIT 2 FEEDWATER SYSTEM - DEAERATOR

The curve indicates that the remaining life (RL) of the Unit 2 feedwater system - deaerator exceeds the desired life (DL) which is end date for generation of 2020, with the potential though unlikely exception of some deaerator internals. The plant inspections form an excellent base of condition information supporting the ability of the deaerator as a whole to meet the EOL date. There is however insufficient detailed inspection information of some of the difficult to reach internals to fully assess their condition. A detailed Level 2 inspection in 2013 is recommended to provide information for that assessment.

9.2.3.8 Level 2 Inspections – Unit 2 Feedwater System - Deaerator

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 9-40 below, assuming that the current plant inspection and maintenance program is maintained or improved.

TABLE 9-40 LEVEL 2 INSPECTION – UNIT 2 FEEDWATER SYSTEM - DEAERATOR

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Sub System Comment	L2#	Appendix #	Level 2 Work	Year	Priority	Cost k$
1296	7635	7978	7992	8017	0	2	#2 CONDENSATE & F.W. SYSTEM	L P FEEDWATER SYSTEM	DEAERATOR SYSTEM	None	112	31	NDE inspection of the areas that were not inspected is required.	2013	2	$222
1296	7635	7978	7992	8017	0	2	#2 CONDENSATE & F.W. SYSTEM	L P FEEDWATER SYSTEM	DEAERATOR SYSTEM	None	113	31	Visual inspection for FAC damage (shiny black surface) of the susceptible areas. UT thickness measurement to be carried out if FAC damage is evident.	2013	2	
1296	7635	7978	7992	8017	0	2	#2 CONDENSATE & F.W. SYSTEM	L P FEEDWATER SYSTEM	DEAERATOR SYSTEM	None	114	31	Inspection of all accessible shell and head surfaces for pitting, and for water streaks or signs of erosion (erosion will normally appear as a clean, pitted surface).	2013	2	
1296	7635	7978	7992	8017	0	2	#2 CONDENSATE & F.W. SYSTEM	L P FEEDWATER SYSTEM	DEAERATOR SYSTEM	None	115	31	Inspection of the tray stack.	2013	2	
1296	7635	7978	7992	8017	0	2	#2 CONDENSATE & F.W. SYSTEM	L P FEEDWATER SYSTEM	DEAERATOR SYSTEM	None	116	31	Inspection of the spray valves.	2013		
1296	7635	7978	7992	8017	0	2	#2 CONDENSATE & F.W. SYSTEM	L P FEEDWATER SYSTEM	DEAERATOR SYSTEM	None	117	31	Inspections for cracking. Re-inspection intervals to be based on operating/inspection/repair history as per NACE recommendations and local regulations.	2013	2	

9.2.3.9 Capital Projects

The suggested typical capital enhancements for the system include:

TABLE 9-41 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – UNIT 2 FEEDWATER SYSTEM – DEAERATOR

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Detail	CAP#	Appendix #	Capital Item	Date	Priority
1296	7635	7978	7992	8017	0	2	#2 CONDENSATE & F.W. SYSTEM	L P FEEDWATER SYSTEM	DEAERATOR SYSTEM	N/A	109	31	None, pending Level 2 or next inspection.		

9.2.4 Asset 7992 – Unit 2 Feedwater System - Low Pressure (LP) Feedwater Heat Exchangers

(Detailed Technical Assessment in Working Papers, Appendix 24)

Unit #:	2
Asset Class #	BU 1296 - Assets Generations
SCI & System:	7978 #2 Condensate & Feedwater System
Sub-Systems:	7992 #2 Low pressure Feedwater
Components:	7997 #2 L.P. Heater 1
	7998 #2 L.P. Heater 2
	8032 #2 LP FW Reserve
	8800 #2 Condensate Extraction System

9.2.4.1 Description

The low pressure (LP) feedwater system servicing Unit 2 contains two LP feedwater heat exchangers that are referred to as LP-1 and LP-2. The primary function of the LP feedwater heat exchangers is to increase plant thermal efficiency by preheating the boiler feedwater prior entering to the deaerator.

The LP feedwater heat exchangers are horizontally mounted, 100% capacity pressure vessels of U-tube type construction. There are two tube passes on the feedwater side and a divided flow of heating steam on the shell side of each heater.

The main components of the LP feedwater heat exchangers are shell, shell skirt, tubes, tubesheet, channel, impingement plates, tube support plates/pass partition plates/baffles, shrouds, impingement plate and channel cover. The tubesheet and channel are made from a single forging. The heat exchangers are designed according to ASME Boiler and Pressure Vessel Code Section VIII Div. 1, Heat Exchanger Institute standard for the closed feedwater heat exchangers.

Two condensate extraction pumps service Unit 2, driven by 4 kV electric motors. The pumps are original equipment and the motors were installed during the upgrade in 1990. The pumps draw condensate from the condenser and circulate it to the low pressure feedwater heaters and deaerator. The system also includes condensate make-up and a low pressure feedwater reserve tank system to enable the unit to manage high and low water levels throughout the condensate and feedwater system.

9.2.4.2 History

Manufactured/Delivered	1970
In-Service Date	Apr 1971
Generation Base Load End Date	Dec 2015
Generation Peak/Emerg Gen End Date	Dec 2020

The hours associated with the analyses are:

Hours Generation Actual - Ops to Dec 2009	158
Max Hours Generation Ops – to Dec 2015	188
Max Hrs Gen Ops to Gen End Date Dec 2020	212

9.2.4.3 Inspection and Repair History

Leak tests are generally performed on the LP feedwater heat exchangers during annual outages, but records of these tests were not available. Leaking tubes are plugged when identified during a leak test. In addition, tube plugging maps and history were not available. During interviews with plant operations staff, it was noted that there were no performance issues associated with the LP feedwater heat exchangers servicing Unit 2.

The condensate extraction system is regularly inspected as part of the plant PM program. No significant issues have been identified with the pumps or motors. The motors are electrically checked annually and appear to be in reasonable condition for their age. However, the motors are at an age where reliability and failure may be issues in the future. The condensate extraction piping is experiencing some external corrosion, but no leaks or failures were identified.

No internal inspections of the reserve tank have been undertaken recently, due primarily to concerns with enclosed space requirements. Externally, there is some minor surface pitting evident but no significant problems or leaks were noted.

9.2.4.4 Condition Assessment

The condition assessment of the Unit 2 feedwater system – LP feedwater heat exchangers (and associated condensate extraction system) components is illustrated below in Table 9-42:

TABLE 9-42 CONDITION ASSESSMENT – UNIT 2 FEEDWATER SYSTEM - LP FEEDWATER HEAT EXCHANGERS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset Level 2	Asset Level 3	Description	Detail	Condition Summary ID#	Append #	Condition	EPRI Identifier	Original Life (Base Load) Ops Hrs (Yrs)	Current Expected Minimum Remaining Life Years (Subject to Test)	End of Life (EOL) Required	Next Regular Inspection	Next Planned Overhaul or Major Inspection	Capability to Reach Next Overhaul	Capability to Reach EOL	In Service
1296	7635	7978	0	0	0	2	#2 CONDENSATE & F.W. SYSTEM	CONDENSATE & F.W. SYSTEM	CONDENSATE & F.W. SYSTEM	N/A	103	N/A	See details below.	4	200000 (30)	10	2020	2011	2011	No	Yes	1971
1296	7635	7978	8800	0	0	2	#2 CONDENSATE & F.W. SYSTEM	CONDENSATE EXTRACTION SYST	CONDENSATE EXTRACTION SYST	N/A	104	20	No issues identified.	3a	(30)	10	2020			Yes	Yes	1971
1296	7635	7978	8800	7986	0	2	#1 UNIT GENERATION SERVICES	CONDENSATE EXTRACTION SYST	COND EXTRACTION PUMP NORTH	N/A	105	20	Pump installed in 1970 and motor in 1990. No issue identified.	3a	(30)	10	2020	2012		Yes	Yes	1971/1990
1296	7635	7978	8800	7987	0	2	#1 UNIT GENERATION SERVICES	CONDENSATE EXTRACTION SYST	COND.EXTRACTION PUMP SOUTH	N/A	106	20	Pump installed in 1970 and motor in 1990. No issue identified.	3a	(30)	10	2020	2012		Yes	Yes	1971/1990
1296	7635	7978	7980	0	0	2	#2 CONDENSATE & F.W. SYSTEM	CONDENSATE MAKE UP SYSTEM	CONDENSATE MAKE UP SYSTEM	N/A	107	31	See polisher assessment.	4	200000 (30)	10	2020	2011	2011	No	Yes	1971
1296	7635	7978	7992	0	0	2	#2 CONDENSATE & F.W. SYSTEM	L P FEEDWATER SYSTEM	L P FEEDWATER SYSTEM	N/A	110	26	Not reviewed in detail, primarily LP heaters.	4	200000 (30)	(10)	2020	2011	2011	Yes	Yes	1971
1296	7635	7978	7992	7997	0	2	#2 CONDENSATE & F.W. SYSTEM	L P FEEDWATER SYSTEM	LOW PRESSURE HEATER 1	N/A	111	26	No NDE inspections done. Annual cleaning and tube leak testing. Two heaters on the units may have been replaced, but no records or other interviews could confirm	4	(30)	(10)	2020	2011	2011	Yes	Yes	1971
1296	7635	7978	7992	7998	0	2	#2 CONDENSATE & F.W. SYSTEM	L P FEEDWATER SYSTEM	LOW PRESSURE HEATER 2	N/A	112	26	No NDE inspections done. Annual cleaning and tube leak testing. Two heaters on the units may have been replaced, but no records or other interviews could confirm	4	(30)	(10)	2020	2011	2011	Yes	Yes	1971
1296	7635	7978	7992	8032	0	2	#2 CONDENSATE & F.W. SYSTEM	L P FEEDWATER SYSTEM	RESERVE FW SYSTEM	N/A	113	26	No internal visual inspections recently. Minor external pitting corrosion. Relatively minor internal corrosion identified during interviews. No recent NDE inspections.	4	(60)	(20)	2020	2011	2011	Yes	Yes	1971

Notes:
1. A "(bracketed)" value in the "Current Expected Remaining Life" column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation, including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as "(X/Y)" has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.
2. The "Next Regular Inspection" column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The "Next Planned Overhaul or Major Inspection" column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a "Desired Life" stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or not known by AMEC.

9.2.4.5 Actions

Based on the condition assessment, the following actions are recommended for the Unit 2 feedwater system - LP feedwater heat exchangers (and associated condensate extraction system) components:

TABLE 9-43 RECOMMENDED ACTIONS – UNIT 2 FEEDWATER SYSTEM - LP FEEDWATER HEAT EXCHANGERS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Unit	Asset 2/3	Asset 3/4	Description	Detail	Action #	App #	Action	Year	Priority
1296	7635	7978	0	0	2	#2 CONDENSATE & F.W. SYSTEM	CONDENSATE & F.W. SYSTEM	CONDENSATE & F.W. SYSTEM	N/A	144	20	See details below.		
1296	7635	7978	8800	0	2	#2 CONDENSATE & F.W. SYSTEM	CONDENSATE EXTRACTION SYST	CONDENSATE EXTRACTION SYST	N/A	145	20	Spot check likely critical parts of piping and valving – thickness and corrosion.	2011	2
1296	7635	7978	8800	0	2	#2 CONDENSATE & F.W. SYSTEM	CONDENSATE EXTRACTION SYST	CONDENSATE EXTRACTION SYST	N/A	146	20	Maintain current program of ongoing inspections and overhauls. Procure a spare motor to service all three units in the event of a failure of an existing unit.	2011	2
1296	7635	7978	8800	7986	2	#2 UNIT GENERATION SERVICES	CONDENSATE EXTRACTION SYST	COND EXTRACTION PUMP NORTH	N/A	147	20	Continue current inspection and maintenance activities.	2011	2
1296	7635	7978	8800	7987	2	#2 UNIT GENERATION SERVICES	CONDENSATE EXTRACTION SYST	COND.EXTRACTION PUMP SOUTH	N/A	148	20	Continue current inspection and maintenance activities.	2011	2
1296	7635	7978	7980	0	2	#2 CONDENSATE & F.W. SYSTEM	CONDENSATE MAKE UP SYSTEM	CONDENSATE MAKE UP SYSTEM	N/A	149	21	No recommended action.		
1296	7635	7978	7992	0	2	#2 CONDENSATE & F.W. SYSTEM	L P FEEDWATER SYSTEM	L P FEEDWATER SYSTEM	N/A	152	24	Implement ongoing inspections and performance testing based on industry practices.	20111	2
1296	7635	7978	7992	7997	2	#2 CONDENSATE & F.W. SYSTEM	L P FEEDWATER SYSTEM	LOW PRESSURE HEATER 1	N/A	153	24	Perform Level 2 inspections.	2011	2
1296	7635	7978	7992	7998	2	#2 CONDENSATE & F.W. SYSTEM	L P FEEDWATER SYSTEM	LOW PRESSURE HEATER 2	N/A	154	24	Perform Level 2 inspections.	2011	2
1296	7635	7978	7992	8032	2	#2 CONDENSATE & F.W. SYSTEM	L P FEEDWATER SYSTEM	RESERVE FW SYSTEM	N/A	155	26	Perform Level 2 inspections on tanks – thickness checks and internals inspections.	2011	3
1296	7635	7978	7992	8032	2	#2 CONDENSATE & F.W. SYSTEM	L P FEEDWATER SYSTEM	RESERVE FW SYSTEM	N/A	156	26	Implement ongoing inspections and performance testing based on industry practices.	2011	2

9.2.4.6 Risk Assessment

Table 9-44 below illustrates the risk assessment for the Unit 2 feedwater system - LP feedwater heat exchangers (and associated condensate extraction system) components, both from a technological perspective and a safety perspective using the models presented in Section 3.

TABLE 9-44 RISK ASSESSMENT – UNIT 2 FEEDWATER SYSTEM - LP FEEDWATER HEAT EXCHANGERS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Component	Risk Assess #	Appendix #	Major Issues	Remaining Life Years	Remaining Life Comments	TECHNO-ECO RISK ASSESSMENT MODEL			SAFETY RISK ASSESSMENT MODEL			Possible Failure Event	Mitigation
														(Insufficient Info - Inspection Required Within (x) Years)		Likeli-hood	Conse-quence	Risk Level	Likeli-hood	Conse-quence	Safety Risk		
1296	7635	7978	8800	0	0	2	#2 CONDENSATE & F.W. SYSTEM	CONDENSATE EXTRACTION SYST	CONDENSATE EXTRACTION SYST	CE Piping/Valves	129	20	Weld failure, rupture.	10	None	1	A	Low	1	B	Low	Piping leak; short duration shutdown for repair.	Inspect and maintain.
1296	7635	7978	8800	7986	0	2	#2 CONDENSATE & F.W. SYSTEM	CONDENSATE EXTRACTION SYST	COND EXTRACTION PUMP NORTH	CE Pumps	130	20	Seal, bearing, impeller failure.	10	None	1	A	Low	1	B	Low	Pump failure; 0% capability reduction due to redundancy.	Current inspection and maintain.
1296	7635	7978	8800	7986	0	2	#2 CONDENSATE & F.W. SYSTEM	CONDENSATE EXTRACTION SYST	COND EXTRACTION PUMP NORTH	4 kV Condensate Extraction Pump Motor	131	25	Electrical fault, mechanical fatigue, ops error.	(10)	None	1	B	Low	1	B	Low	Loss 60% unit generation.	Spare and current inspection and maintain.
1296	7635	7978	8800	7987	0	2	#2 CONDENSATE & F.W. SYSTEM	CONDENSATE EXTRACTION SYST	COND.EXTRACTION PUMP SOUTH	CE Pumps	132	20	Seal, nearing, impeller failure.	10	None	1	A	Low	1	B	Low	Pump failure; 0% capability reduction due to redundancy.	Current inspection and maintain.
1296	7635	7978	8800	7987	0	2	#2 CONDENSATE & F.W. SYSTEM	CONDENSATE EXTRACTION SYST	COND.EXTRACTION PUMP SOUTH	4 kV Condensate Extraction Pump Motor	133	25	Electrical fault, mechanical fatigue, ops error.	(10)	None	1	B	Low	1	B	Low	Loss 60% unit generation.	Spare and current inspection and maintain.
1296	7635	7978	7980	0	0	2	#2 CONDENSATE & F.W. SYSTEM	CONDENSATE MAKE UP SYSTEM	CONDENSATE MAKE UP SYSTEM	N/A	134		Not addressed.	(5)	None								
1296	7635	7978	7992	0	0	2	#2 CONDENSATE & F.W. SYSTEM	L P FEEDWATER SYSTEM	L P FEEDWATER SYSTEM	N/A	137	24	SCC, thermal/ mechanical fatigue.	(10)	Life management program is required	1	C	Low	1	B	Low	Excessive tube failure event resulting in Turbine water induction.	Inspect and maintain.
1296	7635	7978	7992	7997	0	2	#2 CONDENSATE & F.W. SYSTEM	L P FEEDWATER SYSTEM	LOW PRESSURE HEATER 1	N/A	138	24	SCC, FAC, thermal/ mechanical fatigue, corrosion fatigue.	(10)	Inspections are required to assess the remaining life.	1	B	Low	1	B	Low	Tube failures, internal hardware failure and shell wall thinning due FAC and weld cracking.	Inspect and maintain.
1296	7635	7978	7992	7998	0	2	#2 CONDENSATE & F.W. SYSTEM	L P FEEDWATER SYSTEM	LOW PRESSURE HEATER 2	N/A	139	24	SCC, FAC, thermal/mechanical fatigue, corrosion fatigue.	(10)	Brand new Heater can meet the desired life with routine inspections.	1	B	Low	1	B	Low	Tube failures, internal hardware failure and shell wall thinning due FAC and weld cracking.	Inspect and maintain.
1296	7635	7978	7992	8032	0	2	#2 CONDENSATE & F.W. SYSTEM	L P FEEDWATER SYSTEM	RESERVE FW SYSTEM	LP Feedwater Reserve Tanks	140	26	Corrosion, impingement.	(20)	>10 Years. Inspections are required to confirm.	1	A	Low	1	A	Low	Major Leak, loss condensate.	Inspect and maintain.

9.2.4.7 Life Cycle Curve and Remaining Life

The life cycle curve for the Unit 2 feedwater system - LP feedwater heat exchangers is illustrated below. One curve represents both of the low pressure heat exchangers which are original equipment. The life curve is a plot of current and projected operating hours (generation mode only) on the y-axis versus calendar year on the x-axis. The figure has several vertical lines representing differing representative nominal age limits for various components. It also has several horizontal lines that represent a range of practical equipment equivalent base loaded operating hour life limits. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view.

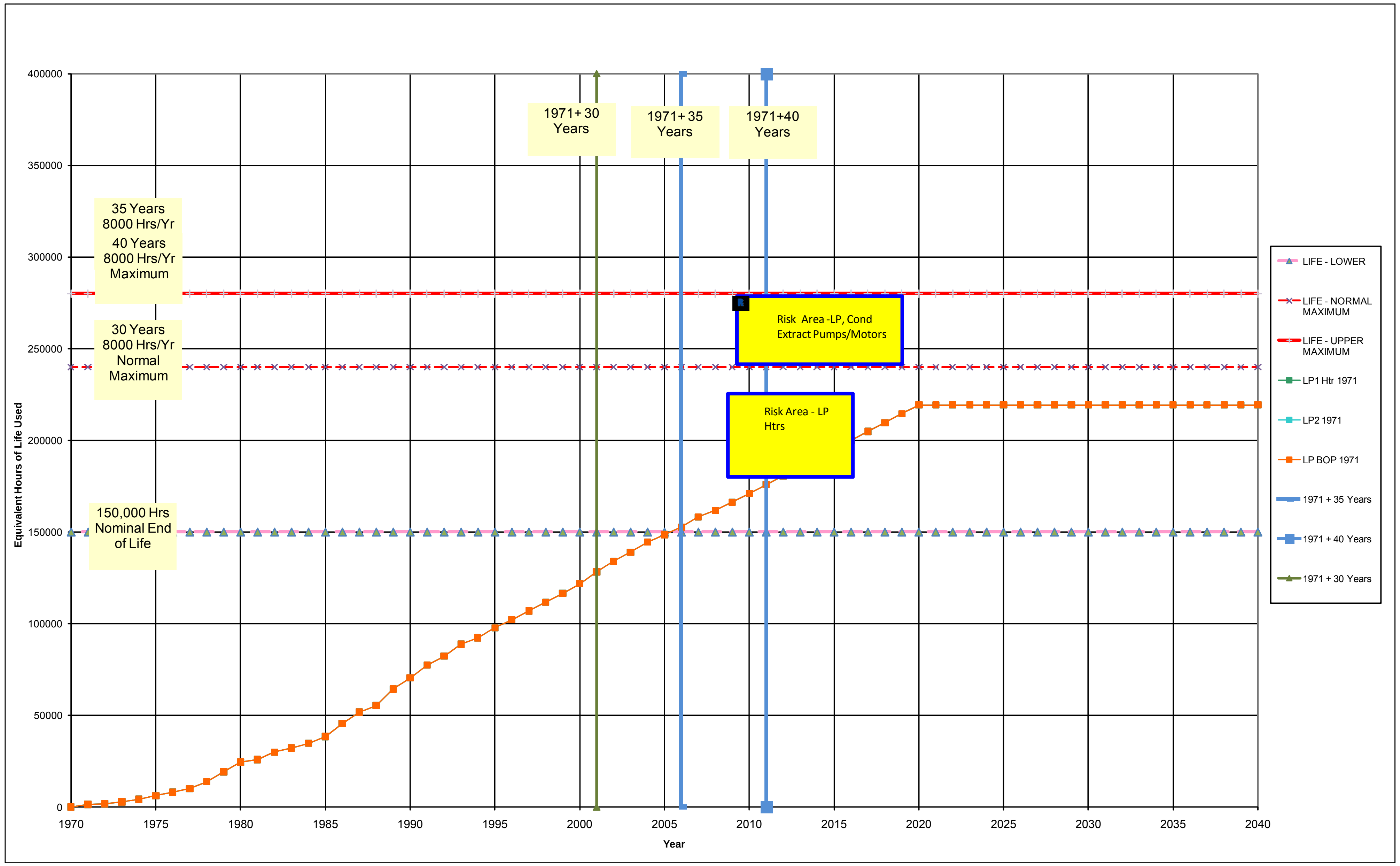

FIGURE 9-16 LIFE CYCLE CURVE – UNIT 2 FEEDWATER SYSTEM - LP FEEDWATER HEAT EXCHANGERS

The curve indicates that the remaining life (RL) of the Unit 2 feedwater system - LP heat exchangers may not be able to reach the desired life (DL) 2020 end date for generation. Given that no detailed NDE information has been obtained on the LP heat exchangers, a detailed Level 2 inspection is recommended for 2011.

The life cycle curve for the Unit 2 condensate extraction pumps and motors is illustrated below. Two curves are used to represent the original equipment pump and the pump motor (upgraded in 1990). The life curve is a plot of current and projected operating hours (generation mode only) on the y-axis versus calendar year on the x-axis. The figure has several vertical lines representing differing representative nominal age limits for various components. It also has several horizontal lines that represent a range of practical equipment equivalent base loaded operating hour life limits. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view.

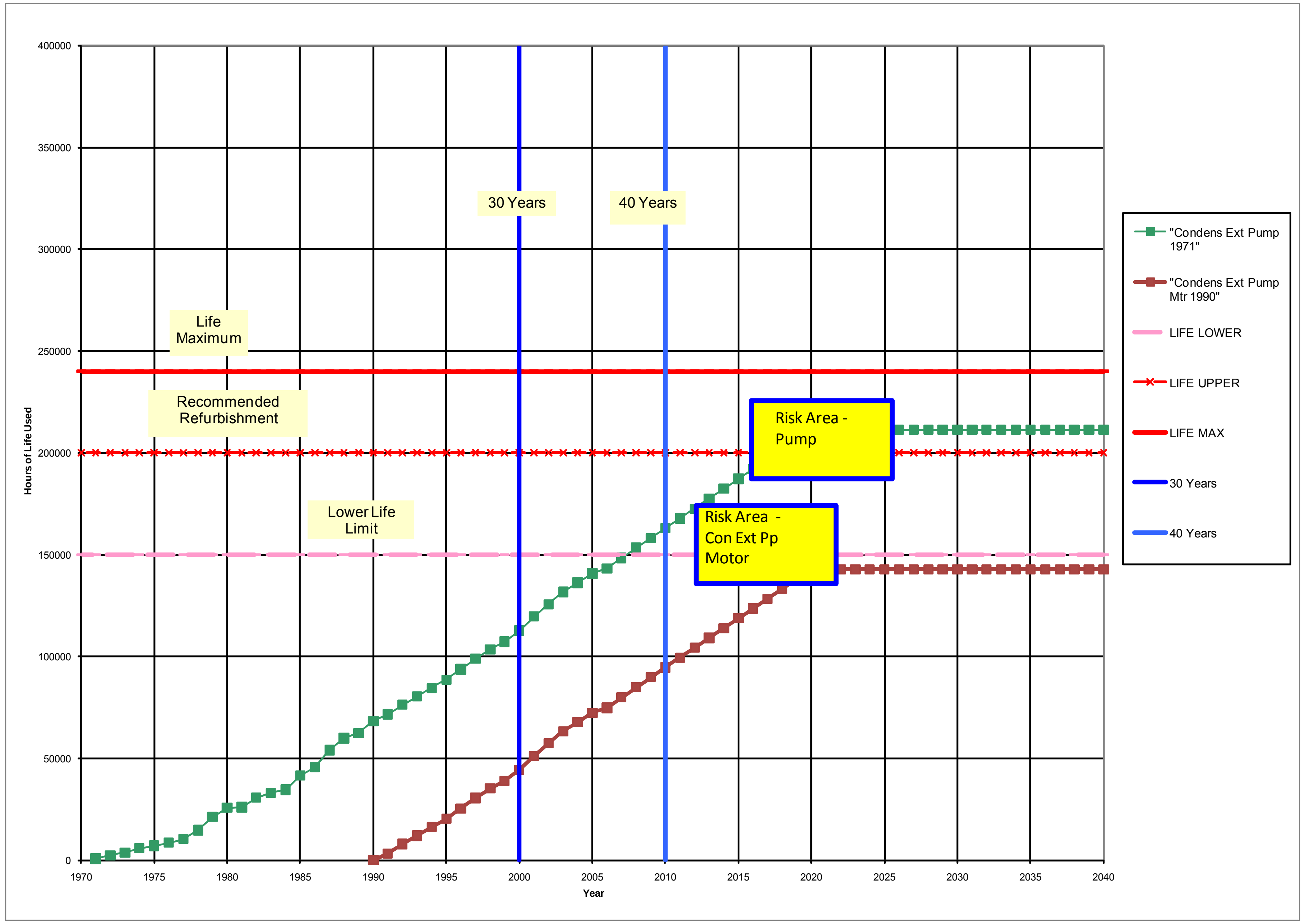

FIGURE 9-17 LIFE CYCLE CURVE – UNIT 2 CONDENSATE EXTRACTION SYSTEM

The curves indicate that the remaining life (RL) of the condenser condensate extraction pumps and motors can likely be able to reach the desired life (DL) 2020 end date for generation. The condensate extraction pump motors are expected however to be entering a period of higher unreliability.

9.2.4.8 Level 2 Inspections – Unit 2 Feedwater System - LP Feedwater Heat Exchangers

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 9-45 below, assuming that the current plant inspection and maintenance program is maintained or improved.

TABLE 9-45 LEVEL 2 INSPECTIONS – UNIT 2 FEEDWATER SYSTEM - LP FEEDWATER HEAT EXCHANGERS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Sub System Comment	L2#	Appendix #	Level 2 Work	Year	Cost k$
1296	7635	7978	0	0	0	2	#2 CONDENSATE & F.W. SYSTEM	CONDENSATE & F.W. SYSTEM	CONDENSATE & F.W. SYSTEM	None	97	24	No Level 2 required.		
1296	7635	7978	8800	0	0	2	#2 CONDENSATE & F.W. SYSTEM	CONDENSATE EXTRACTION SYST	CONDENSATE EXTRACTION SYST	None	98	20	No Level 2 inspections required at this time. Continue program of regular inspections and overhauls.		
1296	7635	7978	8800	7986	0	2	#2 CONDENSATE & F.W. SYSTEM	CONDENSATE EXTRACTION SYST	COND EXTRACTION PUMP NORTH	None	99	20	No Level 2 inspections required at this time. Continue program of regular inspections and overhauls.		
1296	7635	7978	8800	7987	0	2	#2 CONDENSATE & F.W. SYSTEM	CONDENSATE EXTRACTION SYST	COND.EXTRACTION PUMP SOUTH	None	100	20	No Level 2 inspections required at this time. Continue program of regular inspections and overhauls.		
1296	7635	7978	7980	0	0	2	#2 CONDENSATE & F.W. SYSTEM	CONDENSATE MAKE UP SYSTEM	CONDENSATE MAKE UP SYSTEM	None	101	24	No Level 2 required.		
1296	7635	7978	7992	0	0	2	#2 CONDENSATE & F.W. SYSTEM	L P FEEDWATER SYSTEM	L P FEEDWATER SYSTEM	None	102	24	No Level 2 required.	2011	
1296	7635	7978	7992	7997	0	2	#2 CONDENSATE & F.W. SYSTEM	L P FEEDWATER SYSTEM	LOW PRESSURE HEATER 1	None	103	24	Shell side inspections and channel side for the degradation mechanisms.	2011	
1296	7635	7978	7992	7997	0	2	#2 CONDENSATE & F.W. SYSTEM	L P FEEDWATER SYSTEM	LOW PRESSURE HEATER 1	None	104	24	Assessment of the tube plug map.	2011	
1296	7635	7978	7992	7997	0	2	#2 CONDENSATE & F.W. SYSTEM	L P FEEDWATER SYSTEM	LOW PRESSURE HEATER 1	None	105	24	ET inspection of tubes to assess the present condition (metallurgical evaluation may also be required depending upon the condition of the tubes).	2011	
1296	7635	7978	7992	7997	0	2	#2 CONDENSATE & F.W. SYSTEM	L P FEEDWATER SYSTEM	LOW PRESSURE HEATER 1	None	106	24	NDE inspection the major welds (seam, supports and nozzle welds) for the degradation mechanisms. PT or Magnetic particle testing (MT) or Conventional UT or Phased array (focused) can be used depending upon location.	2011	$57
1296	7635	7978	7992	7998	0	2	#2 CONDENSATE & F.W. SYSTEM	L P FEEDWATER SYSTEM	LOW PRESSURE HEATER 2	None	107	24	Shell side inspections and channel side for the degradation mechanisms.	2011	
1296	7635	7978	7992	7998	0	2	#2 CONDENSATE & F.W. SYSTEM	L P FEEDWATER SYSTEM	LOW PRESSURE HEATER 2	None	108	24	Assessment of the tube plug map.	2011	
1296	7635	7978	7992	7998	0	2	#2 CONDENSATE & F.W. SYSTEM	L P FEEDWATER SYSTEM	LOW PRESSURE HEATER 2	None	109	24	ET inspection of tubes to assess the present condition (metallurgical evaluation may also be required depending upon the condition of the tubes).	2011	$57
1296	7635	7978	7992	7998	0	2	#2 CONDENSATE & F.W. SYSTEM	L P FEEDWATER SYSTEM	LOW PRESSURE HEATER 2	None	110	24	NDE inspection the major welds (seam, supports and nozzle welds) for the degradation mechanisms. PT or Magnetic particle testing (MT) or Conventional UT or Phased array (focused) can be used depending upon location.	2011	
1296	7635	7978	7992	8032	0	2	#2 CONDENSATE & F.W. SYSTEM	L P FEEDWATER SYSTEM	RESERVE FW SYSTEM	None	111	26	Inspections of interior wall inspections and thickness measurements of walls and impaired major welds. Internals visual inspection.	2011	$15

9.2.4.9 Capital Projects

The suggested typical capital enhancements for the low pressure feedwater heat exchangers (and associated condensate extraction system) components include:

TABLE 9-46 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – UNIT 2 FEEDWATER SYSTEM - LP FEEDWATER HEAT EXCHANGERS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Detail	CAP#	Appendix #	Capital Item	Date	Priority
1296	7635	7978	0	0	0	2	#2 CONDENSATE & F.W. SYSTEM	CONDENSATE & F.W. SYSTEM	CONDENSATE & F.W. SYSTEM	N/A	96	20	No capital investment required.		
1296	7635	7978	8800	0	0	2	#2 CONDENSATE & F.W. SYSTEM	CONDENSATE EXTRACTION SYST	CONDENSATE EXTRACTION SYST	N/A	97	20	No capital investment required.		
1296	7635	7978	8800	7986	0	2	#2 UNIT GENERATION SERVICES	CONDENSATE EXTRACTION SYST	COND EXTRACTION PUMP NORTH	N/A	98	20	Replace as required per current inspection and overhaul findings.	2013	3
1296	7635	7978	8800	7987	0	2	#2 UNIT GENERATION SERVICES	CONDENSATE EXTRACTION SYST	COND.EXTRACTION PUMP SOUTH	N/A	99	20	Replace as required per current inspection and overhaul findings.	2013	3
1296	7635	7978	7980	0	0	2	#2 CONDENSATE & F.W. SYSTEM	CONDENSATE MAKE UP SYSTEM	CONDENSATE MAKE UP SYSTEM	N/A	100		No capital investment required.		
1296	7635	7978	7992	0	0	2	#2 CONDENSATE & F.W. SYSTEM	L P FEEDWATER SYSTEM	L P FEEDWATER SYSTEM	N/A	103	24	None, pending Level 2 or next inspection.		
1296	7635	7978	7992	8032	0	2	#2 CONDENSATE & F.W. SYSTEM	L P FEEDWATER SYSTEM	RESERVE FW SYSTEM	N/A	104	26	None, pending Level 2 or next inspection.		
1296	7635	7978	7992	7997	0	2	#2 CONDENSATE & F.W. SYSTEM	L P FEEDWATER SYSTEM	LOW PRESSURE HEATER 1	N/A	105	24	None, pending Level 2 or next inspection.		
1296	7635	7978	7992	7998	0	2	#2 CONDENSATE & F.W. SYSTEM	L P FEEDWATER SYSTEM	LOW PRESSURE HEATER 2	N/A	106	24	None, pending Level 2 or next inspection.		

9.2.5 Asset 7664 – Unit 2 Condenser

(Detailed Technical Assessment in Working Papers, Appendix 22)

Unit #:	2
Asset Class #	BU 1296 - Assets Generations
SCI & System:	7638 - #2 Turbine & Generator
Sub-Systems:	7664 # 2 Turbine & Condenser
Components:	271326 #2 Condenser
	7694 #2 Condenser Air Extraction

9.2.5.1 Description

The Unit 2 condenser is shell and tube type heat exchanger with two passes. There are two tube bundles in a single shell. The inlet and the outlet waterboxes are divided. Each tube bundle has an air removing zone (ARZ) in the middle of the bundle. There are 2 x 100% liquid ring vacuum pumps to remove the air and non condensable gases from the condenser shell. The pumps are sized to allow the unit to run at full vacuum with only one pump operating. Each is equipped with a nominally 70 kW, 600 V motor. The condenser also has a stainless steel bellow joint between the condenser shell and the turbine lower exhaust casing to compensate for turbine and condenser expansion.

The condenser cooling water is a combination of sea water and fresh water. The carbon steel waterbox material is protected by an epoxy coating and a sacrificial anodic system. The condenser waterboxes are equipped with a back wash system for cleaning the tubes internally while the unit is in operation. Nylon brushes are used to clean the tubes prior to the condenser lay-up.

The condenser was designed, fabricated and supplied Foster Wheeler in 1971.

9.2.5.2 History

Manufactured/Delivered	1970
In-Service Date	Apr 1971
Generation Base Load End Date	Dec 2015
Generation Peak/Emerg Gen End Date	Dec 2020
Next Major Overhaul/Inspection	2014

The hours associated with the analyses are:

Hours Generation Actual - Ops to Dec 2009	158
Max Hours Generation Ops – to Dec 2015	188
Max Hrs Gen Ops to Gen End Date Dec 2020	212

9.2.5.3 Inspection and Repair History

The Unit 2 condenser is in good shape for its age. The number of plugged tubes is quite low, and the rate of increase in plugging has remained steadily low. The condition is monitored, but no aggressive inspection program is either in place or seems to be required.

A recent tubes plug survey completed in 2010 indicated that 3.3% of the condenser tubes are plugged. The 2001 survey indicates that 2.8% of the tubes were plugged at that time. Based on this result, the in-service tube degradation rate of 0.5% over 9 years is very slow. This is also supported by the eddy current testing that was completed in 1998 when 70% of the total condenser tubes were inspected. Results show that 95% of the tubes tested had a wall loss of less than 25%. This is very close to the tube nominal wall thickness and the accuracy of the eddy current testing.

Inspections also confirm that there is no condensate grooving on the tube outside diameter (OD) in the air removing zone of the tube bundle. With the exception of minor wear, the waterboxes and the condenser shell are in good condition.

According to plant staff, the condenser steel piping at the inlet and outlet between the condensers and the underground concrete pipes, have been replaced once but no date was provided. Some patching is evident on some units.

The two condenser air extraction vacuum pumps and system are original equipment and approaching their expected end of life. No major issues were identified with achieving the required condenser back pressure at turbine full load or during unit start up. The pumps and motors are serviced yearly under the plant PM program. The plant is modifying the existing vent system to enable venting externally in order to eliminate the exhaust of its moisture into the powerhouse.

9.2.5.4 Condition Assessment

The condition assessment of the Unit condenser is illustrated below in Table 9-47:

TABLE 9-47 CONDITION ASSESSMENT – UNIT 2 CONDENSER

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset Level 2	Asset Level 3	Description	Detail	Condition Summary ID#	Append #	Condition	EPRI Identifier	Original Life (Base Load) Ops Hrs (Yrs)	Current Expected Minimum Remaining Life Years (Subject to Test)	End of Life (EOL) Required	Next Regular Inspection	Next Planned Overhaul or Major Inspection	Capability to Reach Next Overhaul	Capability to Reach EOL	In Service
1296	7635	7636	7664	0	0	2	#2 TURBINE CONDENSER SYSTEM	TURBINE CONDENSER SYSTEM	TURBINE CONDENSER SYSTEM	N/A	4	22	Good condition	3a	200000 (40)	10	2020		2014	Yes	Yes	1971
1296	7635	7636	7664	7694	0	2	#2 TURBINE CONDENSER SYSTEM	TURBINE CONDENSER SYSTEM	CONDENSER AIR EXTRACTION	N/A	5	22	System in good condition. External venting needed.	10	150000 (30)	5	2020		2014	Yes	No	1971
1296	7635	7636	7664	7694	8884	2	#2 TURBINE CONDENSER SYSTEM	TURBINE CONDENSER SYSTEM	CONDENSER AIR VAC P/P NORTH	N/A	6	22	Near end of life.	10	150000 (30)	(2)	2020		2014	Yes	No	1971
1296	7635	7636	7664	7694	8891	2	#2 TURBINE CONDENSER SYSTEM	TURBINE CONDENSER SYSTEM	CONDENSER AIR VAC P/P SOUTH	N/A	7	22	Near end of life.	10	150000 (30)	(2)	2020		2014	Yes	No	1971
1296	7635	7636	7664	271326	0	2	#2 TURBINE CONDENSER SYSTEM	TURBINE CONDENSER SYSTEM	TURBINE CONDENSER	N/A	8	22	Condition is very good. 2010 tubes plug survey shows 3.3% of tubes plugged vs 2.8% in 2001. Condensate grooving on the tube OD in the air removing zone. Minor wear and tear of waterboxes and condenser shell.	3a	300000 (50)	20	2020	2011	2014	Yes	Yes	1971

Notes:

1. A "(bracketed)" value in the "Current Expected Remaining Life" column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation, including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as "(X/Y)" has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

2. The "Next Regular Inspection" column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The "Next Planned Overhaul or Major Inspection" column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a "Desired Life" stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or not known by AMEC.

9.2.5.5 Actions

Based on the condition assessment, the following actions are recommended for the Unit 2 condenser:

TABLE 9-48 RECOMMENDED ACTIONS – UNIT 2 CONDENSER

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Unit	Asset 2/3	Asset 3/4	Description	Detail	Action #	App #	Action	Year	Priority
1296	7635	7636	7664	0	2	#2 TURBINE CONDENSER SYSTEM	TURBINE CONDENSER SYSTEM	TURBINE CONDENSER SYSTEM	N/A	1	22	Develop a ongoing program of monitoring CW inlet/outlet pipe conditions.	2011	2
1296	7635	7636	7664	7694	2	#2 TURBINE CONDENSER SYSTEM	TURBINE CONDENSER SYSTEM	CONDENSER AIR EXTRACTION	N/A	2	22	See details below.		
1296	7635	7636	7664	7694	2	#2 TURBINE CONDENSER SYSTEM	TURBINE CONDENSER SYSTEM	CONDENSER AIR VAC P/P NORTH	N/A	3	22	Inspect CW Vacuum pump and refurbish or replace motor and pump.	2011	2
1296	7635	7636	7664	7694	2	#2 TURBINE CONDENSER SYSTEM	TURBINE CONDENSER SYSTEM	CONDENSER AIR VAC P/P SOUTH	N/A	4	22	Inspect CW Vacuum pump and refurbish or replace motor and pump.	2011	2
1296	7635	7636	7664	271326	2	#2 TURBINE CONDENSER SYSTEM	TURBINE CONDENSER SYSTEM	TURBINE CONDENSER	N/A	5	22	Perform Level 2 inspections on waterboxes for Unit 2 at a practical time.	2011	2

9.2.5.6 Risk Assessment

Table 9-49 below illustrates the risk assessment for the Unit 2 condenser, both from a technological perspective and a safety perspective using the models presented in Section 3.

TABLE 9-49 RISK ASSESSMENT – UNIT 2 CONDENSER

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Component	Risk Assess #	Appendix #	Major Issues	Remaining Life Years	Remaining Life Comments	TECHNO-ECO RISK ASSESSMENT MODEL			SAFETY RISK ASSESSMENT MODEL			Possible Failure Event	Mitigation
														(Insufficient Info - Inspection Required Within (x) Years)		Likeli-hood	Conse-quence	Risk Level	Likeli-hood	Conse-quence	Safety Risk		
1296	7635	7636	7664	0	0	2	#2 TURBINE CONDENSER SYSTEM	TURBINE CONDENSER SYSTEM	TURBINE CONDENSER SYSTEM	N/A	5	22	See details below.		None								
1296	7635	7636	7664	7694	0	2	#2 TURBINE CONDENSER SYSTEM	TURBINE CONDENSER SYSTEM	CONDENSER AIR EXTRACTION	N/A	6	22	See details below.	10	None								
1296	7635	7636	7664	7694	8884	2	#2 TURBINE CONDENSER SYSTEM	TURBINE CONDENSER SYSTEM	CONDENSER AIR VAC P/P NORTH	Condenser Vacuum Pumps & System	7	22	Mechanical failure/leaks.	2	None	1	A	Low	1	A	Low	Derate/Eff Decrease while replaced.	Maintain, refurbish or replace as required.
1296	7635	7636	7664	7694	8891	2	#2 TURBINE CONDENSER SYSTEM	TURBINE CONDENSER SYSTEM	CONDENSER AIR VAC P/P SOUTH	Condenser Vacuum Pumps & System	8	22	Mechanical failure/leaks.	2	None	1	A	Low	1	A	Low	Derate/Eff Decrease while replaced.	Maintain, refurbish or replace as required.
1296	7635	7636	7664	271326	0	2	#2 TURBINE CONDENSER SYSTEM	TURBINE CONDENSER SYSTEM	TURBINE CONDENSER	Condenser	9	22	Corrosion, erosion.	20	None	2	B	Low	2	A	Low	Major seawater leak to condenser - unit shutdown. Water cleanup.	Inspect and repair. Track history.

9.2.5.7 Life Cycle Curve and Remaining Life

The life cycle curve for the Unit 2 condenser is illustrated below. Only one curve is used as the major elements of the condenser are of the same age and condition. The life curve is a plot of current and projected operating hours (generation mode only) on the y-axis versus calendar year on the x-axis. The figure has several vertical lines representing differing representative nominal age limits for various components. It also has several horizontal lines that represent a range of practical equipment equivalent base loaded operating hour life limits. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view.

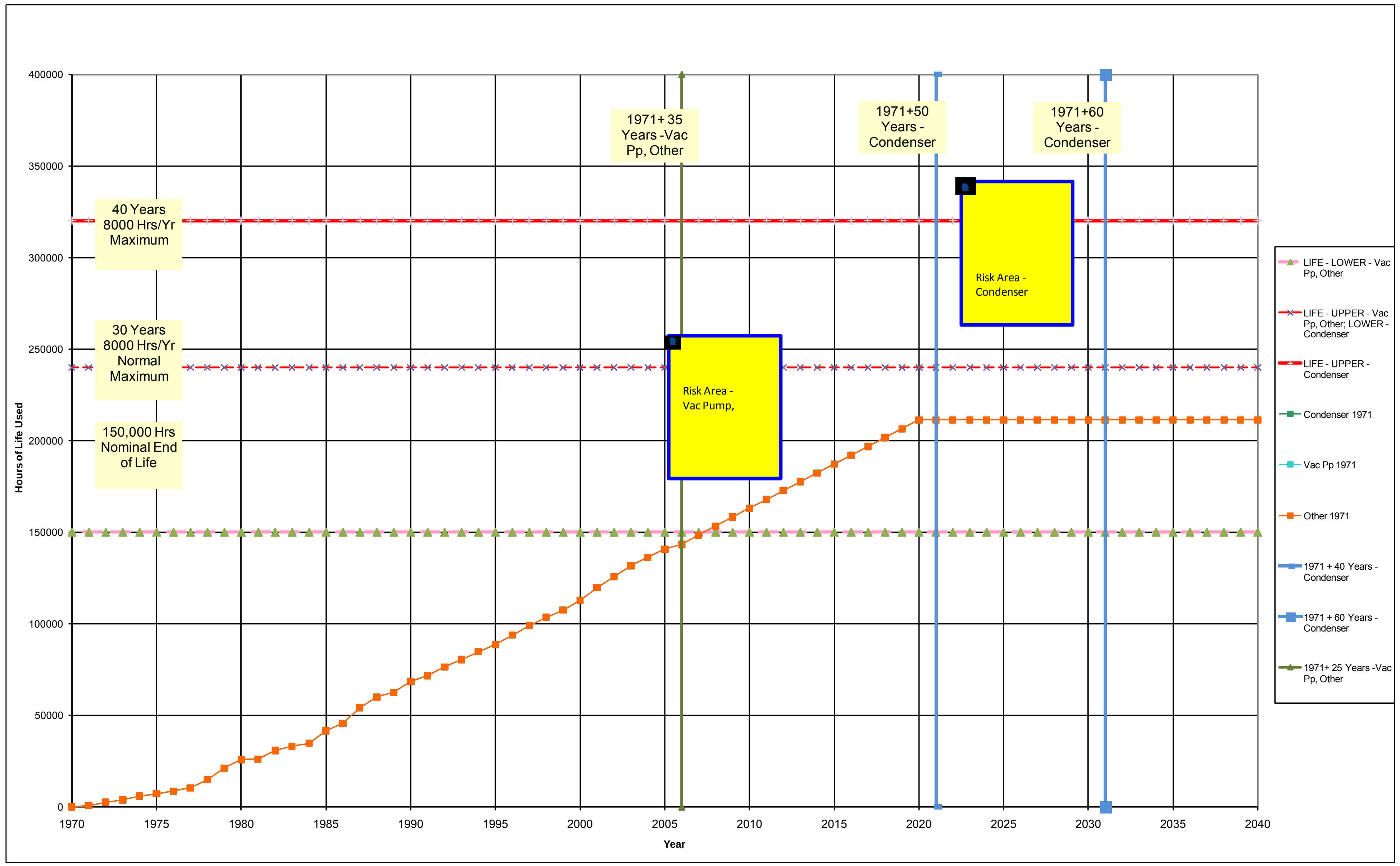

FIGURE 9-18 LIFE CYCLE CURVE – UNIT 2 CONDENSER

The curves indicate that the remaining life (RL) of the Unit 2 condenser can easily reach the desired life (DL) 2020 end date for generation. The exception to this, as illustrated by the risk boxes, is the vacuum pumps. These are original equipment, and likely at or near end of life.

9.2.5.8 Level 2 Inspections – Unit 2 Condenser

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 9-50 below, assuming the current plant inspection and maintenance program is maintained or improved.

TABLE 9-50 LEVEL 2 INSPECTIONS – UNIT 2 CONDENSER

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Sub System Comment	L2#	Appendix #	Level 2 Work	Year	Priority	Cost k$
1296	7635	7636	7664	0	0	2	#2 TURBINE CONDENSER SYSTEM	TURBINE CONDENSER SYSTEM	TURBINE CONDENSER SYSTEM	None	1	22	NDE spot check inspection of major inlet and outlet pipes. Condensers themselves continue ongoing maintenance and inspection.	2011	2	$4
1296	7635	7636	7664	0	0	2	#2 TURBINE CONDENSER SYSTEM	TURBINE CONDENSER SYSTEM	TURBINE CONDENSER SYSTEM	None	2	22	At next turbine valve overhaul in 2011: - Leak test and update the tubesheet maps for both the waterboxes. - Check the inlet waterboxes for tubes with water erosion at the tube inlets. - Inspect condenser hotwell internal piping and supports for steam and water erosion. - Inspect hotwell drip drains for eroded or missing baffle plates.	2011	2	$0
1296	7635	7636	7664	7694	0	2	#2 TURBINE CONDENSER SYSTEM	TURBINE CONDENSER SYSTEM	CONDENSER AIR EXTRACTION	None	3	22	No Level 2 required.			
1296	7635	7636	7664	7694	8884	2	#2 TURBINE CONDENSER SYSTEM	TURBINE CONDENSER SYSTEM	CONDENSER AIR VAC P/P NORTH	None	4	22	No Level 2 required.			
1296	7635	7636	7664	7694	8891	2	#2 TURBINE CONDENSER SYSTEM	TURBINE CONDENSER SYSTEM	CONDENSER AIR VAC P/P SOUTH	None	5	22	No Level 2 required.			

9.2.5.9 Capital Projects

The suggested typical capital enhancements for the system include:

TABLE 9-51 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – UNIT 2 CONDENSER

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Detail	CAP#	Appendix #	Capital Item	Date	Priority
1296	7635	7636	7664	0	0	2	#2 TURBINE CONDENSER SYSTEM	TURBINE CONDENSER SYSTEM	TURBINE CONDENSER SYSTEM	N/A	5	22	No capital investment required.		
1296	7635	7636	7664	7694	0	2	#2 TURBINE CONDENSER SYSTEM	TURBINE CONDENSER SYSTEM	CONDENSER AIR EXTRACTION	N/A	6	22	No capital investment required.		
1296	7635	7636	7664	7694	8884	2	#2 TURBINE CONDENSER SYSTEM	TURBINE CONDENSER SYSTEM	CONDENSER AIR VAC P/P NORTH	N/A	7	22	Refurbish/replace vacuum pumps and motors as required.	2012	2
1296	7635	7636	7664	7694	8891	2	#2 TURBINE CONDENSER SYSTEM	TURBINE CONDENSER SYSTEM	CONDENSER AIR VAC P/P SOUTH	N/A	8	22	Refurbish/replace vacuum pumps and motors as required.	2012	2
1296	7635	7636	7664	271326	0	2	#2 TURBINE CONDENSER SYSTEM	TURBINE CONDENSER SYSTEM	TURBINE CONDENSER	N/A	9	22	No capital investment required.		

9.2.6 Asset 8878 – Unit 2 FD Fans (and System)

(Detailed Technical Assessment in Working Papers, Appendix 19)

Unit #:	2
Asset Class #	BU 1296 - Assets Generations
SCI & System:	7786 - # 2 Boiler Plant
Sub-Systems:	7838 - # 2 Boiler Air System
	7890 - # 2 Boiler Gas System
	7912 - # 2 Boiler Fuel Firing
	7913 #2 Bir Heavy Oil System
	7935 #2 Boiler Light Oil
Components:	88781#1 Boiler FD Fan System 7843 # 2 Boiler FD Fan East 7844 # 2 Boiler FD Fan West 7855 # 2 Boiler Steam Air Heater East 7856 # 2 Boiler Steam Air Heater West 7883 # 2 Boiler Main Air Heater East 7884 # 2 Boiler Main Air Heater West
	7916 #2 Boiler Heavy Oil Pump East 7917 #2 Boiler Heavy Oil Pump West 7920 #2 Boiler Heavy Oil Pump steam, valves and pipe 7933 #2 Boiler Heavy Oil Firing 8980 #2 Boiler Light Oil Pump East 8981 #2 Boiler Light Oil Pump West
	7882 #2 Boiler Air Supply Seal Air 7885 #2 Boiler Scanner Air System

9.2.6.1 Description

The Unit 2 Combustion Engineering (CE) boiler has two 50% duty 4KV AC constant speed motor driven Howden forced draft fans (East/West) which supply the combustion air for both the heavy #6 residual oil and the lighter #2 ignition oil. These fans are centrifugal in design and draw air from the top of the boiler house through ducts specifically connected to each fan inlet.

The air flow required for combustion is regulated by the use of variable inlet vanes which allow the required amount of air into the boiler furnace to ensure that the fuel oil is completely burned. The FD fan inlet vanes are controlled automatically either by the plant DCS system or manually by the operator if required.

In addition, each of the FD fans has a set of steam coil air heaters and a rotating Ljungstrom air heater to heat the air used in the combustion process. The combustion air is heated prior to being admitted to the furnace windbox in order to improve fuel firing and also to reduce back end corrosion. Before using the steam coil air heater to heat the combustion air, at least one boiler in the plant must be generating sufficient steam for this function.

9.2.6.2 History

Manufactured/Delivered	1970
In-Service Date	Apr 1971
Generation Base Load End Date	Dec 2015
Generation Peak/Emerg Gen End Date	Dec 2020

The hours associated with the analyses are:

Hours Generation Actual - Ops to Dec 2009	158
Max Hours Generation Ops – to Dec 2015	188
Max Hrs Gen Ops to Gen End Date Dec 2020	212
Max Hours Ops – 1986 to Dec 2009	113
Max Hrs - 1986 to Dec 2015	142
Max Hrs – 1986 to Gen End Date Dec 2020	164

9.2.6.3 Inspection and Repair History

The FD fans and Ljungstrom air heaters were installed when the unit was constructed in the late 1960's. They are checked annually as part of the boiler inspection program. Generally, all are in reasonable condition considering their age. Issues such as fan component cracking and air heater corrosion are addressed as required. The steam coil air heater was upgraded in 1990 to include a second row of steam coils.

The 2009 Alstom report indicates that Unit 2 West FD fan was inspected and some cracks were repaired on the ductwork and expansion joints. The report did not indicate what work was carried out on the East fan. However, in 2008, a complete evaluation of both fans was conducted by Fan Dynamics out of Cambridge, Ontario. Both FD fans at that time were deemed to be in good condition.

A cold end rebuild of the Unit 2 East and West Ljungstrom air heaters was completed in 2009 as a capital project. The work on the West Ljungstrom air heater as per the Alstom 2009 report indicated that the cold end baskets were reversed to extend the overall life of the baskets. However, these possibly will require changing in a couple of years. Based on experience that Ontario Power Generation had using lower sulphur #6 residual fuel oil (0.7% sulphur), its use at Holyrood should continue to have very positive effects on the air heaters. Corrosion issues and ash deposits (as long as the rotary sootblowers are maintained and used consistently) should not be an issue.

As reported by Alstom in 2008, the combustion steam coils on both the east and the west sides of Unit 2 had a large number of the fins that were bent and possibly creating a higher FD fan differential pressure across these coils. Alstom's recommendation at that time was to fabricate a tool to straighten the fins. However, the final outcome was not documented. In addition, during site visits, AMEC staff was not made aware of any Unit 2 full load limitations caused by either lower than required air flows or excessive FD fan motor amps.

The last outage report completed in 2009 indicated that detailed inspections of this equipment were carried out with minor repairs made to cracks in the ductwork, seals replaced in the air heaters, some gap discrepancies rectified and a recognition that some fins on the combustion coils had bent during operation.

The continued use of the much lower sulphur residual fuel oil (0.7% sulphur) may reduce the corrosion levels noted, especially in the air heaters, and may reduce the maintenance requirements performed by Alstom, depending on a series of operating parameters. The steam coils are pressure tested every year, although no data sheets were reviewed and the inspection dates were not marked on the tubes as had previously been done.

The unit has experienced significant forced draft system vibration, as a consequence of the original ductwork design. Flow induced turbulence in ductwork causing vibration has the potential to result in significant damage to forced draft fans and in cracks in the ductwork. The plant has plans to modify the ductwork system in an effort to reduce vibration levels caused by air flow turbulence and also to improve overall noise and efficiency. These changes are strongly supported.

Asset 7890 Boilers Flue Gas System, Sootblowers

The Unit 2 back end flue gas ductwork is original and was installed in 1969. During yearly plant outages, the accessible ductwork has been inspected by Alstom. Reports obtained from the plant indicate that due diligence has been carried out to ensure the structural integrity of the ductwork is maintained and any repairs were being completed at the time of inspection. Structural supports were inspected and all have been identified to be in good condition and will last for the foreseeable future.

With regards to the sootblowing system, minor maintenance is carried out during normal operation. Any major work requires a unit shutdown. Boiler fouling and opacity excursions were observed and changes were implemented to improve the sootblowing sequences.

With the use of a lower sulphur fuel oil, the implementation of an intelligent sootblowing controls system should be considered so that sootblowing is only carried out when needed.

Asset 7912 Fuel Oil Firing

Reports at the plant regarding the condition of the light and heavy oil systems were not available. However they appear to have been properly maintained. Although these two systems are critical to unit operation, replacement parts or systems will typically be available for the life of a plant and therefore are not considered to be life limiting.

Asset 7879 Boiler Air Supply Seal Air and Scanner Air

These two auxiliary systems are totally external to the main boiler and have limited control circuitry to ensure they operate correctly. Any piping or hose leaks can be repaired at minimum costs as long as proper maintenance activity is carried out. Replacement of flame scanner heads is the single most costly expenditure if the system fails. Both of these systems appear to be well maintained as noted during AMEC's inspection.

9.2.6.4 Condition Assessment

The condition assessment of the Unit 2 FD fans (and system) is illustrated below in Table 9-52:

TABLE 9-52 CONDITION ASSESSMENT – UNIT 2 FD FANS (AND SYSTEM)

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset Level 2	Asset Level 3	Description	Detail	Condition Summary ID#	Append #	Condition	EPRI Identifier	Original Life (Base Load) Ops Hrs (Yrs)	Current Expected Minimum Remaining Life Years (Subject to Test)	End of Life (EOL) Required	Next Regular Inspection	Next Planned Overhaul or Major Inspection	Capability to Reach Next Overhaul	Capability to Reach EOL	In Service
1296	7635	7786	7838	0	0	2	#2 BOILER PLANT	BOILER AIR SYSTEM	BOILER AIR SYSTEM	N/A	77	19, 30	Inspected yearly and repairs completed. Flow induced turbulence in ductwork causing vibration with potential for damage to fD fans and cracks in ductwork.	3a	200000 (40)	10	2020	2011		Yes	Yes	1971
1296	7635	7786	7838	7879	7885	2	#2 BOILER PLANT	BOILER AIR SYSTEM	BOILER SCANNER AIR	N/A	78	19, 30	Inspected yearly and repairs completed.	3a	200000 (30)	10	2020	2011		Yes	Yes	1971
1296	7635	7786	7838	8781	0	2	#2 BOILER PLANT	BOILER AIR SYSTEM	BOILER F.D. FAN ASSEMBLY	N/A	79	19, 30	Inspected yearly and repairs completed.	3a	200000 (30)	10	2020	2011		Yes	Yes	1971
1296	7635	7786	7838	8781	7843	2	#2 BOILER PLANT	BOILER AIR SYSTEM	BOILER F.D. FAN EAST	Fan	80	19, 30	Inspected yearly and repairs completed as required. Good condition.	3a	200000 (30)	10	2020	2011		Yes	Yes	1971
1296	7635	7786	7838	8781	7844	2	#2 BOILER PLANT	BOILER AIR SYSTEM	BOILER F.D. FAN WEST	Fan	81	19, 30	Inspected yearly and repairs completed as required. Good condition.	3a	200000 (30)	10	2020	2011		Yes	Yes	1971
1296	7635	7786	7838	8781	7843	2	#2 BOILER PLANT	BOILER AIR SYSTEM	BOILER F.D. FAN EAST	Motors	82	25	Inspected yearly and repairs completed as required. Good condition.	3a	200000 (30)	(5)	2020	2011		Yes	No	1971
1296	7635	7786	7838	8781	7844	2	#2 BOILER PLANT	BOILER AIR SYSTEM	BOILER F.D. FAN WEST	Motors	83	25	Inspected yearly and repairs completed as required. Good condition.	3a	200000 (30)	(5)	2020	2011		Yes	No	1971
1296	7635	7786	7838	8785	0	2	#2 BOILER PLANT	BOILER AIR SYSTEM	BOILER STEAM AIR HEATER	N/A	84	19, 30	Inspected yearly and repairs completed as required. Unit upgraded in 1990.	3a	200000 (30)	10	2020	2011		Yes	Yes	1990
1296	7635	7786	7838	8785	7855	2	#2 BOILER PLANT	BOILER AIR SYSTEM	BOILER STEAM AIR HEATER EAST	N/A	85	19, 30	Inspected yearly and repairs completed as required. Unit upgraded in 1990.	3a	200000 (30)	10	2020	2011		Yes	Yes	1990
1296	7635	7786	7838	8785	7856	2	#2 BOILER PLANT	BOILER AIR SYSTEM	BOILER STEAM AIR HEATER WEST	N/A	86	19, 30	Inspected yearly and repairs completed as required. Unit upgraded in 1990.	3a	200000 (30)	10	2020	2011		Yes	Yes	1990
1296	7635	7786	7838	8786	0	2	#2 BOILER PLANT	BOILER AIR SYSTEM	BOILER MAIN AIR HEATER	N/A	87	19, 30	Inspected yearly and repairs completed as required.	3a	200000 (30)	10	2020	2011		Yes	Yes	1971
1296	7635	7786	7838	8786	7863	2	#2 BOILER PLANT	BOILER AIR SYSTEM	BOILER MAIN AIR HEATER EAST	N/A	88	19, 30	Inspected yearly and repairs completed as required. Cold end rebuild of the east Ljungstrom Air Heater on Unit 2 was completed in 2009.	3a	200000 (30)	10	2020	2011		Yes	Yes	1971/2009
1296	7635	7786	7890	0	0	2	#2 BOILER PLANT	BOILER GAS SYSTEM	BOILER GAS SYSTEM	N/A	89	19, 30	Inspected yearly and repairs completed.	3a	200000 (40)	10	2020	2011		Yes	Yes	1971
1296	7635	7786	7890	7891	0	2	#2 BOILER PLANT	BOILER GAS SYSTEM	BOILER GAS PASSES	N/A	90	19, 30	Inspected yearly and repairs completed.	3a	200000 (40)	10	2020	2011		Yes	Yes	1971
1296	7635	7786	7890	7904	0	2	#2 BOILER PLANT	BOILER GAS SYSTEM	BOILER SOOTBLOWING SYSTEM	N/A	91	19	Installed about 1979 with yearly major or minor overhauls.	3a	200000 (30)	10	2020	2011		Yes	Yes	1979
1296	7635	7786	7912	0	0	2	#2 BOILER PLANT	BOILER FUEL FIRING SYSTEM	BOILER FUEL FIRING SYSTEM	N/A	92	19	Inspected yearly and repairs completed as required.	3a	200000 (30)	10	2020	2011		Yes	Yes	1971
1296	7635	7786	7912	7935	0	2	#2 BOILER PLANT	BOILER FUEL FIRING SYSTEM	BOILER LIGHT OIL	N/A	93	19	Inspected yearly and repairs completed as required.	3a	200000 (30)	10	2020	2011		Yes	Yes	1971
1296	7635	7786	7953	0	0	2	#2 BOILER PLANT	BLR AUX STEAM & CONDENSATE	BLR AUX STEAM & CONDENSATE	N/A	94	N/A	Not reviewed in detail - primarily unit heaters from good to poor condition. New source needed after close of generation.	4	200000 (30)	(5)	2041	2011		No	No	1971
1296	7635	7786	7787	0	0	2	#2 BOILER PLANT	BOILER STRUCTURE	BOILER STRUCTURE	N/A	95	17	No recent evaluation. Visual inspection in walkdown indicated no issues except some minor roof leaks.	3a	200000 (30)	20	2041	2011	2011	Yes	Yes	1971

Notes:

1. A “(bracketed)” value in the “Current Expected Remaining Life” column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation, including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as “(X/Y)” has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

2. The “Next Regular Inspection” column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The “Next Planned Overhaul or Major Inspection” column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a “Desired Life” stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or not known by AMEC.

3. The ability of the east and west FD fans to meet a 2020 EOL date may be affected if the planned duct reconfiguration is not undertaken.

9.2.6.5 Actions

Based on the condition assessment, the following actions are recommended for the Unit 2 FD fans (and system):

TABLE 9-53 RECOMMENDED ACTIONS – UNIT 2 FD FANS (AND SYSTEM)

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Unit	Asset 2/3	Asset 3/4	Description	Detail	Action #	App #	Action	Year	Priority
1296	7635	7786	7838	0	2	#2 BOILER PLANT	BOILER AIR SYSTEM	BOILER AIR SYSTEM	N/A	115	19,30	Continue routine inspection, maintenance and overhaul - evaluate air heater hot end baskets; connect installed FD fans vibration probes to online monitoring system; refurbish and use the furnace exit thermoprobe during start-up activities to avoid distortion and overheating of the secondary superheater and reheater sections tubes.	2010	1
1296	7635	7786	7838	7879	2	#2 BOILER PLANT	BOILER AIR SYSTEM	BOILER SCANNER AIR	N/A	116	19,30	No recommended action.		
1296	7635	7786	7838	8781	2	#2 BOILER PLANT	BOILER AIR SYSTEM	BOILER F.D. FAN ASSEMBLY	N/A	117	19,30	Maintain ongoing inspection and maintenance programs. Maintain a spare motor be maintained to service all three units in the event of a failure of an existing unit.	2010	2
1296	7635	7786	7838	8781	2	#2 BOILER PLANT	BOILER AIR SYSTEM	BOILER F.D. FAN EAST	N/A	118	19,30	Assess replacement of ductwork with lower vibration, lower noise, more efficient design.	2011	2
1296	7635	7786	7838	8781	2	#2 BOILER PLANT	BOILER AIR SYSTEM	BOILER F.D. FAN WEST	N/A	119	19,30	Assess replacement of ductwork with lower vibration, lower noise, more efficient design.	2011	2
1296	7635	7786	7838	8785	2	#2 BOILER PLANT	BOILER AIR SYSTEM	BOILER STEAM AIR HEATER	N/A	120	19,30	Continue current inspection and maintenance activities.	2010	2
1296	7635	7786	7838	8785	2	#2 BOILER PLANT	BOILER AIR SYSTEM	BOILER STEAM AIR HEATER EAST	N/A	121	19,30	Continue current inspection and maintenance activities.	2010	2
1296	7635	7786	7838	8785	2	#2 BOILER PLANT	BOILER AIR SYSTEM	BOILER STEAM AIR HEATER WEST	N/A	122	19,30	Continue current inspection and maintenance activities.	2010	2
1296	7635	7786	7838	8786	2	#2 BOILER PLANT	BOILER AIR SYSTEM	BOILER MAIN AIR HEATER	N/A	123	19,30	Continue current inspection and maintenance activities.	2010	2
1296	7635	7786	7838	8786	2	#2 BOILER PLANT	BOILER AIR SYSTEM	BOILER MAIN AIR HEATER EAST	N/A	124	19,30	Continue current inspection and maintenance activities.	2010	2
1296	7635	7786	7890	0	2	#2 BOILER PLANT	BOILER GAS SYSTEM	BOILER GAS SYSTEM	N/A	125	19,30	See details below.		
1296	7635	7786	7890	7891	2	#2 BOILER PLANT	BOILER GAS SYSTEM	BOILER GAS PASSES	N/A	126	19,30	Continue current inspection and maintenance activities.	2010	2
1296	7635	7786	7890	7904	2	#2 BOILER PLANT	BOILER GAS SYSTEM	BOILER SOOTBLOWING SYSTEM	N/A	127	19	Update obsolete controls as appropriate. Evaluate/implement Intelligent Sootblowing (ISB) to reduce sootblowing energy consumption and mechanical damage impacts.	2012	2
1296	7635	7786	7890	7904	2	#2 BOILER PLANT	BOILER GAS SYSTEM	BOILER SOOTBLOWING SYSTEM	N/A	128	19	Continue yearly inspections and repair work.	2011	2
1296	7635	7786	7912	0	2	#2 BOILER PLANT	BOILER FUEL FIRING SYSTEM	BOILER FUEL FIRING SYSTEM	N/A	129	19	Continue yearly inspections and repair work.	2011	2
1296	7635	7786	7912	7935	2	#2 BOILER PLANT	BOILER FUEL FIRING SYSTEM	BOILER LIGHT OIL	N/A	130	19	Continue yearly inspections and repair work.	2011	2
1296	7635	7786	7953	0	2	#2 BOILER PLANT	BLR AUX STEAM & CONDENSATE	BLR AUX STEAM & CONDENSATE	N/A	131	19	Refurbish and replace unit heaters as required.	2011	2
1296	7635	7786	7787	0	2	#2 BOILER PLANT	BOILER STRUCTURE	BOILER STRUCTURE	N/A	132	17	Visually inspect difficult to access areas.	2011	2
1296	7635	7786	7787	0	2	#2 BOILER PLANT	BOILER STRUCTURE	BOILER STRUCTURE	N/A	133	30	Continue present inspection and maintenance program. Evaluate a preventive replacement of the boiler expansion joints.	2011	2
1296	7635	7786	7787	0	2	#2 BOILER PLANT	BOILER STRUCTURE	BOILER STRUCTURE	N/A	134	30	Evaluate corrosion on the steel structure and hangers in the boilers' penthouse areas during the boiler routine maintenance and inspection activities. Review condition of the boiler refractory to assess the requirement for replacement during the boiler routine maintenance and inspection activities.	2011	2

9.2.6.6 Risk Assessment

Table 9-54 below illustrates the risk assessment for the Unit 2 FD fans (and system), both from a technological perspective and a safety perspective using the models presented in Section 3.

TABLE 9-54 RISK ASSESSMENT – UNIT 2 FD FANS (AND SYSTEM)

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Component	Risk Assess #	Appendix #	Major Issues	Remaining Life Years	Remaining Life Comments	TECHNO-ECO RISK ASSESSMENT MODEL			SAFETY RISK ASSESSMENT MODEL			Possible Failure Event	Mitigation
														(Insufficient Info - Inspection Required Within (x) Years)		Likeli-hood	Conse-quence	Risk Level	Likeli-hood	Conse-quence	Safety Risk		
1296	7635	7786	7838	0	0	2	#2 BOILER PLANT	BOILER AIR SYSTEM	BOILER SEAL AIR SYSTEM	Scanner & Seal Air	100	19	Mechanical fatigue, corrosion, ops error.	10	None	1	A	Low	1	D	Low	Worst case - Short duration shutdown for repair. Outage.	Current inspection and maintain.
1296	7635	7786	7838	7879	7885	2	#2 BOILER PLANT	BOILER AIR SYSTEM	BOILER SCANNER AIR	Scanner & Seal Air	101	19	Mechanical fatigue, corrosion, ops error.	10	None	1	A	Low	1	A	Low	Worst case - Short duration shutdown for repair. Outage.	Current inspection and maintain.
1296	7635	7786	7838	8781	0	2	#2 BOILER PLANT	BOILER AIR SYSTEM	BOILER F.D. FAN ASSEMBLY	N/A	102		See details below.		None								
1296	7635	7786	7838	8781	7843	2	#2 BOILER PLANT	BOILER AIR SYSTEM	BOILER F.D. FAN EAST	Unit #2 LP FD Fan & Motor	103	19	Mechanical fatigue, corrosion, ops error.	10	None	1	B	Low	1	B	Low	Derate by 50% for short period. Consider spare motor.	Current inspection and maintain.
1296	7635	7786	7838	8781	7844	2	#2 BOILER PLANT	BOILER AIR SYSTEM	BOILER F.D. FAN WEST	4 kV Forced Draft Fan Motor	104	25	Electrical fault, mechanical fatigue, ops error.	(5)	None	1	C	Low	1	C	Low	Loss 60% of 1 unit generation and damages.	Spare and current inspection and maintain.
1296	7635	7786	7838	8781	7843	2	#2 BOILER PLANT	BOILER AIR SYSTEM	BOILER F.D. FAN EAST	4 kV Forced Draft Fan Motor	105	25	Electrical fault, mechanical fatigue, ops error.	(5)	None	1	C	Low	1	C	Low	Loss 60% of 1 unit generation and damages.	Spare and current inspection and maintain.
1296	7635	7786	7838	8781	7844	2	#2 BOILER PLANT	BOILER AIR SYSTEM	BOILER F.D. FAN WEST	Unit #2 LP FD Fan & Motor	106	19	Mechanical fatigue, corrosion, ops error.	10	None	1	B	Low	1	B	Low	Derate by 50% for short period. Consider spare motor.	Current inspection and maintain.
1296	7635	7786	7838	8785	0	2	#2 BOILER PLANT	BOILER AIR SYSTEM	BOILER STEAM AIR HEATER	N/A	107		See details below.		None								
1296	7635	7786	7838	8785	7855	2	#2 BOILER PLANT	BOILER AIR SYSTEM	BOILER STEAM AIR HEATER EAST	Unit #2 Steam Preheat Coils	108	19	Corrosion, erosion, mechanical distortion.	10	None	1	A	Low	1	B	Low	Short term shutdown for repairs, derated or run at increased impact.	Current inspection and maintain.
1296	7635	7786	7838	8785	7856	2	#2 BOILER PLANT	BOILER AIR SYSTEM	BOILER STEAM AIR HEATER WEST	Unit #2 Steam Preheat Coils	109	19	Corrosion, erosion, mechanical distortion.	10	None	1	A	Low	1	B	Low	Short term shutdown for repairs, derated or run at increased impact.	Current inspection and maintain.
1296	7635	7786	7838	8786	0	2	#2 BOILER PLANT	BOILER AIR SYSTEM	BOILER MAIN AIR HEATER	APH Ductwork – Gas & Air	110	19	Corrosion, erosion thinning.	10	None	2	A	Low	2	A	Low	Short duration shutdown for repair/patch.	Current inspection and maintain.
1296	7635	7786	7838	8786	7863	2	#2 BOILER PLANT	BOILER AIR SYSTEM	BOILER MAIN AIR HEATER EAST	Unit #2 APH	111	19	Corrosion, mechanical failure.	10	None	1	B	Low	1	B	Low	50% shutdown for maintenance and repairs.	Current inspection and maintain.
1296	7635	7786	7890	0	0	2	#2 BOILER PLANT	BOILER GAS SYSTEM	BOILER GAS SYSTEM	N/A	112	19,20	Leaks into powerhouse.	10	None	3	B	Medium	3	B	Medium	Overpressure.	Maintain and inspect.
1296	7635	7786	7890	7891	0	2	#2 BOILER PLANT	BOILER GAS SYSTEM	BOILER GAS PASSES	N/A	113	19,20	Leaks into powerhouse.	10	None	3	B	Medium	3	B	Medium	Duct split/corrosion.	Maintain and inspect.
1296	7635	7786	7890	7904	0	2	#2 BOILER PLANT	BOILER GAS SYSTEM	BOILER SOOTBLOWING SYSTEM	N/A	114		Mechanical failure.	10	None	2	B	Low	2	B	Low	Steam leak. Tube erosion.	Current inspection and maintain.
1296	7635	7786	7912	0	0	2	#2 BOILER PLANT	BOILER FUEL FIRING SYSTEM	BOILER FUEL FIRING SYSTEM	Fuel Feed System	115	19	Mechanical fatigue, corrosion, ops error.	10	None	1	A	Low	1	C	Low	Derate for short period. Safety.	Current inspection and maintain.
1296	7635	7786	7912	7935	0	2	#2 BOILER PLANT	BOILER FUEL FIRING SYSTEM	BOILER LIGHT OIL	N/A	116		Not addressed.	10	None								
1296	7635	7786	7953	0	0	2	#2 BOILER PLANT	BLR AUX STEAM & CONDENSATE	BLR AUX STEAM & CONDENSATE	N/A	117		Mechanical failure.	(5)	None	3	A	Low	3	B	Medium	Steam leak.	Current inspection and maintain.
1296	7635	7786	7787	0	0	2	#2 BOILER PLANT	BOILER STRUCTURE	BOILER STRUCTURE	N/A	118		Mechanical failure	20	None	1	D	Medium	1	D	Low	Structure collapse.	Maintain and inspect.

9.2.6.7 Life Cycle Curve and Remaining Life

The life cycle curve for the Unit 2 FD fans (and system) is illustrated below. Two curves are required to represent the various elements given their different in-service dates and operating history. The life curves are plots of current and projected operating hours (generation mode only) on the y-axis versus calendar year on the x-axis. The figure has several vertical lines representing differing representative nominal age limits for various components. It also has several horizontal lines that represent a range of practical equipment equivalent base loaded operating hour life limits. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view.

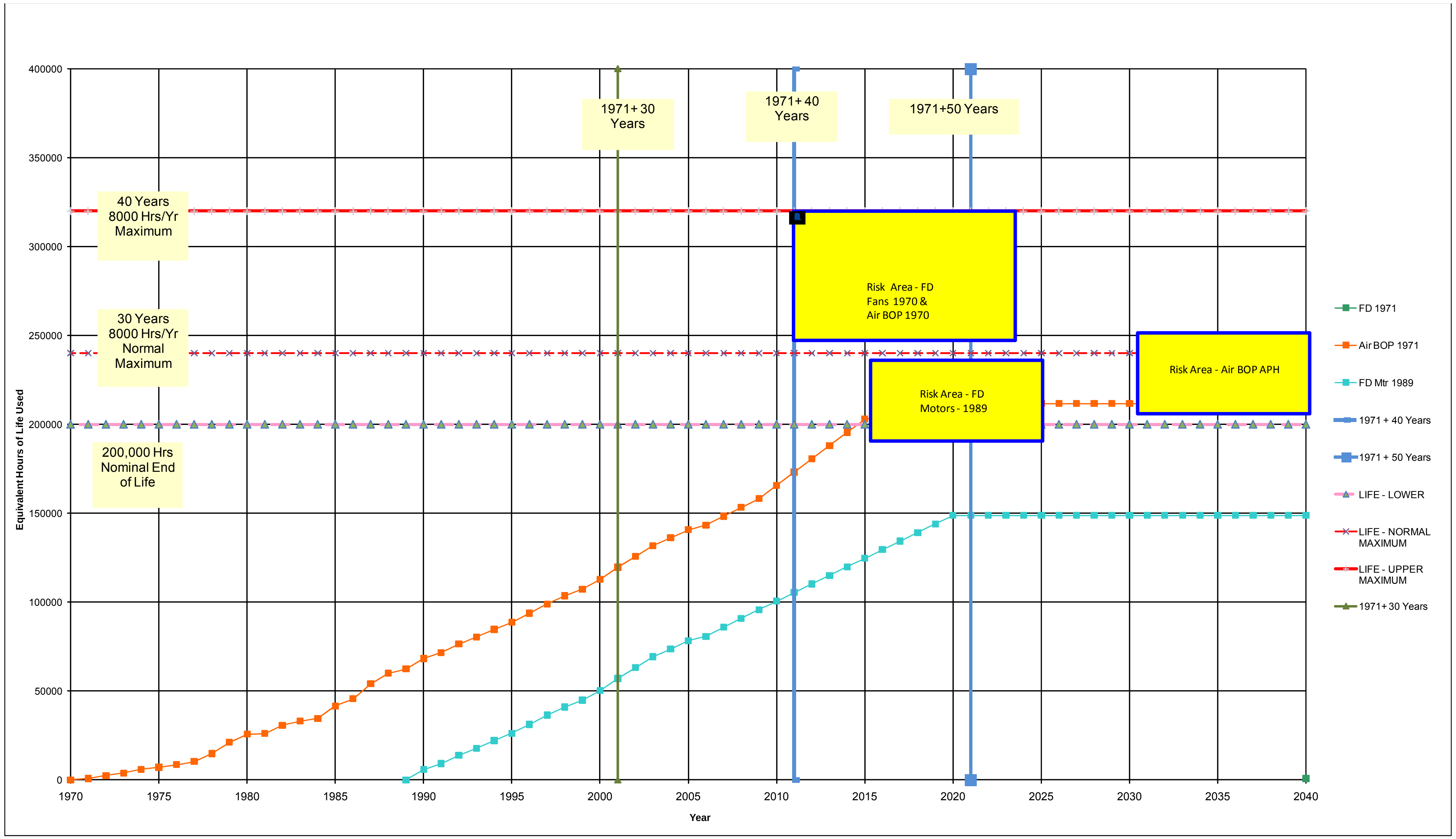

FIGURE 9-19 LIFE CYCLE CURVE – UNIT 2 FD FANS (AND SYSTEM)

The curves indicate that the remaining life (RL) of the Unit 2 FD fans (and system) is expected to meet or exceed the desired life (DL) 2020 end date for generation. The age of the large 4 kV motors makes them a logical cost-effective candidate for sparing to ensure reliability, although plant testing/monitoring programs are effectively monitoring their status.

9.2.6.8 Level 2 Inspections – Unit 2 FD Fans (and System)

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 9-55 below, assuming the current plant inspection and maintenance program is maintained or improved.

TABLE 9-55 LEVEL 2 INSPECTIONS – UNIT 2 FD FANS (AND SYSTEM)

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Sub System Comment	L2#	Appendix #	Level 2 Work	Year	Priority	Cost k$
1296	7635	7786	7838	0	0	2	#2 BOILER PLANT	BOILER AIR SYSTEM	BOILER AIR SYSTEM	None	78	19	No Level 2 required.			
1296	7635	7786	7838	7879	7885	2	#2 BOILER PLANT	BOILER AIR SYSTEM	BOILER SCANNER AIR	None	79	19	No Level 2 inspections or testing is required.			
1296	7635	7786	7838	8781	0	2	#2 BOILER PLANT	BOILER AIR SYSTEM	BOILER F.D. FAN ASSEMBLY	None	80	19	No Level 2 required.			
1296	7635	7786	7838	8781	7843	2	#2 BOILER PLANT	BOILER AIR SYSTEM	BOILER F.D. FAN EAST	None	81	19	No Level 2 inspections or testing is required on fan or 4 kV motors, provided the current inspection and maintenance program is maintained. Assumes FD turbulence upgrades undertaken.			
1296	7635	7786	7838	8781	7844	2	#2 BOILER PLANT	BOILER AIR SYSTEM	BOILER F.D. FAN WEST	None	82	19	No Level 2 inspections or testing is required on fan or 4 kV motors, provided the current inspection and maintenance program is maintained. Assumes FD turbulence upgrades undertaken.			
1296	7635	7786	7838	8785	0	2	#2 BOILER PLANT	BOILER AIR SYSTEM	BOILER STEAM AIR HEATER	None	83	19	No Level 2 inspections or testing is required.			
1296	7635	7786	7838	8785	7855	2	#2 BOILER PLANT	BOILER AIR SYSTEM	BOILER STEAM AIR HEATER EAST	None	84	19	No Level 2 inspections or testing is required.			
1296	7635	7786	7838	8785	7856	2	#2 BOILER PLANT	BOILER AIR SYSTEM	BOILER STEAM AIR HEATER WEST	None	85	19	No Level 2 inspections or testing is required.			
1296	7635	7786	7838	8786	0	2	#2 BOILER PLANT	BOILER AIR SYSTEM	BOILER MAIN AIR HEATER	None	86	19	No Level 2 inspections or testing is required.			
1296	7635	7786	7838	8786	7863	2	#2 BOILER PLANT	BOILER AIR SYSTEM	BOILER MAIN AIR HEATER EAST	None	87	19	No Level 2 inspections or testing is required.			
1296	7635	7786	7890	0	0	2	#2 BOILER PLANT	BOILER GAS SYSTEM	BOILER GAS SYSTEM	None	88	19	No Level 2 inspections or testing is required.			
1296	7635	7786	7890	7891	0	2	#2 BOILER PLANT	BOILER GAS SYSTEM	BOILER GAS PASSES	None	89	19	No Level 2 inspections or testing is required.			
1296	7635	7786	7890	7904	0	2	#2 BOILER PLANT	BOILER GAS SYSTEM	BOILER SOOTBLOWING SYSTEM	None	90	19	No Level 2 inspections or testing is required.			
1296	7635	7786	7912	0	0	2	#2 BOILER PLANT	BOILER FUEL FIRING SYSTEM	BOILER FUEL FIRING SYSTEM	None	91	19	No Level 2 inspections or testing is required.			
1296	7635	7786	7912	7935	0	2	#2 BOILER PLANT	BOILER FUEL FIRING SYSTEM	BOILER LIGHT OIL	None	92	19	No Level 2 inspections or testing is required.			
1296	7635	7786	7953	0	0	2	#2 BOILER PLANT	BLR AUX STEAM & CONDENSATE	BLR AUX STEAM & CONDENSATE	None	93	N/A	No Level 2 required.			

9.2.6.9 Capital Projects

The suggested typical capital enhancements for the system include:

TABLE 9-56 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – UNIT 2 FD FANS (AND SYSTEM)

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Detail	CAP#	Appendix #	Capital Item	Date	Priority
1296	7635	7786	7838	0	0	2	#2 BOILER PLANT	BOILER AIR SYSTEM	BOILER AIR SYSTEM	N/A	72	19	Upgrade air ducts to reduce vibration, improve efficiency.	2014	1
1296	7635	7786	7838	7879	7885	2	#2 BOILER PLANT	BOILER AIR SYSTEM	BOILER SCANNER AIR	N/A	73		No capital investment required.		
1296	7635	7786	7838	8781	0	2	#2 BOILER PLANT	BOILER AIR SYSTEM	BOILER F.D. FAN ASSEMBLY	N/A	74	19,25	Procure spare motor - common to Units 1 & 2; adaptable Unit 3 to extent practical.	2012	1
1296	7635	7786	7838	8781	7843	2	#2 BOILER PLANT	BOILER AIR SYSTEM	BOILER F.D. FAN EAST	N/A	75	19	Install vibration monitoring.	2012	2
1296	7635	7786	7838	8781	7844	2	#2 BOILER PLANT	BOILER AIR SYSTEM	BOILER F.D. FAN WEST	N/A	76	19	Install vibration monitoring.	2012	2
1296	7635	7786	7838	8785	0	2	#2 BOILER PLANT	BOILER AIR SYSTEM	BOILER STEAM AIR HEATER	N/A	77	19	No capital investment required.		
1296	7635	7786	7838	8785	7855	2	#2 BOILER PLANT	BOILER AIR SYSTEM	BOILER STEAM AIR HEATER EAST	N/A	78	19	No capital investment required.		
1296	7635	7786	7838	8785	7856	2	#2 BOILER PLANT	BOILER AIR SYSTEM	BOILER STEAM AIR HEATER WEST	N/A	79	19	No capital investment required.		
1296	7635	7786	7838	8786	0	2	#2 BOILER PLANT	BOILER AIR SYSTEM	BOILER MAIN AIR HEATER	N/A	80	19	No capital investment required.		
1296	7635	7786	7838	8786	7863	2	#2 BOILER PLANT	BOILER AIR SYSTEM	BOILER MAIN AIR HEATER EAST	N/A	81	19	No capital investment required.		
1296	7635	7786	7890	0	0	2	#2 BOILER PLANT	BOILER GAS SYSTEM	BOILER GAS SYSTEM	N/A	82	19	No capital investment required.		
1296	7635	7786	7890	7891	0	2	#2 BOILER PLANT	BOILER GAS SYSTEM	BOILER GAS PASSES	N/A	83	19	No capital investment required.		
1296	7635	7786	7890	7904	0	2	#2 BOILER PLANT	BOILER GAS SYSTEM	BOILER SOOTBLOWING	N/A	84	19	FD fan ductwork modifications.	2011	3
1296	7635	7786	7912	0	0	2	#2 BOILER PLANT	BOILER FUEL FIRING SYSTEM	BOILER FUEL FIRING SYSTEM	N/A	85	19	No capital investment required.		
1296	7635	7786	7912	7935	0	2	#2 BOILER PLANT	BOILER FUEL FIRING SYSTEM	BOILER LIGHT OIL	N/A	86	19	No capital investment required.		
1296	7635	7786	7953	0	0	2	#2 BOILER PLANT	BLR AUX STEAM & CONDENSATE	BLR AUX STEAM & CONDENSATE	N/A	87		New building heating system	2015-2020	2
1296	7635	7786	7787	0	0	2	#2 BOILER PLANT	BOILER STRUCTURE	BOILER STRUCTURE	N/A	88		No capital investment required.		

9.2.7 Asset 7900 – Unit 2 Stack and Breeching

(Detailed Technical Assessment in Working Papers, Appendix 17)

Unit #:	2
Asset Class #	BU 1296 - Assets Generations
SCI & System:	7786 #2 Boiler Plant
Sub-Systems:	7890 #2 Boiler Gas System
Components:	7900 #2 Boiler Stack 271327 #2 Stack Breeching

9.2.7.1 Description

The Unit 2 stack was constructed in 1969 from reinforced concrete and contains a steel liner with some sections constructed from stainless steel and the remaining sections constructed from carbon steel. The stack breeching is the insulated steel ductwork that conveys the hot flue gas from the boiler air preheater to the stack.

9.2.7.2 History

Description	Stack Calendar Life	Operating hours/Equiv Op Yrs since Installation to 2009	Operating hours/Equiv Op Yrs to 2015/2020
Unit 2 Stack	44	158,000 (19)	195,000/212,000 (27)

The hours are based on 70% ACF/85% operating factor (OF) to 2015 (where the OF is equal to the actual running hours at any load in a year divided by 8760) and 10% ACF/20% OF from 2015-2020. The hours for 2015 and 2020 would be about 16,000 hours less if plant runs closer to historical 40% ACF up to 2015.

Manufactured/Delivered	1970
In-Service Date	Apr 1971
Generation Base Load End Date	Dec 2015
Generation Peak/Emerg Gen End Date	Dec 2020

The hours associated with the analyses are:

Hours Generation Actual - Ops to Dec 2009	158
Max Hours Generation Ops – to Dec 2015	188
Max Hrs Gen Ops to Gen End Date Dec 2020	212
Max Hours Ops – 1986 to Dec 2009	113
Max Hrs - 1986 to Dec 2015	142
Max Hrs – 1986 to Gen End Date Dec 2020	164

Max Hours Ops – 2007/8 to Dec 2009	5
Max Hrs – 2007/8 to Dec 2015	35
Max Hrs – 2007/8 to Gen End Date Dec 2020	59

9.2.7.3 Inspection and Repair History

The Unit 2 stack was built in 1966. Since the original construction, the plant has performed regular PM inspections and completed the suggested repairs.

Previous stack inspection reports indicate that there has been no major cracking or structural issues. There is some small cracking in portions of the stack and some water infiltration around construction joints. The carbon steel portions of the liners have localized areas of heavy corrosion as well as areas with minimal corrosion. The condition of the current linings and cap seem to suggest that Unit 2 has not been operating below the sulphuric acid dew point. The recent change to a much lower sulphur fuel oil has reduced the acid dew point, thereby allowing the plant to operate at a lower stack exit temperature to improve efficiency.

The life of the steel liners will vary depending on the materials of construction, the flue gas constituents, and the flue gas exit temperature. The upper liner sections of the stack are made of stainless steel to address the higher likelihood of acid attack as the flue gas cools going up the stack to levels approaching the acid dew point (local cooling could be below the dew point). The lower section of the liner is carbon steel which is adequate, provided the temperature in that zone does not frequently fall below the acid dew point of the stack. The design life of the liners should have been at least 30 years for the design fuels and operating conditions. Unit 2 carbon steel liner was replaced in 2001.

The inspections also suggest that life should not be an issue for the liners for the next ten years, despite the fact that portions of the liner are in excess of 43 and 33 years of age. The Unit 2 stack has seen approximately 19 years of operation over the period and therefore should be in reasonable shape. An additional 6 to 8 years of equivalent operation life may require some more careful examination. It is suggested during the next stack inspection that some NDE thickness measurements be taken at strategic points on both the stainless steel and carbon steel liners.

The Unit 2 stack breeching, referred to as the East and West stack breeching, is connected to the outlet of each air pre-heater and conveys the hot flue gas to the boiler exhaust stack. The original Unit 2 stack breeching was installed in 1970 and had a rectangular cross section that was constructed from carbon steel plate. It was insulated externally with water tight insulation and metal cladding. The original breeching had a life span of approximately twenty years. During operation, there were numerous problems associated with corrosion that led to a complete replacement in 1989.

The existing Unit 2 stack breeching installed in 1989 also has a rectangular cross section that is constructed from carbon steel plate but is insulated internally on the sides and top with borosilicate (glass) block. The breeching sections are also coated externally with a protective film to inhibit corrosion. In addition, the breeching sections also have a silicate concrete floor.

Early into the Unit 2 operation following the upgrade in 1989, problems associated with cracking of the breeching internal insulating liner and concrete floor began develop. The concrete floor began to crack and the insulation blocks began to fall off the breeching, allowing the flue gas to penetrate the breeching plate where it would then cool and form sulphuric acid condensation causing localized corrosion necessitating plate repairs. As a result, the internal insulation liner and breeching plate has required frequent repairs and relatively high maintenance cost during scheduled Unit 2 annual outages.

Hydro completed thickness scanning on Unit 2 stack breeching steel casing in August 2010. The scan indicated that the casing was generally in good condition but localized areas required steel plate replacement due to corrosion. The current plan is to refurbish the steel casing based on the results of the plate thickness scan, replace the expansion joints and the corroded support structure, and insulate the breeching externally complete with water tight cladding and flashing. Ice protection shelters will also be constructed above the replacement breeching in order to protect the external insulation from damage caused by ice falling from the stack and the plant power house. The upgrade will be completed in 2012. Following the upgrade, the stack breeching is expected to be able to make the 2020 generation end date without additional major refurbishment or replacement.

9.2.7.4 Condition Assessment

The condition assessment of the Unit 2 stack and breeching is illustrated below in Table 9-57:

TABLE 9-57 CONDITION ASSESSMENT – UNIT 2 STACK AND BREECHING

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset Level 2	Asset Level 3	Description	Detail	Condition Summary ID#	Append #	Condition	EPRI Identifier	Original Life (Base Load) Ops Hrs (Yrs)	Current Expected Minimum Remaining Life Years (Subject to Test)	End of Life (EOL) Required	Next Regular Inspection	Next Planned Overhaul or Major Inspection	Capability to Reach Next Overhaul	Capability to Reach EOL	In Service
1296	7635	7786	7890	7900	0	2	#2 BOILER PLANT	BOILER GAS SYSTEM	BOILER STACK	N/A	98	17	The concrete stacks are in good condition. The carbon steel portions of the liners have localized areas of heavy corrosion as well as areas with minimal corrosion. Carbon steel liner replaced in 2001.	3a	(60/30)	30	2041	2011	2011	Yes	Yes	1971/2001
1296	7635	7786	7890	7900	271327	2	#2 BOILER PLANT	BOILER GAS SYSTEM	STACK BREECHING	N/A	99	17	Installed in 1990. The current refractory brick lining in the breeching is cracked, causing local corrosion. It is planned to refurbish the breeching and replace the brick refractory with an insulated steel lined duct.	10	(30)	3	2020	2011	2012	Yes	No	1990/2012
1296	7635	7786	7890	7900	299552	2	#2 BOILER PLANT	BOILER GAS SYSTEM	BOILER STACK LINER	N/A	100	17	The carbon steel portions of the liners have localized areas of heavy corrosion as well as areas with minimal corrosion. Unit 1 carbon steel liner was replaced in 2000 and Unit 2 in 2001.	3a	200000 (30)	10	2020	2011	2012	Yes	Yes	2001

Notes:
1. A “(bracketed)” value in the “Current Expected Remaining Life” column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation, including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as “(X/Y)” has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.
2. The “Next Regular Inspection” column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The “Next Planned Overhaul or Major Inspection” column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a “Desired Life” stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or not known by AMEC.
3. The ability of the stack breeching to meet the EOL date of 2020 will be affected if planned refurbishments in 2012 are not undertaken.
4. The stack end of life is identified as 2041, assuming that it would not be demolished before the plant itself is closed.

9.2.7.5 Actions

Based on the condition assessment, the following actions are recommended for the Unit 2 stack and breeching:

TABLE 9-58 RECOMMENDED ACTIONS – UNIT 2 STACK AND BREECHING

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Unit	Asset 2/3	Asset 3/4	Description	Detail	Action #	App #	Action	Year	Priority
1296	7635	7786	7890	7900	2	#2 BOILER PLANT	BOILER GAS SYSTEM	BOILER STACK	N/A	137	17	See details below.		
1296	7635	7786	7890	7900	2	#2 BOILER PLANT	BOILER GAS SYSTEM	BOILER STACK	N/A	138	17	Paint stack, at least top portions, within next five years.	2013	2
1296	7635	7786	7890	7900	2	#2 BOILER PLANT	BOILER GAS SYSTEM	BOILER STACK	N/A	139	17	Continue current stack inspections every 3 years and monitor degradation of concrete stacks and steel liners.	2012	1
1296	7635	7786	7890	7900	2	#2 BOILER PLANT	BOILER GAS SYSTEM	BOILER STACK	N/A	140	17	Continue to make repairs to deficiencies found in inspection reports.	2012	1
1296	7635	7786	7890	7900	2	#2 BOILER PLANT	BOILER GAS SYSTEM	STACK BREECHING	N/A	141	17	Undertake planned stack breeching refurbishment incuding patching steel liner, installing external insulation, replacing corroded supports structure, and installing ice protection.	2012	1

9.2.7.6 Risk Assessment

Table 9-59 below illustrates the risk assessment for the Unit 2 stack and breeching, both from a technological perspective and a safety perspective using the models presented in Section 3.

TABLE 9-59 RISK ASSESSMENT – UNIT 2 STACK AND BREECHING

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Component	Risk Assess #	Appendix #	Major Issues	Remaining Life Years	Remaining Life Comments	TECHNO-ECO RISK ASSESSMENT MODEL			SAFETY RISK ASSESSMENT MODEL			Possible Failure Event	Mitigation
														(Insufficient Info - Inspection Required Within (x) Years)		Likeli-hood	Conse-quence	Risk Level	Likeli-hood	Conse-quence	Safety Risk		
1296	7635	7786	7890	7900	0	2	#2 BOILER PLANT	BOILER GAS SYSTEM	BOILER STACK	Unit #2 Concrete Shell	121	17	Structural cracking.	30	None	1	D	Medium	1	D	Medium	Structural failure requiring shutdown.	Current inspection and maintain.
1296	7635	7786	7890	7900	0	2	#2 BOILER PLANT	BOILER GAS SYSTEM	BOILER STACK	Unit #2 Stainless Steel Liner	122	17	Corrosion/failure.	10	None	1	B	Low	1	C	Low	Corrosion causing major leak or failure – major leak requiring repair.	Current inspection and maintain.
1296	7635	7786	7890	7900	0	2	#2 BOILER PLANT	BOILER GAS SYSTEM	BOILER STACK	Unit #2 Carbon Steel Liner	123	17	Corrosion/failure.	(10)	None	3	B	Medium	2	C	Medium	Corrosion causing major leak or failure – major leak requiring repair.	Current inspection and maintain.
1296	7635	7786	7890	7900	271327	2	#2 BOILER PLANT	BOILER GAS SYSTEM	STACK BREECHING	Unit #2 Stack Breeching	124	17	Corrosion/failure.	3	None	3	B	High	2	B	Low	Corrosion causing major leak or failure – major leak requiring repair.	Repair and maintain.

9.2.7.7 Life Cycle Curve and Remaining Life

The life cycle curve for the Unit 2 stack and breeching is illustrated below. Four curves represent the stack, the stack breeching, and the stack liners based on their in-service dates. The life curves are plots of current and projected operating hours (generation mode only) on the y-axis versus calendar year on the x-axis. The figure has several vertical lines representing differing representative nominal age limits for various components. It also has several horizontal lines that represent a range of practical equivalent base loaded operating hour life limits. Several risk areas reflect also the differing normal lives of the components. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view.

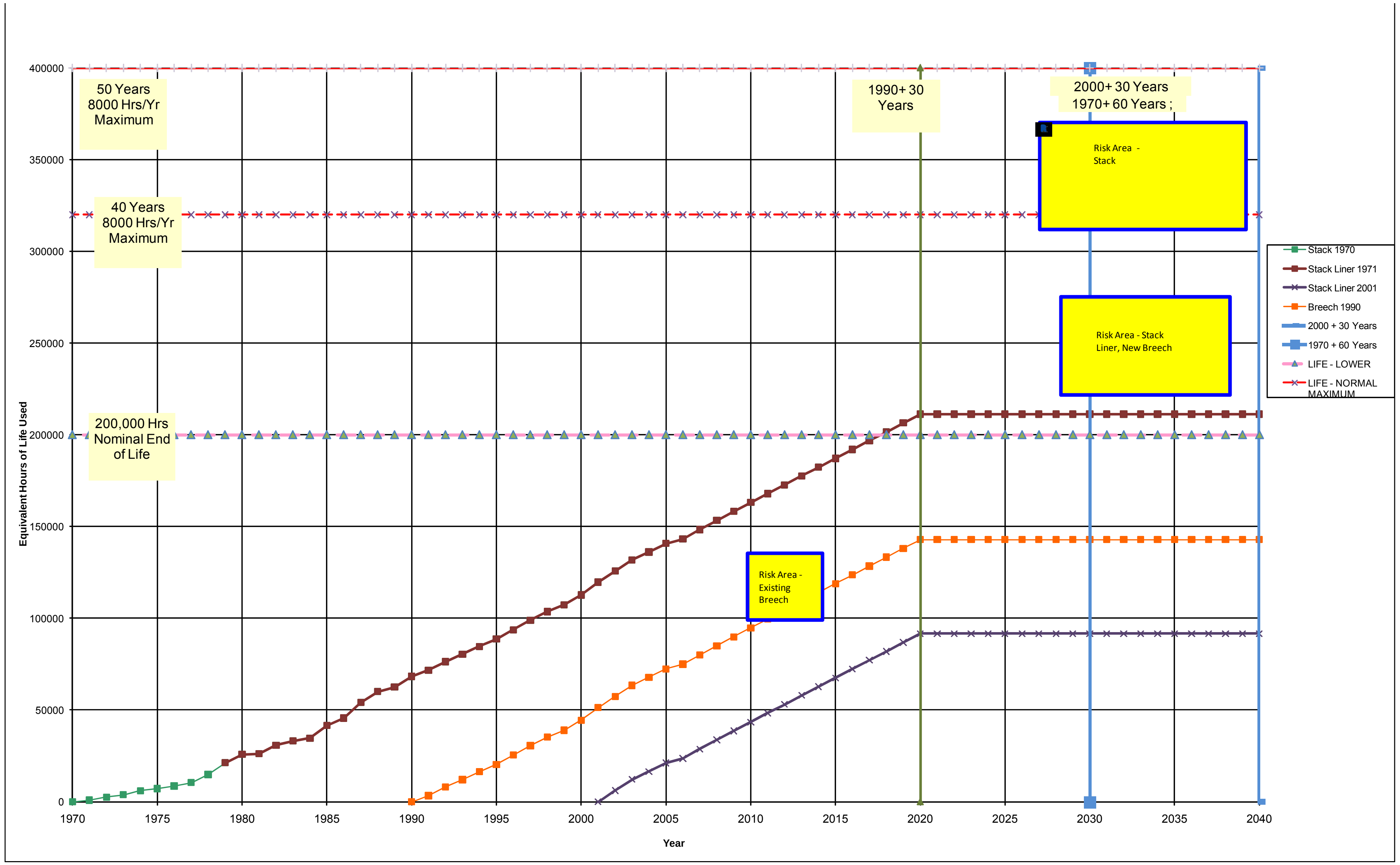

FIGURE 9-20 LIFE CYCLE CURVE – UNIT 2 STACK AND BREECHING

The curves indicate that the remaining life (RL) of the Unit 2 stack is able to reach the desired life (DL) 2020 end date for generation, as well as the end date of 2040 for synchronous condensing/plant life. It does show that the stack breeching is in need of immediate repair. The breeching requirement is not a normal life issue, but one of poor design. Other elements can achieve the 2020 end date for generation with the ongoing plant maintenance program.

9.2.7.8 Level 2 Inspections – Unit 2 Stack and Breeching

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 9-60 below, assuming the current plant inspection and maintenance program is maintained or improved.

TABLE 9-60 LEVEL 2 INSPECTIONS – UNIT 2 STACK AND BREECHING

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Sub System Comment	L2#	Appendix #	Level 2 Work	Year	Priority	Cost k$
1296	7635	7786	7890	7900	0	2	#2 BOILER PLANT	BOILER GAS SYSTEM	BOILER STACK	Stacks	94	17	No Level 2 inspections. Continue inspections every 3 years and monitor degradation of concrete stacks and steel liners.			
1296	7635	7786	7890	7900	271327	2	#2 BOILER PLANT	BOILER GAS SYSTEM	STACK BREECHING	None	95	17	No Level 2 required. (Assumes breeching refurbishment undertaken in 2012)			
1296	7635	7786	7890	7900	299552	2	#2 BOILER PLANT	BOILER GAS SYSTEM	BOILER STACK LINER	None	96	17	No Level 2 required.			

9.2.7.9 Capital Projects

The suggested typical capital enhancements for the system include:

TABLE 9-61 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – UNIT 2 STACK AND BREECHING

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Detail	CAP#	Appendix #	Capital Item	Date	Priority
1296	7635	7786	7890	7900	0	2	#2 BOILER PLANT	BOILER GAS SYSTEM	BOILER STACK	N/A	91	17	See details below.		
1296	7635	7786	7890	7900	271327	2	#2 BOILER PLANT	BOILER GAS SYSTEM	STACK BREECHING	N/A	92	17	Refurbish stack breeching .	2012	1
1296	7635	7786	7890	7900	299552	2	#2 BOILER PLANT	BOILER GAS SYSTEM	BOILER STACK LINER	N/A	93	17	No capital investment required.		

9.2.8 Asset 8152 – Unit 2 Electrical and Control Systems (including DCS) Associated with Steam Systems

(Detailed Technical Assessment in Working Papers, Appendix 6)

The assets listed include only those identified as exclusive to the plant steam systems.

Unit #:	2
Asset Class #	BU 1296 - Assets Generation
SCI & System:	8152 #2 Electrical System & Controls
Sub-Systems:	8152 #2 Electrical System & Controls
Components:	7677 #2 Turbine Governor System 8139 #2 Burner Management 309898 #2, Boiler Protection & Control

9.2.8.1 Description

The following information covers the Unit 2 electrical and control systems within the plant and its associated buildings.

Asset 7677 Unit 2 Turbine Governor System

The system is comprised of an electronic speed governor, (GE SpeedTronic Mark V), manufactured by General Electric, and installed in 2003. The governor is complete with protection and monitors speed, metal temperatures, vibration and steam valve positions into the turbine. A human machine interface (HMI) for operator use is provided in the control room.

Asset 8139 Unit 2 Burner Management

The present burner management system is comprised of a Modicon PLC and Operator Control (HMI), and was installed in 1995. Field wiring in the bottom of the PLC cabinets is the original as installed in 1969.

The PLC hardware is a Modicon 984 CPU with 800 series I/O and uses Schneider Electric ProWorx software. HMI hardware is a PC with Factory Link Version 6.5 software.

The system controls the operation of the burners, provides start-up and shut-down of the burner, and protection of the fuel and air systems.

In 1995, a major upgrade was completed and the Combustion Engineering Cygnus operator consoles were removed and replaced with a PC based HMI console. At this time the Windows based Factory Link Version 6.5 was installed in the console. During the upgrade the original Modicon 884 processor was replaced with a 984 processor. The original 800 series I/O modules remained and today these are 25 years old.

Asset 299451 Unit 2 DCS

The DCS was manufactured by Foxboro and is an Invensys system that was installed in 2004. The Westinghouse panels housing the DCS were installed in the late 1990's, and new cabling was also installed at that time. The original system was hard-wired, but later updated to a Westinghouse system.

Asset 309898 Unit 2 Boiler Protection & Control

The boiler protection and control system provides safety of personnel, protection of the boiler and its equipment, and control of the boiler processes. The original Bailey system was replaced by Westinghouse WDPF, and in 2004 the system was again updated from the Westinghouse WDPF to the present Foxboro DCS mounted within the original Westinghouse WDPF enclosures.

9.2.8.2 History

The requirements for the electrical and control systems associated with the steam system for Holyrood are as follows:

Manufactured/Delivered	1970
In-Service Date	Apr 1971
Generation Base Load End Date	Dec 2015
Generation Peak/Emerg Gen End Date	Dec 2020
Last Controls Upgrade	2004

9.2.8.3 Inspection and Repair History

Foxboro technical support is provided a number of times per year under a support agreement. Upgrades have been and will be carried out as required. Field adjustments and modifications will continue as necessary.

9.2.8.4 Condition Assessment

The condition assessment of the Unit 2 E&C control system associated with steam is illustrated below in Table 9-62:

TABLE 9-62 CONDITION ASSESSMENT – UNIT 2 ELECTRICAL AND CONTROL SYSTEMS (INCLUDING DCS) ASSOCIATED WITH STEAM SYSTEMS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset Level 2	Asset Level 3	Description	Detail	Condition Summary ID#	Append #	Condition	EPRI Identifier	Original Life (Base Load) Ops Hrs (Yrs)	Current Expected Minimum Remaining Life Years (Subject to Test)	End of Life (EOL) Required	Next Regular Inspection	Next Planned Overhaul or Major Inspection	Capability to Reach Next Overhaul	Capability to Reach EOL	In Service
1296	7635	8152	0	0	0	2	#2 ELECTRICAL & CONTROLS SYS	ELECTRICAL & CONTROLS SYS	ELECTRICAL & CONTROLS SYS	N/A	179	6	See details below.									
1296	7635	8152	8138	0	0	2	#2 ELECTRICAL & CONTROLS SYS	RELAY RM PROTECT & CONTROL	RELAY RM PROTECT & CONTROL	N/A	180	6	Generator, Transformer and Auxiliary Protection and Metering Panels tests in 2006 were satisfactory. Some ingress of dust and foreign material. Testing is on a 6 year cycle (2012, 2018, 2024, etc.).	10	(30)	10	2041			No	No	1971
1296	7635	8152	271478	0	0	2	#2 ELECTRICAL & CONTROLS SYS	SWITCHGEAR 4160 & 600 VOLT	SWITCHGEAR 4160 & 600 VOLT	N/A	181	6	Breaker overhauls have been carried out in 2006 and 2007, except UB2-2 in 1996 (See Appendix). All 4160V switchgear is applied within ratings. Past normal life - extended by overhauls/maintenance.	10	(25)	5	2041			No	No	1971
1296	7635	8152	7677	0	0	2	#2 ELECTRICAL & CONTROLS SYS	TURBINE GOVERNOR SYSTEM	TURBINE GOVERNOR SYSTEM	N/A	182	6	Maintenance (PM) and corrective actions (CA) are performed as required. Servos are checked annually due to problems with "dirty" hydraulic lines resulting in blocked pilot strainers. From an electrical and controls point of view, the system is operating well. GE support until 2012-2013 with no guarantee of spares.	10	(30)	(10)	2020	2011		Yes	No	1999
1296	7635	8152	271479	0	0	2	#2 ELECTRICAL & CONTROLS SYS	TURBINE SUPERVISORY SYSTEM (TSI)	TSI	N/A	183	6	Operating well, with numerous spares. In 2010 will progress toward Phase 5 (Obsolescence) status at some indeterminate time.	10	(25)	5	2020			No	No	1971/2004
1296	7635	8152	8144	0	0	2	#2 ELECTRICAL & CONTROLS SYS	MAIN CONTROLS	MAIN CONTROLS	N/A	184	6	There are age and spares problems with the relaying system.	4	(30)	10	2041			Yes	No	1971
1296	7635	8152	299451	0	0	2	#2 ELECTRICAL & CONTROLS SYS	DISTRIBUTED CONTROL SYSTEM (DCS)	DCS	N/A	185	6	Installed in 2004 - state of the art.	3a	(20)	10+	2041			Yes	No	2004
1296	7635	8152	8139	0	0	2	#2 ELECTRICAL & CONTROLS SYS	BURNER MANAGEMENT	BURNER MANAGEMENT	N/A	186	6	Major upgrade in 1995 with HMI operator consoles and processor. Original 800 series I/O modules remained. Minor failures only. Annual maintenance inspections and repairs.	4	(25)	10	2020			Yes	Yes	1995
1296	7635	8152	309898	0	0	2	#2 ELECTRICAL & CONTROLS SYS	BOILER PROTECTION & CONTROL	BOILER PROTECTION & CONTROL	N/A	187	6	In 2004 the system was updated to the Foxboro DCS system in the original WDPF enclosures.	3a	(20)	10+	2020			Yes	Yes	2004

Notes:

1. A "(bracketed)" value in the "Current Expected Remaining Life" column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation, including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as "(X/Y)" has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

2. The "Next Regular Inspection" column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The "Next Planned Overhaul or Major Inspection" column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a "Desired Life" stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or not known by AMEC.

9.2.8.5 Actions

Based on the condition assessment, the following actions are recommended for the Unit 2 electrical and control systems (including DCS) associated with steam systems:

TABLE 9-63 RECOMMENDED ACTIONS – UNIT 2 ELECTRICAL AND CONTROL SYSTEMS (INCLUDING DCS) ASSOCIATED WITH STEAM SYSTEMS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Unit	Asset 2/3	Asset 3/4	Description	Detail	Action #	App #	Action	Year	Priority
1296	7635	8152	8138	0	2	#2 ELECTRICAL & CONTROLS SYS	RELAY RM PROTECT & CONTROL	RELAY RM PROTECT & CONTROL	N/A	245	6	Test Generator G1, Transformer T1 and Auxiliaries P&C Panels - next tests planned for 2011, 2017, 2023, etc.	2011	1
1296	7635	8152	271478	0	2	#2 ELECTRICAL & CONTROLS SYS	SWITCHGEAR 4160 & 600 VOLT	SWITCHGEAR 4160 & 600 VOLT	N/A	246	6	Include this Switchgear 4160V/600V relaying in UB2 modernization study (5.3.2.15 IV) for the protection relays. Consider that the remaining P&B Golds relays remain and not be replaced by Schweitzer 701 MPR's. As of 2015 the breakers utilizing these will become standby and as of 2020 will become spare.	2011	2
1296	7635	8152	271479	0	2	#2 ELECTRICAL & CONTROLS SYS	TURBINE SUPERVISORY SYSTEM (TSI)	TSI	N/A	247	6	Assess Turbine Supervisory System replacement options (vendor, GE 3500 Series Monitoring System, other GE options) that might be available in 2010-2011.	2011	1
1296	7635	8152	7677	0	2	#2 ELECTRICAL & CONTROLS SYS	TURBINE GOVERNOR SYSTEM	TURBINE GOVERNOR SYSTEM	N/A	248	6	Assess and implement GE migration of the Turbine Governor System Mark V to the Mark Ve system.	2012	2
1296	7635	8152	8144	0	2	#2 ELECTRICAL & CONTROLS SYS	MAIN CONTROLS	MAIN CONTROLS	N/A	249	6	Assess removing existing Main Controls control relaying and transducers, re-direct field cabling to the DCS and re-configure the software.	2011	2
1296	7635	8152	299451	0	2	#2 ELECTRICAL & CONTROLS SYS	DISTRIBUTED CONTROL SYSTEM (DCS)	DCS	N/A	250	6	Maintain DCS system current through existing Foxboro replacement service agreement.	2014	1
1296	7635	8152	8139	0	2	#2 ELECTRICAL & CONTROLS SYS	BURNER MANAGEMENT	BURNER MANAGEMENT	N/A	251	6	Transfer the Burner Management system from the PLC system to the DCS as per the 2011 Capital Budget. Remove existing field mounted pressure switches and replace by analog transducers for continuous status monitoring. The Flame Scanners will remain unchanged.	2011	2
1296	7635	8152	309898	0	2	#2 ELECTRICAL & CONTROLS SYS	BOILER PROTECTION & CONTROL	BOILER PROTECTION & CONTROL	N/A	252	6	Maintain the Boiler Protection and Control System current through existing Foxboro migration process infinitum.	2014	1

9.2.8.6 Risk Assessment

Table 9-64 below illustrates the risk assessment for the Unit 2 electrical and control systems (including DCS) associated with steam systems, both from a technological perspective and a safety perspective using the models presented in Section 3.

TABLE 9-64 RISK ASSESSMENT – UNIT 2 ELECTRICAL AND CONTROL SYSTEMS (INCLUDING DCS) ASSOCIATED WITH STEAM SYSTEMS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Component	Risk Assess #	Appendix #	Major Issues	Remaining Life Years	Remaining Life Comments	TECHNO-ECO RISK ASSESSMENT MODEL			SAFETY RISK ASSESSMENT MODEL			Possible Failure Event	Mitigation
														(Insufficient Info - Inspection Required Within (x) Years)		Likeli-hood	Conse-quence	Risk Level	Likeli-hood	Conse-quence	Safety Risk		
1296	7635	8152	8138	0	0	2	#2 ELECTRICAL & CONTROLS SYS	RELAY RM PROTECT & CONTROL	RELAY RM PROTECT & CONTROL	N/A	215	6	Electrical fault, mechanical fatigue, ops error.	10	None	2	C-D	Medium	2	C-D	Medium	Loss 1 unit generation, damage to unit or equipment.	Current inspection and maintain.
1296	7635	8152	271478	0	0	2	#2 ELECTRICAL & CONTROLS SYS	SWITCHGEAR 4160 & 600 VOLT	SWITCHGEAR 4160 & 600 VOLT	N/A	216	6	Electrical fault, mechanical fatigue, ops error.	5	None	3	B-C	Medium	3	B-C	Medium	Loss up to 1 unit generation. Damage to equipment.	Refurbish or replace.
1296	7635	8152	8144	0	0	2	#2 ELECTRICAL & CONTROLS SYS	MAIN CONTROLS	MAIN CONTROLS	N/A	217	6	Electrical fault, mechanical fatigue, ops error.	10	None	1	C	Low	1	C	Low	Loss 1 unit generation. Damage to unit.	Current inspection and maintain.
1296	7635	8152	299451	0	0	2	#2 ELECTRICAL & CONTROLS SYS	DISTRIBUTED CONTROL SYSTEM (DCS)	DCS	N/A	218	6	Electrical fault, ops error.	10+	None	1	C	Low	1	C	Low	Loss 1 unit generation. Damage to unit.	Maintain.
1296	7635	8152	7677	0	0	2	#2 ELECTRICAL & CONTROLS SYS	TURBINE GOVERNOR SYSTEM	TURBINE GOVERNOR SYSTEM	N/A	219	6	Electrical/mechanical failure, ops error.	5	None	1	C-D	Low	1	C	Low	Loss 1 unit generation. Damage to unit.	Upgrade governor system.
1296	7635	8152	271479	0	0	2	#2 ELECTRICAL & CONTROLS SYS	TURBINE SUPERVISORY SYSTEM (TSI)	TSI	Turbine Supervisory System	220	6	Electrical fault, mechanical fatigue, ops error.	5	None	3	C	Medium	3	C	Medium	Loss 1 unit generation. Damage to unit.	Refurbish or replace.
1296	7635	8152	8139	0	0	2	#2 ELECTRICAL & CONTROLS SYS	BURNER MANAGEMENT	BURNER MANAGEMENT	N/A	221	6	Electrical fault, mechanical fatigue, ops error.	10	None	3,1	C	Medium, Low	1	C	Low	Loss 1 unit generation. Equipment damage.	Refurbish or replace.
1296	7635	8152	309898	0	0	2	#2 ELECTRICAL & CONTROLS SYS	BOILER PROTECTION & CONTROL	BOILER PROTECTION & CONTROL	N/A	222	6	Electrical fault, mechanical fatigue, ops error.	10+	None	1	2	Low	1	B	Low	Loss 1 unit generation. Equipment damage.	Maintain.

9.2.8.7 Life Cycle Curve and Remaining Life

The life cycle curve for the Unit 2 electrical and control systems (including DCS) associated with steam systems is illustrated below. Several curves are required to represent the various elements of and their operational timing. The life curves are plots of current and projected operating hours (generation mode only) on the y-axis versus calendar year on the x-axis. The figure has several vertical lines representing differing representative nominal age limits for various components. It also has several horizontal lines that represent a range of practical equipment equivalent base loaded operating hour life limits. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view.

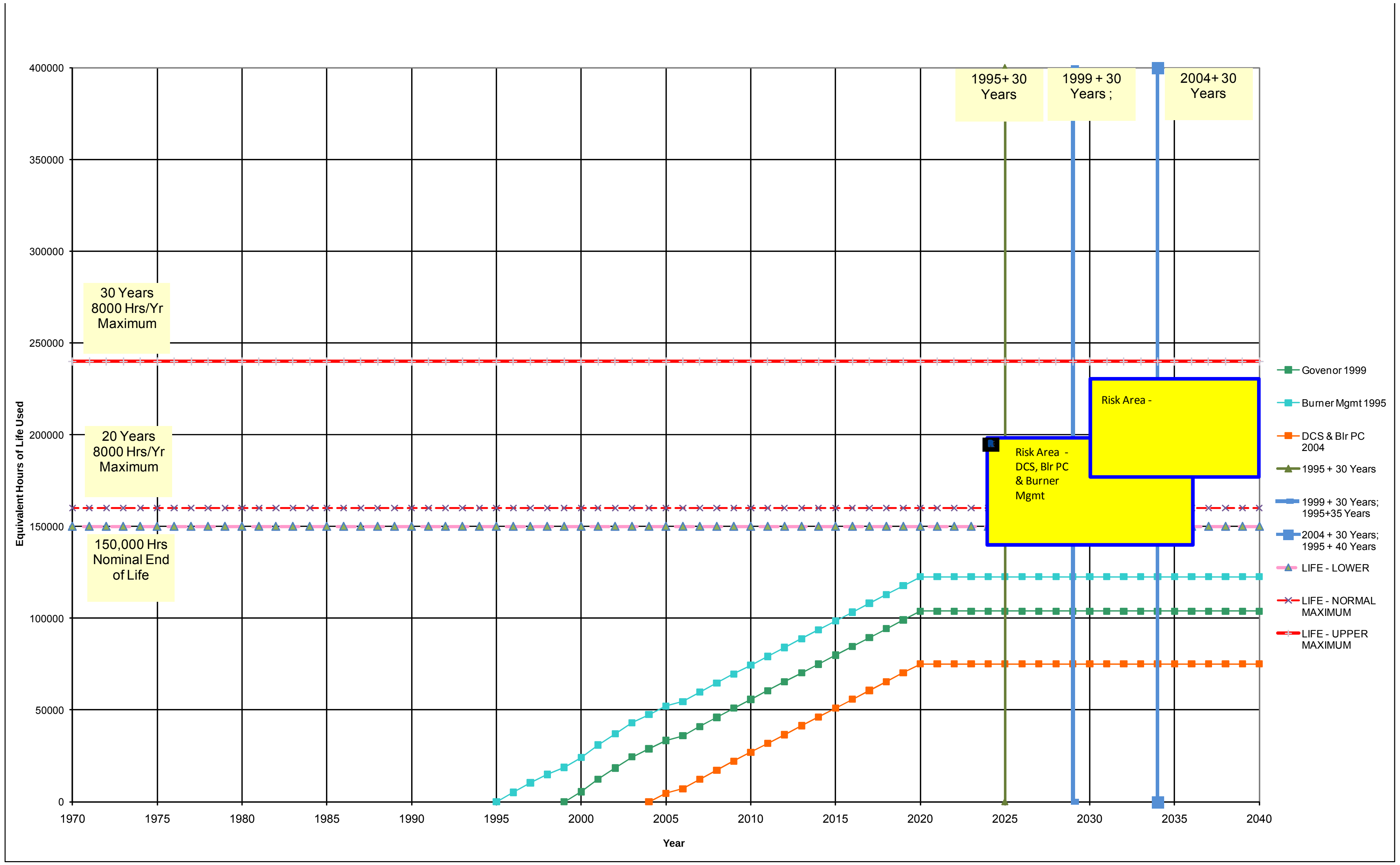

FIGURE 9-21 LIFE CYCLE CURVE – UNIT 2 ELECTRICAL AND CONTROL SYSTEMS (INCLUDING DCS) ASSOCIATED WITH STEAM SYSTEMS

The curves indicate that the remaining life (RL) of the Unit 2 control systems (including DCS) associated with steam systems can readily reach the desired life (DL) 2020 end date for generation, provided regular inspection and service per the station PM plan is maintained. The electrical systems, particularly breakers and motor controls are addressed in more detail as part of Section 9.1.3. It is clear that in order to meet the end date for generation service, some of these systems must be replaced or in some cases refurbished.

9.2.8.8 Level 2 Inspections – Unit 2 Electrical and Control Systems (including DCS) Associated with Steam Systems

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 9-65 below, assuming the current plant inspection and maintenance program is maintained or improved.

TABLE 9-65 LEVEL 2 INSPECTIONS – UNIT 2 ELECTRICAL AND CONTROL SYSTEMS (INCLUDING DCS) ASSOCIATED WITH STEAM SYSTEMS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Sub System Comment	L2#	Appendix #	Level 2 Work	Year	Priority	Cost k$
1296	7635	8152	0	0	0	2	#2 ELECTRICAL & CONTROLS SYS	ELECTRICAL & CONTROLS SYS	ELECTRICAL & CONTROLS SYS	None	176	6	No Level 2 required.			
1296	7635	8152	8138	0	0	2	#2 ELECTRICAL & CONTROLS SYS	RELAY RM PROTECT & CONTROL	RELAY RM PROTECT & CONTROL	None	177	6	No Level 2 required.			
1296	7635	8152	271478	0	0	2	#2 ELECTRICAL & CONTROLS SYS	SWITCHGEAR 4160 & 600 VOLT	SWITCHGEAR 4160 & 600 VOLT	None	178	6	No Level 2 required.			
1296	7635	8152	7677	0	0	2	#2 ELECTRICAL & CONTROLS SYS	TURBINE GOVERNOR SYSTEM	TURBINE GOVERNOR SYSTEM	None	179	6	No Level 2 required.			
1296	7635	8152	271479	0	0	2	#2 ELECTRICAL & CONTROLS SYS	TURBINE SUPERVISORY SYSTEM (TSI)	TSI	None	180	6	No Level 2 required.			
1296	7635	8152	8144	0	0	2	#2 ELECTRICAL & CONTROLS SYS	MAIN CONTROLS	MAIN CONTROLS	None	181	6	No Level 2 required.			
1296	7635	8152	299451	0	0	2	#2 ELECTRICAL & CONTROLS SYS	DISTRIBUTED CONTROL SYSTEM (DCS)	DCS	None	182	6	No Level 2 required.			
1296	7635	8152	8139	0	0	2	#2 ELECTRICAL & CONTROLS SYS	BURNER MANAGEMENT	BURNER MANAGEMENT	None	183	6	No Level 2 required.			
1296	7635	8152	309898	0	0	2	#2 ELECTRICAL & CONTROLS SYS	BOILER PROTECTION & CONTROL	BOILER PROTECTION & CONTROL	None	184	6	No Level 2 required.			

9.2.8.9 Capital Projects

The suggested typical capital enhancements for the system include:

TABLE 9-66 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – UNIT 2 ELECTRICAL AND CONTROL SYSTEMS (INCLUDING DCS) ASSOCIATED WITH STEAM SYSTEMS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Detail	CAP#	Appendix #	Capital Item	Date	Priority
1296	7635	8152	0	0	0	2	#2 ELECTRICAL & CONTROLS SYS	ELECTRICAL & CONTROLS SYS	ELECTRICAL & CONTROLS SYS	N/A	178	6	No capital investment required.		
1296	7635	8152	8138	0	0	2	#2 ELECTRICAL & CONTROLS SYS	RELAY RM PROTECT & CONTROL	RELAY RM PROTECT & CONTROL	N/A	179	6	No capital investment required.		
1296	7635	8152	271478	0	0	2	#2 ELECTRICAL & CONTROLS SYS	SWITCHGEAR 4160 & 600 VOLT	SWITCHGEAR 4160 & 600 VOLT	N/A	180	6	Implement changes to this Switchgear 4160V/600V relaying in UB2 modernization study (5.3.2.15 IV) for the protection relays. Consider that the remaining P&B Golds relays remain and not be replaced by Schweitzer 701 MPR's. As of 2015 the breakers utilizing these will become standby and as of 2020 will become spare.	2013	1
1296	7635	8152	271479	0	0	2	#2 ELECTRICAL & CONTROLS SYS	TURBINE SUPERVISORY SYSTEM (TSI)	TSI	N/A	181	6	Implement Turbine Supervisory System replacement.	2013	1
1296	7635	8152	7677	0	0	2	#2 ELECTRICAL & CONTROLS SYS	TURBINE GOVERNOR SYSTEM	TURBINE GOVERNOR SYSTEM	N/A	182	6	Assess and implement GE migration of the Mark V to the Mark Ve system. Replace existing 196 processors and modernize operator and maintenance stations. Field wiring and devices remain the same.	2013	1
1296	7635	8152	8144	0	0	2	#2 ELECTRICAL & CONTROLS SYS	MAIN CONTROLS	MAIN CONTROLS	N/A	183	6	No capital investment required.		
1296	7635	8152	299451	0	0	2	#2 ELECTRICAL & CONTROLS SYS	DISTRIBUTED CONTROL SYSTEM (DCS)	DCS	N/A	184	6	No capital investment required.		
1296	7635	8152	8139	0	0	2	#2 ELECTRICAL & CONTROLS SYS	BURNER MANAGEMENT	BURNER MANAGEMENT	N/A	185	6	No capital investment required.		
1296	7635	8152	309898	0	0	2	#2 ELECTRICAL & CONTROLS SYS	BOILER PROTECTION & CONTROL	BOILER PROTECTION & CONTROL	N/A	186	6	No capital investment required.		

9.2.9 Asset 271317 – Unit 2 Steam Turbine

(Detailed Technical Assessment in Working Papers, Appendix 18)

Unit #:	2
Asset Class #	BU 1296 - Assets Generations
SCI & System:	7638 #2 Turbine & Generator
Sub-Systems:	271317 # 2 Steam turbine
Components:	7638 #2 Main Steam Chest
	7643 #2 HP Turbine
	7652 #2 IP Turbine
	7658 #2 LP Turbine
	7671 #2 Front Standard

Note: High energy piping and hangers are addressed within the Boiler Section (Section 9.2.1) under heading Boiler Main Steam Lines (Asset Code 7823). The scope is assumed to include piping and hangers up to the steam turbine.

9.2.9.1 Description

The Unit 2 turbine went into service in 1971. It was originally a 150 MW turbine supplied by General Electrical (GE). The original turbine was a 1970 vintage Lynn D3 model. The turbine is rated to operate at a main steam inlet pressure of 13.0 MPag (1890 psig) and steam temperature of 538 °C (1,000 °F). The reheat steam inlet temperature is 538 °C (1,000 °F). The turbine rotating speed is 3,600 RPM.

The unit consists of one combined high pressure (HP) and intermediate pressure (IP) turbine and one double flow low pressure (LP) turbine. The HP/IP and LP rotors are integral with the blade wheels. There is no centerline bore through the rotors. The turbine rotors are supported by three journal bearings. The trust bearing and the turning gear are located in the HP front standard.

The generator rotor is directly-coupled to the turbine. It is supported by two journal bearings located at the stator end-shields. In 1989, the unit was upgraded to produce 175 MW by replacing the HP/IP rotor and the HP/IP steam path components including the HP nozzle block. No changes were made to the LP turbine or the auxiliary equipment.

The Unit 2 turbine has an upgraded Mk 5 electro-hydraulic controlled (EHC) governor system with a partial arc steam admission system through the 6 control valves. Unit 2 also has one main stop valve (MSV) with an internal pilot valve to control the run up of the turbine to full speed. There are two combined casing reheat stop and intercept valves.

The steam seal regulator (SSR) is the key component of the steam turbine gland steam sealing system. The SSR controls the flow of steam to and from all of the turbine shaft seals. The seals minimize the leakage of process steam along the rotor shaft from the turbine casing. The SSR must be able to respond differently at low and high loads.

The turbine auxiliaries included in this report are:

- The lube oil system;
- The gland steam sealing system, including steam seal regulator;
- The control oil system;
- Steam blow down valve; and
- Power assisted extraction steam non return valves (NRV).

9.2.9.2 History

Manufactured/Delivered	1970
In-Service Date	Apr 1971
Units 1 and 2 Upgrade	1987
Units 1 and 2 Governor Valves	2003
Units 1 and 2 HP Nozzle Block Replacement	2007
Generation Base Load End Date	Dec 2015
Generation Peak/Emerg Gen End Date	Dec 2020
Last Major Overhaul	2005
Last Valve (Minor) Overhaul	2002/2007
Next Major Overhaul/Inspection	2014
Next Valve (Minor) Overhaul	2011/2017

The hours associated with the analyses are:

Hours Generation Actual - Ops to Dec 2009	158
Max Hours Generation Ops – to Dec 2015	188
Max Hrs Gen Ops to Gen End Date Dec 2020	212

9.2.9.3 Inspection and Repair History

The turbine major overhauls have been completed on a six year frequency. As of 2003, the overhauls are scheduled to be done every 9 years with the next overhaul scheduled for 2012.

The turbine valves overhaul frequency of 3 years was not changed. The last valves overhaul was completed in 2007, including a replacement of the HP turbine sections nozzle block. The next valve overhaul is scheduled for 2014.

The Unit 2 SSR is an automated hydraulic control system. Its many moving parts and wear points have resulted in frequent binding and sticking requiring manual intervention during operation. Parts are very difficult to obtain and the system should be considered obsolete. Failure to address the SSR could result in premature deterioration of the steam turbine generator bearings.

The reports indicate that the overhaul work has been done by GE since the year 1999.

1989 HP/IP Turbine Upgrade

The upgrade was done to up rate the Unit from 150 MW to 175 MW. The following components were replaced.

- New HP/IP rotor with some stages removed.
- Inner casing steam path change for both the HP and IP turbines.

The upgrade report was not submitted and has not been reviewed. It is assumed that the inner and outer casings of the HP and IP turbines were not replaced. It is also assumed that the casing joint studs were not replaced.

1999 Major Turbine & Valve Overhaul

Note: The reports were not complete - pages 39 to 77 are blank. Information on the nozzle partition and turbines is missing. No NDE reports were attached.

- Installed new static exciter;
- Extensive SPE of nozzle block partitions. The partition plates were weld repaired off site;
- SPE of the HP diaphragms. The diaphragm surfaces were polished (NDE reports not available);
- SPE of the IP diaphragms. The affected areas were weld repaired and polished (NDE reports not available);
- Cracks in the LP diaphragm partition plates were weld repaired;
- Replaced all LP inner casing studs. The studs were damaged or over stretched;
- Replaced various turbine valves stems, seats, bushes etc. that were damaged, bent, worn or had run out beyond the allowable limits;
- The CV stems #2, #3 & #4 were bent and replaced. Stem #5 was broken. Attempts had been made to align this stem in 1997;
- Five out of the six crossheads were replaced. All crosshead bushes that had excessive run out and were out of tolerance were replaced:
- Serviced turbine journal bearings, trust bearings, all lube oil pumps and turning gear, etc. Flushed the lube oil system; and.
- The unit had to be shut down 5 times after startup to correct bearing vibration, EHC fluid leaks in front standard and the control valve #1 problems (foreign object in steam chest).

2002 Turbine Valve Overhaul

No NDE reports were attached. The valve may **not** have been NDE inspected.

- MSV stem was bent and replaced. There was a crack in the seat seal weld which was weld repaired. Details of weld procedure were not provided. If a weld repair was not done per the approve weld procedure, the crack could reappear or new cracks may start in the heat effect zone of the weld;
- Four out of the six CV stems were replaced. Stem #2 had high run out. Stem #3 was cut to allow valve disassembly. Stems #4 and #5 were worn out and bent. Various valve bushes were replaced;

- The spigots fit on all CV to steam chest were found to be loose. An alignment jig was fabricated and stem #3 was aligned. Two dowel pins were installed in valve stand to maintain the stem alignment. Since other CVs were already installed, they were not aligned per valve #3; and
- All #3 CV bushes were replaced. The wear tear in this valve was to be checked during the next 2005 outage to see if there is any improvement. If successful, this alignment was to be applied to all the CVs. It appears this fix did not work or was not followed through.

2005 Turbine Major Overhaul

Note that many NDE reports did not identify clearly what component was inspected.

- The MSV stem was bent and replaced;
- The CV stems #2, #3, and #5 had high run out and were replaced. The CV #6 was replaced due to erosion and wear. The four cross heads #2, #3, #4 and #6 were replaced due to wear and high run out. All cross head bushes were replaced. Many other stems bushes were replaced because of excessive clearances;
- The "stands" for CV #3 and #5 were sent out to have the "spigot fit between the valve stand and the crosshead guide bushing cap machined to align the crosshead guide bushes with the valve stem bushing". There was no mention of the 2002 CV #3 fix and if it worked. See 2002 overhaul report above;
- 2 cracks in seat seal weld of the left RSV were removed and weld repaired. If the weld repair was not done per the approve weld procedure, crack will reappear or new cracks may start in the heat effect zone of the weld;
- The nozzle block was sent off site to restore axial clearance of the block to the design value by weld build up. The repair work also included the weld repairs of the partition plates, spill strip weld built up & machining and austenitic filler piece modification. Information is missing on the condition and what partition plates were repaired. This information would have helped to check if FOD contributed to the failure of the same partition plate in 2007;
- The HP inner shell ring was sent off site for machining. A crack was found growing from the old crack stopper hole. A new crack stopper hole was drilled and the crack blended out. More details and pictures are required to analyze the risk for failure;
- There was a significant SPE to the HP diaphragms. Stage 2 to 6 diaphragms were weld repaired at site using the Inconel and polished;
- There was some SPE of the IP diaphragms. The damaged areas were weld repaired using the Inconel and polished;
- A crack in the LP upper half outer casing was removed by grinding;
- Various LP hood support struts had cracks that were removed and weld repaired;
- The LP turbine two last stage diaphragm partitions had water erosion and were repaired;
- Serviced and cleaned lube oil coolers, pumps, vapour extractor and flushed the lube oil lines;
- Mark 5 control cabinets were installed. (The report did not specify if a new teeth wheel and speed pickups were install for over speed protection); and
- The report did not specify if the lube oil system full flow in-line filter cubical was hooked up during this outage or earlier 2002 outage.

2007 Forced Outage

On May 13, 2007, a marked change in unit vibration was noted. However, the unit was kept on line until a control valve malfunctioned and caused a forced outage. The stuck CV #5 was investigated and a partition plate was found wedged between the valve plug and the seat. A bore scope inspection confirmed two nozzle partition plates had liberated in the valve #5 segment. After opening the HP turbine, extensive damage was found in the HP steam path.

Most repair work was limited to HP turbine only. The 2008 valve overhaul work was brought forward and included in the 2007 forced outage, except for the overhauls of the extraction steam NRVs air actuators. The following work was completed during the forced outage:

- Installed a new HP nozzle block;
- Replaced the first three stage blades of the HP turbine. Prior to blade installation, the wheel dove tails were inspected and found acceptable;
- There was some minor foreign object damage (FOD) on the remaining 4 to 9 stage blades. The blades were NDE inspected and no cracks were found. The blades were straightened and polished. GE has recommended replacing the stage 4 to 9 blades earlier than later;
- Repaired all HP diaphragms off site. Stage 2 to 6 diaphragms underwent major repairs. Weld repair was done to stages 2, 3, 4 and 6 partition plates using 410 SS filler wire. Inconel was used on stage 5 partition plates;
- GE had recommended a major repair on 7th stage partitions but these were polished per NLH direction. The 8th and 9th stage partitions underwent minor trimming, straightening and Inconel repair;
- New spill strip seals were installed on all HP diaphragms;
- The IP turbine first RH stage (stage 11) blades had considerable solid particle erosion (SPE) and foreign object damage (FOD). The blades were NDE inspected and no cracks were found. Due to the blades replacement cost and delivery, the blades were not replaced. Polishing and cold straightening was done as required;
- IP 12th stage blades had SPE on some trailing edges. The edges were straightened and the damage blended out;
- IP 14th stage blades had abnormal impact damage. It is heavy and localized to a few blades. Minor repair was done;
- The IP 14th, 15th and 16th stage diaphragm horizontal joints and the support keyways were damaged due to an error during the last reassembly and alignment of the diaphragms. The keyways were repaired at site using Inconel and the joint was sanded and stone flat;
- GE has recommended that during the next outage, the three diaphragms be sent off site for repair to the support block keyways and the horizontal joint;
- The MSV stem was bent and replaced;
- The stem of the CV #5 was broken that had forced the unit outage. The stem breakage was caused by a portion of a nozzle partition plate wedged between the seat and the plug;
- The CV #3 stem was bent. Stem #6 was cut out. Both stems were replaced. GE recommended Inconel stems for future stem replacement;
- The CV #3, #4 and #5 stem lower bushings were found over sized. The bushes were replaced;
- The crosshead of the CV #5 were replaced as it was heavily worn and 0.10" out of round (this is very high). The crosshead brass bushings of all the valves, except CV#6, were found to be out of round and significantly over tolerance and replaced;

- There was a crack in the #102 extraction steam NRV. The crack was repaired. The valve has had weld repairs many times and may have internal casting defects. GE has recommended that the valve body be replaced; and
- Bearing #1 liner was replaced. The lube oil and hydraulic oil systems were flushed.

After the overhaul and the mechanical over speed test, the MSV was reading open when it should have been closed. The MSV was disassembled and 2.3 kg (5 lbs) of debris was found in the valve. The fine mesh screen was completely covered and plugged. Smaller particles had passed through the screen. The screen was cleaned. The control servo was replaced as a part of the valve problem investigation. The rivets damaged by the debris were replaced. No boroscope inspection was done to record the damage to the new nozzle block.

9.2.9.4 Condition Assessment

The condition assessment of the Unit 2 steam turbine is illustrated below in Table 9-67:

TABLE 9-67 CONDITION ASSESSMENT – UNIT 2 STEAM TURBINE

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset Level 2	Asset Level 3	Description	Detail	Condition Summary ID#	Append #	Condition	EPRI Identifier	Original Life (Base Load) Ops Hrs (Yrs)	Current Expected Minimum Remaining Life Years (Subject to Test)	End of Life (EOL) Required	Next Regular Inspection	Next Planned Overhaul or Major Inspection	Capability to Reach Next Overhaul	Capability to Reach EOL	In Service
1296	7635	7636	271317	0	0	2	#2 TURBINE	TURBINE	TURBINE	N/A	34	18	See details below.									
1296	7635	7636	271317	7638	0	2	#2 TURBINE	TURBINE	TURBINE MAIN STEAM CHEST	N/A	35	18	Many control valve stem failures and the wear/tear of various stem bushes. High temperature studs and valves are original equipment.	4	200000 (30)	(2)	2020	2011	2011	Yes	No	1971
1296	7635	7636	271317	7643	0	2	#2 TURBINE	TURBINE	H.P. TURBINE	N/A	36	18	Nozzle block and the first three HP stage blades were replaced in 2007 forced outage. Extensive solid particle erosion (SPE) and foreign object damage (FOD). Turbine casing, high temperature studs and valves are original equipment. HP rotor and HP steam paths that see the high pressure and temperature service replaced in 1989. Lot of studs with excessive over projection in the HP inner and outer casings.	4	200000 (30)	(10)	2020		2014	Yes	No	1971/1988/ 2007
1296	7635	7636	271317	7647	0	2	#2 TURBINE	TURBINE	TURB REHEAT/IP STEAM CHEST	N/A	37	18	Many control valve stem failures and the wear/tear of various stem bushes. High temperature studs and valves are original equipment. Generally valves in good shape.	4	200000 (30)	(2)	2020	2011	2011	Yes	No	1971
1296	7635	7636	271317	7652	0	2	#2 TURBINE	TURBINE	I.P. TURBINE	N/A	38	18	Extensive solid particle erosion (SPE) or foreign object damage (FOD). The first reheat stage blades have significant impact damage. Generally turbine and valves in good shape. Turbine casing, high temperature studs and valves are original equipment. IP rotor and IP steam paths that see the high pressure and temperature service replaced in 1989.	4	200000 (30)	(10+)	2020		2014	Yes	No	1971/1988
1296	7635	7636	271317	7658	0	2	#2 TURBINE	TURBINE	L.P. TURBINE	N/A	39	18	Generally turbine in good shape. LP rotor, LP turbine casings are the original equipment.	3a	200000 (40)	10+	2020		2014	Yes	Yes	1971
1296	7635	7636	271317	7671	0	2	#2 TURBINE	TURBINE	TURBINE FRONT STANDARD	N/A	40	18	High temperature studs and valves are original equipment. Generally valves in good shape.	4	(30)	10	2020	2011	2011	Yes	Yes	1971
1296	7635	7636	271317	7686	0	2	#2 TURBINE	TURBINE	TURBINE GLAND STEAM SYSTEM	N/A	41	18	Original equipment.	4	(30)	10	2020		2014	Yes	Yes	1971
1296	7635	7636	271317	7686	0	2	#2 TURBINE	TURBINE	TURBINE GLAND STEAM SYSTEM	Steam Seal Regulator	42	18	Original equipment. The Steam seal regulator 's many moving parts and wear points result in frequent binding and sticking requiring manual intervention. Parts are very difficult to obtain and the system should be considered obsolete. Failure to address could result in premature deterioration of the steam turbine generator bearings.	10	(30)	(2)	2020		2012	Yes	No	1971
1296	7635	7636	271317	7690	0	2	#2 TURBINE	TURBINE	TURBINE PRE-WARMING SYSTEM	N/A	43	18	Original equipment.	4	(30)	10	2020		2014	Yes	Yes	1971
1296	7635	7636	271317	7692	0	2	#2 TURBINE	TURBINE	TURBINE TURNING GEAR	N/A	44	18	Original equipment. Problems with chain system.	4	(30)	(2)	2020	2011	2011	Yes	No	1971

Notes:

1. A "(bracketed)" value in the "Current Expected Remaining Life" column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation, including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as "(X/Y)" has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

2. The "Next Regular Inspection" column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The "Next Planned Overhaul or Major Inspection" column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a "Desired Life" stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or not known by AMEC.

3. The ability of the steam seal regulator (SSR) to meet its next overhaul date and the EOL date of 2020 is conditional on its replacement as planned in 2012

9.2.9.5 Actions

Based on the condition assessment, the following actions are recommended for the Unit 2 steam turbine:

TABLE 9-68 RECOMMENDED ACTIONS – UNIT 2 STEAM TURBINE

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Unit	Asset 2/3	Asset 3/4	Description	Detail	Action #	App #	Action	Year	Priority
1296	7635	7636	271317	0	2	#2 TURBINE	TURBINE	TURBINE	N/A	44	18	During upcoming 2011 minor overhauls and the 2014 major overhaul (and every valve outage): 1. Perform a bore scope inspection of the nozzle block partitions to check for cracks at the interface weld between the partition plates and the retaining rings. Check for cracks that may have propagated into the partition plate material. Extra attention should be given to the partitions plates in the control valves 2 and 5 segments. 2. Perform an inspection (record and pictures)of the SPE/FOD damage due to the 2007 debris in the MSV.	2011	1
1296	7635	7636	271317	0	2	#2 TURBINE	TURBINE	TURBINE	N/A	45	18	Inspect and record (take pictures) during the upcoming 2014 major overhaul, the SPE/FOD damage due to the 2007 debris in the MSV.	2014	1
1296	7635	7636	271317	0	2	#2 TURBINE	TURBINE	TURBINE	N/A	46	18	Replace only studs that have mechanical damage, thread deformation or thread wear, irrespective of the temperature service or stud location.	2014	1
1296	7635	7636	271317	0	2	#2 TURBINE	TURBINE	TURBINE	N/A	47	18	Maintain records on stud replacements - why, date and location. Mark all high temperature studs and install at the same location during every stud change out.	2010	1
1296	7635	7636	271317	0	2	#2 TURBINE	TURBINE	TURBINE	N/A	48	18	Evaluate and resolve the many control valve stem failures. The change of the stem material to Inconel will not solve this problem. Contact Bill Dumbleton (former Saskpower - turbtech@telusnet.net).	2010	1
1296	7635	7636	271317	7638	2	#2 TURBINE	TURBINE	TURBINE MAIN STEAM CHEST	N/A	49	18	Estimate MSV/CV/RSV and ICV AR283 casing studs close to the nozzle block studs that operate above 850 °F - see HP a IP inner casings. Since the turbine valves are opened more often and operated at 1000 °F, their operating creep life will be shorter. They are also more liable to be damaged and are subjected to wear and tear during the valve 3 year disassemble. Replace all if the majority of the studs in a valve body are being replaced due to mechanical wear or tear damage.	2011	1
1296	7635	7636	271317	7638	2	#2 TURBINE	TURBINE	TURBINE MAIN STEAM CHEST	N/A	50	18	Work with vendor to identify and resolve key valve issues. Undertake thorough inspection for cracks in both the RH/LH main steam stop valve. Re-inspect all repair welds for cracks in the MSV seat seal weld and/or cracks in the anti-swirl dam (may have been weld repaired during the last few outages). Repair where required using a temper bead weld procedure.	2014	1
1296	7635	7636	271317	7638	2	#2 TURBINE	TURBINE	TURBINE MAIN STEAM CHEST	N/A	51	18	Replace the extraction steam NRV # 102 valve body. The valve may have various internal imperfections and over time various cracks at different locations will reappear or the valve may fail. Increase Extraction steam NRV inspection from 3 years to 6 years. Top heater NRV need not be checked as there is no danger of over speed damage if the valve does not function. Check pneumatic actuator every 3 years. Ensure dry air is supplied to the cylinders. Check NRV valve operation on the seasonal restart every year.	2011	1
1296	7635	7636	271317	7643	2	#2 TURBINE	TURBINE	H.P. TURBINE	N/A	52	18	In 2011 minor overhauls and the 2014 major overhaul, carry out the following work and inspections: 1. Replace the HP diaphragm and spill strip if NL Hydro wants to improve the unit efficiency. 2. Inspect the first three dressed up HP stage blade surfaces for cracks, wear and tear. Blade replacement is not recommended for relatively minor efficiency loss if unit is operated above 75% MCR. 3. Inspect repaired HP diaphragm partition trailing edges (built up using Inconel 82 TIG wire) to check if the Inconel is washing or wearing out. Repair minor damage using Inconel 82, but for extensive damage be prepared to repair the partition off site with 410SS filler material (including stress relief and post weld heat treatment). 4. Check past 410 SS and Inconel repairs in HP and IP diaphragms. Record and compare the condition of wear of the 410 SS and Inconel repairs. Repair and dress damage where required. 5. Check condition of 7th stage diaphragm for further damage since 2007 (damage not repaired in 2007). 6. Re-inspect dressed up HP 2nd and 3rd stage blades (from 2007 nozzle partition plate failure).	2011	1

Table 9-68 Cont'd

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Unit	Asset 2/3	Asset 3/4	Description	Detail	Action #	App #	Action	Year	Priority
1296	7635	7636	271317	7643	2	#2 TURBINE	TURBINE	H.P. TURBINE	N/A	53	18	Estimate HP inner casing studs close to the nozzle block studs that operate above 850 °F that may have reached or are close to the end of their predicted creep life (GE to identify studs that operate close to and above 850 °F and supply their engineering article on their recommended practice for the high temperature stud replacement). Replace studs close to the end of their creep life. Typically per past GE stud creep life evaluation, turbine half casing studs have a life of around 250,000 to 300,00 hrs.	2011	1
1296	7635	7636	271317	7643	2	#2 TURBINE	TURBINE	H.P. TURBINE	N/A	54	18	Inspect HP inner casing stud #101 (found broken in 2005), if stud is available - did stud fail due to creep and verify the stud material.	2011	1
1296	7635	7636	271317	7643	2	#2 TURBINE	TURBINE	H.P. TURBINE	N/A	55	18	Turn in the HP outer and inner casing studs that have a projection over the allowable limits. Machine seized studs that do not move. Clean, re-tape holes and re-install studs that are not damaged. Asses stud supply options - OEM or other.	2014	1
1296	7635	7636	271317	7647	2	#2 TURBINE	TURBINE	TURB REHEAT/IP STEAM CHEST	N/A	56	18	Estimate MSV/CV/RSV and ICV casing studs close to the nozzle block studs that operate above 850 °F - see HP & IP inner casings. Since the turbine valves are opened more often and operated at 1000 °F, their operating creep life will be shorter. They are also more liable to be damaged and are subjected to wear and tear during the valve 3 year disassemble. Replace all if the majority of the studs in a valve body are being replaced due to mechanical wear or tear damage.	2011	1
1296	7635	7636	271317	7647	2	#2 TURBINE	TURBINE	TURB REHEAT/IP STEAM CHEST	N/A	57	18	Re-inspect all cracks in the RSV seat seal weld and/or cracks in the anti-swirl dam. Repair where required using a temper bead weld procedure.	2014	1
1296	7635	7636	271317	7652	2	#2 TURBINE	TURBINE	I.P. TURBINE	N/A	58	18	Repair the IP 14th, 15th and 16th stage diaphragm horizontal joints and the support keyways found damaged due to an error during the 2005 reassembly. Send these three diaphragms off site for repair and repair the partition plates of these diaphragms using the 410 SS material.	2014	1
1296	7635	7636	271317	7652	2	#2 TURBINE	TURBINE	I.P. TURBINE	N/A	59	18	The first RH stage blades have considerable SPE damage from particles carry over from the boiler reheater. GE has recommended that blades are replaced. Since there are no pictures, the condition or the risk of blade failure can not be assessed. Re-inspect the blades and a strategy must be in place to: 1. Replace the blades if the blade surface has worn down to the level that there is a danger of blade failure. Little impact damage will not fail the blade but will have impact on the IP turbine efficiency. 2. Replace blades after 2014 if they will not last for another 5 years of operation (new row blades could cost $300,000 installed).	2013	1
1296	7635	7636	271317	7652	2	#2 TURBINE	TURBINE	I.P. TURBINE	N/A	60	18	The IP 14th stage blades have localized damage on a few blades. The damage was blended out. GE has recommended the blades be replaced. Per pictures, the damage is not bad. Inspect blades for cracks and have a strategy in place to replace only the blades that have the damage ($0 estimated as most likely the blades will not require replacement).	2013	1
1296	7635	7636	271317	7652	2	#2 TURBINE	TURBINE	I.P. TURBINE	N/A	61	18	Inspect and have a plan in place to do a permanent repair for steam cutting of the LP inner horizontal joint around 5th stage both flow.	2013	1
1296	7635	7636	271317	7658	2	#2 TURBINE	TURBINE	L.P. TURBINE	N/A	62	18	Do a borescope inspection of LP L0 blades once a year through the LP turbine inspection door. This should be done after the unit is shut down after the seasonal operation.	2011	1
1296	7635	7636	271317	7658	2	#2 TURBINE	TURBINE	L.P. TURBINE	N/A	63	18	In 2011 minor overhauls and the 2014 major overhaul, carry out the following work and inspections: 1. Inspect and braze broken tie wires on any LP blades to ensure that the designed blade damping condition is maintained. 2. Inspect, where possible, L0 and L-1 blade root and wheel steeple surfaces. Repair and replace blade as required. 3. Inspect L0 and L-1 blades for water erosion and report. Past reports did not comment on the condition of the blades. Take pictures of the blade surfaces with water wear.	2011	1
1296	7635	7636	271317	7671	2	#2 TURBINE	TURBINE	TURBINE FRONT STANDARD	N/A	64	18	Undertake normal major inspection checks.	2014	1
1296	7635	7636	271317	7686	2	#2 TURBINE	TURBINE	TURBINE GLAND STEAM SYSTEM	N/A	65	18	No specific recommended actions beyond normal major overhaul work.	2014	1
1296	7635	7636	271317	7686	2	#2 TURBINE	TURBINE	TURBINE GLAND STEAM SYSTEM	Steam Seal regulator	66	18	Replace steam seal regulator.	2011	1
1296	7635	7636	271317	7690	2	#2 TURBINE	TURBINE	TURBINE PRE-WARMING SYSTEM	N/A	67	18	No specific recommended actions beyond normal major overhaul work.	2011	1
1296	7635	7636	271317	7692	2	#2 TURBINE	TURBINE	TURBINE TURNING GEAR	N/A	68	18	No specific recommended actions beyond normal major overhaul work.	2014	1

9.2.9.6 Risk Assessment

Table 9-69 below illustrates the risk assessment for the Unit 2 steam turbine, both from a technological perspective and a safety perspective using the models presented in Section 3.

TABLE 9-69 RISK ASSESSMENT – UNIT 2 STEAM TURBINE

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Component	Risk Assess #	Appendix #	Major Issues	Remaining Life Years	Remaining Life Comments	TECHNO-ECO RISK ASSESSMENT MODEL			SAFETY RISK ASSESSMENT MODEL			Possible Failure Event	Mitigation
														(Insufficient Info - Inspection Required Within (x) Years)		Likeli-hood	Conse-quence	Risk Level	Likeli-hood	Conse-quence	Safety Risk		
1296	7635	7636	271317	0	0	2	#2 TURBINE	TURBINE	TURBINE	N/A	40		See details below.		None								
1296	7635	7636	271317	7638	0	2	#2 TURBINE	TURBINE	TURBINE MAIN STEAM CHEST	N/A	41	4	Valve mechanical failure.	(2)	None	2	C	Medium	2	C	Medium	Turbine shutdown, overspeed failure.	Inspect and maintain. Identify long term solution.
1296	7635	7636	271317	7643	0	2	#2 TURBINE	TURBINE	H.P. TURBINE	High Pressure Turbine Diaphragms, Nozzle Partition Plates and Turbine Blades	42	18	Mechanical failure - relative higher risk from erosion and Foreign Object Damage (FOD).	10	None	2	B	Low	2	A	Low	Turbine lost generation, efficiency, capacity. Safety.	New nozzle block and some partitions replaced in 2009. Inspect and maintain. Eliminate FOD.
1296	7635	7636	271317	7647	0	2	#2 TURBINE	TURBINE	TURB REHEAT/IP STEAM CHEST	N/A	43	18	Valve mechanical failure.	(2)	None	2	C	Medium	2	C	Medium	Turbine shutdown, overspeed failure.	Inspect and maintain. Identify long term solution.
1296	7635	7636	271317	7652	0	2	#2 TURBINE	TURBINE	I.P. TURBINE	Intermediate Pressure Turbine Diaphragms, and First Stage Turbine Blades	44	18	Mechanical failure - SPE and erosion from Foreign Object Damage (FOD).	5	None	2	B	Low	2	A	Low	Turbine lost generation, efficiency, capacity. Safety.	The diaphragms haves been repaired. The blades cannot be repaired. No current condition assessment of the blades. Check condition of the first stage RH blades in 2012 overhaul. Eliminate SP and FOD.
1296	7635	7636	271317	7658	0	2	#2 TURBINE	TURBINE	L.P. TURBINE	Low Pressure (LP) Turbine	45	18	Chemical/Mechanical failure - LP monoblock integral discs - SCC failure.	10	None	1	B	Low	1	B	Low	Turbine lost generation, efficiency, capacity.	Manage the condensate and feedwater chemistry within the ASME guidelines.
1296	7635	7636	271317	7671	0	2	#2 TURBINE	TURBINE	TURBINE FRONT STANDARD	N/A	46	18	Not addressed in detail. Mechanical failure.	10	None	1	C	Medium	1	C	Low	Turbine shutdown, overspeed failure.	Inspect and maintain.
1296	7635	7636	271317	7686	0	2	#2 TURBINE	TURBINE	TURBINE GLAND STEAM SYSTEM	N/A	47		Not addressed. Mechanical sealing failure.	10	None	1	C	Low	1	C	Low	Steam leak.	Inspect and maintain.
1296	7635	7636	271317	7686	0	2	#2 TURBINE	TURBINE	TURBINE GLAND STEAM SYSTEM	Steam Seal Regulator	48		Mechanical sealing failure. Obsolete.	(2)	None	3	C	Medium	3	C	medium	Turbine shutdown. Bearing failure. Safety risk under turbine.	Replace.
1296	7635	7636	271317	7690	0	2	#2 TURBINE	TURBINE	TURBINE PRE-WARMING SYSTEM	N/A	49		Not addressed in detail. Mechanical failure.	10	None	2	A	Low	1	A	Low	Slow start up.	Inspect and maintain.
1296	7635	7636	271317	7692	0	2	#2 TURBINE	TURBINE	TURBINE TURNING GEAR	N/A	50		Not addressed in detail. Mechanical failure.	10	None	3	B	Medium	3	A	Low	Turbine bowing without turning gear on shutdown.	Inspect and maintain.

9.2.9.7 Life Cycle Curve and Remaining Life

The life cycle curve for the Unit 2 steam turbine is illustrated below. The two curves represent either the original equipment or that upgraded in 1988 when the turbine was uprated. The unit is due to undergo a major overhaul in 2014. The life curve is a plot of current and projected operating hours (generation mode only) on the y-axis versus calendar year on the x-axis. The figure has several vertical lines representing differing representative nominal age limits for various components. It also has several horizontal lines that represent a range of practical equipment equivalent base loaded operating hour life limits. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view.

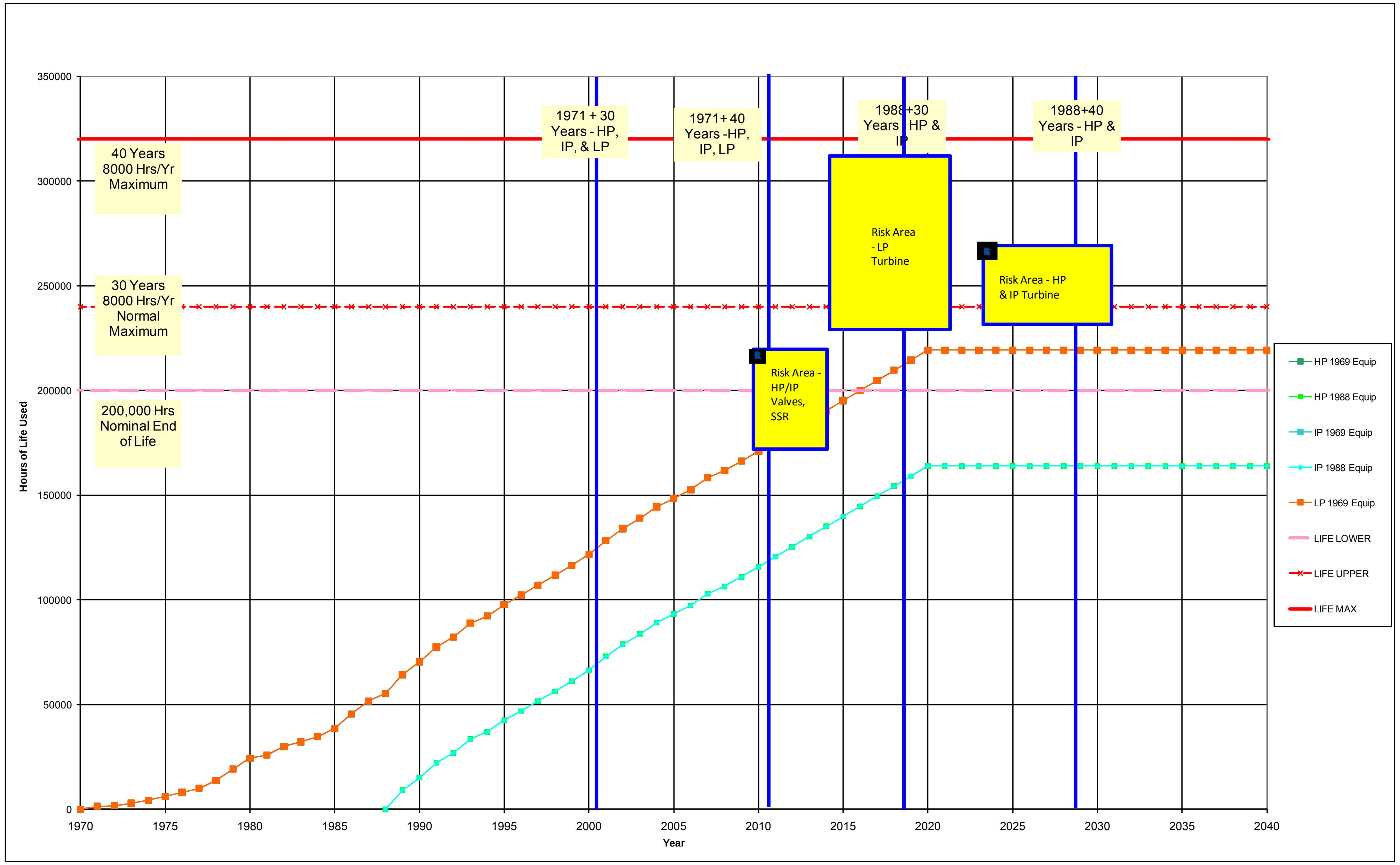

FIGURE 9-22 LIFE CYCLE CURVE – UNIT 2 STEAM TURBINE

The curves indicate that the remaining life (RL) of the various elements of the Unit 2 steam turbine exceeds the desired life (DL) which is the lesser of the time to its next major planned overhaul/inspection (2014) or to the desired End of Life (EOL) date of 2020. In fact, the 2020 end date should be readily achievable. Hence, no specific dedicated Level 2 is required, but sufficient inspection and testing will be required in the 2014 overhaul to confirm the ability to meet the 2020 EOL date. The exception to that are the HP and IP valves which continue to have reliability and life issues, the steam seal regulator, as well potentially as high temperature stud bolts. It is clear that the current inspection schedule seems suitable.

9.2.9.8 Level 2 Inspections – Unit 2 Steam Turbine

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 9-70 below, assuming the current plant inspection and maintenance program is maintained or improved.

TABLE 9-70 LEVEL 2 INSPECTIONS – UNIT 2 STEAM TURBINE

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Sub System Comment	L2#	Appendix #	Level 2 Work	Year	Priority	Cost k$
1296	7635	7636	271317	0	0	2	#2 TURBINE	TURBINE	TURBINE	None	24	18	No Level 2 inspections. Actions identified fall under the norms of the overhaul scopes.	2014	1	$2,451
1296	7635	7636	271317	0	0	2	#2 TURBINE	TURBINE	TURBINE	None	25	18	Nozzle Block Partitions Borescope: During every valve outage, do a bore scope inspection of the nozzle block partitions to check for cracks at the interface weld between the partition plates and the retaining rings. Check for cracks that may have propagated into the partition plate material. Extra attention should be given to the partitions plates in the control valves 2 and 5 segments. Also, inspect and record (take pictures) the SPE/FOD damage due to the 2007 debris in the MSV.	2014	1	
1296	7635	7636	271317	0	0	2	#2 TURBINE	TURBINE	TURBINE	None	26	18	No Level 2			
1296	7635	7636	271317	7638	0	2	#1 TURBINE	TURBINE	TURBINE MAIN STEAM CHEST	None	27	18	Identify and asses studs that operate above 850 °F may have reached or are close to the end of their predicted creep life (HP MSV studs).	2011	1	$6
1296	7635	7636	271317	7643	0	2	#2 TURBINE	TURBINE	H.P. TURBINE	None	28	18	Identify and asses studs that operate above 850 °F may have reached or are close to the end of their predicted creep life (HP inner casing studs close to the nozzle block).	2011	1	$6
1296	7635	7636	271317	7647	0	2	#2 TURBINE	TURBINE	TURB REHEAT/IP STEAM CHEST	None	29	18	Identify and asses studs that operate above 850 °F may have reached or are close to the end of their predicted creep life (CV/RSV and ICV studs).	2011	1	$6
1296	7635	7636	271317	7652	0	2	#2 TURBINE	TURBINE	I.P. TURBINE	None	30	18	Identify and assess those studs that operate above 850 °F may have reached or are close to the end of their predicted creep life (IP inner casing studs).	2011	1	$6
1296	7635	7636	271317	7658	0	2	#2 TURBINE	TURBINE	L.P. TURBINE	None	31	18	LP L0 blades Boroscope: If possible, do boroscope inspection of LP L0 blades once a year through the LP turbine inspection door after the unit is shut down after every seasonal operation.	2011	1	$6
1296	7635	7636	271317	7671	0	2	#2 TURBINE	TURBINE	TURBINE FRONT STANDARD	None	32	18	No Level 2 required - included in steam turbine overhaul.	2011		
1296	7635	7636	271317	7686	0	2	#2 TURBINE	TURBINE	TURBINE GLAND STEAM SYSTEM	None	33	18	No Level 2 required - included in steam turbine overhaul.	2011		
1296	7635	7636	271317	7690	0	2	#2 TURBINE	TURBINE	TURBINE PRE-WARMING SYSTEM	None	34	18	No Level 2 required - included in steam turbine overhaul.	2011		
1296	7635	7636	271317	7692	0	2	#2 TURBINE	TURBINE	TURBINE TURNING GEAR	None	35	18	No Level 2 required - included in steam turbine overhaul.	2011		

9.2.9.9 Capital Projects

The suggested typical capital enhancements for the system include:

TABLE 9-71 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – UNIT 2 STEAM TURBINE

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Detail	CAP#	Appendix #	Capital Item	Date	Priority
1296	7635	7636	271317	0	0	2	#2 TURBINE	TURBINE	TURBINE	N/A	32	18	No capital investment required.		
1296	7635	7636	271317	7638	0	2	#2 TURBINE	TURBINE	TURBINE MAIN STEAM CHEST	N/A	33	18	No capital investment required.		
1296	7635	7636	271317	7643	0	2	#2 TURBINE	TURBINE	H.P. TURBINE	N/A	34	18	No capital investment required.		
1296	7635	7636	271317	7647	0	2	#2 TURBINE	TURBINE	TURB REHEAT/IP STEAM CHEST	N/A	35	18	No capital investment required.		
1296	7635	7636	271317	7652	0	2	#2 TURBINE	TURBINE	I.P. TURBINE	N/A	36	18	No capital investment required.		
1296	7635	7636	271317	7658	0	2	#2 TURBINE	TURBINE	L.P. TURBINE	N/A	37	18	No capital investment required.		
1296	7635	7636	271317	7671	0	2	#2 TURBINE	TURBINE	TURBINE FRONT STANDARD	N/A	38	18	No capital investment required.		
1296	7635	7636	271317	7686	0	2	#2 TURBINE	TURBINE	TURBINE GLAND STEAM SYSTEM	N/A	39	18	Replace the steam seal regulator.	2012	1
1296	7635	7636	271317	7690	0	2	#2 TURBINE	TURBINE	TURBINE PRE-WARMING SYSTEM	N/A	40		No capital investment required.		
1296	7635	7636	271317	7692	0	2	#2 TURBINE	TURBINE	TURBINE TURNING GEAR	N/A	41	18	Refurbish chain and mechanism.	2014	1

9.2.10 Asset 271486 – Unit 2 Cooling Water System - Associated with Steam Systems

(Detailed Technical Assessment in Working Papers, Appendix 11, 25)

Unit #:	2
Asset Class #	BU 1296 - Assets Generations
SCI & System:	8093 #2 Unit Generation Services
Sub-Systems:	271486 #2 CW System
Components:	8097 #2 CW Travelling Screens East
	8098 #2 CW Travelling Screens West
	8106 #2 CW Pump East
	8107 #2 CW Pump West
	8095 #2 CW Intake
	8120 #2 CW Discharge to Outfall

9.2.10.1 Description

The circulating water (CW) systems servicing Unit 2 consist of two 50% CW vertical turbine pumps driven by 4 kV motors and auxiliary systems. The pump drive motors are original. Two travelling screen systems are used to remove debris from the cooling water prior to entering the pumps. The primary function of the CW system is to provide condenser cooling water, but also cooling water for other closed loop systems. It is necessary that the CW system operate efficiently in order to maintain optimal plant thermal efficiency by minimizing steam turbine condenser backpressures.

