2023-27
POWERLINK QUEENSLAND REVENUE PROPOSAL

Project Pack – PUBLIC

CP.02360
Nebo Transformers 3 and 4 Replacement

CP.02360 – Nebo Transformers 3 and 4 Replacement

Project Status: Not Approved

1. Network Need

H011 Nebo Substation, approx. 90km southwest of Mackay, is a major 275/132kV network injection point for North Queensland and supplies Nebo township. Nebo Substation contains two aged 132/11kV, 5MVA transformers (T3 and T4). An outage on these transformers would leave up to 3MW and up to 50MWh of customer load per day at risk[2].

A Condition Assessment (CA) conducted in March 2020 identified that T3 and T4, which are both 37 years old (commissioned in 1983), are approaching the end of their technical service life[1]. T3 and T4 are exhibiting the following end of life attributes: HV bushings have exceeded their design life, minor oil leaks and deteriorated gaskets, areas of Grade 3 (Medium) and Grade 4 (High) corrosion, deteriorated transformer bunds, deteriorating oil quality, and 11kV control cubicles in poor condition. The CA found that a series of refit works could be undertaken to extend the useful life of the transformers to 2031. The associated 11kV switchgear is obsolete and is approaching the end of its technical service life, with no refit identified as credible.

Energy Queensland forecasts confirm there is an enduring need to maintain electricity supply to the Nebo area. The removal or failure of T3 or T4 at Nebo Substation would violate Powerlink's Transmission Authority reliability obligations (N-1-50MW / maximum 600MWh unserved energy) as well as Energy Queensland's reliability standard[2].

Further decline in T3 and T4 asset condition, or that of the associated 11kV switchgear, increases the risk of failure that may cause network outages, safety incidents and additional network costs to replace assets under emergency conditions. The CA recommends reinvestment in the asset prior to 2023 to manage these risks and ensure network reliability. Failure to address the existing condition of this asset is likely to result in non-compliance with Powerlink's reliability and safety obligations[6].

2. Recommended Option

As this project is currently 'Not Approved'.

The current recommended option is to replace T3 and T4 and the 11kV switchgear at Nebo Substation in a single state by 2022[4].

The following options have been identified to address the condition issues of the transformers:

- Do Nothing – rejected due to non-compliance with reliability standards and safety obligations.
- Staged Replacement – Stage 1 replacement of 11kV switchgear and life extension of T3 & T4 (2022). Stage 2 Replacement of T3 & T4 (2031). This option was rejected as single stage replacement in favour of the NPV least-cost single-stage replacement option.
- Alternative Staged Replacement – Stage 1 replacement of 11kV switchgear and T3, and life extension of T4 (2022). Stage 2 Replacement of T4 (2031). This option was rejected in favour of the NPV least-cost single-stage replacement option.
- Non Network Option – an option to establish isolated distribution system via gas or diesel generators was considered financially non-viable due to high establishment and running costs.

Figure 2-1 shows the current recommended option reduces the forecast risk monetisation profile of Nebo Substation T3 & T4 transformers to less than $50k per annum from 2023 until 2034. The recommended option will extend the asset life by 40 years.

Where a 'Do Nothing' scenario is adopted, the forecast level of risk associated with the asset escalates to over $100k per annum in 2028. This is predominantly due to network risks (unserved energy) associated with potential concurrent outages of T3 and T4[3].