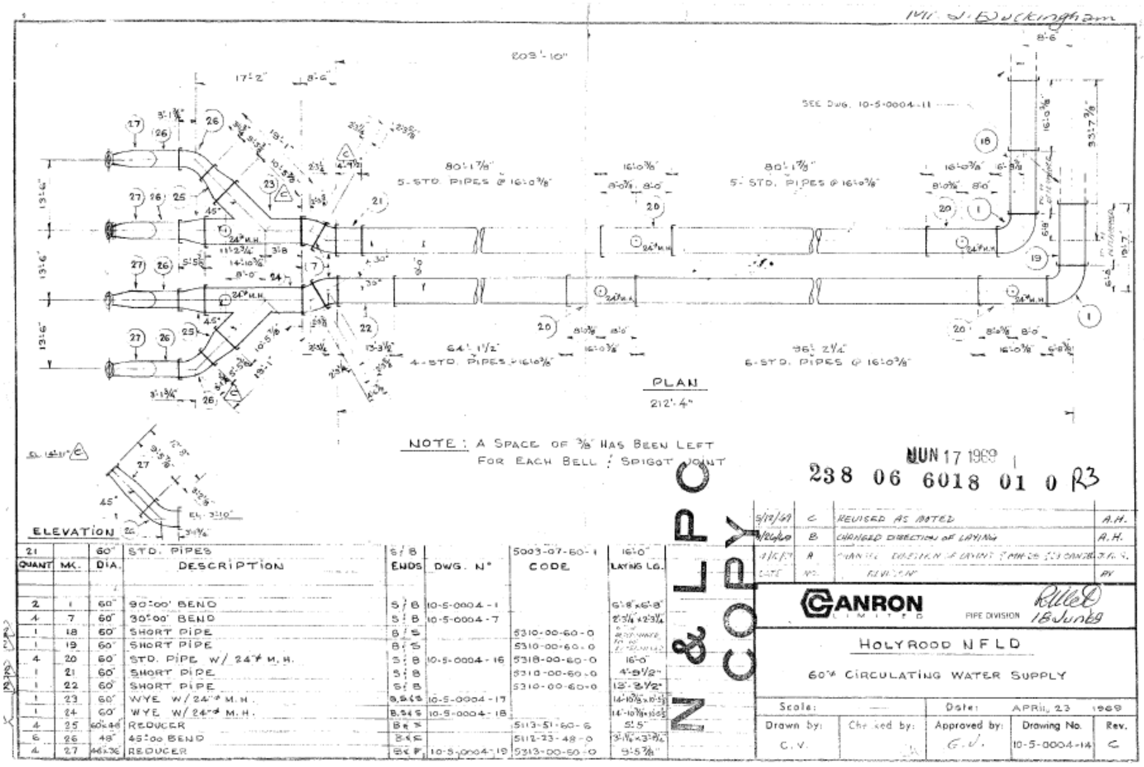

FIGURE 9-23 STAGE 1 CIRCULATING WATER PIPING SCHEMATIC

FIGURE 9-24 UNIT 1 & 2 CIRCULATING WATER PUMPS

FIGURE 9-25 UNIT 1 & 2 CIRCULATING WATER TRAVELLING SCREENS

9.2.10.2 History

Manufactured/Delivered	1970
In-Service Date	Apr 1971
Generation Base Load End Date	Dec 2015
Generation Peak/Emerg Gen End Date	Dec 2020
Synchronous Condensing Start Date	Jan 2015
Synchronous Condensing End Date	Dec 2041
Next Major Overhaul/Inspection	2014

The hours associated with the analyses are:

Hours Generation Actual - Ops to Dec 2009	158
Max Hours Generation Ops – to Dec 2015	188
Max Hrs Gen Ops to Gen End Date Dec 2020	212

9.2.10.3 Inspection and Repair History

Cooling Water Pumps & Motors, Screens, and Piping Systems

CW Travelling Screens: The travelling screen internals have been replaced on Unit 2 in the last 5 to 10 years. Interviews suggest that no recent issues have been experienced with these units. Visual examination confirmed that the Unit 2 screens generally appear to be in good condition.

The external casings are in differing states, with some parts more corroded than others. None appears to impair current or short term performance.

CW Wash Water Pumps and Motors: Externally, these are generally in a much corroded state, but were performing at the time of the visual inspection. They are considered to be a minor maintenance issue and not addressed as a part of this assessment.

CW Pumps: CW pumps on all units are performing fairly well. No reports were available on the condition of the pumps, but interviews suggest that regular maintenance has been kept up and the units should be able to meet 2015 and 2020 timelines with satisfactory maintenance. Major pump overhauls are scheduled on a twelve year cycle.

TABLE 9-72 MAJOR PUMP OVERHAULS

Annual Asset Maintenance

Pumps	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
1 CW Pump East			X												83,000.00			
1 CW Pump West											75,000.00							
2 CW Pump East	X				X												87,000.00	
2 CW Pump West												77,000.00						
3 CW Pump East		X									75,000.00							
3 CW Pump West						10,000.00												89,000.00

It is understood that a temporary CW pump is being used in the existing Unit 4 intake to supply smaller quantities of cooling water to Unit 3 for Synchronous Condensing duty. The system has been designed to supply all three units if and when converted. In addition, there are interconnections between Units 1 to 3 CW systems to allow them to provide back-up for this purpose if necessary. The temporary pump set appears to be satisfactorily performing.

CW Pump Motors: Motors are electrically tested every year (following PM process).

CW Pump Outlet Piping, Valves & Fittings: Outlet piping, valves and fittings from the pump to the inlet of the 162 cm (64 inch) concrete piping that goes underground to the unit condensers has generally experienced significant corrosion and some patching of the system has been done. It is in need of clean-up and testing for fitness of duty – a Level 2 inspection, or perhaps complete replacement.

Cooling Water System Intake & Discharge: The 91 cm (36 inch) and 162 cm (64 inch) CW intake and discharge concrete piping that goes underground to the unit condensers has periodically been pumped out and walked down by station staff, although not in the last five years. There have been no obvious issues with the systems, although no detailed engineering evaluations and NDE work has been undertaken.

No specific corrosion, spalling, cracks or fractures were identified, and no patching of the system has been done.

Inspections are planned going forward on a three year cycle, per schedule below.

TABLE 9-73 ANNUAL ASSET MAINTENANCE

Annual Asset Maintenance																	
CW Inspection		2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Unit 1													25,625.00			26,625.00	
Unit 2														25,625.00			26,625.00
Unit 3												25,000.00			25,625.00		

9.2.10.4 Condition Assessment

The condition assessment of the Unit 2 cooling water system associated with steam systems is illustrated below in Table 9-74:

TABLE 9-74 CONDITION ASSESSMENT – UNIT 2 COOLING WATER SYSTEM - ASSOCIATED WITH STEAM SYSTEMS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset Level 2	Asset Level 3	Description	Detail	Condition Summary ID#	Append #	Condition	EPRI Identifier	Original Life (Base Load) Ops Hrs (Yrs)	Current Expected Minimum Remaining Life Years (Subject to Test)	End of Life (EOL) Required	Next Regular Inspection	Next Planned Overhaul or Major Inspection	Capability to Reach Next Overhaul	Capability to Reach EOL	In Service
1296	7635	8093	271486	0	0	2	#2 UNIT GENERATION SERVICES	CW SYSTEM	CW SYSTEM	N/A	140	11	Generally in good condition, however significant corrosion on major steel pipes, pumps and valves.	4	200000 (30)	10+	2041			No	No	1971
1296	7635	8093	271486	8095	0	2	#2 UNIT GENERATION SERVICES	CW SYSTEM	C.W. INTAKE SYSTEM	Concrete pipe from Pumps to Condenser	141	11	No recent inspections of cement pipes, but walk-downs about 5 years ago indicated that the pipe looked intact. Given the geotechnical conditions and soil, there is no reason to expect any kind of aggressive attack. A copper ion system was installed to minimize any internal mussel growth on the CW pipe.	4	(60)	(20)	2041		2011	Yes	Yes	2000
1296	7635	8093	271486	8120	0	2	#2 UNIT GENERATION SERVICES	CW SYSTEM	C.W. DISCHARGE TO OUTFALL	Concrete pipe from Condenser to outfall pit	142	11	No recent inspections of cement pipes, but walk-downs about 5 years ago indicated that the pipe looked intact. Some moderate issues with stop log structures were identified. Given the geotechnical conditions and soil, there is no reason to expect any kind of aggressive attack. A copper ion system was installed to minimize any internal mussel growth on the CW pipe.	4	(60)	(20)	2041		2011	Yes	Yes	1971
1296	7635	8093	271486	8106	0	2	#2 UNIT GENERATION SERVICES	CW SYSTEM	C.W. PUMP EAST	N/A	143	11	The CW pumps have major inspections and overhauls about every twelve years. The motors are electrically checked annually per their PM requirements. Overall the pumps and motors seem to be performing satisfactorily. Several patches are evident on the CW steel pipes and valves associated with the pumps.	3a	(30)	(10)	2020	2012		Yes	No	1971
1296	7635	8093	271486	8107	0	2	#2 UNIT GENERATION SERVICES	CW SYSTEM	C.W. PUMP WEST	N/A	144	11	The CW pumps have major inspections and overhauls about every twelve years. The motors are electrically checked annually per their PM requirements. Overall the pumps and motors seem to be performing satisfactorily. Several patches are evident on the CW steel pipes and valves associated with the pumps.	3a	(30)	(10)	2020	2012		Yes	No	1971

Notes:

1. A "(bracketed)" value in the "Current Expected Remaining Life" column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation, including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as "(X/Y)" has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

2. The "Next Regular Inspection" column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The "Next Planned Overhaul or Major Inspection" column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a "Desired Life" stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or not known by AMEC.

9.2.10.5 Actions

Based on the condition assessment, the following actions are recommended for the Unit 2 cooling water system associated with steam systems:

TABLE 9-75 RECOMMENDED ACTIONS – UNIT 2 COOLING WATER SYSTEM - ASSOCIATED WITH STEAM SYSTEMS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Unit	Asset 2/3	Asset 3/4	Description	Detail	Action #	App #	Action	Year	Priority
1296	7635	8093	271486	0	2	#2 UNIT GENERATION SERVICES	CW SYSTEM	CW SYSTEM	N/A	194	11	Maintain current program of ongoing inspections and overhauls. Procure a spare motor to service all three units in the event of a failure of an existing unit.	2011	2
1296	7635	8093	271486	8095	2	#2 UNIT GENERATION SERVICES	CW SYSTEM	C.W. INTAKE SYSTEM	N/A	195	11	Perform a detailed visible inspection, with some NDE spotchecks, within the next two to four years of the concrete intake and discharge pipes.	2011	2
1296	7635	8093	271486	8120	2	#2 UNIT GENERATION SERVICES	CW SYSTEM	C.W. DISCHARGE TO OUTFALL	N/A	196	11	Perform a detailed visible inspection with some NDE spotchecks of the concrete intake and discharge pipes.	2011	2
1296	7635	8093	271486	8106	2	#2 UNIT GENERATION SERVICES	CW SYSTEM	C.W. PUMP EAST	N/A	197	11	Perform planned CW pump inspections on one pump per unit in 2010 to 2012 (Level 2).	2011	2
1296	7635	8093	271486	8107	2	#2 UNIT GENERATION SERVICES	CW SYSTEM	C.W. PUMP WEST	N/A	198	11	Perform planned CW pump inspections on one pump per unit in 2010 to 2012 (Level 2).	2012	2
1296	7635	8093	271486	8106	2	#2 UNIT GENERATION SERVICES	CW SYSTEM	C.W. PUMP EAST	N/A	199	11	Clean CW steel pipe and check thickness measurements (Level 2).	2011	2
1296	7635	8093	271486	8107	2	#2 UNIT GENERATION SERVICES	CW SYSTEM	C.W. PUMP WEST	N/A	200	11	Clean CW steel pipe and check thickness measurements (Level 2).	2011	2

9.2.10.6 Risk Assessment

Table 9-76 below illustrates the risk assessment for the Unit 2 cooling water system associated with steam systems, both from a technological perspective and a safety perspective using the models presented in Section 3.

TABLE 9-76 RISK ASSESSMENT – UNIT 2 COOLING WATER SYSTEM - ASSOCIATED WITH STEAM SYSTEMS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Component	Risk Assess #	Appendix #	Major Issues	Remaining Life Years	Remaining Life Comments	TECHNO-ECO RISK ASSESSMENT MODEL			SAFETY RISK ASSESSMENT MODEL			Possible Failure Event	Mitigation
														(Insufficient Info - Inspection Required Within (x) Years)		Likeli-hood	Conse-quence	Risk Level	Likeli-hood	Conse-quence	Safety Risk		
1296	7635	8093	271486	0	0	2	#2 UNIT GENERATION SERVICES	CW SYSTEM	CW SYSTEM	CW Concrete Pipe to Condenser	171	11	Concrete racking.	(20)	None	1	B	Low	1	A	Low	Cracking or failure – major leak requiring repair.	Inspect and maintain.
1296	7635	8093	271486	0	0	2	#2 UNIT GENERATION SERVICES	CW SYSTEM	CW SYSTEM	CW Pipe to Outfall Structure	172	11	Concrete racking.	(20)	None	1	B	Low	1	A	Low	Cracking or failure – major leak requiring repair.	Inspect and maintain.
1296	7635	8093	271486	8106	0	2	#2 UNIT GENERATION SERVICES	CW SYSTEM	C.W. PUMP EAST	CW Pumps	173	11	Corrosion - internal/external.	(10)	None	2	B	Low	2	A	Low	50% unit output loss while replaced with spare.	Current inspection and maintain.
1296	7635	8093	271486	8106	0	2	#2 UNIT GENERATION SERVICES	CW SYSTEM	C.W. PUMP EAST	4 kV Cooling Water Pump Motor	174	25	Electrical fault, mechanical fatigue, ops error.	(10)	None	1	B	Low	1	A	Low	Loss 60% of 1 unit generation.	Current inspection and maintain.
1296	7635	8093	271486	8106	0	2	#2 UNIT GENERATION SERVICES	CW SYSTEM	C.W. PUMP EAST	CW Outlet Piping, Valves, Fittings	175	11	Corrosion - internal/external.	(10)	None	3	A	Low	3	A	Low	Major leak and repair/patch.	Current inspection and maintain.
1296	7635	8093	271486	8107	0	2	#2 UNIT GENERATION SERVICES	CW SYSTEM	C.W. PUMP WEST	CW Pumps	176	11	Corrosion - internal/external.	(10)	None	2	B	Low	2	A	Low	50% unit output loss while replaced with spare.	Current inspection and maintain.
1296	7635	8093	271486	8107	0	2	#2 UNIT GENERATION SERVICES	CW SYSTEM	C.W. PUMP WEST	4 kV Cooling Water Pump Motor	177	25	Electrical fault, mechanical fatigue, ops error.	(10)	None	1	B	Low	1	A	Low	Loss 60% of 1 unit generation.	Current inspection and maintain.
1296	7635	8093	271486	8107	0	2	#2 UNIT GENERATION SERVICES	CW SYSTEM	C.W. PUMP WEST	CW Outlet Piping, Valves, Fittings	178	11	Corrosion - internal/external.	(10)	None	3	A	Low	3	A	Low	Major leak and repair/patch.	Inspect and maintain.

9.2.10.7 Life Cycle Curve and Remaining Life

The life cycle curve for the Unit 2 cooling water system associated with steam systems is illustrated below. One curve represents all the major elements of the system which are about the same age. No information existed on the condition of the large CW pipe to and from the condensers. Although it was not plotted here, its life would be expected to be on the order of 60 years, given no incidents to date as a result of original poor design or installation. The life curve is a plot of current and projected operating hours (generation mode only) on the y-axis versus calendar year on the x-axis. The figure has vertical lines representing differing representative nominal age limits. It also has several horizontal lines that represent a range of practical equivalent base loaded operating hour life limits. Both limits can come into play and both are extendable through maintenance refurbishment and component replacement. The risk area box provides an indication of the timing of potential issues either from an age or equivalent operating hours view.

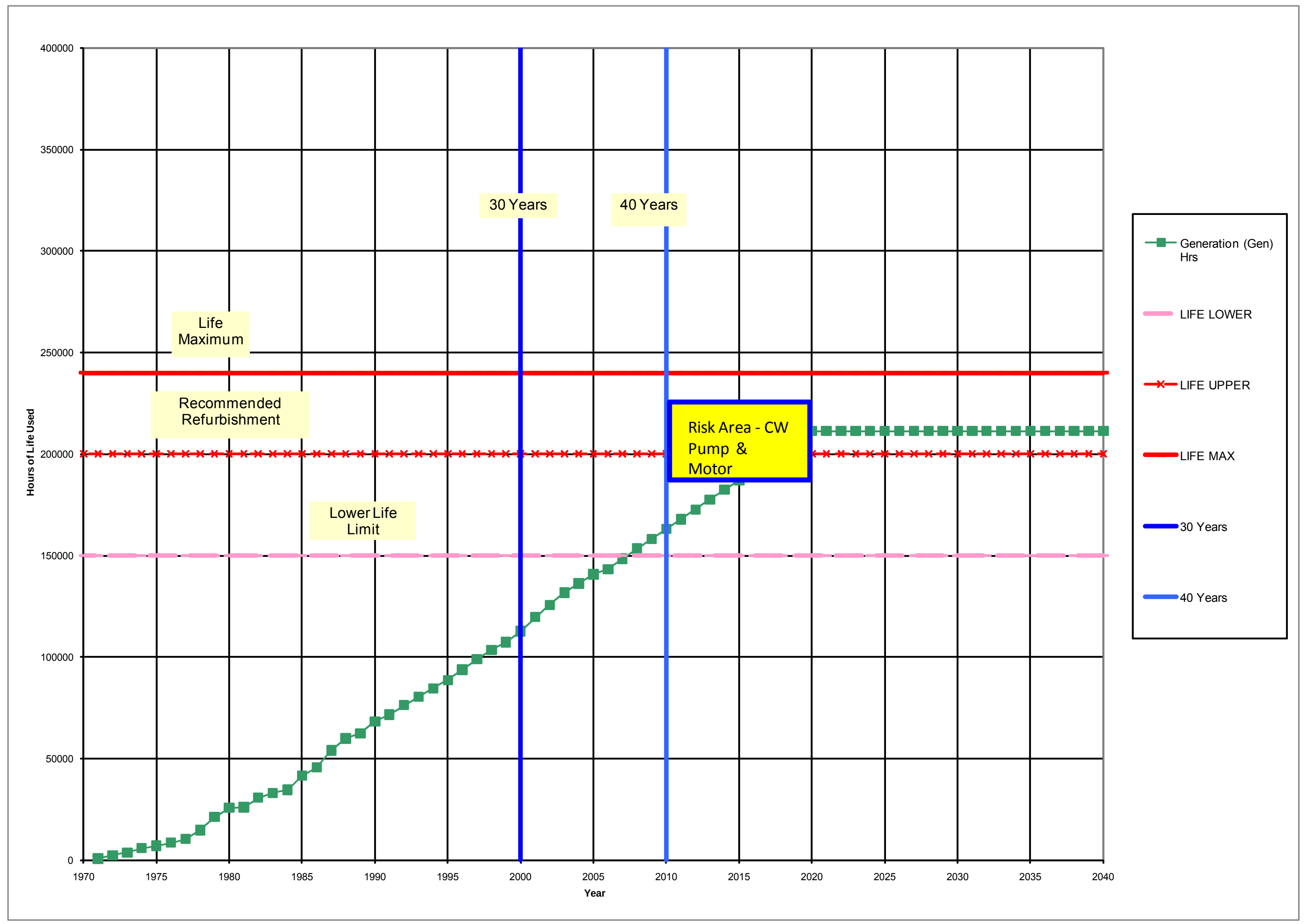

FIGURE 9-26 LIFE CYCLE CURVE – UNIT 2 COOLING WATER SYSTEM - ASSOCIATED WITH STEAM SYSTEMS

The curves indicate that the remaining life (RL) of the Unit 2 cooling water system - associated with steam systems can likely reach the desired life (DL) end date for generation of 2020, but with some reliability risk, particularly as it pertains to the 4 kV motors. It is recommended that a spare motor shared between units would be a reasonable precaution. Corrosion of the steel pipe, valves, and fittings was also evident suggesting that some maintenance on these issues is required.

9.2.10.8 Level 2 Inspections – Unit 2 Cooling Water System - Associated with Steam Systems

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 9-77 below, assuming the current plant inspection and maintenance program is maintained or improved.

TABLE 9-77 LEVEL 2 INSPECTIONS – UNIT 2 COOLING WATER SYSTEM - ASSOCIATED WITH STEAM SYSTEMS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Sub System Comment	L2#	Appendix #	Level 2 Work	Year	Cost k$
1296	7635	8093	271486	0	0	2	#2 UNIT GENERATION SERVICES	CW SYSTEM	CW SYSTEM	Concrete pipe to/from pump to condenser	143	11	Inspections - dry walk-down and NDE spotcheck.	2011	$6
1296	7635	8093	271486	0	0	2	#2 UNIT GENERATION SERVICES	CW SYSTEM	CW SYSTEM	Steel pipe to/from condenser	144	11	Clean steel pipe and check thickness measurements.	2011	$6
1296	7635	8093	271486	8106	0	2	#2 UNIT GENERATION SERVICES	CW SYSTEM	CW PUMP EAST	CW Pumps	145	11	Perform planned inspections on one pump per unit in 2010 to 2012 (similar to Level 2). No Level 2 on 4 kV motor if current maintenance program continues.	2011	
1296	7635	8093	271486	8107	0	2	#2 UNIT GENERATION SERVICES	CW SYSTEM	CW PUMP WEST	CW Pumps	146	11	Perform planned inspections on one pump per unit in 2010 to 2012 (similar to Level 2). No Level 2 on 4 kV motor if current maintenance program continues.	2011	

9.2.10.9 Capital Projects

The suggested typical capital enhancements for the system include:

TABLE 9-78 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – UNIT 2 COOLING WATER SYSTEM - ASSOCIATED WITH STEAM SYSTEMS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Detail	CAP#	Appendix #	Capital Item	Date	Priority
1296	7635	8093	271486	0	0	2	#2 UNIT GENERATION SERVICES	CW SYSTEM	CW SYSTEM	N/A	134	11	No capital investment required.		
1296	7635	8093	271486	8095	0	2	#2 UNIT GENERATION SERVICES	CW SYSTEM	CW INTAKE SYSTEM	Concrete pipe from pump to condenser	135	11	No capital investment required.		
1296	7635	8093	271486	8120	0	2	#2 UNIT GENERATION SERVICES	CW SYSTEM	CW DISCHARGE TO OUTFALL	Concrete pipe from condenser to CW outfall pit	136	11	No capital investment required.		
1296	7635	8093	271486	8106	0	2	#2 UNIT GENERATION SERVICES	CW SYSTEM	CW PUMP EAST	N/A	137	25	Procure spare motor - common to Units 1 & 2; adaptable Unit 3 to extent practical.	2012	1
1296	7635	8093	271486	8107	0	2	#2 UNIT GENERATION SERVICES	CW SYSTEM	CW PUMP WEST	N/A	138	25	Procure spare motor - common to Units 1 & 2; adaptable Unit 3 to extent practical.	2012	1

10 UNIT 3

10.1 Unit 3 - Key Systems

10.1.1 Asset 8298 – Unit 3 Generator

(Detailed Technical Assessment in Working Papers, Appendix 4)

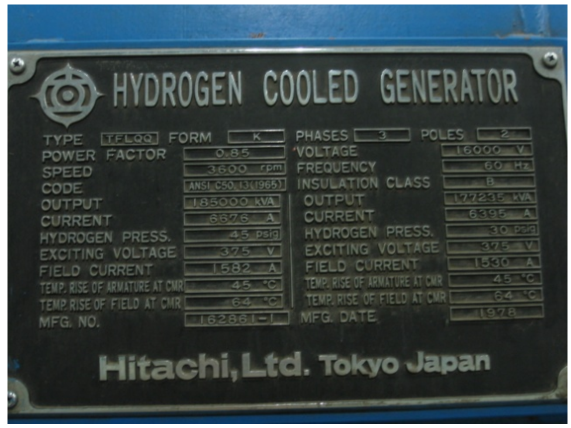

FIGURE 10-1 UNIT 3 GENERATOR

The equipment covered in this section includes:

Unit #:	3
Asset Class #	BU 1296 - Assets Generations
SCI & System:	8194 #3 Turbine & Generator
Sub-Systems:	8298 #3 Generator Assembly
Components:	8299 #3 Generator Rotor
	8304 #3 Generator Stator
	8312 #3 Excitation System
	8313 #3 Hydrogen System
	8326 #3 Synchronous Condensing System

10.1.1.1 Description

The Unit 3 generator, supplied by Hitachi, Tokyo, is rated at 185 MVA, hydrogen cooled at 207 kPa (30 psi), 0.85 power factor. It has an overload rating of 185 MVA at 310 kPa (45 psi). It went into service in 1979. The last major inspection was by General Electric Canada in 2007.

The stator core and windings are flexibly-mounted in the stator frame, which contains four vertical hydrogen coolers. The stator windings operate at 16.0 KV and are indirectly cooled by hydrogen. The hydrogen is circulated throughout the generator in a closed system, at 310 kPa (45 psi) pressure, by an axial fan mounted on each end of the rotor. Isolated phase bus delivers the power from the generator to the unit transformer. It is generally similar to the stators of Units 1 and 2.

Although the Unit 3 generator was installed 10 years after the installation of Units 1 and 2, it uses an earlier rotor design, which incorporates several inherently weaker features. Unlike Units 1 and 2, this rotor is indirectly-cooled with hydrogen, and the retaining rings are shrunk onto the rotor shaft, and held in place with locking keys. The field windings are indirectly-cooled by hydrogen, axially fed through separate ventilation slots located between each winding slot. The hot rotor gas discharges radially from the central part of the rotor. The rotor shaft has a larger diameter and is longer than the rotor shafts servicing Units 1 and 2, but is less efficiently cooled. The rotor forging is believed to use an air-quenched forging that will have a higher fracture appearance transition temperature (FATT) and is more sensitive to brittle fracture in a cold environment. The retaining ring at the turbine end has an integral balance ring, while the retaining ring at the collector-end has a separate balance ring. Both retaining rings are held to the balance rings with shrink fits and locking keys.

The generator rotor is directly-coupled to the turbine, and is supported on bearings located in the end-shields of the stator frame. Hydrogen seals prevent the hydrogen from escaping around the rotating shaft. The seals are pressurized by oil and are located inboard of the bearings. Unlike Units 1 and 2, the field current is supplied to the field windings via four collector rings and sets of brush gear, outboard of the main bearing. There is an axial fan mounted on the end of the shaft, to cool the four collector rings, but it is believed there is no steady bearing to support the extra weight and shaft length.

In 1986, the generator was modified to operate as a synchronous condenser in order to provide voltage support to the Island Interconnected transmission system for electrical power that is transmitted over large distances. The synchronous condenser drive includes a Siemens 4 kV, 1500 HP induction drive motor (known as a pony motor), a Philadelphia Gear Starter Drive Gearpak (Model HL60/9HS), and a SSS Clutches Size 60T SSS Clutch and casing assembly, as well as associated auxiliaries (extension shaft, flexible coupling, hydraulic transmission). During this operating mode, the generator is de-coupled from the turbine and is accelerated up to synchronous speed using the pony motor drive and “disk-pack” clutch in the Philadelphia Gear Starter Drive Gearpak that is attached to the outer-end coupling of the generator rotor via the SSS clutch. As soon as the generator rotor reaches synchronous speed, the pony motor shuts down and is disengaged from the generator rotor via the SSS Clutch assembly. Unit 3 operates as a synchronous condenser for approximately seven months each year from May to November. The Unit 3 synchronous condenser is illustrated below in Figures 10-2 and 10-3.

FIGURE 10-2 SYNCHRONOUS CONDENSING UNIT

FIGURE 10-3 SYNCHRONOUS CONDENSING UNIT

The retrofit of the Unit 3 synchronous condensing capability required an extension of the turbine-generator support structure. One reliability issue is the lack of thrust and radial bearings on the stub shaft that connects the generator rotor to the SSS Clutch when the generator is de-coupled from the steam turbine for synchronous condenser operation. This allows the generator rotor to move axially and radially as operating conditions shift causing high vibration levels.

The excitation to the field is supplied by a Westinghouse static thyristor excitation system, with a fast-response automatic voltage regulator to control the generator voltage by adjusting the field current and MVAR output from the generator. The excitation has a high ceiling voltage capability in order to enable the generator to help the power system recover from faults and disturbances.

The auxiliary systems include:

- A static thyristor controlled excitation system fed from the generator terminals, with field flashing from a battery for initial energization, i.e. black start capability;
- A seal oil vacuum tank to remove the hydrogen that becomes entrained in the seal oil, (instead of the scavenging system used on units 1 and 2);
- A closed-loop distilled water cooling system and temperature controller to remove the heat from the generator, with a temperature controller to maintain constant cold hydrogen temperature;
- Potential transformers (PT's), located below the isolated phase bus, measure the generator voltage; Current transformers (CT's) mounted over the generator lead bushings measure the generator current. These devices provide signals to measure the generator output, and for the electro-mechanical protection relays;
- A vibration monitoring system that continuously monitors the vibration amplitudes at each turbine generator bearing in the control room, and alerts the operator to increasing vibration, especially during run-up, load changes and shut-down; and
- Generator protection that uses the original electro-mechanical relays. A digital multi-functional generator protection relay has been added, but at present it is primarily used for extra ground fault protection of the stator windings. It also provides supplementary alarms and sequence-of-events monitoring.

10.1.1.2 History

The requirements for the generators on Unit 3 are as follows:

Manufactured/Delivered	1979
In-Service Date	Feb 1980
Generation Base Load End Date	Dec 2015
Generation Peak/Emerg Gen End Date	Dec 2020
Synchronous Condensing Start Date	1988
Synchronous Condensing End Date	Dec 2041
Last Major Inspection	2007
Next Major Overhaul/Inspection	2016

The thousands of hours associated with the analyses, and the number of starts per year are:

	Generation (Gen)	Synchronous Condensing (SC)
Hours Actual - Ops to Dec 2009	126	35.1
Hours - Ops to Gen End Date Dec 2015	170	44.0
Hours - Ops to Gen End Date Dec 2020	179	67
Hours – Ops to SC End Date Dec 2040	179	163
Starts Actual - Ops to Dec 2009	328	46
Starts - Ops to Gen End Date Dec 2015	400	58
Starts - Ops to Gen End Date Dec 2020	460	83
Starts – Ops to SC End Date Dec 2040	560	183

10.1.1.3 Inspection and Repair History

2007 Overhaul

- Full stator re-wedge using similar wedges to those originally supplied by Hitachi (not top ripple springs);
- A damaged series connection and a damaged phase joint were repaired and cured;
- Stator frame was realigned with the new T-G shaft position;
- Turbine generator shaft was realigned to minimize the bending stress at the coupling;
- Some rotor slot end-wedges had migrated and were moved back into position and staked;
- Field winding measurements were taken but no repairs were necessary;
- Hydrogen seals were cleaned, segments lapped, and clearances were adjusted;
- Bearing journals were cleaned and strap lapped;
- Water-pressure test done on hydrogen coolers – OK; and
- New bearings and seals were installed in the seal oil vacuum pump.

2001 Overhaul

- New retaining rings were installed on the rotor and a broken packing block was replaced;
- The field windings were reported to be in good condition – no serious defects were found;
- Coupling bolt hole #11 was badly scored. It was honed smooth and an oversize bolt was installed;
- Hydrogen coolers were water-tested and found satisfactory. New gaskets were installed;
- CE seal upper and lower seal insulation frames were replaced;
- Hydrogen seals were cleaned, segments lapped, and clearances were adjusted; and
- Score marks were lapped out of the seal oil vacuum pump, and their seals were replaced.

Note: Oil was not reported to have leaked into the generator during the 2001 and the 2007 inspections, despite the larger hydrogen seal clearances on the Hitachi seals permitting a higher seal oil flow. It is concluded that the vacuum seal oil treatment unit is more effective than the GE detraining tank and scavenging system on Units 1 and 2.

10.1.1.4 Condition Assessment

The Unit 3 generator and its auxiliary systems are in reasonably good condition for their age.

- Stator Core: satisfactory, based on El-cid test results;
- Stator Windings: satisfactory after 29 years, but the re-wedged bars are likely to loosen again;
- Rotor forging: Not known - no NDE checks have been done for 14 years or more. (concerns are based on design details);
- Field winding: satisfactory, per CGE report 2001, (there are some concerns, based on experience with similar Hitachi and GE generators in Canada); and

Details of the sub-systems are presented in Table 10-1 below and in more detail in Appendix 4.

TABLE 10-1 CONDITION ASSESSMENT – UNIT 3 GENERATOR

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset Level 2	Asset Level 3	Description	Detail	Condition Summary ID#	Append #	Condition	EPRI Identifier	Original Life (Base Load) Ops Hrs (Yrs)	Current Expected Minimum Remaining Life Years (Subject to Test)	End of Life (EOL) Required	Next Regular Inspection	Next Planned Overhaul or Major Inspection	Capability to Reach Next Overhaul	Capability to Reach EOL	In Service
1296	8193	8194	8298	0	0	3	U3 GENERATOR	GENERATOR	GENERATOR	N/A	10	4	Stator: core - satisfactory; Windings: Satisfactory, wedges likely loose. Rotor: Forging: Not known, likely satisfactory - no NDE for 14 years; Winding: Satisfactory, but concerns with similar units Overhaul required in 2016.	4	200000 (30)	10	2041	2016	2016	Yes	No	1980
1296	8193	8194	8298	8299	0	3	U3 GENERATOR	GENERATOR	GENERATOR ROTOR	Core	11	4	Forging: Satisfactory to good condition in 2007. See windings.	4	200000 (40)	15	2041	2016	2016	Yes	No	1980
1296	8193	8194	8298	8299	0	3	U3 GENERATOR	GENERATOR	GENERATOR ROTOR	Winding	12	4	Field Winding: Satisfactory, wedges likely loose. Generator has inherently weak design features incorporated (fretting of the locking keys, and of the top turns of copper at the ends of the rotor below the retaining ring leading to damaged top cap insulation and shorted field turns; risk of a broken top turn creating arc damage to the retaining ring; risk that fretting at the locking keys and shrink fit can lead to a fatigue crack developing in the rotor forging shaft, necessitating its replacement). Insulation found in satisfactory to good condition.	4	200000 (30)	(6/15)	2041	2016	2016	Yes	No	1980
1296	8193	8194	8298	8304	0	3	U3 GENERATOR	GENERATOR	GENERATOR STATOR	Core	13	4	Core - satisfactory to good. The stator core and frame are reported to be in good condition, with no looseness or fretting damage at the bore, or at the outside flexible mounting. GE reported show no significant core deterioration in 2003, and that the stator core is fit to be re-wound.	4	200000 (40)	(10)	2041	2016	2016	Yes	No	1980
1296	8193	8194	8298	8304	0	3	U3 GENERATOR	GENERATOR	GENERATOR STATOR	Winding	14	4	Windings: Satisfactory condition. Wedges likely loose, but good insulation condition in 2007. High winding temperatures due to low operating hydrogen pressure, 182 KPa versus rated value of 310 KPa. The stator core temperature is not monitored continuously, although this is desirable for synchronous condenser operation.	4	200000 (30)	(10)	2041	2016	2016	Yes	No	1980
1296	8193	8194	8298	8313	0	3	U3 GENERATOR	GENERATOR	GEN.HYDROGEN GAS SYSTEM		15	4		3a	200000 (30)	3	2041	2010	2013	Yes	No	1980
1296	8193	8194	8298	8313	8288	3	U3 GENERATOR	GENERATOR	GENERATOR SEAL OIL SYSTEM	N/A	16	4	The hydrogen seal clearances are large on the air-side at 0.006 and 0.010 mil, where the differential pressure is 210 KPa: likely why considerable oil leakage out of the #6 bearing onto the IPB. The hydrogen-side clearances are more typical at 0.009 and 0.012 mils. In 2007, the hydrogen seal assemblies were dismantled, cleaned and lapped to obtain matching contact with the shaft. The seal oil vacuum pump was cleaned and inspected, and new bearings and seals were installed.	4	200000 (30)	10	2041	2010	2013	Yes	No	1980
1296	8193	8194	8298	8313	8318	3	U3 GENERATOR	GENERATOR	GENERATOR CO2 GAS PURGE	N/A	17	4	No issues identified, aside from system capacity and supply limits.	3a	200000 (30)	(10)	2041	2011	2013	Yes	No	1980
1296	8193	8194	8298	8313	8321	3	U3 GENERATOR	GENERATOR	GENERATOR COMPRESSED AIR	N/A	18	4	No issues identified.	4	200000 (30)	(10)	2041	2013	2013	Yes	No	1980
1296	8193	8194	8298	8322	0	3	U3 GENERATOR	GENERATOR	GENERATOR HYDROGEN COOLING	N/A	19	4	In 2007, the hydrogen seal assemblies were dismantled, cleaned and lapped to obtain matching contact with the shaft. The seal oil vacuum pump was cleaned and inspected, and new bearings and seals were installed. The hydrogen cooler leak tested satisfactory.	4	200000 (30)	10	2041	2011	2013	Yes	No	1980
1296	8193	8194	8298	99039100	0	3	U3 GENERATOR	GENERATOR	PARTIAL DISCHARGE ANALYSIS	N/A	20	4	Not functional.	10	200000 (30)	1	2041	2010	2013	Yes	No	1980
1296	8193	8194	8312	0	0	3	U3 GENERATOR	GENERATOR EXCITATION SYSTEM	GENERATOR EXCITATION SYSTEM	N/A	21	4,6	See detail below	10	200000 (30)	3	2041		2016	Yes	No	1980
1296	8193	8194	8312	271679	0	3	U3 GENERATOR	GENERATOR EXCITATION SYSTEM	EXCITER	N/A	22	4,6	System operates very well. Annual maintenance check in 2009. Modifications to the AVR in 2000. Supplier support and parts limited, but some parts available on site.	10	200000 (30)	3	2041	2009	2016	Yes	No	1980
1296	8193	8194	8312	271680	0	3	U3 GENERATOR	GENERATOR EXCITATION SYSTEM	EXCITATION TRANSFORMER	N/A	23	4,6	Original dry transformer equipment installed in 1979. Unit has a moderately high level of risk due to its age, although tests in 2007 identified satisfactory results. Replacement with exciter recommended.	4	200000 (30)	3	2041		2016	Yes	No	1980
1296	8193	8194	8312	271680	0	3	U3 GENERATOR	GENERATOR EXCITATION SYSTEM	RT3 RECTIFYING TRANSFORMER	N/A	25	5,6	Installed in 1979 as part of Unit 3 Exciter system, the unit has a moderately high level of risk due to its age. A dry transformer, tests in 2007 identified satisfactory results.	4	(45)	15	2041	2013		Yes	No	1980
1296	8193	8194	8312	271681	0	3	U3 GENERATOR	GENERATOR EXCITATION SYSTEM	FIELD BREAKER	N/A	26	4,6	Installed in 1979 as part of Unit 3 Exciter system, breaker has a moderately high level of risk due to its age. No issues identified in 2007 test.	4	200000 (30)	3	2041		2016	Yes	No	1980
1296	8193	8194	8326	0	0	3	U3 GENERATOR	GENERATOR SYNCRONOUS COND	GENERATOR SYNCRONOUS COND	N/A	27	4	System has generally performed well, but causing higher than normal generator vibration readings, primarily as a result of a lack of a thrust bearing. Its condition appears mechanically quite good, but likely will require a major overhaul in 2016.	4	150000 (30)	10	2041		2016	Yes	No	1986

Notes:

1. A "(bracketed)" value in the "Current Expected Remaining Life" column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation, including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as "(X/Y)" has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

2. The "Next Regular Inspection" column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The "Next Planned Overhaul or Major Inspection" column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a "Desired Life" stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or simply are not known to AMEC.

10.1.1.5 Actions

The following table highlights a number of the issues and defects associated with Unit 3 generator and the actions recommended to address them.

TABLE 10-2 8304 #3 GENERATOR STATOR

Issues	Recommended Actions
1. There is a risk of oil leaking into the stator, reducing the effectiveness of the winding support. (Oil and grease has been found on the end-windings during recent past inspections of Units 1 and 2.)	1. Keep the differential seal oil/hydrogen differential pressure constant and between 27 – 40 kPa (4 and 6 psi). 2. Check the oil level in the de-training tank is not high, and the flow in the seal oil drain lines is not excessive or foaming, which increases the risk of oil backing up and leaking into the generator 3. Monitor the partial discharge activity every 3 months for signs of increased partial discharge activity. If the end-winding partial discharge activity exceeds 30 mV on any of the phases, plan an early intervention for repair of the stator end-winding looseness. 4. Check the hydrogen consumption and seal oil consumption for leakage. 5. Check the liquid leak detector for oil deposits.
2. The stator core appears to be in satisfactory condition, but the GE El-Cid test report is incomplete. (It is important to confirm that the condition of the core is sound, before ordering a replacement stator winding for installation in 2012, see next item).	1. Plan for an El-cid test during the next major inspection. Check the stepped end packets, and record the highest defect values in each slot. 2. Repeat the measurements in the highest three slots and note the positions, for boroscope inspection. 3. If a stator rewind is planned, carry out a high flux test of the stator core. Take infra-red photos of the core and note the hot spots (areas greater than 3 °C above the surrounding areas).
3. The 5 KV Megger readings are considerably lower than the GE units 1 and 2. It is believed this is due to high moisture present during the test, as the DC hipot test results were good (low and uniform leakage current in each phase).	1. At the next major inspection, repeat the 10 KV Megger test, and the DC hipot test at 34 KV. (make sure the windings are clean and dry before doing the tests)
4. The stator was fully re-wedged with flat wedges in 2007. This wedging system has been found to require frequent re-tightening during past inspections. Windings firmly in place and no loosening of the wedges/windings has occurred.	1. Carry out a wedge tap survey, to check for loose wedges, and re-wedge any slots with more than 2 adjacent loose wedges or more than 4 loose in any slot. 2. Visually inspect the core teeth for signs of fretting dust or "grease".

Issues	Recommended Actions
5. Further information is desirable regarding the deterioration of the stator winding in operation, and the possible need for more frequent maintenance.	1. Take Doble test measurements at each major inspection, after the windings have been cleaned and tightened.
A. Operation	
1. The stator winding and core RTD's do not read credible values. They are too low.	1. Using the GE calibration from the last outage, monitor the most accurate RTD of each phase, and the hottest core RTD, on the DCS display.
2. The partial discharge monitoring is not working. The GE test report shows the stator windings are in very poor condition, so the partial discharge levels in operation should be monitored carefully, to minimize the risk of a winding failure – see also item 2 above)	1. Contact IRIS service dept, to obtain advice on how to get it working. Record the values every 3 months and watch for an increase of >20 % in the readings of the highest 3 sensors. Bring forward the planned outage if necessary.
3. During the two month summer outage and the major inspection outages, moisture collects on the stator and rotor windings. Corrosion of the collector distributor bolts was found on units 1 and 2 at the last outage. It greatly affects the Megger and DC hipot test results.	1. When the generator is out of service and de-gassed, blow warm dry instrument air through the generator. When the rotor is out, install heaters in the stator ends, and a tarp over the ends to keep it warm and reduce dust ingress. 2. Consider fitting pad heaters to the lower outer surface of the stator ends, with a switch to turn the heat on when the unit is off-line. 3. The rotor should be kept in a clean conditions "tent" and air heaters installed to keep the windings warm and dry.
4. Four of the stator (winding) slot temperatures are monitored on the "turbine generator" screen, but the stator core temperature is not monitored in operation. During high over-excited load the centre of the stator becomes the hottest, but during under-excited operation the core end temperatures are the highest. This is particularly important during synchronous condenser operation.	1. Use three of the lines for the hottest winding temperature in each phase, and label them phase A, phase B and phase C. Use the fourth line to monitor the hottest stator core-end temperature. Add a fifth line to show the hottest core temperature at the centre of the stator.

TABLE 10-3 8299 #3 GENERATOR ROTOR

Issues	Recommended Actions
1. The retaining rings and the rotor forging, and slot wedges do not appear to have been NDE checked for defects since they were installed in 2001. (Defects have been found in other similar rotors after less than 30 years operation).	1. Remove the retaining rings and the slot wedges. 2. Carry out a detailed visual and NDE inspection for defects and fatigue cracks developing, in the dovetails, wedge ends, rotor bore, retaining rings, etc. Remove any crack-like defects. Check the shrink fit areas for fretting, and contact of end-wedges with the retaining rings.
2. The condition of the end-windings is not known and some deformation of the turns in the coil stacks is expected, especially at the series connections between longer coils and at the lead connections to the winding. The packing blocks are expected to be fretted and dust will have collected under the retaining ring insulation that should be removed.	1. Check the end-windings for fretting, fatigue cracks in the top turns under the retaining rings, any distortion or cracking of the flexible connections.
3. The turn insulation may be damaged, or the packing blocks broken, fretted or displaced, and the ends of the slot cells may be abraded, overheated, or crushed by the retaining rings.	1. Check the insulation blocks and re-place or re-tighten as necessary. (note the dust found probably contains asbestos).
4. The turbine generator shaft line has been realigned at each major inspection. The adjustment seems to be too much to be due to bearing wear, and it appears that the foundation is settling over time.	1. Trend the bearing vibration levels over time, and record the changes. Try to relate them to the MVAR load, as well as the MW load. 2. If the vibration level is high put the readings on a polar plot (Bode) and compromise balance it with marked weights. 3. Re-align and re-balance the rotor after the shaft line has been corrected, at the major inspection.
5. There is no record of the generator bearings being re-metalled but GE recommended sending out the generator bearings for refurbishment at the next major overhaul. Other rotors have found uneven wear, poor Babbitt bond, and electrical damage. The #5 bearing insulation was found defective.	1. Re-furbish both generator bearings. 2. NDE the bearing Babbitt for good bond with the shell. 3. Check the surface for even wear 4. Check the insulation resistance of #5 bearing and hydrogen seal, and inspect visually. 5. Replace if defective. Replace oil deflectors.

Issues	Recommended Actions
A. Operation	
1. The field current is not credible, it is much too low.	1. Check the source and calibrate the DCCT, or use the field current value shown on the exciter.
2. The field winding temperature is not monitored. (During overexcited synchronous condenser operation the field current will be higher, and there is an increased risk of overheating the field winding insulation).	1. Install a mean field winding temperature simulator(if one does not already exist in the static excitation system), or 2. Obtain an algorithm for the mean field winding temperature, based on the field current, cold resistance and the cold gas temperature. Show the mean field winding temperature on the control room display.
3. There is no on-line monitoring for shorted field turns (this is the most common indication the rotor needs to be re-wound).	1. Install a flux probe in the stator bore at the next major outage, when the rotor is out of the stator core.
4. The shaft voltage and the shaft ground current are not monitored or checked in operation. A harmful current could flow through the bearing or hydrogen seal. (the risk of damage increases when the starting package is added at the collector end, for synchronous condenser operation).	1. Upgrade the shaft grounding brushes with a constant-tension spring brush box, and replace the other with a copper braid, to clean the shaft. 2. Fit a shaft voltage monitoring brush at the outer end of the shaft, so the shaft voltage can be checked safely in operation, or 3. Install a Sohre grounding brush and shaft current and voltage monitoring system.
5. During the major inspection outages, and the switchover to synchronous condenser operation, moisture collects on the stator and rotor windings. (Corrosion of the collector distributor bolts was found on units 1 and 2 at the last outage). The moisture greatly affects the Megger and DC hipot test results, and leads to pessimistic assessment of aging and reduced remaining life of the windings..	1. - When the generator is out of service and de-gassed, blow warm dry instrument air through the generator. When the rotor is out, install heaters in the stator ends, and a tarp over the ends to keep it warm and reduce dust ingress 2. Consider fitting pad heaters to the lower outer surface of the stator ends, with a switch to turn the heat on when the unit is off-line. 3. The rotor should be kept in a clean conditions “tent” and air heaters installed to keep the windings warm and dry.

TABLE 10-4 8313 #3 HYDROGEN SYSTEM

Issues	Recommended Actions
1. The seal oil vacuum pump is a high maintenance item. The level control and the vacuum pump require preventive maintenance at every major inspection, to prevent foaming, and remove moisture effectively, and minimize the risk of oil entering the generator.	1. Replace the seals, and gaskets, and check the operating level in the tank, at both 207 and 310 kPa (30 and 45 psi) hydrogen pressures. 2. Hitachi recommends the seal oil system be flushed regularly, to prevent contamination of the controls. Carry out preventive maintenance on the vacuum pump
2. The hydrogen coolers were leak tested and found satisfactory but GE recommended the gaskets be replaced at each major inspection.	1. Replace the gaskets and seals, and leak test at every major inspection. Check cold parts for green slime (operating temp too low!)
3. The liquid leak detector valve is prone to failure (it had incorrect flanges and gaskets on units 1 and 2	1. Check the operation of the liquid leak detector relay, and service the parts.).(Frequent operation wastes hydrogen).
4. Hydrogen dryer. The replacement hydrogen dryer is of small capacity and will require frequent regeneration. Oil from the leaking hydrogen seals reduces its effectiveness. A pipe blockage can burn out the heater.	1. Carry out preventive maintenance on the hydrogen dryer, replace the desiccant, check the regeneration operation, check for hydrogen leaks, especially at the purity meter and sampling valves.
5. The hydrogen pressure is automatically controlled by a valve, but this generator operates at low pressure. Is the valve not in service or is it broken? Keeping the pressure constant reduces the risk of oil ingress into the generator.	1. Service the hydrogen pressure control valve. 2. Locate and repair hydrogen leaks ASAP.
A. Operation	
1. The hydrogen pressure is low, probably due to hydrogen leaks, resulting in extra heating of the generator core and windings.	1. Locate and repair the hydrogen leaks. 2. Increase the hydrogen pressure to 207 kPa (30 psi).
2. The hydrogen consumption of each generator is not recorded.	1. Fit a totalizer in the hydrogen supply line, so the daily hydrogen consumption of each generator can be recorded.
3. The cold gas temperature is low at 30 C, GE usually recommend a minimum of 35 °C to avoid algae forming on the windings and the increased risk of brittle fracture in the rotor forging.	1. Ask GE to confirm the rotor forging is water-quenched, not air-quenched. 2. Increase the cold gas temperature setting to 35 °C, especially if the forging is air-quenched.

Issues	Recommended Actions
4. The hot gas temperatures are not recorded, so it is not possible to check the temperature rise across each cooler, i.e. whether the hydrogen coolers are balanced. Sometimes a cooler leak occurs, or a plug of the vent pipe after return to service, that should be detected.	1. Every month check the temperature rise across each cooler, to ensure they are balanced, and no gas lock, plugged vent, or cooler leak has occurred, which will unbalance the temperatures across the generator, and result in undesirable overheating.
5. The hydrogen pressure is automatically controlled by a valve, but this generator operates at low pressure. Is the valve not in service or is it broken? Keeping the pressure constant reduces the risk of oil ingress into the generator.	1. Service the hydrogen pressure control valve. 2. Locate and repair hydrogen leaks ASAP.

TABLE 10-5 8312 #3 EXCITATION SYSTEM

Issues	Recommended Actions
1. The excitation system is expected to have a V/f limiter to protect the generator against over-fluxing, - the risk of generator damage is highest during initial energization on AVR control.	1. Connect the V/f element of the multi-functional generator protection relay to trip the excitation when off-line, if over-fluxing occurs.

10.1.1.6 Actions - Unit 3 Generator

The following table highlights a number of the basic issues/defects found and the actions recommended to address them.

TABLE 10-6 RECOMMENDED ACTIONS – UNIT 3 GENERATOR

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Unit	Asset 2/3	Asset 3/4	Description	Detail	Action #	App #	Action	Year	Priority
1296	8193	8194	8298	0	3	U3 GENERATOR	GENERATOR	GENERATOR	General	12	4	Reduce operating intervals between major outages to 6 years: poor condition of the stator windings, loosening of the end-winding supports (per 2005), extra fretting and insulation deterioration of the stator end-windings expected at the next major outage in 2016, continued oil leakage into the windings, current lack of stiffness of end-winding supports.	2010	1
1296	8193	8194	8298	0	3	U3 GENERATOR	GENERATOR	GENERATOR	General	13	4	Review generator drawings, contract information, and operating manual to clarify design details.	2010	2
1296	8193	8194	8298	8299	3	U3 GENERATOR	GENERATOR	GENERATOR ROTOR	Rotor Core	14	4	Verify whether the rotor is an air-quenched forging, which is sensitive to brittle fracture, or is a water-quenched forging that is not sensitive to brittle fracture.	2010	1
1296	8193	8194	8298	8299	3	U3 GENERATOR	GENERATOR	GENERATOR ROTOR	Rotor Core	15	4	Confirm whether the rotor has 4 collector rings at the outer end of the rotor shaft (two per pole) instead of the 2 collector rings (one per pole), used on other generators of this rating, e.g. units 1 and 2.	2010	1
1296	8193	8194	8298	8299	3	U3 GENERATOR	GENERATOR	GENERATOR ROTOR	Rotor Core	16	4	Carry out electrical and mechanical inspection of the rotor in 2016.	2016	1
1296	8193	8194	8298	8299	3	U3 GENERATOR	GENERATOR	GENERATOR ROTOR	Rotor Core	17	4	Remove the retaining rings and perform a detailed NDE inspection.	2016	1
1296	8193	8194	8298	8299	3	U3 GENERATOR	GENERATOR	GENERATOR ROTOR	Rotor Core	18	4	Provide more details in next inspection of parts inspected, deterioration observed and severity or action needed. It should include photos, description of fretting dust, grease, sparking, accumulated dust and debris, as well as details of repair work done, e.g. cleaning out dust, re-fitting packing blocks, realigning turns in coils, turn insulation damage found and repairs made.	2016	1
1296	8193	8194	8298	8299	3	U3 GENERATOR	GENERATOR	GENERATOR ROTOR	Rotor Core	19	4	Make a visual check of the extent of restrictions of the radial gas cooling passages, and of any displaced turn insulation. Any accumulated debris in the radial ventilation ducts, the sub-slots, and in the end-windings should be blown or vacuumed out.	2016	1
1296	8193	8194	8298	8299	3	U3 GENERATOR	GENERATOR	GENERATOR ROTOR	Field Winding	20	4	Perform annual 500 volt megger checks on the rotor, to confirm that there is no major deterioration of the ground insulation (below 3 Gig-ohms).	2010	1
1296	8193	8194	8298	8299	3	U3 GENERATOR	GENERATOR	GENERATOR ROTOR	Field Winding	21	4	Install a field winding temperature indicator in control room.	2010	1
1296	8193	8194	8298	8299	3	U3 GENERATOR	GENERATOR	GENERATOR ROTOR	Field Winding	22	4	Use the volts/hertz element of the new multi-functional relay to ensure this condition is recognized and tripped promptly, as a back-up to the normal excitation/AVR limiters.	2010	1
1296	8193	8194	8298	8304	3	U3 GENERATOR	GENERATOR	GENERATOR STATOR	Stator Core	23	4	Check slots 57 and 59 at the CE, slots 8 and 10 at the centre of the core, but particularly slot 18, at the centre of the core, at the next inspection by el-cid test and with a boroscope.	2016	1
1296	8193	8194	8298	8304	3	U3 GENERATOR	GENERATOR	GENERATOR STATOR	Stator Core	24	4	Take and record the peak El-cid readings in each slot and check manually and record the stepped end–packets of plate.	2016	1
1296	8193	8194	8298	8304	3	U3 GENERATOR	GENERATOR	GENERATOR STATOR	Stator Core	25	4	Visually check with the hydrogen coolers removed the back of the core for fretting at the core bar supports, and for signs of overheating at the surface of the iron and restriction of the ventilation ducts. Take photos of main findings for future reference.	2016	1
1296	8193	8194	8298	8304	3	U3 GENERATOR	GENERATOR	GENERATOR STATOR	Stator Core	26	4	Carry out (if a complete rewind of the stator is contemplated in 2016) an El-cid test and a core high flux (loop) test, with thermovision camera check for hot spots, and temporary flux coils around the end-packets of iron - to ensure the core is in good enough condition to warrant the expenditure of a rewind.	2016	1
1296	8193	8194	8298	8304	3	U3 GENERATOR	GENERATOR	GENERATOR STATOR	Stator Core	27	4	Maintain a careful record should be kept of all stator core deterioration found, especially if it is not repaired. Manufacturers' records are generally too brief and inadequate; the inspection summaries outlined in the IEEE press book "Inspection of Synchronous Machines" by I. Kerszenbaum and G. Klempner provide a more detailed record, and have been endorsed by EPRI.	2016	1
1296	8193	8194	8298	8304	3	U3 GENERATOR	GENERATOR	GENERATOR STATOR	Stator Winding	28	4	Take Doble reading before and after the windings have been maintained, Doble test readings for 2007, or for earlier inspections should be obtained and updated when the 2016 readings are available.	2016	1
1296	8193	8194	8298	8304	3	U3 GENERATOR	GENERATOR	GENERATOR STATOR	Stator Winding	29	4	Take the partial discharge readings of the slot part and of the end-winding part every year, at full load. Have a set of data analyzed by IRIS a year before the 2016 outage, to help evaluate whether a stator rewind is necessary or desirable.	2014	1
1296	8193	8194	8298	8304	3	U3 GENERATOR	GENERATOR	GENERATOR STATOR	Stator Winding	30	4	Perform annual 5 KV megger readings - the simplest and most basic indication of the insulation condition, and is often done annually, or every two years. A reading below 4 Gig-ohms is considered unsatisfactory for this insulation system.	2011	1

Table 10-6 Cont'd

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Unit	Asset 2/3	Asset 3/4	Description	Detail	Action #	App #	Action	Year	Priority
1296	8193	8194	8298	8304	3	U3 GENERATOR	GENERATOR	GENERATOR STATOR	Stator Winding	31	4	Perform Doble test in service. Care must be taken to compare only similar conditions, e.g. clean or dirty, and tests should be consistently in hydrogen (preferably not in air). Some users take Doble measurements every two years to obtain a better historical record, as an alternative to high voltage testing. The Doble test energizes all the coils in each phase up to rated phase voltage, and is considered a less harmful and less riskier test on old dirty or greasy insulation. It requires splitting the neutral connections more frequently, which increases the risk of a hot joint developing in these connections that can overheat and damage the bushings and the current transformers. It shows when accumulated dirt and grease from loose windings warrant bringing forward the next major inspection. An insulation power factor reading higher than 2.5 %, or a tip-up of more than 1%, after cleaning, would indicate the insulation is in very poor condition, and a rewind is required.	2016	1
1296	8193	8194	8298	8304	3	U3 GENERATOR	GENERATOR	GENERATOR STATOR	Stator Winding	32	4	Measure the wedge tightness during the 2016 inspection, to see how much looseness has developed.	2016	1
1296	8193	8194	8298	8304	3	U3 GENERATOR	GENERATOR	GENERATOR STATOR	Stator Winding	33	4	Carry out electrical tests on the windings in 2016, as in past years.	2016	1
1296	8193	8194	8298	8304	3	U3 GENERATOR	GENERATOR	GENERATOR STATOR	Stator Winding	34	4	Plan for stator rewind in 2020.	2016	1
1296	8193	8194	8298	8299	3	U3 GENERATOR	GENERATOR	GENERATOR ROTOR	Rotor Core	36	4	Stator core: Core loop test and thermal image of core for hot spots, before the stator is re-wound.	2016	1
1296	8193	8194	8298	8299	3	U3 GENERATOR	GENERATOR	GENERATOR ROTOR	Field Winding	37	4	Stator Winding: Obtain Doble test data and on-line partial discharge measurements.	2016	1
1296	8193	8194	8298	8304	3	U3 GENERATOR	GENERATOR	GENERATOR STATOR	Stator Core	38	4	Rotor Forging: A full NDE inspection of the high-stress areas of the forging and attachments.	2016	1
1296	8193	8194	8298	8304	3	U3 GENERATOR	GENERATOR	GENERATOR STATOR	Stator Winding	39	4	Field Winding: A detailed inspection of the field winding should be carried out, and a flux probe should be installed to check for shorted field turns.	2016	1
1296	8193	8194	8298	8313	3	U3 GENERATOR	GENERATOR	GEN.HYDROGEN GAS SYSTEM	Hydrogen	40	4	Install a hydrogen consumption "totalizer" in each hydrogen supply line, for recording daily and checked for leaks.	2011	1
1296	8193	8194	8298	8313	3	U3 GENERATOR	GENERATOR	GENERATOR SEAL OIL SYSTEM	N/A	41	4	No specific recommended actions, beyond normal major overhaul work.	2016	2
1296	8193	8194	8298	8313	3	U3 GENERATOR	GENERATOR	GENERATOR CO2 GAS PURGE	N/A	42	4	No specific recommended actions, beyond normal major overhaul work.	2016	2
1296	8193	8194	8298	8313	3	U3 GENERATOR	GENERATOR	GENERATOR COMPRESSED AIR	N/A	43	4	No specific recommended actions, beyond normal major overhaul work.	2016	2
1296	8193	8194	8298	8322	3	U3 GENERATOR	GENERATOR	GENERATOR HYDROGEN COOLING		44	4	Maintain hydrogen pressure steady at the rated value of 310 KPag to simplify differential pressure controller operation and help to ensure a constant and appropriate oil flow through the hydrogen seals, reducing the risk of a seal oil spill into the generator. Also reduces the risk of the sealant at the stator end shields cracking and permitting a hydrogen leak. It will also avoid a change in the bearing height, and alignment of the rotor, which can increase the bearing vibration levels.	2011	1
1296	8193	8194	8298	99039100	3	U3 GENERATOR	GENERATOR	PARTIAL DISCHARGE ANALYSIS	N/A	45	4	Repair and monitor results for generator condition analyses.	2010	1
1296	8193	8194	8312	0	3	U3 GENERATOR	GENERATOR EXCITATION SYSTEM	GENERATOR EXCITATION SYSTEM	N/A	46	4,6	Replace Unit 3 static exciter.	2012	1
1296	8193	8194	8312	271679	3	U3 GENERATOR	EXCITER	EXCITER	Static Exciter	47	4,6	Replace Unit 3 static exciter.	2012	1
1296	8193	8194	8312	271680	3	U3 GENERATOR	EXCITATION TRANSFORMER	EXCITATION TRANSFORMER	N/A	48	4,6	Replace Unit 3 static exciter rectifying transformer.	2012	1

10.1.1.7 Risk Assessment

The risk assessment associated with the Unit 3 generator, both from a technological perspective and a safety perspective, is illustrated below in Table 10-7.

TABLE 10-7 RISK ASSESSMENT – UNIT 3 GENERATOR

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Component	Risk Assess #	Appendix #	Major Issues	Remaining Life Years	Remaining Life Comments	TECHNO_ECO RISK ASSESS MODEL			SAFETY RISK ASSESS MODEL			Possible Failure Event	Mitigation
														(Insufficient Info - Inspection Required Within (x) Years)		Likeli-hood	Conse-quence	Risk Level	Likeli-hood	Conse-quence	Safety Risk		
1296	8193	8194	8298	0	0	3	U3 GENERATOR	GENERATOR	GENERATOR		13		See detail below.	10									
1296	8193	8194	8298	8299	0	3	U3 GENERATOR	GENERATOR	GENERATOR ROTOR	Rotor Forging and Field Windings	14	4	Electrical failure - EOL.	15	None	2	D	Medium	2	D	High	Loss of unit generator and SC capability. Potential life threatening.	Plan for a rotor rewind by 2020 subject to findings of 2016 detailed inspection/overhaul. Undertake techno-economic assessment of performing in 2016.
1296	8193	8194	8298	8299	0	3	U3 GENERATOR	GENERATOR	GENERATOR ROTOR	Rotor Forging and Field Windings	15	4	Mechanical failure retaining rings.	15	None	2	D	Medium	2	D	High	Loss of unit generator and SC capability. Potential life threatening.	Removal of the retaining rings and inspection in 2016.
1296	8193	8194	8298	8304	0	3	U3 GENERATOR	GENERATOR	GENERATOR STATOR	Stator Core and Frame	16	4	Electrical - sustained over-fluxing off–line (e.g. if the PT has one phase open or a blown fuse).	15	None	3	C	Medium	3	C	High	Loss of unit generator and SC capability. Potential serious injury situation.	Extra V/f protection is desirable if the generator is energized on AVR control, as core damage occurs faster, because it goes to ceiling excitation (typically 160% rated flux). It should be noted that this V/f protection may not be applicable if the generator is energized on manual control. The standard protection against over-fluxing is the volts/hertz relay. It is recommended that the V/f element of the new generator multi-functional relay be set up to provide back-up protection, especially during off-line conditions. Initial energization is the time of highest risk.
1296	8193	8194	8298	8304	0	3	U3 GENERATOR	GENERATOR	GENERATOR STATOR	Stator Core and Frame	17	4	Mechanical damage - Inspection related.	15	None	2	B	Low	2	B	Low	Damage is local.	Repair during outage.
1296	8193	8194	8298	8304	0	3	U3 GENERATOR	GENERATOR	GENERATOR STATOR	Stator Core and Frame	18	4	Mechanical - loose plates vibrating in the magnetic field then break off and damage the stator winding, more prevalent at the core ends.	(6/15)	None	3	C	Medium	3	B	Medium	Loose plates break off and damage the stator winding.	Check for signs of red iron oxide dust in the stator bore are the standard sign of loose iron, and can be confirmed by pushing a paint scraper between the plates. Loose areas can usually be treated with penetrating epoxy and re-tightened by driving tapered wedges into the loose packets of iron.
1296	8193	8194	8298	8304	0	3	U3 GENERATOR	GENERATOR	GENERATOR STATOR	Stator Core and Frame	19	4	Electrical - failures of the stator winding, and/or poor stator winding ground protection.	15	None	3	D	High	3	C	High	Damage to stator core.	2016 Inspection and repairs/stator rewind.
1296	8193	8194	8298	8304	0	3	U3 GENERATOR	GENERATOR	GENERATOR STATOR	Stator Core and Frame	20	4	Electrical - insulation/winding failure - most likely to occur during serious system over-voltage transients,	(6/15)	None	3	D	High	3	C	High	Stator winding failure - possible stator core effects. GE contention that the insulation is at high risk of failing and cannot be considered to be reliable.	Recommend rewinding the stator in 2020. Evaluate techno-economic risk of deferral at next overhaul in 2016 based on new data collected. The generator is currently relying upon the lightning and surge arrestors fitted at the generator terminals to attenuate the surges, or upon the statistical unlikelihood of the worst over-voltage
1296	8193	8194	8298	8304	0	3	U3 GENERATOR	GENERATOR	GENERATOR STATOR	Stator Windings	21	4	Mechanical/electrical - can open up the glued layers of insulation and lead to mechanical breakdown of the mica flakes, which have poor mechanical properties.	(6/15)	None	3	D	High	3	B	Medium	Stator winding failure - possible stator core effects. GE contention that the insulation is at high risk of failing and cannot be considered to be reliable.	Recommend rewinding the stator in 2020. Evaluate techno-economic risk of deferral at next overhaul in 2016 based on new data collected. Very important to control the mechanical stresses that can open up the glued layers of insulation and lead to mechanical breakdown of the mica flakes, especially if re-wedging required.
1296	8193	8194	8298	8304	0	3	U3 GENERATOR	GENERATOR	GENERATOR STATOR	Stator Windings	22	4	Mechanical/electrical - an increasing risk that the end-windings will loosen again after seven years of operation after 2003 rewedging. The line-end coils and phase leads are at most risk, of distortion, and could fail during a severe or a sustained system fault condition.	(6/15)	None	2	D	Medium	2	B	Low	The line-end coils and phase leads are at most risk of distortion and could fail during a severe or a sustained system fault condition.	Wedge tightening and/or re-wedging. Repair line-end coils and phase leads during overhaul. Stator rewind.
1296	8193	8194	8298	8313	0	3	U3 GENERATOR	GENERATOR	GEN.HYDROGEN GAS SYSTEM	Auxiliaries - Hydrogen System Pressure Control	23	4	Mechanical/electrical/fire.	3	None	3	C	Medium	3	D	High	Seal leak, hydrogen fire/expl - oil leaks into the stator if the flow rate is too high, and overheating and failure of the hydrogen seals if the flow rate is too low.	New hydrogen seals and totalizer.
1296	8193	8194	8298	8313	0	3	U3 GENERATOR	GENERATOR	GEN.HYDROGEN GAS SYSTEM	Auxiliaries - Hydrogen System - Purity meter and dryer	24		Electrical/fire.	3	None	1	C	Low	1	D	High	Hydrogen fire/explosion.	Recent replacement - monitor condition and maintain.
1296	8193	8194	8298	8313	8288	3	U3 GENERATOR	GENERATOR	GENERATOR SEAL OIL SYSTEM	N/A	25		Mechanical - loss, spill - hydrogen leak.	10	None	1	C	Low	2	C	Medium	Hydrogen fire/explosion.	Inspect and test per current maintenance program.
1296	8193	8194	8298	8313	8318	3	U3 GENERATOR	GENERATOR	GENERATOR CO2 GAS PURGE	N/A	26		Mechanical failure.	10	None	1	C	Low	2	C	Medium	Hydrogen fire/explosion.	Inspect and rest per current maintenance program.
1296	8193	8194	8298	8313	8321	3	U3 GENERATOR	GENERATOR	GENERATOR COMPRESSED AIR	N/A	27		Not addressed.	10	None								

Table 10-7 Cont'd

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Component	Risk Assess #	Appendix #	Major Issues	Remaining Life Years	Remaining Life Comments	TECHNO_ECO RISK ASSESS MODEL			SAFETY RISK ASSESS MODEL			Possible Failure Event	Mitigation
														(Insufficient Info - Inspection Required Within (x) Years)		Likeli-hood	Conse-quence	Risk Level	Likeli-hood	Conse-quence	Safety Risk		
1296	8193	8194	8298	8322	0	3	U3 GENERATOR	GENERATOR	GENERATOR HYDROGEN COOLING	Auxiliaries - Hydrogen Coolers	28	4	Electrical/fire.	10	None	1	C	Low	1	C	Medium	Hydrogen fire/explosion.	Monitor condition and maintain.
1296	8193	8194	8298	99039100	0	3	U3 GENERATOR	GENERATOR	PARTIAL DISCHARGE ANALYSIS	N/A	29		Measurement error.	0	None	4	D	High	4	A	Low	Missed generator problem.	Refurbish.
1296	8193	8194	8312	0	0	3	U3 GENERATOR	GENERATOR EXCITATION SYSTEM	GENERATOR EXCITATION SYSTEM	N/A	30		See detail below.		None								
1296	8193	8194	8312	271679	0	3	U3 GENERATOR	EXCITER	EXCITER	Static Exciter Controls	31	6	Electrical fault, mechanical fatigue, ctrls fault, ops error.	3	None	2	C	Medium	2	A	Low	Loss 1 unit generation. Damage to unit.	Replace in 2012.
1296	8193	8194	8312	271679	0	3	U3 GENERATOR	EXCITER	EXCITER	Static Exciter	32	6	Electrical fault, mechanical fatigue, ctrls fault, ops error.	3	None	2	C	Medium	2	B	Low	Loss 1 unit generation. Damage to unit.	Replace in 2012
1296	8193	8194	8312	271680	0	3	U3 GENERATOR	EXCITATION TRANSFORMER	EXCITATION TRANSFORMER	N/A	34		Electrical fault.	3	None	2	C	Medium	2	B	Low	Electrical fire, unit overspeed.	Replace in 2012
1296	8193	8194	8312	271681	0	3	U3 GENERATOR	FIELD BREAKER	FIELD BREAKER	N/A	36		Electrical fault.	10	None	2	C	Medium	2	B	Low	Electrical fire, unit overspeed.	Replace in 2012 with exciter
1296	8193	8194	8326	0	0	3	U3 GENERATOR	GENERATOR SYNCRONOUS COND	GENERATOR SYNCRONOUS COND	N/A	37		Electrical fault, mechanical failure/fatigue, ctrls fault, ops error.	10	None	2	C	Medium	2	C	Medium	Unit VARS loss, Generator overspeed.	Inspect and Test per current maintenance program

10.1.1.8 Life Cycle Curve and Remaining Life

Figures10-4 and 10-5 below illustrates the life cycle curve for the Unit 3 generator. It is broken into two parts – the generator and the exciter. Differences in the scenarios identified in Section 6 do not materially affect the curve. The curves are plots of current and projected operating hours (generation plus synchronous condensing mode) on the y-axis versus calendar year on the x-axis. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view.

The generator figure below shows the operating hours as an electricity generator, in synchronous condensing mode, as well as the sum of the two. Only one set of curves is required, given that the major elements of the generator (stator and rotor windings and core) and the hydrogen system are the same age. One vertical line illustrates the timing of the next generator overhaul in 2016. The lowest two horizontal lines represent the ranges of expected generator life (primarily the rotor winding) for Holyrood Unit 3 based on current and historical information and expert opinion. The “Early Rotor Rewind Unit 3 Recommended” line is based on an estimated minimum remaining reliable rotor winding life of seven years at current generation levels. The other two represent longer rotor winding lives that may be achievable with decreasing reliability and higher failure risk, as well as a maximum 20 years likely for the stator and rotor cores.

The “Rewind Unit 3 Recommended” line is based on the estimated remaining reliable rotor and stator winding life of five years at current generation levels. The other two represent longer lives that may be achievable with decreasing reliability and higher failure risk. The two upper lines also represent a longer assessment of the remaining life of the rotor winding and maximum 20 years likely for the stator and rotor cores. The same curves apply as no major changes in equipment have taken place to date.

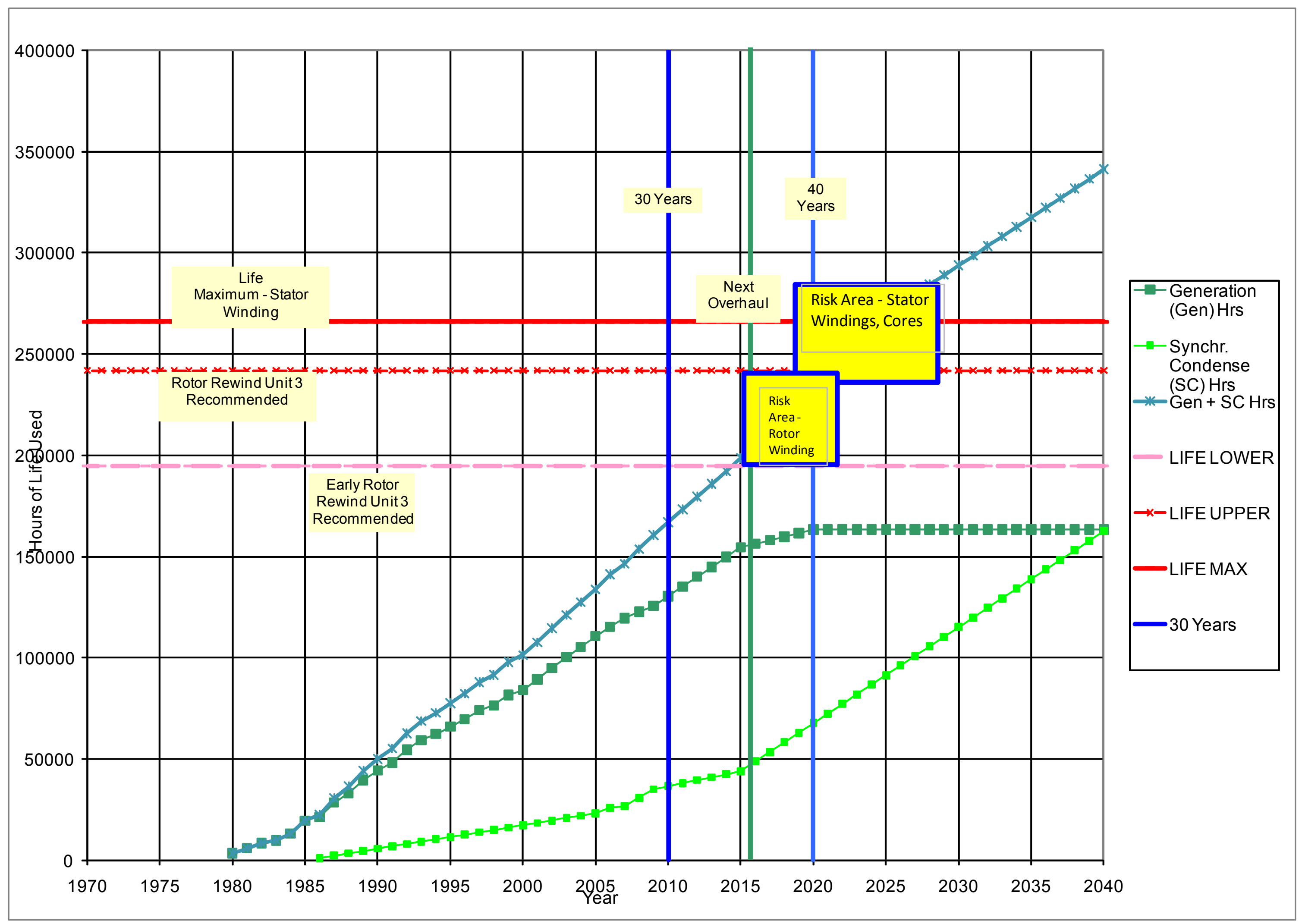

FIGURE 10-4 LIFE CYCLE CURVE – UNIT 3 GENERATOR

The exciter figure shows only the total operating hours as an electricity generator plus in synchronous condensing mode. It has one curve for the original equipment

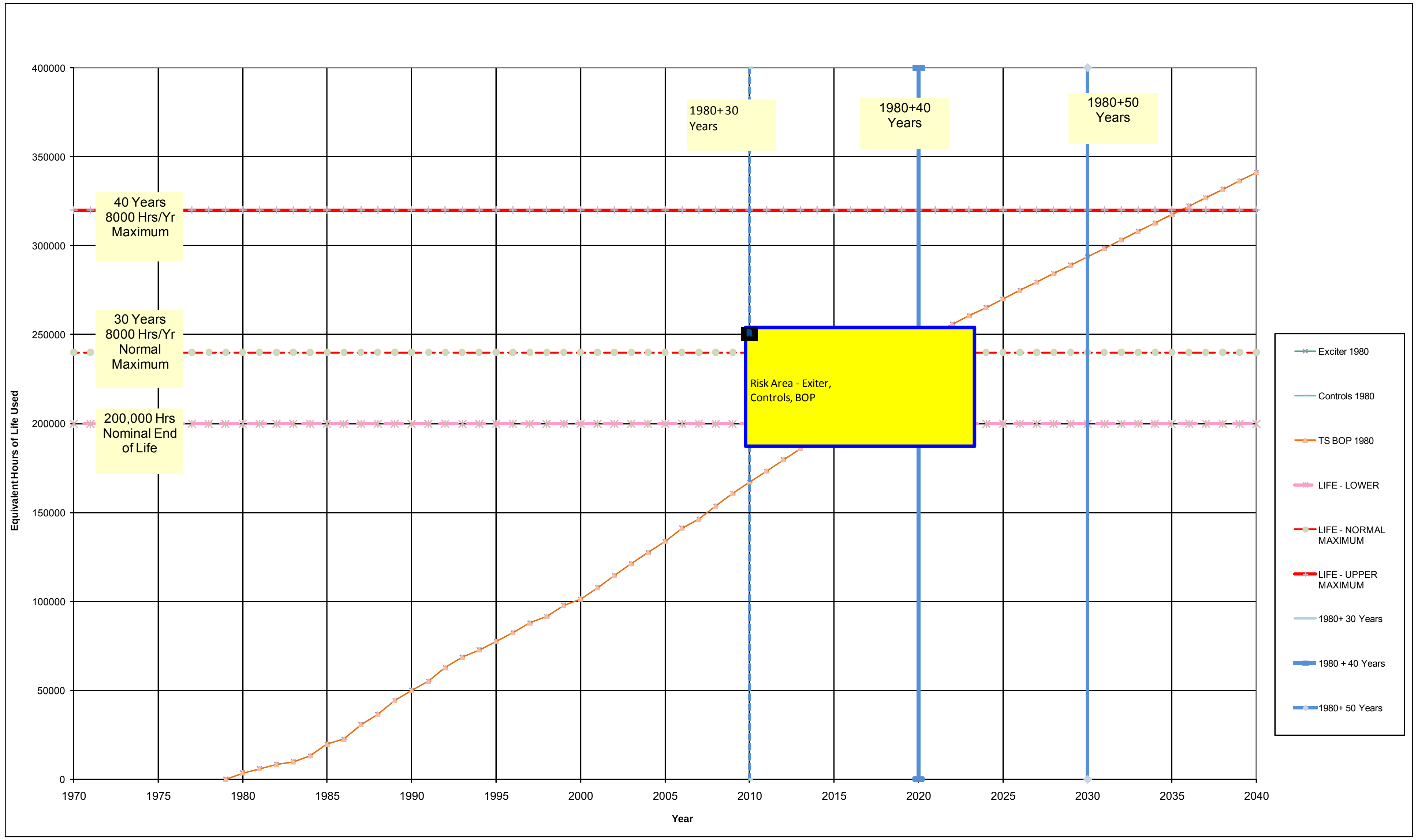

FIGURE 10-5 LIFE CYCLE CURVE – UNIT 3 GENERATOR - EXCITER

The curves indicate that the remaining life (RL) of the Unit 3 generator exceeds the desired life (DL) of 2016, which is the lesser of the time to its next major planned overhaul/inspection (2016) or to the desired End of Life (EOL) date of 2041. Thus no specific dedicated Level 2 is required, but sufficient inspection and testing will be required in the 2016 overhaul to assess key issues with the rotor windings, rotor core, and stator windings. The primary issue will be whether a rotor rewind is necessary in or about 2020. The remaining life (RL) of the Unit 3 generator exciter does not exceed the desired life (DL) and in fact has exceeded its normal expected life and should be replaced as soon as practical to meet the desired life of 2041.The highlighted near term risk areas include the rotor winding, exciter, the rectifying transformer, and BOP equipment. The curve also suggests that a nine year time between generator overhauls is impractical at this time in the generator's life and should be a six year cycle.

10.1.1.9 Level 2 Inspections – Unit 3 Generator

No Level 2 analyses are specifically required given their current condition and their ability to make their next major outage/overhauls. This is provided that the plant maintains their current maintenance and inspection programs and addresses the issues identified in the Issues and Actions list. The current overhaul interval was increased from 6 years to 9 years based on a recent (2005) assessment by the Holyrood insurance supplier. This 9 year interval between majors is considered excessive, given the age and condition of the generators. A return to a six or seven year interval is considered necessary.

TABLE 10-8 LEVEL 2 INSPECTIONS – UNIT 3 GENERATOR

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Sub System Comment	L2#	Appendix #	Level 2 Work	Year	Priority	Cost k$
1296	8193	8194	8298	0	0	3	U3 GENERATOR	GENERATOR	GENERATOR	None	9	4	Level 2 allowance for 2011 Pre-Major Outage Inspection work.	2011	1	$100
1296	8193	8194	8298	0	0	3	U3 GENERATOR	GENERATOR	GENERATOR	None	10	4	No Level 2 work required before the next inspection/overhaul. Work required to scope and be ready for the next planned inspection/overhaul includes: - Review generator drawings, contract information, and operating manual to clarify design details. Check whether enough technical details exist to "reverse engineer" a specification for a replacement stator winding or a replacement field winding from Contractors other than Hitachi and GE - Stator core: Core loop test and thermal image of core for hot spots, before the stator is re-wound. - Stator Winding: Obtain Doble test data and on-line partial discharge measurements.	2016	1	$2,081
1296	8193	8194	8298	8299	0	3	U3 GENERATOR	GENERATOR	GENERATOR ROTOR	None	11	4	No Level 2 required - include in generator overhaul.	2016		
1296	8193	8194	8298	8304	0	3	U3 GENERATOR	GENERATOR	GENERATOR STATOR	None	12	4	No Level 2 required - include in generator overhaul.	2016		
1296	8193	8194	8298	8313	0	3	U3 GENERATOR	GENERATOR	GEN.HYDROGEN GAS SYSTEM	None	13	4	No Level 2 required - include in generator overhaul.	2016		
1296	8193	8194	8298	8313	8288	3	U3 GENERATOR	GENERATOR	GENERATOR SEAL OIL SYSTEM	None	14	4	No Level 2 required - include in generator overhaul.	2016		
1296	8193	8194	8298	8313	8318	3	U3 GENERATOR	GENERATOR	GENERATOR CO2 GAS PURGE	None	15		No Level 2 required - include in generator overhaul.	2016		
1296	8193	8194	8298	8313	8321	3	U3 GENERATOR	GENERATOR	GENERATOR COMPRESSED AIR	None	16		No Level 2 required - include in generator overhaul.	2016		
1296	8193	8194	8298	8322	0	3	U3 GENERATOR	GENERATOR	GENERATOR HYDROGEN COOLING	None	17	4	No Level 2 required - include in generator overhaul.	2016		
1296	8193	8194	8298	99039100	0	3	U3 GENERATOR	GENERATOR	PARTIAL DISCHARGE ANALYSIS	None	18	4	No Level 2 required - include in generator overhaul.	2016		
1296	8193	8194	8312	0	0	3	U3 GENERATOR	GENERATOR EXCITATION SYSTEM	GENERATOR EXCITATION SYSTEM	None	19	4,6	No Level 2 required - include in generator overhaul.	2016		
1296	8193	8194	8312	271679	0	3	U3 GENERATOR	EXCITER	EXCITER	None	20	4,6	No Level 2 required - include in generator overhaul.	2016		
1296	8193	8194	8312	271680	0	3	U3 GENERATOR	EXCITATION TRANSFORMER	EXCITATION TRANSFORMER	None	21	4,5	No Level 2 required - include in generator overhaul.	2016		$0
1296	8193	8194	8312	271681	0	3	U3 GENERATOR	FIELD BREAKER	FIELD BREAKER	None	23	4,6	No Level 2 required - include in generator overhaul.	2016		
1296	8193	8194	8326	0	0	3	U3 GENERATOR	GENERATOR SYNCRONOUS COND	GENERATOR SYNCRONOUS COND	None	24	4,6	No Level 2 required - include in generator overhaul.	2016		

10.1.1.10 2011 Level 2 Inspection Requirements and Costs – Hydro Request

As part of the effort to optimize the requirements of the 2012, 2014, and 2016 Generator Outages, Hydro staff asked for an assessment of testing and inspections (Level 2) that could be performed in 2011 with the generator rotor in place. AMEC provided the following generic initial preliminary listing, with an allowance of $200,000 per unit. Given the major overhaul in 2016, AMEC recommends that those items that would assist in better preparing for the 2016 overhaul be undertaken and that an allowance of $100,000 per unit be set aside pending further detailed review.

The following are the tests that could be considered, with the scope adjusted as appropriate within the $100K/unit allowance suggested. It must be recognized that the list appears much more all-encompassing than it is. It is a generic checklist and will not and cannot address much of what needs to be addressed in the major outage in 2016 when the rotor is removed from the stator. There are several safety related issues that would have to be addressed when considering the scope.

INSPECTIONS

Inspections – External Components: The following external component items could be inspected:

- Frame footing and bolts – torque for tightness, damage (likely not an issue – no vibration issue);
- Generator foundation – free from cracks other structural damage; footing grouting cracking/spalling;
- Grounding cables – tightness, condition (corrosion, overheating, fraying, cracking), current flow (unexpected);
- Piping & connections – condition, grounding, gasket and o-ring conditions, tightness, oil-free;
- Generator end brackets (end doors) – seal damage, cleaning/replacement of seal material, hydrogen leaks (NDE surface penetrant if leaking);
- Bearing Insulation & pedestals – grounding and bearing insulation device condition; bearing and journal pitting, insulation carbon contamination, insulation resistance (>Million ohm range); and
- RTD, Thermocouple and Misc devices, Instrument Panel - hydrogen leak test, gaskets/O-ring check, wiring to external device – condition, operational check.

Inspection – Stator Internal Components: The following stator internal component items may be able to be inspected with the rotor in:

- Frame & support structure - compression bolts – greasing (oil/dust indicating loose bolts/core/nut lock device vibration), surge ring supports – cracking/looseness; fingerplates – cracked/bent fingers – likely very limited access; stator core – looseness, mechanical damage; stator windings – looseness, cracking, greasing.
- RTD and TC wiring and monitoring devices – visually inspect wiring to and from stator RTD and TC devices as possible – tightly secured. Damaged ones that are accessible may be replaced, others left for major overhaul/rewind. and
- Winding TC's – inspect and check for function.

Inspection – Stator Core: The following stator core items could be inspected with the Stator Core (Rotor In) to the Extent Possible

- Core back – partial through cooler openings;
- Core Compression plates – inspect at turbine end (difficult at generator end due to phase leads) for looseness and condition;

- Core End Flux Screens and Flux Shunts – overheating, insulation resistance and thermal and distortion damage; and
- Frame to Core Compression Bands – check through cooler openings. No stator casing underbelly inspection ports so unlikely to tighten if required – stator vibration does not appear to be an issue so likely unnecessary.

Inspection – Stator Windings: The following stator windings could be inspected with the Stator Core (Rotor In) to the Extent Possible. If the inner end shields can be moved out of way, up to about 50% of turbine end and 25% of the generator end (phase lead interference) can be checked.

- End winding blocking and roving – inspect condition of blocking, roving, ties – looseness, greasing, dryness, powder, abrasion, cracked painting, missing bits;
- Surge rings - inspect condition of blocking, roving, ties – looseness, greasing, dryness, powder, abrasion, cracked painting, missing bits;
- Surge ring insulation - inspect (mirrors) integrity of insulation, especially beneath ties;
- End winding support structures - inspect (mirrors/other) condition – looseness, loose parts, missing/loose bolts/nuts, cracked supports (solid insulation material), greasing bolts, cracked/loose welding; retighten carefully and if possible; check retightening system condition (if exists);
- Tape separation/Girth cracking – inspect for near ends;
- Insulation galling/necking beyond slot – inspect for lack of insulation or cracking/separation;
- Corona discharge: End windings – white or brownish powder on end bars, dark brown burn marks; and
- End Wedge Migration Out of Slot – inspection by eye or mirror (likely difficult to see (may not be applicable – locking mechanism).

Inspection – Phase Bus Connectors and Terminals: The following could be inspected with the Stator Core (Rotor In) to the Extent Possible. Access is very tight and may not be possible from a safety perspective. Lower part may be more accessible through bussing box.

- Phase Bus Circumferential Bus Insulation: fretting, greasing, cracking insulation/paint, cracks in connectors/support ties;
- Phase Bus Phase Droppers: greasing, cracking insulation;
- High Voltage Bushings: Cracks, oil leakage (if applicable), looseness, dirt, tracking residues, Vent clogging (if applicable);
- Stand-off Insulators: Cracks, oil leakage (if applicable), looseness, dirt, tracking residues;
- Bushing Well (If Applicable) Insulators & Hydrogen Sealant Condition: sealant condition, gasket condition; and
- Generator Current Transformers (CT's): visual if in bushing box (IPB less accessible) - cracks, leaking resin, discolouration.

Inspection - Hydrogen Coolers: The hydrogen coolers could be inspected with the Rotor, assuming the coolers can be readily removed, in to the Extent Practical

- Tube clogging: visual inspection and descale;
- Tube leaks: hydrogen sensors, water inside casing, pressure test; and
- Tube thinning: eddy current tests.

Inspection – Rotor: The following rotor item could be inspected with the Rotor in to the Extent Practical

- Rotor cleanliness: copper dust (dc field coils on turning gear), copper dust in vent holes in winding slot wedges (shorted turns/ground faults) – short turn testing; copper dust in rotor end winding – blocking, insulation; “megger” to check insulation resistance; inspect before and after cleaning;
- Fan Rings/Hubs: Cracks in shrink area – visual if possible, NDE if fans removed; cracks/snugness at fan blade attachment to hub – NDE as appropriate;
- Bearings & Journals: (if bearing dismantled) journals, Babbitt materials, oil-baffle labyrinth, oil-seal ring clearance, bearing clearance; used oil condition (including tiny rounded electrical pits); bearing insulation and grounding brush integrity;
- End Wedges (using boroscope): discoloration, electric pitting between wedges and slot; different wedges, wedges and retaining ring;
- C-Channel Subslot (if applicable): physical damage - boroscope examination through slot under retaining ring may be possible but very difficult;
- Collector Rings: condition, insulation condition, collector thickness/groove depth, spring condition;
- Shaft Voltage Discharge Brushes: visual inspection, monitor system (applicable?);
- Rotor Winding main Lead Hydrogen Sealing: Pressure test, visual not practical;
- Couplings and Coupling Bolts: chafing, fretting, thread condition;
- Bearing insulation: inspect grounding devices, insulation, electric pitting of Babbitt, insulation carbon dust, electrical testing – megger; and
- Hydrogen Seals: Requires hydrogen seals be dismantled. Seals: inspect Babbitt and steel shell, seal rings, seal housing, wipers, springs/pressure components, gaskets/O-rings, NDE – Liquid Penetrant inspection (LPI) for cracks, Ultrasonics (UT) for Babbitt bonding to shell, Insulation resistance – megger seal insulation to ground.

Inspection – Auxiliaries: The following systems could undergo inspections as part of overall generator program, but specific details to be developed:

- Lube oil system – pre-shutdown detailed system readings, tank condition/cleanliness, piping looseness defects, valve operation, oil coolers condition (possible leak test), filters, switches, gauges, pump bearings, monitoring instrumentation check, purifier/centrifuge check;
- Hydrogen Cooling System: general condition and functionality – dryers and control, bulk supply, controls and instruments, desiccant condition;
- Seal Oil System: general condition and functionality – coolers condition (possible leak test), filters, reservoirs condition/cleanliness, hydrogen detraining, piping looseness defects, switches, gauges, pump bearings, monitoring instrumentation check; and
- Exciters: Electrical and Mechanical systems.

TESTS

Test – Stator: The tests to be further evaluated for the Stator with the rotor in could include:

- Stator Winding Electrical Tests – dry, phase isolation
    - Insulation Resistance: Megger - ohmic resistance between conductors in each phase and ground (stator core) – gross insulation issues so that further hi-voltage testing can be carried out safely;
    - Polarization Index (PI) – Megger - change in IR in first minutes (IR minute 10/IR minute 1) = function of insulation condition, contamination, moisture;

- A Doble test can be done to measure the insulation power factor and tip-up of the stator winding, with the rotor in place. (all the stator coils are raised in steps, up to rated phase voltage, during this test, and each phase is energized separately);
- DC Hi Pot: high voltage to winding (each phase separately or all) – done in hydrogen
- Series Winding Resistance: ohmic resistance of copper in each phase – shorted windings, bad connections, wrong/open connections;
- Dielectric Absorption during DC voltage Application: measures aging of resin binder in ground wall insulation – time dependent current flow. Affected by voids in insulation;
- DC leakage or Ramped Voltage: leakage current versus applied voltage applied increasingly over time – warns of impending insulation breakdown; and
- Dissipation/Power Factor Tip-Up Testing: measures the void content of insulation, also other ionizing losses (PD or slot discharges).

Test – Rotor: The tests to be further evaluated for the rotor with the rotor in could include:

- Mechanical Testing
  - Rotor Vibration: typically on-line measurements, detailed testing (using on-line device connections – characterize magnitude, phase relation, frequency spectrum.
- Test – Rotor Electrical Testing
  - Rotor Winding Resistance Tests: Megger - ohmic resistance of total copper winding shorter turns, bad connections, wrong/open connections;
  - Insulation Resistance: Megger - ohmic resistance between conductors in each phase and ground (rotor forging) – gross insulation issues so that further hi-voltage testing can be carried out safely;
  - Polarization Index (PI) – Megger - change in IR in first minutes (IR minute 10/IR minute 1) = function of insulation condition, contamination, moisture;
  - Shorted turns Detection;
  - Off-Line Testing: winding impedance measurement during acceleration and deceleration for comparison with past tests (Low Voltage DC – Volt Drop Shorted Turn Test likely preferred otherwise);
  - Hydrogen Seals: NDE - Megger seal insulation;.
  - Bearings: Megger bearing insulation.

10.1.1.11 Capital Projects

The suggested typical capital enhancements for the Unit 3 generator include:

TABLE 10-9 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – UNIT 3 GENERATOR

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Detail	CAP#	Appendix #	Unit #	Capital Item	Date	Priority
1296	8193	8194	8298	0	0	3	U3 GENERATOR	GENERATOR	GENERATOR	N/A	13	4	3	Install a rotor flux probe near the turbine end of the stator bore when the rotor is removed in 2016.	2016	1
1296	8193	8194	8298	8299	0	3	U3 GENERATOR	GENERATOR	GENERATOR ROTOR	N/A	14	4	3	Plan for a rotor rewind by 2020 subject to findings of 2016 detailed inspection/overhaul. Undertake techno-economic assessment of performing in 2016.	2016	1
1296	8193	8194	8298	8304	0	3	U3 GENERATOR	GENERATOR	GENERATOR STATOR	N/A	15	4	3	Plan for stator rewinding in 2020, subject to findings of 2016 detailed inspection/overhaul. Undertake techno-economic assessment in 2016 with input from operational testing from 2011 onward.	2016	1
1296	8193	8194	8298	8313	0	3	U3 GENERATOR	GENERATOR	GEN.HYDROGEN GAS SYSTEM	N/A	16	4	3	Install a hydrogen consumption “totalizer” in each hydrogen supply line.	2011	1
1296	8193	8194	8298	8313	8288	3	U3 GENERATOR	GENERATOR	GENERATOR SEAL OIL SYSTEM	N/A	17	4	3	Provide electrical control (both “On” and “Off”) for the AC and DC seal oil pumps in parallel with the local controls in the Control Room.	2011	1
1296	8193	8194	8298	8313	8318	3	U3 GENERATOR	GENERATOR	GENERATOR CO2 GAS PURGE	N/A	18		3	No capital required.		
1296	8193	8194	8298	8313	8321	3	U3 GENERATOR	GENERATOR	GENERATOR COMPRESSED AIR	N/A	19		3	No capital required.		
1296	8193	8194	8298	8322	0	3	U3 GENERATOR	GENERATOR	GENERATOR HYDROGEN COOLING	N/A	20	4	3	No capital required.		
1296	8193	8194	8298	99039100	0	3	U3 GENERATOR	GENERATOR	PARTIAL DISCHARGE ANALYSIS	N/A	21	4	3	Repair/refurbish.	2011	1
1296	8193	8194	8312	0	0	3	U3 GENERATOR	GENERATOR EXCITATION SYSTEM	GENERATOR EXCITATION SYSTEM	N/A	22	4,6	3	Replace Unit 3 static exciter (also impact the Unit 3 rectifying transformer).	2012	1
1296	8193	8194	8312	271679	0	3	U3 GENERATOR	EXCITER	EXCITER	N/A	23	4,6	3	Replace Unit 3 static exciter (also impact the Unit 3 rectifying transformer).	2012	1
1296	8193	8194	8312	271680	0	3	U3 GENERATOR	EXCITATION TRANSFORMER	EXCITATION TRANSFORMER	N/A	24	4,5	3	Replace Unit 3 static exciter rectifying transformer.	2012	1
1296	8193	8194	8312	271681	0	3	U3 GENERATOR	FIELD BREAKER	FIELD BREAKER	N/A	26	4,6	3	No capital, subject to assessment of techno-economic need to replace with exciter.		
1296	8193	8194	8326	0	0	3	U3 GENERATOR	GENERATOR SYNCRONOUS COND	GENERATOR SYNCRONOUS COND	N/A	27	4	3	Modify synchronous condenser - thrust bearing.	2011	1

10.1.2 Asset 8270 – Unit 3 Generator Lube Oil System

(Detailed Technical Assessment in Working Papers, Appendix 9)

Unit #:	3
Asset Class #	BU 1296 - Assets Generations
SCI & System:	8194 #3 Turbine & Generator
Sub-Systems:	8270 #3 Turbine Oil Systems 8275 #3 Turbine Lubricating Oil 8294 #3 Jacking Oil Systems
Components:	8271 #3 Tank & Equip 8274 #3 Purification 8276 #3 Flushing Oil Pump 8277 #3 AC Pump South 8281 #3 DC Pump 8546 #3 Aux Oil pump 8285 #3 Jacking Oil pump

10.1.2.1 Description

The Unit 3 generator lube oil system consists of:

- One turbine lube oil tank with three oil pumps;
- Two 100% duty oil coolers;
- Two 100% duty oil filters;
- One jacking oil pump system located near the lube oil tank;
- One oil purifier; and
- One main oil turbine shaft driven pump located in the front standard of the steam turbine.

The lube oil tank has a capacity of 18000L (4754 US gallons) of lubricating oil.

Three pumps, two 100% duty lube oil coolers, associated oil piping and valves are located within the tank. The AC Motor driven “Aux Oil Pump” operates at a discharge pressure of 1210 kPa and supplies bearing oil and power oil (relay oil) to drive the Main Stop Valves, Control Valves, and Combined Reheat / Intercept valves along with other valves and components requiring high pressure oil when the unit is started up or shut down and the turbine speed is less than 3600 rpm. The AC “Flushing Oil Pump” is used when lubricating oil is needed and the unit is on turning gear, operating at 315kPa. The “DC Flushing Oil Pump" operates at a discharge pressure of 272 kPa and provides lubrication to the bearings as the backup to the AC Oil Pump and the AC Flushing Oil Pump if all AC power is lost to the unit.

The two 100% duty oil coolers supply 35-45^{o}C lubricating oil to the unit and have exposed cooling water heads that are isolatable and removable in order to clean the tubes as required.

Unit 3 has two 100% duty lube oil filters located on the ground floor elevation which are capable of handling the full lubricating oil flow. One oil purifier is separately connected to the lube oil tank through a piping arrangement that allows for the water that has accumulated due to steam leakage and condensation to be removed from the lubricating oil.

The jacking oil pumping system located next to turbine lube oil tank on the ground floor elevation uses a separate piping arrangement connected to the lube oil tank and operates at a discharge pressure of 15.5 MPa with a flow rate of 11 USGPM. Jacking oil is used prior to operating the turbine/generator on turning gear to lift the turbine/generator rotors off the bearing babbitt surfaces and before engaging the turbine/ generator turning gear. The jacking system oil remains in service until the turbine reaches 2000 rpm on start up and restarts on shutdown at approx 2200 rpm.

Unit 3 steam turbine generator, unlike Units 1 & 2, has an internal shaft driven oil pump in the front standard, which at 3600 rpm supplies lubricating oil to the bearings and power oil (relay oil) to drive the east and west main steam stop valves, the control valves and the east and west combined reheat intercept stop valves along with various other valves and components associated with the unit.

10.1.2.2 History

Manufactured/Delivered	1979
In-Service Date	Feb 1980
Generation Base Load End Date	Dec 2015
Generation Peak/Emerg Gen End Date	Dec 2020
Synchronous Condensing Start Date	1988
Synchronous Condensing End Date	Dec 2041
Next Major Overhaul/Inspection	2016

The thousands of hours associated with the analyses, and the number of starts per year are:

	Generation (Gen)	Synchronous Condensing (SC)
Hours Actual - Ops to Dec 2009	126	0
Hours - Ops to Gen End Date Dec 2015	170	1.5
Hours - Ops to Gen End Date Dec 2020	179	25
Hours – Ops to SC End Date Dec 2040	219	120
Starts Actual - Ops to Dec 2009	482	0
Starts - Ops to Gen End Date Dec 2015	554	5
Starts - Ops to Gen End Date Dec 2020	614	30
Starts – Ops to SC End Date Dec 2040	714	130

10.1.2.3 Inspection and Repair History

The system was examined extensively as part of a plant fire protection system evaluation. It is in good condition and, with regular maintenance and inspection during major generator inspections, is capable of meeting the requirements for the generator up to 2041.

10.1.2.4 Condition Assessment

The system has been in service since Unit 3 was placed in service in 1980. Although this system is critical to the operation of the steam turbine/generator and may cause the unit to be shut down for short periods, the only likely major issue creating a longer shutdown would be the major failure of the lubricating oil piping system which cannot be easily inspected because the supply piping resides inside of the oil return piping back to the oil tank. Externally, the tank appears to be in good condition. Internal inspection reports were not available. Any failures of the oil pumps or the oil purifier are easily repaired. This system should continue to operate reliably for the time frames required. If this unit is required to support synchronous condenser operation after the generation mode is discontinued, it will be required to be in operation continuously and should not present any major issue.

All components of the generator lube oil system are expected to be able to make their next inspection date. All are expected to require more rigorous evaluation at that time. Most will be able with maintenance and replacement to meet the generation end dates. None are expected to be able to make their 2041 synchronous condensing end date without a major refurbishment and replacement program.

TABLE 10-10 CONDITION ASSESSMENT – UNIT 3 GENERATOR LUBE OIL SYSTEM

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset Level 2	Asset Level 3	Description	Detail	Condition Summary ID#	Append #	Condition	EPRI Identifier	Original Life (Base Load) Ops Hrs (Yrs)	Current Expected Minimum Remaining Life Years (Subject to Test)	End of Life (EOL) Required	Next Regular Inspection	Next Planned Overhaul or Major Inspection	Capability to Reach Next Overhaul	Capability to Reach EOL	In Service
1296	8193	8194	271675	8270	0	3	U3 GENERATOR	TURBINE	TURBINE OIL SYSTEMS	N/A	43	18	See details below.	3a	(30)	10	2041	2013	2013	Yes	No	1980
1296	8193	8194	271675	8270	8275	3	U3 GENERATOR	TURBINE	TURBINE LUBE OIL SYSTEM	N/A	44	18	Lube oil system is in good condition. No NDE of piping was obtained and reviewed, but interviews indicated no issues. Failures of any of the oil pumps or the oil purifier are easily repaired.	3a	(30)	10	2041	2013	2013	Yes	No	1980
1296	8193	8194	271675	8270	8275	3	U3 GENERATOR	TURBINE	TURB LUBE OIL TANK & EQUIP	N/A	45	18	Lube oil tank appears to be in good condition. Internal inspection reports were not available.	4	(30)	10	2041	2013	2013	Yes	No	1980
1296	8193	8194	271675	8270	8275	3	U3 GENERATOR	TURBINE	TURB LUBE OIL PURIFICATION	N/A	46	18	Lube oil purification system is relatively new and in good condition.	3a	(30)	10	2041	2013	2013	Yes	No	1980
1296	8193	8194	271675	8270	8275	3	U3 GENERATOR	TURBINE	TURB AC FLUSHING OIL PUMP	N/A	47	18	Original equipment.	3a	(30)	10	2041	2013	2013	Yes	No	1980
1296	8193	8194	271675	8270	8275	3	U3 GENERATOR	TURBINE	TURB LUBE A.C OIL P/P SOUTH	N/A	48	18	Lube oil pumps in good condition based on interviews. Failures readily dealt with through backups and replacements as required.	3a	(30)	10	2041	2013	2013	Yes	No	1980
1296	8193	8194	271675	8270	8275	3	U3 GENERATOR	TURBINE	TURBINE LUBE D.C. PUMP	N/A	49	18	Lube oil pumps in good condition based on interviews. Failures readily dealt with through backups and replacements as required.	3a	(30)	10	2041	2013	2013	Yes	No	1980
1296	8193	8194	271675	8270	8275	3	U3 GENERATOR	TURBINE	TURBINE AUXILIARY OIL PUMP	N/A	50	18	Original equipment. No issues identified with system.	3a	(30)	10	2041	2013	2013	Yes	No	1980
1296	8193	8194	271675	8270	8294	3	U3 GENERATOR	TURBINE	TURBINE JACKING OIL SYSTEM	N/A	51	18	Original equipment. No issues identified with system.	3a	(30)	10	2041	2013	2013	Yes	No	1980
1296	8193	8194	271675	8270	8294	3	U3 GENERATOR	TURBINE	TURBINE JACKING OIL PUMP	N/A	52	18	Original equipment. No issues identified with system.	3a	(30)	10	2041	2013	2013	No	No	1980

Notes:

1. A "(bracketed)" value in the "Current Expected Remaining Life" column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation, including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as "(X/Y)" has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

2. The "Next Regular Inspection" column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The "Next Planned Overhaul or Major Inspection" column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a "Desired Life" stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or simply are not known to AMEC.

10.1.2.5 Actions

Based on the condition assessment, the following actions are recommended for the Unit 3 lube oil system.

10-11 RECOMMENDED ACTIONS – UNIT 3 GENERATOR LUBE OIL SYSTEM

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Unit	Asset 2/3	Asset 3/4	Description	Detail	Action #	App #	Action	Year	Priority
1296	8193	8194	271675	8270	3	U3 GENERATOR	TURBINE	TURBINE OIL SYSTEMS	N/A	76	18	See details below. Provide concrete curbing around each unit turbine lube oil tanks and seal oil tanks so as to collect any oil that leaks. Provide Isolation for generator requirements from turbine system requirements during synchronous generation operation		
1296	8193	8194	271675	8270	3	U3 GENERATOR	TURBINE	TURBINE LUBE OIL SYSTEM	N/A	77	18	Flush lube oil, seal oil and seal oil bypass lines prior to the seasonal restart of the unit every year.	2011	1
1296	8193	8194	271675	8270	3	U3 GENERATOR	TURBINE	TURBINE LUBE OIL TANK & EQUIP	N/A	78	9	Perform Level 2 inspections on oil storage tanks and internals.	2011	1
1296	8193	8194	271675	8270	3	U3 GENERATOR	TURBINE	TURBINE LUBE OIL PURIFICATION	N/A	79	9	No recommended action.		
1296	8193	8194	271675	8270	3	U3 GENERATOR	TURBINE	TURBINE AC FLUSHING OIL PUMP	N/A	80	9	Provide paralleled electrical control for the DC Flushing Oil Pump from the Control Room.	2011	1
1296	8193	8194	271675	8270	3	U3 GENERATOR	TURBINE	TURBINE LUBE A.C OIL P/P SOUTH	N/A	81	9	No recommended action.		
1296	8193	8194	271675	8270	3	U3 GENERATOR	TURBINE	TURBINE LUBE D.C. PUMP	N/A	82	9	No recommended action.		
1296	8193	8194	271675	8270	3	U3 GENERATOR	TURBINE	TURBINE AUXILIARY OIL PUMP	N/A	83	9	No recommended action.		
1296	8193	8194	271675	8270	3	U3 GENERATOR	TURBINE	TURBINE JACKING OIL SYSTEM	N/A	84	9	No recommended action.		
1296	8193	8194	271675	8270	3	U3 GENERATOR	TURBINE	TURBINE JACKING OIL PUMP	N/A	85	9	No recommended action.		

10.1.2.6 Risk Assessment

The risk assessment associated with the Unit 3 generator lube oil system, both from a technological perspective and a safety perspective, is illustrated below in Table 10-12.

TABLE 10-12 RISK ASSESSMENT – UNIT 3 GENERATOR LUBE OIL SYSTEM

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Component	Risk Assess #	Appendix #	Major Issues	Remaining Life Years	Remaining Life Comments	TECHNO_ECO RISK ASSESS MODEL			SAFETY RISK ASSESS MODEL			Possible Failure Event	Mitigation
														(Insufficient Info - Inspection Required Within (x) Years)		Likeli-hood	Conse-quence	Risk Level	Likeli-hood	Conse-quence	Safety Risk		
1296	8193	8194	271675	8270	0	3	U3 GENERATOR	TURBINE	TURBINE OIL SYSTEMS		55		See detail below.	10	None								
1296	8193	8194	271675	8270	8275	3	U3 GENERATOR	TURBINE	TURBINE LUBE OIL SYSTEM		56		See detail below.	10	None								
1296	8193	8194	271675	8270	8275	3	U3 GENERATOR	TURBINE	TURBINE LUBE OIL TANK & EQUIPMENT	Lube Oil Tanks	57	9	Corrosion, erosion.	10	None	1	A	Low	1	A	Low	Oil leak – containment overflow.	Inspect and maintain.
1296	8193	8194	271675	8270	8275	3	U3 GENERATOR	TURBINE	TURBINE LUBE OIL TANK & EQUIPMENT	Lube Oil Pumps & Motors	58	9	Mechanical and/or electrical failure.	10	None	1	A	Low	1	A	Low	Unit shutdown – multiple systems.	Inspect and maintain.
1296	8193	8194	271675	8270	8275	3	U3 GENERATOR	TURBINE	TURBINE LUBE OIL TANK & EQUIPMENT	Lube Oil Coolers	59	9	Mechanical failure/leaks.	10	None	1	A	Low	1	A	Low	Unit shutdown for repairs.	Maintain and inspect full-flow filter and by-pass to reduce the risk of bearing damage.
1296	8193	8194	271675	8270	8275	3	U3 GENERATOR	TURBINE	TURBINE LUBE OIL TANK & EQUIPMENT	Lube Oil Filters	60	9	Bearing failure.	10	None	1	A	Low	1	A	Low	Unit shutdown for repairs.	Inspect and maintain.
1296	8193	8194	271675	8270	8275	3	U3 GENERATOR	TURBINE	TURBINE LUBE OIL PURIFICATION	Lube Oil Filters	61	9	Mechanical and/or pluggage failure.	10	None	1	A	Low	1	A	Low	Water & particulate contamination.	Inspect and maintain.
1296	8193	8194	271675	8270	8275	3	U3 GENERATOR	TURBINE	TURBINE AC FLUSHING OIL PUMP	N/A	62	9	Mechanical electrical failure.	10	None	1	A	Low	1	A	Low	Unit shutdown – multiple systems.	Inspect and maintain.
1296	8193	8194	271675	8270	8275	3	U3 GENERATOR	TURBINE	TURBINE LUBE A.C OIL P/P SOUTH	N/A	63	9	Mechanical electrical failure.	10	None	1	A	Low	1	A	Low	Unit shutdown – multiple systems.	Inspect and maintain.
1296	8193	8194	271675	8270	8275	3	U3 GENERATOR	TURBINE	TURBINE LUBE D.C. PUMP	N/A	64	9	Mechanical electrical failure.	10	None	1	A	Low	1	A	Low	Unit shutdown – multiple systems.	Inspect and maintain.
1296	8193	8194	271675	8270	8275	3	U3 GENERATOR	TURBINE	TURBINE AUXILIARY OIL PUMP	N/A	65	9	Mechanical electrical failure.	10	None	1	A	Low	1	A	Low	Unit shutdown – multiple systems.	Inspect and maintain.
1296	8193	8194	271675	8270	8294	3	U3 GENERATOR	TURBINE	TURBINE JACKING OIL SYSTEM	N/A	66	9	Mechanical electrical failure.	10	None	1	A	Low	1	A	Low	Unit shutdown – multiple systems.	Inspect and maintain.
1296	8193	8194	271675	8270	8294	3	U3 GENERATOR	TURBINE	TURBINE JACKING OIL PUMP	N/A	67	9	Mechanical electrical failure.	10	None	1	A	Low	1	A	Low	Unit shutdown – multiple systems.	Inspect and maintain.

Notes: 1. The risk assessment for the lube oil pumps is based on the lube oil pump controls being added to the control room as per the recommendations of the 2009 Emergency Shutdown Procedure study.

10.1.2.7 Life Cycle Curve and Remaining Life

Figure 10-6 below illustrates the life cycle curve for the Unit 3 generator lube oil system. One curve is required, given that the major elements of the lube oil system are approximately the same age. There is insufficient information to develop specific accurate curves for the storage tank. Further detailed examination during the 2016 turbine overhaul should provide the basis going forward. The life curve is a plot of current and projected operating hours (generation plus synchronous condensing mode0 on the y-axis versus calendar year on the x-axis. Vertical lines represent bands of nominal years of normal base loaded life (typically 200,000 operating hours, thirty years and 200,000 to 240,000 operating hours, and forty years, and 280,000 to 320,000 operating hours). Horizontal lines represent the ranges of equipment life based on current and historical information and expert opinion. The risk area box provides an indication of the timing of potential issues either from an age or equivalent operating hours view.

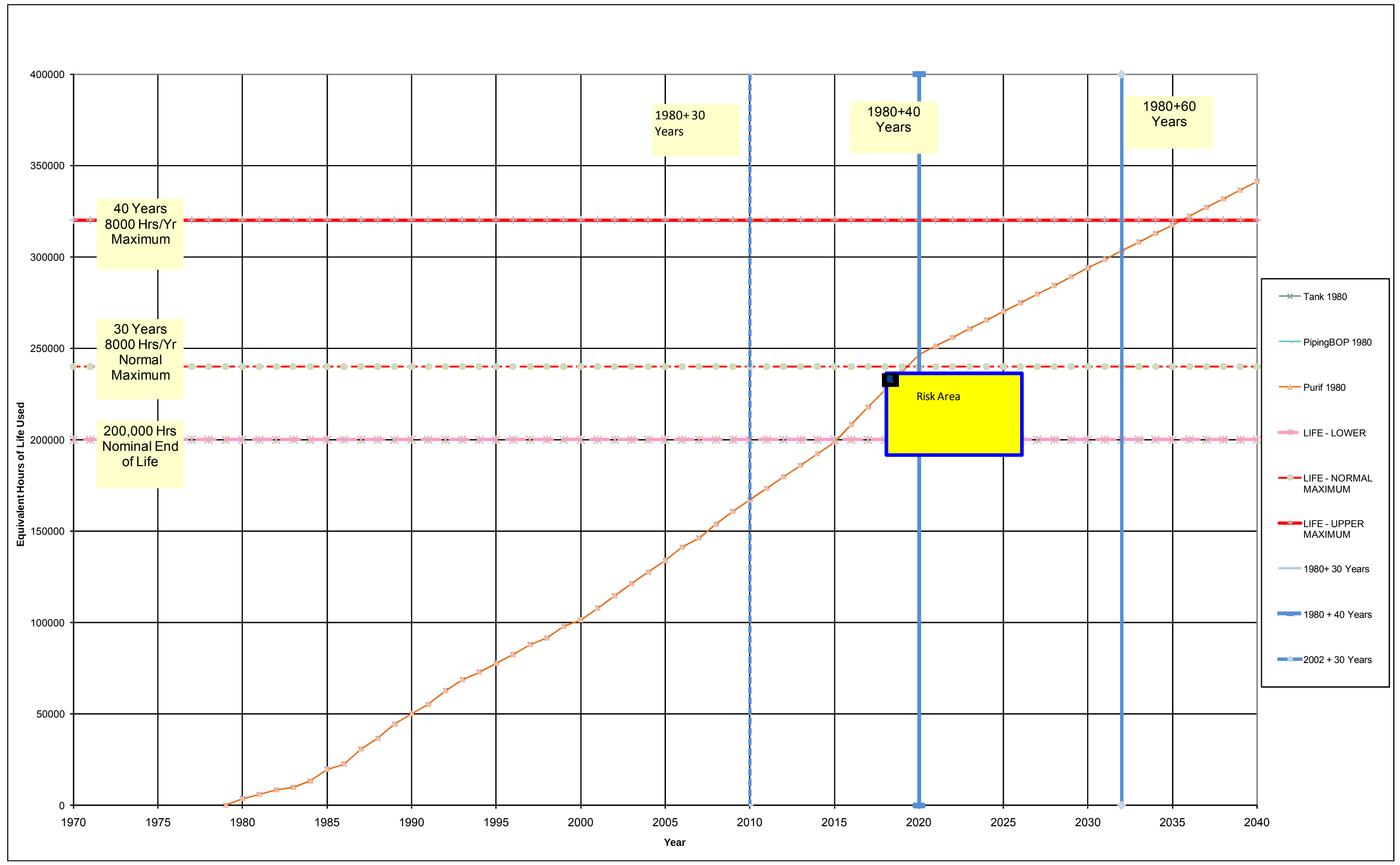

FIGURE 10-6 LIFE CYCLE CURVE – UNIT 3 GENERATOR LUBE OIL SYSTEM

The curves indicate that the remaining life (RL) of the Unit 3 generator lube oil system exceeds the desired life (DL) which is the lesser of the time to its next major planned overhaul/inspection (2016) or to the desired End of Life (EOL) date of 2041. Thus no specific dedicated Level 2 is required of the system as a whole, but sufficient inspection and testing will be required in 2013 steam turbine valve overhaul or the 2016 steam turbine generator overhaul to demonstrate the ability to meet the EOL date. The exception is the storage tank for which information was considered inadequate to form a firm conclusion and level 2 testing is recommended in 2011. The figure's highlighted risk areas is primarily operating hours driven and likely to shift further out in time after the 2016 turbine generator overhaul. The 2013 steam turbine valve overhaul and the 2016 overhaul/inspection are fundamental elements in changing the current assessment.

10.1.2.8 Level 2 Inspections – Unit 3 Generator Lube Oil System

Given the condition historical data reviewed, a Level 2 analysis of the lube oil storage tank is recommended. No other Level 2 analyses is required, provided the current inspection and maintenance program for the system is maintained and a more detailed inspection is performed at the turbine overhaul.

TABLE 10-13 LEVEL 2 INSPECTIONS – UNIT 3 GENERATOR LUBE OIL SYSTEM

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Sub System Comment	L2#	Appendix #	Level 2 Work	Year	Priority	Cost k$
1296	8193	8194	271675	8270	0	3	U3 GENERATOR	TURBINE	TURBINE OIL SYSTEMS	None	42	9	No Level 2 required - include in steam turbine overhaul.	2013		
1296	8193	8194	271675	8270	8275	3	U3 GENERATOR	TURBINE	TURBINE LUBE OIL SYSTEM	None	43	9	No Level 2 required - include in steam turbine overhaul.	2013		
1296	8193	8194	271675	8270	8275	3	U3 GENERATOR	TURBINE	TURB LUBE OIL TANK & EQUIP	None	44	9	No Level 2 required - include in steam turbine overhaul.	2011	2	$6
1296	8193	8194	271675	8270	8275	3	U3 GENERATOR	TURBINE	TURB LUBE OIL PURIFICATION	None	45	9	No Level 2 required - include in steam turbine overhaul.	2013		
1296	8193	8194	271675	8270	8275	3	U3 GENERATOR	TURBINE	TURB AC FLUSHING OIL PUMP	None	46	9	No Level 2 required - include in steam turbine overhaul.	2013		
1296	8193	8194	271675	8270	8275	3	U3 GENERATOR	TURBINE	TURB LUBE A.C OIL P/P SOUTH	None	47	9	No Level 2 required - include in steam turbine overhaul.	2013		
1296	8193	8194	271675	8270	8275	3	U3 GENERATOR	TURBINE	TURBINE LUBE D.C. PUMP	None	48	9	No Level 2 required - include in steam turbine overhaul.	2013		
1296	8193	8194	271675	8270	8275	3	U3 GENERATOR	TURBINE	TURBINE AUXILIARY OIL PUMP	None	49	9	No Level 2 required - include in steam turbine overhaul.	2013		
1296	8193	8194	271675	8270	8294	3	U3 GENERATOR	TURBINE	TURBINE JACKING OIL SYSTEM	None	50	9	No Level 2 required - include in steam turbine overhaul.	2013		
1296	8193	8194	271675	8270	8294	3	U3 GENERATOR	TURBINE	TURBINE JACKING OIL PUMP	None	51	9	No Level 2 required - include in steam turbine overhaul.	2013		

10.1.2.9 Capital Projects

The suggested typical capital enhancements include:

TABLE 10-14 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – UNIT 3 GENERATOR LUBE OIL SYSTEM

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Detail	CAP#	Appendix #	Unit #	Capital Item	Date	Priority
1296	8193	8194	271675	8270	0	3	U3 GENERATOR	TURBINE	TURBINE OIL SYSTEMS	N/A	44	9	3	Provide concrete curbing around each unit turbine lube oil tanks and seal oil tanks so as to collect any oil that leaks. Provide Isolation for generator requirements from turbine system requirements during synchronous generation operation.	2012	1
1296	8193	8194	271675	8270	8275	3	U3 GENERATOR	TURBINE	TURBINE LUBE OIL SYSTEM	N/A	45	9	3	Replace turbine lube oil conditioners.	2013	1
1296	8193	8194	271675	8270	8275	3	U3 GENERATOR	TURBINE	TURBINE LUBE OIL TANK & EQUIP	N/A	46	9	3	No capital required.		
1296	8193	8194	271675	8270	8275	3	U3 GENERATOR	TURBINE	TURBINE LUBE OIL PURIFICATION	N/A	47	9	3	No capital required.		
1296	8193	8194	271675	8270	8275	3	U3 GENERATOR	TURBINE	TURBINE AC FLUSHING OIL PUMP	N/A	48	9	3	Provide paralleled electrical control for the DC Flushing Oil Pump from the Control Room.	2011	1
1296	8193	8194	271675	8270	8275	3	U3 GENERATOR	TURBINE	TURBINE LUBE A.C OIL P/P SOUTH	N/A	49	9	3	No capital required.		
1296	8193	8194	271675	8270	8275	3	U3 GENERATOR	TURBINE	TURBINE LUBE D.C. PUMP	N/A	50	9	3	No capital required.		
1296	8193	8194	271675	8270	8275	3	U3 GENERATOR	TURBINE	TURBINE AUXILIARY OIL PUMP	N/A	51	9	3	No capital required.		
1296	8193	8194	271675	8270	8294	3	U3 GENERATOR	TURBINE	TURBINE JACKING OIL SYSTEM	N/A	52	9	3	No capital required.		
1296	8193	8194	271675	8270	8294	3	U3 GENERATOR	TURBINE	TURBINE JACKING OIL PUMP	N/A	53	9	3	No capital required.		

10.1.3 Asset 8712 – Unit 3 Electrical and Control System Associated with Generators

(Detailed Technical Assessment in Working Papers, Appendix 6)

The requirements for the Electrical and Control Systems associated with the Unit 3 generator are as follows:

Unit #:	3
Asset Class #	BU 1296 - Assets Generation
SCI & System:	8317 #3 Electrical Systems & Control
Sub-Systems:	8317 #3 Electrical Systems & Control
Components:	8698 #3 Relay Room Protection & Control 8704 #3 Main Controls 8713 #3 Generator Bus-duct and Connections 8750 #3 Battery Chargers 8751 #3 UPS3 Inverter 8757 #3 UPS4 Inverter 8763 #3 Battery Banks 271766 #3 Switchgear 4160V/600V. 271767 #3 Turbine Supervisory System 301711 #3 DCS 271769 #3 Static Exciter **COMMON SYSTEMS** 271764 Common, Control Cables 271765 Common, Control Cables 309896 Common 600V Metric Plugs

10.1.3.1 Description

Asset 8698, Unit 3 Relay Room Protection and Control

Generator G3 Transformer T3, ST3/ST4 and Auxiliaries P & C: Manufactured by Canadian General Electric, and installed in 1979.

Generator G3 and Transformer T3 Protection Panels: These panels utilize GE electro-mechanical relays and blocking switches. In addition, they show lockouts, annunciation and indications.

Unit Transformer T3 and Unit #3 Protection Panel: This panel utilizes GE electro-mechanical relays and blocking switches. In addition, they show lockouts, annunciation and indications.

Unit 3 Metering Panel: This panel contains G3, T3 UST3 MWH meters and stator ground fault protection that was added in 2008. (Schweitzer SEL 300G multi-function relay and AREVA MML G01 test plugs.)

Transformer ST3/ST4 Protection Panel: This panel utilizes GE electro-mechanical relays and blocking switches. In addition, they show lockouts, annunciation, and indications.

Two Blank Panels: One panel shows L47-1 Combiflex control relays.

The rear of the panels shows the original ASEA Combiflex relays and Agastat timers.

Asset 8704 Unit 3 Main Controls

The original Unit 3 main controls were console mounted and utilized, typically GE SBM type switches, incandescent indications, analog instruments and Panalarm annunciation. Modifications were made to adapt the generator, turbine and boiler controls to the Distributed Control System (DCS) and to replace some of the original controls, indications and annunciation.

G1, MW, Amps, MVAR's, kV, Field Volts, Speed Load Position, Load Limit position and Balance, are shown on the original analog instruments above the console, and are also indicated on the screens via the DCS.

Unit 3 valve and motor controls repeat relaying and transducers are situated in ASEA cabinets behind the control room. The system includes ASEA Combiflex relays and bases. The ASEA cabinets are in a hazardous state, with cabling so congested that it renders the doors in the vertical sections of the cabinet unable to be closed. Should connections or conductors require moving or tracing, catastrophic results may occur taking Unit 3 out of service for an indeterminate period of time.

Asset 8713 Unit 3 Generator Bus-duct and Connections

The generator bus-duct is a 3 phase isolated phase bus complete with PT's and a neutral cubicle manufactured by Westinghouse and installed in 1979.

Asset 8750 Unit 3 Battery Chargers

Unit 3, 129VDC Battery Charger 1, manufactured by CTS Canada, was installed in 1978. Charger 1 is a type 6732B 1978, 600V input, 129VDC system, with a 125A maximum rated charger output.

Unit 3, 258VDC Battery Charger 2, manufactured by CIGENTEC, Inc., was installed in 2001. Charger 2 is a type C3-250-250PMF3BHRGCU0DS2X6, 600V input, 258VDC system, with a 250A maximum rated charger output.

Other Information:

Unit 3, 258VDC distribution panel was manufactured by Westinghouse and installed in 1979 complete with breakers, typically FPE type GADC.

Asset 8751 Unit 3 UPS3 Inverter

The Inverter is a 9315 Series, and was manufactured by Eaton Powerware and installed in 2001. Battery manufactured by C&D Technologies, Inc. (UPS Dynasty batteries). 600V input (transformer 600V:480V into Inverter), 120/208V output, 30kVA rated power, 93Ah @ 20 hour rate to 1.75V per cell @ 77 °F (25 °C).

Other Information: 120/208V, 3 phase Distribution Panel-boards fed from UPS3 Inverter, via Distribution Splitter are as follows:

- Unit 3 UPS Panel No.3 in Unit 3 exciter room, fed via 125A fused disconnect, Cutler-Hammer, Type PL1, 3 phase, 4W, 225A, 42 circuit; and
- Unit 3 WDPF Panel, DP-3 relay room, fed via 125A fused disconnect, Cutler-Hammer, Type PL1, 3 phase, 4W, 225A, 42 circuit.

Asset 8757 Unit 3 UPS4 Inverter

The Inverter is a 9315 Series, and was manufactured by Eaton Powerware and installed in 2001. Battery manufactured by C&D Technologies, Inc. (UPS Dynasty batteries), 600V input (transformer 600V:480V into Inverter), 120/208V output, 30kVA rated power, 93Ah @ 20 hour rate to 1.75V per cell @ 77 °F (25 °C).

Other Information: 120/208V, 3 phase Distribution Panel-boards fed from UPS4 inverter, via Distribution Splitter are as follows:

- Unit 3 UPS Panel No.4 in Unit 3 exciter room, fed via 125A fused disconnect, Cutler-Hammer, Type PL1, 3 phase, 4W, 225A, 42 circuit; and
- Unit 3 WDPF Panel, DP-4 relay room, fed via 125A fused disconnect, Cutler-hammer, Type PL1, 3 phase, 4W, 225A, 42 circuit.

Asset 8763 Unit 3 Battery Banks

Unit 3 129VDC Battery Bank was manufactured by C&D Technologies, Inc. and installed in 1996. Battery Bank is a Model KCR-11 and is Flooded, Lead-calcium.

Unit 3 258VDC Battery Bank was manufactured by C&D Technologies, Inc. and installed in 1996. Battery Bank is a Model KCR-11 and is Flooded, Lead-calcium.

Asset 271766 Unit 3 Switchgear, 4160V/600V

Unit Board UB3 and Station Board SB34, (4160V) were manufactured by FPE and installed in 1980.

The 4160V switchgear, utilizes original draw-out ITE type 5HK power breakers. Protection, synch, and control relays are original CGE electro-mechanical. All feeders have Schweitzer.

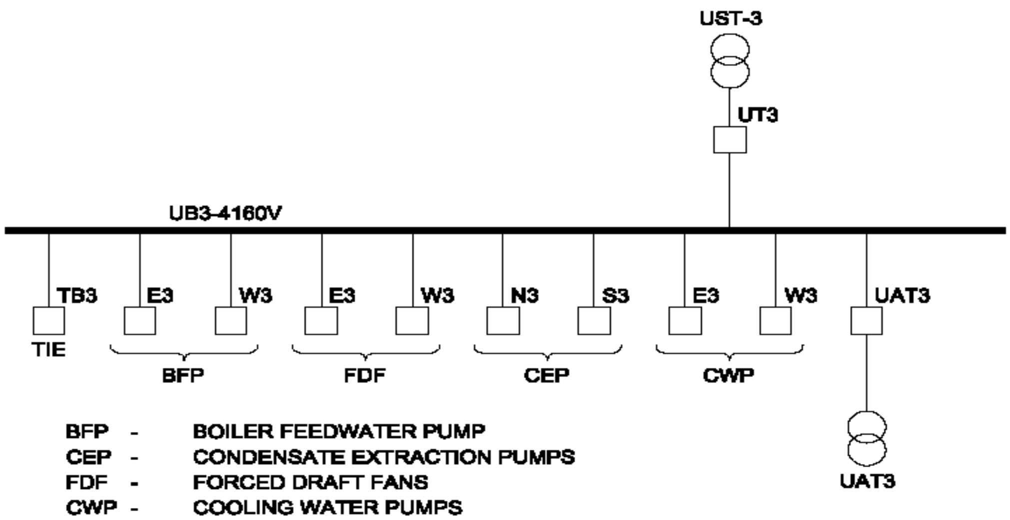

FIGURE 10-7 UB3 SWITCHGEAR

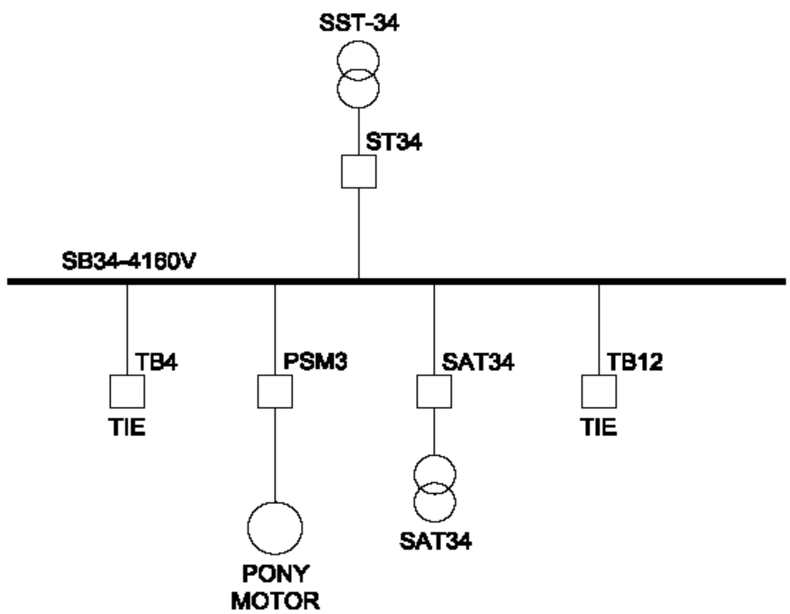

FIGURE 10-8 SB34 SWITCHGEAR

Unit Aux. Board UAB3 and Station Aux. Board SAB34 (600V) were manufactured by ITE and installed in 1980. The switchboards are complete with FPE 50H-2 incoming, tie and feeder breakers. All protection, synch, and control relays are original CGE electro-mechanical.

Unit Auxiliary Transformers, UAT3 and SAT34, were manufactured by FPE, and were installed in 1980. Both transformers are 1500/2000kVA, 4160:600/347V, ANAF, complete with tap-changer, +2@2.5%, Dy1, Z1=12%.

Asset 271767 Unit 3 Turbine Supervisory System

The Turbine Supervisory System was manufactured by Bently Nevada and installed in 1994. It is a type 3300 System, complete with TDXnet Transient Data Interface and Delta Manager.

Functionality of the Bently Nevada system has been transferred to the GE Speedtronic Mark V Turbine Governor System. There is a link to the DCS. Data acquisition is still part of the Bently Nevad system, and is transferred via a DDX link in the plant instrument shop. Machine protection is provided by the Mark V using information from the Bently Nevada, and is part of the Unit 3 mechanical protection, with the exception of the turbine vibration differential protection tripping, which is provided by the Bently Nevada system.

Asset 301711 Unit 3 DCS

The DCS, manufactured by Foxboro, is an Invensys system and was installed in 2004.

The Westinghouse panels housing the DCS were installed in the late 1990's, and new cabling was installed at that time. Original system was hard-wired, but was later updated to a Westinghouse system. Westinghouse could not support the system and it was then updated to Foxboro in 2004.

The process CPU → ZCP is set-up in the original enclosures, (Westinghouse Migration Cards). All I/O is tied-in to these for analog and digital functions.

The following system and programs being used are:

- IA series – Version 8.4.2
- IACC, Version 2.3.1 (Configuration Program)
- FoxView Version 10.2. Sept. 30, 2008 (Graphics Program)

Reference Foxboro Drawing D545390-SA-001 for system configuration.

Asset 271769 Unit 3 Static Exciter

Unit 3 Exciter is a Westinghouse system commissioned in 1979. Information, including drawings and bills of material are dated around 1978 and its technology is at least 20-30 years old.

10.1.3.2 History

Manufactured/Delivered	1979
In-Service Date	Feb 1980
Replaced (DCS)	2002-2003
Generation Base Load End Date	Dec 2015
Generation Peak/Emerg Gen End Date	Dec 2020
Synchronous Condensing Start Date	1988
Synchronous Condensing End Date	Dec 2041
Next Major Overhaul/Inspection	2016

10.1.3.3 Inspection and Repair History

Inspections and refurbishments are done on an ongoing basis and identified in Section 10.1.2.1 Description and in 10.1.2.3 Condition Assessment.

10.1.3.4 Condition Assessment

Where a system is fully or partially required for synchronous condensing, it is included here. The basic DCS, protections, alarms associated with generators and auxiliaries are in good shape, but will over the next fifteen years need to be re-examined about every five years or so. The areas of most concern are the exciter and relay cabinets which have been identified by the plant as an area in need of upgrade. Some auxiliary systems such as hydrogen monitoring and generator temperature monitoring need replacement or refurbishment. The condition assessment for the various systems is presented in the following table.

TABLE 10-15 CONDITION ASSESSMENT – UNIT 3 ELECTRICAL AND CONTROL SYSTEM ASSOCIATED WITH GENERATORS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset Level 2	Asset Level 3	Description	Detail	Condition Summary ID#	Append #	Condition	EPRI Identifier	Original Life (Base Load) Ops Hrs (Yrs)	Current Expected Minimum Remaining Life Years (Subject to Test)	End of Life (EOL) Required	Next Regular Inspection	Next Planned Overhaul or Major Inspection	Capability to Reach Next Overhaul	Capability to Reach EOL	In Service
1296	8193	8712	8698	0	0	3	ELECTRICAL SYSTEM & CONTROL	RELAY RM PROTECTION&CONTROL	RELAY RM PROTECTION&CONTROL	N/A	159	6	Generator & Transformer & Auxiliary Protection and Metering Panels tests were satisfactory (2007). Some ingress of dust and foreign material. Testing is on a 6 year cycle (2013, 2017, 2025, etc.).	10	(30)	10+	2041	2013		Yes	No	1980
1296	8193	8712	271766	0	0	3	ELECTRICAL SYSTEM & CONTROL	SWITCHGEAR 4160 & 600 VOLT	SWITCHGEAR 4160 & 600 VOLT	N/A	160	6	Installed in 1980. Protection, synch, and control relays are original electro-mechanical. Feeders Motor Protection Relays installed in 2009. All overhauled in 2007-2009 OK except corrective actions on CWW3 Jan, 2010. (status 80). and UAT-3 breaker, no date but status 90. Transformers UAT3 and SAT34 in 2007 showed reasonable tolerances. All 600V switchgear is applied within their ratings.	10	(30)	10	2041	2007		Yes	No	1980
1296	8193	8712	8704	0	0	3	ELECTRICAL SYSTEM & CONTROL	MAIN CONTROLS	MAIN CONTROLS	N/A	161	6	Generator, turbine and boiler controls linked to the DCS with some original controls, indications and annunciations replaced. ASEA cabinets behind control room in hazardous state, with cabling so congested as to render the doors in the vertical sections unable to be closed. Potential for major failure and unit out of service for an indeterminate time.	4	(30)	2	2041			Yes	No	1980/2007
1296	8193	8712	301711	0	0	3	ELECTRICAL SYSTEM & CONTROL	DISTRIBUTED CONTROL SYSTEM (DCS)	DCS	N/A	162	6	Installed in 2004 - state of the art.	3a	(20)	20	2041			Yes	Yes	1980/2004
1296	8193	8712	8713	0	0	3	ELECTRICAL SYSTEM & CONTROL	GENERATOR BUS DUCT & CONN'S	GENERATOR BUS DUCT & CONN'S	N/A	163	6	No recorded maintenance inspections have been carried out since installation. Generator oil leak evident from duct.	4	200000 (30)	(10)	2041		2016	No	No	1980
1296	8193	8712	8715	0	0	3	ELECTRICAL SYSTEM & CONTROL	GEN. TRANSFORMER & AUX	GEN. TRANSFORMER & AUX	N/A	164	6	Good condition.	4	(30)	10	2041			No	No	1980
1296	8193	8712	8716	0	0	3	ELECTRICAL SYSTEM & CONTROL	UNIT SERVICE POWER SYSTEM	UNIT SERVICE POWER SYSTEM	N/A	165	6	See details below.	3a	(25)	10	2041			Yes	No	1980
1296	8193	8712	8716	8717	0	3	ELECTRICAL SYSTEM & CONTROL	UNIT SERVICE POWER SYSTEM	UNIT BOARD UB-3	N/A	166	6	Tests in 2007 are satisfactory. Some ingress of dust and foreign material.	3a	(30)	10	2041	2013		Yes	No	1980
1296	8193	8712	8716	8718	0	3	ELECTRICAL SYSTEM & CONTROL	UNIT SERVICE POWER SYSTEM	UNIT AUX. BOARD UAB-3	N/A	167	6	Acceptable condition.	3a	(30)	10	2041			Yes	No	1980
1296	8193	8712	8716	8722	0	3	ELECTRICAL SYSTEM & CONTROL	UNIT SERVICE POWER SYSTEM	TURBINE AREA MCC TAB-34	N/A	168	6	Acceptable condition.	3a	(25)	10	2020			Yes	Yes	1980
1296	8193	8712	8716	8724	0	3	ELECTRICAL SYSTEM & CONTROL	UNIT SERVICE POWER SYSTEM	BOILER AREA BAB-3	N/A	169	6	Acceptable condition.	3a	(25)	10	2020			Yes	Yes	1980
1296	8193	8712	8750	0	0	3	ELECTRICAL SYSTEM & CONTROL	BATTERY CHARGERS	BATTERY CHARGERS	129 VDC	170	6	Installed in 1978. Last equipment check 04 Feb. 2010.	3a	(25)	10	2041	2010		No	No	1980
1296	8193	8712	8751	0	0	3	ELECTRICAL SYSTEM & CONTROL	UPS 3 INVERTER	UPS 3 INVERTER	N/A	171	6	Installed in 2001. Last maintenance performed 04 Feb. 2010. Lightly loaded at 7kW. Panels and breakers are in good conditions, and if monitored, in a PM program, should provide service until 2041.	3a	(20)	10+	2041	2010		Yes	No	2001
1296	8193	8712	8757	0	0	3	ELECTRICAL SYSTEM & CONTROL	UPS 4 INVERTER	UPS 4 INVERTER	N/A	172	6	Installed in 2001. Last maintenance performed 04 Feb. 2010. Lightly loaded at 4kW. Panels and breakers are in good conditions, and if monitored, in a PM program, should provide service until 2041.	3a	(20)	10+	2041	2010		Yes	No	2001
1296	8193	8712	8763	0	0	3	ELECTRICAL SYSTEM & CONTROL	BATTERY BANKS	BATTERY BANKS	129 VDC	173	6	Installed in 1996. Replacement date 2021. Last equipment maintenance check was 04 Feb. 2010.	3a	(25)	10	2041	2010		Yes	No	1996
1296	8193	8712	8763	0	0	3	ELECTRICAL SYSTEM & CONTROL	BATTERY BANKS	BATTERY BANKS	258 VDC	174	6	Installed in 1996. Replacement date 2021. Last equipment maintenance check was 04 Feb. 2010.	3a	(25)	10	2041	2010		Yes	No	1996
1296	8193	8712	8763	99038706	0	3	ELECTRICAL SYSTEM & CONTROL	BATTERY BANKS	BATTERY CHARGER	258 VDC	175	6	Installed in 2001. Last equipment check 04 Feb. 2010.	3a	(20)	10	2041	2010		Yes	No	2001
1296	8193	8712	271763	0	0	3	ELECTRICAL SYSTEM & CONTROL	CABLE RACEWAYS	CABLE RACEWAYS	N/A	176	6	Normal inspections and PM every 10 years have not been done since 1995. Some contamination of trays in the boiler areas due to asbestos and heavy metal-dust. Some cables, power and control, are “thrown” into trays that have been convenient in the routings associated with the new installations.	3a	(50)	(30)	2041			Yes	No	1980
1296	8193	8712	271764	0	0	3	ELECTRICAL SYSTEM & CONTROL	CONTROL CABLES	CONTROL CABLES	N/A	177	6	No recent testing.	4	(50)	(20)	2041			No	No	1980
1296	8193	8712	271765	0	0	3	ELECTRICAL SYSTEM & CONTROL	POWER CABLES	POWER CABLES	N/A	178	6	No recent testing.	4	(50)	(20)	2041			No	No	1980

Notes:

1. A “(bracketed)” value in the “Current Expected Remaining Life” column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation, including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as “(X/Y)” has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

2. The “Next Regular Inspection” column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The “Next Planned Overhaul or Major Inspection” column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a “Desired Life” stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or simply are not known to AMEC.

10.1.3.5 Actions – Unit 3 Electrical and Control System Associated with Generators

Where a system is fully or partially required for synchronous condensing, it is included here. Based on the condition assessment, the following actions are recommended for the Unit 3 electrical and control system associated with generators:

TABLE 10-16 RECOMMENDED ACTIONS – UNIT 3 ELECTRICAL AND CONTROL SYSTEM ASSOCIATED WITH GENERATORS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Unit	Asset 2/3	Asset 3/4	Description	Detail	Action #	App #	Action	Year	Priority
1296	8193	8712	0	0	3	ELECTRICAL SYSTEM & CONTROL	ELECTRICAL SYSTEM & CONTROL	ELECTRICAL SYSTEM & CONTROL	N/A	231	6	See details below.	2011	2
1296	8193	8712	8698	0	3	ELECTRICAL SYSTEM & CONTROL	RELAY RM PROTECTION&CONTROL	RELAY RM PROTECTION&CONTROL	N/A	232	6	Test Generator G3, Transformer T3 and Auxiliaries P&C Panels - next tests planned for 2011, 2017, 2023, etc.	2011	1
1296	8193	8712	8698	0	3	ELECTRICAL SYSTEM & CONTROL	RELAY RM PROTECTION&CONTROL	RELAY RM PROTECTION&CONTROL	N/A	233	6	Relay Room Protection & Control includes: Unit 3 Generator; Transformer, ST3/ST4 and Auxiliaries P & C; Generator and Transformer Protection Panels; Unit Transformer T3 and Unit #3 Protection Panel; Unit 3 Metering Panel; Transformer ST3/ST4 protection panel; and Two Blank Panels - Conduct a modernization study - refurbishing the old GE electro-magnetic relays versus multi-function relaying for periods to 2015, to 2020 then to 2041. Extend scope of existing Schweitzer SEL 300G from present ground fault monitoring to include all unit protection. Assess similar multi-function relay for back-up protection and consider for control, indication and annunciation functions an ABB Combiflex system.	2011	2
1296	8193	8712	271766	0	3	ELECTRICAL SYSTEM & CONTROL	SWITCHGEAR 4160 & 600 VOLT	SWITCHGEAR 4160 & 600 VOLT	N/A	234	6	Include this Switchgear, 4160V/600V relaying in SB2 modernization study (5.3.2.28 IV) for the protection relays.	2014	1
1296	8193	8712	271766	0	3	ELECTRICAL SYSTEM & CONTROL	SWITCHGEAR 4160 & 600 VOLT	SWITCHGEAR 4160 & 600 VOLT	N/A	235	6	Overhaul all 4160V switchgear breakers. Consider with the availability of spare breaker elements a program to overhaul UB3 breakers BFPE3, BFPW3, FDFE3, FDFW3, CEPN3, CEPS3, CWPE3, CWPW3, off site if necessary, with essentially no interruption to plant requirements recognizing that these will be in standby mode from 2015-2020 and as of 2020 will become “spare” but in good condition.	2013	1
1296	8193	8712	271766	0	3	ELECTRICAL SYSTEM & CONTROL	SWITCHGEAR 4160 & 600 VOLT	SWITCHGEAR 4160 & 600 VOLT	N/A	236	6	Replace existing UB3 breakers UT3, UAT3, TB3 and SB34 during the complete overhaul with Eaton Electrical VR-Series breakers for a life expectancy to at least 2041. Consideration should be given to the Eaton Electrical Remote racking device (RPR2), which allows remote racking of a breaker from up to 50 ft away, and is programmable for other types of breaker that might be used.	2013	1
1296	8193	8712	271766	0	3	ELECTRICAL SYSTEM & CONTROL	SWITCHGEAR 4160 & 600 VOLT	SWITCHGEAR 4160 & 600 VOLT	N/A	237	6	Note: When the 4160V CWP pumps are taken out of service, cooling water needs will be taken up by new 600V pumps. It should also be considered to offset the upgrade of the Boiler Feed pumps to VFD’s. See overhauling of breakers BFE3 and BFW3 above.	2013	1
1296	8193	8712	271766	0	3	ELECTRICAL SYSTEM & CONTROL	SWITCHGEAR 4160 & 600 VOLT	SWITCHGEAR 4160 & 600 VOLT	N/A	238	6	Upgrade Unit Aux. Board UAB3 and Station Aux. Board SAB34, (600V), manufactured by ITE and installed in 1980. The switchboards are c/w FPE 50H-2 Incoming, Tie and Feeder Breakers. All protection, synch, and control relays are original CGE electro-mechanical.	2012	1
1296	8193	8712	8704	0	3	ELECTRICAL SYSTEM & CONTROL	MAIN CONTROLS	MAIN CONTROLS	N/A	239	6	Carry out the NLH capital budget item to “Upgrade Unit 3 Relay Panels” in 2011, to provide a safe system and discard the existing cabinets and their contents, and redirect the existing field cables to the DCS system for Unit 3. Investigations will need to be conducted at site, and discussions held with Foxboro to determine if the present DCS physical size can accommodate the changes, or if it will need to be extended.	2011	2
1296	8193	8712	301711	0	3	ELECTRICAL SYSTEM & CONTROL	DISTRIBUTED CONTROL SYSTEM (DCS)	DCS	N/A	240	6	Maintain DCS system current through existing Foxboro replacement service agreement.	2014	1
1296	8193	8712	8713	0	3	ELECTRICAL SYSTEM & CONTROL	GENERATOR BUS DUCT & CONN'S	GENERATOR BUS DUCT & CONN'S	N/A	241	6	Conduct tests on the generator bus-duct, using the Holyrood Bus-Duct PM Inspection sheet extended to also record the low resistance tests, as outlined below, and to show comments on the condition of sectional gaskets, sectional grounding straps and condition of all grounding points. tests are as follows: Low Resistance Test : Measure the resistance of bolted connections using a low-resistance ohmmeter (Ductor). Compare resistance readings between similar bolted connections. There must not be any difference greater than 50% between resistance readings. Check the resistance values are below the manufacturer’s recommended maximum value. Insulation Resistance Test: Measure the phase-to-phase and phase-to-ground insulation resistance, which must be at least 100Mohm per 1000 ft. of bus-duct.	2011	2
1296	8193	8712	8713	0	3	ELECTRICAL SYSTEM & CONTROL	GENERATOR BUS DUCT & CONN'S	GENERATOR BUS DUCT & CONN'S	N/A	242	6	Conduct generator bus-duct inspection tests using Holyrood Bus-Duct PM Inspection sheet extended to also record the low resistance tests and comments on the condition of sectional gaskets, sectional grounding straps and condition of all grounding points. Tests are as follows: Low Resistance Test : Measure the resistance of bolted connections using a low-resistance ohmmeter (Ductor). Compare resistance readings between similar bolted connections. There must not be any difference greater than 50% between resistance readings. Check the resistance values are below the manufacturer’s recommended maximum value. Insulation Resistance Test: Measure the phase-to-phase and phase-to-ground insulation resistance, which must be at least 100Mohm per 1000 ft. of bus-duct.	2011	2

Table 10-16 Cont'd

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Unit	Asset 2/3	Asset 3/4	Description	Detail	Action #	App #	Action	Year	Priority
1296	8193	8712	8715	0	3	ELECTRICAL SYSTEM & CONTROL	GEN. TRANSFORMER & AUX	GEN. TRANSFORMER & AUX	N/A	245	6	No recommended actions.		
1296	8193	8712	8716	0	3	ELECTRICAL SYSTEM & CONTROL	UNIT SERVICE POWER SYSTEM	UNIT SERVICE POWER SYSTEM	N/A	246	6	No recommended actions.		
1296	8193	8712	8716	8717	3	ELECTRICAL SYSTEM & CONTROL	UNIT SERVICE POWER SYSTEM	UNIT BOARD UB-3	N/A	247	6	No recommended actions.		
1296	8193	8712	8716	8718	3	ELECTRICAL SYSTEM & CONTROL	UNIT SERVICE POWER SYSTEM	UNIT AUX. BOARD UAB-3	N/A	248	6	No recommended actions.		
1296	8193	8712	8716	8722	3	ELECTRICAL SYSTEM & CONTROL	UNIT SERVICE POWER SYSTEM	TURBINE AREA MCC TAB-34	N/A	249	6	Refurbish selective MCC elements.	2012	2
1296	8193	8712	8716	8724	3	ELECTRICAL SYSTEM & CONTROL	UNIT SERVICE POWER SYSTEM	BOILER AREA BAB-3	N/A	250	6	Monitor condition and refurbish as required from spares.	2012	2
1296	8193	8712	8750	0	3	ELECTRICAL SYSTEM & CONTROL	BATTERY CHARGERS	BATTERY CHARGERS	N/A	251	6	Replace Unit 3, 129VDC Battery Charger 1.	2012	2
1296	8193	8712	8750	0	3	ELECTRICAL SYSTEM & CONTROL	BATTERY CHARGERS	BATTERY CHARGERS	N/A	252	6	Replace Unit 3, 129VDC Battery Charger 2.	2012	2
1296	8193	8712	8750	0	3	ELECTRICAL SYSTEM & CONTROL	BATTERY CHARGERS	BATTERY CHARGERS	N/A	253	6	Replace Unit 3, 258VDC Distribution Panel and breakers.	2012	2
1296	8193	8712	8751	0	3	ELECTRICAL SYSTEM & CONTROL	UPS 3 INVERTER	UPS 3 INVERTER	N/A	254	6	No specific actions required.		
1296	8193	8712	8751	0	3	ELECTRICAL SYSTEM & CONTROL	UPS 3 INVERTER	UPS 3 INVERTER	N/A	255	6	Optimize in conjunction with UPS1, UPS2 and UPS4 the possible replacement of the units with two parallel units for requirement for inverters from 2020 to 2041.	2012	2
1296	8193	8712	8757	0	3	ELECTRICAL SYSTEM & CONTROL	UPS 4 INVERTER	UPS 4 INVERTER	N/A	256	6	No specific actions required.		
1296	8193	8712	8757	0	3	ELECTRICAL SYSTEM & CONTROL	UPS 4 INVERTER	UPS 4 INVERTER	N/A	257	6	Optimize in conjunction with UPS1, UPS2 and UPS4 the possible replacement of the units with two parallel units for requirement for inverters from 2020 to 2041.	2012	2
1296	8193	8712	8763	0	3	ELECTRICAL SYSTEM & CONTROL	BATTERY BANKS	BATTERY BANKS	N/A	258	6	No action is required.		
1296	8193	8712	8763	99038706	3	ELECTRICAL SYSTEM & CONTROL	BATTERY BANKS	BATTERY CHARGER	N/A	259	6	No action is required.		
1296	8193	8712	271763	0	3	ELECTRICAL SYSTEM & CONTROL	CABLE RACEWAYS	CABLE RACEWAYS	N/A	260	6	Clean raceways, trays and cables to be tested by a crew of specialized hazardous area cleaners before any inspections or tests are carried out.	2011	3
1296	8193	8712	271764	0	3	ELECTRICAL SYSTEM & CONTROL	CONTROL CABLES	CONTROL CABLES	N/A	261	6	Test selected control cables selected based on how the distribution will be affected post SC conversion, especially if the cables are required to be re-run. Low Resistance Test: Measure the resistance of bolted connections using a low-resistance ohmmeter (Ductor). Compare resistance readings between similar bolted connections. There must not be any difference greater than 50% between resistance readings. Check the resistance values are below the manufacturer's recommended maximum value.	2011	3
1296	8193	8712	271765	0	3	ELECTRICAL SYSTEM & CONTROL	POWER CABLES	POWER CABLES	N/A	262	6	Test selected power cables - 4160V, 600V cables selected based on how the distribution will be affected post SC conversion, especially if the cables are required to be re-run. Low Resistance Test: Measure the resistance of bolted connections using a low-resistance ohmmeter (Ductor). Compare resistance readings between similar bolted connections. There must not be any difference greater than 50% between resistance readings. Check the resistance values are below the manufacturer's recommended maximum value. Insulation Resistance Test: Apply a test voltage of 5kV for cable used for 4160V, 1000V for cable rated at 600V, and 500V for cable rated at 300V. Record phase-to-phase and phase-to-ground insulation resistance tests, which must be at least 100Mohm per 1000 ft. of cable.	2011	3

10.1.3.6 Risk Assessment

Where a system is fully or partially required for synchronous condensing, it is included here. The risk assessment associated with the Unit 3 electrical and control system associated with generators, both from a technological perspective and a safety perspective, is illustrated below in Table 10-17.

TABLE 10-17 RISK ASSESSMENT – UNIT 3 ELECTRICAL AND CONTROL SYSTEM ASSOCIATED WITH GENERATORS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Component	Risk Assess #	Appendix #	Major Issues	Remaining Life Years	Remaining Life Comments	TECHNO_ECO RISK ASSESS MODEL			SAFETY RISK ASSESS MODEL			Possible Failure Event	Mitigation
														(Insufficient Info - Inspection Required Within (x) Years)		Likeli-hood	Conse-quence	Risk Level	Likeli-hood	Conse-quence	Safety Risk		
1296	8193	8712	0	0	0	3	ELECTRICAL SYSTEM & CONTROL	ELECTRICAL SYSTEM & CONTROL	ELECTRICAL SYSTEM & CONTROL	N/A	200		See detail below.										
1296	8193	8712	8698	0	0	3	ELECTRICAL SYSTEM & CONTROL	RELAY RM PROTECTION&CONTROL	RELAY RM PROTECTION&CONTROL	N/A	201	6	Electrical fault, mechanical fault, ops error.	5+	None	2	C-D	Medium	2	C-D	Medium	Loss 1 unit generation, damage to unit or equipment.	Current inspection and maintain.
1296	8193	8712	271766	0	0	3	ELECTRICAL SYSTEM & CONTROL	SWITCHGEAR 4160 & 600 VOLT	SWITCHGEAR 4160 & 600 VOLT	N/A	202	6	Electrical fault, mechanical fatigue, ops error.	(5)	None	3	B-C	Medium	3	B-C	Medium	Loss up to 1 unit generation. Damage to equipment.	Refurbish or replace.
1296	8193	8712	8704	0	0	3	ELECTRICAL SYSTEM & CONTROL	MAIN CONTROLS	MAIN CONTROLS	N/A	203	6	Electrical fault, mechanical fatigue, ops error.	2	None	1	C	Low	1	C	Low	Loss 1 unit generation, damage to unit.	Current inspection and maintain.
1296	8193	8712	301711	0	0	3	ELECTRICAL SYSTEM & CONTROL	DISTRIBUTED CONTROL SYSTEM (DCS)	DCS	N/A	204	6	Electrical fault, ops error.	20	None	1	C	Low	1	C	Low	Loss 1 unit generation. Damage to unit.	Maintain.
1296	8193	8712	8713	0	0	3	ELECTRICAL SYSTEM & CONTROL	GENERATOR BUS DUCT & CONN'S	GENERATOR BUS DUCT & CONN'S	N/A	205	6	Electrical fault.	(10)	None	3	C-D	Medium/ High	3	C-D	High	Loss 1 unit generation, damage to unit.	Current inspection and maintain.
1296	8193	8712	8715	0	0	3	ELECTRICAL SYSTEM & CONTROL	GEN. TRANSFORMER & AUX	GEN. TRANSFORMER & AUX	N/A	206		Regulatory PCB.	3	2013 PCB Reg likely.	3	C	Medium	2	B	Low	Oil spill/PCB contamination.	Replace per regulations when required.
1296	8193	8712	8716	0	0	3	ELECTRICAL SYSTEM & CONTROL	UNIT SERVICE POWER SYSTEM	UNIT SERVICE POWER SYSTEM	N/A	207		Electrical fault, mechanical fatigue, controls fault, ops error.	20	None	1	C	Medium	2	B	Low	Loss 1 unit generation. Damage to unit.	Inspect and test per current maintenance program.
1296	8193	8712	8716	8717	0	3	ELECTRICAL SYSTEM & CONTROL	UNIT SERVICE POWER SYSTEM	UNIT BOARD UB-3	N/A	208		See details below.	5	None	3	B	Medium	3	B	Medium	Loss of part of 1 unit generation. Damage to equipment.	Refurbish or replace.
1296	8193	8712	8716	8718	0	3	ELECTRICAL SYSTEM & CONTROL	UNIT SERVICE POWER SYSTEM	UNIT AUX. BOARD UAB-3	N/A	209		Electrical fault, mechanical fatigue, ops error.	10	None	3	B	Medium	3	B	Medium	Loss of part of 1 unit generation. Damage to equipment.	Refurbish or replace.
1296	8193	8712	8716	8722	0	3	ELECTRICAL SYSTEM & CONTROL	UNIT SERVICE POWER SYSTEM	TURBINE AREA MCC TAB-34	N/A	210		Not addressed in detail - electrical failure.	5	None	3	B	M	3	A	Low	Loss of part of 1 unit generation. Damage to equipment.	Refurbish or replace.
1296	8193	8712	8716	8724	0	3	ELECTRICAL SYSTEM & CONTROL	UNIT SERVICE POWER SYSTEM	BOILER AREA BAB-3	N/A	211		Mechanical/electrical failure.	5	None	3	B	M	4	A	Low	Loss of part of 1 unit generation. Damage to equipment.	Refurbish or replace.
1296	8193	8712	8750	0	0	3	ELECTRICAL SYSTEM & CONTROL	BATTERY CHARGERS	BATTERY CHARGERS	N/A	214	6	Electrical or chemical fault.	10	None	3,1	B-C	Medium, Low	1	B	Low	Unit damage on fail to safe shutdown.	Refurbish or replace.
1296	8193	8712	8751	0	0	3	ELECTRICAL SYSTEM & CONTROL	UPS 3 INVERTER	UPS 3 INVERTER	N/A	215	6	Electrical fault.	10+	None	3,1	B	Medium, Low	1	B	Low	Unit damage on fail to safe shutdown.	Refurbish or replace.
1296	8193	8712	8757	0	0	3	ELECTRICAL SYSTEM & CONTROL	UPS 4 INVERTER	UPS 4 INVERTER	N/A	216	6	Electrical fault.	10+	None	3,1	B	Medium, Low	1	B	Low	Unit damage on fail to safe shutdown.	Refurbish or replace.
1296	8193	8712	8763	0	0	3	ELECTRICAL SYSTEM & CONTROL	BATTERY BANKS	BATTERY BANKS	N/A	217		Electrical failure.	10	None	1	B	Low	1	C	Low	Regular test and maintenance.	
1296	8193	8712	8763	99038706	0	3	ELECTRICAL SYSTEM & CONTROL	BATTERY BANKS	BATTERY CHARGER	N/A	218		Electrical failure.	10	None	1	B	Low	1	C	Low	Regular test and maintenance.	
1296	8193	8712	271763	0	0	3	ELECTRICAL SYSTEM & CONTROL	CABLE RACEWAYS	CABLE RACEWAYS	N/A	219		Electrical short.	(30)	None	1	C	Low	1	C	Low	PM inspections.	
1296	8193	8712	271764	0	0	3	ELECTRICAL SYSTEM & CONTROL	CONTROL CABLES	CONTROL CABLES	N/A	220	6	Electrical fault.	(20)	None	2	B-C	Low	2	B-C	Low	Loss of up to 1 unit generation. Equipment/unit damage.	Test indicative number.
1296	8193	8712	271765	0	0	3	ELECTRICAL SYSTEM & CONTROL	POWER CABLES	POWER CABLES	N/A	221	6	Electrical fault.	(20)	None	2	B-C	Low	2	B-C	Low	Loss of up to 1 unit generation. Equipment/unit damage.	Test indicative number.
1296	8193	8712	309896	0	0	3	ELECTRICAL SYSTEM & CONTROL	600 V MELTRIC PLUGS	600 V MELTRIC PLUGS	N/A	222		Not addressed.	30	None	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

10.1.3.7 Life Cycle Curve and Remaining Life

Figures 10-9 and 10-10 below illustrate the life cycle curve for the Unit 3 electrical and control system associated with the Unit 3 generators. Several curves are required to represent the various elements. They have been broken into two parts – the electrical and control systems (MCC's, relays, breakers, TSI, DCS) and those primarily associated with batteries and chargers. The curves are plots of current and projected years in service on the y-axis versus calendar year on the x-axis. Age in-service due to either aging or obsolescence is more an issue than unit operating hours. Vertical lines represent bands of nominal years of in-service life for different in service dates. Horizontal lines represent the ranges of equipment life based on current and historical information and expert opinion. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view.

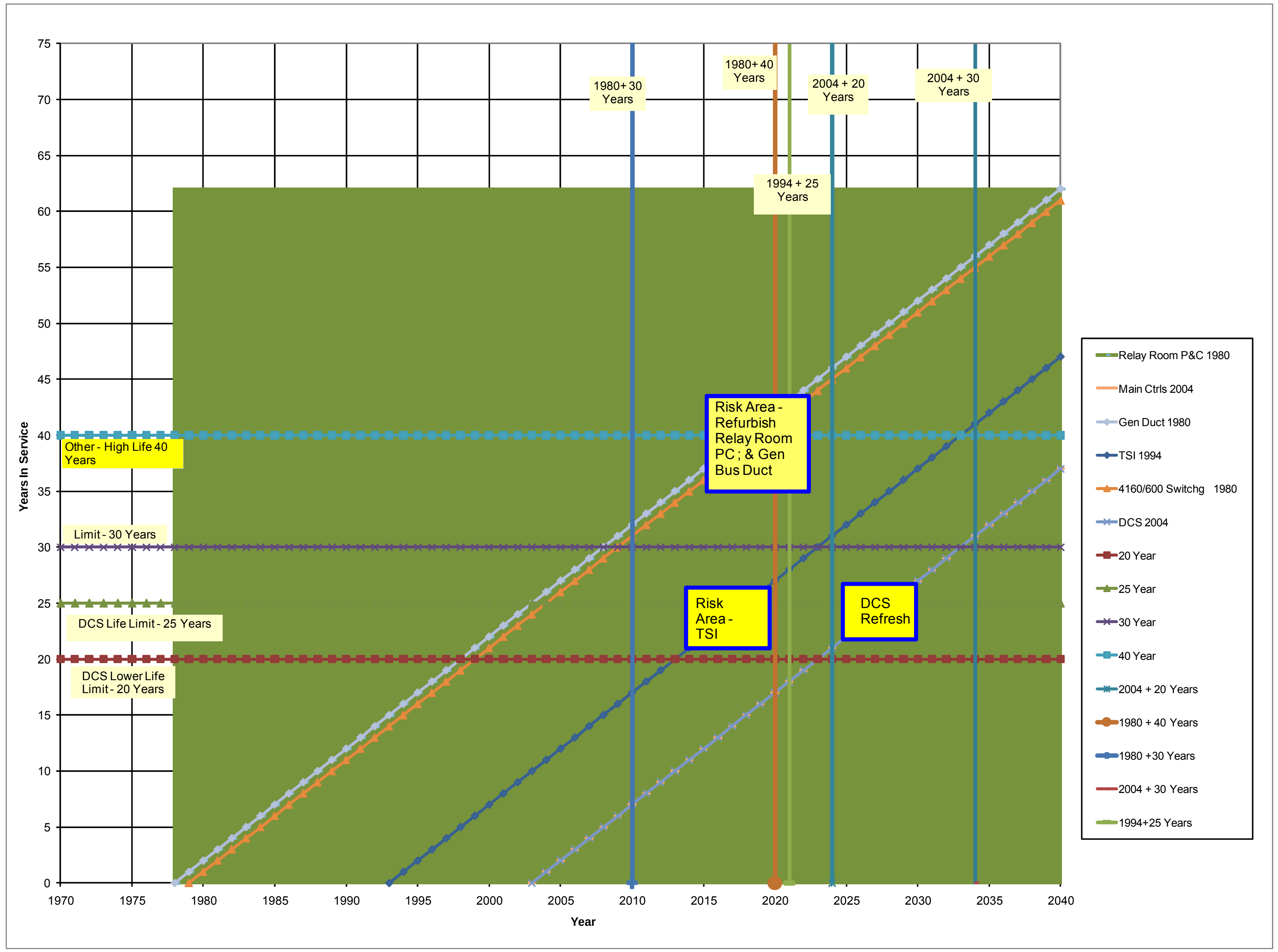

FIGURE 10-9 LIFE CYCLE CURVE – UNIT 3 ELECTRICAL AND CONTROL SYSTEM ASSOCIATED WITH GENERATORS (MCC'S, RELAYS, BREAKERS, TSI, DCS)

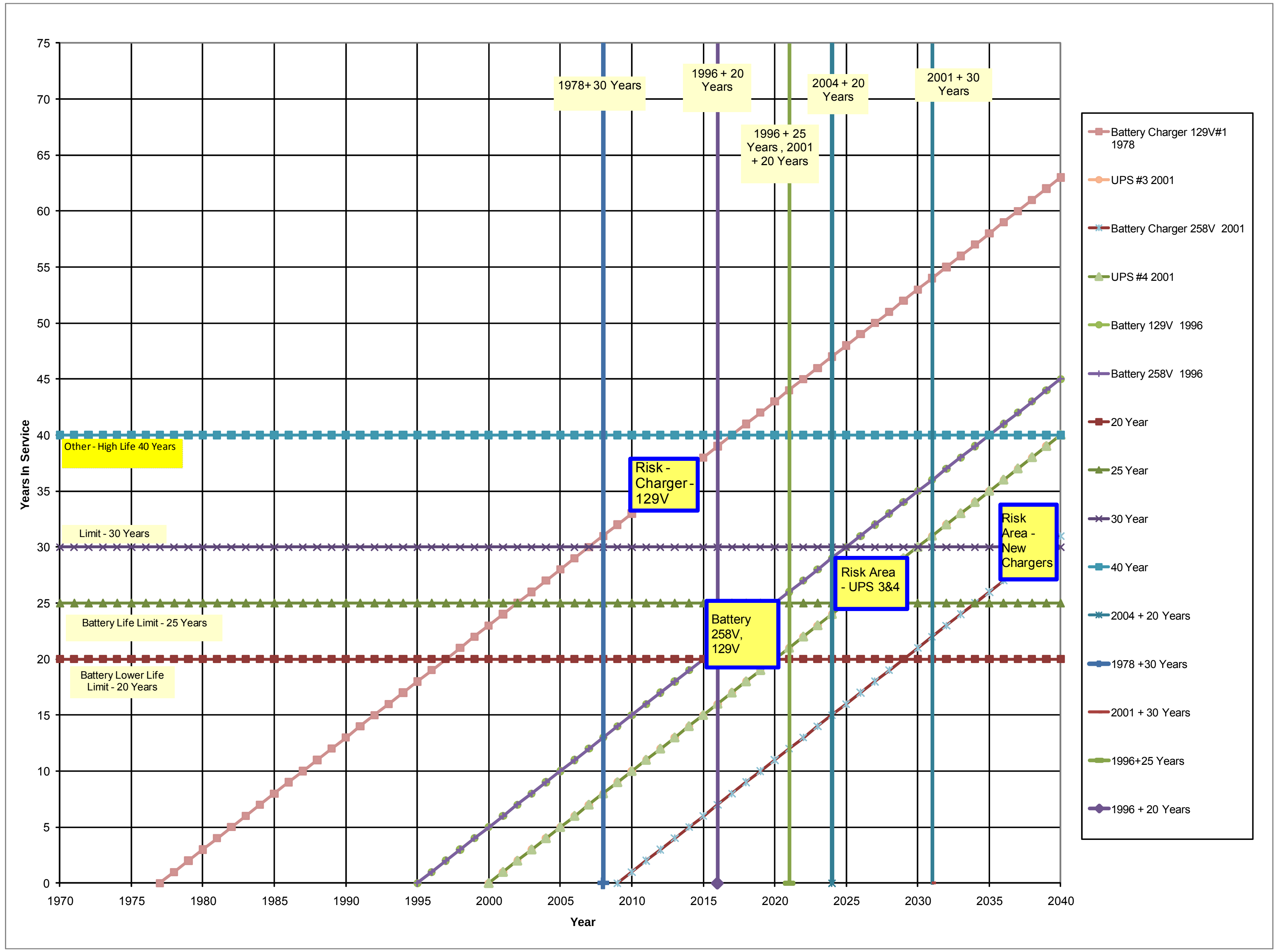

FIGURE 10-10 LIFE CYCLE CURVE – UNIT 3 ELECTRICAL AND CONTROL SYSTEM ASSOCIATED WITH GENERATORS (BATTERIES AND CHARGERS)

The curves indicate that the remaining life (RL) of much of the equipment does not exceed the desired life (DL) for generation of 2020 and for synchronous condensing of 2041, without extensive refurbishment or replacement. This is well illustrated by the highlighted risk areas which highlights that many original MCC's and relays as well as the TSI are in need or replacement or extensive refurbishment in the very near term. The risk figures also illustrate that some equipment (DCS, batteries, and chargers) will require replacement or refurbishment in the 2020+ period.