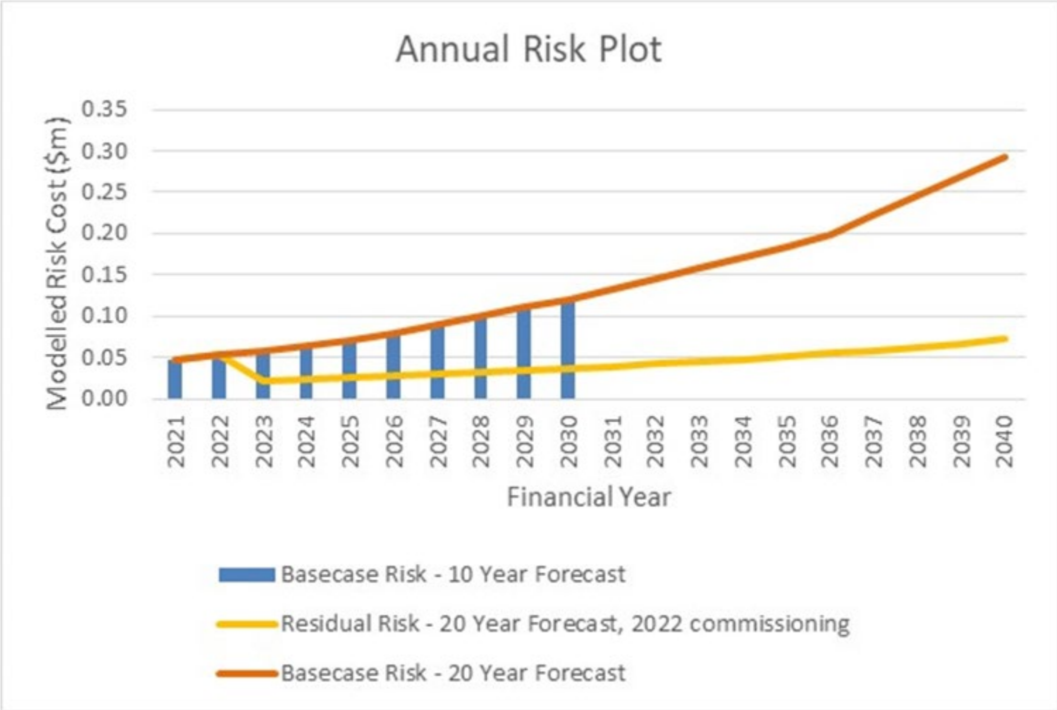

Figure 2-1 Annual Risk Monetisation Profile (Nominal)

3. Cost and Timing

The estimated cost to replace T3 and T4 as a single stage replacement is $5.6m ($2019/20 Base).

Target Commissioning Date: June 2022

4. Documents in CP. 02360 Project Pack

Public Documents

1. T3 & T4 Transformer Condition Assessment H011 Nebo Substation
2. CP.02360 - H011 Nebo Transformer 3 & 4 Replacement – Planning Statement
3. Base Case Risk and Maintenance Costs Summary Report CP.02360 Nebo Transformer T3 & T4 Replacement
4. Project Scope Report CP.02360 Nebo Transformer 3 & 4 Replacement
5. Concept Estimate for CP.02360 – H011 Nebo Transformer 3 & 4 Replacement

Supporting Documents

6. Asset Reinvestment Criteria - Framework
7. Asset Management Plan 2021

T3 &T4 Transformer Condition Assessment H011 Nebo Substation

Asset Category	Power transformers	**Author**	[redacted]	**Authorisation**	[redacted]
Activity	Condition assessment - primary substation plant, power transformers.				
Reviewed by:	[redacted]		Review Date:		
Document Type	Report	**Team**	Substation Strategies		
Issue date	13/03/2020	**Date of site visit**	16/12/2019		

Date	Version	Objective ID	Nature of Change	Author	Authorisation
30/3/2020	2.0	A3309779			
26/10/2015	1.0	A2371244			

***Note:** Where the indicator symbol ☼# is used (# referring to version number), it indicates a change / addition was introduced to that specific point in the document. If the indicator symbol ☼# is used in a section heading, it means the whole section was added / changed.*

IMPORTANT: - As this condition assessment is a snapshot in time and subject to the accuracy of the assessment methodology and ongoing in-service operating environment, the recommendations and comments in this report are valid for 3 years from the date of the site visit stated above.

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1 SUMMARY

A condition assessment was performed on transformers T3 and T4 each rated at 5 MVA and being 132/11 kV bulk supply transformers installed at H011 Nebo substation to determine their residual service life and any issues that may need to be considered. No internal inspections nor electrical tests were performed on these in-service transformers for this assessment and due to the presence of restricted access zones at this site, only limited onsite inspection was performed. Therefore, it is based on the available condition data, previous condition assessment report dated in 2015 and limited visual inspection on site.

This report does not attempt to cover any detailed economic analysis of the viability of rectifying the highlighted issues associated with these transformers but provides a condition assessment of the "key" parameters for these transformers and reinvestment recommendations for their future service.

However, the transformer reinvestment decision should also consider the associated 11kV switchgear. Although outside of the scope of this condition assessment, visual inspection was made of the 11kV switchgear associated with these transformers. These are VG-35 HI VAC 36kV rated SF6 circuit breakers with spring mechanisms, manufactured by Hitachi (not manufactured anymore). The circuit breaker and cable termination box are all enclosed within one cabinet. The cabinets are substantially corroded and plastic components have failed, possibly due to exposure to excessive heat. Powerlink does not have any spare parts for this type of circuit breaker.

The condition of the 11kV switchgear increases substantially the risk of the transformers experiencing a significant through fault.

1.1 INVESTIGATION:

A brief on-site inspection of T3 &T4 was performed on the 16th December 2019 supplemented by a detailed review of all available maintenance data and the major findings which may impact its serviceability are discussed in this report. The substation Operating Diagram is shown in Figure 1.

[redacted]

Figure 1: H011 132 kV Nebo Substation Operating Diagram

TABLE 1: SUMMARY OF CONDITION AND MINIMUM REFURBISHMENT WORKS:

Parameter	Estimated Residual Life		Further Comments
	T1	T2	
Anti-corrosion system	10-15 years	10-15 years	Existing paint system for both T3 & T4 is in reasonable condition – although any G3 or G4 should be addressed.
Winding paper life	10-15 years	10-15 years	
Winding mechanical stability	5-10 years	5-10 years	Clamping structure considered to be weak. High uncertainty in remaining stability – significant through faults will impact remaining life.
External HV bushings	0-3 years	0-3 years	All bushings are approaching 40 years with porcelain housings and have significantly exceeded their expected service life.
Insulating Oil	0-3 years	0-3 years	Increasing oil acidity and oil resistivity suggest nearing end of life. Silica gel breathers require replacement.
Repairs to leaking gaskets.	5-10 years	5-10 years	Notable deterioration of gaskets, but only minor oil leaks present.
Cubicles	5-10 years	5-10 years	Subject to rectification of exposed terminals (not compliant with AS3000).
OVERALL RESIDUAL LIFE	**5-10 years**	**5-10 years**	Subject to minimum refurbishment/refit works

TABLE 2: MINIMUM WORKS TO EXTEND USEFUL LIFE OF TRANSFORMERS

Transformer T3	Transformer T4
• replace oil; • replace HV bushings; • replace Buchholz relay; • replace any parts with corrosion Grade 4; • repair and address minor oil leaks; • replace main tank and OLTC silica gel breather; • upgrade main control cubicle to AS3000 requirements, treat corrosion on cubicle and test/mange asbestos containing materials (secondary cabling must not be disturbed); and • inspect and reseal bund area cracks.	• replace oil; • replace HV bushings; • replace Buchholz relay; • replace tap changer shaft couplings; • replace any parts with corrosion Grade 4; • replace main tank and OLTC silica gel breather; • upgrade main control cubicle to AS3000 requirements, treat corrosion on cubicle and test/manage asbestos containing materials (secondary cabling must not be disturbed); and • inspect and reseal bund area cracks.

2 H011 NEBO TRANSFORMER T3

2.1 Identification Details:

Transformer T3 details are shown below.

- Manufacturer - Westralian Transformers Pty Ltd
- Contract - H409/82
- YOM = 1983 (37 years)
- Commissioned 1983
- Capacity - 5 MVA ONAN
- Voltage 132/11 kV
- Serial No. 47207
- SAP Equipment No. 20004062
- Reinhausen OLTC model no. MS111 300 60/13 12 23 3G (C/F), serial no. 88867
- OLTC counter reading = 70191 (Sept.2019)

This transformer has an on-board cooler bank consisting of only two radiator panels.

2.2 Onsite Inspection:

2.2.1 Anti-corrosion System:

Maintenance records do not provide any indication of corrosion issues, but visual inspection on site undertaken in 2015 and 2019 identified a number of corroded parts with corrosion levels varying from Grade 1 to Grade 4 (Figures 4, 5, 6, 7, 8, 9, 10 & 11). There are no records either indicating the transformer has been partially or fully painted (Figure 12). The original coating is oxidised in most locations (Figure 2) and the paint is falling from radiators especially (Figure 3).