10.1.3.8 Level 2 Inspection Requirements and Costs

Where a system is fully or partially required for synchronous condensing, it is included here. Recommended Level 2 analyses are identified in the following table.

TABLE 10-18 LEVEL 2 INSPECTION – UNIT 3 ELECTRICAL AND CONTROL SYSTEM ASSOCIATED WITH GENERATORS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Sub System Comment	L2#	Appendix #	Level 2 Work	Year	Priority	Cost k$
1296	8193	8712	0	0	0	3	ELECTRICAL SYSTEM & CONTROL	ELECTRICAL SYSTEM & CONTROL	ELECTRICAL SYSTEM & CONTROL	None	185	6	No Level 2 inspections or testing is required.			
1296	8193	8712	8698	0	0	3	ELECTRICAL SYSTEM & CONTROL	RELAY RM PROTECTION & CONTROL	RELAY RM PROTECTION & CONTROL	None	186	6	No Level 2 inspections or testing is required.			
1296	8193	8712	271766	0	0	3	ELECTRICAL SYSTEM & CONTROL	SWITCHGEAR 4160 & 600 VOLT	SWITCHGEAR 4160 & 600 VOLT	None	187	6	No Level 2 inspections or testing is required.			
1296	8193	8712	8704	0	0	3	ELECTRICAL SYSTEM & CONTROL	MAIN CONTROLS	MAIN CONTROLS	None	188	6	No Level 2 inspections or testing is required.			
1296	8193	8712	301711	0	0	3	ELECTRICAL SYSTEM & CONTROL	DISTRIBUTED CONTROL SYSTEM (DCS)	DCS	None	189	6	No Level 2 inspections or testing is required.			
1296	8193	8712	8713	0	0	3	ELECTRICAL SYSTEM & CONTROL	GENERATOR BUS DUCT & CONN'S	GENERATOR BUS DUCT & CONN'S	Generator Bus-duct and Connections	190	6	Conduct complete generator bus-duct partial maintenance inspection and tests on the U1 bus-duct: Low Resistance Test : Measure the resistance of bolted connections using a low-resistance ohmmeter (Ductor). Insulation Resistance Test: Measure phase-to-phase and phase-to-ground insulation resistance, must be > 100Mohm per 1000 ft. of bus-duct.	2011	1	$15
1296	8193	8712	8715	0	0	3	ELECTRICAL SYSTEM & CONTROL	GEN. TRANSFORMER & AUX	GEN. TRANSFORMER & AUX	Unit Auxiliary Transformers, UAT3 and SAT34,	191	6	Inspect and test transformers UAT3 and SAT34 and 50H-2 air circuit breakers. Check the bussing. Inspection/testing of transformers - turns ratio, power and dissipation factor, winding resistance, movement of coils, core grounds, taps and general condition and cleanliness.	See Transformers	1	
1296	8193	8712	8716	0	0	3	ELECTRICAL SYSTEM & CONTROL	UNIT SERVICE POWER SYSTEM	UNIT SERVICE POWER SYSTEM	None	192	6	No Level 2 inspections or testing is required.			
1296	8193	8712	8716	8717	0	3	ELECTRICAL SYSTEM & CONTROL	UNIT SERVICE POWER SYSTEM	UNIT BOARD UB-3	None	193	6	No Level 2 inspections or testing is required.			
1296	8193	8712	8716	8718	0	3	ELECTRICAL SYSTEM & CONTROL	UNIT SERVICE POWER SYSTEM	UNIT AUX. BOARD UAB-3	None	194	6	No Level 2 inspections or testing is required.			
1296	8193	8712	8716	8722	0	3	ELECTRICAL SYSTEM & CONTROL	UNIT SERVICE POWER SYSTEM	TURBINE AREA MCC TAB-34	None	195	6	No Level 2 inspections or testing is required.			
1296	8193	8712	8750	0	0	3	ELECTRICAL SYSTEM & CONTROL	BATTERY CHARGERS	BATTERY CHARGERS	None	198	6	No Level 2 inspections or testing is required.			

Table 10-18 Cont'd

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Sub System Comment	L2#	Appendix #	Level 2 Work	Year	Priority	Cost k$
1296	8193	8712	8751	0	0	3	ELECTRICAL SYSTEM & CONTROL	UPS 3 INVERTER	UPS 3 INVERTER	None	199	6	No Level 2 inspections or testing is required.			
1296	8193	8712	8757	0	0	3	LECTRICAL SYSTEM & CONTROL	UPS 4 INVERTER	UPS 4 INVERTER	None	200	6	No Level 2 inspections or testing is required.			
1296	8193	8712	8763	0	0	3	ELECTRICAL SYSTEM & CONTROL	BATTERY BANKS	BATTERY BANKS	None	201	6	No Level 2 inspections or testing is required.			
1296	8193	8712	8763	9.9E+07	0	3	ELECTRICAL SYSTEM & CONTROL	BATTERY BANKS	BATTERY CHARGER	None	202	6	No Level 2 inspections or testing is required.			
1296	8193	8712	271763	0	0	3	ELECTRICAL SYSTEM & CONTROL	CABLE RACEWAYS	CABLE RACEWAYS	Units 1, 2, 3 Cable Raceways, Control Cables, Power Cables	203	6				
1296	8193	8712	271764	0	0	3	ELECTRICAL SYSTEM & CONTROL	CONTROL CABLES	CONTROL CABLES	Units 1, 2, 3 Cable Raceways, Control Cables, Power Cables	204	6	Inspection and test selected control cables: Low Resistance Test: Measure the resistance of bolted connections using a low-resistance ohmmeter (Ductor).	2011	3	$7
1296	8193	8712	271765	0	0	3	ELECTRICAL SYSTEM & CONTROL	POWER CABLES	POWER CABLES	Units 1, 2, 3 Cable Raceways, Control Cables, Power Cables	205	6	Inspect/test selected power (4160V, 600V) cables: Low Resistance Test: Measure the resistance of bolted connections using a low-resistance ohmmeter (Ductor). - Insulation Resistance Test: Apply a test voltage of 5kV for cable used for 4160V, 1000V for cable rated at 600V, and 500V for cable rated at 300V. Phase-to-phase and phase-to-ground insulation resistance tests, must be >100Mohm per 1000 ft.	2011	3	$10
1296	8193	8712	309896	0	0	3	ELECTRICAL SYSTEM & CONTROL	600 V MELTRIC PLUGS	600 V MELTRIC PLUGS	None	206	6	No Level 2 inspections or testing is required.			

10.1.3.9 Capital Projects

Where a system is fully or partially required for synchronous condensing, it is included here. The suggested typical capital enhancements include:

TABLE 10-19 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – UNIT 3 ELECTRICAL AND CONTROL SYSTEM ASSOCIATED WITH GENERATORS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Detail	CAP#	Appendix #	Unit #	Capital Item	Date	Priority
1296	8193	8712	0	0	0	3	ELECTRICAL SYSTEM & CONTROL	ELECTRICAL SYSTEM & CONTROL	ELECTRICAL SYSTEM & CONTROL	N/A	156	6	3	No capital required.		
1296	8193	8712	8698	0	0	3	ELECTRICAL SYSTEM & CONTROL	RELAY RM PROTECTION & CONTROL	RELAY RM PROTECTION & CONTROL	N/A	157	6	3	Implement modernization study refurbishing the old GE electro-magnetic relays or new multi-function relaying.	2014	1
1296	8193	8712	271766	0	0	3	ELECTRICAL SYSTEM & CONTROL	SWITCHGEAR 4160 & 600 VOLT	SWITCHGEAR 4160 & 600 VOLT	N/A	158	6	3	Include this switchgear, 4160V/600V relaying in SB2 modernization implementation for the protection relays.	2012	1
1296	8193	8712	271766	0	0	3	ELECTRICAL SYSTEM & CONTROL	SWITCHGEAR 4160 & 600 VOLT	SWITCHGEAR 4160 & 600 VOLT	N/A	159	6	3	Overhaul all 4160V switchgear breakers. Use spare breaker elements a program to overhaul UB3 breakers BFPE3, BFPW3, FDFE3, FDFW3, CEPN3, CEPS3, CWPE3, CWPW3, off site if necessary, with essentially no interruption to plant requirements recognizing that these will be in standby mode from 2015-2020 and as of 2020 will become “spare” but in good condition.	2014	1
1296	8193	8712	271766	0	0	3	ELECTRICAL SYSTEM & CONTROL	SWITCHGEAR 4160 & 600 VOLT	SWITCHGEAR 4160 & 600 VOLT	N/A	160	6	3	Replace existing UB3 breakers UT3, UAT3, TB3 and SB34 during the complete overhaul with Eaton Electrical VR-Series breakers for a life expectancy to at least 2041. Implement as required Eaton Electrical Remote racking device (RPR2) for remote racking. Note: When the 4160V CWP pumps are taken out of service, cooling water needs will be taken up by new 600V pumps. It should also be considered to offset the upgrade of the Boiler Feed pumps to VFD’s. See overhauling of breakers BFE3 and BFW3 above.	2014	1
1296	8193	8712	271766	0	0	3	ELECTRICAL SYSTEM & CONTROL	SWITCHGEAR 4160 & 600 VOLT	SWITCHGEAR 4160 & 600 VOLT	N/A	161	6	3	Unit Aux. Board UAB3 and Station Aux. Board SAB34, (600V), manufactured by ITE and installed in 1980. The switchboards are c/w FPE 50H-2 Incoming, tie and feeder breakers. All protection, synch, and control relays are original CGE electro-mechanical.	2014	1
1296	8193	8712	271766	0	0	3	ELECTRICAL SYSTEM & CONTROL	SWITCHGEAR 4160 & 600 VOLT	SWITCHGEAR 4160 & 600 VOLT	N/A	162	6	3	No capital required.		
1296	8193	8712	8704	0	0	3	ELECTRICAL SYSTEM & CONTROL	MAIN CONTROLS	MAIN CONTROLS	N/A	163	6	3	Upgrade Unit 3 Relay Panels to provide a safe system and discard the existing cabinets and their contents, and redirect the existing field cables to the DCS system including changes to present DCS physical size to accommodate the changes.	2014	1

Table 10-19 Cont’d

Newfoundland and Labrador Hydro a NALCOR Energy Co.
Holyrood Thermal Generating Station
Condition Assessment & Life Extension Study

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Detail	CAP#	Appendix #	Unit #	Capital Item	Date	Priority
1296	8193	8712	301711	0	0	3	ELECTRICAL SYSTEM & CONTROL	DCS	DCS	N/A	164	6	3	No capital required.		
1296	8193	8712	8713	0	0	3	ELECTRICAL SYSTEM & CONTROL	GENERATOR BUS DUCT & CONN'S	GENERATOR BUS DUCT & CONN'S	N/A	165	6	3	None planned, but may result from tests.		
1296	8193	8712	8715	0	0	3	ELECTRICAL SYSTEM & CONTROL	GEN. TRANSFORMER & AUX	GEN. TRANSFORMER & AUX	N/A	166	6,5	3	No capital required.		
1296	8193	8712	8716	0	0	3	ELECTRICAL SYSTEM & CONTROL	UNIT SERVICE POWER SYSTEM	UNIT SERVICE POWER SYSTEM	N/A	169	6	3	No capital required.		
1296	8193	8712	8716	8717	0	3	ELECTRICAL SYSTEM & CONTROL	UNIT SERVICE POWER SYSTEM	UNIT BOARD UB-3	N/A	170	6	3	No capital required.		
1296	8193	8712	8716	8718	0	3	ELECTRICAL SYSTEM & CONTROL	UNIT SERVICE POWER SYSTEM	UNIT AUX. BOARD UAB-3	N/A	171	6	3	No capital required.		
1296	8193	8712	8716	8722	0	3	ELECTRICAL SYSTEM & CONTROL	UNIT SERVICE POWER SYSTEM	TURBINE AREA MCC TAB-34	N/A	172	6	3	No capital required.		
1296	8193	8712	8716	8724	0	3	ELECTRICAL SYSTEM & CONTROL	UNIT SERVICE POWER SYSTEM	BOILER AREA BAB-3	N/A	173	6	3	No capital required.		
1296	8193	8712	8750	0	0	3	ELECTRICAL SYSTEM & CONTROL	BATTERY CHARGERS	BATTERY CHARGERS	N/A	174	6	3	No capital required.		
1296	8193	8712	8751	0	0	3	ELECTRICAL SYSTEM & CONTROL	UPS 3 INVERTER	UPS 3 INVERTER	N/A	175	6	3	No capital required.		
1296	8193	8712	8751	0	0	3	ELECTRICAL SYSTEM & CONTROL	UPS 3 INVERTER	UPS 3 INVERTER	N/A	176	6	3	Implement optimization study in conjunction with UPS2, UPS3 and UPS4 replacement.	2012	1
1296	8193	8712	8757	0	0	3	ELECTRICAL SYSTEM & CONTROL	UPS 4 INVERTER	UPS 4 INVERTER	N/A	177	6	3	No capital required.		
1296	8193	8712	8763	0	0	3	ELECTRICAL SYSTEM & CONTROL	BATTERY BANKS	BATTERY BANKS	N/A	178	6	3	No action is required.		
1296	8193	8712	8763	99038706	0	3	ELECTRICAL SYSTEM & CONTROL	BATTERY BANKS	BATTERY CHARGER	N/A	179	6	3	Replace Unit 3, 129VDC battery charger 1.	2012	1
1296	8193	8712	8763	99038706	0	3	ELECTRICAL SYSTEM & CONTROL	BATTERY BANKS	BATTERY CHARGER	N/A	180	6	3	Replace Unit 3, 129VDC battery charger 2.	2012	1
1296	8193	8712	8763	99038706	0	3	ELECTRICAL SYSTEM & CONTROL	BATTERY BANKS	BATTERY CHARGER	N/A	181	6	3	Replace Unit 3, 258VDC distribution panel and breakers.	2012	1
1296	8193	8712	271763	0	0	3	ELECTRICAL SYSTEM & CONTROL	CABLE RACEWAYS	CABLE RACEWAYS	N/A	182	6	3	Install any new cable installations on new tray, and in accordance with the applicable codes.	2011	1
1296	8193	8712	271764	0	0	3	ELECTRICAL SYSTEM & CONTROL	CONTROL CABLES	CONTROL CABLES	N/A	183	6	3	Install any new cable installations on new tray, and in accordance with the applicable codes.	2011	1
1296	8193	8712	271765	0	0	3	ELECTRICAL SYSTEM & CONTROL	POWER CABLES	POWER CABLES	N/A	184	6	3	Install any new cable installations on new tray, and in accordance with the applicable codes.	2011	1

10.1.4 Asset 271678 – Unit 3 Cooling Water Systems Associated with Generators

(Detailed Technical Assessment in Working Papers, Appendices 8 and 11)

Equipment Scope:

Unit #:	3
Asset Class #	BU 1296 - Assets Generations
SCI & System:	8645 #3 Unit Generation Services
Sub-Systems:	271678 #3 CW System
	8691 #3 T/gen Water Cooling
	8291 #3 Gen Service Cooling
Components:	8649 #3 CW Travelling Screens East
	8650 #3 CW Travelling Screens West
	8658 #3 CW Pump East
	8659 #3 CW Pump West
	8647 #3 CW Intake
	8676 #3 CW Discharge to Outfall
	8691 #3 General Service Water
	8262 #3 Turbine Generator Cooling Water

10.1.4.1 Description

The items examined were limited to those required to achieve the 2041 synchronous condensing end date:

- The main pumphouse sea water intake, traveling screens, and general service water system;
- Heat exchange system;
- Seawater discharge system; and
- Electrical and control requirements.

Asset 271678 Circulating Water (CW) Pump and Screens Systems

Circulating water (CW) systems servicing Unit 3 consist of two 50% CW vertical turbine pumps, travelling screens, and associated wash pumps and systems. The primary function of the CW system is to provide condenser cooling water, but also cooling water for other closed loop systems. It is necessary that the

CW system operate efficiently in order maintain optimal plant thermal efficiency by minimizing steam turbine condenser backpressures.

Asset 8262 TG Auxiliary Cooling Water System

Sea water cooling is used for the Turbine Generator (TG) auxiliary cooling water system which is required for synchronous condensing operation. Sea water can currently be supplied by a sump pump and dedicated line from the Stage 2 pumphouse (Unit 4 CW pump pit), from a water take-off from the Stage 2 pumphouse circulating water pumps, or from an interconnection with the Units 1 and 2 cooling water systems. Typically, when only Unit 3 is running in synchronous condensing mode, the smaller sump pump and dedicated line from the Stage 2 pumphouse is used.

For long term synchronous condensing operation to 2041, the intent is to supply seawater from a small, permanent pump arrangement similar to the temporary system.

FIGURE 10-11 DEDICATED SEAWATER COOLING WATER LINE FOR UNIT 3 SYNCHRONOUS CONDENSING GT AUXILIARY COOLING WATER

10.1.4.2 History

Manufactured/Delivered	1979
In-Service Date	Feb 1980
Generation Base Load End Date	Dec 2015
Generation Peak/Emerg Gen End Date	Dec 2020
Synchronous Condensing Start Date	1986
Synchronous Condensing End Date	Dec 2041
Last Major Overhaul/Inspection	Not identified
Next Major Overhaul/Inspection	Not Identified

10.1.4.3 Inspection and Repair History

CW Travelling Screens: The Unit 3 CW travelling screens have not been refurbished and should be within the next 5 years. The external casings have some corroded parts, but nothing that appears to impair current or short term performance.

CW Wash Water Pumps and Motors: An external inspection of the CW wash pumps and motors indicated that they have extensive corrosion but were running at the time of the visual inspection. They are considered to be a minor maintenance issue and not addressed as a part of this assessment.

CW Pumps: CW pumps servicing Unit 3 are performing fairly well. Reports outlining the condition of the pumps were not available, but interviews suggest that regular maintenance has been ongoing and the units should be able to meet 2015 and 2020 timelines with continued maintenance. Major pump overhauls are scheduled on a twelve year cycle, as indicated in Table 10-20 below.

TABLE 10-20 MAJOR PUMP OVERHAULS

Annual Asset Maintenance																		
Pumps	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
1 CW Pump East			X												83,000.00			
1 CW Pump West											75,000.00							
2 CW Pump East	X				X												87,000.00	
2 CW Pump West												77,000.00						
3 CW Pump East		X									75,000.00							
3 CW Pump West						10,000.00												89,000.00

A temporary CW pump is being used in the existing Unit 4 intake to supply smaller quantities of cooling water to Unit 3 for synchronous condensing operation. There are also interconnections between the Units 1, 2, and 3 CW systems that allow them to provide back-up for this purpose if necessary.

CW Pump Motors: Motors are electrically tested every year (as a component of the PM process).

CW Pump Outlet Piping, Valves & Fittings: Outlet piping, valves and fittings from the CW pump discharge to the inlet of the 64 inch concrete piping that is installed underground to the Unit 3 condenser has generally experienced significant corrosion and some patching of the system has been done. It requires a Level 2 inspection and possibly replacement or refurbishment.

Cooling Water System Intake & Discharge: The 36 inch and 64 inch CW intake and discharge concrete piping that is installed underground to the Unit 3 condenser has periodically been dewatered and inspected by plant staff, although not in the last five years. Specific corrosion, spalling, cracks or fractures were not identified and patching of the system has not been done. There have been no obvious issues with the systems, although no detailed engineering evaluations and NDE work has been undertaken.

PM inspections are planned going forward on a three year cycle, as per schedule below in Table 10-21.

TABLE 10-21 PM INSPECTIONS

Annual Asset Maintenance																	
CW Inspection		2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Unit 1													25,625.00			26,625.00	
Unit 2														25,625.00			26,625.00
Unit 3												25,000.00			25,625.00		

10.1.4.4 Condition Assessment

The condition assessment of the Unit 3 cooling water system associated with generators is illustrated below in Table 10-22.

TABLE 10-22 CONDITION ASSESSMENT – UNIT 3 COOLING WATER SYSTEMS ASSOCIATED WITH GENERATORS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset Level 2	Asset Level 3	Description	Detail	Condition Summary ID#	Append #	Condition	EPRI Identifier	Original Life (Base Load) Ops Hrs (Yrs)	Current Expected Minimum Remaining Life Years (Subject to Test)	End of Life (EOL) Required	Next Regular Inspection	Next Planned Overhaul or Major Inspection	Capability to Reach Next Overhaul	Capability to Reach EOL	In Service
1296	8193	8645	8262	0	0	3	UNIT GENERATION SERVICES	TURB/GEN WATER COOLING SYS	TURB/GEN WATER COOLING SYS	N/A	135	12	Piping is pitted. Pumps and motors are original. Heat exchangers appear in good condition. Heat exchangers are cleaned and checked for leaks annually, and are cathodically protected and a closed cooling system corrosion inhibitor used. No issues had been encountered with the heat exchangers. No inspection or maintenance data was available.	4	(30)	10	2041	2011		No	No	1980
1296	8193	8645	8262	0	0	3	UNIT GENERATION SERVICES	TURB/GEN WATER COOLING SYS	TURB/GEN WATER COOLING SYS	Sea Water Piping	136	11,15	Sea Water piping 18" lines and associated valving is original equipment for all units. No condition data but no significant issues identified. Piping and valves have external corrosion and pitting, but rate seems not to be rapid.	4	(30)	(10)	2041	2011		No	No	1980
1296	8193	8645	8262	9658	0	3	UNIT GENERATION SERVICES	TURB/GEN WATER COOLING SYS	T/G COOLING WATER PUMP EAST	N/A	137	11,15	Pumps and motors are original equipment and are in relatively poor condition - primarily due to age and use.	4	(30)	10	2041	2012		No	No	1980
1296	8193	8645	8262	9660	0	3	UNIT GENERATION SERVICES	TURB/GEN WATER COOLING SYS	T/G COOLING WATER PUMP WEST	N/A	138	11,15	Pumps and motors are original equipment and are in relatively poor condition - primarily due to age and use.	4	(30)	10	2041	2012		No	No	1980
1296	8193	8645	8691	0	0	3	UNIT GENERATION SERVICES	GENERAL SERVICE COOLING	GENERAL SERVICE COOLING	N/A	139	11,15	PVC piping can have lifetimes of up to 100 years. The current pipe is less than 20 years old. No difficulties identified or expected.	4	(50)	20	2041			Yes	Yes	1990
1296	8193	8645	271678	8647	0	3	UNIT GENERATION SERVICES	CW SYSTEM	CW INTAKE SYSTEM	Intake Structure and Foreay	150	11	No recent underwater inspections of intake structures or bay, but surface visual check looked good. There is no reason to expect any kind of aggressive attack.	4	(60)	(20+)	2041		2011	Yes	Yes	1980
1296	8193	8645	271678	8676	0	3	UNIT GENERATION SERVICES	CW SYSTEM	CW DISCHARGE TO OUTFALL	Pit, Stoplogs and Discharge	151	11	No recent underwater inspections of pit, stoplogs or outfall structures.	4	(60)	(20+)	2041		2011	Yes	Yes	1980
1296	8193	8645	271678	8649	0	3	UNIT GENERATION SERVICES	CW SYSTEM	CW TRAVELLING SCREENS EAST	N/A	152	11	Internals in good condition after major upgrade within the last five to ten years. External casings and auxiliaries have some corrosion.	4	(20)	(10)	2041	2012		No	No	1980
1296	8193	8645	271678	8650	0	3	UNIT GENERATION SERVICES	CW SYSTEM	CW TRAVELLING SCREENS WEST	N/A	153	11	Internals in good condition after major upgrade within the last five to ten years. External casings and auxiliaries have some corrosion.	4	(20)	(10)	2041	2012		No	No	1980
1296	8193	8645	271678	8823	0	3	UNIT GENERATION SERVICES	CW SYSTEM	C.W. SCREEN WASH SYSTEM	N/A	154	11	Significant corrosion,. Likely near end of life.	3a	200000 (30)	5	2041			No	No	1980
1296	8193	8645	271678	279782	0	3	UNIT GENERATION SERVICES	CW SYSTEM	SYNCH CONDENSER AUX CW SYSTEM	N/A	155	11	Recent addition rigged in temporary fashion. No issues with performance.	3a	(30)	10	2041			No	No	1990

Notes: 1. A "(bracketed)" value in the "Current Expected Remaining Life" column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation, including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as "(X/Y)" has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

2. The "Next Regular Inspection" column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The "Next Planned Overhaul or Major Inspection" column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a "Desired Life" stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or simply are not known to AMEC.

10.1.4.5 Actions

Based on the condition assessment, the following actions are recommended for the Unit 3 cooling water systems associated with generators:

TABLE 10-23 RECOMMENDED ACTIONS – UNIT 3 COOLING WATER SYSTEMS ASSOCIATED WITH GENERATORS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Unit	Asset 2/3	Asset 3/4	Description	Detail	Action #	App #	Action	Year	Priority
1296	8193	8645	8262	0	3	UNIT GENERATION SERVICES	TURB/GEN WATER COOLING SYS	TURB/GEN WATER COOLING SYS	N/A	202	8	Continue current condition monitoring and heat exchanger servicing.	2011	2
1296	8193	8645	8262	0	3	UNIT GENERATION SERVICES	TURB/GEN WATER COOLING SYS	TURB/GEN WATER COOLING SYS	Aux Cooling Water Piping	203	8	Clean and coat remaining auxiliary cooling water piping.	2011	2
1296	8193	8645	8262	0	3	UNIT GENERATION SERVICES	TURB/GEN WATER COOLING SYS	TURB/GEN WATER COOLING SYS	TG Piping	204	8	Perform representative Level 2 pipe thickness checks on seawater intake and discharge piping.	2011	2
1296	8193	8645	8262	0	3	UNIT GENERATION SERVICES	TURB/GEN WATER COOLING SYS	TURB/GEN WATER COOLING SYS	Aux Cooling Water Piping	205	8	Perform Level 2 on auxiliary Cooling Pipes during next five years.	2011	2
1296	8193	8645	8262	0	3	UNIT GENERATION SERVICES	TURB/GEN WATER COOLING SYS	TURB/GEN WATER COOLING SYS	Aux Cooling Water Pumps	206	8	Replace Unit 3 auxiliary cooling water pumps and motors in next five years.	2012	1
1296	8193	8645	8262	0	3	UNIT GENERATION SERVICES	TURB/GEN WATER COOLING SYS	TURB/GEN WATER COOLING SYS	Aux Cooling Water Pumps	207	8	Perform Level 2 on auxiliary cooling heat exchangers during next five years.	2011	2
1296	8193	8645	8262	9658	3	UNIT GENERATION SERVICES	TURB/GEN WATER COOLING SYS	T/G COOLING WATER PUMP EAST	N/A	208	8	Continue current condition monitoring and heat exchanger servicing.	2011	2
1296	8193	8645	8262	9660	3	UNIT GENERATION SERVICES	TURB/GEN WATER COOLING SYS	T/G COOLING WATER PUMP WEST	N/A	209	8	Continue current condition monitoring and heat exchanger servicing.	2011	2
1296	8193	8645	8691	0	3	UNIT GENERATION SERVICES	GENERAL SERVICE COOLING	GENERAL SERVICE COOLING	N/A	210	12	Continue current condition monitoring and heat exchanger servicing.	2011	2
1296	8193	8645	271678	8647	3	UNIT GENERATION SERVICES	CW SYSTEM	CW INTAKE SYSTEM	N/A	223	11	Perform an underwater inspection of intake and outfall structures - including areas such as stoplog.	2011	2
1296	8193	8645	271678	8649	3	UNIT GENERATION SERVICES	CW SYSTEM	CW TRAVELLING SCREENS EAST	N/A	224	11	Assess Unit 3 travelling screen refurbishment requirements.	2011	2
1296	8193	8645	271678	8650	3	UNIT GENERATION SERVICES	CW SYSTEM	CW TRAVELLING SCREENS WEST	N/A	225	11	Assess Unit 3 travelling screen refurbishment requirements.	2011	2
1296	8193	8645	271678	8676	3	UNIT GENERATION SERVICES	CW SYSTEM	CW DISCHARGE TO OUTFALL	N/A	226	11	Perform an underwater inspection of intake and outfall structures - including areas such as stoplog.	2011	2
1296	8193	8645	271678	8823	3	UNIT GENERATION SERVICES	CW SYSTEM	CW SCREEN WASH SYSTEM	N/A	227	11	Clean and refurbish.	2011	3
1296	8193	8645	271678	279782	3	UNIT GENERATION SERVICES	CW SYSTEM	SYNCH CONDENSER AUX CW SYSTEM	N/A	228	11	Implement a permanent system.	2012	2

10.1.4.6 Risk Assessment

The risk assessment associated with the Unit 3 cooling water systems associated with generators, both from a technological perspective and a safety perspective, is illustrated below in Table 10-24.

TABLE 10-24 RISK ASSESSMENT– UNIT 3 COOLING WATER SYSTEMS ASSOCIATED WITH GENERATORS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Component	Risk Assess #	Appendix #	Major Issues	Remaining Life Years	Remaining Life Comments	TECHNO_ECO RISK ASSESS MODEL			SAFETY RISK ASSESS MODEL			Possible Failure Event	Mitigation
														(Insufficient Info - Inspection Required Within (x) Years)		Likeli-hood	Conse-quence	Risk Level	Likeli-hood	Conse-quence	Safety Risk		
1296	8193	8645	8262	0	0	3	UNIT GENERATION SERVICES	TURBINE/GENERATOR WATER COOLING SYSTEM	TURBINE/GENERATOR WATER COOLING SYSTEM	Unit 3 ACW Ht Exch	171	8	Corrosion, mechanical failure/pluggage.	20+	None	1	A	Low	1	A	Low	Sparing, minimal.	Inspect and maintain.
1296	8193	8645	8262	0	0	3	UNIT GENERATION SERVICES	TURBINE/GENERATOR WATER COOLING SYSTEM	TURBINE/GENERATOR WATER COOLING SYSTEM	Unit 3 ACW Piping	172	8	Corrosion, mechanical failure.	20+	None	1	A	Low	1	A	Low	Leak and short duration impact.	Inspect and maintain.
1296	8193	8645	8262	0	0	3	UNIT GENERATION SERVICES	TURBINE/GENERATOR WATER COOLING SYSTEM	TURBINE/GENERATOR WATER COOLING SYSTEM	Unit 3 Seawater Piping	173	8	Corrosion mechanical failure.	(10)	None	1	A	Low	1	A	Low	Leak and short duration impact.	Inspect and maintain.
1296	8193	8645	8262	0	0	3	UNIT GENERATION SERVICES	TURBINE/GENERATOR WATER COOLING SYSTEM	TURBINE/GENERATOR WATER COOLING SYSTEM	Unit 3 Seawater Piping – Synch Condensing	174	8	Mechanical failure.	10+	None	1	A	Low	1	A	Low	Sparing, minimal – retain at least 1 CW capable supply.	Maintain spare capability. Inspect and maintain.
1296	8193	8645	8262	9658	0	3	UNIT GENERATION SERVICES	TURBINE/GENERATOR WATER COOLING SYSTEM	T/G COOLING WATER PUMP EAST	Unit 3 ACW Pump/Motor	175	8	Mechanical or electrical failure.	5	None	1	A	Low	1	A	Low	Sparing, minimal.	Current inspection and maintain.
1296	8193	8645	8262	9660	0	3	UNIT GENERATION SERVICES	TURBINE/GENERATOR WATER COOLING SYSTEM	T/G COOLING WATER PUMP WEST	Unit 3 ACW Pump/Motor	176	8	Mechanical or electrical failure.	5	None	1	A	Low	1	A	Low	Sparing, minimal.	Current inspection and maintain.
1296	8193	8645	8691	0	0	3	UNIT GENERATION SERVICES	GENERAL SERVICE COOLING	GENERAL SERVICE COOLING	GSW Pump/Motor Failure	177	12	Mechanical or electrical failure.	10+	None	1	A	Low	1	A	Low	Minimum.	Current inspection and maintain.
1296	8193	8645	8691	0	0	3	UNIT GENERATION SERVICES	GENERAL SERVICE COOLING	GENERAL SERVICE COOLING	GSW Ht Exch Failure	178	12	Mechanical failure/pluggage.	10+	None	1	A	Low	1	A	Low	Seawater contamination (unlikely).	Inspect and maintain.
1296	8193	8645	8691	0	0	3	UNIT GENERATION SERVICES	GENERAL SERVICE COOLING	GENERAL SERVICE COOLING	GSW Piping Failure	179	12	Mechanical failure.	20+	None	1	A	Low	1	A	Low	Leak and short duration impact.	Inspect and maintain.
1296	8193	8645	271678	8647	0	3	UNIT GENERATION SERVICES	CW SYSTEM	CW INTAKE SYSTEM	Unit #3 Intake Structure	192	17	Structural cracking; steel corrosion.	20+)	None	1	B	Low	1	A	Low	Structural failure requiring shutdown.	Inspect and maintain.
1296	8193	8645	271678	8649	0	3	UNIT GENERATION SERVICES	CW SYSTEM	CW TRAVELLING SCREENS EAST	Unit #3 Travelling Screens	193	11	Corrosion-internal/ext.	5+	None	2	B	Low	2	A	Low	Condenser plugging.	Current inspection and maintain.
1296	8193	8645	271678	8650	0	3	UNIT GENERATION SERVICES	CW SYSTEM	CW TRAVELLING SCREENS WEST	Unit #3 Travelling Screens	194	11	Corrosion-internal/ext.	5+	None	2	B	Low	2	A	Low	Condenser plugging.	Current inspection and maintain.
1296	8193	8645	271678	8676	0	3	UNIT GENERATION SERVICES	CW SYSTEM	CW DISCHARGE TO OUTFALL	Unit #3 CW Outfall Piping	195	11	Concrete cracking.	(20+)	None	1	B	Low	1	A	Low	Cracking or failure – major leak requiring repair.	Inspect and maintain.
1296	8193	8645	271678	8823	0	3	UNIT GENERATION SERVICES	CW SYSTEM	CW SCREEN WASH SYSTEM	N/A	196		Mechanical failure.	2	None	3	A	Low	3	A	Low	Unit performance loss.	Inspect, refurbish, replace.
1296	8193	8645	271678	279782	0	3	UNIT GENERATION SERVICES	CW SYSTEM	SYNCH CONDENSER AUX CW SYSTEM	N/A	197		Mechanical/electrical failure.	(20)	None	1	B	Low	1	B	Low	Loss of unit for short period.	Inspect and maintain.

10.1.4.7 Life Cycle Curve and Remaining Life

Figure 10-12 below illustrates the life cycle curve for the various elements of the Unit 3 CW systems associated with generators. The life curves are plots of current and projected operating hours (generation plus synchronous condensing mode) on the y-axis versus calendar year on the x-axis. The figure has vertical lines representing differing representative nominal age limits for various components. It has horizontal lines that represent a range of practical equivalent base loaded operating hour life limits. Data specific to the intake and outfall structures were not sufficient to include them, but they are not expected to be an issue (perhaps the condition of some operational equipment such as stoplogs or their supports). Data specific to the pumps and motors for the general service cooling water and the turbine generator cooling water are also not presented as they are relatively new and/or modest equipment elements. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view.

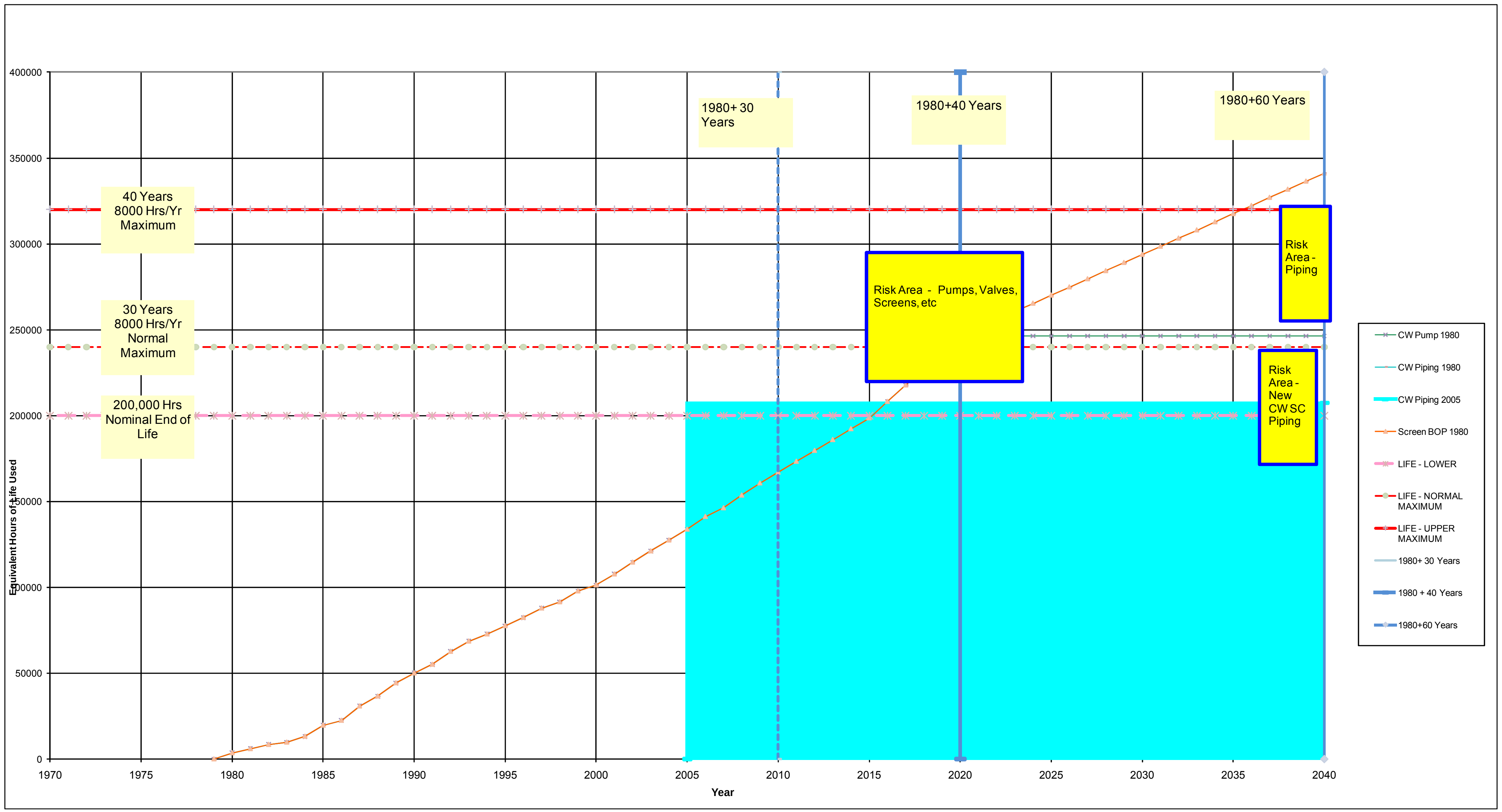

FIGURE 10-12 LIFE CYCLE CURVE – UNIT 3 WATER SYSTEMS ASSOCIATED WITH GENERATORS

The curve indicates that the remaining life (RL) of most elements of the Unit 3 cooling water systems associated with generators is sufficient to reach the end date of 2020 for generation, but not the 2041 desired life (DL) end date for synchronous condensing. The CW pumps and associated equipment are the primary nearer term issues highlighted by the risk boxes. The actual end date and remaining life will become clearer through the series of ongoing routine inspections that forms part of the plant's PM program and the Level 2 inspections recommended in the report. The intake and outfall structures and associated sub-components should be added as a result of a Level 2 inspection.

10.1.4.8 Level 2 Inspection Requirements and Costs

Given the condition historical data reviewed, the following Level 2 analyses are recommended.

TABLE 10-25 LEVEL 2 INSPECTION – UNIT 3 COOLING WATER SYSTEMS ASSOCIATED WITH GENERATORS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Sub System Comment	L2#	Appendix #	Level 2 Work	Year	Priority	Cost k$
1296	8193	8645	0	0	0	3	UNIT GENERATION SERVICES	UNIT GENERATION SERVICES	UNIT GENERATION SERVICES	None	162		No Level 2 inspections or testing is required.			
1296	8193	8645	8262	0	0	3	UNIT GENERATION SERVICES	TURB/GEN WATER COOLING SYS	TURB/GEN WATER COOLING SYS	Seawater intake and discharge piping	163	8	Perform representative Level 2 pipe thickness checks.	2011	2	$6
1296	8193	8645	8262	0	0	3	UNIT GENERATION SERVICES	TURB/GEN WATER COOLING SYS	TURB/GEN WATER COOLING SYS	AC water piping	164	8	Thickness spot checks within 5 years.	2011	2	$6
1296	8193	8645	8262	0	0	3	UNIT GENERATION SERVICES	TURB/GEN WATER COOLING SYS	TURB/GEN WATER COOLING SYS	Ht Exch	165	8	AC Water Ht Exchangers shell and tubes within 5 years.	2011	2	$6
1296	8193	8645	8262	9658	0	3	UNIT GENERATION SERVICES	TURB/GEN WATER COOLING SYS	T/G COOLING WATER PUMP EAST	None	166	8	No Level 2 inspections or testing is required.			
1296	8193	8645	8262	9660	0	3	UNIT GENERATION SERVICES	TURB/GEN WATER COOLING SYS	T/G COOLING WATER PUMP WEST	None	167	8	No Level 2 inspections or testing is required.			
1296	8193	8645	8691	0	0	3	UNIT GENERATION SERVICES	GENERAL SERVICE COOLING	GENERAL SERVICE COOLING	None	168	12	None planned.			
1296	8193	8645	271678	8647	0	3	UNIT GENERATION SERVICES	CW SYSTEM	CW INTAKE SYSTEM	CW intake and discharge structures and piping	177	11	Inspections – diver visual inspection.	2011	2	$30
1296	8193	8645	271678	8649	0	3	UNIT GENERATION SERVICES	CW SYSTEM	CW TRAVELLING SCREENS EAST	None	178	11	No Level 2 inspections or testing is required.	2011		
1296	8193	8645	271678	8650	0	3	UNIT GENERATION SERVICES	CW SYSTEM	CW TRAVELLING SCREENS WEST	None	179	11	No Level 2 inspections or testing is required.	2011		
1296	8193	8645	271678	8676	0	3	UNIT GENERATION SERVICES	CW SYSTEM	CW DISCHARGE TO OUTFALL	CW intake and discharge structures and piping	180	11	Inspections – diver visual inspection.	2011	2	$30
1296	8193	8645	271678	8823	0	3	UNIT GENERATION SERVICES	CW SYSTEM	CW SCREEN WASH SYSTEM	None	181	11	No Level 2 inspections or testing is required.	2011		
1296	8193	8645	271678	279782	0	3	UNIT GENERATION SERVICES	CW SYSTEM	SYNCH CONDENSER AUX CW SYSTEM	None	182	11	No Level 2 inspections or testing is required.	2011		

10.1.4.9 Capital Projects

The suggested typical capital enhancements for the Unit 3 cooling water systems associated with generators include:

Table 10-26 Suggested Typical Capital Enhancements – Unit 3 Cooling Water Systems Associated with Generators

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Detail	CAP#	Appendix #	Unit #	Capital Item	Date	Priority
1296	8193	8645	0	0	0	3	UNIT GENERATION SERVICES	UNIT GENERATION SERVICES	UNIT GENERATION SERVICES	N/A	134		3	No capital required.		
1296	8193	8645	8262	0	0	3	UNIT GENERATION SERVICES	TURB/GEN WATER COOLING SYS	TURB/GEN WATER COOLING SYS	N/A	135	8	3	Clean and coat AC water pipes.	2012	1
1296	8193	8645	8262	9658	0	3	UNIT GENERATION SERVICES	TURB/GEN WATER COOLING SYS	T/G COOLING WATER PUMP EAST	N/A	136	8	3	Replace Unit 3 AC water pumps and motors.	2014	1
1296	8193	8645	8262	9660	0	3	UNIT GENERATION SERVICES	TURB/GEN WATER COOLING SYS	T/G COOLING WATER PUMP WEST	N/A	137	8	3	No capital required.		
1296	8193	8645	8691	0	0	3	UNIT GENERATION SERVICES	GENERAL SERVICE COOLING	GENERAL SERVICE COOLING	N/A	138	12	3	No capital required.		
1296	8193	8645	271678	8647	0	3	UNIT GENERATION SERVICES	CW SYSTEM	CW INTAKE SYSTEM	Intake structure and pit	148	11	3	No capital required.		
1296	8193	8645	271678	8649	0	3	UNIT GENERATION SERVICES	CW SYSTEM	CW TRAVELLING SCREENS EAST	N/A	149	11	3	Refurbish Unit 3 CW travelling screen.	2012	1
1296	8193	8645	271678	8650	0	3	UNIT GENERATION SERVICES	CW SYSTEM	CW TRAVELLING SCREENS WEST	N/A	150	11	3	Refurbish Unit 3 CW travelling screen.	2012	1
1296	8193	8645	271678	8676	0	3	UNIT GENERATION SERVICES	CW SYSTEM	CW DISCHARGE TO OUTFALL	Outfall structure, pit, stoplogs	151	11	3	No capital required.		
1296	8193	8645	271678	8823	0	3	UNIT GENERATION SERVICES	CW SYSTEM	CW SCREEN WASH SYSTEM	N/A	152	11	3	No capital required.		
1296	8193	8645	271678	279782	0	3	UNIT GENERATION SERVICES	CW SYSTEM	SYNCH CONDENSER AUX CW SYSTEM	N/A	153	11	3	No capital required.		

10.2 Unit 3 – Lower Priority Systems

10.2.1 Asset 8336 – Unit 3 Boiler System

(Detailed Technical Assessment in Working Papers, Appendices 29, 30, 34)

Unit #:	3
Asset Class #	BU 1296 - Assets Generations
SCI & System:	8336 #3 Boiler Plant
Sub-Systems:	8337 #3 Boiler Structure
	8339 #3 Boiler F.W. & Sat. Steam
	8359 #3 Boiler Superheats Reheat
Components:	8340 #3 Economizer, tubing and headers
	8339 #3 Linking piping (boiler internals I)
	8351 #3 Furnace water circuit 8344 #3 Steam drum 8351 #3 Downcomers and feeder piping as required 8351 #3 Lower Waterwall headers 8351 #3 Waterwall tubing 8351 #3 Upper Waterwall headers, and riser piping as re
	8360 #3 Superheater; headers and tubing
	8384 #3 Reheater; headers and tubing
	8339 #3 Safety Valves
	8372 #3 Boiler Main Steam lines
	8273 #3 Boiler Stop Valve
	8460 #3 Furnace combustion systems; burners, fans, air
	8337#3 Furnace structural, hangers and casing
	8494 #3 Boiler Blowdown Tank

10.2.1.1 Description

The Unit 3 boiler is a Babcock and Wilcox natural circulation, single reheat, pressurized unit of 1980 vintage design .The boiler is designed for an output of 150 MW with a maximum steam flow rate of 135 kg/s (1,072,000 lbs/hr), at 13 MPag (1890 psig) and 541°C (1005 °F) with an inlet feedwater temperature of 246 °C (476 °F). The reheat steam flow was designed at 125 kg/s (993,000 lbs/hr) with an inlet temperature of 282 °C (539 °F) and an outlet temperature of 538 °C (1005 °F). Unit 3 boiler was commissioned in 1979.

The system includes:

- Economizer, tubing and headers
- Linking piping (boiler internal)
- Furnace water circuit:
    - Steam drum;
    - Downcomers and feeder piping;
    - Lower Waterwall headers;
    - Waterwall tubing; and
    - Upper Waterwall headers and riser piping;
- Superheater headers and tubing;
- Reheater headers and tubing;
- Safety valves;
- Furnace combustion systems: burners, fans, and air heaters;
- Furnace structural, hangers and casing; and
- Boiler Main Steam lines
- Boiler Stop Valve
- Boiler blow down tank.

10.2.1.2 History

	Unit 3
Manufactured/Delivered	1979
In-Service Date	Feb 1980
Generation Base Load End Date	Dec 2015
Generation Peak/Emerg Gen End Date	Dec 2020
Major Inspection/Maintenance Repair	Annual May to Sep on all units

The hours associated with the analyses are:

Hours Generation Actual - Ops to Dec 2009	126
Max Hours Generation Ops – to Dec 2015	170
Max Hrs Gen Ops to Gen End Date Dec 2020	179
Max Hours Ops – 1986 to Dec 2009	113
Max Hrs - 1986 to Dec 2015	142
Max Hrs – 1986 to Gen End Date Dec 2020	164

Max Hours Ops – 2007/8 to Dec 2009	5
Max Hrs – 2007/8 to Dec 2015	35
Max Hrs – 2007/8 to Gen End Date Dec 2020	59

10.2.1.3 Inspection and Repair History

Asset 8340 Economizer

As per part of routine non destructive evaluation (NDE) inspections, ultrasonic thickness (UT) measurement readings are taken at specified locations on the economizer inlet and outlet headers. However, inspection results were not available. The following discussion summarizes the significant inspections and repairs completed on the economizer section servicing Unit 3.

During the 2002 outage, the economizer inlet header was opened for debris removal and internal visual inspection using boroscope. Loose debris was found in the inlet header and was removed. The findings of internal inspection are not mentioned in the outage report.

During the 2004 outage, a thermocouple was installed on the inlet header near the inlet pipe. However, it appears from the outage reports that the thermocouple has not been commissioned yet.

During 2008 outage, an angle beam UT inspection of the first 3 inches of twelve tubes at the economizer inlet header was carried out. The first two and last two rows were selected along with other tubes at random. No defects were found.

During the field walkdown by AMEC, it was observed that the economizer link piping did not have any pipe support.

Asset 8351 Waterwall Headers, Downcomers, and Lower and Upper Feeder Tubes

Exterior visual inspections of the lower and upper waterwall headers are carried out during the boiler outage inspections. Lower waterwall headers were opened a number of times for debris removal after boiler repairs. There were no internal inspections done for checking for ligament cracking or cracking at other locations.

During 2008 outage, all eight of the lower waterwall headers were opened for inspection and cleaning after completion of the boiler chemical clean. In the two east/west headers, there was a circumferential weld at the handhole location. The inside of the weld across from the handhole in both headers appeared to have poor fusion at the root and it was considered to be superficial.

UT measurements were taken on the waterwall circuit feeder and riser tubes. During 2004 outage, four of the 5 inch diameter riser (upper feeder) tubes were inspected with angle beam UT method to look for cracking. No defect was found.

Asset 8344 Steam Drum

All the accessible internal seam and nozzle welds are inspected using the Wet Fluorescent Magnetic Particle Examination (WFMT) method during every outage. A varying degree of magnetite layer was observed during outage inspections. Although slight pitting was observed but not active, it is not considered a pressure integrity issue for the steam drums.

Asset 8351 High Temperature Headers and Piping

During annual maintenance outages, Magnetic Particle Inspection (MPI) is carried out on the selective tube to header welds on the superheater and reheater section headers subject to accessibility. There has been no abnormality observed to date. Also, UT measurements were taken on the headers next to MPI locations. No significant header wall thinning was noted.

During the 2001 outage, the reheater inlet header and all ten vertical reheater headers were internally inspected. Handhole caps in the vertical headers were not removed. These headers were inspected through tube stubs with a boroscope prior to installing plugs.

During the 2003 outage, a boroscope inspection of the reheater outlet header was conducted and a layer of scale was noted on the inside surfaces. The scale was adhered and there did not appear to be any significant accumulation of loose scale in the header.

During the 2007 outage, the reheater outlet header was inspected using a boroscope. Evidence of exfoliating scale was found and it was noted that it could be the source of solid particle erosion that has been found in the turbine. There was no indication of any ligament cracking but a close-up view of the ligaments could not be taken due to the limitations of the boroscope.

Asset 8360 Superheater Link Piping and Attemperator

During the 2009 outage, a boroscopic internal visual inspection of the superheater attemperator was completed. Also, the spray assembly was removed for a better inspection of the liner. There were no obvious problems detected. However, it would have been difficult to identify fine defects with the limitations of the equipment. It was concluded the liner was 100% intact and appeared to be in good condition.

Asset 8340 Economizer Tubes

There were minor tube misalignment problems experienced in the past when the misalignment caused a sharp contact with tube support saddles. These were primarily due to the offset tubes that accommodate the circumferential seams in the economizer outlet header. Such problems were corrected during outages. Also, some of the spacer pins on the tubes were seen to overlap causing the tubes to be close together. However, there was no contact between the tubes.

During the 2008 outage, an angle beam UT inspection of the first 3 inches of twelve tubes at the economizer inlet header was carried out. The first two and last two rows were selected along with other tubes at random and no defects were found.

Asset 8351 Waterwall Tubes

During the 2007 outage, two tube samples were removed and a boroscope inspection of the remaining tubes above and below these tube samples was completed. The samples were removed from each side wall at a location approximately 1/3 of the boiler depth from the rear furnace wall. The tubes were found to be free of any heavy build-up or attack. However some corrosion was noted on butt joints. Also, a thermocouple was installed on each sidewall to measure the inside membrane temperature at the request of the regulator as a result of the Unit 2 waterwall experience.

Extensive pitting has been observed throughout the furnace, particularly on the front and side walls around the burner elevations. General wastage has been noted with some isolated deep pits. Also, corrosion of the furnace floor tubes has been observed. UT measurement readings are taken to monitor the corrosion.

Assets 8360/8384 Superheater and Reheater Tubes

The 2007 outage report documents slight pitting in the primary superheater section tube at the 8th floor above the sootblower. A random thickness measurement was taken on the lower secondary superheater section of Unit 3 during the 2003 outage and all tubes checked were found to be well above the design thickness. There was tube misalignment experienced due to burned back support saddles, failure of alignment lugs due to fretting, tube hanger detachment from the support lug along the front/baffle wall, and the tubes were not contacting on the support saddles. New saddles are installed as required and the loops are pulled up and set onto the new saddles depending upon the outage schedule. There was no evidence of sootblower erosion.

Asset 8384 Reheater

During the 2001 outage, a total of 44 square metres (460 square feet) was removed from the primary (lower) reheater section by removing and plugging one tube from each platen. The remaining tubes were replaced, with the lower two rows upgraded from SA-213-T22 to SA-213-TP 347H and the remaining tubes with SA-213-T22 material. Also, a total of 175 square metres (1858 square feet) of heating surface was removed from the secondary (upper) reheater by removing four passes from each of the 60 elements. New “dog-leg” sections were installed to join the original tube ends in the horizontal section to the original tube ends in the vertical section near the baffle wall. Sagging has been observed in the primary reheater tubes (these were new tubes installed in 2001). Some tubes have sagged and are nearly in contact with the tube below in most platens near the middle of the unit.

Asset 8337 Safety Valves, Casings, & Structure/Hangers

Safety relieve valves (SRVs) are inspected and maintained as per the plant SRV testing and overhaul program. The program and is considered adequate to maintain the SRVs for the desired life of 2020.

Casing: The casing has a history of failures associated with both fabric and metallic expansion joints. These are repaired and replaced as required. Failures of both fabric and metallic expansion joints are an ongoing issue. During the AMEC field walkdown, some boiler expansion joints were found leaking.

Steel Structure and Hangers: Corrosion in the boilers penthouse areas was identified in walkdowns of the unit. The condition of the boiler refractory is uncertain.

Asset 8494/8495 Boiler Blow Down Tank

The unit is inspected annually, except in 2009 and 2010. In 2009, the unit was inspected externally only due to access and isolation issues. Deterioration of internals and corrosion have been continuing issues, but safety concerns with access, isolation, and cramped spaces are primary concerns.

10.2.1.4 Condition Assessment

The condition assessment of the Unit boiler system is illustrated below in Table 10-27.

TABLE 10-27 CONDITION ASSESSMENT – UNIT 3 BOILER SYSTEM

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset Level 2	Asset Level 3	Description	Detail	Condition Summary ID#	Append #	Condition	EPRI Identifier	Original Life (Base Load) Ops Hrs (Yrs)	Current Expected Minimum Remaining Life Years (Subject to Test)	End of Life (EOL) Required	Next Regular Inspection	Next Planned Overhaul or Major Inspection	Capability to Reach Next Overhaul	Capability to Reach EOL	In Service
1296	8193	8336	0	0	0	3	BOILER PLANT	BOILER PLANT	BOILER PLANT	N/A	55	30	No active high energy piping management program. High temperature piping constant support hanger monitoring program discontinued after 2001. A few skewed hangers, topped or bottomed up constant spring support, and interference problem (only Unit 3) for main steam, hot reheat and cold reheat lines.	4	200000 (30)	(5)	2020	2011	2014	Yes	Yes	1980
1296	8193	8336	8339	0	0	3	BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER FW & SAT'D STEAM SYS	N/A	56	30	Four upper riser tubes inspected during 2004 outage and no defect found. no internal inspections of the lower waterwall headers for ligament cracking or cracking at other locations due to thermal/corrosion fatigue.	4	200000 (30)	(10)	2020	2011	2014	Yes	Yes	1980
1296	8193	8336	8339	8340	0	3	BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER ECONOMIZER	Headers & link Piping	57	30	Few problems with economizer outlet headers or link piping to the steam drum. 2008 outlet tubes inspection considered adequate. Results of internal inspection of inlet header in 2002 not known. No inspections of economizer recirculation line at connection points to economizer inlet and waterwall circuit.	4	200000 (30)	(10)	2020	2011	2014	Yes	Yes	1980
1296	8193	8336	8339	8340	0	3	BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER ECONOMIZER	Tubing	58	30	Insufficient inspections to assess damage. Wall thickness review inconclusive -some 2009 readings decreased and some increased vs 2004.	4	200000 (30)	(10)	2020	2011	2014	Yes	Yes	1980
1296	8193	8336	8339	8344	0	3	BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER STEAM DRUM	N/A	59	30	No major life limiting issues observed during previous limited steam drum inspections. Design assessed as having no significant concerns. Inspections were focused at visible areas only and many of the susceptible locations have not been inspected.	4	200000 (30)	10	2020	2011	2014	Yes	Yes	1980
1296	8193	8336	8359	8360	0	3	BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER PRIMARY SUPERHEATER	tubes	62	30	No significant life limiting issue has been observed in the primary superheater section tubes. No thickness measurement record available. Slight OD pitting noted on primary superheater tubes.	4	200000 (30)	10	2020	2011	2014	Yes	Yes	1980
1296	8193	8336	8359	8362	0	3	BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER SUPERHEATER ATTEMPERATOR	N/A	63	30	Design calculations for combination creep and fatigue damage from thermal fatigue raises concern with attemperators. Internal inspection of superheater attemperator in 2009 found no thermal fatigue damage.	4	200000 (30)	(10)	2020	2011	2014	Yes	Yes	1980
1296	8193	8336	8359	8366	0	3	BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER SECONDARY SUPERHEATER	Headers & link Piping	64	30	Design creep life calculations for secondary superheater outlet headers suggest concern.	4	200000 (30)	10	2020	2011	2014	Yes	Yes	1980
1296	8193	8336	8359	8366	0	3	BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER SECONDARY SUPERHEATER	Tubes	65	30	No inspections, including destructive tube sample analysis, done assessing the extent of damage due to creep, sagging, OD liquid ash corrosion and ID high temperature corrosion.	4	200000 (30)	(10)	2020	2011	2014	Yes	Yes	1980
1296	8193	8336	8359	8379	0	3	BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER REHEATER ATTEMPERATOR	N/A	68	30	Design calculations for combination creep and fatigue damage from thermal fatigue raises concern with attemperators. Internal inspection of superheater attemperator in 2009 found no thermal fatigue damage.	4	200000 (30)	(10)	2020	2011	2014	Yes	Yes	1980
1296	8193	8336	8359	8384	0	3	BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER REHEATER	Pipes	69	30	No NDE or metallographic examination reports were found.	4	200000 (30)	(10)	2020	2011	2014	Yes	Yes	1980
1296	8193	8336	8359	8384	0	3	BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER REHEATER	Headers & link Piping	70	30	Design creep life calculations for reheater outlet headers suggest concern. Internal scale noted in reheater outlet header during previous outage inspections.	4	200000 (30)	(10)	2020	2011	2014	Yes	Yes	1980
1296	8193	8336	8359	8384	0	3	BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER REHEATER	Tubing	71	30	No inspections, including destructive tube sample analysis, done assessing the extent of damage due to creep, sagging, OD liquid ash corrosion and ID high temperature corrosion.	4	200000 (30)	(10)	2020	2011	2014	Yes	Yes	1980
1296	8193	8336	8359	8372	0	3	BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER MAIN STEAM LINES	Piping	72	30	No NDE or metallographic examination reports were found.	4	200000 (30)	(10)	2020		2012	Yes	Yes	1980
1296	8193	8336	8359	8372	8373	3	BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER STOP VALVE	N/A	73	30	Original Equipment. No details available.	4	200000 (30)	(10)	2020	2011	2012	Yes	No	1980
1296	8193	8336	8339	8339	0	3	BOILER PLANT	BLR FW & SAT STM	BOILER BLOWDOWN TANKS	N/A	74	30	Thinning, corrosion. Safety issues - isolation and access.	10	200000 (30)	(3)	2020	2013	2013	Yes	No	1980

Notes:

1. A "(bracketed)" value in the "Current Expected Remaining Life" column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation, including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as "(X/Y)" has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

2. The "Next Regular Inspection" column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The "Next Planned Overhaul or Major Inspection" column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a "Desired Life" stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or simply are not known to AMEC.

10.2.1.5 Actions

Based on the condition assessment, the following actions are recommended for the Unit 3 boiler system.

TABLE 10-28 RECOMMENDED ACTIONS – UNIT 3 BOILER SYSTEM

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Unit	Asset 2/3	Asset 3/4	Description	Detail	Action #	App #	Action	Year	Priority
1296	8193	8336	0	0	3	BOILER PLANT	BOILER PLANT	BOILER PLANT	N/A	88		See details below.		
1296	8193	8336	8339	0	3	BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER FW & SAT'D STEAM SYS	N/A	89	30	Perform Level 2 inspections to assess corrosion fatigue, general wall loss and pitting.	2014	2
1296	8193	8336	8339	0	3	BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER FW & SAT'D STEAM SYS	N/A	90	30	Review the destructive testing 2007 report of waterwall tubes to evaluate the findings.	2011	2
1296	8193	8336	8339	0	3	BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER FW & SAT'D STEAM SYS	N/A	91	30	Inspect selective flat end welds of the upper waterwall headers.	2014	2
1296	8193	8336	8339	0	3	BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER FW & SAT'D STEAM SYS	N/A	92	30	Inspect the selective feeder and riser tubes for corrosion fatigue damage.	2014	2
1296	8193	8336	8339	0	3	BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER FW & SAT'D STEAM SYS	N/A	93	30	Perform preliminary internal inspection of lower waterwall headers of the locations and degradation mechanisms identified for steam drum, using boroscope; inspection of selective flat end welds, feeder tube attachment welds and downcomers connection welds.	2014	2
1296	8193	8336	8339	0	3	BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER FW & SAT'D STEAM SYS	N/A	94	30	Perform preliminary inspection of superheater and reheater headers support locations on the downcomers for thermal/mechanical fatigue.	2014	2
1296	8193	8336	8339	8340	3	BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER ECONOMIZER	N/A	95	30	Perform inspection including sample tube removal and ultrasonic sonic testing survey at the accessible locations to assess the potential corrosion fatigue damage	2014	2
1296	8193	8336	8339	8340	3	BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER ECONOMIZER	N/A	96	30	Modify start-up procedures to include monitoring of the thermocouple temperature and using the continuous feed during start-ups.	2014	2
1296	8193	8336	8339	8340	3	BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER ECONOMIZER	N/A	97	30	Perform Level 2 inspections for the economizer inlet header. i. ID visual inspection of bore holes, girth welds and tee welds. If cracking is identified, depth must be assessed.	2014	2
1296	8193	8336	8339	8340	3	BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER ECONOMIZER	N/A	98	30	Visually inspect the economizer outlet headers and supports and the economizer link piping during annual outages to ensure there is no change in the state and/or abnormal movement.	2011	2
1296	8193	8336	8339	8340	3	BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER ECONOMIZER	N/A	99	30	Inspect economizer recirculation line welds to economizer inlet and waterwall circuit.	2014	2
1296	8193	8336	8339	8344	3	BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER STEAM DRUM	N/A	100	30	Remove the drum furniture and a section of the liner to inspect seam welds, nozzle welds, ligaments, downcomers and feedwater inlet pipe.	2014	2
1296	8193	8336	8339	8344	3	BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER STEAM DRUM	N/A	101	30	Perform external inspection of feeder tube welds.	2014	2
1296	8193	8336	8339	8344	3	BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER STEAM DRUM	N/A	102	30	Manage steam drum target life with appropriate operational control and routine inspection and maintenance.	2010	1
1296	8193	8336	8359	0	3	BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER SUPERHEATER & REHEAT	N/A	104	30	Inspect superheater and reheater outlet headers and superheater attemperator header for creep and creep fatigue damage including internal boroscopic, external visual, dimensional on body spool pieces, UT inspections on welds and stub tubes and replica inspection.	2014	2
1296	8193	8336	8359	8360	3	BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER PRIMARY SUPERHEATER	N/A	105	30	Inspect to check the presence of inside pitting and scaling.	2014	2
1296	8193	8336	8359	8360	3	BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER PRIMARY SUPERHEATER	N/A	106	30	Inspect to assess OD pitting and corrosion.	2014	2
1296	8193	8336	8359	8360	3	BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER PRIMARY SUPERHEATER	N/A	107	30	Enhance the present inspection and maintenance program to monitor and control the tubes alignment issues including failure of saddle supports and alignment lugs.	2014	2
1296	8193	8336	8359	8362	3	BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER SUPERHEATER ATTEMP	N/A	108	30	No action recommended.	2014	2
1296	8193	8336	8359	8366	3	BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER SECONDARY SUPERHEATER	N/A	109	30	Perform destructive tube sample analysis on the secondary superheater section to assess the extent of the damage due to creep, sagging, OD liquid ash corrosion and ID high temperature corrosion.	2014	2
1296	8193	8336	8359	8366	3	BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER SECONDARY SUPERHEATER	N/A	110	30	Enhance the present inspection and maintenance program to monitor and control failures of saddle supports and alignment lugs issues.	2011	2

Table 10-28 Cont'd

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Unit	Asset 2/3	Asset 3/4	Description	Detail	Action #	App #	Action	Year	Priority
1296	8193	8336	8359	8379	3	BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER REHEATER ATTEMPERATOR	N/A	111	30	Inspect attemperator and ID of the link piping for evidence of thermal fatigue.	2014	2
1296	8193	8336	8359	8384	3	BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER REHEATER	N/A	112	30	Check the presence of inside pitting and scaling.	2014	2
1296	8193	8336	8359	8384	3	BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER REHEATER	N/A	113	30	Inspect to assess OD pitting and corrosion.	2014	2
1296	8193	8336	8359	8384	3	BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER REHEATER	N/A	114	30	Perform destructive tube sample analysis to assess the extent of the damage due to creep, sagging, OD liquid ash corrosion, ID high temperature corrosion and DMWs.	2014	2
1296	8193	8336	8359	8384	3	BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER REHEATER	N/A	115	30	Enhance the present inspection and maintenance program to monitor and control failures of saddle supports and alignment lugs issues.	2012	2
1296	8193	8336	8359	8384	3	BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER REHEATER	N/A	116	30	Refurbish and use the furnace exit thermoprobe during start-up activities.	2011	2
1296	8193	8336	8359	8372	3	BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER MAIN STEAM LINES	N/A	117	30	Implement an active high energy piping management program including NDE testing at key locations and an high temperature piping constant support hanger monitoring program.	2012	2
1296	8193	8336	8359	8372	3	BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER STOP VALVE	N/A	117a	30	Not assessed in detail. Inspect and refurbish/replace during next major boiler outage.	2012	2
1296	8193	8336	8339	8339	3	BOILER PLANT	BLR FW & SAT STM	BOILER BLOWDOWN TANKS	N/A	118	30	Replace tank.	2013	1

10.2.1.6 Risk Assessment

The risk assessment associated with the Unit 3 boiler system, both from a technological perspective and a safety perspective, is illustrated below in Table 10-29.

TABLE 10-29 RISK ASSESSMENT – UNIT 3 BOILER SYSTEM

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Component	Risk Assess #	Appendix #	Major Issues	Remaining Life Years	Remaining Life Comments	TECHNO_ECO RISK ASSESS MODEL			SAFETY RISK ASSESS MODEL			Possible Failure Event	Mitigation
														(Insufficient Info - Inspection Required Within (x) Years)		Likeli-hood	Conse-quence	Risk Level	Likeli-hood	Conse-quence	Safety Risk		
1296	8193	8336	0	0	0	3	BOILER PLANT	BOILER PLANT	BOILER PLANT		70	30	See detail below.										
1296	8193	8336	8339	0	0	3	BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER FW & SAT'D STEAM SYS	Upper WW Headers	71	30	Thermal fatigue cracking, corrosion-fatigue cracking in flat end welds, corrosion.	10	Could meet the desired life with routine inspections.	2	B	Low	2	C	Medium	Flat end weld cracking. Wall thinning due to corrosion.	Routine inspections.
1296	8193	8336	8339	0	0	3	BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER FW & SAT'D STEAM SYS	Riser Tubes	72	30	Corrosion, corrosion fatigue.	(10)	Inspections are required to assess the remaining life.	1	B	Low	2	C	Medium	Wall thinning due to corrosion.	Inspections are required to assess remaining life.
1296	8193	8336	8339	0	0	3	BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER FW & SAT'D STEAM SYS	Lower WW Headers	73	30	Thermal fatigue cracking, corrosion-fatigue cracking, corrosion.	(10)	No real life limiting issue. Additional inspections	3	B	Med	3	B	Medium	Ligament cracking and weld cracking.	Additional inspections required.
1296	8193	8336	8339	0	0	3	BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER FW & SAT'D STEAM SYS	Feeder Tubes	74	30	Corrosion, corrosion fatigue.	(10)	Inspections are required to assess the remaining life.	3	B	Med	3	B	Medium	Corrosion fatigue cracking and wall thinning due to corrosion related mechanism.	Inspections are required to assess remaining life.
1296	8193	8336	8339	0	0	3	BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER FW & SAT'D STEAM SYS	Downcomers	75	30	Thermal/mechanical fatigue.	10	No real life limiting issue.	1	B	Low	3	B	Medium	Thermal/mechanical fatigue.	Inspections are required to assess remaining life.
1296	8193	8336	8339	0	0	3	BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER FW & SAT'D STEAM SYS	Primary Sat. Steam Header	76	30	Thermal fatigue.	10	No real life limiting issue. Could meet the desired life with routine inspections.	1	B	Low	1	C	High	Thermal fatigue cracking.	Inspections are required to assess remaining life.
1296	8193	8336	8339	0	0	3	BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER FW & SAT'D STEAM SYS	Waterwall Tubes	77	30	Corrosion fatigue, thermal/mechanical fatigue, water side under-deposit corrosion, short-term overheat, fireside corrosion/erosion.	(10)	Some sections of floor tubes require attention, other than that no major life limiting issue observed. Additional inspections required.	3	B	Med	3	B	Medium	Tube failure due to corrosion fatigue, general wall loss and pitting at the susceptible locations.	Pitting in some areas require attention.
1296	8193	8336	8339	8340	0	3	BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER ECONOMIZER	Economizer Inlet Headers	78	30	Thermal/mechanical fatigue cracking, corrosion-fatigue cracking, corrosion, FAC.	(10)	No real issue as per inspection to date. Additional inspections required	3	B	Med	3	B	Medium	Ligament cracking, tube stub thinning/cracking, weld cracking.	Additional inspections required.
1296	8193	8336	8339	8340	0	3	BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER ECONOMIZER	Economizer Outlet Headers and Link Piping	79	30	Mechanical fatigue cracking, corrosion-fatigue cracking, corrosion.	10	Could meet the desired life with routine inspections.	1	B	Low	1	B	Low	Weld cracking due to support failure.	Routine inspections.
1296	8193	8336	8339	8340	0	3	BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER ECONOMIZER	Economizer Recirculation Line	80	30	Thermal fatigue.	(10)	Inspections are required to assess the remaining life.	3	B	Med	3	B	Medium	Weld cracking.	Inspections are required to assess remaining life.
1296	8193	8336	8339	8340	0	3	BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER ECONOMIZER	Economizer Tubes	81	30	External corrosion and corrosion-fatigue.	(10)	Inspections are required to assess the remaining life.	1	B	Low	1	B	Low	Tube failure due to corrosion, corrosion-fatigue.	Inspections are required to assess remaining life.
1296	8193	8336	8339	8344	0	3	BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER STEAM DRUM	Steam Drum	82	30	Thermal/mechanical fatigue.	10	No real life limiting issue.	3	C	Med	3	C	High	Thermal/mechanical fatigue.	Additional inspections required.
1296	8193	8336	8359	8360	0	3	BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER PRIMARY SUPERHEATER	Primary Superheater Inlet Header	85	30	Thermal fatigue.	10	No real life limiting issue. Could meet the desired life with routine inspections.	1	B	Low	1	D	High	Thermal fatigue cracking.	Additional inspections required.
1296	8193	8336	8359	8360	0	3	BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER PRIMARY SUPERHEATER	Primary Superheater Outlet Header	86	30	Creep and thermal fatigue.	10	No real life limiting issue. Could meet the desired life with routine inspections.	1	B	Low	1	D	High	Creep and thermal fatigue cracking.	Additional inspections required.
1296	8193	8336	8359	8360	0	3	BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER PRIMARY SUPERHEATER	Primary Superheater Tubes	87	30	Fatigue, OD/ID corrosion, ID pitting.	10	No real life limiting issues; however, the presence inside pitting and scaling is not known.	1	C	Low	1	C	High	Tube failure due to excessive pitting and corrosion.	Additional inspections required.
1296	8193	8336	8359	8362	0	3	BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER SUPERHEATER ATTEMP	Superheater Attemperator Header	88	30	Creep and thermal fatigue.	(10)	Additional inspections required to assess the remaining life.	3	C	Med	3	D	High	Creep and thermal fatigue cracking.	Additional inspections required.
1296	8193	8336	8359	8366	0	3	BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER SECONDARY SUPERHEATER	Secondary Superheater Inlet Header	89	30	Creep and thermal fatigue.	10	No real life limiting issue. Could meet the desired life with routine inspections.	1	C	Low	1	D	High	Creep and thermal fatigue cracking.	Additional inspections required.
1296	8193	8336	8359	8366	0	3	BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER SECONDARY SUPERHEATER	Secondary Superheater Outlet Header	90	30	Creep and thermal fatigue.	(10)	Additional inspections required to assess the remaining life.	3	D	High	3	D	High	Creep and thermal fatigue cracking.	Additional inspections required.
1296	8193	8336	8359	8366	0	3	BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER SECONDARY SUPERHEATER	Secondary Superheater Tubes	91	30	Creep, OD/ID corrosion, ID pitting and sagging.	(10)	Inspections are required to assess the remaining life.	3	C	Med	3	C	High	Tube failure due to creep and Creep, OD/ID corrosion, ID pitting.	Additional inspections required.
1296	8193	8336	8359	8379	0	3	BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER REHEATER ATTEMPERATOR	N/A	94	33	Not addressed in detail	(10)	Additional inspections required to assess the remaining life.	3	B	Medium	3	C	High	Creep and thermal fatigue cracking.	Inspection and refurbish or replace.

Table 10-29 Cont'd

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Component	Risk Assess #	Appendix #	Major Issues	Remaining Life Years (Insufficient Info - Inspection Required Within (x) Years)	Remaining Life Comments	TECHNO_ECO RISK ASSESS MODEL Likeli-hood	TECHNO_ECO RISK ASSESS MODEL Conse-quence	TECHNO_ECO RISK ASSESS MODEL Risk Level	SAFETY RISK ASSESS MODEL Likeli-hood	SAFETY RISK ASSESS MODEL Conse-quence	SAFETY RISK ASSESS MODEL Safety Risk	Possible Failure Event	Mitigation
1296	8193	8336	8359	8384	0	3	BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER REHEATER	Hot Reheat	95	33	Thermal/mechanical fatigue, creep, creep-fatigue, corrosion.	(10)	Major issue is creep and creep fatigue. Creep life fraction expended is high (> 25% for Unit 3 at end 2009). No evidence of upset or thermal fatigue. Metallographic inspections conducted in past for U1 & 2 (1987 to 2002); no significant crack or damage found. No major damage found during walkdowns.	3	C	Med	3	D	High	Pipe and/or weld failures at potentially high stress locations.	Inspect hot and cold walkdowns to assess hanger condition and potential high stress locations. FOCUS Phased Array and Metallographic Inspections at key locations Hanger/Support Inspection and Monitoring Program. Level 2 assessments.
1296	8193	8336	8359	8384	0	3	BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER REHEATER	Cold Reheat	96	33	Thermal/mechanical fatigue, corrosion-fatigue, cracking, corrosion.	(10)	No seam-welded pipe. No NDE inspection or material testing done in recent past. Not possible to assess current condition or remaining life. No major damage found during walkdowns.	1	B	Low	1	D	Low	Pipe and/or weld failures at potentially high stress locations.	Piping Management Program. Hanger/Support Inspection and Monitoring Program. Level 2 assessments.
1296	8193	8336	8359	8384	0	3	BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER REHEATER	Reheater Inlet Header	97	30	Thermal fatigue.	10	Could meet the desired life with routine inspections.	1	B	Low	1	D	Low	Thermal fatigue cracking.	Inspect and maintain.
1296	8193	8336	8359	8384	0	3	BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER REHEATER	Lower and upper Reheater Link Header	98	30	Thermal fatigue.	10	Could meet the desired life with routine inspections.	1	B	Low	1	D	Low	Thermal fatigue cracking.	Inspect and maintain.
1296	8193	8336	8359	8384	0	3	BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER REHEATER	Reheater Outlet Header	99	30	Creep and thermal fatigue.	(10)	Additional inspections required to assess the remaining life.	3	D	High	3	D	High	Creep and thermal fatigue cracking.	Inspect and maintain.
1296	8193	8336	8359	8384	0	3	BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER REHEATER	Reheater Tubes	100	30	Creep, OD/ID corrosion, ID pitting, stress corrosion cracking and DMWs.	(10)	Inspections are required to assess the remaining life.	3	C	Med	3	C	High	Creep, fatigue and stress corrosion cracking damage, wall thinning due to corrosion and pitting and DMW failures.	Additional inspections required.
1296	8193	8336	8359	8372	0	3	BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER MAIN STEAM LINES	N/A	101	33	Thermal/mechanical fatigue, creep, creep-fatigue, corrosion.	(10)	Major issue is creep and creep fatigue. Creep life fraction expended is high (> 25% for Unit 3 at end 2009). No evidence of upset or thermal fatigue. Metallographic inspections conducted in past for U1 & 2 (1987 to 2002); no significant crack or damage found. No major damage found during walkdowns.	3	D	High	3	D	High	Pipe and/or weld failures at potentially high stress locations.	Inspect hot and cold walkdowns to assess hanger condition and potential high stress locations. Conduct inspections of welds at potentially high stress locations.
1296	8193	8336	8359	8372	8373	3	BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER STOP VALVE	N/A	101a	33	Not addressed in detail. Thermal/mechanical fatigue. creep, creep-fatigue, corrosion.	(5)	Additional inspections required to assess the remaining life.	3	C	Medium	3	C	High	Creep and thermal fatigue cracking.	Inspection and refurbish or replace.
1296	8193	8336	8339	8339	0	3	BOILER PLANT	BLR FW & SAT STM	BOILER BLOWDOWN TANKS	N/A	102	33	Not addressed in detail. Thermal/mechanical fatigue. creep, erosion.	(2)	Safety issue. End of life.	2	B	Medium	3	C	High	Mechanical failure. Steam leak. Personal injury.	Replace

10.2.1.7 Life Cycle Curve and Remaining Life

The life cycle curves for the various elements of the Unit 3 boiler system is broken into three separate parts – the boiler headers and components outside the flue gas path, the high pressure and temperature steam lines (main steam, reheat steam), and the tubes exposed to the combustion process and/or flue gas within the boiler. Differences between the scenarios do not materially affect the curve.

The boiler headers and components are subject primarily to time spent under the effects of steam pressure and temperature. Their equivalent expended life presented in figure below is primarily related to the material properties and the steam conditions. As a result several curves are required to represent the range of the various elements of the system. Details are included in Appendix 30. The life curves are plots on the y-axis of current and projected consumed equivalent life hours based on the theoretical metallurgical assessments. This differs from other sections that use nominal operating hours of usage on the y-axis versus calendar year on the x-axis. The figure has several vertical lines representing differing representative nominal age limits for various components. It also has several horizontal lines that represent a range of practical equipment equivalent base loaded operating hour life limits. The figure also included two highlighted boxes. The risk box is representative of typical life expectations. The second identified as the “Level 2 Test” box identifies where EPRI recommends an initial Level 2 analyses or equivalent for these sorts of components (consumed life = 10% of expected or design life).

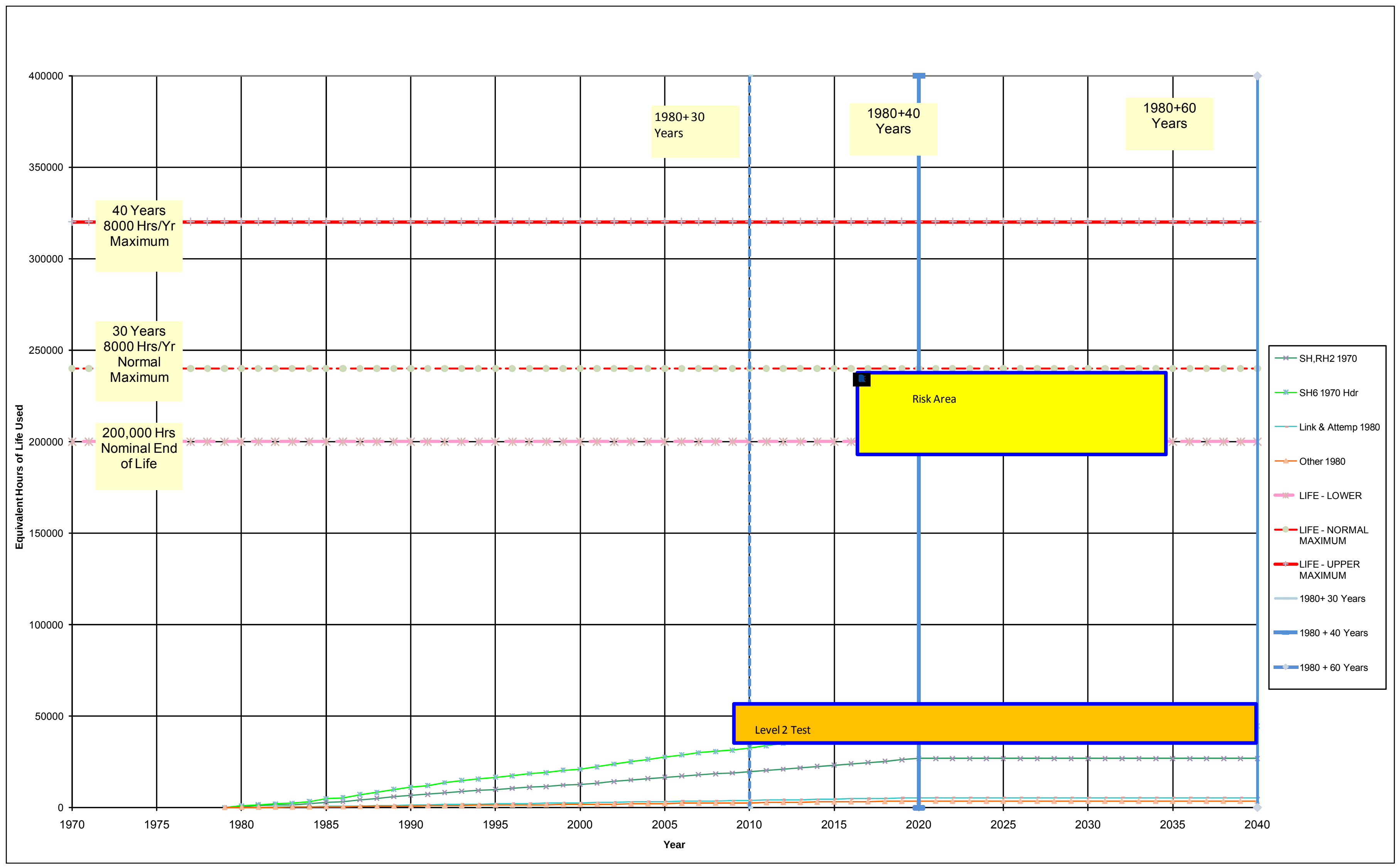

FIGURE 10-13 LIFE CYCLE CURVE – UNIT 3 BOILERS (HEADERS AND COMPONENTS)

The header life curves indicate that the remaining life (RL) of the Unit 3 boiler headers and associated components is expected to exceed the desired life (DL) which is the generation end of life in 2020. Nevertheless, it also identifies that some of higher temperature components should undergo a Level 2 inspection (identified later in this section of the report) if not already planned or undertaken.

Three curves represent the high pressure, high temperature steam lines (main steam, hot reheat, and cold reheat). Their life expenditure (illustrated in figure below) is primarily related to the time spent under the effects of steam pressure and temperature (similar to the boiler headers) and to the material properties of the steam lines. Details are included in Appendix 33. The life curves are plots on the y-axis of current and projected "consumed equivalent life hours" based on the theoretical metallurgical assessments. The figure has three vertical lines representing differing representative nominal age limits. It also has several horizontal lines that represent a range of practical equipment equivalent base loaded operating hour life limits. The figure also included two highlighted boxes. The risk box is representative of typical life expectations. The second identified as the "Level 2 Test" box identifies where an initial Level 2 analyses or equivalent is likely required (consumed life = 10% of expected life).

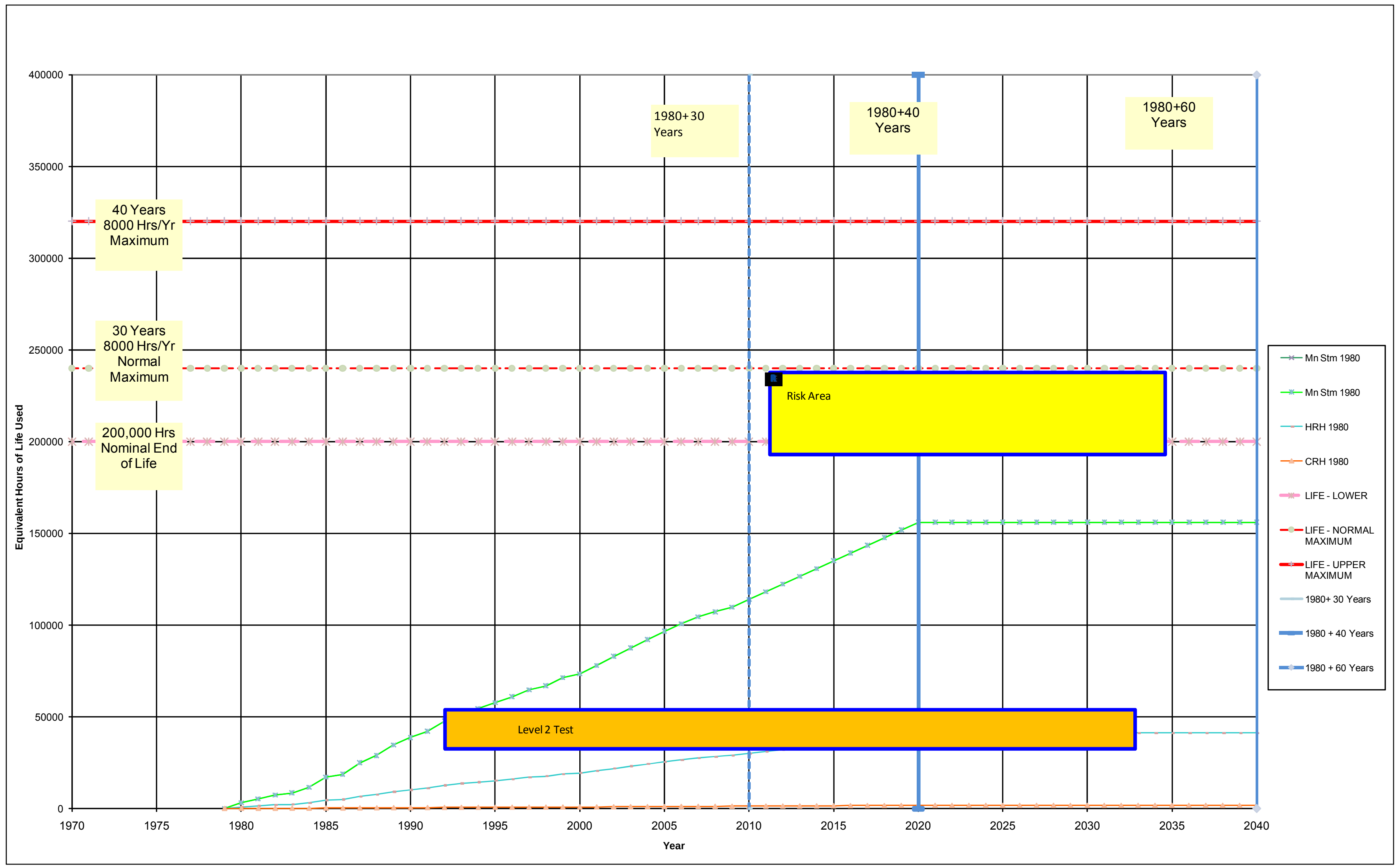

FIGURE 10-14 LIFE CYCLE CURVE – UNIT 3 BOILERS (HIGH PRESSURE AND TEMPERATURE STEAM LINES)

The high pressure steam line life curves indicate that the remaining life (RL) of the Unit 3 steam lines and their associated components are expected to exceed the desired life (DL) which is the generation end of life in 2020. Nevertheless it also identifies that both the main steam and hot reheat steam lines exceed EPRI's 10% consumed life guide for a Level 2 inspection of these systems. Given that they have not been tested for some time, this is considered appropriate at this time.

The Unit 3 boiler system tubes and associated components (exposed to combustion process and/or flue gas within the boiler) are subject to both internal water and/or steam intermediate temperatures and high pressures, but also externally to higher combustion temperatures, and corrosive and erosive conditions. Typically, the externally conditions often are the life limiting factor. This is certainly the case for Holyrood units which were fuelled with a high sulphur, high vanadium, moderate ash heavy oil up until 2009. This is evident in the reliability statistics for the boilers, the multiple boiler outages for air preheater cleaning, economizer fouling history, and in the fairly extensive tube surface changes to 2009. The move to a lower sulphur, lower vanadium oil has effectively minimized these going forward, but some legacy effects are inevitable.

A single life cycle curve is presented beginning with the in-service date of the unit. It is meant to represent initial design goals, using nominally operating hours. It was considered impractical to accurately document or reasonably present in one curve the many changes that have occurred, and are likely to continue to occur going forward due to legacy impacts. It is shows the current status of the boiler blowdown tank, which is both a life issue and a safety issue. It uses nominal operating hours as opposed to metallurgical equivalent hours in the two previous boiler curves as a more appropriate way of expressing its normal lifetime.

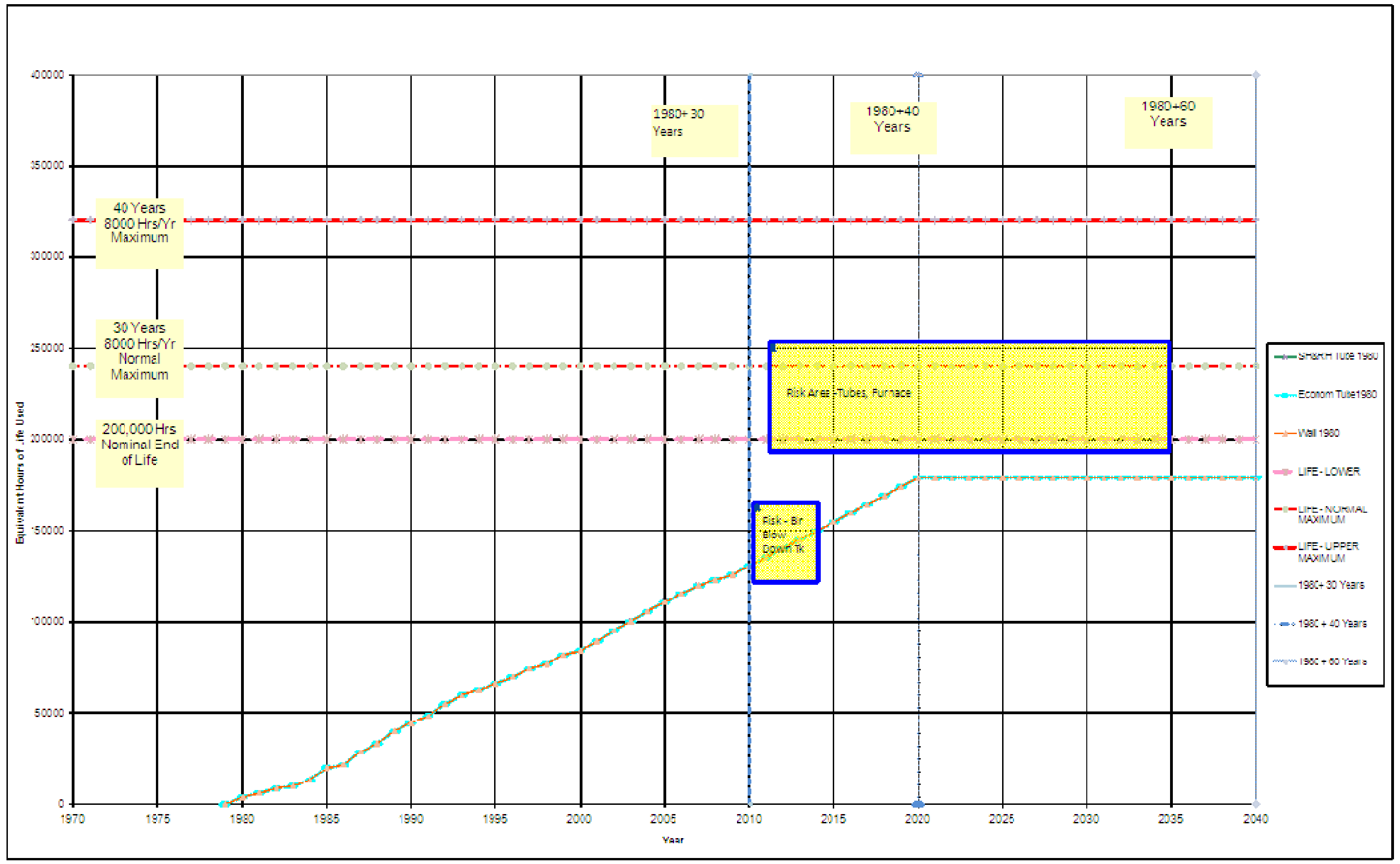

FIGURE 10-15 LIFE CYCLE CURVE – UNIT 3 BOILER SYSTEM (TUBES EXPOSED TO THE COMBUSTION PROCESS)

The curve indicates that the boiler tubes within the furnace envelope would have been expected to be seeing some end of life component concerns with original equipment. Nevertheless, it is more likely legacy impacts that will have greater effects on component replacements and refurbishments going forward to 2020. With ongoing inspections and refurbishments, 2020 is achievable with good reliability with the new fuel. It also shows that the boiler blowdown tank should be replaced.

10.2.1.8 Level 2 Inspection Requirements and Costs

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 10-30 below, assuming the current plant inspection and maintenance program is maintained or improved.

TABLE 10-30 LEVEL 2 INSPECTION – UNIT 3 BOILER SYSTEM

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Sub System Comment	L2#	Appendix #	Level 2 Work	Year	Priority	Cost k$
1296	8193	8336	0	0	0	3	BOILER PLANT	BOILER PLANT	BOILER PLANT	None	54	30	Level 2 - Covers all boiler pressure part system costs - economizer, reheat, superheat, drum.	2014	1	$1,520
1296	8193	8336	8339	0	0	3	BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER FW & SAT'D STEAM SYS	Upper WW Headers	55	30	Inspection of selective flat end welds. External visual and thickness measurement.	2014	3	
1296	8193	8336	8339	0	0	3	BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER FW & SAT'D STEAM SYS	Riser Tubes	56	30	No Level 2 inspections or testing is required.	2014	3	
1296	8193	8336	8339	0	0	3	BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER FW & SAT'D STEAM SYS	Lower WW Headers	57	30	Inspections of ligament cracking, selective flat end welds, body spool pieces welds, feeder tube attachment welds and downcomers connection welds.	2014	2	
1296	8193	8336	8339	0	0	3	BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER FW & SAT'D STEAM SYS	Feeder Tubes	58	30	Inspection of selective riser tube for corrosion fatigue cracking.	2014	2	
1296	8193	8336	8339	0	0	3	BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER FW & SAT'D STEAM SYS	Downcomers	59	30	No Level 2 inspections or testing is required.	2014	3	
1296	8193	8336	8339	0	0	3	BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER FW & SAT'D STEAM SYS	Waterwall Tubes	60	30	Inspections to assess corrosion fatigue, general wall loss and pitting at the susceptible locations.	2014	2	
1296	8193	8336	8339	8340	0	3	BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER ECONOMIZER	Economizer Inlet Headers	61	30	Inspection of internal surfaces, ligaments, major girth and seam welds and drain line penetrations. UT inspection of stub tubes and a stub tube sample removal to assess evidence of FAC.	2014	2	
1296	8193	8336	8339	8340	0	3	BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER ECONOMIZER	Economizer Outlet Headers and Link Piping	62	30	External visual inspection to ensure that there is no change in the state and/or abnormal movement.	2014	3	
1296	8193	8336	8339	8340	0	3	BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER ECONOMIZER	Economizer Recirculation Line	63	30	Inspect economizer recirculation line welds to economizer inlet and waterwall circuit.	2014	2	
1296	8193	8336	8339	8340	0	3	BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER ECONOMIZER	Economizer Tubes	64	30	Sample tubes removal.	2014	3	
1296	8193	8336	8339	8344	0	3	BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER STEAM DRUM	Steam Drum	65	30	Removal of the drum furniture and a section of the liner to inspect seam welds, nozzle welds, ligaments, downcomers and feedwater inlet pipe. External inspection of feeder tube welds.	2014	2	
1296	8193	8336	8359	8360	0	3	BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER PRIMARY SUPERHEATER	Primary Sat. Steam Header	68	30	No Level 2 inspections or testing is required.	2014	3	
1296	8193	8336	8359	8360	0	3	BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER PRIMARY SUPERHEATER	Primary Superheater Inlet Header	69	30	No Level 2 inspections or testing is required.	2014	3	
1296	8193	8336	8359	8360	0	3	BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER PRIMARY SUPERHEATER	Primary Superheater Outlet Header	70	30	No Level 2 inspections or testing is required.	2014	3	

Table 10-30 Cont'd

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Sub System Comment	L2#	Appendix #	Level 2 Work	Year	Priority	Cost k$
1296	8193	8336	8359	8360	0	3	BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER PRIMARY SUPERHEATER	Primary Superheater Tubes	71	30	Inspections to check the presence inside pitting and scaling.	2014	3	
1296	8193	8336	8359	8362	0	3	BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER SUPERHEATER ATTEMP	Superheater Attemperator Header	72	30	Creep and creep fatigue damage including internal boroscopic, external visual, dimensional on body spool pieces, UT inspections on welds and stub tubes and replica inspection.	2014	2	
1296	8193	8336	8359	8366	0	3	BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER SECONDARY SUPERHEATER	Secondary Superheater Inlet Header	73	30	No Level 2 inspections or testing is required.	2014	3	
1296	8193	8336	8359	8366	0	3	BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER SECONDARY SUPERHEATER	Secondary Superheater Outlet Header	74	30	Internal boroscopic, external visual, dimensional on body spool pieces for creep and creep fatigue damage; UT inspections on welds and stub tubes and replica inspection.	2014	1	
1296	8193	8336	8359	8366	0	3	BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER SECONDARY SUPERHEATER	Secondary Superheater Tubes	75	30	Inspections to assess the extent of the damage due to creep, sagging, OD liquid ash corrosion and ID high temperature corrosion for creep, fatigue corrosion and pitting.	2014	2	
1296	8193	8336	8359	8379	0	3	BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER REHEATER ATTEMPERATOR	None	76	30	No Level 2 inspections or testing is required.	2014		
1296	8193	8336	8359	8384	0	3	BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER REHEATER	Reheater Inlet Header	77	30	No Level 2 inspections or testing is required.	2014	3	
1296	8193	8336	8359	8384	0	3	BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER REHEATER	Lower and Upper Reheater Link Header	78	30	No Level 2 inspections or testing is required.	2014	3	
1296	8193	8336	8359	8384	0	3	BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER REHEATER	Reheater Outlet Header	79	30	Internal boroscopic, external visual, dimensional on body spool pieces for creep and creep fatigue damage; UT inspections on welds and stub tubes and replica inspection.	2014	1	
1296	8193	8336	8359	8384	0	3	BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER REHEATER	Reheater Tubes	80	30	Inspections to assess the extent of the damage due to destructive tube sample analysis to assess the extent of the damage due to creep, OD liquid ash corrosion, ID high temperature corrosion, stress corrosion cracking and DMWs.	2014	2	
1296	8193	8336	8359	8372	99000154	3	BOILER PLANT	BOILER SUPERHEATER & REHEAT	HIGH PRESSURE STEAM SYSTEM	None	81	30	No Level 2 inspections or testing is required.	2014		
1296	8193	8336	8359	8372	99000155	3	BOILER PLANT	BOILER SUPERHEATER & REHEAT	HIGH PRESSURE STEAM SYSTEM UNI	None	82	30	No Level 2 inspections or testing is required.	2014		
1296	8193	8336	8359	8372	0	3	BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER MAIN STEAM LINES	(Testing of Main Steam, Hot Reheat, Cold Reheat, HP feedwater	83	30	Level 2 testing of steam and high pressure feedwater lines.	2012	1	$407
1296	8193	8336	8359	8372	8373	3	BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER STOP VALVE	None	83a	30	Level 2 testing of boiler stop valves as part of main steam lines program.	2012	1	$31
1296	8193	8336	8339	8339	0	3	BOILER PLANT	BLR FW & SAT STM	BOILER BLOWDOWN TANKS	None	84	30	No Level 2 inspections or testing is required.			

10.2.1.9 Capital Projects

The suggested typical capital enhancements for the Unit 3 boiler system include:

TABLE 10-31 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – UNIT 3 BOILER SYSTEM

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Detail	CAP#	Appendix #	Unit #	Capital Item	Date	Priority
1296	8193	8336	0	0	0	3	BOILER PLANT	BOILER PLANT	BOILER PLANT	N/A	56	30	3	Install nitrogen blanketing. No other pending Level 2 or next inspection.	2013	2
1296	8193	8336	8339	0	0	3	BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER FW & SAT'D STEAM SYS	N/A	57	30	3	None, pending Level 2 or next inspection.		
1296	8193	8336	8339	8340	0	3	BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER ECONOMIZER	N/A	58	30	3	None, pending Level 2 or next inspection.		
1296	8193	8336	8339	8344	0	3	BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER STEAM DRUM	N/A	59	30	3	None, pending Level 2 or next inspection.		
1296	8193	8336	8359	0	0	3	BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER SUPERHEATER & REHEAT	N/A	61	30	3	None, pending Level 2 or next inspection.		
1296	8193	8336	8359	8360	0	3	BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER PRIMARY SUPERHEATER	N/A	62	30	3	None, pending Level 2 or next inspection.		
1296	8193	8336	8359	8362	0	3	BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER SUPERHEATER ATTEMP	N/A	63	30	3	None, pending Level 2 or next inspection.		
1296	8193	8336	8359	8366	0	3	BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER SECONDARY SUPERHEATER	N/A	64	30	3	None, pending Level 2 or next inspection.		
1296	8193	8336	8359	8372	99000154	3	BOILER PLANT	BOILER SUPERHEATER & REHEAT	HIGH PRESSURE STEAM SYSTEM	N/A	65	30	3	None, pending Level 2 or next inspection.		
1296	8193	8336	8359	8372	99000155	3	BOILER PLANT	BOILER SUPERHEATER & REHEAT	HIGH PRESSURE STEAM SYSTEM UNI	N/A	66	30	3	None, pending Level 2 or next inspection.		
1296	8193	8336	8359	8379	0	3	BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER REHEATER ATTEMPERATOR	N/A	67	30	3	None, pending Level 2 or next inspection.		
1296	8193	8336	8359	8384	0	3	BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER REHEATER	N/A	68	30	3	None, pending Level 2 or next inspection.		
1296	8193	8336	8359	8372	0	3	BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER MAIN STEAM LINES	N/A	69	30	3	None, pending Level 2 or next inspection.		
1296	8193	8336	8359	8372	8373	3	BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER STOP VALVE	N/A	69a	30	3	None, pending Level 2 or next inspection.		
1296	8193	8336	8339	8339	0	3	BOILER PLANT	BLR FW & SAT STM	BOILER BLOWDOWN TANKS	N/A	70	30	3	Replace blowdown tank.	2011	1

10.2.2 Asset 8611 – Unit 3 Feedwater System - HP Feedwater Heat Exchangers

(Detailed Technical Assessment in Working Papers, Appendices 32 and 34)

Unit #:	3
Asset Class #	BU 1296 - Assets Generations
SCI & System:	8523 #3 Condensate & Feedwater System
Sub-Systems:	8611 #3 High Pressure Feedwater
Components:	8818 #3 H.P. Heater 4
	8819 #3 H.P. Heater 5
	8820 #3 H.P. Heater 6
	8848 #3 Boiler Feed Pump East
	8847 #3 Boiler Feed Pump West

10.2.2.1 Description

High pressure (HP) feedwater systems servicing Unit 3 contain three HP feedwater heat exchangers that are referred to as HP-4, HP-5 and HP-6. The primary function of the HP feedwater heat exchangers is to optimize the unit thermal efficiency by preheating the feedwater prior to entering the boilers.

Each HP feedwater heat exchanger is a horizontally mounted, 100% capacity pressure vessel of the U-tube type construction. There are two tube passes on the feedwater side and divided flow of steam on the shell side of the HP feedwater heater. The main components of the HP feedwater heaters are shell, shell skirt, tubes, tubesheet, channel, impingement plates, tube support plates/pass partition plates/baffles, shrouds, impingement plate and channel cover. Tubesheet and channel are made from a single forging. The tubes material for all three HP feedwater heaters is stainless steel SA-688.

There are three zones on the shell side that are commonly referred to as desuperheating, condensing, and drains subcooling.

1. Desuperheating Zone: This is an enclosed portion at the outlet end of the tube bundle. An impingement plate is installed below the steam inlet nozzle to prevent impingement damage to the tubes. The desuperheating zone is enveloped by a separate shroud which conducts the steam from the inlet nozzle to the condensing zone.

2. Condensing Zone: Steam exiting the desuperheating zone is condensed as it traverses through the condensing zone. Also, any drains from higher pressure heater flow into the condensing zone through the drains inlet nozzle. An impingement plate is installed just inside this nozzle to protect the tubes from these flashing drains. The condensing zone is vented continuously to remove non-condensable gases.

3. Drains Subcooling Zone: This zone is an enclosed portion of the inlet end of the tube bundle to maximize heat transfer from the shell side condensate to the incoming feedwater before the condensate exits. The condensate should be sub-cooled sufficiently to prevent flashing as the condensate leaves the HP feedwater heater shell through the drains outlet nozzle.

Two motor driven boiler feed pumps (BFP) service Unit 3. The pumps are multiple stage, barrel centrifugal pumps. Each can provide up to 60% of full load requirement. They have been in service since 1980. The pump motors are 4 kV with a power rating of approximately 1750 kW. They directly drive the pumps. There is no variable speed devices such as variable frequency drives or fluid couplings.

10.2.2.2 History

Manufactured/Delivered	1979
In-Service Date	Feb 1980
Generation Base Load End Date	Dec 2015
Generation Peak/Emerg Gen End Date	Dec 2020

The hours associated with the analyses are:

Hours Generation Actual - Ops to Dec 2009	126
Max Hours Generation Ops – to Dec 2015	170
Max Hrs Gen Ops to Gen End Date Dec 2020	179

10.2.2.3 Inspection and Repair History

There have been no NDE inspections carried out on the HP feedwater heat exchangers currently in service, with the exception of tube leak testing and yearly PM checks. A long term commitment (life-cycle management plan) is required to track and diagnose failures and identify possible remedial actions in order to mitigate similar future occurrences.

HP-4, HP-5 and HP-6 were installed in December 1997 and hence have accumulated less operating hours than other plant HP feedwater heat exchangers, with the exception of Unit 2 HP-5 that was installed in 2009. However, their operating life is greater than the EPRI recommended interval of 5 years for NDE inspections.

The Unit 3 boiler feed pumps and motors are regularly maintained. The plant has a common spare pump barrel that they use to be able to refurbish all of the plant pumps on a six to seven year cycle. The 4 kV motors are tested electrically annually. No specific issues have been identified, but the BFP motors are at a stage in life where failures may be anticipated.

10.2.2.4 Condition Assessment

The condition assessment of the Unit 3 feedwater system – HP feedwater heat exchangers is illustrated below in Table 10-32.

TABLE 10-32 CONDITION ASSESSMENT – UNIT 3 FEED WATER SYSTEM HP FEEDWATER HEAT EXCHANGERS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset Level 2	Asset Level 3	Description	Detail	Condition Summary ID#	Append #	Condition	EPRI Identifier	Original Life (Base Load) Ops Hrs (Yrs)	Current Expected Minimum Remaining Life Years (Subject to Test)	End of Life (EOL) Required	Next Regular Inspection	Next Planned Overhaul or Major Inspection	Capability to Reach Next Overhaul	Capability to Reach EOL	In Service
1296	8193	8528	8590	0	0	3	CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEEDWATER PUMPING	Motors	125	23	4160V Motor annual tests. On-line bearing and winding temperature monitoring and system alarms based on motor current levels. Pumps, using a spare barrel, are refurbished about every seven years.	3a	150000 (25)	(5+)	2020		2014	Yes	No	1980
1296	8193	8528	8590	8859	0	3	CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEED PUMP - EAST	N/A	126	23	Pumps installed in 1978 and motors in 1979. Good condition due to pump refurbishment using spare barrel. Last pump refurbishment 2008, planned for 2014.	3a	200000 (30)	10+	2020	2014	2014	Yes	Yes	1980
1296	8193	8528	8590	8860	0	3	CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEED PUMP - WEST	N/A	127	23	Pumps installed in 1978 and motors in 1979. Good condition due to pump refurbishment using spare barrel. Last pump refurbishment 2005, planned for 2013.	3a	200000 (30)	10+	2020	2013	2013	Yes	Yes	1980
1296	8193	8528	8611	0	0	3	CONDENSATE & F.W. SYSTEM	H.P. FEEDWATER SYSTEM	H.P. FEEDWATER SYSTEM	N/A	128	32,33	No Flow Accelerated Corrosion (FAC) management program. Present water chemistry and operating conditions indicates that the feedwater system is susceptible to FAC.	4	150000 (20)	(5)	2020	2012	2014	Yes	No	1980
1296	8193	8528	8611	8618	0	3	CONDENSATE & F.W. SYSTEM	H.P. FEEDWATER SYSTEM	H.P. HEATER 4	N/A	129	32	Installed Dec 1997. HP feedwater tube leaks experienced plugged in order to satisfy the short-term problem with cause uncertain. Numbers of leaks and locations not known. Uncertain if SCC tube failure degradation mechanism observed at Unit 2 HP-5 applicable to other HP feedwater heaters.	4	(25)	(10)	2020	2012	2014	Yes	Yes	2007
1296	8193	8528	8611	8619	0	3	CONDENSATE & F.W. SYSTEM	H.P. FEEDWATER SYSTEM	H.P. HEATER 5	N/A	130	32	Installed Dec 1997. HP feedwater tube leaks experienced plugged in order to satisfy the short-term problem with cause uncertain. Numbers of leaks and locations not known. Uncertain if SCC tube failure degradation mechanism observed at Unit 2 HP-5 applicable to other HP feedwater heaters.	4	(20)	(10)	2020	2012	2014	Yes	Yes	2007
1296	8193	8528	8611	8620	0	3	CONDENSATE & F.W. SYSTEM	H.P. FEEDWATER SYSTEM	H.P. HEATER 6	N/A	131	32	Installed Dec 1997. HP feedwater tube leaks experienced plugged in order to satisfy the short-term problem with cause uncertain. Numbers of leaks and locations not known. Uncertain if SCC tube failure degradation mechanism observed at Unit 2 HP-5 applicable to other HP feedwater heaters.	4	(25)	(10)	2020	2012	2014	Yes	Yes	2007

Notes:

1. A "(bracketed)" value in the "Current Expected Remaining Life" column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation, including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as "(X/Y)" has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

2. The "Next Regular Inspection" column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The "Next Planned Overhaul or Major Inspection" column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a "Desired Life" stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or simply are not known to AMEC.

10.2.2.5 Actions

Based on the condition assessment, the following actions are recommended for Unit 3 feed water system – HP feedwater heat exchangers:

TABLE 10-33 RECOMMENDED ACTIONS – UNIT 3 FEED WATER SYSTEM - HP FEEDWATER HEAT EXCHANGERS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Unit	Asset 2/3	Asset 3/4	Description	Detail	Action #	App #	Action	Year	Priority
1296	8193	8528	8590	0	3	CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEEDWATER PUMPING	N/A	184	23	Assess potential for variable speed control of BFW pumps.	2011	2
1296	8193	8528	8590	0	3	CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEEDWATER PUMPING	N/A	185	23	Assess potential for spare BFP motor, and subsequent refurbishment/rewind of Unit 3 motors.	2011	2
1296	8193	8528	8590	8859	3	CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEED PUMP - EAST	N/A	186	23	Maintain current program of ongoing inspections and overhauls.	2011	2
1296	8193	8528	8590	8860	3	CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEED PUMP - WEST	N/A	187	23	Maintain current program of ongoing inspections and overhauls.	2011	2
1296	8193	8528	8590	0	3	CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEEDWATER PUMPING	N/A	188	23	Assess potential for variable speed control of BFW pumps.	2011	2
1296	8193	8528	8590	0	3	CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEEDWATER PUMPING	N/A	189	23	Assess potential for spare BFP motor, and subsequent refurbishment/rewind of Unit 3 motors.	2011	2
1296	8193	8528	8590	8859	3	CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEED PUMP - EAST	N/A	190	23	Maintain current program of ongoing inspections and overhauls.	2011	2
1296	8193	8528	8590	8860	3	CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEED PUMP - WEST	N/A	191	23	Maintain current program of ongoing inspections and overhauls	2011	2
1296	8193	8528	8611	0	3	CONDENSATE & F.W. SYSTEM	H.P. FEEDWATER SYSTEM	H.P. FEEDWATER SYSTEM	N/A	192	32	See detail below.		
1296	8193	8528	8611	8618	3	CONDENSATE & F.W. SYSTEM	H.P. FEEDWATER SYSTEM	H.P. HEATER 4	N/A	193	32	Develop a program of ongoing inspections and performance testing.	2011	2
1296	8193	8528	8611	8618	3	CONDENSATE & F.W. SYSTEM	H.P. FEEDWATER SYSTEM	H.P. HEATER 4	N/A	194	32	Perform Level 2 inspections.	2014	2
1296	8193	8528	8611	8619	3	CONDENSATE & F.W. SYSTEM	H.P. FEEDWATER SYSTEM	H.P. HEATER 5	N/A	195	32	Develop a program of ongoing inspections and performance testing.	2011	2
1296	8193	8528	8611	8619	3	CONDENSATE & F.W. SYSTEM	H.P. FEEDWATER SYSTEM	H.P. HEATER 5	N/A	196	32	Perform Level 2 inspections.	2014	2
1296	8193	8528	8611	8620	3	CONDENSATE & F.W. SYSTEM	H.P. FEEDWATER SYSTEM	H.P. HEATER 6	N/A	197	32	Develop a program of ongoing inspections and performance testing.	2011	2
1296	8193	8528	8611	8620	3	CONDENSATE & F.W. SYSTEM	H.P. FEEDWATER SYSTEM	H.P. HEATER 6	N/A	198	32	Perform Level 2 inspections.	2014	2

10.2.2.6 Risk Assessment

Table 10-34 below illustrates the risk assessment for the Unit 3 feedwater system – HP feedwater heat exchangers, both from a technological perspective and a safety perspective using the models presented in Section 3.

TABLE 10-34 RISK ASSESSMENT – UNIT 3 FEEDWATER SYSTEM - HP FEEDWATER HEAT EXCHANGERS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Component	Risk Assess #	Appendix #	Major Issues	Remaining Life Years	Remaining Life Comments	TECHNO_ECO RISK ASSESS MODEL			SAFETY RISK ASSESS MODEL			Possible Failure Event	Mitigation
														(Insufficient Info - Inspection Required Within (x) Years)		Likeli-hood	Conse-quence	Risk Level	Likeli-hood	Conse-quence	Safety Risk		
1296	8193	8528	8590	0	0	3	CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEEDWATER PUMPING	Feedwater Discharge	159	33	Flow accelerated corrosion (FAC), thermal/mechanical fatigue cracking, corrosion-fatigue cracking, corrosion.	(10)	None	3	D	High	3	D	High	Conduct sample FAC inspections using EPRI methodology.	Inspect and maintain.
1296	8193	8528	8590	8859	0	3	CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEED PUMP - EAST	FW Pump East	160	23	Seal, bearing, impeller failure.	10	None	1	C	Low	1	C	Low	Pump failure; 50% capability reduction.	Current inspection and maintain.
1296	8193	8528	8590	8859	0	3	CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEED PUMP - EAST	4 kV Boiler Feed Pump Motor	161	25	Electrical fault, mechanical fatigue, ops error.	5+	None	2	C	Medium	2	B	Low	Loss 60% unit generation for extended time.	Spare and current inspection and maintain.
1296	8193	8528	8590	8860	0	3	CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEED PUMP - WEST	FW Pump West	162	23	Seal, bearing, impeller failure.	10	None	1	C	Low	1	C	Low	Pump failure; 50% capability reduction	Current inspection and maintain.
1296	8193	8528	8590	8860	0	3	CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEED PUMP - WEST	4 kV Boiler Feed Pump Motor	163	25	Electrical fault, mechanical fatigue, ops error.	5+	None	2	C	Medium	2	B	Low	Loss 60% unit generation for extended time.	Spare and Current Inspection and Maintain
1296	8193	8528	8611	0	0	3	CONDENSATE & F.W. SYSTEM	H.P. FEEDWATER SYSTEM	H.P. FEEDWATER SYSTEM	N/A	164	32	SCC, thermal/mechanical fatigue.	(10)	Life management program is required.	1	C	Low	1	B	Low	Excessive tube failure event resulting in turbine water induction.	Inspect and maintain.
1296	8193	8528	8611	8618	0	3	CONDENSATE & F.W. SYSTEM	H.P. FEEDWATER SYSTEM	H.P. HEATER 4	N/A	165	32	SCC, FAC, thermal/mechanical fatigue, corrosion-fatigue.	(10)	Could meet the desired life; however, baseline	2	B	Low	2	B	Medium	Tube failures, internal hardware failure and shell wall thinning due to FAC and weld cracking.	Inspect and maintain.
1296	8193	8528	8611	8619	0	3	CONDENSATE & F.W. SYSTEM	H.P. FEEDWATER SYSTEM	H.P. HEATER 5	N/A	166	32	SCC, FAC, thermal/mechanical fatigue, corrosion-fatigue.	(10)	Could meet the desired life; however, baseline	2	B	Low	2	B	Low	Tube failures, internal hardware failure and shell wall thinning due to FAC and weld cracking.	Inspect and maintain.
1296	8193	8528	8611	8620	0	3	CONDENSATE & F.W. SYSTEM	H.P. FEEDWATER SYSTEM	H.P. HEATER 6	N/A	167	32	SCC, FAC, thermal/mechanical fatigue, corrosion-fatigue.	(10)	Could meet the desired life; however, baseline	2	B	Low	2	B	Low	Tube failures, internal hardware failure and shell wall thinning due to FAC and weld cracking.	Inspect and maintain.

10.2.2.7 Life Cycle Curve and Remaining Life

The life cycle curves for the Unit 3 feed water system HP heat exchangers and Unit 3 boiler feed pumps are illustrated below. The life curves are plots of current and projected operating hours (generation mode only) on the y-axis versus calendar year on the x-axis. The figure has several vertical lines representing differing representative nominal age limits for various components. It also has several horizontal lines that represent a range of practical equipment equivalent base loaded operating hour life limits. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view.

For the HP heat exchangers, curves represent the three heat exchangers and components, as well as a curve to represent any balance of plant that is original equipment.

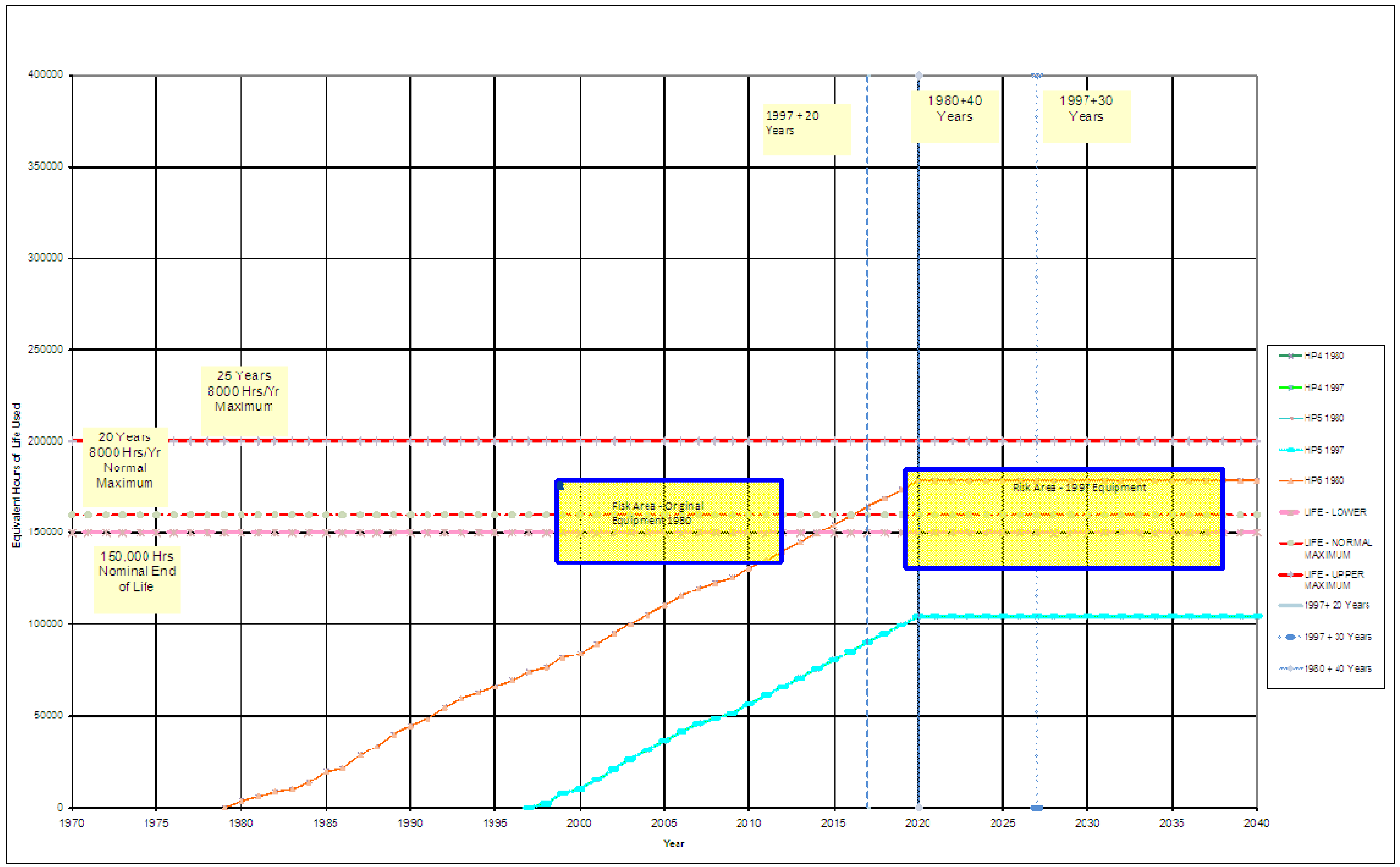

FIGURE 10-16 LIFE CYCLE CURVE – UNIT 3 FEED WATER SYSTEM HP HEAT EXCHANGERS

The curves indicate that the remaining life (RL) of the Unit 3 HP heat exchangers (and the associated feedwater systems) may be able to reach the desired life (DL) 2020 end date for generation. Nevertheless, given that no detailed NDE information has been obtained on the HP heat exchangers for some time, a detailed Level 2 inspection is recommended for 2014.

For the Unit 3 boiler feed pumps, a single curve represents each of the two boiler feed pumps dating back to their original installation. While indicative of expected life with good maintenance practice, the pumps have been and continue to be refurbished on a six year cycle using a spare pump section. Their actual condition is therefore substantially better than might otherwise be expected.

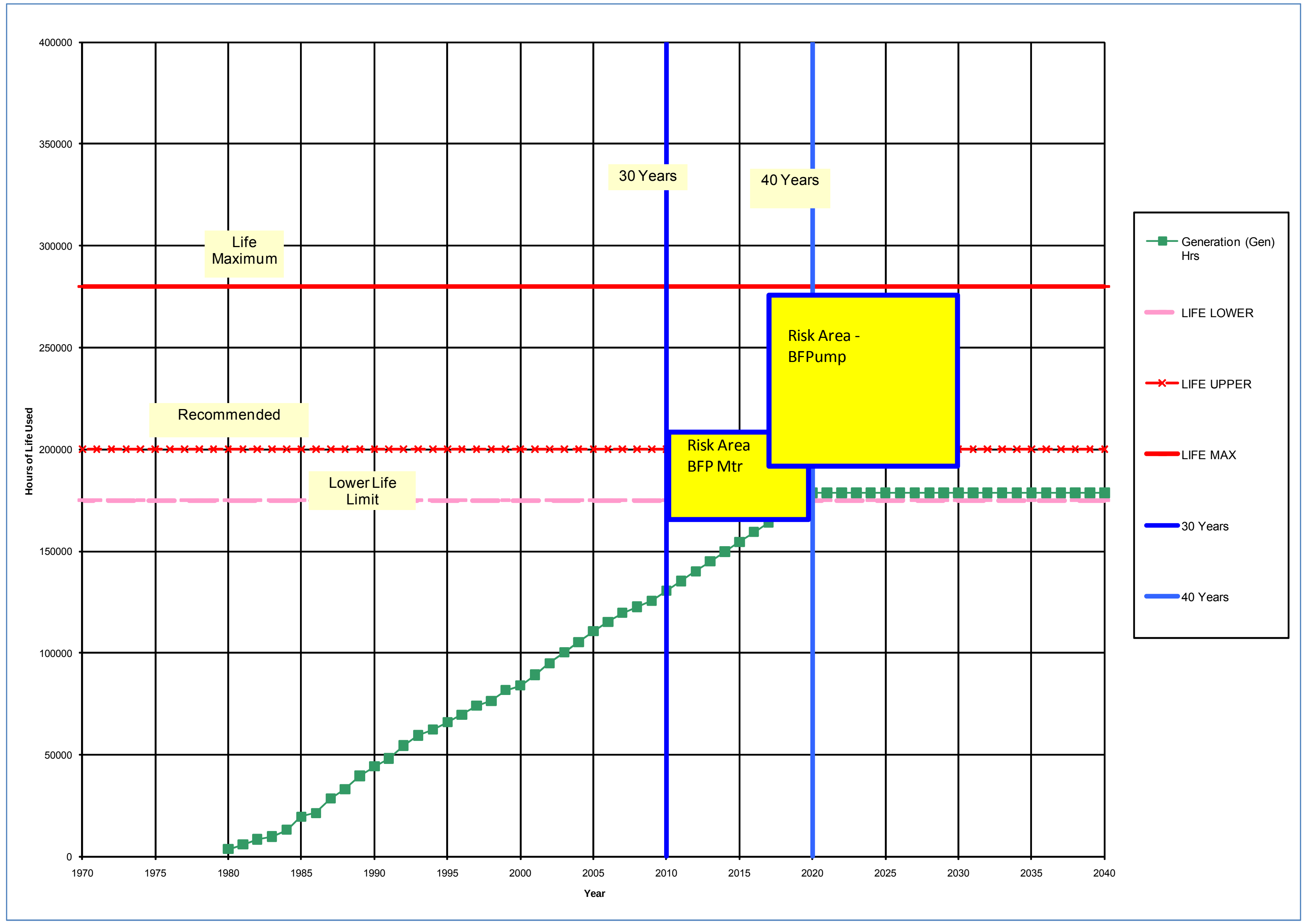

FIGURE 10-17 LIFE CYCLE CURVE – UNIT 3 FEEDWATER SYSTEM - BOILER FEED PUMPS

The curve indicates that the remaining life (RL) of the Unit 3 HP boiler feed pumps is likely able to reach desired end date which is the 2020 end date for generation. Given their six year refurbishment cycle and a spare pump section, they are expected to continue to perform reliably well past the 2020 end date for generation. The BFP motors are approaching older age and entering areas where reliability and unexpected failure may become more an issue than expected life.

10.2.2.8 Level 2 Inspection Requirements and Costs

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 10-35 below, assuming the current plant inspection and maintenance program is maintained or improved.

TABLE 10-35 LEVEL 2 INSPECTION – UNIT 3 FEED WATER SYSTEM HP HEAT EXCHANGERS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Sub System Comment	L2#	Appendix #	Level 2 Work	Year	Priority	Cost k$
1296	8193	8528	8590	0	0	3	CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEEDWATER PUMPING	None	144	23	No Level 2 inspections required at this time. Continue program of regular tests and overhauls.	2014		
1296	8193	8528	8590	8859	0	3	CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEED PUMP - EAST	None	145	23	No Level 2 inspections required. Continue program of regular tests and overhauls.	2014		
1296	8193	8528	8590	8860	0	3	CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEED PUMP - WEST	None	146	23	No Level 2 inspections required. Continue program of regular tests and overhauls.	2014		
1296	8193	8528	8611	0	0	3	CONDENSATE & F.W. SYSTEM	H.P. FEEDWATER SYSTEM	H.P. FEEDWATER SYSTEM	None	147	31	See detail below.	2014	1	$239
1296	8193	8528	8611	8618	0	3	CONDENSATE & F.W. SYSTEM	H.P. FEEDWATER SYSTEM	H.P. HEATER 4	None	148	31	Shell side inspections and channel side for the degradation mechanisms.	2014	2	
1296	8193	8528	8611	8618	0	3	CONDENSATE & F.W. SYSTEM	H.P. FEEDWATER SYSTEM	H.P. HEATER 4	None	149	31	Assessment of the tube plug map.	2014	2	
1296	8193	8528	8611	8618	0	3	CONDENSATE & F.W. SYSTEM	H.P. FEEDWATER SYSTEM	H.P. HEATER 4	None	150	31	ET inspection of tubes to assess the present condition (metallurgical evaluation may also be required depending upon the condition of the tubes).	2014	2	
1296	8193	8528	8611	8618	0	3	CONDENSATE & F.W. SYSTEM	H.P. FEEDWATER SYSTEM	H.P. HEATER 4	None	151	31	NDE inspection the major welds (seam, supports and nozzle welds) for the degradation mechanisms. PT or Magnetic particle testing (MT) or Conventional UT or Phased array (focused) can be used depending upon location.	2014	2	
1296	8193	8528	8611	8619	0	3	CONDENSATE & F.W. SYSTEM	H.P. FEEDWATER SYSTEM	H.P. HEATER 5	None	152	31	Shell side inspections and channel side for the degradation mechanisms.	2014	2	
1296	8193	8528	8611	8619	0	3	CONDENSATE & F.W. SYSTEM	H.P. FEEDWATER SYSTEM	H.P. HEATER 5	None	153	31	Assessment of the tube plug map.	2014	2	
1296	8193	8528	8611	8619	0	3	CONDENSATE & F.W. SYSTEM	H.P. FEEDWATER SYSTEM	H.P. HEATER 5	None	154	31	ET inspection of tubes to assess the present condition (metallurgical evaluation may also be required depending upon the condition of the tubes)	2014	2	
1296	8193	8528	8611	8619	0	3	CONDENSATE & F.W. SYSTEM	H.P. FEEDWATER SYSTEM	H.P. HEATER 5	None	155	31	NDE inspection the major welds (seam, supports and nozzle welds) for the degradation mechanisms. PT or Magnetic particle testing (MT) or Conventional UT or Phased array (focused) can be used depending upon location.	2014	2	

Table 10-35 Cont'd

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Sub System Comment	L2#	Appendix #	Level 2 Work	Year	Priority	Cost k$
1296	8193	8528	8611	8620	0	3	CONDENSATE & F.W. SYSTEM	H.P. FEEDWATER SYSTEM	H.P. HEATER 6	None	156	31	Shell side inspections and channel side for the degradation mechanisms.	2014	2	
1296	8193	8528	8611	8620	0	3	CONDENSATE & F.W. SYSTEM	H.P. FEEDWATER SYSTEM	H.P. HEATER 6	None	157	31	Assessment of the tube plug map.	2014	2	
1296	8193	8528	8611	8620	0	3	CONDENSATE & F.W. SYSTEM	H.P. FEEDWATER SYSTEM	H.P. HEATER 6	None	158	31	ET inspection of tubes to assess the present condition (metallurgical evaluation may also be required depending upon the condition of the tubes)	2014	2	
1296	8193	8528	8611	8620	0	3	CONDENSATE & F.W. SYSTEM	H.P. FEEDWATER SYSTEM	H.P. HEATER 6	None	159	31	NDE inspection the major welds (seam, supports and nozzle welds) for the degradation mechanisms. PT or Magnetic particle testing (MT) or Conventional UT or Phased array (focused) can be used depending upon location.	2014	2	

10.2.2.9 Capital Projects

The suggested typical capital enhancements for the Unit 3 feedwater system – HP feedwater heat exchangers include:

TABLE 10-36 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – UNIT 3 FEED WATER SYSTEM HP FEEDWATER HEAT EXCHANGERS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Detail	CAP#	Appendix #	Unit #	Capital Item	Date	Priority
1296	8193	8528	8590	0	0	3	CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEEDWATER PUMPING	N/A	121		3	No capital required.		
1296	8193	8528	8590	8859	0	3	CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEED PUMP - EAST	N/A	122	23	3	Retrofit of variable speed control – fluid couplings or variable speed drives to reduce energy consumption and improve efficiency.	2013	2
1296	8193	8528	8590	8859	0	3	CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEED PUMP - EAST	N/A	123	23	3	Procure a spare 4 kV motor, to allow rewind of Units 1 and 2 and if practical Unit 3 motors as required.	2012	1
1296	8193	8528	8590	8859	0	3	CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEED PUMP - EAST	N/A	124	23	3	Install vibration monitoring.	2012	1
1296	8193	8528	8590	8860	0	3	CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEED PUMP - WEST	N/A	125	23	3	Retrofit of variable speed control – fluid couplings or variable speed drives to reduce energy consumption and improve efficiency.	2013	2
1296	8193	8528	8590	8860	0	3	CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEED PUMP - WEST	N/A	126	23	3	Procure a spare 4 kV motor, to allow rewind of Units 1 and 2 and if practical Unit 3 motors as required.	2012	1
1296	8193	8528	8590	8860	0	3	CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEED PUMP - WEST	N/A	127	23	3	Install vibration monitoring.	2012	1
1296	8193	8528	8611	0	0	3	CONDENSATE & F.W. SYSTEM	H.P. FEEDWATER SYSTEM	H.P. FEEDWATER SYSTEM	N/A	128		3	No capital required.		
1296	8193	8528	8611	8618	0	3	CONDENSATE & F.W. SYSTEM	H.P. FEEDWATER SYSTEM	H.P. HEATER 4	N/A	129	31	3	None, pending Level 2 or next inspection.		
1296	8193	8528	8611	8619	0	3	CONDENSATE & F.W. SYSTEM	H.P. FEEDWATER SYSTEM	H.P. HEATER 5	N/A	130	31	3	None, pending Level 2 or next inspection.		
1296	8193	8528	8611	8620	0	3	CONDENSATE & F.W. SYSTEM	H.P. FEEDWATER SYSTEM	H.P. HEATER 6	N/A	131	31	3	None, pending Level 2 or next inspection.		

10.2.3 Asset 8571 – Unit 3 Feedwater System - Deaerator

(Detailed Technical Assessment in Working Papers, Appendices 31 and 34)

Equipment Scope:

Unit #:	3
Asset Class #	BU 1296 - Assets Generations
SCI & System:	8523 #3 Condensate & Feedwater System
Sub-Systems:	8546 #3 Low Pressure Feedwater
Components:	8571 #3 Deaerator System (Deaerator and Deaerator Storage Tank)

10.2.3.1 Description

Deaerator systems consist of two vessels, a heater (deaerator) and a storage tank (deaerator storage tank). The Unit 3 deaerator is a vertical spray type, with the deaerator mounted on the horizontal deaerator storage tank.

The deaerator and deaerator storage tank vessels are of welded construction using carbon steel with some of the deaerator internal hardware fabricated from stainless steel. The vessels are designed as per American Society of Mechanical Engineers (ASME) Boilers and Pressure Vessels Code Section VIII, Div. 1. There is one safety valve on the top of the each deaerator vessel.

The function of the deaerator is to remove oxygen and other dissolved gases in the feedwater in order to lower the potential for corrosion during the steam/water cycle. Condensate is sprayed over a cascading series of trays to maximize the surface area of the water. Bleed steam is used as a main source of steam to strip the oxygen and other non-condensable gases from the condensate. Pegging steam is provided from the auxiliary steam system. The steam and gases are vented from the top of the deaerator vessel.

The deaerated water is collected in the storage tank where steam coil heaters maintain water temperatures during off-line periods.

The deaerator storage tank is the suction tank for the boiler feedwater pumps (BFP's). High pressure (HP) feedwater heat exchangers drains are fed to the deaerator. The BFP recirculation line is fed back to the storage tank.

The deaerator storage tank is provided with two cradle type supports. One support is anchored and the other support is free to allow thermal expansion.

10.2.3.2 History

Manufactured/Delivered	1979
In-Service Date	Feb 1980
Generation Base Load End Date	Dec 2015
Generation Peak/Emerg Gen End Date	Dec 2020

The hours associated with the analyses are:

Hours Generation Actual - Ops to Dec 2009	126
Max Hours Generation Ops – to Dec 2015	170
Max Hrs Gen Ops to Gen End Date Dec 2020	179

10.2.3.3 Inspection and Repair History

The deaerator and deaerator storage tank vessels internal visual inspections and NDE of selective welds were carried out in accordance with the plant annual outage inspection plan. The inspections were mostly focused on the accessible areas. There were very limited inspections carried out on the deaerator vessels as there is no real access to the shell without removing the trays. The following is a summary of the inspection findings that were reported in the ALSTOM outage reports from the years 2001 to 2009.

Deaerator

- Cracks in the stainless steel liner;
- Loose trays;
- Cracks in the centre nozzle sleeve;
- Erosion of spray nozzles; and
- No evidence of cracking in the accessible shell seam welds during limited inspections.

Deaerator Storage Tank

- Light pitting has been observed on the inside surfaces in general, especially around the weld seams and in the bottom of shells.
- It was noted in the 2004 outage report that the hot feedwater inlet nozzle to shell attachment welds appeared to be in poor condition. These have not been repaired.
- During the 2007 outage, one small crack was found in the western most stiffener at a seam weld on the south side.

10.2.3.4 Condition Assessment

The condition assessment of the Unit 3 feedwater system - deaerator is illustrated below in Table 10-37.

TABLE 10-37 CONDITION ASSESSMENT – UNIT 3 FEEDWATER SYSTEM - DEAERATOR

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset Level 2	Asset Level 3	Description	Detail	Condition Summary ID#	Append #	Condition	EPRI Identifier	Original Life (Base Load) Ops Hrs (Yrs)	Current Expected Minimum Remaining Life Years (Subject to Test)	End of Life (EOL) Required	Next Regular Inspection	Next Planned Overhaul or Major Inspection	Capability to Reach Next Overhaul	Capability to Reach EOL	In Service
1296	8193	8528	8546	8571	0	3	CONDENSATE & F.W. SYSTEM	LOW PRESSURE FEEDWATER	DEAERATOR SYSTEM	N/A	122	31	No major life limiting issue observed during the past limited deaerator and deaerator storage tank inspections. Many susceptible locations have not been inspected. The corrosion fatigue issues experienced in the past are not re-occurring. Some pitting in the both deaerator and deaerator storage tank vessels and wall thinning observed in the bottom of the deaerator shells. Some erosion of spray nozzles observed.	4	200000 (30)	(10)	2020	2011	2014	No	No	1980

Notes: 1. A "(bracketed)" value in the "Current Expected Remaining Life" column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation, including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as "(X/Y)" has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

2. The "Next Regular Inspection" column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The "Next Planned Overhaul or Major Inspection" column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a "Desired Life" stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or simply are not known to AMEC.

10.2.3.5 Actions

Based on the condition assessment, the following actions are recommended for the Unit 3 feedwater system – deaerator:

TABLE 10-38 RECOMMENDED ACTIONS – UNIT 3 FEEDWATER SYSTEM - DEAERATOR

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Unit	Asset 2/3	Asset 3/4	Description	Detail	Action #	App #	Action	Year	Priority
1296	8193	8528	8546	8571	3	CONDENSATE & F.W. SYSTEM	LOW PRESSURE FEEDWATER	DEAERATOR SYSTEM	N/A	174	31	Perform Level 2 inspections.	2014	2
1296	8193	8528	8546	8571	3	CONDENSATE & F.W. SYSTEM	LOW PRESSURE FEEDWATER	DEAERATOR SYSTEM	N/A	175	31	Implement ongoing inspections and performance testing based on industry practices.	2014	3
1296	8193	8528	8546	8571	3	CONDENSATE & F.W. SYSTEM	LOW PRESSURE FEEDWATER	DEAERATOR SYSTEM	N/A	176	31	Repair the feedwater recirculation inlet nozzles at the deaerator storage tank from inside at Unit 1, if not repaired yet.	2014	2
1296	8193	8528	8546	8571	3	CONDENSATE & F.W. SYSTEM	LOW PRESSURE FEEDWATER	DEAERATOR SYSTEM	N/A	177	31	Refurbish manway seating surfaces that are in poor condition.	2014	2
1296	8193	8528	8546	8571	3	CONDENSATE & F.W. SYSTEM	LOW PRESSURE FEEDWATER	DEAERATOR SYSTEM	N/A	178	31	Monitor pitting corrosion in the both deaerator and deaerator storage tank vessels and wall thinning in the bottom of the deaerators.	2014	2
1296	8193	8528	8546	8571	3	CONDENSATE & F.W. SYSTEM	LOW PRESSURE FEEDWATER	DEAERATOR SYSTEM	N/A	179	31	Investigate the root cause of the ridges observed in Units 1&2 deaerator vessels.	2014	2
1296	8193	8528	8546	8571	3	CONDENSATE & F.W. SYSTEM	LOW PRESSURE FEEDWATER	DEAERATOR SYSTEM	N/A	180	31	Assess the significance of weld undercut that was observed in Unit 1 deaerator storage tank.	2014	2
1296	8193	8528	8546	8571	3	CONDENSATE & F.W. SYSTEM	LOW PRESSURE FEEDWATER	DEAERATOR SYSTEM	N/A	181	31	Evaluate condition of spray nozzles that were observed eroding in Unit 3.	2014	2

10.2.3.6 Risk Assessment

The risk assessment associated with the Unit 3 feedwater system - deaerator, both from a technological perspective and a safety perspective, is illustrated below in Table 10-39.

TABLE 10-39 RISK ASSESSMENT – UNIT 3 FEEDWATER SYSTEM – DEAERATOR

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Component	Risk Assess #	Appendix #	Major Issues	Remaining Life Years	Remaining Life Comments	TECHNO_ECO RISK ASSESS MODEL			SAFETY RISK ASSESS MODEL			Possible Failure Event	Mitigation
														(Insufficient Info - Inspection Required Within (x) Years)		Likeli-hood	Conse-quence	Risk Level	Likeli-hood	Conse-quence	Safety Risk		
1296	8193	8528	8546	8571	0	3	CONDENSATE & F.W. SYSTEM	LOW PRESSURE FEEDWATER	DEAERATOR SYSTEM	Units 1-3 Deaerators	154	31	Corrosion-fatigue, thermal fatigue, corrosion and FAC.	(10)	No real life limiting issue as per inspection to date. Additional inspections required.	3	B	Medium	3	B	Medium	Weld cracking, corrosion fatigue, wall thinning due FAC and internal hardware failure leading to functional failure.	Inspect and maintain.
1296	8193	8528	8546	8571	0	3	CONDENSATE & F.W. SYSTEM	LOW PRESSURE FEEDWATER	DEAERATOR SYSTEM	Units 1-3 Deaerator Storage Tanks	155	31	Corrosion-fatigue, thermal fatigue, corrosion and FAC.	(10)	No real life limiting issue as per inspection to date. Additional inspections required.	2	B	Low	2	B	Low	Weld cracking, corrosion fatigue cracking, pitting corrosion cracking and support failure.	Inspect and maintain.
1296	8193	8528	8546	8571	0	3	CONDENSATE & F.W. SYSTEM	LOW PRESSURE FEEDWATER	DEAERATOR SYSTEM	Units 1-3 Deaerators/ Storage Tanks	156	31	Corrosion-fatigue and thermal fatigue,	(10)	No evidence of susceptibly during limited inspection to date. Ongoing monitoring required.	1	D	Medium	1	D	Low	Catastrophic failure at seam weld.	Inspect and maintain.

10.2.3.7 Life Cycle Curve and Remaining Life

The life cycle curve for the Unit 3 feedwater system – deaerator is illustrated below. Only one curve is used as the major elements of the deaerator are approximately of the same age and condition. The life curve is a plot of current and projected operating hours of usage on the y-axis versus calendar year on the x-axis. The figure has several vertical lines representing differing representative nominal age limits for various components. It also has several horizontal lines that represent a range of practical equipment equivalent base loaded operating hour life limits. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view.

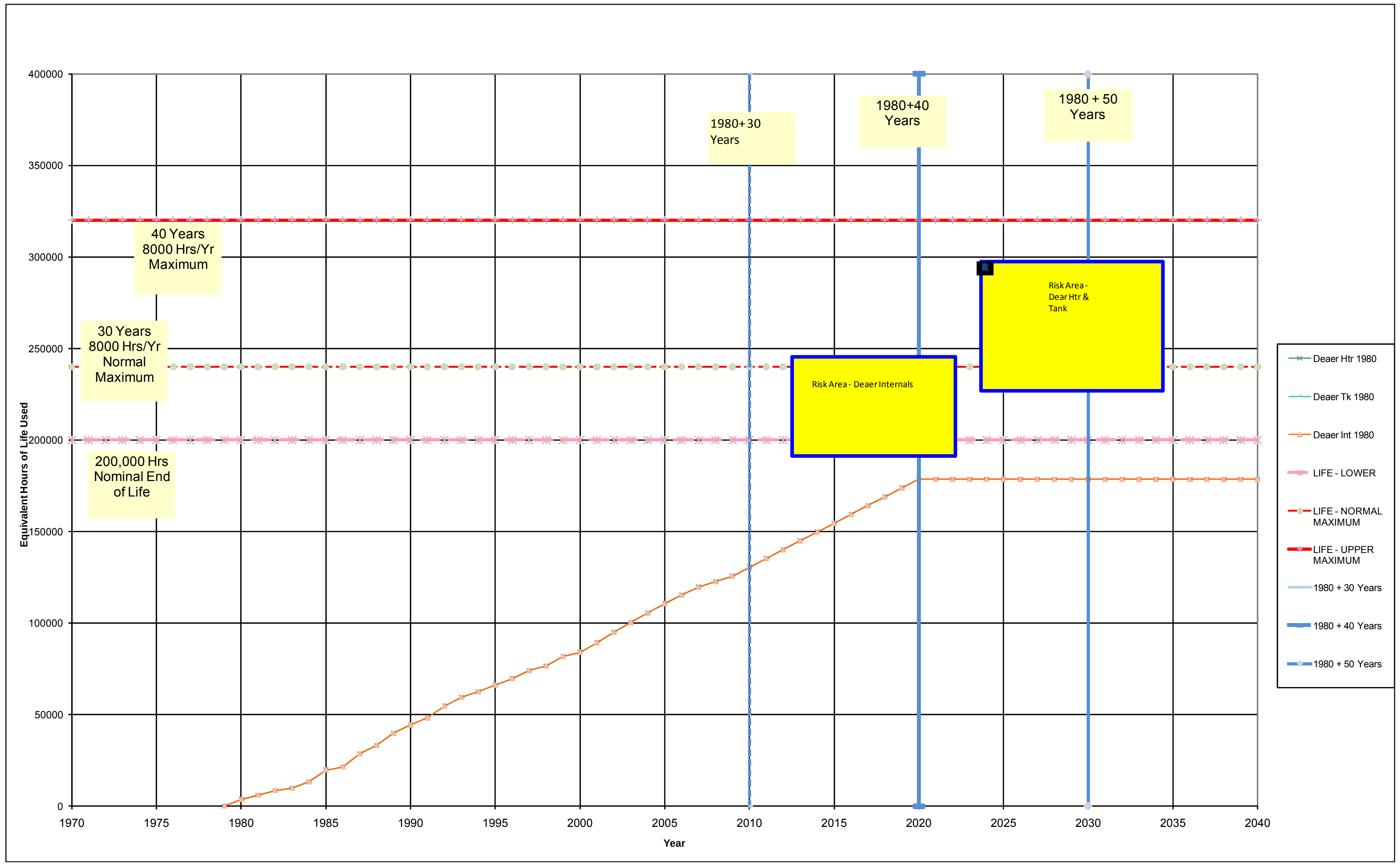

FIGURE 10-18 LIFE CYCLE CURVE – UNIT 3 FEEDWATER SYSTEM - DEAERATOR

The curve indicates that the remaining life (RL) of the Unit 3 feedwater system - deaerator exceeds the desired life (DL) which is end date for generation of 2020, with the potential though unlikely exception of some deaerator internals. The plant inspections form an excellent base of condition information supporting the ability of the deaerator as a whole to meet the EOL date. However, there is insufficient detailed inspection information of some of the internals that are difficult to access in order to fully assess their condition. A detailed Level 2 inspection is recommended in 2014.

10.2.3.8 Level 2 Inspection Requirements and Costs

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 10-40 below, assuming the current plant inspection and maintenance program is maintained or improved.

TABLE 10-40 LEVEL 2 INSPECTIONS – UNIT 3 FEEDWATER SYSTEM - DEAERATOR

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Sub System Comment	L2#	Appendix #	Level 2 Work	Year	Priority	Cost k$
1296	8193	8528	8546	8571	0	3	CONDENSATE & F.W. SYSTEM	LOW PRESSURE FEEDWATER	DEAERATOR SYSTEM	None	136	31	NDE inspection of the areas that were not inspected is required.	2014	2	$229
1296	8193	8528	8546	8571	0	3	CONDENSATE & F.W. SYSTEM	LOW PRESSURE FEEDWATER	DEAERATOR SYSTEM	None	137	31	Visual inspection for FAC damage (shiny black surface) of the susceptible areas. UT thickness measurement to be carried out if FAC damage is evident.	2014	2	
1296	8193	8528	8546	8571	0	3	CONDENSATE & F.W. SYSTEM	LOW PRESSURE FEEDWATER	DEAERATOR SYSTEM	None	138	31	Inspection of all accessible shell and head surfaces for pitting, and for water streaks or signs of erosion (erosion will normally appear as a clean, pitted surface).	2014	2	
1296	8193	8528	8546	8571	0	3	CONDENSATE & F.W. SYSTEM	LOW PRESSURE FEEDWATER	DEAERATOR SYSTEM	None	139	31	Inspection of the tray stack.	2014	2	
1296	8193	8528	8546	8571	0	3	CONDENSATE & F.W. SYSTEM	LOW PRESSURE FEEDWATER	DEAERATOR SYSTEM	None	140	31	Inspection of the spray valves.	2014	2	
1296	8193	8528	8546	8571	0	3	CONDENSATE & F.W. SYSTEM	LOW PRESSURE FEEDWATER	DEAERATOR SYSTEM	None	141	31	Inspections for cracking Re-inspection intervals to be based on operating/inspection/repair history as per NACE recommendations and local regulations.	2014	2	

10.2.3.9 Capital Projects

The suggested typical capital enhancements for the Unit 3 feedwater system - deaerator include:

TABLE 10-41 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – UNIT 3 FEEDWATER SYSTEM - DEAERATOR

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Detail	CAP#	Appendix #	Unit #	Capital Item	Date	Priority
1296	8193	8528	8546	8571	0	3	CONDENSATE & F.W. SYSTEM	LOW PRESSURE FEEDWATER	DEAERATOR SYSTEM	N/A	118	31	3	None, pending Level 2 or next inspection.		

10.2.4 Asset 8546 – Unit 3 Feedwater System - Low Pressure Feedwater Heat Exchangers

(Detailed Technical Assessment in Working Papers, Appendix 24)

Unit #:	3
Asset Class #	BU 1296 - Assets Generations
SCI & System:	8528 #3 Condensate & Feedwater System
Sub-Systems:	8546 #3 Low Pressure Feedwater
	8801 #3 Condensate Extraction (Tables Only)
Components:	8551 #3 L.P. Heater 1
	8552 #3 L.P. Heater 2
	8586 #3 LP FW Reserve
	8801 #3 Condensate Extraction System

10.2.4.1 Description

The low pressure (LP) feedwater system servicing Unit 3 includes two LP feedwater heat exchangers that are referred to as LP-1 and LP-2. The primary function of the LP feedwater heat exchangers is to increase plant thermal efficiency by preheating the boiler feedwater prior entering to the deaerator.

The LP feedwater heat exchangers are horizontally mounted, 100% capacity pressure vessels of the U-tube type construction. There are two tube passes on the feedwater side and a divided flow of heating steam on the shell side of each heater.

The main components of the LP feedwater heat exchangers are shell, shell skirt, tubes, tubesheet, channel, impingement plates, tube support plates/pass partition plates/baffles, shrouds, impingement plate and channel cover. The tubesheet and channel are made from a single forging. The heat exchangers are designed according to ASME Boiler and Pressure Vessel Code Section VIII Div. 1, Heat Exchanger Institute standard for the closed feedwater heaters.

Two condensate extraction pumps service Unit 3 and are driven by 4 kV electric motors. They draw condensate from the condenser and circulate it to the low pressure feedwater heaters and deaerator. The system also includes condensate make-up and a low pressure feedwater reserve tank system to enable the unit to manage high and low water levels throughout the condensate and feedwater system.

10.2.4.2 History

Manufactured/Delivered	1979
In-Service Date	Feb 1980
Generation Base Load End Date	Dec 2015
Generation Peak/Emerg Gen End Date	Dec 2020

The hours associated with the analyses are:

Hours Generation Actual - Ops to Dec 2009	126
Max Hours Generation Ops – to Dec 2015	170
Max Hrs Gen Ops to Gen End Date Dec 2020	179

10.2.4.3 Inspection and Repair History

Leak tests are generally performed on the LP feedwater heat exchangers during annual outages, but records of these tests were not available. Leaking tubes are plugged when identified during a leak test. In addition, the tube plugging maps and history were not available. During interview with plant operations staff, it was noted that there were no performance issues associated with the LP feedwater heat exchangers servicing Unit 3.

The condensate extraction system is regularly inspected as part of the plant PM program. No significant issues have been identified with the pumps. The motors are electrically checked annually and appear to be in reasonable condition for their age. However, the motors are at an age where reliability and failure may be issues in future. The condensate extraction piping is experiencing some external corrosion, but no leaks or failures were identified.

No internal inspections of the reserve tank have been undertaken recently, due primarily to concerns with enclosed space requirements. Externally, there is some minor surface pitting evident. No significant problems or leaks were noted as having been a concern.

10.2.4.4 Condition Assessment

The condition assessment of the Unit 3 feedwater system – low pressure feedwater heat exchangers (and associated condensate extraction system) components illustrated below in Table 10-42.

TABLE 10-42 CONDITION ASSESSMENT – UNIT 3 FEEDWATER SYSTEM - LOW PRESSURE FEEDWATER HEAT EXCHANGERS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset Level 2	Asset Level 3	Description	Detail	Condition Summary ID#	Append #	Condition	EPRI Identifier	Original Life (Base Load) Ops Hrs (Yrs)	Current Expected Minimum Remaining Life Years (Subject to Test)	End of Life (EOL) Required	Next Regular Inspection	Next Planned Overhaul or Major Inspection	Capability to Reach Next Overhaul	Capability to Reach EOL	In Service
1296	8193	8528	8801	0	0	3	CONDENSATE & F.W. SYSTEM	CONDENSATE EXTRACTION SYST	CONDENSATE EXTRACTION SYST	N/A	109	20	No issues identified.	3a	(30)	10	2020	2011		Yes	Yes	1980
1296	8193	8528	8801	8536	0	3	CONDENSATE & F.W. SYSTEM	CONDENSATE EXTRACTION P/P NORTH	CONDENSATE EXTRACTION P/P NORTH	Pump	110	20	Pump and motor in 1978. No issue identified.	3a	(30)	10	2020	2012		Yes	Yes	1980
1296	8193	8528	8801	8536	0	3	CONDENSATE & F.W. SYSTEM	CONDENSATE EXTRACTION P/P NORTH	CONDENSATE EXTRACTION P/P NORTH	Motor	111	20	Pump and motor in 1978. No major issue identified. Annual motor test OK, but motor age an issue.	3a	(25)	(5+)	2020	2012		Yes	No	1980
1296	8193	8528	8801	8537	0	3	CONDENSATE & F.W. SYSTEM	CONDENSATE EXTRACTION P/P SOUTH	CONDENSATE EXTRACTION P/P SOUTH	Pump	112	20	Pump and motor in 1978. No issue identified.	3a	(30)	10	2020	2012		Yes	Yes	1980
1296	8193	8528	8801	8537	0	3	CONDENSATE & F.W. SYSTEM	CONDENSATE EXTRACTION P/P SOUTH	CONDENSATE EXTRACTION P/P SOUTH	Motor	113	20	Pump and motor in 1978. No major issue identified. Annual motor test OK, but motor age an issue.	3a	(25)	(5+)	2020	2012		Yes	No	1980
1296	8193	8528	0	0	0	3	CONDENSATE & F.W. SYSTEM	CONDENSATE & F.W. SYSTEM	CONDENSATE & F.W. SYSTEM	N/A	114		Not reviewed.	4	200000 (30)	10	2020	2011	2011	Yes	Yes	1980
1296	8193	8528	8530	0	0	3	CONDENSATE & F.W. SYSTEM	CONDENSATE MAKE UP SYSTEM	CONDENSATE MAKE UP SYSTEM	N/A	115	31	Not reviewed.	4	200000 (30)	10	2020	2011	2011	Yes	Yes	1980
1296	8193	8528	8546	0	0	3	CONDENSATE & F.W. SYSTEM	LOW PRESSURE FEEDWATER	LOW PRESSURE FEEDWATER	N/A	116	26		4	200000 (30)	(10)	2020	2011	2011	Yes	Yes	1980
1296	8193	8528	8546	8551	0	3	CONDENSATE & F.W. SYSTEM	LOW PRESSURE FEEDWATER	LOW PRESSURE HEATER 1	N/A	117	26	No NDE inspections done. Annual cleaning and tube leak testing. Two heaters on the units may have been replaced, but no records or other interviews could confirm.	4	(25)	(10)	2020	2011	2011	Yes	Yes	1980
1296	8193	8528	8546	8552	0	3	CONDENSATE & F.W. SYSTEM	LOW PRESSURE FEEDWATER	LOW PRESSURE HEATER 2	N/A	118	26	No NDE inspections done. Annual cleaning and tube leak testing. Two heaters on the units may have been replaced, but no records or other interviews could confirm.	4	(25)	(10)	2020	2011	2011	Yes	Yes	1980
1296	8193	8528	8546	8586	0	3	CONDENSATE & F.W. SYSTEM	LOW PRESSURE FEEDWATER	LOW PRESSURE F.W. RESERVE	N/A	119	26	No internal visual inspections recently. Minor external pitting corrosion. Relatively minor internal corrosion identified during interviews. No recent NDE inspections.	4	(60)	(20)	2020	2011	2011	Yes	Yes	1980

Notes:
1. A “(bracketed)” value in the “Current Expected Remaining Life” column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation, including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as “(X/Y)” has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

2. The “Next Regular Inspection” column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The “Next Planned Overhaul or Major Inspection” column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a “Desired Life” stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or simply are not known to AMEC.

10.2.4.5 Actions

Based on the condition assessment, the following actions are recommended for the Unit 3 feedwater system – low pressure feedwater heat exchangers (and associated condensate extraction system) components:

TABLE 10-43 RECOMMENDED ACTIONS – UNIT 3 FEEDWATER SYSTEM - LOW PRESSURE FEEDWATER HEAT EXCHANGERS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Unit	Asset 2/3	Asset 3/4	Description	Detail	Action #	App #	Action	Year	Priority
1296	8193	8528	0	0	3	CONDENSATE & F.W. SYSTEM	CONDENSATE & F.W. SYSTEM	CONDENSATE & F.W. SYSTEM	N/A	157	20	See details below.		
1296	8193	8528	8801	0	3	CONDENSATE & F.W. SYSTEM	CONDENSATE EXTRACTION SYST	CONDENSATE EXTRACTION SYST	N/A	158	20	Spot check likely critical parts of piping and valving – thickness and corrosion.	2011	2
1296	8193	8528	8801	0	3	CONDENSATE & F.W. SYSTEM	CONDENSATE EXTRACTION SYST	CONDENSATE EXTRACTION SYST	N/A	159	20	Maintain current program of ongoing inspections and overhauls. Procure a spare motor to service all three units, in the event of a failure of an existing unit.	2011	2
1296	8193	8528	8801	8536	3	CONDENSATE & F.W. SYSTEM	CONDENSATE EXTRACTION P/P NORTH	CONDENSATE EXTRACTION P/P NORTH	N/A	160	20	Procure a spare condensate extraction motor, primarily for Units 1 & 2 but compatible with Unit 3. Continue current inspection and maintenance activities.	2012	1
1296	8193	8528	8801	8537	3	CONDENSATE & F.W. SYSTEM	CONDENSATE EXTRACTION P/P SOUTH	CONDENSATE EXTRACTION P/P SOUTH	N/A	161	20	Procure a spare condensate extraction motor, primarily for Units 1 & 2 but compatible with Unit 3. Continue current inspection and maintenance activities.	2012	1
1296	8193	8528	8530	0	3	CONDENSATE & F.W. SYSTEM	CONDENSATE MAKE UP SYSTEM	CONDENSATE MAKE UP SYSTEM	N/A	162	21	No recommended action.		
1296	8193	8528	8546	0	3	CONDENSATE & F.W. SYSTEM	LOW PRESSURE FEEDWATER	LOW PRESSURE FEEDWATER	N/A	165	24	Implement ongoing inspections and performance testing based on industry practices.	2011	2
1296	8193	8528	8546	8586	3	CONDENSATE & F.W. SYSTEM	LOW PRESSURE FEEDWATER	LOW PRESSURE F.W. RESERVE	N/A	166	26	Perform Level 2 inspections on tanks – thickness checks and internals inspections.	2011	2
1296	8193	8528	8546	8586	3	CONDENSATE & F.W. SYSTEM	LOW PRESSURE FEEDWATER	LOW PRESSURE F.W. RESERVE	N/A	167	26	Continue a program of ongoing inspections and compare against industry practices.	2011	2
1296	8193	8528	8546	8551	3	CONDENSATE & F.W. SYSTEM	LOW PRESSURE FEEDWATER	LOW PRESSURE HEATER 1	N/A	168	24	Perform Level 2 inspections.	2011	2
1296	8193	8528	8546	8552	3	CONDENSATE & F.W. SYSTEM	LOW PRESSURE FEEDWATER	LOW PRESSURE HEATER 2	N/A	169	24	Perform Level 2 inspections.	2011	2
1296	8193	8528	8546	8586	3	CONDENSATE & F.W. SYSTEM	LOW PRESSURE FEEDWATER	LOW PRESSURE F.W. RESERVE	N/A	170	26	Perform Level 2 inspections on tanks – thickness checks and internals inspections.	2011	2
1296	8193	8528	8546	8586	3	CONDENSATE & F.W. SYSTEM	LOW PRESSURE FEEDWATER	LOW PRESSURE F.W. RESERVE	N/A	171	26	Continue a program of ongoing inspections and compare against industry practices.	2011	2

10.2.4.6 Risk Assessment

The risk assessment associated with the Unit 3 feedwater system – low pressure feedwater heat exchangers (and associated condensate extraction system) components, both from a technological perspective and a safety perspective, is illustrated below in Table 10-44.

TABLE 10-44 RISK ASSESSMENT – UNIT 3 FEEDWATER SYSTEM - LOW PRESSURE FEEDWATER HEAT EXCHANGERS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Component	Risk Assess #	Appendix #	Major Issues	Remaining Life Years	Remaining Life Comments	TECHNO_ECO RISK ASSESS MODEL			SAFETY RISK ASSESS MODEL			Possible Failure Event	Mitigation
														(Insufficient Info - Inspection Required Within (x) Years)		Likeli-hood	Conse-quence	Risk Level	Likeli-hood	Conse-quence	Safety Risk		
1296	8193	8528	0	0	0	3	CONDENSATE & F.W. SYSTEM	CONDENSATE & F.W. SYSTEM	CONDENSATE & F.W. SYSTEM		138		Not addressed.	10	None								
1296	8193	8528	8801	0	0	3	CONDENSATE & F.W. SYSTEM	CONDENSATE EXTRACTION SYST	CONDENSATE EXTRACTION SYST	CE Piping/Valves	139	20	Weld failure, rupture.	10	None	1	A	Low	1	B	Low	Piping leak; short duration shutdown for repair.	Inspect and maintain.
1296	8193	8528	8801	8536	0	3	CONDENSATE & F.W. SYSTEM	CONDENSATE EXTRACTION P/P NORTH	CONDENSATE EXTRACTION P/P NORTH	CE Pumps	140	20	Seal, bearing, impeller failure.	10	None	1	A	Low	1	B	Low	Pump failure; 0% capability reduction due to redundancy.	Current inspection and maintain.
1296	8193	8528	8801	8536	0	3	CONDENSATE & F.W. SYSTEM	CONDENSATE EXTRACTION P/P NORTH	CONDENSATE EXTRACTION P/P NORTH	4 kV Condensate Extraction Pump Motor	141	25	Electrical fault, mechanical fatigue, ops error.	5+	None	2	B	Low	1	B	Low	Pump failure; 0% capability reduction due to redundancy.	Spare and current inspection and maintain.
1296	8193	8528	8801	8537	0	3	CONDENSATE & F.W. SYSTEM	CONDENSATE EXTRACTION P/P SOUTH	CONDENSATE EXTRACTION P/P SOUTH	CE Pumps	142	20	Seal, bearing, impeller failure.	10	None	1	A	Low	1	B	Low	Pump failure; 0% capability reduction due to redundancy.	Current inspection and maintain.
1296	8193	8528	8801	8537	0	3	CONDENSATE & F.W. SYSTEM	CONDENSATE EXTRACTION P/P SOUTH	CONDENSATE EXTRACTION P/P SOUTH	4 kV Condensate Extraction Pump Motor	143	25	Electrical fault, mechanical fatigue, ops error.	5+	None	2	B	Low	1	B	Low	Pump failure; 0% capability reduction due to redundancy.	Spare and current inspection and maintain.
1296	8193	8528	8546	0	0	3	CONDENSATE & F.W. SYSTEM	LOW PRESSURE FEEDWATER	LOW PRESSURE FEEDWATER	All LP Feedwater Heaters	147	24	SCC, thermal/ mechanical fatigue.	(10)	Life management program is required.	1	C	Low	1	B	Low	Excessive tube failure event resulting in Turbine water induction.	Inspect and maintain.
1296	8193	8528	8546	8586	0	3	CONDENSATE & F.W. SYSTEM	LOW PRESSURE FEEDWATER	LOW PRESSURE F.W. RESERVE	LP Feedwater Reserve Tanks	148	26	Corrosion, impingement.	(20)	None	1	A	Low	1	A	Low	Major Leak, loss condensate.	Inspect and maintain.
1296	8193	8528	8546	8586	0	3	CONDENSATE & F.W. SYSTEM	LOW PRESSURE FEEDWATER	LOW PRESSURE F.W. RESERVE	Common Feedwater Reserve Tanks	149	26	Corrosion, impingement.	(20)	None	1	A	Low	1	A	Low	Major Leak, loss condensate.	Inspect and maintain.
1296	8193	8528	8546	8551	0	3	CONDENSATE & F.W. SYSTEM	LOW PRESSURE FEEDWATER	LOW PRESSURE HEATER 1	N/A	150	24	SCC, FAC, thermal/mechanical fatigue, corrosion-fatigue.	(10)	Could meet the desired life; however, baseline inspection required.	1	B	Low	1	B	Low	Tube failures, internal hardware failure and shell wall thinning due FAC and weld cracking.	Inspect and maintain.
1296	8193	8528	8546	8552	0	3	CONDENSATE & F.W. SYSTEM	LOW PRESSURE FEEDWATER	LOW PRESSURE HEATER 2	N/A	151	24	SCC, FAC, thermal/mechanical fatigue, corrosion-fatigue.	(10)	Could meet the desired life; however, baseline inspection required.	1	B	Low	1	B	Low	Tube failures, internal hardware failure and shell wall thinning due FAC and weld cracking.	Inspect and maintain.

10.2.4.7 Life Cycle Curve and Remaining Life

The life cycle curve for the Unit 3 feedwater system - low pressure feedwater heat exchangers is illustrated below. One curve represents both low pressure heat exchangers which are original equipment. The life curve is a plot of current and projected operating hours (generation mode only) on the y-axis versus calendar year on the x-axis. The figure has several vertical lines representing differing representative nominal age limits for various components. It also has several horizontal lines that represent a range of practical equipment equivalent base loaded operating hour life limits. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view.

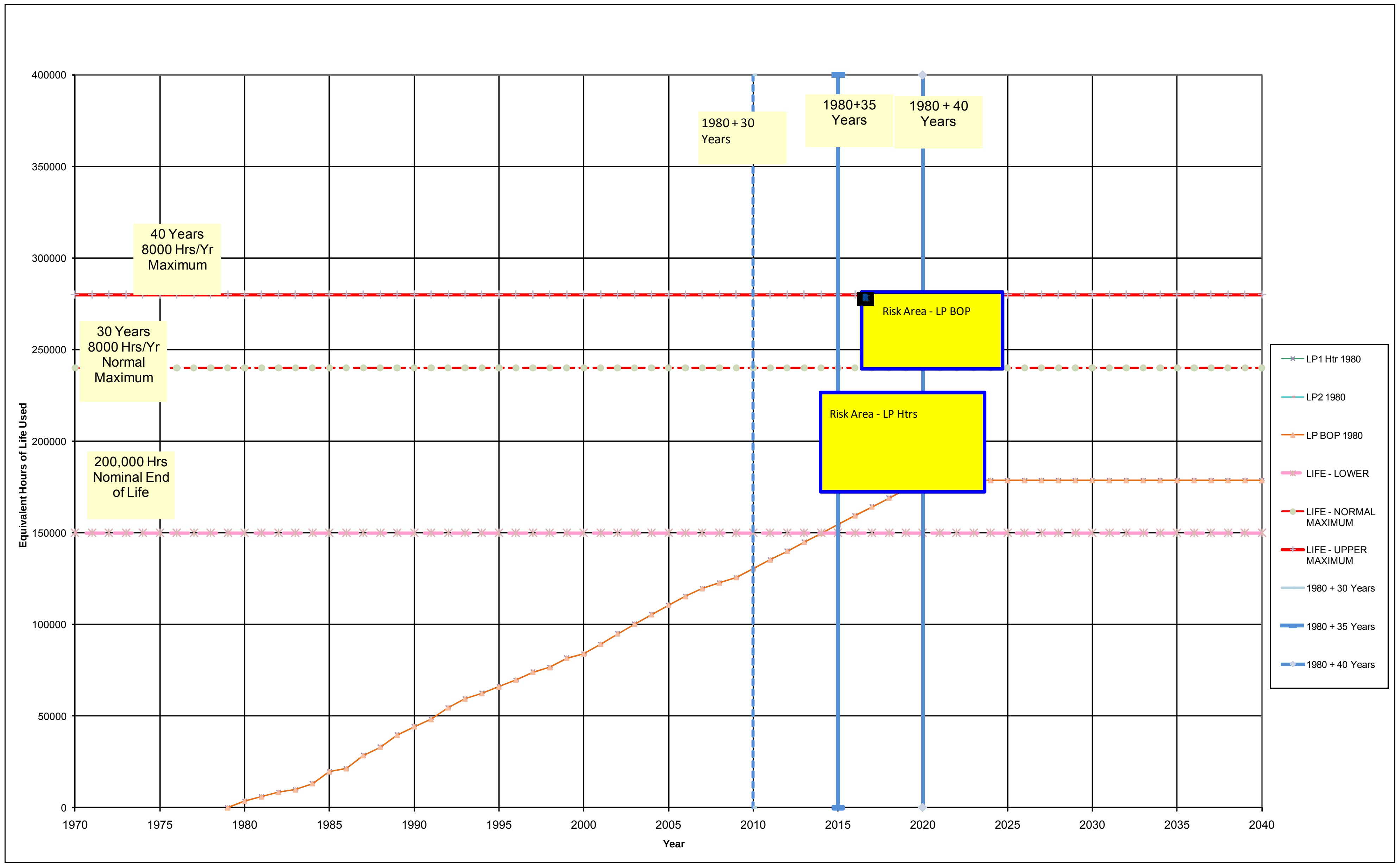

FIGURE 10-19 LIFE CYCLE CURVE – UNIT 3 FEEDWATER SYSTEM - LOW PRESSURE FEEDWATER HEAT EXCHANGERS

The curve indicates that the remaining life (RL) of the Unit 3 feed water system LP heat exchangers may not be able to reach the desired life (DL) 2020 end date for generation. Given that no detailed NDE information has been obtained on the LP heat exchangers, a detailed Level 2 inspection is recommended for 2011.

The life cycle curve for the Unit 3 condensate extraction pumps and motors is illustrated below. One curve is used to represent the pumps and motors as they are all original equipment. The life curve is a plot of current and projected operating hours (generation mode only) on the y-axis versus calendar year on the x-axis. The figure has two vertical lines representing differing representative nominal age limits. It also has several horizontal lines that represent a range of practical equipment equivalent base loaded operating hour life limits. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view.

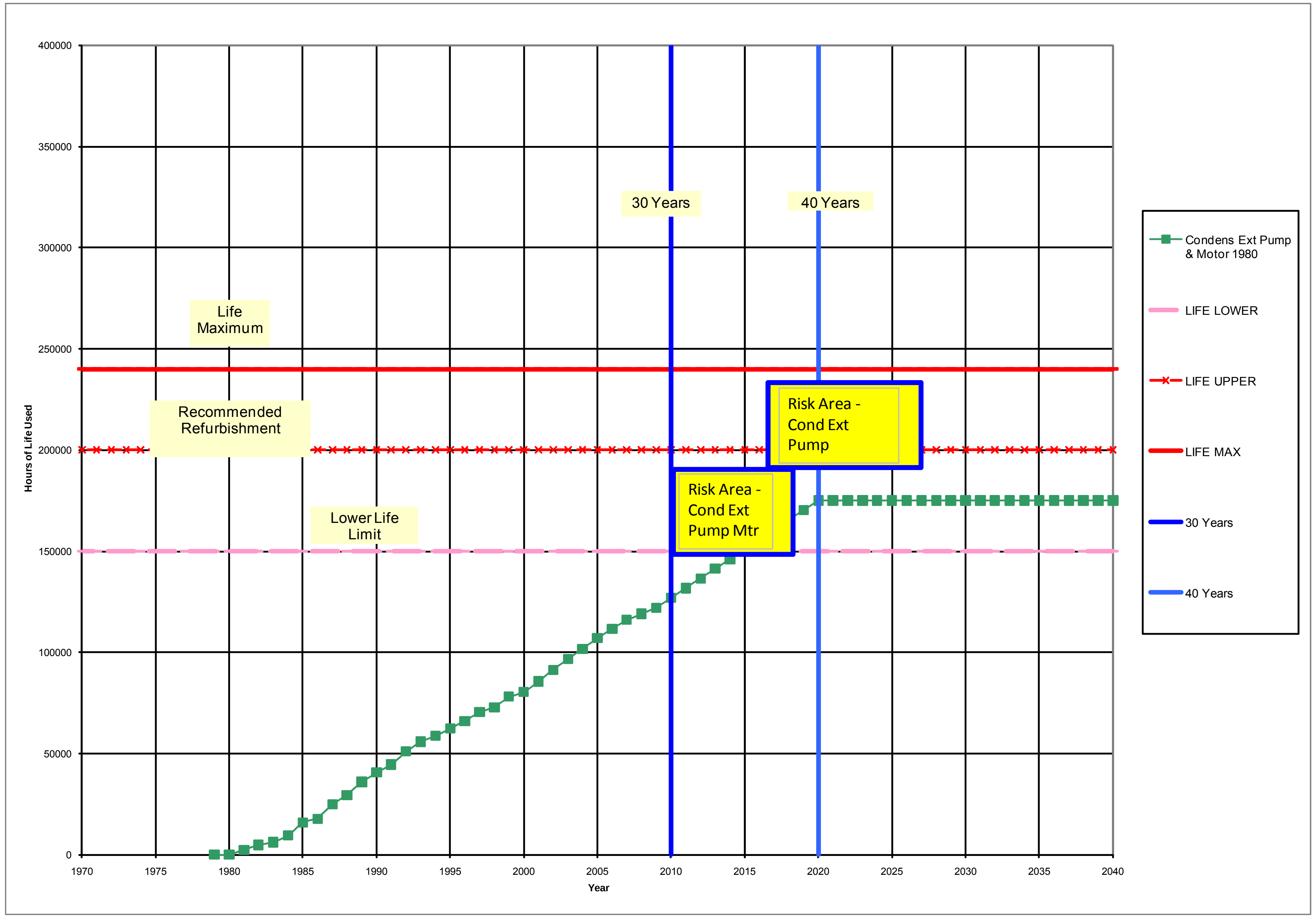

FIGURE 10-20 LIFE CYCLE CURVE – UNIT 3 FEEDWATER SYSTEM - CONDENSATE EXTRACTION SYSTEM

The curves indicate that the remaining life (RL) of the condenser condensate extraction pumps and motors can likely be able to reach the desired life (DL) 2020 end date for generation. The condensate extraction pump motors are expected however to be entering a period of higher unreliability.

10.2.4.8 Level 2 Inspection Requirements and Costs

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 10-45 below, assuming the current plant inspection and maintenance program is maintained or improved.

TABLE 10-45 LEVEL 2 INSPECTION – UNIT 3 FEEDWATER SYSTEM - LOW PRESSURE FEEDWATER HEAT EXCHANGERS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Sub System Comment	L2#	Appendix #	Level 2 Work	Year	Priority	Cost k$
1296	8193	8528	0	0	0	3	CONDENSATE & F.W. SYSTEM	CONDENSATE & F.W. SYSTEM	CONDENSATE & F.W. SYSTEM	None	117	20	No Level 2 inspections or testing is required.			
1296	8193	8528	8801	0	0	3	CONDENSATE & F.W. SYSTEM	CONDENSATE EXTRACTION SYST	CONDENSATE EXTRACTION SYST	None	118	20	No Level 2 inspections required at this time. Continue program of regular inspections and overhauls.			
1296	8193	8528	8801	8536	0	3	CONDENSATE & F.W. SYSTEM	CONDENSATE EXTRACTION P/P NORTH	CONDENSATE EXTRACTION P/P NORTH	None	119	20	No Level 2 inspections required at this time. Continue program of regular inspections and overhauls.			
1296	8193	8528	8801	8537	0	3	CONDENSATE & F.W. SYSTEM	CONDENSATE EXTRACTION P/P SOUTH	CONDENSATE EXTRACTION P/P SOUTH	None	120	20	No Level 2 inspections required at this time. Continue program of regular inspections and overhauls.			
1296	8193	8528	8530	0	0	3	CONDENSATE & F.W. SYSTEM	CONDENSATE MAKE UP SYSTEM	CONDENSATE MAKE UP SYSTEM	None	121	20	No Level 2 inspections or testing is required.			
1296	8193	8528	8546	0	0	3	CONDENSATE & F.W. SYSTEM	LOW PRESSURE FEEDWATER	LOW PRESSURE FEEDWATER	None	124		See details below.	2011	3	$105
1296	8193	8528	8546	8551	0	3	CONDENSATE & F.W. SYSTEM	LOW PRESSURE FEEDWATER	LOW PRESSURE HEATER 1	None	125	24	Shell side inspections and channel side for the degradation mechanisms.	2011	2	
1296	8193	8528	8546	8551	0	3	CONDENSATE & F.W. SYSTEM	LOW PRESSURE FEEDWATER	LOW PRESSURE HEATER 1	None	126	24	Assessment of the tube plug map.	2011	2	
1296	8193	8528	8546	8551	0	3	CONDENSATE & F.W. SYSTEM	LOW PRESSURE FEEDWATER	LOW PRESSURE HEATER 1	None	127	24	ET inspection of tubes to assess the present condition (metallurgical evaluation may also be required depending upon the condition of the tubes).	2011	2	
1296	8193	8528	8546	8551	0	3	CONDENSATE & F.W. SYSTEM	LOW PRESSURE FEEDWATER	LOW PRESSURE HEATER 1	None	128	24	NDE inspection the major welds (seam, supports and nozzle welds) for the degradation mechanisms. PT or Magnetic particle testing (MT) or Conventional UT or Phased array (focused) can be used depending upon location.	2011	2	
1296	8193	8528	8546	8552	0	3	CONDENSATE & F.W. SYSTEM	LOW PRESSURE FEEDWATER	LOW PRESSURE HEATER 2	None	129	24	Shell side inspections and channel side for the degradation mechanisms.	2011	2	
1296	8193	8528	8546	8552	0	3	CONDENSATE & F.W. SYSTEM	LOW PRESSURE FEEDWATER	LOW PRESSURE HEATER 2	None	130	24	Assessment of the tube plug map.	2011	2	
1296	8193	8528	8546	8552	0	3	CONDENSATE & F.W. SYSTEM	LOW PRESSURE FEEDWATER	LOW PRESSURE HEATER 2	None	131	24	ET inspection of tubes to assess the present condition (metallurgical evaluation may also be required depending upon the condition of the tubes).	2011	2	
1296	8193	8528	8546	8552	0	3	CONDENSATE & F.W. SYSTEM	LOW PRESSURE FEEDWATER	LOW PRESSURE HEATER 2	None	132	24	NDE inspection the major welds (seam, supports and nozzle welds) for the degradation mechanisms. PT or Magnetic particle testing (MT) or Conventional UT or Phased array (focused) can be used depending upon location.	2011	2	
1296	8193	8528	8546	8586	0	3	CONDENSATE & F.W. SYSTEM	LOW PRESSURE FEEDWATER	LOW PRESSURE F.W. RESERVE	None	133	26	Inspections of interior wall inspections and thickness measurements of walls and impaired major welds. Internals visual inspection.	2011	3	

10.2.4.9 Capital Projects

The suggested typical capital enhancements for the Unit 3 feedwater system – low pressure feedwater heat exchangers (and associated condensate extraction system) components include:

TABLE 10-46 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – UNIT 3 FEEDWATER SYSTEM - LOW PRESSURE FEEDWATER HEAT EXCHANGERS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Detail	CAP#	Appendix #	Unit #	Capital Item	Date	Priority
1296	8193	8528	0	0	0	3	CONDENSATE & F.W. SYSTEM	CONDENSATE & F.W. SYSTEM	CONDENSATE & F.W. SYSTEM	N/A	105		3	No capital required.		
1296	8193	8528	8801	0	0	3	CONDENSATE & F.W. SYSTEM	CONDENSATE EXTRACTION SYSTEM	CONDENSATE EXTRACTION SYSTEM	N/A	106	20	3	No capital required.		
1296	8193	8528	8801	8536	0	3	CONDENSATE & F.W. SYSTEM	CONDENSATE EXTRACTION P/P NORTH	CONDENSATE EXTRACTION P/P NORTH	N/A	107	20	3	Refurbish and replace as required per next inspection and overhaul findings. Procure spare motor compatable with all units.	2014	3
1296	8193	8528	8801	8537	0	3	CONDENSATE & F.W. SYSTEM	CONDENSATE EXTRACTION P/P SOUTH	CONDENSATE EXTRACTION P/P SOUTH	N/A	108	20	3	Refurbish and replace as required per next inspection and overhaul findings. Procure spare motor compatable with all units.	2014	3
1296	8193	8528	8530	0	0	3	CONDENSATE & F.W. SYSTEM	CONDENSATE MAKE UP SYSTEM	CONDENSATE MAKE UP SYSTEM	N/A	109		3	No capital required.		
1296	8193	8528	8546	0	0	3	CONDENSATE & F.W. SYSTEM	LOW PRESSURE FEEDWATER	LOW PRESSURE FEEDWATER	N/A	112	26	3	None, pending Level 2 or next inspection.		
1296	8193	8528	8546	8586	0	3	CONDENSATE & F.W. SYSTEM	LOW PRESSURE FEEDWATER	LOW PRESSURE F.W. RESERVE	N/A	113	26	3	None, pending Level 2 or next inspection.		
1296	8193	8528	8546	8551	0	3	CONDENSATE & F.W. SYSTEM	LOW PRESSURE FEEDWATER	LOW PRESSURE HEATER 1	N/A	114	24	3	None, pending Level 2 or next inspection.		
1296	8193	8528	8546	8552	0	3	CONDENSATE & F.W. SYSTEM	LOW PRESSURE FEEDWATER	LOW PRESSURE HEATER 2	N/A	115	24	3	None, pending Level 2 or next inspection.		

10.2.5 Asset 271677 – Unit 3 Condenser

(Detailed Technical Assessment in Working Papers, Appendix 22)

Unit #:	3
Asset Class #	BU 1296 - Assets Generations
SCI & System:	8194 #1 Turbine & Generator
Sub-Systems:	8223 # 3 Turbine & Condenser
Components:	271677 #3 Condenser
	8252 #3 Condenser Air Extraction

10.2.5.1 Description

The Unit 3 condenser is a shell and tube type heat exchanger with two passes. There are two tube bundles in a single shell. The inlet and the outlet waterboxes are divided. Each tube bundle has an air removing zone (ARZ) in the middle of the bundle. There are 2 x 100% liquid ring vacuum pumps to remove the air and non condensable gases from the condenser shell. The pumps are designed to allow the unit to run at full vacuum with only one pump operating. Each is equipped with a nominally 70 kW, 600 V motor. The condenser has a stainless steel metal bellow joint between the condenser shell and the turbine lower exhaust casing to compensate for turbine and condenser expansion.

The condenser cooling water is a combination of sea water and fresh water. The carbon steel waterbox material is protected by an epoxy coating and a sacrificial anodic system. The condenser waterboxes are equipped with a back wash system for cleaning the tubes internally while the unit is in operation. Nylon brushes are used to clean the tubes prior to the condenser lay-up.

The condenser was designed, fabricated and supplied by Foster Wheeler in 1979.

10.2.5.2 History

Manufactured/Delivered	1979
In-Service Date	Feb 1980
Generation Base Load End Date	Dec 2015
Generation Peak/Emerg Gen End Date	Dec 2020
Next Major Overhaul/Inspection	2016

The hours associated with the analyses are:

Hours Generation Actual - Ops to Dec 2009	126
Max Hours Generation Ops – to Dec 2015	170
Max Hrs Gen Ops to Gen End Date Dec 2020	179

10.2.5.3 Inspection and Repair History

The Unit 3 condenser is in good shape for its age. The number of plugged tubes is quite low, and the rate of increase in plugging has remained steadily low. The condition is monitored, but no aggressive inspection program is either in place or seems to be required.

As of 2000, 7.8% of the total number of tubes was plugged and by December 2010, 8.4% were plugged. This indicates that the in-service wear/erosion degradation of 0.6% over 10 years is very slow. In April 2003 only 13 out of the 240 tubes were plugged in the ARZ. By December 2010, 14 tubes were plugged. The pattern is random indicating no condensate grooving is present.

The 2003 and 2006 GE Betz inspection reports confirm that both shell and hotwell are in good condition. During 2003 to 2004, the waterboxes were confirmed as having the epoxy lining in good condition and the condition of the water boxes to be well managed in general.

The two condenser air extraction vacuum pumps and system are original equipment and approaching their expected end of life. No major issues were identified with achieving the required condenser back pressure at turbine full load or during unit start up. The pumps and motors are serviced yearly under the plant PM program. The plant is modifying the existing vent system to enable venting externally in order to eliminate the exhaust of its moisture into the powerhouse.

10.2.5.4 Condition Assessment

The condition assessment of the Unit 3 condenser is illustrated below in Table 10-47.

TABLE 10-47 CONDITION ASSESSMENT – UNIT 3 CONDENSER

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset Level 2	Asset Level 3	Description	Detail	Condition Summary ID#	Append #	Condition	EPRI Identifier	Original Life (Base Load) Ops Hrs (Yrs)	Current Expected Minimum Remaining Life Years (Subject to Test)	End of Life (EOL) Required	Next Regular Inspection	Next Planned Overhaul or Major Inspection	Capability to Reach Next Overhaul	Capability to Reach EOL	In Service
1296	8193	8194	8223	0	0	3	TURBINE CONDENSER SYSTEM	TURBINE CONDENSER SYSTEM	TURBINE CONDENSER SYSTEM	N/A	2	22	Excellent condition, with exception of aging pumps.	4	200000 (40)	20	2020	2011	2016	Yes	Yes	1980
1296	8193	8194	8223	8252	0	3	TURBINE CONDENSER SYSTEM	CONDENSER AIR EXTRACTION	CONDENSER AIR EXTRACTION	N/A	3	22	End of Life near. Replace as failure occurs or imminent.	10	150000 (30)	2	2020	2011	2016	Yes	No	1980
1296	8193	8194	8223	8252	8892	3	TURBINE CONDENSER SYSTEM	CONDENSER AIR VACUUMPUMP NORTH	CONDENSER AIR VACUUM PUMP NORTH	N/A	4	22	Functional. Near end of life	10	150000 (30)	2	2020	2011	2016	No	No	1980
1296	8193	8194	8223	8252	8893	3	TURBINE CONDENSER SYSTEM	CONDENSER AIR VACUUM PUMP SOUTH	CONDENSER AIR VACUUM PUMP SOUTH	N/A	5	22	Functional. Near end of life	10	150000 (30)	2	2020	2011	2016	No	No	1980
1296	8193	8194	8223	8252	99000295	3	TURBINE CONDENSER SYSTEM	CONDENSER AIR REMOVAL SYSTEM	CONDENSER AIR REMOVAL SYSTEMS	N/A	6	22	Vacuum pumps near end of life. Exhaust location an issue.	10	200000 (30)	2	2020	2011	2016	Yes	No	1980
1296	8193	8194	8223	271677	0	3	TURBINE CONDENSER SYSTEM	TURBINE CONDENSER	TURBINE CONDENSER	N/A	7	22	Condition is very good. 2010 tubes plug survey shows 8.4 % of tubes plugged vs 7.8% in 2000. More than Units 1 and 2, likely is due to the mechanical damage. No condensate grooving on the tube OD in the air removing zone. Minor wear and tear of waterboxes and condenser shell. The condenser steel piping at inlet and outlet has some patching evident on some units.	3a	300000 (50)	20	2020	2011	2012	Yes	Yes	1980

Notes:
1. A "(bracketed)" value in the "Current Expected Remaining Life" column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation, including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as "(X/Y)" has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.
2. The "Next Regular Inspection" column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The "Next Planned Overhaul or Major Inspection" column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a "Desired Life" stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or simply are not known to AMEC.

10.2.5.5 Actions

Based on the condition assessment, the following actions are recommended for the Unit 3 condenser

TABLE 10-48 RECOMMENDED ACTIONS – UNIT 3 CONDENSER

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Unit	Asset 2/3	Asset 3/4	Description	Detail	Action #	App #	Action	Year	Priority
1296	8193	8194	8223	0	3	TURBINE CONDENSER SYSTEM	TURBINE CONDENSER SYSTEM	TURBINE CONDENSER SYSTEM	N/A	4	22	Develop a ongoing program of monitoring CW inlet/outlet pipe conditions.	2011	2
1296	8193	8194	8223	8252	3	TURBINE CONDENSER SYSTEM	CONDENSER AIR EXTRACTION	CONDENSER AIR EXTRACTION	N/A	5	22	See details below.		
1296	8193	8194	8223	8252	3	TURBINE CONDENSER SYSTEM	CONDENSER AIR VACUUM PUMP NORTH	CONDENSER AIR VACUUM PUMP NORTH	N/A	6	22	Inspect CW Vacuum pump and refurbish or replace motor and pump.	2011	2
1296	8193	8194	8223	8252	3	TURBINE CONDENSER SYSTEM	CONDENSER AIR VACUUM PUMP SOUTH	CONDENSER AIR VACUUM PUMP SOUTH	N/A	7	22	Inspect CW Vacuum pump and refurbish or replace motor and pump.	2011	2
1296	8193	8194	8223	8252	3	TURBINE CONDENSER SYSTEM	CONDENSER AIR REMOVAL SYSTEM	CONDENSER AIR REMOVAL SYSTEM	N/A	8	22	Add new vent line to outside.	2011	2
1296	8193	8194	8223	271677	3	TURBINE CONDENSER SYSTEM	TURBINE CONDENSER	TURBINE CONDENSER	N/A	9	22	No specific recommended actions, maintain annual inspection and tube mapping.	2011	2

10.2.5.6 Risk Assessment

The risk assessment associated with the Unit 3 condenser, both from a technological perspective and a safety perspective, is illustrated below in Table 10-49.

TABLE 10-49 RISK ASSESSMENT – UNIT 3 CONDENSER

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Component	Risk Assess #	Appendix #	Major Issues	Remaining Life Years	Remaining Life Comments	TECHNO_ECO RISK ASSESS MODEL			SAFETY RISK ASSESS MODEL			Possible Failure Event	Mitigation
														(Insufficient Info - Inspection Required Within (x) Years)		Likeli-hood	Conse-quence	Risk Level	Likeli-hood	Conse-quence	Safety Risk		
1296	8193	8194	8223	0	0	3	TURBINE CONDENSER SYSTEM	TURBINE CONDENSER SYSTEM	TURBINE CONDENSER SYSTEM	N/A	5		See detail below.										
1296	8193	8194	8223	8252	0	3	TURBINE CONDENSER SYSTEM	CONDENSER AIR EXTRACTION	CONDENSER AIR EXTRACTION	N/A	6		See detail below.	10									
1296	8193	8194	8223	8252	8892	3	TURBINE CONDENSER SYSTEM	CONDENSER AIR VAC PUMP NORTH	CONDENSER AIR VAC PUMP NORTH	Condenser Vacuum Pumps & System	7	22	Mechanical failure/leaks.	2	None	1	A	Low	1	A	Low	Derate/Eff decrease while replaced.	Maintain, refurbish or replace as required.
1296	8193	8194	8223	8252	8893	3	TURBINE CONDENSER SYSTEM	CONDENSER AIR VAC PUMP SOUTH	CONDENSER AIR VAC PUMP SOUTH	Condenser Vacuum Pumps & System	8	22	Mechanical failure/leaks.	2	None	1	A	Low	1	A	Low	Derate/Eff decrease while replaced.	Maintain, refurbish or replace as required.
1296	8193	8194	8223	8252	99000295	3	TURBINE CONDENSER SYSTEM	CONDENSER AIR REMOVAL SYSTEM S	CONDENSER AIR REMOVAL SYSTEM S	Condenser Air Vent	9	22	Corrosion, erosion.	2	None	1	A	Low	1	A	Low	Derate/Eff decrease while repaired.	Maintain, refurbish or replace as required.
1296	8193	8194	8223	271677	0	3	TURBINE CONDENSER SYSTEM	TURBINE CONDENSER	TURBINE CONDENSER	N/A	10		Erosion, corrosion.	20	None	2	B	Low	2	A	Low	Major seawater leak to condenser - unit shutdown. Water cleanup.	Inspect and Repair. Track history.

10.2.5.7 Life Cycle Curve and Remaining Life

The life cycle curve for the Unit 3 condenser is illustrated below. One curve is used as the major elements of the condenser are of the same age and condition. The life curve is a plot of current and projected operating hours (generation mode only) on the y-axis versus calendar year on the x-axis. The figure has several vertical lines representing differing representative nominal age limits. It also has several horizontal lines that represent a range of practical equipment equivalent base loaded operating hour life limits. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view.

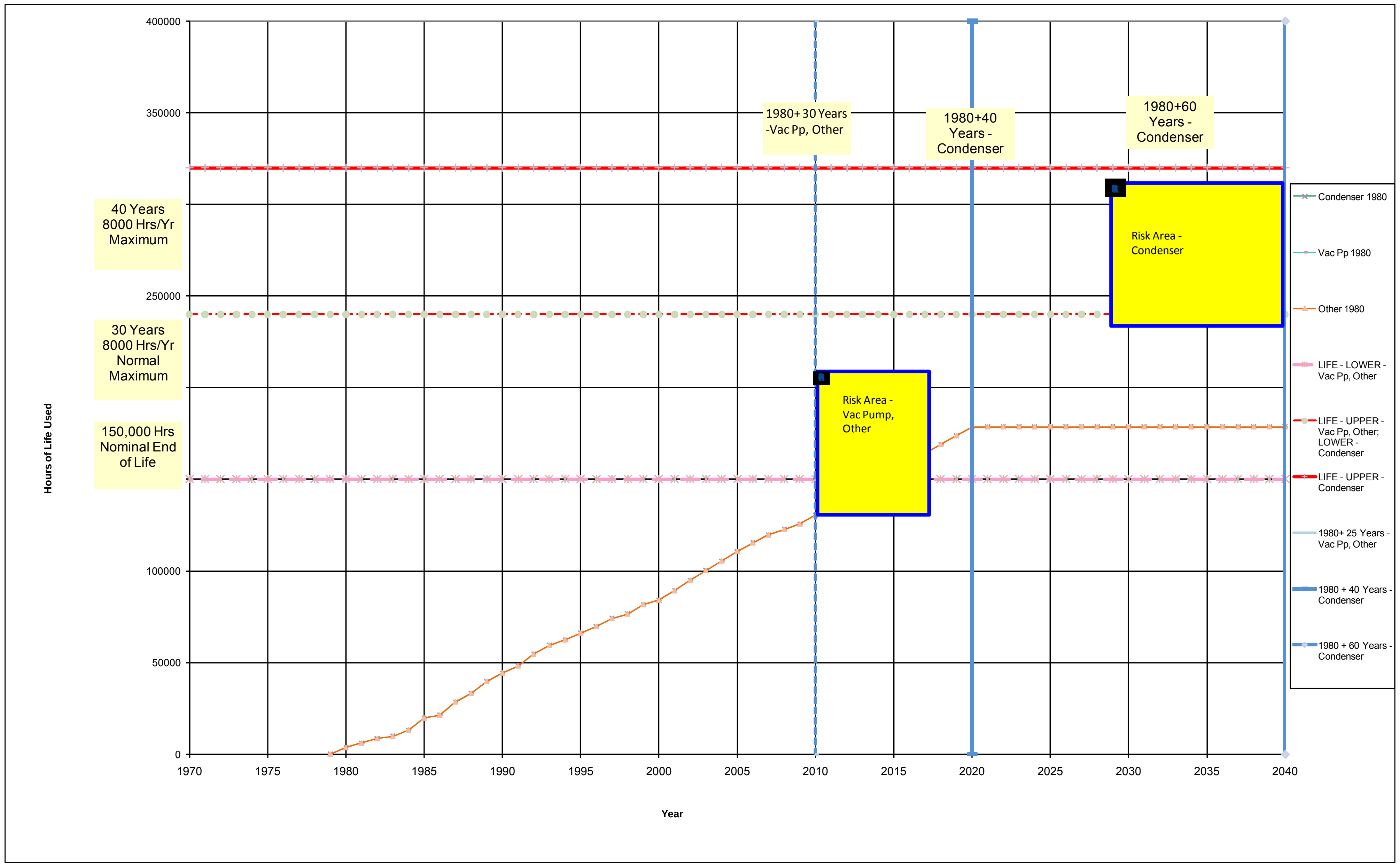

FIGURE 10-21 LIFE CYCLE CURVE – UNIT 3 CONDENSER

With the exception of the vacuum pumps, the curves indicate that the remaining life (RL) of the Unit 3 condenser can easily reach the desired life (DL) 2020 end date for generation. Additional information at the 2013 and 2016 turbine inspections should further confirm the condition. The equipment is original and is likely at or near end of life.

10.2.5.8 Level 2 Inspection Requirements and Costs

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 10-50 below, assuming the current plant inspection and maintenance program is maintained or improved.

TABLE 10-50 LEVEL 2 INSPECTION – UNIT 3 CONDENSER

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Sub System Comment	L2#	Appendix #	Level 2 Work	Year	Priority	Cost k$
1296	8193	8194	8223	0	0	3	TURBINE CONDENSER SYSTEM	TURBINE CONDENSER SYSTEM	TURBINE CONDENSER SYSTEM	None	1	22	NDE spot check inspection of major inlet and outlet pipes. Condensers themselves continue ongoing maintenance and inspection.	2011	2	$6
1296	8193	8194	8223	0	0	3	TURBINE CONDENSER SYSTEM	TURBINE CONDENSER SYSTEM	TURBINE CONDENSER SYSTEM	None	2	22	At next turbine valve overhaul in 2013, the inspection work or repairs (within the plant inspection and maintenance work) should be carried out, including: - Leak test and update the tubesheet maps for both the waterboxes. - Check the inlet waterboxes for tubes with water erosion at the tube inlets. Where required, install 10'' plastic inserts into the tubes to protect them from further wall loss or loss of tube. - Inspect condenser hotwell internal piping and supports for steam and water erosion. Investigate and repair as necessary. - Inspect hotwell drip drains for eroded or missing baffle plates. Replace if eroded or missing.	2013	2	
1296	8193	8194	8223	8252	0	3	TURBINE CONDENSER SYSTEM	CONDENSER AIR EXTRACTION	CONDENSER AIR EXTRACTION	None	3	22	No Level 2 inspections or testing is required.			
1296	8193	8194	8223	8252	8892	3	TURBINE CONDENSER SYSTEM	CONDENSER AIR VACUUM PUMP NORTH	CONDENSER AIR VACUUM PUMP NORTH	None	4	22	No Level 2 inspections or testing is required.			
1296	8193	8194	8223	8252	8893	3	TURBINE CONDENSER SYSTEM	CONDENSER AIR VACUUM PUMP SOUTH	CONDENSER AIR VACUUM PUMP SOUTH	None	5	22	No Level 2 inspections or testing is required.			
1296	8193	8194	8223	8252	99000295	3	TURBINE CONDENSER SYSTEM	CONDENSER AIR REMOVAL SYSTEMS	CONDENSER AIR REMOVAL SYSTEMS	None	6	22	No Level 2 inspections or testing is required.			
1296	8193	8194	8223	271677	0	3	TURBINE CONDENSER SYSTEM	TURBINE CONDENSER	TURBINE CONDENSER	None	7	22	No Level 2 inspections or testing is required.			

10.2.5.9 Capital Projects

The suggested typical capital enhancements for the Unit 3 condenser include:

TABLE 10-51 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – UNIT 3 CONDENSER

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Detail	CAP#	Appendix #	Unit #	Capital Item	Date	Priority
1296	8193	8194	8223	0	0	3	TURBINE CONDENSER SYSTEM	TURBINE CONDENSER SYSTEM	TURBINE CONDENSER SYSTEM	N/A	5	22	3	No capital required.		
1296	8193	8194	8223	8252	0	3	TURBINE CONDENSER SYSTEM	CONDENSER AIR EXTRACTION	CONDENSER AIR EXTRACTION	N/A	6	22	3	No capital required.		
1296	8193	8194	8223	8252	8892	3	TURBINE CONDENSER SYSTEM	CONDENSER AIR VAC PUMP NORTH	CONDENSER AIR VAC PUMP NORTH	N/A	7	22	3	Refurbish/replace vacuum pumps and motors as required. Provide electrical control (both “On” and “Off”) for the vacuum pumps in parallel with the local controls in the Control Room.	2015	1
1296	8193	8194	8223	8252	8893	3	TURBINE CONDENSER SYSTEM	CONDENSER AIR VAC PUMP SOUTH	CONDENSER AIR VAC PUMP SOUTH	N/A	8	22	3	Refurbish/replace vacuum pumps and motors as required. Provide electrical control (both “On” and “Off”) for the vacuum pumps in parallel with the local controls in the Control Room.	2015	1
1296	8193	8194	8223	8252	99000295	3	TURBINE CONDENSER SYSTEM	CONDENSER AIR REMOVAL SYSTEM S	CONDENSER AIR REMOVAL SYSTEM S	N/A	9	22	3	No capital required.		
1296	8193	8194	8223	271677	0	3	TURBINE CONDENSER SYSTEM	TURBINE CONDENSER	TURBINE CONDENSER	N/A	10	22	3	No capital required.		

10.2.6 Asset 8777 – Unit 3 FD Fans (and System)

(Detailed Technical Assessment in Working Papers, Appendix 19)

Unit #:	3
Asset Class #	BU 1296 - Assets Generations
SCI & System:	8336 #3 Boiler Plant
Sub-Systems:	8387 #3 Boiler Air System
	8437 #3 Boiler Gas System
	8460 #3 Boiler Fuel Firing System
	8461 #3 Boiler Heavy oil System
	8462 #3 Boiler Light Oil System
Components:	8782 #3 Boiler FD Fan System 8392 #3 Boiler FD Fan East 8393 #3 Boiler FD Fan West 8404 # 3Boiler Steam Air Heater East 8405 #3 Boiler Steam Air Heater West 8410 #3 Boiler Main Air Heater East 8411 #3 Boiler Main Air Heater West
	8464 #3 Boiler Heavy Oil Pump East 8465 #3 Boiler Heavy Oil Pump West 8468 #3 Boiler Heavy Oil Pump steam, valves and pipe 8471 #3 Boiler Heavy Oil Firing 7740 #3 Boiler Light Oil Pump East 7741 #3 Boiler Light Oil Pump West
	8429 #3 Boiler Air Supply Seal Air 8432 #3 Boiler Scanner Air System

10.2.6.1 Description

The Unit #3 Babcock and Wilcox boiler at Holyrood has two 50% duty 4KV AC motor driven Howden forced draft fans (east/west) which provide the combustion air for both the heavy #6 residual oil and the lighter #2 ignition oil. These fans are centrifugal in design and draw air from the top of the boiler house through ducts specifically connected to each fan inlet.

The air flow required for combustion is regulated by the use of variable inlet vanes which allow the required amount of air into the boiler furnace to ensure the fuel oil is completely burned. The FD fan inlet vanes are controlled automatically either by the boiler controlled DCS system or manually by the operator if required.

In addition, each of the FD fans has a set of steam coil air heaters and a rotating Ljungstrom air heater to heat the air used in the combustion process. The combustion air is heated prior to being admitted to the furnace windbox in order to improve fuel firing and also to reduce back end corrosion. Before using the steam coil air heater to heat the combustion air, at least one boiler in the plant must be generating sufficient steam for this function.

Asset 8437 Boiler #3 Flue Gas System:

The Unit 3 boiler gas passes from the economizer through the flue gas ductwork to the stack breeching. The duct work design is consistent with a steam generator built in the late 1970's.

Asset 8460 Fuel Oil Firing

The Unit 3 Babcock and Wilcox boiler heavy oil system supplies the 9 main burners with residual oil that is supplied from any of the 4 main heavy fuel oil storage tanks to the fuel oil day tank. The viscosity (SSU) of this fuel is high and therefore heat is required in order for it to flow. A series of steam heaters are installed in the storage tanks and steam heat tracing is provided on all of the main fuel oil lines feeding both the fuel oil day tank and the unit pumping and heating set. The main fuel oil is gravity fed from both the main fuel oil storage tanks to the day tanks as well from the day tank to the unit main heavy oil pumping and heating set.

Unit 3 is also equipped with 9 light oil (#2 fuel oil) igniters providing an ignition source for each main burner. The ignition oil (# 2 fuel oil) is gravity fed from the light oil fuel oil tanks to the Unit #3 light oil pumping skid.

Asset 8426 Boiler Air Supply Seal Air and Scanner Air

Each burner requires a flame scanner to be used to determine that a flame associated with a particular burner is either in or out of service, depending on the firing requirements. All of these scanners have electronic circuitry in the scanner heads which must be kept cool relative to the high ambient temperatures near the boilers. In order to accomplish the cooling, two 100% duty fans (north/south) are located externally and totally removed from the FD fan discharge ducts (which is different from Units 1 and 2).

10.2.6.2 History

Manufactured/Delivered	1979
In-Service Date	Feb 1980
Generation Base Load End Date	Dec 2015
Generation Peak/Emerg Gen End Date	Dec 2020

The hours associated with the analyses are:

Hours Generation Actual - Ops to Dec 2009	126
Max Hours Generation Ops – to Dec 2015	170
Max Hrs Gen Ops to Gen End Date Dec 2020	179

Max Hours Ops – 1986 to Dec 2009	113
Max Hrs - 1986 to Dec 2015	142
Max Hrs – 1986 to Gen End Date Dec 2020	164

10.2.6.3 Inspection and Repair History

Based on the Alstom report for 2009, Unit 3 FD fans were inspected during the annual overhaul and very little damage was noted from 2008. A complete evaluation of both fans was conducted in 2008 by Fan Dynamics out of Cambridge Ontario. Both FD fans at that time were deemed to be in good condition.

In 2009, an inspection of Unit 3 east and west Ljungstrom air heaters was completed as part of the annual overhaul. Both of these air heaters had some repair work completed. Alstom determined that in the future, more extensive work may be needed on the cold end elements, especially on the east unit.

The combustion steam coils were reported to have no damage. However, a long standing Unit 3 full load limitation resulting in excessive FD fan motor amps was identified with no specific cause being substantiated. Additional operational evaluations are needed to identify the root cause.

The unit has experienced significant forced draft system vibration, as a consequence of the original ductwork design. Flow induced turbulence in ductwork causing vibration has the potential to result in significant damage to forced draft fans and in cracks in the ductwork. The plant has plans to modify the ductwork system in an effort to reduce vibration levels caused by air flow turbulence and also to improve overall noise and efficiency. These changes are strongly supported.

Asset 8437 Boiler #3 Flue Gas System:

During yearly plant major or minor overhauls, all of the ductwork has been inspected by Alstom maintenance staff. Reports obtained from the plant indicate that due diligence has been carried out to ensure the integrity of the ductwork and any repairs were completed at the time of inspection. Structural supports are inspected and all have been deemed to be in good condition and will last for the foreseeable future.

Sootblowing system has minor maintenance carried out during normal operation.

Asset 8460 Fuel Oil Firing

Reports from the plant regarding the condition of light and heavy systems were not available. However, they appear to have been properly maintained. Although these two systems are critical to unit operation, replacement parts or systems will typically be available for the life of a plant and therefore not considered to be life limiting.

Asset 8426 Boiler Air Supply Seal Air and Scanner Air

These two auxiliary systems are totally external to the main boiler and have limited control circuitry to ensure they operate correctly. Any piping or hose leaks can be repaired at minimum costs as long as proper maintenance activity is carried out. Replacement of flame scanner heads is the single most costly expenditure if the system fails. Both of these systems appear to be well maintained.

10.2.6.4 Condition Assessment

The condition assessment of the Unit 3 FD fans (and system) is illustrated below in Table 10-52.

TABLE 10-52 CONDITION ASSESSMENT – UNIT 3 FD FANS (AND SYSTEM)

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset Level 2	Asset Level 3	Description	Detail	Condition Summary ID#	Append #	Condition	EPRI Identifier	Original Life (Base Load) Ops Hrs (Yrs)	Current Expected Minimum Remaining Life Years (Subject to Test)	End of Life (EOL) Required	Next Regular Inspection	Next Planned Overhaul or Major Inspection	Capability to Reach Next Overhaul	Capability to Reach EOL	In Service
1296	8193	8336	8387	0	0	3	BOILER PLANT	BOILER AIR SYSTEM	BOILER AIR SYSTEM	N/A	76	19, 30	Inspected yearly and repairs completed.	3a	200000 (40)	10	2020	2011		Yes	Yes	1980
1296	8193	8336	8387	8426	0	3	BOILER PLANT	BOILER AIR SYSTEM	BOILER AIR SUPPLY (A/H TO	N/A	77	19, 30	Inspected yearly and repairs completed.	3a	200000 (30)	10	2020	2011		Yes	Yes	1980
1296	8193	8336	8387	8426	8429	3	BOILER PLANT	BOILER AIR SYSTEM	BOILER AIR SUPPLY SEAL AIR	N/A	78	19, 30	Inspected yearly and repairs completed.	3a	200000 (30)	10	2020	2011		Yes	Yes	1980
1296	8193	8336	8387	8426	8432	3	BOILER PLANT	BOILER AIR SYSTEM	BOILER SCANNER AIR SYSTEM	N/A	79	19, 30	Inspected yearly and repairs completed.	3a	200000 (30)	10	2020	2011		Yes	Yes	1980
1296	8193	8336	8387	8433	0	3	BOILER PLANT	BOILER AIR SYSTEM	BOILER WINDBOX	N/A	80	19, 30	Inspected yearly and repairs completed.	3a	200000 (40)	10	2020	2011		Yes	Yes	1980
1296	8193	8336	8387	8782	0	3	BOILER PLANT	BOILER AIR SYSTEM	BOILER F.D. FAN SYSTEM	N/A	81	19, 30	Both FD fans at that time were deemed to be in good condition. Inspected yearly and repairs completed.	3a	200000 (30)	10	2020	2011		Yes	Yes	1980
1296	8193	8336	8387	8782	8392	3	BOILER PLANT	BOILER AIR SYSTEM	BOILER F.D. FAN EAST	N/A	82	19, 30	Both FD fans at that time were deemed to be in good condition. Inspected yearly and repairs completed.	3a	200000 (30)	10	2020	2011		Yes	Yes	1980
1296	8193	8336	8387	8782	8393	3	BOILER PLANT	BOILER AIR SYSTEM	BOILER F.D. FAN WEST	N/A	83	19, 30	Both FD fans at that time were deemed to be in good condition. Inspected yearly and repairs completed.	3a	200000 (30)	10	2020	2011		Yes	Yes	1980
1296	8193	8336	8387	8782	8392	3	BOILER PLANT	BOILER AIR SYSTEM	BOILER F.D. FAN EAST	Motors	84	25	Inspected yearly and repairs completed.	3a	200000 (30)	(5)	2020	2011		Yes	No	1980
1296	8193	8336	8387	8782	8393	3	BOILER PLANT	BOILER AIR SYSTEM	BOILER F.D. FAN WEST	Motors	85	25	Inspected yearly and repairs completed.	3a	200000 (30)	(5)	2020	2011		Yes	No	1980
1296	8193	8336	8387	8787	0	3	BOILER PLANT	BOILER AIR SYSTEM	BOILER STEAM AIR HEATER	N/A	86	19, 30	No damage observed in 2009. Inspected yearly and repairs completed.	3a	200000 (30)	10	2020	2011		Yes	Yes	1980
1296	8193	8336	8387	8787	8404	3	BOILER PLANT	BOILER AIR SYSTEM	BOILER STEAM AIR HEATER EAST	N/A	87	19, 30	No damage observed in 2009. Inspected yearly and repairs completed.	3a	200000 (30)	10	2020	2011		Yes	Yes	1980
1296	8193	8336	8387	8787	8405	3	BOILER PLANT	BOILER AIR SYSTEM	BOILER STEAM AIR HEATER WEST	N/A	88	19, 30	No damage observed in 2009. Inspected yearly and repairs completed.	3a	200000 (30)	10	2020	2011		Yes	Yes	1980
1296	8193	8336	8387	8788	0	3	BOILER PLANT	BOILER AIR SYSTEM	BOILER MAIN AIR HEATER	N/A	89	19, 30	Some repair work in 2009 and more extensive work likely in future years on the cold end elements. Inspected yearly and repairs completed.	3a	200000 (30)	10	2020	2011		Yes	Yes	1980
1296	8193	8336	8387	8788	8410	3	BOILER PLANT	BOILER AIR SYSTEM	BOILER MAIN AIR HEATER EAST	N/A	90	19, 30	Some repair work in 2009 and more extensive work likely in future years on the cold end elements. Inspected yearly and repairs completed.	3a	200000 (30)	10	2020	2011		Yes	Yes	1980
1296	8193	8336	8387	8788	8411	3	BOILER PLANT	BOILER AIR SYSTEM	BOILER MAIN AIR HEATER WEST	N/A	91	19, 30	Some repair work in 2009 and more extensive work likely in future years on the cold end elements. Inspected yearly and repairs completed.	3a	200000 (30)	10	2020	2011		Yes	Yes	1980
1296	8193	8336	8437	0	0	3	BOILER PLANT	BOILER GAS SYSTEM	BOILER GAS SYSTEM	N/A	92	19, 30	Inspected yearly and repairs completed.	3a	200000 (40)	10	2020	2011		Yes	Yes	1980
1296	8193	8336	8437	8438	0	3	BOILER PLANT	BOILER GAS SYSTEM	BOILER GAS PASSES	N/A	93	19, 30	Inspected yearly and repairs completed.	3a	200000 (40)	10	2020	2011		Yes	Yes	1980
1296	8193	8336	8437	8452	0	3	BOILER PLANT	BOILER GAS SYSTEM	BOILER SOOTBLOWING SYSTEM	N/A	94	17	Inspected yearly and repairs completed as required.	4	200000 (30)	10	2020	2011		Yes	Yes	1980
1296	8193	8336	8460	0	0	3	BOILER PLANT	BOILER FUEL FIRING SYSTEM	BOILER FUEL FIRING SYSTEM	N/A	95	19	Inspected yearly and repairs completed as required.	3a	200000 (30)	10	2020	2011		Yes	Yes	1980
1296	8193	8336	8460	8461	0	3	BOILER PLANT	BOILER FUEL FIRING SYSTEM	BOILER HEAVY OIL SYSTEM	N/A	96	19	Inspected yearly and repairs completed as required.	3a	200000 (30)	10	2020	2011		Yes	Yes	1980
1296	8193	8336	8460	8484	0	3	BOILER PLANT	BOILER FUEL FIRING SYSTEM	BOILER LIGHT OIL SYSTEM	N/A	97	19	Inspected yearly and repairs completed as required.	3a	200000 (30)	10	2020	2011		Yes	Yes	1980
1296	8193	8336	8503	0	0	3	BOILER PLANT	BLR AUX STEAM & CONDENSATE	BLR AUX STEAM & CONDENSATE	N/A	98		Not reviewed in detail - primarily unit heaters from good to poor condition. New source needed after close of generation.	4	200000 (30)	10	2041	2011		Yes	Yes	1980
1296	8193	8336	8337	0	0	3	BOILER PLANT	BOILER STRUCTURE	BOILER STRUCTURE	N/A	102	17	No recent inspections. Visual walkdown indicated no issues.	4	60	(30)	2041	2011	2011	Yes	Yes	1980

Notes:

1. A "(bracketed)" value in the "Current Expected Remaining Life" column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation, including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as "(X/Y)" has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

2. The "Next Regular Inspection" column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The "Next Planned Overhaul or Major Inspection" column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a "Desired Life" stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or simply are not known to AMEC.

3. The ability of the FD fans east and west to meet a 2020 EOL date may be affected if planned duct reconfiguration is not undertaken.

10.2.6.5 Actions

Based on the condition assessment, the following actions are recommended for the Unit 3 FD fans (and system).

TABLE 10-53 RECOMMENDED ACTIONS – UNIT 3 FD FANS (AND SYSTEM)

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Unit	Asset 2/3	Asset 3/4	Description	Detail	Action #	App #	Action	Year	Priority
1296	8193	8336	8387	0	3	BOILER PLANT	BOILER AIR SYSTEM	BOILER AIR SYSTEM	N/A	120	19,30	Continue routine inspection, maintenance and overhaul - evaluating air heater hot end baskets; connecting installed FD fans vibration probes to online monitoring system; refurbish and use the furnace exit thermoprobe during start-up activities to avoid distortion and overheating of the secondary superheater and reheater sections tubes.	2010	1
1296	8193	8336	8387	8426	3	BOILER PLANT	BOILER AIR SYSTEM	BOILER AIR SUPPLY (A/H TO	N/A	121	19,30	No recommended action.	2010	2
1296	8193	8336	8387	8426	3	BOILER PLANT	BOILER AIR SYSTEM	BOILER AIR SUPPLY SEAL AIR	N/A	122	19,30	No recommended action.	2010	2
1296	8193	8336	8387	8426	3	BOILER PLANT	BOILER AIR SYSTEM	BOILER SCANNER AIR SYSTEM	N/A	123	19,30	No recommended action.	2010	2
1296	8193	8336	8387	8433	3	BOILER PLANT	BOILER AIR SYSTEM	BOILER WINDBOX	N/A	124	19,30	Continue current inspection and maintenance activities.	2010	2
1296	8193	8336	8387	8782	3	BOILER PLANT	BOILER AIR SYSTEM	BOILER F.D. FAN SYSTEM	N/A	125	19,30, 25	Maintain ongoing inspection and maintenance programs. Maintain a spare motor be maintained to service all three units, in the event of a failure of an existing unit.	2010	2
1296	8193	8336	8387	8782	3	BOILER PLANT	BOILER AIR SYSTEM	BOILER F.D. FAN EAST	N/A	126	19,30, 25	No recommended action.	2010	2
1296	8193	8336	8387	8782	3	BOILER PLANT	BOILER AIR SYSTEM	BOILER F.D. FAN WEST	N/A	127	19,30, 25	No recommended action.	2010	2
1296	8193	8336	8387	8787	3	BOILER PLANT	BOILER AIR SYSTEM	BOILER STEAM AIR HEATER	N/A	128	19,30	Continue current inspection and maintenance activities.	2010	2
1296	8193	8336	8387	8787	3	BOILER PLANT	BOILER AIR SYSTEM	BOILER STEAM AIR HEATER EAST	N/A	129	19,30	Continue current inspection and maintenance activities.	2010	2
1296	8193	8336	8387	8787	3	BOILER PLANT	BOILER AIR SYSTEM	BOILER STEAM AIR HEATER WEST	N/A	130	19,30	Continue current inspection and maintenance activities.	2010	2
1296	8193	8336	8387	8788	3	BOILER PLANT	BOILER AIR SYSTEM	BOILER MAIN AIR HEATER	N/A	131	19,30	Continue current inspection and maintenance activities.	2010	2
1296	8193	8336	8387	8788	3	BOILER PLANT	BOILER AIR SYSTEM	BOILER MAIN AIR HEATER EAST	N/A	132	19,30	Continue current inspection and maintenance activities.	2010	2
1296	8193	8336	8387	8788	3	BOILER PLANT	BOILER AIR SYSTEM	BOILER MAIN AIR HEATER WEST	N/A	133	19,30	Continue current inspection and maintenance activities.	2010	2
1296	8193	8336	8437	0	3	BOILER PLANT	BOILER GAS SYSTEM	BOILER GAS SYSTEM	N/A	134	19,30	See details below.		
1296	8193	8336	8437	8438	3	BOILER PLANT	BOILER GAS SYSTEM	BOILER GAS PASSES	N/A	135	19,30	Inspect ductwork during annual inspections for excessive corrosion.	2011	2
1296	8193	8336	8437	8452	3	BOILER PLANT	BOILER GAS SYSTEM	BOILER SOOTBLOWING SYSTEM	N/A	136	19	Update obsolete controls. Evaluate/implement Intelligent Sootblowing (ISB) to reduce sootblowing energy consumption and mechanical damage impacts.	2012	2
1296	8193	8336	8437	8452	3	BOILER PLANT	BOILER GAS SYSTEM	BOILER SOOTBLOWING SYSTEM	N/A	137	19	Continue yearly inspections and repair work.	2011	2
1296	8193	8336	8460	0	3	BOILER PLANT	BOILER FUEL FIRING SYSTEM	BOILER FUEL FIRING SYSTEM	N/A	138	19	No recommended action.		
1296	8193	8336	8460	8461	3	BOILER PLANT	BOILER FUEL FIRING SYSTEM	BOILER HEAVY OIL SYSTEM	N/A	139	19	Continue yearly inspections and repair work.	2011	2
1296	8193	8336	8460	8484	3	BOILER PLANT	BOILER FUEL FIRING SYSTEM	BOILER LIGHT OIL SYSTEM	N/A	140	19	Continue yearly inspections and repair work.	2011	2
1296	8193	8336	8503	0	3	BOILER PLANT	BOILER AUXILIARY STEAM & CONDENSATE	BOILER AUXILIARY STEAM & CONDENSATE	N/A	141		Refurbish and replace unit heaters as required.	2011	2
1296	8193	8336	8503	8504	3	BOILER PLANT	BOILER AUXILIARY STEAM MAIN	BOILER AUXILIARY STEAM MAIN	N/A	142		Refurbish as required.	2011	2
1296	8193	8336	8503	8510	3	BOILER PLANT	BOILER AUXILIARY STEAM	BOILER AUXILIARY STEAM	N/A	143		Plan to replace as building heating source.	2011	2
1296	8193	8336	8503	8543	3	BOILER PLANT	AUXILIARY STEAM CONDENSATE	AUXILIARY STEAM CONDENSATE	N/A	144		Refurbish as required.	2011	2
1296	8193	8336	8337	0	3	BOILER PLANT	BOILER STRUCTURE	BOILER STRUCTURE	N/A	145	17	Visually inspect difficult to access areas.	2011	2
1296	8193	8336	8337	0	3	BOILER PLANT	BOILER STRUCTURE	BOILER STRUCTURE	N/A	146	30	Continue present inspection and maintenance program. Evaluate a preventive replacement of the boiler expansion joints.	2011	2
1296	8193	8336	8337	0	3	BOILER PLANT	BOILER STRUCTURE	BOILER STRUCTURE	N/A	147		Evaluate corrosion on the steel structure and hangers in the boilers penthouse areas during the boiler routine maintenance and inspection activities. Review condition of the boiler refractory to assess the requirement for replacement during the boiler routine maintenance and inspection activities.	2011	2

10.2.6.6 Risk Assessment

The risk assessment associated with the Unit 3 FD fans (and system), both from a technological perspective and a safety perspective, is illustrated below in Table 10-54.

TABLE 10-54 RISK ASSESSMENT – UNIT 3 FD FANS (AND SYSTEM)

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Component	Risk Assess #	Appendix #	Major Issues	Remaining Life Years	Remaining Life Comments	TECHNO_ECO RISK ASSESS MODEL			SAFETY RISK ASSESS MODEL			Possible Failure Event	Mitigation
														(Insufficient Info - Inspection Required Within (x) Years)		Likeli-hood	Conse-quence	Risk Level	Likeli-hood	Conse-quence	Safety Risk		
1296	8193	8336	8387	0	0	3	BOILER PLANT	BOILER AIR SYSTEM	BOILER AIR SYSTEM		103		See detail below.										
1296	8193	8336	8387	8426	0	3	BOILER PLANT	BOILER AIR SYSTEM	BOILER AIR SUPPLY (A/H TO	N/A	104		See detail below.										
1296	8193	8336	8387	8426	8429	3	BOILER PLANT	BOILER AIR SYSTEM	BOILER AIR SUPPLY SEAL AIR	Scanner & Seal Air	105	19	Mechanical fatigue, corrosion, ops error.	10	None	1	A	Low	1	A	Low	Worst case - short duration shutdown for repair.	Current inspection and maintain.
1296	8193	8336	8387	8426	8432	3	BOILER PLANT	BOILER AIR SYSTEM	BOILER SCANNER AIR SYSTEM	Scanner & Seal Air	106	19	Mechanical fatigue, corrosion, ops error.	10	None	1	A	Low	1	A	Low	Worst case - short duration shutdown for repair.	Current inspection and maintain.
1296	8193	8336	8387	8433	0	3	BOILER PLANT	BOILER AIR SYSTEM	BOILER WINDBOX	N/A	107		Not addressed.	10	None								
1296	8193	8336	8387	8782	0	3	BOILER PLANT	BOILER AIR SYSTEM	BOILER F.D. FAN SYSTEM	N/A	108		See detail below.	10	None								
1296	8193	8336	8387	8782	8392	3	BOILER PLANT	BOILER AIR SYSTEM	BOILER F.D. FAN EAST	Unit #3 LP FD Fan	109	19	Mechanical fatigue, corrosion, ops error.	10	None	1	B	Low	1	B	Low	Derate by 50% for short period. Consider spare motor.	Current inspection and maintain.
1296	8193	8336	8387	8782	8393	3	BOILER PLANT	BOILER AIR SYSTEM	BOILER F.D. FAN WEST	Unit #3 LP FD Fan	110	19	Mechanical fatigue, corrosion, ops error.	10	None	1	B	Low	1	B	Low	Derate by 50% for short period. Consider spare motor.	Spare and current inspection and maintain.
1296	8193	8336	8387	8782	8392	3	BOILER PLANT	BOILER AIR SYSTEM	BOILER F.D. FAN EAST	4 kV Forced Draft Fan Motor	111	25	Electrical fault, mechanical fatigue, ops error.	(5)	None	2	C	Medium	2	C	Medium	Loss 60% of 1 unit generation and damages.	Spare and current inspection and maintain.
1296	8193	8336	8387	8782	8393	3	BOILER PLANT	BOILER AIR SYSTEM	BOILER F.D. FAN WEST	4 kV Forced Draft Fan Motor	112	25	Electrical fault, mechanical fatigue, ops error.	(5)	None	2	C	Medium	2	C	Medium	Loss 60% of 1 unit generation and damages.	Current inspection and maintain.
1296	8193	8336	8387	8787	0	3	BOILER PLANT	BOILER AIR SYSTEM	BOILER STEAM AIR HEATER		113		Not addressed.		None								
1296	8193	8336	8387	8787	8404	3	BOILER PLANT	BOILER AIR SYSTEM	BOILER STEAM AIR HEATER EAST	Unit #3 Steam Preheat Coils	114	19	Corrosion, erosion, mechanical distortion.	10	None	1	A	Low	1	A	Low	Short term shutdown for repairs, derated or run at increased impact.	Current inspection and maintain.
1296	8193	8336	8387	8787	8405	3	BOILER PLANT	BOILER AIR SYSTEM	BOILER STEAM AIR HEATER WEST	Unit #3 Steam Preheat Coils	115	19	Corrosion, erosion, mechanical distortion.	10	None	1	A	Low	1	A	Low	Short term shutdown for repairs, derated or run at increased impact.	Current inspection and maintain.
1296	8193	8336	8387	8788	0	3	BOILER PLANT	BOILER AIR SYSTEM	BOILER MAIN AIR HEATER	APH Ductwork – Gas & Air	116	19	Corrosion, erosion thinning.	10	None	2	A	Low	2	A	Low	Short duration shutdown for repair/patch.	Current inspection and maintain.
1296	8193	8336	8387	8788	8410	3	BOILER PLANT	BOILER AIR SYSTEM	BOILER MAIN AIR HEATER EAST	Unit #3 APH	117	19	Corrosion, mechanical failure.	10	None	1	B	Low	1	B	Low	50% shutdown for maintenance and repairs.	Current inspection and maintain.
1296	8193	8336	8387	8788	8411	3	BOILER PLANT	BOILER AIR SYSTEM	BOILER MAIN AIR HEATER WEST	Unit #3 APH	118	19	Corrosion, mechanical failure.	10	None	1	B	Low	1	B	Low	50% shutdown for maintenance and repairs.	Current inspection and maintain.
1296	8193	8336	8437	0	0	3	BOILER PLANT	BOILER GAS SYSTEM	BOILER GAS SYSTEM	N/A	119	19,20	Leaks into powerhouse.	10	None	3	B	Medium	3	B	Medium	Overpressure.	Maintenance, inspection.
1296	8193	8336	8437	8438	0	3	BOILER PLANT	BOILER GAS SYSTEM	BOILER GAS PASSES	N/A	120	19,20	Leaks into powerhouse.	10	None	3	B	Medium	3	B	Medium	Duct split/corrosion.	Maintenance, inspection.
1296	8193	8336	8437	8452	0	3	BOILER PLANT	BOILER GAS SYSTEM	BOILER SOOTBLOWING SYSTEM	N/A	121		Mechanical failure.	10	None	2	B	Low	2	B	Low	Steam leak. Tube erosion.	Current inspection and maintain.
1296	8193	8336	8460	0	0	3	BOILER PLANT	BOILER FUEL FIRING SYSTEM	BOILER FUEL FIRING SYSTEM	Fuel Feed System	122	19	Mechanical fatigue, corrosion, ops error.	10	None	1	A	Low	1	C	Low	Derate for short period.	Current inspection and maintain.
1296	8193	8336	8460	8461	0	3	BOILER PLANT	BOILER FUEL FIRING SYSTEM	BOILER HEAVY OIL SYSTEM	N/A	123	19	Mechanical fatigue, corrosion, ops error.	10	None	1	A	Low	1	C	Low	Derate for short period. Safety.	Current inspection and maintain.
1296	8193	8336	8460	8484	0	3	BOILER PLANT	BOILER FUEL FIRING SYSTEM	BOILER LIGHT OIL SYSTEM	N/A	124	19	Mechanical fatigue, corrosion, ops error.	10	None	1	A	Low	1	C	Low	Derate for short period. Safety.	Current inspection and maintain.
1296	8193	8336	8503	0	0	3	BOILER PLANT	BOILER AUXILIARY STEAM AND CONDENSATE	BOILER AUXILIARY STEAM AND CONDENSATE	N/A	125		Mechanical failure.	(5)	None	3	A	Low	3	B	Medium	Steam leak.	Current inspection and maintain.
1296	8193	8336	8337	0	0	3	BOILER PLANT	BOILER STRUCTURE	BOILER STRUCTURE	N/A	129	17	Mechanical failure.	20	None	1	D	Medium	1	D	Low	Structure collapse.	Maintain and inspect.

10.2.6.7 Life Cycle Curve and Remaining Life

The life cycle curve for the system is illustrated below. One curve is required to represent the all elements given all is original equipment. The life curves are plots of current and projected operating hours (generation mode only) on the y-axis versus calendar year on the x-axis. The figure has several vertical lines representing differing representative nominal age limits. It also has several horizontal lines that represent a range of practical equipment equivalent base loaded operating hour life limits. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view.

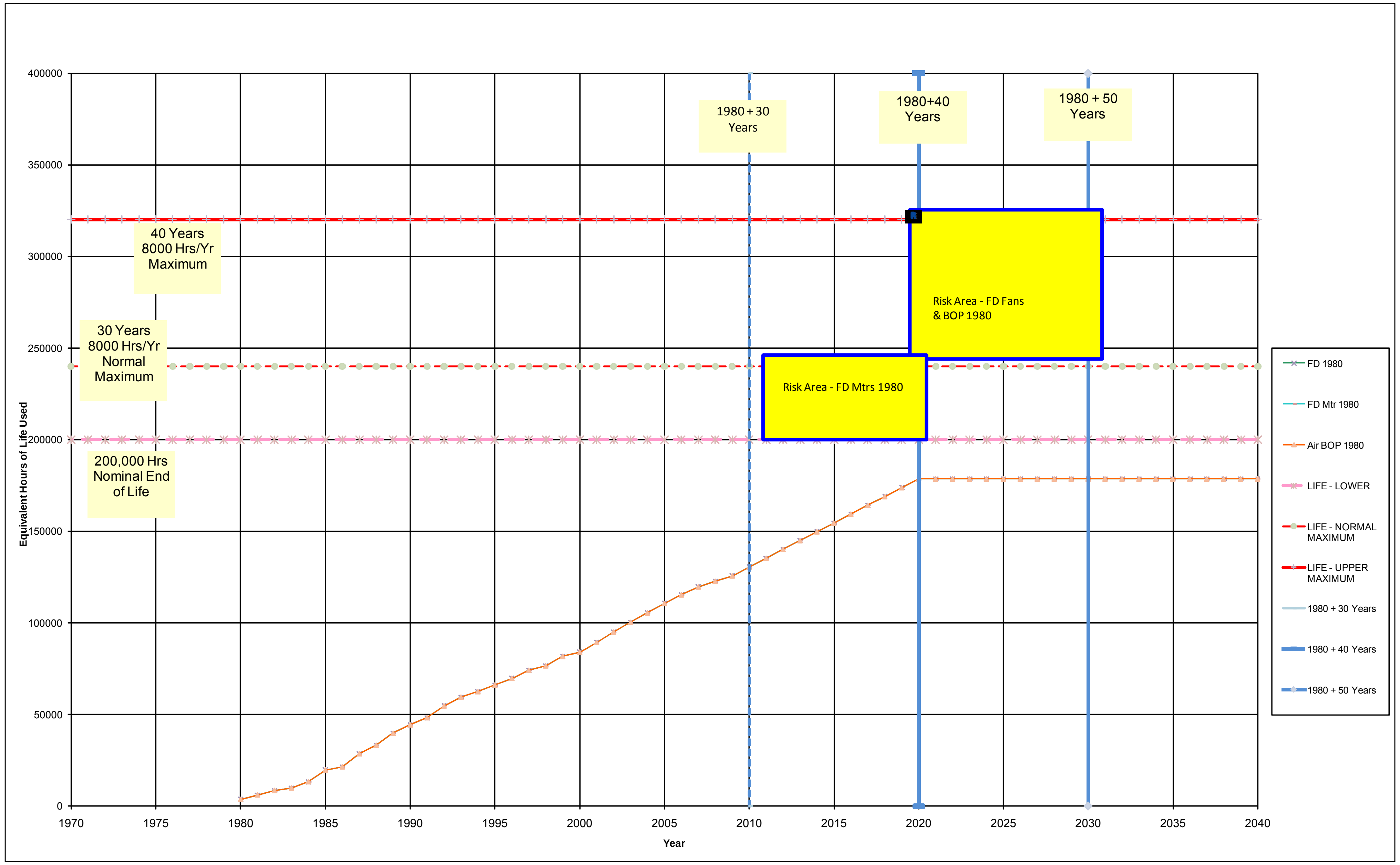

FIGURE 10-22 LIFE CYCLE CURVE – UNIT 3 FD FANS (AND SYSTEM)

The curves indicate that the remaining life (RL) of the Unit 3 FD fans (and system) are likely able to meet or exceed the desired life (DL) 2020 end date for generation. The age of the large 4 kV motors makes them a logical cost-effective candidate for sparing to ensure reliability, although plant testing/monitoring programs are effectively monitoring their status.

10.2.6.8 Level 2 Inspection Requirements and Costs

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 10-55 below, assuming the current plant inspection and maintenance program is maintained or improved.

TABLE 10-55 LEVEL 2 INSPECTION – UNIT 3 FD FANS (AND SYSTEM)

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Sub System Comment	L2#	Appendix #	Level 2 Work	Year	Priority	Cost k$
1296	8193	8336	8387	0	0	3	BOILER PLANT	BOILER AIR SYSTEM	BOILER AIR SYSTEM	None	86	19	No Level 2 inspections or testing is required.	2011		$0
1296	8193	8336	8387	8426	0	3	BOILER PLANT	BOILER AIR SYSTEM	BOILER AIR SUPPLY (A/H TO	None	87	19	No Level 2 inspections or testing is required.			
1296	8193	8336	8387	8426	8429	3	BOILER PLANT	BOILER AIR SYSTEM	BOILER AIR SUPPLY SEAL AIR	None	88	19	No Level 2 inspections or testing is required.			
1296	8193	8336	8387	8426	8432	3	BOILER PLANT	BOILER AIR SYSTEM	BOILER SCANNER AIR SYSTEM	None	89	19	No Level 2 inspections or testing is required.			
1296	8193	8336	8387	8433	0	3	BOILER PLANT	BOILER AIR SYSTEM	BOILER WINDBOX	None	90	19	No Level 2 inspections or testing is required.			
1296	8193	8336	8387	8782	0	3	BOILER PLANT	BOILER AIR SYSTEM	BOILER F.D. FAN SYSTEM	None	91	19	No Level 2 inspections or testing is required.			
1296	8193	8336	8387	8782	8392	3	BOILER PLANT	BOILER AIR SYSTEM	BOILER F.D. FAN EAST	None	92	19	No Level 2 inspections or testing is required on fan or 4 kV Motors, provided the current inspection and maintenance program is maintained.			
1296	8193	8336	8387	8782	8393	3	BOILER PLANT	BOILER AIR SYSTEM	BOILER F.D. FAN WEST	None	93	19	No Level 2 inspections or testing is required on fan or 4 kV Motors, provided the current inspection and maintenance program is maintained.			
1296	8193	8336	8387	8787	0	3	BOILER PLANT	BOILER AIR SYSTEM	BOILER STEAM AIR HEATER	None	94	19	No Level 2 inspections or testing is required.			
1296	8193	8336	8387	8787	8404	3	BOILER PLANT	BOILER AIR SYSTEM	BOILER STEAM AIR HEATER EAST	None	95	19	No Level 2 inspections or testing is required.			
1296	8193	8336	8387	8787	8405	3	BOILER PLANT	BOILER AIR SYSTEM	BOILER STEAM AIR HEATER WEST	None	96	19	No Level 2 inspections or testing is required.			
1296	8193	8336	8387	8788	0	3	BOILER PLANT	BOILER AIR SYSTEM	BOILER MAIN AIR HEATER	None	97	19	No Level 2 inspections or testing is required.			
1296	8193	8336	8387	8788	8410	3	BOILER PLANT	BOILER AIR SYSTEM	BOILER MAIN AIR HEATER EAST	None	98	19	No Level 2 inspections or testing is required.			
1296	8193	8336	8387	8788	8411	3	BOILER PLANT	BOILER AIR SYSTEM	BOILER MAIN AIR HEATER WEST	None	99	19	No Level 2 inspections or testing is required.			
1296	8193	8336	8437	0	0	3	BOILER PLANT	BOILER GAS SYSTEM	BOILER GAS SYSTEM	None	100	19	No Level 2 inspections or testing is required.			
1296	8193	8336	8437	8438	0	3	BOILER PLANT	BOILER GAS SYSTEM	BOILER GAS PASSES	None	101	19	No Level 2 inspections or testing is required.			
1296	8193	8336	8437	8452	0	3	BOILER PLANT	BOILER GAS SYSTEM	BOILER SOOTBLOWING SYSTEM	None	102	19	No Level 2 inspections or testing is required.			
1296	8193	8336	8460	0	0	3	BOILER PLANT	BOILER FUEL FIRING SYSTEM	BOILER FUEL FIRING SYSTEM	None	103	19	No Level 2 inspections or testing is required.			

Table 10-55 Cont'd

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Sub System Comment	L2#	Appendix #	Level 2 Work	Year	Priority	Cost k$
1296	8193	8336	8460	8461	0	3	BOILER PLANT	BOILER FUEL FIRING SYSTEM	BOILER HEAVY OIL SYSTEM	None	104	19	No Level 2 inspections or testing is required.			
1296	8193	8336	8460	8484	0	3	BOILER PLANT	BOILER FUEL FIRING SYSTEM	BOILER LIGHT OIL SYSTEM	None	105	19	No Level 2 inspections or testing is required.			
1296	8193	8336	8503	0	0	3	BOILER PLANT	BLR AUX STEAM & CONDENSATE	BLR AUX STEAM & CONDENSATE	None	106	19	No Level 2 inspections or testing is required.			
1296	8193	8336	8503	8504	0	3	BOILER PLANT	BOILER AUX. STEAM MAIN	BOILER AUX. STEAM MAIN	None	107	19	No Level 2 inspections or testing is required.			
1296	8193	8336	8503	8510	0	3	BOILER PLANT	BOILER AUXILIARY STEAM	BOILER AUXILIARY STEAM	None	108	19	No Level 2 inspections or testing is required.			
1296	8193	8336	8503	8543	0	3	BOILER PLANT	AUXILIARY STEAM CONDENSATE	AUXILIARY STEAM CONDENSATE	None	109		No Level 2 inspections or testing is required.			
1296	8193	8336	8337	0	0	3	BOILER PLANT	BOILER STRUCTURE	BOILER STRUCTURE	None	110		Level 2 - Visual Inspection of near rood structure	2011	2	$3

10.2.6.9 Capital Projects

The suggested typical capital enhancements for the Unit 3 FD fans (and system) include:

TABLE 10-56 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – UNIT 3 FD FANS (AND SYSTEM)

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Detail	CAP#	Appendix #	Unit #	Capital Item	Date	Priority
1296	8193	8336	8387	0	0	3	BOILER PLANT	BOILER AIR SYSTEM	BOILER AIR SYSTEM	N/A	73	19	3	Upgrade air ducts to reduce vibration, improve efficiency.	2013	1
1296	8193	8336	8387	8426	0	3	BOILER PLANT	BOILER AIR SYSTEM	BOILER AIR SUPPLY (A/H TO	N/A	74	19	3	No capital required.		
1296	8193	8336	8387	8426	8429	3	BOILER PLANT	BOILER AIR SYSTEM	BOILER AIR SUPPLY SEAL AIR	N/A	75	19	3	No capital required.		
1296	8193	8336	8387	8426	8432	3	BOILER PLANT	BOILER AIR SYSTEM	BOILER SCANNER AIR SYSTEM	N/A	76	19	3	No capital required.		
1296	8193	8336	8387	8433	0	3	BOILER PLANT	BOILER AIR SYSTEM	BOILER WINDBOX	N/A	77	19	3	No capital required.		
1296	8193	8336	8387	8782	0	3	BOILER PLANT	BOILER AIR SYSTEM	BOILER F.D. FAN SYSTEM	N/A	78	19	3	Procure spare motor - common to Units 1 & 2; adaptable Unit 3 to extent practical.	2012	1
1296	8193	8336	8387	8782	8392	3	BOILER PLANT	BOILER AIR SYSTEM	BOILER F.D. FAN EAST	N/A	79	19	3	Install vibration monitoring.	2012	2
1296	8193	8336	8387	8782	8393	3	BOILER PLANT	BOILER AIR SYSTEM	BOILER F.D. FAN WEST	N/A	80	19	3	Install vibration monitoring.	2012	2
1296	8193	8336	8387	8787	0	3	BOILER PLANT	BOILER AIR SYSTEM	BOILER STEAM AIR HEATER	N/A	81	19	3	No capital required.		
1296	8193	8336	8387	8787	8404	3	BOILER PLANT	BOILER AIR SYSTEM	BOILER STEAM AIR HEATER EAST	N/A	82	19	3	No capital required.		
1296	8193	8336	8387	8787	8405	3	BOILER PLANT	BOILER AIR SYSTEM	BOILER STEAM AIR HEATER WEST	N/A	83	19	3	No capital required.		
1296	8193	8336	8387	8788	0	3	BOILER PLANT	BOILER AIR SYSTEM	BOILER MAIN AIR HEATER	N/A	84	19	3	No capital required.		
1296	8193	8336	8387	8788	8410	3	BOILER PLANT	BOILER AIR SYSTEM	BOILER MAIN AIR HEATER EAST	N/A	85	19	3	No capital required.		
1296	8193	8336	8387	8788	8411	3	BOILER PLANT	BOILER AIR SYSTEM	BOILER MAIN AIR HEATER WEST	N/A	86	19	3	No capital required.		
1296	8193	8336	8437	0	0	3	BOILER PLANT	BOILER GAS SYSTEM	BOILER GAS SYSTEM	N/A	87	19	3	No capital required.		
1296	8193	8336	8437	8438	0	3	BOILER PLANT	BOILER GAS SYSTEM	BOILER GAS PASSES	N/A	88	19	3	No capital required.		
1296	8193	8336	8437	8452	0	3	BOILER PLANT	BOILER GAS SYSTEM	BOILER SOOTBLOWING SYSTEM	N/A	89	19	3	FD fan ductwork modifications.	2012	3
1296	8193	8336	8460	0	0	3	BOILER PLANT	BOILER FUEL FIRING SYSTEM	BOILER FUEL FIRING SYSTEM	N/A	90	19	3	No capital required.		
1296	8193	8336	8460	8461	0	3	BOILER PLANT	BOILER FUEL FIRING SYSTEM	BOILER HEAVY OIL SYSTEM	N/A	91	19	3	No capital required.		
1296	8193	8336	8460	8484	0	3	BOILER PLANT	BOILER FUEL FIRING SYSTEM	BOILER LIGHT OIL SYSTEM	N/A	92	19	3	No capital required.		
1296	8193	8336	8503	0	0	3	BOILER PLANT	BLR AUX STEAM & CONDENSATE	BLR AUX STEAM & CONDENSATE	N/A	93	19	3	New building heating system	2015-2020	2

10.2.7 Asset 8448 – Unit 3 Stacks and Breeching

(Detailed Technical Assessment in Working Papers, Appendix 17)

Unit #:	3
Asset Class #	BU 1296 - Assets Generations
SCI & System:	8336 #3 Boiler Plant
Sub-Systems:	8437 #3 Boiler Gas System
Components:	8448 #3 Boiler Stack 271682 – Stack Breeching

10.2.7.1 Description

The Unit 3 stack is constructed from reinforced concrete and contains a steel liner with some sections constructed from stainless steel and the remaining sections constructed from carbon steel. The stack breeching is the insulated steel ductwork that conveys the hot flue gas from the boiler air preheater to the stack. The stack was added in 1977.

10.2.7.2 History

Description	Stack Calendar Life	Operating Hours (Equiv Op Yrs) since Installation to 2009	Operating Hours (Equiv Op Yrs) to 2015/2020
Unit 3 Stack	33	126,000 (16)	170,000/179,000 (22)

The hours are based on 70% ACF/85% operating factor (OF) to 2015 (where the OF is equal to the actual running hours at any load in a year divided by 8760) and 10% ACF/20% OF from 2015-2020. The hours for 2015 and 2020 would be about 16,000 hours less if plant runs closer to historical 40% ACF up to 2015.

Manufactured/Delivered	1979
In-Service Date	Feb 1980
Generation Base Load End Date	Dec 2015
Generation Peak/Emerg Gen End Date	Dec 2020

The hours associated with the analyses are:

Hours Generation Actual - Ops to Dec 2009	126
Max Hours Generation Ops – to Dec 2015	170
Max Hrs Gen Ops to Gen End Date Dec 2020	179

10.2.7.3 Inspection and Repair History

The plant has been diligent in its inspections of the stack and has performed regular PM inspections and completed the suggested repairs.

Previous stack inspection reports indicate that there has been no major cracking or structural issues. There is some small cracking in portions of the stack and some water infiltration around construction joints. The carbon steel portions of the liners have localized areas of heavy corrosion as well as areas with minimal corrosion. The condition of the current linings and cap seems to suggest that Unit 3 has not been operating below the sulphuric acid dew point. The recent change to a much lower sulphur fuel oil has also reduced the acid dew point temperature, thereby allowing the plant to operate at a lower stack exit temperature to improve efficiency.

The life of the steel liners will vary depending on the materials of construction, the flue gas constituents, and the flue gas exit temperature. The upper liner sections of the stack are made of stainless steel to address the higher likelihood of acid attack as the flue gas cools going up the stack to levels approaching the acid dew point (local cooling could be below the dew point). The lower section of the liner is carbon steel which is adequate, provided the temperature in that zone does not frequently fall below the acid dew point of the stack. The design life of the liners should have been at least 30 years for the design fuels and operating conditions.

The inspections also suggest that life should not be an issue for the liner for the next ten years, despite the fact that portions of the liner are in excess of 33 years of age. The Unit 3 stack has seen approximately 16 years of operation over the period and therefore should be in reasonable shape. An additional 6 to 8 years of equivalent operation life may require some more careful examination. It is suggested that during the next stack inspection, NDE thickness measurements be taken at strategic points on both the stainless steel and carbon steel liners.

The stack breeching is designed to connect the ductwork into the liner of the stack. Currently it is the primary issue. The insulated steel lined duct stack breeching was replaced in 1990 with an internal refractory brick insulated duct. This was unsuccessful due to an adhesive membrane failure which caused the refractory to fall off and resulted in duct corrosion. Due to the unreliability and cost of the refractory brick lined duct, it is planned to refurbish it with an exterior insulated steel duct.

The stacks and the stack breeching (after being upgraded) are expected to make the 2020 generation end date.

10.2.7.4 Condition Assessment

The condition assessment of the Unit 3 stacks and breeching is illustrated below in Table 10-57.

TABLE 10-57 CONDITION ASSESSMENT – UNIT 3 STACKS AND BREECHING

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset Level 2	Asset Level 3	Description	Detail	Condition Summary ID#	Append #	Condition	EPRI Identifier	Original Life (Base Load) Ops Hrs (Yrs)	Current Expected Minimum Remaining Life Years (Subject to Test)	End of Life (EOL) Required	Next Regular Inspection	Next Planned Overhaul or Major Inspection	Capability to Reach Next Overhaul	Capability to Reach EOL	In Service
1296	8193	8336	8437	8448	0	3	BOILER PLANT	BOILER GAS SYSTEM	BOILER STACK	N/A	105	17	The concrete stacks are in good condition. The carbon steel portions of the liners have localized areas of heavy corrosion as well as areas with minimal corrosion. Carbon steel liner was replaced in 2001.	3a	(60/30)	30	2041	2012	2012	Yes	Yes	1980
1296	8193	8336	8437	8448	271682	3	BOILER PLANT	BOILER GAS SYSTEM	STACK BREECHING	N/A	106	17	Installed in 1990 , the current refractory brick lining in the breeching is cracked, causing local corrosion. It is planned to refurbish the ducting and replace the refractory brick with and insulated steel lined duct.	10	(30)	2	2020	2012	2012	Yes	No	1990/2013

Notes:
1. A "(bracketed)" value in the "Current Expected Remaining Life" column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation, including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as "(X/Y)" has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.
2. The "Next Regular Inspection" column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The "Next Planned Overhaul or Major Inspection" column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a "Desired Life" stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or simply are not known to AMEC.
3. The ability of the stack breeching to meet the EOL date of 2020 will be affected if planned refurbishments in 2013 are not undertaken.
4. The stack end of life is identified as 2041, assuming that it would not be demolished before the plant itself is closed.

10.2.7.5 Actions

Based on the condition assessment, the following actions are recommended for the Unit 3 stacks and breeching:

TABLE 10-58 RECOMMENDED ACTIONS – UNIT 3 STACKS AND BREECHING

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Unit	Asset 2/3	Asset 3/4	Description	Detail	Action #	App #	Action	Year	Priority
1296	8193	8336	8437	8448	3	BOILER PLANT	BOILER GAS SYSTEM	BOILER STACK	N/A	150	17	Paint stack, at least top portions, within next five years.	2013	1
1296	8193	8336	8437	8448	3	BOILER PLANT	BOILER GAS SYSTEM	BOILER STACK	N/A	151	17	Continue current stack inspections every 3 years and monitor degradation of concrete stacks and steel liners.	2013	1
1296	8193	8336	8437	8448	3	BOILER PLANT	BOILER GAS SYSTEM	BOILER STACK	N/A	152	17	Continue to make repairs to deficiencies found in inspection reports.	2013	1
1296	8193	8336	8437	8448	3	BOILER PLANT	BOILER GAS SYSTEM	STACK BREECHING	N/A	153	17	Undertake planned stack breeching repairs, including patching steel liner, installing external insulation, refurbishing corroded support structure, and providing ice protection shelter.	2013	1
1296	8193	8336	8437	8448	3	BOILER PLANT	BOILER GAS SYSTEM	STACK BREECHING	N/A	154	17	Re-assess need to replace carbon steel lining.	2013	1

10.2.7.6 Risk Assessment

The risk assessment associated with the Unit 3 stacks and breeching, both from a technological perspective and a safety perspective, is illustrated below in Table 10-59

TABLE 10-59 RISK ASSESSMENT – UNIT 3 STACKS AND BREECHING

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Component	Risk Assess #	Appendix #	Major Issues	Remaining Life Years	Remaining Life Comments	TECHNO_ECO RISK ASSESS MODEL			SAFETY RISK ASSESS MODEL			Possible Failure Event	Mitigation
														(Insufficient Info - Inspection Required Within (x) Years)		Likeli-hood	Conse-quence	Risk Level	Likeli-hood	Conse-quence	Safety Risk		
1296	8193	8336	8437	8448	0	3	BOILER PLANT	BOILER GAS SYSTEM	BOILER STACK	Unit #3 Concrete Shell	132	17	Structural cracking.	30	None	1	D	Medium	1	D	Medium	Structural failure requiring shutdown, unit outage.	Current inspection and maintain.
1296	8193	8336	8437	8448	0	3	BOILER PLANT	BOILER GAS SYSTEM	BOILER STACK	Unit #3 Stainless Steel Liner	133	17	Corrosion/failure.	10	None	1	B	Low	1	C	Low	Corrosion causing major leak or failure – major leak requiring repair and unit outage.	Current inspection and maintain.
1296	8193	8336	8437	8448	0	3	BOILER PLANT	BOILER GAS SYSTEM	BOILER STACK	Unit #3 Carbon Steel Liner	134	17	Corrosion/failure.	10	None	3	B	Medium	3	C	Medium	Corrosion causing major leak or failure – major leak requiring repair and unit outage.	Current inspection and maintain.
1296	8193	8336	8437	8448	271682	3	BOILER PLANT	BOILER GAS SYSTEM	STACK BREECHING	Unit #3 Stack Breeching	135	17	Corrosion/failure.	2	None	1	D	High	3	C	Medium	Corrosion causing major leak or failure – major leak requiring repair and unit outage.	Repair and maintain.

10.2.7.7 Life Cycle Curve and Remaining Life

The life cycle curve for the Unit 3 stack and breeching system is illustrated below. Two curves represent the stack, the stack breeching, and the stack liners based on their in-service dates. The life curves are plots of current and projected operating hours (generation mode only) on the y-axis versus calendar year on the x-axis. The figure has several vertical lines representing differing representative nominal age limits for various components. It also has several horizontal lines that represent a range of practical equivalent base loaded operating hour life limits. Several risk areas reflect also the differing normal lives of the components. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view.

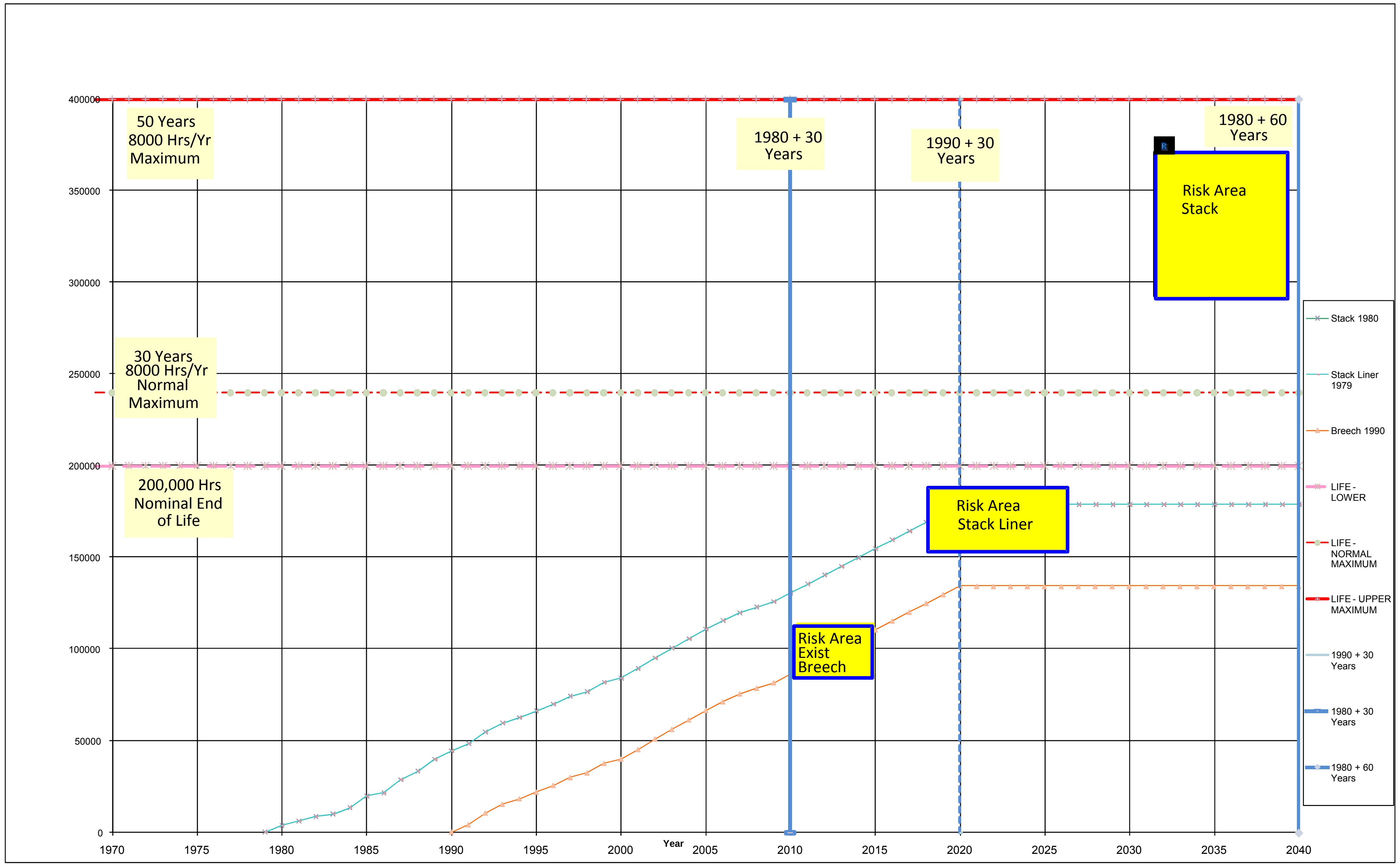

FIGURE 10-23 LIFE CYCLE CURVE – UNIT 3 STACKS AND BREECHING

The curves indicate that the remaining life (RL) of the Unit 3 stack is able to reach the desired life (DL) 2020 end date for generation, as well as the end date of 2041 for synchronous condensing/plant life. It does show that the stack breeching is in need of immediate repair. The breeching requirement is not a normal life issue, but one of design. Other elements can achieve the 2020 end date for generation with the ongoing plant maintenance program.

10.2.7.8 Level 2 Inspection Requirements and Costs

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 10-60 below, assuming the current plant inspection and maintenance program is maintained or improved.

TABLE 10-60 LEVEL 2 INSPECTION – UNIT 3 STACKS AND BREECHING

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Sub System Comment	L2#	Appendix #	Level 2 Work	Year	Priority	Cost k$
1296	8193	8336	8437	8448	0	3	BOILER PLANT	BOILER GAS SYSTEM	BOILER STACK	None	113	17	No Level 2 inspections required. Continue inspections every 3 years and monitor degradation of concrete stacks and steel liners.			
1296	8193	8336	8437	8448	271682	3	BOILER PLANT	BOILER GAS SYSTEM	STACK BREECHING	None	114	17	No Level 2 inspections or testing is required (based on breeching refurbishment as planned).			

10.2.7.9 Capital Projects

The suggested typical capital enhancements for the Unit 3 stacks and breeching include:

TABLE 10-61 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – UNIT 3 STACKS AND BREECHING

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Detail	CAP#	Appendix #	Unit #	Capital Item	Date	Priority
1296	8193	8336	8437	8448	0	3	BOILER PLANT	BOILER GAS SYSTEM	BOILER STACK	N/A	99	17	3	No capital required.		
1296	8193	8336	8437	8448	0	3	BOILER PLANT	BOILER GAS SYSTEM	BOILER STACK	N/A	100	17	3	No capital required.		
1296	8193	8336	8437	8448	271682	3	BOILER PLANT	BOILER GAS SYSTEM	STACK BREECHING	N/A	101	17	3	Refurbish stack breeching.	2014	1

10.2.8 Asset 8712 – Unit 3 Electrical and Control Systems (including DCS) Associated with Steam Systems

(Detailed Technical Assessment in Working Papers, Appendix 6)

The assets listed below include only those identified as exclusive to the plant steam systems.

Unit #:	3
Asset Class #	BU 1296 – Assets Generation
SCI & System:	3712 #3 Electrical Systems & Control
Sub-Systems:	3712 #3 Electrical Systems & Control
Components:	8699 #3 Burner Management 309901 #3 Boiler Protection and Control 8238 #3 Turbine Governor System

10.2.8.1 Description

The following information covers the Unit 3 electrical and control systems with the plant and its associated buildings:

Asset 8238 Unit 3 Turbine Governor System

The turbine governor system is mechanical fly-ball type system manufactured by Hitachi, and installed in 1979. Speed control is via linkages and dashpots. Monitoring of the governor is by the Bently Nevada system which provides vibration monitoring, differential protection, etc. Load limit control is an ongoing problem, which appears "course" at times. However, there is ongoing discussion between the plant and GE as to the root cause and eventual rectification of this problem. Control (Instrument) involvement with the governor is limited to the monitoring of valve positions, speed load, and load limit control points. All outputs are into the DCS and are monitored in the control room.

Asset 8699 Unit 3 Burner Management

The burner management system is a Foxboro (DCS) system, which was changed over in 2007. The soot-blower control system was installed in approximately 1980. It contains control relaying, motor starters and overloads, etc. The control relaying was replaced, in 2003 with an Omron SYSMAC C200HS PLC, with PS221 controllers and I/O modules. The starters are original CGE type CR205APO, with Allen Bradley type 810-!04 AB dashpot overloads. Field junction boxes are not very accessible. The igniter relay marshalling cabinets have some issues but they are not excessive.

Asset 301711 Unit 3 DCS

The DCS, manufactured by Foxboro, is an Invensys system that was installed in 2004. New cabling and Westinghouse panels housing the DCS were installed in the late 1990's. The original system was hard-wired but later upgraded to a Westinghouse system. Westinghouse could not support the system which was then updated to Foxboro in 2004.

Asset 309901 Unit 3 Boiler Protection and Control

The boiler protection and control system provides safety of personnel, protection of the boiler and its equipment, and control of the boiler processes. In 2004, the system was upgraded to the present Foxboro DCS system and control algorithms again were revisited. The Foxboro DCS equipment was mounted within the original Westinghouse WDPF enclosures.

10.2.8.2 History

The requirements for the electrical and control systems associated with the steam system for Holyrood are as follows:

Manufactured/Delivered	1979
In-Service Date	Feb 1980
Generation Base Load End Date	Dec 2015
Generation Peak/Emerg Gen End Date	Dec 2020
Last Controls Upgrade	2004

10.2.8.3 Inspection and Repair History

Foxboro technical support is provided a number of times per year under a service contract and upgrades are completed as required. Field adjustments and modifications will continue as necessary.

10.2.8.4 Condition Assessment

The condition assessment of the Unit 3 electrical and control system (including DCS) associated with steam systems is illustrated below in Table 10-62.

TABLE 10-62 CONDITION ASSESSMENT – UNIT 3 ELECTRICAL AND CONTROL SYSTEMS (INCLUDING DCS) ASSOCIATED WITH STEAM SYSTEMS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset Level 2	Asset Level 3	Description	Detail	Condition Summary ID#	Append #	Condition	EPRI Identifier	Original Life (Base Load) Ops Hrs (Yrs)	Current Expected Minimum Remaining Life Years (Subject to Test)	End of Life (EOL) Required	Next Regular Inspection	Next Planned Overhaul or Major Inspection	Capability to Reach Next Overhaul	Capability to Reach EOL	In Service
1296	8193	8712	8698	0	0	3	ELECTRICAL SYSTEM & CONTROL	RELAY RM PROTECTION&CONTROL	RELAY RM PROTECTION & CONTROL	N/A	182	6	Generator & Transformer & Auxiliary Protection and Metering Panels tests were satisfactory (2007). Some ingress of dust and foreign material. Testing is on a 6 year cycle (2013, 2019, 2025, etc.).	10	(30)	10+	2020	2013		Yes	No	1980
1296	8193	8712	271766	0	0	3	ELECTRICAL SYSTEM & CONTROL	SWITCHGEAR 4160 & 600 VOLT	SWITCHGEAR 4160 & 600 VOLT	N/A	183	6	Installed in 1980. Protection, synch, and control relays are original electro-mechanical. Feeders Motor Protection Relays installed in 2009. All overhauled in 2007-2009 OK except corrective actions on CWW3 Jan, 2010. (status 80). and UAT-3 breaker, no date but status 90. Transformers UAT3 and SAT34 in 2007 showed reasonable tolerances. All 600V switchgear is	10	(30)	10	2020	2007		Yes	No	1980
1296	8193	8194	271675	8236	0	3	U3 GENERATOR	TURBINE GOVERNOR	TURBINE GOVERNOR SYSTEM	N/A	184	18	"Course" load limit control is an ongoing problem. Control (Instrument) involvement of DCS limited to the monitoring of valve positions, speed load and load limit control points.	4	200000 (30)	5	2020	2013	2013	Yes	No	1980
1296	8193	8712	271767	0	0	3	ELECTRICAL SYSTEM & CONTROL	TURBINE SUPERVISORY SYSTEM (TSI)	TSI	N/A	185	6	Operating well, with numerous spares. In 2010 will progress toward Phase 5 (Obsolescence) status at some indeterminate time.	10	(20)	(5)	2020			No	No	2004
1296	8193	8712	8704	0	0	3	ELECTRICAL SYSTEM & CONTROL	MAIN CONTROLS	MAIN CONTROLS	N/A	186	6	Generator, turbine and boiler controls linked to the DCS with some original controls, indications and annunciations replaced. ASEA cabinets behind control room in hazardous state, with cabling so congested as to render the doors in the vertical sections unable to be closed. Potential for major failure and unit out of service for an indeterminate time.	4	(30)	2	2020			Yes	No	1980/2007
1296	8193	8712	301711	0	0	3	ELECTRICAL SYSTEM & CONTROL	DISTRIBUTED CONTROL SYSTEM (DCS)	DCS	N/A	187	6	Installed in 2004 - state of the art.	3a	(20)	20	2041			Yes	Yes	1980/2004
1296	8193	8712	309896	0	0	3	ELECTRICAL SYSTEM & CONTROL	600 V MELTRIC PLUGS	600 V MELTRIC PLUGS	N/A	188	6	New system.	3a	(50)	30	2041			No	No	2007
1296	8193	8712	8699	0	0	3	ELECTRICAL SYSTEM & CONTROL	BURNER MANAGEMENT	BURNER MANAGEMENT	N/A	189	6	Foxboro (DCS) system in 2007. Soot-blower controls from 1980, with control relaying replaced in 2003. Igniter relay marshalling cabinets have some troubles but not excessive.	4	(25)	10	2020			Yes	Yes	2007
1296	8193	8712	309901	0	0	3	ELECTRICAL SYSTEM & CONTROL	BOILER PROTECTION & CONTROL	BOILER PROTECTION & CONTROL	N/A	190	6	In 2004, the system was updated to the Foxboro DCS system in the original WDPF enclosures.	3a	(20)	15+	2020			Yes	Yes	2004

Notes:

1. A "(bracketed)" value in the "Current Expected Remaining Life" column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation, including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as "(X/Y)" has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

2. The "Next Regular Inspection" column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The "Next Planned Overhaul or Major Inspection" column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a "Desired Life" stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or simply are not known to AMEC.

10.2.8.5 Actions

Based on the condition assessment, the following actions are recommended for the Unit 3 electrical and control systems (including DCS) associated with steam systems:

TABLE 10-63 RECOMMENDED ACTIONS – UNIT 3 ELECTRICAL AND CONTROL SYSTEMS (INCLUDING DCS) ASSOCIATED WITH STEAM SYSTEMS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Unit	Asset 2/3	Asset 3/4	Description	Detail	Action #	App #	Action	Year	Priority
1296	8193	8712	0	0	3	ELECTRICAL SYSTEM & CONTROL	ELECTRICAL SYSTEM & CONTROL	ELECTRICAL SYSTEM & CONTROL	N/A	266	6	See details below.		
1296	8193	8712	8698	0	3	ELECTRICAL SYSTEM & CONTROL	RELAY RM PROTECTION & CONTROL	RELAY RM PROTECTION & CONTROL	N/A	267	6	Test Generator G3, Transformer T3 and Auxiliaries P&C Panels - next tests planned for 2013 2019, 2025, etc.	2011	1
1296	8193	8712	271766	0	3	ELECTRICAL SYSTEM & CONTROL	SWITCHGEAR 4160 & 600 VOLT	SWITCHGEAR 4160 & 600 VOLT	N/A	268	6	Include this Switchgear, 4160V/600V relaying in SB2 modernization study (5.3.2.28 IV) for the protection relays.	2014	1
1296	8193	8712	8704	0	3	ELECTRICAL SYSTEM & CONTROL	MAIN CONTROLS	MAIN CONTROLS	N/A	269	6	Carry out the NLH capital budget item to "Upgrade Unit 3 Relay Panels" in 2011, to provide a safe system and discard the existing cabinets and their contents, and redirect the existing field cables to the DCS system for Unit 3. Investigations will need to be conducted at site, and discussions held with Foxboro to determine if the present DCS physical size can accommodate the changes, or if it will need to be extended.	2011	2
1296	8193	8712	301711	0	3	ELECTRICAL SYSTEM & CONTROL	DISTRIBUTED CONTROL SYSTEM (DCS)	DCS	N/A	270	6	Maintain DCS system current through existing Foxboro replacement service agreement.	2014	1
1296	8193	8712	271767	0	3	ELECTRICAL SYSTEM & CONTROL	TURBINE SUPERVISORY SYSTEM (TSI)	TSI	N/A	271	6	Assess Turbine Supervisory System replacement options (vendor, GE 3500 Series Monitoring System, other GE options) that might be available in 2010-2011.	2011	1
1296	8193	8712	8699	0	3	ELECTRICAL SYSTEM & CONTROL	BURNER MANAGEMENT	BURNER MANAGEMENT	N/A	272	6	No action is required.	2011	2
1296	8193	8712	309901	0	3	ELECTRICAL SYSTEM & CONTROL	BOILER PROTECTION & CONTROL	BOILER PROTECTION & CONTROL	N/A	273	6	No recommended action.		

10.2.8.6 Risk Assessment

The risk assessment associated with the Unit 3 electrical and control system (including DCS) associated with steam systems, both from a technological perspective and a safety perspective, is illustrated below in Table 10-64.

TABLE 10-64 RISK ASSESSMENT – UNIT 3 ELECTRICAL AND CONTROL SYSTEMS (INCLUDING DCS) ASSOCIATED WITH STEAM SYSTEMS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Component	Risk Assess #	Appendix #	Major Issues	Remaining Life Years	Remaining Life Comments	TECHNO_ECO RISK ASSESS MODEL			SAFETY RISK ASSESS MODEL			Possible Failure Event	Mitigation
														(Insufficient Info - Inspection Required Within (x) Years)		Likeli-hood	Conse-quence	Risk Level	Likeli-hood	Conse-quence	Safety Risk		
1296	8193	8712	8698	0	0	3	ELECTRICAL SYSTEM & CONTROL	RELAY RM PROTECTION & CONTROL	RELAY RM PROTECTION&CONTROL	N/A	226	6	Electrical fault, mechanical fault, ops error.	5+	None	2	C-D	Medium	2	C-D	Medium	Loss 1 unit generation, damage to unit or equipment.	Current inspection and maintain.
1296	8193	8712	271766	0	0	3	ELECTRICAL SYSTEM & CONTROL	SWITCHGEAR 4160 & 600 VOLT	SWITCHGEAR 4160 & 600 VOLT	N/A	227	6	Electrical fault, mechanical fault, ops error.	(5)	None	3	B-C	Medium	3	B-C	Medium	Loss up to 1 unit generation. Damage to equipment.	Refurbish or replace.
1296	8193	8712	8704	0	0	3	ELECTRICAL SYSTEM & CONTROL	MAIN CONTROLS	MAIN CONTROLS	N/A	228	6	Electrical fault, mechanical fault, ops error.	2	None	1	C	Low	1	C	Low	Loss 1 unit generation. Damage to unit.	Current inspection and maintain.
1296	8193	8712	301711	0	0	3	ELECTRICAL SYSTEM & CONTROL	DISTRIBUTED CONTROL SYSTEM (DCS)	DCS	N/A	229	6	Electrical fault, ops error.	20	None	1	C	Low	1	C	Low	Loss 1 unit generation. Damage to unit.	Maintain.
1296	8193	8712	271767	0	0	3	ELECTRICAL SYSTEM & CONTROL	TURBINE SUPERVISORY SYSTEM (TSI)	TURBINE SUPERVISORY SYSTEM	N/A	230	6	Electrical fault, mechanical fault, ops error.	(5)	None	3	C	Medium	3	C	Medium	Loss 1 unit generation. Damage to unit.	Refurbish or replace.
1296	8193	8712	8699	0	0	3	ELECTRICAL SYSTEM & CONTROL	BURNER MANAGEMENT	BURNER MANAGEMENT	N/A	231	6	Electrical fault, mechanical fault, ops error.	10+	None	3,1	C	Medium/ Low	1	C	Low	Loss 1 unit generation. Equipment damage.	Refurbish or replace.
1296	8193	8712	309901	0	0	3	ELECTRICAL SYSTEM & CONTROL	BOILER PROTECTION & CONTROL	BOILER PROTECTION & CONTROL	N/A	232	6	Electrical fault, mechanical fault, ops error.	15+	None	1	2	Low	1	B	Low	Loss of part of 1 unit generation. Equipment damage.	Maintain.

10.2.8.7 Life Cycle Curve and Remaining Life

The life cycle curve for the Unit 3 electrical and control systems (including DCS) associated with steam systems is illustrated below. Several curves are required to represent the various elements of and their operational timing. The life curves are plots of current and projected operating hours (generation mode only) on the y-axis versus calendar year on the x-axis. The figure has several vertical lines representing differing representative nominal age limits for various components. It also has several horizontal lines that represent a range of practical equipment equivalent base loaded operating hour life limits. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view.

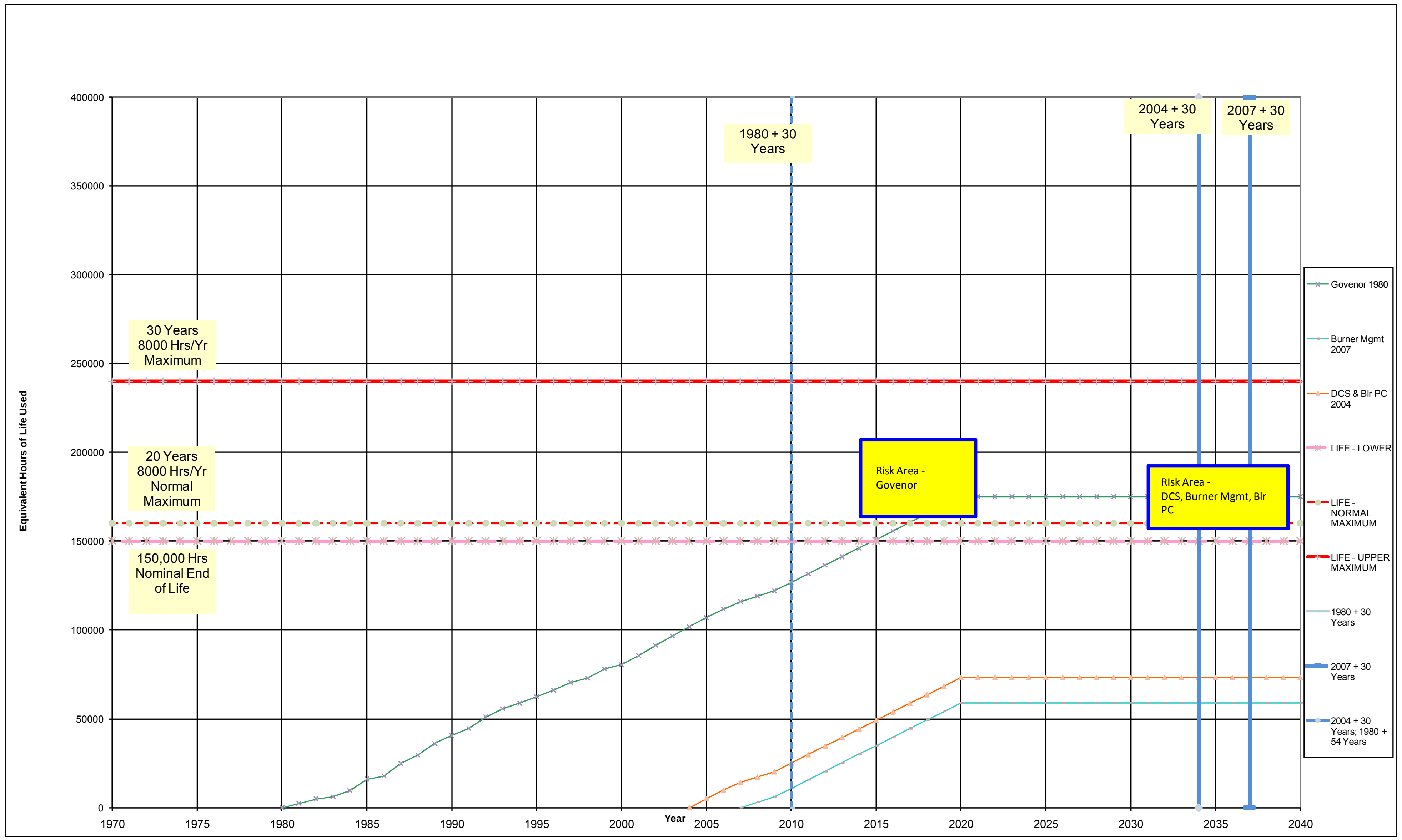

FIGURE 10-24 LIFE CYCLE CURVE – UNIT 3 ELECTRICAL AND CONTROL SYSTEMS (INCLUDING DCS) ASSOCIATED WITH STEAM SYSTEMS

The curves indicate that the remaining life (RL) of the Unit 3 control systems (including DCS) associated with steam systems can readily reach the desired life (DL) 2020 end date for generation, provided regular inspection and service per the station PM plan is maintained. The electrical systems, particularly breakers and motor controls are addressed in more detail as part of Section 10.1.3. It is clear that in order to meet the end date for generation service, some of these components must be replaced or in some cases refurbished.

10.2.8.8 Level 2 Inspection Requirements and Costs

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 10-65 below, assuming the current plant inspection and maintenance program is maintained or improved.

TABLE 10-65 LEVEL 2 INSPECTIONS – UNIT 3 ELECTRICAL AND CONTROL SYSTEMS (INCLUDING DCS) ASSOCIATED WITH STEAM SYSTEMS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Sub System Comment	L2#	Appendix #	Level 2 Work	Year	Priority	Cost k$
1296	8193	8712	0	0	0	3	ELECTRICAL SYSTEM & CONTROL	ELECTRICAL SYSTEM & CONTROL	ELECTRICAL SYSTEM & CONTROL	None	209	6	No Level 2 inspections or testing is required.			
1296	8193	8712	8698	0	0	3	ELECTRICAL SYSTEM & CONTROL	RELAY RM PROTECTION & CONTROL	RELAY RM PROTECTION & CONTROL	None	210	6	No Level 2 inspections or testing is required.			
1296	8193	8712	271766	0	0	3	ELECTRICAL SYSTEM & CONTROL	SWITCHGEAR 4160 & 600 VOLT	SWITCHGEAR 4160 & 600 VOLT	None	211	6	No Level 2 inspections or testing is required.			
1296	8193	8712	8716	8724	0	3	ELECTRICAL SYSTEM & CONTROL	UNIT SERVICE POWER SYSTEM	BOILER AREA BAB-3	None	212	6	No Level 2 inspections or testing is required.			
1296	8193	8712	8704	0	0	3	ELECTRICAL SYSTEM & CONTROL	MAIN CONTROLS	MAIN CONTROLS	None	213	6	No Level 2 inspections or testing is required.			
1296	8193	8712	301711	0	0	3	ELECTRICAL SYSTEM & CONTROL	DISTRIBUTED CONTROL SYSTEM (DCS)	DCS	None	214	6	No Level 2 inspections or testing is required.			
1296	8193	8712	271767	0	0	3	ELECTRICAL SYSTEM & CONTROL	TURBINE SUPERVISORY SYSTEM (TSI)	TSI	None	215	6	No Level 2 inspections or testing is required.			
1296	8193	8712	8699	0	0	3	ELECTRICAL SYSTEM & CONTROL	BURNER MANAGEMENT	BURNER MANAGEMENT	None	216	6	No Level 2 inspections or testing is required.			
1296	8193	8712	309901	0	0	3	ELECTRICAL SYSTEM & CONTROL	BOILER PROTECTION & CONTROL	BOILER PROTECTION & CONTROL	None	217	6	No Level 2 inspections or testing is required.			

10.2.8.9 Capital Projects

The suggested typical capital enhancements for the Unit 3 electrical and control systems (including DCS) associated with steam systems include:

TABLE 10-66 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – UNIT 3 ELECTRICAL AND CONTROL SYSTEMS (INCLUDING DCS) ASSOCIATED WITH STEAM SYSTEMS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Detail	CAP#	Appendix #	Unit #	Capital Item	Date	Priority
1296	8193	8712	0	0	0	3	ELECTRICAL SYSTEM & CONTROL	ELECTRICAL SYSTEM & CONTROL	ELECTRICAL SYSTEM & CONTROL	N/A	187	6	3	No capital required.		
1296	8193	8712	271766	0	0	3	ELECTRICAL SYSTEM & CONTROL	SWITCHGEAR 4160 & 600 VOLT	SWITCHGEAR 4160 & 600 VOLT	N/A	188	6	3	No capital required.		
1296	8193	8712	8698	0	0	3	ELECTRICAL SYSTEM & CONTROL	RELAY RM PROTECTION & CONTROL	RELAY RM PROTECTION & CONTROL	N/A	189	6	3	Implement modernization study refurbishing the old GE electro-magnetic relays or new multi-function relaying.	2014	1
1296	8193	8712	271766	0	0	3	ELECTRICAL SYSTEM & CONTROL	SWITCHGEAR 4160 & 600 VOLT	SWITCHGEAR 4160 & 600 VOLT	N/A	190	6	3	No capital required.		
1296	8193	8712	271767	0	0	3	ELECTRICAL SYSTEM & CONTROL	TURBINE SUPERVISORY SYSTEM (TSI)	TSI	N/A	191	6	3	Replace with selected preferred option.	2013	1
1296	8193	8712	8704	0	0	3	ELECTRICAL SYSTEM & CONTROL	MAIN CONTROLS	MAIN CONTROLS	N/A	192	6	3	No capital required.		
1296	8193	8712	301711	0	0	3	ELECTRICAL SYSTEM & CONTROL	DISTRIBUTED CONTROL SYSTEM (DCS)	DCS	N/A	193	6	3	No capital required.		
1296	8193	8712	309896	0	0	3	ELECTRICAL SYSTEM & CONTROL	600 V MELTRIC PLUGS	601 V MELTRIC PLUGS	N/A	194	6		No capital required.		
1296	8193	8712	8699	0	0	3	ELECTRICAL SYSTEM & CONTROL	BURNER MANAGEMENT	BURNER MANAGEMENT	N/A	195	6	3	No capital required.		
1296	8193	8712	309901	0	0	3	ELECTRICAL SYSTEM & CONTROL	BOILER PROTECTION & CONTROL	BOILER PROTECTION & CONTROL	N/A	196	6	3	No capital required.		

10.2.9 Asset 271675 – Unit 3 Steam Turbine

(Detailed Technical Assessment in Working Papers, Appendix 18)

Unit #:	3
Asset Class #	BU 1296 - Assets Generation
SCI & System:	8194 #3 Turbine & Generator
Sub-Systems:	271675 #3 Steam Turbine
Components:	8196 #3 Main Steam Chest
	8201 #3 HP Turbine
	8211 #3 IP Turbine
	8217 #3 LP Turbine
	8230 #3 Front Standard

Note: High energy piping and hangers are addressed within the Boiler Section (Section 10.2.1) under heading Boiler Main Steam Lines (Asset Code 8372). The scope is assumed to include piping and hangers up to the steam turbine.

10.2.9.1 Description

The Unit 3 150 MW model D5 Hitachi turbine was supplied in 1979. The turbine is rated to operate at the main steam inlet pressure of 13 MPag (1890 psig) and steam temperature of 538 °C (1,000 °F). The reheat steam inlet temperature is 538 °C (1,000 °F). The turbine shaft speed is 3,600 RPM.

The unit consists of one combined high pressure (HP) and intermediate (IP) turbine and one double flow LP turbine. The HP/IP and LP rotors are integral with the blade wheels. There is no centerline bore through the rotors. The turbine rotors are supported by four journal bearings. The trust bearing is located between the IP and LP turbines. The turning gear is located between the LP turbine and the generator.

The generator rotor is directly-coupled to the turbine. It is supported by two journal bearings located in the stator end-shields.

The Unit 3 steam turbine has a hydraulic control system that uses the same lube oil as the turbine bearings. The unit is partial arc machine with 4 control valves.

The unit has two main stop valves (MSVs). One of the MSVs has an internal pilot valve to control the turbine run up to full speed. There are two combined casing reheat stop and intercept valves.

The steam seal regulator (SSR) is the key component of the steam turbine gland steam sealing system. The SSR controls the flow of steam to and from all of the turbine shaft seals. The seals minimize the leakage of process steam along the rotor shaft from the turbine casing. There SSR must be able to respond differently at low and high loads.

The turbine auxiliaries included in this report are:

- The lube oil system
- The hydraulic control oil system, ;
- The gland steam sealing system, including steam seal regulator;
- The emergency blow down valve; and
- The power assisted extraction steam non return valves (NRVs).

10.2.9.2 History

Manufactured/Delivered	1979
In-Service Date	Feb 1980
Unit 3 IP 1st Stage Blades	2007
Generation Base Load End Date	Dec 2015
Generation Peak/Emerg Gen End Date	Dec 2020
Last Major Overhaul	2007
Last Valve (Minor) Overhaul	2004
Next Major Overhaul/Inspection	2016
Next Valve (Minor) Overhaul	2010/2013

The hours associated with the analyses are:

Hours Generation Actual - Ops to Dec 2009	126
Max Hours Generation Ops – to Dec 2015	170
Max Hrs Gen Ops to Gen End Date Dec 2020	179

10.2.9.3 Inspection and Repair History

The turbine major overhauls have been completed on a six year frequency. As of the year 2007, the overhauls are scheduled to be done every 9 years with the next overall scheduled for the year 2016. The turbine valve overhaul that is on 3 year frequency remains unchanged. The last valve overhaul was completed in the year 2007. The next overhauls are scheduled for years 2010 and 2013.

The reports indicate the overhaul work has been done by General Electric (GE) since the year 2001.

Over speed testing is completed once a year prior to the unit seasonal shut down and after every valve or turbine major overhaul.

The original SSR was an automated hydraulic system that contained many moving parts and wear points requiring manual intervention etc. In 2009, the existing SSR was replaced by a pneumatically operated pressure control valve system in order to improve the system reliability.

2001 Major Turbine & Valve Overhaul

Sometimes prior to the outage, a turbine water induction (TWI) incident likely (plant indicated otherwise) took place on this unit where the cold saturated steam flowed to the hot IP turbine from the boiler reheater section. The date of the incident or number of incidents is not known. A cold quenching steam flow through a turbine is considered a TWI incident per the ASME guideline. The damage to the turbine rotor, casings, steam path components etc. will depend on the duration, temperature differential, and the flow rate of the cold steam. The TWI can cause the inner and outer casings to distort and crack, shaft to bow, and excessive shaft vibrations that would damage the steam path components. The damage reported below (HP/IP outer casing distortion, excessive integral root and spill strips damage, cracks in the steam chest, etc.) are caused by TWI:

- The HP nozzle partition plates had cracks. These were removed and site weld repaired using inconel wire. GE recommended these be inspected and repaired off site during the next outage.
- HP/IP outer upper casings had cracks. These were ground out and not weld repaired. The depth ground out was about 3/8 inch. The lower inner casing was not removed and therefore the lower outer casing could not be inspected. GE recommended that the lower inner casing be removed during the next outage and both the inner and outer casing be inspected for cracks.
- The HP/IP outer casing horizontal joint has significant distortion in the mid section. GE recommended that the distortion be monitored for change during the next outage. Note that the cold RH steam was admitted in the mid section of the HP/IP casing and would come into direct contact with the casing which resulted in distortion.
- Most HP spill strips were damaged. They were straightened and dressed.
- The 7th IP stage (1st reheat) diaphragm was repaired off site. A protective coating was not reapplied.
- The IP 8th, 9th and 10th stage diaphragms partitions were damaged. They were dressed and weld repaired on site. The 11th and 12th stage diaphragms have cracks in the half joint. These were removed and weld repaired.
- Most IP diaphragms root radial seals and the tip spill strip seals were badly damaged. Some were weld repaired, straightened and dressed up. GE recommended that all IP diaphragms be sent off site during the next outage for major repair.
- Most shaft and gland packing were damaged. No spares were available. The packing seals were chased and sharpened.
- Some LP turbine diaphragm partition plates in both flows had cracks and were weld repaired.
- Cracks in the struts welds of the LP inner upper and lower casings were weld repaired.
- The LP inner half casing joints had groove cutting due to water erosion. Both top and bottom joint surfaces were weld repaired, grinded and stone levelled.
- The upper steam chest snout rings were replaced per GE new style locking rings. GE recommended that during the next outage, the lower snout rings must be replaced.
- The stems of both MSVs were replaced due to excessive run out.
- Serviced all lube oil pumps. Cleaned the oil tank and the coolers. The lube oil system was flushed.
- Steam seal regulator broken stem was replaced.

On startup, the turbine shaft vibrations were high. For unknown reasons, the balance weights installed during the year 1994 were removed and had to be reinstalled.

There is no mention in the report if ultrasonic testing (UT) was completed on the lower steam chest. Turbine Consults Inc. recommended that UT be completed to monitor the crack growth rate. The last UT inspections were done in years 1999 and 2000.

The cracks in the lower steam chest and the distortion in the mid section of the HP/IP outer casing are connected to the TWI incident.

2004 Turbine Valve Overhaul

- The UT inspection of the lower steam chest indicated that the crack found in 1998 had not grown since the 1999 UT inspection. The report also referred to a weld repair in 2001 (a pad of weld added to the outside of the area where the crack was found). No details were provided in the 2001 report.
- The upper steam chest was inspected using liquid dye penetrant (red dye). No cracks were found.

- Balance weights were added to the journal bearing #1 and #2 ends. The vibrations levels at bearing #1 were high during the past operating season cycle.
- The stems of both MSVs were replaced due to excessive run out.

The report did not specify if the full flow in-line filter cubical was hooked up to the lube oil system during this outage or earlier during the 2002 outage.

2007 Turbine Major Overhaul

- The follow up UT inspection on the lower steam chest indicated that the crack found in 1998 had not grown since the 1999 UT inspection. However, the NDE Company that did the UT is not confident with the crack size depth estimation.
- The upper steam chest was inspected using red dye. No cracks were found.
- The distortion in the mid section of the HP/IP outer casing horizontal joint was checked. There was no change (see 2002 overhaul summary above).
- The HP nozzle partition plates #1 and #14 had erosion notching and thinning. Both were TIG inconel weld repaired at site.
- The HP stage 2 diaphragm was shipped to off site for a major weld repair and a correction of the pitch to throat ratio. The spill strips were replaced.
- The HP stage 3 diaphragm had three cracks in the partition. It is not clear if these were weld repaired.
- The spill strip seal of the HP diaphragm stages 3 to 6 were damaged and were not replaced or repaired
- The IP first stage blades were replace and coated with GE diamond Tuff coating to protect the blades against solid particle erosion (SPE). The rotor dovetails were inspected and no cracks were found.
- The IP first stage diaphragm was sent off site for major partition repairs using 410 SS weld filler metal. The root radial integral seal was restored. The caulking groove was repaired and new tip spill strips were installed. After repair, the diaphragm was coated with GE diamond Tuff coating.
- The IP 8th stage diaphragm was sent off site for major partition repairs. The old inconel weld was removed and a new 410 SS weld repair was done. The root radial integral seal was restored. The caulking groove was repaired and new tip spill strips were installed.
- The IP 9th stage diaphragm partitions were refurbished and polished. The root radial and tip spill strip seals were not replaced or repaired.
- The IP 10th stage diaphragm was sent off site for major partition 410 SS weld repair and the correction of the pitch to throat ratio.
- The LP both flow diaphragms #13 and #14 were inconel weld repaired, "benching back", cold straightened and the surfaces polished where required. The 14th stage spill strip seals were replaced.
- The 18th stage generator end diaphragm partition #1 had some inconel repairs and cold straightening.
- The Lo blades had extensive water erosion in the last 10 cm (4 inches) of the blade height. The trailing edges are worn with deep sharp edges near the tip. There is also water erosion in the base metal ahead of the stellite bar nose. GE had a concern that the sharp edges could turn into cracks. No repair work was done.
- GE recommended that the Lo blades be repaired during the next outage.
- Finger dovetail pins were broken on two Lo blades and were replaced.
- All control valve (CV) main camshaft bearings and bushes were found defective or worn. They were replaced.

- All four CV snout rings were replaced by the new GE style locking rings.
- Stems of both Main Stop Valves (MSV)s were replaced due to an excessive run out.
- The stem of right side Reheat Stop Valves (RSV) was replaced due to an excessive run out.
- Stems of both Intercept Vales (IV) had to be cut to allow valve disassembly.
- A crack was repaired in the weld joint between the mesh and the strainer body of the left hand RSV. The weld repair was performed as per a GE approved procedure.
- Bearings No.'s 2, 3 and 5 were replaced due to poor bonding of the Babbitt linings. Bearing No. 4 was replaced as it was partially wiped.
- Serviced all lube oil pumps. Cleaned the oil tank and the coolers.
- Both turbine rotors were low speed balanced on site.

10.2.9.4 Condition Assessment

The condition assessment of the Unit 3 steam turbine is illustrated below in Table 10-67.

TABLE 10-67 CONDITION ASSESSMENT – UNIT 3 STEAM TURBINE

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset Level 2	Asset Level 3	Description	Detail	Condition Summary ID#	Append #	Condition	EPRI Identifier	Original Life (Base Load) Ops Hrs (Yrs)	Current Expected Minimum Remaining Life Years (Subject to Test)	End of Life (EOL) Required	Next Regular Inspection	Next Planned Overhaul or Major Inspection	Capability to Reach Next Overhaul	Capability to Reach EOL	In Service
1296	8193	8194	271675	0	0	3	U3 GENERATOR	TURBINE	TURBINE	N/A	30	18	See detail below	4	200000 (30)	10	2020		2016	Yes	No	1980
1296	8193	8194	271675	8196	0	3	U3 GENERATOR	TURBINE	TURBINE MAIN STEAM CHEST	N/A	31	18	Large cracks in the weld joint between the lower steam chest and the outer casing - first seen in 1998 and are on the inside surface. No weld repair work has been done. Per the inspections, the cracks are not growing, but the NDE Company that did the UT in 2007 is not confident with the cracks size estimation. distortion of the HIP outer casing half joint at the mid section.	4	200000 (30)	(3)	2020	2013	2013	Yes	No	1980
1296	8193	8194	271675	8201	0	3	U3 GENERATOR	TURBINE	H.P. TURBINE	N/A	32	18	Some minor SPE in the HP steam path components - repaired in 2007. Turbine is fairly good condition. The turbine valves and auxiliaries are in good condition.	4	200000 (30)	10	2020		2016	Yes	Yes	1980
1296	8193	8194	271675	8206	0	3	U3 GENERATOR	TURBINE	TURB REHEAT/IP STEAM CHEST	N/A	33	18	The turbine valves and auxiliaries are in good condition.	4	200000 (30)	10	2020	2013	2013	Yes	No	1980
1296	8193	8194	271675	8211	0	3	U3 GENERATOR	TURBINE	I.P. TURBINE	N/A	34	18	Turbine is fairly good condition. Substantial SPE in IP steam path components. First stage blades replaced in 2007. First stage diaphragm had a major partition repairs. New blades and diaphragm coated with a diamond tuff coating to protect the blades against future SPE damage.	4	200000 (30)	10	2020		2016	Yes	Yes	1980/2007
1296	8193	8194	271675	8217	0	3	U3 GENERATOR	TURBINE	L.P. TURBINE	N/A	35	18	Turbine is fairly good condition. The Lo blades have extensive water erosion in the last 4 inches of the blade height. Trailing edges worn with deep sharp edges near the tip. There is also water erosion in the base metal ahead of the stellite bar nose.	4	200000 (30)	6	2020		2016	Yes	No	1980
1296	8193	8194	271675	8230	0	3	U3 GENERATOR	TURBINE	TURBINE FRONT STANDARD	N/A	36	18	High temperature studs and valves are original equipment. Generally valves in good shape.	4	200000 (30)	10	2020	2013	2013	Yes	No	1980
1296	8193	8194	271675	8236	99024410	3	U3 GENERATOR	TURBINE	BENTLEY NEVADA TURBINE SUPERVISORY	N/A	37	18	See TSI	4	(25)	5	2020		2016	Yes	No	1980
1296	8193	8194	271675	8244	0	3	U3 GENERATOR	TURBINE	TURBINE GLAND STEAM SYSTEM	N/A	38	18	Original equipment. No issues identified except steam seal regulator (below)	4	(30)	10	2020		2016	Yes	Yes	1980
1296	8193	8194	271675	8244	0	3	U3 GENERATOR	TURBINE	TURBINE GLAND STEAM SYSTEM	Steam Seal Regulator	39	18	Original equipment. The Steam seal regulator 's many moving parts and wear points result in frequent binding and sticking requiring manual intervention. Parts are very difficult to obtain and the system should be considered obsolete. Failure to address could result in premature deterioration of the steam turbine generator bearings.	10	(30)	2	2020		2013	Yes	No	1980
1296	8193	8194	271675	8248	0	3	U3 GENERATOR	TURBINE	TURBINE PRE-WARMING SYSTEM	N/A	40	18	Original equipment. Good condition. Not reviewed.	4	(30)	10	2020		2016	Yes	No	1980
1296	8193	8194	271675	8250	0	3	U3 GENERATOR	TURBINE	TURBINE TURNING GEAR	N/A	41	18	Original equipment. Good condition. Not reviewed.	4	(30)	10	2020	2013	2013	Yes	No	1980

Notes:

1. A "(bracketed)" value in the "Current Expected Remaining Life" column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation, including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as "(X/Y)" has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

2. The "Next Regular Inspection" column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The "Next Planned Overhaul or Major Inspection" column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a "Desired Life" stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or simply are not known to AMEC.

3. The ability of the steam seal regulator (SSR) to meet its next overhaul date and the EOL date of 2020 is conditional on its replacement as planned in 2013

10.2.9.5 Actions

Based on the condition assessment, the following actions are recommended for the Unit 3 steam turbine:

TABLE 10-68 RECOMMENDED ACTIONS – UNIT 3 STEAM TURBINE

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Unit	Asset 2/3	Asset 3/4	Description	Detail	Action #	App #	Action	Year	Priority
1296	8193	8194	271675	0	3	U3 GENERATOR	TURBINE	TURBINE	N/A	54	18	Maintain records on stud replacements - why, date and location. Mark all high temperature studs and install at the same location during every stud change out.	2010	1
1296	8193	8194	271675	0	3	U3 GENERATOR	TURBINE	TURBINE	N/A	55	18	Increase Extraction steam NRV inspection from 3 years to 6 years. Top heater NRV need not be checked as there is no danger of over speed damage if the valve does not function. Check pneumatic actuator every 3 years. Ensure dry air is supplied to the cylinders. Check NRV valve operation on the seasonal restart every year.	2011	1
1296	8193	8194	271675	8196	3	U3 GENERATOR	TURBINE	TURBINE MAIN STEAM CHEST	N/A	56	18	Do phase array inspection of the cracks in the lower steam chest root area of the weld that joins the steam chest to the HIP outer casing. The 2010 bench mark PAI should be compared with the next phase array inspection in 2013 to establish if the crack is active and growing.	2010	1
1296	8193	8194	271675	8196	3	U3 GENERATOR	TURBINE	TURBINE MAIN STEAM CHEST	N/A	57	18	Perform during every valve outage a boroscope inspection of the first stage nozzle for wear and tear and FOD/SPE damage. Take pictures for record.	2013	1
1296	8193	8194	271675	8196	3	U3 GENERATOR	TURBINE	TURBINE MAIN STEAM CHEST	N/A	58	18	Have Hitachi identify casing studs close to the nozzle block studs that operate above 850○F prior to Unit 2016 overhaul that may have reached or are close to the end of their predicted creep life. Have Hitachi supply their engineering recommendations on the high temperature stud replacement and estimate the remaining creep life of the studs. Since the turbine valves are opened more often and operated at 1000oF, their operating creep life will be shorter. They are also more liable to be damaged and are subjected to wear and tear during the valve 3 year disassemble. Replace all if the other majority of the studs in a valve body are being replaced due to mechanical, wear or tear damage.	2014	1
1296	8193	8194	271675	8201	3	U3 GENERATOR	TURBINE	H.P. TURBINE	N/A	59	18	Inspect and record (take pictures) of the SPE/FOD damage to the HP and IP blades and the diaphragms.	2016	1
1296	8193	8194	271675	8201	3	U3 GENERATOR	TURBINE	H.P. TURBINE	N/A	60	18	Check the past 410 SS and inconel repairs in all HP and IP diaphragms. Record and compare the condition of wear of the 410 SS and inconel repairs. Repair and dress damage where required.	2016	1
1296	8193	8194	271675	8201	3	U3 GENERATOR	TURBINE	H.P. TURBINE	N/A	61	18	Recheck the HP Stage 3 partitions and repair. During the 2016 Major Overhaul - per the 2007 report (page 68), there were three cracks in the HP stage 3 lower half diaphragm where the partitions entered the inner sidewall. The cracks may not have been repaired.	2016	1
1296	8193	8194	271675	8201	3	U3 GENERATOR	TURBINE	H.P. TURBINE	N/A	62	18	Have Hitachi identify studs that operate close to or above 850 ◦F that may have reached or are close to the end of their predicted creep life. Have Hitachi supply their engineering recommendations on the high temperature stud replacement. Estimate the remaining creep life of the studs and replace studs close to the end of their life creep life	2014	1
1296	8193	8194	271675	8206	3	U3 GENERATOR	TURBINE	TURB REHEAT/IP STEAM CHEST	N/A	63	18	Have Hitachi identify casing studs close to the nozzle block studs that operate above 850 °F prior to Unit 2016 overhaul that may have reached or are close to the end of their predicted creep life. Have Hitachi supply their engineering recommendations on the high temperature stud replacement and estimate the remaining creep life of the studs. Since the turbine valves are opened more often and operated at 1000 °F, their operating creep life will be shorter. They are also more liable to be damaged and are subjected to wear and tear during the valve 3 year disassemble. Replace all if the other majority of the studs in a valve body are being replaced due to mechanical, wear or tear damage.	2014	1
1296	8193	8194	271675	8211	3	U3 GENERATOR	TURBINE	I.P. TURBINE	N/A	64	18	Check the past 410 SS and inconel repairs in all HP and IP diaphragms. Record and compare the condition of wear of the 410 SS and inconel repairs. Repair and dress damage where required.	2016	1
1296	8193	8194	271675	8211	3	U3 GENERATOR	TURBINE	I.P. TURBINE	N/A	65	18	Have Hitachi identify studs that operate close to or above 850 °F that may have reached or are close to the end of their predicted creep life. Hitachi supply their engineering recommendations on the high temperature stud replacement. Estimate the remaining creep life of the studs and replace studs close to the end of their life creep life.	2014	1

Table 10-68 Cont'd

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Unit	Asset 2/3	Asset 3/4	Description	Detail	Action #	App #	Action	Year	Priority
1296	8193	8194	271675	8217	3	U3 GENERATOR	TURBINE	L.P. TURBINE	N/A	66	18	During the 2016 Major Overhaul: - Where possible, inspection L0 and L-1 blade root and wheel steeple surfaces. - Inspect L0 blades for water erosion near the tips and report. Take pictures of the blade surfaces with water wear. Per GE recommendation, have a plan ready to weld repair the blades if necessary.	2016	1
1296	8193	8194	271675	8217	3	U3 GENERATOR	TURBINE	L.P. TURBINE	N/A	67	18	If possible, do bore scope inspection of LP L0 blades once a year through the LP turbine inspection door. This should be done after the unit is shut down after every seasonal operation.	2011	1
1296	8193	8194	271675	8230	3	U3 GENERATOR	TURBINE	TURBINE FRONT STANDARD	N/A	68	18	No specific recommended actions, beyond normal major overhaul work.	2016	1
1296	8193	8194	271675	8236	3	U3 GENERATOR	TURBINE	TURBINE GOVERNOR SYSTEM	N/A	69	6	Upgrade the mechanical fly-ball type turbine governor system to as-built condition or be replaced.	2016	1
1296	8193	8194	271675	8236	3	U3 GENERATOR	TURBINE	BENTLEY NEVADA TURBINE SUPERVISORY SYSTEM	N/A	70	6	Assess and replace turbine supervisory system.	2012	1
1296	8193	8194	271675	8244	3	U3 GENERATOR	TURBINE	TURBINE GLAND STEAM SYSTEM	N/A	71	18	Replace seal seal regulator in 2013. Undertake other normal major overhaul work.	2013	1
1296	8193	8194	271675	8248	3	U3 GENERATOR	TURBINE	TURBINE PRE-WARMING SYSTEM	N/A	72	18	No specific recommended actions, beyond normal major overhaul work.	2016	1
1296	8193	8194	271675	8250	3	U3 GENERATOR	TURBINE	TURBINE TURNING GEAR	N/A	73	18	No specific recommended actions, beyond normal major overhaul work.	2016	1

10.2.9.6 Risk Assessment

The risk assessment associated with the Unit 3 steam turbine, both from a technological perspective and a safety perspective, is illustrated below in Table 10-69

TABLE 10-69 RISK ASSESSMENT – UNIT 3 STEAM TURBINE

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Component	Risk Assess #	Appendix #	Major Issues	Remaining Life Years	Remaining Life Comments	TECHNO_ECO RISK ASSESS MODEL			SAFETY RISK ASSESS MODEL			Possible Failure Event	Mitigation
														(Insufficient Info - Inspection Required Within (x) Years)		Likeli-hood	Conse-quence	Risk Level	Likeli-hood	Conse-quence	Safety Risk		
1296	8193	8194	271675	0	0	3	U3 GENERATOR	TURBINE	TURBINE		40		See detail below.	10									
1296	8193	8194	271675	8196	0	3	U3 GENERATOR	TURBINE	TURBINE MAIN STEAM CHEST	N/A	41		Cracks in lower steam chest and casing. Valve mechanical failure.	(1)	None	2	C	Medium	2	C	Medium	Turbine shutdown, overspeed failure.	Inspect and maintain. Identify long term solution.
1296	8193	8194	271675	8201	0	3	U3 GENERATOR	TURBINE	HP TURBINE	High pressure turbine diaphragms, nozzle partition plates and turbine blades.	42	18	Mechanical failure - relative higher risk from erosion and Foreign Object Damage (FOD).	10	None	2	C	Medium	2	C	Medium	Turbine lost generation, efficiency, capacity.	Some repairs in 2007. Inspect and maintain. Eliminate FOD.
1296	8193	8194	271675	8206	0	3	U3 GENERATOR	TURBINE	TURBINE REHEAT/IP STEAM CHEST		43		Valve mechanical failure.	10	None	2	C	Medium	2	C	Medium	Turbine shutdown, overspeed failure.	Inspect and maintain. Identify long term solution.
1296	8193	8194	271675	8211	0	3	U3 GENERATOR	TURBINE	IP TURBINE	Intermediate pressure turbine diaphragms, and first stage turbine blades.	44	18	Mechanical failure - SPE and erosion from foreign object damage (FOD).	10	None	2	C	Medium	2	C	Medium	Turbine lost generation, efficiency, capacity.	In 2007, the IP first stage blades replaced and the IP first stage diaphragm (and others) had a major partition repairs. New blades and diaphragm diamond tuff coated. Check condition of the first stage RH blades in 2016 overhaul. Eliminate SPE.
1296	8193	8194	271675	8217	0	3	U3 GENERATOR	TURBINE	LP TURBINE	Low pressure turbine	45	18	Chemical/mechanical failure - LP monoblock integral discs - SCC failure.	10	None	1	C	Low	1	C	Low	Turbine lost generation, efficiency, capacity.	Manage the condensate and feedwater chemistry within the ASME guidelines,
1296	8193	8194	271675	8230	0	3	U3 GENERATOR	TURBINE	TURBINE FRONT STANDARD		46		Not addressed. Mechanical failure.	10	None	1	C	Medium	1	C	Low	Turbine shutdown, overspeed failure.	Inspect and maintain. Identify long term solution.
1296	8193	8194	271675	8236	0	3	U3 GENERATOR	TURBINE	TURBINE GOVERNOR SYSTEM	Turbine governor system	47	6	Electrical, mechanical failure, ops error.	5	None	1	C	Low	1	C	Low	Loss 1 unit generation. Damage to unit.	Current inspection and maintain.
1296	8193	8194	271675	8236	99024410	3	U3 GENERATOR	TURBINE	BENTLEY NEVADA TURBINE SUPERVISORY SYSTEM	Turbine supervisory system	48	6	Electrical fault, mechanical fatigue, ops error.	5	None	3	C	Medium	3	C	Medium	Loss 1 unit generation. Damage to unit.	Refurbish or replace.
1296	8193	8194	271675	8244	0	3	U3 GENERATOR	TURBINE	TURBINE GLAND STEAM SYSTEM	N/A	49		Not addressed. Mechanical sealing failure.	10	None	1	C	Low	1	C	Low	Steam leak.	Inspect and maintain. .
1296	8193	8194	271675	8244	0	3	U3 GENERATOR	TURBINE	TURBINE GLAND STEAM SYSTEM	Steam Seal regulator	50	18	Control failure/Parts obsolete	(4)	Essentially at EOL	3	C	Medium	3	C	Medium	Turbine shut down. Bearing failure.	Replace
1296	8193	8194	271675	8248	0	3	U3 GENERATOR	TURBINE	TURBINE PRE-WARMING SYSTEM	N/A	51		Not addressed.	10	None	2	A	Low	1	A	Low	Slow start up.	Inspect and maintain.
1296	8193	8194	271675	8250	0	3	U3 GENERATOR	TURBINE	TURBINE TURNING GEAR	N/A	52		Not addressed. Mechanical chain failure.	10	None	3	B	Medium	3	A	Low	Turbine bowing without turning - gear on shutdown.	Inspect and maintain.

10.2.9.7 Life Cycle Curve and Remaining Life

The life cycle curve for the Unit 3 steam turbine is illustrated below. One curve indicates that the major elements of the turbine are original equipment. The unit is due to undergo a major overhaul in 2016. The life curve is a plot of current and projected operating hours (generation mode only) on the y-axis versus calendar year on the x-axis. The figure has several vertical lines representing differing representative nominal age limits for various components. It also has several horizontal lines that represent a range of practical equipment equivalent base loaded operating hour life limits. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view.

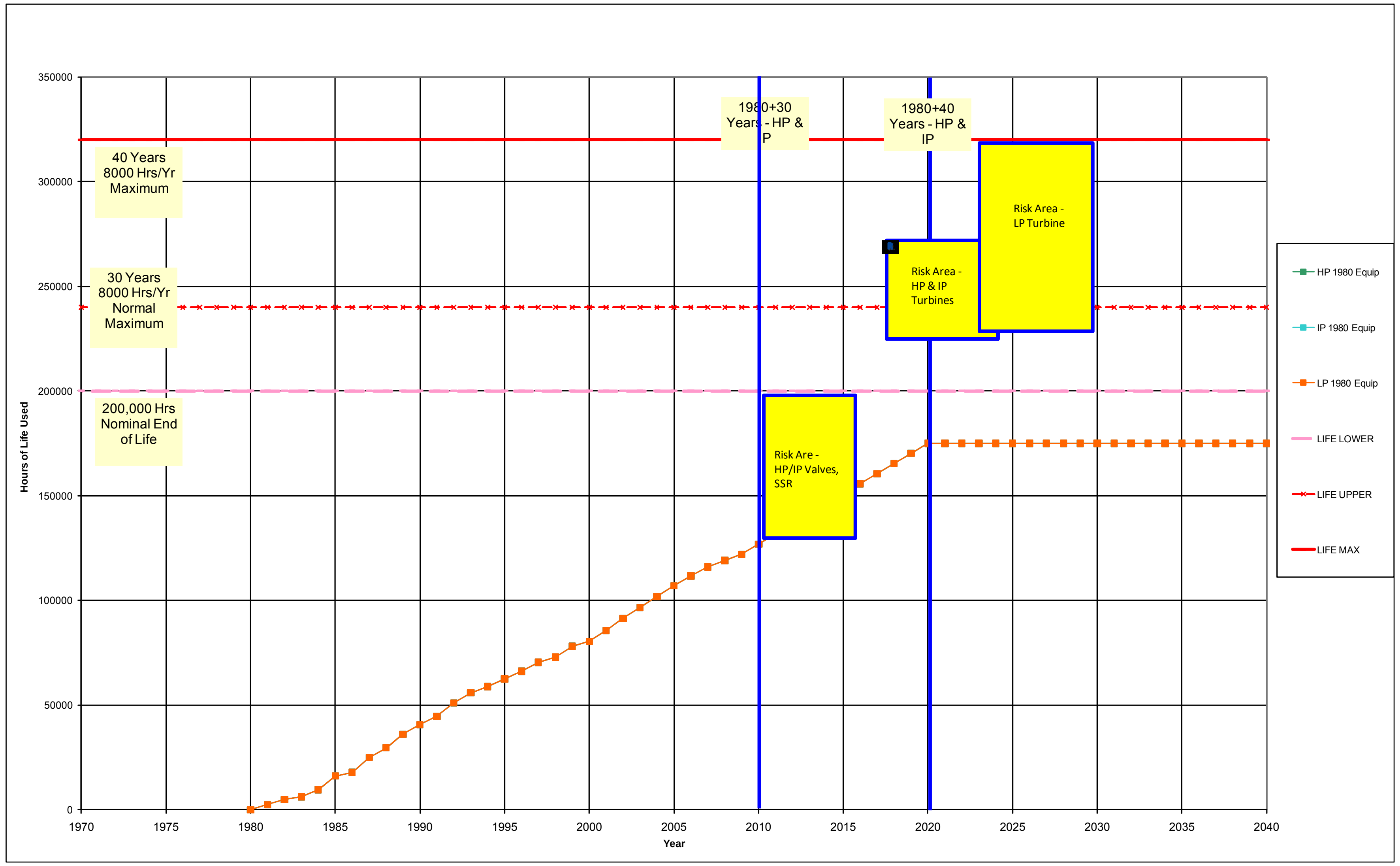

FIGURE 10-25 LIFE CYCLE CURVE – UNIT 3 STEAM TURBINE

The curves indicate that the remaining life (RL) of the various elements of the Unit 3 steam turbine exceeds the desired life (DL) which is the lesser of the time to its next major planned overhaul/inspection (2016) or to the desired End of Life (EOL) date of 2020. In fact the 2020 end date should be readily achievable. No specific dedicated Level 2 is required, but sufficient inspection and testing will be required in the 2016 overhaul to confirm the ability to meet the 2020 EOL date. The exception to this is the SSR and the high temperature stud bolts. It is clear that the current inspection schedule seems suitable.

10.2.9.8 Level 2 Inspection Requirements and Costs

Given the condition historical data reviewed, the Level 2 analyses recommended are presented in Table 10-70 below, assuming the current plant inspection and maintenance program is maintained or improved.

TABLE 10-70 LEVEL 2 INSPECTION – UNIT 3 STEAM TURBINE

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Sub System Comment	L2#	Appendix #	Level 2 Work	Year	Priority	Cost k$
1296	8193	8194	271675	0	0	3	U3 GENERATOR	TURBINE	TURBINE	None	27	18	Level 2 is essentially the Steam Turbine Overhaul	2016	1	$2,601
1296	8193	8194	271675	8196	0	3	U3 GENERATOR	TURBINE	TURBINE MAIN STEAM CHEST	None	28	18	HP Steam Chest Phased Array Inspection (PAI) - In 2010, do the phase array inspection of the cracks in the lower steam chest root area of the weld that joins the steam chest to the HIP outer casing. The 2010 bench mark PAI should be compared with the next phase array inspection in 2013 to establish if the crack is active and growing.	2010	1	$22
1296	8193	8194	271675	8201	0	3	U3 GENERATOR	TURBINE	H.P. TURBINE	None	29	18	First Stage Nozzle Borescope: During every valve outage, do a bore scope inspection of the first stage nozzle for wear and tear and FOD/SPE damage. Take pictures for record.	2011	1	$6
1296	8193	8194	271675	8201	0	3	U3 GENERATOR	TURBINE	H.P. TURBINE	None	30	18	Identify and assess HP Inner Casing Studs prior to Unit 2016 overhaul NL Hydro should have Hitachi identify studs that operate close to and above 850 ○ F and have Hitachi supply their engineering recommendations on the high temperature stud replacement.	2011	1	$6
1296	8193	8194	271675	8206	0	3	U3 GENERATOR	TURBINE	TURB REHEAT/IP STEAM CHEST	None	31	18	Identify and asses studs that operate above 850 ○ F may have reached or are close to the end of their predicted creep life (CV/RSV and ICV studs)	2011	1	$6
1296	8193	8194	271675	8211	0	3	U3 GENERATOR	TURBINE	I.P. TURBINE	None	32	18	Identify and assess IP Inner Casing Studs prior to Unit 2016 overhaul NL Hydro should have Hitachi identify studs that operate close to and above 850 ○ F and have Hitachi supply their engineering recommendations on the high temperature stud replacement.	2011	1	$6
1296	8193	8194	271675	8217	0	3	U3 GENERATOR	TURBINE	L.P. TURBINE	None	33	18	LP L0 blades Boroscope: If possible, do bore scope inspection of LP L0 blades once a year through the LP turbine inspection door, done after the unit is shut down after every seasonal operation.	2010	1	
1296	8193	8194	271675	8230	0	3	U3 GENERATOR	TURBINE	TURBINE FRONT STANDARD	None	34	18	No Level 2 required - include in steam turbine overhaul.	2013		
1296	8193	8194	271675	8236	0	3	U3 GENERATOR	TURBINE	TURBINE GOVERNOR SYSTEM	None	35	18	No Level 2 required - include in steam turbine overhaul.	2013		
1296	8193	8194	271675	8236	99024410	3	U3 GENERATOR	TURBINE	BENTLEY NEVADA TURBINE SUPERVISORY	None	36	18	No Level 2 required - include in steam turbine overhaul.	2013		
1296	8193	8194	271675	8244	0	3	U3 GENERATOR	TURBINE	TURBINE GLAND STEAM SYSTEM	None	37	18	No Level 2 required - include in steam turbine overhaul (Assuming SSR is replaced in 2013).	2013		
1296	8193	8194	271675	8248	0	3	U3 GENERATOR	TURBINE	TURBINE PRE-WARMING SYSTEM	None	38	18	No Level 2 required - include in steam turbine overhaul.	2013		
1296	8193	8194	271675	8250	0	3	U3 GENERATOR	TURBINE	TURBINE TURNING GEAR	None	39	18	No Level 2 required - include in steam turbine overhaul.	2013		

10.2.9.9 Capital Projects

The suggested typical capital enhancements for the Unit 3 steam turbine include:

TABLE 10-71 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – UNIT 3 STEAM TURBINE

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Detail	CAP#	Appendix #	Unit #	Capital Item	Date	Priority
1296	8193	8194	271675	0	0	3	U3 GENERATOR	TURBINE	TURBINE	N/A	30	18	3	No capital required.		
1296	8193	8194	271675	8196	0	3	U3 GENERATOR	TURBINE	TURBINE MAIN STEAM CHEST	N/A	31	18	3	No capital required.		
1296	8193	8194	271675	8201	0	3	U3 GENERATOR	TURBINE	H.P. TURBINE	N/A	32	18	3	No capital required.		
1296	8193	8194	271675	8206	0	3	U3 GENERATOR	TURBINE	TURB REHEAT/IP STEAM CHEST	N/A	33	18	3	No capital required.		
1296	8193	8194	271675	8211	0	3	U3 GENERATOR	TURBINE	I.P. TURBINE	N/A	34	18	3	No capital required.		
1296	8193	8194	271675	8217	0	3	U3 GENERATOR	TURBINE	L.P. TURBINE	N/A	35	18	3	No capital required.		
1296	8193	8194	271675	8230	0	3	U3 GENERATOR	TURBINE	TURBINE FRONT STANDARD	N/A	36	18	3	No capital required.		
1296	8193	8194	271675	8236	0	3	U3 GENERATOR	TURBINE	TURBINE GOVERNOR SYSTEM	N/A	37	18	3	Upgrade the mechanical fly-ball type turbine governor system to as-built condition or be replaced using electronic controls.	2013	1
1296	8193	8194	271675	8236	99024410	3	U3 GENERATOR	TURBINE	BENTLEY NEVADA TURBINE SUPERVI	N/A	38	18	3	Implement replacement option.	2013	2
1296	8193	8194	271675	8244	0	3	U3 GENERATOR	TURBINE	TURBINE GLAND STEAM SYSTEM	N/A	39	18	3	Replace steam seal regulator	2013	1
1296	8193	8194	271675	8248	0	3	U3 GENERATOR	TURBINE	TURBINE PRE-WARMING SYSTEM	N/A	40	18	3	No capital required.		
1296	8193	8194	271675	8250	0	3	U3 GENERATOR	TURBINE	TURBINE TURNING GEAR	N/A	41	18	3	No capital required.		

10.2.10 Asset 271768 – Cooling Water System - Associated with Steam Systems

(Detailed Technical Assessment in Working Papers, Appendix 11, 25)

Unit #:	3
Asset Class #	BU 1296 - Assets Generations
SCI & System:	8645 #3 Unit Generation Services
Sub-Systems:	271678 #3 CW System
Components:	8649 #3 CW Travelling Screens East
	8650 #3 CW Travelling Screens West
	8658 #3 CW Pump East
	8659 #3 CW Pump West
	8647#3 CW Intake (Pipe from CW Pumps)
	8676 #3 CW Discharge to Outfall (Piping from Condenser)

10.2.10.1 Description

The circulating water (CW) systems, servicing Unit 3 consist of two 50% CW vertical turbine pumps driven by 4kV motors and auxiliary systems. The pump drive motors are original. Two travelling screen systems are used to remove debris from the cooling water prior to entering the pumps. The primary function of the CW system is to provide condenser cooling water but also cooling water for other closed loop systems. It is necessary that the CW system operate efficiently in order to maintain optimal plant thermal efficiency by minimizing steam turbine condenser backpressures.

The requirements for Unit are as follows:

Manufactured/Delivered	1979
In-Service Date	Feb 1980
Generation Base Load End Date	Dec 2015
Generation Peak/Emerg Gen End Date	Dec 2020
Next Major Overhaul/Inspection	2016

The hours associated with the analyses are:

Hours Generation Actual - Ops to Dec 2009	126
Max Hours Generation Ops – to Dec 2015	170
Max Hrs Gen Ops to Gen End Date Dec 2020	179

FIGURE 10-26 UNIT 3 CIRCULATING WATER INLET

FIGURE 10-27 UNIT 3 CIRCULATING WATER TRAVELLING SCREENS

FIGURE 10-28 UNIT 3 CIRCULATING WATER PUMPS

10.2.10.2 History

The requirements for the cooling water system on Units 3 are as follows:

Manufactured/Delivered	1979
In-Service Date	Feb 1980
Generation Base Load End Date	Dec 2015
Generation Peak/Emerg Gen End Date	Dec 2020

The hours associated with the analyses are:

Hours Generation Actual - Ops to Dec 2009	126
Max Hours Generation Ops – to Dec 2015	170
Max Hrs Gen Ops to Gen End Date Dec 2020	179

10.2.10.3 Inspection and Repair History

Cooling Water Pumps & Motors, Screens, and Piping Systems

Asset 8649/8650 CW Travelling Screens

The Unit 3 CW pumps and motors, screens, and piping systems have not been refurbished. The screens on Unit 3 have not been refurbished and likely should be within next five years.

The external casings are in differing states, with some parts more corroded than others. None appears to impair current or short term performance.

Asset 6823 Wash Water Pumps and Motors

Externally, the wash water pumps and motors are generally in a corroded state, but were performing at the time of the visual inspection. They are considered to be a minor maintenance issue and not addressed as a part of this assessment.

Asset 8858/8859 CW Pumps

The CW pumps servicing Unit 3 are performing fairly well. No reports were available on the condition of the pumps, but interviews suggest that regular maintenance has been kept up and the units should be able to meet 2015 and 2020 timelines with satisfactory maintenance. Major pump overhauls are scheduled on a twelve year cycle.

TABLE 10-72 MAJOR PUMP OVERHAULS

Annual Asset Maintenance																		
Pumps	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
1 CW Pump East			X												83,000.00			
1 CW Pump West											75,000.00							
2 CW Pump East	X				X												87,000.00	
2 CW Pump West												77,000.00						
3 CW Pump East		X									75,000.00							
3 CW Pump West						10,000.00												89,000.00

CW Pump Motors: Motors are electrically tested every year as a component of the plant PM process. See 4 kV motor discussion in Appendix 25.

CW Pump Outlet Piping, Valves & Fittings: Outlet piping, valves and fittings from the pump discharge to the inlet of the 64 inch concrete piping that is installed underground to the unit condensers has generally experienced significant degrees of corrosion and some patching of the system has been done. It is in need of clean-up and a Level 2 inspection, or perhaps a complete replacement.

Asset 8647/6678 Cooling Water System Intake & Discharge

The 36 inch and 64 inch CW intake and discharge concrete piping that goes underground to the Unit 3 condenser has periodically been pumped out and walked down by plant staff, although not in the last five years. There have been no obvious issues with the system, although no detailed engineering evaluations and NDE work have been undertaken.

No specific corrosion, spalling, cracks or fractures were identified, and no patching of the system has been done. Inspections are planned going forward on a three year frequency as per the schedule below.

TABLE 10-73 ANNUAL ASSET MAINTENANCE

Annual Asset Maintenance																	
CW Inspection		2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Unit 1													25,625.00			26,625.00	
Unit 2														25,625.00			26,625.00
Unit 3												25,000.00			25,625.00		

10.2.10.4 Condition Assessment

The condition assessment of the Unit 3 cooling water system associated with steam systems is illustrated below in Table 10-74.

TABLE 10-74 CONDITION ASSESSMENT – COOLING WATER SYSTEM - ASSOCIATED WITH STEAM SYSTEMS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset Level 2	Asset Level 3	Description	Detail	Condition Summary ID#	Append #	Condition	EPRI Identifier	Original Life (Base Load) Ops Hrs (Yrs)	Current Expected Minimum Remaining Life Years (Subject to Test)	End of Life (EOL) Required	Next Regular Inspection	Next Planned Overhaul or Major Inspection	Capability to Reach Next Overhaul	Capability to Reach EOL	In Service
1296	8193	8645	271678	0	0	3	UNIT GENERATION SERVICES	CW SYSTEM	CW SYSTEM	N/A	142	11										
1296	8193	8645	271678	8647	0	3	UNIT GENERATION SERVICES	CW SYSTEM	C.W. INTAKE SYSTEM	Concrete pipe from Pumps to Condenser	143	11	No recent inspections of cement pipes, but walk-downs about 5 years ago indicated that the pipe looked intact. Given the geotechnical conditions and soil, there is no reason to expect any kind of aggressive attack. A copper ion system was installed to minimize mussel growth on the CW pipe internally.	4	(60)	(20+)	2041		2011	Yes	Yes	1980
1296	8193	8645	271678	8676	0	3	UNIT GENERATION SERVICES	CW SYSTEM	C.W. DISCHARGE TO OUTFALL	Concrete pipe from Condenser to outfall pit	144	11	No recent inspections of cement pipes, but walk-downs about 5 years ago indicated that the pipe looked intact. Some moderate issues with stop log structures were identified. Given the geotechnical conditions and soil, there is no reason to expect any kind of aggressive attack. A copper ion system was installed to minimize mussel growth on the CW pipe internally.	4	(60)	(20+)	2041		2011	Yes	Yes	1980
1296	8193	8645	271678	8658	0	3	UNIT GENERATION SERVICES	CW SYSTEM	C.W. PUMP EAST	N/A	145	11	The CW pumps have major inspections and overhauls about every twelve years. The motors are electrically checked annually per their PM requirements. Overall the pumps and motors seem to be performing satisfactorily. Several patches are evident on the CW steel pipes and valves associated with the pumps.	3a	(30)	10	2020	2012		Yes	Yes	1980
1296	8193	8645	271678	8659	0	3	UNIT GENERATION SERVICES	CW SYSTEM	C.W. PUMP WEST	N/A	146	11	The CW pumps have major inspections and overhauls about every twelve years. The motors are electrically checked annually per their PM requirements. Overall the pumps and motors seem to be performing satisfactorily. Several patches are evident on the CW steel pipes and valves associated with the pumps.	3a	(30)	10	2020	2012		Yes	Yes	1980

Notes:

1. A "(bracketed)" value in the "Current Expected Remaining Life" column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation, including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as "(X/Y)" has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

2. The "Next Regular Inspection" column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The "Next Planned Overhaul or Major Inspection" column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a "Desired Life" stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or simply are not known to AMEC.

10.2.10.5 Actions

Based on the condition assessment, the following actions are recommended for the Unit 3 cooling water system associated with steam systems.

TABLE 10-75 RECOMMENDED ACTIONS – COOLING WATER SYSTEM ASSOCIATED WITH STEAM SYSTEMS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Unit	Asset 2/3	Asset 3/4	Description	Detail	Action #	App #	Action	Year	Priority
1296	8193	8645	271678	0	3	UNIT GENERATION SERVICES	CW SYSTEM	CW SYSTEM	N/A	213	11	Maintain ongoing inspection and maintenance programs It is recommended that a spare 4 kV motor be maintained to service all three units, in the event of a failure of an existing unit..	2011	2
1296	8193	8645	271678	8647	3	UNIT GENERATION SERVICES	CW SYSTEM	CW INTAKE SYSTEM	N/A	214	11	Perform a detailed visible inspection, with some NDE spotchecks, within the next two to four years of the concrete intake and discharge pipes.	2011	2
1296	8193	8645	271678	8676	3	UNIT GENERATION SERVICES	CW SYSTEM	CW DISCHARGE TO OUTFALL	N/A	215	11	Perform a detailed visible inspection, with some NDE spotchecks of the concrete intake and discharge pipes.	2011	2
1296	8193	8645	271678	8658	3	UNIT GENERATION SERVICES	CW SYSTEM	CW PUMP EAST	Pipe	216	11	Clean CW steel pipe and check thickness measurements (Level 2).	2011	2
1296	8193	8645	271678	8659	3	UNIT GENERATION SERVICES	CW SYSTEM	CW PUMP WEST	Pipe	217	11	Clean CW steel pipe and check thickness measurements (Level 2).	2011	2
1296	8193	8645	271678	8658	3	UNIT GENERATION SERVICES	CW SYSTEM	CW PUMP EAST	N/A	218	11	Perform planned CW pump inspections on one pump per unit in 2010 to 2012 (Level 2).	2011	2
1296	8193	8645	271678	8659	3	UNIT GENERATION SERVICES	CW SYSTEM	CW PUMP WEST	N/A	219	11	Perform planned CW pump inspections on one pump per unit in 2010 to 2012 (Level 2).	2012	2
1296	8193	8645	271678	0	3	UNIT GENERATION SERVICES	CW SYSTEM	CW SYSTEM	N/A	220	11	Maintain ongoing inspection and maintenance programs.	2011	2

10.2.10.6 Risk Assessment

The risk assessment associated with the Unit 3 cooling water system – associated with steam systems, both from a technological perspective and a safety perspective, is illustrated below in Table 10-76.

TABLE 10-76 RISK ASSESSMENT – COOLING WATER SYSTEM - ASSOCIATED WITH STEAM SYSTEMS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Component	Risk Assess #	Appendix #	Major Issues	Remaining Life Years	Remaining Life Comments	TECHNO_ECO RISK ASSESS MODEL			SAFETY RISK ASSESS MODEL			Possible Failure Event	Mitigation
														(Insufficient Info - Inspection Required Within (x) Years)		Likeli-hood	Conse-quence	Risk Level	Likeli-hood	Conse-quence	Safety Risk		
1296	8193	8645	271678	0	0	3	UNIT GENERATION SERVICES	CW SYSTEM	CW SYSTEM	Unit #3 CW Concrete Pipe to Condenser	182	11	Concrete racking.	(20+)	None	1	B	Low	1	A	Low	Cracking or failure – major leak requiring repair.	Inspect and maintain.
1296	8193	8645	271678	0	0	3	UNIT GENERATION SERVICES	CW SYSTEM	CW SYSTEM	Unit #3 CW Pipe to Outfall Structure	183	11	Concrete racking.	(20+)	None	1	B	Low	1	A	Low	Cracking or failure – major leak requiring repair.	Inspect and maintain.
1296	8193	8645	271678	8658	0	3	UNIT GENERATION SERVICES	CW SYSTEM	CW PUMP EAST	Unit #3 CW Pumps	184	11	Corrosion-internal/ext.	10+	None	2	B	Low	2	A	Low	50% unit output loss while replaced with spare.	Current inspection and maintain.
1296	8193	8645	271678	8658	0	3	UNIT GENERATION SERVICES	CW SYSTEM	CW PUMP EAST	4 kV Cooling Water Pump Motor	185	25	Electrical fault, mechanical fatigue, ops error.	5+	None	2	B	Low	1	A	Low	Loss 60% unit generation.	Current inspection and maintain.
1296	8193	8645	271678	8658	0	3	UNIT GENERATION SERVICES	CW SYSTEM	CW PUMP EAST	Unit #3 CW Outlet Piping, Valves, Fittings	186	11	Corrosion-internal/ext.	5+	None	3	A	Low	3	A	Low	Major leak and repair/patch.	Current inspection and maintain.
1296	8193	8645	271678	8659	0	3	UNIT GENERATION SERVICES	CW SYSTEM	CW PUMP WEST	Unit #3 CW Pumps	187	11	Corrosion-internal/ext.	10+	None	2	B	Low	2	A	Low	50% unit output loss while replaced with spare.	Current inspection and maintain.
1296	8193	8645	271678	8659	0	3	UNIT GENERATION SERVICES	CW SYSTEM	CW PUMP WEST	4 kV Cooling Water Pump Motor	188	25	Electrical fault, mechanical fatigue, ops error.	5+	None	2	B	Low	1	A	Low	Loss 60% unit generation.	Current inspection and maintain.
1296	8193	8645	271678	8659	0	3	UNIT GENERATION SERVICES	CW SYSTEM	CW PUMP WEST	Unit #3 CW Outlet Piping, Valves, Fittings	189	11	Corrosion-internal/ext.	5+	None	3	A	Low	3	A	Low	Major leak and repair/patch.	Inspect and maintain.