Figure 2- Transformer coating condition

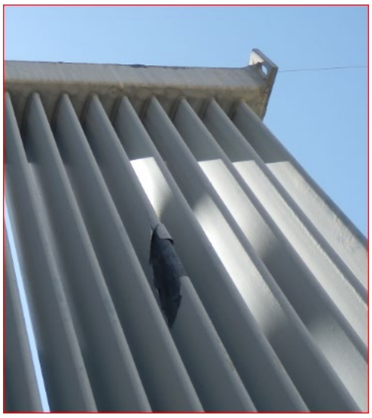


Figure 3 – Paint peeling from radiators

Figure 4–Grade 4 Corrosion

Figure 5 - Grade 2 Corrosion

Figure 6 – Grade 3 Corrosion

Figure 7 –Corrosion Grade 2

Figure 8 – Corroded Part

Figure 9–Tank Base Condition

Figure 10 - Minor Bolt Corrosion

Figure 11 – Tank Lid Corrosion

Figure 12 – Evidence of Painting

Whilst corrosion is present on many parts of this transformer, it is associated mainly with replaceable parts and will not determine the end of transformer service life unless the cost of their replacement makes it uneconomical.

2.2.2 Structural:

There were no signs of any structural issues associated with main supports for the cooler bank or main tank.

2.2.3 Oil Leaks:

According to the maintenance records, no oil leaks were detected. Visual inspection in 2015 and photos form 2019 indicate that there is at least one small oil leak (Figure 13) present around the sight glass on the conservator tank (most likely due to the sight glass gasket failure). It is expected that more oil leaks may eventuate based on the observed deteriorated condition of the gaskets (Figure 14).

Figure 13 –Minor Oil Leak

Figure 14 – Deteriorated Gasket

2.2.4 Silica Gel Breathers:

The conservator is shared between OLTC and main tank and is equipped with a single homemade type breather, not allowing inspection of the oil bath on the bottom due to the design of the breather. This makes it very difficult to determine if the oil bath needs maintaining or is functioning correctly as a particulate filter.

In addition to this silica gel breather, the transformer is equipped with two more breathers, one for the earthing transformer and one for the earthing transformer disconnect chamber – all are homemade types with the same issues as mentioned above.

Figure 15 – Three desiccant breathers

2.2.5 Temperature Indication Instruments:

Figure 16 – WTI and OTI (Installed in Shared Control Cubicle)

Both the single winding hot spot and top oil temperature monitoring instruments have been replaced some years ago and were installed inside the Main Control Cubicle / tap changer control cubicle instead of on the side of the main tank where the full sun exposure accelerated their aging.

2.2.6 Control Cubicles:

There is only one shared cubicle housing both transformer and OLTC controls. Whilst it was compliant when installed, presently a number of issues would not make it compliant with modern AS 3000 (Wiring Rules), the major issue being exposed 400 V AC terminals. It is recommended to have, as a minimum, plastic covers installed and materials to be checked for the presence of asbestos to ensure the transformer can be maintained in a safe manner until it is replaced.

2.2.7 Transformer Bushings:

High voltage bushings are oil impregnated paper (OIP) bushings in porcelain housing and have now being in service for 37 years. In accordance with maintenance practices the bushing capacitance and dielectric loss angle (DLA) are monitored every 6 years, but unfortunately only test results form 2000 and 2006 are recorded in SAP. The next routine measurements are due in 2023. The bushings' manufacturer recommends 25 years to be considered as the expected OIP bushing service life. There is insufficient data to calculate the probability of failure for this type of bushing beyond 40 years old, as historically the majority of power transformers required replacement after 40 years in service.

Due to the bushing service age and aging mechanisms associated with oil impregnated paper, it is no longer sufficient to monitor their capacitance and DLA every 6 years.

It is recommended to preventively replace these bushings within 3 years rather than leaving them in service and adopting an increased monitoring frequency of once a year. Whilst either option is acceptable, preventive bushing replacement is likely to be the lowest cost and safer option for personnel considering the costs and exposure of personnel necessary to switch the transformer out of service for these measurements to be undertaken. The previously used on-line DLA monitoring instruments did not perform reliably.