10.2.10.7 Life Cycle Curve and Remaining Life

The life cycle curve for the Unit 3 cooling water system associated with steam systems is illustrated below. One curve represents all the major elements of the system which are about the same age. No information existed on the condition of the large CW pipe to and from the condensers. Although it was not plotted here, its life would be expected to be on the order of 50 years, given no incidents to date as a result of original poor design or installation. The life curve is a plot of current and projected operating hours (generation mode only) on the y-axis versus calendar year on the x-axis. The figure has vertical lines representing differing representative nominal age limits. It also has several horizontal lines that represent a range of practical equivalent base loaded operating hour life limits. Both limits can come into play and both are extendable through maintenance refurbishment and component replacement. The risk area box provides an indication of the timing of potential issues either from an age or equivalent operating hours view.

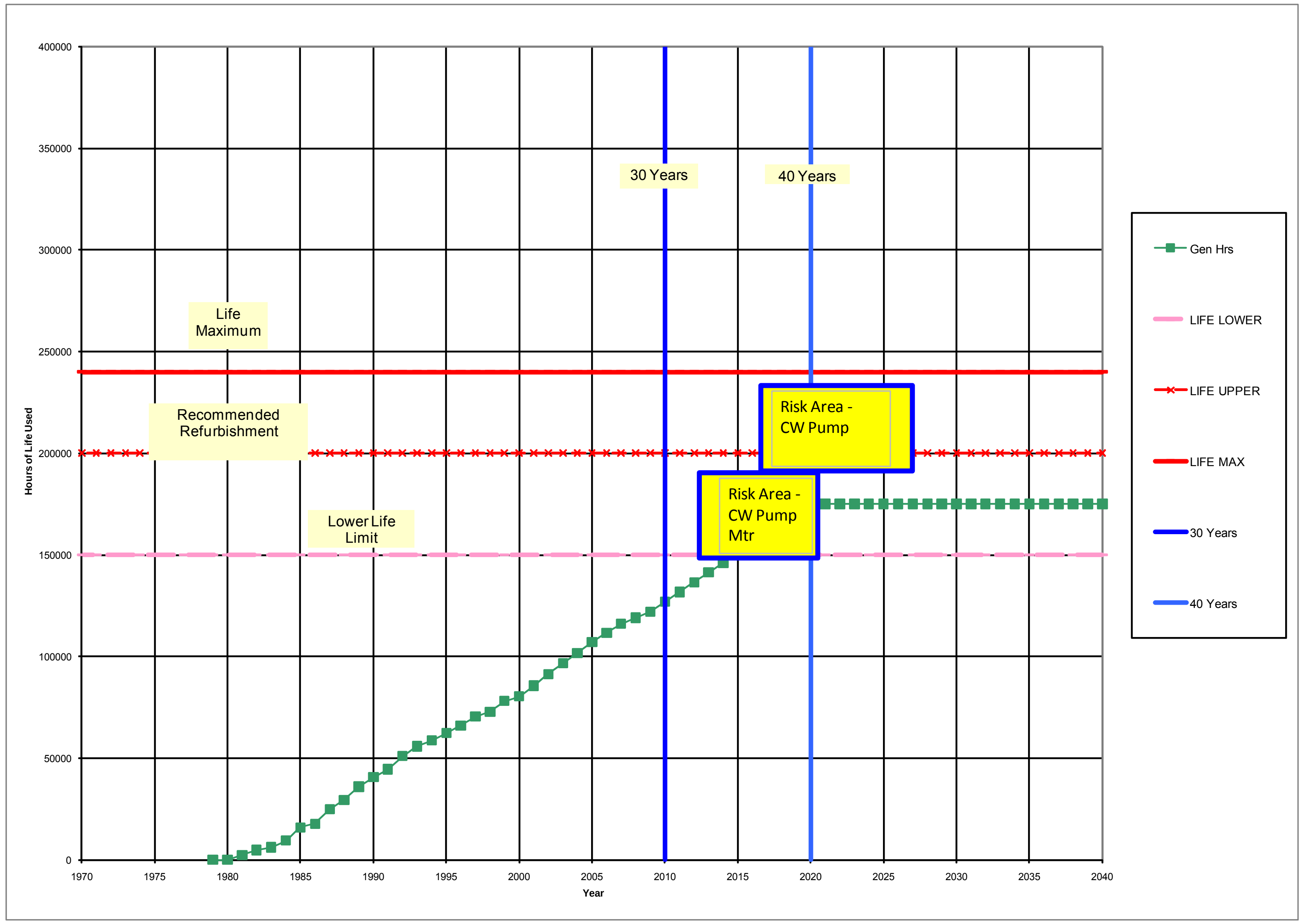

FIGURE 10-29 LIFE CYCLE CURVE – COOLING WATER SYSTEM - ASSOCIATED WITH STEAM SYSTEMS

The curves indicate that the remaining life (RL) of the Unit 3 cooling water system - associated with steam systems can likely reach the desired life (DL) end date for generation of 2020, but with some reliability risk, particularly as it pertains to the 4 kV motors. It is recommended that a spare motor shared between units would be a reasonable precaution. Corrosion of the steel pipe, valves, and fittings was also evident suggesting that some maintenance on these issues is required.

10.2.10.8 Level 2 Inspection Requirements and Costs

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 10-77 below, assuming the current plant inspection and maintenance program is maintained or improved.

TABLE 10-77 LEVEL 2 INSPECTION – COOLING WATER SYSTEM - ASSOCIATED WITH STEAM SYSTEMS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Sub System Comment	L2#	Appendix #	Level 2 Work	Year	Priority	Cost k$
1296	8193	8645	271678	0	0	3	UNIT GENERATION SERVICES	CW SYSTEM	CW SYSTEM	Concrete Pipe to/from pump to condenser	171	11	Inspections - dry walk-down and NDE spotcheck.	2011	2	$6
1296	8193	8645	271678	0	0	3	UNIT GENERATION SERVICES	CW SYSTEM	CW SYSTEM	Steel Pipe to/from condenser	172	11	Clean steel pipe and check thickness measurements.	2011	2	
1296	8193	8645	271678	8658	0	3	UNIT GENERATION SERVICES	CW SYSTEM	C.W. PUMP EAST	CW Pumps	173	25	Perform planned inspections on one pump per unit in 2010 to 2012 (Level 2 like). No Level 2 on 4 kV motor if current maintenance program continues			
1296	8193	8645	271678	8659	0	3	UNIT GENERATION SERVICES	CW SYSTEM	C.W. PUMP WEST	CW Pumps	174	25	Perform planned inspections on one pump per unit in 2010 to 2012 (Level 2 like). No Level 2 on 4 kV motor if current maintenance program continues			

10.2.10.9 Capital Projects

The suggested typical capital enhancements for the Unit 3 cooling water system associated with steam systems include:

TABLE 10-78 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – COOLING WATER SYSTEM - ASSOCIATED WITH STEAM SYSTEMS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Detail	CAP#	Appendix #	Unit #	Capital Item	Date	Priority
1296	8193	8645	271678	0	0	3	UNIT GENERATION SERVICES	CW SYSTEM	CW SYSTEM		141	11	3	No capital required.		
1296	8193	8645	271678	8647	0	3	UNIT GENERATION SERVICES	CW SYSTEM	C.W. INTAKE SYSTEM	Concrete Pipe from pump to Condenser	142	11	3	No capital required.		
1296	8193	8645	271678	8676	0	3	UNIT GENERATION SERVICES	CW SYSTEM	C.W. DISCHARGE TO OUTFALL	Concrete Pipe from condenser to CW Outfall pit	143	11	3	No capital required.		
1296	8193	8645	271678	8658	0	3	UNIT GENERATION SERVICES	CW SYSTEM	C.W. PUMP EAST	N/A	144	25	3	Procure spare motor - common to Units 1 & 2; adaptable Unit 3 to extent practical.	2012	1
1296	8193	8645	271678	8659	0	3	UNIT GENERATION SERVICES	CW SYSTEM	C.W. PUMP WEST	N/A	145	25	3	Procure spare motor - common to Units 1 & 2; adaptable Unit 3 to extent practical.	2012	1

11 COMMON SYSTEMS

11.1 Common Systems - Key Systems

11.1.1 Asset 1325: 5990 to 6052 – Switchyard Switchgear

(Detailed Technical Assessment in Working Papers, Appendix 7)

Unit #:	Common
Asset Class #	BU 1325 – Holyrood Switchyard
Components:	5990-6007 Switchyard Breakers 6008-6041 275789 Motorized Disconnect Switches 6042-6053 Manual Disconnect Switches

11.1.1.1 Description

The switchyard electrical and controls assets that are itemized in the Holyrood Present State Asset List and the electrical and control systems/equipment associated with the switchyard are generally shown in the same order as Hydro's Present State Asset List. The station single line diagrams should be consulted to provide the electrical locations in the switchyard:

230kV Breakers: Breakers B12L17, B2L42, B1L17 are Brown Boveri, Air Blast type DLF 245 nc2, installed in 1973. Additional breakers were subsequently identified as B1B11, B2B11, B12B42, B3L18, B3B13, and B12B15 (Air Blast Breakers). The following are SF6 Breakers: B13B15, B12L18, B12T10.

138kV Breakers: Breaker B8L39 is CGE Oil type, KSO-138-5000, and installed in 1978.

69kV Breakers

- Breakers B7L38, B7L2 are CGE Oil type KSO-69-1500 and installed in 1969;
- Breaker B6L3 is CGE Oil type FKP and installed in 1978; and
- Breakers B7T5, B6T10 are AEG SF6 type DT1-72F1 and installed in 1996.

230kV Motorized Disconnects

- Motorized disconnects B11T5, B15T6 are Raised Vertical Break type Kearney RVB, c/w Kearney KMT operator, vintage 1969-1978;
- Motorized disconnect B15T7 is Raised Vertical Break type Kearney AVB, c/w ITE MO-10X operator, vintage 1969-1978;
- Motorized disconnects B12T10-1, B15T8 are Raised Vertical Break type Siemens AVB, c/w Siemens CM-4A operator, vintage 1969-1978;

- Motorized disconnects B12B15-1, B12B15-2, B12L18-1, B12L18-2, B13B15-1, B13B15-2, B1T1, B3L18-1, B3L18-2, B2T2, B3B13-1, B3B13-2, B3T3 are Double Horizontal Break type Kearney DHB, c/w Kearney KMT operator, vintage 1969-1978; and
- Motorized disconnects B12L17-1, B12L17-2, B12L42-1, B12L42-2, B1B11-1, B1B11-2, B1L17-1, B1L17-2, B2B11-1, B2B11-2, B2L42-1, B2L42-2 are Horizontal Center Break type Kearney CHB, c/w Kearney KMT operator, vintage 1969-1978. The following maintenance has been recorded as completed by the JDE.

138kV Motorized Disconnects

- Motorized disconnects B8T6, B8T7, B8T8 are Raised Vertical Break type Joslyn RF-2, c/w Joslyn JMO operator, vintage 1969-1978.

FIGURE 11-1 HOLYROOD SWITCHYARD

The switchyard compressed air system includes

- Air Compressor A
- Air Compressor B
- Air Compressor C
- Compressed Air Distribution Piping

11.1.1.2 Inspection and Repair History

The hours associated with the various systems and equipment varies as parts have been replaced and/or refurbished over the years. The majority of equipment is over 15 years old. However it is regularly tested and inspected based on the Hydro's PM protocol. The switchyard switchgear is functional and in reasonable condition. The equipment will be required through to 2041 so it will require extensive refurbishment and/or replacement.

The switchyard compressor air supply distribution piping for the air blast breakers is originally copper and in the past, it has been necessary to replace corroded sections with a flexible hose material know as synflex. Corrosion has led to compressed air dew point problems. Hydro currently has a capital project in progress to replace (2010/2011) the copper piping with a welded stainless system and install a redundant air dryer and an online dew point monitoring system.

11.1.1.3 Condition Assessment

The condition assessment of the switchyard switchgear is illustrated below in Table 11-1.

TABLE 11-1 CONDITION ASSESSMENT – SWITCHYARD SWITCHGEAR

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset Level 2	Asset Level 3	Description	Detail	Cond. Summ. ID#	Append #	Condition	EPRI Identifier	Original Life (Base Load) Ops Hrs (Yrs)	Current Expected Minimum Remaining Life Years (Subject to Test)	End of Life Required (EOL)	Next Regular Inspection	Next Planned Overhaul/ Major Inspection	Capability to Reach Next Overhaul	Capability to Reach EOL	In Service
1325	5990	5990	310-77-1	HRDB3B13	HRDTS	BREAKER,B3B13,HRD TS	230 KV	N/A	179	7	Sanded & painted in 1999 and 2003. Planned maintenance performed in 2001 and 2008. Washed in 2004. Capacitor replaced in 2008. Doble test in 2009.	3a	(40)	8	2041	2014	2014	Yes	No	1978
1325	5991	5991	310-77-3	HRDB12B15	HRDTS	BREAKER,B12B15,HRD TS	230 KV	N/A	180	7	Sanded & painted in 1999 and 2003. Planned maintenance performed in 2001 and 2008. Doble test in 2001. Capacitor replaced in 2001. Washed in 2004. Safety relief valve replaced in 2007.	3a	(40)	8	2041	2014	2014	Yes	No	1978
1325	5992	5992	460-80 AD/2	HRDB12L18	HRDTS	BREAKER,B12L18,HRD TS	230 KV	N/A	181	7	Solenoid valve replaced in 1999. P3 Maintenance performed in 2001. Doble test in 2001. Indication repaired in 2003. Sanded and painted in 2003. Washed in 2004. Air leak repaired in 2004. Breaker mechanism overhauled and planned maintenance performed in 2006.	3a	(40)	11	2041	2012	2012	Yes	No	1981
1325	5993	5993	310-77-2	HRDB3L18	HRDTS	BREAKER,B3L18,HRD TS	230 KV	N/A	182	7	Sanded and painted in 1999 and 2003. Indication repaired in 2001. P3 maintenance in 2001. Capacitor replaced in 2001 and 2003. Drain valve replaced in 2003. Washed in 2004. Planned maintenance performed in 1985 and 1991.	3a	(40)	8	2041	2011	2011	Yes	No	1978
1325	5994	5994	170-73-3	HRDB1L17	HRDTS	BREAKER,B1L17,HRD TS	230 KV	N/A	183	7	P3 maintenance performed in 2001. Jumpers replaced in 2001. Doble test in 2001. Air leak repaired in 2003. Sanded and painted in 2003. Control valve leak repaired in 2003. Washed in 2004. PLC control installed in 2007. Operation check in 2007. Protection and time tests performed in 2007. Planned maintenance performed in 2006. Trip coil contacts cleaned in 2009.	3a	(40)	3	2041	2012	2012	Yes	No	1973
1325	5995	5995	310-77-4	HRDB12L42	HRDTS	BREAKER,B12L42,HRD TS	230 KV	N/A	184	7	Sanded & painted in 1999 and 2003. P3 maintenance performed in 2000. Doble test in 2000 and 2009. Washed in 2004. Air leak repaired in 2007. Planned maintenance performed in 2008.	3a	(40)	8	2041	2014	2014	Yes	No	1978
1325	5996	5996	188-74-2	HRDB2B11	HRDTS	BREAKER,B2B11,HRD TS	230 KV	N/A	185	7	Sanded & painted in 1999 and 2003. P3 maintenance in 2001. Doble tested in 2001. Capacitor replaced in 2004. Washed in 2004. Handle replaced in 2007. Indication repair in 2007. RTV coating in 2006. Hinges replaced in 2008. Relief valve replaced in 2009. Planned maintenance performed in 2009.	3a	(40)	6	2041	2015	2015	Yes	No	1974
1325	5997	5997	188-74-1	HRDB1B11	HRDTS	BREAKER,B1B11,HRD TS	230 KV	N/A	186	7	Sanded & painted in 1999 and 2003. P3 maintenance in 2001. Doble tested in 2001. Fuse holder replace in 2003. Indication relay replaced in 2004. Washed in 2004. Capacitor replaced in 2007. Pressure reducing valve replaced in 2007. Hinges replaced in 2008. RTV coating in 2006. Planned maintenance performed in 2007. Heat trace replaced in 2008. Relief valve replaced in 2009.	3a	(40)	4	2041	2014	2014	Yes	No	1974
1325	5998	5998	170-73-2	HRDB12L17	HRDTS	BREAKER,B12L17,HRD TS	230 KV	N/A	187	7	Pressure reducing valve replaced in 1999. Sanded & painted in 1999 and 2003. Washed in 2004. Leslie valve regulator replaced in 2006. Planned maintenance performed in 2008. Relief valve replaced in 2009. Doble tested in 2009.	3a	(40)	7	2041	2015	2015	Yes	No	1973
1325	5999	5999	170-73-1	HRDB2L42	HRDTS	BREAKER,B2L42,HRD TS	230 KV	N/A	188	7	Sanded & painted in 1999 and 2003. P3 maintenance performed in 2001. Washed in 2004. Doble tested in 2004. Indication repaired in 2007. Capacitor replaced in 2008. Relief valve replaced in 2009. Planned Maintenance performed in 2009.	3a	(40)	7	2041	2015	2015	Yes	No	1973
1325	6000	6000	0464DT72	HRDB6T10	HRDTS	BREAKER,B6T10,HRD TS	69 KV	N/A	189	7	P3 Maintenance performed in 2001. Sanded and painted in 2001 and 2007. Moisture heater installed in 2007.	3a	(40)	26	2041	2011	2011	Yes	No	1996
1325	6001	6001	90/K31238935	HRDB12T10	HRDTS	BREAKER,B12T10,HRD TS	230 KV	N/A	190	7	P3 Maintenance performed in 2000. Washed in 2004. Contacts replaced in 2006. Hydraulic overhaul in 2007. Planned maintenance performed in 2007.	3a	(40)	20	2041	2013	2013	Yes	No	1990
1325	6002	6002	45510DD/1	HRDB13B15	HRDTS	BREAKER,B13B15,HRD TS	230 KV	N/A	191	7	Sanded & painted in 2000 and 2003. P3 maintenance performed in 2001 and 2007. Doble tests in 2001 and 2007. Indications repaired in 2002. New thermostat installed in 2004. Washed in 2004. Fittings and hoses replaced in 2006. Drive mechanism overhaul in 2007. Planned maintenance performed in 2007.	3a	(40)	11	2041	2013	2013	Yes	No	1981
1325	6003	6003	0465DT72	HRDB7T5	HRDTS	BREAKER,B7T5,HRD TS	69 KV	N/A	192	7	P3 Maintenance performed in 2000. Sanded and painted in 2001. Cabinet heater installed in 2007. Planned maintenance performed in 2009.	3a	(40)	26	2041	2015	2015	Yes	No	1996
1325	6004	6004	61130	HRDB7L2	HRDTS	BREAKER,B7L2,HRD TS	69 KV	N/A	193	7	P3 (PM) Maintenance performed in 2001. Oil sample taken in 2007. (PM completed in 2010, but not availab at time of report.)	3a	(40)	5	2041	2011	2011	Yes	No	1969
1325	6005	6005	63257	HRDB8L39	HRDTS	BREAKER,B8L39,HRD TS	138 KV	N/A	194	7	Mounting bracket replaced in 1999. Doble test in 2001. P3 Maintenance in 2001. Revised trip interlock circuit in 2001. Breaker overhaul in 2002 (ref. WO#241903). Junction box replaced in 2002. Planned maintenance performed in 2005 and 2008. Oil sample taken in 2007.	3a	(40)	8	2041	2014	2014	Yes	No	1978
1325	6006	6006	64018	HRDB6L3	HRDTS	BREAKER,B6L3,HRD TS	69 KV	N/A	195	7	P3 Maintenance performed in 2000. Doble test in 2000. Oil sample taken in 2007. Gaskets replaced in 2009. Planned maintenance performed in 2009.	3a	(40)	8	2041	2015	2015	Yes	No	1978
1325	6007	6007	61131	HRDB7L38	HRDTS	BREAKER,B7L38,HRD TS	69 KV	N/A	196	7	P3 Maintenance performed in 2001. Oil sample taken in 2007. (PM completed in 2010, but not availab at time of report.)	3a	(40)	5	2041	2011	2011	Yes	No	1969

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Table 11-1 Cont'd

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset Level 2	Asset Level 3	Description	Detail	Cond. Summ. ID#	Append #	Condition	EPRI Identifier	Original Life (Base Load) Ops Hrs (Yrs)	Current Expected Minimum Remaining Life Years (Subject to Test)	End of Life Required (EOL)	Next Regular Inspection	Next Planned Overhaul/ Major Inspection	Capability to Reach Next Overhaul	Capability to Reach EOL	In Service
1325	6008	6008		HRDB12L17-1	HRDTS	DISCONNECT,B12L17-1,HRD TS	230 KV	Motor Operated HV Switch (MOD)	199	7	Brake coil replaced in 1999. Greased, main contacts and aux contacts cleaned, bearing assembly and linkage cleaned and greased alignment in 2000. Cabinet heater replaced in 2003. Grease nipples installed in 2006. Planned maintenance performed in 2006. Adjusted and checked in 2009.	3a	(40)	10	2041	N/A	N/A	Yes	No	1969-1978
1325	6009	6009		HRDB12L42-1	HRDTS	DISCONNECT,B12L42-1,HRD TS	230 KV	Motor Operated HV Switch (MOD)	200	7	Greased, main contacts and aux contacts cleaned, bearing assembly and linkage cleaned and greased alignment in 2000. Operation repaired in 2003. Blade clamp assembly repaired in 2007. Gearbox repaired in 2007. Grease nipples installed in 2006. Function tested in 2006.	3a	(40)	10	2041	N/A	N/A	Yes	No	1969-1978
1325	6010	6010		HRDB2L42-1	HRDTS	DISCONNECT,B2L42-1,HRD TS	230 KV	Motor Operated HV Switch (MOD)	201	7	Gearbox repaired 2004.	3a	(40)	10	2041	N/A	N/A	Yes	No	1969-1978
1325	6011	6011		HRDB2B11-1	HRDTS	DISCONNECT,B2B11-1,HRD TS	230 KV	Motor Operated HV Switch (MOD)	202	7	DC motor contacts cleaned in 2001. Gearbox replaced in 2002. Grease nipples installed in 2009.	3a	(40)	10	2041	N/A	N/A	Yes	No	1969-1978
1325	6012	6012		HRDB2B11-2	HRDTS	DISCONNECT,B2B11-2,HRD TS	230 KV	Motor Operated HV Switch (MOD)	203	7	Greased, main contacts and aux contacts cleaned, bearing assembly and linkage cleaned and greased alignment in 2000. Grease nipples installed in 2009. Planned maintenance performed in 2009.	3a	(40)	10	2041	N/A	N/A	Yes	No	1969-1978
1325	6013	6013		HRDB12L17-2	HRDTS	DISCONNECT,B12L17-2,HRD TS	230 KV	Motor Operated HV Switch (MOD)	204	7	Grease nipples installed in 2009.	3a	(40)	10	2041	N/A	N/A	Yes	No	1969-1978
1325	6014	6014		HRDB2L42-2	HRDTS	DISCONNECT,B2L42-2,HRD TS	230 KV	Motor Operated HV Switch (MOD)	205	7	Planned maintenance performed in 2008.	3a	(40)	10	2041	N/A	N/A	Yes	No	1969-1978
1325	6015	6015		HRDB1L17-2	HRDTS	DISCONNECT,B1L17-2,HRD TS	230 KV	Motor Operated HV Switch (MOD)	206	7	Ground switch repaired in 2006. Grease nipples installed in 2006.	3a	(40)	10	2041	N/A	N/A	Yes	No	1969-1978
1325	6016	6016		HRDB12L42-2	HRDTS	DISCONNECT,B12L42-2,HRD TS	230 KV	Motor Operated HV Switch (MOD)	207	7	Contacts blade replaced in 2000. Grease nipples installed in 2008. Planned maintenance performed in 2008.	3a	(40)	10	2041	N/A	N/A	Yes	No	1969-1978
1325	6017	6017		HRDB1L17-1	HRDTS	DISCONNECT,B1L17-1,HRD TS	230 KV	Motor Operated HV Switch (MOD)	208	7	Greased, main contacts and aux contacts cleaned, bearing assembly and linkage cleaned and greased alignment in 2000. Motor/Manual button repaired in 2003. Grease nipples installed in 2006, 2007, and 2009.	3a	(40)	10	2041	N/A	N/A	Yes	No	1969-1978
1325	6018	6018		HRDB1B11-1	HRDTS	DISCONNECT,B1B11-1,HRD TS	230 KV	Motor Operated HV Switch (MOD)	209	7	Brake coil replaced in 2001. Grease nipples installed in 2007.	3a	(40)	10	2041	N/A	N/A	Yes	No	1969-1978
1325	6019	6019		HRDB12T10-1	HRDTS	DISCONNECT,B12T10-1,HRD TS	230 KV	Motor Operated HV Switch (MOD)	210	7	Greased, main contacts and aux contacts cleaned, bearing assembly and linkage cleaned and greased, alignment in 2000. Grease nipples installed in 2006. Function test performed in 2006.	3a	(40)	10	2041	N/A	N/A	Yes	No	1969-1978
1325	6020	6020		HRDB12L18-1	HRDTS	DISCONNECT,B12L18-1,HRD TS	230 KV	Motor Operated HV Switch (MOD)	211	7	Blade assembly repaired in 1999. Greased, main contacts and aux contacts cleaned, bearing assembly and linkage cleaned and greased, alignment in 2000. DC motor contacts cleaned in 2001. Grease nipples installed in 2006. Function tested in 2006.	3a	(40)	10	2041	N/A	N/A	Yes	No	1969-1978
1325	6021	6021		HRDB12B15-2	HRDTS	DISCONNECT,B12B15-2,HRD TS	230 KV	Motor Operated HV Switch (MOD)	212	7	Jumpers replaced in 2007. Infrared scan in 2007.	3a	(40)	10	2041	N/A	N/A	Yes	No	1969-1978
1325	6022	6022		HRDB13B15-2	HRDTS	DISCONNECT,B13B15-2,HRD TS	230 KV	Motor Operated HV Switch (MOD)	213	7	Disconnect alignment checked in 2004.	3a	(40)	10	2041	N/A	N/A	Yes	No	1969-1978
1325	6023	6023		HRDB3L18-2	HRDTS	DISCONNECT,B3L18-2,HRD TS	230 KV	Motor Operated HV Switch (MOD)	214	7	C phase arm repaired in 2001. Doble test in 2002. Planned maintenance in 2002. Heater circuit repaired in 2003. Grease nipples installed in 2009.	3a	(40)	10	2041	N/A	N/A	Yes	No	1969-1978
1325	6024	6024		HRDB3L18-1	HRDTS	DISCONNECT,B3L18-1,HRD TS	230 KV	Motor Operated HV Switch (MOD)	215	7	Pedestal welding repaired in 2009. Grease nipples installed in 2009.	3a	(40)	10	2041	N/A	N/A	Yes	No	1969-1978
1325	6025	6025		HRDB3B13-1	HRDTS	DISCONNECT,B3B13-1,HRD TS	230 KV	Motor Operated HV Switch (MOD)	216	7	Contacts greased and cleaned in 2000.	3a	(40)	10	2041	N/A	N/A	Yes	No	1969-1978
1325	6026	6026		HRDB3B13-2	HRDTS	DISCONNECT,B3B13-2,HRD TS	230 KV	Motor Operated HV Switch (MOD)	217	7	Blades cleaned and greased in 2001. Seized arm repaired in 2001. Linkages repaired in 2007. Grease nipples installed in 2009. Function test in 2009. Planned maintenance performed in 2009.	3a	(40)	10	2041	N/A	N/A	Yes	No	1969-1978
1325	6027	6027		HRDB13B15-1	HRDTS	DISCONNECT,B13B15-1,HRD TS	230 KV	Motor Operated HV Switch (MOD)	218	7	Spring replaced in 2001. Disconnect cleaned in 2001. Jumpers replaced in 2002. Grease nipples installed in 2009. Function test in 2009.	3a	(40)	10	2041	N/A	N/A	Yes	No	1969-1978
1325	6028	6028		HRDB12B15-1	HRDTS	DISCONNECT,B12B15-1,HRD TS	230 KV	Motor Operated HV Switch (MOD)	219	7	Greased, main contacts and aux contacts cleaned, bearing assembly and linkage cleaned and greased, alignment in 2000. Grease nipples installed in 2006. Function test performed in 2006.	3a	(40)	10	2041	N/A	N/A	Yes	No	1969-1978
1325	6029	6029		HRDB1B11-2	HRDTS	DISCONNECT,B1B11-2,HRD TS	230 KV	Motor Operated HV Switch (MOD)	220	7	Planned maintenance performed in 2009. Grease nipples installed in 2009.	3a	(40)	10	2041	N/A	N/A	Yes	No	1969-1978
1325	6030	6030		HRDB11T5	HRDTS	DISCONNECT,B11T5,HRD TS	230 KV	Motor Operated HV Switch (MOD)	221	7	Greased, and main contacts and aux contacts cleaned in 2001.	3a	(40)	10	2041	N/A	N/A	Yes	No	1969-1978
1325	6031	6031		HRDB8T6	HRDTS	DISCONNECT,B8T6,HRD TS	138 KV	Motor Operated HV Switch (MOD)	222	7	Planned maintenance was performed in 2002.	3a	(40)	10	2041	N/A	N/A	Yes	No	1969-1978
1325	6032	6032		HRDB8T7	HRDTS	DISCONNECT,B8T7,HRD TS	138 KV	Motor Operated HV Switch (MOD)	223	7	Planned maintenance was performed in 2002. Heater circuit repaired in 2003.	3a	(40)	10	2041	N/A	N/A	Yes	No	1969-1978
1325	6033	6033		HRDB8T8	HRDTS	DISCONNECT,B8T8,HRD TS	138 KV	Motor Operated HV Switch (MOD)	224	7	Planned maintenance was performed in 2002. Phase B aligned in 2004.	3a	(40)	10	2041	N/A	N/A	Yes	No	1969-1978
1325	6034	6034		HRDB15T6	HRDTS	DISCONNECT,B15T6,HRD TS	230 KV	Motor Operated HV Switch (MOD)	225	7	Function test and planned maintenance performed in 2002. Alignment in 2007. Cam switch repaired in 2007. DC motor replaced in 2009.	3a	(40)	10	2041	N/A	N/A	Yes	No	1969-1978
1325	6035	6035		HRDB3T3	HRDTS	DISCONNECT,B3T3,HRD TS	230 KV	Motor Operated HV Switch (MOD)	226	7	Contacts cleaned and greased in 2000. Heating wiring repaired in 2004. Jaws assembly replaced in 2005 and 2010. Arm inserts replaced in 2007. Brakes cleaned in 2006. Broken linkage pin replaced in 2006. Alignment in 2007. Ground switch lubricated in 2008.	3a	(40)	10	2041	N/A	N/A	Yes	No	1969-1978
1325	6036	6036		HRDB15T8	HRDTS	DISCONNECT,B15T8,HRD TS	230 KV	Motor Operated HV Switch (MOD)	227	7	Function test and planned maintenance performed in 2002. Cabinet heater installed in 2004.	3a	(40)	10	2041	N/A	N/A	Yes	No	1969-1978
1325	6037	6037		HRDB2T2	HRDTS	DISCONNECT,B2T2,HRD TS	230 KV	Motor Operated HV Switch (MOD)	228	7	DC motor contacts cleaned in 2001. Greased and function tested in 2006. Brakes replaced in 2007. Gear box ground switch replaced in 2007.	3a	(40)	10	2041	N/A	N/A	Yes	No	1969-1978
1325	6038	6038		HRDB1T1	HRDTS	DISCONNECT,B1T1,HRD TS	230 KV	Motor Operated HV Switch (MOD)	229	7	Disc adjusted in 2001. Cabinet repaired in 2002. Locking and chaining wheel adjusted in 2003. Indications repaired in 2003. Cam switches greased and aligned in 2003 and then adjusted in 2007. DC switch cleaned in 2007.	3a	(40)	10	2041	N/A	N/A	Yes	No	1969-1978
1325	6039	6039		HRDB15T7	HRDTS	DISCONNECT,B15T7,HRD TS	230 KV	Motor Operated HV Switch (MOD)	230	7	Function tested and planned maintenance performed in 2002.	3a	(40)	10	2041	N/A	N/A	Yes	No	1969-1978
1325	6040	6040		HRDB8L39-2	HRDTS	DISCONNECT,B8L39-2,HRD TS	138 KV	Motor Operated HV Switch (MOD)	231	7	Not reviewed in detail. No specific issues or maintenance identified. Maintained per requirements.	3a	(40)	10	2041	N/A	N/A	Yes	No	1969-1978
1325	6041	6041		HRDB8L39-1	HRDTS	DISCONNECT,B8L39-1,HRD TS	138 KV	Motor Operated HV Switch (MOD)	232	7	Not reviewed in detail. No specific issues or maintenance identified. Maintained per requirements.	3a	(40)	10	2041	N/A	N/A	Yes	No	1969-1978

Table 11-1 Cont'd

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset Level 2	Asset Level 3	Description	Detail	Cond. Summ. ID#	Append #	Condition	EPRI Identifier	Original Life (Base Load) Ops Hrs (Yrs)	Current Expected Minimum Remaining Life Years (Subject to Test)	End of Life Required (EOL)	Next Regular Inspection	Next Planned Overhaul/ Major Inspection	Capability to Reach Next Overhaul	Capability to Reach EOL	In Service
1325	6042	6042		HRDB7T5-2	HRDTS	DISCONNECT,B7T5-2,HRD TS	69 KV	Manual Operated HV Switch	235	7	Not reviewed in detail. No specific issues or maintenance identified. Maintained per requirements.	3a	(40)	10	2041	N/A	N/A	Yes	No	1969-1978
1325	6043	6043		HRDL2L38	HRDTS	DISCONNECT,L2L38,HRD TS	69 KV	Manual Operated HV Switch	236	7	Not reviewed in detail. No specific issues or maintenance identified. Maintained per requirements.	3a	(40)	10	2041	N/A	N/A	Yes	No	1969-1978
1325	6044	6044		HRDB7L38-1	HRDTS	DISCONNECT,B7L38-1,HRD TS	69 KV	Manual Operated HV Switch	237	7	Not reviewed in detail. No specific issues or maintenance identified. Maintained per requirements.	3a	(40)	10	2041	N/A	N/A	Yes	No	1969-1978
1325	6045	6045		HRDB7L38-2	HRDTS	DISCONNECT,B7L38-2,HRD TS	69 KV	Manual Operated HV Switch	238	7	Not reviewed in detail. No specific issues or maintenance identified. Maintained per requirements.	3a	(40)	10	2041	N/A	N/A	Yes	No	1969-1978
1325	6046	6046		HRDB7L2-2	HRDTS	DISCONNECT,B7L2-2,HRD TS	69 KV	Manual Operated HV Switch	239	7	Not reviewed in detail. No specific issues or maintenance identified. Maintained per requirements.	3a	(40)	10	2041	N/A	N/A	Yes	No	1969-1978
1325	6047	6047		HRDB7L2-1	HRDTS	DISCONNECT,B7L2-1,HRD TS	69 KV	Manual Operated HV Switch	240	7	Not reviewed in detail. No specific issues or maintenance identified. Maintained per requirements.	3a	(40)	10	2041	N/A	N/A	Yes	No	1969-1978
1325	6048	6048		HRDB6L3-1	HRDTS	DISCONNECT,B6L3-1,HRD TS	69 KV	Manual Operated HV Switch	241	7	Not reviewed in detail. No specific issues or maintenance identified. Maintained per requirements.	3a	(40)	10	2041	N/A	N/A	Yes	No	1969-1978
1325	6049	6049		HRDB6L3-2	HRDTS	DISCONNECT,B6L3-2,HRD TS	69 KV	Manual Operated HV Switch	242	7	Not reviewed in detail. No specific issues or maintenance identified. Maintained per requirements.	3a	(40)	10	2041	N/A	N/A	Yes	No	1969-1978
1325	6050	6050		HRDB6B7	HRDTS	DISCONNECT,B6B7,HRD TS	69 KV	Manual Operated HV Switch	243	7	Not reviewed in detail. No specific issues or maintenance identified. Maintained per requirements.	3a	(40)	10	2041	N/A	N/A	Yes	No	1969-1978
1325	6051	6051		HRDB7T5-1	HRDTS	DISCONNECT,B7T5-1,HRD TS	69 KV	Manual Operated HV Switch	244	7	Not reviewed in detail. No specific issues or maintenance identified. Maintained per requirements.	3a	(40)	10	2041	N/A	N/A	Yes	No	1969-1978
1325	6052	6052		HRDB6T10-1	HRDTS	DISCONNECT,B6T10-1,HRD TS	69 KV	Manual Operated HV Switch	245	7	Not reviewed in detail. No specific issues or maintenance identified. Maintained per requirements.	3a	(40)	10	2041	N/A	N/A	Yes	No	1969-1978
1325	6053	6053		HRDB11B13	HRDTS	DISCONNECT,B11B13,HRD TS	230 KV	Motor Operated HV Switch (MOD)	246	7	Not reviewed in detail. No specific issues or maintenance identified. Maintained per requirements.	3a	(40)	10	2041	N/A	N/A	Yes	No	1969-1978
1325	6546	6546		HRDB12L18-2	HRDTS	DISCONNECT,B12L18-2,HRD TS	230 KV	Motor Operated HV Switch (MOD)	247	7	Hand wheel lubricated in 2001. Wiring repaired in 2001. Doble tested 2002. Planned maintenance performed in 2002.	3a	(40)	10	2041	N/A	N/A	Yes	No	1969-1978
1325	275789	275789		HRDB12L42-1	HRDTS	DISCONNECTS B12L42-1,HRD TS	230 KV	Motor Operated HV Switch (MOD)	248	7	Greased, main contacts and aux contacts cleaned, bearing assembly and linkage cleaned and greased, and alignment in 2000. Operation repaired in 2003. Blade clamp assembly repaired in 2007. Gearbox repaired in 2007. Grease nipples installed in 2006. Function tested in 2006.	3a	(40)	10	2041	N/A	N/A	Yes	No	1969-1978

Notes:

1. A "(bracketed)" value in the "Current Expected Remaining Life" column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation, including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as "(X/Y)" has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

2. The "Next Regular Inspection" column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The "Next Planned Overhaul or Major Inspection" column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a "Desired Life" stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where no specific dates have been identified for "Next Regular Inspection" or "Next Planned Overhaul/Major Inspection", they are left blank.

11.1.1.4 Actions

Based on the condition assessment, the following actions are recommended for the switchyard switchgear:

11-2 RECOMMENDED ACTIONS – SWITCHYARD SWITCHGEAR

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset 2/3	Asset 3/4	Description	Action #	App #	Action	Year	Priority
1325	5990	5990	310-77-1	HRDB3B13	HRDTS	BREAKER,B3B13,HRD TS	230 KV	180	7	Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9)	2012	1
1325	5991	5991	310-77-3	HRDB12B15	HRDTS	BREAKER,B12B15,HRD TS	230 KV	181	7	Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9)	2012	1
1325	5992	5992	460-80 AD/2	HRDB12L18	HRDTS	BREAKER,B12L18,HRD TS	230 KV	182	7	Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9)	2012	1
1325	5993	5993	310-77-2	HRDB3L18	HRDTS	BREAKER,B3L18,HRD TS	230 KV	183	7	Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9)	2012	1
1325	5994	5994	170-73-3	HRDB1L17	HRDTS	BREAKER,B1L17,HRD TS	230 KV	184	7	Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9)	2012	1
1325	5995	5995	310-77-4	HRDB12L42	HRDTS	BREAKER,B12L42,HRD TS	230 KV	185	7	Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9)	2012	1
1325	5996	5996	188-74-2	HRDB2B11	HRDTS	BREAKER,B2B11,HRD TS	230 KV	186	7	Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9)	2012	1
1325	5997	5997	188-74-1	HRDB1B11	HRDTS	BREAKER,B1B11,HRD TS	230 KV	187	7	Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9)	2012	1
1325	5998	5998	170-73-2	HRDB12L17	HRDTS	BREAKER,B12L17,HRD TS	230 KV	188	7	Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9)	2012	1
1325	5999	5999	170-73-1	HRDB2L42	HRDTS	BREAKER,B2L42,HRD TS	230 KV	189	7	Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9)	2012	1
1325	6001	6001	90/K31238935	HRDB12T10	HRDTS	BREAKER,B12T10,HRD TS	230 KV	190	7	Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9)	2012	1
1325	6002	6002	45510DD/1	HRDB13B15	HRDTS	BREAKER,B13B15,HRD TS	230 KV	191	7	Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9)	2012	1
1325	6005	6005	63257	HRDB8L39	HRDTS	BREAKER,B8L39,HRD TS	138 KV	193	7	Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9)	2012	1
1325	6003	6003	0465DT72	HRDB7T5	HRDTS	BREAKER,B7T5,HRD TS	69 KV	195	7	Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9)	2012	1

Table 11-2 Cont'd

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset 2/3	Asset 3/4	Description	Action #	App #	Action	Year	Priority
1325	6004	6004	61130	HRDB7L2	HRDTS	BREAKER,B7L2,HRD TS	69 KV	196	7	Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9)	2012	1
1325	6006	6006	64018	HRDB6L3	HRDTS	BREAKER,B6L3,HRD TS	69 KV	197	7	Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9)	2012	1
1325	6007	6007	61131	HRDB7L38	HRDTS	BREAKER,B7L38,HRD TS	69 KV	198	7	Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9)	2012	1
1325	6008	6008	6008	HRDB12L17-1	HRDTS	DISCONNECT,B12L17-1,HRD TS	230 KV MOTOR OPERATED HV SWITCH (MOD)	202	7	Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9)	2012	1
1325	6009	6009	6009	HRDB12L42-1	HRDTS	DISCONNECT,B12L42-1,HRD TS	230 KV MOTOR OPERATED HV SWITCH (MOD)	203	7	Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9)	2012	1
1325	6010	6010	6010	HRDB2L42-1	HRDTS	DISCONNECT,B2L42-1,HRD TS	230 KV MOTOR OPERATED HV SWITCH (MOD)	204	7	Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9)	2012	1
1325	6011	6011	6011	HRDB2B11-1	HRDTS	DISCONNECT,B2B11-1,HRD TS	230 KV MOTOR OPERATED HV SWITCH (MOD)	205	7	Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9)	2012	1
1325	6012	6012	6012	HRDB2B11-2	HRDTS	DISCONNECT,B2B11-2,HRD TS	230 KV MOTOR OPERATED HV SWITCH (MOD)	206	7	Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9)	2012	1
1325	6013	6013	6013	HRDB12L17-2	HRDTS	DISCONNECT,B12L17-2,HRD TS	230 KV MOTOR OPERATED HV SWITCH (MOD)	207	7	Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9)	2012	1
1325	6014	6014	6014	HRDB2L42-2	HRDTS	DISCONNECT,B2L42-2,HRD TS	230 KV MOTOR OPERATED HV SWITCH (MOD)	208	7	Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9)	2012	1
1325	6015	6015	6015	HRDB1L17-2	HRDTS	DISCONNECT,B1L17-2,HRD TS	230 KV MOTOR OPERATED HV SWITCH (MOD)	209	7	Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9)	2012	1
1325	6016	6016	6016	HRDB12L42-2	HRDTS	DISCONNECT,B12L42-2,HRD TS	230 KV MOTOR OPERATED HV SWITCH (MOD)	210	7	Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9)	2012	1
1325	6017	6017	6017	HRDB1L17-1	HRDTS	DISCONNECT,B1L17-1,HRD TS	230 KV MOTOR OPERATED HV SWITCH (MOD)	211	7	Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9)	2012	1
1325	6018	6018	6018	HRDB1B11-1	HRDTS	DISCONNECT,B1B11-1,HRD TS	230 KV MOTOR OPERATED HV SWITCH (MOD)	212	7	Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9)	2012	1
1325	6019	6019	6019	HRDB12T10-1	HRDTS	DISCONNECT,B12T10-1,HRD TS	230 KV MOTOR OPERATED HV SWITCH (MOD)	213	7	Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9)	2012	1
1325	6020	6020	6020	HRDB12L18-1	HRDTS	DISCONNECT,B12L18-1,HRD TS	230 KV MOTOR OPERATED HV SWITCH (MOD)	214	7	Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9)	2012	1
1325	6021	6021	6021	HRDB12B15-2	HRDTS	DISCONNECT,B12B15-2,HRD TS	230 KV MOTOR OPERATED HV SWITCH (MOD)	215	7	Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9)	2012	1
1325	6022	6022	6022	HRDB13B15-2	HRDTS	DISCONNECT,B13B15-2,HRD TS	230 KV MOTOR OPERATED HV SWITCH (MOD)	216	7	Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9)	2012	1
1325	6023	6023	6023	HRDB3L18-2	HRDTS	DISCONNECT,B3L18-2,HRD TS	230 KV MOTOR OPERATED HV SWITCH (MOD)	217	7	Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9)	2012	1
1325	6024	6024	6024	HRDB3L18-1	HRDTS	DISCONNECT,B3L18-1,HRD TS	230 KV MOTOR OPERATED HV SWITCH (MOD)	218	7	Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9)	2012	1
1325	6025	6025	6025	HRDB3B13-1	HRDTS	DISCONNECT,B3B13-1,HRD TS	230 KV MOTOR OPERATED HV SWITCH (MOD)	219	7	Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9)	2012	1
1325	6026	6026	6026	HRDB3B13-2	HRDTS	DISCONNECT,B3B13-2,HRD TS	230 KV MOTOR OPERATED HV SWITCH (MOD)	220	7	Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9)	2012	1

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BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset 2/3	Asset 3/4	Description	Action #	App #	Action	Year	Priority
1325	6027	6027	6027	HRDB13B15-1	HRDTS	DISCONNECT,B13B15-1,HRD TS	230 KV MOTOR OPERATED HV SWITCH (MOD)	221	7	Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9)	2012	1
1325	6028	6028	6028	HRDB12B15-1	HRDTS	DISCONNECT,B12B15-1,HRD TS	230 KV MOTOR OPERATED HV SWITCH (MOD)	222	7	Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9)	2012	1
1325	6029	6029	6029	HRDB1B11-2	HRDTS	DISCONNECT,B1B11-2,HRD TS	230 KV MOTOR OPERATED HV SWITCH (MOD)	223	7	Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9)	2012	1
1325	6030	6030	6030	HRDB11T5	HRDTS	DISCONNECT,B11T5,HRD TS	230 KV MOTOR OPERATED HV SWITCH (MOD)	224	7	Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9)	2012	1
1325	6034	6034	6034	HRDB15T6	HRDTS	DISCONNECT,B15T6,HRD TS	230 KV MOTOR OPERATED HV SWITCH (MOD)	225	7	Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9)	2012	1
1325	6035	6035	6035	HRDB3T3	HRDTS	DISCONNECT,B3T3,HRD TS	230 KV MOTOR OPERATED HV SWITCH (MOD)	226	7	Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9)	2012	1
1325	6036	6036	6036	HRDB15T8	HRDTS	DISCONNECT,B15T8,HRD TS	230 KV MOTOR OPERATED HV SWITCH (MOD)	227	7	Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9)	2012	1
1325	6037	6037	6037	HRDB2T2	HRDTS	DISCONNECT,B2T2,HRD TS	230 KV MOTOR OPERATED HV SWITCH (MOD)	228	7	Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9)	2012	1
1325	6038	6038	6038	HRDB1T1	HRDTS	DISCONNECT,B1T1,HRD TS	230 KV MOTOR OPERATED HV SWITCH (MOD)	229	7	Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9)	2012	1
1325	6039	6039	6039	HRDB15T7	HRDTS	DISCONNECT,B15T7,HRD TS	230 KV MOTOR OPERATED HV SWITCH (MOD)	230	7	Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9)	2012	1
1325	6053	6053	6053	HRDB11B13	HRDTS	DISCONNECT,B11B13,HRD TS	230 KV MOTOR OPERATED HV SWITCH (MOD)	231	7	Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9)	2012	1
1325	6546	6546	6546	HRDB12L18-2	HRDTS	DISCONNECT,B12L18-2,HRD TS	230 KV MOTOR OPERATED HV SWITCH (MOD)	232	7	Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9)	2012	1
1325	275789	275789	275789	HRDB12L42-1	HRDTS	DISCONNECTS B12L42-1,HRD TS	230 KV MOTOR OPERATED HV SWITCH (MOD)	233	7	Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9)	2012	1
1325	6031	6031	6031	HRDB8T6	HRDTS	DISCONNECT,B8T6,HRD TS	138 KV MOTOR OPERATED HV SWITCH (MOD)	235	7	Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9)	2012	1
1325	6032	6032	6032	HRDB8T7	HRDTS	DISCONNECT,B8T7,HRD TS	138 KV MOTOR OPERATED HV SWITCH (MOD)	236	7	Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9)	2012	1
1325	6033	6033	6033	HRDB8T8	HRDTS	DISCONNECT,B8T8,HRD TS	138 KV MOTOR OPERATED HV SWITCH (MOD)	237	7	Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9)	2012	1
1325	6040	6040	6040	HRDB8L39-2	HRDTS	DISCONNECT,B8L39-2,HRD TS	138 KV MOTOR OPERATED HV SWITCH (MOD)	238	7	Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9)	2012	1
1325	6041	6041	6041	HRDB8L39-1	HRDTS	DISCONNECT,B8L39-1,HRD TS	138 KV MOTOR OPERATED HV SWITCH (MOD)	239	7	Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9)	2012	1
1325	6042	6042	6042	HRDB7T5-2	HRDTS	DISCONNECT,B7T5-2,HRD TS	66 KV MANUAL OPERATED HV SWITCH	243	7	Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9)	2012	1
1325	6043	6043	6043	HRDL2L38	HRDTS	DISCONNECT,L2L38,HRD TS	67 KV MANUAL OPERATED HV SWITCH	244	7	Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9)	2012	1
1325	6044	6044	6044	HRDB7L38-1	HRDTS	DISCONNECT,B7L38-1,HRD TS	68 KV MANUAL OPERATED HV SWITCH	245	7	Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9)	2012	1

Table 11-2 Cont'd

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset 2/3	Asset 3/4	Description	Action #	App #	Action	Year	Priority
1325	6045	6045	6045	HRDB7L38-2	HRDTS	DISCONNECT,B7L38-2,HRD TS	69 KV MANUAL OPERATED HV SWITCH	246	7	Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9)	2012	1
1325	6046	6046	6046	HRDB7L2-2	HRDTS	DISCONNECT,B7L2-2,HRD TS	69 KV MANUAL OPERATED HV SWITCH	247	7	Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9)	2012	1
1325	6047	6047	6047	HRDB7L2-1	HRDTS	DISCONNECT,B7L2-1,HRD TS	69 KV MANUAL OPERATED HV SWITCH	248	7	Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9)	2012	1
1325	6048	6048	6048	HRDB6L3-1	HRDTS	DISCONNECT,B6L3-1,HRD TS	69 KV MANUAL OPERATED HV SWITCH	249	7	Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9)	2012	1
1325	6049	6049	6049	HRDB6L3-2	HRDTS	DISCONNECT,B6L3-2,HRD TS	69 KV MANUAL OPERATED HV SWITCH	250	7	Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9)	2012	1
1325	6050	6050	6050	HRDB6B7	HRDTS	DISCONNECT,B6B7,HRD TS	69 KV MANUAL OPERATED HV SWITCH	251	7	Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9)	2012	1
1325	6051	6051	6051	HRDB7T5-1	HRDTS	DISCONNECT,B7T5-1,HRD TS	69 KV MANUAL OPERATED HV SWITCH	252	7	Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9)	2012	1
1325	6052	6052	6052	HRDB6T10-1	HRDTS	DISCONNECT,B6T10-1,HRD TS	69 KV MANUAL OPERATED HV SWITCH	253	7	Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9)	2012	1

Notes:

1. The intent is to develop a life plan for the switchyard breakers and switches in 2012 for implementation (per Table 11-5) starting in or about 2015 to 2020.

11.1.1.5 Risk Assessment

The risk assessment associated with the switchyard switchgear, both from a technological perspective and a safety perspective, is illustrated below in Table 11-3.

TABLE 11-3 RISK ASSESSMENT – SWITCHYARD SWITCHGEAR

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset 2/3	Asset 3/4	Description	Component	Risk Assess #	Appendix #	Major Issues	Remaining Life Years	Remaining Life	Techno-Eco Risk Assess Model			Safety Risk Assess Model			Possible Failure Event	Mitigation
												(Insufficient Info - Inspection Required Within (x) Years)	Comments	Likeli-hood	Conse-quence	Risk Level	Likeli-hood	Conse-quence	Safety Risk		
1325	5990	5990	310-77-1		HRDTS	BREAKER,B3B13,HRD TS	230 KV	None	185	7	Mechanical/electrical failure - system, stn, amb induced.	8	N/A	2	C	Medium	2	C	Medium	Loss 1 connection path generation to ring bus	Parallel paths (existing). Test, maintain. refurbish.
1325	5991	5991	310-77-3		HRDTS	BREAKER,B12B15,HRD TS	230 KV	None	186	7	Mechanical/electrical failure - system, stn, amb induced.	8	N/A	2	C	Medium	2	C	Medium	Loss 1 connection path ring bus to load 39L Whitborne	Parallel paths (existing). Test, maintain. refurbish.
1325	5992	5992	460-80 AD/2		HRDTS	BREAKER,B12L18,HRD TS	230 KV	None	187	7	Mechanical/electrical failure - system, stn, amb induced.	11	N/A	2	C	Medium	2	C	Medium	Loss 1 connection path ring bus to load TL218 Oxen Pond	Parallel paths (existing). Test, maintain. refurbish.
1325	5993	5993	310-77-2		HRDTS	BREAKER,B3L18,HRD TS	230 KV	None	188	7	Mechanical/electrical failure - system, stn, amb induced.	8	N/A	2	C	Medium	2	C	Medium	Loss 1 connection path ring bus to load TL218 Oxen Pond	Parallel paths (existing). Test, maintain. refurbish.
1325	5994	5994	170-73-3		HRDTS	BREAKER,B1L17,HRD TS	230 KV	None	189	7	Mechanical/electrical failure - system, stn, amb induced.	3	N/A	2	C	Medium	2	C	Medium	Loss 1 connection path ring bus to load TL217 Western Avalon	Parallel paths (existing). Test, maintain. refurbish.
1325	5995	5995	310-77-4		HRDTS	BREAKER,B12L42,HRD TS	230 KV	None	190	7	Mechanical/electrical failure - system, stn, amb induced.	8	N/A	2	C	Medium	2	C	Medium	Loss 1 connection path ring bus to load TL242 Hardwoods	Parallel paths (existing). Test, maintain. refurbish.
1325	5996	5996	188-74-2		HRDTS	BREAKER,B2B11,HRD TS	230 KV	None	191	7	Mechanical/electrical failure - system, stn, amb induced.	6	N/A	2	C	Medium	2	C	Medium	Loss 1 ring bus connection Bus B2 from unit 2 generator to Bus B11	Parallel paths (existing). Test, maintain. refurbish.
1325	5997	5997	188-74-1		HRDTS	BREAKER,B1B11,HRD TS	230 KV	None	192	7	Mechanical/electrical failure - system, stn, amb induced.	4	N/A	2	C	Medium	2	C	Medium	Loss 1 ring bus connection Bus B1 from unit 1 generator to Bus B11	Parallel paths (existing). Test, maintain. refurbish.
1325	5998	5998	170-73-2		HRDTS	BREAKER,B12L17,HRD TS	230 KV	None	193	7	Mechanical/electrical failure - system, stn, amb induced.	7	N/A	2	C	Medium	2	C	Medium	Loss 1 connection path ring bus to load TL217 Western Avalon	Parallel paths (existing). Test, maintain. refurbish.
1325	5999	5999	170-73-1		HRDTS	BREAKER,B2L42,HRD TS	230 KV	None	194	7	Mechanical/electrical failure - system, stn, amb induced.	7	N/A	2	C	Medium	2	C	Medium	Loss 1 connection path ring bus to load TL242 Hardwoods	Parallel paths (existing). Test, maintain. refurbish.
1325	6000	6000	0464DT72		HRDTS	BREAKER,B6T10,HRD TS	69 KV	None	195	7	Mechanical/electrical failure - system, stn, amb induced.	26	N/A	2	C	Medium	2	C	Medium	Loss of connection Bus B6 to transformer T10 - 69 kV loads and Seal Point	Parallel paths (existing). Test, maintain. refurbish.
1325	6001	6001	90/K31238935		HRDTS	BREAKER,B12T10,HRD TS	230 KV	None	196	7	Mechanical/electrical failure - system, stn, amb induced.	20	N/A	2	C	Medium	2	C	Medium	Loss of connection Bus B12 to transformer T10 - 69 kV loads and Seal Point	Parallel paths (existing). Test, maintain. refurbish.
1325	6002	6002	45510DD/1		HRDTS	BREAKER,B13B15,HRD TS	230 KV	None	197	7	Mechanical/electrical failure - system, stn, amb induced.	11	N/A	2	C	Medium	2	C	Medium	Loss 1 connection path ring bus to load 39L Whitborne	Parallel paths (existing). Test, maintain. refurbish.
1325	6003	6003	0465DT72		HRDTS	BREAKER,B7T5,HRD TS	69 KV	None	198	7	Mechanical/electrical failure - system, stn, amb induced.	26	N/A	2	C	Medium	2	C	Medium	Loss of connection from Transformer T5 to Bus 7 - 69 kV loads and Seal Point	Parallel paths (existing). Test, maintain. refurbish.
1325	6004	6004	61130		HRDTS	BREAKER,B7L2,HRD TS	69 KV	None	199	7	Mechanical/electrical failure - system, stn, amb induced.	5	N/A	2	C	Medium	2	C	Medium	Loss of connection Bus B7 to Bus 2 - 69 kV loads and Seal Point	Parallel paths (existing). Test, maintain. refurbish.
1325	6005	6005	63257		HRDTS	BREAKER,B8L39,HRD TS	138 KV	None	200	7	Mechanical/electrical failure - system, stn, amb induced.	8	N/A	2	D	High	2	C	Medium	Loss of feed to Line 39L to Whitbourne	Test, maintain. refurbish.
1325	6006	6006	64018		HRDTS	BREAKER,B6L3,HRD TS	69 KV	None	201	7	Mechanical/electrical failure - system, stn, amb induced.	8	N/A	2	C	Medium	2	C	Medium	Loss of connection Bus B6 to Line 3 - 69 kV loads and Seal Point	Parallel paths (existing). Test, maintain. refurbish.
1325	6007	6007	61131		HRDTS	BREAKER,B7L38,HRD TS	69 KV	None	202	7	Mechanical/electrical failure - system, stn, amb induced.	5	N/A	2	C	Medium	2	C	Medium	Loss of connection Bus B7 to Line 38 - 69 kV loads and Seal Point	Parallel paths (existing). Test, maintain. refurbish.
1325	6008	6008	991110		HRDTS	DISCONNECT,B12L17-1,HRD TS	230 KV	Motor Operated HV Switch (MOD)	206	7	Mechanical/electrical failure - system, stn, amb induced.	10	N/A	2	C	Medium	2	C	Medium	Loss 1 connection path ring bus to load TL217 Western Avalon	Parallel paths (existing). Test, maintain. refurbish.
1325	6009	6009	991110		HRDTS	DISCONNECT,B12L42-1,HRD TS	230 KV	Motor Operated HV Switch (MOD)	207	7	Mechanical/electrical failure - system, stn, amb induced.	10	N/A	2	C	Medium	2	C	Medium	Loss 1 connection path ring bus to load TL242 Hardwoods	Parallel paths (existing). Test, maintain. refurbish.
1325	6010	6010	991110		HRDTS	DISCONNECT,B2L42-1,HRD TS	230 KV	Motor Operated HV Switch (MOD)	208	7	Mechanical/electrical failure - system, stn, amb induced.	10	N/A	2	C	Medium	2	C	Medium	Loss 1 connection path to ring bus	Parallel paths (existing). Test, maintain. refurbish.
1325	6011	6011	991110		HRDTS	DISCONNECT,B2B11-1,HRD TS	230 KV	Motor Operated HV Switch (MOD)	209	7	Mechanical/electrical failure - system, stn, amb induced.	10	N/A	2	C	Medium	2	C	Medium	Loss 1 connection path Unit 2 generator to ring bus	Parallel paths (existing). Test, maintain. refurbish.
1325	6012	6012	991110		HRDTS	DISCONNECT,B2B11-2,HRD TS	230 KV	Motor Operated HV Switch (MOD)	210	7	Mechanical/electrical failure - system, stn, amb induced.	10	N/A	2	C	Medium	2	C	Medium	Loss 1 connection path Unit 2 generator to ring bus	Parallel paths (existing). Test, maintain. refurbish.
1325	6013	6013	991110		HRDTS	DISCONNECT,B12L17-2,HRD TS	230 KV	Motor Operated HV Switch (MOD)	211	7	Mechanical/electrical failure - system, stn, amb induced.	10	N/A	2	C	Medium	2	C	Medium	Loss 1 connection path ring bus to load TL217 Western Avalon	Parallel paths (existing). Test, maintain. refurbish.

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Table 11-3 Cont'd

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset 2/3	Asset 3/4	Description	Component	Risk Assess #	Appendix #	Major Issues	Remaining Life Years	Remaining Life	Techno-Eco Risk Assess Model			Safety Risk Assess Model			Possible Failure Event	Mitigation
												(Insufficient Info - Inspection Required Within (x) Years)	Comments	Likeli-hood	Conse-quence	Risk Level	Likeli-hood	Conse-quence	Safety Risk		
1325	6014	6014	991110		HRDTS	DISCONNECT,B2L42-2,HRD TS	230 KV	Motor Operated HV Switch (MOD)	212	7	Mechanical/electrical failure - system, stn, amb induced.	10	N/A	2	C	Medium	2	C	Medium	Loss 1 connection path ring bus to load TL242 Hardwoods	Parallel paths (existing). Test, maintain. refurbish.
1325	6015	6015	991110		HRDTS	DISCONNECT,B1L17-2,HRD TS	230 KV	Motor Operated HV Switch (MOD)	213	7	Mechanical/electrical failure - system, stn, amb induced.	10	N/A	2	C	Medium	2	C	Medium	Loss 1 connection path ring bus to load TL217 Western Avalon	Parallel paths (existing). Test, maintain. refurbish.
1325	6016	6016	991110		HRDTS	DISCONNECT,B12L42-2,HRD TS	230 KV	Motor Operated HV Switch (MOD)	214	7	Mechanical/electrical failure - system, stn, amb induced.	10	N/A	2	C	Medium	2	C	Medium	Loss 1 connection path ring bus to load TL242 Hardwoods	Parallel paths (existing). Test, maintain. refurbish.
1325	6017	6017	991110		HRDTS	DISCONNECT,B1L17-1,HRD TS	230 KV	Motor Operated HV Switch (MOD)	215	7	Mechanical/electrical failure - system, stn, amb induced.	10	N/A	2	C	Medium	2	C	Medium	Loss 1 connection path ring bus to load TL217 Western Avalon	Parallel paths (existing). Test, maintain. refurbish.
1325	6018	6018	991110		HRDTS	DISCONNECT,B1B11-1,HRD TS	230 KV	Motor Operated HV Switch (MOD)	216	7	Mechanical/electrical failure - system, stn, amb induced.	10	N/A	2	C	Medium	2	C	Medium	Loss 1 connection path Unit 1 generator to ring bus	Parallel paths (existing). Test, maintain. refurbish.
1325	6019	6019	991110		HRDTS	DISCONNECT,B12T10-1,HRD TS	230 KV	Motor Operated HV Switch (MOD)	217	7	Mechanical/electrical failure - system, stn, amb induced.	10	N/A	2	C	Medium	2	C	Medium	Loss of connection transformer T10 to Bus 6 - 69 kV loads and Seal Point	Parallel paths (existing). Test, maintain. refurbish.
1325	6020	6020	991110		HRDTS	DISCONNECT,B12L18-1,HRD TS	230 KV	Motor Operated HV Switch (MOD)	218	7	Mechanical/electrical failure - system, stn, amb induced.	10	N/A	2	C	Medium	2	C	Medium	Loss 1 connection path ring bus to load TL218 Oxen Pond	Parallel paths (existing). Test, maintain. refurbish.
1325	6021	6021	991110		HRDTS	DISCONNECT,B12B15-2,HRD TS	230 KV	Motor Operated HV Switch (MOD)	219	7	Mechanical/electrical failure - system, stn, amb induced.	10	N/A	2	C	Medium	2	C	Medium	Loss 1 connection path ring bus to Bus 15 to load 39L Whitbone	Parallel paths (existing). Test, maintain. refurbish.
1325	6022	6022	991110		HRDTS	DISCONNECT,B13B15-2,HRD TS	230 KV	Motor Operated HV Switch (MOD)	220	7	Mechanical/electrical failure - system, stn, amb induced.	10	N/A	2	C	Medium	2	C	Medium	Loss 1 connection path ring bus to Bus 15 to load 39L Whitbone	Parallel paths (existing). Test, maintain. refurbish.
1325	6023	6023	991110		HRDTS	DISCONNECT,B3L18-2,HRD TS	230 KV	Motor Operated HV Switch (MOD)	221	7	Mechanical/electrical failure - system, stn, amb induced.	10	N/A	2	C	Medium	2	C	Medium	Loss 1 connection path ring bus to load TL218 Oxen Pond	Parallel paths (existing). Test, maintain. refurbish.
1325	6024	6024	991110		HRDTS	DISCONNECT,B3L18-1,HRD TS	230 KV	Motor Operated HV Switch (MOD)	222	7	Mechanical/electrical failure - system, stn, amb induced.	10	N/A	2	C	Medium	2	C	Medium	Loss 1 connection path ring bus to load TL218 Oxen Pond	Parallel paths (existing). Test, maintain. refurbish.
1325	6025	6025	991110		HRDTS	DISCONNECT,B3B13-1,HRD TS	230 KV	Motor Operated HV Switch (MOD)	223	7	Mechanical/electrical failure - system, stn, amb induced.	10	N/A	2	C	Medium	2	C	Medium	Loss 1 connection path Unit 3 generator to ring bus	Parallel paths (existing). Test, maintain. refurbish.
1325	6026	6026	991110		HRDTS	DISCONNECT,B3B13-2,HRD TS	230 KV	Motor Operated HV Switch (MOD)	224	7	Mechanical/electrical failure - system, stn, amb induced.	10	N/A	2	C	Medium	2	C	Medium	Loss 1 connection path Unit 3 generator to ring bus	Parallel paths (existing). Test, maintain. refurbish.
1325	6027	6027	991110		HRDTS	DISCONNECT,B13B15-1,HRD TS	230 KV	Motor Operated HV Switch (MOD)	225	7	Mechanical/electrical failure - system, stn, amb induced.	10	N/A	2	C	Medium	2	C	Medium	Loss 1 connection path ring bus to Bus 15 to load 39L Whitbone	Parallel paths (existing). Test, maintain. refurbish.
1325	6028	6028	991110		HRDTS	DISCONNECT,B12B15-1,HRD TS	230 KV	Motor Operated HV Switch (MOD)	226	7	Mechanical/electrical failure - system, stn, amb induced.	10	N/A	2	C	Medium	2	C	Medium	Loss 1 connection path ring bus to Bus 15 to load 39L Whitbone	Parallel paths (existing). Test, maintain. refurbish.
1325	6029	6029	991110		HRDTS	DISCONNECT,B1B11-2,HRD TS	230 KV	Motor Operated HV Switch (MOD)	227	7	Mechanical/electrical failure - system, stn, amb induced.	10	N/A	2	C	Medium	2	C	Medium	Loss 1 connection path Unit 1 generator to ring bus	Parallel paths (existing). Test, maintain. refurbish.
1325	6030	6030	991110		HRDTS	DISCONNECT,B11T5,HRD TS	230 KV	Motor Operated HV Switch (MOD)	228	7	Mechanical/electrical failure - system, stn, amb induced.	10	N/A	2	C	Medium	2	C	Medium	Loss of connection transformer T5to Bus 11 - 69 kV loads and Seal Point	Parallel paths (existing). Test, maintain. refurbish.
1325	6034	6034	991110		HRDTS	DISCONNECT,B15T6,HRD TS	138 KV	Motor Operated HV Switch (MOD)	229	7	Mechanical/electrical failure - system, stn, amb induced.	10	N/A	2	C	Medium	2	C	Medium	Loss 1 of 3 connection paths Bus 15 to Bus 8 and load 39L Whitborne	Parallel paths (existing). Test, maintain. refurbish.
1325	6035	6035	991110		HRDTS	DISCONNECT,B3T3,HRD TS	138 KV	Motor Operated HV Switch (MOD)	230	7	Mechanical/electrical failure - system, stn, amb induced.	10	N/A	2	D	High	2	C	Medium	Loss of connection from Unit 3 generator - Loss of one unit.	Test, maintain. refurbish.
1325	6036	6036	991110		HRDTS	DISCONNECT,B15T8,HRD TS	138 KV	Motor Operated HV Switch (MOD)	231	7	Mechanical/electrical failure - system, stn, amb induced.	10	N/A	2	C	Medium	2	C	Medium	Loss 1 of 3 connection paths Bus 15 to Bus 8 and load 39L Whitborne	Parallel paths (existing). Test, maintain. refurbish.
1325	6037	6037	991110		HRDTS	DISCONNECT,B2T2,HRD TS	230 KV	Motor Operated HV Switch (MOD)	232	7	Mechanical/electrical failure - system, stn, amb induced.	10	N/A	2	D	High	2	C	Medium	Loss of connection from Unit 2 generator - Loss of one unit.	Test, maintain. refurbish.
1325	6038	6038	991110		HRDTS	DISCONNECT,B1T1,HRD TS	230 KV	Motor Operated HV Switch (MOD)	233	7	Mechanical/electrical failure - system, stn, amb induced.	10	N/A	2	D	High	2	C	Medium	Loss of connection from Unit 1 generator - Loss of one unit.	Test, maintain. refurbish.
1325	6039	6039	991110		HRDTS	DISCONNECT,B15T7,HRD TS	230 KV	Motor Operated HV Switch (MOD)	234	7	Mechanical/electrical failure - system, stn, amb induced.	10	N/A	2	C	Medium	2	C	Medium	Loss 1 of 3 connection paths Bus 15 to Bus 8 and load 39L Whitborne	Parallel paths (existing). Test, maintain. refurbish.
1325	6053	6053	991110		HRDTS	DISCONNECT,B11B13,HRD TS	230 KV	Motor Operated HV Switch (MOD)	235	7	Mechanical/electrical failure - system, stn, amb induced.		N/A	2	C	Medium	2	C	Medium	Loss of 1 internal ring bus connection	Parallel paths (existing). Test, maintain. refurbish.
1325	6546	6546	991110		HRDTS	DISCONNECT,B12L18-2,HRD TS	230 KV	Motor Operated HV Switch (MOD)	236	7	Mechanical/electrical failure - system, stn, amb induced.	10	N/A	2	C	Medium	2	C	Medium	Loss 1 connection path ring bus to load TL218 Oxen Pond	Parallel paths (existing). Test, maintain. refurbish.
1325	275789	275789	991110		HRDTS	DISCONNECTS B12L42-1,HRD TS	230 KV	Motor Operated HV Switch (MOD)	237	7	Mechanical/electrical failure - system, stn, amb induced.	10	N/A	2	C	Medium	2	C	Medium	Loss 1 connection path ring bus to load TL242 Hardwoods	Parallel paths (existing). Test, maintain. refurbish.
1325	6031	6031	991110		HRDTS	DISCONNECT,B8T6,HRD TS	138 KV	Motor Operated HV Switch (MOD)	238	7	Mechanical/electrical failure - system, stn, amb induced.	10	N/A	2	C	Medium	2	C	Medium	Loss 1 of 3 connection path transformer 6 to Bus 8 to load 39L Whitborne	Parallel paths (existing). Test, maintain. refurbish.
1325	6032	6032	991110		HRDTS	DISCONNECT,B8T7,HRD TS	138 KV	Motor Operated HV Switch (MOD)	239	7	Mechanical/electrical failure - system, stn, amb induced.	10	N/A	2	C	Medium	2	C	Medium	Loss 1 of 3 connection path transformer 7 to Bus 8 to load 39L Whitborne	Parallel paths (existing). Test, maintain. refurbish.
1325	6033	6033	991110		HRDTS	DISCONNECT,B8T8,HRD TS	138 KV	Motor Operated HV Switch (MOD)	240	7	Mechanical/electrical failure - system, stn, amb induced.	10	N/A	2	D	High	2	C	Medium	Loss 1 of 3 connection path transformer 8 to Bus 8 to load 39L Whitborne	Parallel paths (existing). Test, maintain. refurbish.
1325	6040	6040	991110		HRDTS	DISCONNECT,B8L39-2,HRD TS	138 KV	Manual Operated HV Switch	241	7	Mechanical/electrical failure - system, stn, amb induced.	10	N/A	2	D	High	2	C	Medium	Loss connection path Bus 8 to load 39L Whitborne	Test, maintain. refurbish.
1325	6041	6041	991110		HRDTS	DISCONNECT,B8L39-1,HRD TS	138 KV	Manual Operated HV Switch	242	7	Mechanical/electrical failure - system, stn, amb induced.	10	N/A	2	D	High	2	C	Medium	Loss connection path Bus 8 to load 39L Whitborne	Test, maintain. refurbish.

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Table 11-3 Cont'd

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset 2/3	Asset 3/4	Description	Component	Risk Assess #	Appendix #	Major Issues	Remaining Life Years	Remaining Life	Techno-Eco Risk Assess Model			Safety Risk Assess Model			Possible Failure Event	Mitigation
												(Insufficient Info - Inspection Required Within (x) Years)	Comments	Likeli-hood	Conse-quence	Risk Level	Likeli-hood	Conse-quence	Safety Risk		
1325	6042	6042	991110		HRDTS	DISCONNECT,B7T5-2,HRD TS	69 KV	Manual Operated HV Switch	245	7	Mechanical/electrical failure - system, stn, amb induced.	10	N/A	2	C	Medium	2	C	Medium	Loss of connection to Bus 7 from transformer T5 - 69 kV loads and Seal Point	Parallel paths (existing). Test, maintain. refurbish.
1325	6043	6043	991110		HRDTS	DISCONNECT,L2L38,HRD TS	69 KV	Manual Operated HV Switch	246	7	Mechanical/electrical failure - system, stn, amb induced.	10	N/A	2	C	Medium	2	C	Medium	Loss of connection transformerline L2 to L38 - 69 kV loads and Seal Point	Parallel paths (existing). Test, maintain. refurbish.
1325	6044	6044	991110		HRDTS	DISCONNECT,B7L38-1,HRD TS	69 KV	Manual Operated HV Switch	247	7	Mechanical/electrical failure - system, stn, amb induced.	10	N/A	2	C	Medium	2	C	Medium	Loss of connection transformer Bus 7 to line 38 - 69 kV loads and Seal Point	Parallel paths (existing). Test, maintain. refurbish.
1325	6045	6045	991110		HRDTS	DISCONNECT,B7L38-2,HRD TS	69 KV	Manual Operated HV Switch	248	7	Mechanical/electrical failure - system, stn, amb induced.	10	N/A	2	C	Medium	2	C	Medium	Loss of connection transformer Bus 7 to line 38 - 69 kV loads and Seal Point	Parallel paths (existing). Test, maintain. refurbish.
1325	6046	6046	991110		HRDTS	DISCONNECT,B7L2-2,HRD TS	69 KV	Manual Operated HV Switch	249	7	Mechanical/electrical failure - system, stn, amb induced.	10	N/A	2	C	Medium	2	C	Medium	Loss of connection transformer Bus 7 to line 2 - 69 kV loads and Seal Point	Parallel paths (existing). Test, maintain. refurbish.
1325	6047	6047	991110		HRDTS	DISCONNECT,B7L2-1,HRD TS	69 KV	Manual Operated HV Switch	250	7	Mechanical/electrical failure - system, stn, amb induced.	10	N/A	2	C	Medium	2	C	Medium	Loss of connection transformer T10 to Bus 6 - 69 kV loads and Seal Point	Parallel paths (existing). Test, maintain. refurbish.
1325	6048	6048	991110		HRDTS	DISCONNECT,B6L3-1,HRD TS	69 KV	Manual Operated HV Switch	251	7	Mechanical/electrical failure - system, stn, amb induced.	10	N/A	2	C	Medium	2	C	Medium	Loss of connection transformer Bus 6 to Line 3 - 69 kV to SB34 Interconnection	Parallel paths (existing). Test, maintain. refurbish.
1325	6049	6049	991110		HRDTS	DISCONNECT,B6L3-2,HRD TS	69 KV	Manual Operated HV Switch	252	7	Mechanical/electrical failure - system, stn, amb induced.	10	N/A	2	C	Medium	2	C	Medium	Loss of connection Bus 6 to Line 3 - Inter-unit connection to Station Board 34-69 kV	Parallel paths (existing). Test, maintain. refurbish.
1325	6050	6050	991110		HRDTS	DISCONNECT,B6B7,HRD TS	69 KV	Manual Operated HV Switch	253	7	Mechanical/electrical failure - system, stn, amb induced.	10	N/A	2	C	Medium	2	C	Medium	Loss of connection Bus 6 to Bus 7 - Inter-unit connection - 69 kV to Units 1&2 loads and Seal Point	Parallel paths (existing). Test, maintain. refurbish.
1325	6051	6051	991110		HRDTS	DISCONNECT,B7T5-1,HRD TS	69 KV	Manual Operated HV Switch	254	7	Mechanical/electrical failure - system, stn, amb induced.	10	N/A	2	C	Medium	2	C	Medium	Loss of connection transformer T5 to Bus 7 - 69 kV loads and Seal Point	Parallel paths (existing). Test, maintain. refurbish.
1325	6052	6052	991110		HRDTS	DISCONNECT,B6T10-1,HRD TS	69 KV	Manual Operated HV Switch	255	7	Mechanical/electrical failure - system, stn, amb induced.	10	N/A	2	C	Medium	2	C	Medium	Loss of connection transformer T10 to Bus 6 - 69 kV loads and Seal Point	Parallel paths (existing). Test, maintain. refurbish.

Notes:

1. In most cases, the electrical connections associated with breakers and switches have been paralleled to reduce risk of unit loss or loss of generation supply to loads.

2. Compressor air line information is premised on completion of replacement in 2010/11. Otherwise risk level would be "High".

11.1.1.6 Life Cycle Curve and Remaining Life

The life cycle curves for the switchyard equipment (excluding transformers) are illustrated in the two figures below. The first represents the breakers and the second is for the motorized disconnects and switches. Several curves are required to represent the various elements of and their operational timing. The life curves are plots of the estimated current and projected numbers of operation on the y-axis versus calendar year on the x-axis. The numbers of operation is an estimate by AMEC based on unit starts and stops and not on actual values for which there was no data available. The chart has several vertical lines representing differing representative nominal age limits for various components. It also has several horizontal lines that represent a range of practical equipment equivalent base loaded operating hour life limits. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view.

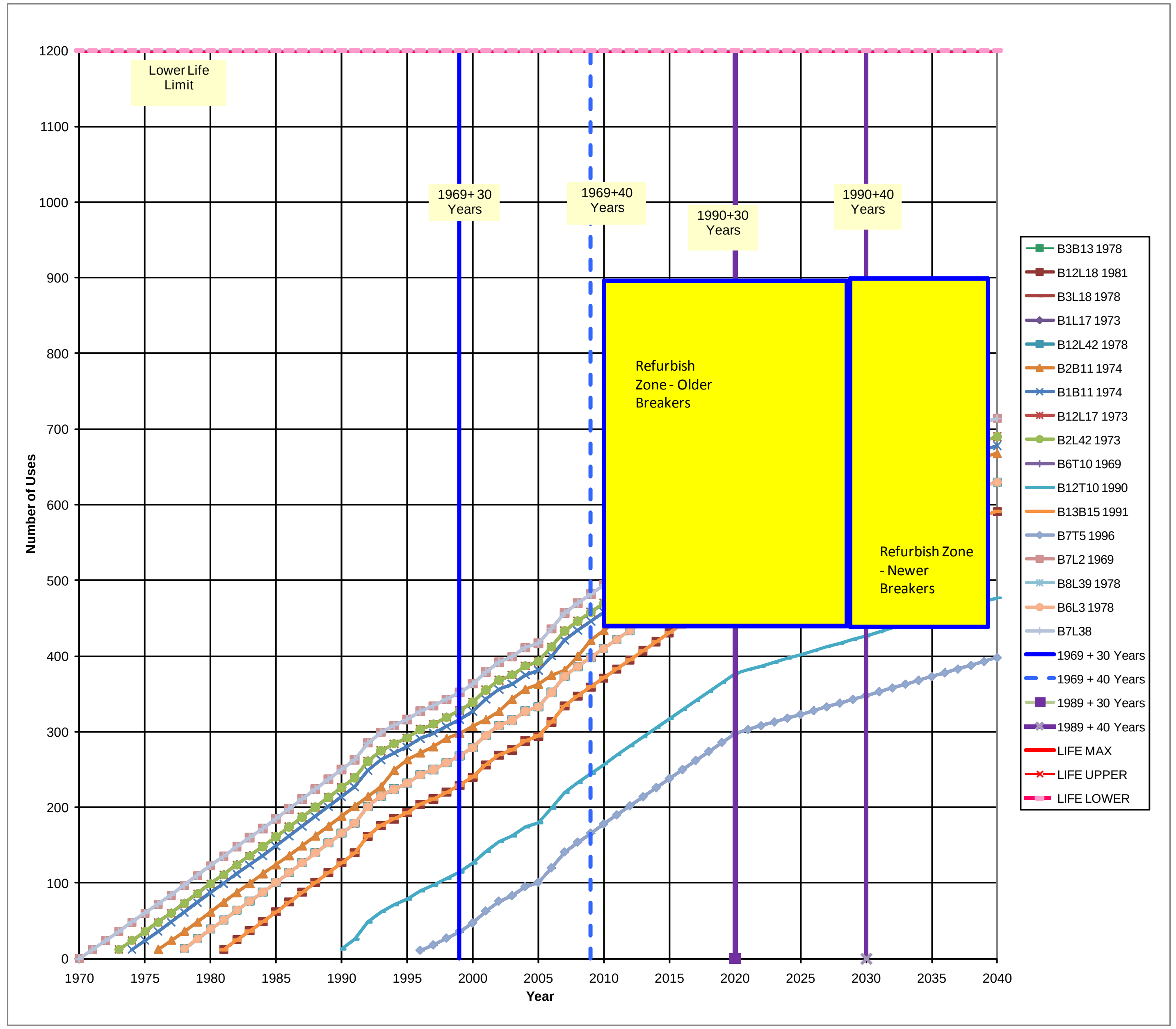

FIGURE 11-2 LIFE CYCLE CURVE – SWITCHYARD SWITCHGEAR - BREAKERS

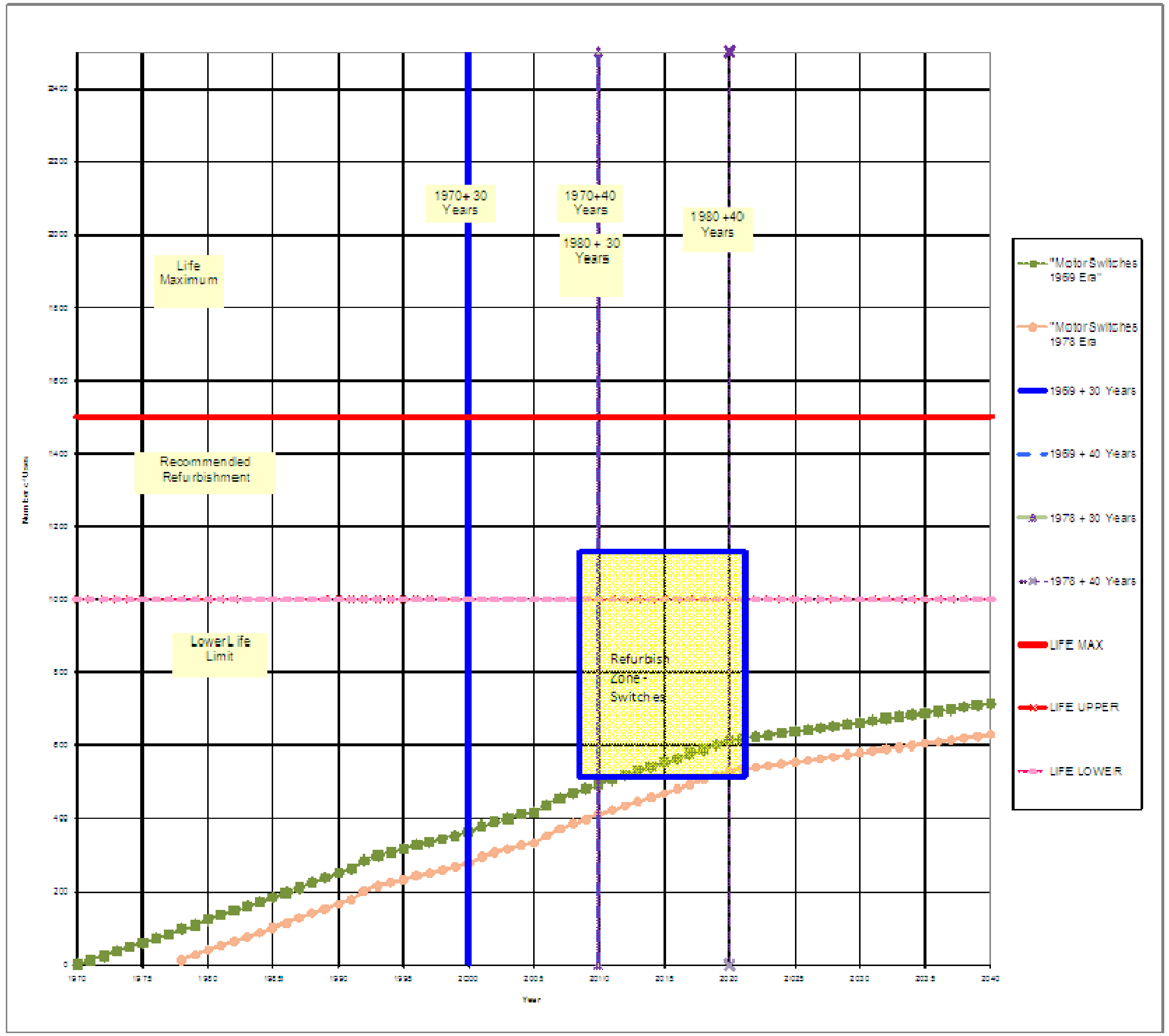

FIGURE 11-3 LIFE CYCLE CURVE – SWITCHYARD SWITCHGEAR - MOTORIZED DISCONNECTS AND SWITCHES

The curves indicate that the remaining life (RL) of the switchyard switchgear exceeds the end date for generation of 2020, but not the desired life (DL) of 2041 (at the end of synchronous condensing life) without refurbishment and/or replacement. The equipment has reached an age where reliability is a concern, particularly where system interruptions or lightning storm impacts play a role. Given the critical nature of the station and its switchyard to the supply of the mainland, a pro-active program of testing and refurbishment is a priority.

11.1.1.7 Level 2 Inspection Requirements and Costs

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 11-4 below, assuming the current plant inspection and maintenance program is maintained or improved.

TABLE 11-4 LEVEL 2 INSPECTION – SWITCHYARD SWITCHGEAR

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset 2/3	Asset 3/4	Description	Sub System Comment	L2#	Appendix #	Level 2 Work	Year	Priority	Cost k$
1325	5990	5990	310-77-1	HRDTS	BREAKER,B3B13,HRD TS	230 KV	N/A	162	7	No Level 2 required.			
1325	5991	5991	310-77-3	HRDTS	BREAKER,B12B15,HRD TS	230 KV	N/A	163	7	No Level 2 required.			
1325	5992	5992	460-80 AD/2	HRDTS	BREAKER,B12L18,HRD TS	230 KV	N/A	164	7	No Level 2 required.			
1325	5993	5993	310-77-2	HRDTS	BREAKER,B3L18,HRD TS	230 KV	N/A	165	7	No Level 2 required.			
1325	5994	5994	170-73-3	HRDTS	BREAKER,B1L17,HRD TS	230 KV	N/A	166	7	No Level 2 required.			
1325	5995	5995	310-77-4	HRDTS	BREAKER,B12L42,HRD TS	230 KV	N/A	167	7	No Level 2 required.			
1325	5996	5996	188-74-2	HRDTS	BREAKER,B2B11,HRD TS	230 KV	N/A	168	7	No Level 2 required.			
1325	5997	5997	188-74-1	HRDTS	BREAKER,B1B11,HRD TS	230 KV	N/A	169	7	No Level 2 required.			
1325	5998	5998	170-73-2	HRDTS	BREAKER,B12L17,HRD TS	230 KV	N/A	170	7	No Level 2 required.			
1325	5999	5999	170-73-1	HRDTS	BREAKER,B2L42,HRD TS	230 KV	N/A	171	7	No Level 2 required.			
1325	6000	6000	0464DT72	HRDTS	BREAKER,B6T10,HRD TS	69 KV	N/A	172	7	No Level 2 required.			
1325	6001	6001	90/K31238935	HRDTS	BREAKER,B12T10,HRD TS	230 KV	N/A	173	7	No Level 2 required.			
1325	6002	6002	45510DD/1	HRDTS	BREAKER,B13B15,HRD TS	230 KV	N/A	174	7	No Level 2 required.			
1325	6003	6003	0465DT72	HRDTS	BREAKER,B7T5,HRD TS	69 KV	N/A	175	7	No Level 2 required.			
1325	6004	6004	61130	HRDTS	BREAKER,B7L2,HRD TS	69 KV	N/A	176	7	No Level 2 required.			
1325	6005	6005	63257	HRDTS	BREAKER,B8L39,HRD TS	138 KV	N/A	177	7	No Level 2 required.			
1325	6006	6006	64018	HRDTS	BREAKER,B6L3,HRD TS	69 KV	N/A	178	7	No Level 2 required.			
1325	6007	6007	61131	HRDTS	BREAKER,B7L38,HRD TS	69 KV	N/A	179	7	No Level 2 required.			

Table 11-4 Cont'd

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset 2/3	Asset 3/4	Description	Sub System Comment	L2#	Appendix #	Level 2 Work	Year	Priority	Cost k$
1325	6008	6008	6008	HRDTS	DISCONNECT,B12L17-1,HRD TS	230 KV	Motor Operated HV Switch (MOD)	183	7	No Level 2 required.			
1325	6009	6009	6009	HRDTS	DISCONNECT,B12L42-1,HRD TS	230 KV	Motor Operated HV Switch (MOD)	184	7	No Level 2 required.			
1325	6010	6010	6010	HRDTS	DISCONNECT,B2L42-1,HRD TS	230 KV	Motor Operated HV Switch (MOD)	185	7	No Level 2 required.			
1325	6011	6011	6011	HRDTS	DISCONNECT,B2B11-1,HRD TS	230 KV	Motor Operated HV Switch (MOD)	186	7	No Level 2 required.			
1325	6012	6012	6012	HRDTS	DISCONNECT,B2B11-2,HRD TS	230 KV	Motor Operated HV Switch (MOD)	187	7	No Level 2 required.			
1325	6013	6013	6013	HRDTS	DISCONNECT,B12L17-2,HRD TS	230 KV	Motor Operated HV Switch (MOD)	188	7	No Level 2 required.			
1325	6014	6014	6014	HRDTS	DISCONNECT,B2L42-2,HRD TS	230 KV	Motor Operated HV Switch (MOD)	189	7	No Level 2 required.			
1325	6015	6015	6015	HRDTS	DISCONNECT,B1L17-2,HRD TS	230 KV	Motor Operated HV Switch (MOD)	190	7	No Level 2 required.			
1325	6016	6016	6016	HRDTS	DISCONNECT,B12L42-2,HRD TS	230 KV	Motor Operated HV Switch (MOD)	191	7	No Level 2 required.			
1325	6017	6017	6017	HRDTS	DISCONNECT,B1L17-1,HRD TS	230 KV	Motor Operated HV Switch (MOD)	192	7	No Level 2 required.			
1325	6018	6018	6018	HRDTS	DISCONNECT,B1B11-1,HRD TS	230 KV	Motor Operated HV Switch (MOD)	193	7	No Level 2 required.			
1325	6019	6019	6019	HRDTS	DISCONNECT,B12T10-1,HRD TS	230 KV	Motor Operated HV Switch (MOD)	194	7	No Level 2 required.			
1325	6020	6020	6020	HRDTS	DISCONNECT,B12L18-1,HRD TS	230 KV	Motor Operated HV Switch (MOD)	195	7	No Level 2 required.			
1325	6021	6021	6021	HRDTS	DISCONNECT,B12B15-2,HRD TS	230 KV	Motor Operated HV Switch (MOD)	196	7	No Level 2 required.			
1325	6022	6022	6022	HRDTS	DISCONNECT,B13B15-2,HRD TS	230 KV	Motor Operated HV Switch (MOD)	197	7	No Level 2 required.			
1325	6023	6023	6023	HRDTS	DISCONNECT,B3L18-2,HRD TS	230 KV	Motor Operated HV Switch (MOD)	198	7	No Level 2 required.			
1325	6024	6024	6024	HRDTS	DISCONNECT,B3L18-1,HRD TS	230 KV	Motor Operated HV Switch (MOD)	199	7	No Level 2 required.			
1325	6025	6025	6025	HRDTS	DISCONNECT,B3B13-1,HRD TS	230 KV	Motor Operated HV Switch (MOD)	200	7	No Level 2 required.			
1325	6026	6026	6026	HRDTS	DISCONNECT,B3B13-2,HRD TS	230 KV	Motor Operated HV Switch (MOD)	201	7	No Level 2 required.			

Table 11-4 Cont'd

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset 2/3	Asset 3/4	Description	Sub System Comment	L2#	Appendix #	Level 2 Work	Year	Priority	Cost k$
1325	6027	6027	6027	HRDTS	DISCONNECT,B13B15-1,HRD TS	230 KV	Motor Operated HV Switch (MOD)	202	7	No Level 2 required.			
1325	6028	6028	6028	HRDTS	DISCONNECT,B12B15-1,HRD TS	230 KV	Motor Operated HV Switch (MOD)	203	7	No Level 2 required.			
1325	6029	6029	6029	HRDTS	DISCONNECT,B1B11-2,HRD TS	230 KV	Motor Operated HV Switch (MOD)	204	7	No Level 2 required.			
1325	6030	6030	6030	HRDTS	DISCONNECT,B11T5,HRD TS	230 KV	Motor Operated HV Switch (MOD)	205	7	No Level 2 required.			
1325	6034	6034	6034	HRDTS	DISCONNECT,B15T6,HRD TS	230 KV	Motor Operated HV Switch (MOD)	206	7	No Level 2 required.			
1325	6035	6035	6035	HRDTS	DISCONNECT,B3T3,HRD TS	230 KV	Motor Operated HV Switch (MOD)	207	7	No Level 2 required.			
1325	6036	6036	6036	HRDTS	DISCONNECT,B15T8,HRD TS	230 KV	Motor Operated HV Switch (MOD)	208	7	No Level 2 required.			
1325	6037	6037	6037	HRDTS	DISCONNECT,B2T2,HRD TS	230 KV	Motor Operated HV Switch (MOD)	209	7	No Level 2 required.			
1325	6038	6038	6038	HRDTS	DISCONNECT,B1T1,HRD TS	230 KV	Motor Operated HV Switch (MOD)	210	7	No Level 2 required.			
1325	6039	6039	6039	HRDTS	DISCONNECT,B15T7,HRD TS	230 KV	Motor Operated HV Switch (MOD)	211	7	No Level 2 required.			
1325	6053	6053	6053	HRDTS	DISCONNECT,B11B13,HRD TS	230 KV	Motor Operated HV Switch (MOD)	212	7	No Level 2 required.			
1325	6546	6546	6546	HRDTS	DISCONNECT,B12L18-2,HRD TS	230 KV	Motor Operated HV Switch (MOD)	213	7	No Level 2 required.			
1325	275789	275789	275789	HRDTS	DISCONNECTS B12L42-1,HRD TS	230 KV	Motor Operated HV Switch (MOD)	214	7	No Level 2 required.			
1325	6031	6031	6031	HRDTS	DISCONNECT,B8T6,HRD TS	138 KV	Motor Operated HV Switch (MOD)	215	7	No Level 2 required.			
1325	6032	6032	6032	HRDTS	DISCONNECT,B8T7,HRD TS	138 KV	Motor Operated HV Switch (MOD)	216	7	No Level 2 required.			
1325	6033	6033	6033	HRDTS	DISCONNECT,B8T8,HRD TS	138 KV	Motor Operated HV Switch (MOD)	217	7	No Level 2 required.			
1325	6040	6040	6040	HRDTS	DISCONNECT,B8L39-2,HRD TS	138 KV	Manual Operated HV Switch	220	7	No Level 2 required.			
1325	6041	6041	6041	HRDTS	DISCONNECT,B8L39-1,HRD TS	138 KV	Manual Operated HV Switch	221	7	No Level 2 required.			
1325	6042	6042	6042	HRDTS	DISCONNECT,B7T5-2,HRD TS	69 KV	Manual Operated HV Switch	222	7	No Level 2 required.			
1325	6043	6043	6043	HRDTS	DISCONNECT,L2L38,HRD TS	69 KV	Manual Operated HV Switch	223	7	No Level 2 required.			

Table 11-4 Cont'd

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset 2/3	Asset 3/4	Description	Sub System Comment	L2#	Appendix #	Level 2 Work	Year	Priority	Cost k$
1325	6044	6044	6044	HRDTS	DISCONNECT,B7L38-1,HRD TS	69 KV	Manual Operated HV Switch	224	7	No Level 2 required.			
1325	6045	6045	6045	HRDTS	DISCONNECT,B7L38-2,HRD TS	69 KV	Manual Operated HV Switch	225	7	No Level 2 required.			
1325	6046	6046	6046	HRDTS	DISCONNECT,B7L2-2,HRD TS	69 KV	Manual Operated HV Switch	226	7	No Level 2 required.			
1325	6047	6047	6047	HRDTS	DISCONNECT,B7L2-1,HRD TS	69 KV	Manual Operated HV Switch	227	7	No Level 2 required.			
1325	6048	6048	6048	HRDTS	DISCONNECT,B6L3-1,HRD TS	69 KV	Manual Operated HV Switch	228	7	No Level 2 required.			
1325	6049	6049	6049	HRDTS	DISCONNECT,B6L3-2,HRD TS	69 KV	Manual Operated HV Switch	229	7	No Level 2 required.			
1325	6050	6050	6050	HRDTS	DISCONNECT,B6B7,HRD TS	69 KV	Manual Operated HV Switch	230	7	No Level 2 required.			
1325	6051	6051	6051	HRDTS	DISCONNECT,B7T5-1,HRD TS	69 KV	Manual Operated HV Switch	231	7	No Level 2 required.			
1325	6052	6052	6052	HRDTS	DISCONNECT,B6T10-1,HRD TS	69 KV	Manual Operated HV Switch	232	7	No Level 2 required.			

11.1.1.8 Capital Projects

The suggested typical capital enhancements for the switchyard switchgear include:

TABLE 11-5 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – SWITCHYARD SWITCHGEAR

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset 2/3	Asset 3/4	Description	CAP#	Appendix #	Capital Item	Date	Priority
1325	5990	5990	310-77-1	HRDB3B13	HRDTS	BREAKER,B3B13,HRD TS	230 KV	168	7	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	5991	5991	310-77-3	HRDB12B15	HRDTS	BREAKER,B12B15,HRD TS	230 KV	169	7	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	5992	5992	460-80 AD/2	HRDB12L18	HRDTS	BREAKER,B12L18,HRD TS	230 KV	170	7	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	5993	5993	310-77-2	HRDB3L18	HRDTS	BREAKER,B3L18,HRD TS	230 KV	171	7	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	5994	5994	170-73-3	HRDB1L17	HRDTS	BREAKER,B1L17,HRD TS	230 KV	172	7	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	5995	5995	310-77-4	HRDB12L42	HRDTS	BREAKER,B12L42,HRD TS	230 KV	173	7	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	5996	5996	188-74-2	HRDB2B11	HRDTS	BREAKER,B2B11,HRD TS	230 KV	174	7	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	5997	5997	188-74-1	HRDB1B11	HRDTS	BREAKER,B1B11,HRD TS	230 KV	175	7	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	5998	5998	170-73-2	HRDB12L17	HRDTS	BREAKER,B12L17,HRD TS	230 KV	176	7	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	5999	5999	170-73-1	HRDB2L42	HRDTS	BREAKER,B2L42,HRD TS	230 KV	177	7	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6000	6000	0464DT72	HRDB6T10	HRDTS	BREAKER,B6T10,HRD TS	69 KV	178	7	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6001	6001	90/K31238935	HRDB12T10	HRDTS	BREAKER,B12T10,HRD TS	230 KV	179	7	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6002	6002	45510DD/1	HRDB13B15	HRDTS	BREAKER,B13B15,HRD TS	230 KV	180	7	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6003	6003	0465DT72	HRDB7T5	HRDTS	BREAKER,B7T5,HRD TS	69 KV	181	7	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6004	6004	61130	HRDB7L2	HRDTS	BREAKER,B7L2,HRD TS	69 KV	182	7	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6005	6005	63257	HRDB8L39	HRDTS	BREAKER,B8L39,HRD TS	138 KV	183	7	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6006	6006	64018	HRDB6L3	HRDTS	BREAKER,B6L3,HRD TS	69 KV	184	7	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6007	6007	61131	HRDB7L38	HRDTS	BREAKER,B7L38,HRD TS	69 KV	185	7	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1

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BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset 2/3	Asset 3/4	Description	CAP#	Appendix #	Capital Item	Date	Priority
1325	6008	6008	6008	HRDB12L17-1	HRDTS	DISCONNECT,B12L17-1,HRD TS	230 KV	189	7	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6009	6009	6009	HRDB12L42-1	HRDTS	DISCONNECT,B12L42-1,HRD TS	230 KV	190	7	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6010	6010	6010	HRDB2L42-1	HRDTS	DISCONNECT,B2L42-1,HRD TS	230 KV	191	7	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6011	6011	6011	HRDB2B11-1	HRDTS	DISCONNECT,B2B11-1,HRD TS	230 KV	192	7	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6012	6012	6012	HRDB2B11-2	HRDTS	DISCONNECT,B2B11-2,HRD TS	230 KV	193	7	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6013	6013	6013	HRDB12L17-2	HRDTS	DISCONNECT,B12L17-2,HRD TS	230 KV	194	7	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6014	6014	6014	HRDB2L42-2	HRDTS	DISCONNECT,B2L42-2,HRD TS	230 KV	195	7	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6015	6015	6015	HRDB1L17-2	HRDTS	DISCONNECT,B1L17-2,HRD TS	230 KV	196	7	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6016	6016	6016	HRDB12L42-2	HRDTS	DISCONNECT,B12L42-2,HRD TS	230 KV	197	7	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6017	6017	6017	HRDB1L17-1	HRDTS	DISCONNECT,B1L17-1,HRD TS	230 KV	198	7	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6018	6018	6018	HRDB1B11-1	HRDTS	DISCONNECT,B1B11-1,HRD TS	230 KV	199	7	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6019	6019	6019	HRDB12T10-1	HRDTS	DISCONNECT,B12T10-1,HRD TS	230 KV	200	7	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6020	6020	6020	HRDB12L18-1	HRDTS	DISCONNECT,B12L18-1,HRD TS	230 KV	201	7	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6021	6021	6021	HRDB12B15-2	HRDTS	DISCONNECT,B12B15-2,HRD TS	230 KV	202	7	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6022	6022	6022	HRDB13B15-2	HRDTS	DISCONNECT,B13B15-2,HRD TS	230 KV	203	7	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6023	6023	6023	HRDB3L18-2	HRDTS	DISCONNECT,B3L18-2,HRD TS	230 KV	204	7	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6024	6024	6024	HRDB3L18-1	HRDTS	DISCONNECT,B3L18-1,HRD TS	230 KV	205	7	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6025	6025	6025	HRDB3B13-1	HRDTS	DISCONNECT,B3B13-1,HRD TS	230 KV	206	7	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6026	6026	6026	HRDB3B13-2	HRDTS	DISCONNECT,B3B13-2,HRD TS	230 KV	207	7	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6027	6027	6027	HRDB13B15-1	HRDTS	DISCONNECT,B13B15-1,HRD TS	230 KV	208	7	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6028	6028	6028	HRDB12B15-1	HRDTS	DISCONNECT,B12B15-1,HRD TS	230 KV	209	7	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6029	6029	6029	HRDB1B11-2	HRDTS	DISCONNECT,B1B11-2,HRD TS	230 KV	210	7	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6030	6030	6030	HRDB11T5	HRDTS	DISCONNECT,B11T5,HRD TS	230 KV	211	7	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6034	6034	6034	HRDB15T6	HRDTS	DISCONNECT,B15T6,HRD TS	230 KV	212	7	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6035	6035	6035	HRDB3T3	HRDTS	DISCONNECT,B3T3,HRD TS	230 KV	213	7	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1

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BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset 2/3	Asset 3/4	Description	CAP#	Appendix #	Capital Item	Date	Priority
1325	6036	6036	6036	HRDB15T8	HRDTS	DISCONNECT,B15T8,HRD TS	230 KV	214	7	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6037	6037	6037	HRDB2T2	HRDTS	DISCONNECT,B2T2,HRD TS	230 KV	215	7	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6038	6038	6038	HRDB1T1	HRDTS	DISCONNECT,B1T1,HRD TS	230 KV	216	7	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6039	6039	6039	HRDB15T7	HRDTS	DISCONNECT,B15T7,HRD TS	230 KV	217	7	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6053	6053	6053	HRDB11B13	HRDTS	DISCONNECT,B11B13,HRD TS	230 KV	218	7	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6546	6546	6546	HRDB12L18-2	HRDTS	DISCONNECT,B12L18-2,HRD TS	230 KV	219	7	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	275789	275789	275789	HRDB12L42-1	HRDTS	DISCONNECTS B12L42-1,HRD TS	230 KV	220	7	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6031	6031	6031	HRDB8T6	HRDTS	DISCONNECT,B8T6,HRD TS	138 KV	221	7	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6032	6032	6032	HRDB8T7	HRDTS	DISCONNECT,B8T7,HRD TS	138 KV	222	7	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6033	6033	6033	HRDB8T8	HRDTS	DISCONNECT,B8T8,HRD TS	138 KV	223	7	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6040	6040	6040	HRDB8L39-2	HRDTS	DISCONNECT,B8L39-2,HRD TS	138 KV	224	7	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6041	6041	6041	HRDB8L39-1	HRDTS	DISCONNECT,B8L39-1,HRD TS	138 KV	225	7	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6042	6042	6042	HRDB7T5-2	HRDTS	DISCONNECT,B7T5-2,HRD TS	69 KV	228	7	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6043	6043	6043	HRDL2L38	HRDTS	DISCONNECT,L2L38,HRD TS	69 KV	229	7	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6044	6044	6044	HRDB7L38-1	HRDTS	DISCONNECT,B7L38-1,HRD TS	69 KV	230	7	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6045	6045	6045	HRDB7L38-2	HRDTS	DISCONNECT,B7L38-2,HRD TS	69 KV	231	7	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6046	6046	6046	HRDB7L2-2	HRDTS	DISCONNECT,B7L2-2,HRD TS	69 KV	232	7	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6047	6047	6047	HRDB7L2-1	HRDTS	DISCONNECT,B7L2-1,HRD TS	69 KV	233	7	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6048	6048	6048	HRDB6L3-1	HRDTS	DISCONNECT,B6L3-1,HRD TS	69 KV	234	7	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6049	6049	6049	HRDB6L3-2	HRDTS	DISCONNECT,B6L3-2,HRD TS	69 KV	235	7	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6050	6050	6050	HRDB6B7	HRDTS	DISCONNECT,B6B7,HRD TS	69 KV	236	7	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6051	6051	6051	HRDB7T5-1	HRDTS	DISCONNECT,B7T5-1,HRD TS	69 KV	237	7	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6052	6052	6052	HRDB6T10-1	HRDTS	DISCONNECT,B6T10-1,HRD TS	69 KV	238	7	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1

11.1.2 Asset 1325: 5975 to 5989 – Transformers

(Detailed Technical Assessment in Working Papers, Appendix 5)

Unit #:	1,2,3, Common, Holyrood Switchyard
Asset Class #	BU 1296 – Assets Generation BU 1297 – Assets Commons BU 1325 – Assets Holyrood Switchyard
Components:	BU1325 5975 Unit 1 T1 Power Transformer BU1325 5976 Unit 2 T2 Power Transformer BU1325 5977 Unit 3 T3 Power Transformer BU1325 5978 Transformer T4 (spare) BU1325 5979 Transformer T5 BU1325 5980 Transformer T6 BU1325 5981 Transformer T7 BU1325 5982 Transformer T8 BU1325 5983 Transformer T9 BU1325 5984 Transformer T10 BU1325 6726 Unit 1 Service Power System UST-1 Transformer BU1325 8156 Unit 2 Service Power System UST-2 Transformer BU1325 8716 Unit 3 Unit Service Power System UST-3 Transformer BU1325 6727 Common Stage 1 Station Service Power SST-12 Trans BU1325 5989 Common Stage 2 Station Service Power SST-34 Trans BU 1296 271311 RT1 Unit 1 Rectifying Transformer BU 1296 271324 RT2 Unit 2 Rectifying Transformer BU 1296 271680 RT3 Unit 3 Rectifying Transformer

There are transformers within the Holyrood plant that are managed by plant operations (the unit rectifying transformers), and transformers outside the plant that are managed by the Transmission and Rural Operations (TRO) group. The requirements for the transformers vary depending on their role, but most will be required to operate until the year 2041. The station has a spare power transformer on site. It was installed as the Unit 2 transformer in 1970, and made the spare as part of the Unit 1 and 2 upgrade to provide some measure of reliability.

Main Power Transformers	**T1** **Unit 1**	**T2** **Unit 2**	**T3** **Unit 3**
Manufactured/Delivered	1969	1970	1979
In-Service Date	Sep 1970	Apr 1971	Feb 1980
Replaced	1987	1987	N/A
Generation Peak/Emerg Gen End Date	Dec 2020		
Synchronous Condensing Start Date	Jan 2015	Jan 2015	1986
Synchronous Condensing End Date	Dec 2041	Dec 2041	Dec 2041
Last Major Overhaul/Inspection	See Condition Assessment		

FIGURE 11-4 UNIT 1 T1

FIGURE 11-5 UNIT 2 T2

FIGURE 11-6 UNIT 3 T3

11.1.2.1 Description

Asset 5975 Unit 1 T1 Power Transformer

The present T1 transformer was manufactured by Trafo-Union, Germany and installed at the T1 location in 1988. It was located originally at the T3 location, being installed there in 1979. It is a 105/140/180 MVA, Star-Delta, 230kV:16kV, ONAN/ONAF/OFAF, with tap-changer of +2@4.35%, -1@4.35%, Yd1, Z1=13.6%, Z0=11.7%. T1 transforms the electricity from the Unit 1 generator from 16kV to 230kV.

Asset 5976 Unit 2 T2 Power Transformer

The T2 transformer was manufactured by Federal Pioneer and installed in 1989, and is a 115/152/190 MVA, Star-Delta, 230kV:16kV, ONAN/ONAF/ONAF, with primary tap-changer of +2@4.35%, -1@4.35%, Yd1, Z1=13.7%, Z0=11.75%. This transformer was a replacement for the original T2 transformer that had been installed in 1970. This original 170 MVA T2 transformer is now designated as T4 and is kept as a spare. T2 transforms the electricity from the Unit 2 generator from 16kV to 230kV.

Asset 5977 Unit 3 T3 Power Transformer

The present T3 transformer was manufactured by General Electric and installed at the T3 location in 1978. It was located originally at the T1 location, being installed there in 1970. It is a 170 MVA, Star-Delta, 230kV:16kV, OFAF, +2@4.35%, -1@4.35%, Yd1, Z1=13.5%. T3 transforms the electricity from the Unit 3 generator from 16kV to 230kV.

Asset 5978 Transformer T4 (spare)

The present T4 (spare) transformer was manufactured by Canadian General Electric and installed in its current location in 1988. It was located originally at the T2 location, being installed there in 1970. It is a 115/152/170 MVA, Delta-Wye, 230kV:16kV, oil cooled. It can replace T1, T2, or T3, provided the output is limited to 170 MVA.

Asset 5979 Transformer T5

T5 transformer was manufactured by Westinghouse and installed in 1969. It is a 15/20/25 MVA, Delta-Wye, 230kV:69kV, oil cooled. It is located between Bus 7 and Bus 11, providing 69kV power, along with T10, to the Station Board SB12 through transformer SST12 and seal core.

Asset 5980 Transformer T6

T6 transformer was manufactured by Canadian General Electric in 1960. It is a 25/33.3/41.7 MVA, ONAN/ONAF/ONAF, Wye-Wye, 230kV:138kV, with primary tap-changer of +4@1.25%, -12@1.25%, Yd, Z1=7.5%. Along with T7 and T8, it is one of three transformers between 230kV Bus 15 and 138KV Bus 8 which supplies power to Line 39L to Whitbourne.

Asset 5981 Transformer T7

T7 transformer was manufactured by Canadian General Electric pre 1974. It is a 25/33.3/41.7 MVA, ONAN/ONAF/ONAF, Wye-Wye, 230kV:138kV, with primary tap-changer of +4@1.25%, -12@1.25%, Yd, Z1=7.5%. Along with T6 and T8, it is one of three transformers between 230kV Bus 15 and 138KV Bus 8 which supplies power to Line 39L to Whitbourne.

Asset 5982 Transformer T8

T8 transformer was manufactured by Federal Pioneer in 1989. It is a 75/100/125 MVA, ONAN/ONAF/ONAF, Wye-Wye, 230kV:138kV, oil cooled. Along with T6 and T7, it is one of three transformers between 230kV Bus 15 and 138KV Bus 8 which supplies power to Line 39L to Whitbourne.

Asset 5982 Transformer T9

T9 transformer was manufactured by Federal Pioneer in 1970. It is a 10.5/14 MVA, ONAN/ONAF, Wye-Delta, 13.8kV:4160Y/2400V, resistance grounded, with primary tap-changer of +2@2.5%, -2@2.5%, Dy1, Z1=7.5%. T9 transforms the electricity from the gas turbine generator to the Station Board SB12.

Asset 5983 Transformer T10

T10 transformer was manufactured by Federal Pioneer in 1990. It is a 15/20/25 MVA, ONAN/ONAF/ONAF, Wye-Delta, 230kV:69kV. T10 is located between Bus B11 and B6, providing 69kV power, along with T5, to the Station Board SB12 through Transformer SST12 and to seal core.

Asset 6726 Unit 1 Service Power System, UST-1 Transformer

The UST-1 transformer was manufactured by Federal Pioneer, installed in 1969 and is 10MVA, Star-Delta, resistance grounded, ONAN, 16kV:4160/2400V, with primary tap-changer, +2@2.5%, -2@2.5%, Dy1. UST-1 is located between the Unit 1 generator and the 4160V Unit Board UB1.

Asset 8156 Unit 2 Service Power System, UST-2 Transformer

The UST-2 transformer was manufactured by Federal Pioneer, installed in 1969 and is 10MVA, Star-Delta, resistance grounded, ONAN, 16kV:4160/2400V, with primary tap-changer +2@2.5%, -2@2.5%, Dy1. UST-2 is located between the Unit 2 generator and the 4160V Unit Board UB2

Asset 8716 Unit 3 Unit Service Power System, UST-3 Transformer

The UST-3 transformer was manufactured by General Electric, installed in 1978 and is 10MVA, Star-Delta, resistance grounded, ONAN, 16kV:4160/2400V, with primary tap-changer +2@2.5%, -2@2.5%, Dy1, Z1-6%. UST-3 is located between the Unit 3 generator and the 4160V Unit Board UB3

Asset 6727 Common Stage 1 Station Service Power. SST-12 Trans

The SST-12 transformer was manufactured by Federal Pioneer, installed in 1969, and is a 10.5/14MVA, Star-Delta, resistance grounded, ONAN/ONAF, 69kV:4160/2400V, with primary tap-changer +2@2.5%, -2@2.5%, Dy1, Z1-6.86%. SST12 is located between Bus 2 (which can take power from Bus 6 or Bus 7) and the 4160V Station Board SB12.

Asset 5989 Common, Stage 2 Station Service Power, SST-34 Trans.

The SST-34 transformer was manufactured by Westinghouse, installed in 1978 and is a 10.5/14MVA, Star-Delta, resistance grounded, ONAN/ONAF, 69kV:4160/2400V, with primary tap-changer +2@2.5%, -2@2.5%, Dy1, Z1-6%. SST34 is located between Bus 3 (which can take power from Bus 6 or Bus 7) and the 4160V Station Board SB34.

Asset 271311 RT1 Unit 1 Rectifying Transformer

Rectifying Transformer RT1 was manufactured by CGE, installed in 1969, and is a 2154/1077kVA, LNAN, 16000:750:575 Tertiary, oil filled type. Original Askarel oil was changed in 2004 to Perchloroethylene with below 50mg/kg PCB's. RT1 is part of the Unit 1 generator exciter.

Asset 271324 RT2 Unit 2 Rectifying Transformer

Rectifying Transformer RT2 was manufactured by CGE, installed in 1969, and is a 2154/1077kVA, LNAN, 16000:750:575 Tertiary, oil filled type. Original Askarel oil was changed in 2004 to Perchloroethylene with below 50mg/kg PCB's. RT2 is part of the Unit 2 generator exciter.

Asset 271680 RT3 Unit 3 Rectifying Transformer

Rectifying Transformer RT3 was manufactured by FPE, installed in 1979, and is a 1400 kVA, 16000: 575V, dry type. It is installed as part of Unit 3 exciter system.

11.1.2.2 Inspection and Repair History

The following information covers the transformers outside the building and in the switchyard, and Units 1, 2 and 3 excitation transformers inside the building. Planned maintenance (PM) and corrective action (CA) sheets are available for the transformer equipment.

Scheduled maintenance for the transformer equipment is as follows:

- 6 year detailed Planned Maintenance;
- Thermography tests each year;
- Visual inspections every 4 months; and
- Annual oil sampling.

Transformer insulating oil test results versus the Institute of Electrical and Electronics Engineers (IEEE) recommendations and standards are given for each section. It should be noted that NL Hydro TRO transmission system staff indicated that AMEC used a reference to an IEEE standard with parameters of new oil whereas NL Hydro use an IEEE standard for in service transformer oil (IEEE Standard 637 Guideline which has parameters for Reclaimed Transformer Oil). NL Hydro also uses SD Myers Transformer Maintenance Institute parameters for evaluating oil quality for in service transformer oil. NL Hydro's practice is in fact standard practice within the electric utility sector.

TRO maintains a significant and regularly scheduled transformer maintenance and inspection program. Shifts in document management have made it difficult to find records of the results of all of the work that have been performed in the last five to seven years. Some work on Hydro's standard work sheets has not been completed, for which there may be many valid reasons. Given the age of the equipment, more rigorous testing and monitoring/trending of equipment condition will be necessary. Monitoring and trending of unusual system disturbances or environmental events such as lightning strikes needs more attention.

Asset 5975 Unit 1 T1 Power Transformer

Doble tests and PM were completed in 2000 and 2005. Given a six year test cycle, no more recent PM or tests are expected before 2011. Typical maintenance request sheets were reviewed, but not all work was indicated as having been done (for which there can be many valid reasons) Maintenance completed during years 2000 to 2005 included some fan maintenance, various gauge/relay maintenance, and pump maintenance. Silica gel was replaced in 2007. No other maintenance was identified for the period from

2005 to present, except for T1 oil reclamation in 2008, were identified (Closed PM Work Order in 2008 subsequently identified). Transformer maintenance history sheets were available from July 1979 to June 2005. Reference "Significant Work Performed" identified by work orders in JD Edwards (JDE) database for maintenance history.

Asset 5976 Unit 2 T2 Power Transformer

Doble tests were completed in 2002, but there was no record available to AMEC of more recent tests that would have been completed in 2008. Maintenance records were reviewed indicating work carried out during years 2000 to 2006, including the fans. No indication of similar maintenance was available for 2007 to present. Silica gel was replaced in 2002 and 2007. T2 had its oil reclaimed in 2008. Six year planned maintenance sheets are originally available for 2009. The last PM date was subsequently identified as 2009, same as oil test date.

Asset 5977 Unit 3 T3 Power Transformer

Doble tests were completed in 2002, but there was no record available to AMEC of more recent tests that would have been completed in 2008. Typical maintenance has been recorded as completed during years 2008 and 2009 for various gauge/relay maintenance, pump maintenance and structural work, but there are no records available and reviewed by AMEC of other maintenance prior to 2008. Radiators were replaced in 2003, 2005 and 2008. Silica gel was replaced in 2008. The latest planned maintenance was in 2002, with no outstanding remarks originally. Reference "Significant Work Performed" identified by work orders in the JDE database for maintenance history. The last PM date was identified subsequently as 2010.

Asset 5978 Transformer T4 (spare)

Doble tests were completed in 2004. Radiators were replaced in 2007 and silica gel was replaced in 2008. Planned maintenance was performed in 2004.

Asset 5979 Transformer T5

Doble tests were completed in 2001 and 2009. Maintenance has been recorded as completed during years 2000 to 2005 for fan maintenance and various gauge/relay maintenance. Silica gel was replaced in 2002 and the transformer was sanded and painted in 2003. Lightning arrestors were replaced and Doble tested in 2007. The latest planned maintenance was completed in 2009.

Asset 5980 Transformer T6

Doble tests were completed in 2002 and 2009. Maintenance has been recorded as completed during years 2007 and 2008 for various gauge/relay maintenance. Lightning arrestor were replaced in 2007. The latest planned maintenance was completed in 2007.

Asset 5981 Transformer T7

Doble tests were completed in 2002. Maintenance has been recorded as completed during years 2003, 2007 and 2008 for various gauge/relay and pressure switch maintenance. Silica gel was replaced in 2002, 2006 and 2008. Structural work was completed in 2003 and 2008. The lightning counter was removed in 2004 and the lightning arrestor was replaced in 2007. The latest planned maintenance was completed 2007.

Asset 5982 Transformer T8

Doble tests were completed in 2001. Maintenance has been recorded as completed during years 2004 and 2008 for various gauge/relay and fan maintenance. Silica gel was replaced in 2007 and 2008. Structural work was completed in 2008. TRO Central subsequently identified that T8 also had a tap changer overhaul in 2009. The latest planned maintenance was performed in 2008.

Asset 5982 Transformer T9

Doble tests were completed in 2001. Maintenance has been recorded as completed during years 2000, 2004 and 2006 for various gauge/relay maintenance. A dielectric test was performed in 1983 and silica gel was replaced in 2002. The latest planned maintenance was completed in 2006.

Asset 5983 Transformer T10

Doble tests were completed in 2000. The transformer was sanded and painted in 2001. In 2004, the gas relay was repaired, silica gel was replaced and the lightning counter was removed. The lightning arrestor was repaired in 2007. The latest planned maintenance was completed in 2006.

Asset 6726 Unit 1 Service Power System UST-1 Transformer

The following maintenance has been recorded as completed: Doble tested in 2000, winding temperature gauge repaired in 2000, and silica gel replaced in 2003 and 2008. The last planned maintenance routine was performed in 2004.

Asset 8156 Unit 2 Service Power System UST-2 Transformer

The following maintenance has been recorded as completed: Doble tested in 2002, oil level gauge and radiators repaired in 2003, silica gel replaced in 2006, and winding temperature relay and winding temperature gauge replaced in 2007. Planned maintenance was performed in 2007.

Asset 8716 Unit 3, Unit Service Power System UST-3 Transformer

The following maintenance has been recorded as completed: Doble tested in 2000 and 2006, structural work in 2001, silica gel replaced in 2002 and 2008, and gas relay, oil level gauge, and radiator replaced in 2007. The control cabinet was repaired in 2008. Planned maintenance was performed in 2006.

Asset 6727 Common Stage 1 Station Service Power SST-12 Trans

Completed test sheets for Transformer SST12 Protection dated 2006 were available and the results were satisfactory at the time of the inspection. Relays and cases required cleaning due to ingress of dust and foreign material. The following maintenance has been recorded as completed: 69kV cable repaired, Doble test and pothead and silica gel replaced in 2002, fan motor replaced in 2003, structural work completed in 2004, and oil level gauge and radiators replaced in 2009. Planned maintenance was performed in 2009.

Asset 5989 Common Stage 2 Station Service Power SST-34 Trans

The following maintenance has been recorded as completed: Insulator replaced in 1999; Doble tested in 2000 and 2006, silica gel replaced in 2002 and 2007, oil temperature gauge replaced in 2004, and oil leak in conservator repaired in 2009. Planned maintenance was performed in 2006. Completed test sheets for Transformer SST34 Protection dated 2007/2008 indicate reasonable tolerances.

Asset 271311 Transformer RT1 Unit 1 Rectifying Transformer

Original Askarel oil was changed to Perchloroethylene (with <50mg/kg PCB's) in 2004. Completed Test Plan Activity sheets dated 2005 are available for RT1 protection, with satisfactory results at this time.

Asset 271324 Transformer RT2 Unit 2 Rectifying Transformer

Original Askarel oil was changed to Perchloroethylene (with <50mg/kg PCB's) in 2004. Completed Test Plan Activity sheets dated 2006 are available for RT2 protection, with satisfactory results at this time.

Asset 271680 Transformer RT3 Unit 3 Rectifying Transformer

Completed Test Plan Activity sheets dated 2007 for RT3 protection indicate satisfactory results at this time.

11.1.2.3 Condition Assessment

Overall the equipment is in reasonable good shape for its age, but an adequate sparing, testing/monitoring refurbishment and replacement program should be part of the focus, along with more rigorous and probably more frequent inspections and testing. The condition assessment of the transformers is illustrated below in Table 11-6.

TABLE 11-6 CONDITION ASSESSMENT – TRANSFORMERS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset Level 2	Asset Level 3	Description	Detail	Cond. Summ. ID#	Append #	Condition	EPRI Identifier	Original Life (Base Load) Ops Hrs (Yrs)	Current Expected Minimum Remaining Life Years (Subject to Test)	End of Life Required (EOL)	Next Regular Inspection	Next Planned Overhaul/ Major Inspection	Capability to Reach Next Overhaul	Capability to Reach EOL	In Service
1325	5975	5975	303236	HRDT1	HRDTS	TRANSFORMERS	T1 POWER TRANSFORMER	230 KV	162	6,7	Installed in 1979, the "generic age" risk of transformer failure is fairly high and rising. There has been an unusual and noticeable increase in the moisture level during the past 6 months before the test in 2009. This may be a indication that the oil needs to be reconditioned, despite oil reclaim in 2008. Moisture Remarks in the 2009 Fluid Analysis Report also deems the relative saturation as high, indicating it might be due to a recent temperature drop, moist cellulose or increased water solubility in aged oil.	4	(45)	15	2041	2014	2014	Yes	No	1979
1325	5976	5976	61-00-69225	HRDT2	HRDTS	TRANSFORMERS	T2 POWER TRANSFORMER	230 KV	163	6,7	Installed in 1989, the "generic age" risk of transformer failure is low, but approaching the zone of higher risk growth. The higher oil color number could be an indication of the possible start of contaminations, and the higher power factor at 100 degrees Celsius indicates higher power loss when under operation. Moisture Remarks in the 2009 Fluid Analysis Report indicates the water content of the oil being acceptable. (Last PM date subsequently identified as 2009, same as oil test date.)	4	(45)	25	2041	2013	2013	Yes	No	1989
1325	5977	5977	287198	HRDT3	HRDTS	TRANSFORMERS	T3 POWER TRANSFORMER	230 KV	164	6,7	Installed in 1978 originally on Unit 1, the "generic age" risk of transformer failure is fairly high and rising. The last electrical test were in 2002. 2009 oil tests showed higher power factors at 25 and 100 degrees Celsius which indicate higher power loss. The interfacial tension of the oil shows a lower value than that of the IEEE standards which suggests the oil has a higher solubility of polar contaminants and oxidation products and it is likely the cause of the high color number. Scheduled maintenance seems over-due since 2008. (Last PM date identified subsequently as 2010).	4	(45)	15	2041	2016	2016	Yes	No	1978
1325	5978	5978	287199	HRDT4	HRDTS	TRANSFORMERS	TRANSFORMER T4 (spare)	230 KV	165	6,7	Installed in 1970 on Unit 1 and then moved as the spare transformer in 1988, its generic age risk is fairly high. Electrical Doble tests and planned maintenance were last done in 2004. Radiators were replaced in 2007. Silica gel replaced in 2008. The condition is somewhat uncertain.	4	(45)	20	2041	2011	2011	Yes	No	1970-1988
1325	5979	5979	A-3-S-7520	HRDT5	HRDTS	TRANSFORMERS	TRANSFORMER T5	230 KV	166	6,7	Installed in 1969, the unit is at a high level of risk on the basis of its time in service. No significant issues were identified in Doble tests done in 2001 and 2009. Lightning arrestors were replaced and doble tested in 2007. Planned Maintenance was done in 2009. 2009 insulating oil test results indicates higher power loss, and a higher solubility of polar contaminants and oxidation products.	4	(45)	5	2041	2015	2015	Yes	No	1969
1325	5980	5980	287065	HRDT6	HRDTS	TRANSFORMERS	TRANSFORMER T6	230 KV	167	6,7	Installed in 1960. the unit is at a high level of risk given its time in service. No significant issues were identified in Doble tests done in 2002 and 2009. Maintenance in 2007 and 2008 for various gauges/relays and lightning arrestor replaced in 2007. 2009 insulation oil tests suggests greater thermal decomposition of cellulose, higher power loss when under operation, and a higher solubility of polar contaminants and oxidation products (possible cause of the low dielectric breakdown voltage).	4	(45)	5	2041	2013	2013	Yes	No	1960
1325	5981	5981	287064	HRDT7	HRDTS	TRANSFORMERS	TRANSFORMER T7	230 KV	168	6,7	Installed pre-1974, the unit is at a high level of risk given its time in service. No significant issues were identified in Doble tests in 2002. Maintenance in 2003, 2007 and 2008 for various gauges/relays and pressure switches. Silica gel was replaced in 2002, 2006 and 2008. Lightning arrestor replaced in 2007. Structural work was done in 2003 and 2008. Latest Planned Maintenance was in 2007. Insulating oil tests in 2009 suggests thermal decomposition of cellulose, higher power loss when under operation, and a higher solubility of polar contaminants and oxidation products (potential cause of the low dielectric breakdown voltage).	4	(45)	10	2041	2013	2013	Yes	No	1974
1325	5982	5982	61-00-68928	HRDT8	HRDTS	TRANSFORMERS	TRANSFORMER T8	230 KV	169	6,7	Installed in 1989, the unit is at a relatively low level of risk. No significant issues were identified in Doble tests in 2001. Maintenance in 2004 and 2008 was for various gauges/relays and fans. Silica gel was replaced in 2007 and 2008. Structural and planned maintenance work was completed in 2008. TRO Central subsequently identified that T8 also had a tap changer overhaul in 2009. Insulating oil tests in 2009 suggests thermal decomposition of cellulose, higher power loss when under operation, and a higher solubility of polar contaminants and oxidation products.	4	(45)	25	2041	2014	2014	Yes	Yes	1989
1325	5983	5983	61-00-69576	HRDT9	HRDTS	TRANSFORMERS	TRANSFORMER T9	13.8 kV	170	6,7	Installed in 1970, the unit is at a high level of risk due to its age. No significant issues were identified in Doble tests last done in 2001. Maintenance in 2000, 2004 and 2006 was for various gauges/relays. Silica gel was replaced in 2002 and a Dielectric test performed in 1983. The latest Planned Maintenance was in 2006. Insulating oil tests in 2009 suggests higher power loss when under operation, and also the oil has a higher solubility of polar contaminants and oxidation products.	4	(45)	5	2041	2012	2012	Yes	No	1970
1325	5984	5984	61-00-69576	HRDT10	HRDTS	TRANSFORMERS	TRANSFORMER T10	230 KV	171	6,7	Installed in 1990, the unit is at a low level of risk due to its age. No significant issues were identified in Doble tests done in 2000. A gas relay was repaired in 2004 and silica gel was replaced in 2004. Its lightning arrestor was repaired in 2007. Latest Planned Maintenance was in 2006. The 2009 insulating oil test suggests thermal decomposition of cellulose, higher power loss when under operation, and higher solubility of polar contaminants and oxidation products (potential cause of the low dielectric breakdown voltage).	4	(45)	25	2041	2012	2012	Yes	Yes	1990
1325	5985	5989	A-3-S-7608	HRDUST-1	HRDTS	TRANSFORMERS	UST-1 TRANSFORMER	69 KV	172	6,7	Installed in 1969, the unit has a relatively high level of risk due to its age. No significant issues were identified in Doble tests in 2000. Its Winding temperature gauge repaired in 2000 and silica gel replaced in 2003 and 2008. Last planned maintenance performed in 2004. 2009 insulating oil tests indicate higher power loss, and a higher solubility of polar contaminants and oxidation products.	4	(45)	5	2041	2010	2010	Yes	No	1969
1325	5986	5986	N/A	HRDUST-2	HRDTS	TRANSFORMERS	UST-2 TRANSFORMER	69 KV	173	6,7	Installed in 1969, the unit has a relatively high level of risk due to its age. No significant issues were identified in Doble tests in 2002. Maintenance: oil level gauge repaired in 2003, radiators in 2003, winding temperature relay replaced in 2007, winding temperature gauge replaced in 2007, silica gel replaced in 2006. Planned maintenance performed in 2007. 2009 insulating oil tests indicate higher power loss, and a higher solubility of polar contaminants and oxidation products.	4	(45)	5	2041	2013	2013	Yes	No	1969

Table 11-6 Cont'd

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset Level 2	Asset Level 3	Description	Detail	Cond. Summ. ID#	Append #	Condition	EPRI Identifier	Original Life (Base Load) Ops Hrs (Yrs)	Current Expected Minimum Remaining Life Years (Subject to Test)	End of Life Required (EOL)	Next Regular Inspection	Next Planned Overhaul/ Major Inspection	Capability to Reach Next Overhaul	Capability to Reach EOL	In Service
1325	5987	5987	N/A	HRDUST-3	HRDTS	TRANSFORMERS	UST-3 TRANSFORMER	69 KV	174	6,7	Installed in 1978, the unit has a relatively high level of risk due to its age. No significant issues were identified in Doble tests in 2000 and 2006. Maintenance: structural work in 2001, silica gel in 2002 and 2008, oil level gauge in 2007, radiator replaced in 2007, gas relay in 2007, and control cabinet repaired in 2008. Planned maintenance performed in 2006. 2009 insulating oil tests suggest higher power loss, a higher solubility of polar contaminants and oxidation products and a steady trend of decrease re performance of the transformer.	4	(45)	15	2041	2013	2013	Yes	No	1978
1325	5988	5988	WT-1976-1	HRDSST-12	HRDTS	TRANSFORMERS	STAGE 1 SST-12 TRANSFORMER	69 KV	175	6,7	Installed in 1969, the unit has a relatively high level of risk due to its age. No significant issues were identified in Doble tests in 2002. Maintenance: 69kV cable repaired in 2002, pothead replaced in 2002, silica gel replaced in 2002, fan motor replaced in 2003, structural work done in 2004, oil level gauge replaced in 2009, and radiators replaced in 2009. Planned maintenance performed in 2009. 2009 insulating oil tests indicate higher power loss, and a higher solubility of polar contaminants and oxidation products.	4	(45)	5	2041	2015	2015	Yes	No	1969
1325	5989	5989	A-3-S-7608	HRDSST-34	HRDTS	TRANSFORMERS	STAGE 2 SST-34 TRANSFORMER	69 kV	176	6,7	Installed in 1978, the unit has a moderately high level of risk due to its age. No significant issues were identified in Doble tests in 2000 and 2006. Maintenance: insulator replaced in 1999, silica gel replaced in 2002 and 2007, oil temperature gauge replaced in 2004, and an oil leak in conservator repaired in 2009. Planned maintenance performed in 2006. .2009 insulating oil tests indicate a higher solubility of polar contaminants and oxidation products.	4	(45)	15	2041	2012	2012	Yes	No	1978

Notes:

1. A "(bracketed)" value in the "Current Expected Remaining Life" column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation, including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as "(X/Y)" has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

2. The "Next Regular Inspection" column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The "Next Planned Overhaul or Major Inspection" column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a "Desired Life" stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where no specific dates have been identified for "Next Regular Inspection" or "Next Planned Overhaul/Major Inspection", they are left blank.

. 3. Hydro TRO transmission system staff indicated that AMEC used a reference to an IEEE standard with parameters of new oil whereas NL Hydro use an IEE standard for in service transformer oil (IEEE Standard 637 Guideline which has parameters for Reclaimed Transformer Oil). NL Hydro also use SD Myers Transformer Maintenance Institute parameters for evaluating oil quality for in service transformer oil. AMEC's primary interest is that oil analyses be continued and indeed enhanced to allow trending and analyses of results as the units age.

11.1.2.4 Actions

Based on the condition assessment, the following actions are recommended for the transformers:

TABLE 11-7 RECOMMENDED ACTIONS – TRANSFORMERS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset 2/3	Asset 3/4	Description	Action #	App #	Action	Year	Priority
1325					HRDTS	TRANSFORMERS	TRANSFORMERS	262	6,7	Develop programs dealing with testing, overhauling, retrofitting, and modifications to extend the life of all transformers to 2041,	2012	1
1325	5975	5975	303236	N/A	HRDTS	TRANSFORMERS	T1 POWER TRANSFORMER	263	6,7	Implement all requirements of Transformer Maintenance History Sheets. Comparative analyses with previous history.	2014	1
1325	5976	5976	61-00-69225	N/A	HRDTS	TRANSFORMERS	T2 POWER TRANSFORMER	264	6,7	Implement all requirements of Transformer Maintenance History Sheets. Comparative analyses with previous history.	2013	1
1325	5977	5977	287198	N/A	HRDTS	TRANSFORMERS	T3 POWER TRANSFORMER	265	6,7	Implement all requirements of Transformer Maintenance History Sheets. Comparative analyses with previous history.	2016	1
1325	5978	5978	287199	N/A	HRDTS	TRANSFORMERS	TRANSFORMER T4 (spare)	266	6,7	Implement all requirements of Transformer Maintenance History Sheets. Comparative analyses with previous history.	2011	1
1325	5979	5979	A-3-S-7520	N/A	HRDTS	TRANSFORMERS	TRANSFORMER T5	267	6,7	Implement all requirements of Transformer Maintenance History Sheets. Comparative analyses with previous history.	2015	1
1325	5980	5980	287065	N/A	HRDTS	TRANSFORMERS	TRANSFORMER T6	268	6,7	Implement all requirements of Transformer Maintenance History Sheets. Comparative analyses with previous history.	2013	1
1325	5981	5981	287064	N/A	HRDTS	TRANSFORMERS	TRANSFORMER T7	269	6,7	Implement all requirements of Transformer Maintenance History Sheets. Comparative analyses with previous history.	2013	1
1325	5982	5982	61-00-68928	N/A	HRDTS	TRANSFORMERS	TRANSFORMER T8	270	6,7	Implement all requirements of Transformer Maintenance History Sheets. Comparative analyses with previous history.	2014	1
1325	5983	5983	61-00-69576	N/A	HRDTS	TRANSFORMERS	TRANSFORMER T9	271	6,7	Implement all requirements of Transformer Maintenance History Sheets. Comparative analyses with previous history.	2012	1
1325	5984	5984	61-00-69576	N/A	HRDTS	TRANSFORMERS	TRANSFORMER T10	272	6,7	Implement all requirements of Transformer Maintenance History Sheets. Comparative analyses with previous history.	2012	1
1325	5985	5985	N/A	N/A	HRDTS	TRANSFORMERS	UST-1 TRANSFORMER	273	6,7	Implement all requirements of Transformer Maintenance History Sheets. Comparative analyses with previous history.	2010	1
1325	5986	5986	N/A	N/A	HRDTS	TRANSFORMERS	UST-2 TRANSFORMER	274	6,7	Implement all requirements of Transformer Maintenance History Sheets. Comparative analyses with previous history.	2013	1
1325	5987	5987	N/A	N/A	HRDTS	TRANSFORMERS	UST-3 TRANSFORMER	275	6,7	Implement all requirements of Transformer Maintenance History Sheets. Comparative analyses with previous history.	2013	1
1325	5988	5988	WT-1976-1	N/A	HRDTS	TRANSFORMERS	STAGE 1 SST-12 TRANSFORMER	276	6,7	Implement all requirements of Transformer Maintenance History Sheets. Comparative analyses with previous history.	2015	1
1325	5989	5989	A-3-S-7608	N/A	HRDTS	TRANSFORMERS	STAGE 2 SST-34 TRANSFORMER	277	6,7	Implement all requirements of Transformer Maintenance History Sheets. Comparative analyses with previous history.	2012	1

Table 11-7 Cont'd

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset 2/3	Asset 3/4	Description	Action #	App #	Action	Year	Priority
1325	5975	5975	303236	N/A	HRDTS	TRANSFORMERS	T1 POWER TRANSFORMER	280	6,7	Dissolved gas analysis and oil quality tests and analysis, including previous years.	2010	1
1325	5976	5976	61-00-69225	N/A	HRDTS	TRANSFORMERS	T2 POWER TRANSFORMER	281	6,7	Dissolved gas analysis and oil quality tests and analysis, including previous years.	2010	1
1325	5977	5977	287198	N/A	HRDTS	TRANSFORMERS	T3 POWER TRANSFORMER	282	6,7	Dissolved gas analysis and oil quality tests and analysis, including previous years.	2010	1
1325	5978	5978	287199	N/A	HRDTS	TRANSFORMERS	TRANSFORMER T4 (spare)	283	6,7	Dissolved gas analysis and oil quality tests and analysis, including previous years.	2010	1
1325	5979	5979	A-3-S-7520	N/A	HRDTS	TRANSFORMERS	TRANSFORMER T5	284	6,7	Dissolved gas analysis and oil quality tests and analysis, including previous years.	2010	1
1325	5980	5980	287065	N/A	HRDTS	TRANSFORMERS	TRANSFORMER T6	285	6,7	Dissolved gas analysis and oil quality tests and analysis, including previous years.	2010	1
1325	5981	5981	287064	N/A	HRDTS	TRANSFORMERS	TRANSFORMER T7	286	6,7	Dissolved gas analysis and oil quality tests and analysis, including previous years.	2010	1
1325	5982	5982	61-00-68928	N/A	HRDTS	TRANSFORMERS	TRANSFORMER T8	287	6,7	Dissolved gas analysis and oil quality tests and analysis, including previous years.	2010	1
1325	5983	5983	61-00-69576	N/A	HRDTS	TRANSFORMERS	TRANSFORMER T9	288	6,7	Dissolved gas analysis and oil quality tests and analysis, including previous years.	2010	1
1325	5984	5984	61-00-69576	N/A	HRDTS	TRANSFORMERS	TRANSFORMER T10	289	6,7	Dissolved gas analysis and oil quality tests and analysis, including previous years.	2010	1
1325	5985	5985	N/A	N/A	HRDTS	TRANSFORMERS	UST-1 TRANSFORMER	290	6,7	Dissolved gas analysis and oil quality tests and analysis, including previous years.	2010	1
1325	5986	5986	N/A	N/A	HRDTS	TRANSFORMERS	UST-2 TRANSFORMER	291	6,7	Dissolved gas analysis and oil quality tests and analysis, including previous years.	2010	1
1325	5987	5987	N/A	N/A	HRDTS	TRANSFORMERS	UST-3 TRANSFORMER	292	6,7	Dissolved gas analysis and oil quality tests and analysis, including previous years.	2010	1
1325	5988	5988	WT-1976-1	N/A	HRDTS	TRANSFORMERS	STAGE 1 SST-12 TRANSFORMER	293	6,7	Dissolved gas analysis and oil quality tests and analysis, including previous years.	2010	1
1325	5989	5989	A-3-S-7608	N/A	HRDTS	TRANSFORMERS	STAGE 2 SST-34 TRANSFORMER	294	6,7	Dissolved gas analysis and oil quality tests and analysis, including previous years.	2010	1
1296	6690	6691	6696	6849	U1 GENERATOR	GENERATOR EXCITATION SYSTEM	RT1, UNIT 1 RECTIFYING TRANSFORMER	296	6,7	Align with current PCB Regulation SOR/2008-273, posted in the CEPA Environmental Registry as required .	2013	1
1296	6690	6691	6696	6849	U1 GENERATOR	GENERATOR EXCITATION SYSTEM	RT1, UNIT 1 RECTIFYING TRANSFORMER	297	6,7	Dissolved gas analysis and oil quality tests and analysis, including previous years.	2010	1
1296	7635	7636	7767	271324	U2 GENERATOR	GENERATOR EXCITATION SYSTEM	RT2, UNIT 2 RECTIFYING TRANSFORMER	298	6,7	Align with current PCB Regulation SOR/2008-273, posted in the CEPA Environmental Registry as required.	2013	1
1296	7635	7636	7767	271324	U2 GENERATOR	GENERATOR EXCITATION SYSTEM	RT2, UNIT 2 RECTIFYING TRANSFORMER	299	6,7	Dissolved gas analysis and oil quality tests and analysis, including previous years.	2010	1
1296	8193	8194	8312	271680	U3 GENERATOR	GENERATOR EXCITATION SYSTEM	RT3, UNIT 3 RECTIFYING TRANSFORMER	300	6,7	Inspect and test the transformer: turns ratio, power and dissipation factor, winding resistance, movement of coils, core grounds and general condition and cleanliness.	2013	1

11.1.2.5 Risk Assessment

The risk assessment associated with the transformer, both from a technological perspective and a safety perspective, is illustrated below in Table 11-8.

TABLE 11-8 RISK ASSESSMENT – TRANSFORMERS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset 2/3	Asset 3/4	Description	Component	Risk Assess #	Appendix #	Major Issues	Remaining Life Years	Remaining Life	Techno-Eco Risk Assess Model			Safety Risk Assess Model			Possible Failure Event	Mitigation
												(Insufficient Info - Inspection Required Within (x) Years)	Comments	Likeli-hood	Conse-quence	Risk Level	Likeli-hood	Conse-quence	Safety Risk		
1325	5975	5975	303236		HRDTS	TRANSFORMERS	T1 POWER TRANSFORMER	None	264	7	Electrical fault, mechanical fatigue, ops error.	15	N/A	2	C	Medium	2	C	Medium	Loss 1 unit generation.	Test, maintain. refurbish.
1325	5976	5976	61-00-69225		HRDTS	TRANSFORMERS	T2 POWER TRANSFORMER	None	265	7	Electrical fault, mechanical fatigue, ops error.	25	N/A	2	C	Medium	2	C	Medium	Loss 1 unit generation.	Test, maintain. refurbish.
1325	5977	5977	287198		HRDTS	TRANSFORMERS	T3 POWER TRANSFORMER	None	266	7	Electrical fault, mechanical fatigue, ops error.	15	N/A	2	C	Medium	2	C	Medium	Loss 1 unit generation.	Test, maintain. refurbish.
1325	5978	5978	287199		HRDTS	TRANSFORMERS	TRANSFORMER T4 (spare)	None	267	7	Electrical fault, mechanical fatigue, ops error.	20	N/A	2	C	Medium	2	A	Low	Loss 1 unit generation, if failure while installed.	Parallel paths (existing). Test, maintain. refurbish.
1325	5979	5979	A-3-S-7520		HRDTS	TRANSFORMERS	TRANSFORMER T5	None	268	7	Electrical fault, mechanical fatigue, ops error.	5	N/A	2	C	Medium	2	C	Medium	Partial loss 4kV to SB12	Test, maintain. refurbish.
1325	5980	5980	287065		HRDTS	TRANSFORMERS	TRANSFORMER T6	None	269	7	Electrical fault, mechanical fatigue, ops error.	5	N/A	2	C	Medium	2	C	Medium	Partial loss of supply to Line 39L to Whitbourne	Parallel paths (existing). Test, maintain. refurbish.
1325	5981	5981	287064		HRDTS	TRANSFORMERS	TRANSFORMER T7	None	270	7	Electrical fault, mechanical fatigue, ops error.	10	N/A	2	C	Medium	2	C	Medium	Partial loss of supply to Line 39L to Whitbourne	Parallel paths (existing). Test, maintain. refurbish.
1325	5982	5982	61-00-68928		HRDTS	TRANSFORMERS	TRANSFORMER T8	None	271	7	Electrical fault, mechanical fatigue, ops error.	25	N/A	2	C	Medium	2	C	Medium	Partial loss of supply to Line 39L to Whitbourne	Parallel paths (existing). Test, maintain. refurbish.
1325	5983	5983	61-00-69576		HRDTS	TRANSFORMERS	TRANSFORMER T9	None	272	7	Electrical fault, mechanical fatigue, ops error.	5	N/A	2	C	Medium	2	C	Medium	Loss gas turbine generator generation to SB12	Test, maintain. refurbish.
1325	5984	5984	61-00-69576		HRDTS	TRANSFORMERS	TRANSFORMER T10	None	273	7	Electrical fault, mechanical fatigue, ops error.	25	N/A	2	C	Medium	2	C	Medium	Partial loss 4kV to SB12	Parallel paths (existing). Test, maintain. refurbish.
1325	5985	5985	N/A		HRDTS	TRANSFORMERS	UST-1 TRANSFORMER	None	274	7	Electrical fault, mechanical fatigue, ops error.	5	N/A	2	C	Medium	2	C	Medium	Partial loss 4kV to UB1	Parallel paths (existing). Test, maintain. refurbish.
1325	5986	5986	N/A		HRDTS	TRANSFORMERS	UST-2 TRANSFORMER	None	275	7	Electrical fault, mechanical fatigue, ops error.	5	N/A	2	C	Medium	2	C	Medium	Partial loss 4kV to UB2	Parallel paths (existing). Test, maintain. refurbish.
1325	5987	5987	N/A		HRDTS	TRANSFORMERS	UST-3 TRANSFORMER	None	276	7	Electrical fault, mechanical fatigue, ops error.	15	N/A	2	C	Medium	2	C	Medium	Partial loss 4kV to UB3	Parallel paths (existing). Test, maintain. refurbish.
1325	5988	5988	WT-1976-1		HRDTS	TRANSFORMERS	STAGE 1 SST-12 TRANSFORMER	None	277	7	Electrical fault, mechanical fatigue, ops error.	5	N/A	2	C	Medium	2	C	Medium	Partial loss 4kV to SB12	Parallel paths (existing). Test, maintain. refurbish.
1325	5989	5989	A-3-S-7608		HRDTS	TRANSFORMERS	STAGE 2 SST-34 TRANSFORMER	None	278	7	Electrical fault, mechanical fatigue, ops error.	15	N/A	2	C	Medium	2	C	Medium	Partial loss 4kV to SB34	Parallel paths (existing). Test, maintain. refurbish.
1296	6690	6691	6696	6849	U1 GENERATOR	GENERATOR EXCITATION SYSTEM	RT1, UNIT 1 RECTIFYING TRANSFORMER	None	279	7	Electrical fault, mechanical fatigue, ops error.	(3)	N/A	2	C	Medium	2	C	Medium	Loss Unit 1 generation.	Test, maintain. refurbish.
1296	7635	7636	7767	271324	U2 GENERATOR	GENERATOR EXCITATION SYSTEM	RT2, UNIT 2 RECTIFYING TRANSFORMER	None	280	7	Electrical fault, mechanical fatigue, ops error.	(3)	N/A	2	C	Medium	2	C	Medium	Loss Unit 2 generation.	Test, maintain. refurbish.
1296	8193	8194	8312	271680	U3 GENERATOR	GENERATOR EXCITATION SYSTEM	RT3, UNIT 3 RECTIFYING TRANSFORMER	None	281	7	Electrical fault, mechanical fatigue, ops error.	15	N/A	2	C	Medium	2	C	Medium	Loss Unit 3 generation.	Test, maintain. refurbish.

11.1.2.6 Life Cycle Curve and Remaining Life

The life cycle curves for the system are illustrated below. Several curves are required to represent the various transformers. The life curves are plots of current and projected operating hours (generation plus synchronous condensing mode) on the y-axis versus calendar year on the x-axis. No equivalent hours for low load or no load operation are known or included. Operating hours for both generating mode and synchronous condensing mode (assuming Unit 1 and 2 modification in 2014) as well as physical age are important, as well as the number of significant system disturbances. The chart has several vertical lines representing differing representative nominal age limits for various components. It also has several horizontal lines that represent a range of practical equipment equivalent base loaded operating hour life limits.

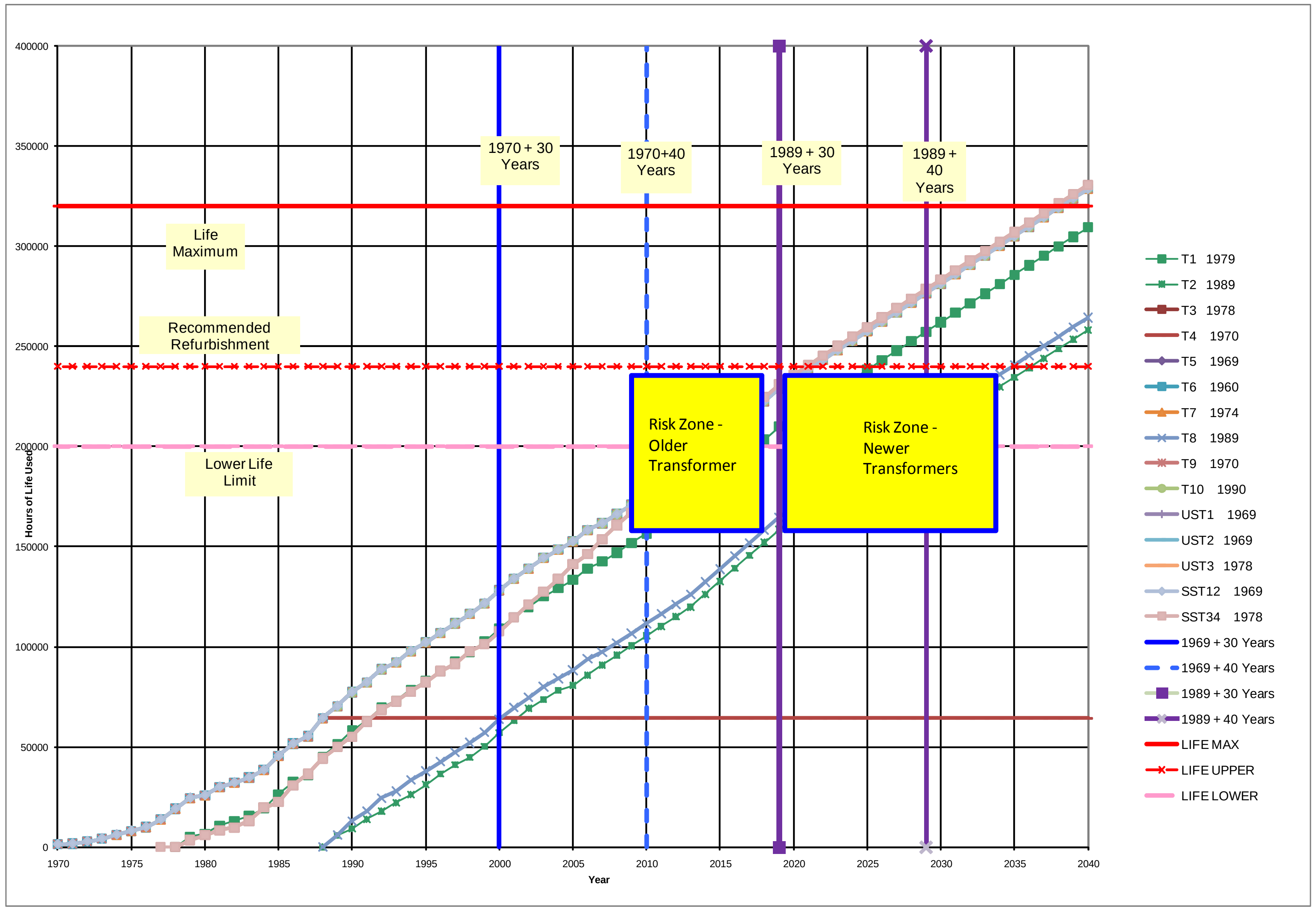

FIGURE 11-7 LIFE CYCLE CURVE – TRANSFORMERS

The curves indicate that the older transformers are in a critical period in their life where their reliability decreases and their likely susceptibility to system distance effects is higher. The remaining life (RL) of the transformers exceeds the end date for generation of 2020, but may not exceed the desired life (DL) of 2041 (at the end of synchronous condensing life) without refurbishment and/or replacement. The equipment has reached an age where reliability is a concern, particularly where system interruptions or lightning storm impacts play a role. Given the critical nature of the station and its switchyard to the supply of the mainland, a pro-active program of testing and refurbishment is a priority.

11.1.2.7 Level 2 Inspection Requirements and Costs

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 11-9 below, assuming the current plant inspection and maintenance program is maintained or improved.

TABLE 11-9 LEVEL 2 INSPECTION – TRANSFORMERS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset 2/3	Asset 3/4	Description	Sub System Comment	L2#	Appendix #	Level 2 Work	Year	Priority	Cost k$
1325	5975	5975	303236	HRDTS	TRANSFORMERS	T1 POWER TRANSFORMER	N/A	239	7	Complete all requirements of relevant transformer maintenance history sheets and comparative analyses with previous history. Condition Assessment review	2014	1	$20
1325	5976	5976	61-00-69225	HRDTS	TRANSFORMERS	T2 POWER TRANSFORMER	N/A	240	7	Complete all requirements of relevant transformer maintenance history sheets and comparative analyses with previous history. Condition Assessment review	2013	1	$17
1325	5977	5977	287198	HRDTS	TRANSFORMERS	T3 POWER TRANSFORMER	N/A	241	7	Complete all requirements of relevant transformer maintenance history sheets and comparative analyses with previous history.	2016	1	$6
1325	5978	5978	287199	HRDTS	TRANSFORMERS	TRANSFORMER T4 (spare)	N/A	242	7	Complete all requirements of relevant transformer maintenance history sheets and comparative analyses with previous history.	2011	3	$6
1325	5979	5979	A-3-S-7520	HRDTS	TRANSFORMERS	TRANSFORMER T5	N/A	243	7	Complete all requirements of relevant transformer maintenance history sheets and comparative analyses with previous history.	2015	2	$7
1325	5980	5980	287065	HRDTS	TRANSFORMERS	TRANSFORMER T6	N/A	244	7	Complete all requirements of relevant transformer maintenance history sheets and comparative analyses with previous history.	2013	2	$6
1325	5981	5981	287064	HRDTS	TRANSFORMERS	TRANSFORMER T7	N/A	245	7	Complete all requirements of relevant transformer maintenance history sheets and comparative analyses with previous history.	2013	2	$6
1325	5982	5982	61-00-68928	HRDTS	TRANSFORMERS	TRANSFORMER T8	N/A	246	7	Complete all requirements of relevant transformer maintenance history sheets and comparative analyses with previous history.	2014	2	$7
1325	5983	5983	61-00-69576	HRDTS	TRANSFORMERS	TRANSFORMER T9	N/A	247	7	Complete all requirements of relevant transformer maintenance history sheets and comparative analyses with previous history.	2012	1	$6
1325	5984	5984	61-00-69576	HRDTS	TRANSFORMERS	TRANSFORMER T10	N/A	248	7	Complete all requirements of relevant transformer maintenance history sheets and comparative analyses with previous history.	2012	2	$6
1325	5985	5985	N/A	HRDTS	TRANSFORMERS	UST-1 TRANSFORMER	N/A	249	7	Complete all requirements of relevant transformer maintenance history sheets and comparative analyses with previous history.	2010	1	$6
1325	5986	5986	N/A	HRDTS	TRANSFORMERS	UST-2 TRANSFORMER	N/A	250	7	Complete all requirements of relevant transformer maintenance history sheets and comparative analyses with previous history.	2013	1	$6
1325	5987	5987	N/A	HRDTS	TRANSFORMERS	UST-3 TRANSFORMER	N/A	251	7	Complete all requirements of relevant transformer maintenance history sheets and comparative analyses with previous history.	2013	1	$6
1325	5988	5988	WT-1976-1	HRDTS	TRANSFORMERS	STAGE 1 SST-12 TRANSFORMER	N/A	252	7	Complete all requirements of relevant transformer maintenance history sheets and comparative analyses with previous history.	2015	1	$7
1325	5989	5989	A-3-S-7608	HRDTS	TRANSFORMERS	STAGE 2 SST-34 TRANSFORMER	N/A	253	7	Complete all requirements of relevant transformer maintenance history sheets and comparative analyses with previous history.	2012	1	$6

Table 11-9 Cont'd

Newfoundland and Labrador Hydro a NALCOR Energy Co.
Holyrood Thermal Generating Station
Condition Assessment & Life Extension Study

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset 2/3	Asset 3/4	Description	Sub System Comment	L2#	Appendix #	Level 2 Work	Year	Priority	Cost k$
1325	6016	6016	991110	HRDTS	TRANSFORMERS	T1 POWER TRANSFORMER	N/A	254	7	Perform and analyze a dissolved gas analysis and oil quality tests, and compare to previous years. Condition Assessment review	2010	1	$17
1325	6017	6017	991110	HRDTS	TRANSFORMERS	T2 POWER TRANSFORMER	N/A	255	7	Perform and analyze a dissolved gas analysis and oil quality tests, and compare to previous years. Condition Assessment review	2010	1	$17
1325	6018	6018	991110	HRDTS	TRANSFORMERS	T3 POWER TRANSFORMER	N/A	256	7	Perform and analyze a dissolved gas analysis and oil quality tests, and compare to previous years.	2010	1	$6
1325	6019	6019	991110	HRDTS	TRANSFORMERS	TRANSFORMER T4 (spare)	N/A	257	7	Perform and analyze a dissolved gas analysis and oil quality tests, and compare to previous years.	2010	3	$6
1325	6020	6020	991110	HRDTS	TRANSFORMERS	TRANSFORMER T5	N/A	258	7	Perform and analyze a dissolved gas analysis and oil quality tests, and compare to previous years.	2010	2	$6
1325	6021	6021	991110	HRDTS	TRANSFORMERS	TRANSFORMER T6	N/A	259	7	Perform and analyze a dissolved gas analysis and oil quality tests, and compare to previous years.	2010	2	$6
1325	6022	6022	991110	HRDTS	TRANSFORMERS	TRANSFORMER T7	N/A	260	7	Perform and analyze a dissolved gas analysis and oil quality tests, and compare to previous years.	2010	2	$6
1325	6023	6023	991110	HRDTS	TRANSFORMERS	TRANSFORMER T8	N/A	261	7	Perform and analyze a dissolved gas analysis and oil quality tests, and compare to previous years.	2010	2	$6
1325	6024	6024	991110	HRDTS	TRANSFORMERS	TRANSFORMER T9	N/A	262	7	Perform and analyze a dissolved gas analysis and oil quality tests, and compare to previous years.	2010	1	$6
1325	6025	6025	991110	HRDTS	TRANSFORMERS	TRANSFORMER T10	N/A	263	7	Perform and analyze a dissolved gas analysis and oil quality tests, and compare to previous years.	2010	2	$6
1325	6026	6026	991110	HRDTS	TRANSFORMERS	UST-1 TRANSFORMER	N/A	264	7	Perform and analyze a dissolved gas analysis and oil quality tests, and compare to previous years.	2010	1	$6
1325	6027	6027	991110	HRDTS	TRANSFORMERS	UST-2 TRANSFORMER	N/A	265	7	Perform and analyze a dissolved gas analysis and oil quality tests, and compare to previous years.	2010	1	$6
1325	6028	6028	991110	HRDTS	TRANSFORMERS	UST-3 TRANSFORMER	N/A	266	7	Perform and analyze a dissolved gas analysis and oil quality tests, and compare to previous years.	2010	1	$6
1325	6029	6029	991110	HRDTS	TRANSFORMERS	STAGE 1 SST-12 TRANSFORMER	N/A	267	7	Perform and analyze a dissolved gas analysis and oil quality tests, and compare to previous years.	2010	1	$6
1325	6030	6030	991110	HRDTS	TRANSFORMERS	STAGE 2 SST-34 TRANSFORMER	N/A	268	7	Perform and analyze a dissolved gas analysis and oil quality tests, and compare to previous years.	2010	1	$6

11.1.2.8 Capital Projects

The suggested typical capital enhancements for the transformers include:

TABLE 11-10 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – TRANSFORMERS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset 2/3	Asset 3/4	Description	CAP#	Appendix #	Capital Item	Date	Priority
1325	5975	5975	303236	HRDT1	HRDTS	TRANSFORMERS	T1 POWER TRANSFORMER	242	7	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Actions in Section 11.1.2.4.	2015 to 2035	1
1325	5976	5976	61-00-69225	HRDT2	HRDTS	TRANSFORMERS	T2 POWER TRANSFORMER	243	7	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Actions in Section 11.1.2.4.	2015 to 2035	1
1325	5977	5977	287198	HRDT3	HRDTS	TRANSFORMERS	T3 POWER TRANSFORMER	244	7	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Actions in Section 11.1.2.4.	2015 to 2035	1
1325	5978	5978	287199	HRDT4	HRDTS	TRANSFORMERS	TRANSFORMER T4 (spare)	245	7	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Actions in Section 11.1.2.4.	2015 to 2035	3
1325	5979	5979	A-3-S-7520	HRDT5	HRDTS	TRANSFORMERS	TRANSFORMER T5	246	7	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Actions in Section 11.1.2.4.	2015 to 2035	1
1325	5980	5980	287065	HRDT6	HRDTS	TRANSFORMERS	TRANSFORMER T6	247	7	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Actions in Section 11.1.2.4.	2015 to 2035	1
1325	5981	5981	287064	HRDT7	HRDTS	TRANSFORMERS	TRANSFORMER T7	248	7	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Actions in Section 11.1.2.4.	2015 to 2035	1
1325	5982	5982	61-00-68928	HRDT8	HRDTS	TRANSFORMERS	TRANSFORMER T8	249	7	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Actions in Section 11.1.2.4.	2015 to 2035	1
1325	5983	5983	61-00-69576	HRDT9	HRDTS	TRANSFORMERS	TRANSFORMER T9	250	7	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Actions in Section 11.1.2.4.	2015 to 2035	1
1325	5984	5984	61-00-69576	HRDT10	HRDTS	TRANSFORMERS	TRANSFORMER T10	251	7	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Actions in Section 11.1.2.4.	2015 to 2035	1
1325	5985	5985	N/A	HRDUST-1	HRDTS	TRANSFORMERS	UST-1 TRANSFORMER	252	7	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Actions in Section 11.1.2.4.	2015 to 2035	1
1325	5986	5986	N/A	HRDUST-2	HRDTS	TRANSFORMERS	UST-2 TRANSFORMER	253	7	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Actions in Section 11.1.2.4.	2015 to 2035	1
1325	5987	5987	N/A	HRDUST-3	HRDTS	TRANSFORMERS	UST-3 TRANSFORMER	254	7	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Actions in Section 11.1.2.4.	2015 to 2035	1
1325	5988	5988	WT-1976-1	HRDSST-12	HRDTS	TRANSFORMERS	STAGE 1 SST-12 TRANSFORMER	255	7	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Actions in Section 11.1.2.4.	2015 to 2035	1
1325	5989	5989	A-3-S-7608	HRDSST-34	HRDTS	TRANSFORMERS	STAGE 2 SST-34 TRANSFORMER	256	7	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Actions in Section 11.1.2.4.	2015 to 2035	1

11.1.3 Assets 6860 and 8730 – Common Electrical and Control Assets

The requirements for the common electrical and control systems associated with the Holyrood generators are as follows:

Unit #:	Common
Asset Class #	BU 1297 – Assets Commons
SCI & System:	7199 HRD Common Systems
Components:	6904 Common, Computers Foxboro 7189 Common, Switchgear 4160V/600V (SB12) 7190 Common, Diesel Bus, DB12 7192 Power Centre C (SAB12, Diesel Bus DB12) 7197 Common, Stage 1, 129VDC Supply System 8771 Common, Stage 2, 129VDC Supply System Units 1 to 3 Common Control Cables Common Power Cables Common 600V Metric Plugs

11.1.3.1 Description

Asset 6904 Common Computers Foxboro

This is integrated with the Foxboro system as a whole. Reference Foxboro Drawing D545390-SA-001 for system configuration. It was installed in 2004.

Asset 7189 Common Switchgear 4160V/600V (SB12)

Station Board SB12 (4160V) was manufactured by ITE and installed in 1968. The 4160V switchgear utilizes original ITE type 5HK draw-out power breakers, 1200A and 2000A. Some feeders have Schweitzer 701 motor protection relays added. All other loads utilize original P&B Golds relays. All power breakers are original. All protection, synch, and control relays are original CGE electro-mechanical.

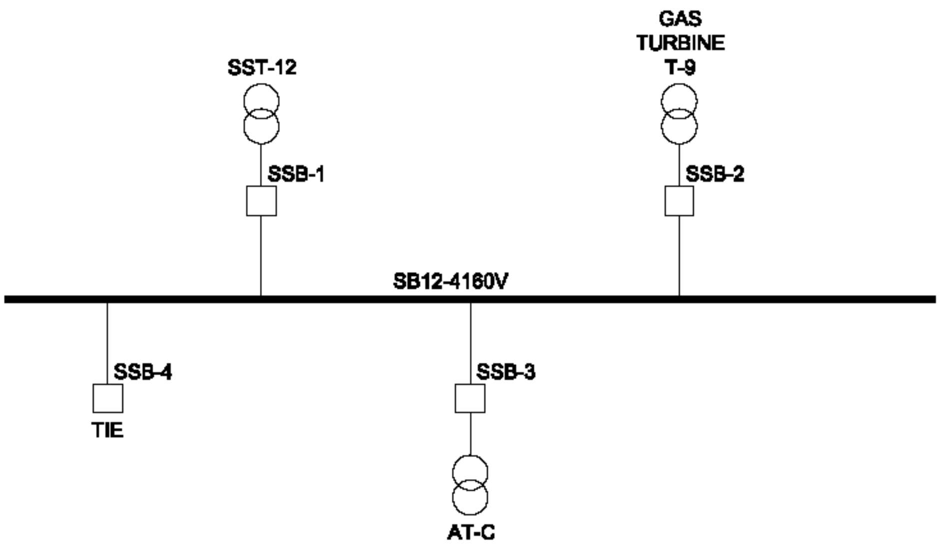

FIGURE 11-8 SB12 SWITCHGEAR

Asset 7190 Common Diesel Bus, DB12

Diesel Bus DB12 is part of Power Centre “C”. Refer to Section 8.4.

Asset 7192 Power Centre C (SAB12, Diesel Bus DB12)

Power Centre “C” SAB12 and Diesel Bus DB12 (600V), was manufactured by CGE and installed in 1968. It is supplied with 600V electricity primarily from Station Board SB12 through Transformer AT-C.

The switchboard utilizes CGE AK-50 Incoming and Tie Breakers and AK-25 Feeder Breakers. Unit Aux. Transformer AT-C is a Westinghouse type ASL, AN 1500kVA, 4160V:600/347V, complete with tap-changer, +2@2.5%, Dy1, Z1=12% and was installed in 1968.

Asset 7197 Common Stage 1 129VDC Supply System

Unit 1 129VDC Distribution Panel was manufactured by Westinghouse and installed in 1973. The panel is a type NFB, complete with FB type Breakers.

Unit 2 129VDC Distribution Panel was manufactured by Westinghouse and installed in 1973. The panel is a type NFB, complete with FB type Breakers.

Common 129VDC Distribution Panel was manufactured by Westinghouse and installed in 1973. The panel is a type NFB, complete with FB type Breakers.

NFB panels and FB breakers have been superseded by PRL-3 panels and FD breakers.

COMMON CABLES

Associated Assets

- Asset 270296 Unit 1 Cable Raceways
- Asset 271475 Unit 2 Cable Raceways
- Asset 271763 Unit 3 Cable Raceways
- Asset 270297 Unit 1 Control Cables
- Asset 271476 Unit 2 Control Cables
- Asset 271764 Unit 3 Control Cables
- Asset 270298 Unit 1 Power Cables
- Asset 271477 Unit 2 Power Cables
- Asset 271765 Unit 3 Power Cables

Prior to 1995, preventative maintenance (PM) was carried out on power cables approximately every 10 years. Since 1995, no PM has been done and no records have been kept. Visual inspection indicated some contamination of trays in the boiler areas. Plant modifications over the past 40 years have resulted in power and control cables being placed into cable trays that have been convenient in the routings associated with the new installations.

Common 600V Meltric Plugs

The 600V 3 phase plugs and receptacles 30A and 60A are manufactured by Meltric and have been installed under an ongoing NLH program. This program has been completed with the exception of the LP drain pumps. There are four LP drain pump feeders remaining to modify; two servicing Unit 1 and two servicing Unit 2.

11.1.3.2 History - Inspection and Repair History

Asset 6904 Common Computers Foxboro

The DCS is a relatively new, state of the art system and regularly maintained.

Asset 7189 Common Switchgear 4160V/600V (SB12)

Completed Test Plan Activity sheets dated 2007 are available for Unit Board SB12 Protection. Results are satisfactory at this time. Relays and cases required cleaning due to ingress of dust and foreign material.

Station Board SB12 - Overhauls

- Breaker SSB-1 - overhauled 16 Sept. 2006
- Breaker SSB-2 – overhauled 1996
- Breaker SSB-3 - overhauled 17 Sept. 2006
- Breaker SSB-4 - overhauled 04 Oct. 2006

Unit Board UB2 - Corrective Actions

- Breaker SSB-1, Sept. 2006. (status 90)
- Breaker SSB-12, Sept. 2006. (status 90)

The Stantec Engineering Report – MCC Assessments, Section 1.0 concludes that all 4160V switchgear is applied within their ratings.

Asset 7190 Common Diesel Bus, DB12

Diesel Bus DB12 is a component of Power Centre "C". Maintenance request sheets, dated June 2005, indicate breaker C18 was overhauled and cleaned after being found in an extremely dusty and dirty state.

Asset 7192 Power Centre C (SAB12, Diesel Bus DB12)

The last PM performed was between 1992 and 1997. Breakers were sent away to an external company for maintenance and the protection relay on each breaker was changed. The Stantec Engineering Report – MCC Assessments, Section 1.0 concludes that all 600V switchgear is applied within their ratings.

Asset 7197 Common Stage 1, 129VDC Supply System

Common, 129VDC Distribution Panel was manufactured by Westinghouse and installed in 1973. The Panel is a type NFB, c/w FB type Breakers. NFB panels and FB breakers have been superseded by PRL-3 panels and FD breakers.

COMMON CABLES

Associated Assets

- Asset 270296 Unit 1 Cable Raceways
- Asset 271475 Unit 2 Cable Raceways
- Asset 271763 Unit 3 Cable Raceways
- Asset 270297 Unit 1 Control Cables
- Asset 271476 Unit 2 Control Cables
- Asset 271764 Unit 3 Control Cables
- Asset 270298 Unit 1 Power Cables
- Asset 271477 Unit 2 Power Cables
- Asset 271765 Unit 3 Power Cables

Prior to 1995 PM was carried out on power cables approximately on a 10 year frequency. Since 1995 no PM has been done and no records have been kept. Visual inspection indicated some contamination of trays in the boiler areas. Plant modifications over the past 40 years have resulted in power and control cables being installed in existing cable trays that have been convenient routings associated with the new installations, as well as in new trays.

11.1.3.3 Condition Assessment

The condition assessment of the common electrical and control assets is illustrated below in Table 11-11.

TABLE 11-11 CONDITION ASSESSMENT – COMMON ELECTRICAL AND CONTROL ASSETS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset Level 2	Asset Level 3	Description	Detail	Cond. Summ. ID#	Append #	Condition	EPRI Identifier	Original Life (Base Load) Ops Hrs (Yrs)	Current Expected Minimum Remaining Life Years (Subject to Test)	End of Life Required (EOL)	Next Regular Inspection	Next Planned Overhaul/ Major Inspection	Capability to Reach Next Overhaul	Capability to Reach EOL	In Service
1297	7199	6727	0	0	COMMON SYSTEMS	STAGE 1 STATION SERVICE POWER	STAGE 1 STATION SERVICE POWER	N/A	5	6	Not specifically addressed in detail.	4	(40)	10	2041			No	No	1968
1297	7199	6904	301712	0	COMMON SYSTEMS	STATION SERVICE DCS	STATION SERVICE DCS	N/A	6	6	Not specifically addressed in detail.	4	(40)	10+	2041			No	No	2004
1297	7199	7189	0	0	COMMON SYSTEMS	STATION BOARD SB-12	STATION BOARD SB-12	Switchgear 4160V/600V (SB12)	7	6	Installed in 1968. Breakers overhauled in 2006, Motor protection relays added. Tested 2007 satisfactory. Some ingress of dust and foreign material. Corrective actions on Breaker SSB-1 in 2006 (status 90) and Breaker SSB-12 in 2006. (status 90).	3a	(40)	(5)	2041			No	No	1968
1297	7199	7190	0	0	COMMON SYSTEMS	DIESEL BUS DB12	DIESEL BUS DB12	N/A	8	6	Maintenance in 2005 - Breaker C18 overhauled and cleaned after being found in an extremely dusty and dirty state.	4	(40)	(5)	2041			No	No	1968
1297	7199	7191	0	0	COMMON SYSTEMS	ESSENTIAL SERVICE MCC E1	ESSENTIAL SERVICE MCC E1	N/A	9	6	Not addressed.	4	(25)	(5)	2041			No	No	1968
1297	7199	7192	0	0	COMMON SYSTEMS	POWER CENTER C	POWER CENTER C	N/A	10	6	Last PM between 1992 and 1997 when breakers refurbished externally, and changed the protection relay. All 600V switchgear is applied within their ratings.	4	(40)	(5)	2041			No	No	1968
1297	7199	7192	7188	0	COMMON SYSTEMS	POWER CENTER C	COMMON SERVICES MCC C1	N/A	11	6	Acceptable condition. Old system may need replacement to align with higher firefighting flow requirements.	4	(25)	(5)	2041			No	No	1968
1297	7199	7195	303344	0	COMMON SYSTEMS	STAGE 1 129V D.C.SUPPLY SYSTEM	129 VDC Stage 1 Batteries	N/A	12	6	New in 2006	3a	(25)	20	2041			Yes	No	2006
1297	7199	7195	303345	0	COMMON SYSTEMS	STAGE 1 129V D.C.SUPPLY SYSTEM	129 VDC Charger A	N/A	13	6	New in 2006	10	(25)	20	2041			Yes	No	2006
1297	7199	7195	303351	0	COMMON SYSTEMS	STAGE 1 129V D.C.SUPPLY SYSTEM	129 VDC Charger B	N/A	16	6	Last equipment check 04 Feb 2010. 129VDC Battery Charger 2 (1969) to be replaced in 2010	10	(25)	25	2041			Yes	Yes	1969/2010
1297	7199	7192	7411	0	COMMON SYSTEMS	POWER CENTER C	C.W. PUMPHOUSE MCC C6	N/A	17	6	End of Life. Replace.	10	(25)	2	2041			No	No	1968
1297	7199	7195	0	0	COMMON SYSTEMS	STAGE 1 129V D.C.SUPPLY SYSTEM	STAGE 1 129V D.C.SUPPLY SYSTEM	N/A	18	6	End of life. Original equipment. NFB panels and FB breakers have been superseded by PRL-3 panels and FD breakers.	10	(25)	(5)	2041			No	No	1973
1297	7199	8730	0	0	COMMON SYSTEMS	STATION SERVICE POWER SYSTEM	STATION SERVICE POWER SYSTEM	N/A	19	6	See details below.	3a	(30)	5	2041			No	No	1980
1297	7199	8730	8731	0	COMMON SYSTEMS	STATION SERVICE POWER SYSTEM	STATION SERVICE BOARD SB-34	N/A	20	6	Acceptable condition.	3a	(30)	10	2041			No	No	1980
1297	7199	8730	8732	0	COMMON SYSTEMS	STATION SERVICE POWER SYSTEM	STATION AUXILIARY BOARD SAB-34	N/A	21	6	Station Board SB34 Protection tests in 2007 weare satisfactory. Breakers overhauled in 2006 OK, with corrective actions on TB12 breaker, Sept, 2006. (status 90) and SAT34 breaker (status 90).	3a	(30)	10	2041			No	No	1980
1297	7199	8730	8738	0	COMMON SYSTEMS	STATION SERVICE POWER SYSTEM	GENERAL PURPOSE MCC GPB-34	N/A	22	6	Not reviewed. Aging equipment obsolescence issue.	4	(30)	(5)	2041			No	No	1980
1297	7199	8730	8740	0	COMMON SYSTEMS	STATION SERVICE POWER SYSTEM	TURB & BLR STANDBY MCC SDB-34	N/A	23	6	Not reviewed. Aging equipment obsolescence issue.	4	(30)	(5)	2020			No	No	1980
1297	7199	8730	8742	0	COMMON SYSTEMS	STATION SERVICE POWER SYSTEM	DIESEL BUS DB-34	N/A	24	6	Reasonable condition. Not reviewed in detail.	3a	(30)	(10)	2041			No	No	1980
1297	7199	8730	8743	0	COMMON SYSTEMS	STATION SERVICE POWER SYSTEM	ESSENTIAL SERVICES MCC ESB-34	N/A	25	6	Reasonable condition. Not reviewed in detail.	3a	(30)	(5)	2041			No	No	1980
1297	7199	8730	8746	0	COMMON SYSTEMS	STATION SERVICE POWER SYSTEM	C.W. PUMPHOUSE MCC CWP-34	N/A	26	6	Refurbishment required.	10	(30)	10	2041			No	No	1980
1297	7199	8771	0	0	COMMON SYSTEMS	STAGE 2 129V D.C. SUPPLY	STAGE 2 129V D.C. SUPPLY	N/A	28	6	Installed in 1978. Last equipment check 04 Feb. 2010. Essentially at end of life.	10	(25)	(5)	2041			No	No	1978
1297	7199	8771	99029568	0	COMMON SYSTEMS	STAGE 2 129V D.C. SUPPLY	C & D 60 CELL BATTERY BANK		30	6	Replaced in 1996. Last test in 2010 OK.	4	(25)	10	2041	2015		Yes	No	1996

Notes:

1. A "(bracketed)" value in the "Current Expected Remaining Life" column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation, including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as "(X/Y)" has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

2. The "Next Regular Inspection" column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The "Next Planned Overhaul or Major Inspection" column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a "Desired Life" stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where no specific dates have been identified for "Next Regular Inspection" or "Next Planned Overhaul/Major Inspection", they are left blank.

11.1.3.4 Actions

Based on the condition assessment, the following actions are recommended for common electrical and control assets:

TABLE 11-12 RECOMMENDED ACTIONS – COMMON ELECTRICAL AND CONTROL ASSETS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset 2/3	Asset 3/4	Description	Action #	App #	Action	Year	Priority
1297	7199	6727	0	0	COMMON	STAGE 1 STATION SERVICE	STAGE 1 STATION SERVICE	8	6	No recommended action.		
1297	7199	6904	301712	0	COMMON	STATION SERVICE DCS	STATION SERVICE DCS	9	6	No recommended action.		
1297	7199	7189	0	0	COMMON	STATION BOARD SB-12	STATION BOARD SB-12	10	6	Refurbish and/or replace components.	2013	2
1297	7199	7190	0	0	COMMON SYSTEMS	DIESEL BUS DB12	DIESEL BUS DB12	11	6	Carry out inspection and testing of transformer AT-C and the individual AK-50 / AK-25 air circuit breakers and the bussing - turns ratio, power and dissipation factor, winding resistance, movement of coils, core grounds, taps and general condition and cleanliness. Check bus-bar bolts sand retorqued. Overhaul in next 5 years	2011	1
1297	7199	7191	0	0	COMMON	ESSENTIAL SERVICE MCC E1	ESSENTIAL SERVICE MCC	12	6	Not addressed in detail. Given age and service, refurbish and/or replace components	2013	2
1297	7199	7192	0	0	COMMON SYSTEMS	POWER CENTER C	POWER CENTER C	13	6	Carry out inspection and testing of transformer AT-C and the individual AK-50 / AK-25 air circuit breakers and the bussing - turns ratio, power and dissipation factor, winding resistance, movement of coils, core grounds, taps and general condition and cleanliness.. Check bus-bar bolts and retorqued.	2011	1
1297	7199	7192	7188	0	COMMON	POWER CENTER C	COMMON SERVICES MCC	14	6	Refurbish or replace.	2014	2
1297	7199	7192	7411	0	COMMON	POWER CENTER C	C.W. PUMPHOUSE MCC C6	15	6	Replace.	2011	2
1297	7199	7195	0	0	COMMON	STAGE 1 129V D.C.SUPPLY	STAGE 1 129V D.C.SUPPLY	16	6	Replace panels and breakers.	2012	2
1297	7199	7195	303344	0	COMMON	STAGE 1 129V D.C.SUPPLY	129 VDC Stage 1 Batteries	17	6	No recommended action.		
1297	7199	7195	303350	0	COMMON	STAGE 1 129V D.C.SUPPLY	129 VDC Charger A	20	6	No recommended action.		
1297	7199	7195	303351	0	COMMON	STAGE 1 129V D.C.SUPPLY	129 VDC Charger B	21	6	Replace Units 1/2, 129VDC Battery Charger 2 with a new Primax Charger.	2010	1
1297	7199	8730	0	0	COMMON	STATION SERVICE POWER	STATION SERVICE POWER	22	6	Refurbish or replace as required to achieve 2020 or 2040. Not examined in detail.	2015	2
1297	7199	8730	8731	0	COMMON	STATION SERVICE POWER	STATION SERVICE BOARD	23	6	Refurbish or replace as required to achieve 2020 or 2040. Not examined in detail.	2015	2
1297	7199	8730	8732	0	COMMON	STATION SERVICE POWER	STATION AUXILIARY BOARD	24	6	Refurbish or replace as required to achieve 2020 or 2040. Not examined in detail.	2015	2
1297	7199	8730	8738	0	COMMON	STATION SERVICE POWER	GENERAL PURPOSE MCC	25	6	Refurbish or replace as required to achieve 2020 or 2040. Not examined in detail.	2015	2
1297	7199	8730	8740	0	COMMON	STATION SERVICE POWER	TURB & BLR STANDBY MCC	26	6	Refurbish or replace as required to achieve 2020 or 2040. Not examined in detail.	2015	2
1297	7199	8730	8742	0	COMMON	STATION SERVICE POWER	DIESEL BUS DB-34	27	6	Refurbish or replace as required to achieve 2020 or 2040. Not examined in detail.	2015	2
1297	7199	8730	8743	0	COMMON	STATION SERVICE POWER	ESSENTIAL SERVICES MCC	28	6	Refurbish or replace as required to achieve 2020 or 2040. Not examined in detail.	2015	2
1297	7199	8730	8746	0	COMMON	STATION SERVICE POWER	C.W. PUMPHOUSE MCC	29	6	Refurbish or replace as required to achieve 2020 or 2040. Not examined in detail.	2015	2
1297	7199	8771	0	0	COMMON	STAGE 2 129V D.C. SUPPLY	STAGE 2 129V D.C. SUPPLY	31	6	Replace as required to achieve 2020 or 2040. Not examined in detail.	2015	2
1297	7199	8771	99029568	0	COMMON	STAGE 2 129V D.C. SUPPLY	C & D 60 CELL BATTERY	33	6	Continue to monitor performance. Replace as required.	2015	2

11.1.3.5 Risk Assessment

The risk assessment associated with the common electrical and control assets, both from a technological perspective and a safety perspective, is illustrated below in Table 11-13.

TABLE 11-13 RISK ASSESSMENT – COMMON ELECTRICAL AND CONTROL ASSETS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset 2/3	Asset 3/4	Description	Component	Risk Assess #	Appendix #	Major Issues	Remaining Life Years	Remaining Life	Techno-Eco Risk Assess Model			Safety Risk Assess Model			Possible Failure Event	Mitigation
												(Insufficient Info - Inspection Required Within (x) Years)	Comments	Likeli-hood	Conse-quence	Risk Level	Likeli-hood	Conse-quence	Safety Risk		
1297	7199	6727	0	0	COMMON SYSTEMS	STAGE 1 STATION SERVICE POWER	STAGE 1 STATION SERVICE POWER	None	5	6											
1297	7199	6904	301712	0	COMMON SYSTEMS	STATION SERVICE DCS	STATION SERVICE DCS	None	6	6	Electrical failure.	10+	N/A	2	2	Low	2	B	Low	Unit trip.	Monitor and maintain.
1297	7199	7189	0	0	COMMON SYSTEMS	STATION BOARD SB-12	STATION BOARD SB-12	Common, Switchgear 4160V/600V (SB12)	7	6	Electrical fault, mechanical fault, ops error.	(5)	N/A	3	B	Medium	3	B	Medium	Loss up to 1 unit generation. Damage to equipment.	Parallel path suply (existnig). Refurbish or replace.
1297	7199	7190	0	0	COMMON SYSTEMS	DIESEL BUS DB12	DIESEL BUS DB12	Common, Diesel Bus, DB12	8	6	See Power Centres ©.	(5)	N/A	2	C	Medium	2	B	Medium	Safe Unit shutdown failure. Loss of 1 unit.	Parallel path suply (existing). Refurbish or replace.
1297	7199	7191	0	0	COMMON SYSTEMS	ESSENTIAL SERVICE MCC E1	ESSENTIAL SERVICE MCC E1	None	9	6	See detail below.		N/A	3	C	Medium	3	B	Medium	Loss essential services causing loss 1 unit generation, damage to equipment.	Parallel path suply (existing). Refurbish or replace.
1297	7199	7192	0	0	COMMON SYSTEMS	POWER CENTER C	POWER CENTER C	Power Centre (600V)	10	6	Electrical fault, mechanical fatigue, ops error.	(5)	N/A	3	B	Medium	3	B	Medium	Loss of part of 1 unit generation. Damage to equipment.	Parallel path suply (existing). Refurbish or replace.
1297	7199	7192	7188	0	COMMON SYSTEMS	POWER CENTER C	COMMON SERVICES MCC C1	None	11	6	Electrical fault, mechanical fatigue, ops error.	(5)	N/A	3	B	Medium	3	B	Medium	Loss common services causing loss 1 unit generation, damage to equipment.	Parallel path suply (existing). Refurbish or replace.
1297	7199	7192	7411	0	COMMON SYSTEMS	POWER CENTER C	C.W. PUMPHOUSE MCC C6	None	12	6	Electrical fault, mechanical fatigue, ops error.	2	N/A	3	B	Medium	3	C	High	Loss pumphouse services causing loss 1 unit generation, damage to equipment.	Refurbish or replace.
1297	7199	7195	0	0	COMMON SYSTEMS	STAGE 1 129V D.C.SUPPLY SYSTEM	STAGE 1 129V D.C.SUPPLY SYSTEM	Common, Stage 1, 129VDC Supply System	13	6	Electrical fault, mechanical fault.	(3)	0-3 Years. Replace	3	C	Medium	3	C	Medium	Fails to shut down safely. Personnel risk.	Replace
1297	7199	7195	303344	0	COMMON SYSTEMS	STAGE 1 129V D.C.SUPPLY SYSTEM	129 VDC Stage 1 Batteries	None	14		Emergency shutdown power failure	20	N/A	1	C	Low	2	C	Medium	Fails to shut down safely. Personnel risk.	Existing parallel path redundancy and PM program
1297	7199	7195	303345	0	COMMON SYSTEMS	STAGE 1 129V D.C.SUPPLY SYSTEM	129 VDC Charger A	None	15		Emergency shutdown power failure	20	N/A	1	C	Low	2	C	Medium	Fails to shut down safely. Personnel risk.	Existing parallel path redundancy and PM program
1297	7199	7195	303351	0	COMMON SYSTEMS	STAGE 1 129V D.C.SUPPLY SYSTEM	129 VDC Charger B	None	18		Emergency shutdown power failure	25	N/A	1	C	Low	2	C	Medium	Fails to shut down safely. Personnel risk.	Existing parallel path redundancy and PM program
1297	7199	8730	0	0	COMMON SYSTEMS	STAGE 2 STATION SERVICE POWER SYSTEM	STAGE 2 STATION SERVICE POWER SYSTEM	None	19	6	Electrical fault, mechanical fault.	(10)	0-3 Years. Replace	3	C	Medium	3	C	Medium	Fails to shut down safely. Personnel risk.	Replace
1297	7199	8730	8731	0	COMMON SYSTEMS	STAGE 2 STATION SERVICE POWER SYSTEM	STATION SERVICE BOARD SB-34	None	20	6	Electrical fault, mechanical fatigue, ops error.	(10)	N/A	3	B	Medium	3	B	Medium	Loss up to 1 unit generation. Damage to equipment.	Parallel path suply (existnig). Refurbish or replace.
1297	7199	8730	8732	0	COMMON SYSTEMS	STAGE 2 STATION SERVICE POWER SYSTEM	STATION AUXILIARY BOARD SAB-34	None	21	6	Electrical fault, mechanical fatigue, ops error.	(10)	N/A	3	C	Medium	3	B	Medium	Loss up to 1 unit generation. Damage to equipment.	Refurbish or replace.
1297	7199	8730	8738	0	COMMON SYSTEMS	STAGE 2 STATION SERVICE POWER SYSTEM	GENERAL PURPOSE MCC GPB-34	None	22	6	Electrical fault, mechanical fatigue, ops error.	(10)	N/A	3	B	Medium	3	B	Medium	Loss common services causing loss 1 unit generation, damage to equipment.	Parallel path suply (existing). Refurbish or replace.
1297	7199	8730	8740	0	COMMON SYSTEMS	STAGE 2 STATION SERVICE POWER SYSTEM	TURB & BLR STANDBY MCC SDB-34	None	23	6	Electrical fault, mechanical fatigue, ops error.	(10)	N/A	3	B	Medium	3	B	Medium	Loss turbien & boiler area services causing loss 1 unit generation, damage to equipment.	Refurbish or replace.
1297	7199	8730	8742	0	COMMON SYSTEMS	STAGE 2 STATION SERVICE POWER SYSTEM	DIESEL BUS DB-34	None	24	6	Electrical fault, mechanical fatigue, ops error.	(10)	N/A	3	C	Medium	3	B	Medium	Safe Unit shutdown failure. Loss of 1 unit.	Parallel path suply (existing). Refurbish or replace.
1297	7199	8730	8743	0	COMMON SYSTEMS	STAGE 2 STATION SERVICE POWER SYSTEM	ESSENTIAL SERVICES MCC ESB-34	None	25	6	Electrical fault, mechanical fatigue, ops error.	(10)	N/A	3	C	Medium	3	B	Medium	Loss essential services causing loss 1 unit generation, damage to equipment.	Parallel path suply (existing). Refurbish or replace.
1297	7199	8730	8746	0	COMMON SYSTEMS	STAGE 2 STATION SERVICE POWER SYSTEM	C.W. PUMPHOUSE MCC CWP-34	None	26	6	Electrical fault, mechanical fatigue, ops error.	(2)	N/A	3	B	Medium	3	C	High	Loss pumphouse services causing loss 1 unit generation, damage to equipment.	Refurbish or replace.
1297	7199	8771	0	0	COMMON SYSTEMS	STAGE 2 129V D.C. SUPPLY	STAGE 2 129V D.C. SUPPLY	None	28	6	Emergency shutdown power failure	(5)	N/A	3	C	Medium	3	C	Medium	Fails to shut down safely. Personnel risk.	Replace
1297	7199	8771	99029568	0	COMMON SYSTEMS	STAGE 2 129V D.C. SUPPLY	C & D 60 CELL BATTERY BANK	None	30	6	Emergency shutdown power failure	10	N/A	1	C	Low	2	C	Medium	Fails to shut down safely. Personnel risk.	Existing parallel path redundancy and PM program

11.1.3.6 Life Cycle Curve and Remaining Life

The life cycle curve for the system is illustrated below. Several curves are required to represent the various elements. The curves are plots of current and projected operating hours (generation plus synchronous condensing mode) on the y-axis versus calendar year on the x-axis. Vertical lines represent bands of nominal years of normal base loaded life. Horizontal lines represent the ranges of equipment life based on current and historical information and expert opinion. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view.

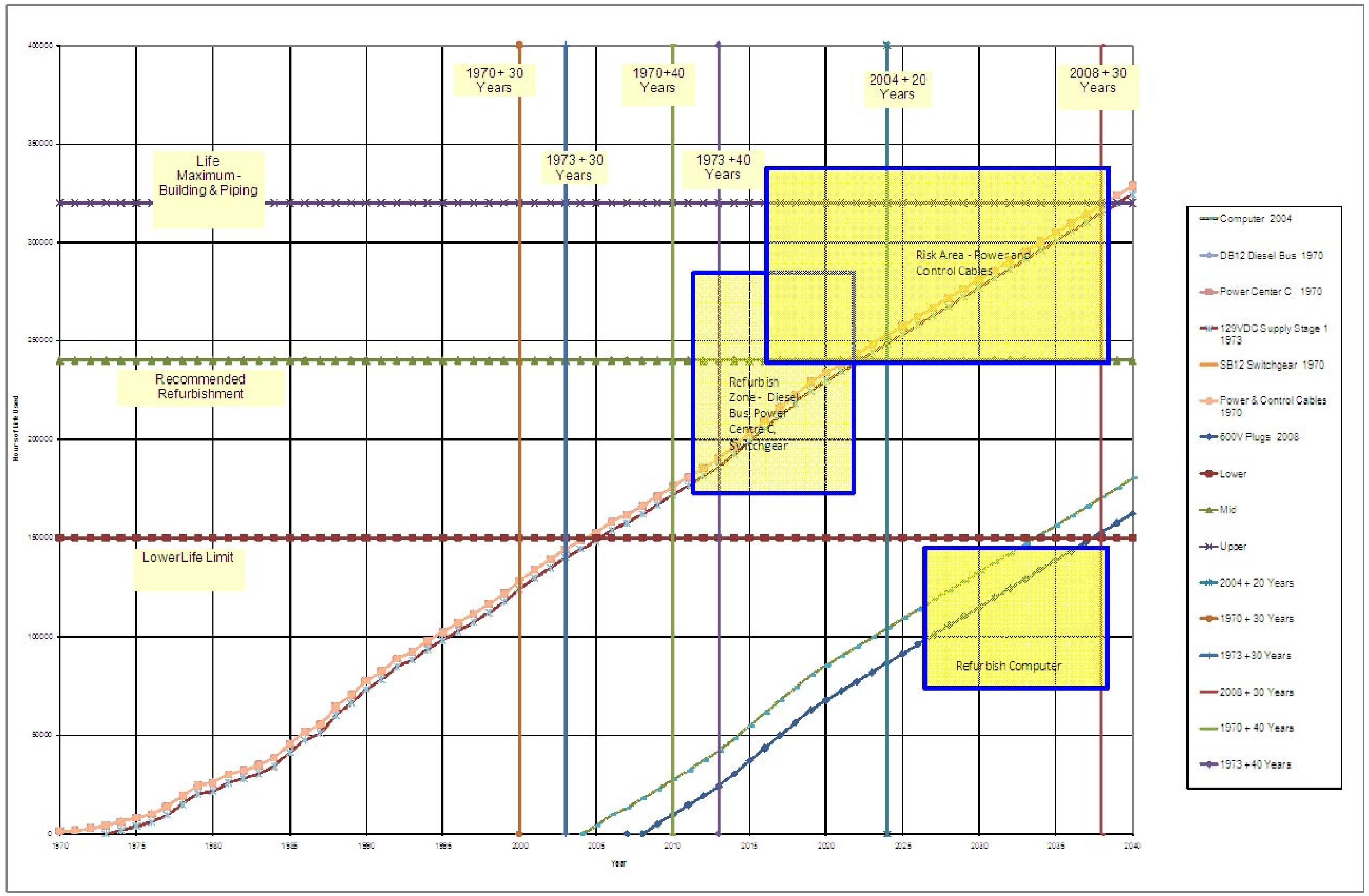

FIGURE 11-9 LIFE CYCLE CURVE – COMMON ELECTRICAL AND CONTROL ASSETS

The curves indicate that the remaining life (RL) of most of the common electrical and control assets exceeds the end date for generation of 2020, but not the desired life (DL) which is the end date for synchronous condensing of 2041. Further, any older switchgear such as breakers or motor control centres will need to be replaced (some possibly refurbished) within the next five years or risk increasing rates of failure.

11.1.3.7 Level 2 Inspection Requirements and Costs

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 11-14 below, assuming the current plant inspection and maintenance program is maintained or improved.

TABLE 11-14 LEVEL 2 INSPECTION – COMMON ELECTRICAL AND CONTROL ASSETS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset 2/3	Asset 3/4	Description	Sub System Comment	L2#	Appendix #	Level 2 Work	Year	Priority	Cost k$
1297	7199	6727	0	COMMON SYSTEMS	STAGE 1 STATION SERVICE POWER	STAGE 1 STATION SERVICE POWER	N/A	5	6	No Level 2 required.			
1297	7199	6904	301712	COMMON SYSTEMS	STATION SERVICE DCS	STATION SERVICE DCS	N/A	6	6	No Level 2 required.			
1297	7199	7189	0	COMMON SYSTEMS	STATION BOARD SB-12	STATION BOARD SB-12	N/A	7	6	No Level 2 required.			
1297	7199	7190	0	COMMON SYSTEMS	DIESEL BUS DB12	DIESEL BUS DB12	Power Centre C (SAB12, Diesel Bus DB12)	8	6	See Power Centre C			
1297	7199	7191	0	COMMON SYSTEMS	ESSENTIAL SERVICE MCC E1	ESSENTIAL SERVICE MCC E1	N/A	9	6	No Level 2 required.			
1297	7199	7192	0	COMMON SYSTEMS	POWER CENTER C	POWER CENTER C	Power Centre C (SAB12, Diesel Bus DB12)	10	6	Inspect and test transformer AT-C and the individual AK-50 / AK-25 air circuit breakers and the bussing Check bus-bar bolts and retorqued. Transformer: turns ratio, power and dissipation factor, winding resistance, movement of coils, core grounds, taps and general condition and cleanliness.	2011	2	$75
1297	7199	7192	7188	COMMON SYSTEMS	POWER CENTER C	COMMON SERVICES MCC C1	N/A	11	6	No Level 2 required.			
1297	7199	7192	7411	COMMON SYSTEMS	POWER CENTER C	C.W. PUMPHOUSE MCC C6	N/A	12	6	No Level 2 required.			
1297	7199	7195	0	COMMON SYSTEMS	STAGE 1 129V D.C.SUPPLY SYSTEM	STAGE 1 129V D.C.SUPPLY SYSTEM	N/A	13	6	No Level 2 required.			
1297	7199	7195	303344	COMMON SYSTEMS	STAGE 1 129V D.C.SUPPLY SYSTEM	129 VDC STAGE 1 BATTERIES	N/A	14	6	No Level 2 required.			
1297	7199	7195	303345	COMMON SYSTEMS	STAGE 1 129V D.C.SUPPLY SYSTEM	129 VDC CHARGER A	N/A	15	6	No Level 2 required.			
1297	7199	7195	303346	COMMON SYSTEMS	STAGE 1 129V D.C.SUPPLY SYSTEM	129 VDC CHARGER A	N/A	16	6	No Level 2 required.			

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Table 11-14 Cont'd

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset 2/3	Asset 3/4	Description	Sub System Comment	L2#	Appendix #	Level 2 Work	Year	Priority	Cost k$
1297	7199	7195	303350	COMMON SYSTEMS	STAGE 1 129V D.C.SUPPLY SYSTEM	129 VDC CHARGER A	N/A	17	6	No Level 2 required.			
1297	7199	7195	303351	COMMON SYSTEMS	STAGE 1 129V D.C.SUPPLY SYSTEM	129 VDC CHARGER B	N/A	18	6	No Level 2 required.			
1297	7199	8730	0	COMMON SYSTEMS	STATION SERVICE POWER SYSTEM	STATION SERVICE POWER SYSTEM	N/A	19	6	No Level 2 required.			
1297	7199	8730	8731	COMMON SYSTEMS	STATION SERVICE POWER SYSTEM	STATION SERVICE BOARD SB-34	N/A	20	6	No Level 2 required.			
1297	7199	8730	8732	COMMON SYSTEMS	STATION SERVICE POWER SYSTEM	STATION AUXILIARY BOARD SAB-34	N/A	21	6	No Level 2 required.			
1297	7199	8730	8738	COMMON SYSTEMS	STATION SERVICE POWER SYSTEM	GENERAL PURPOSE MCC GPB-34	N/A	22	6	No Level 2 required.			
1297	7199	8730	8740	COMMON SYSTEMS	STATION SERVICE POWER SYSTEM	TURB & BLR STANDBY MCC SDB-34	N/A	23	6	No Level 2 required.			
1297	7199	8730	8742	COMMON SYSTEMS	STATION SERVICE POWER SYSTEM	DIESEL BUS DB-34	N/A	24	6	No Level 2 required.			
1297	7199	8730	8743	COMMON SYSTEMS	STATION SERVICE POWER SYSTEM	ESSENTIAL SERVICES MCC ESB-34	N/A	25	6	No Level 2 required.			
1297	7199	8730	8746	COMMON SYSTEMS	STATION SERVICE POWER SYSTEM	C.W. PUMPHOUSE MCC CWP-34	N/A	26	6	No Level 2 required.			
1297	7199	8730	99000405	COMMON SYSTEMS	STATION SERVICE POWER SYSTEM	INSTALL STATION SERVICE TRANSF	N/A	27	6	No Level 2 required.			
1297	7199	8771	0	COMMON SYSTEMS	STAGE 2 129V D.C. SUPPLY	STAGE 2 129V D.C. SUPPLY	N/A	28	6	No Level 2 required.			
1297	7199	8771	99000355	COMMON SYSTEMS	STAGE 2 129V D.C. SUPPLY	INSTALL D.C. DISTRIBUTION BOAR	N/A	29	6	No Level 2 required.			
1297	7199	8771	99029568	COMMON SYSTEMS	STAGE 2 129V D.C. SUPPLY	C & D 60 CELL BATTERY BANK	N/A	30	6	No Level 2 required.			

11.1.3.8 Capital Projects

The suggested typical capital enhancements for the common electrical and control assets include:

TABLE 11-15 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – COMMON ELECTRICAL AND CONTROL ASSETS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset 2/3	Asset 3/4	Description	CAP#	Appendix #	Capital Item	Date	Priority
1297	7199	6727	0	0	COMMON SYSTEMS	STAGE 1 STATION SERVICE POWER	STAGE 1 STATION SERVICE POWER	5	6	No capital required.		
1297	7199	6904	301712	0	COMMON SYSTEMS	STATION SERVICE DCS	STATION SERVICE DCS	6	6	No capital required.		
1297	7199	7189	0	0	COMMON SYSTEMS	STATION BOARD SB-12	STATION BOARD SB-12	7	6	Include this relaying in SB12 modernization implementation for the protection relays.	2014	1
1297	7199	7189	0	0	COMMON SYSTEMS	STATION BOARD SB-12	STATION BOARD SB-12	8	6	Replace existing breakers SSB1, SSB2, SSB3, SSB4 during the complete overhaul with Eaton Electrical VR-Series breakers for a life expectancy to at least 2041. Implement, as required, Eaton Electrical Remote racking device (RPR2)remote racking.	2013	1
1297	7199	7190	0	0	COMMON SYSTEMS	DIESEL BUS DB12	DIESEL BUS DB12	9	6	Diesel Bus DB12 is part of Power Centre "C" and addressed there.	2013	1
1297	7199	7191	0	0	COMMON SYSTEMS	ESSENTIAL SERVICE MCC E1	ESSENTIAL SERVICE MCC E1	10	6	No capital identified as required.		
1297	7199	7192	0	0	COMMON SYSTEMS	POWER CENTER C	POWER CENTER C	11	6	Change all Power Centre C (SAB12, Diesel Bus DB12) protection setting to improve arc-flash ratings, unless already completed, including: - Protection settings adjustment on breaker C1, secondary of transformer AT-C.	2013	1
1297	7199	7192	0	0	COMMON SYSTEMS	POWER CENTER C	POWER CENTER C	12	6	Overhaul to an "as new condition" of the switchgear or replace - including cubicles and breaker elements, extending the life expectancy of the existing switchgear for a further 15-20 years. Use spare breaker elements to overhaul each breaker off site with essentially no interruption to plant requirements.	2013	1
1297	7199	7192	7188	0	COMMON SYSTEMS	POWER CENTER C	COMMON SERVICES MCC C1	13	6	No capital identified as required.		
1297	7199	7192	7411	0	COMMON SYSTEMS	POWER CENTER C	C.W. PUMPHOUSE MCC C6	14	6	Replace.	2011	1
1297	7199	7195	0	0	COMMON SYSTEMS	STAGE 1 129V D.C.SUPPLY SYSTEM	STAGE 1 129V D.C.SUPPLY SYSTEM	15	6	Replace Common Stage 1 129VDC Supply System Panel and breakers.	2012	1
1297	7199	7195	303344	0	COMMON SYSTEMS	STAGE 1 129V D.C.SUPPLY SYSTEM	129 VDC Stage 1 Batteries	16	6	No capital required.		
1297	7199	7195	303345	0	COMMON SYSTEMS	STAGE 1 129V D.C.SUPPLY SYSTEM	129 VDC Charger A	17	6	No capital required.		
1297	7199	7195	303351	0	COMMON SYSTEMS	STAGE 1 129V D.C.SUPPLY SYSTEM	129 VDC Charger B	20	6	No capital required.		
1297	7199	8730	0	0	COMMON SYSTEMS	STAGE 2 STATION SERVICE POWER SYSTEM	STAGE 2 STATION SERVICE POWER SYSTEM	21	6	No capital required.	2015	2

Table 11-15 Cont'd

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset 2/3	Asset 3/4	Description	CAP#	Appendix #	Capital Item	Date	Priority
1297	7199	8730	8731	0	COMMON SYSTEMS	STAGE 2 STATION SERVICE POWER SYSTEM	STATION SERVICE BOARD SB-34	22	6	No capital required.	2015	2
1297	7199	8730	8732	0	COMMON SYSTEMS	STAGE 2 STATION SERVICE POWER SYSTEM	STATION AUXILIARY BOARD SAB-34	23	6	No capital required.	2015	2
1297	7199	8730	8738	0	COMMON SYSTEMS	STAGE 2 STATION SERVICE POWER SYSTEM	GENERAL PURPOSE MCC GPB-34	24	6	Refurbish/replace as required	2015	2
1297	7199	8730	8740	0	COMMON SYSTEMS	STAGE 2 STATION SERVICE POWER SYSTEM	TURB & BLR STANDBY MCC SDB-34	25	6	Refurbish/replace as required	2015	2
1297	7199	8730	8742	0	COMMON SYSTEMS	STAGE 2 STATION SERVICE POWER SYSTEM	DIESEL BUS DB-34	26	6	Refurbish/replace as required	2015	2
1297	7199	8730	8743	0	COMMON SYSTEMS	STAGE 2 STATION SERVICE POWER SYSTEM	ESSENTIAL SERVICES MCC ESB-34	27	6	Refurbish/replace as required	2015	2
1297	7199	8730	8746	0	COMMON SYSTEMS	STAGE 2 STATION SERVICE POWER SYSTEM	C.W. PUMPHOUSE MCC CWP-34	28	6	Refurbish/replace as required	2015	2
1297	7199	8771	0	0	COMMON SYSTEMS	STAGE 2 129V D.C. SUPPLY	STAGE 2 129V D.C. SUPPLY	29	6	Replace	2015	2
1297	7199	8771	99029568	0	COMMON SYSTEMS	STAGE 2 129V D.C. SUPPLY	C & D 60 CELL BATTERY BANK	31		No capital required.		

11.1.4 Asset 272255 – Buildings and Building M and E System

(Detailed Technical Assessment in Working Papers - Appendices 6, 4, 17)

Unit #:	COMMON
Asset Class #	BU 1297 – Assets Common
SCI & System:	7255 HRD Buildings & Site
Sub-Systems:	272255 HRD Buildings
Components: +	7283 Main Powerhouse 7285 HRD Stage 1 Pumphouse 7286 HRD Stage 2 Pumphouse 7284 HRD Training Centre 7287 HRD Guardhouse 7288 HRD H2 and CO2 Storage Building 7302 HRD Shawmont building 7303 HRD Main Warehouse 7307 HRD Gas Turbine Building

Note: Asbestos was not specifically addressed as a program is in place to address it.

11.1.4.1 Description

Asset 7283 - Main Powerhouse

The main powerhouse building houses Unit 1, Unit 2 and Unit 3. It is a single building/structure that includes the boiler building, the steam turbine hall, and the administration block. The assessment includes:

- Structural supports
- Roof condition (Envelope)
- HVAC system

The boiler building is constructed with concrete foundations and a steel superstructure. The boilers are hung from large steel beams at the top of the building. The building was installed in two stages – Stage 1 included Units 1 and 2 and was completed in 1966, and Stage 2 – Unit 3 which was completed in 1977. The building has a flat asphalt roof. It has large motorized ventilation fans at the roof and steam coil heated air make-up rooms on the basement level.

The steam turbine hall is constructed with concrete foundations and a steel superstructure. The turbines and generators sit on large, concrete foundations and pedestals and are independent of the building. The building has a flat asphalt roof.

The administration building includes the administration block as well as the water treatment plant. It is constructed with concrete foundations, a steel superstructure, and steel panel roofing.

The powerhouse HVAC system consists primarily of a steam coil warm air make-up system. In 1992 it was installed on the basement level of the powerhouse to replace the original ventilation panels. The system also includes roof and near roof ventilation fans, and dispersed steam coil heaters that are supplemented by electric heaters. The steam supply for the auxiliary heaters is extracted from the main boilers. It was originally extracted from the plant auxiliary boiler. The original auxiliary boiler was removed.

The main powerhouse crane is a large bridge crane spanning the turbine hall. The bridge crane has both a main and auxiliary crane hook. In addition there are unit boiler house cranes. The powerhouse crane is due for a planned crane/hoist upgrade to its controls and brakes in 2012.

Asset 7285 HRD Stage 1 Pumphouse

The Stage 1 pump house serves Units 1 and 2 and includes an intake structure, two traveling screens and auxiliaries per unit, and two cooling water pumps and auxiliaries per unit. It was completed in 1966. The Stage 1 pumphouse also houses the raw water and fire water facilities. It is connected via an underground tunnel to the plant.

The building is an industrial class building with a concrete foundation and a steel superstructure with metal cladding. There are 15 tonne and 25 tonne overhead cranes in each pumphouse. Large concrete cavities under the floor are filled with water from the adjacent saltwater-freshwater pond.

Asset 7286 HRD Stage 2 Pumphouse

The Stage 2 pump house services Unit 3. It was completed in 1977 and includes an intake structure, two traveling screens and auxiliaries, and two cooling water pumps and auxiliaries. Stage 2 also has space and sub-floor provision for a fourth unit. A sump pump in one of the fourth unit CW pump pits provides turbine cooling water for Unit 3 when in synchronous condensing operation. It is connected via an underground tunnel to the plant.

The building is an industrial class building with a concrete foundation and a steel superstructure with metal cladding. There are 15 tonne and 25 tonne overhead cranes. Large concrete cavities under floor are filled with water from the adjacent saltwater-freshwater pond.

Asset 7284 HRD Training Centre

The training centre is a pre-engineered steel building on a concrete foundation.

Asset 7287 HRD Guardhouse

The guardhouse is a structural supported steel building on a concrete foundation.

Asset 7288 HRD H2 and CO2 Storage Building

The H2 and CO2 storage building is a pre-engineered steel building on a concrete foundation. The assessment includes the general building condition and the roof and siding condition

Asset 7302 HRD Shawmont Building

The Shawmont building is a pre-engineered steel building on a concrete foundation.

Asset 7303 HRD Main Warehouse

The main warehouse is a structural supported steel building on a concrete foundation.

Asset 7307 HRD Gas Turbine Building

The gas turbine building at the plant houses the gas turbine that is used in the event of a black start. The existing gas turbine building was constructed in 1986. The building is of pre-engineered, galvanized metal-panel construction, 40 ft in width and 50 ft in length with R20 exterior wall insulation. The foundation is of conventional reinforced concrete pier/wall and floor slab construction and incorporates the original turbine and module slabs. A full height concrete block partition wall was installed to completely separate the turbine/generator sections from the remaining building area. It houses a one tonne hoist/track provision to move equipment to the service area. The electrical area is divided into a battery room, a control room and an MCC/switchgear section. It has an oil drain provision for both the service and turbine rooms complete with a reinforced concrete trap. A rolling service door between the turbine and work area is provided for fire containment but easily removed for heavy equipment.

Waste Water Treatment Plant (WWTP) Batch Reactor & Building

The WWTP process equipment was installed in a separate building in 1994. It consists of a batch stirred reactor and a filter press. As a result, the mechanical filter is about 16 years old and the filter press less than 10 years.

Waste Water Treatment Plant Treatment Basin & Building

The two WWTP treatment basins and their building enclosure were built in 1992 to address effluent concerns. The two settling ponds serve dirty sources and cleaner sources respectively. No automated treatment is installed, but the pH is addressed periodically. The basins are hard concrete built on bedrock.

11.1.4.2 History - Inspection and Repair History

Asset 7283 Main Powerhouse

Structural: No structural steel inspection reports were identified or reviewed. A visual inspection found no misaligned boiler buckstays or other members that suggested an issue. Some modifications to Unit 3 in the area of the synchronous condenser were made when it was retrofitted to ensure suitable isolation from the rest of the powerhouse similar to that of the rest of the steam turbine generator. No changes were made when Units 1 and 2 were upgraded to 175 MW from 150 MW in 1987.

Roofs & Siding: Prior to 2005 there was a roof life management program in place. As a result, the roofs were replaced and the siding was upgraded during the 1990 to 2000 period. This is consistent with a typical industry multi-year roofing plan after approximately 25 years in-service.

Visually the difference between the conditions of various sections of the asphalt roofing was evident. Water pooling and some reported small leaks and patching indicate the roof is approaching end of life again. The sloped metal roofs of the administration building and water treatment plant show some signs of corrosion and wear due to the marine environment.

No specific assessments of the siding condition were identified. It was upgraded in 1990-2000, and visibly appeared in reasonably good shape, although some areas are likely to need repainting or refurbishment within the next five to 10 years. Asbestos was identified as being an issue with the siding and will require considerable care. It was not addressed as it was assumed to be part of the station asbestos management program.

HVAC: The heating and ventilation system of the main powerhouse (boiler and steam turbine) vents on the top floor of the boiler house appear to perform well. No specific reports on their condition were identified and reviewed. Interviews identified some issues with water ingress and the ability of the fans to overcome ambient backpressure during high wind period. This has led to some units being equipped with outlet hoods (likely be adopted across the board). No other issues appear likely, provided the motors are periodically checked and maintained as required.

In 1992, the steam coil warm air make-up system was installed on the basement level of the powerhouse to replace the original ventilation panels. It was designed to automatically adjust its output to maintain the powerhouse pressure and temperature using PLC controllers. There have been issues with the system control when large building access doors have been open. As a result, the station is considering reverting to manual control of these systems.

The powerhouse auxiliary steam system is currently supplied with steam from an operating boiler supplemented by electrical heaters. The original auxiliary boiler was removed. Many of the current steam coil heaters dispersed throughout the powerhouse are in very poor condition and are operating inefficiently. While maintained regularly, primarily on an as-required basis, it is clear that the system's condition is not adequate for the requirement when the main boilers are not in-service and the units are operated as synchronous condensers.

The HVAC system for the main administration building was replaced in 2002 to 2005. With regular maintenance, it should last until 2020. Beyond 2020, additional selective replacements may be required.

Elevators: There are two elevators: the boiler house elevator and the administration office elevator. The boiler house elevator: is a 7 foot x 6 foot 2 inches passenger elevator capable of carrying 3500 pounds from the ground floor to tenth floor, serving eleven stops. The administration office elevator is a 6 foot 4 inches x 4 foot 5 inches passenger elevator capable of carrying 2000 pounds from the ground floor to second floor, serving two stops. Both elevators are inspected and maintained as required. There are no major failures identified in the service records, but the units' frequency of maintenance is increasing and their physical age is of concern.

Crane: The main powerhouse crane, the boiler building crane, and the two pumphouse cranes have been inspected regularly and where cables or brakes have been modified, they have undergone the standard 120+% waterbag test to ensure they are functioning. There does not appear to be any major issue with the crane, outside of the norm expected for maintenance and life management purposes. Some improvements are planned on the controls and brake systems of the auxiliary portion of the powerhouse crane. A waterbag test would be conducted as a part of that program.

Electrical System: Consistent with the station PM protocol, components of the electrical systems throughout the facility are inspected and refurbished on a regular basis, but are also nearing end of life or time for a major refurbishment. Most original motor control centres require replacement in the next 1 to 5 years. Most 600V and 4kV breakers require refurbishment.

Water Treatment Plant: A new demineralizer section of the water treatment plant was built in 1992 as part of a building addition to the water treatment plant. The building is in good shape with only some metal roofing showing some signs of corrosion and wear from the marine environment.

Asset 7285 HRD Stage 1 Pumphouse

Inspection records specific to the pumphouse were not available. A visual walkthrough of the pumphouse building was performed to gauge the existing condition of the buildings.

Structural: The structural steel in the building appears to be in good condition with minor corrosion on some of the steel members. The concrete floor shows some signs of cracking and wear.

Roofs & Siding: The pumphouse roofs were included in the powerhouse upgrade between 1990 and 2000. Visually, the metal roofs show some signs of corrosion and wear due to the marine environment. In general they are in good condition.

The siding is in reasonably good shape, with some areas likely to need repainting or refurbishment in the near future.

Crane: The pumphouse cranes have been inspected regularly and where cables or brakes have been modified they have undergone the standard 120+% waterbag test to ensure they are functioning properly. There does not appear to be any major issue with the crane, outside of the norm expected for maintenance and life management purposes.

Electrical System: Components of the electrical systems are inspected and refurbished on a regular basis consistent with the station PM protocol, but are also nearing end of life or time for a major refurbishment. Most original Motor Control Centres require replacement in the next 1 to 5 years. Most 600V and 4kV breakers require refurbishment.

Asset 7286 HRD Stage 2 Pumphouse

Inspection records specific to the Stage 2 pumphouse were not available. A visual walkthrough of the pumphouse building was performed to gauge the existing condition of the buildings.

Structural: The structural steel in the building appears to be in good condition with minor corrosion on some of the steel members. The concrete floor shows some signs of cracking and wear.

Roofs & Siding: The pumphouse roofs were included in the powerhouse upgrade between 1990 and 2000. Visually, the metal roofs show some signs of corrosion and wear due to the marine environment. In general, they are in good condition.

The siding is in reasonably good shape, with some areas likely to need repainting or refurbishment in the near future.

Crane: The pumphouse cranes have been inspected regularly and where cables or brakes have been modified they have undergone the standard 120+% waterbag test to ensure they are functioning properly. There does not appear to be any major issue with the crane, outside of the norm expected for maintenance and life management purposes.

Electrical System: Consistent with PM protocol, components of the electrical systems are inspected and refurbished on a regular basis but are also nearing end of life or time for a major refurbishment. Most original motor control centres require replacement in the next 1 to 5 years. Most 600V and 4kV breakers require refurbishment.

Asset 7284 HRD Training Centre

Inspection records specific to the training centre were not available. A visual walkthrough was performed to gauge the existing condition of the building.

Structural: The structural systems that comprise the building are in excellent condition with very little corrosion found and no major structural deficiencies noted.

Roofs & Siding: The siding and roof are in excellent condition, aside from some modest marine ambient corrosion in some portions.

Asset 7287 HRD Guardhouse

Inspection records specific to guardhouse were not available. A visual walkthrough was performed to gauge the existing condition of the building.

Structural: The structural systems that comprise the building are in excellent condition with very little corrosion found and no major structural deficiencies noted.

Roofs & Siding: The siding and roof are in excellent condition, aside from some modest marine ambient corrosion in some portions.

Asset 7288 HRD H2 and CO2 Storage Building

Inspection records specific to the C02 storage building were not available. A visual walkthrough was performed to gauge the existing condition of the building.

Structural: The structural systems that comprise the building are in excellent condition with very little corrosion found and no major structural deficiencies noted.

Roofs & Siding: The siding and roof are in excellent condition, aside from some modest marine ambient corrosion in some portions.

Asset 7302 HRD Shawmont Building

Inspection records specific to the Shawmont building were not available. A visual walkthrough was performed to gauge the existing condition of the building.

Structural: The structural systems that comprise the building are in excellent condition with very little corrosion found and no major structural deficiencies noted.

Roofs & Siding: The siding and roof are in excellent condition, aside from some modest marine ambient corrosion in some portions.

Asset 7303 HRD Main Warehouse

Inspection records specific to the main warehouse were not available. A visual walkthrough was performed to gauge the existing condition of the building.

Structural: The structural systems that comprise the building are in excellent condition with very little corrosion found and no major structural deficiencies noted.

Roofs & Siding: The siding and roof are in excellent condition, aside from some modest marine ambient corrosion in some portions.

Waste Water Treatment Plant (WWTP) Batch Reactor & Building: The WWTP process equipment was installed in a separate building in 1994. It consists of a batch stirred reactor and a filter press. As a result, the mechanical filter is about 16 years old and the filter press less than 10 years. The building and equipment were visually inspected and appeared to be in excellent condition, as would be expected given their age. A need for a second exit from the upper level was identified by station staff.

Waste Water Treatment Plant Treatment Basin & Building: The two WWTP treatment basins and their building enclosure were built in 1992 to address effluent concerns. The two settling ponds serve dirty sources and cleaner sources respectively. No automated treatment is installed, but the pH is addressed periodically. The basins are hard concrete built on bedrock. The building shell, the building ventilation system, and the structural steel supports have experienced significant corrosion as a result of the humid atmosphere both inside and external to the building. The basins appear to be in good shape with minimal cracking identified in the records and a solid foundation. Some health and safety concerns were expressed with the building environment and pond exit in the event of someone falling in.

Asset 7307 HRD Gas Turbine Building

Inspection records specific to the turbine building were not available. A visual walkthrough of the entire gas turbine building was performed to gauge the existing condition of the building.

Structural: The structural systems that comprise the building are in excellent condition with very little corrosion found and no major structural deficiencies noted. There was significant surface corrosion found on the structural members located below the exhaust stack that sits on the roof of the building over the turbine.

Roofs & Siding: The siding and roof of the gas turbine building, specifically in the area around the stack, at the roofliner, and at the base of the building, show evidence of significant corrosion.

Exhaust Stack: The exhaust stack is extensively corroded with leaks into the building and into the turbine, and should be replaced.

Picture shows corroded exhaust stack

Picture shows corroded exhaust stack

Picture shows corroded exhaust stack

Picture shows corroded exhaust stack

FIGURE 11-10 CORRODED EXHAUST STACK (GAS TURBINE PLANT)

11.1.4.3 Condition Assessment

The condition assessment of the buildings and building M and E system is illustrated below in Table 11-16.

TABLE 11-16 CONDITION ASSESSMENT – BUILDINGS AND BUILDING M AND E SYSTEM

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset Level 2	Asset Level 3	Description	Detail	Cond. Summ. ID#	Append #	Condition	EPRI Identifier	Original Life (Base Load) Ops Hrs (Yrs)	Current Expected Minimum Remaining Life Years (Subject to Test)	End of Life Required (EOL)	Next Regular Inspection	Next Planned Overhaul/ Major Inspection	Capability to Reach Next Overhaul	Capability to Reach EOL	In Service
1297	7255	272255	7283	0	BUILDINGS AND SITE	BUILDINGS	MAIN POWERHOUSE		70	17	Structurally in good condition. No visual inspections of roof structures at close range possible. Little corrosion evident. Roofs replaced in 1990 to 2000, with some evidence of age and small leaks. Sloped metal roofs of Administration Building and WTP have some corrosion and wear. Some siding replaced in 1996, but lower levels not done and in need of refurbishment.	3a	(60)	(5-30)	2041	2011		Yes	Yes	1969/79
1297	7199	7256	271815	0	COMMON SYSTEMS	CRANES AND HOISTS	POWERHOUSE CRANE	N/A	71	17	Good condition. Regular inspections and load test when major modifications undertaken. Auxiliary crane brakes and controls work planned.	4	(50)	(2/20)	2041	2011		No	No	1969
1297	7199	7256	271816	0	COMMON SYSTEMS	CRANES AND HOISTS	BOILER ROOM HOISTS	N/A	72	17	Good condition. No information on testing	4	(50)	(5)	2041	2011		No	No	1969
1297	7255	272255	7283	7306	BUILDINGS AND SITE	BUILDINGS	BUILDING SERVICES ELEVATOR	Plant	73	17	Service work required monthly. Acceptable condition, but decreased reliability. Nearing end of life.	4	(40)	5	2041	2011		Yes	No	1969
1297	7255	272255	7283	7306	BUILDINGS AND SITE	BUILDINGS	BUILDING SERVICES ELEVATOR	Admin	74	17	Service work required monthly. Acceptable condition. Approaching end of life.	3a	(40)	5+	2041	2011		Yes	No	1991
1297	7199	7208	99000093	0	COMMON SYSTEMS	AUXILIARY STEAM SYSTEM	AUXILIARY STEAM SYSTEM	N/A	76		Not reviewed. Visually checked OK. Needed when synchronous condensing	10	(30)	5	2041			No	No	1968-1970
1297	7199	7251	0	0	COMMON SYSTEMS	FIRE PROTECTION SYSTEMS	FIRE PROTECTION SYSTEMS	N/A	77		Major portion relatively new, about 5 to 6 years. No inspections. Little recent information on older underground services	3a	(30)	(5-20)	2041	2011		No	No	2005-2010
1297	7199	6769	0	0	COMMON SYSTEMS	HEATING AND VENTILATION	HEATING AND VENTILATION	Auxiliary steam unit heaters	79	6	Numerous auxiliary steam unit heaters in poor condition. Auxiliary steam system upgrade needed consistent with plan for replacement energy source post synchronous condenser conversion.	4	(40)	20	2041			No	No	1968-2004
1297	7199	6769	0	0	COMMON SYSTEMS	HEATING AND VENTILATION	HEATING AND VENTILATION	Near-roof fan weather hoods	80	6	Windy ambient conditions restricts near-roof fans ability to maintain upper powerhouse air quality levels without weather hoods.	4	(40)	20	2041	2011		Yes	No	1968-2010
1297	7199	7297	0	0	COMMON SYSTEMS	WARM AIR MAKE-UP	WARM AIR MAKE-UP	N/A	81	17	Relatively new and good condition, but control improvements required to prevent nearby equipment freeze-up.	10	(30)	(20)	2041	2011		Yes	No	1969/79/99
1297	7255	272255	7285	0	BUILDINGS AND SITE	BUILDINGS	STAGE 1 PUMPHOUSE	N/A	97	17	The structural systems appear generally in good condition, but no visual inspections of roof structures at close range were possible. Very little corrosion was evident and no major structural deficiencies noted. The sidings and roofs are in good shape with only some modest corrosion.	4	(60)	(5-20)	2041			Yes	No	1968
1297	7199	7256	271817	0	COMMON SYSTEMS	CRANES AND HOISTS	PUMPHOUSE CRANE STAGE 1	N/A	98	17	Good condition. Load tested within 5 years.	3a	(50)	(10)	2041	2011		No	No	1969
1297	7199	7251	7486	0	COMMON SYSTEMS	FIRE PROTECTION SYSTEMS	FIRE PUMPS - ELECTRIC	N/A	99	12,15	Acceptable condition. Old system may need replacement to align with higher firefighting flow requirements.	3a	(30)	5	2041	2011		No	No	1969
1297	7199	7251	7487	0	COMMON SYSTEMS	FIRE PROTECTION SYSTEMS	FIRE PUMPS - DIESEL	N/A	100	12,15	Replace diesel.	10	(25)	1	2041	2011		No	No	1969
1297	7255	272255	7286	0	BUILDINGS AND SITE	BUILDINGS	STAGE 2 PUMPHOUSE		101	17	The structural systems appear generally in good condition, but no visual inspections of near roof structure at close range were possible. Very little corrosion was evident and no major structural deficiencies noted. The sidings and roofs are in good shape with only some modest corrosion.	4	(60)	(5-20)	2041			Yes	No	1979
1297	7199	7256	271818	0	COMMON SYSTEMS	CRANES AND HOISTS	PUMPHOUSE CRANE STAGE 2	N/A	102	17	Good condition. Load tested within 5 years.	3a	(50)	(10)	2041	2011		No	No	1979
1297	7255	272255	7287	0	BUILDINGS AND SITE	BUILDINGS	GUARDHOUSE	N/A	105	17	The structural systems are in good condition with very little corrosion found and no major structural deficiencies noted. The sidings and roofs are in good shape with only some modest corrosion.	3a	(40)	20+	2041			Yes	No	2006
1297	7255	272255	7284	0	BUILDINGS AND SITE	BUILDINGS	TRAINING CENTRE	N/A	106	17	The structural systems are in good condition with very little corrosion found and no major structural deficiencies noted. The sidings and roofs are in good shape with only some modest corrosion.	3a	(40)	10	2041			Yes	No	1969
1297	7255	272255	7288	0	BUILDINGS AND SITE	BUILDINGS	H2 & CO2 STORAGE BUILDING	N/A	107	17	The structural systems are in good condition with very little corrosion found and no major structural deficiencies noted. The sidings and roofs are in good shape with only some modest corrosion.	4	(40)	(5-20)	2041			Yes	No	1969
1297	7255	272255	7302	0	BUILDINGS AND SITE	BUILDINGS	SHAWMONT BUILDING	N/A	108	17	The structural systems are in good condition with very little corrosion found and no major structural deficiencies noted. The sidings and roofs are in good shape with only some modest corrosion.	4	(40)	(5-20)	2041			Yes	No	1969
1297	7255	272255	7303	0	BUILDINGS AND SITE	BUILDINGS	MAIN WAREHOUSE	N/A	109	17	The structural systems are in good condition with very little corrosion found and no major structural deficiencies noted. The sidings and roofs are in good shape with only some modest corrosion.	4	(40)	(5-20)	2041			Yes	No	1969
1297	7255	272255	7304	0	BUILDINGS AND SITE	BUILDINGS	WWT PLANT BUILDING	N/A	110	17	Structurally in excellent condition with very little corrosion found and no major structural deficiencies noted. Some rusting siding. No second emergency egress from the building 2nd floor batch reactor work station.	4	(50)	(5-20)	2041			Yes	No	1994
1297	7255	272255	7305	0	BUILDINGS AND SITE	BUILDINGS	WWT BASINS BUILDING	N/A	111	17	Basins building built in 1992 has some OHSA air quality concerns by staff and safety issues around basin access (exit routes). Very humid atmosphere has damaged ventilation systems and roofing. The structural steel has also experienced significant rusting.	10	(30)	(3)	2041			No	No	1992
1297	7255	272255	7307	0	BUILDINGS AND SITE	BUILDINGS	GAS TURBINE BUILDING	N/A	112	17	Structurally in good condition with modest corrosion and no significant structural deficiencies noted, except where related to gas turbine intake and exhaaust. Some surface corrosion on structural members located below the exhaust stack. Sidings and roofs of the Gas Turbine Building have some corrosion requiring repair.	4	(40)	(2-10)	2020	2010		Yes	No	1986
1297	7255	272255	272256	0	BUILDINGS AND SITE	BUILDINGS	WATER TREATMENT BUILDING	N/A	113	17	The structural systems appear generally in good condition, but no visual inspections at close range were possible. Very little corrosion was evident and no major structural deficiencies noted. The sidings and in particular the roof have some modest corrosion.	4	(40)	30	2041			Yes	Yes	1998

Notes:

1. A "(bracketed)" value in the "Current Expected Remaining Life" column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation, including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as "(X/Y)" has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

2. The "Next Regular Inspection" column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The "Next Planned Overhaul or Major Inspection" column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a "Desired Life" stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where no specific dates have been identified for "Next Regular Inspection" or "Next Planned Overhaul/Major Inspection", they are left blank.

11.1.4.4 Actions

Based on the condition assessment, the following actions are recommended for the buildings and building M and E system:

TABLE 11-17 RECOMMENDED ACTIONS – BUILDINGS AND BUILDING M AND E SYSTEM

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset 2/3	Asset 3/4	Description	Action #	App #	Action	Year	Priority
1297	7255	272255	7283	0	BUILDINGS AND SITE	BUILDINGS	MAIN POWERHOUSE	73	17	Develop & implement roofing replacing and siding refurbishment plan.	2012	1
1297	7255	272255	7283	0	BUILDINGS AND SITE	BUILDINGS	MAIN POWERHOUSE	74	17	Modify remaining roof vents with weather hoods.	2011	2
1297	7255	272255	7283	0	BUILDINGS AND SITE	BUILDINGS	MAIN POWERHOUSE	75	17	Spot check structural members near roof in crane area; and in visible corrosion areas of boiler structural support.	2011	2
1297	7255	272255	7283	0	BUILDINGS AND SITE	BUILDINGS	MAIN POWERHOUSE	76	17	Optimize Warm Air Make Up system.	2011	2
1297	7199	7256	271815	0	COMMON SYSTEMS	CRANES AND HOISTS	POWERHOUSE CRANE	77	17	Implement modifications to brakes, cables of aux hoist. Continue current inspections and tests.	2011	1
1297	7199	7256	271816	0	COMMON SYSTEMS	CRANES AND HOISTS	BOILER ROOM HOISTS	78	17	Inspection and maintain as per current program.	2011	1
1297	7255	272255	7283	7306	BUILDINGS AND SITE	BUILDINGS	BUILDING SERVICES ELEVATOR	79	17	Continue ongoing life maintenance. Replace powerhouse and possibly administration elevators.	2012-2015	2
1297	7199	7208	0	0	COMMON SYSTEMS	AUXILIARY STEAM SYSTEM	AUXILIARY STEAM SYSTEM	80		Maintain existing system. Develop replacement for synchronous condensing operation. Upgrade individual unit auxiliary heaters and system as required.	2012	1
1297	7199	7208	99000093	0	COMMON SYSTEMS	AUXILIARY STEAM SYSTEM	AUXILIARY STEAM SYSTEM	81		Refurbish system. Develop alternative heating system for post-generation period.	2012	2
1297	7199	7251	0	0	COMMON SYSTEMS	FIRE PROTECTION SYSTEMS	FIRE PROTECTION SYSTEMS	82	15	No recommended action.		
1297	7199	7251	7270	0	COMMON SYSTEMS	FIRE PROTECTION SYSTEMS	GAS FIRE SUPPRESSION SYSTEMS	83	15	No recommended action.		
1297	7199	7251	327186	0	COMMON SYSTEMS	FIRE PROTECTION SYSTEMS	FIRE PROTECTION SYSTEM UPGRADE	84	15	No recommended action.		
1297	7199	6769	0	0	COMMON SYSTEMS	HEATING AND VENTILATION	HEATING AND VENTILATION	85	17	Modify ventilation hoods. Optimize control of Warm Air Make-Up System. Develop a plan for auxiliary steam heating alternative for Synchronous Condensing operation.	2012	2
1297	7199	7297	0	0	COMMON SYSTEMS	WARM AIR MAKE-UP	WARM AIR MAKE-UP	86	17	Implement management changes - manual control.	2011	1
1297	7255	272255	7285	0	BUILDINGS AND SITE	BUILDINGS	STAGE 1 PUMPHOUSE	102	17	Undertake a Level 2 inspection of the concrete floor to make a recommendation on remaining service life.	2011	1
1297	7255	272255	7285	0	BUILDINGS AND SITE	BUILDINGS	STAGE 1 PUMPHOUSE	103	17	Develop a roofing and siding refurbishment plan. Maintain program of inspection and repairs as required, including painting structural members Flag any structural deficiencies.	2014	2

Table 11-17 Cont'd

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset 2/3	Asset 3/4	Description	Action #	App #	Action	Year	Priority
1297	7255	272255	7285	0	BUILDINGS AND SITE	BUILDINGS	STAGE 1 PUMPHOUSE	104	17	Spot check structural members near roof in crane area.	2011	1
1297	7199	7256	271817	0	COMMON	CRANES AND HOISTS	PUMPHOUSE CRANE STAGE 1	105	17	Inspection and maintain as per current program.	2011	1
1297	7199	7251	7486	0	COMMON SYSTEMS	FIRE PROTECTION SYSTEMS	FIRE PUMPS - ELECTRIC	106	15	No recommended action. Evaluate increased capacity needs.		
1297	7199	7251	7487	0	COMMON SYSTEMS	FIRE PROTECTION SYSTEMS	FIRE PUMPS - DIESEL	107	15	Replace fire pump diesel.	2011	1
1297	7255	272255	7286	0	BUILDINGS AND SITE	BUILDINGS	STAGE 2 PUMPHOUSE	108	17	Undertake a Level 2 inspection of the concrete floor to make a recommendation on remaining service life.	2011	1
1297	7255	272255	7286	0	BUILDINGS AND SITE	BUILDINGS	STAGE 2 PUMPHOUSE	109	17	Develop a roofing and siding refurbishment plan. Maintain program of inspection and repairs as required, including painting structural members Flag any structural deficiencies.	2014	2
1297	7255	272255	7286	0	BUILDINGS AND SITE	BUILDINGS	STAGE 2 PUMPHOUSE	110	17	Spot check structural members near roof in crane area.	2011	1
1297	7199	7256	271818	0	COMMON SYSTEMS	CRANES AND HOISTS	PUMPHOUSE CRANE STAGE 2	111	17	Inspection and maintain as per current program.	2011	1
1297	7255	272255	7287	0	BUILDINGS AND SITE	BUILDINGS	GUARDHOUSE	114	17	Maintain program of inspection and repairs as required, including painting structural members and siding, and roofing. Flag any structural deficiencies.	2011	1
1297	7255	272255	7284	0	BUILDINGS AND SITE	BUILDINGS	TRAINING CENTRE	115	17	Maintain program of inspection and repairs as required, including painting structural members and siding, and roofing. Flag any structural deficiencies.	2011	3
1297	7255	272255	7288	0	BUILDINGS AND SITE	BUILDINGS	H2 & CO2 STORAGE BUILDING	116	17	Maintain program of inspection and repairs as required, including painting structural members and siding, and roofing. Flag any structural deficiencies.	2011	1
1297	7255	272255	7302	0	BUILDINGS AND SITE	BUILDINGS	SHAWMONT BUILDING	117	17	Maintain program of inspection and repairs as required, including painting structural members and siding, and roofing. Flag any structural deficiencies.	2011	1
1297	7255	272255	7303	0	BUILDINGS AND SITE	BUILDINGS	MAIN WAREHOUSE	118	17	Maintain program of inspection and repairs as required, including painting structural members and siding, and roofing. Flag any structural deficiencies.	2011	1
1297	7255	272255	7304	0	BUILDINGS AND SITE	BUILDINGS	WWT PLANT BUILDING	119	16	Maintain program of inspection and repairs as required, including painting structural members and siding, and roofing. Flag any structural deficiencies.	2011	1
1297	7255	272255	7305	0	BUILDINGS AND SITE	BUILDINGS	WWT BASINS BUILDING	120	16	Perform Level 2 inspections.	2011	1
1297	7255	272255	7305	0	BUILDINGS AND SITE	BUILDINGS	WWT BASINS BUILDING	121	16	Modify building walls, ventilation, roof.	2012	1
1297	7255	272255	7307	0	BUILDINGS AND SITE	BUILDINGS	GAS TURBINE BUILDING	122	17	Repair roof, and siding corrosion, repaint.	2011	1
1297	7255	272255	272256	0	BUILDINGS AND SITE	BUILDINGS	WATER TREATMENT BUILDING	123	17	Maintain program of inspection and repairs as required, including painting structural members and siding, and roofing. Flag any structural deficiencies.	2011	1

11.1.4.5 Risk Assessment

The risk assessment associated with the buildings and building M and E system, both from a technological perspective and a safety perspective, is illustrated below in Table 11-18.

TABLE 11-18 RISK ASSESSMENT – BUILDINGS AND BUILDING M AND E SYSTEM

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset 2/3	Asset 3/4	Description	Component	Risk Assess #	Appendix #	Major Issues	Remaining Life Years	Remaining Life	Techno-Eco Risk Assess Model			Safety Risk Assess Model			Possible Failure Event	Mitigation
												(Insufficient Info - Inspection Required Within (x) Years)	Comments	Likeli-hood	Conse-quence	Risk Level	Likeli-hood	Conse-quence	Safety Risk		
1297	7255	272255	7283	0	BUILDINGS AND SITE	BUILDINGS	MAIN POWERHOUSE	Powerhouse Roofs	75	17	Mechanical, civil.	(5-10)	N/A	2	C	Medium	2	C	Medium	Safety – personnel, electric.	Inspect, maintain and replace.
1297	7255	272255	7283	0	BUILDINGS AND SITE	BUILDINGS	MAIN POWERHOUSE	Powerhouse Siding	76	17	Corrosion-appearance.	(5-10)	N/A	1	B	Low	1	A	Low	Leak, appearance.	Inspect and refurbish.
1297	7255	272255	7283	0	BUILDINGS AND SITE	BUILDINGS	MAIN POWERHOUSE	Structure - Powerhouse	77	17	Corrosion.	30	Visual inspection near roof reqd	1	B	Low	1	C	Low	Local failure - safety.	Inspect and refurbish.
1297	7199	7256	271815	0	COMMON SYSTEMS	CRANES AND HOISTS	POWERHOUSE CRANE	None	78	17	Crane mechanical, brake refurbishment.	(2/20)	Aux Crane Brake & Controls in 2012	1	D	Medium	1	D	Medium	Failure during lift. Dropped load.	Isolate, refurbish, maintain, test.
1297	7199	7256	271816	0	COMMON SYSTEMS	CRANES AND HOISTS	BOILER ROOM HOISTS	None	79	17	Mechanical failure.	(5)	N/A	2	C	Medium	2	D	Medium	Failure during lift. Dropped load.	Isolate, refurbish, maintain, test.
1297	7255	272255	7283	7306	BUILDINGS AND SITE	BUILDINGS	BUILDING SERVICES ELEVATOR	Powerhouse	80		Mechanical/electrical failure.	(3)	Major refurbishment	3	C	Medium	3	D	High	Failure in service -people on board.	Maintain, inspect, refurbish.
1297	7255	272255	7283	7306	BUILDINGS AND SITE	BUILDINGS	BUILDING SERVICES ELEVATOR	Admin	81		Mechanical/electrical failure.	(5)	Ongoing maintenance. Refurbish.	2	B	Low	2	D	Medium	Failure in service -people on board.	Maintain, inspect, refurbish.
1297	7199	7208	0	0	COMMON SYSTEMS	AUXILIARY STEAM SYSTEM	AUXILIARY STEAM SYSTEM	None	82		Mechanical failure/leaks.	5	N/A	2	A	Low	2	B	Low	Frozen equipment, possible shutdown of unit.	Inspection, maintenance, monitor, restrict.
1297	7199	7251	0	0	COMMON SYSTEMS	FIRE PROTECTION SYSTEMS	FIRE PROTECTION SYSTEMS	None	84		Mechanical failure. Not addressed in detail.	(5-20)	New system for most of major plant	2	C	Medium	2	D	High	Failure to contain fire - major damage, thret to life.	Inspect, maintain, test.
1297	7255	272255	7283	0	BUILDINGS AND SITE	BUILDINGS	MAIN POWERHOUSE	HVAC - Powerhouse	86	17	Temp and press control; poor air quality in uper powerhouse.	10+	Optimization reqd	1	B	Low	2	B-C	Low-Medium	Building over/underpressure - safety. Health effects of poor air quality.	Modify control. Complete fan weather hood install.
1297	7199	6769	0	0	COMMON SYSTEMS	HEATING AND VENTILATION	HEATING AND VENTILATION	None	87	17	Mechanical failure.	20	N/A	1	3	Low	1	B	Low	Unit shutdown due to low pressure.	Maintain and test.
1297	7199	7297	0	0	COMMON SYSTEMS	WARM AIR MAKE-UP	WARM AIR MAKE-UP	None	88	17	Mechanical failure. Not addressed in detail.	20+	Requires controls fix	2	A	Low	2	A	Low	Unit shutdown due to low pressure.	Fix controls. Maintain.
1297	7255	272255	7285	0	BUILDINGS AND SITE	BUILDINGS	STAGE 1 PUMPHOUSE	Pumphouse 1 Roof	104	17	Leaks – end of life.	(5-10)	N/A	1	A	Low	1	B	Low	Leak – electrical issue, safety.	Inspect and maintain.
1297	7255	272255	7285	0	BUILDINGS AND SITE	BUILDINGS	STAGE 1 PUMPHOUSE	Pumphouse 1 Siding	105	17	Corrosion-appearance.	5+	N/A	1	A	Low	1	A	Low	Leak, appearance.	Inspect and maintain.
1297	7255	272255	7285	0	BUILDINGS AND SITE	BUILDINGS	STAGE 1 PUMPHOUSE	Pumphouse 1 Structure	106	17	Corrosion-safety.	20+	Visual inspection near roof reqd	1	C	Low	1	C	Low	Local failure - safety.	Inspect and maintain.
1297	7255	272255	7285	0	BUILDINGS AND SITE	BUILDINGS	STAGE 1 PUMPHOUSE	Pumphouse 1 Concrete Floor	107	17	Corrosion-safety/perf.	(10+)	Requires Level 2 Test	2	C	Medium	2	C	Medium	Safety, unit performance, shutdown.	Inspect and refurbish.
1297	7199	7256	271817	0	COMMON SYSTEMS	CRANES AND HOISTS	PUMPHOUSE CRANE STAGE 1	None	108	17	Crane mechanical, brake failure.	(10)	N/A	1	C	Low	1	D	Medium	Isolate, refurbish, maintain, test.	Isolate, refurbish, maintain, test.
1297	7199	7251	7486	0	COMMON SYSTEMS	FIRE PROTECTION SYSTEMS	FIRE PUMPS - ELECTRIC	None	109	15	Mechanical/electrical failure.	5	N/A	3	C	Low	1	C	Low	Failure during fire	Diesel back-up. Test, inspect, maintain.
1297	7199	7251	7487	0	COMMON SYSTEMS	FIRE PROTECTION SYSTEMS	FIRE PUMPS - DIESEL	None	110	15	Mechanical failure.	1	Replacement in 2011	3	C	Medium	3	C	High	Failure during fire	Replace with new.
1297	7255	272255	7286	0	BUILDINGS AND SITE	BUILDINGS	STAGE 2 PUMPHOUSE	Pumphouse 2 Roof	111	17	Leaks – end of life.	(5-10)	N/A	1	A	Low	1	B	Low	Leak – electrical issue, safety.	Inspect and maintain.
1297	7255	272255	7286	0	BUILDINGS AND SITE	BUILDINGS	STAGE 2 PUMPHOUSE	Pumphouse 2 Siding	112	17	Corrosion-appearance.	5+	N/A	1	A	Low	1	A	Low	Leak, appearance.	Inspect and maintain.
1297	7255	272255	7286	0	BUILDINGS AND SITE	BUILDINGS	STAGE 2 PUMPHOUSE	Pumphouse 2 Structure	113	17	Corrosion.	20+	Visual inspection near roof reqd	1	C	Low	1	C	Low	Local failure - safety.	Inspect and maintain.
1297	7255	272255	7286	0	BUILDINGS AND SITE	BUILDINGS	STAGE 2 PUMPHOUSE	Pumphouse 2 Concrete Floor	114	17	Temp and press control.	(10+)	Requires Level 2 Test	2	C	Medium	2	C	Medium	Safety, unit performance, shutdown.	Inspect and refurbish.
1297	7199	7256	271818	0	COMMON SYSTEMS	CRANES AND HOISTS	PUMPHOUSE CRANE STAGE 2	None	115	17	Crane mechanical, brake failure.	(10)	N/A	1	C	Low	2	D	medium	Failure during load - damage and injury.	Isolate, refurbish, maintain, test.

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Table 11-18 Cont'd

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset 2/3	Asset 3/4	Description	Component	Risk Assess #	Appendix #	Major Issues	Remaining Life Years	Remaining Life	Techno-Eco Risk Assess Model			Safety Risk Assess Model			Possible Failure Event	Mitigation
												(Insufficient Info - Inspection Required Within (x) Years)	Comments	Likeli-hood	Conse-quence	Risk Level	Likeli-hood	Conse-quence	Safety Risk		
1297	7255	272255	7287	0	BUILDINGS AND SITE	BUILDINGS	GUARDHOUSE	Peripheral Building Roofing	118	17	Leaks – end of life.	20+	N/A	1	A	Low	1	B	Low	Safety – personnel.	Inspect and maintain.
1297	7255	272255	7287	0	BUILDINGS AND SITE	BUILDINGS	GUARDHOUSE	Peripheral Building Siding	119	17	Corrosion-appearance.	20+	N/A	1	A	Low	1	A	Low	Leak, appearance.	Inspect and maintain.
1297	7255	272255	7287	0	BUILDINGS AND SITE	BUILDINGS	GUARDHOUSE	Structure - Peripheral Building	120	17	Corrosion.	20+	N/A	1	A	Low	1	C	Low	Local failure - safety.	Inspect and maintain.
1297	7255	272255	7284	0	BUILDINGS AND SITE	BUILDINGS	TRAINING CENTRE	Peripheral Building Roofing	121	17	Leaks – end of life.	10+	N/A	1	A	Low	1	B	Low	Safety – personnel.	Inspect and maintain.
1297	7255	272255	7284	0	BUILDINGS AND SITE	BUILDINGS	TRAINING CENTRE	Peripheral Building Siding	122	17	Corrosion-appearance.	5+	N/A	1	A	Low	1	A	Low	Leak, appearance.	Inspect and maintain.
1297	7255	272255	7284	0	BUILDINGS AND SITE	BUILDINGS	TRAINING CENTRE	Structure - Peripheral Building	123	17	Corrosion.	20+	N/A	1	A	Low	1	C	Low	Local failure - safety.	Inspect and maintain.
1297	7255	272255	7288	0	BUILDINGS AND SITE	BUILDINGS	H2 & CO2 STORAGE BUILDING	Peripheral Building Roofing	124	17	Leaks – end of life.	10+	N/A	1	A	Low	1	B	Low	Safety – personnel.	Inspect and maintain.
1297	7255	272255	7288	0	BUILDINGS AND SITE	BUILDINGS	H2 & CO2 STORAGE BUILDING	Peripheral Building Siding	125	17	Corrosion-appearance.	5+	N/A	1	A	Low	1	A	Low	Leak, appearance.	Inspect and maintain.
1297	7255	272255	7288	0	BUILDINGS AND SITE	BUILDINGS	H2 & CO2 STORAGE BUILDING	Structure - Peripheral Building	126	17	Corrosion.	20+	N/A	1	A	Low	1	C	Low	Local failure - safety.	Inspect and maintain.
1297	7255	272255	7302	0	BUILDINGS AND SITE	BUILDINGS	SHAWMONT BUILDING	Peripheral Building Roofing	127	17	Leaks – end of life.	10+	N/A	1	A	Low	1	B	Low	Safety – personnel.	Inspect and maintain.
1297	7255	272255	7302	0	BUILDINGS AND SITE	BUILDINGS	SHAWMONT BUILDING	Peripheral Building Siding	128	17	Corrosion-appearance.	5+	N/A	1	A	Low	1	A	Low	Leak, appearance.	Inspect and maintain.
1297	7255	272255	7302	0	BUILDINGS AND SITE	BUILDINGS	SHAWMONT BUILDING	Structure - Peripheral Building	129	17	Corrosion.	20+	N/A	1	A	Low	1	C	Low	Local failure - safety.	Inspect and maintain.
1297	7255	272255	7303	0	BUILDINGS AND SITE	BUILDINGS	MAIN WAREHOUSE	Peripheral Building Roofing	130	17	Leaks – end of life.	10+	N/A	1	A	Low	1	B	Low	Safety – personnel.	Inspect and maintain.
1297	7255	272255	7303	0	BUILDINGS AND SITE	BUILDINGS	MAIN WAREHOUSE	Peripheral Building Siding	131	17	Corrosion-appearance.	5+	N/A	1	A	Low	1	A	Low	Leak, appearance.	Inspect and maintain.
1297	7255	272255	7303	0	BUILDINGS AND SITE	BUILDINGS	MAIN WAREHOUSE	Structure - Peripheral Building	132	17	Corrosion.	20+	N/A	1	A	Low	1	C	Low	Local failure - safety.	Inspect and maintain.
1297	7255	272255	7304	0	BUILDINGS AND SITE	BUILDINGS	WWT PLANT BUILDING	Batch reactor Building	133	16	Corrosion-roof, walls.	20+	Visual inspection near roof reqd	1	A	Low	1	B	Low	Roof leak – minor impact.	Inspect and maintain.
1297	7255	272255	7305	0	BUILDINGS AND SITE	BUILDINGS	WWT BASINS BUILDING	Treatment Basin Building	134	16	Corrosion-roof, walls.	(3)	Likely <5 yrs. Inspections not required to assess the remaining life.	3	A	Low	3	C	High	Safety issue.	Refurbish or replace.
1297	7255	272255	7307	0	BUILDINGS AND SITE	BUILDINGS	GAS TURBINE BUILDING	GTG Building	135	13,17	Roof leaks.	(2-10)	N/A	3	C	Medium	3	B	Medium	Loss of generator, equipment damage.	Inspect and refurbish.
1297	7255	272255	7307	0	BUILDINGS AND SITE	BUILDINGS	GAS TURBINE BUILDING	GTG Building	136	13,17	Side corrosion and appearance.	5	N/A	1	A	Low	1	A	Low	Appearance/equipment damage.	Inspect and refurbish.
1297	7255	272255	7307	0	BUILDINGS AND SITE	BUILDINGS	GAS TURBINE BUILDING	Gas Turbine Building Roofing	137	13,17	Leaks – end of life.	(1)	N/A	2	B	Low	2	B	Medium	Safety – personnel.	Inspect and refurbish.

11.1.4.6 Life Cycle Curve and Remaining Life

The life cycle curves for the buildings are illustrated below – Powerhouse, Stage 1 Pumphouse, Stage 2 Pumphouse and the peripheral buildings. Several curves are required to represent the various buildings and their operational timing. The life curves are plots of physical age of the equipment on the y-axis versus calendar year on the x-axis. The chart has several vertical lines representing differing representative nominal age limits for various buildings. It also has several horizontal lines that represent a range of practical equipment life limits in years. The risk area boxes provide an indication of the timing of potential issues either from an age and calendar perspective.

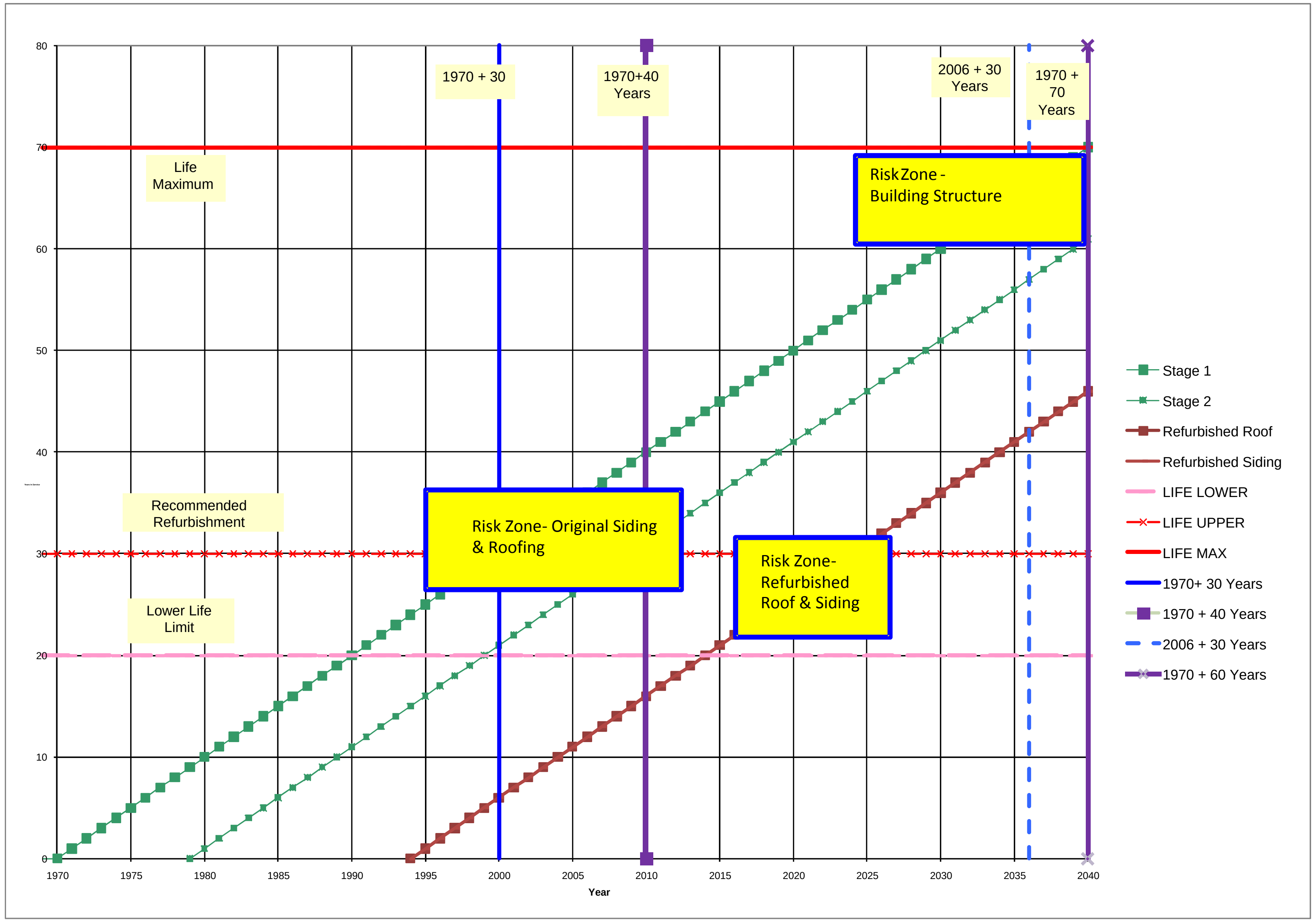


FIGURE 11-11 LIFE CYCLE CURVE - BUILDINGS AND BUILDING M AND E SYSTEM (POWERHOUSE)

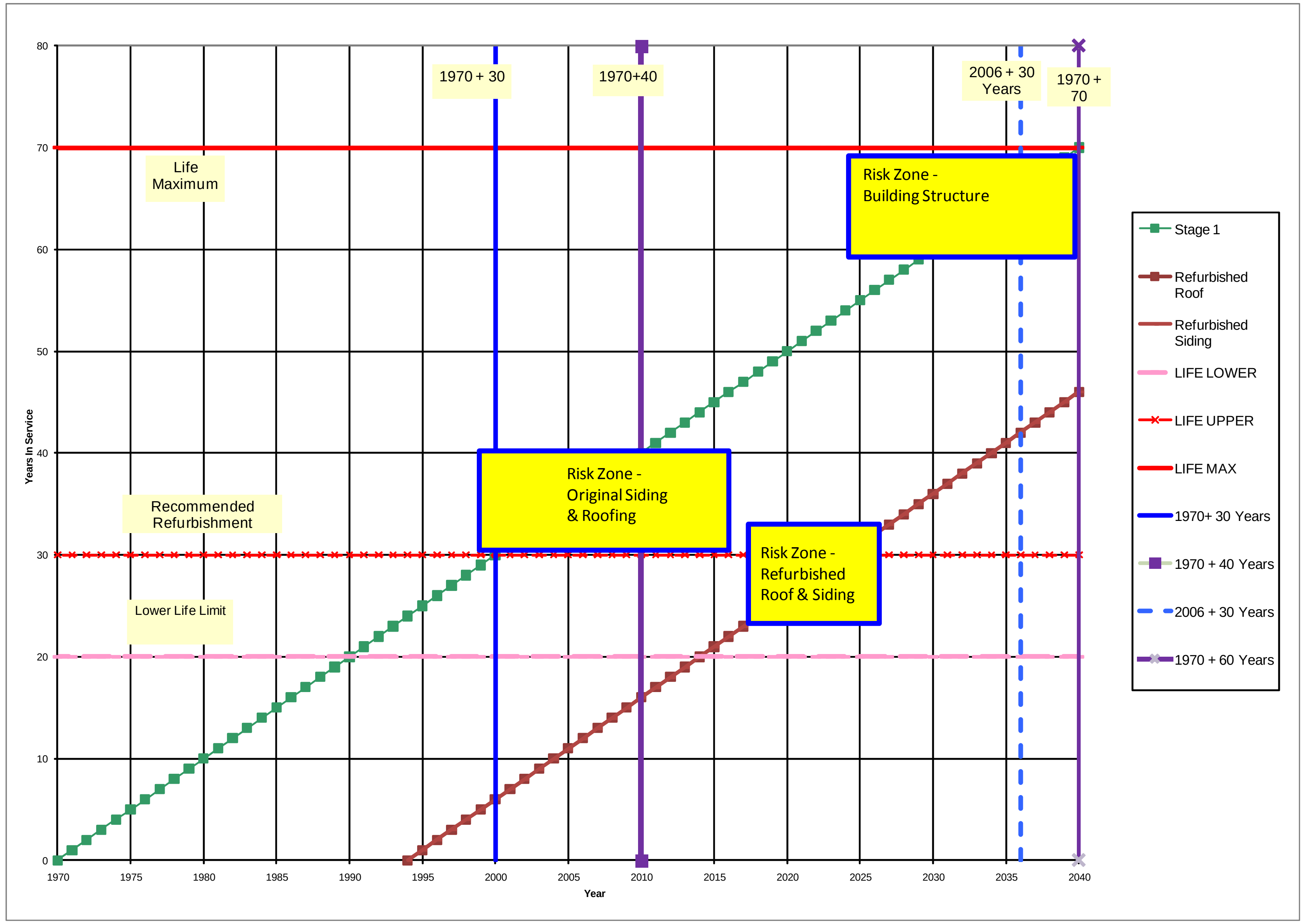


FIGURE 11-12 LIFE CYCLE CURVE - BUILDINGS AND BUILDING M AND E SYSTEM (STAGE 1 PUMPHOUSE)

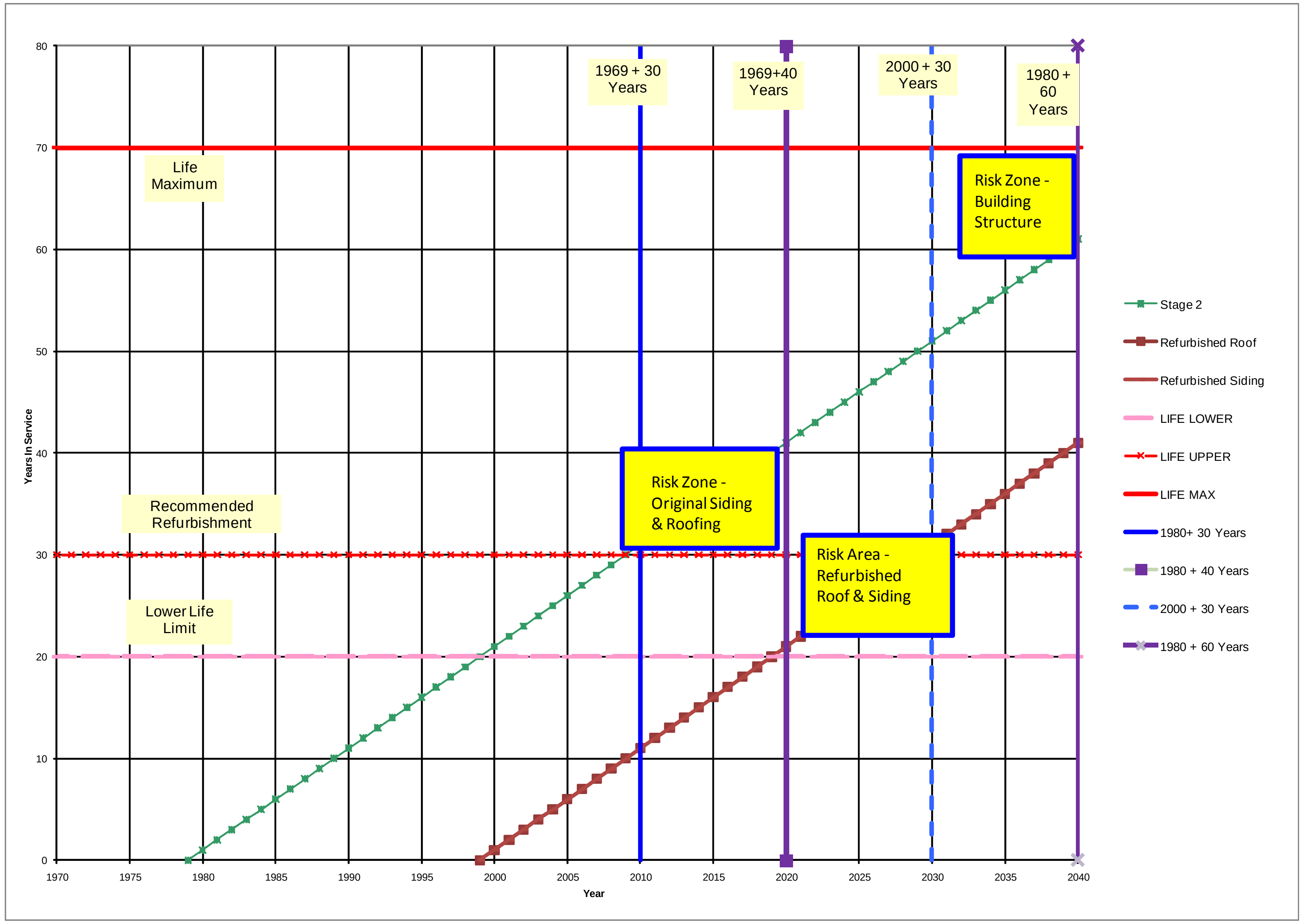


FIGURE 11-13 LIFE CYCLE CURVE - BUILDINGS AND BUILDING M AND E SYSTEM (STAGE 2 PUMPHOUSE)

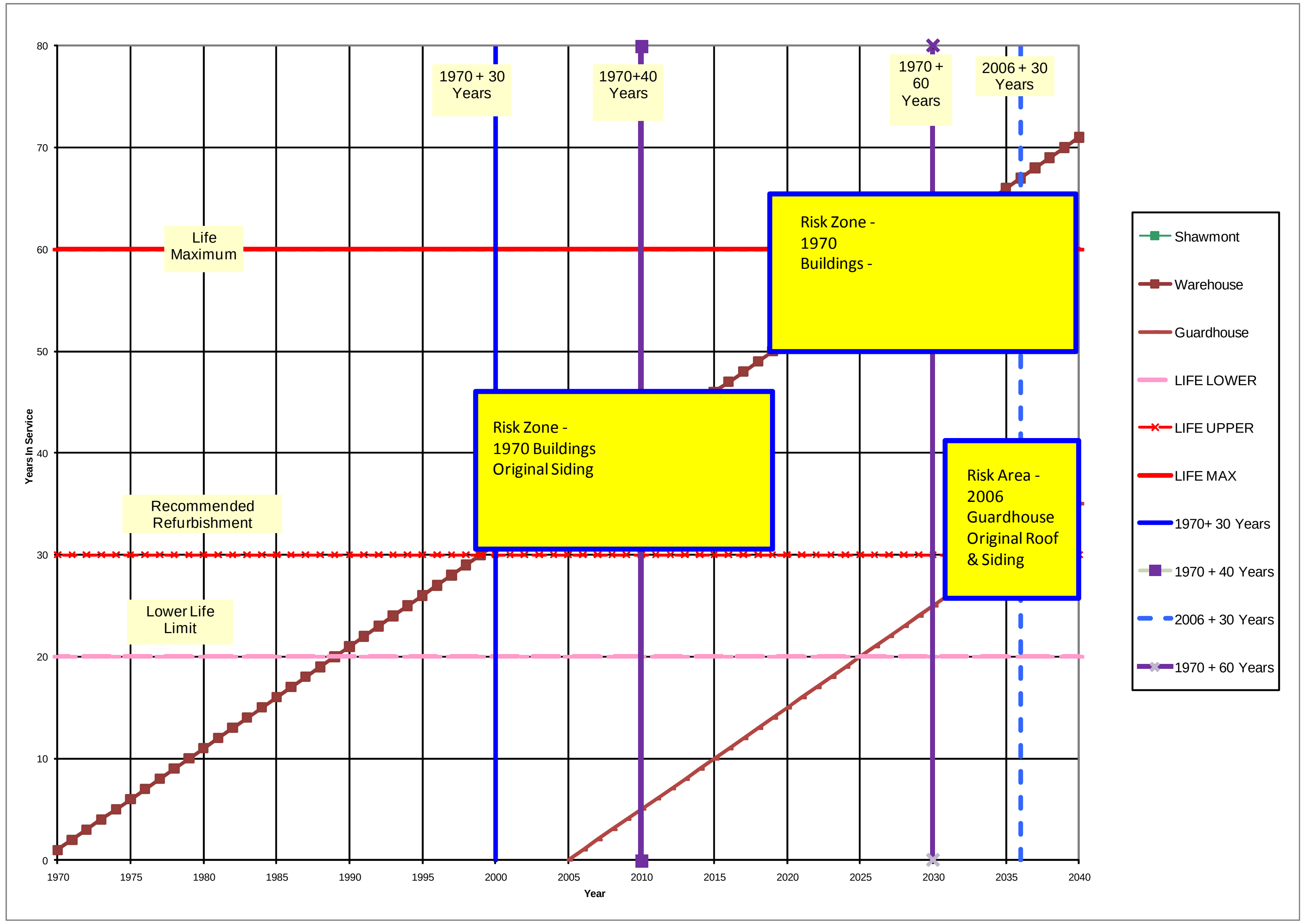


FIGURE 11-14 LIFE CYCLE CURVE – BUILDINGS AND BUILDING M AND E SYSTEM (PERIPHERAL BUILDINGS)

The curves indicate that the remaining life (RL) of most buildings exceeds the generation end date of 2020 and likely the desired life (DL) which is the end date for synchronous generation of 2041. The implementation of a roofing and siding refurbishment program will be necessary between the 2015 to 2025 period, and later for newer buildings or parts of buildings (WTP, guardhouse). The basic structure of most buildings is considered sound, but with limited data available. The primary M and E system of concern (not shown) are the powerhouse house elevators which are likely nearing the end of their reliable service life and should have a major refurbishment or be replaced. Cranes are an issue to continue regular testing, but no specific life issues were identified. Other aspects such as HVAC also will come into play (i.e. condenser vacuum venting, upper roof vent wind protection) in the short term, but nothing major beyond these in the immediate future.

11.1.4.7 Level 2 Inspection Requirements and Costs

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 11-19 below, assuming the current plant inspection and maintenance program is maintained or improved.

TABLE 11-19 LEVEL 2 INSPECTION – BUILDINGS AND BUILDING M AND E SYSTEM

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset 2/3	Asset 3/4	Description	Sub System Comment	L2#	Appendix #	Level 2 Work	Year	Priority	Cost k$
1297	7255	272255	7283	BUILDINGS AND SITE	BUILDINGS	MAIN POWERHOUSE	Powerhouse	83	17	Level 2 test check of structural steel checks especially in crane and turbine hall area.	2014	3	$5
1297	7255	272255	7283	BUILDINGS AND SITE	BUILDINGS	BUILDING SERVICES ELEVATOR	N/A	84	17	No Level 2 required.			
1297	7199	7256	271815	COMMON SYSTEMS	CRANES AND HOISTS	POWERHOUSE CRANE	N/A	85	17	No Level 2 required.			
1297	7199	7256	271816	COMMON SYSTEMS	CRANES AND HOISTS	BOILER ROOM HOISTS	N/A	86	17	No Level 2 required.			
1297	7199	7208	0	COMMON SYSTEMS	AUXILIARY STEAM SYSTEM	AUXILIARY STEAM SYSTEM	N/A	87	N/A	No Level 2 required.			
1297	7199	7208	99000093	COMMON SYSTEMS	AUXILIARY STEAM SYSTEM	AUXILIARY STEAM SYSTEM	N/A	88	N/A	No Level 2 required.			
1297	7199	7251	0	COMMON SYSTEMS	FIRE PROTECTION SYSTEMS	FIRE PROTECTION SYSTEMS	Fire Supply Lines	89	15	No Level 2 - Consider NDE of major fire supply lines (single contingency failure) – in-pipe crawler of other device to check for thickness and/or leaks.			
1297	7199	7251	7270	COMMON SYSTEMS	FIRE PROTECTION SYSTEMS	GAS FIRE SUPPRESSION SYSTEMS	N/A	90	N/A	No Level 2 required.			
1297	7199	6769	0	COMMON SYSTEMS	HEATING AND VENTILATION	HEATING AND VENTILATION	N/A	91	NA	No Level 2 required.			
1297	7199	7297	0	COMMON SYSTEMS	WARM AIR MAKE-UP	WARM AIR MAKE-UP	N/A	92	17	No Level 2 required.			
1297	7255	272255	7285	BUILDINGS AND SITE	BUILDINGS	STAGE 1 PUMPHOUSE	Pumphouse	95	17	Inspect and test concrete floor slabs in areas exhibiting distress to determine the condition of the concrete and steel reinforcement - the east-west walkways along the north end of Pumphouse 1&2 at El. 11.17' - four cores. Suitable cores (assume a total of six cores) tested for compressive strength; and chloride ion profile. If needed, a corrosion potential survey will assist in evaluating the extent and severity of the corrosion.	2011	2	$15

Table 11-19 Cont'd

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset 2/3	Asset 3/4	Description	Sub System Comment	L2#	Appendix #	Level 2 Work	Year	Priority	Cost k$
1297	7255	272255	7285	BUILDINGS AND SITE	BUILDINGS	STAGE 1 PUMPHOUSE	Stoplogs	96	17	Inspect stoplog seals area -See Units.	2011	2	(Incl in 95)
1297	7199	7256	271817	COMMON SYSTEMS	CRANES AND HOISTS	PUMPHOUSE CRANE STAGE 1	N/A	97	17	No Level 2 required.			
1297	7199	7251	7486	COMMON SYSTEMS	FIRE PROTECTION SYSTEMS	FIRE PUMPS - ELECTRIC	N/A	98	N/A	No Level 2 required.			
1297	7199	7251	7487	COMMON SYSTEMS	FIRE PROTECTION SYSTEMS	FIRE PUMPS - DIESEL	N/A	99	N/A	No Level 2 required.			
1297	7255	272255	7286	BUILDINGS AND SITE	BUILDINGS	STAGE 2 PUMPHOUSE	Pumphouse	100	17	Inspect and test concrete floor slabs in areas exhibiting distress to determine the condition of the concrete and steel reinforcement - included the east-west walkways along the north end of Pumphouse 3 at El. 11.17' - four cores. Suitable cores (assume a total of six cores) tested for compressive strength; and chloride ion profile. If needed, a corrosion potential survey will assist in evaluating the extent and severity of the corrosion.	2011	2	$15
1297	7255	272255	7286	BUILDINGS AND SITE	BUILDINGS	STAGE 2 PUMPHOUSE	Stoplogs	101	17	Inspect stoplog seals area - See Units.	2011	2	(Incl in 100)
1297	7199	7256	271818	COMMON SYSTEMS	CRANES AND HOISTS	PUMPHOUSE CRANE STAGE 2	N/A	102	17	No Level 2 required.			
1297	7255	272255	7287	BUILDINGS AND SITE	BUILDINGS	GUARDHOUSE	Peripheral	105	17	No Level 2 required. Roof structural steel visual checks could lead to more detailed investigation.			
1297	7255	272255	7284	BUILDINGS AND SITE	BUILDINGS	TRAINING CENTRE	Peripheral	106	17	No Level 2 required. Roof structural steel visual checks could lead to more detailed investigation.			
1297	7255	272255	7288	BUILDINGS AND SITE	BUILDINGS	H2 & CO2 STORAGE BUILDING	Peripheral	107	17	No Level 2 required. Roof structural steel visual checks could lead to more detailed investigation.			
1297	7255	272255	7302	BUILDINGS AND SITE	BUILDINGS	SHAWMONT BUILDING	Peripheral	108	17	No Level 2 required. Roof structural steel visual checks could lead to more detailed investigation.			
1297	7255	272255	7303	BUILDINGS AND SITE	BUILDINGS	MAIN WAREHOUSE	Peripheral	109	17	No Level 2 required. Roof structural steel visual checks could lead to more detailed investigation.			
1297	7255	272255	7304	BUILDINGS AND SITE	BUILDINGS	WWT PLANT BUILDING	Equalization Treatment Building	110	16	Inspection of structural steel members - thickness measurements of the steel members to determine how much cross section loss.	2011	3	(Incl in 111)
1297	7255	272255	7305	BUILDINGS AND SITE	BUILDINGS	WWT BASINS BUILDING	Equalization Basin Tanks	111	16	Inspection of the two equalization treatment basin tanks - cores will be taken from the concrete walkways and tested for compressive strength and chloride ion profile.	2011	3	$37
1297	7255	272255	7307	BUILDINGS AND SITE	BUILDINGS	GAS TURBINE BUILDING	GTG	112	17	No Level 2 required – see GT system analyses.			
1297	7255	272255	272256	BUILDINGS AND SITE	BUILDINGS	WATER TREATMENT BUILDING	Peripheral	113	17	No Level 2 required. Roof structural steel visual checks could lead to more detailed investigation.	2011	3	$0

11.1.4.8 Capital Projects

The suggested typical capital enhancements for the buildings and building M and E system include:

TABLE 11-20 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – BUILDINGS AND BUILDING M AND E SYSTEM

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset 2/3	Asset 3/4	Description	CAP#	Appendix #	Capital Item	Date	Priority
1297	7255	272255	7283	0	BUILDINGS AND SITE	BUILDINGS	MAIN POWERHOUSE	70	17	Re-paint any corroded steel members in boiler house building to help stop corrosion. Also, repair any leaky pipes to ensure that steel is not exposed to water.	2012	2
1297	7255	272255	7283	0	BUILDINGS AND SITE	BUILDINGS	MAIN POWERHOUSE	71	17	Prepare and implement roofing replacement and siding upgrade plan in 2012-13 for 2015-2020.	2015	1
1297	7255	272255	7283	0	BUILDINGS AND SITE	BUILDINGS	MAIN POWERHOUSE	72	17	Modify roof vents hoods.	2011	1
1297	7255	272255	7283	0	BUILDINGS AND SITE	BUILDINGS	MAIN POWERHOUSE	73	17	Optimize warm air make up system.	2011	2
1297	7255	272255	7283	7306	BUILDINGS AND SITE	BUILDINGS	BUILDING SERVICES ELEVATOR	74		Refurbish/replace powerhouse and administration elevators.	2012-2015	2
1297	7199	7256	271815	0	COMMON SYSTEMS	CRANES AND HOISTS	POWERHOUSE CRANE	75		Replace controls and brakes for auxiliary (and main if necessary) crane.	2011	1
1297	7199	7256	0	0	COMMON SYSTEMS	CRANES AND HOISTS	CRANES AND HOISTS	76		No capital required.		
1297	7199	7256	271816	0	COMMON SYSTEMS	CRANES AND HOISTS	BOILER ROOM HOISTS	77		No capital required.		
1297	7199	7208	0	0	COMMON SYSTEMS	AUXILIARY STEAM SYSTEM	AUXILIARY STEAM SYSTEM	78		No capital required.		
1297	7199	7208	99000093	0	COMMON SYSTEMS	AUXILIARY STEAM SYSTEM	AUXILIARY STEAM SYSTEM	79		No capital required.		
1297	7199	7251	0	0	COMMON SYSTEMS	FIRE PROTECTION SYSTEMS	FIRE PROTECTION SYSTEMS	80		No capital required.		
1297	7199	7251	7270	0	COMMON SYSTEMS	FIRE PROTECTION SYSTEMS	GAS FIRE SUPPRESSION SYSTEMS	81		No capital required.		
1297	7199	6769	0	0	COMMON SYSTEMS	HEATING AND VENTILATION	HEATING AND VENTILATION	82		No capital required.		
1297	7199	7297	0	0	COMMON SYSTEMS	WARM AIR MAKE-UP	WARM AIR MAKE-UP	83		No capital required.		
1297	7255	272255	7285	0	BUILDINGS AND SITE	BUILDINGS	STAGE 1 PUMPHOUSE	99		Re-paint any corroded steel members to prevent further corrosion lost to members.	2012	2
1297	7255	272255	7285	0	BUILDINGS AND SITE	BUILDINGS	STAGE 1 PUMPHOUSE	100		Repaint and/or refurbish roofing and siding as required.	2012	2
1297	7199	7256	271817	0	COMMON SYSTEMS	CRANES AND HOISTS	PUMPHOUSE CRANE STAGE 1	101		No capital required.		
1297	7199	7251	7486	0	COMMON SYSTEMS	FIRE PROTECTION SYSTEMS	FIRE PUMPS - ELECTRIC	102		No Capital, unless larger pump is required to supply enhanced fire protection system.		
1297	7199	7251	7487	0	COMMON SYSTEMS	FIRE PROTECTION SYSTEMS	FIRE PUMPS - DIESEL	103		Replace fire pump diesel.	2011	1
1297	7255	272255	7286	0	BUILDINGS AND SITE	BUILDINGS	STAGE 2 PUMPHOUSE	104		Re-paint any corroded steel members to prevent further corrosion lost to members.	2012	2
1297	7255	272255	7286	0	BUILDINGS AND SITE	BUILDINGS	STAGE 2 PUMPHOUSE	105		Repaint and/or refurbish roofing and siding as required.	2012	2
1297	7199	7256	271818	0	COMMON SYSTEMS	CRANES AND HOISTS	PUMPHOUSE CRANE STAGE 2	106		No capital required.		

Table 11-20 Cont'd

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset 2/3	Asset 3/4	Description	CAP#	Appendix #	Capital Item	Date	Priority
1297	7255	272255	7287	0	BUILDINGS AND SITE	BUILDINGS	GUARDHOUSE	109		Refurbish and re- paint siding and steel members and roofing as required. Fix any structural deficiencies as they appear.	2015	3
1297	7255	272255	7284	0	BUILDINGS AND SITE	BUILDINGS	TRAINING CENTRE	110		Refurbish and re-paint siding and steel members and roofing as required. Fix any structural deficiencies as they appear.	2013	3
1297	7255	272255	7288	0	BUILDINGS AND SITE	BUILDINGS	H2 & CO2 STORAGE BUILDING	111		Refurbish and re-paint siding and steel members and roofing as required. Fix any structural deficiencies as they appear.	2013	3
1297	7255	272255	7302	0	BUILDINGS AND SITE	BUILDINGS	SHAWMONT BUILDING	112		Refurbish and re-paint siding and steel members and roofing as required. Fix any structural deficiencies as they appear.	2012	3
1297	7255	272255	7303	0	BUILDINGS AND SITE	BUILDINGS	MAIN WAREHOUSE	113		Refurbish and re-paint siding and steel members and roofing as required. Fix any structural deficiencies as they appear.	2013	3
1297	7255	272255	7304	0	BUILDINGS AND SITE	BUILDINGS	WWT PLANT BUILDING	114		Refurbish and re-paint siding and steel members and roofing as required. Fix any structural deficiencies as they appear.	2012	2
1297	7255	272255	7305	0	BUILDINGS AND SITE	BUILDINGS	WWT BASINS BUILDING	115	16	Replace/modify WWTP Treatment Basin building. Refurbish and re-paint siding and steel members and roofing as required. Fix any structural deficiencies as they appear .	2012	1
1297	7255	272255	7305	0	BUILDINGS AND SITE	BUILDINGS	WWT BASINS BUILDING	116	16	Improve WWTP basins oil capture and basin escape accesses.	2012	1
1297	7255	272255	7305	0	BUILDINGS AND SITE	BUILDINGS	WWT BASINS BUILDING	117	16	Replace/modify WWTP Treatment Basin building.	2012	1
1297	7255	272255	7307	0	BUILDINGS AND SITE	BUILDINGS	GAS TURBINE BUILDING	118	17	Re-paint any corroded steel members.	2011	2
1297	7255	272255	7307	0	BUILDINGS AND SITE	BUILDINGS	GAS TURBINE BUILDING	119	17	Replace stack and affected roof areas.	2011	1
1297	7255	272255	7307	0	BUILDINGS AND SITE	BUILDINGS	GAS TURBINE BUILDING	120	17	Refurbish and re- paint siding and roofing as required.	2011	2
1297	7255	272255	7307	0	BUILDINGS AND SITE	BUILDINGS	GAS TURBINE BUILDING	121	17	Replace air intake for marine environment - filter media and/or intake structure.	2011	1
1297	7255	272255	272256	0	BUILDINGS AND SITE	BUILDINGS	WATER TREATMENT BUILDING	122		No capital required.		

11.1.5 Asset 7206 – Hydrogen, Nitrogen, and Carbon Dioxide Supply Systems

The requirements for the hydrogen, nitrogen, and carbon dioxide supply systems are as follows:

Unit #:	Common
Asset Class #	BU 1297 – Assets Commons
SCI & System:	7199 HRD Common Systems
Sub-Systems:	7205 Compressed Air Systems
Components:	7236 Hydrogen Storage & Supply 7237 Carbon Dioxide Storage & Supply 7238 Nitrogen Storage & Supply

11.1.5.1 Description

Manufactured/Delivered	1969
In-Service Date	Sep 1970
Generation Base Load End Date	Dec 2015
Generation Peak/Emerg Gen End Date	Dec 2020
Synchronous Condensing Start Date	Jan 2015
Synchronous Condensing End Date	Dec 2041

The scope examined includes only the hydrogen, nitrogen, and carbon dioxide storage and delivery elements. The building itself is addressed separately.

Hydrogen, nitrogen, and carbon dioxide are supplied from a gas storage steel building to the east of the powerhouse. Both gases, as well as nitrogen, are stored in high pressure cylinder packs connected to lines that go underground to the plant to the individual units. A cost and reliability issue with the hydrogen system is that there is no other major Newfoundland user. There is a Newfoundland based supplier and hydrogen has to be shipped from off-island.

FIGURE 11-15 HYDROGEN STORAGE RACKS

FIGURE 11-16 HYDROGEN STORAGE BUILDING

FIGURE 11-17 HYDROGEN LINES IN POWERHOUSE

FIGURE 11-18 HYDROGEN LINES INTO POWERHOUSE

11.1.5.2 History - Inspection and Repair History

Inspections of the system are performed annually as well as frequent systems checks by operators and ongoing system monitoring. No specific testing information was identified. Interviews identified no unusual conditions or concerns, except the difficulties and costs associated with the supply of hydrogen using the current procurement approach. Some representative sampling of the distribution system piping for thickness testing is likely warranted if the entire system is not replaced as part of the new on-site hydrogen production project.

11.1.5.3 Condition Assessment

The condition assessment of the hydrogen, nitrogen, and carbon dioxide supply systems is illustrated below in Table 11-21.

TABLE 11-21 CONDITION ASSESSMENT – HYDROGEN, NITROGEN, AND CARBON DIOXIDE SUPPLY SYSTEMS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset Level 2	Asset Level 3	Description	Detail	Cond. Summ. ID#	Append #	Condition	EPRI Identifier	Original Life (Base Load) Ops Hrs (Yrs)	Current Expected Minimum Remaining Life Years (Subject to Test)	End of Life Required (EOL)	Next Regular Inspection	Next Planned Overhaul/ Major Inspection	Capability to Reach Next Overhaul	Capability to Reach EOL	In Service
1297	7199	7206	0	0	COMMON SYSTEMS	GAS STORAGE SYSTEMS	GAS STORAGE SYSTEMS	N/A	59	17	Not reviewed in detail. Visually checked OK.	4	(30)	20	2041	2011		Yes	No	1968-1970
1297	7199	7206	7236	0	COMMON SYSTEMS	GAS STORAGE SYSTEMS	HYDROGEN STORAGE AND SUPPLY	N/A	60	17	Not reviewed in detail. Visually checked OK.	4	(30)	20	2041	2011		Yes	No	1968-1970
1297	7199	7206	7237	0	COMMON SYSTEMS	GAS STORAGE SYSTEMS	CARBON DIOXIDE STORAGE/SUPPLY	N/A	61	17	Not reviewed in detail. Visually checked OK.	4	(30)	20	2041	2011		Yes	No	1968-1970
1297	7199	7206	7238	0	COMMON SYSTEMS	GAS STORAGE SYSTEMS	NITROGEN STORAGE/SUPPLY SYSTEM	N/A	62	17	Not reviewed in detail. Visually checked OK.	4	(30)	20	2041	2011		Yes	No	1968-1970

Notes:

1. A "(bracketed)" value in the "Current Expected Remaining Life" column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation, including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as "(X/Y)" has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

2. The "Next Regular Inspection" column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The "Next Planned Overhaul or Major Inspection" column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a "Desired Life" stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where no specific dates have been identified for "Next Regular Inspection" or "Next Planned Overhaul/Major Inspection", they are left blank.

11.1.5.4 Actions

Based on the condition assessment, the following actions are recommended for the hydrogen, nitrogen, and carbon dioxide supply systems:

TABLE 11-22 RECOMMENDED ACTIONS – HYDROGEN, NITROGEN, AND CARBON DIOXIDE SUPPLY SYSTEMS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset 2/3	Asset 3/4	Description	Action #	App #	Action	Year	Priority
1297	7199	7206	0	0	COMMON SYSTEMS	GAS STORAGE SYSTEMS	GAS STORAGE SYSTEMS	63	17	No recommended action.		
1297	7199	7206	7236	0	COMMON SYSTEMS	GAS STORAGE SYSTEMS	HYDROGEN STORAGE AND SUPPLY	64	17	Maintain current inspection and maintenance until system replaced by low pressure bulk storage. Distribution pipe representative sampling and thickness checks.	2012	1
1297	7199	7206	7237	0	COMMON SYSTEMS	GAS STORAGE SYSTEMS	CARBON DIOXIDE STORAGE/SUPPLY	65	17	Maintain current inspection and maintenance. Distribution pipe representative sampling and thickness checks.	2011	1
1297	7199	7206	7238	0	COMMON SYSTEMS	GAS STORAGE SYSTEMS	NITROGEN STORAGE/SUPPLY SYSTEM	66	17	Maintain current inspection and maintenance. Distribution pipe representative sampling and thickness checks.	2011	1

11.1.5.5 Risk Assessment

The risk assessment associated with the hydrogen, nitrogen, and carbon dioxide supply systems, both from a technological perspective and a safety perspective, is illustrated below in Table 11-23.

TABLE 11-23 RISK ASSESSMENT – HYDROGEN, NITROGEN, AND CARBON DIOXIDE SUPPLY SYSTEMS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset 2/3	Asset 3/4	Description	Component	Risk Assess #	Appendix #	Major Issues	Remaining Life Years	Remaining Life	Techno-Eco Risk Assess Model			Safety Risk Assess Model			Possible Failure Event	Mitigation
												(Insufficient Info - Inspection Required Within (x) Years)	Comments	Likeli-hood	Conse-quence	Risk Level	Likeli-hood	Conse-quence	Safety Risk		
1297	7199	7206	0	0	COMMON SYSTEMS	GAS STORAGE SYSTEMS	GAS STORAGE SYSTEMS	None	64	17	Mechanical failure/leaks/fire.	20	N/A	2	B	Low	2	B	Low	leaks, Fire	Inspection, maintenance, monitor, restrict.
1297	7199	7206	7236	0	COMMON SYSTEMS	GAS STORAGE SYSTEMS	HYDROGEN STORAGE AND SUPPLY	None	65	17	Mechanical failure/leaks/fire.	20	Plan for on-site production to replace	2	C	Medium	3	C	Medium	Units shutdown.. Fire.	Inspection, maintenance, monitor, restrict. Representative tube sampling.
1297	7199	7206	7237	0	COMMON SYSTEMS	GAS STORAGE SYSTEMS	CARBON DIOXIDE STORAGE/SUPPLY	None	66	17	Mechanical failure/leaks.	20	N/A	2	C	Medium	3	C	Medium	Personnel safety risk. Units shutdown.	Inspection, maintenance, monitor, restrict. Representative tube sampling.
1297	7199	7206	7238	0	COMMON SYSTEMS	GAS STORAGE SYSTEMS	NITROGEN STORAGE/SUPPLY SYSTEM	None	67	17	Mechanical failure/leaks.	20	N/A	2	C	Medium	3	B	Medium	Safety risk. Units shutdown.	Inspection, maintenance, monitor, restrict. Representative tube sampling.

11.1.5.6 Life Cycle Curve and Remaining Life

The life cycle curve for the system is illustrated below. Two curves are included to represent the system and the piping (and building structure). The life curves are plots of physical age of the equipment on the y-axis versus calendar year on the x-axis. The chart has several vertical lines representing differing representative nominal age limits for various components. It also has several horizontal lines that represent a range of practical equipment life limits in years.

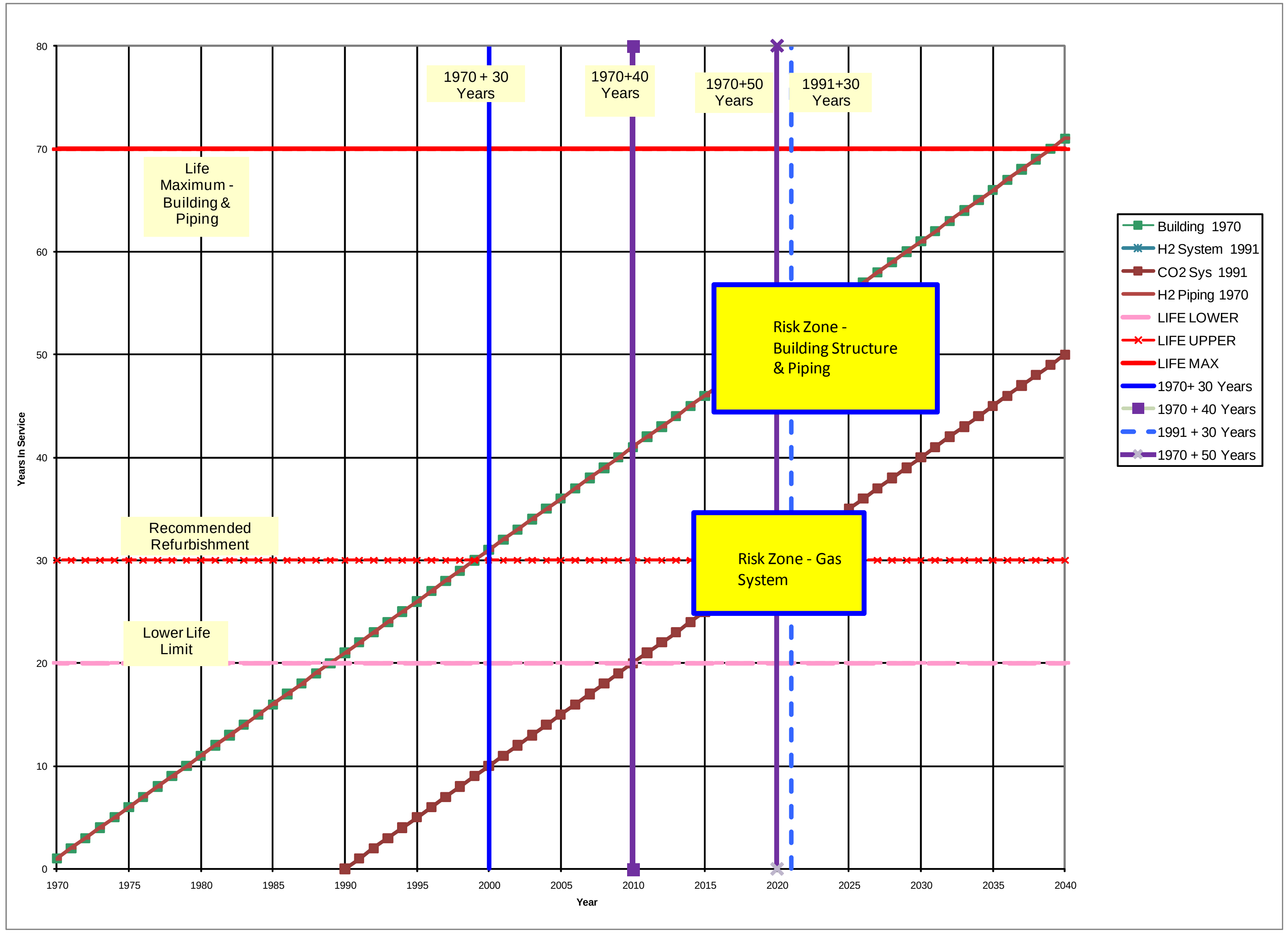


FIGURE 11-19 LIFE CYCLE CURVE – HYDROGEN, NITROGEN, AND CARBON DIOXIDE SUPPLY SYSTEMS

The curves indicates the remaining life (RL) of the hydrogen, nitrogen, and carbon dioxide supply systems exceeds the end date for generation of 2020 but not likely the desired life (DL) which is the end date for synchronous generation of 2041. It is clear that the system generally has considerable technical life remaining. Three concerns not reflected are i) the condition of the distribution piping for which no test information was reviewed, ii) the restricted supply capability of the carbon dioxide delivery system; and iii) the limited supply infrastructure for hydrogen on the mainland.

11.1.5.7 Level 2 Inspection Requirements and Costs

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 11-24 below, assuming the current plant inspection and maintenance program is maintained or improved.

TABLE 11-24 LEVEL 2 INSPECTION – HYDROGEN, NITROGEN, AND CARBON DIOXIDE SUPPLY SYSTEMS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset 2/3	Asset 3/4	Description	Sub System Comment	L2#	Appendix #	Level 2 Work	Year	Priority	Cost k$
1297	7199	7206	0	COMMON SYSTEMS	GAS STORAGE SYSTEMS	GAS STORAGE SYSTEMS	N/A	59		Level 2 required - representative tube sampling and thickness tests.	2011	1	$15
1297	7199	7206	7236	COMMON SYSTEMS	GAS STORAGE SYSTEMS	HYDROGEN STORAGE AND SUPPLY	N/A	60		Level 2 required - representative tube sampling and thickness tests.	2011	1	(Incl in 59)
1297	7199	7206	7237	COMMON SYSTEMS	GAS STORAGE SYSTEMS	CARBON DIOXIDE STORAGE/SUPPLY	N/A	61		Level 2 required - representative tube sampling and thickness tests.	2011	1	(Incl in 59)
1297	7199	7206	7238	COMMON SYSTEMS	GAS STORAGE SYSTEMS	NITROGEN STORAGE/SUPPLY SYSTEM	N/A	62		Level 2 required - representative tube sampling and thickness tests.	2011	1	(Incl in 59)

11.1.5.8 Capital Projects

The suggested typical capital enhancements for the hydrogen, nitrogen, and carbon dioxide supply systems include:

TABLE 11-25 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – HYDROGEN, NITROGEN, AND CARBON DIOXIDE SUPPLY SYSTEMS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset 2/3	Asset 3/4	Description	CAP#	Appendix #	Capital Item	Date	Priority
1297	7199	7206	0	0	COMMON SYSTEMS	GAS STORAGE SYSTEMS	GAS STORAGE SYSTEMS	60	17	No capital required.		
1297	7199	7206	7236	0	COMMON SYSTEMS	GAS STORAGE SYSTEMS	HYDROGEN STORAGE AND SUPPLY	61	17	Upgrade to hydrogen storage - LP production & bulk storage.	2012	1
1297	7199	7206	7237	0	COMMON SYSTEMS	GAS STORAGE SYSTEMS	CARBON DIOXIDE STORAGE/SUPPLY	62	17	No capital required.		
1297	7199	7206	7238	0	COMMON SYSTEMS	GAS STORAGE SYSTEMS	NITROGEN STORAGE/SUPPLY SYSTEM	63	17	No capital required.		

11.1.6 Asset 7231 – Compressed Air

(Detailed Technical Assessment in Working Papers, Appendix 10)

Unit #:	1
Asset Class #	BU 1297 - Assets Commons
SCI & System:	7199 HRD Common Systems
Sub-Systems:	7205 Compressed Air Systems
Components:	7231 Compressors 7234 Compressed Air Dryers Systems 7235 Compressed Air Receivers

11.1.6.1 Description

	Stage 1	**Stage 2**
Manufactured/Delivered	1969	1979
In-Service Date	Sep 1970	Feb 1980
Generation Base Load End Date	Dec 2015	
Generation Peak/Emerg Gen End Date	Dec 2020	
Synchronous Condensing End Date	Dec 2041	Dec 2041
Actual/Planned Compressor Replacement		2014/2015

Compressed air systems are provided for both Stage 1 and Stage 2. The compressors feed the service air system at about 793 kPa (115 psig). A portion of compressed air is drawn from service air receivers and is filtered and dried for use as instrument air. Cooling water is provided from the general service water system for the cooler and aftercooler requirements for each compressor.

Stage 1 Compressor #1 (ZR3-67) is an Atlas Copco oil-free screw compressor. Model number ZR3-67. The compressor is rated at 315 L/s @ 1.05 MPa. It was commissioned in December 1997.

Stage 1 Compressor #2 (ZR3-B) is an Atlas Copco oil-free screw compressor. Model number ZR3-B. The compressor is rated at 310 L/s @ 1.05 MPa. Its commissioning date is uncertain, but likely around 1997.

Stage 2, Compressor #3 (ZR132-VSD) is an Atlas Copco oil-free screw compressor. The compressor is designed to efficiently produce compressed air between 127 and 357 L/s. This compressor uses a variable speed drive for capacity control. It was commissioned in December 2008.

The service air and instrument air pressure vessels for both Stage 1 and Stage 2 are original equipment. The air compressor and Stage 1, Unit 1 instrument air receivers are illustrated below.

FIGURE 11-20 STAGE 1 COMPRESSOR & INSTRUMENT AIR RECEIVER

11.1.6.2 History - Inspection and Repair History

The service air pressure vessels and instrument air pressure vessels are original equipment, but are inspected annually in accordance with government regulations. Based on information reviewed and on discussions with station staff, no indication of any significant degradation or maintenance/regulatory issues during annual inspections were identified.

The instrument air filtering and drying systems also receive annual maintenance and there is no indication of significant maintenance issues.

11.1.6.3 Condition Assessment

The condition assessment of the compressed air system is illustrated below in Table 11-26.

TABLE 11-26 CONDITION ASSESSMENT – COMPRESSED AIR

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset Level 2	Asset Level 3	Description	Detail	Cond. Summ. ID#	Append #	Condition	EPRI Identifier	Original Life (Base Load) Ops Hrs (Yrs)	Current Expected Minimum Remaining Life Years (Subject to Test)	End of Life Required (EOL)	Next Regular Inspection	Next Planned Overhaul/ Major Inspection	Capability to Reach Next Overhaul	Capability to Reach EOL	In Service
1297	7199	7205	0	0	COMMON SYSTEMS	COMPRESSED AIR SYSTEMS	COMPRESSED AIR SYSTEMS	N/A	49	10	The service air pressure vessels and instrument air pressure vessels are original equipment, but are inspected annually in accordance with government regulations. Based on discussions with station staff, there has been no indication of any significant degradation.									
1297	7199	7205	7231	0	COMMON SYSTEMS	COMPRESSED AIR SYSTEMS	AIR COMPRESSORS	N/A	50	10										
1297	7199	7205	7231	8918	COMMON SYSTEMS	COMPRESSED AIR SYSTEMS	#2 ATLAS COPCO ROTARY COMP	N/A	51	10	Near end of life.	10	(20)	3	2041	2011		Yes	No	1997
1297	7199	7205	7231	9488	COMMON SYSTEMS	COMPRESSED AIR SYSTEMS	#1 ATLAS COPCO ROTARY COMP	N/A	52	10	Near end of life.	10	(20)	3	2041	2011		Yes	No	1997
1297	7199	7205	7231	325028	COMMON SYSTEMS	COMPRESSED AIR SYSTEMS	#3 ATLAS COPCO ROTARY COMP	N/A	53	10	New in 2008.	10	(20)	20	2041	2011		Yes	No	2008
1297	7199	7205	7231	99000081	COMMON SYSTEMS	COMPRESSED AIR SYSTEMS	BALANCE OF AIR COMPRESSORS SYSTEM	N/A	54	10	Good condition. No significant issues identified beyond replacement of aging compressors.	3a	(30)	15+	2041	2011	2011	Yes	No	1968-1979
1297	7199	7205	7234	0	COMMON SYSTEMS	COMPRESSED AIR SYSTEMS	COMPRESSED AIR DRYERS SYSTEMS	N/A	55	10	Instrument air filtering and drying systems receive annual maintenance and are working per requirements.	3a	(50)	15+	2041	2011	2011	Yes	No	1968-1979
1297	7199	7205	7235	0	COMMON SYSTEMS	COMPRESSED AIR SYSTEMS	COMPRESSED AIR RECEIVERS	N/A	56	10	Service and instrument air pressure vessels are original equipment, but are in good shape with no noted degradation. They are inspected annually in accordance with government regulations.	3a	(50)	15+	2041	2011	2011	Yes	No	1968-1979

Notes:

1. A “(bracketed)” value in the “Current Expected Remaining Life” column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation, including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as “(X/Y)” has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

2. The “Next Regular Inspection” column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The “Next Planned Overhaul or Major Inspection” column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a “Desired Life” stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where no specific dates have been identified for “Next Regular Inspection” or “Next Planned Overhaul/Major Inspection”, they are left blank.

11.1.6.4 Actions

Based on the condition assessment, the following actions are recommended for the compressed air system:

TABLE 11-27 RECOMMENDED ACTIONS – COMPRESSED AIR

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset 2/3	Asset 3/4	Description	Action #	App #	Action	Year	Priority
1297	7199	7205	0	0	COMMON	COMPRESSED AIR SYSTEMS	COMPRESSED AIR	53	10	Maintain annual inspections of current air dryer and receiver.	2011	1
1297	7199	7205	7231	8918	COMMON SYSTEMS	COMPRESSED AIR SYSTEMS	#2 ATLAS COPCO ROTARY COMP	55	10	Procure and install new air compressors.	2014	1
1297	7199	7205	7231	9488	COMMON SYSTEMS	COMPRESSED AIR SYSTEMS	#1 ATLAS COPCO ROTARY COMP	56	10	Procure and install new air compressors.	2015	1
1297	7199	7205	7231	325028	COMMON SYSTEMS	COMPRESSED AIR SYSTEMS	#3 ATLAS COPCO ROTARY COMP	57	10	New in 2008. No Action.		
1297	7199	7205	7231	99000081	COMMON SYSTEMS	COMPRESSED AIR SYSTEMS	BALANCE OF AIR COMPRESSORS STA	58	10	No recommended action.		
1297	7199	7205	7234	0	COMMON SYSTEMS	COMPRESSED AIR SYSTEMS	COMPRESSED AIR DRYERS SYSTEMS	59	10	No recommended action.		
1297	7199	7205	7235	0	COMMON SYSTEMS	COMPRESSED AIR SYSTEMS	COMPRESSED AIR RECEIVERS	60	10	No recommended action.		

11.1.6.5 Risk Assessment

The risk assessment associated with the compressed air system, both from a technological perspective and a safety perspective, is illustrated below in Table 11-28.

TABLE 11-28 RISK ASSESSMENT – COMPRESSED AIR

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset 2/3	Asset 3/4	Description	Component	Risk Assess #	Appendix #	Major Issues	Remaining Life Years	Remaining Life	Techno-Eco Risk Assess Model			Safety Risk Assess Model			Possible Failure Event	Mitigation
												(Insufficient Info - Inspection Required Within (x) Years)	Comments	Likeli-hood	Conse-quence	Risk Level	Likeli-hood	Conse-quence	Safety Risk		
1297	7199	7205	0	0	COMMON SYSTEMS	COMPRESSED AIR SYSTEMS	COMPRESSED AIR SYSTEMS	None	50	10	See details below.		N/A								
1297	7199	7205	7231	0	COMMON SYSTEMS	COMPRESSED AIR SYSTEMS	AIR COMPRESSORS	None	51		See details below.		N/A								
1297	7199	7205	7231	8918	COMMON SYSTEMS	COMPRESSED AIR SYSTEMS	#2 ATLAS COPCO ROTARY COMP	Air Compressor failure –original units	52	10	Mechanical fatigue.	3	near EOL	3	B	Medium	3	B	Low	Loss air – interconnected, minimal, but increased risk of further failure.	Replace.
1297	7199	7205	7231	9488	COMMON SYSTEMS	COMPRESSED AIR SYSTEMS	#1 ATLAS COPCO ROTARY COMP	Air Compressor failure –original units	53	10	Mechanical fatigue.	3	near EOL	3	B	Medium	3	B	Low		Replace.
1297	7199	7205	7231	325028	COMMON SYSTEMS	COMPRESSED AIR SYSTEMS	#3 ATLAS COPCO ROTARY COMP	Air Compressor failure –newer unit	54	10	Mechanical fatigue.	20	N/A	1	B	Low	1	B	Low	Loss air – interconnected, minimal.	Inspect, maintain.
1297	7199	7205	7234	0	COMMON SYSTEMS	COMPRESSED AIR SYSTEMS	COMPRESSED AIR DRYERS SYSTEMS	Air Dryers	56	10	Corrosion, mechanical failure.	15+	N/A	1	A	Low	1	C	Low	Loss air – interconnected.	Annual and regulatory inspect and maintain.
1297	7199	7205	7234	0	COMMON SYSTEMS	COMPRESSED AIR SYSTEMS	COMPRESSED AIR DRYERS SYSTEMS	Air Dryers	57	10	Corrosion, mechanical failure.	15+	N/A	1	A	Low	1	C	Low	Loss air – interconnected.	Annual and regulatory inspect and maintain.
1297	7199	7205	7235	0	COMMON SYSTEMS	COMPRESSED AIR SYSTEMS	COMPRESSED AIR RECEIVERS	Air Receivers – Service Air	58	10	Corrosion, mechanical failure.	20	N/A	1	A	Low	1	C	Low	Loss air – interconnected.	Annual and regulatory inspect and maintain.
1297	7199	7205	7235	0	COMMON SYSTEMS	COMPRESSED AIR SYSTEMS	COMPRESSED AIR RECEIVERS	Air receivers – Instrument Air	59	10	Corrosion, mechanical failure.	20	N/A	1	A	Low	1	C	Low	Loss air – interconnected.	Annual and regulatory inspect and maintain.
1297	7199	7205	7235	0	COMMON SYSTEMS	COMPRESSED AIR SYSTEMS	COMPRESSED AIR RECEIVERS	Air Receivers – Service Air	60	10	Corrosion, mechanical failure.	20	N/A	1	A	Low	1	C	Low	Loss air – interconnected.	Annual and regulatory inspect and maintain.
1297	7199	7205	7235	0	COMMON SYSTEMS	COMPRESSED AIR SYSTEMS	COMPRESSED AIR RECEIVERS	Air receivers – Instrument Air	61	10	Corrosion, mechanical failure.	20	N/A	1	A	Low	1	C	Low	Loss air – interconnected.	Annual and regulatory inspect and maintain.

11.1.6.6 Life Cycle Curve and Remaining Life

The life cycle curve for the system is illustrated below. Several curves are required to represent the various elements of and their operational timing. The life curves are plots of current and projected unit operating hours of usage on the y-axis versus calendar year on the x-axis. The unit operating hours is used as a substitute for actual compressor hours data not available. In these cases only one operating hours scenario is illustrated post 2009 to minimize the confusion. It includes hours for both generating mode and synchronous condensing mode (assuming modification in 2014). The chart has several vertical lines representing differing representative nominal age limits for various components. It also has several horizontal lines that represent a range of practical equipment equivalent base loaded operating hour life limits. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view.

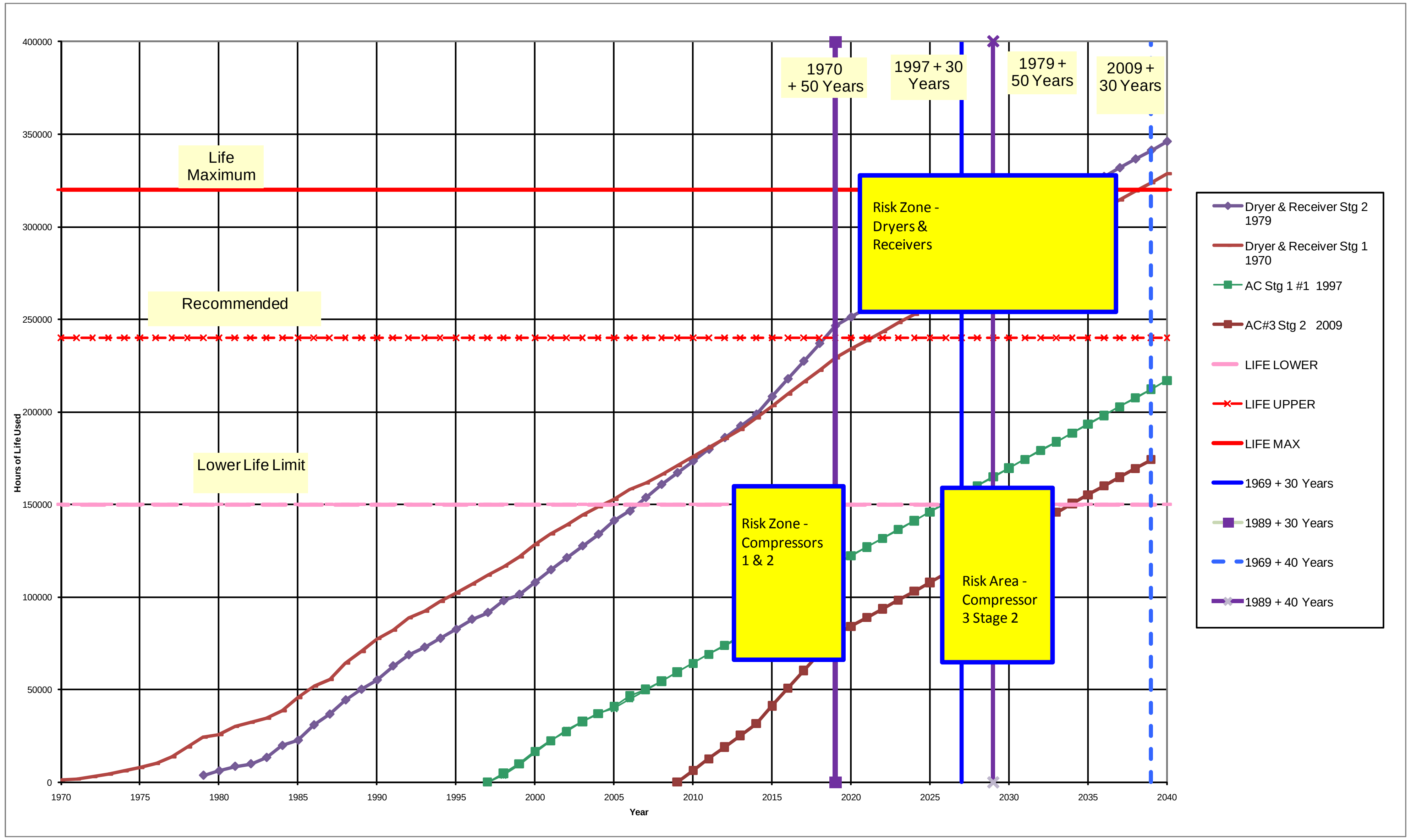


FIGURE 11-21 LIFE CYCLE CURVE – COMPRESSED AIR

The curves indicate that the remaining life (RL) of the compressed air system exceeds the end date for generation of 2020, but maybe not the desired life (DL) of 2041 (at the end of synchronous condensing life) without refurbishment and/or replacement. The exception is the current stage 1 compressors which are in need of replacement in the next few years and the newer Stage 2 compressors which will likely need replacement in the period after 2020.

11.1.6.7 Level 2 Inspection Requirements and Costs

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 11-29 below, assuming the current plant inspection and maintenance program is maintained or improved.

TABLE 11-29 LEVEL 2 INSPECTION – COMPRESSED AIR

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset 2/3	Asset 3/4	Description	Sub System Comment	L2#	Appendix #	Level 2 Work	Year	Priority	Cost k$
1297	7199	7205	0	COMMON SYSTEMS	COMPRESSED AIR SYSTEMS	COMPRESSED AIR SYSTEMS		49	10	No Level 2 analyses is required, provided the current inspection and maintenance program is maintained.			
1297	7199	7205	7231	COMMON SYSTEMS	COMPRESSED AIR SYSTEMS	AIR COMPRESSORS	N/A	50	10	No Level 2 analyses is required, provided the current inspection and maintenance program is maintained.			
1297	7199	7205	7231	COMMON SYSTEMS	COMPRESSED AIR SYSTEMS	#2 ATLAS COPCO ROTARY COMP	N/A	51	10	No Level 2 analyses is required, provided the current inspection and maintenance program is maintained.			
1297	7199	7205	7231	COMMON SYSTEMS	COMPRESSED AIR SYSTEMS	#1 ATLAS COPCO ROTARY COMP	N/A	52	10	No Level 2 analyses is required, provided the current inspection and maintenance program is maintained.			
1297	7199	7205	7231	COMMON SYSTEMS	COMPRESSED AIR SYSTEMS	ATLAS COPCO ROTARY COMP	N/A	53	10	No Level 2 analyses is required, provided the current inspection and maintenance program is maintained.			
1297	7199	7205	7231	COMMON SYSTEMS	COMPRESSED AIR SYSTEMS	BALANCE OF AIR COMPRESSORS STA	N/A	54	10	No Level 2 analyses is required, provided the current inspection and maintenance program is maintained.			
1297	7199	7205	7234	COMMON SYSTEMS	COMPRESSED AIR SYSTEMS	COMPRESSED AIR DRYERS SYSTEMS	N/A	55	10	No Level 2 analyses is required, provided the current inspection and maintenance program is maintained.			
1297	7199	7205	7235	COMMON SYSTEMS	COMPRESSED AIR SYSTEMS	COMPRESSED AIR RECEIVERS	N/A	56	10	No Level 2 analyses is required, provided the current inspection and maintenance program is maintained.			

11.1.6.8 Capital Projects

The suggested typical capital enhancements for the compressed air system include:

TABLE 11-30 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – COMPRESSED AIR

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset 2/3	Asset 3/4	Description	CAP#	Appendix #	Capital Item	Date	Priority
1297	7199	7205	0	0	COMMON SYSTEMS	COMPRESSED AIR SYSTEMS	COMPRESSED AIR SYSTEMS	50	10	No capital required.		
1297	7199	7205	7231	0	COMMON SYSTEMS	COMPRESSED AIR SYSTEMS	AIR COMPRESSORS	51	10	No Capital		
1297	7199	7205	7231	8918	COMMON SYSTEMS	COMPRESSED AIR SYSTEMS	#2 ATLAS COPCO ROTARY COMP	52	10	Replace compressor.	2014	1
1297	7199	7205	7231	9488	COMMON SYSTEMS	COMPRESSED AIR SYSTEMS	#1 ATLAS COPCO ROTARY COMP	53	10	Replace compressor.	2015	1
1297	7199	7205	7231	325028	COMMON SYSTEMS	COMPRESSED AIR SYSTEMS	ATLAS COPCO ROTARY COMP	54	10	No capital required.		
1297	7199	7205	7231	99000081	COMMON SYSTEMS	COMPRESSED AIR SYSTEMS	BALANCE OF AIR COMPRESSORS STA	55	10	No capital required.		
1297	7199	7205	7234	0	COMMON SYSTEMS	COMPRESSED AIR SYSTEMS	COMPRESSED AIR DRYERS SYSTEMS	56	10	No capital required.		
1297	7199	7205	7235	0	COMMON SYSTEMS	COMPRESSED AIR SYSTEMS	COMPRESSED AIR RECEIVERS	57	10	No capital required.		

11.2 Common Systems - Lower Priority Systems

11.2.1 Assets 7209 and 7204 – Fuel Systems (Light and Heavy Oil)

(Detailed Technical Assessment in Working Papers, Appendix 27)

Unit #:	Common
Asset Class #	BU 1297 - Assets Common
SCI & System:	7199 HRD Common Systems
Sub-Systems:	7204 Heavy Oil & Fuel Additive
	7209 Light Oil System
Components:	7223 Heavy oil Transfer to Storage
	7224 Heavy Oil Storage & Piping
	271814 HRD Tank Farm Dykes & Liners

11.2.1.1 Description

	Stage 1	Stage2
Manufactured/Delivered	1969	1979
In-Service Date	Sep 1970	Feb 1980
Refurbishment – Heavy Oil	Tanks 2008 to 2012; Civil/Supports: last 5 Yrs	
Refurbishment – Light Oil System	Tanks in last 5 years	
Base Load Requirement End Date	Dec 2015	
Boiler Use End Date (Light/Heavy)	Dec 2020	
Requirement – GTG Use End Date	Dec 2020	

Heavy Oil System

Heavy Oil Main Storage Tanks: Holyrood has 4 large heavy oil storage tanks that store the sites' supply of No. 6 fuel oil. Oil is piped to tanks from ships at the marine terminal. Tanks 1 and 2 were installed in 1969 and tanks 3 and 4 in 1977. Each tank is 55 m (180 feet) in diameter and 14.6 m (48 feet) high with a capacity of 31.6 million litres (200,000 bbl). Tanks are made of carbon steel and have an interior coating that functions to slow the rate of corrosion.

The residual oil that is supplied from any of the 4 main heavy fuel oil storage tanks flows to the fuel oil day tank. The main fuel oil is gravity fed from both the main fuel oil storage tanks to the day tanks as well from the day tank to the unit main heavy oil pumping and heating station.

FIGURE 11-22 HEAVY OIL MAIN STORAGE TANKS

FIGURE 11-23 HEAVY OIL – PIPING FROM STORAGE TO POWERHOUSE

Heavy Oil Day Tanks: The heavy oil day tank is approximately 12 to 15 years old. It has a rubber lined floor. The capacity was increased from 57 to 114 million litres (2000 to 4000 bbls) in 1980's. The piping layout for Unit 3 heavy oil system includes the use of a "short" recirculation valve which is piped back to the fuel oil day tank allowing the heavy oil pumps to be in service with the main oil trip valve closed. A "main fuel oil recirculation valve" and line is provided just upstream of the main oil trip valve and is used to re-circulate the oil back to the day tank.

FIGURE 11-24 HEAVY OIL DAY TANK AND PIPING TO POWERHOUSE

Heating Systems: The viscosity (SSU) of No. 6 fuel oil is high and hence requires heat for it to flow. Electric heat tracing is provided on the 46 cm (18 inch) pipeline from the receiving dock to the main oil tank farm.

Each storage tank is equipped with steam heat exchangers to enable the oil to gravity flow from the tanks to the main fuel oil lines.

Steam heat tracing is provided on all the main fuel oil lines feeding both the fuel oil day tank and the unit pumping and heating set.

Miscellaneous: The heavy oil system includes a magnesium oxide (MgO) fuel oil additive system (skids, tank), but the requirement for the system has been minimized since the lower sulphur oil has been used. This system is not specifically addressed.

FIGURE 11-25 FUEL ADDITIVE STORAGE TANK

Light Oil System

Light oil (#2 fuel oil) is used for diesel gensets, the black start gas turbine, and main unit ignition oil. It is gravity fed from the light oil fuel oil tanks.

Oil is received at the side of the black start diesel building and transferred to two 100,000 litre light oil tanks. There is very obvious corrosion pitting of the receiving lines and valves. The light oil pressure at the main units is maintained through constant recirculation back to the light oil storage tanks through a pressure control valve and piping arrangement.

The tanks themselves are relatively new (5 to 6 years). The lines under the roadway have been replaced as part of road repair work carried out in 2007.

FIGURE 11-26 LIGHT OIL RECEIVING SYSTEM AND STORAGE TANKS

11.2.1.2 History - Inspection and Repair History

A review of the 2006 SGE Acres report "Evaluation of Fuel Oil Storage Tanks, Associated Pipelines and Diced Drainage System Holyrood Thermal Generating Station" was used to determine the existing condition of the tanks in conjunction with a walkthrough of the tank farm.

Heavy Oil Main Storage Tanks: Tank inspections were last undertaken and the remaining life of the tanks estimated at the time as follows:

Tank #	Inspection Date	Remaining Floor Life
1	Dec 2005	10 years
2	Oct 19987	Not estimated. Next planned inspection was scheduled for 2008, but no indication it was carried out.
3	Nov 2003	5-6 years
4	Aug 2004	5-6 years

These led to the current tank refurbishment program to extend the life of the tanks by at least 20 years. The main issues with the tanks tended to be roof and floor repairs.

Tank Refurbishment Plan

- #4 tank bottom replacement - 2010
- #3 tank bottom replacement - 2011
- #1 tank bottom - 2012
- #2 tank refurbishment - 2008

The timing of inspections associated with API 653 and regulatory requirements are planned to continue.

A great deal of upgrade work has been recently undertaken with regard to the tank farm auxiliaries and areas – dykes, retention area drainage, pipe supports, pipe insulation and heat tracing (steam heat tracing from tanks to station). As a result, all are expected to be in good condition.

Heavy Oil Day Storage Tank: The heavy oil day tank is 12 years old. It has a rubber lined floor. No information was available on past inspections or on the condition of the tank. Given its age, it is assumed the tank is still in reasonable condition, however a condition assessment, whether a Level 2 or an API inspection, is warranted as soon as practical.

Heavy Oil Electric Trace Heating: Electric heat tracing is provided on the 46 cm (18 inch) pipeline from the receiving dock to the main oil tank farm. The electric heat tracing system has failed, and though repair work has been able to restart 2 of the 3 phases, they could fail anytime. An immediate repair or replacement is necessary.

Heavy Oil Steam Trace Heating: The heavy oil steam trace heating system on the pipeline in and from the tank farm to the powerhouse and day tank have been refurbished (along with civil supports) in last few years. It is operating well and in good condition.

Heavy Oil Heating & Pumping: The in-plant heavy oil heating and pumping systems receive regular maintenance and inspections. No specific information was reviewed on their condition, but maintenance discussions and visual inspections (limited) indicate that they appear to be in reasonable condition, given their service and age.

Light Oil Storage Tanks & Receiving System: The light oil storage tanks are relatively new (approximately 5 years old). The lines under the roadway have been replaced as part of road repair work carried out in 2007. Inspection information was not considered given the relatively short duration since their in-service date. They are subject to API regulatory inspection requirements.

The light oil receiving, pumping and piping system located at the gas turbine building are operational, but have experienced significant external corrosion due to the marine environment, including the lines to the light oil storage tanks and to the powerhouse ignition oil system. No data on inspections or testing was available during the study to indicate the extent of the corrosion or possible remaining life.

11.2.1.3 Condition Assessment

The condition assessment of the fuel systems (light and heavy oil) is illustrated below in Table 11-31.

TABLE 11-31 CONDITION ASSESSMENT – FUEL SYSTEMS (LIGHT AND HEAVY OIL)

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset Level 2	Asset Level 3	Description	Detail	Cond. Summ. ID#	Append #	Condition	EPRI Identifier	Original Life (Base Load) Ops Hrs (Yrs)	Current Expected Minimum Remaining Life Years (Subject to Test)	End of Life Required (EOL)	Next Regular Inspection	Next Planned Overhaul/ Major Inspection	Capability to Reach Next Overhaul	Capability to Reach EOL	In Service
1297	7199	7204	0	0	COMMON SYSTEMS	HEAVY OIL & FUEL ADDITIVE	HEAVY OIL & FUEL ADDITIVE	N/A	33	27	Not addressed. Out of service.									
1297	7199	7204	7223	0	COMMON SYSTEMS	HEAVY OIL & FUEL ADDITIVE	*HEAVY OIL TRANSFER TO STORAGE	N/A	34	27	Electric heat tracing system on the heavy oil delivery line from the dock to tank farm area has failed. Bootstrapped to work on two of three phases. Needs immediate redesign and repair/replacement.	4	(30)	1	2020			No	No	2000
1297	7199	7204	7224	0	COMMON SYSTEMS	HEAVY OIL & FUEL ADDITIVE	HEAVY OIL STORAGE & PIPING	N/A	35	27	Steam heat tracing from tank farm to the plant day tank has been upgraded. Steam heat tracing in the plant day tank area is functional but leaking.	4	200000 (30)	15+	2020			Yes	Yes	2009
1297	7199	7204	7224	7439	COMMON SYSTEMS	HEAVY OIL & FUEL ADDITIVE	HEAVY OIL DAY TANK	N/A	36	27	12 years old. No information was available on past inspections and the condition of the tanks.	4	(40)	(15+)	2020	2011	2011	Yes	No	1988
1297	7199	7204	7224	7441	COMMON SYSTEMS	HEAVY OIL & FUEL ADDITIVE	HEAVY OIL - #1 TANK	N/A	37	27	Major tank refurbishment to extend by 20+ years, primarily roof and floor.	4	(40)	20	2020	2010	2020	Yes	Yes	2011
1297	7199	7204	7224	7442	COMMON SYSTEMS	HEAVY OIL & FUEL ADDITIVE	HEAVY OIL - #2 TANK	N/A	38	27	Major tank refurbishment to extend by 20+ years, primarily roof and floor.	4	(40)	20	2020	2011	2020	Yes	Yes	2012
1297	7199	7204	7224	7443	COMMON SYSTEMS	HEAVY OIL & FUEL ADDITIVE	HEAVY OIL - #3 TANK	N/A	39	27	Major tank refurbishment to extend by 20+ years, primarily roof and floor.	4	(40)	20	2020	2012	2021	Yes	Yes	2012
1297	7199	7204	7224	7444	COMMON SYSTEMS	HEAVY OIL & FUEL ADDITIVE	HEAVY OIL - #4 TANK	N/A	40	27	Major tank refurbishment to extend by 20+ years, primarily roof and floor.	4	(40)	20	2020	2012	2021	Yes	Yes	2010
1297	7199	7204	286055	0	COMMON SYSTEMS	HEAVY OIL & FUEL ADDITIVE	FUEL ADDITIVE SYSTEMS	N/A	41	27	Not addressed. Out of service.									
1297	7199	7204	286055	7227	COMMON SYSTEMS	HEAVY OIL & FUEL ADDITIVE	F/A STORAGE TANK & PUMPS	N/A	44	27	Not addressed. Out of service.									
1297	7199	7209	0	0	COMMON SYSTEMS	LIGHT OIL SYSTEM	LIGHT OIL SYSTEM	N/A	45	27	Receiving and delivery system corroded. No data on inspections or testing available. The lines under the roadway replaced in 2007. No inspection information on lines in powerhouse available.	4	(40)	(2)	2041	2011		No	No	1968/2007
1297	7199	7209	99034713	0	COMMON SYSTEMS	LIGHT OIL SYSTEM	OIL STORAGE TANK	N/A	46	27	Relatively new, about 5 to 6 years. No inspections.	3a	(40)	10+	2041	2011		No	No	2004

Notes:

1. A “(bracketed)” value in the “Current Expected Remaining Life” column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation, including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as “(X/Y)” has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

2. The “Next Regular Inspection” column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The “Next Planned Overhaul or Major Inspection” column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a “Desired Life” stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where no specific dates have been identified for “Next Regular Inspection” or “Next Planned Overhaul/Major Inspection”, they are left blank.

11.2.1.4 Actions

Based on the condition assessment, the following actions are recommended for the fuel systems (light and heavy oil):

TABLE 11-32 RECOMMENDED ACTIONS – FUEL SYSTEMS (LIGHT AND HEAVY OIL)

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset 2/3	Asset 3/4	Description	Action #	App #	Action	Year	Priority
1297	7199	7204	0	0	COMMON	HEAVY OIL & FUEL ADDITIVE	HEAVY OIL & FUEL	36	27	No recommended action.		
1297	7199	7204	7223	0	COMMON SYSTEMS	HEAVY OIL & FUEL ADDITIVE	*HEAVY OIL TRANSFER TO STORAGE	37	27	Undertake design work and replacement of the electric trace heating system from the dock unloading to the storage tanks.	2010	1
1297	7199	7204	7224	0	COMMON SYSTEMS	HEAVY OIL & FUEL ADDITIVE	HEAVY OIL STORAGE & PIPING	38	27	Continue with external inspections of each tank approximately every 3 to 5 years and internally per corrosion determination but less than 20 years. Complete all recommendations that stem from inspection reports.	2011	1
1297	7199	7204	7224	7439	COMMON	HEAVY OIL & FUEL ADDITIVE	HEAVY OIL DAY TANK	39	27	Perform heavy oil day tank inspection as per API 653 requirements.	2011	1
1297	7199	7204	7224	7441	COMMON	HEAVY OIL & FUEL ADDITIVE	HEAVY OIL - #1 TANK	40	27	Continue the main fuel oil storage tank upgrade program.	2012	1
1297	7199	7204	7224	7442	COMMON	HEAVY OIL & FUEL ADDITIVE	HEAVY OIL - #2 TANK	41	27	None. Done in 2008.	2008	1
1297	7199	7204	7224	7443	COMMON	HEAVY OIL & FUEL ADDITIVE	HEAVY OIL - #3 TANK	42	27	Continue the main fuel oil storage tank upgrade program.	2011	1
1297	7199	7204	7224	7444	COMMON	HEAVY OIL & FUEL ADDITIVE	HEAVY OIL - #4 TANK	43	27	Finish the main fuel oil storage tank upgrade.	2010	1
1297	7199	7209	0	0	COMMON	LIGHT OIL SYSTEM	LIGHT OIL SYSTEM	44	27	See details below.		
1297	7199	7209	99034713	0	COMMON SYSTEMS	LIGHT OIL SYSTEM	OIL STORAGE TANK	45	27	Perform Level 2 inspections on light oil storage receiving and handling system and external tank inspection (per API653).	2011	1
1297	7199	7209	99034713	0	COMMON SYSTEMS	LIGHT OIL SYSTEM	OIL STORAGE TANK	46	27	Continue with external inspections of each tank approximately every 3 to 5 years and internally per corrosion determination but less than 20 years. Complete all recommendations that stem from inspection reports.	2011	1
1297	7199	7204	286055	0	COMMON	HEAVY OIL & FUEL ADDITIVE	FUEL ADDITIVE SYSTEMS	47	27	No recommended action.		
1297	7199	7204	286055	6991	COMMON	HEAVY OIL & FUEL ADDITIVE	#1 BOILER FUEL ADDITIVE	48	27	No recommended action.		
1297	7199	7204	286055	6991	COMMON	HEAVY OIL & FUEL ADDITIVE	MODIFY FUEL ADDITIVE	49	27	No recommended action.		
1297	7199	7204	286055	7227	COMMON	HEAVY OIL & FUEL ADDITIVE	F/A STORAGE TANK &	50	27	No recommended action.		

11.2.1.5 Risk Assessment

The risk assessment associated with the fuel systems (light and heavy oil), both from a technological perspective and a safety perspective, is illustrated below in Table 11-33.

TABLE 11-33 RISK ASSESSMENT – FUEL SYSTEMS (LIGHT AND HEAVY OIL)

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset 2/3	Asset 3/4	Description	Component	Risk Assess #	Appendix #	Major Issues	Remaining Life Years	Remaining Life	Techno-Eco Risk Assess Model			Safety Risk Assess Model			Possible Failure Event	Mitigation
												(Insufficient Info - Inspection Required Within (x) Years)	Comments	Likeli-hood	Conse-quence	Risk Level	Likeli-hood	Conse-quence	Safety Risk		
1297	7199	7204	0	0	COMMON SYSTEMS	HEAVY OIL & FUEL ADDITIVE	HEAVY OIL & FUEL ADDITIVE	None	33	27	Not addressed - out of service.		N/A								
1297	7199	7204	7223	0	COMMON SYSTEMS	HEAVY OIL & FUEL ADDITIVE	*HEAVY OIL TRANSFER TO STORAGE	Heavy Oil Steam Trace	34	27	Mechanical corrosion failure.	10+	N/A	1	C	Low	1	A	Low	Leak – shutdown for repair.	Inspect and maintain.
1297	7199	7204	7224	0	COMMON SYSTEMS	HEAVY OIL & FUEL ADDITIVE	HEAVY OIL STORAGE & PIPING	Heavy Oil Steam & Electric Ht Trace	35	27	Electrical or mechanical.	1	Failed state. Needs replacement. Critical to plant viability and reliability	4	D	High	4	A	Low	Inability to deliver oil. Plant would subsequently have to shut down. Major repair.	Inspect and replace as soon as possible.
1297	7199	7204	7224	7439	COMMON SYSTEMS	HEAVY OIL & FUEL ADDITIVE	HEAVY OIL DAY TANK	Heavy Oil Day Tanks	36	27	Corrosion.	10+	N/A	1	C	Low	1	A	Low	Unit shutdown – bypass possible for repairs.	Annual and regulatory inspect and maintain.
1297	7199	7204	7224	7441	COMMON SYSTEMS	HEAVY OIL & FUEL ADDITIVE	HEAVY OIL - #1 TANK	Heavy Oil Main Tanks	37	27	Corrosion.	10+	N/A	1	B	Low	1	A	Low	Oil leak – containment overflow.	Annual and regulatory inspect and maintain.
1297	7199	7204	7224	7442	COMMON SYSTEMS	HEAVY OIL & FUEL ADDITIVE	HEAVY OIL - #2 TANK	Heavy Oil Main Tanks	38	27	Corrosion.	10+	N/A	1	B	Low	1	A	Low	Oil leak – containment overflow.	Annual and regulatory inspect and maintain.
1297	7199	7204	7224	7443	COMMON SYSTEMS	HEAVY OIL & FUEL ADDITIVE	HEAVY OIL - #3 TANK	Heavy Oil Main Tanks	39	27	Corrosion.	10+	N/A	1	B	Low	1	A	Low	Oil leak – containment overflow.	Annual and regulatory inspect and maintain.
1297	7199	7204	7224	7444	COMMON SYSTEMS	HEAVY OIL & FUEL ADDITIVE	HEAVY OIL - #4 TANK	Heavy Oil Main Tanks	40	27	Corrosion.	10+	N/A	1	B	Low	1	A	Low	Oil leak – containment overflow.	Annual and regulatory inspect and maintain.
1297	7199	7209	0	0	COMMON SYSTEMS	LIGHT OIL SYSTEM	LIGHT OIL SYSTEM	Light Oil Receiving System	45	27	Mechanical failure/leaks.	(2)	N/A	3	B	Medium	3	B	Medium	Unit shutdown for repairs. GTG shutdown for repairs.	Inspect and refurbish/replace.
1297	7199	7209	0	0	COMMON SYSTEMS	LIGHT OIL SYSTEM	LIGHT OIL SYSTEM	Light Oil Piping to station	46	27	Mechanical failure/leaks.	(2)	N/A	2	B	Low	2	B	Medium	Unit shutdown for repairs.	Inspect and refurbish/replace.
1297	7199	7209	99034713	0	COMMON SYSTEMS	LIGHT OIL SYSTEM	OIL STORAGE TANK	Light Oil Tanks	47	27	Mechanical failure/leaks.	10+	N/A	1	A	Low	1	A	Low	Unit shutdown for repairs.	Annual and regulatory inspect and maintain.