The LV bushings are hollow porcelain with no other insulation material subject to aging, and therefore should last for many more years.

2.2.8 On Line Tap Changer (OLTC):

This OLTC has only done a very small number of operations and has been maintained at regular intervals. There are no known failure modes associated with this type of tap changer. It is noted that that it needed to be adjusted manually to be able to control the voltage at the 11kV Ergon bus. As a consequence, it is operating in a low range of taps. This will have to be reviewed and managed operationally.

2.2.9 Transformer Bund & Oil Separation System:

The transformer bund is in a deteriorated condition and will need to be resealed within the next 3 years (2023) to ensure that any oil leaks that cannot be repaired will not allow oil to escape from the bunded area. In addition, a 2nd stage oil-water separator (such as a SPEL above ground system) will need to be added to the existing oil separation tank to manage hydrocarbon release within acceptable limits. This recommendation can be re-assessed in 5 years as it is dependent on the severity of oil leaks.

2.3 Oil and Insulation Assessment:

A desktop assessment was performed on the oil laboratory test data for this transformer and the following information is derived.

2.3.1 Oil Quality:

When last tested for polychlorinated biphenyl (PCB) content in 2014, 0 mg/kg of PCB was detected in oil. Based on this, this transformer is classified as "PCB free".

It has tested positive to the presence of corrosive sulphur and has been passivated with the level of passivator maintained to prevent further copper corrosion.