11.2.1.6 Life Cycle Curve and Remaining Life

The life cycle curves for the oil systems are illustrated below. Two figures are used - one for the heavy oil and light oil tanks and the other for the heavy and light oil BOP. Several curves are required to represent the various elements of and their operational timing. The life curves are plots of physical age of the equipment on the y-axis versus calendar year on the x-axis. For this system the actual life may only need to extend to 2020, although the curves are continued to 2041.The chart has several vertical lines representing differing representative nominal age limits for various components. It also has several horizontal lines that represent a range of practical equipment life limits in years.

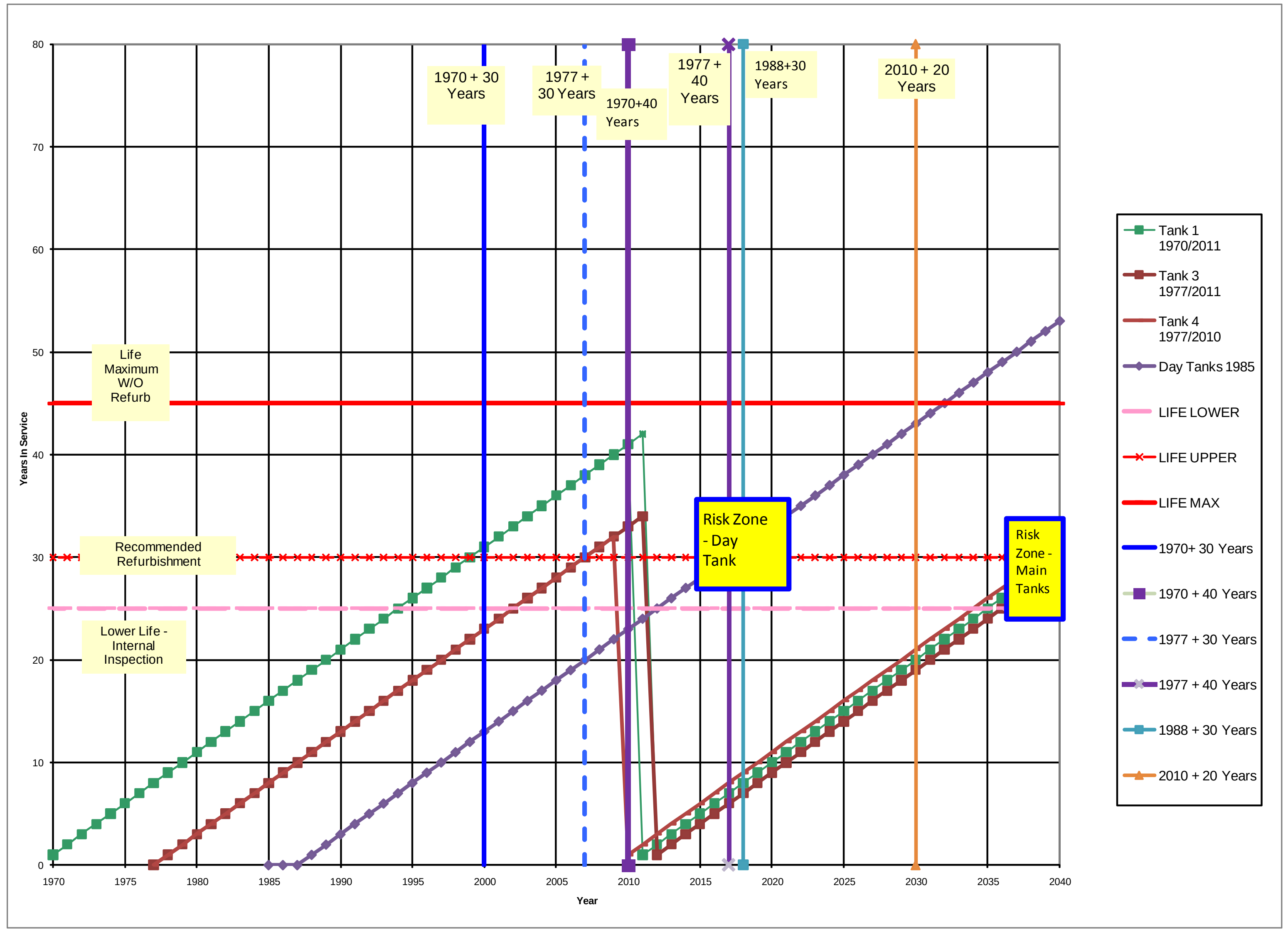


FIGURE 11-27 LIFE CYCLE CURVE – FUEL SYSTEMS (LIGHT AND HEAVY OIL TANKS)

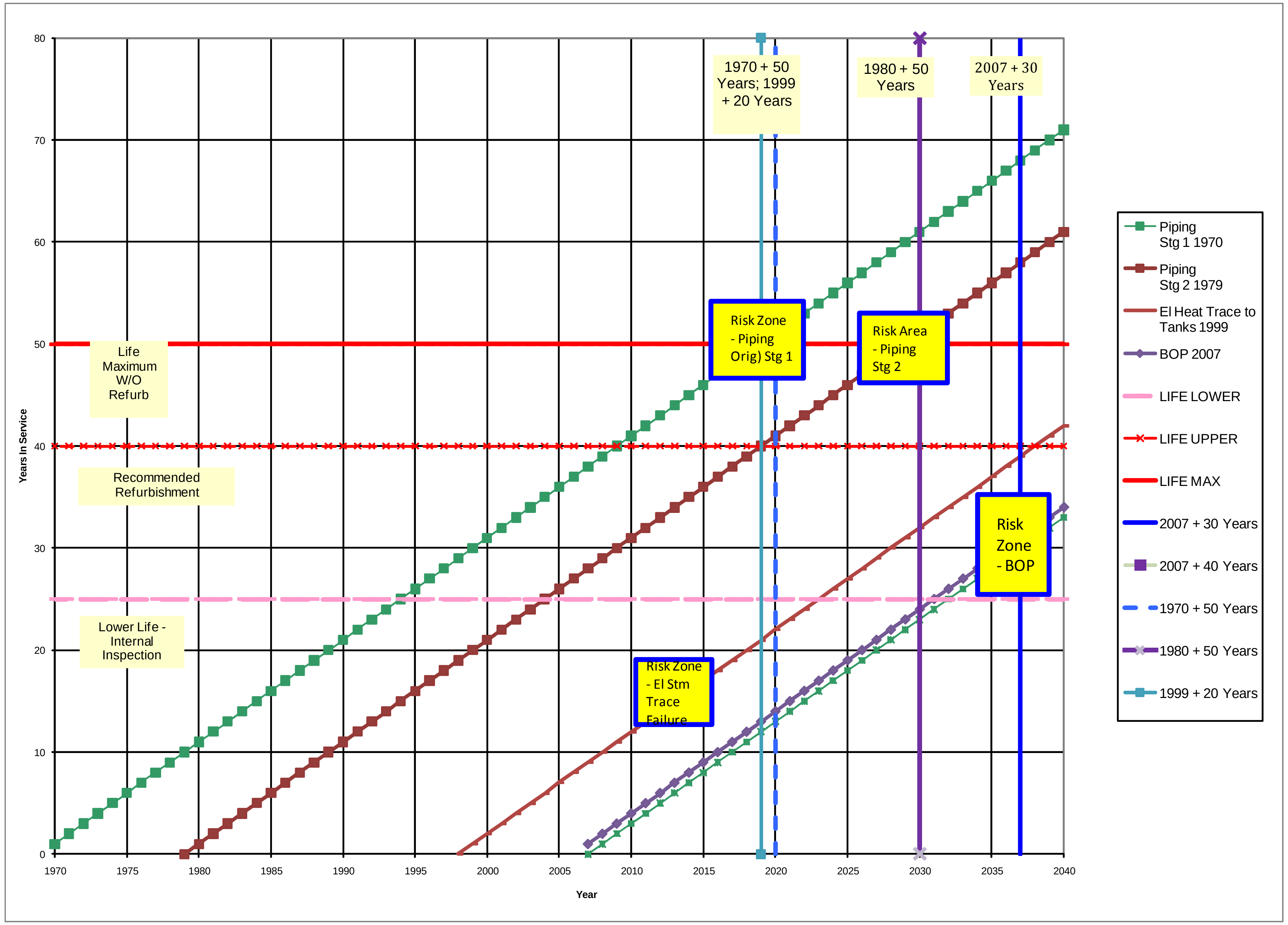


FIGURE 11-28 LIFE CYCLE CURVE – FUEL SYSTEMS (LIGHT AND HEAVY OIL - BOP)

The curves indicate that the remaining life (RL) of the light oil and heavy oil tanks can reach the desired life (DL) of the end date for generation of 2020 once the current heavy oil tank refurbishment is completed. It does identify a need for the heavy oil day tank to be inspected and refurbished in the near future. It also identified the immediate and critical problem of the electric heat tracing on the oil delivery line to the heavy oil tank farm.

11.2.1.7 Level 2 Inspection Requirements and Costs

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 11-34 below, assuming the current plant inspection and maintenance program is maintained or improved.

TABLE 11-34 LEVEL 2 INSPECTION – FUEL SYSTEMS (LIGHT AND HEAVY OIL)

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset 2/3	Asset 3/4	Description	Sub System Comment	L2#	Appendix #	Level 2 Work	Year	Priority	Cost k$
1297	7199	7204	0	COMMON SYSTEMS	HEAVY OIL & FUEL ADDITIVE	HEAVY OIL & FUEL ADDITIVE	N/A	33	N/A	No Level 2 required.			
1297	7199	7204	7223	COMMON SYSTEMS	HEAVY OIL & FUEL ADDITIVE	HEAVY OIL TRANSFER TO STORAGE	N/A	34	27	Replacement assessment	2010	1	$73
1297	7199	7204	7224	COMMON SYSTEMS	HEAVY OIL & FUEL ADDITIVE	HEAVY OIL STORAGE & PIPING	N/A	35	27	No Level 2 required.			
1297	7199	7204	7224	COMMON SYSTEMS	HEAVY OIL & FUEL ADDITIVE	HEAVY OIL DAY TANK	Heavy oil Tanks	36	27	API 653 internal inspection of heavy oil day tank, unless already done, by 2012	2012	1	$37
1297	7199	7204	7224	COMMON SYSTEMS	HEAVY OIL & FUEL ADDITIVE	HEAVY OIL - #1 TANK	N/A	37	27	No Level 2 required.			
1297	7199	7204	7224	COMMON SYSTEMS	HEAVY OIL & FUEL ADDITIVE	HEAVY OIL - #2 TANK	N/A	38	27	No Level 2 required.			
1297	7199	7204	7224	COMMON SYSTEMS	HEAVY OIL & FUEL ADDITIVE	HEAVY OIL - TANK	N/A	39	27	No Level 2 required.			
1297	7199	7204	7224	COMMON SYSTEMS	HEAVY OIL & FUEL ADDITIVE	HEAVY OIL - #4 TANK	N/A	40	27	No Level 2 required.			
1297	7199	7204	286055	COMMON SYSTEMS	HEAVY OIL & FUEL ADDITIVE	FUEL ADDITIVE SYSTEMS	N/A	41	N/A	No Level 2 required.			
1297	7199	7204	286055	COMMON SYSTEMS	HEAVY OIL & FUEL ADDITIVE	#1 BOILER FUEL ADDITIVE SYSTEM	N/A	42	N/A	No Level 2 required.			
1297	7199	7204	286055	COMMON SYSTEMS	HEAVY OIL & FUEL ADDITIVE	MODIFY FUEL ADDITIVE SYSTEM, S	N/A	43	N/A	No Level 2 required.			
1297	7199	7204	286055	COMMON SYSTEMS	HEAVY OIL & FUEL ADDITIVE	F/A STORAGE TANK & PUMPS	N/A	44	N/A	No Level 2 required.			
1297	7199	7209	0	COMMON SYSTEMS	LIGHT OIL SYSTEM	LIGHT OIL SYSTEM	Light Oil receiving & handling	45	27	Level 2 inspection of light oil receiving and forwarding pumps, valves, and piping - See GTG.			
1297	7199	7209	99034713	COMMON SYSTEMS	LIGHT OIL SYSTEM	OIL STORAGE TANK	Light Oil Tanks	46	27	API 653 external inspection of light oil tanks .	2012	1	(Incl in 36)

11.2.1.8 Capital Projects

The suggested typical capital enhancements for the fuel systems (light and heavy oil) include:

TABLE 11-35 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – FUEL SYSTEMS (LIGHT AND HEAVY OIL)

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset 2/3	Asset 3/4	Description	CAP#	Appendix #	Capital Item	Date	Priority
1297	7199	7204	0	0	COMMON SYSTEMS	HEAVY OIL & FUEL ADDITIVE	HEAVY OIL & FUEL ADDITIVE	34	27	No capital required.		
1297	7199	7204	7223	0	COMMON SYSTEMS	HEAVY OIL & FUEL ADDITIVE	*HEAVY OIL TRANSFER TO STORAGE	35	27	Replace electric heat trace system.	2011	1
1297	7199	7204	7224	0	COMMON SYSTEMS	HEAVY OIL & FUEL ADDITIVE	HEAVY OIL STORAGE & PIPING	36	27	No capital required.		
1297	7199	7204	7224	7439	COMMON SYSTEMS	HEAVY OIL & FUEL ADDITIVE	HEAVY OIL DAY TANK	37	27	No capital required.		
1297	7199	7204	7224	7441	COMMON SYSTEMS	HEAVY OIL & FUEL ADDITIVE	HEAVY OIL - #1 TANK	38	27	Complete recommended actions from SGE Acres report - replace tank bottom and apply protective coating to new bottom and 1 meter of shell. Complete API653 inspection.	2012	1
1297	7199	7204	7224	7442	COMMON SYSTEMS	HEAVY OIL & FUEL ADDITIVE	HEAVY OIL - #2 TANK	39	27	No capital required.		
1297	7199	7204	7224	7443	COMMON SYSTEMS	HEAVY OIL & FUEL ADDITIVE	HEAVY OIL - #3 TANK	40	27	Complete recommended actions from SGE Acres report - replace tank bottom and apply protective coating to new bottom and 1 meter of shell. Complete API653 inspection.	2011	1
1297	7199	7204	7224	7444	COMMON SYSTEMS	HEAVY OIL & FUEL ADDITIVE	HEAVY OIL - #4 TANK	41	27	Complete recommended actions from SGE Acres report - replace tank bottom and apply protective coating to new bottom and 1 meter of shell. Complete API653 inspection.	2010	1
1297	7199	7209	0	0	COMMON SYSTEMS	LIGHT OIL SYSTEM	LIGHT OIL SYSTEM	46	27	No capital required. Piping associated with gas turbine is a priority and is addressed as part of gas turbine package.		
1297	7199	7209	99034713	0	COMMON SYSTEMS	LIGHT OIL SYSTEM	OIL STORAGE TANK	47	27	No capital required.		

11.2.2 Waste Water Treatment Plant (WWTP)

(Detailed Technical Assessment in Working Papers, Appendix 16)

Unit #:	Common Facilities
Asset Class #	BU 1297 - Assets Common
SCI & System:	9739 HRD Waste Water Treatment & Environment
Sub-Systems:	10038 HRD Waste Water Treatment Plant
Components:	286057 Waste Water Treatment Plant Systems
Components:	7263 Oil/Water Separators

The following buildings are addressed in the Buildings section in Section 11.1.4.

Unit #:	Buildings
Asset Class #	BU 1297 - Assets Common
SCI & System:	72559739 HRD Buildings & Site
Sub-Systems:	272255 HRD Buildings
Components:	7304 Waste Water Treatment Plant Building
	7305 Waste Water Treatment Basins Building

11.2.2.1 Description

The waste water treatment facility is common to the whole plant:

Installed Waste Water Treatment Basins	1992
Installed New Waste Water Treatment Plant	1994
Upgraded Process Plant (filter press)	2002
Generation Base Load End Date	Dec 2015
Generation Peak/Emerg Gen End Date	Dec 2020
Synchronous Condensing End Date	Dec 2041 (Lower Usage required)

The hours (anticipated maximum operating hours associated with 3 units) associated with the analyses are:

Hours Generation Actual – 1994/2002 to Dec 2009	74,000/32,000
Max Hrs Ops to Gen End Date Dec 2015	104,000/62,000
Max Hours Ops – to Gen End Date - Dec 2020	127,000/85,000
Max Hrs Ops to SC End Date Dec 2041	220,000/185,000

The WWT plant will be required to process plant run-off and other site waste water year round up to the year 2041. The WWTP treats the wastewater generated at the plant, including Unit 1, Unit 2 and Unit 3, as well as common areas.

The WWTP building is a pre-engineered steel building that sits on a concrete foundation.

The waste water equalization basin building covers two large tanks. It is a pre-engineered steel building that sits on a concrete foundation with two large open concrete tanks that occupy the majority of the building. The tanks receive drainage water from the power plant. One tank holds “cleaner” water while the other tank holds contaminated water (boiler blowdown, boiler cleans, etc.). Contaminated water is fed into the WWTP where it is treated and then released into the environment. The cleaned water is then released directly into the environment when the water level reaches a certain elevation in the tank.

The WWTP process includes the following major equipment elements:

- Oil/water separator
- Equalization basins
- Mechanical settler
- Solids filter press

Collected solids from the WWTP and its processes are transported to the on-site landfill for final disposal. Cleaned water is released.

Waste Water Treatment Plant (WWTP) Batch Reactor & Building: The WWTP process equipment was installed in a separate building in 1994. It consists of a batch stirred reactor and a filter press. As a result, the mechanical filter is about 16 years old and the filter press less than 10 years.

Waste Water Treatment Plant Treatment Basin & Building: The two WWTP treatment basins and their building enclosure were built in 1992 to address effluent concerns. The two settling ponds serve dirty sources and cleaner sources respectively. No automated treatment is installed, but the pH is addressed periodically. The basins are hard concrete built on bedrock.

Oily Water Separator and Piping: Four buried passive oily-water separation tanks were installed in 1991 between the power plant and the waste water basins. The tanks are coated internally and are expected to remove the oil from waste water flowing to the treatment basin ponds

Waste Water Piping: Waste water from the site is routed to the WWTP basins. In the powerhouse there are two sump pits (between Units 1 and 2 and one near Unit 3). Normally waste water is collected in the sump pits and is pumped via 63 mm CPVC underground lines to the WWTP basins. Several manholes and flushing connections are located between the sumps and the WWTP basins. Periodic drainage for air preheater washes, fireside boiler washes or boiler acid cleans is handled using temporary piping to the basins.

11.2.2.2 History - Inspection and Repair History

Waste Water Treatment Plant (WWTP) Batch Reactor & Building: The WWTP is about 16 years old and the filter press less than 10 years. Although no major inspections were identified as having been undertaken, it was clear from staff interviews and from a high level visual inspection when the settling tank and its auxiliaries were empty that the equipment is in good condition.

Until approximately 2007, these systems were in continuous use due to the frequency of boiler cleans during operational seasons. Since 2007, less boiler cleanup water has meant there is more time to access the mechanical settler and filter press for maintenance and inspection. Overall the entire system has had considerably less operation since the adoption of the new fuel oil which has required less boiler and airpreheater washes.

The building is structurally sound. The structural systems that comprise the building are in excellent condition with very little corrosion found and no major structural deficiencies were noted. It does have some rusty siding.

Waste Water Treatment Plant Treatment Basin & Building: The two WWTP treatment basins and their building enclosure were built in 1992 to address effluent concerns. The basins are cleaned out approximately on a one to two year frequency. The last inspection was identified as being in 2007/2008 and one minor crack was identified, but no detailed examination has been completed.

There are some OHSA air quality concerns by staff and safety issues around basin access (exit routes). Some initial assessment on replacement of the roof and exhaust fans, as well as some side wall ventilation, was considered for 2011 at a cost of about $800k-$1M.

A walkthrough of the equalization basin building was performed to gauge the existing condition of the building. It was clear both the interior and exterior have been affected by the very humid atmosphere. Ventilation systems have not been very effective and have experienced corrosion. The roofing is considered by staff to be unsafe. Improved oily surface skimming and basin pond egress is considered desirable. The structural steel has also experienced significant rusting.

Oily Water Separator and Piping: The four buried passive oily-water separation tanks are periodically inspected, but typically only visually. They are expected to remove the oil from waste water flowing to the treatment basin ponds. It was evident from an oily sheen on the surface of the water in the WWTP basin during visual walkdowns that this is not always the case.

The last inspection of one of the tanks was less than five years ago, but no report was available. The tanks are identified as being in reasonably good shape, although there was some internal corrosion. No specific NDE testing was undertaken.

Site Waste Water Piping: Staff interviews identified a concern that not all of the plant drains are draining properly and may have breaks or blockages. No specific inspection documentation was available that indicated the condition of the underground waste water piping. Some of it is assumed to be original equipment and some presumably has only been in place since the WWTP in-service date of 1994. It is generally expected to be in good shape, but there is some concern that leakage might be occurring.

11.2.2.3 Condition Assessment

The condition assessment of the waste water treatment plant is illustrated below in Table 11-36.

TABLE 11-36 CONDITION ASSESSMENT – WASTE WATER TREATMENT PLANT (WWTP)

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset Level 2	Asset Level 3	Description	Detail	Cond. Summ. ID#	Append #	Condition	EPRI Identifier	Original Life (Base Load) Ops Hrs (Yrs)	Current Expected Minimum Remaining Life Years (Subject to Test)	End of Life Required (EOL)	Next Regular Inspection	Next Planned Overhaul/ Major Inspection	Capability to Reach Next Overhaul	Capability to Reach EOL	In Service
1297	9739	10038	0	0	WATER TREATMENT AND ENVIRONMENT	WASTE WATER TREATMENT SYSTEM	WASTE WATER TREATMENT SYSTEM	N/A	154	16	Process equipment installed in 1994 and new filter press in the past ten years. No major inspections have been undertaken, but interviews and visual inspection indicate it is in good shape.	3a	(30)	20	2041			Yes	No	1994/2000
1297	9739	10038	7263	0	WATER TREATMENT AND ENVIRONMENT	WASTE WATER TREATMENT SYSTEM	OIL/WATER SEPARATORS	N/A	155	16	Basin water oil suggest separators are not always effective. Some concerns that some plant drains may have breaks or blockages. No specific inspection documentation was available that indicated the state of the lines.	4	(30)	(10+)	2041			No	No	1991
1297	9739	10038	99003527	0	WATER TREATMENT AND ENVIRONMENT	WASTE WATER TREATMENT SYSTEM	CONCRETE BASINS FOR W.W.T.S.	N/A	156	16,17	Two basins built in 1992 are periodically cleaned and visually inspected, typically every two years. No major issues have been identified with the basins themselves - some minor cracking of the concrete in the last inspection two to three years ago. The system has no automated or formal effluent pH control, although it meets site permit requirements.	4	(30)	(20+)	2041			No	No	1992
1297	9739	10038	99003531	0	WATER TREATMENT AND ENVIRONMENT	WASTE WATER TREATMENT SYSTEM	BALANCE OF WASTE WATER TREATMENT	N/A	157	16	Relatively new and in good condition.	3a	(20)	20	2041			No	No	1994
1297	9739	7260	7405	0	WATER TREATMENT AND ENVIRONMENT	WASTE WATER TREATMENT SYSTEM	WASTE WATER TREATMENT MCC C12	N/A	158	6	Relatively new and in good condition.	3a	(30)	20+	2041			Yes	Yes	1994

Notes:

1. A "(bracketed)" value in the "Current Expected Remaining Life" column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation, including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as "(X/Y)" has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

2. The "Next Regular Inspection" column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The "Next Planned Overhaul or Major Inspection" column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a "Desired Life" stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where no specific dates have been identified for "Next Regular Inspection" or "Next Planned Overhaul/Major Inspection", they are left blank

11.2.2.4 Actions

Based on the condition assessment, the following actions are recommended for the waste water treatment plant (WWTP):

TABLE 11-37 RECOMMENDED ACTIONS – WASTE WATER TREATMENT PLANT (WWTP)

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset 2/3	Asset 3/4	Description	Action #	App #	Action	Year	Priority
1297	9739	10038	0	0	WATER TREATMENT & ENVIRONMENT	WASTE WATER TREATMENT SYSTEM	WASTE WATER TREATMENT SYSTEM	171	16	Relatively new. No action recommended.		
1297	9739	10038	7263	0	WATER TREATMENT & ENVIRONMENT	WASTE WATER TREATMENT SYSTEM	OIL/WATER SEPARATORS	172	16	Perform Level 2 thickness measurements of the vessels and visual inspections of the internals. Test lines to oil/water separators and to WWTP basins for flow.	2011	1
1297	9739	10038	99003527	0	WATER TREATMENT & ENVIRONMENT	WASTE WATER TREATMENT SYSTEM	CONCRETE BASINS FOR W.W.T.S.	173	16	Perform Level 2 concrete base and structural steel.	2011	1
1297	9739	10038	99003531	0	WATER TREATMENT & ENVIRONMENT	WASTE WATER TREATMENT SYSTEM	BALANCE OF WASTE WATER TREATMENT	174	16	No recommended action.		

11.2.2.5 Risk Assessment

The risk assessment associated with the waste water treatment plant, both from a technological perspective and a safety perspective, is illustrated below in Table 11-38.

TABLE 11-38 RISK ASSESSMENT – WASTE WATER TREATMENT PLANT (WWTP)

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset 2/3	Asset 3/4	Description	Component	Risk Assess #	Appendix #	Major Issues	Remaining Life Years	Remaining Life	Techno-Eco Risk Assess Model			Safety Risk Assess Model			Possible Failure Event	Mitigation
												(Insufficient Info - Inspection Required Within (x) Years)	Comments	Likeli-hood	Conse-quence	Risk Level	Likeli-hood	Conse-quence	Safety Risk		
1297	9739	10038	0	0	WATER TREATMENT & ENVIRONMENT	WASTE WATER TREATMENT SYSTEM	WASTE WATER TREATMENT SYSTEM	None	174	28	See detail below.										
1297	9739	10038	0	0	WATER TREATMENT & ENVIRONMENT	WASTE WATER TREATMENT SYSTEM	WASTE WATER TREATMENT SYSTEM	Batch Reactor	175	16	Minimal corrosion at base and side walls.	20	N/A	1	A	Low	1	B	Low	Tank leak, difficult to access and fix. Station outage if extensive at wrong time.	Inspect, maintain.
1297	9739	10038	0	0	WATER TREATMENT & ENVIRONMENT	WASTE WATER TREATMENT SYSTEM	WASTE WATER TREATMENT SYSTEM	Filter Press	176	16	Failure of press elements.	25	N/A	1	A	Low	1	B	Low	Temporary measures for waste storage.	Inspect, maintain.
1297	9739	7260	7405	0	WATER TREATMENT & ENVIRONMENT	ENVIRONMENTAL MONITORING	WASTE WATER TREATMENT MCC C12	MCC	177	6	Not addressed in detail.	10	Electrical failure	2	A	Low	2	A	Low	System shutdown.	Inspect, maintain.
1297	9739	10038	7263	0	WATER TREATMENT & ENVIRONMENT	WASTE WATER TREATMENT SYSTEM	OIL/WATER SEPARATORS	Oil Water Separator & Underground Drain Pipes	178	16	Oil leakage, underground drain leakage.	(10+)	Likely 10+ Years. Inspections are required to assess the remaining life.	3	B	Medium	3	B	Medium	Leak of drains and possible oil to environment.	Test, maintain.
1297	9739	10038	99003527	0	WATER TREATMENT & ENVIRONMENT	WASTE WATER TREATMENT SYSTEM	CONCRETE BASINS FOR W.W.T.S.	Treatment Basins	179	16	Crack and failure.	(20+)	Likely 20 years. Inspections are required to verify the remaining life.	1	C	Low	1	B	Low	Basin leak and spill to environment.	Test, maintain.
1297	9739	10038	99003531	0	WATER TREATMENT & ENVIRONMENT	WASTE WATER TREATMENT SYSTEM	BALANCE OF WASTE WATER TREATMENT	None	180	16											

11.2.2.6 Life Cycle Curve and Remaining Life

The life cycle curve for the system is illustrated below. Several curves are required to represent the various elements. The life curves are plots of physical age of the equipment on the y-axis versus calendar year on the x-axis. The chart has several vertical lines representing differing representative nominal age limits for various components. It also has several horizontal lines that represent a range of practical equipment equivalent base loaded operating life limits.

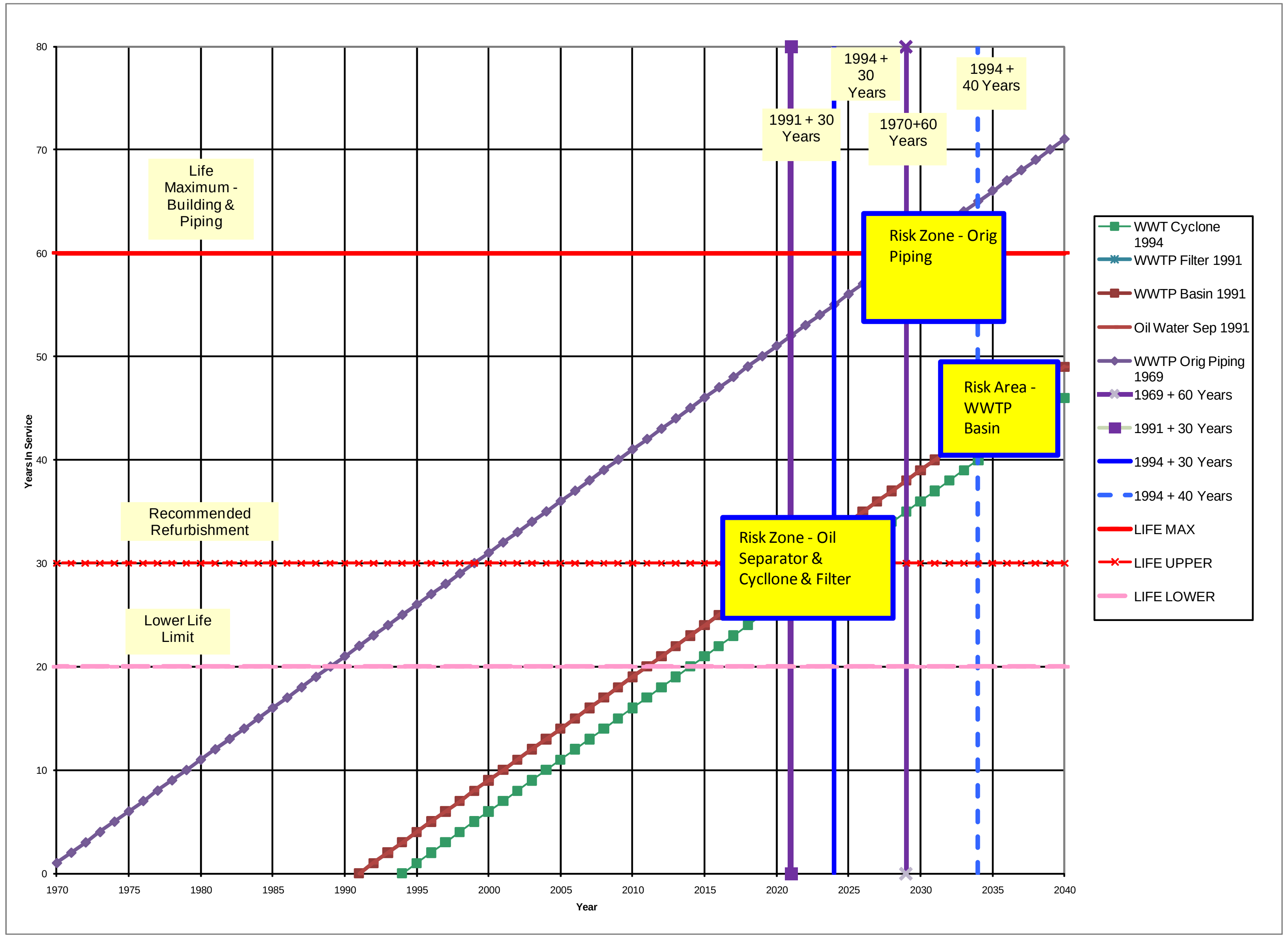


FIGURE 11-29 LIFE CYCLE CURVE – WASTE WATER TREATMENT PLANT (WWTP)

The curves indicate that the remaining life (RL) of most of the waste water treatment plant (WWTP) system exceeds the desired life (DL) which is the end date for generation of 2020. The exception is the WWTP basin building which requires refurbishment/replacement. The dates for the oil separation and piping and basin tanks are subject to inspection information required.

11.2.2.7 Level 2 Inspection Requirements and Costs

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 11-39 below, assuming the current plant inspection and maintenance program is maintained or improved.

TABLE 11-39 LEVEL 2 INSPECTION – WASTE WATER TREATMENT PLANT (WWTP)

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset 2/3	Asset 3/4	Description	Sub System Comment	L2#	Appendix #	Level 2 Work	Year	Priority	Cost k$
1297	9739	10038	0	WATER TREATMENT AND ENVIRONMENT	WASTE WATER TREATMENT SYSTEM	WASTE WATER TREATMENT SYSTEM	N/A	151	16	For Building: See Building-WWTP in Table 11-19.			
1297	9739	10038	7263	WATER TREATMENT AND ENVIRONMENT	WASTE WATER TREATMENT SYSTEM	OIL/WATER SEPARATORS	Oil Water Separators	152	16	Thickness measurement of oil water separators and coating, and visual Inspection of internals.	2011	2	$75
1297	9739	10038	7263	WATER TREATMENT AND ENVIRONMENT	WASTE WATER TREATMENT SYSTEM	OIL/WATER SEPARATORS	Oily Water & Discharge Pipes	153	16	Thickness measurement of underground oily water pipes and other discharge pipes underground. Leak check.	2011	2	$15
1297	9739	10038	99003527	WATER TREATMENT AND ENVIRONMENT	WASTE WATER TREATMENT SYSTEM	CONCRETE BASINS FOR W.W.T.S.	N/A	154	16	Concrete test of basin floor.	2011	3	$18
1297	9739	10038	99003531	WATER TREATMENT AND ENVIRONMENT	WASTE WATER TREATMENT SYSTEM	BALANCE OF WASTE WATER TREATMENT	N/A	156	16	No Level 2 required.			

11.2.2.8 Capital Projects

The suggested typical capital enhancements for the waste water treatment plant include:

TABLE 11-40 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – WASTE WATER TREATMENT PLANT (WWTP)

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset 2/3	Asset 3/4	Description	CAP#	Appendix #	Capital Item	Date	Priority
1297	9739	10038	0	0	WATER TREATMENT & ENVIRONMENT	WASTE WATER TREATMENT SYSTEM	WASTE WATER TREATMENT SYSTEM	160		For Building: See Building-WWTP in Table 11-20.		
1297	9739	10038	7263	0	WATER TREATMENT & ENVIRONMENT	WASTE WATER TREATMENT SYSTEM	OIL/WATER SEPARATORS	161	16	Refurbish oil water separator.	2015	1
1297	9739	10038	99003527	0	WATER TREATMENT & ENVIRONMENT	WASTE WATER TREATMENT SYSTEM	CONCRETE BASINS FOR W.W.T.S.	162		No capital required.		
1297	9739	7260	7405	0	WATER TREATMENT & ENVIRONMENT	ENVIRONMENTAL MONITORING	WASTE WATER TREATMENT MCC C12	163		No capital required.		
1297	9739	10038	99003531	0	WATER TREATMENT & ENVIRONMENT	WASTE WATER TREATMENT SYSTEM	BALANCE OF WASTE WATER TREATMENT	164		No capital required.		

11.2.3 Asset 9739 – Water Treatment Plant (WTP) System

(Detailed Technical Assessment in Working Papers, Appendix 2, Condensate Polishing - Appendices 15, 21)

Unit #:	Common Facilities
Asset Class #	BU 1297 - Assets Common
SCI & System:	9739 HRD Water Treatment & Environment
Sub-Systems:	7203 HRD Water Treatment Plant
Components:	286057 Water Treatment Plant Systems
Sub-Components:	6802 WTP Brine System 7185 WTP & MCC C5 7212 WTP Sulphuric Acid System 7213 WTP Flocculent Chem Inj 7214 WTP Primary Train 7220 WTP Mixed Bed 7410 WT MCC C10 7422 WTP Clarifier System 8748 WTP & Aux Blr MCC WTP-34 9864 WTP Sand Filter 9879 WTP Clearwell System 9995 6400 Chem Inj 10037 WTP Caustic System

11.2.3.1 Description

The Water Treatment Plant at Holyrood Thermal Generation Station (HTGS) serves Unit 1, Unit 2 and Unit 3. This includes the major equipment elements:

- Clarifier system (1) and auxiliaries;
- Sand filters (3) and auxiliaries;
- Clearwell System (1) and auxiliaries;
- Primary Cation and Anion demineralizer Trains - replaced in 1992;
- Mixed Cation/Anion Bed Trains - replaced in 1992;
- Bulk Acid and Caustic Storage Vessels; and
- Demin Water Storage Vessel – replaced in 1992.

In addition, there are other smaller items such as acid and caustic storage tanks, brine system, chemical injection systems, flocculent chemical injection systems, and pumps.

FIGURE 11-30 WATER TREATMENT PLANT – SAND FILTERS; CLARIFIER ADDITIVE TANKS

FIGURE 11-31 WATER TREATMENT PLANT – CLEARWELL AND DEMINERALIZED WATER TANK

FIGURE 11-32 ACID & CAUSTIC AREA

The fresh water supply for the water treatment plant originates at Quarry Brook dam and moves through a 41 cm (16 inch) underground line to the circulating water pumphouse. It moves from the pumphouse through a 20 cm (8 inch) branch line which terminates at the raw water sump. From the raw water sump the water is pumped to the clarifier.

11.2.3.2 History - Inspection and Repair History

Water Storage Vessels: The major storage vessels (clarifier, sand filters, demin storage) are original equipment, installed around 1969. They have generally been reasonably well maintained and checked for process integrity.

The clarifier has received minimum inspections and written record was not available. Visual inspections are said to occur on a 5 year frequency. There is no record of thickness testing or NDT examination of the clarifier. Several sub-systems (impellors, mixer motors, etc.) have been replaced or improved over the years as a part of a regular maintenance program. The impeller shaft steady bearing and sample lines have recently been replaced. In some cases, various internal and external patching has been undertaken on an as-required basis.

In 2009, one sand filter vessel had an ultrasonic thickness assessment done which showed some metal losses at the base. Visually the tank walls are in good shape for their age. However, some localized repairs have been made to the coating on the vessel walls and there is some corrosion at vessel base.

No major structural inspections seem to have been undertaken recently and there is external evidence of corrosion at the base of some of the carbon steel vessels.

Bulk Acid & Bulk Caustic Storage Tanks: The bulk acid and bulk caustic storage tanks are only about 13 years old. They have been reasonably well maintained and checked for process integrity. Several sub-systems (pumps, motors, etc.) have been replaced or improved over the years as a part of a regular maintenance program. There have been no regular inspections on these tanks, although there may have been some thickness testing performed, but no records were found. It is known that some of the piping external to the tanks is plugged and, based on interviews with plant staff, there may be as much as 30 cm of sludge in the bottom of these tanks.

Major Process Systems & Vessels: The major process systems and their associated vessels (primarily the anion, cation and mixed bed systems) were upgraded in 1992, after the original systems were in-service for approximately 22 years (approximately 80,000 hours of operation). They are reported to be in excellent shape and performing well. No regular inspections on these vessels were identified, although their performance is continuously recorded and examined for significant changes.

11.2.3.3 Condition Assessment

The condition assessment of the water treatment plant system is illustrated below in Table 11-41.

TABLE 11-41 CONDITION ASSESSMENT – WATER TREATMENT PLANT (WTP) SYSTEM

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset Level 2	Asset Level 3	Description	Detail	Cond. Summ. ID#	Append #	Condition	EPRI Identifier	Original Life (Base Load) Ops Hrs (Yrs)	Current Expected Minimum Remaining Life Years (Subject to Test)	End of Life Required (EOL)	Next Regular Inspection	Next Planned Overhaul/ Major Inspection	Capability to Reach Next Overhaul	Capability to Reach EOL	In Service
1297	9739	7203	0	0	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	WATER TREATMENT PLANT	N/A	117	28	Upgraded in 1992 to address water quality issues.	4	200000 (30)	20	2041			Yes	No	1968/1992/ 1997
1297	9739	7203	7210	0	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	RAW WATER SYSTEM	N/A	118	15	Largely 16" asbestos concrete pipe, installed in 1969. Two sections replaced: 105 m in the warehouse yard replaced with 400 mm PVC pipe in 1996, and 80 m near Pumphouse #2 with 18" Sclair pipe in 1976. No documentation of a recent inspection of the piping appears to exist, although generic data suggests that it should be in good condition.	4	(50+)	(20)	2041			No	No	1968
1297	9739	7203	7210	7534	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	QUARRY BROOK DAM & FISHWAY	N/A	119	15	Surface inspection in March 2009 indicated the structure was in good shape. No diving inspection has been carried out since 2007 so subsurface condition is uncertain..	4	(30)	(20)	2041			No	No	1968-1990
1297	9739	7203	7210	8937	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	RAW WATER PUMP SOUTH	N/A	120	15	Good with continued maintenance and replace as required.	3a	(40)	10	2041			No	No	
1297	9739	7203	7210	8975	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	RAW WATER PUMP NORTH	N/A	121	15	Good with continued maintenance and replace as required.	3a	(40)	10	2041			No	No	
1297	9739	7203	7211	0	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	DOMESTIC WATER SYSTEM	N/A	122	15	Domestic Water Treatment Plant is in reasonable shape, but likely to required ongoing maintenance and repairs. The polyethylene pipe used for distribution is generally good for approximately 50 years. No issues have been identified other than the quality (i.e. non-drinking water quality).	3a	(40)	5+	2041			No	No	1968-1990
1297	9739	7203	9857	0	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	GENERAL SERVICE COOLING WATER	N/A	123	12	Good with continued maintenance and replace as required.	4	(30)	10	2041			No	No	1968-1990
1297	9739	7203	286053	0	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	CONDENSATE POLISHERS	N/A	124	21	See details below.									
1297	9739	7203	286053	6967	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	#1 CONDENSATE POLISHER PLANT	N/A	125	21	No known inspections or information. Likely internals and lining issues.	4	(25)	5+	2020			No	No	1979
1297	9739	7203	286053	6967	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	#1 CONDENSATE POLISHER PLANT	acid and caustic storage tanks	126	21	Relatively new and likely in good shape, but should be cleaned, No recent inspection. Transfer pumps old and likely needing replacement.	4	(25)	(10)	2020			No	No	1995
1297	9739	7203	286053	6967	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	#1 CONDENSATE POLISHER PLANT	operating panels	127	21	Panel in poor shape and near obsolescence end of life, alarm panel as well.	4	(25)	(2+)	2020			No	No	1995
1297	9739	7203	286053	7401	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	CONDENSATE POLISHER MCC A1-3	N/A	128	6	Not reviewed. Aging equipment likely obsolete.	4	(25)	(5)	2020			No	No	1979
1297	9739	7203	286053	8127	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	#2 CONDENSATE POLISHER PLANT	N/A	129	21	No known inspections or information. Likely some internals and lining issues.	4	(25)	(5+)	2020			No	No	1979
1297	9739	7203	286053	8127	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	#2 CONDENSATE POLISHER PLANT	acid and caustic storage tanks	130	21	No recent inspection. Likely in good shape, but should be cleaned. Transfer pumps likely need replacement.	4	(20)	(10)	2020			No	No	1995
1297	9739	7203	286053	8127	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	#2 CONDENSATE POLISHER PLANT	operating panels	131	21	Panel in poor shape and likely near obsolescence end of life, alarm panel as well.	4	(20)	(2+)	2020			No	No	1995
1297	9739	7203	286053	8171	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	CONDENSATE POLISHER MCC B1-3	N/A	134	6	Not reviewed. Aging equipment likely obsolete.	4	(25)	5	2020			No	No	1979
1297	9739	7203	286053	8686	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	#3 CONDENSATE POLISHER PLANT	N/A	135	21	No known inspections or information. Likely internals and lining issues.	4	(25)	5	2020			No	No	1979
1297	9739	7203	286053	8686	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	#3 CONDENSATE POLISHER PLANT	acid and caustic storage tanks	136	21	Likely in good shape, but should be cleaned, No recent inspection. Transfer pumps likely need replacement.	4	(20)	(10)	2020			No	no	1995
1297	9739	7203	286053	8686	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	#3 CONDENSATE POLISHER PLANT	operating panels	137	21	Panel in poor shape and likely near obsolescence end of life. Alarm panel replaced in 2009.	4	(20)	(2+)	2020			No	No	1995
1297	9739	7203	286053	8727	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	CONDENSATE POLISHER BAB 3-3	N/A	138	6	Not reviewed. Aging equipment likely obsolete.	4	(25)	(5)	2020			No	No	1979
1297	9739	7203	286057	0	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	WATER TREATMENT PLANT SYSTEMS	N/A	139	28		4	(30)	20	2020			Yes	Yes	1979
1297	9739	7203	286057	6802	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	W.T.P. BRINE SYSTEM	N/A	140	28	Upgraded in 1992 to address water quality issues.	3a	(30)	15	2020			Yes	Yes	1992
1297	9739	7203	286057	7185	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	WATER TREAT & MCC C5	N/A	141	6	Relatively new. Upgraded during WTP upgrade.	3a	(30)	(15+)	2020			No	No	1968/1992
1297	9739	7203	286057	7212	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	W.T.P. SULFURIC ACID SYSTEM	N/A	142	28	Installed in 1997.Several sub-systems (pumps, motors, etc.) replaced or improved. Acid and caustic lines into the plant replaced.	3a	(30)	(15+)	2020			No	No	1997
1297	9739	7203	286057	7213	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	WTP FLOCULANT CHEMICAL INJECT.	N/A	143	28	Upgraded in 1992 to address water quality issues.	3a	(40)	15	2020			Yes	Yes	1992
1297	9739	7203	286057	7214	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	W.T.P. PRIMARY TRAINS	N/A	144	28	Upgraded in 1992 to address water quality issues.	3a	(40)	15+	2020			Yes	Yes	1992
1297	9739	7203	286057	7220	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	W.T.P. MIXED BEDS	N/A	145	28	Upgraded in 1992 to address water quality issues.	3a	(30)	15+	2020			Yes	Yes	1992
1297	9739	7203	286057	7410	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	WATER TREATMENT MCC C10	N/A	146	28	Upgraded in 1992 to address water quality issues.	3a	(40)	15	2020			Yes	Yes	1992

Table 11-41 Cont'd

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset Level 2	Asset Level 3	Description	Detail	Cond. Summ. ID#	Append #	Condition
1297	9739	7203	286057	7422	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	W.T.P. CLARIFIER SYSTEM	N/A	147	28	Installed in 1969. Reasonably well maintained. Several sub-systems (impellors, mixer motors, etc.) replaced or improved. Some internal and external patching applied. No thickness testing or other major structural inspections recently. Some external corrosion at the tank base.
1297	9739	7203	286057	8748	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	W T P & AUX. BLR MCC WTP-34	N/A	148	6	Relatively new during upgrade.
1297	9739	7203	286057	9864	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	W.T.P. SAND FILTER SYSTEM	N/A	149	28	Installed in 1969. Well maintained, but some external evidence of corrosion at vessel base. 2009 thickness measurements near the tank bottoms.
1297	9739	7203	286057	9879	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	W.T.P. CLEARWELL SYSTEM	N/A	150	28	Installed in 1969. Well maintained as a part of a regular maintenance program.

Notes:
1. A "(bracketed)" value in the "Current Expected Remaining Life" column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation, including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as "(X/Y)" has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.
2. The "Next Regular Inspection" column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The "Next Planned Overhaul or Major Inspection" column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a "Desired Life" stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where no specific dates have been identified for "Next Regular Inspection" or "Next Planned Overhaul/Major Inspection", they are left blank.

11.2.3.4 Actions

Based on the condition assessment, the following actions are recommended for the water treatment plant system:

TABLE 11-42 RECOMMENDED ACTIONS – WATER TREATMENT PLANT (WTP) SYSTEM

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset 2/3	Asset 3/4	Description	Action #	App #	Action	Year	Priority
1297	9739	0	0	0	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT & ENVIRONMENT	126	28	Improve ventilation and paint roofing.	2012	1
1297	9739	7203	0	0	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	WATER TREATMENT PLANT	127	28	Refurbish roofing.	2015	1
1297	9739	7203	7210	0	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	RAW WATER SYSTEM	128	15	Perform Level 2 inspections.	2011	1
1297	9739	7203	7210	0	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	RAW WATER SYSTEM	129	15	Develop a program of ongoing inspections and performance testing based on industry best practices.	2011	1
1297	9739	7203	7210	7534	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	QUARRY BROOK DAM & FISHWAY SYS	130	15	Perform Level 2 inspections.	2011	1
1297	9739	7203	7210	8937	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	RAW WATER PUMP SOUTH	131	15	No recommended action.		
1297	9739	7203	7210	8975	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	RAW WATER PUMP NORTH	132	15	No recommended action.		
1297	9739	7203	7211	0	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	DOMESTIC WATER SYSTEM	133	15	Perform Level 2 inspections.	2011	2
1297	9739	7203	7211	0	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	DOMESTIC WATER SYSTEM	134	15	Develop a program of ongoing inspections and performance testing based on industry best practices.	2011	2
1297	9739	7203	9857	0	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	GENERAL SERVICE COOLING WATER	135	12	Maintain and refurbish.	2012	2
1297	9739	7203	286053	0	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	CONDENSATE POLISHERS	136	21	See details below.		
1297	9739	7203	286053	6967	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	#1 CONDENSATE POLISHER PLANT	137	21	Perform Level 2 inspections on polisher process vessels.	2011	1
1297	9739	7203	286053	6967	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	#1 CONDENSATE POLISHER PLANT	138	21	Clean and inspect acid and caustic storage tanks at next resin change-out.	2011	1

Table 11-42 Cont'd

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset 2/3	Asset 3/4	Description	Action #	App #	Action	Year	Priority
1297	9739	7203	286053	6967	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	#1 CONDENSATE POLISHER PLANT	139	21	Replace Units 1 and 2 annunciator panels.	2011	1
1297	9739	7203	286053	6967	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	#1 CONDENSATE POLISHER PLANT	140	21	Assess the replacement of operating panels and acid/caustic piping.	2012	1
1297	9739	7203	286053	7401	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	CONDENSATE POLISHER MCC A1-3	141	6	Refurbish or replace.	2012	2
1297	9739	7203	286053	8127	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	#2 CONDENSATE POLISHER PLANT	144	21	Perform Level 2 inspections on polisher process vessels.	2011	1
1297	9739	7203	286053	8127	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	#2 CONDENSATE POLISHER PLANT	145	21	Clean and inspect acid and caustic storage tanks at next resin change-out.	2011	1
1297	9739	7203	286053	8127	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	#2 CONDENSATE POLISHER PLANT	146	21	Replace Units 1 and 2 annunciator panels.	2011	1
1297	9739	7203	286053	8127	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	#2 CONDENSATE POLISHER PLANT	147	21	Assess the replacement of operating panels and acid/caustic piping.	2012	1
1297	9739	7203	286053	8171	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	CONDENSATE POLISHER MCC B1-3	148	6	Refurbish or replace.	2012	2
1297	9739	7203	286053	8686	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	CONDENSATE POLISHER PLANT	149	21	Perform Level 2 inspections on polisher process vessels.	2011	1
1297	9739	7203	286053	8686	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	CONDENSATE POLISHER PLANT	150	21	Clean and inspect acid and caustic storage tanks at next resin change-out.	2011	1
1297	9739	7203	286053	8686	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	CONDENSATE POLISHER PLANT	151	21	Assess the replacement of operating panels and acid/caustic piping.	2012	1
1297	9739	7203	286053	8686	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	CONDENSATE POLISHER PLANT	152	21	See detail below.		
1297	9739	7203	286053	8727	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	CONDENSATE POLISHER BAB 3-3	153	6	No recommended action.		
1297	9739	7203	286057	0	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	WATER TREATMENT PLANT SYSTEMS	154		See details below		
1297	9739	7203	286057	0	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	WATER TREATMENT PLANT SYSTEMS	155	34	Identify Level 2 activities to investigate potential damage mechanisms from lay-up.	2011	1
1297	9739	7203	286057	0	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	WATER TREATMENT PLANT SYSTEMS	156	34	Review lay-up practices re: industry guidelines. Use Level 2 results to define relative risk of not complying with industry guidelines.	2013	1

Table 11-42 Cont'd

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset 2/3	Asset 3/4	Description	Action #	App #	Action	Year	Priority
1297	9739	7203	286057	6802	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	W.T.P. BRINE SYSTEM	157	28	No recommended action.		
1297	9739	7203	286057	7185	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	WATER TREAT & MCC C5	158	6	No recommended action.		
1297	9739	7203	286057	7212	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	W.T.P. SULFURIC ACID SYSTEM	159	28	No recommended action.		
1297	9739	7203	286057	7213	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	WTP FLOCCULANT CHEMICAL INJECT.	160	28	No recommended action.		
1297	9739	7203	286057	7214	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	W.T.P. PRIMARY TRAINS	161	28	No recommended action.		
1297	9739	7203	286057	7220	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	W.T.P. MIXED BEDS	162	28	No recommended action.		
1297	9739	7203	286057	7410	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	WATER TREATMENT MCC C10	163	6	Relatively new. Not examined in detail.		
1297	9739	7203	286057	7422	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	W.T.P. CLARIFIER SYSTEM	164	28	Perform Level 2 thickness measurements of the clarifier vessel and visual inspections of the internals.	2011	1
1297	9739	7203	286057	8748	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	W T P & AUX. BLR MCC WTP-34	165	6	Relatively new. Not examined in detail. No action advised.		
1297	9739	7203	286057	9864	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	W.T.P. SAND FILTER SYSTEM	166	28	Perform Level 2 thickness measurements of the clarifier vessel and visual inspections of the internals.	2011	1
1297	9739	7203	286057	9879	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	W.T.P. CLEARWELL SYSTEM	167	28	No recommended action.		

11.2.3.5 Risk Assessment

The risk assessment associated with the water treatment plant, both from a technological perspective and a safety perspective, is illustrated below in Table 11-43.

TABLE 11-43 RISK ASSESSMENT – WATER TREATMENT PLANT (WTP) SYSTEM

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset 2/3	Asset 3/4	Description	Component	Risk Assess #	Appendix #	Major Issues	Remaining Life Years	Remaining Life	Techno-Eco Risk Assess Model			Safety Risk Assess Model			Possible Failure Event	Mitigation
												(Insufficient Info - Inspection Required Within (x) Years)	Comments	Likeli-hood	Conse-quence	Risk Level	Likeli-hood	Conse-quence	Safety Risk		
1297	9739	0	0	0	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT & ENVIRONMENT	None	140	15	See details below.		N/A								
1297	9739	7203	0	0	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	WATER TREATMENT PLANT	None	141	15	See details below.		N/A								
1297	9739	7203	7210	0	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	RAW WATER SYSTEM	Raw Fresh Water Supply Pipe	142	15	Mechanical fatigue.	(20)	N/A	2	C	Medium	2	C	Medium	Loss of fresh water for services – unit shutdowns for repairs.	Inspect, maintain and replicate.
1297	9739	7203	7210	0	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	RAW WATER SYSTEM	Fire Supply Mains	143	15	SCC, FAC, thermal/ mechanical fatigue, corrosion-fatigue.	(20)	N/A	1	C	Low	2	C	Medium	Inability to operate safely – unit shutdowns until repaired.	Inspect and maintain.
1297	9739	7203	7210	0	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	RAW WATER SYSTEM	Fire Supply Sub-Systems	144	15	SCC, FAC, thermal/ mechanical fatigue, corrosion-fatigue.	(20)	N/A	1	B	Low	2	B	Medium	Inability to operate safely – unit shutdowns until repaired or temporary measures in place.	Inspect and maintain.
1297	9739	7203	7210	7534	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	QUARRY BROOK DAM & FISHWAY SYS	Quarry Brook Dam	145	15	Mechanical aging.	(20)	N/A	2	C	Medium	2	C	Medium	Dam leak/failure – loss of fresh water for all services – unit shutdowns for repairs.	Inspect and maintain.
1297	9739	7203	7210	8937	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	RAW WATER PUMP SOUTH	None	146	15	Mechanical/electrical failure.	5+	N/A	1	B	Low	1	B	Low	Reliability of 2nd pump re ability to operate safely.	Spare, maintain.
1297	9739	7203	7210	8975	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	RAW WATER PUMP NORTH	None	147	15	Mechanical/electrical failure.	5+	N/A	1	B	Low	1	B	Low	Reliability of 2nd pump re ability to operate safely.	Spare, maintain.
1297	9739	7203	7211	0	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	DOMESTIC WATER SYSTEM	Domestic Water Supply	148	15	Mechanical/electrical failure.	5+	N/A	2	A	Low	2	A	Low	Loss of domestic water services – minimal impact.	Inspect and maintain.
1297	9739	7203	9857	0	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	GENERAL SERVICE COOLING WATER	None	149	12	Mechanical/corrosion.	(5+)	N/A	3	A	Low	3	a	Low	Loss of GSW Cooling	Inspect, maintain.
1297	9739	7203	286053	0	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	CONDENSATE POLISHERS	None	150	21	See details below.		N/A								
1297	9739	7203	286053	6967	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	#1 CONDENSATE POLISHER PLANT	Polisher Vessels	151	21	Corrosion.	(5+)	Spark Test and internals inspections are required to assess the remaining life.	2	B	Low	2	A	Low	Rubber liner and shell failure/leak requires patch and subsequent short shutdown of unit.	Test, maintain.
1297	9739	7203	286053	7401	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	CONDENSATE POLISHER MCC A1-3	None	152	6	Electrical failure.	(5)	N/A	2	B	Low	2	A	Low	Loss of polished condensate	Inspect, maintain.
1297	9739	7203	286053	8127	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	#2 CONDENSATE POLISHER PLANT	Polisher Vessels	155	21	Corrosion.	(5+)	Spark Test and internals inspections are required to assess the remaining life.	2	B	Low	2	A	Low	Rubber liner and shell failure/leak requires patch and subsequent short shutdown of unit.	Test, maintain.
1297	9739	7203	286053	8171	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	CONDENSATE POLISHER MCC B1-3	None	156	6	Electrical failure.	(5)	N/A	2	B	Low	2	A	Low	Loss of polished condensate	Inspect, maintain.
1297	9739	7203	286053	8686	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	CONDENSATE POLISHER PLANT	Polisher Vessels	157	21	Corrosion.	(5+)	Spark Test and internals inspections are required to assess the remaining life.	2	B	Low	2	A	Low	Rubber liner and shell failure/leak requires patch and subsequent short shutdown of unit.	Test, maintain.
1297	9739	7203	286053	8727	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	CONDENSATE POLISHER BAB 3-3	None	158	6	Electrical failure.	(5)	N/A	2	B	Low	2	A	Low	Loss of polished condensate	Inspect, maintain.
1297	9739	7203	286057	0	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	WATER TREATMENT PLANT SYSTEMS	Demin Water Tank	159	28	Demin water corrosion.	15+	2020 OK	1	B	Low	2	A	Low	Tank leak, difficult to access and fix. Station outage if extensive.	Maintain.
1297	9739	7203	286057	6802	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	W.T.P. BRINE SYSTEM	None	160	17	Not addressed.	15	N/A	1	B	Low	1	B	Low	Water quality drop. Rely on storage until fix.	Inspect, clean, maintain.
1297	9739	7203	286057	7185	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	WATER TREAT & MCC C5	None	161	6	Electrical failure.	15+	2	2	B	Low	2	A	Low	Storage until fixed.	Inspect and maintain.
1297	9739	7203	286057	7212	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	W.T.P. SULFURIC ACID SYSTEM	Acid & Caustic Storage Tanks	162	28	Acid and Caustic Corrosion;;	(15+)	Inspections are required to assess the remaining life.	1	B	Low	1	B	Low	Tank leak, difficult to access and fix. Station outage if extensive.	Inspect, clean, maintain.
1297	9739	7203	286057	7213	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	WTP FLOCCULANT CHEMICAL INJECT.	None	163	28	Not addressed	15	N/A	1	B	Low	1	B	Low	Tank leak, difficult to access and fix. Station outage if extensive.	Inspect, clean, maintain.

Table 11-43 Cont'd

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset 2/3	Asset 3/4	Description	Component	Risk Assess #	Appendix #	Major Issues	Remaining Life Years	Remaining Life	Techno-Eco Risk Assess Model			Safety Risk Assess Model			Possible Failure Event	Mitigation
												(Insufficient Info - Inspection Required Within (x) Years)	Comments	Likeli-hood	Conse-quence	Risk Level	Likeli-hood	Conse-quence	Safety Risk		
1297	9739	7203	286057	7214	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	W.T.P. PRIMARY TRAINS	None	164	28	Mechanical, process failure.	15+	N/A	2	B	Low	2	C	Medium	Loss of demineralized water supply	Inspect, maintain.
1297	9739	7203	286057	7220	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	W.T.P. MIXED BEDS	Anion/Cation/Mixed Bed Demineralizers	165	28	Demin water, acid and caustic corrosion.	15+	Life to 2020+ very likely	1	B	Low	1	B	Low	Tank leak. Redundancy limits impact.	Inspect, clean, maintain.
1297	9739	7203	286057	7410	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	WATER TREATMENT MCC C10	None	166	6	Electrical failure.	15+		2	B	Low	2	A	Low	Short WYTP shutdown. Storage until fixed.	Inspect, maintain.
1297	9739	7203	286057	7422	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	W.T.P. CLARIFIER SYSTEM	Clarifier	167	28	Corrosion at base and side walls.	(10+)	Ultrasonic thickness and visual internal inspections are required to assess the remaining life.	3	C	Medium	3	A	Low	Tank leak, difficult to access and fix. Station outage if extensive.	Test, maintain.
1297	9739	7203	286057	8748	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	W T P & AUX. BLR MCC WTP-34		168	6	Electric Failure	10	N/A	2	B	Low	2	A	Low	Short WYTP shutdown. Storage until fixed.	Inspect, maintain.
1297	9739	7203	286057	9864	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	W.T.P. SAND FILTER SYSTEM	Sand Filters	169	28	Corrosion at base and side walls.	(10+)	Likely Ok to 2020. Visual internal inspections are required to assess the remaining life.	2	A	Low	2	A	Low	Tank Leak. Redundancy limits impact.	Test, maintain.
1297	9739	7203	286057	9879	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	W.T.P. CLEARWELL SYSTEM	Clearwell	170	28	Corrosion at base and side walls.	(10+)	Ultrasonic thickness and visual internal inspections are required to assess the remaining life.	2	B	Low	2	A	Low	Tank leak, difficult to access and fix. Station outage if extensive.	Inspect, maintain.

11.2.3.6 Life Cycle Curve and Remaining Life

The life cycle curve for the system is illustrated below. Two curves are illustrated to represent the original equipment (clarifiers, sand filters, clearwell) and the new systems (demineralizers, demin storage, acid and caustic systems). The life curves are plots of physical age of the equipment on the y-axis versus calendar year on the x-axis. Although linked to water production levels and hence to steam generation operation, it was felt that the best indicator was physical aging. The chart has several vertical lines representing differing representative nominal age limits for various components. It also has several horizontal lines that represent a range of practical equipment life limits in years.

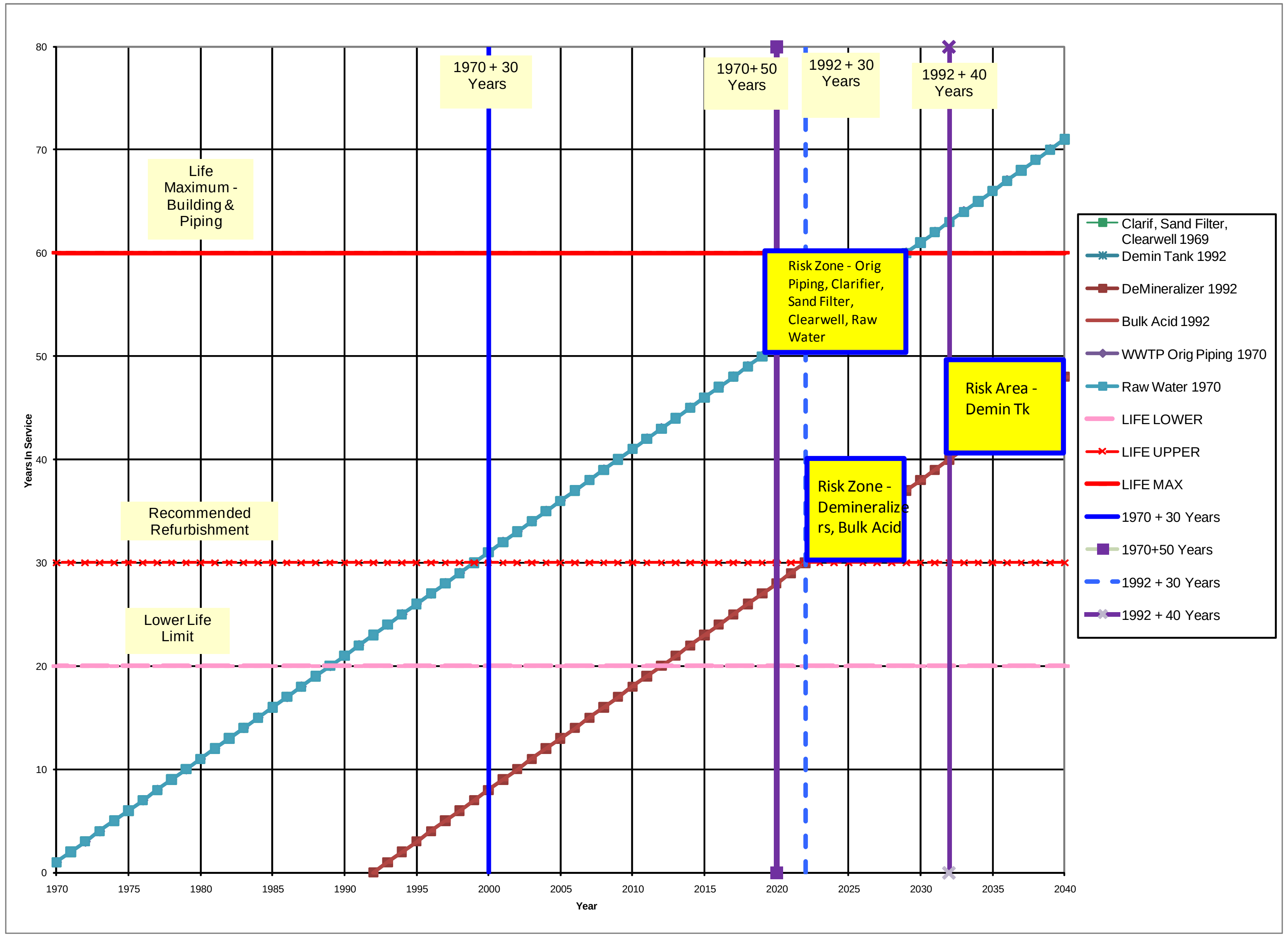


FIGURE 11-33 LIFE CYCLE CURVE – WATER TREATMENT PLANT (WTP) SYSTEM

The curves indicate that the remaining life (RL) of the water treatment plant (WTP) system exceeds the desired life (DL) which is the end date for generation of 2020. This is dependent on the condition primarily of the original equipment. Given they represent a single contingency failure mode, an assessment of their condition is critical to firming this assessment. Similarly, their importance as a single contingency failure mode makes an understanding of the condition of the raw water line from the storage pond and the dam at the storage pond a critical task.

11.2.3.7 Level 2 Inspection Requirements and Costs

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 11-44 below, assuming the current plant inspection and maintenance program is maintained or improved.

TABLE 11-44 LEVEL 2 INSPECTION – WATER TREATMENT PLANT (WTP) SYSTEM

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset 2/3	Asset 3/4	Description	Sub System Comment	L2#	Appendix #	Level 2 Work	Year	Priority	Cost k$
1297	9739	7203	0	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	WATER TREATMENT PLANT		117	28	No Level 2			
1297	9739	7203	7210	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	RAW WATER SYSTEM	Pipeline	118	15	NDE pipeline from Quarry Brook Dam to pumphouse – in-pipe crawler or other device to check for thickness and/or leaks.	2011	1	$37
1297	9739	7203	7210	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	QUARRY BROOK DAM & FISHWAY SYS	Dam	119	15	Visual inspection of dam underwater – diver investigate visually for any unusual signs of deterioration.	2011	1	$22
1297	9739	7203	7210	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	RAW WATER PUMP SOUTH	N/A	120	15	No Level 2 required.			
1297	9739	7203	7210	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	RAW WATER PUMP NORTH	N/A	121	15	No Level 2 required.			
1297	9739	7203	7211	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	DOMESTIC WATER SYSTEM	N/A	122	15	No Level 2 required.			
1297	9739	7203	9857	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	GENERAL SERVICE COOLING WATER	N/A	123	15	No Level 2 required.			
1297	9739	7203	286053	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	CONDENSATE POLISHERS	N/A	124	15	No Level 2 required.			
1297	9739	7203	286053	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	#1 CONDENSATE POLISHER PLANT	N/A	125	21	Visual inspection of polisher vessel internals; spark test rubber liner; NDE polisher vessel representative thickness; clean and inspect acid and caustic vessels.	2011	1	$30
1297	9739	7203	286053	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	CONDENSATE POLISHER MCC A1-3	N/A	126	6	No Level 2 required.	0		
1297	9739	7203	286053	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	#2 CONDENSATE POLISHER PLANT	N/A	127	21	Visual inspection of polisher vessel internals; spark test rubber liner; NDE polisher vessel representative thickness; clean and inspect acid and caustic vessels.	2011	1	$30
1297	9739	7203	286053	WATER TREATMENT AND ENVIRONMENT	WATER TREATMENT PLANT	CONDENSATE POLISHER MCC B1-3	N/A	130	6	No Level 2 required.			
1297	9739	7203	286053	WATER TREATMENT AND ENVIRONMENT	WATER TREATMENT PLANT	#3 CONDENSATE POLISHER PLANT	N/A	131	21	Visual inspection of polisher vessel internals; spark test rubber liner; NDE polisher vessel representative thickness; clean and inspect acid and caustic vessels.	2011	1	$30
1297	9739	7203	286053	WATER TREATMENT AND ENVIRONMENT	WATER TREATMENT PLANT	CONDENSATE POLISHER BAB 3-3	N/A	132	6	No Level 2 required.			
1297	9739	7203	286057	WATER TREATMENT AND ENVIRONMENT	WATER TREATMENT PLANT	WATER TREATMENT PLANT SYSTEMS	Clarifier, Sand Filters, Clearwell	133	28	Inspections of clarifier, sand filters, clearwell internals.	2011	1	$75
1297	9739	7203	286057	WATER TREATMENT AND ENVIRONMENT	WATER TREATMENT PLANT	WATER TREATMENT PLANT SYSTEMS	Water Chemistry	134	34	Identify Level 2 condition assessment activities to investigate the potential damage mechanisms resulting from lay-up.	2012	2	(Incl in Unit 1 Blr)
1297	9739	7203	286057	WATER TREATMENT AND ENVIRONMENT	WATER TREATMENT PLANT	WATER TREATMENT PLANT SYSTEMS	Water Chemistry	135	34	Review lay-up practices relative to industry guidelines. Results of Level 2 inspections will assist in defining the relative risk of not complying with industry guidelines.	2012	2	(Incl in Unit 1 Blr)

Table 11-44 Cont'd

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset 2/3	Asset 3/4	Description	Sub System Comment	L2#	Appendix #	Level 2 Work	Year	Priority	Cost k$
1297	9739	7203	286057	WATER TREATMENT AND ENVIRONMENT	WATER TREATMENT PLANT	WATER TREATMENT PLANT SYSTEMS	Water Chemistry	136	34	Review cycle water treatment to 2020, including: operating data to assess the actual operating targets and compliance; physical assets including sample points, analyzers, and chemical injection; equipment inspection results to corroborate effects and risks with the current chemistry treatment regime, and identification of potential changes to the present cycle chemistry treatment regime, and the benefits of those changes relative to the operating objectives.	2012	2	(Incl in Unit 1 Blr)
1297	9739	7203	286057	WATER TREATMENT AND ENVIRONMENT	WATER TREATMENT PLANT	W.T.P. BRINE SYSTEM	N/A	137	28	No Level 2 required.			
1297	9739	7203	286057	WATER TREATMENT AND ENVIRONMENT	WATER TREATMENT PLANT	WATER TREAT & MCC C5	N/A	138	28	No Level 2 required.			
1297	9739	7203	286057	WATER TREATMENT AND ENVIRONMENT	WATER TREATMENT PLANT	W.T.P. SULFURIC ACID SYSTEM	Acid & Caustic Tanks	139	28	Inspect internals and NDE thickness of acid and caustic tanks.	2011	2	$15
1297	9739	7203	286057	WATER TREATMENT AND ENVIRONMENT	WATER TREATMENT PLANT	WTP FLOCULANT CHEMICAL INJECT.	N/A	140	28	No Level 2 required.			
1297	9739	7203	286057	WATER TREATMENT AND ENVIRONMENT	WATER TREATMENT PLANT	W.T.P. PRIMARY TRAINS	N/A	141	28	No Level 2 required.			
1297	9739	7203	286057	WATER TREATMENT AND ENVIRONMENT	WATER TREATMENT PLANT	W.T.P. MIXED BEDS	N/A	142	28	No Level 2 required.			
1297	9739	7203	286057	WATER TREATMENT AND ENVIRONMENT	WATER TREATMENT PLANT	WATER TREATMENT MCC C10	N/A	143	28	No Level 2 required.			
1297	9739	7203	286057	WATER TREATMENT AND ENVIRONMENT	WATER TREATMENT PLANT	W.T.P. CLARIFIER SYSTEM	Clarifier	144	28	Ultrasonic NDE thickness of clarifier walls.	2011	2	(Incl in 133)
1297	9739	7203	286057	WATER TREATMENT AND ENVIRONMENT	WATER TREATMENT PLANT	W T P & AUX. BLR MCC WTP-34	N/A	145	28	No Level 2 required.			
1297	9739	7203	286057	WATER TREATMENT AND ENVIRONMENT	WATER TREATMENT PLANT	W.T.P. SAND FILTER SYSTEM	N/A	146	28	No Level 2 required.			
1297	9739	7203	286057	WATER TREATMENT AND ENVIRONMENT	WATER TREATMENT PLANT	W.T.P. CLEARWELL SYSTEM	N/A	147	28	No Level 2 required.			

11.2.3.8 Capital Projects

The suggested typical capital enhancements for the water treatment plant include:

TABLE 11-45 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – WATER TREATMENT PLANT (WTP) SYSTEM

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset 2/3	Asset 3/4	Description	CAP#	Appendix #	Capital Item	Date	Priority
1297	9739	0	0	0	WATER TREATMENT AND ENVIRONMENT	WATER TREATMENT AND ENVIRONMENT	WATER TREATMENT &ENVIRONMENT	125		No capital required.		
1297	9739	7203	0	0	WATER TREATMENT AND ENVIRONMENT	WATER TREATMENT PLANT	WATER TREATMENT PLANT	126	28	None; connect to DCS (PLC obsolescence).	2011	1
1297	9739	7203	7210	0	WATER TREATMENT AND ENVIRONMENT	WATER TREATMENT PLANT	RAW WATER SYSTEM	127	15	Implement new or parallel fresh water line from Quarry Brook Dam.	2013	1
1297	9739	7203	7210	7534	WATER TREATMENT AND ENVIRONMENT	WATER TREATMENT PLANT	QUARRY BROOK DAM & FISHWAY SYS	128		No capital required.		
1297	9739	7203	7210	8937	WATER TREATMENT AND ENVIRONMENT	WATER TREATMENT PLANT	RAW WATER PUMP SOUTH	129		No capital required.		
1297	9739	7203	7210	8975	WATER TREATMENT AND ENVIRONMENT	WATER TREATMENT PLANT	RAW WATER PUMP NORTH	130		No capital required.		
1297	9739	7203	7211	0	WATER TREATMENT AND ENVIRONMENT	WATER TREATMENT PLANT	DOMESTIC WATER SYSTEM	131		No capital required.		
1297	9739	7203	9857	0	WATER TREATMENT AND ENVIRONMENT	WATER TREATMENT PLANT	GENERAL SERVICE COOLING WATER	132		No capital required.		
1297	9739	7203	286053	0	WATER TREATMENT AND ENVIRONMENT	WATER TREATMENT PLANT	CONDENSATE POLISHERS	133		No capital required.		
1297	9739	7203	286053	6967	WATER TREATMENT AND ENVIRONMENT	WATER TREATMENT PLANT	#1 CONDENSATE POLISHER PLANT	134	21	Replace alarm annunciation panels	2011	2
1297	9739	7203	286053	6967	WATER TREATMENT AND ENVIRONMENT	WATER TREATMENT PLANT	#1 CONDENSATE POLISHER PLANT	135	21	Replace control operating panels, subject to decision on generation continues to 2020+.	2014	2
1297	9739	7203	286053	7401	WATER TREATMENT AND ENVIRONMENT	WATER TREATMENT PLANT	CONDENSATE POLISHER MCC A1-3	136		No capital required.		
1297	9739	7203	286053	8127	WATER TREATMENT AND ENVIRONMENT	WATER TREATMENT PLANT	#2 CONDENSATE POLISHER PLANT	137	21	Replace alarm annunciation panels.	2011	2
1297	9739	7203	286053	8127	WATER TREATMENT AND ENVIRONMENT	WATER TREATMENT PLANT	#2 CONDENSATE POLISHER PLANT	138	21	Replace control operating panels, subject to decision on generation continues to 2020+.	2014	2
1297	9739	7203	286053	8171	WATER TREATMENT AND ENVIRONMENT	WATER TREATMENT PLANT	CONDENSATE POLISHER MCC B1-3	141		No capital required.		
1297	9739	7203	286053	8686	WATER TREATMENT AND ENVIRONMENT	WATER TREATMENT PLANT	#3 CONDENSATE POLISHER PLANT	142	21	Replace control operating panels, subject to decision on generation continues to 2020+.	2014	1
1297	9739	7203	286053	8686	WATER TREATMENT AND ENVIRONMENT	WATER TREATMENT PLANT	#3 CONDENSATE POLISHER PLANT	143		No capital required.		
1297	9739	7203	286053	8727	WATER TREATMENT AND ENVIRONMENT	WATER TREATMENT PLANT	CONDENSATE POLISHER BAB 3-3	144		No capital required.		
1297	9739	7203	286057	0	WATER TREATMENT AND ENVIRONMENT	WATER TREATMENT PLANT	WATER TREATMENT PLANT SYSTEMS	145	34	No capital required.		
1297	9739	7203	286057	6802	WATER TREATMENT AND ENVIRONMENT	WATER TREATMENT PLANT	W.T.P. BRINE SYSTEM	146		No capital required.		

Table 11-45 Cont'd

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset 2/3	Asset 3/4	Description	CAP#	Appendix #	Capital Item	Date	Priority
1297	9739	7203	286057	7185	WATER TREATMENT AND ENVIRONMENT	WATER TREATMENT PLANT	WATER TREAT & MCC C5	147		No capital required.		
1297	9739	7203	286057	7212	WATER TREATMENT AND ENVIRONMENT	WATER TREATMENT PLANT	W.T.P. SULFURIC ACID SYSTEM	148		No capital required.		
1297	9739	7203	286057	7213	WATER TREATMENT AND ENVIRONMENT	WATER TREATMENT PLANT	WTP FLOCCULANT CHEMICAL INJECT.	149		No capital required.		
1297	9739	7203	286057	7214	WATER TREATMENT AND ENVIRONMENT	WATER TREATMENT PLANT	W.T.P. PRIMARY TRAINS	150		No capital required.		
1297	9739	7203	286057	7220	WATER TREATMENT AND ENVIRONMENT	WATER TREATMENT PLANT	W.T.P. MIXED BEDS	151		No capital required.		
1297	9739	7203	286057	7410	WATER TREATMENT AND ENVIRONMENT	WATER TREATMENT PLANT	WATER TREATMENT MCC C10	152		No capital required.		
1297	9739	7203	286057	7422	WATER TREATMENT AND ENVIRONMENT	WATER TREATMENT PLANT	W.T.P. CLARIFIER SYSTEM	153		No capital required.		
1297	9739	7203	286057	8748	WATER TREATMENT AND ENVIRONMENT	WATER TREATMENT PLANT	W T P & AUX. BLR MCC WTP-34	154		No capital required.		
1297	9739	7203	286057	9864	WATER TREATMENT AND ENVIRONMENT	WATER TREATMENT PLANT	W.T.P. SAND FILTER SYSTEM	155		No capital required.		
1297	9739	7203	286057	9879	WATER TREATMENT AND ENVIRONMENT	WATER TREATMENT PLANT	W.T.P. CLEARWELL SYSTEM	156		No capital required.		

11.2.4 Asset 7133 – Marine Terminal

The marine terminal and facilities was excluded from the assessment at the kick-off meeting and are being looked at by others.

11.2.5 Asset 7202 – Gas Turbine Genset

(Detailed Technical Assessment in Working Papers, Appendix 13)

Unit #:	GAS TURBINE
Asset Class #	BU 1273 Gas Turbine
SCI & System:	7202 Gas Turbine System
Sub-Systems:	7058 GT Power Turb & G/B 7308 GT Avon Jet Engine 7309 GT Gen 7310 HRD GT E&C 7311 GT Aux Systems

11.2.5.1 Description

Original Manufactured/Delivered	1969
In-Service Date at Holyrood	1986
End of Planned Life Date	2041
Last Combustion System Inspection/Overhaul	2009
Next Major Overhaul/Inspection	2011 (Recommended)
Next Major Overhaul/Inspection (Planned)	2011 (On Hold)
Planned air intake Upgrade	2011 (On Hold)
Planned new exhaust stack	2011 (On Hold)
Planned air radiator replacement	2012 (On Hold)
Planned air intake & building upgrade	2014 (On Hold)
Planned Upgrades	2015/16 (On Hold)

The hours associated with the unit are:

Hours Actual - Ops to Dec 2009

- 1978 – 1,749 operating hrs since new (+85,000 idle hours)
- 1985 – 2,139 operating hrs since new (+170,000 idle hours)
- 1995 – 3,475 operating hrs since new (+256,000 idle hours)
- 2005 – 3,807 operating hrs since new (+343,000 idle hours)
- 2010 – 4,717 operating hrs since new (+386,000 idle hours)

Starts Actual – to Dec 2009

- 1978 – 611 starts, since new
- 1985 – 796 starts
- 1995 – 1,440 starts
- 2005 – 2,025 starts
- 2010 – 2,548 starts (likely between 2,300 and 2,548)

Max Hrs Gen - Ops to End Date 2020 and 2041 (Assuming 4,717 hours in 2010)

- Combustor: 1,400 to 2,800 operating hours to 2023; 3,100 to 6,200 hours to 2041
- PT Volute: 2,900 to 5,300 operating hours to 2023; 4,600 to 7,700 hours to 2041
- Balance: 6,000 to 7,400 operating hours to 2023; 7,700 to 10,800 hours to 2041

Max Starts – Ops to End Date 2020 (assuming 2,548 starts since new as of 2010)

- Combustor: 1,300 starts to 2020; 2,000 starts to 2041
- PT Volute: 2,100 starts to 2020; 2,800 starts to 2041
- Balance: 2,900 starts to 2020; 3,600 starts to 2041

One interesting aspect for early Avon units without corrosion protection was that each standby hour may have consumed the equivalent of 0.3 hours of running life. (Maintenance and Support of Mature Gas Turbines – M. Hudson, Siemens 2005)

The gas turbine generator system at the plant serves as a black start unit for the station. It is occasionally used for system support as well.

Gas Generator: The gas generator employs a Rolls-Royce AVON 1533-70L (#37029) aeroderivative gas turbine used by Associated Electrical Industries (AEI) of Manchester, England as the power source for the 13.5 MW packaged generating unit. Manufacture of this type generating unit began in the mid 1960's. The unit supplied to the Newfoundland and Labrador Power Commission in 1966 was the first one off the drawing board and was considered to be a development model. The generator unit itself is comprised of a number of components: inlet plenum, AVON 1533-70L, power turbine, exhaust system, gearbox, generator, fuel oil system, governor/fuel control and lubricating oil system. The three stage turbine in the aft end of the AVON 1533-70L uses a portion of the axial air flow to increase compressor rpm and boost delivery. The high temperature, high velocity gas exits the jet through an exhaust transition duct which is used to drive the Power Turbine and thus the generator through a gearbox.

Inlet Plenum: The inlet plenum is designed to provide approximately 140,000 cubic feet per minute of combustion air to the jet intake. This plenum is constructed of structural steel plate and framing supported by a concrete foundation. To reduce compressor damage and blade fouling, the inlet air must be free of dust and dirt. Filtration is accomplished by 72 high efficiency "Farr" filter assemblies supported on tubular columns above the intake. The inlet silencer consists of acoustical splitters in a steel shell that is designed with round leading edges to create a bell-mouth entry. The trailing edges are tapered to ensure a low pressure drop and uniform flow characteristics. The plenum chamber is built from 10 cm (4 inch) thick noise-shield panels, packed with acoustic fill and secured to a rigid steel frame.

Power Turbine: The power turbine is an Associated Electric Industries Ltd. (AEI) design, manufactured in Manchester, England in early 1966. The power turbine is a single stage overhung machine designed for a normal operational speed of approximately 4900 rpm. The power turbine is connected to the generator via a gearbox with a ratio of 4:1. The power turbine and gearbox are mounted on the centre section of the unit bedplate with this section also forming the main lubricating oil tank. Auxiliary and emergency oil pumps are mounted on this same base plate.

The power turbine casings (Volute) were replaced in 1986 as part of the major upgrade.

Exhaust System: The exhaust casing (volute) is a welded fabrication divided along the horizontal centreline. It turns the gasses transversely to the machine and vertically upwards to the exhaust silencer.

The exhaust stack is constructed of heavy gauge steel plate with light gauge steel cladding on the exterior. The exterior cladding of the lower half of the exhaust stack is constructed of heavy gauge steel plate. This stack was replaced during the 1986 major upgrade. The snow doors on the exhaust stacks are pneumatically actuated and were a new addition in 1986 to reduce corrosion of the volute and power turbine from infiltration of snow and rain water which promoted corrosion within the unit. New limit switches installed on the doors in 2009 indicate the position (opened or closed) of each door at the control station.

Gear Box: The main gearbox was manufactured by AEI in Manchester, England. It is designed to provide an approximate 4:1 speed ratio from the power turbine shaft to the main generator shaft. The gear train is fitted to the power turbine rotor by semi-flexible coupling housed within the gearbox. The gears are of the single helical, single reduction type with the pinion mounted directly above the wheel. A removable top cover allows for inspection without disturbing the alignments.

Generator: The Generator is an air-cooled, 14MW, 13.8 kV, 3 phase, Type AG 80/100, built by Associated Electric Industries (AEI) of Rugby, England in 1966. It has a rotating-field, salient-pole tube with 6 poles and rotates at 1200 rpm. The brushless exciter eliminates the danger of contamination by carbon dust and minimizes maintenance. Semi-conductor rectifiers rotating within the generator / exciter shaft provide excitation for the main generator field.

The generator is a critical component in the availability and reliability of the gas turbine, in that its loss would mean the total loss of the GT generation as well as black start capability for the Holyrood operation.

Fuel Oil System: The plant's gas turbine uses No. 2 diesel fuel which is delivered to site by truck. The off-loading pump is located outdoors at the northwest corner of the gas turbine building and has above-ground piping stretching to the bulk storage tanks. The two fuel tanks were fabricated in 1998 to ULC-S601-93 standards, with an above ground doubled wall and have a total storage capacity of 200,000 litres.

The offloading system is comprised of a single 600 volt pump arrangement with local start / stop control. Power for the motor is supplied from the gas turbine MCC control centre. The piping installation is typical with a 3 inch Y strainer, isolation valves and piping to the storage tanks.

Two 100%, 600 volt, centrifugal forwarding pumps provide low pressure No. 2 diesel fuel for the jet engine. The fuel passes through a duplex suction strainer and a 5 micron discharge filter before reaching the jet engine. The fuel line also incorporates a fuel flow / totalizing meter and a fire system trip valve prior to entering the building.

Governor and Fuel Control: The standard Avon fuel control system is used without alteration as a basis for the AP1 governing and fuel control system. The throttle valve is used as a generator valve and the H.P. cock as a fuel shut-off valve for normal and emergency shut-downs. The governing system is of the sensitive oil type in which fluid pressure is used to transmit the movement of the governor pilot valve to the operating mechanism of the governor valve, in this case the Avon throttle.

The governor is manufactured by Woodward and is driven via gearing from the end of the high speed pinion shaft. The governor is a fly-weight type and carries its own oil supply.

Woodward Governor suggests that the present system has a reliability of about 50%. In addition spare parts for this system are not carried and would have to be fabricated requiring long delivery times.

Control Room & MCC/ Switchgear Room: Within the gas turbine building, the electrical and control systems consist of a rotating brushless exciter, an automatic voltage regulator (AVR), a start rectifier, PLC control modules, motor control centre (MCC), electronic governors, synchronizer, and protection and monitoring equipment. The brushless exciter, AVR and start rectifier were manufactured by AEI Limited of Manchester, England in the mid-1960s. The programmable logic controller (PLC), governor, synchronizer and monitoring equipment were newly installed in 1986. The exciter and AVR unit act in combination to supply a controlled DC current to the wound rotor of the main generator which in turn controls its stator terminal voltage (13.8 kV) and Mvar delivery. The start rectifier converts station AC current into the high DC current necessary to rotate the Jet engine to ignition. The governor consists of two Woodward units: one that controls the jet acceleration on start-up and the second that controls the power turbine/generator during synchronization and Mwatt loading. In 1986, the current Gem 80/500 PLC replaced all relay logic and is now the primary controlling medium for the gas turbine. A current assessment undertaken by Hydro Engineering Services will determine the feasibility of replacing or upgrading all the AEI electrical equipment for the Holyrood Gas Turbine

Excitation System: The exciter is a rotating brushless type mounted on a stub to the main rotating shaft. It was designed to ANSI Specification C50-13. The AC output from the exciter armature is fed through a set of diodes that are mounted on the rotor and are used to produce a DC voltage. The voltage is fed directly to the field winding of the main generator which is also mounted on the same rotating shaft.

The excitation control system consists of a “Normal” and “Standby” automatic voltage regulator (AVR) backed up by a “Manual” control mode. The AVR controls the strength of the magnetic field in the exciter by varying the amount of current through the stationary exciter field windings.

Switchgear: Primary voltage generated by the GT (Gas Turbine) is 13,300 Volts. The installed gas turbine capacity is 13.5 MW, however based on limiting factors the unit sees normal operation of ~12 MW. Originally this power was fed through a 13.8 kV oil circuit breaker and then through a 13.8 kV fusible switch. The oil circuit breaker is no longer functional but remains installed due to the current transformer (CT’s) in this breaker. These CT’s are essential to the protection of the generator and the 13.8 kV/4.160 14 MVA transformer. Power is then fed from the transformer at 4.160 kV to breaker SSB-2 in station panelboard SB12. Power from the CT or station power also feeds a 13.8 kV fused disconnect switch through a 75 kVA 13.8 kV/575 V transformer that provides power back to the station system.

Fire Protection System: The fire system is an Ansul Inergen total-flooding type that can operate automatically via fire detection or manually via pull stations. The system is comprised of Inergen storage containers, piping, nozzles, control panel, actuators, detection and alarm devices, and pressure relief dampers. It was installed in 2000 to replace the Halon fire system in respect of the ozone depleting substance regulations.

FIGURE 11-34 GTG BUILDING & LIGHT OIL STORAGE

FIGURE 11-35 LIGHT OIL RECEIVING & LUBE OIL RADIATOR

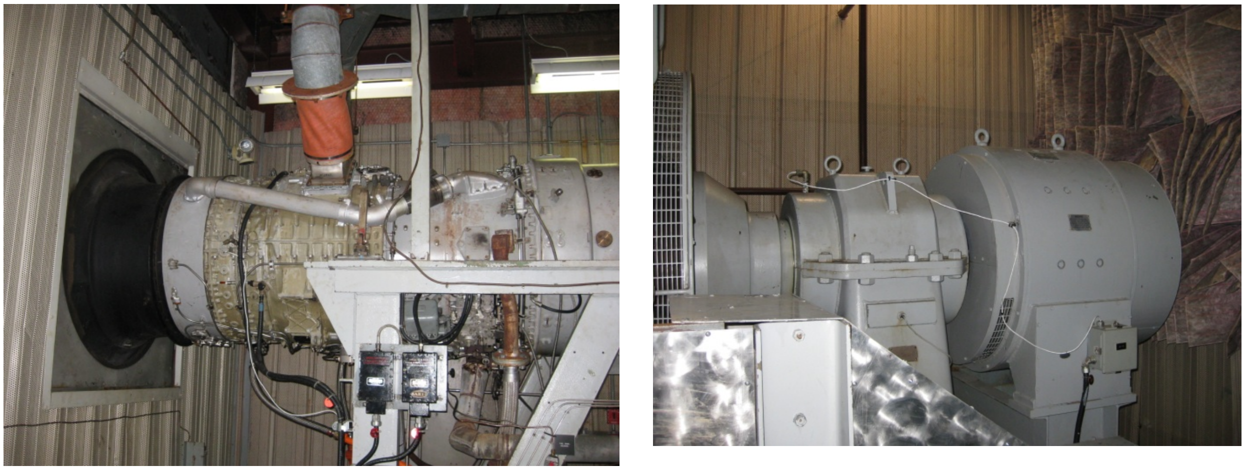


FIGURE 11-36 GTG GAS ENGINE & GENERATOR

FIGURE 11-37 GTG LIGHT OIL RECEIVING

Compressed Air System: The compressed air system consists of a single 600 volt motor/compressor unit, a 310 L (82 gallon) storage tank, a Pall instrument air dryer and a small control and monitoring panel. The system is designed to supply 700 kPa instrument air to operate the power turbine snow doors, the main generator exhaust and intake louvers and the jet engine intake and exhaust cooling air louvers. It also has provisions for a four-bottle nitrogen back-up supply in the event of a compressor system failure. The control panel provides pressure indication for the system and a transfer valve to the N2 supply.

FIGURE 11-38 GTG EXHAUST STACK & DUCT

Inspection and Repair History

The following is a summary of significant work completed since 2003. No major overhauls have been completed on the entire machine.

16 October 2003

- Annual boroscope inspection;
- Slight erosion on casing. Reprotect next shop visit;
- Normal amount of carbon build up on nozzle heads;
- Boroscope inspection satisfactory; and
- Intake plenum contained debris, chipped floor and flaking paint. Recommended clean up.

10 August 2004

- Annual hot section inspection & failure to start;
- Housing found to have corrosion on struts, will require protective coating next shop visit;
- Air plenum cleaner than last visit, holes still visible in walls;
- Compressor rotor and stator vane blades in dirty condition;
- Normal amount of carbon build up on nozzle heads;
- Slight damage to #7 Combustion Can; and
- Starting motor replaced, due to seizure. (Solved starting issue).

27 September 2005

- Annual inspection and boroscope inspection;
- Front Bearing Housing, outer bushes loose;
- Front Bearing Housing, Corrosion/ pitting;
- Corrosion/ Rust found in Plenum;
- HP NGV's have slight erosion of the leading edges and minor cracks in the trailing edges;
- Flame tubes have minor erosion on some of the wiggle strips and some carbon build up within the flame tube, especially around the dish where liquid fuel has collected;
- Normal amount of carbon build up on nozzle heads; and
- Hot gas leakage at Exhaust Transition duct to power turbine.

13 March 2006

- Leak in each end of the gearbox at the bearing seals. (Caused fire when oil leaked into insulation around PT and dripped onto top of tank). Greenray discovered turbine shaft/seal modifications, recommended machining and reconditioning.

13 April 2006

- Fuel oil leak on underside of gas turbine at IGV Ram, seal deterioration.

25 May 2007

- AVON repair and boroscope inspection: IGV ram leak, ignitor failure, hot air leak from #6 burner, bellmouth nuts loose, combustion casing boroscope port bolts loose, bleed valve ducting broken and separated, fuel lag at idle and struggling at speed;
- Significant sparking coming from PT splash plate (rubbing shaft). Suggests bearings are worn and thus damaged seal;
- 2 IGV bushes replaced due to wear in the bush. (Majority of bushes and retaining nuts were replaced as well as the locking bush);
- Rebuild of the intake with securing bolts torque and locked;
- IGV ram replaced due to leak;
- Fuel filter replaced due to feed issues;
- Bolts holding PT seal were not tight, seal incorrectly installed;
- Ignitor, lead and box were replaced;
- High fuel consumption noticed at fuel drain valve, suspect worn seals on FCU and fuel pumps;
- Additional breather recommended for rear of gearbox unit, to reduce leaks;
- Compressor section; front bearing housing, inlet guide vanes have significant corrosion and coating loss;
- Combustion cans show signs of cracking, material loss (could lead to further turbine damage);
- IP nozzle guide vanes and HP nozzle guide vanes show signs of cracking on trailing edges;
- Change PT lube oil filters; and
- Replace/ Repair exhaust snow doors.

21 May 2008

- Package filtration inspection;
- Plenum survey;
- Windmill inspection of compressor;
- Boroscope of compressor and VIGV;
- Fuel/oil system: connection, fuel pump/ oil pump, pipelines, oil level & quality, filter and basket removal (replacement consumables);
- On engine review: bleed valves, IGV ram (filter review), gearbox inspection (filters, speed pick up, consumable change), fuel control unit review, oil cooler, fuel filter change, burner removal (ultrasonic cleaning), fuel rail inspection, drain valve operation, thermocouple inspection (terminal cleaning), transition inspection, removal of insulation, rectify leaks, inspect LP blades;
- Boroscope inspection: rear of compressor, snout area, combustion can, HP nozzle guide vanes, cooper beams (crooks washers), turbine section;
- PT and gearbox review; and
- Controls review.

10 June 2008

- Water pooling noted in intake plenum along with holes in structure and loose debris;
- Compressor showing significant corrosion and pitting on front bearing housing, inlet guide vanes and compressor stages, physical signs of salt evident;
- Combustion cans need to be replaced due to extensive corrosion, #1 and #2 burners removed for inspection. Seized bolts prevented removal of others;
- Hard impact damage evident in turbine stages, suspect debris from combustion cans and/or intake plenum;
- Suggested unit overhaul for blade recoating etc.; and
- Fuel pump and FCU to be repaired.

15 October 2009

- Engine removed and placed on site, in vertical stand for repairs (combustion cans);
- Combustion cans were replaced and FCU and fuel pump repaired;
- Loose discharge nozzles, due to broken brackets (2 off) to be replaced in future;
- PT inspection showed signs of light blade rub, none on stators. Diaphragm free of damage;
- PT inlet cone cranks, to be repaired;
- Thermocouple damage, quick fixed. To be upgraded;
- Exhaust stack needs replacement, lower components noted in good condition. Door opening components to be serviced; and
- Transition duct piston rings seals to be replaced.

20 November 2009

- Commissioning;
- Fuel control solenoid valve burnt out and replaced;
- Multiple start trips due to; low fuel pressure, low oil pressure, incomplete start sequence; determined igniter box malfunction, N2 probe incorrectly connected & FCU actuator tuning;

- Exhaust transition lagging replaced due to fuel saturation;
- Split air manifold cracks, to be repaired; and
- Suggest monitoring setup for the 8 EGT thermocouples.

11.2.5.2 Condition Assessment

Essentially the unit is in very poor condition and overdue for a major overhaul of most components. The condition assessment of the gas turbine gensets is as follows in Table 11-46.

TABLE 11-46 CONDITION ASSESSMENT – GAS TURBINE GENSETS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset Level 2	Asset Level 3	Description	Detail	Cond. Summ. ID#	Append #	Condition	Status Identifier	Original Life (Base Load) Ops Hrs (Yrs)	Current Expected Minimum Remaining Life Years (Subject to Test)	End of Life (EOL) Required	Next Regular Inspection	Next Planned Overhaul/ Major Inspection	Capability to Reach Next Overhaul	Capability to Reach EOL	In Service
1273	7202	0	0	GAS TURBINE SYSTEM	GAS TURBINE SYSTEM	GAS TURBINE SYSTEM		1	13	44 years old and has accumulated about 4,717 hours with 1,548 starts. Four significant overhauls/repairs in 1978, 1986, and 1991 and a combustor replacement in 2007	4/10	150,000 (30)	1	2020	2010	2011	No	No	1969
1273	7202	7058	0	GAS TURBINE SYSTEM	GAS TURBINE POWER TURB & G/B	GAS TURBINE POWER TURB & G/B	Power Turbine	2	13	Overdue for overhaul; corrosion/cracking from moisture leakage.	4/10	150,000 (30)	2	2020	2010	2011	No	No	1969
1273	7202	7058	0	GAS TURBINE SYSTEM	GAS TURBINE POWER TURB & G/B	GAS TURBINE POWER TURB & G/B	Gearbox	3	13	Overdue for overhaul; corrosion/cracking from moisture leakage.	4/10	150,000 (30)	2	2020	2010	2011	No	No	1969
1273	7202	7308	0	GAS TURBINE SYSTEM	GAS TURBINE AVON JET ENGINE	GAS TURBINE AVON JET ENGINE		4	13	Overdue for overhaul; corrosion/cracking from seaside moisture and starts.	4/10	150,000 (30)	2	2020	2010	2011	No	No	1969
1273	7202	7309	0	GAS TURBINE SYSTEM	GAS TURBINE GENERATOR	GAS TURBINE GENERATOR		5	13	Overdue for testing of rotor/stator/auxiliaries.	4/10	200000 (40)	5	2020	2010	2011	Yes	No	1969
1273	7202	7310	0	GAS TURBINE SYSTEM	GAS TURBINE ELECT & CONTROL	GAS TURBINE ELECT & CONTROL		6	13	Relatively new.	4/10	(15)	12	2020	2010	2011	Yes	Yes	1986
1273	7202	7310	333927	GAS TURBINE SYSTEM	GAS TURBINE ELECT & CONTROL	GAS TURBINE DCS CONTROL		7	13	Relatively new.	4/10	(15)	12	2020	2010	2011	Yes	Yes	1986
1273	7202	7311	0	GAS TURBINE SYSTEM	GAS TURBINE AUXILIARY SYSTEMS	GAS TURBINE AUXILIARY SYSTEMS	Fire System	8	13	Fire system upgraded to Inergen system in 2000.	4/10	(30)	20	2020	2010	N/A	Yes	Yes	2000
1273	7202	7311	0	GAS TURBINE SYSTEM	GAS TURBINE AUXILIARY SYSTEMS	GAS TURBINE AUXILIARY SYSTEMS	Exhaust Stack	9	13	Corroded, leaking, Requires replacement.	4/10	(20)	1	2020	2010	2011	No	No	1986
1273	7202	7311	0	GAS TURBINE SYSTEM	GAS TURBINE AUXILIARY SYSTEMS	GAS TURBINE AUXILIARY SYSTEMS	Radiator	10	13	Corroded.	4	(20)	3	2020	2010	2011	Yes	No	1986
1273	7202	7311	0	GAS TURBINE SYSTEM	GAS TURBINE AUXILIARY SYSTEMS	GAS TURBINE AUXILIARY SYSTEMS	Fuel delivery	11	13	Corroded, external pitting.	4	(30)	3	2020	2010	2011	Yes	No	1986
1273	7202	7311	0	GAS TURBINE SYSTEM	GAS TURBINE AUXILIARY SYSTEMS	GAS TURBINE AUXILIARY SYSTEMS	Lube Oil	12	13	Overdue for overhaul.	4	(30)	10	2020	2010	2011	Yes	No	1986
1273	7202	7311	99003602	GAS TURBINE SYSTEM	GAS TURBINE AUXILIARY SYSTEMS	AIR INLET PLENUM CHAMBER	Filter Material	13	13	Inlet housing and filtration system replaced in 1986. Water leaking; inappropriate material for environment.	4/10	(30)	2	2020	2010	2011	Yes	No	1986

Notes:

1. A “(bracketed)” value in the “Current Expected Remaining Life” column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation, including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as “(X/Y)” has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

2. The “Next Regular Inspection” column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The “Next Planned Overhaul or Major Inspection” column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a “Desired Life” stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where no specific dates have been identified for “Next Regular Inspection” or “Next Planned Overhaul/Major Inspection”, they are left blank.

11.2.5.3 Actions

Based on the condition assessment, the following actions are recommended for the gas turbine genset.

TABLE 11-47 RECOMMENDED ACTIONS – GAS TURBINE GENSET

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset 2/3	Asset 3/4	Description	Action #	App #	Action	Year	Priority
1273	7202	0	0	GAS TURBINE SYSTEM	GAS TURBINE SYSTEM	GAS TURBINE SYSTEM	1	13			
1273	7202	7058	0	GAS TURBINE SYSTEM	GAS TURBINE POWER TURB & G/B	GAS TURBINE POWER TURB & GEARBOX	2	13	Level 2 assessment in 2010 and/or overhaul in 2011/12.	2010	1
1273	7202	7308	0	GAS TURBINE SYSTEM	GAS TURBINE AVON JET ENGINE	GAS TURBINE AVON JET ENGINE	3	13	Level 2 assessment in 2010 and/or overhaul in 2011/13.	2010	1
1273	7202	7309	0	GAS TURBINE SYSTEM	GAS TURBINE GENERATOR	GAS TURBINE GENERATOR	4	13	Level 2 assessment in 2010 and/or overhaul in 2011/14.	2010	1
1273	7202	7310	0	GAS TURBINE SYSTEM	GAS TURBINE ELECT & CONTROL	GAS TURBINE ELECT & CONTROL	5	6,13	Test in 2014 (6 Year cycle)	2014	2
1273	7202	7310	333927	GAS TURBINE SYSTEM	GAS TURBINE ELECT & CONTROL	GAS TURBINE DCS CONTROL	6	6,13	No action recommended.		
1273	7202	7311	0	GAS TURBINE SYSTEM	GAS TURBINE AUXILIARY SYSTEMS	GAS TURBINE AUXILIARY SYSTEMS	7	13	No action recommended.		
1273	7202	7311	0	GAS TURBINE SYSTEM	GAS TURBINE AUXILIARY SYSTEMS	GAS TURBINE AUXILIARY SYSTEMS - STACK	8	13,17	Conduct Level 2 inspections of the exhaust stack in 2010.	2010	1
1273	7202	7311	0	GAS TURBINE SYSTEM	GAS TURBINE AUXILIARY SYSTEMS	GAS TURBINE AUXILIARY SYSTEMS - STACK	9	13,17	Replace the gas turbine stack and affected roof areas asap.	2011	1
1273	7202	7311	0	GAS TURBINE SYSTEM	GAS TURBINE AUXILIARY SYSTEMS	GAS TURBINE AUXILIARY SYSTEMS - INTAKE	10	13,17	Replace the intake filter system suitable for seaside environment asap. Assess intake structure and corrosion.	2011	1
1273	7202	7311	0	GAS TURBINE SYSTEM	GAS TURBINE AUXILIARY SYSTEMS	GAS TURBINE AUXILIARY SYSTEMS - ENCLOSURE	11	13,17	Expand enclosure and include fuel delivery/rad, etc.	2011	2
1273	7202	7311	0	GAS TURBINE SYSTEM	GAS TURBINE AUXILIARY SYSTEMS	GAS TURBINE AUXILIARY SYSTEMS - Building	12	13,17	Paint structural members as required, roofing and siding painting.	2010	1
1273	7202	7311	99003602	GAS TURBINE SYSTEM	GAS TURBINE AUXILIARY SYSTEMS	AIR INLET PLENUM CHAMBER	13	13,17	Replace air filter media and repair inlet plenum.	2011	1

11.2.5.4 Risk Assessment

The risk assessment associated with the gas turbine genset, both from a technological perspective and a safety perspective, is illustrated below in Table 11-48.

TABLE 11-48 RISK ASSESSMENT – GAS TURBINE GENSET

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset 2/3	Asset 3/4	Description	Component	RA#	Appendix #	Major Issues	Remaining Life Years	TECHNO-ECO RISK ASSESS MODEL			SAFETY RISK ASSESS MODEL			Possible Failure Event	Mitigation
											(Insufficient Info - Inspection Required Within (x) Years)	Likeli--hood	Conse-quence	Risk Level	Likeli-hood	Conse-quence	Safety Risk		
1273	7202	0	0	GAS TURBINE SYSTEM	GAS TURBINE SYSTEM	GAS TURBINE SYSTEM		1	13	Unit failure during system failure - continued system blackout.	1	4	D	High	3	C	High	Loss of generator, potential loss of hydro system, machine damage, safety – personnel.	Major overhaul or replacement.
1273	7202	7058	0	GAS TURBINE SYSTEM	GAS TURBINE POWER TURB & G/B	GAS TURBINE POWER TURB & G/B	GTG Power Turbine	2	13	Thermo-mechanical failure, foreign object.	2	3	C	Medium	3	C	High	Loss of generator, potential loss of hydro system, machine damage, safety – personnel.	Inspection and major overhaul or replacement.
1273	7202	7058	0	GAS TURBINE SYSTEM	GAS TURBINE POWER TURB & G/B	GAS TURBINE POWER TURB & G/B	GTG Gear Box	3	13	Mechanical failure, seal oil leak.	2	3	C	Medium	3	C	High	Loss of generator, potential loss of hydro system, machine damage, safety – personnel.	Inspection and major overhaul or replacement.
1273	7202	7308	0	GAS TURBINE SYSTEM	GAS TURBINE AVON JET ENGINE	GAS TURBINE AVON JET ENGINE	GTG Engine/Compressor	4	13	Corrosion, thermo-mechanical fatigue.	2	3	C	Medium	3	C	High	Loss of generator, potential loss of hydro system, machine damage, safety – personnel.	Inspection and major overhaul or replacement.
1273	7202	7308	0	GAS TURBINE SYSTEM	GAS TURBINE AVON JET ENGINE	GAS TURBINE AVON JET ENGINE	GTG Combustors	5	13	Corrosion, thermo-mechanical failure.	5	2	C	Medium	2	C	High	Loss of generator, potential loss of hydro system, machine damage, safety – personnel.	New in 2009. Inspection and overhaul or replacement.
1273	7202	7308	0	GAS TURBINE SYSTEM	GAS TURBINE AVON JET ENGINE	GAS TURBINE AVON JET ENGINE	GTG Combustors	6	13	Corrosion, thermo-mechanical failure.	5	2	C	Medium	2	C	High	Loss of generator, potential loss of hydro system, machine damage, safety – personnel.	New in 2009. Inspection and overhaul or replacement.
1273	7202	7309	0	GAS TURBINE SYSTEM	GAS TURBINE GENERATOR	GAS TURBINE GENERATOR	GTG Generator Exciter	7	13	Mechanical, electrical failures.	12	2	C	Low	2	B	Low	Loss of generator, potential loss of hydro system, machine damage, safety – personnel.	Inspection and overhaul or replacement.
1273	7202	7310	0	GAS TURBINE SYSTEM	GAS TURBINE ELECT & CONTROL	GAS TURBINE ELECT & CONTROL		8	13	Not addressed.	12	2	C	Low	2	B	Low	Loss of generator, potential loss of hydro system, machine damage, safety – personnel.	Inspection and maintenance.
1273	7202	7310	333927	GAS TURBINE SYSTEM	GAS TURBINE ELECT & CONTROL	GAS TURB DCS CONTROL		9	13	Not addressed.	12	1	C	Low	2	B	Low	Loss of generator, potential loss of hydro system, machine damage, safety – personnel.	Inspection and maintenance.
1273	7202	7311	0	GAS TURBINE SYSTEM	GAS TURBINE AUXILIARY SYSTEMS	GAS TURBINE AUXILIARY SYSTEMS	GTG Exhaust	10	13	Leaks – end of life.	1	4	D	High	4	C	High	Loss of generator, machine damage, safety – personnel.	Refurbish or replacement asap.
1273	7202	7311	0	GAS TURBINE SYSTEM	GAS TURBINE AUXILIARY SYSTEMS	GAS TURBINE AUXILIARY SYSTEMS	GTG Lube Oil and Rad	11	13	Mechanical, leak/fire.	10	3	B	Medium	3	B	Medium	Short loss of generator, equipment damage, safety – personnel.	Refurbish or replacement asap.
1273	7202	7311	0	GAS TURBINE SYSTEM	GAS TURBINE AUXILIARY SYSTEMS	GAS TURBINE AUXILIARY SYSTEMS	GTG Fuel Oil Receipt, Piping, Feed	12	13	Mechanical failures.	3	2	C	Low	3	C	High	Temp loss of generator, unit damage, safety – personnel.	Refurbish or replacement asap.
1273	7202	7311	99003602	GAS TURBINE SYSTEM	GAS TURBINE AUXILIARY SYSTEMS	AIR INLET PLENUM CHAMBER	GTG Air Intake	13	13	Leakage salt air.	2	3	C	High	3	B	Medium	Loss of generator, unit damage.	Refurbish or replacement asap.

11.2.5.5 Life Cycle Curve and Remaining Life

Two life cycle curves are presented for the gas turbine system. The first is basically a plot of physical age of the equipment on the y-axis versus calendar year on the x-axis. The chart has several vertical lines representing differing representative nominal age limits for various components. It also has several horizontal lines that represent a range of practical equipment life limits in years. The risk area boxes provide an indication of the timing of potential issues either from an age and timing perspective.

The second is a plot of equivalent operating hours of the major parts of the unit impacted by the unit's mode of operation. The chart has several vertical lines representing the overhaul history of the unit. There are three units hours curves. The lowest is the actual hours of operation. The middle curve is the actual hours plus an allowance of twenty equivalent operating hours per start and stop. The highest is the middle value plus an allowance for time spent idle in a seaside harsh environment of 0.3 hours per actual idle hours which was identified for very early units (similar to Holyrood's) as a factor by Siemens

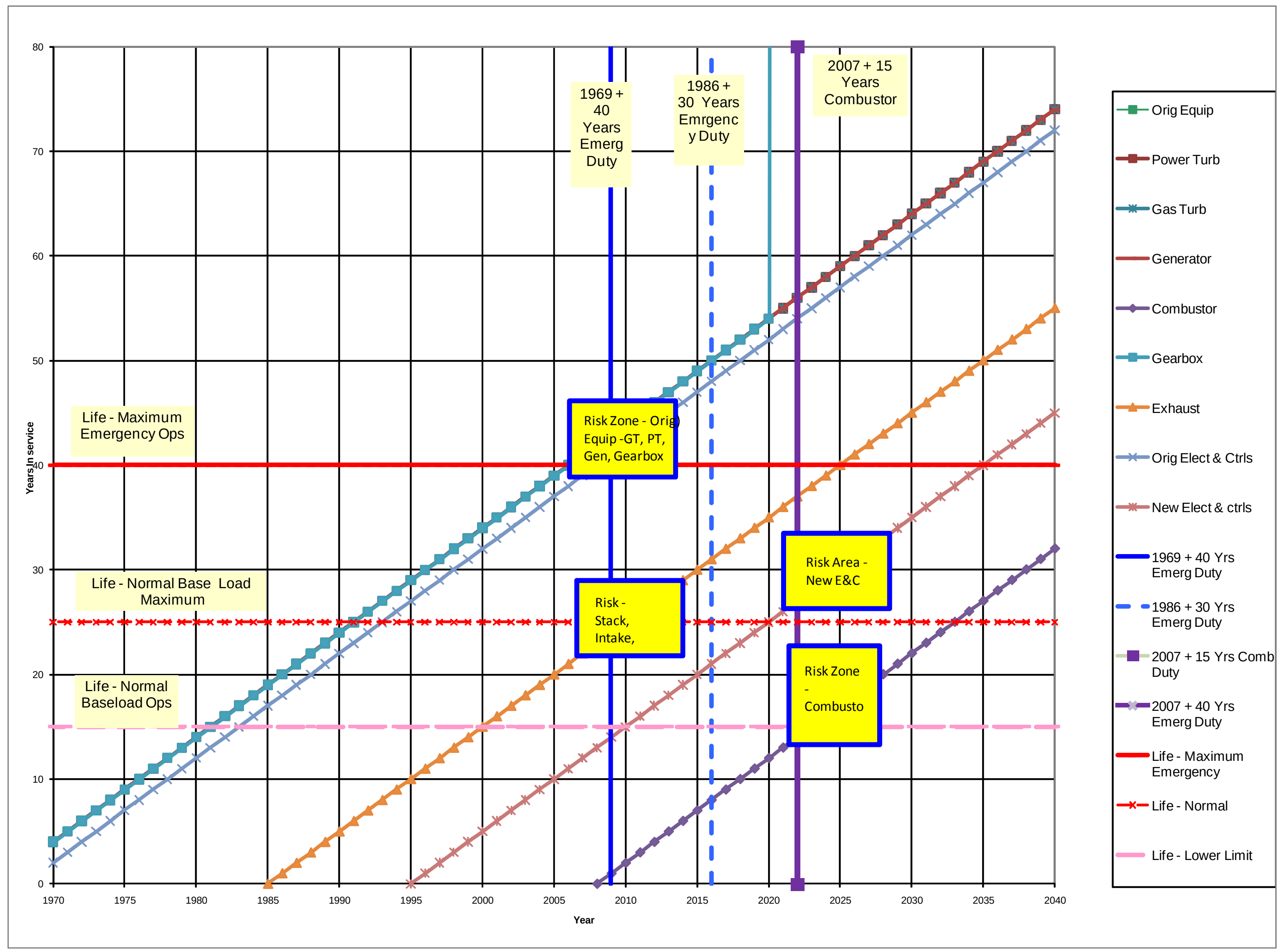


FIGURE 11-39 LIFE CYCLE CURVE – GAS TURBINE GENSET (PHYSICAL AGE BASIS)

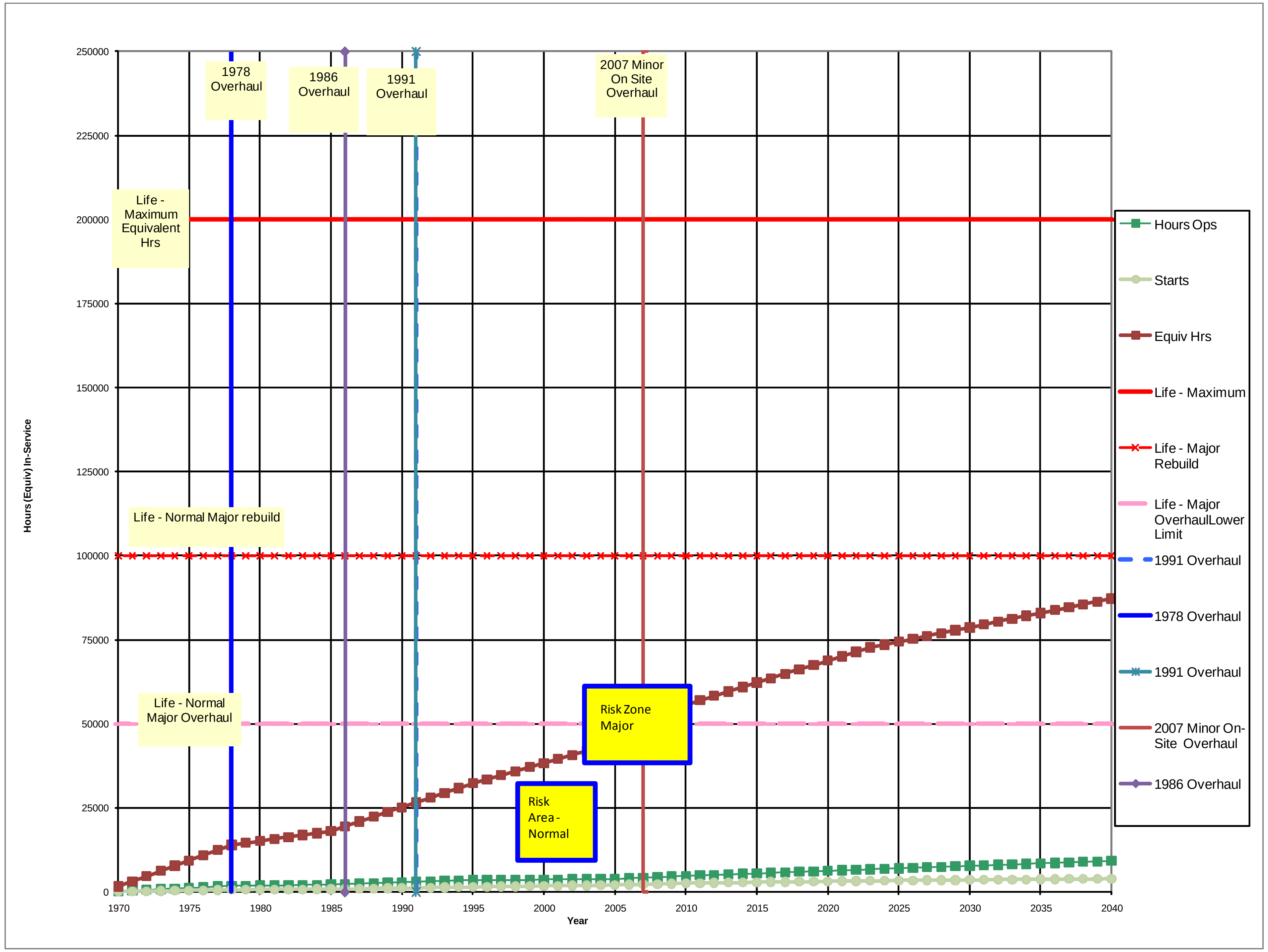


FIGURE 11-40 LIFE CYCLE CURVE – GAS TURBINE GENSET (EQUIVALENT OPERATING HOURS BASIS)

The curves, as well as the condition assessment, indicate the unit is in need of a significant and immediate overhaul and refurbishment or replacement. Its remaining life (RL) is less than the desired life (DL) which is 2020. The importance of a near term overhaul or replacement is highlighted by the critical system role that the unit needs to play in black starting the Holyrood units in the event of a system failure. The stack is physically in need of refurbishment or replacement. The intake likely needs a better filter media. The fuel system and coolers need repairs and better ambient protection. The gearbox seals continue to be an issue and a fire safety hazard. The gas turbine has not been overhauled for a considerable period, and recent inspections as well as the life cycle curve for a marine environment suggest that this necessary.

11.2.5.6 Level 2 Inspection Requirements and Costs

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 11-49 below, assuming the current plant inspection and maintenance program is maintained or improved.

TABLE 11-49 LEVEL 2 INSPECTION – GAS TURBINE GENSET

BU # 1	Asset # 2	Asset 3/4	Description	L2#	Appendix #	Level 2 Work	Year	Priority	Test	Cost k$
1273	7202	GAS TURBINE SYSTEM	GAS TURBINE SYSTEM	1	13	Options Assessment	2010	1	Options Assessment	$73
1273	7202	GAS TURBINE SYSTEM	GAS TURBINE SYSTEM	2	13	On-site Non-invasive inspection supplement to planned boroscope tests	2010	1	Inspection	$131

11.2.5.7 Capital Projects

The suggested typical capital enhancements for the gas turbine gensets include:

TABLE 11-50 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS FOR THE GAS TURBINE GENSETS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset 2/3	Asset 3/4	Description	CAP#	Appendix #	Capital Item	Date	Priority
1273	7202	0	0	GAS TURBINE SYSTEM	GAS TURBINE SYSTEM	GAS TURBINE SYSTEM	1		No capital investment.		
1273	7202	7058	0	GAS TURBINE SYSTEM	GAS TURBINE POWER TURB & G/B	GAS TURBINE POWER TURB & G/B	2	13	Overhaul of power turbine, gearbox.	2011	1
1273	7202	7308	0	GAS TURBINE SYSTEM	GAS TURBINE AVON JET ENGINE	GAS TURBINE AVON JET ENGINE	3	13	Overhaul gas turbine.	2011	1
1273	7202	7309	0	GAS TURBINE SYSTEM	GAS TURBINE GENERATOR	GAS TURBINE GENERATOR	4		Refurbish generator.	2015+	3
1273	7202	7310	0	GAS TURBINE SYSTEM	GAS TURBINE ELECT & CONTROL	GAS TURBINE ELECT & CONTROL	5	13	Replace electrical equipment for gas turbine.	2010	1
1273	7202	7310	333927	GAS TURBINE SYSTEM	GAS TURBINE ELECT & CONTROL	GAS TURBINE DCS CONTROL	6		No capital investment.		
1273	7202	7311	0	GAS TURBINE SYSTEM	GAS TURBINE AUXILIARY SYSTEMS	GAS TURBINE AUXILIARY SYSTEMS	7	13	Replace the exhaust stack.	2011	1
1273	7202	7311	0	GAS TURBINE SYSTEM	GAS TURBINE AUXILIARY SYSTEMS	GAS TURBINE AUXILIARY SYSTEMS	8	13	Upgrade fuel receipt and feeding and radiator - enclosure.	2012	2
1273	7202	7311	99003602	GAS TURBINE SYSTEM	GAS TURBINE AUXILIARY SYSTEMS	AIR INLET PLENUM CHAMBER	9	13	Replace air inlet plenum/filter media.	2011	2

11.2.6 Assets 6717 and 8680 – Diesel Gensets

(Detailed Technical Assessment in Working Papers, Appendix 13)

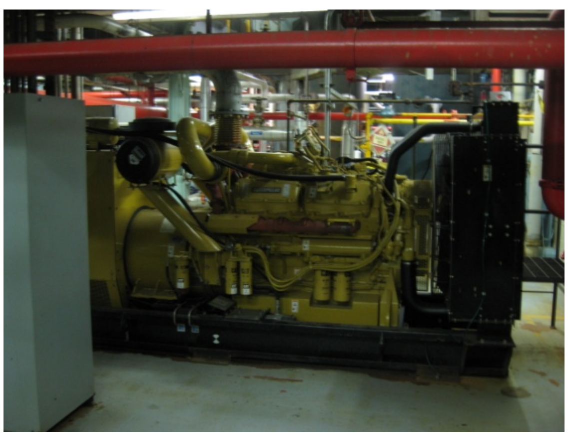
Unit #:	HRD COMMON SYSTEMS
Asset Class #	BU 1297 Assets Common Gas Turbine
SCI & System:	7199 HRD Common Systems Gas Turbine System
Sub-Systems:	6717 Stage 1 Auxiliary Diesel Generator 8680 Stage 2 Auxiliary Diesel Generator

11.2.6.1 Description

The Stage 1 emergency diesel was replaced in 2007 with a CAT H-6-1F, capable of supplying 635 Kw of 600 volt, 3 phase electrical power for the plant's emergency and back-up systems including the start-up of the gas turbine.

The Stage 2 emergency diesel was installed in 1980. It is at the end of its normal useful life. It should be replaced between 2012 and 2015 and would then be expected to last to 2041.

Both diesel gensets are designed for controlled safe shutdown of Units 1, 2, and 3. They have the necessary auxiliaries (controls, switchgear, cooling, and lubrication) to be stand-alone units. The diesels are redundant and can be operated individually to supply power to the essential services board (600v switchgear) either via a 'dead bus' or a synchronized transfer. Each diesel can supply power to the other essential service board through the use of tie-breakers.



Stage 1 Diesel

Stage 2 Diesel

FIGURE 11-41 HOLYROOD DIESEL GENSETS

11.2.6.2 History

	Stage 1	Stage 2
Manufactured/Delivered	2007	1979
In-Service Date	2007	Feb 1980
Replacement (Actual or Planned)	2007	2015

The Stage 1 diesel was replaced in 2007, and the Stage 2 diesel is currently planned to be replaced in 2015.

11.2.6.3 Condition Assessment

The condition assessment of the diesel gensets is illustrated below in Table 11-51.

TABLE 11-51 CONDITION ASSESSMENT – DIESEL GENSETS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset Level 2	Asset Level 3	Description	Detail	Cond. Summ. ID#	Append #	Condition	EPRI Identifier	Original Life (Base Load) Ops Hrs (Yrs)	Current Expected Minimum Remaining Life Years (Subject to Test)	End of Life Required (EOL)	Next Regular Inspection	Next Planned Overhaul/ Major Inspection	Capability to Reach Next Overhaul	Capability to Reach EOL	In Service
1297	7199	303240	0	0	COMMON SYSTEMS	STAGE 1 AUX.DIESEL GENERATOR	STAGE 1 AUX.DIESEL GENERATOR	N/A	1	13	New in 2007. Good condition.	3a	(25)	20+	2041	2011		No	No	2007
1297	7199	8680	0	0	COMMON SYSTEMS	STAGE 2 AUX. DIESEL GENERATOR	STAGE 2 AUX. DIESEL GENERATOR	N/A	2	13	Cummins V-1710-G installed in 1980. Scheduled to be replaced in 2014.	10	(30)	4	2041	2011		Yes	No	1980

Notes:
1. A "(bracketed)" value in the "Current Expected Remaining Life" column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation, including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as "(X/Y)" has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.
2. The "Next Regular Inspection" column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The "Next Planned Overhaul or Major Inspection" column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a "Desired Life" stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where no specific dates have been identified for "Next Regular Inspection" or "Next Planned Overhaul/Major Inspection", they are left blank.

11.2.6.4 Actions

Based on the condition assessment, the following actions are recommended for the diesel gensets:

TABLE 11-52 RECOMMENDED ACTIONS – DIESEL GENSETS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset 2/3	Asset 3/4	Description	Action #	App #	Action	Year	Priority
1297	7199	303240	0	0	COMMON	STAGE 1 AUX.DIESEL GENERATOR	STAGE 1 AUX.DIESEL	4	13,6	New in 2007. No action recommended.		
1297	7199	8680	0	0	COMMON	STAGE 2 AUX. DIESEL GENERATOR	STAGE 2 AUX. DIESEL	5	13,6	Replace 1980 machine.	2014	1

11.2.6.5 Risk Assessment

The risk assessment associated with the diesel gensets, both from a technological perspective and a safety perspective, is illustrated below in Table 11-53.

TABLE 11-53 RISK ASSESSMENT – DIESEL GENSETS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset 2/3	Asset 3/4	Description	Component	Risk Assess #	Appendix #	Major Issues	Remaining Life Years	Remaining Life	Techno-Eco Risk Assess Model			Safety Risk Assess Model			Possible Failure Event	Mitigation
												(Insufficient Info - Inspection Required Within (x) Years)	Comments	Likeli-hood	Conse-quence	Risk Level	Likeli-hood	Conse-quence	Safety Risk		
1297	7199	303240	0	0	COMMON SYSTEMS	STAGE 1 AUX.DIESEL GENERATOR	STAGE 1 AUX.DIESEL GENERATOR	None	1	13,6	Mechanical failure during emergency.	20+	New in 2007	1	C	Low	1	A	Low	Start failure during emergency.	Inspect, maintain.
1297	7199	8680	0	0	COMMON SYSTEMS	STAGE 2 AUX. DIESEL GENERATOR	STAGE 2 AUX. DIESEL GENERATOR	None	2	13,6	Mechanical failure.	4	Replacement planned in 2014	3	C	Medium	3	A	Low	Start failure during emergency.	End of Life - replace.

11.2.6.6 Life Cycle Curve and Remaining Life

The life cycle curve for the system is illustrated below. Two curves are required to represent the two emergency diesels in the plant. The life curves are plots of physical age of the equipment on the y-axis versus calendar year on the x-axis. The chart has several vertical lines representing representative nominal calendar limits for the engines, with normal life maintenance in an emergency power mode. It also has several horizontal lines that represent a range of practical equipment life limits in years.

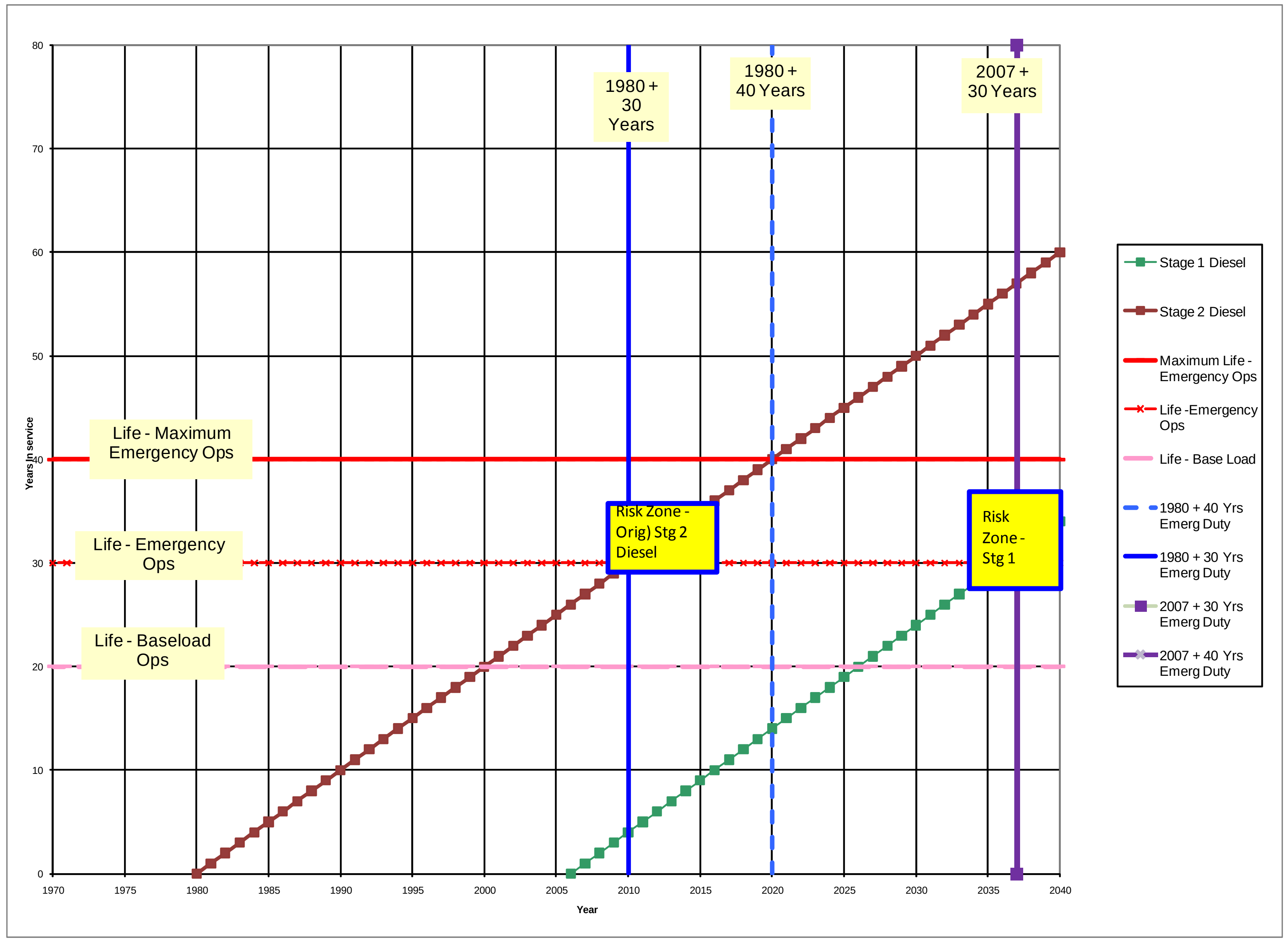


FIGURE 11-42 LIFE CYCLE CURVE – DIESEL GENSETS

The curves indicate that the remaining life (RL) of the newer Stage 1 diesel genset exceeds the end date for generation of 2020, and likely the desired life (DL) of 2041 (at the end of synchronous condensing life). It also indicates that the original Stage 2 diesel genset is at or very near its end of life and should be replaced. Given the critical role these units play in emergency safe shutdown, the replacement should be a high priority.

11.2.6.7 Level 2 Inspection Requirements and Costs

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 11-54 below, assuming the current plant inspection and maintenance program is maintained or improved.

TABLE 11-54 LEVEL 2 INSPECTION – DIESEL GENSETS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset 2/3	Asset 3/4	Description	Sub System Comment	L2#	Appendix #	Level 2 Work	Year	Priority	Cost k$
1297	7199	303240	0	COMMON SYSTEMS	STAGE 1 AUX.DIESEL GENERATOR	STAGE 1 AUX.DIESEL GENERATOR	N/A	1	13,6	No Level 2 required.			
1297	7199	8680	0	COMMON SYSTEMS	STAGE 2 AUX. DIESEL GENERATOR	STAGE 2 AUX. DIESEL GENERATOR	N/A	2	13	No Level 2 required.			

11.2.6.8 Capital Projects

The suggested typical capital enhancements for the diesel gensets include:

TABLE 11-55 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – DIESEL GENSETS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset 2/3	Asset 3/4	Description	CAP#	Appendix #	Capital Item	Date	Priority
1297	7199	303240	0	0	COMMON SYSTEMS	STAGE 1 AUX.DIESEL GENERATOR	STAGE 1 AUX.DIESEL GENERATOR	1	13,6	No capital required.		
1297	7199	8680	0	0	COMMON SYSTEMS	STAGE 2 AUX. DIESEL GENERATOR	STAGE 2 AUX. DIESEL GENERATOR	2	13,6	Replace Stage 2 Emergency Diesel, Cummins V-1710-G.	2014	1

12 LEVEL 2 REQUIREMENTS SUMMARY

Level 2 inspections were identified in Chapters 8 to 11. Summary level information is provided in this chapter. It is summarized by Priorities in Section 12.1 and by Major Plant Area and Priorities in Section 12.2. The costs include all costs identified in the detail sheets below, including contingency and escalation and some allowances for set-up and Holyrood costs.

It should be remembered that the costs include those for the enhanced inspection/overhauls for the steam turbine and generator for Units 1, 2, and 3 in 2012, 2014, and 2016 respectively.

12.1 Level 2 Activities Prioritized Summary

Table 12-1 is a summary of Level 2 costs by Priorities assigned by AMEC, with Priority 1 being the highest priority. It is presented as both a breakdown of how the costs were developed (sub-categories) as well as by year.

TABLE 12-1 LEVEL 2 ACTIVITIES PRIORITIZED SUMMARY

	Cost k$	Base NDE + AMEC Directs	Scaffold/Infrast	HTGS Costs	OEM Supp	PM NDE	Software Check	Mob & Demob	Fit for Serv Rep	Sub-Total	Conting	Total 2010	Escal	Total Esc $
Priority 1	$17,547	$10,866	$543	$435	$326	$652	$0	$326	$0	$13,148	$2,630	$15,777	$1,770	$17,547
Priority 2	$4,811	$3,093	$155	$124	$93	$186	$0	$93	$0	$3,743	$749	$4,491	$320	$4,811
Priority 3	$222	$148	$7	$6	$4	$9	$0	$4	$0	$179	$36	$215	$7	$222
Priority 4	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total	$22,580	$14,107	$705	$564	$423	$846	$0	$423	$0	$17,069	$3,414	$20,483	$2,096	$22,580

	Total k$	2010	2011	2012	2013	2014	2015	2016	2017
Priority 1	$17,547	$392	$1,600	$4,615	$44	$6,195	$13	$4,687	$0
Priority 2	$4,811	$0	$773	$1,879	$1,929	$229	$0	$0	$0
Priority 3	$222	$0	$217	$0	$0	$5	$0	$0	$0
Priority 4	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total	$22,580	$392	$2,590	$6,494	$1,973	$6,429	$13	$4,687	$0

12.2 Level 2 Activities Prioritized Summary by Major Plant Area

Table 12-2 is a summary of Level 2 costs by Major Plant Area priorities. It is presented as both a breakdown of how the costs were developed (sub-categories) as well as by year. The plant areas are broken down into synchronous condensing required plant equipment (Synch Cond); steam turbine and auxiliaries (Stm Turb) plant equipment required only for electricity generation; boiler and auxiliaries (Blr Stm) plant equipment (boilers and auxiliaries, HP heaters, dearators) required only for electricity generation; switchyard and transformer (Switchy & TS) equipment required for both synchronous condensing and electricity generation; and black start gas turbine and auxiliaries (GTG) equipment and facilities.

TABLE 12-2 LEVEL 2 ACTIVITIES PRIORITIZED SUMMARY BY PLANT AREA

	Cost k$	Base NDE + AMEC Directs	Scaffold/ Infrast	HTGS Costs	OEM Supp	PM NDE	Software Check	Mob & Demob	Fit for Serv Rep	Sub-Total	Conting	Total 2010	Escal	Total Esc $
Synch Cond Priority 1	$7,894	$4,933	$247	$197	$148	$296	$0	$148	$0	$5,969	$1,194	$7,163	$732	$7,894
Synch Cond Priority 2	$594	$397	$20	$16	$12	$24	$0	$12	$0	$480	$96	$576	$17	$594
Synch Cond Priority 3	$207	$138	$7	$6	$4	$8	$0	$4	$0	$167	$33	$200	$6	$207
Synch Cond Priority 4	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Stm Turb Priority 1	$7,463	$4,567	$228	$183	$137	$274	$0	$137	$0	$5,526	$1,105	$6,631	$832	$7,463
Stm Turb Priority 2	$147	$98	$5	$4	$3	$6	$0	$3	$0	$119	$24	$142	$4	$147
Stm Turb Priority 3	$15	$10	$1	$0	$0	$1	$0	$0	$0	$12	$2	$15	$0	$15
Stm Turb Priority 4	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Blr Stm Prioirity 1	$1,758	$1,076	$54	$43	$32	$65	$0	$32	$0	$1,302	$260	$1,562	$196	$1,758
Blr Stm Prioirity 2	$4,070	$2,598	$130	$104	$78	$156	$0	$78	$0	$3,144	$629	$3,772	$298	$4,070
Blr Stm Prioirity 3	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Blr Stm Prioirity 4	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Switchy & TS Priority 1	$228	$150	$8	$6	$5	$9	$0	$5	$0	$182	$36	$218	$11	$228
Switchy & TS Priority 2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Switchy & TS Priority 3	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Switchy & TS Priority 4	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
GTG Priority 1	$203	$140	$7	$6	$4	$8	$0	$4	$0	$169	$34	$203	$0	$203
GTG Priority 2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
GTG Priority 3	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
GTG Priority 4	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total	$22,580	$14,107	$705	$564	$423	$846	$0	$423	$0	$17,069	$3,414	$20,483	$2,096	$22,580

Table 12-2 Cont'd

	Total k$	2010	2011	2012	2013	2014	2015	2016	2017
Synch Cond Priority 1	$7,894	$73	$1,494	$2,286	$0	$1,961	$0	$2,081	$0
Synch Cond Priority 2	$594	$0	$594	$0	$0	$0	$0	$0	$0
Synch Cond Priority 3	$207	$0	$202	$0	$0	$5	$0	$0	$0
Synch Cond Priority 4	$0	$0	$0	$0	$0	$0	$0	$0	$0
Stm Turb Priority 1	$7,463	$0	$100	$2,311	$0	$2,451	$0	$2,601	$0
Stm Turb Priority 2	$147	$0	$147	$0	$0	$0	$0	$0	$0
Stm Turb Priority 3	$15	$0	$15	$0	$0	$0	$0	$0	$0
Stm Turb Priority 4	$0	$0	$0	$0	$0	$0	$0	$0	$0
Blr Stm Prioirity 1	$1,758	$0	$0	$0	$0	$1,758	$0	$0	$0
Blr Stm Prioirity 2	$4,070	$0	$33	$1,879	$1,929	$229	$0	$0	$0
Blr Stm Prioirity 3	$0	$0	$0	$0	$0	$0	$0	$0	$0
Blr Stm Prioirity 4	$0	$0	$0	$0	$0	$0	$0	$0	$0
Switchy & TS Priority 1	$228	$116	$6	$18	$44	$25	$13	$6	$0
Switchy & TS Priority 2	$0	$0	$0	$0	$0	$0	$0	$0	$0
Switchy & TS Priority 3	$0	$0	$0	$0	$0	$0	$0	$0	$0
Switchy & TS Priority 4	$0	$0	$0	$0	$0	$0	$0	$0	$0
GTG Priority 1	$203	$203	$0	$0	$0	$0	$0	$0	$0
GTG Priority 2	$0	$0	$0	$0	$0	$0	$0	$0	$0
GTG Priority 3	$0	$0	$0	$0	$0	$0	$0	$0	$0
GTG Priority 4	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total	$22,580	$392	$2,590	$6,494	$1,973	$6,429	$13	$4,687	$0

Table 12-2 Cont'd

		Total Cost k$	Base NDE + AMEC Directs	Scaffold/ Infrast	HTGS Costs	OEM Supp	PM NDE	Software Check	Mob & Demob	Fit for Serv Rep	Sub-Total	Conting	Total 2010	Escal	Total Esc $
GAS TURBINE GENERATOR															
Total	GTG	$203	$140	$7	$6	$4	$8	$0	$4	$0	$169	$34	$203	$0	$203
Stm Turb	GTG	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Blr Stm Stm	GTG	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Switchy & TS	GTG	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
GTG	GTG	$203	$140	$7	$6	$4	$8	$0	$4	$0	$169	$34	$203	$0	$203
Total Excl Stm Turb	GTG	$203	$140	$7	$6	$4	$8	$0	$4	$0	$169	$34	$203	$0	$203
Total Excl Blr Stm,Stm Turb	GTG	$203	$140	$7	$6	$4	$8	$0	$4	$0	$169	$34	$203	$0	$203
Total Excl Blr Stm,Stm Turb,Switchy & TS	GTG	$203	$140	$7	$6	$4	$8	$0	$4	$0	$169	$34	$203	$0	$203
Total Excl Blr Stm,Stm Turb,Switchy & TS,GTG	GTG	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
UNIT 1															
Total	U1	$6,860	$4,469	$223	$179	$134	$268	$0	$134	$0	$5,407	$1,081	$6,489	$371	$6,860
Stm Turb	U1	$2,345	$1,523	$76	$61	$46	$91	$0	$46	$0	$1,843	$369	$2,211	$134	$2,345
Blr Stm Stm	U1	$1,885	$1,224	$61	$49	$37	$73	$0	$37	$0	$1,481	$296	$1,777	$108	$1,885
Switchy & TS	U1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
GTG	U1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Excl Stm Turb	U1	$4,514	$2,946	$147	$118	$88	$177	$0	$88	$0	$3,565	$713	$4,278	$237	$4,514
Total Excl Blr Stm,Stm Turb	U1	$2,629	$1,722	$86	$69	$52	$103	$0	$52	$0	$2,084	$417	$2,500	$129	$2,629
Total Excl Blr Stm,Stm Turb,Switchy & TS	U1	$2,629	$1,722	$86	$69	$52	$103	$0	$52	$0	$2,084	$417	$2,500	$129	$2,629
Total Excl Blr Stm,Stm Turb,Switchy & TS,GTG	U1	$2,629	$1,722	$86	$69	$52	$103	$0	$52	$0	$2,084	$417	$2,500	$129	$2,629
UNIT 2															
Total	U2	$7,158	$4,462	$223	$178	$134	$268	$0	$134	$0	$5,399	$1,080	$6,479	$680	$7,158
Stm Turb	U2	$2,620	$1,613	$81	$65	$48	$97	$0	$48	$0	$1,952	$390	$2,342	$278	$2,620
Blr Stm Stm	U2	$1,929	$1,216	$61	$49	$36	$73	$0	$36	$0	$1,471	$294	$1,766	$164	$1,929
Switchy & TS	U2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
GTG	U2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Excl Stm Turb	U2	$4,538	$2,849	$142	$114	$85	$171	$0	$85	$0	$3,447	$689	$4,137	$401	$4,538
Total Excl Blr Stm,Stm Turb	U2	$2,609	$1,633	$82	$65	$49	$98	$0	$49	$0	$1,976	$395	$2,371	$238	$2,609
Total Excl Blr Stm,Stm Turb,Switchy & TS	U2	$2,609	$1,633	$82	$65	$49	$98	$0	$49	$0	$1,976	$395	$2,371	$238	$2,609
Total Excl Blr Stm,Stm Turb,Switchy & TS,GTG	U2	$2,609	$1,633	$82	$65	$49	$98	$0	$49	$0	$1,976	$395	$2,371	$238	$2,609

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Table 12-2 Cont'd

		Total Cost k$	Base NDE + AMEC Directs	Scaffold/ Infrast	HTGS Costs	OEM Supp	PM NDE	Software Check	Mob & Demob	Fit for Serv Rep	Sub-Total	Conting	Total 2010	Escal	Total Esc $
UNIT 3															
Total	U3	$7,489	$4,456	$223	$178	$134	$267	$0	$134	$0	$5,392	$1,078	$6,470	$1,019	$7,489
Stm Turb	U3	$2,659	$1,539	$77	$62	$46	$92	$0	$46	$0	$1,862	$372	$2,235	$424	$2,659
Blr Stm Stm	U3	$2,014	$1,234	$62	$49	$37	$74	$0	$37	$0	$1,493	$299	$1,792	$222	$2,014
Switchy & TS	U3	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
GTG	U3	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Excl Stm Turb	U3	$4,830	$2,917	$146	$117	$88	$175	$0	$88	$0	$3,530	$706	$4,235	$594	$4,830
Total Excl Blr Stm,Stm Turb	U3	$2,816	$1,683	$84	$67	$50	$101	$0	$50	$0	$2,036	$407	$2,444	$372	$2,816
Total Excl Blr Stm,Stm Turb,Switchy & TS	U3	$2,816	$1,683	$84	$67	$50	$101	$0	$50	$0	$2,036	$407	$2,444	$372	$2,816
Total Excl Blr Stm,Stm Turb,Switchy & TS,GTG	U3	$2,816	$1,683	$84	$67	$50	$101	$0	$50	$0	$2,036	$407	$2,444	$372	$2,816
COMMON FACILITIES															
Total	Common	$870	$580	$29	$23	$17	$35	$0	$17	$0	$702	$140	$842	$27	$870
Stm Turb	Common	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Blr Stm Stm	Common	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Switchy & TS	Common	$228	$150	$8	$6	$5	$9	$0	$5	$0	$182	$36	$218	$11	$228
GTG	Common	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Excl Stm Turb	Common	$870	$580	$29	$23	$17	$35	$0	$17	$0	$702	$140	$842	$27	$870
Total Excl Blr Stm,Stm Turb	Common	$870	$580	$29	$23	$17	$35	$0	$17	$0	$702	$140	$842	$27	$870
Total Excl Blr Stm,Stm Turb,Switchy & TS	Common	$641	$430	$22	$17	$13	$26	$0	$13	$0	$520	$104	$624	$17	$641
Total Excl Blr Stm,Stm Turb,Switchy & TS,GTG	Common	$641	$430	$22	$17	$13	$26	$0	$13	$0	$520	$104	$624	$17	$641
SUMMARY TOTAL															
Total	TOTAL	$22,580	$14,107	$705	$564	$423	$846	$0	$423	$0	$17,069	$3,414	$20,483	$2,096	$22,580
Stm Turb	TOTAL	$7,624	$4,675	$234	$187	$140	$281	$0	$140	$0	$5,657	$1,131	$6,788	$836	$7,624
Blr Stm Stm	TOTAL	$5,829	$3,674	$184	$147	$110	$220	$0	$110	$0	$4,446	$889	$5,335	$494	$5,829
Switchy & TS	TOTAL	$228	$150	$8	$6	$5	$9	$0	$5	$0	$182	$36	$218	$11	$228
GTG	TOTAL	$203	$140	$7	$6	$4	$8	$0	$4	$0	$169	$34	$203	$0	$203
Total Excl Stm Turb	TOTAL	$14,955	$9,432	$472	$377	$283	$566	$0	$283	$0	$11,413	$2,283	$13,695	$1,260	$14,955
Total Excl Blr Stm,Stm Turb	TOTAL	$9,126	$5,758	$288	$230	$173	$345	$0	$173	$0	$6,967	$1,393	$8,361	$766	$9,126
Total Excl Blr Stm,Stm Turb,Switchy & TS	TOTAL	$8,898	$5,608	$280	$224	$168	$336	$0	$168	$0	$6,786	$1,357	$8,143	$755	$8,898
Total Excl Blr Stm,Stm Turb,Switchy & TS,GTG	TOTAL	$8,695	$5,468	$273	$219	$164	$328	$0	$164	$0	$6,616	$1,323	$7,940	$755	$8,695

Table 12-2 Cont'd

		Total k$	2010	2011	2012	2013	2014	2015	2016	2017
GAS TURBINE GENERATOR										
Total	GTG	$203	$203	$0	$0	$0	$0	$0	$0	$0
Stm Turb	GTG	$0	$0	$0	$0	$0	$0	$0	$0	$0
Blr Stm Stm	GTG	$0	$0	$0	$0	$0	$0	$0	$0	$0
Switchy & TS	GTG	$0	$0	$0	$0	$0	$0	$0	$0	$0
GTG	GTG	$203	$203	$0	$0	$0	$0	$0	$0	$0
Total Excl Stm Turb	GTG	$203	$203	$0	$0	$0	$0	$0	$0	$0
Total Excl Blr Stm,Stm Turb	GTG	$203	$203	$0	$0	$0	$0	$0	$0	$0
Total Excl Blr Stm,Stm Turb,Switchy & TS	GTG	$203	$203	$0	$0	$0	$0	$0	$0	$0
Total Excl Blr Stm,Stm Turb,Switchy & TS,GTG	GTG	$0	$0	$0	$0	$0	$0	$0	$0	$0
UNIT 1										
Total	U1	$6,860	$0	$821	$6,038	$0	$0	$0	$0	$0
Stm Turb	U1	$2,345	$0	$34	$2,311	$0	$0	$0	$0	$0
Blr Stm Stm	U1	$1,885	$0	$6	$1,879	$0	$0	$0	$0	$0
Switchy & TS	U1	$0	$0	$0	$0	$0	$0	$0	$0	$0
GTG	U1	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Excl Stm Turb	U1	$4,514	$0	$787	$3,728	$0	$0	$0	$0	$0
Total Excl Blr Stm,Stm Turb	U1	$2,629	$0	$781	$1,849	$0	$0	$0	$0	$0
Total Excl Blr Stm,Stm Turb,Switchy & TS	U1	$2,629	$0	$781	$1,849	$0	$0	$0	$0	$0
Total Excl Blr Stm,Stm Turb,Switchy & TS,GTG	U1	$2,629	$0	$781	$1,849	$0	$0	$0	$0	$0
UNIT 2										
Total	U2	$0	$0	$817	$0	$1,929	$4,412	$0	$0	$0
Stm Turb	U2	$0	$0	$169	$0	$0	$2,451	$0	$0	$0
Blr Stm Stm	U2	$0	$0	$0	$0	$1,929	$0	$0	$0	$0
Switchy & TS	U2	$0	$0	$0	$0	$0	$0	$0	$0	$0
GTG	U2	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Excl Stm Turb	U2	$0	$0	$648	$0	$1,929	$1,961	$0	$0	$0
Total Excl Blr Stm,Stm Turb	U2	$0	$0	$648	$0	$0	$1,961	$0	$0	$0
Total Excl Blr Stm,Stm Turb,Switchy & TS	U2	$0	$0	$648	$0	$0	$1,961	$0	$0	$0
Total Excl Blr Stm,Stm Turb,Switchy & TS,GTG	U2	$0	$0	$648	$0	$0	$1,961	$0	$0	$0

Table 12-2 Cont'd

		Total k$	2010	2011	2012	2013	2014	2015	2016	2017
UNIT 3										
Total	U3	$0	$0	$383	$437	$0	$1,987	$0	$4,681	$0
Stm Turb	U3	$0	$0	$58	$0	$0	$0	$0	$2,601	$0
Blr Stm Stm	U3	$0	$0	$27	$0	$0	$1,987	$0	$0	$0
Switchy & TS	U3	$0	$0	$0	$0	$0	$0	$0	$0	$0
GTG	U3	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Excl Stm Turb	U3	$0	$0	$325	$437	$0	$1,987	$0	$2,081	$0
Total Excl Blr Stm,Stm Turb	U3	$0	$0	$298	$437	$0	$0	$0	$2,081	$0
Total Excl Blr Stm,Stm Turb,Switchy & TS	U3	$0	$0	$298	$437	$0	$0	$0	$2,081	$0
Total Excl Blr Stm,Stm Turb,Switchy & TS,GTG	U3	$0	$0	$298	$437	$0	$0	$0	$2,081	$0
COMMON FACILITIES										
Total	Common	$870	$189	$570	$18	$44	$29	$13	$6	$0
Stm Turb	Common	$0	$0	$0	$0	$0	$0	$0	$0	$0
Blr Stm Stm	Common	$0	$0	$0	$0	$0	$0	$0	$0	$0
Switchy & TS	Common	$228	$116	$6	$18	$44	$25	$13	$6	$0
GTG	Common	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Excl Stm Turb	Common	$870	$189	$570	$18	$44	$29	$13	$6	$0
Total Excl Blr Stm,Stm Turb	Common	$870	$189	$570	$18	$44	$29	$13	$6	$0
Total Excl Blr Stm,Stm Turb,Switchy & TS	Common	$641	$73	$564	$0	$0	$5	$0	$0	$0
Total Excl Blr Stm,Stm Turb,Switchy & TS,GTG	Common	$641	$73	$564	$0	$0	$5	$0	$0	$0
SUMMARY TOTAL										
Total	TOTAL	$7,932	$392	$2,590	$6,494	$1,973	$6,429	$13	$4,687	$0
Stm Turb	TOTAL	$2,345	$0	$262	$2,311	$0	$2,451	$0	$2,601	$0
Blr Stm Stm	TOTAL	$1,885	$0	$33	$1,879	$1,929	$1,987	$0	$0	$0
Switchy & TS	TOTAL	$228	$116	$6	$18	$44	$25	$13	$6	$0
GTG	TOTAL	$203	$203	$0	$0	$0	$0	$0	$0	$0
Total Excl Stm Turb	TOTAL	$5,587	$392	$2,329	$4,184	$1,973	$3,978	$13	$2,087	$0
Total Excl Blr Stm,Stm Turb	TOTAL	$3,702	$392	$2,296	$2,304	$44	$1,991	$13	$2,087	$0
Total Excl Blr Stm,Stm Turb,Switchy & TS	TOTAL	$3,474	$276	$2,290	$2,286	$0	$1,966	$0	$2,081	$0
Total Excl Blr Stm,Stm Turb,Switchy & TS,GTG	TOTAL	$3,271	$73	$2,290	$2,286	$0	$1,966	$0	$2,081	$0

12.2.1 Level 2 Activities – Unit 1

Table 12-3 is a summary of the Level 2 costs identified in Chapter 8 for Unit 1. Charts show both costs broken down into its sub-categories and by year.

TABLE 12-3 LEVEL 2 ACTIVITIES SUMMARY – UNIT 1

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Sub System Comment	Year	Priority	Cost k$	Base NDE + AMEC Directs	Scaffold/ Infrast	HTGS Costs	OEM Supp	PM NDE	Software Check	Mob & Demob	Fit for Serv Rep	Sub-Total	Conting	Total 2010	Escal	Total Esc $
1296	6690	0	0	0	0	1	UNIT 1																			
1296	6690	6691	6696	0	0	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	GENERATOR ASSEMBLY	2011 Pre-Outage Inspection Work Allowance	2011	1	$100	$67	$3	$3	$2	$4	$0	$2	$0	$81	$16	$97	$3	$100
1296	6690	6691	6696	0	0	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	GENERATOR ASSEMBLY	Outage/Inspection	2012	1	$1,849	$1,200	$60	$48	$36	$72	$0	$36	$0	$1,452	$290	$1,742	$106	$1,849
1296	6690	6691	6733	0	0	1	#1 TURBINE & GENERATOR	TURBINE CONDENSER SYSTEM	TURBINE CONDENSER SYSTEM	Inspection	2011	2	$4	$3	$0.2	$0.1	$0.1	$0.2	$0.0	$0.1	$0.0	$3.6	$0.7	$4.4	$0.1	$4.5
1296	6690	6691	271309	0	0	1	#1 TURBINE & GENERATOR	TURBINE	TURBINE	Outage/Inspection	2012	1	$2,311	$1,500	$75.0	$60.0	$45.0	$90.0	$0.0	$45.0	$0.0	$1,815.0	$363.0	$2,178.0	$132.6	$2,310.6
1296	6690	6691	271309	6729	0	1	#1 TURBINE & GENERATOR	TURBINE	TURBINE MAIN STEAM CHEST	Vlve/Stud Check	2011	1	$6	$4	$0.2	$0.2	$0.1	$0.2	$0.0	$0.1	$0.0	$4.8	$1.0	$5.8	$0.2	$6.0
1296	6690	6691	271309	6730	0	1	#1 TURBINE & GENERATOR	TURBINE	H.P. TURBINE	Vlve/Stud Check	2011	1	$6	$4	$0.2	$0.2	$0.1	$0.2	$0.0	$0.1	$0.0	$4.8	$1.0	$5.8	$0.2	$6.0
1296	6690	6691	271309	6731	0	1	#1 TURBINE & GENERATOR	TURBINE	I.P. TURBINE	Vlve/Stud Check	2011	1	$6	$4	$0.2	$0.2	$0.1	$0.2	$0.0	$0.1	$0.0	$4.8	$1.0	$5.8	$0.2	$6.0
1296	6690	6691	271309	6732	0	1	#1 TURBINE & GENERATOR	TURBINE	L.P. TURBINE	Borescope Check	2011	2	$6	$4	$0.2	$0.2	$0.1	$0.2	$0.0	$0.1	$0.0	$4.8	$1.0	$5.8	$0.2	$6.0
1296	6690	6691	271309	6766	0	1	#1 TURBINE & GENERATOR	TURBINE	TURBINE RH/IP STEAM CHEST	Vlve/Stud Check	2011	1	$6	$4	$0.2	$0.2	$0.1	$0.2	$0.0	$0.1	$0.0	$4.8	$1.0	$5.8	$0.2	$6.0
1296	6690	6691	271309	6695	6805	1	#1 TURBINE & GENERATOR	TURBINE	TURB LUBE OIL TANK & EQUIP	Thickness/Integrity	2011	2	$6	$4	$0.2	$0.2	$0.1	$0.2	$0.0	$0.1	$0.0	$4.8	$1.0	$5.8	$0.2	$6.0
1296	6690	6699	0	0	0	1	#1 BOILER PLANT	BOILER PLANT	BOILER PLANT	Outage/Inspection	2012	2	$1,433	$930	$46.5	$37.2	$27.9	$55.8	$0.0	$27.9	$0.0	$1,125.3	$225.1	$1,350.4	$82.2	$1,432.6
1296	6690	6699	6702	6876	0	1	#1 BOILER PLANT	BLR SUPERHEAT& REHEAT ASS'Y	BOILER MAIN STEAM LINES	(Testing of Main Steam, Hot Reheat, Cold Reheat, HP feedwater	2011	1	$395	$264	$13.2	$10.6	$7.9	$15.8	$0.0	$7.9	$0.0	$319.4	$63.9	$383.3	$11.5	$394.8
1296	6690	6699	6702	6876	6902	1	#1 BOILER PLANT	BLR SUPERHEAT& REHEAT ASS'Y	BOILER STOP VALVE	Inspection/NDE Test	2011	1	$30	$20	$1.0	$0.8	$0.6	$1.2	$0.0	$0.6	$0.0	$24.2	$4.8	$29.0	$0.9	$29.9
1296	6690	6699	6700	0	0	1	#1 BOILER PLANT	BOILER STRUCTURE	BOILER STRUCTURE	Visual Inspion	2012	2	$6	$4	$0.2	$0.2	$0.1	$0.2	$0.0	$0.1	$0.0	$4.8	$1.0	$5.8	$0.4	$6.2
1296	6690	6709	6711	7056	0	1	#1 CONDENSATE & F.W. SYSTEM	CONDENSATE & F.W. SYSTEM	LOW PRESSURE FW RESERVE	Inspection	2011	2	$15	$10	$0.5	$0.4	$0.3	$0.6	$0.0	$0.3	$0.0	$12.1	$2.4	$14.5	$0.4	$15.0
1296	6690	6709	6711	7059	0	1	#1 CONDENSATE & F.W. SYSTEM	#1 CONDENSATE & F.W. SYSTEM	LOW PRESSURE HEATER 1	Inspection/NDE Test	2011	2	$56	$38	$1.9	$1.5	$1.1	$2.3	$0.0	$1.1	$0.0	$45.4	$9.1	$54.5	$1.6	$56.1
1296	6690	6709	6711	7066	0	1	#1 CONDENSATE & F.W. SYSTEM	#1 CONDENSATE & F.W. SYSTEM	LOW PRESSURE HEATER 2	Inspection/NDE Test	2011	2	$56	$38	$1.9	$1.5	$1.1	$2.3	$0.0	$1.1	$0.0	$45.4	$9.1	$54.5	$1.6	$56.1
1296	6690	6709	6711	7053	0	1	#1 CONDENSATE & F.W. SYSTEM	CONDENSATE & F.W. SYSTEM	DEAERATOR SYSTEM	Inspection/NDE Test	2012	2	$216	$140	$7.0	$5.6	$4.2	$8.4	$0.0	$4.2	$0.0	$169.4	$33.9	$203.3	$12.4	$215.7
1296	6690	6709	6713	0	0	1	#1 CONDENSATE & F.W. SYSTEM	HIGH PRESSURE FEEDWATER SYS	HIGH PRESSURE FEEDWATER SYS	Inspection/NDE Test	2012	2	$225	$146	$7.3	$5.8	$4.4	$8.8	$0.0	$4.4	$0.0	$176.7	$35.3	$212.0	$12.9	$224.9
1296	6690	6715	6782	0	0	1	#1 UNIT GENERATION SERVICES	TURB/GEN COOLING SYSTEM	TURB/GEN COOLING SYSTEM	Seawater intake and discharge piping inspection	2011	2	$6	$4	$0.2	$0.2	$0.1	$0.2	$0.0	$0.1	$0.0	$4.8	$1.0	$5.8	$0.2	$6.0
1296	6690	6715	6782	0	0	1	#1 UNIT GENERATION SERVICES	TURB/GEN COOLING SYSTEM	TURB/GEN COOLING SYSTEM	Test AC water piping thickness	2011	2	$6	$4	$0.2	$0.2	$0.1	$0.2	$0.0	$0.1	$0.0	$4.8	$1.0	$5.8	$0.2	$6.0
1296	6690	6715	6782	0	0	1	#1 UNIT GENERATION SERVICES	TURB/GEN COOLING SYSTEM	TURB/GEN COOLING SYSTEM	Inspect heat exchanger	2011	2	$6	$4	$0.2	$0.2	$0.1	$0.2	$0.0	$0.1	$0.0	$4.8	$1.0	$5.8	$0.2	$6.0
1296	6690	6715	270182	0	0	1	#1 UNIT GENERATION SERVICES	CW SYSTEM	CW SYSTEM	Inspect concrete pipe to/from pump to condenser	2011	2	$6	$4	$0.2	$0.2	$0.1	$0.2	$0.0	$0.1	$0.0	$4.8	$1.0	$5.8	$0.2	$6.0

Table 12-3 Cont'd

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Sub System Comment	Year	Priority	Cost k$	Base NDE + AMEC Directs	Scaffold/ Infrast	HTGS Costs	OEM Supp	PM NDE	Software Check	Mob & Demob	Fit for Serv Rep	Sub-Total	Conting	Total 2010	Escal	Total Esc $
1296	6690	6715	270182	0	0	1	#1 UNIT GENERATION SERVICES	CW SYSTEM	CW SYSTEM	Test steel pipe to/from condenser	2011	2	$6	$4	$0.2	$0.2	$0.1	$0.2	$0.0	$0.1	$0.0	$4.8	$1.0	$5.8	$0.2	$6.0
1296	6690	6715	270182	7134	0	1	#1 UNIT GENERATION SERVICES	CW SYSTEM	C.W. INTAKE	Inspection CW intake and discharge structures and piping	2011	2	$30	$20	$1.0	$0.8	$0.6	$1.2	$0.0	$0.6	$0.0	$24.2	$4.8	$29.0	$0.9	$29.9
1296	6690	6715	270182	7135	0	1	#1 UNIT GENERATION SERVICES	CW SYSTEM	C.W. DISCHARGE TO OUTFALL	Inspection CW intake and discharge structures and piping	2011	2	$30	$20	$1.0	$0.8	$0.6	$1.2	$0.0	$0.6	$0.0	$24.2	$4.8	$29.0	$0.9	$29.9
1296	6690	6723	6724	0	0	1	#1 UNIT GENERATION SERVICES	GENERATOR BUS DUCT & CONNS	GENERATOR BUS DUCT & CONNS	Inspect Generator Bus-Duct and Connections	2011	1	$15	$10	$0.5	$0.4	$0.3	$0.6	$0.0	$0.3	$0.0	$12.1	$2.4	$14.5	$0.4	$15.0
1296	6690	6723	6726	7182	0	1	#1 UNIT GENERATION SERVICES	UNIT SERVICE POWER SYSTEM	POWER CENTRE A	Inspect Power Centre "A" UAB1, (600	2011	2	$6	$4	$0.2	$0.2	$0.1	$0.2	$0.0	$0.1	$0.0	$4.8	$1.0	$5.8	$0.2	$6.0
1296	6690	6723	270297	0	0	1	#1 UNIT GENERATION SERVICES	CONTROL CABLES	CONTROL CABLES	Test Control Cables	2011	2	$7	$5	$0.3	$0.2	$0.2	$0.3	$0.0	$0.2	$0.0	$6.1	$1.2	$7.3	$0.2	$7.5
1296	6690	6723	270298	0	0	1	#1 UNIT GENERATION SERVICES	POWER CABLES	POWER CABLES	Test Power Cables	2011	2	$10	$7	$0.4	$0.3	$0.2	$0.4	$0.0	$0.2	$0.0	$8.5	$1.7	$10.2	$0.3	$10.5

	Total	Base NDE + AMEC Directs	Scaffold/ Infrast	HTGS Costs	OEM Supp	PM NDE	Software Check	Mob & Demob	Fit for Serv Rep	Sub-Total	Conting	Total 2010	Escal	Total Esc $
Total	$6,860	$4,469	$223	$179	$134	$268	$0	$134	$0	$5,407	$1,081	$6,489	$371	$6,860
Stm Turb	$2,345	$1,523	$76	$61	$46	$91	$0	$46	$0	$1,843	$369	$2,211	$134	$2,345
Blr Stm	$1,885	$1,224	$61	$49	$37	$73	$0	$37	$0	$1,481	$296	$1,777	$108	$1,885
Switchy & TS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
GTG	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Excl Stm Turb	$4,514	$2,946	$147	$118	$88	$177	$0	$88	$0	$3,565	$713	$4,278	$237	$4,514
Total Excl Blr Stm, Stm Turb	$2,629	$1,722	$86	$69	$52	$103	$0	$52	$0	$2,084	$417	$2,500	$129	$2,629
Total Excl Blr Stm, Stm Turb, Switchy & TS	$2,629	$1,722	$86	$69	$52	$103	$0	$52	$0	$2,084	$417	$2,500	$129	$2,629
Total Excl Blr Stm, Stm Turb, Switchy & TS, GTG	$2,629	$1,722	$86	$69	$52	$103	$0	$52	$0	$2,084	$417	$2,500	$129	$2,629

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Table 12-3 Cont'd

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Sub System Comment	Year	Priority	Cost k$	2010	2011	2012	2013	2014	2015	2016	2017
1296	6690	0	0	0	0	1	UNIT 1														
1296	6690	6691	6696	0	0	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	GENERATOR ASSEMBLY	2011 Pre-Outage Inspection Work Allowance	2011	1	$100	$0.0	$100.2	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1296	6690	6691	6696	0	0	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	GENERATOR ASSEMBLY	Outage/Inspection	2012	1	$1,849	$0.0	$0.0	$1,848.5	$0.0	$0.0	$0.0	$0.0	$0.0
1296	6690	6691	6733	0	0	1	#1 TURBINE & GENERATOR	TURBINE CONDENSER SYSTEM	TURBINE CONDENSER SYSTEM	Inspection	2011	2	$4	$0.0	$4.5	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1296	6690	6691	271309	0	0	1	#1 TURBINE & GENERATOR	TURBINE	TURBINE	Outage/Inspection	2012	1	$2,311	$0.0	$0.0	$2,310.6	$0.0	$0.0	$0.0	$0.0	$0.0
1296	6690	6691	271309	6729	0	1	#1 TURBINE & GENERATOR	TURBINE	TURBINE MAIN STEAM CHEST	Vlve/Stud Check	2011	1	$6	$0.0	$6.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1296	6690	6691	271309	6730	0	1	#1 TURBINE & GENERATOR	TURBINE	H.P. TURBINE	Vlve/Stud Check	2011	1	$6	$0.0	$6.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1296	6690	6691	271309	6731	0	1	#1 TURBINE & GENERATOR	TURBINE	I.P. TURBINE	Vlve/Stud Check	2011	1	$6	$0.0	$6.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1296	6690	6691	271309	6732	0	1	#1 TURBINE & GENERATOR	TURBINE	L.P. TURBINE	Borescope Check	2011	2	$6	$0.0	$6.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1296	6690	6691	271309	6766	0	1	#1 TURBINE & GENERATOR	TURBINE	TURBINE RH/IP STEAM CHEST	Vlve/Stud Check	2011	1	$6	$0.0	$6.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1296	6690	6691	271309	6695	6805	1	#1 TURBINE & GENERATOR	TURBINE	TURB LUBE OIL TANK & EQUIP	Thickness/Integrity	2011	2	$6	$0.0	$6.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1296	6690	6699	0	0	0	1	#1 BOILER PLANT	BOILER PLANT	BOILER PLANT	Outage/Inspection	2012	2	$1,433	$0.0	$0.0	$1,432.6	$0.0	$0.0	$0.0	$0.0	$0.0
1296	6690	6699	6702	6876	0	1	#1 BOILER PLANT	BLR SUPERHEAT& REHEAT ASS'Y	BOILER MAIN STEAM LINES	(Testing of Main Steam , Hot Reheat, Cold Reheat, HP feedwater	2011	1	$395	$0.0	$394.8	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1296	6690	6699	6702	6876	6902	1	#1 BOILER PLANT	BLR SUPERHEAT& REHEAT ASS'Y	BOILER STOP VALVE	Inspection/NDE Test	2011	1	$30	$0.0	$29.9	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1296	6690	6699	6700	0	0	1	#1 BOILER PLANT	BOILER STRUCTURE	BOILER STRUCTURE	Visual Inspion	2012	2	$6	$0.0	$0.0	$6.2	$0.0	$0.0	$0.0	$0.0	$0.0
1296	6690	6709	6711	7056	0	1	#1 CONDENSATE & F.W. SYSTEM	CONDENSATE & F.W. SYSTEM	LOW PRESSURE FW RESERVE	Inspection	2011	2	$15	$0.0	$15.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1296	6690	6709	6711	7059	0	1	#1 CONDENSATE & F.W. SYSTEM	#1 CONDENSATE & F.W. SYSTEM	LOW PRESSURE HEATER 1	Inspection/NDE Test	2011	2	$56	$0.0	$56.1	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1296	6690	6709	6711	7066	0	1	#1 CONDENSATE & F.W. SYSTEM	#1 CONDENSATE & F.W. SYSTEM	LOW PRESSURE HEATER 2	Inspection/NDE Test	2011	2	$56	$0.0	$56.1	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1296	6690	6709	6711	7053	0	1	#1 CONDENSATE & F.W. SYSTEM	CONDENSATE & F.W. SYSTEM	DEAERATOR SYSTEM	Inspection/NDE Test	2012	2	$216	$0.0	$0.0	$215.7	$0.0	$0.0	$0.0	$0.0	$0.0
1296	6690	6709	6713	0	0	1	#1 CONDENSATE & F.W. SYSTEM	HIGH PRESSURE FEEDWATER SYS	HIGH PRESSURE FEEDWATER SYS	Inspection/NDE Test	2012	2	$225	$0.0	$0.0	$224.9	$0.0	$0.0	$0.0	$0.0	$0.0
1296	6690	6715	6782	0	0	1	#1 UNIT GENERATION SERVICES	TURB/GEN COOLING SYSTEM	TURB/GEN COOLING SYSTEM	Seawater intake and discharge piping inspection	2011	2	$6	$0.0	$6.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1296	6690	6715	6782	0	0	1	#1 UNIT GENERATION SERVICES	TURB/GEN COOLING SYSTEM	TURB/GEN COOLING SYSTEM	Test AC Water piping thickness	2011	2	$6	$0.0	$6.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1296	6690	6715	6782	0	0	1	#1 UNIT GENERATION SERVICES	TURB/GEN COOLING SYSTEM	TURB/GEN COOLING SYSTEM	Inspect Heat exchanger	2011	2	$6	$0.0	$6.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1296	6690	6715	270182	0	0	1	#1 UNIT GENERATION SERVICES	CW SYSTEM	CW SYSTEM	Inspect Concrete Pipe to/from pump to condenser	2011	2	$6	$0.0	$6.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0

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Table 12-3 Cont'd

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Sub System Comment	Year	Priority	Cost k$	2010	2011	2012	2013	2014	2015	2016	2017
1296	6690	6715	270182	0	0	1	#1 UNIT GENERATION SERVICES	CW SYSTEM	CW SYSTEM	Test steel Pipe to/from condenser	2011	2	$6	$0.0	$6.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1296	6690	6715	270182	7134	0	1	#1 UNIT GENERATION SERVICES	CW SYSTEM	C.W. INTAKE	Inspection CW intake and discharge structures and piping	2011	2	$30	$0.0	$29.9	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1296	6690	6715	270182	7135	0	1	#1 UNIT GENERATION SERVICES	CW SYSTEM	C.W. DISCHARGE TO OUTFALL	Inspection CW intake and discharge structures and piping	2011	2	$30	$0.0	$29.9	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1296	6690	6723	6724	0	0	1	#1 UNIT GENERATION SERVICES	GENERATOR BUS DUCT & CONNS	GENERATOR BUS DUCT & CONNS	Inspect Generator Bus-Duct and Connections	2011	1	$15	$0.0	$15.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1296	6690	6723	6726	7182	0	1	#1 UNIT GENERATION SERVICES	UNIT SERVICE POWER SYSTEM	POWER CENTRE A	Inspect Power Centre "A" UAB1, (600	2011	2	$6	$0.0	$6.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1296	6690	6723	270297	0	0	1	#1 UNIT GENERATION SERVICES	CONTROL CABLES	CONTROL CABLES	Test Control Cables	2011	2	$7	$0.0	$7.5	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1296	6690	6723	270298	0	0	1	#1 UNIT GENERATION SERVICES	POWER CABLES	POWER CABLES	Test Power Cables	2011	2	$10	$0.0	$10.5	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0

	Total	2010	2011	2012	2013	2014	2015	2016	2017
Total	$6,860	$0	$821	$6,038	$0	$0	$0	$0	$0
Stm Turb	$2,345	$0	$34	$2,311	$0	$0	$0	$0	$0
Blr Stm	$1,885	$0	$6	$1,879	$0	$0	$0	$0	$0
Switchy & TS	$0	$0	$0	$0	$0	$0	$0	$0	$0
GTG	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Excl Stm Turb	$4,514	$0	$787	$3,728	$0	$0	$0	$0	$0
Total Excl Blr Stm, Stm Turb	$2,629	$0	$781	$1,849	$0	$0	$0	$0	$0
Total Excl Blr Stm, Stm Turb, Switchy & TS	$2,629	$0	$781	$1,849	$0	$0	$0	$0	$0
Total Excl Blr Stm, Stm Turb, Switchy & TS, GTG	$2,629	$0	$781	$1,849	$0	$0	$0	$0	$0

12.2.2 Level 2 Activities – Unit 2

Table 12-4 is a summary of the Level 2 costs identified in Chapter 9 for Unit 2. Charts show both costs broken down into its sub-categories and by year.

TABLE 12-4 LEVEL 2 ACTIVITIES SUMMARY – UNIT 2

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Sub System Comment	Year	Priority	Cost k$	Base NDE + AMEC Directs	Scaffold/Infrast	HTGS Costs	OEM Supp	PM NDE	Software Check	Mob & Demob	Fit for Serv Rep	Sub-Total	Conting	Total 2010	Escal	Total Esc $
1296	7635	0	0	0	0	2	UNIT 2																			
1296	7635	7636	7664	0	0	2	#2 TURBINE CONDENSER SYSTEM	TURBINE CONDENSER SYSTEM	TURBINE CONDENSER SYSTEM	Inspection	2011	2	$4	$3	$0.2	$0.1	$0.1	$0.2	$0.0	$0.1	$0.0	$3.6	$0.7	$4.4	$0.1	$4.5
1296	7635	7636	7753	0	0	2	U2 GENERATOR	GENERATOR ASSEMBLY	GENERATOR	2011 Pre-Outage Inspection Work Allowance	2011	1	$100	$67	$3.4	$2.7	$2.0	$4.0	$0.0	$2.0	$0.0	$81.1	$16.2	$97.3	$2.9	$100.2
1296	7635	7636	7753	0	0	2	U2 GENERATOR	GENERATOR ASSEMBLY	GENERATOR	Outage/Inspection	2014	1	$1,961	$1,200	$60.0	$48.0	$36.0	$72.0	$0.0	$36.0	$0.0	$1,452.0	$290.4	$1,742.4	$218.7	$1,961.1
1296	7635	7636	271317	0	0	2	#2 TURBINE	TURBINE	TURBINE	Outage/Inspection	2014	1	$2,451	$1,500	$75.0	$60.0	$45.0	$90.0	$0.0	$45.0	$0.0	$1,815.0	$363.0	$2,178.0	$273.4	$2,451.4
1296	7635	7636	271317	7638	0	2	#1 TURBINE	TURBINE	TURBINE MAIN STEAM CHEST	Vlve/Stud Check	2011	1	$6	$4	$0.2	$0.2	$0.1	$0.2	$0.0	$0.1	$0.0	$4.8	$1.0	$5.8	$0.2	$6.0
1296	7635	7636	271317	7643	0	2	#2 TURBINE	TURBINE	H.P. TURBINE	Vlve/Stud Check	2011	1	$6	$4	$0.2	$0.2	$0.1	$0.2	$0.0	$0.1	$0.0	$4.8	$1.0	$5.8	$0.2	$6.0
1296	7635	7636	271317	7647	0	2	#2 TURBINE	TURBINE	TURB REHEAT/IP STEAM CHEST	Vlve/Stud Check	2011	1	$6	$4	$0.2	$0.2	$0.1	$0.2	$0.0	$0.1	$0.0	$4.8	$1.0	$5.8	$0.2	$6.0
1296	7635	7636	271317	7652	0	2	#2 TURBINE	TURBINE	I.P. TURBINE	Vlve/Stud Check	2011	1	$6	$4	$0.2	$0.2	$0.1	$0.2	$0.0	$0.1	$0.0	$4.8	$1.0	$5.8	$0.2	$6.0
1296	7635	7636	271317	7658	0	2	#2 TURBINE	TURBINE	L.P. TURBINE	Borescope Check	2011	1	$6	$4	$0.2	$0.2	$0.1	$0.2	$0.0	$0.1	$0.0	$4.8	$1.0	$5.8	$0.2	$6.0
1296	7635	7636	271317	7711	7719	2	#2 TURBINE	TURBINE	TURB LUBE OIL TANK & EQUIP	Thickness/Integrity	2011	2	$6	$4	$0.2	$0.2	$0.1	$0.2	$0.0	$0.1	$0.0	$4.8	$1.0	$5.8	$0.2	$6.0
1296	7635	7786	0	0	0	2	#2 BOILER PLANT	BOILER PLANT	BOILER PLANT	Outage/Inspection	2013	2	$1,476	$930	$46.5	$37.2	$27.9	$55.8	$0.0	$27.9	$0.0	$1,125.3	$225.1	$1,350.4	$125.2	$1,475.6
1296	7635	7786	7810	7823	0	2	#2 BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER MAIN STEAM LINES	(Testing of Main Steam , Hot Reheat, Cold Reheat, HP feedwater	2011	1	$395	$264	$13.2	$10.6	$7.9	$15.8	$0.0	$7.9	$0.0	$319.4	$63.9	$383.3	$11.5	$394.8
1296	7635	7786	7810	7823	322451	2	#2 BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER STIOP VALVES	Inspection/NDE Test	2011	1	$30	$20	$1.0	$0.8	$0.6	$1.2	$0.0	$0.6	$0.0	$24.2	$4.8	$29.0	$0.9	$29.9
1296	7635	7978	7992	7997	0	2	#2 CONDENSATE & F.W. SYSTEM	L P FEEDWATER SYSTEM	LOW PRESSURE HEATER 1	Inspection/NDE Test	2011	2	$57	38	$1.9	$1.5	$1.1	$2.3	$0.0	$1.1	$0.0	$46.0	$9.2	$55.2	$1.7	$56.8
1296	7635	7978	7992	7998	0	2	#2 CONDENSATE & F.W. SYSTEM	L P FEEDWATER SYSTEM	LOW PRESSURE HEATER 2	Inspection/NDE Test	2011	2	$57	38	$1.9	$1.5	$1.1	$2.3	$0.0	$1.1	$0.0	$46.0	$9.2	$55.2	$1.7	$56.8

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Table 12-4 Cont'd

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Sub System Comment	Year	Priority	Cost k$	Base NDE + AMEC Directs	Scaffold/Infrast	HTGS Costs	OEM Supp	PM NDE	Software Check	Mob & Demob	Fit for Serv Rep	Sub-Total	Conting	Total 2010	Escal	Total Esc $
1296	7635	0	0	0	0	2	UNIT 2																			
1296	7635	7978	7992	8032	0	2	#2 CONDENSATE & F.W. SYSTEM	L P FEEDWATER SYSTEM	RESERVE FW SYSTEM	Inspection	2011	3	$15	$10	$0.5	$0.4	$0.3	$0.6	$0.0	$0.3	$0.0	$12.1	$2.4	$14.5	$0.4	$15.0
1296	7635	7978	7992	8017	0	2	#2 CONDENSATE & F.W. SYSTEM	L P FEEDWATER SYSTEM	DEAERATOR SYSTEM	Inspection/NDE Test	2013	2	$222	$140	$7.0	$5.6	$4.2	$8.4	$0.0	$4.2	$0.0	$169.4	$33.9	$203.3	$18.8	$222.1
1296	7635	7978	8059	0	0	2	#2 CONDENSATE & F.W. SYSTEM	H.P. FEEDWATER SYSTEM	H.P. FEEDWATER SYSTEM	Inspection/NDE Test	2013	2	$232	$146	$7.3	$5.8	$4.4	$8.8	$0.0	$4.4	$0.0	$176.7	$35.3	$212.0	$19.7	$231.6
1296	7635	8093	7703	0	0	2	#2 UNIT GENERATION SERVICES	TURB/GEN COOLING SYSTEM	TURB/GEN COOLING SYSTEM	Test seawater intake and discharge piping	2011	2	$6	$4	$0.2	$0.2	$0.1	$0.2	$0.0	$0.1	$0.0	$4.8	$1.0	$5.8	$0.2	$6.0
1296	7635	8093	7703	0	0	2	#2 UNIT GENERATION SERVICES	TURB/GEN COOLING SYSTEM	TURB/GEN COOLING SYSTEM	Test AC Water piping thickness	2011	2	$6	$4	$0.2	$0.2	$0.1	$0.2	$0.0	$0.1	$0.0	$4.8	$1.0	$5.8	$0.2	$6.0
1296	7635	8093	7703	0	0	2	#2 UNIT GENERATION SERVICES	TURB/GEN COOLING SYSTEM	TURB/GEN COOLING SYSTEM	Inspect Heat exchanger	2011	2	$6	$4	$0.2	$0.2	$0.1	$0.2	$0.0	$0.1	$0.0	$4.8	$1.0	$5.8	$0.2	$6.0
1296	7635	8093	271486	0	0	2	#2 UNIT GENERATION SERVICES	CW SYSTEM	CW SYSTEM	Inspect Concrete Pipe to/from pump to condenser	2011	2	$6	$4	$0.2	$0.2	$0.1	$0.2	$0.0	$0.1	$0.0	$4.8	$1.0	$5.8	$0.2	$6.0
1296	7635	8093	271486	0	0	2	#2 UNIT GENERATION SERVICES	CW SYSTEM	CW SYSTEM	Test steel Pipe to/from condenser	2011	3	$6	$4	$0.2	$0.2	$0.1	$0.2	$0.0	$0.1	$0.0	$4.8	$1.0	$5.8	$0.2	$6.0
1296	7635	8093	271486	8095	0	2	#2 UNIT GENERATION SERVICES	CW SYSTEM	C.W. INTAKE SYSTEM	Inspect CW intake structures and piping	2011	2	$30	$20	$1.0	$0.8	$0.6	$1.2	$0.0	$0.6	$0.0	$24.2	$4.8	$29.0	$0.9	$29.9
1296	7635	8093	271486	8120	0	2	#2 UNIT GENERATION SERVICES	CW SYSTEM	C.W. DISCHARGE TO OUTFALL	Inspection CW discharge structures and piping	2011	2	$30	$20	$1.0	$0.8	$0.6	$1.2	$0.0	$0.6	$0.0	$24.2	$4.8	$29.0	$0.9	$29.9
1296	7635	8152	8153	0	0	2	#2 ELECTRICAL & CONTROLS SYS	GEN. BUS DUCTS & CONN'S	GEN. BUS DUCTS & CONN'S	Inspect Generator Bus-Duct and Connections	2011	1	$15	$10	$0.5	$0.4	$0.3	$0.6	$0.0	$0.3	$0.0	$12.1	$2.4	$14.5	$0.4	$15.0
1296	7635	8152	271476	0	0	2	#2 ELECTRICAL & CONTROLS SYS	CONTROL CABLES	CONTROL CABLES	Test Control Cables	2011	3	$7	$5	$0.3	$0.2	$0.2	$0.3	$0.0	$0.2	$0.0	$6.1	$1.2	$7.3	$0.2	$7.5
1296	7635	8152	271477	0	0	2	#2 ELECTRICAL & CONTROLS SYS	POWER CABLES	POWER CABLES	Test Power Cables	2011	3	$10	$7	$0.4	$0.3	$0.2	$0.4	$0.0	$0.2	$0.0	$8.5	$1.7	$10.2	$0.3	$10.5

	Total	Base NDE + AMEC Directs	Scaffold/Infrast	HTGS Costs	OEM Supp	PM NDE	Software Check	Mob & Demob	Fit for Serv Rep	Sub-Total	Conting	Total 2010	Escal	Total Esc $
Total	$7,158	$4,462	$223	$178	$134	$268	$0	$134	$0	$5,399	$1,080	$6,479	$680	$7,158
Stm Turb	$2,620	$1,613	$81	$65	$48	$97	$0	$48	$0	$1,952	$390	$2,342	$278	$2,620
Blr Stm	$1,929	$1,216	$61	$49	$36	$73	$0	$36	$0	$1,471	$294	$1,766	$164	$1,929
Switchy & TS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
GTG	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Excl Stm Turb	$4,538	$2,849	$142	$114	$85	$171	$0	$85	$0	$3,447	$689	$4,137	$401	$4,538
Total Excl Blr Stm, Stm Turb	$2,609	$1,633	$82	$65	$49	$98	$0	$49	$0	$1,976	$395	$2,371	$238	$2,609
Total Excl Blr Stm, Stm Turb, Switchy & TS	$2,609	$1,633	$82	$65	$49	$98	$0	$49	$0	$1,976	$395	$2,371	$238	$2,609
Total Excl Blr Stm, Stm Turb, Switchy & TS, GTG	$2,609	$1,633	$82	$65	$49	$98	$0	$49	$0	$1,976	$395	$2,371	$238	$2,609

Table 12-4 Cont'd

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Sub System Comment	Year	Priority	Cost k$	2010	2011	2012	2013	2014	2015	2016	2017
1296	7635	0	0	0	0	2	UNIT 2														
1296	7635	7636	7664	0	0	2	#2 TURBINE CONDENSER SYSTEM	TURBINE CONDENSER SYSTEM	TURBINE CONDENSER SYSTEM	Inspection	2011	2	$4	$0.0	$4.5	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1296	7635	7636	7753	0	0	2	U2 GENERATOR	GENERATOR ASSEMBLY	GENERATOR	2011 Pre-Outage Inspection Work Allowance	2011	1	$100	$0.0	$100.2	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1296	7635	7636	7753	0	0	2	U2 GENERATOR	GENERATOR ASSEMBLY	GENERATOR	Outage/Inspection	2014	1	$1,961	$0.0	$0.0	$0.0	$0.0	$1,961.1	$0.0	$0.0	$0.0
1296	7635	7636	271317	0	0	2	#2 TURBINE	TURBINE	TURBINE	Outage/Inspection	2014	1	$2,451	$0.0	$0.0	$0.0	$0.0	$2,451.4	$0.0	$0.0	$0.0
1296	7635	7636	271317	7638	0	2	#1 TURBINE	TURBINE	TURBINE MAIN STEAM CHEST	Vlve/Stud Check	2011	1	$6	$0.0	$6.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1296	7635	7636	271317	7643	0	2	#2 TURBINE	TURBINE	H.P. TURBINE	Vlve/Stud Check	2011	1	$6	$0.0	$6.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1296	7635	7636	271317	7647	0	2	#2 TURBINE	TURBINE	TURB REHEAT/IP STEAM CHEST	Vlve/Stud Check	2011	1	$6	$0.0	$6.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1296	7635	7636	271317	7652	0	2	#2 TURBINE	TURBINE	I.P. TURBINE	Vlve/Stud Check	2011	1	$6	$0.0	$6.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1296	7635	7636	271317	7658	0	2	#2 TURBINE	TURBINE	L.P. TURBINE	Borescope Check	2011	1	$6	$0.0	$6.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1296	7635	7636	271317	7711	7719	2	#2 TURBINE	TURBINE	TURB LUBE OIL TANK & EQUIP	Thickness/Integrity	2011	2	$6	$0.0	$6.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1296	7635	7786	0	0	0	2	#2 BOILER PLANT	BOILER PLANT	BOILER PLANT	Outage/Inspection	2013	2	$1,476	$0.0	$0.0	$0.0	$1,475.6	$0.0	$0.0	$0.0	$0.0
1296	7635	7786	7810	7823	0	2	#2 BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER MAIN STEAM LINES	(Testing of Main Steam , Hot Reheat, Cold Reheat, HP feedwater	2011	1	$395	$0.0	$394.8	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1296	7635	7786	7810	7823	322451	2	#2 BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER STIOP VALVES	Inspection/NDE Test	2011	1	$30	$0.0	$29.9	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1296	7635	7978	7992	7997	0	2	#2 CONDENSATE & F.W. SYSTEM	L P FEEDWATER SYSTEM	LOW PRESSURE HEATER 1	Inspection/NDE Test	2011	2	$57	$0.0	$56.8	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1296	7635	7978	7992	7998	0	2	#2 CONDENSATE & F.W. SYSTEM	L P FEEDWATER SYSTEM	LOW PRESSURE HEATER 2	Inspection/NDE Test	2011	2	$57	$0.0	$56.8	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0

Table 12-4 Cont'd

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Sub System Comment	Year	Priority	Cost k$	2010	2011	2012	2013	2014	2015	2016	2017
1296	7635	0	0	0	0	2	UNIT 2														
1296	7635	7978	7992	8032	0	2	#2 CONDENSATE & F.W. SYSTEM	L P FEEDWATER SYSTEM	RESERVE FW SYSTEM	Inspection	2011	3	$15	$0.0	$15.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1296	7635	7978	7992	8017	0	2	#2 CONDENSATE & F.W. SYSTEM	L P FEEDWATER SYSTEM	DEAERATOR SYSTEM	Inspection/NDE Test	2013	2	$222	$0.0	$0.0	$0.0	$222.1	$0.0	$0.0	$0.0	$0.0
1296	7635	7978	8059	0	0	2	#2 CONDENSATE & F.W. SYSTEM	H.P. FEEDWATER SYSTEM	H.P. FEEDWATER SYSTEM	Inspection/NDE Test	2013	2	$232	$0.0	$0.0	$0.0	$231.6	$0.0	$0.0	$0.0	$0.0
1296	7635	8093	7703	0	0	2	#2 UNIT GENERATION SERVICES	TURB/GEN COOLING SYSTEM	TURB/GEN COOLING SYSTEM	Test seawater intake and discharge piping	2011	2	$6	$0.0	$6.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1296	7635	8093	7703	0	0	2	#2 UNIT GENERATION SERVICES	TURB/GEN COOLING SYSTEM	TURB/GEN COOLING SYSTEM	Test AC Water piping thickness	2011	2	$6	$0.0	$6.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1296	7635	8093	7703	0	0	2	#2 UNIT GENERATION SERVICES	TURB/GEN COOLING SYSTEM	TURB/GEN COOLING SYSTEM	Inspect Heat exchanger	2011	2	$6	$0.0	$6.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1296	7635	8093	271486	0	0	2	#2 UNIT GENERATION SERVICES	CW SYSTEM	CW SYSTEM	Inspect Concrete Pipe to/from pump to condenser	2011	2	$6	$0.0	$6.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1296	7635	8093	271486	0	0	2	#2 UNIT GENERATION SERVICES	CW SYSTEM	CW SYSTEM	Test steel Pipe to/from condenser	2011	3	$6	$0.0	$6.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1296	7635	8093	271486	8095	0	2	#2 UNIT GENERATION SERVICES	CW SYSTEM	C.W. INTAKE SYSTEM	Inspect CW intake structures and piping	2011	2	$30	$0.0	$29.9	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1296	7635	8093	271486	8120	0	2	#2 UNIT GENERATION SERVICES	CW SYSTEM	C.W. DISCHARGE TO OUTFALL	Inspection CW discharge structures and piping	2011	2	$30	$0.0	$29.9	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1296	7635	8152	8153	0	0	2	#2 ELECTRICAL & CONTROLS SYS	GEN. BUS DUCTS & CONN'S	GEN. BUS DUCTS & CONN'S	Inspect Generator Bus-Duct and Connections	2011	1	$15	$0.0	$15.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1296	7635	8152	271476	0	0	2	#2 ELECTRICAL & CONTROLS SYS	CONTROL CABLES	CONTROL CABLES	Test Control Cables	2011	3	$7	$0.0	$7.5	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1296	7635	8152	271477	0	0	2	#2 ELECTRICAL & CONTROLS SYS	POWER CABLES	POWER CABLES	Test Power Cables	2011	3	$10	$0.0	$10.5	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0

	Total	2010	2011	2012	2013	2014	2015	2016	2017
Total	$7,158	$0	$817	$0	$1,929	$4,412	$0	$0	$0
Stm Turb	$2,620	$0	$169	$0	$0	$2,451	$0	$0	$0
Blr Stm	$1,929	$0	$0	$0	$1,929	$0	$0	$0	$0
Switchy & TS	$0	$0	$0	$0	$0	$0	$0	$0	$0
GTG	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Excl Stm Turb	$4,538	$0	$648	$0	$1,929	$1,961	$0	$0	$0
Total Excl Blr Stm, Stm Turb	$2,609	$0	$648	$0	$0	$1,961	$0	$0	$0
Total Excl Blr Stm, Stm Turb, Switchy & TS	$2,609	$0	$648	$0	$0	$1,961	$0	$0	$0
Total Excl Blr Stm, Stm Turb, Switchy & TS, GTG	$2,609	$0	$648	$0	$0	$1,961	$0	$0	$0

12.2.3 Level 2 Activities – Unit 3

Table 12-5 is a summary of the Level 2 costs identified in Chapter 10 for Unit 3. Charts show both costs broken down into its sub-categories and by year.

TABLE 12-5 LEVEL 2 ACTIVITIES SUMMARY – UNIT 3

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Sub System Comment	Year	Priority	Cost k$	Base NDE + AMEC Directs	Scaffold/Infrast	HTGS Costs	OEM Supp	PM NDE	Software Check	Mob & Demob	Fit for Serv Rep	Sub-Total	Conting	Total 2010	Escal	Total Esc $
1296	8193	0	0	0	0	3	UNIT 3																			
1296	8193	8194	8223	0	0	3	TURBINE CONDENSER SYSTEM	TURBINE CONDENSER SYSTEM	TURBINE CONDENSER SYSTEM	Inspection	2011	2	$6	$4	$0.2	$0.2	$0.1	$0.2	$0.0	$0.1	$0.0	$4.8	$1.0	$5.8	$0.2	$6.0
1296	8193	8194	8298	0	0	3	U3 GENERATOR	GENERATOR	GENERATOR	2011 Pre-Outage Inspection Work Allowance	2011	1	$100	$67	$3.4	$2.7	$2.0	$4.0	$0.0	$2.0	$0.0	$81.1	$16.2	$97.3	$2.9	$100.2
1296	8193	8194	8298	0	0	3	U3 GENERATOR	GENERATOR	GENERATOR	Outage/Inspection	2016	1	$2,081	$1,200	$60.0	$48.0	$36.0	$72.0	$0.0	$36.0	$0.0	$1,452.0	$290.4	$1,742.4	$338.1	$2,080.5
1296	8193	8194	271675	0	0	3	U3 GENERATOR	TURBINE	TURBINE	Outage/Inspection	2016	1	$2,601	$1,500	$75.0	$60.0	$45.0	$90.0	$0.0	$45.0	$0.0	$1,815.0	$363.0	$2,178.0	$422.6	$2,600.6
1296	8193	8194	271675	8196	0	3	U3 GENERATOR	TURBINE	TURBINE MAIN STEAM CHEST	Vlve/Stud Check	2011	1	$22	$15	$0.8	$0.6	$0.5	$0.9	$0.0	$0.5	$0.0	$18.2	$3.6	$21.8	$0.7	$22.4
1296	8193	8194	271675	8201	0	3	U3 GENERATOR	TURBINE	H.P. TURBINE	Vlve/Stud Check	2011	1	$6	$4	$0.2	$0.2	$0.1	$0.2	$0.0	$0.1	$0.0	$4.8	$1.0	$5.8	$0.2	$6.0
1296	8193	8194	271675	8201	0	3	U3 GENERATOR	TURBINE	H.P. TURBINE	Vlve/Stud Check	2011	1	$6	$4	$0.2	$0.2	$0.1	$0.2	$0.0	$0.1	$0.0	$4.8	$1.0	$5.8	$0.2	$6.0
1296	8193	8194	271675	8206	0	3	U3 GENERATOR	TURBINE	TURB REHEAT/IP STEAM CHEST	Vlve/Stud Check	2011	1	$6	$4	$0.2	$0.2	$0.1	$0.2	$0.0	$0.1	$0.0	$4.8	$1.0	$5.8	$0.2	$6.0
1296	8193	8194	271675	8211	0	3	U3 GENERATOR	TURBINE	I.P. TURBINE	Vlve/Stud Check	2011	1	$6	$4	$0.2	$0.2	$0.1	$0.2	$0.0	$0.1	$0.0	$4.8	$1.0	$5.8	$0.2	$6.0
1296	8193	8194	271675	8270	8275	3	U3 GENERATOR	TURBINE	TURB LUBE OIL TANK & EQUIP	Thickness/Integrity	2011	2	$6	$4	$0.2	$0.2	$0.1	$0.2	$0.0	$0.1	$0.0	$4.8	$1.0	$5.8	$0.2	$6.0
1296	8193	8336	0	0	0	3	BOILER PLANT	BOILER PLANT	BOILER PLANT	Outage/Inspection	2014	1	$1,520	$930	$46.5	$37.2	$27.9	$55.8	$0.0	$27.9	$0.0	$1,125.3	$225.1	$1,350.4	$169.5	$1,519.8
1296	8193	8336	8337	0	0	3	BOILER PLANT	BOILER STRUCTURE	BOILER STRUCTURE	Visual Inspion	2011	2	$3	$2	$0.1	$0.1	$0.1	$0.1	$0.0	$0.1	$0.0	$2.4	$0.5	$2.9	$0.1	$3.0
1296	8193	8336	8359	8372	0	3	BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER MAIN STEAM LINES	(Testing of Main Steam , Hot Reheat, Cold Reheat, HP feedwater	2012	1	$407	$264	$13.2	$10.6	$7.9	$15.8	$0.0	$7.9	$0.0	$319.4	$63.9	$383.3	$23.3	$406.7
1296	8193	8336	8359	8372	8373	3	BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER STOP VALVE	Inspection/NDE Test	2012	1	$31	$20	$1.0	$0.8	$0.6	$1.2	$0.0	$0.6	$0.0	$24.2	$4.8	$29.0	$1.8	$30.8
1296	8193	8528	8546	0	0	3	CONDENSATE & F.W. SYSTEM	LOW PRESSURE FEEDWATER	LOW PRESSURE FEEDWATER	Inspection/NDE Test	2011	3	$105	$70	$3.5	$2.8	$2.1	$4.2	$0.0	$2.1	$0.0	$84.7	$16.9	$101.6	$3.0	$104.7

Table 12-5 Cont'd

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Sub System Comment	Year	Priority	Cost k$	Base NDE + AMEC Directs	Scaffold/Infrast	HTGS Costs	OEM Supp	PM NDE	Software Check	Mob & Demob	Fit for Serv Rep	Sub-Total	Conting	Total 2010	Escal	Total Esc $
1296	8193	0	0	0	0	3	UNIT 3																			
1296	8193	8528	8546	8571	0	3	CONDENSATE & F.W. SYSTEM	LOW PRESSURE FEEDWATER	DEAERATOR SYSTEM	Inspection/NDE Test	2014	2	$229	$140	$7.0	$5.6	$4.2	$8.4	$0.0	$4.2	$0.0	$169.4	$33.9	$203.3	$25.5	$228.8
1296	8193	8528	8611	0	0	3	CONDENSATE & F.W. SYSTEM	H.P. FEEDWATER SYSTEM	H.P. FEEDWATER SYSTEM	Inspection/NDE Test	2014	1	$239	$146	$7.3	$5.8	$4.4	$8.8	$0.0	$4.4	$0.0	$176.7	$35.3	$212.0	$26.6	$238.6
1296	8193	8645	8262	0	0	3	UNIT GENERATION SERVICES	TURB/GEN WATER COOLING SYS	TURB/GEN WATER COOLING SYS	Test seawater intake and discharge piping	2011	2	$6	$4	$0.2	$0.2	$0.1	$0.2	$0.0	$0.1	$0.0	$4.8	$1.0	$5.8	$0.2	$6.0
1296	8193	8645	8262	0	0	3	UNIT GENERATION SERVICES	TURB/GEN WATER COOLING SYS	TURB/GEN WATER COOLING SYS	Test AC Water piping thickness	2011	2	$6	$4	$0.2	$0.2	$0.1	$0.2	$0.0	$0.1	$0.0	$4.8	$1.0	$5.8	$0.2	$6.0
1296	8193	8645	8262	0	0	3	UNIT GENERATION SERVICES	TURB/GEN WATER COOLING SYS	TURB/GEN WATER COOLING SYS	Inspect Heat exchanger	2011	2	$6	$4	$0.2	$0.2	$0.1	$0.2	$0.0	$0.1	$0.0	$4.8	$1.0	$5.8	$0.2	$6.0
1296	8193	8645	271678	0	0	3	UNIT GENERATION SERVICES	CW SYSTEM	CW SYSTEM	Inspect Concrete Pipe to/from pump to condenser	2011	2	$6	$4	$0.2	$0.2	$0.1	$0.2	$0.0	$0.1	$0.0	$4.8	$1.0	$5.8	$0.2	$6.0
1296	8193	8645	271678	8647	0	3	UNIT GENERATION SERVICES	CW SYSTEM	C.W. INTAKE SYSTEM	Inspect CW intake structures and piping	2011	2	$30	$20	$1.0	$0.8	$0.6	$1.2	$0.0	$0.6	$0.0	$24.2	$4.8	$29.0	$0.9	$29.9
1296	8193	8645	271678	8676	0	3	UNIT GENERATION SERVICES	CW SYSTEM	C.W. DISCHARGE TO OUTFALL	Inspection CW discharge structures and piping	2011	2	$30	$20	$1.0	$0.8	$0.6	$1.2	$0.0	$0.6	$0.0	$24.2	$4.8	$29.0	$0.9	$29.9
1296	8193	8712	8713	0	0	3	ELECTRICAL SYSTEM & CONTROL	GENERATOR BUS DUCT & CONN'S	GENERATOR BUS DUCT & CONN'S	Inspect Generator Bus-Duct and Connections	2011	1	$15	$10	$0.5	$0.4	$0.3	$0.6	$0.0	$0.3	$0.0	$12.1	$2.4	$14.5	$0.4	$15.0
1296	8193	8712	271764	0	0	3	ELECTRICAL SYSTEM & CONTROL	CONTROL CABLES	CONTROL CABLES	Test Control Cables	2011	3	$7	$5	$0.3	$0.2	$0.2	$0.3	$0.0	$0.2	$0.0	$6.1	$1.2	$7.3	$0.2	$7.5
1296	8193	8712	271765	0	0	3	ELECTRICAL SYSTEM & CONTROL	POWER CABLES	POWER CABLES	Test Power Cables	2011	3	$10	$7	$0.4	$0.3	$0.2	$0.4	$0.0	$0.2	$0.0	$8.5	$1.7	$10.2	$0.3	$10.5
											Total		$7,489	$4,456	$223	$178	$134	$267	$0	$134	$0	$5,392	$1,078	$6,470	$1,019	$7,489
											Stm Turb		$2,659	$1,539	$77	$62	$46	$92	$0	$46	$0	$1,862	$372	$2,235	$424	$2,659
											Blr Stm		$2,014	$1,234	$62	$49	$37	$74	$0	$37	$0	$1,493	$299	$1,792	$222	$2,014
											Switchy & TS		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
											GTG		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
											Total Excl Stm Turb		$4,830	$2,917	$146	$117	$88	$175	$0	$88	$0	$3,530	$706	$4,235	$594	$4,830
											Total Excl Blr Stm, Stm Turb		$2,816	$1,683	$84	$67	$50	$101	$0	$50	$0	$2,036	$407	$2,444	$372	$2,816
											Total Excl Blr Stm, Stm Turb, Switchy & TS		$2,816	$1,683	$84	$67	$50	$101	$0	$50	$0	$2,036	$407	$2,444	$372	$2,816
											Total Excl Blr Stm, Stm Turb, Switchy & TS, GTG		$2,816	$1,683	$84	$67	$50	$101	$0	$50	$0	$2,036	$407	$2,444	$372	$2,816

Table 12-5 Cont'd

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Sub System Comment	Year	Priority	Cost k$	2010	2011	2012	2013	2014	2015	2016	2017
1296	8193	0	0	0	0	3	UNIT 3														
1296	8193	8194	8223	0	0	3	TURBINE CONDENSER SYSTEM	TURBINE CONDENSER SYSTEM	TURBINE CONDENSER SYSTEM	Inspection	2011	2	$6	$0.0	$6.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1296	8193	8194	8298	0	0	3	U3 GENERATOR	GENERATOR	GENERATOR	2011 Pre-Outage Inspection Work Allowance	2011	1	$100	$0.0	$100.2	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1296	8193	8194	8298	0	0	3	U3 GENERATOR	GENERATOR	GENERATOR	Outage/Inspection	2016	1	$2,081	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$2,080.5	$0.0
1296	8193	8194	271675	0	0	3	U3 GENERATOR	TURBINE	TURBINE	Outage/Inspection	2016	1	$2,601	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$2,600.6	$0.0
1296	8193	8194	271675	8196	0	3	U3 GENERATOR	TURBINE	TURBINE MAIN STEAM CHEST	Vlve/Stud Check	2011	1	$22	$0.0	$22.4	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1296	8193	8194	271675	8201	0	3	U3 GENERATOR	TURBINE	H.P. TURBINE	Vlve/Stud Check	2011	1	$6	$0.0	$6.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1296	8193	8194	271675	8201	0	3	U3 GENERATOR	TURBINE	H.P. TURBINE	Vlve/Stud Check	2011	1	$6	$0.0	$6.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1296	8193	8194	271675	8206	0	3	U3 GENERATOR	TURBINE	TURB REHEAT/IP STEAM CHEST	Vlve/Stud Check	2011	1	$6	$0.0	$6.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1296	8193	8194	271675	8211	0	3	U3 GENERATOR	TURBINE	I.P. TURBINE	Vlve/Stud Check	2011	1	$6	$0.0	$6.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1296	8193	8194	271675	8270	8275	3	U3 GENERATOR	TURBINE	TURB LUBE OIL TANK & EQUIP	Thickness/Integrity	2011	2	$6	$0.0	$6.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1296	8193	8336	0	0	0	3	BOILER PLANT	BOILER PLANT	BOILER PLANT	Outage/Inspection	2014	1	$1,520	$0.0	$0.0	$0.0	$0.0	$1,519.8	$0.0	$0.0	$0.0
1296	8193	8336	8337	0	0	3	BOILER PLANT	BOILER STRUCTURE	BOILER STRUCTURE	Visual Inspion	2011	2	$3	$0.0	$3.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1296	8193	8336	8359	8372	0	3	BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER MAIN STEAM LINES	(Testing of Main Steam , Hot Reheat, Cold Reheat, HP feedwater	2012	1	$407	$0.0	$0.0	$406.7	$0.0	$0.0	$0.0	$0.0	$0.0
1296	8193	8336	8359	8372	8373	3	BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER STOP VALVE	Inspection/NDE Test	2012	1	$31	$0.0	$0.0	$30.8	$0.0	$0.0	$0.0	$0.0	$0.0
1296	8193	8528	8546	0	0	3	CONDENSATE & F.W. SYSTEM	LOW PRESSURE FEEDWATER	LOW PRESSURE FEEDWATER	Inspection/NDE Test	2011	3	$105	$0.0	$104.7	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0

Table 12-5 Cont'd

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Sub System Comment	Year	Priority	Cost k$	2010	2011	2012	2013	2014	2015	2016	2017
1296	8193	0	0	0	0	3	UNIT 3														
1296	8193	8528	8546	8571	0	3	CONDENSATE & F.W. SYSTEM	LOW PRESSURE FEEDWATER	DEAERATOR SYSTEM	Inspection/NDE Test	2014	2	$229	$0.0	$0.0	$0.0	$0.0	$228.8	$0.0	$0.0	$0.0
1296	8193	8528	8611	0	0	3	CONDENSATE & F.W. SYSTEM	H.P. FEEDWATER SYSTEM	H.P. FEEDWATER SYSTEM	Inspection/NDE Test	2014	1	$239	$0.0	$0.0	$0.0	$0.0	$238.6	$0.0	$0.0	$0.0
1296	8193	8645	8262	0	0	3	UNIT GENERATION SERVICES	TURB/GEN WATER COOLING SYS	TURB/GEN WATER COOLING SYS	Test seawater intake and discharge piping	2011	2	$6	$0.0	$6.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1296	8193	8645	8262	0	0	3	UNIT GENERATION SERVICES	TURB/GEN WATER COOLING SYS	TURB/GEN WATER COOLING SYS	Test AC Water piping thickness	2011	2	$6	$0.0	$6.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1296	8193	8645	8262	0	0	3	UNIT GENERATION SERVICES	TURB/GEN WATER COOLING SYS	TURB/GEN WATER COOLING SYS	Inspect Heat exchanger	2011	2	$6	$0.0	$6.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1296	8193	8645	271678	0	0	3	UNIT GENERATION SERVICES	CW SYSTEM	CW SYSTEM	Inspect Concrete Pipe to/from pump to condenser	2011	2	$6	$0.0	$6.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1296	8193	8645	271678	8647	0	3	UNIT GENERATION SERVICES	CW SYSTEM	C.W. INTAKE SYSTEM	Inspect CW intake structures and piping	2011	2	$30	$0.0	$29.9	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1296	8193	8645	271678	8676	0	3	UNIT GENERATION SERVICES	CW SYSTEM	C.W. DISCHARGE TO OUTFALL	Inspection CW discharge structures and piping	2011	2	$30	$0.0	$29.9	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1296	8193	8712	8713	0	0	3	ELECTRICAL SYSTEM & CONTROL	GENERATOR BUS DUCT & CONN'S	GENERATOR BUS DUCT & CONN'S	Inspect Generator Bus-Duct and Connections	2011	1	$15	$0.0	$15.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1296	8193	8712	271764	0	0	3	ELECTRICAL SYSTEM & CONTROL	CONTROL CABLES	CONTROL CABLES	Test Control Cables	2011	3	$7	$0.0	$7.5	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1296	8193	8712	271765	0	0	3	ELECTRICAL SYSTEM & CONTROL	POWER CABLES	POWER CABLES	Test Power Cables	2011	3	$10	$0.0	$10.5	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
											Total		$7,489	$0	$383	$437	$0	$1,987	$0	$4,681	$0
											Stm Turb		$2,659	$0	$58	$0	$0	$0	$0	$2,601	$0
											Blr Stm		$2,014	$0	$27	$0	$0	$1,987	$0	$0	$0
											Switchy & TS		$0	$0	$0	$0	$0	$0	$0	$0	$0
											GTG		$0	$0	$0	$0	$0	$0	$0	$0	$0
											Total Excl Stm Turb		$4,830	$0	$325	$437	$0	$1,987	$0	$2,081	$0
											Total Excl Blr Stm, Stm Turb		$2,816	$0	$298	$437	$0	$0	$0	$2,081	$0
											Total Excl Blr Stm, Stm Turb, Switchy & TS		$2,816	$0	$298	$437	$0	$0	$0	$2,081	$0
											Total Excl Blr Stm, Stm Turb, Switchy & TS, GTG		$2,816	$0	$298	$437	$0	$0	$0	$2,081	$0

12.2.4 Level 2 Activities – Common Facilities

Table 12-6 is a summary of the Level 2 costs identified in Chapter 11 for Common Facilities. Charts show both costs broken down into its sub-categories and by year.

TABLE 12-6 LEVEL 2 ACTIVITIES SUMMARY – COMMON FACILITIES

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset 2/3	Asset 3/4	Description	Sub System Comment	Year	Priority	Cost	Base NDE + AMEC Directs	Scaffold/Infrast	HTGS Costs	OEM Supp	PM NDE	Software Check	Mob & Demob	Fit for Serv Rep	Sub-Total	Conting	Total 2010	Escal	Total Esc $
1297	7199	0	0	COMMON SYSTEMS	COMMON SYSTEMS																		
1297	7199	7192	0	COMMON SYSTEMS	POWER CENTER C	POWER CENTER C	Inspect E&C Systems	2011	2	$75	$50	$2.5	$2.0	$1.5	$3.0	$0.0	$1.5	$0.0	$60.5	$12.1	$72.6	$2.2	$74.8
1297	7199	7204	7223	COMMON SYSTEMS	HEAVY OIL & FUEL ADDITIVE	HEAVY OIL TRANSFER TO STORAGE	Redesign electric heat trace	2010	1	$73	$50	$2.5	$2.0	$1.5	$3.0	$0.0	$1.5	$0.0	$60.5	$12.1	$72.6	$0.0	$72.6
1297	7199	7204	7224	COMMON SYSTEMS	HEAVY OIL & FUEL ADDITIVE	HEAVY OIL STORAGE & PIPING	Inspect day tank, light oil tanks, and associated systems	2011	1	$37	$25	$1.3	$1.0	$0.8	$1.5	$0.0	$0.8	$0.0	$30.3	$6.1	$36.3	$1.1	$37.4
1297	7199	7206	0	COMMON SYSTEMS	GAS STORAGE SYSTEMS	GAS STORAGE SYSTEMS	Hydrogen, Carbon dioxide, and Nitrogen piping thickness sampling	2011	1	$15	$10	$0.5	$0.4	$0.3	$0.6	$0.0	$0.3	$0.0	$12.1	$2.4	$14.5	$0.4	$15.0
1297	7255	272255	7283	BUILDINGS AND SITE	BUILDINGS	MAIN POWERHOUSE	Structural walkdown checkPowerhouse	2014	3	$5	$3	$0.2	$0.1	$0.1	$0.2	$0.0	$0.1	$0.0	$3.6	$0.7	$4.4	$0.5	$4.9
1297	7255	272255	7285	BUILDINGS AND SITE	BUILDINGS	STAGE 1 PUMPHOUSE	Concrete Testing and stoplog structure inspection	2011	2	$15	$10	$0.5	$0.4	$0.3	$0.6	$0.0	$0.3	$0.0	$12.1	$2.4	$14.5	$0.4	$15.0
1297	7255	272255	7286	BUILDINGS AND SITE	BUILDINGS	STAGE 2 PUMPHOUSE	Concrete Testing and stoplog structure inspection	2011	2	$15	$10	$0.5	$0.4	$0.3	$0.6	$0.0	$0.3	$0.0	$12.1	$2.4	$14.5	$0.4	$15.0
1297	7255	272255	7305	BUILDINGS AND SITE	BUILDINGS	WWT BASINS BUILDING	Structural and concrete testing building	2011	3	$37	$25	$1.3	$1.0	$0.8	$1.5	$0.0	$0.8	$0.0	$30.3	$6.1	$36.3	$1.1	$37.4
1297	9739	7203	7210	WATER TREATMENT &ENVIRONMT	WATER TREATMENT PLANT	RAW WATER SYSTEM	Inspect pipeline	2011	1	$37	$25	$1.3	$1.0	$0.8	$1.5	$0.0	$0.8	$0.0	$30.3	$6.1	$36.3	$1.1	$37.4
1297	9739	7203	7210	WATER TREATMENT &ENVIRONMT	WATER TREATMENT PLANT	QUARRY BROOK DAM & FISHWAY SYS	Inspect dam	2011	1	$22	$15	$0.8	$0.6	$0.5	$0.9	$0.0	$0.5	$0.0	$18.2	$3.6	$21.8	$0.7	$22.4
1297	9739	7203	286053	WATER TREATMENT &ENVIRONMT	WATER TREATMENT PLANT	#1 CONDENSATE POLISHER PLANT	Inspect/test ploisher	2011	1	$30	$20	$1.0	$0.8	$0.6	$1.2	$0.0	$0.6	$0.0	$24.2	$4.8	$29.0	$0.9	$29.9

Table 12-6 Cont'd

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset 2/3	Asset 3/4	Description	Sub System Comment	Year	Priority	Cost	Base NDE + AMEC Directs	Scaffold/Infrast	HTGS Costs	OEM Supp	PM NDE	Software Check	Mob & Demob	Fit for Serv Rep	Sub-Total	Conting	Total 2010	Escal	Total Esc $
1297	7199	0	0	COMMON SYSTEMS	COMMON SYSTEMS																		
1297	9739	7203	286053	WATER TREATMENT &ENVIRONMT	WATER TREATMENT PLANT	#2 CONDENSATE POLISHER PLANT	Inspect/test ploisher	2011	1	$30	$20	$1.0	$0.8	$0.6	$1.2	$0.0	$0.6	$0.0	$24.2	$4.8	$29.0	$0.9	$29.9
1297	9739	7203	286053	WATER TREATMENT &ENVIRONMT	WATER TREATMENT PLANT	#3 CONDENSATE POLISHER PLANT	Inspect/test ploisher	2011	1	$30	$20	$1.0	$0.8	$0.6	$1.2	$0.0	$0.6	$0.0	$24.2	$4.8	$29.0	$0.9	$29.9
1297	9739	7203	286057	WATER TREATMENT &ENVIRONMT	WATER TREATMENT PLANT	WATER TREATMENT PLANT SYSTEMS	Inspect Clarifier, Sand Filters, Clearwell	2011	1	$75	$50	$2.5	$2.0	$1.5	$3.0	$0.0	$1.5	$0.0	$60.5	$12.1	$72.6	$2.2	$74.8
1297	9739	7203	286057	WATER TREATMENT &ENVIRONMT	WATER TREATMENT PLANT	W.T.P. SULFURIC ACID SYSTEM	Inspect/clean Acid & Caustic Tanks	2011	2	$15	$10	$0.5	$0.4	$0.3	$0.6	$0.0	$0.3	$0.0	$12.1	$2.4	$14.5	$0.4	$15.0
1297	9739	10038	7263	WATER TREATMENT &ENVIRONMT	WASTE WATER TREATMNT SYSTM	OIL/WATER SEPARATORS	Inspect Oil Water Separators	2011	2	$75	$50	$2.5	$2.0	$1.5	$3.0	$0.0	$1.5	$0.0	$60.5	$12.1	$72.6	$2.2	$74.8
1297	9739	10038	7263	WATER TREATMENT &ENVIRONMT	WASTE WATER TREATMNT SYSTM	OIL/WATER SEPARATORS	Check Oily Water & Discharge Pipes	2011	2	$15	$10	$0.5	$0.4	$0.3	$0.6	$0.0	$0.3	$0.0	$12.1	$2.4	$14.5	$0.4	$15.0
1297	9739	10038	99003527	WATER TREATMENT &ENVIRONMT	WASTE WATER TREATMNT SYSTM	CONCRETE BASINS FOR W.W.T.S.	Concrete testing basin tanks	2011	3	$18	$12	$0.6	$0.5	$0.4	$0.7	$0.0	$0.4	$0.0	$14.5	$2.9	$17.4	$0.5	$17.9
1325	5975	5975	303236	HRDTS	TRANSFORMERS	T1 Power Transformer	Elect Test & insp	2014	1	$18	$11	$0.6	$0.4	$0.3	$0.7	$0.0	$0.3	$0.0	$13.3	$2.7	$16.0	$2.0	$18.0
1325	5976	5976	61-00-69225	HRDTS	TRANSFORMERS	T2 Power Transformer	Elect Test & insp	2013	1	$18	$12	$0.6	$0.5	$0.3	$0.7	$0.0	$0.3	$0.0	$13.9	$2.8	$16.7	$1.5	$18.2
1325	5977	5977	287198	HRDTS	TRANSFORMERS	T3 Power Transformer	Elect Test & insp	2016	1	$6	$4	$0.2	$0.1	$0.1	$0.2	$0.0	$0.1	$0.0	$4.2	$0.8	$5.1	$1.0	$6.1
1325	5978	5978	287199	HRDTS	TRANSFORMERS	Transformer T4 (spare)	Elect Test & insp	2011	1	$6	$4	$0.2	$0.2	$0.1	$0.2	$0.0	$0.1	$0.0	$4.8	$1.0	$5.8	$0.2	$6.0
1325	5979	5979	A-3-S-7520	HRDTS	TRANSFORMERS	Transformer T5	Elect Test & insp	2015	1	$7	$4	$0.2	$0.2	$0.1	$0.2	$0.0	$0.1	$0.0	$4.8	$1.0	$5.8	$0.9	$6.7
1325	5980	5980	287065	HRDTS	TRANSFORMERS	Transformer T6	Elect Test & insp	2013	1	$6	$4	$0.2	$0.2	$0.1	$0.2	$0.0	$0.1	$0.0	$4.8	$1.0	$5.8	$0.5	$6.3
1325	5981	5981	287064	HRDTS	TRANSFORMERS	Transformer T7	Elect Test & insp	2013	1	$6	$4	$0.2	$0.2	$0.1	$0.2	$0.0	$0.1	$0.0	$4.8	$1.0	$5.8	$0.5	$6.3
1325	5982	5982	61-00-68928	HRDTS	TRANSFORMERS	Transformer T8	Elect Test & insp	2014	1	$7	$4	$0.2	$0.2	$0.1	$0.2	$0.0	$0.1	$0.0	$4.8	$1.0	$5.8	$0.7	$6.5
1325	5983	5983	61-00-69576	HRDTS	TRANSFORMERS	Transformer T9	Elect Test & insp	2012	1	$6	$4	$0.2	$0.2	$0.1	$0.2	$0.0	$0.1	$0.0	$4.8	$1.0	$5.8	$0.4	$6.2
1325	5984	5984	61-00-69576	HRDTS	TRANSFORMERS	Transformer T10	Elect Test & insp	2012	1	$6	$4	$0.2	$0.2	$0.1	$0.2	$0.0	$0.1	$0.0	$4.8	$1.0	$5.8	$0.4	$6.2
1325	991000	991100	991110	SWITCHYARD	TRANSFORMERS	Service Power System, UST-1 Transformer	Elect Test & insp	2010	1	$6	$4	$0.2	$0.2	$0.1	$0.2	$0.0	$0.1	$0.0	$4.8	$1.0	$5.8	$0.0	$5.8
1325	991000	991100	991110	SWITCHYARD	TRANSFORMERS	Service Power System, UST-2 Transformer	Elect Test & insp	2013	1	$6	$4	$0.2	$0.2	$0.1	$0.2	$0.0	$0.1	$0.0	$4.8	$1.0	$5.8	$0.5	$6.3
1325	991000	991100	991110	SWITCHYARD	TRANSFORMERS	Unit Service Power System, UST-3 Transformer	Elect Test & insp	2013	1	$6	$4	$0.2	$0.2	$0.1	$0.2	$0.0	$0.1	$0.0	$4.8	$1.0	$5.8	$0.5	$6.3
1325	5988	5988	WT-1976-1	HRDTS	TRANSFORMERS	Stage 1, Station Service Power. SST-12 Trans.	Elect Test & insp	2015	1	$7	$4	$0.2	$0.2	$0.1	$0.2	$0.0	$0.1	$0.0	$4.8	$1.0	$5.8	$0.9	$6.7
1325	5989	5989	A-3-S-7608	HRDTS	TRANSFORMERS	Stage 2, Station Service Power, SST-34 Trans.	Elect Test & insp	2012	1	$6	$4	$0.2	$0.2	$0.1	$0.2	$0.0	$0.1	$0.0	$4.8	$1.0	$5.8	$0.4	$6.2

Table 12-6 Cont'd

Newfoundland and Labrador Hydro a NALCOR Energy Co.
Holyrood Thermal Generating Station
Condition Assessment & Life Extension Study

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset 2/3	Asset 3/4	Description	Sub System Comment	Year	Priority	Cost	Base NDE + AMEC Directs	Scaffold/Infrast	HTGS Costs	OEM Supp	PM NDE	Software Check	Mob & Demob	Fit for Serv Rep	Sub-Total	Conting	Total 2010	Escal	Total Esc $
1297	7199	0	0	COMMON SYSTEMS	COMMON SYSTEMS																		
1325	6016	6016	991110	HRDTS	TRANSFORMERS	T1 Power Transformer	Gas in Oil test & checks	2010	1	$17	$12	$0.6	$0.5	$0.4	$0.7	$0.0	$0.4	$0.0	$15	$2.9	$17	$0.0	$17.4
1325	6017	6017	991110	HRDTS	TRANSFORMERS	T2 Power Transformer	Gas in Oil test & checks	2010	1	$17	$12	$0.6	$0.5	$0.4	$0.7	$0.0	$0.4	$0.0	$15	$2.9	$17	$0.0	$17.4
1325	6018	6018	991110	HRDTS	TRANSFORMERS	T3 Power Transformer	Gas in Oil test & checks	2010	1	$6	$4	$0.2	$0.2	$0.1	$0.2	$0.0	$0.1	$0.0	$5	$1.0	$6	$0.0	$5.8
1325	6019	6019	991110	HRDTS	TRANSFORMERS	Transformer T4 (spare)	Gas in Oil test & checks	2010	1	$6	$4	$0.2	$0.2	$0.1	$0.2	$0.0	$0.1	$0.0	$4.8	$1.0	$5.8	$0.0	$5.8
1325	6020	6020	991110	HRDTS	TRANSFORMERS	Transformer T5	Gas in Oil test & checks	2010	1	$6	$4	$0.2	$0.2	$0.1	$0.2	$0.0	$0.1	$0.0	$4.8	$1.0	$5.8	$0.0	$5.8
1325	6021	6021	991110	HRDTS	TRANSFORMERS	Transformer T6	Gas in Oil test & checks	2010	1	$6	$4	$0.2	$0.2	$0.1	$0.2	$0.0	$0.1	$0.0	$4.8	$1.0	$5.8	$0.0	$5.8
1325	6022	6022	991110	HRDTS	TRANSFORMERS	Transformer T7	Gas in Oil test & checks	2010	1	$6	$4	$0.2	$0.2	$0.1	$0.2	$0.0	$0.1	$0.0	$4.8	$1.0	$5.8	$0.0	$5.8
1325	6023	6023	991110	HRDTS	TRANSFORMERS	Transformer T8	Gas in Oil test & checks	2010	1	$6	$4	$0.2	$0.2	$0.1	$0.2	$0.0	$0.1	$0.0	$4.8	$1.0	$5.8	$0.0	$5.8
1325	6024	6024	991110	HRDTS	TRANSFORMERS	Transformer T9	Gas in Oil test & checks	2010	1	$6	$4	$0.2	$0.2	$0.1	$0.2	$0.0	$0.1	$0.0	$4.8	$1.0	$5.8	$0.0	$5.8
1325	6025	6025	991110	HRDTS	TRANSFORMERS	Transformer T10	Gas in Oil test & checks	2010	1	$6	$4	$0.2	$0.2	$0.1	$0.2	$0.0	$0.1	$0.0	$4.8	$1.0	$5.8	$0.0	$5.8
1325	6026	6026	991110	HRDTS	TRANSFORMERS	Service Power System, UST-1 Transformer	Gas in Oil test & checks	2010	1	$6	$4	$0.2	$0.2	$0.1	$0.2	$0.0	$0.1	$0.0	$4.8	$1.0	$5.8	$0.0	$5.8
1325	6027	6027	991110	HRDTS	TRANSFORMERS	Service Power System, UST-2 Transformer	Gas in Oil test & checks	2010	1	$6	$4	$0.2	$0.2	$0.1	$0.2	$0.0	$0.1	$0.0	$4.8	$1.0	$5.8	$0.0	$5.8
1325	6028	6028	991110	HRDTS	TRANSFORMERS	Unit Service Power System, UST-3 Transformer	Gas in Oil test & checks	2010	1	$6	$4	$0.2	$0.2	$0.1	$0.2	$0.0	$0.1	$0.0	$4.8	$1.0	$5.8	$0.0	$5.8
1325	6029	6029	991110	HRDTS	TRANSFORMERS	Stage 1, Station Service Power. SST-12 Trans.	Gas in Oil test & checks	2010	1	$6	$4	$0.2	$0.2	$0.1	$0.2	$0.0	$0.1	$0.0	$4.8	$1.0	$5.8	$0.0	$5.8
1325	6030	6030	991110	HRDTS	TRANSFORMERS	Stage 2, Station Service Power, SST-34 Trans.	Gas in Oil & checks	2010	1	$6	$4	$0.2	$0.2	$0.1	$0.2	$0.0	$0.1	$0.0	$4.8	$1.0	$5.8	$0.0	$5.8

	Total	Base NDE + AMEC Directs	Scaffold/Infrast	HTGS Costs	OEM Supp	PM NDE	Software Check	Mob & Demob	Fit for Serv Rep	Sub-Total	Conting	Total 2010	Escal	Total Esc $
Total	$870	$580	$29	$23	$17	$35	$0	$17	$0	$702	$140	$842	$27	$870
Stm Turb	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Blr Stm	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Switchy & TS	$228	$150	$8	$6	$5	$9	$0	$5	$0	$182	$36	$218	$11	$228
GTG	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Excl Stm Turb	$870	$580	$29	$23	$17	$35	$0	$17	$0	$702	$140	$842	$27	$870
Total Excl Blr Stm, Stm Turb	$870	$580	$29	$23	$17	$35	$0	$17	$0	$702	$140	$842	$27	$870
Total Excl Blr Stm, Stm Turb, Switchy & TS	$641	$430	$22	$17	$13	$26	$0	$13	$0	$520	$104	$624	$17	$641
Total Excl Blr Stm, Stm Turb, Switchy & TS, GTG	$641	$430	$22	$17	$13	$26	$0	$13	$0	$520	$104	$624	$17	$641

Priority 1	$600	$400	$20	$16	$12	$24	$0	$12	$0	$484	$97	$581	$19	$600
Priority 2	$209	$140	$7	$6	$4	$8	$0	$4	$0	$169	$34	$203	$6	$209
Priority 3	$60	$40	$2	$2	$1	$2	$0	$1	$0	$48	$10	$58	$2	$60
Priority 4	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total	$870	$580	$29	$23	$17	$35	$0	$17	$0	$702	$140	$842	$27	$870

Table 12-6 Cont'd

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset 2/3	Asset 3/4	Description	Sub System Comment	Year	Priority	Cost	2010	2011	2012	2013	2014	2015	2016	2017
1297	7199	0	0	COMMON SYSTEMS	COMMON SYSTEMS													
1297	7199	7192	0	COMMON SYSTEMS	POWER CENTER C	POWER CENTER C	Inspect E&C Systems	2011	2	$75	$0.0	$74.8	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1297	7199	7204	7223	COMMON SYSTEMS	HEAVY OIL & FUEL ADDITIVE	HEAVY OIL TRANSFER TO STORAGE	Redesign electric heat trace	2010	1	$73	$72.6	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1297	7199	7204	7224	COMMON SYSTEMS	HEAVY OIL & FUEL ADDITIVE	HEAVY OIL STORAGE & PIPING	Inspect day tank, light oil tanks, and associated systems	2011	1	$37	$0.0	$37.4	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1297	7199	7206	0	COMMON SYSTEMS	GAS STORAGE SYSTEMS	GAS STORAGE SYSTEMS	Hydrogen, Carbon dioxide, and Nitrogen piping thickness sampling	2011	1	$15	$0.0	$15.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1297	7255	272255	7283	BUILDINGS AND SITE	BUILDINGS	MAIN POWERHOUSE	Structural walkdown checkPowerhouse	2014	3	$5	$0.0	$0.0	$0.0	$0.0	$4.9	$0.0	$0.0	$0.0
1297	7255	272255	7285	BUILDINGS AND SITE	BUILDINGS	STAGE 1 PUMPHOUSE	Concrete Testing and stoplog structure inspection	2011	2	$15	$0.0	$15.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1297	7255	272255	7286	BUILDINGS AND SITE	BUILDINGS	STAGE 2 PUMPHOUSE	Concrete Testing and stoplog structure inspection	2011	2	$15	$0.0	$15.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1297	7255	272255	7305	BUILDINGS AND SITE	BUILDINGS	WWT BASINS BUILDING	Structural and concrete testing building	2011	3	$37	$0.0	$37.4	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1297	9739	7203	7210	WATER TREATMENT &ENVIRONMT	WATER TREATMENT PLANT	RAW WATER SYSTEM	Inspect pipeline	2011	1	$37	$0.0	$37.4	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1297	9739	7203	7210	WATER TREATMENT &ENVIRONMT	WATER TREATMENT PLANT	QUARRY BROOK DAM & FISHWAY SYS	Inspect dam	2011	1	$22	$0.0	$22.4	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1297	9739	7203	286053	WATER TREATMENT &ENVIRONMT	WATER TREATMENT PLANT	#1 CONDENSATE POLISHER PLANT	Inspect/test ploisher	2011	1	$30	$0.0	$29.9	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0

Table 12-6 Cont'd

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset 2/3	Asset 3/4	Description	Sub System Comment	Year	Priority	Cost	2010	2011	2012	2013	2014	2015	2016	2017
1297	7199	0	0	COMMON SYSTEMS	COMMON SYSTEMS													
1297	9739	7203	286053	WATER TREATMENT &ENVIRONMT	WATER TREATMENT PLANT	#2 CONDENSATE POLISHER PLANT	Inspect/test ploisher	2011	1	$30	$0.0	$29.9	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1297	9739	7203	286053	WATER TREATMENT &ENVIRONMT	WATER TREATMENT PLANT	#3 CONDENSATE POLISHER PLANT	Inspect/test ploisher	2011	1	$30	$0.0	$29.9	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1297	9739	7203	286057	WATER TREATMENT &ENVIRONMT	WATER TREATMENT PLANT	WATER TREATMENT PLANT SYSTEMS	Inspect Clarifier, Sand Filters, Clearwell	2011	1	$75	$0.0	$74.8	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1297	9739	7203	286057	WATER TREATMENT &ENVIRONMT	WATER TREATMENT PLANT	W.T.P. SULFURIC ACID SYSTEM	Inspect/clean Acid & Caustic Tanks	2011	2	$15	$0.0	$15.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1297	9739	10038	7263	WATER TREATMENT &ENVIRONMT	WASTE WATER TREATMNT SYSTM	OIL/WATER SEPARATORS	Inspect Oil Water Separators	2011	2	$75	$0.0	$74.8	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1297	9739	10038	7263	WATER TREATMENT &ENVIRONMT	WASTE WATER TREATMNT SYSTM	OIL/WATER SEPARATORS	Check Oily Water & Discharge Pipes	2011	2	$15	$0.0	$15.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1297	9739	10038	99003527	WATER TREATMENT &ENVIRONMT	WASTE WATER TREATMNT SYSTM	CONCRETE BASINS FOR W.W.T.S.	Concrete testing basin tanks	2011	3	$18	$0.0	$17.9	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1325	5975	5975	303236	HRDTS	TRANSFORMERS	T1 Power Transformer	Elect Test & insp	2014	1	$18	$0.0	$0.0	$0.0	$0.0	$18.0	$0.0	$0.0	$0.0
1325	5976	5976	61-00-69225	HRDTS	TRANSFORMERS	T2 Power Transformer	Elect Test & insp	2013	1	$18	$0.0	$0.0	$0.0	$18.2	$0.0	$0.0	$0.0	$0.0
1325	5977	5977	287198	HRDTS	TRANSFORMERS	T3 Power Transformer	Elect Test & insp	2016	1	$6	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$6.1	$0.0
1325	5978	5978	287199	HRDTS	TRANSFORMERS	Transformer T4 (spare)	Elect Test & insp	2011	1	$6	$0.0	$6.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1325	5979	5979	A-3-S-7520	HRDTS	TRANSFORMERS	Transformer T5	Elect Test & insp	2015	1	$7	$0.0	$0.0	$0.0	$0.0	$0.0	$6.7	$0.0	$0.0
1325	5980	5980	287065	HRDTS	TRANSFORMERS	Transformer T6	Elect Test & insp	2013	1	$6	$0.0	$0.0	$0.0	$6.3	$0.0	$0.0	$0.0	$0.0
1325	5981	5981	287064	HRDTS	TRANSFORMERS	Transformer T7	Elect Test & insp	2013	1	$6	$0.0	$0.0	$0.0	$6.3	$0.0	$0.0	$0.0	$0.0
1325	5982	5982	61-00-68928	HRDTS	TRANSFORMERS	Transformer T8	Elect Test & insp	2014	1	$7	$0.0	$0.0	$0.0	$0.0	$6.5	$0.0	$0.0	$0.0
1325	5983	5983	61-00-69576	HRDTS	TRANSFORMERS	Transformer T9	Elect Test & insp	2012	1	$6	$0.0	$0.0	$6.2	$0.0	$0.0	$0.0	$0.0	$0.0
1325	5984	5984	61-00-69576	HRDTS	TRANSFORMERS	Transformer T10	Elect Test & insp	2012	1	$6	$0.0	$0.0	$6.2	$0.0	$0.0	$0.0	$0.0	$0.0
1325	991000	991100	991110	SWITCHYARD	TRANSFORMERS	Service Power System, UST-1 Transformer	Elect Test & insp	2010	1	$6	$5.8	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1325	991000	991100	991110	SWITCHYARD	TRANSFORMERS	Service Power System, UST-2 Transformer	Elect Test & insp	2013	1	$6	$0.0	$0.0	$0.0	$6.3	$0.0	$0.0	$0.0	$0.0
1325	991000	991100	991110	SWITCHYARD	TRANSFORMERS	Unit Service Power System, UST-3 Transformer	Elect Test & insp	2013	1	$6	$0.0	$0.0	$0.0	$6.3	$0.0	$0.0	$0.0	$0.0
1325	5988	5988	WT-1976-1	HRDTS	TRANSFORMERS	Stage 1, Station Service Power. SST-12 Trans.	Elect Test & insp	2015	1	$7	$0.0	$0.0	$0.0	$0.0	$0.0	$6.7	$0.0	$0.0
1325	5989	5989	A-3-S-7608	HRDTS	TRANSFORMERS	Stage 2, Station Service Power, SST-34 Trans.	Elect Test & insp	2012	1	$6	$0.0	$0.0	$6.2	$0.0	$0.0	$0.0	$0.0	$0.0

Table 12-6 Cont'd

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset 2/3	Asset 3/4	Description	Sub System Comment	Year	Priority	Cost	2010	2011	2012	2013	2014	2015	2016	2017
1297	7199	0	0	COMMON SYSTEMS	COMMON SYSTEMS													
1325	6016	6016	991110	HRDTS	TRANSFORMERS	T1 Power Transformer	Gas in Oil test & checks	2010	1	$17	$17.4	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1325	6017	6017	991110	HRDTS	TRANSFORMERS	T2 Power Transformer	Gas in Oil test & checks	2010	1	$17	$17.4	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1325	6018	6018	991110	HRDTS	TRANSFORMERS	T3 Power Transformer	Gas in Oil test & checks	2010	1	$6	$5.8	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1325	6019	6019	991110	HRDTS	TRANSFORMERS	Transformer T4 (spare)	Gas in Oil test & checks	2010	1	$6	$5.8	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1325	6020	6020	991110	HRDTS	TRANSFORMERS	Transformer T5	Gas in Oil test & checks	2010	1	$6	$5.8	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1325	6021	6021	991110	HRDTS	TRANSFORMERS	Transformer T6	Gas in Oil test & checks	2010	1	$6	$5.8	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1325	6022	6022	991110	HRDTS	TRANSFORMERS	Transformer T7	Gas in Oil test & checks	2010	1	$6	$5.8	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1325	6023	6023	991110	HRDTS	TRANSFORMERS	Transformer T8	Gas in Oil test & checks	2010	1	$6	$5.8	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1325	6024	6024	991110	HRDTS	TRANSFORMERS	Transformer T9	Gas in Oil test & checks	2010	1	$6	$5.8	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1325	6025	6025	991110	HRDTS	TRANSFORMERS	Transformer T10	Gas in Oil test & checks	2010	1	$6	$5.8	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1325	6026	6026	991110	HRDTS	TRANSFORMERS	Service Power System, UST-1 Transformer	Gas in Oil test & checks	2010	1	$6	$5.8	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1325	6027	6027	991110	HRDTS	TRANSFORMERS	Service Power System, UST-2 Transformer	Gas in Oil test & checks	2010	1	$6	$5.8	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1325	6028	6028	991110	HRDTS	TRANSFORMERS	Unit Service Power System, UST-3 Transformer	Gas in Oil test & checks	2010	1	$6	$5.8	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1325	6029	6029	991110	HRDTS	TRANSFORMERS	Stage 1, Station Service Power. SST-12 Trans.	Gas in Oil test & checks	2010	1	$6	$5.8	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1325	6030	6030	991110	HRDTS	TRANSFORMERS	Stage 2, Station Service Power, SST-34 Trans.	Gas in Oil & checks	2010	1	$6	$5.8	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0

	Total	2010	2011	2012	2013	2014	2015	2016	2017
Total	$870	$189	$570	$18	$44	$29	$13	$6	$0
Stm Turb	$0	$0	$0	$0	$0	$0	$0	$0	$0
Blr Stm	$0	$0	$0	$0	$0	$0	$0	$0	$0
Switchy & TS	$228	$116	$6	$18	$44	$25	$13	$6	$0
GTG	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Excl Stm Turb	$870	$189	$570	$18	$44	$29	$13	$6	$0
Total Excl Blr Stm, Stm Turb	$870	$189	$570	$18	$44	$29	$13	$6	$0
Total Excl Blr Stm, Stm Turb, Switchy & TS	$641	$73	$564	$0	$0	$5	$0	$0	$0
Total Excl Blr Stm, Stm Turb, Switchy & TS, GTG	$641	$73	$564	$0	$0	$5	$0	$0	$0

Priority 1	$600	$189	$305	$18	$44	$25	$13	$6	$0
Priority 2	$209	$0	$209	$0	$0	$0	$0	$0	$0
Priority 3	$60	$0	$55	$0	$0	$5	$0	$0	$0
Priority 4	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total	$870	$189	$570	$18	$44	$29	$13	$6	$0

12.2.5 Level 2 Activities – Gas Turbine Generator

Table 12-7 is a summary of the Level 2 costs identified in Chapter 11 for the Gas Turbine Generator Unit. Charts show both costs broken down into its sub-categories and by year.

TABLE 12-7 LEVEL 2 ACTIVITIES SUMMARY – GAS TURBINE GENERATOR

BU # 1	Asset # 2	Asset 3/4	Description	Level II Work	Year	Priority	Cost k$	Base NDE + AMEC Directs	Scaffold/Infrast	HTGS Costs	OEM Supp	PM NDE	Software Check	Mob & Demob	Fit for Serv Rep	Sub-Total	Conting	Total 2010	Escal	Total Esc $
1273	7202	GAS TURBINE SYSTEM	GAS TURBINE SYSTEM	Options Assessment	2010	1	$73	$50	$3	$2	$2	$3	$0	$2	$0	$61	$12	$73	$0	$73
1273	7202	GAS TURBINE SYSTEM	GAS TURBINE SYSTEM	On-site Non-invasive inspection supplement to planned boroscope tests	2010	1	$131	$90	$5	$4	$3	$5	$0	$3	$0	$109	$22	$131	$0	$131
					Total		$203	$140	$7	$6	$4	$8	$0	$4	$0	$169	$34	$203	$0	$203
					Stm Turb		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
					Blr Stm		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
					Switchy & TS		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
					GTG		$203	$140	$7	$6	$4	$8	$0	$4	$0	$169	$34	$203	$0	$203
					Total Excl Stm Turb		$203	$140	$7	$6	$4	$8	$0	$4	$0	$169	$34	$203	$0	$203
					Total Excl Blr Stm, Stm Turb		$203	$140	$7	$6	$4	$8	$0	$4	$0	$169	$34	$203	$0	$203
					Total Excl Blr Stm, Stm Turb, Switchy & TS		$203	$140	$7	$6	$4	$8	$0	$4	$0	$169	$34	$203	$0	$203
					Total Excl Blr Stm, Stm Turb, Switchy & TS, GTG		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

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Table 12-7 Cont'd

BU # 1	Asset # 2	Asset 3/4	Description	Level II Work	Year	Priority	Cost k$	2010	2011	2012	2013	2014	2015	2016	2017
1273	7202	GAS TURBINE SYSTEM	GAS TURBINE SYSTEM	Options Assessment	2010	1	$73	$72.6	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
1273	7202	GAS TURBINE SYSTEM	GAS TURBINE SYSTEM	On-site Non-invasive inspection supplement to planned boroscope tests	2010	1	$131	$130.7	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
					Total		$203	$203	$0	$0	$0	$0	$0	$0	$0
					Stm Turb		$0	$0	$0	$0	$0	$0	$0	$0	$0
					Blr Stm		$0	$0	$0	$0	$0	$0	$0	$0	$0
					Switchy & TS		$0	$0	$0	$0	$0	$0	$0	$0	$0
					GTG		$203	$203	$0	$0	$0	$0	$0	$0	$0
					Total Excl Stm Turb		$203	$203	$0	$0	$0	$0	$0	$0	$0
					Total Excl Blr Stm, Stm Turb		$203	$203	$0	$0	$0	$0	$0	$0	$0
					Total Excl Blr Stm, Stm Turb, Switchy & TS		$203	$203	$0	$0	$0	$0	$0	$0	$0
					Total Excl Blr Stm, Stm Turb, Switchy & TS, GTG		$0	$0	$0	$0	$0	$0	$0	$0	$0

13 SUMMARY CAPITAL PLAN

A number of suggested capital items were identified in the course of the work, although no attempt was made to quantify the costs. A summary of these capital plan suggestions are presented in two tables – Key Systems Required for Synchronous Condensing Operation to 2041 and Lower Priority Systems, which are primarily related to the steam side of the facility. For details, the reader is referred to the specific systems/equipment assessments in Sections 8 to 11 and the appendices.

13.1 Key Systems for Synchronous Condensing Operation

13.1.1 Unit 1

TABLE 13-1 SUGGESTED CAPITAL PLAN ITEMS – KEY EQUIPMENT – UNIT 1

BU# 1	Asset# 2	Asset# 3	Asset# 4	Asset# 5	Asset# 6	Unit	Asset 2/3	Asset 3/4	Description	Capital Item	Date	Priority
1296	6690	6691	6696	6840	0	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	GENERATOR STATOR	Recommend ordering Stator windings in 2011 for rewinding Stator in 2012. Installation in 2012 subject to techno-economic optimization results.	2011	1
1296	6690	6691	6696	6849	271310	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	EXCITER	Upgrade Static Exciter controls compatible with the latest Unitrol 6000 system.	2013	1
1296	6690	6691	6696	6849	271311	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	EXCITATION TRANSFORMER	Replace rectifying transformer	2013	1
1296	6690	6691	6696	6850	0	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	GEN. HYDROGEN GAS SYSTEM	Install hydrogen consumption "totalizer" in each hydrogen supply line	2011	1
1296	6690	6691	6696	6850	6806	1	#1 TURBINE & GENERATOR	GENERATOR ASSEMBLY	GENERATOR SEAL OIL SYSTEM	Replace/Overhaul Seal Oil skids re SC Operation	2015	1
1296	6690	6691	271309	6695	6805	1	#1 TURBINE & GENERATOR	TURBINE	TURB. LUBE OIL PURIFICATION	Replace turbine lube oil conditioners	2013	1
1296	6690	6699	6707	0	0	1	#1 BOILER PLANT	BLR AUX STM & COND SYSTEM	BLR AUX STM & COND SYSTEM	New building heating system	2015-2020	2
1296	6690	6715	270182	7134	0	1	#1 UNIT GENERATION SERVICES	CW SYSTEM	CW INTAKE	Clean and coat AC Water pipes	2012	2
1296	6690	6715	6782	0	0	1	#1 UNIT GENERATION SERVICES	TURB/GEN COOLING SYSTEM	TURB/GEN COOLING SYSTEM	Add system for synchronous condensing similar to Unit 3.	2014	1
1296	6690	6723	6721	0	0	1	#1 UNIT GENERATION SERVICES	RELAY RM PROTECTION & CONTROL	RELAY RM PROTECTION & CONTROL	Implement modernization study re: appraise the cost of refurbishing the old GE electro-magnetic relays against the cost of multi-function relaying.	2014	1
1296	6690	6723	6722	0	0	1	#1 UNIT GENERATION SERVICES	MAIN CONTROLS	MAIN CONTROLS	Implement study to migrate Governor System and Burner Management to DCS - remove existing control relaying and transducers, re-direct field cabling to the DCS and re-configure the software.	2014	2
1296	6690	6723	6726	7182	0	1	#1 UNIT GENERATION SERVICES	UNIT SERVICE POWER SYSTEM	POWER CENTRE A	Change all protection setting to improve arc-flash ratings, unless already completed, including: - Protection settings adjustment on breaker A1, secondary of transformer AT-A. - Replacement of trip unit on breaker A3, Lighting Transformer LT-A feeder.	2011	1
1296	6690	6723	6726	7182	0	1	#1 UNIT GENERATION SERVICES	UNIT SERVICE POWER SYSTEM	POWER CENTRE A	Conduct a complete overhaul to an "as new condition" or replacement of the switchgear, including cubicles and breaker elements, extending the life expectancy of the existing switchgear for a further 15-20 years. Use spare breaker elements to allow a program can be set up to overhaul each breaker off site with essentially no interruption to plant requirements.	2012	1

Table 13-1 Cont'd

BU# 1	Asset# 2	Asset# 3	Asset# 4	Asset# 5	Asset# 6	Unit	Asset 2/3	Asset 3/4	Description	Capital Item	Date	Priority
1296	6690	6723	6728	99043229	0	1	#1 UNIT GENERATION SERVICES	BATTERY CHARGERS	250 VOLT DC BATTERY BANK	Replace Units 1/2, 129VDC Battery Charger 2 with a new Primax Charger alongside in 2010.	2010	2
1296	6690	6723	6728	99043230	0	1	#1 UNIT GENERATION SERVICES	BATTERY CHARGERS	250 VOLT DC BATTERY CHARGE	Replace Unit 1, 258VDC Panel and breakers	2010	2
1296	6690	6723	7184	0	0	1	#1 UNIT GENERATION SERVICES	TURBINE & BOILER AREA MCC C2	TURBINE & BOILER AREA MCC C2	Address issues of MCC's C1, C2, C3, E1 (GE) and GPB34, SDB34 (Siemens) available fault currents exceeding the rating of the short circuit protection devices within the individual wrappers of each MCC.	2012	1
1296	6690	6723	7186	0	0	1	#1 UNIT GENERATION SERVICES	TURBINE & BOILER AREA MCC C3	TURBINE & BOILER AREA MCC C3	Address issues of MCC's C1, C2, C3, E1 (GE) and GPB34, SDB34 (Siemens) available fault currents exceeding the rating of the short circuit protection devices within the individual wrappers of each MCC.	2012	1
1296	6690	6723	7193	0	0	1	#1 UNIT GENERATION SERVICES	UPS INVERTER#1	UPS INVERTER	Overhaul/upgrade unit to extend the life expectancy to at least 2020	2012	1
1296	6690	6723	7193	0	0	1	#1 UNIT GENERATION SERVICES	UPS INVERTER#1	UPS INVERTER	Implement optimization study in conjunction with UPS2, UPS3 and UPS4 replacement	2012	2
1296	6690	6723	270295	0	0	1	#1 UNIT GENERATION SERVICES	SWITCHGEAR 4160/600V	SWITCHGEAR 4160/600V	Implement changes to this Switchgear, 4160V/600V relaying in UB1modernization study (5.3.2.2 IV) for the protection relays. Consider that the remaining P&B Golds relays remain and not be replaced by Schweitzer 701 MPR's. As of 2015 the breakers utilizing these will become standby and as of 2020 will become spare.	2012	2
1296	6690	6723	270295	0	0	1	#1 UNIT GENERATION SERVICES	SWITCHGEAR 4160/600V	SWITCHGEAR 4160/600V	Overhaul all 4160V switchgear breakers. Use spare breaker elements to overhaul breakers 4,5,6,7,8,9,10,11 off site if necessary with essentially no interruption to plant requirements recognizing that these will be in standby mode from 2015-2020 and as of 2020 will become "spare" but in good condition.	2012	2
1296	6690	6723	270295	0	0	1	#1 UNIT GENERATION SERVICES	SWITCHGEAR 4160/600V	SWITCHGEAR 4160/600V	Replace existing breakers 1, 2 and 3 during the complete overhaul with Eaton Electrical VR-Series breakers for a life expectancy to at least 2041. Use spare cubicle (UB1-12) can be for the new U1 Synchronous Condenser Start Pony Motor breaker 12 using a new Eaton Electrical VR-Series type direct replacements for ITE, 4160V, Type 5HK). Consideration should be given to the Eaton Electrical Remote racking device (RPR2), which allows remote racking of a breaker from up to 50ft away, and is programmable for other types of breaker that might be used. One RPR2 would service U1 and U2 needs.	2012	1
1296	6690	6723	270295	0	0	1	#1 UNIT GENERATION SERVICES	SWITCHGEAR 4160/600V	SWITCHGEAR 4160/600V	Implement changes to this Switchgear, 4160V/600V relaying in UB1modernization study (5.3.2.2 IV) for the protection relays. Consider that the remaining P&B Golds relays remain and not be replaced by Schweitzer 701 MPR's. As of 2015 the breakers utilizing these will become standby and as of 2020 will become spare.	2012	2
1296	6690	6723	270296	0	0	1	#1 UNIT GENERATION SERVICES	CABLE RACEWAYS	CABLE RACEWAYS	Install new cable installations on new tray, and in accordance with the applicable Codes.	2011	1
1296	6690	6723	270297	0	0	1	#1 UNIT GENERATION SERVICES	CONTROL CABLES	CONTROL CABLES	Install new cable installations on new tray, and in accordance with the applicable Codes.	2011	1
1296	6690	6723	270298	0	0	1	#1 UNIT GENERATION SERVICES	POWER CABLES	POWER CABLES	Install any new cable installations on new tray, and in accordance with the applicable Codes.	2011	1
1296	6690	6723	309894	0	0	1	#1 UNIT GENERATION SERVICES	600 V Meltric Plugs	600 V Meltric Plugs	Complete the NLH program of 600V, 3ph, plugs and receptacles on the four Pump feeders left to modify, two on Unit 1 and two on Unit 2 to the LP Drains Pumps.	2010	3

13.1.2 Unit 2

TABLE 13-2 SUGGESTED CAPITAL PLAN ITEMS – KEY EQUIPMENT – UNIT 2

BU# 1	Asset# 2	Asset# 3	Asset# 4	Asset# 5	Asset# 6	Unit	Asset 2/3	Asset 3/4	Description	Capital Item	Date	Priority
1296	7635	7636	7753	0	0	2	U2 GENERATOR	GENERATOR ASSEMBLY	GENERATOR	Install a rotor flux probe near the turbine end of the stator bore when the rotor is removed in 2014	2014	1
1296	7635	7636	7753	7759	0	2	U2 GENERATOR	GENERATOR ASSEMBLY	GENERATOR STATOR	Recommend ordering stator windings in 2013 for rewinding stator in 2014. Installation in 2014 subject to techno-economic optimization results.	2013	1
1296	7635	7636	7753	7768	0	2	U2 GENERATOR	GENERATOR ASSEMBLY	GEN HYDROGEN GAS SYSTEM	Install a hydrogen consumption "totalizer" in each hydrogen supply line.	2011	1
1296	7635	7636	7753	7768	7732	2	U2 GENERATOR	GENERATOR ASSEMBLY	GENERATOR SEAL OIL SYSTEM	Replace/Overhaul Seal Oil skids re SC Operation	2015	1
1296	7635	7636	7753	99034724	0	2	U2 GENERATOR	GENERATOR ASSEMBLY	PARTIAL DISCHARGE ANALYSIS SYS	Repair	2010	1
1296	7635	7636	7767	271322	0	2	U2 GENERATOR	GENERATOR EXCITATION SYSTEM	EXCITER	Upgrade Static Exciter controls compatible with the latest Unitrol 6000 system	2013	1
1296	7635	7636	7767	271324	0	2	#2 TURBINE	TURBINE	EXCITATION TRANSFORMER	Replace rectifying transformer	2013	1
1296	7635	7636	271317	7711	7719	2	#2 TURBINE	TURBINE	TURB LUBE OIL TANK & EQUIP	Replace turbine lube oil conditioners	2013	1
1296	7635	8093	7703	0	0	2	#2 UNIT GENERATION SERVICES	TURB/GEN COOLING SYSTEM	TURB/GEN COOLING SYSTEM	Clean and coat AC Water pipes	2012	2
1296	7635	7636	271317	7711	0	2	#2 TURBINE	TURBINE	TURBINE OIL SYSTEMS	Provide concrete curbing around turbine lube oil tanks and seal oil tanks so as to collect any oil that leaks. Provide Isolation for generator requirements from turbine system requirements during synchronous generation operation	2012	1
1296	7635	7636	271317	7711	7719	2	#2 TURBINE	TURBINE	TURB LUBE OIL TANK & EQUIP	Replace turbine lube oil conditioners.	2013	1
1296	7635	7636	271317	7711	7719	2	#2 TURBINE	TURBINE	DUPLEX FILTER FOR LUBE OIL	Provide mechanical level switches in full flow lube oil filter compartment to detect leaks.	2013	2
1296	7635	7636	271317	7711	7719	2	#2 TURBINE	TURBINE	TURB LUBE AC OIL P/P NORTH	Provide electrical control (both "On" and "Off") for the lube oil pumps in parallel with the local controls in the Control Room	2012	1
1296	7635	7636	271317	7711	7719	2	#2 TURBINE	TURBINE	TURB LUBE AC OIL P/P SOUTH	Provide electrical control (both "On" and "Off") for the lube oil pumps in parallel with the local controls in the Control Room	2012	1
1296	7635	7636	271317	7711	7719	2	#2 TURBINE	TURBINE	TURBINE LUBE D.C. PUMP	Provide paralleled electrical control for the DC Lube Oil Pump and "On" and "Off" control for all lube oil pumps in parallel with the local controls in the Control Room.	2012	1
1296	7635	7786	7953	0	7719	2	#2 BOILER PLANT	BLR AUX STEAM & CONDENSATE	BLR AUX STEAM & CONDENSATE	New building heating system	2015-2020	2
1296	7635	8093	7703	0	0	2	#2 UNIT GENERATION SERVICES	TURB/GEN COOLING SYSTEM	TURB/GEN COOLING SYSTEM	Clean and coat AC Water pipes	2012	2

Table 13-2 Cont'd

BU# 1	Asset# 2	Asset# 3	Asset# 4	Asset# 5	Asset# 6	Unit	Asset 2/3	Asset 3/4	Description	Capital Item	Date	Priority
1296	7635	8152	271478	0	0	2	#2 ELECTRICAL & CONTROLS SYS	SWITCHGEAR 4160 & 600 VOLT	SWITCHGEAR 4160 & 600 VOLT	Implement changes to this Switchgear 4160V/600V relaying in UB2 modernization study (5.3.2.15 IV) for the protection relays. Consider that the remaining P&B Golds relays remain and not be replaced by Schweitzer 701 MPR's. As of 2015 the breakers utilizing these will become standby and as of 2020 will become spare.	2013	1
1296	7635	8152	271478	0	0	2	#2 ELECTRICAL & CONTROLS SYS	SWITCHGEAR 4160 & 600 VOLT	SWITCHGEAR 4160 & 600 VOLT	Overhaul all 4160V switchgear breakers. Use spare breaker elements to overhaul breakers 3,4,5,6,7,8,9,10 off site if necessary. There will be little interruption to plant requirements, recognizing that these will be in standby mode from 2015-2020 and as of 2020 will become "spare" but in good condition.	2013	1
1296	7635	8152	271478	0	0	2	#2 ELECTRICAL & CONTROLS SYS	SWITCHGEAR 4160 & 600 VOLT	SWITCHGEAR 4160 & 600 VOLT	Replace existing breakers 1, 2 and 12 during the complete overhaul with Eaton Electrical VR-Series breakers for a life expectancy to at least 2041. Use spare cubicle (UB2-12) for the new U2 Synchronous Condenser Start Pony Motor breaker 12 using a new Eaton Electrical VR-Series type direct replacement for ITE, 4160V, Type 5HK. Consideration should be given to the Eaton Electrical Remote racking device (RPR2), which allows remote racking of a breaker from up to 50ft away, and is programmable for other types of breakers that might be used. One RPR2 would service U1 and U2 needs.	2013	1
1296	7635	8152	8156	8162	0	2	#2 ELECTRICAL & CONTROLS SYS	UNIT SERVICE POWER SYSTEM	POWER CENTRE B	Change all protection setting to improve arc-flash ratings, unless already completed, including: - Protection settings adjustment on breaker B1, secondary of transformer AT-B. - Replacement of trip unit on breaker B43, Lighting Transformer LT-B feeder.	2011	1
1296	7635	8152	8156	8162	0	2	#2 ELECTRICAL & CONTROLS SYS	UNIT SERVICE POWER SYSTEM	POWER CENTRE B	Conduct a complete overhaul to an "as new condition" or replacement of the switchgear, including cubicles and breaker elements, extending the life expectancy of the existing switchgear for a further 15-20 years. Consider the availability of spare breaker elements to allow a program can be set up to overhaul each breaker off site with essentially no interruption to plant requirements.	2013	1
1296	7635	8152	8173	0	0	2	#2 ELECTRICAL & CONTROLS SYS	BATTERY CHARGERS	BATTERY CHARGERS	Replace Unit 2 Battery Chargers 258VDC Panel and breakers	2013	1
1296	7635	8152	8174	0	0	2	#2 ELECTRICAL & CONTROLS SYS	UPS 2, INVERTER	UPS 2, INVERTER	Overhaul/upgrade unit to extend the life expectancy to at least 2020	2012	1
1296	7635	8152	8174	0	0	2	#2 ELECTRICAL & CONTROLS SYS	UPS 2, INVERTER	UPS 2, INVERTER	Implement optimization study in conjunction with UPS2, UPS3 and UPS4 replacement	2012	2
1296	7635	8152	271475	0	0	2	#2 ELECTRICAL & CONTROLS SYS	CABLE RACEWAYS	CABLE RACEWAYS	Install any new cable installations on new tray, and in accordance with the applicable Codes.	2011	1
1296	7635	8152	271476	0	0	2	#2 ELECTRICAL & CONTROLS SYS	CONTROL CABLES	CONTROL CABLES	Install any new cable installations on new tray, and in accordance with the applicable Codes.	2011	1
1296	7635	8152	271477	0	0	2	#2 ELECTRICAL & CONTROLS SYS	POWER CABLES	POWER CABLES	Install any new cable installations on new tray, and in accordance with the applicable Codes.	2011	1

13.1.3 Unit 3

TABLE 13-3 SUGGESTED CAPITAL PLAN ITEMS – KEY EQUIPMENT – UNIT 3

BU# 1	Asset# 2	Asset# 3	Asset# 4	Asset# 5	Asset# 6	Unit	Asset 2/3	Asset 3/4	Description	Capital Item	Date	Priority
1296	8193	8194	8298	0	0	3	U3 GENERATOR	GENERATOR	GENERATOR	Install a rotor flux probe near the turbine end of the stator bore when the rotor is removed in 2016.	2016	1
1296	8193	8194	8298	8304	0	3	U3 GENERATOR	GENERATOR	GENERATOR STATOR	Plan for a rotor rewind by 2020 subject to findings of 2016 detailed inspection/overhaul. Undertake techno-economic assessment of performing in 2016.	2016	1
1296	8193	8194	8298	8313	0	3	U3 GENERATOR	GENERATOR	GEN. HYDROGEN GAS SYSTEM	Plan for stator rewinding in 2020, subject to findings of 2016 detailed inspection/overhaul. Undertake techno-economic assessment in 2016 with input from operational testing from 2011 onward.	2016	1
1296	8193	8194	8298	8313	0	3	U3 GENERATOR	GENERATOR	GEN. HYDROGEN GAS SYSTEM	Install a hydrogen consumption "totalizer" in each hydrogen supply line.	2011	1
1296	8193	8194	8298	8313	8288	3	U3 GENERATOR	GENERATOR	GENERATOR SEAL OIL SYSTEM	Provide electrical control (both "On" and "Off") for the AC and DC seal oil pumps in parallel with the local controls in the Control Room	2011	1
1296	8193	8194	8312	0	0	3	U3 GENERATOR	GENERATOR EXCITATION SYSTEM	GENERATOR EXCITATION SYSTEM	Replace Unit 3 Static Exciter (also impact the Unit 3 Rectifying Transformer)	2012	1
1296	8193	8194	8312	271680	0	3	U3 GENERATOR	EXCITATION TRANSFORMER	EXCITATION TRANSFORMER	Replace Unit 3 Static Exciter Rectifying Transformer	2012	1
1296	8193	8194	8326	0	0	3	U3 GENERATOR	GENERATOR SYNCHRONOUS COND	GENERATOR SYNCHRONOUS COND	Modify synchronous condenser - thrust bearing	2011	1
1296	8193	8194	271675	8270	0	3	U3 GENERATOR	TURBINE	TURBINE OIL SYSTEMS	Provide concrete curbing around each unit turbine lube oil tanks and seal oil tanks so as to collect any oil that leaks. Provide Isolation for generator requirements from turbine	2012	1
1296	8193	8194	271675	8270	8275	3	BOILER PLANT	TURBINE	TURBINE LUBE OIL SYSTEM	Replace turbine lube Oil conditioners	2013	1
1296	8193	8194	271675	8270	8275	3	U3 GENERATOR	TURBINE	TURB AC FLUSHING OIL PUMP	Provide paralleled electrical control for the DC Flushing Oil Pump from the Control Room	2011	1
1296	8193	8336	8503	0	0	3	BOILER PLANT	BLR AUX STEAM & CONDENSATE	BLR AUX STEAM & CONDENSATE	New building heating system	2015-2020	2
1296	8193	8645	8262	0	0	3	UNIT GENERATION SERVICES	TURB/GEN WATER COOLING SYS	TURB/GEN WATER COOLING SYS	Clean and coat AC water pipes.	2012	1
1296	8193	8645	8262	9658	0	3	UNIT GENERATION SERVICES	TURB/GEN WATER COOLING SYS	T/G COOLING WATER PUMP EAST	Replace Unit 3 AC water pumps and motors.	2014	1

13.1.4 Common Facilities

TABLE 13-4 SUGGESTED CAPITAL PLAN ITEMS – KEY EQUIPMENT – COMMON

BU# 1	Asset# 2	Asset# 3	Asset# 4	Asset# 5	Asset# 6	Unit	Asset 2/3	Asset 3/4	Description	Capital Item	Date	Priority
1296	8193	8645	271678	8649	0	3	UNIT GENERATION SERVICES	CW SYSTEM	CW TRAVELLING SCREENS EAST	Refurbish Unit 3 CW travelling screen	2012	1
1296	8193	8645	271678	8650	0	3	UNIT GENERATION SERVICES	CW SYSTEM	CW TRAVELLING SCREENS WEST	Refurbish Unit 3 CW travelling screen	2012	1
1296	8193	8712	8698	0	0	3	ELECTRICAL SYSTEM & CONTROL	RELAY RM PROTECTION & CONTROL	RELAY RM PROTECTION & CONTROL	Implement modernization study refurbishing the old GE electro-magnetic relays or new multi-function relaying.	2014	1
1296	8193	8712	271766	0	0	3	ELECTRICAL SYSTEM & CONTROL	SWITCHGEAR 4160 & 600 VOLT	SWITCHGEAR 4160 & 600 VOLT	Include this Switchgear, 4160V/600V relaying in SB2 modernization implementation for the protection relays.	2012	1
1296	8193	8712	271766	0	0	3	ELECTRICAL SYSTEM & CONTROL	SWITCHGEAR 4160 & 600 VOLT	SWITCHGEAR 4160 & 600 VOLT	Overhaul all 4160V switchgear breakers. Use spare breaker elements a program to overhaul UB3 breakers BFPE3, BFPW3, FDFE3, FDFW3, CEPN3, CEPS3, CWPE3, CWPW3, off site if necessary, with essentially no interruption to plant requirements recognizing that these will be in standby mode from 2015-2020 and as of 2020 will become “spare” but in good condition.	2014	1
1296	8193	8712	271766	0	0	3	ELECTRICAL SYSTEM & CONTROL	SWITCHGEAR 4160 & 600 VOLT	SWITCHGEAR 4160 & 600 VOLT	Replace existing UB3 breakers UT3, UAT3, TB3 and SB34 during the complete overhaul with Eaton Electrical VR-Series breakers for a life expectancy to at least 2041. Implement as required Eaton Electrical Remote racking device (RPR2) for remote racking.	2014	1
1296	8193	8712	271766	0	0	3	ELECTRICAL SYSTEM & CONTROL	SWITCHGEAR 4160 & 600 VOLT	SWITCHGEAR 4160 & 600 VOLT	Unit Aux. Board UAB3 and Station Aux. Board SAB34, (600V), manufactured by ITE and installed in 1980.	2014	1
1296	8193	8712	8704	0	0	3	ELECTRICAL SYSTEM & CONTROL	MAIN CONTROLS	MAIN CONTROLS	Upgrade Unit 3 Relay Panels to provide a safe system and redirect the existing field cables to the DCS system including changes to present DCS physical size to accommodate the changes	2014	1
1296	8193	8712	8751	0	0	3	ELECTRICAL SYSTEM & CONTROL	UPS 3 INVERTER	UPS 3 INVERTER	Implement optimization study in conjunction with UPS2, UPS3 and UPS4 replacement	2012	1
1296	8193	8712	8763	99038706	0	3	ELECTRICAL SYSTEM & CONTROL	BATTERY BANKS	BATTERY CHARGER	Replace Unit 3, 129VDC Battery Charger 1	2012	1
1296	8193	8712	8763	99038706	0	3	ELECTRICAL SYSTEM & CONTROL	BATTERY BANKS	BATTERY CHARGER	Replace Unit 3, 129VDC Battery Charger 2	2012	1
1296	8193	8712	8763	99038706	0	3	ELECTRICAL SYSTEM & CONTROL	BATTERY BANKS	BATTERY CHARGER	Replace Unit 3, 258VDC Distribution Panel and breakers	2012	1
1296	8193	8712	271763	0	0	3	ELECTRICAL SYSTEM & CONTROL	CABLE RACEWAYS	CABLE RACEWAYS	Install any new cable installations on new tray, and in accordance with the applicable Codes.	2011	1
1296	8193	8712	271764	0	0	3	ELECTRICAL SYSTEM & CONTROL	CONTROL CABLES	CONTROL CABLES	Install any new cable installations on new tray, and in accordance with the applicable Codes.	2011	1
1296	8193	8712	271765	0	0	3	ELECTRICAL SYSTEM & CONTROL	POWER CABLES	POWER CABLES	Install any new cable installations on new tray, and in accordance with the applicable Codes.	2011	1

Table 13-4 Cont'd

BU# 1	Asset# 2	Asset# 3	Asset# 4	Asset# 5	Asset# 6	Unit	Asset 2/3	Asset 3/4	Description	Capital Item	Date	Priority
1297	7199	8680	0	0	0	7	COMMON SYSTEMS	STAGE 2 AUX. DIESEL GENERATOR	STAGE 2 AUX. DIESEL GENERATOR	Replace Stage II Emergency Diesel, Cummins V-1710-G	2014	1
1297	7199	7189	0	0	0	7	COMMON SYSTEMS	STATION BOARD SB-12	STATION BOARD SB-12	Include this relaying in SB12 modernization implementation for the protection relays.	2014	1
1297	7199	7189	0	0	0	7	COMMON SYSTEMS	STATION BOARD SB-12	STATION BOARD SB-12	Replace existing breakers SSB1, SSB2, SSB3, SSB4 for a life expectancy to at least 2041. Implement, as required, Eaton Electrical Remote racking device (RPR2)remote racking.	2013	1
1297	7199	7190	0	0	0	7	COMMON SYSTEMS	DIESEL BUS DB12	DIESEL BUS DB12	Diesel Bus DB12 is part of Power Centre "C" and addressed there.	2013	1
1297	7199	7192	0	0	0	7	COMMON SYSTEMS	POWER CENTER C	POWER CENTER C	Change all Power Centre C (SAB12, Diesel Bus DB12) protection setting to improve arc-flash ratings,	2013	1
1297	7199	7192	0	0	0	7	COMMON SYSTEMS	POWER CENTER C	POWER CENTER C	Overhaul to an "as new condition" or replace - including cubicles and breaker elements, extending the life expectancy of the existing switchgear for a further 15-20 years.	2013	1
1297	7199	7192	7411	0	0	7	COMMON SYSTEMS	POWER CENTER C	CW PUMPHOUSE MCC C6	Replace	2011	1
1297	7199	7195	0	0	0	7	COMMON SYSTEMS	STAGE 1 129V D.C. SUPPLY SYSTEM	STAGE 1 129V D.C. SUPPLY SYSTEM	Replace Common, Stage 1, 129VDC Supply System Panel and breakers	2012	1
1297	7199	8730	8738	0	0	7	COMMON SYSTEMS	STAGE 2 STATION SERVICE POWER SYSTEM	GENERAL PURPOSE MCC GPB-34	Refurbish/replace as required	2015	2
1297	7199	8730	8740	0	0	7	COMMON SYSTEMS	STAGE 2 STATION SERVICE POWER SYSTEM	TURB & BLR STANDBY MCC SDB-34	Refurbish/replace as required	2015	2
1297	7199	8730	8742	0	0	7	COMMON SYSTEMS	STAGE 2 STATION SERVICE POWER SYSTEM	DIESEL BUS DB-34	Refurbish/replace as required	2015	2
1297	7199	8730	8743	0	0	7	COMMON SYSTEMS	STAGE 2 STATION SERVICE POWER SYSTEM	ESSENTIAL SERVICES MCC ESB-34	Refurbish/replace as required	2015	2
1297	7199	8730	8746	0	0	7	COMMON SYSTEMS	STAGE 2 STATION SERVICE POWER SYSTEM	CW PUMPHOUSE MCC CWP-34	Refurbish/replace as required	2015	2
1297	7199	8771	0	0	0	7	COMMON SYSTEMS	STAGE 2 129V D.C. SUPPLY	STAGE 2 129V D.C. SUPPLY	Replace	2015	2
1297	7199	7205	7231	8918	0	7	COMMON SYSTEMS	COMPRESSED AIR SYSTEMS	#2 ATLAS COPCO ROTARY COMP	Replace compressor, subject to the positioning of Holyrood being clarified in 2013	2014	1
1297	7199	7205	7231	9488	0	7	COMMON SYSTEMS	COMPRESSED AIR SYSTEMS	#1 ATLAS COPCO ROTARY COMP	Replace compressor, subject to the positioning of Holyrood being clarified in 2014	2015	1
1297	7199	7206	7236	0	0	7	COMMON SYSTEMS	GAS STORAGE SYSTEMS	HYDROGEN STORAGE AND SUPPLY	Upgrade to Hydrogen storage - LP production & bulk storage	2012	1
1297	7199	7251	7487	0	0	7	COMMON SYSTEMS	FIRE PROTECTION SYSTEMS	FIRE PUMPS - DIESEL	Replace fire pump diesel	2011	1

Table 13-4 Cont'd

BU# 1	Asset# 2	Asset# 3	Asset# 4	Asset# 5	Asset# 6	Unit	Asset 2/3	Asset 3/4	Description	Capital Item	Date	Priority
1297	7255	272255	7283	0	0	8	BUILDINGS AND SITE	BUILDINGS	MAIN POWERHOUSE	Re-paint any corroded steel members in boiler house building to help stop corrosion. Also, repair any leaky pipes to ensure that steel is not exposed to water.	2012	2
1297	7255	272255	7283	0	0	8	BUILDINGS AND SITE	BUILDINGS	MAIN POWERHOUSE	Prepare and implement roofing replacement and siding upgrade plan in 2012-13 for 2015-2020	2015	1
1297	7255	272255	7283	0	0	8	BUILDINGS AND SITE	BUILDINGS	MAIN POWERHOUSE	Modify roof vents hoods	2011	1
1297	7255	272255	7283	0	0	8	BUILDINGS AND SITE	BUILDINGS	MAIN POWERHOUSE	Optimize Warm Air Make Up system.	2011	2
1297	7255	272255	7283	7306	0	8	BUILDINGS AND SITE	BUILDINGS	BUILDING SERVICES ELEVATOR	Refurbish/replace powerhouse and administration elevators.	2012-2015	2
1297	7199	7256	271815	0	0	7	COMMON SYSTEMS	CRANES AND HOISTS	POWERHOUSE CRANE	Replace controls and brakes for auxiliary (and main if necessary) crane	2011	1
1297	7255	272255	7285	0	0	8	BUILDINGS AND SITE	BUILDINGS	STAGE 1 PUMPHOUSE	Re-paint any corroded steel members to prevent further corrosion lost to members.	2012	2
1297	7255	272255	7285	0	0	8	BUILDINGS AND SITE	BUILDINGS	STAGE 1 PUMPHOUSE	Repaint and/or refurbish roofing and siding as required	2012	2
1297	7255	272255	7286	0	0	8	BUILDINGS AND SITE	BUILDINGS	STAGE 2 PUMPHOUSE	Re-paint any corroded steel members to prevent further corrosion lost to members.	2012	2
1297	7255	272255	7286	0	0	8	BUILDINGS AND SITE	BUILDINGS	STAGE 2 PUMPHOUSE	Repaint and/or refurbish roofing and siding as required	2012	2
1297	7255	272255	7287	0	0	8	BUILDINGS AND SITE	BUILDINGS	GUARDHOUSE	Refurbish/re- paint siding and roofing as required. Fix structural deficiencies (corrosion and cracking and spalling concrete).	2015	3
1297	7255	272255	7284	0	0	8	BUILDINGS AND SITE	BUILDINGS	TRAINING CENTRE	Refurbish/re- paint siding and roofing as required. Fix structural deficiencies (corrosion and cracking and spalling concrete).	2013	3
1297	7255	272255	7288	0	0	8	BUILDINGS AND SITE	BUILDINGS	H2 & CO2 STORAGE BUILDING	Refurbish/re- paint siding and roofing as required. Fix structural deficiencies (corrosion and cracking and spalling concrete).	2013	3
1297	7255	272255	7302	0	0	8	BUILDINGS AND SITE	BUILDINGS	SHAWMONT BUILDING	Refurbish/re- paint siding and roofing as required. Fix structural deficiencies (corrosion and cracking and spalling concrete).	2012	3
1297	7255	272255	7303	0	0	8	BUILDINGS AND SITE	BUILDINGS	MAIN WAREHOUSE	Refurbish/re- paint siding and roofing as required. Fix structural deficiencies (corrosion and cracking and spalling concrete).	2013	3

Table 13-4 Cont'd

BU# 1	Asset# 2	Asset# 3	Asset# 4	Asset# 5	Asset# 6	Unit	Asset 2/3	Asset 3/4	Description	Capital Item	Date	Priority
1297	7255	272255	7304	0	0	8	BUILDINGS AND SITE	BUILDINGS	WWT PLANT BUILDING	Refurbish/re- paint siding and roofing as required. Fix structural deficiencies (corrosion and cracking and spalling concrete).	2012	2
1297	7255	272255	7305	0	0	8	BUILDINGS AND SITE	BUILDINGS	WWT BASINS BUILDING	Replace/modify WWTP Treatment Basin building. Refurbish/re- paint siding and roofing as required. Fix structural deficiencies (corrosion and cracking and spalling concrete).	2012	1
1297	7255	272255	7305	0	0	8	BUILDINGS AND SITE	BUILDINGS	WWT BASINS BUILDING	Improve WWTP basins oil capture and basin escape accesses	2012	1
1297	7255	272255	7305	0	0	8	BUILDINGS AND SITE	BUILDINGS	WWT BASINS BUILDING	Replace/modify WWTP Treatment Basin building	2012	1
1297	7255	272255	7307	0	0	8	BUILDINGS AND SITE	BUILDINGS	GAS TURBINE BUILDING	Re-paint any corroded steel members	2011	2
1297	7255	272255	7307	0	0	8	BUILDINGS AND SITE	BUILDINGS	GAS TURBINE BUILDING	Replace stack and affected roof areas	2011	1
1297	7255	272255	7307	0	0	8	BUILDINGS AND SITE	BUILDINGS	GAS TURBINE BUILDING	Refurbish and re- paint siding and roofing as required.	2011	2
1297	7255	272255	7307	0	0	8	BUILDINGS AND SITE	BUILDINGS	GAS TURBINE BUILDING	Replace air intake for marine environment - filter media and/or intake structure	2011	1
1297	9739	7203	7210	0	0	8	WATER TREATMENT &ENVIRONMENT	WTP	RAW WATER SYSTEM	Implement new or parallel fresh water line from Quarry Brook Dam.	2013	1
1297	9739	10038	7263	0	0	8	WATER TREATMENT &ENVIRONMENT	WWTP	OIL/WATER SEPARATORS	Refurbish oil water separator	2015	1

13.1.5 Switchyard

TABLE 13-5 SUGGESTED CAPITAL PLAN ITEMS – KEY EQUIPMENT – SWITCHYARD

BU# 1	Asset# 2	Asset# 3	Asset# 4	Asset# 5	Asset# 6	Unit	Asset 2/3	Asset 3/4	Description	Capital Item	Date	Priority
1325	5990	5990	310-77-1	HRDB3B13		10	HRDTS	BREAKER,B3B13,HRD TS	230 KV	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	5991	5991	310-77-3	HRDB12B15		10	HRDTS	BREAKER,B12B15,HRD TS	230 KV	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	5992	5992	460-80 AD/2	HRDB12L18		10	HRDTS	BREAKER,B12L18,HRD TS	230 KV	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	5993	5993	310-77-2	HRDB3L18		10	HRDTS	BREAKER,B3L18,HRD TS	230 KV	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	5994	5994	170-73-3	HRDB1L17		10	HRDTS	BREAKER,B1L17,HRD TS	230 KV	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	5995	5995	310-77-4	HRDB12L42		10	HRDTS	BREAKER,B12L42,HRD TS	230 KV	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	5996	5996	188-74-2	HRDB2B11		10	HRDTS	BREAKER,B2B11,HRD TS	230 KV	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	5997	5997	188-74-1	HRDB1B11		10	HRDTS	BREAKER,B1B11,HRD TS	230 KV	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	5998	5998	170-73-2	HRDB12L17		10	HRDTS	BREAKER,B12L17,HRD TS	230 KV	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	5999	5999	170-73-1	HRDB2L42		10	HRDTS	BREAKER,B2L42,HRD TS	230 KV	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6000	6000	0464DT72	HRDB6T10		10	HRDTS	BREAKER,B6T10,HRD TS	69 KV	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6001	6001	0/K3123893	HRDB12T10		10	HRDTS	BREAKER,B12T10,HRD TS	230 KV	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6002	6002	45510DD/1	HRDB13B15		10	HRDTS	BREAKER,B13B15,HRD TS	230 KV	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6003	6003	0465DT72	HRDB7T5		10	HRDTS	BREAKER,B7T5,HRD TS	69 KV	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6004	6004	61130	HRDB7L2		10	HRDTS	BREAKER,B7L2,HRD TS	69 KV	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6005	6005	63257	HRDB8L39		10	HRDTS	BREAKER,B8L39,HRD TS	138 KV	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6006	6006	64018	HRDB6L3		10	HRDTS	BREAKER,B6L3,HRD TS	69 KV	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6007	6007	61131	HRDB7L38		10	HRDTS	BREAKER,B7L38,HRD TS	69 KV	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1

Table 13-5 Cont'd

BU# 1	Asset# 2	Asset# 3	Asset# 4	Asset# 5	Asset# 6	Unit	Asset 2/3	Asset 3/4	Description	Capital Item	Date	Priority
1325	6008	6008	991110	HRDB12L17-1		10	HRDTS	MODB12L17-1,	230 KV	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6009	6009	991110	HRDB12L42-1		10	HRDTS	MODB12L42-1,	230 KV	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6010	6010	991110	HRDB2L42-1		10	HRDTS	MODB2L42-1,	230 KV	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6011	6011	991110	HRDB2B11-1		10	HRDTS	MODB2B11-1,	230 KV	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6012	6012	991110	HRDB2B11-2		10	HRDTS	MODB2B11-2,	230 KV	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6013	6013	991110	HRDB12L17-2		10	HRDTS	MODB12L17-2,	230 KV	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6014	6014	991110	HRDB2L42-2		10	HRDTS	MODB2L42-2,	230 KV	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6015	6015	991110	HRDB1L17-2		10	HRDTS	MODB1L17-2,	230 KV	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6016	6016	991110	HRDB12L42-2		10	HRDTS	MODB12L42-2,	230 KV	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6017	6017	991110	HRDB1L17-1		10	HRDTS	MODB1L17-1,	230 KV	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6018	6018	991110	HRDB1B11-1		10	HRDTS	MODB1B11-1,	230 KV	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6019	6019	991110	HRDB12T10-1		10	HRDTS	MODB12T10-1,	230 KV	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6020	6020	991110	HRDB12L18-1		10	HRDTS	MODB12L18-1,	230 KV	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6021	6021	991110	HRDB12B15-2		10	HRDTS	MODB12B15-2,	230 KV	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6022	6022	991110	HRDB13B15-2		10	HRDTS	MODB13B15-2,	230 KV	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6023	6023	991110	HRDB3L18-2		10	HRDTS	MODB3L18-2,	230 KV	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1

Table 13-5 Cont'd

BU# 1	Asset# 2	Asset# 3	Asset# 4	Asset# 5	Asset# 6	Unit	Asset 2/3	Asset 3/4	Description	Capital Item	Date	Priority
1325	6024	6024	991110	HRDB3L18-1		10	HRDTS	MODB3L18-1,	230 KV	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6025	6025	991110	HRDB3B13-1		10	HRDTS	MODB3B13-1,	230 KV	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6026	6026	991110	HRDB3B13-2		10	HRDTS	MODB3B13-2,	230 KV	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6027	6027	991110	HRDB13B15-1		10	HRDTS	MODB13B15-1,	230 KV	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6028	6028	991110	HRDB12B15-1		10	HRDTS	MODB12B15-1,	230 KV	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6029	6029	991110	HRDB1B11-2		10	HRDTS	MODB1B11-2,	230 KV	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6030	6030	991110	HRDB11T5		10	HRDTS	MODB11T5,	230 KV	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6034	6034	991110	HRDB15T6		10	HRDTS	MODB15T6,	230 KV	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6035	6035	991110	HRDB3T3		10	HRDTS	MODB3T3,	230 KV	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6036	6036	991110	HRDB15T8		10	HRDTS	MODB15T8,	230 KV	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6037	6037	991110	HRDB2T2		10	HRDTS	MODB2T2,	230 KV	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6038	6038	991110	HRDB1T1		10	HRDTS	MODB1T1,	230 KV	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6039	6039	991110	HRDB15T7		10	HRDTS	MODB15T7,	230 KV	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6053	6053	991110	HRDB11B13		10	HRDTS	MODB11B13,	230 KV	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6546	6546	991110	HRDB12L18-2		10	HRDTS	MODB12L18-2,	230 KV	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	275789	275789	991110	HRDB12L42-1		10	HRDTS	MOD B12L42-1,	230 KV	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1

Table 13-5 Cont'd

BU# 1	Asset# 2	Asset# 3	Asset# 4	Asset# 5	Asset# 6	Unit	Asset 2/3	Asset 3/4	Description	Capital Item	Date	Priority
1325	6031	6031	991110	HRDB8T6		10	HRDTS	MODB8T6,	138 KV	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6032	6032	991110	HRDB8T7		10	HRDTS	MODB8T7,	138 KV	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6033	6033	991110	HRDB8T8		10	HRDTS	MODB8T8,	138 KV	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6040	6040	991110	HRDB8L39-2		10	HRDTS	Man SwB8L39-2,	138 KV	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6041	6041	991110	HRDB8L39-1		10	HRDTS	Man SwB8L39-1,	138 KV	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6042	6042	991110	HRDB7T5-2		10	HRDTS	Man SwB7T5-2,	69 KV	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6043	6043	991110	HRDL2L38		10	HRDTS	Man SwL2L38,	69 KV	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6044	6044	991110	HRDB7L38-1		10	HRDTS	Man SwB7L38-1,	69 KV	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6045	6045	991110	HRDB7L38-2		10	HRDTS	Man SwB7L38-2,	69 KV	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6046	6046	991110	HRDB7L2-2		10	HRDTS	Man SwB7L2-2,	69 KV	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6047	6047	991110	HRDB7L2-1		10	HRDTS	Man SwB7L2-1,	69 KV	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6048	6048	991110	HRDB6L3-1		10	HRDTS	Man SwB6L3-1,	69 KV	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6049	6049	991110	HRDB6L3-2		10	HRDTS	Man SwB6L3-2,	69 KV	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6050	6050	991110	HRDB6B7		10	HRDTS	Man SwB6B7,	69 KV	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6051	6051	991110	HRDB7T5-1		10	HRDTS	Man SwB7T5-1,	69 KV	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	6052	6052	991110	HRDB6T10-1		10	HRDTS	Man SwB6T10-1,	69 KV	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4.	2015 to 2035	1
1325	991000	991100	991110	UAT3 & SAT35		10	HRDTS	Transformers	UAT3 & SAT35	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Actions in Section 11.1.2.4.	2015 to 2035	1
1325	5975	5975	303236	HRDT1		10	HRDTS	Transformers	T1 Power	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Actions in Section 11.1.2.4.	2015 to 2035	1

Table 13-5 Cont'd

BU# 1	Asset# 2	Asset# 3	Asset# 4	Asset# 5	Asset# 6	Unit	Asset 2/3	Asset 3/4	Description	Capital Item	Date	Priority
1325	5976	5976	61-00-69225	HRDT2		10	HRDTS	Transformers	T2 Power	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Actions in Section 11.1.2.4.	2015 to 2035	1
1325	5977	5977	287198	HRDT3		10	HRDTS	Transformers	T3 Power	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Actions in Section 11.1.2.4.	2015 to 2035	1
1325	5978	5978	287199	HRDT4		10	HRDTS	Transformers	T4 (spare)	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Actions in Section 11.1.2.4.	2015 to 2035	3
1325	5979	5979	A-3-S-7520	HRDT5		10	HRDTS	Transformers	T5	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Actions in Section 11.1.2.4.	2015 to 2035	1
1325	5980	5980	287065	HRDT6		10	HRDTS	Transformers	T6	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Actions in Section 11.1.2.4.	2015 to 2035	1
1325	5981	5981	287064	HRDT7		10	HRDTS	Transformers	T7	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Actions in Section 11.1.2.4.	2015 to 2035	1
1325	5982	5982	61-00-68928	HRDT8		10	HRDTS	Transformers	T8	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Actions in Section 11.1.2.4.	2015 to 2035	1
1325	5983	5983	61-00-69576	HRDT9		10	HRDTS	Transformers	T9	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Actions in Section 11.1.2.4.	2015 to 2035	1
1325	5984	5984	61-00-69576	HRDT10		10	HRDTS	Transformers	T10	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Actions in Section 11.1.2.4.	2015 to 2035	1
31297	991000	991100	991110	UST-1		10	HRDTS	Transformers	UST-1	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Actions in Section 11.1.2.4.	2015 to 2035	1
31297	991000	991100	991110	ST-2		10	HRDTS	Transformers	ST-2	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Actions in Section 11.1.2.4.	2015 to 2035	1
31297	991000	991100	991110	UST-3		10	HRDTS	Transformers	UST-3	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Actions in Section 11.1.2.4.	2015 to 2035	1
1325	5988	5988	WT-1976-1	HRDSST-12		10	HRDTS	Transformers	SST-12	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Actions in Section 11.1.2.4.	2015 to 2035	1
1325	5989	5989	A-3-S-7608	HRDSST-34		10	HRDTS	Transformers	SST-34	Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Actions in Section 11.1.2.4.	2015 to 2035	1

13.1.6 Gas Turbine Generator

TABLE 13-6 SUGGESTED CAPITAL PLAN ITEMS – KEY EQUIPMENT – GAS TURBINE GENERATOR

BU# 1	Asset# 2	Asset# 3	Asset# 4	Asset# 5	Asset# 6	Unit	Asset 2/3	Asset 3/4	Description	Capital Item	Date	Priority
1273	7202	7058	0	0	0	5	GAS TURBINE SYSTEM	GAS TURBINE POWER TURB & G/B	GAS TURBINE POWER TURB & G/B	Overhaul of power turbine, gearbox	2011	1
1273	7202	7308	0	0	0	5	GAS TURBINE SYSTEM	GAS TURBINE AVON JET ENGINE	GAS TURBINE AVON JET ENGINE	Overhaul gas turbine	2011	1
1273	7202	7309	0	0	0	5	GAS TURBINE SYSTEM	GAS TURBINE GENERATOR	GAS TURBINE GENERATOR	Refurbish generator	2015+	3
1273	7202	7310	0	0	0	5	GAS TURBINE SYSTEM	GAS TURB ELECT & CONTROL	GAS TURB ELECT & CONTROL	Replace electrical equipment for gas turbine	2010	1
1273	7202	7311	0	0	0	5	GAS TURBINE SYSTEM	GAS TURBINE AUXILIARY SYSTEMS	GAS TURBINE AUXILIARY SYSTEMS	Replace the exhaust stack	2011	1
1273	7202	7311	0	0	0	5	GAS TURBINE SYSTEM	GAS TURBINE AUXILIARY SYSTEMS	GAS TURBINE AUXILIARY SYSTEMS	Upgrade fuel receipt and feeding and radiator - enclosure	2012	2
1273	7202	7311	99003602	0	0	5	GAS TURBINE SYSTEM	GAS TURBINE AUXILIARY SYSTEMS	AIR INLET PLENUM CHAMBER	Replace air inlet plenum/filter media	2011	2

13.2 Lower Priority Systems Not Required for Synchronous Condensing Operation

13.2.1 Unit

TABLE 13-7 SUGGESTED CAPITAL PLAN ITEMS – LOWER PRIORITY – UNIT 1

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Capital Item	Date	Priority
1296	6690	6691	6733	6780	0	1	#1 TURBINE & GENERATOR	TURBINE CONDENSER	CONDENSER AIR EXTRACTION	Procure spare vacuum pump and motor for Units 1 & 2 (and 3 as practical)	2012	2
1296	6690	6691	6733	6780	8876	1	#1 TURBINE & GENERATOR	TURBINE CONDENSER	CONDENSER VACUUM PUMP NORTH	Refurbish/Replace vacuum pumps and motors as required.	2012	2
1296	6690	6691	6733	6780	8877	1	#1 TURBINE & GENERATOR	TURBINE CONDENSER	CONDENSER VACUUM PUMP SOUTH	Refurbish/Replace vacuum pumps and motors as required.	2012	2
1296	6690	6691	271309	6777	0	1	#1 TURBINE & GENERATOR	TURBINE	TURBINE GLAND STEAM SYSTEM	Replace the steam seal regulator	2011	1
1296	6690	6691	271309	6779	0	1	#1 TURBINE & GENERATOR	TURBINE	TURBINE TURNING GEAR	Refurbish chain and mechanism	2011	2
1296	6690	6699	0	0	0	1	#1 BOILER PLANT	BOILER PLANT	BOILER PLANT	Install nitrogen blanketing. No other pending Level 2 or next inspection	2013	2
1296	6690	6699	6702	6878	0	1	#1 BOILER PLANT	BLR SUPERHEAT& REHEAT ASS'Y	BOILER REHEATER	Implement addition of RH surface to match design temps and efficiency, subject to decision on Holyrood	2012	2
1296	6690	6699	6701	6701	0	1	#1 BOILER PLANT	BOILER F.W. & SAT'D STEAM	BOILER BLOWDOWN TANK	Replace tank	2011	1
1296	6690	6699	6703	0	0	1	#1 BOILER PLANT	BOILER AIR SYSTEM	BOILER AIR SYSTEM	Upgrade air ducts to reduce vibration, improve efficiency	2012	2
1296	6690	6699	6703	8777	0	1	#1 BOILER PLANT	BOILER AIR SYSTEM	BOILER F.D. FAN SYSTEM	Procure spare motor - common to Units 1 & 2; adaptable Unit 3 to extent practical	2012	1
1296	6690	6699	6703	8777	0	1	#1 BOILER PLANT	BOILER AIR SYSTEM	BOILER F.D. FAN SYSTEM	Assess fluid coupling/VFD for BFWP and FDF	2011	2
1296	6690	6699	6703	8777	6943	1	#1 BOILER PLANT	BOILER AIR SYSTEM	BOILER F.D. FAN EAST	Install vibration monitoring	2012	2
1296	6690	6699	6703	8777	6944	1	#1 BOILER PLANT	BOILER AIR SYSTEM	BOILER F.D. FAN WEST	Install vibration monitoring	2012	2
1296	6690	6699	6704	6920	0	1	#1 BOILER PLANT	BOILER GAS SYSTEM	BOILER SOOTBLOWING SYSTEM	Assess economic aspects of Intelligent Sootblowing	2011	3
1296	6690	6699	6704	6920	0	1	#1 BOILER PLANT	BOILER GAS SYSTEM	BOILER SOOTBLOWING SYSTEM	FD fan ductwork modifications	2011	3
1296	6690	6699	6704	6919	270294	1	#1 BOILER PLANT	BOILER GAS SYSTEM	BOILER STACK BREECHING	Refurbish stack breeching	2011	1
1296	6690	6709	8799	7045	0	1	#1 CONDENSATE & F.W. SYSTEM	CONDENSATE EXTRACTION	COND EXTRACTION PUMP NORTH	Replace as required per current inspection and overhaul findings	2013	3
1296	6690	6709	8799	7049	0	1	#1 CONDENSATE & F.W. SYSTEM	CONDENSATE EXTRACTION	COND EXTRACTION PUMP SOUTH	Replace as required per current inspection and overhaul findings	2013	3

Table 13-7 Cont'd

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Capital Item	Date	Priority
1296	6690	6709	6712	8835	0	1	#1 CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEED PUMP EAST	Retrofit of variable speed control – fluid couplings or variable speed drives to reduce energy consumption and improve efficiency	2013	2
1296	6690	6709	6712	8835	0	1	#1 CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEED PUMP EAST	Procure a spare 4 kV motor, to allow rewind of Units 1 and 2 and if practical Unit 3 motors as required	2012	1
1296	6690	6709	6712	8835	0	1	#1 CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEED PUMP EAST	Install vibration monitoring	2012	1
1296	6690	6709	6712	8836	0	1	#1 CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEED PUMP WEST	Retrofit of variable speed control – fluid couplings or variable speed drives to reduce energy consumption and improve efficiency	2013	2
1296	6690	6709	6712	8836	0	1	#1 CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEED PUMP WEST	Procure a spare 4 kV motor, to allow rewind of Units 1 and 2 and if practical Unit 3 motors as required	2012	1
1296	6690	6709	6712	8836	0	1	#1 CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEED PUMP WEST	Install vibration monitoring	2012	1
1296	6690	6709	6713	7113	0	1	#1 CONDENSATE & F.W. SYSTEM	HIGH PRESSURE FEEDWATER SYS	H.P. HEATER 5	Replace HP #5 Heater	2013	1
1296	6690	6715	6782	0	0	1	#1 UNIT GENERATION SERVICES	TURB/GEN COOLING SYSTEM	TURB/GEN COOLING SYSTEM	Clean and coat AC Water pipes	2012	2
1296	6690	6715	270182	7146	0	1	#1 UNIT GENERATION SERVICES	CW SYSTEM	CW PUMP EAST	Procure spare motor - common to Units 1 & 2; adaptable Unit 3 to extent practical	2012	1
1296	6690	6715	270182	7147	0	1	#1 UNIT GENERATION SERVICES	CW SYSTEM	CW PUMP WEST	Procure spare motor - common to Units 1 & 2; adaptable Unit 3 to extent practical	2012	1
1296	6690	6723	6721	0	0	1	#1 UNIT GENERATION SERVICES	RELAY RM PROTECTION & CONTROL	RELAY RM PROTECTION & CONTROL	Implement modernization study re: appraise the cost of refurbishing the old GE electro-magnetic relays against the cost of multi-function relaying.	2014	1
1296	6690	6723	6722	0	0	1	#1 UNIT GENERATION SERVICES	MAIN CONTROLS	MAIN CONTROLS	Implement study to migrate Governor System and Burner Management to DCS	2014	2
1296	6690	6723	6693	0	0	1	#1 UNIT GENERATION SERVICES	TURBINE GOVERNOR SYSTEM	TURBINE GOVERNOR SYSTEM	Assess and implement GE migration of the Mark V to the Mark Ve system.	2013	1
1296	6690	6723	6693	333928	0	1	#1 UNIT GENERATION SERVICES	TURBINE GOVERNOR SYSTEM	Holyrood Mark V Auto Sync	No Capital		
1296	6690	6723	6693	99000260	0	1	#1 UNIT GENERATION SERVICES	#1 UNIT GENERATION SERVICES	INSTALL GOVENOR UNIT 1 - MFG C	No Capital		
1296	6690	6723	7173	0	0	1	#1 UNIT GENERATION SERVICES	BURNER MANAGEMENT	BURNER MANAGEMENT	Transfer Burner Management system from PLC system to DCS. Replace any existing field mounted pressure switches by analog transducers. Flame Scanners remain unchanged.	2011	1

13.2.2 Unit 2

TABLE 13-8 SUGGESTED CAPITAL PLAN ITEMS – LOWER PRIORITY – UNIT 2

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Capital Item	Date	Priority
1296	7635	7636	7664	7694	8884	2	#2 TURBINE CONDENSER SYSTEM	TURBINE CONDENSER SYSTEM	CONDENSER AIR VAC P/P NORTH	Refurbish/Replace vacuum pumps and motors as required.	2012	2
1296	7635	7636	7664	7694	8891	2	#2 TURBINE CONDENSER SYSTEM	TURBINE CONDENSER SYSTEM	CONDENSER AIR VAC P/P SOUTH	Refurbish/Replace vacuum pumps and motors as required.	2012	2
1296	7635	7636	271317	7686	0	2	#2 TURBINE	TURBINE	TURBINE GLAND STEAM SYSTEM	Replace the steam seal regulator	2012	1
1296	7635	7636	271317	7692	0	2	#2 TURBINE	TURBINE	TURBINE TURNING GEAR	Refurbish chain and mechanism	2014	1
1296	7635	7786	0	0	0	2	#2 BOILER PLANT	BOILER PLANT	BOILER PLANT	Install nitrogen blanketing. No other pending Level 2 or next inspection	2013	2
1296	7635	7786	7789	0	0	2	#2 BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER FW & SAT'D STEAM SYS	None , pending Level 2 or next inspection		
1296	7635	7786	7810	7835	0	2	#2 BOILER PLANT	BOILER SUPERHEATER & REHEAT	BOILER REHEATER	Implement addition of RH surface to match design temperatures and efficiency, subject to economic assessment.	2014	2
1296	7635	7786	7789	7789	0	2	#2 BOILER PLANT	BOILER FW & SAT'D STEAM SYS	BOILER BLOWDOWN TANK	Replace tank	2011	1
1296	7635	7786	7838	0	0	2	#2 BOILER PLANT	BOILER AIR SYSTEM	BOILER AIR SYSTEM	Upgrade air ducts to reduce vibration, improve efficiency	2014	1
1296	7635	7786	7838	8781	0	2	#2 BOILER PLANT	BOILER AIR SYSTEM	BOILER F.D. FAN ASSEMBLY	Procure spare motor - common to Units 1 & 2; adaptable Unit 3 to extent practical	2012	1
1296	7635	7786	7838	8781	7843	2	#2 BOILER PLANT	BOILER AIR SYSTEM	BOILER F.D. FAN EAST	Install vibration monitoring	2012	2
1296	7635	7786	7838	8781	7844	2	#2 BOILER PLANT	BOILER AIR SYSTEM	BOILER F.D. FAN WEST	Install vibration monitoring	2012	2
1296	7635	7786	7890	7904	0	2	#2 BOILER PLANT	BOILER GAS SYSTEM	BOILER SOOTBLOWING SYSTEM	Assess economic aspects of Intelligent Sootblowing	2011	3
1296	7635	7786	7890	7904	0	2	#2 BOILER PLANT	BOILER GAS SYSTEM	BOILER SOOTBLOWING SYSTEM	FD fan ductwork modifications	2011	3
1296	7635	7786	7890	7900	271327	2	#2 BOILER PLANT	BOILER GAS SYSTEM	STACK BREECHING	Refurbish stack breeching	2012	1
1296	7635	7978	8800	7986	0	2	#2 UNIT GENERATION SERVICES	CW SYSTEM	COND EXTRACTION PUMP NORTH	Replace as required per current inspection and overhaul findings	2013	3
1296	7635	7978	8800	7987	0	2	#2 UNIT GENERATION SERVICES	CW SYSTEM	COND. EXTRACTION PUMP SOUTH	Replace as required per current inspection and overhaul findings	2013	3

Table 13-8 Cont'd

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Capital Item	Date	Priority
1296	7635	7978	8037	8847	0	2	#2 CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEED PUMP WEST	Retrofit of variable speed control – fluid couplings or variable speed drives to reduce energy consumption and improve efficiency	2013	3
1296	7635	7978	8037	8847	0	2	#2 CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEED PUMP WEST	Procure a spare 4 kV motor, to allow rewind of Units 1 and 2 and if practical Unit 3 motors as required	2012	1
1296	7635	7978	8037	8847	0	2	#2 CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEED PUMP WEST	Install vibration monitoring	2012	1
1296	7635	7978	8037	8848	0	2	#2 CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEED PUMP EAST	Retrofit of variable speed control – fluid couplings or variable speed drives to reduce energy consumption and improve efficiency	2013	3
1296	7635	7978	8037	8848	0	2	#2 CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEED PUMP EAST	Procure a spare 4 kV motor, to allow rewind of Units 1 and 2 and if practical Unit 3 motors as required	2012	1
1296	7635	7978	8037	8848	0	2	#2 CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEED PUMP EAST	Install vibration monitoring	2012	1
1296	7635	7978	8059	8067	0	2	#2 CONDENSATE & F.W. SYSTEM	H.P. FEEDWATER SYSTEM	H.P. HEATER 5	Replace HP Htr 5 - similar to Unit 1.	2013	1
1296	7635	8093	271486	8106	0	2	#2 UNIT GENERATION SERVICES	CW SYSTEM	CW PUMP EAST	Procure spare motor - common to Units 1 & 2; adaptable Unit 3 to extent practical	2012	1
1296	7635	8093	271486	8107	0	2	#2 UNIT GENERATION SERVICES	CW SYSTEM	CW PUMP WEST	Procure spare motor - common to Units 1 & 2; adaptable Unit 3 to extent practical	2012	1
1296	7635	8152	271478	0	0	2	#2 ELECTRICAL & CONTROLS SYS	SWITCHGEAR 4160 & 600 VOLT	SWITCHGEAR 4160 & 600 VOLT	Implement changes to this Switchgear 4160V/600V relaying in UB2 modernization study (5.3.2.15 IV) for the protection relays. Consider that the remaining P&B Golds relays remain and not be replaced by Schweitzer 701 MPR's. As of 2015 the breakers utilizing these will become standby and as of 2020 will become spare.	2013	1
1296	7635	8152	271479	0	0	2	#2 ELECTRICAL & CONTROLS SYS	TSI	TSI	Implement Turbine Supervisory System replacement	2013	1
1296	7635	8152	7677	0	0	2	#2 ELECTRICAL & CONTROLS SYS	TURBINE GOVERNOR SYSTEM	TURBINE GOVERNOR SYSTEM	Assess and implement GE migration of the Mark V to the Mark Ve system. Replace existing 196 processor and modernize operator and maintenance stations. Field wiring and devices remain the same.	2013	1

13.2.3 Unit 3

Table 13-9 Suggested Capital Plan Items – Lower Priority – Unit 3

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Capital Item	Date	Priority
1296	8193	8194	8223	8252	8892	3	TURBINE CONDENSER SYSTEM	CONDENSER AIR VAC PUMP NORTH	CONDENSER AIR VAC PUMP NORTH	Refurbish/replace vacuum pumps and motors as required. Provide electrical control (both “On” and “Off”) for the vacuum pumps in parallel with the local controls in the Control Room	2015	1
1296	8193	8194	8223	8252	8893	3	TURBINE CONDENSER SYSTEM	CONDENSER AIR VAC PUMP NORTH	CONDENSER AIR VAC PUMP SOUTH	Refurbish/replace vacuum pumps and motors as required. Provide electrical control (both “On” and “Off”) for the vacuum pumps in parallel with the local controls in the Control Room	2015	1
1296	8193	8194	271675	8236	0	3	U3 GENERATOR	TURBINE	TURBINE GOVERNOR SYSTEM	Upgrade the mechanical fly-ball type Turbine Governor System to As-Built condition or be replaced using electronic controls..	2013	1
1296	8193	8194	271675	8236	99024410	3	U3 GENERATOR	TURBINE	BENTLEY NEVADA TURBINE SUPERVI	Implement replacement option	2013	2
1296	8193	8194	271675	8244	0	3	U3 GENERATOR	TURBINE	TURBINE GLAND STEAM SYSTEM	Replace steam seal regulator	2013	1
1296	8193	8336	0	0	0	3	BOILER PLANT	BOILER PLANT	BOILER PLANT	Install nitrogen blanketing. No other pending Level 2 or next inspection	2013	2
1296	8193	8336	8339	8339	0	3	BOILER PLANT	BLR FW & SAT STM	BOILER BLOWDOWN TANKS	Replace blowdown tank	2011	1
1296	8193	8336	8387	0	0	3	BOILER PLANT	BOILER AIR SYSTEM	BOILER AIR SYSTEM	Upgrade air ducts to reduce vibration, improve efficiency	2013	1
1296	8193	8336	8387	8782	0	3	BOILER PLANT	BOILER AIR SYSTEM	BOILER F.D. FAN SYSTEM	Procure spare motor - common to Units 1 & 2; adaptable Unit 3 to extent practical	2012	1
1296	8193	8336	8387	8782	8392	3	BOILER PLANT	BOILER AIR SYSTEM	BOILER F.D. FAN EAST	Install vibration monitoring	2012	2
1296	8193	8336	8387	8782	8393	3	BOILER PLANT	BOILER AIR SYSTEM	BOILER F.D. FAN WEST	Install vibration monitoring	2012	2
1296	8193	8336	8437	8452	0	3	CONDENSATE & F.W. SYSTEM	BOILER GAS SYSTEM	BOILER SOOTBLOWING SYSTEM	Assess economic aspects of Intelligent Sootblowing	2012	3
1296	8193	8336	8437	8452	0	3	CONDENSATE & F.W. SYSTEM	BOILER GAS SYSTEM	BOILER SOOTBLOWING SYSTEM	FD fan ductwork modifications	2012	3
1296	8193	8336	8437	8448	271682	3	CONDENSATE & F.W. SYSTEM	BOILER GAS SYSTEM	STACK BREECHING	Refurbish stack breeching	2013	1
1296	8193	8528	8801	8536	0	3	CONDENSATE & F.W. SYSTEM	CONDENSER EXTRACTION P/P NORTH	CONDENS EXTRACTION P/P NORTH	Refurbish and replace as required per next inspection and overhaul findings. Procure spare motor compatible with all units.	2014	3
1296	8193	8528	8801	8537	0	3	CONDENSATE & F.W. SYSTEM	CONDENSER EXTRACTION P/P SOUTH	CONDENS EXTRACTION P/P SOUTH	Refurbish and replace as required per next inspection and overhaul findings. Procure spare motor compatible with all units.	2014	3

Table 13-9 Cont'd

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Capital Item	Date	Priority
1296	8193	8528	8590	8859	0	3	CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEED PUMP - EAST	Retrofit of variable speed control – fluid couplings or variable speed drives to reduce energy consumption and improve efficiency	2013	2
1296	8193	8528	8590	8859	0	3	CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEED PUMP - EAST	Procure a spare 4 kV motor, to allow rewind of Units 1 and 2 and if practical Unit 3 motors as required	2012	1
1296	8193	8528	8590	8859	0	3	CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEED PUMP - EAST	Install vibration monitoring	2012	1
1296	8193	8528	8590	8860	0	3	CONDENSATE & F.W. SYSTEM	BOILER FEEDWATER PUMPING	BOILER FEED PUMP - WEST	Retrofit of variable speed control – fluid couplings or variable speed drives to reduce energy consumption and improve efficiency	2013	2
1296	8193	8528	8590	8860	0	3	UNIT GENERATION SERVICES	BOILER FEEDWATER PUMPING	BOILER FEED PUMP - WEST	Procure a spare 4 kV motor, to allow rewind of Units 1 and 2 and if practical Unit 3 motors as required	2012	1
1296	8193	8528	8590	8860	0	3	UNIT GENERATION SERVICES	BOILER FEEDWATER PUMPING	BOILER FEED PUMP - WEST	Install vibration monitoring	2012	1
1296	8193	8645	271678	8658	0	3	UNIT GENERATION SERVICES	CW SYSTEM	CW PUMP EAST	Procure spare motor - common to Units 1 & 2; adaptable Unit 3 to extent practical	2012	1
1296	8193	8645	271678	8659	0	3	UNIT GENERATION SERVICES	CW SYSTEM	CW PUMP WEST	Procure spare motor - common to Units 1 & 2; adaptable Unit 3 to extent practical	2012	1
1296	8193	8645	271678	8649	0	3	UNIT GENERATION SERVICES	CW SYSTEM	CW TRAVELLING SCREENS EAST	Refurbish Unit 3 CW travelling screen	2012	1
1296	8193	8645	271678	8650	0	3	UNIT GENERATION SERVICES	CW SYSTEM	CW TRAVELLING SCREENS WEST	Refurbish Unit 3 CW travelling screen	2012	1
1296	8193	8712	8698	0	0	3	ELECTRICAL SYSTEM & CONTROL	RELAY RM P&C	RELAY RM P&C	Implement modernization study refurbishing the old GE electro-magnetic relays or new multi-function relaying.	2014	1
1296	8193	8712	271767	0	0	3	ELECTRICAL SYSTEM & CONTROL	TSI	TSI	Replace with selected preferred option	2013	1

13.2.4 Common Facilities

TABLE 13-10 SUGGESTED CAPITAL PLAN ITEMS – LOWER PRIORITY – COMMON

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset # 5	Asset # 6	Unit	Asset 2/3	Asset 3/4	Description	Capital Item	Date	Priority
1297	7199	7204	7223	0	0	7	COMMON SYSTEMS	HEAVY OIL & FUEL ADDITIVE	*HEAVY OIL TRANSFER TO STORAGE	Replace electric heat trace system	2011	1
1297	7199	7204	7224	7441	0	7	COMMON SYSTEMS	HEAVY OIL & FUEL ADDITIVE	HEAVY OIL - #1 TANK	Complete recommended actions from SGE Acres report - replace tank bottom and apply protective coating to new bottom and 1 meter of shell. Complete API653 inspection.	2012	1
1297	7199	7204	7224	7443	0	7	COMMON SYSTEMS	HEAVY OIL & FUEL ADDITIVE	HEAVY OIL - #3 TANK	Complete recommended actions from SGE Acres report - replace tank bottom and apply protective coating to new bottom and 1 meter of shell. Complete API653 inspection.	2011	1
1297	7199	7204	7224	7444	0	7	COMMON SYSTEMS	HEAVY OIL & FUEL ADDITIVE	HEAVY OIL - #4 TANK	Complete recommended actions from SGE Acres report - replace tank bottom and apply protective coating to new bottom and 1 meter of shell. Complete API653 inspection.	2010	1
1297	9739	7203	286053	6967	0	8	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	#1 CONDENSATE POLISHER PLANT	Replace alarm annunciation panels	2011	2
1297	9739	7203	286053	6967	0	8	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	#1 CONDENSATE POLISHER PLANT	Replace control operating panels, subject to decision on generation continues to 2020+.	2014	2
1297	9739	7203	286053	8127	0	8	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	#2 CONDENSATE POLISHER PLANT	Replace alarm annunciation panels	2011	2
1297	9739	7203	286053	8127	0	8	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	#2 CONDENSATE POLISHER PLANT	Replace control operating panels, subject to decision on generation continues to 2020+.	2014	2
1297	9739	7203	286053	8686	0	8	WATER TREATMENT & ENVIRONMENT	WATER TREATMENT PLANT	#3 CONDENSATE POLISHER PLANT	Replace control operating panels, subject to decision on generation continues to 2020+.	2014	1

13.2.5 Switchyard

None apply.

13.2.6 Gas Turbine Generator

None apply.

14 CONCLUSIONS

The following major conclusions are based on the review of the condition assessment documentation in Sections 8 to 12 of this report. They are intended to highlight the key issues at a summary level.

14.1 Overall and Station Wide

1. Holyrood's overall condition is very good. Units 1, 2, and 3 are approximately 41, 40, and 31 years of age respectively. The units' operational ages for the majority of equipment and systems are actually 20, 19, and 16 years respectively, or even less when the typical operating load range of between 70 and 140 MW is considered.

2. Holyrood can, with modest additional refurbishment/investment, be expected to continue to provide reliable electricity generation service to the generation end dates of either 2015 or 2020.

3. Holyrood can, when its units are converted to synchronous condensing operation in or about 2014/2015, with additional life extension investment in the electrical portion of the facility, be expected to make an end date for synchronous condensing of 2041.

4. The Level 2 condition assessments identified in Chapters 8 to 11 and summarized in Chapter 12 are necessary to more accurately assess the ability of the identified systems to meet their respective remaining life requirements. The identified priorities may be useful in assigning funding.

5. The steam turbines are generally considered to be in good condition, with some specific issues identified in Chapters 8 to 10. Their condition supports an inspection/overhaul interval of 9 years supplemented with minor 3 year valve outages, subject to any unexpected changes in conditions found at each outage and in particular their next inspection/overhaul.

6. The generators are generally considered to be in moderately poor condition, particularly Units 1 and 2. Their specifics and suggested actions are identified in Chapters 8 to 10. The condition of all three generators, as well as industry experience and their importance for synchronous condensing to 2041, are not conducive with a nine year generator inspection interval. A six year cycle is more representative of their current condition.

7. The generator operating and monitoring conditions identified in Chapters 8 to 10, particularly those associated with hydrogen conditions and generator monitoring require review and action.

8. Detailed condition assessments of high pressure and temperature feedwater and steam lines, primarily main steam and hot reheat steam lines, on all units have not been carried out for some time and should be considered a very high priority safety and reliability due diligence task.

9. Some of Holyrood's large high pressure and temperature pipe hangers have not been checked and adjusted in some time. The hanger monitoring program appears to have been largely inactive in the last few years.

10. Steam side components of Holyrood's boilers are considered to have considerable remaining life, beyond that required to meet a 2020 end of generation service. A Level 2 condition assessment is necessary for the highest temperature and pressure headers identified in Chapters 8 to 10, as well as those parts not having the necessary inspection and condition assessment data to confirm their remaining life.

11. Holyrood's high pressure feedwater heat exchangers have not been extensively tested, although they are checked and leak tested every year. Those that have been replaced once are considered to have considerable remaining life, enough to meet a 2020 end of generation service. The necessary Level 1 data is not sufficient to confirm this. Level 2 testing, albeit at a lower priority level, is technically warranted based on the process.

12. Holyrood's deaerators are considered to have considerable remaining life, enough to meet a 2020 end of generation service. Inspections are done during the annual boiler inspection and maintenance work. Despite this, however, some internal parts do not have the necessary inspection and condition assessment data to confirm this and require some Level 2 work.

13. Holyrood's low pressure feedwater heat exchangers appear to be original equipment and have not been tested beyond annual leak testing. It is likely that most are capable of meeting the 2020 end of generation service. The necessary Level 1 data is not sufficient to confirm this.

14. Holyrood's programs for major equipment, pumps, and motor inspection scheduling, and overall PM process seem reasonable and effective.

15. Holyrood's large 4 kV motors (boiler feedwater pumps, forced draft fans, condensate extraction pumps, and cooling water pumps) are at the stage in their physical/operating lives where reliability becomes an issue. Existing test data does not suggest an imminent issue. No spares currently exist for these long lead purchase items that would minimize outage duration and are considered to be warranted to maintain high availability.

16. Much of the plant switchgear (all units and common facilities), primarily many breakers and motor control centres, has reached a physical age where extensive replacements over the next three to ten years will be critical for plant reliability. An optimization program involving significant new purchases and sparing is required to balance costs and priorities in light of the plant's role going forward.

17. Condensate polisher annunciator and control panels on all units, with the exception of the new Unit 3 annunciator, are considered obsolete and in need of replacement. No information on the condition of any of the condensate polishers was identified.

18. The control room, while functional, is dated and a mixture of various technologies. A study of the appropriate modifications and upgrades to improve its efficiency and effectiveness is warranted.

14.2 Site Conditions

1. The site is in generally in good condition, especially with the rehabilitation of the main oil tank farm spill retention berms.

2. The plant access road is in very poor condition and needs repair to reduce probability of future accident. On site roads are in fair condition, likely to require replacement/refurbishment over next five years.

3. The on-site landfill is nearing end of life and requires management as well as expansion or replacement.

14.3 Common Facilities

1. The electrically heat traced heavy fuel oil transfer pipe from the fuel off loading dock to main storage tanks has failed in the past and the temporary fix cannot be expected to sustain operation for long term. It is a reliability issue and needs to be replaced immediately to avoid having a major impact on plant operations.

2. The heavy oil day tank does not appear to have been internally inspected since its installation in the late 1980's and should be internally inspected.

3. The transformers have all reached physical and operational ages where reliability degradation and susceptibility to failure (particularly as a result of potential system upsets) are significant concerns. These units are typically long lead replacement or repair items. There is some existing sparing and configurational sparing currently in place. Refurbishment and condition monitoring is undertaken on a regular basis, but condition monitoring should be more frequent and extensive.

4. Circulating water intake and discharge structures and large concrete pipes from the pumphouses to the condensers and to the discharge siphon pits have not been inspected for some time and should be inspected in near future.

5. The condition of underground services (raw water, fire water, grounding, waste water piping, and lighting) was identified as uncertain. Development of an appropriate assessment and/or monitoring program is desirable, although not a detailed Level 2 assessment in most cases.

6. Some older systems are single contingency failure candidates, having no current contingency option. Their condition needs to be assessed and monitored. These include the dam at Quarry Brook, the raw water supply line from the damsite to the Stage 1 pumphouse, the original water treatment plant clarifier, sandfilters, and clearwell. Inspections and any resulting work to mitigate unplanned (not necessarily long) shutdowns during critical periods are warranted.

7. In the period from 2015 through 2025, the powerhouse and pumphouse roofs will be reaching end of life due to aging. Some minor leaks are occurring now. A plan to effectively mitigate equipment damage from roof leaks will be required.

8. Some environmental systems and equipment are inconsistent with current or anticipated short term requirements. They need to be inspected and/or considered for refurbishment or replacement to bring them up to current and expected performance levels. These may include new CEM systems, improvements to waste water basin discharge treatments, oil filled exciter transformer replacement due to PCB levels (when and if new PCB regulations are implemented), and oily water separator and pipes.

9. A new building heating system (auxiliary boiler/steam or electric) will be needed after 2015 when the plant unit boilers may not be operating during winter peak periods. Some existing steam fed unit heaters and piping systems also appear to be in poor condition and likely need replacement.

10. The powerhouse elevator and the administration building elevator will be required up to 2041. The powerhouse elevator is expected to need extensive refurbishment/replacement in the 2012 to 2015 period.

11. The waste water basin building needs repair and modification or replacement to better address current corrosion, safe egress, and ventilation needs.

12. The diesel fire water pump is at end of life and requires replacement. The capacity requirement of the new fire protection system is higher than in the past due to recent expansion. The new pump, and possibly a new electric pump, needs to be capable of handling the additional requirement.

13. The Stage 2 diesel is original equipment at the end of life and needs to be replaced.

14. The Stage 1 air compressors are near end of life and need to be replaced in the next few years.

14.4 Unit 1

1. The generator stator winding is in poor condition. Its next overhaul is in 2012. It has a significant likelihood of encountering issues prior to 2021 when its next overhaul would currently be scheduled. Given an end date of 2041, a rewind in 2012 is recommended. A later date is likely to result in reliability degradation and higher potential for failure.

2. The steam turbine is in generally good condition and is expected to make the 2020 generation end date. It continues to have main and intercept valve issues, stud bolt issues, and turning gear issues. These should be examined further and/or addressed at the next 2012 major overhaul.

3. The boiler is generally in good shape, especially with the change in fuels. Some legacy effects of history of high sulphur, high vanadium oil use is likely to continue – tube leaks and thinness. Others such as economizer plugging, air preheater corrosion and plugging are expected to continue to diminish.

4. The stack breeching requires an upgrade. The steel casing and support structure has localized corrosion and the internal insulating liner has significant deterioration.

There are also options for improving the efficiency of the facility in the short term such as:

a) Addition of reheat boiler tubes to improve reheat steam conditions and cycle efficiency; and

b) Repairing previously damaged (but not fully repaired) steam turbine elements or upgrading existing elements with more efficient designs

14.5 Unit 2

1. The generator stator winding is in poor condition. Its next overhaul is in 2014. It has a significant likelihood of encountering issues prior to 2023 when its next overhaul would currently be scheduled. Given an end date of 2041, a stator rewind in 2014 is recommended, subject to findings in 2012 on Unit 1.

2. The steam turbine is in generally good condition and is expected to make the 2020 generation end date. It continues to have main and intercept valve issues, stud bolt issues, and turning gear issues. These should be examined further and/or addressed at the next 2014 major overhaul.

3. The boiler is generally in good shape, especially with the change in fuels. Some legacy effects of history of high sulphur, high vanadium oil use is likely to continue – tube leaks and thinness. Others such as economizer plugging, air preheater corrosion and plugging are expected to continue to diminish.

4. The stack breeching requires an upgrade or replacement. The steel casing and support structure has localized corrosion and the internal insulating liner has significant deterioration.

There are also options for improving the efficiency of the facility in the short term such as:

a) Addition of reheat boiler tubes to improve reheat steam conditions and cycle efficiency; and

b) Repairing previously damaged (but not fully repaired) steam turbine elements or upgrading existing elements with more efficient designs

14.6 Unit 3

1. The generator is in reasonable condition. Its next overhaul is in 2016. Nevertheless, it has a significant likelihood of encountering rotor winding issues prior to its next currently scheduled outage in 2025. Given an end date of 2041, a rotor rewind may be warranted in 2016 or earlier than 2025.

2. The steam turbine is in generally good condition and is expected to make the 2020 generation end date. It continues to have main and intercept valve issues, as well as stud bolt issues. Its mechanical governor system also experiences some control issues. These should be examined further and/or addressed at the next 2016 major overhaul.

3. The boiler is generally in good shape, especially with the change in fuels. Some legacy effects of history of high sulphur, high vanadium oil use is likely to continue – tube leaks and thinness. Others such as economizer plugging, air preheater corrosion and plugging are expected to continue to diminish.

4. The stack breeching requires an upgrade or replacement. The steel casing and support structure has localized corrosion and the internal insulating liner has significant deterioration.

5. The Unit 3 control room relay panels cannot accommodate the current and required wiring and need to be replaced for safety reasons.

6. When decoupled from the turbine, Unit 3 generator has no thrust bearing to address lateral movement during synchronous condensing operation and requires modification to reduce long term vibration and damage.

7. Unit 3 Exciter is considered at end of life and the entire system should be replaced.

14.7 Black Start Gas Turbine

1. The black start gas turbine is 42 years old, but with few operating hours and several thousand starts and stops.

2. The unit is experiencing significant reliability (starts/stops, operation) and safety problems.

3. The gearbox has been a source of oil leaks and fires, likely a seal issue that has existed for some time. As a result, recent fires have limited the unit's use.

4. The power turbine, gas turbine, gearbox, and generator are overdue for a major inspection/overhaul, based on recent boroscope and on-site power turbine inspections and industry practice.

5. The stack is badly corroded and appears to be leaking water into the back end of the gas turbine.

6. The intake has corrosion at the base and appears to have contributed to front end corrosion of the gas turbine, possibly an issue with the current filter media.

7. The fuel receiving system and lube oil cooler are outdoors and are badly corroded.

14.8 Switchyard

1. The transformers have all reached a physical and operational age where reliability degradation and susceptibility to failure (particularly as a result of potential system upsets) are significant concerns. These units are typically long lead item replacements. There is some existing sparing and configurational sparing (essentially parallel or potentially parallel systems). Refurbishment and condition monitoring is undertaken on a regular basis, but condition monitoring should be more frequent and extensive.

2. Most switchyard switchgear, primarily motor operated breakers, is at physical ages where extensive refurbishment and/or replacement over the next five to ten years will be necessary for station reliability. Hydro has a switchyard inspection program and continuously repairs and modifies breakers and switches as required. Development and implementation of an optimization program which would also include other important switchyard equipment such as potential transformers (PT's) and current transformers(CT's) involving significant new purchases, refurbishing, and sparing to balance costs and priorities in light of the station's role going forward is desirable.

14.9 Facility Management

1. Overall facility management is excellent, and demonstrates a practice of continuous improvement. It is evident that Holyrood staff and management have worked hard to maintain high standards of operation and maintenance and safety, while recognizing economic factors.

2. Existing document management systems and implementation at the plant are difficult to work with, particularly by external contractors. Many records are only available from specific individuals.

3. Technical staffing is good, but some additions to on-site operations engineering support are likely warranted in the area of civil engineering. Succession planning in critical technical and operation areas is underway, but remains a key issue throughout the industry.

4. Operator training for situations not currently standard is needed, such as procedures for more frequent starting and stopping, lower load operation, and addressing critical generator indicators. A simulator may be warranted for training given the long periods of non-operation.

15 RECOMMENDATIONS

15.1 Overall and Station Wide

1. Implement the recommended Level 1 and 2 condition assessment tasks identified in Chapters 8 to 11 and summarized in Chapter 12, including augmented steam turbine and generator overhauls at their next normal overhaul date to the extent economically practical.

2. Retain the 9 year major inspection/overhaul interval and minor 3 year valve outage timing for the steam turbines, subject to any unexpected changes in conditions found at their inspection/overhauls and, in particular, at their next inspection/overhaul. Undertake the steam turbine pre-outage actions identified in Chapters 8 to 10.

3. Modify the generator inspection and overhaul interval back to every six years. Address the specific actions identified in Chapters 8 to 10, in particular those permitting better performance baselining in the balance of 2010 and 2011.

4. Perform in 2011 limited generator testing, with rotor in and on all units but particularly on Unit 1, to the extent safe and economically practical to obtain baseline data. Undertake work needed to scope out the details of the inspection/testing and stator rewind during the 2012 Unit 1 outage.

5. In 2011 and 2012, carry out a detailed condition assessment of high pressure and temperature feedwater and steam lines on all units as a very high priority safety and reliability due diligence task. Plan and implement an extensive high pressure and temperature pipe hanger inspection program as part of the plant's PM, safety, and reliability due diligence programs.

6. Carry out Level 2 inspections and testing in 2012, 2013, and 2014 for Units 1, 2, and 3 respectively on boiler components identified in Chapters 8 to 10.

7. Carry out Level 2 inspections and testing in 2012, 2013, and 2014 for Units 1, 2, and 3 respectively on high pressure heater components identified in Chapters 8 to 10.

8. Carry out Level 2 inspections and testing in 2012, 2013, and 2014 for Units 1, 2, and 3 respectively on deaerator components identified in Chapters 8 to 10.

9. Carry out Level 2 inspections and testing on low pressure heaters in 2011 for Units 1, 2, and 3.

10. Maintain existing programs for major equipment, pumps, and motor inspection scheduling and overall PM process.

11. Procure one spare 4 kV motor for each of the boiler feedwater pumps, the forced draft fans, condensate extraction pumps, and the cooling water pumps – primarily designed for Units 1 and 2, but with plans on how to use them with Unit 3 as necessary.

12. Develop and implement an optimized plan for station switchgear (all units, common facilities), primarily breakers and motor control centres, addressing a combination of extensive replacement and sparing to maintain station reliability without interrupting normal unit operation.

13. Inspect all condensate polishers in 2011. Replace Units 1 and 2 remaining enunciator panels (Unit 3 enunciator panel was replaced in 2007). Assess the cost-benefit of replacing polisher control panels on all units considered obsolete in light of generation end of service timeline.

15.2 Site Conditions

1. Negotiate to have the plant access road repaired to reduce probability of future accident.

2. Develop an onsite road replacement/refurbishment plan in 2011 addressing issues over next five years.

3. Close and manage existing on-site landfill in parallel with opening of a new on-site facility or expansion of the current one.

15.3 Common Facilities

1. Replace the electric heat tracing for the heavy fuel oil transfer pipe line from the off loading dock to the main storage tanks in 2010 or early 2011.

2. Internally inspect the heavy oil day tank in 2011 for regulatory purposes.

3. Perform transformer oil gas analyses in 2010 and 2011 and complete the Hydro transformer electrical testing as per the schedule in Chapter 11.

4. Perform underwater inspections on circulating water intake and discharge structures and piping in 2011. Perform walk down or remote integrity inspections of the large concrete pipes from the pump houses to the condensers and to the discharge siphon pits and inspect the stop log structure in 2011.

5. Develop a program to assess the condition of underground services (raw water, fire water, grounding, waste water piping, and lighting) as the current condition is not clear.

6. Undertake Level 2 integrity inspections of single contingency failure candidates including the dam at Quarry Brook, the raw water supply line from the dam site to the Stage 1 pumphouse, and the original water treatment plant clarifier, sand filters, and clearwell.

7. Develop a powerhouse and pumphouse roof replacement plan.

8. Improve, refurbish or replace CEM systems, waste water basin discharge treatment systems, oil filled exciter transformers (if and when new PCB regulations are implemented), and the oily water separator and pipes.

9. Develop a plan for a new building heating system (auxiliary boiler/steam or electric) needed after 2015. Assess and replace existing steam fed unit heaters and piping systems that are in poor condition.

10. Refurbish or replace the existing powerhouse elevator in the 2012 to 2015 period, and assess the timing requirements for a new administration building elevator.

11. Repair the waste water basin building to address current corrosion, safe egress, and ventilation needs in 2012.

12. Replace in 2011 the diesel fire pump, which is at end of life, in order to match the capacity requirements of the new fire protection system. Replace the electric firewater pump if capacity is less than the new requirement.

13. Replace the Stage 2 diesel generator in or about 2014.

14. Replace the Stage 1 air compressors that are near their end of life in 2014 and 2015.

15.4 Unit 1

1. Undertake a generator stator rewind as part of the 2012 generator overhaul. Initiate planning early in 2011. Undertake the generator actions list in 2010 and 2011.

2. Address issues and action with steam turbine, including wok on main and intercept valve issues, stud bolt issues, and turning gear issues as per sections 8, 9, and 10 of this report.

3. Refurbish stack breeching per current plans.

Where economically feasible, assess and implement those efficiency improvement options for the facility which have short term economic benefits, e.g.:

a) Addition of reheat boiler tubes to improve reheat steam conditions and cycle efficiency.

b) Repair of previously damaged (but not fully repaired) steam turbine elements or upgrading existing elements with more efficient designs.

15.5 Unit 2

1. Undertake a generator stator rewind as part of 2014 generator overhaul. Initiate pre-work early in 2013. Undertake early generator actions list in 2011.

2. Address issues and actions with steam turbine, including work on main and intercept valve issues, stud bolt issues, and turning gear issues.

3. Refurbish stack breeching per current plans.

Where economically feasible, assess and implement those efficiency improvement options for the facility which have short term economic benefits, e.g.:

a) Addition of reheat boiler tubes to improve reheat steam conditions and cycle efficiency.

b) Repair of previously damaged (but not fully repaired) steam turbine elements or upgrading existing elements with more efficient designs.

15.6 Unit 3

1. Undertake a generator rotor rewind at the next generator overhaul in 2016 or, with some additional reliability risk, between 2020 and 2022 subject to the findings of the 2016 inspection.

2. Address issues and actions with the steam turbine, including work on main and intercept valve issues, and stud bolt issues.

3. Assess the cost-benefit of replacing the existing steam turbine mechanical governor system in 2011 for implementation during the 2013 minor valve outage.

4. Refurbish stack breeching per current plans.

5. For safety reasons, replace the Unit 3 control room relay panels as soon as practical to accommodate the current and required wiring.

6. Implement Unit 3 generator thrust bearing retrofit to address lateral movement during synchronous generator operation to eliminate long term vibration and damage.

15.7 Black Start Gas Turbine

1. In 2010 inspect/assess the power turbine, gas turbine, gearbox, and generator without removing the unit to confirm major inspection/overhaul requirement.

2. Complete 2010 boroscope inspections on gas and power turbine, combustor, and gearbox.

3. Inspect and assess in 2010 the air intake and exhaust stack structure.

4. Undertake in 2010 off-site overhaul of power turbine and gas turbine, and on-site or off-site gear-box inspection and gearbox seal replacement.

5. Undertake in 2011 detailed inspection/testing of generator and electrical auxiliaries.

6. Develop a design and implement the replacement the fuel handling and lube oil coolers inside an enclosure.

7. Assess in 2010 the alternative of replacing the black start generator with a new or refurbished unit.

15.8 Switchyard

1. Implement identified Level 2 transformer gas in oil testing in 2010 and 2011. Catch up on backlogged electrical testing using full Hydro test protocol and report during these and future regularly scheduled electrical testing periods.

2. Considering the requirements going forward, assess the cost-benefit of additional transformer equipment sparing and configurational sparing possibilities. Undertake more frequent and complete Hydro condition monitoring.

3. Maintaining station reliability without interrupting normal unit operation, develop and implement an optimized plan for switchyard equipment such as switchgear (primarily older breakers) as well as other components such as potential transformers (PT's) and current transformers (CT's), addressing a combination of extensive refurbishment and/or replacement and sparing.

15.9 Management

1. Upgrade the existing document management procedures, systems, and resources at the plant

2. Implement current station staffing plan, including some moderate additions in operational, on-site engineering support. Develop and implement a succession planning process.