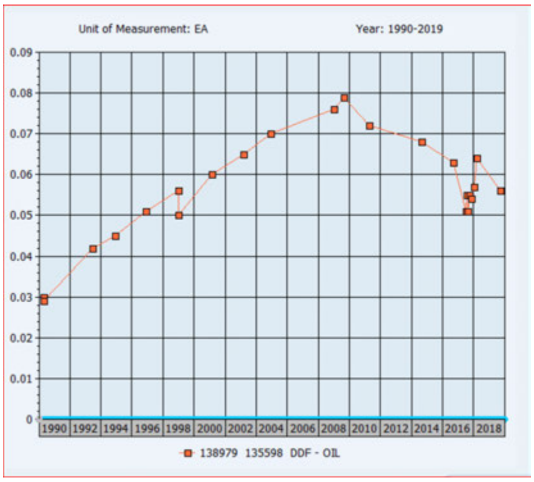


Figure 17– Oil DDF trend

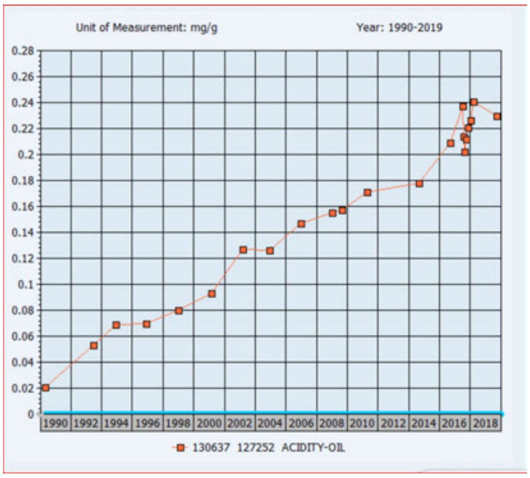


Figure 18 – Oil Acidity Measurements

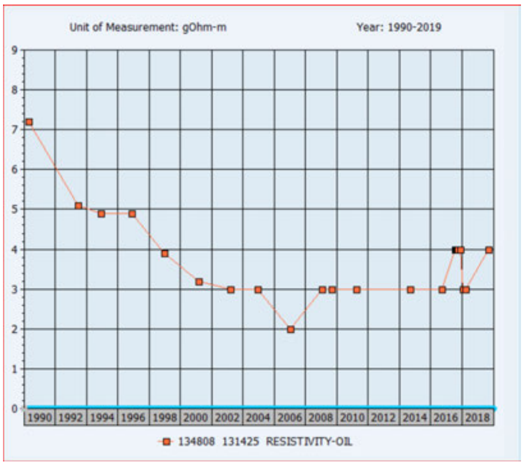


Figure 19 - Oil Resistivity Trend

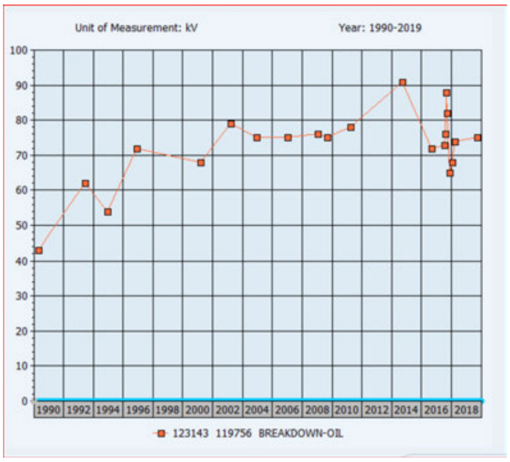


Figure 20 – Oil Breakdown Voltage

As can be seen from the graphs above, the oil quality, although still within acceptable limits, is deteriorating, especially oil acidity and oil resistivity suggesting the end of service life for oil within 3 years (2023).

It is obvious that an increase in oil sampling occurred in 2016 to check transformer condition due to the increase in CO and CO2 during this period and to monitor passivator content. The silica gel breather was replaced during this period.

Assuming that all measurements are adjusted to 20 deg C temperature (unlikely for measurements prior to 2000) and using the SD Myers tool, Figure 22 shows the moisture in solid insulation. When looking at these results, one should be reminded that due to light loading of this transformer, it is possible that moisture equilibrium is such that more moisture is in oil rather than in solid insulation. In any case, the measurements in period 2000-2018 all show moisture content to be below 4%. The calculated moisture in insulation for this transformer at present is still below 4% level beyond which the risks of insulation failure under the right combination of specific operating / environmental conditions is heightened.

Figure 23 below shows Powerlink's approach towards managing changing moisture levels within transformers insulation. If oil is to be replaced within 3 years, then the moisture in oil will decrease significantly for at least a short period of time after which the moisture "stored" in solid insulation will migrate to oil. The oil processing will not assist with acidity and drying may cause damage to the already aged insulating paper.

The only way of monitoring oil condition (rather than replacing it) is to install an on-line moisture and temperature probe in the main oil stream and monitor data under varying loads / temperatures.

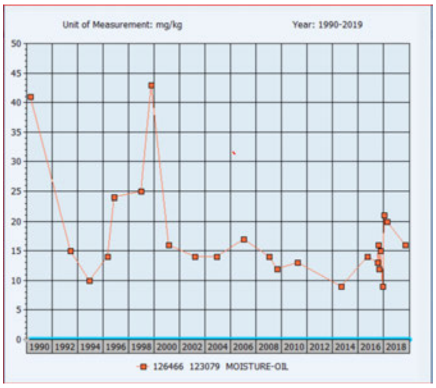


Figure 21– Moisture In Oil

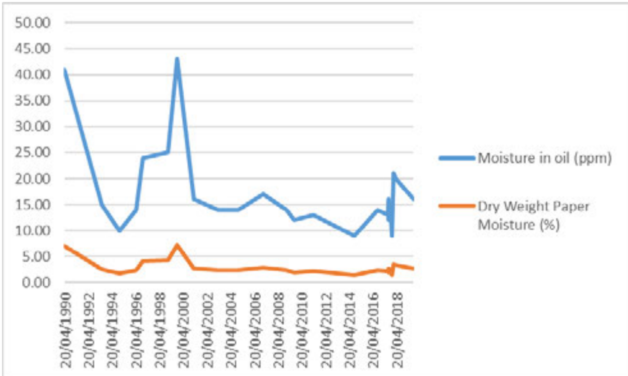


Figure 22 – Dry Weight Paper Moisture (SD Myers)

Moisture % in Cellulose Insulation by Dry Weight	Powerlink's Policy for Recommended Action
≤ 0.5	Take no action. Insulation is considered dry.
1% - 2%	Acceptable but correlate moisture with nameplate age, loading history, leaks, breather maintenance etc.
2% - 3%	Consider if planning for a suitable period to dry insulation before it reaches about 3% is viable / economic.
3% - 4%	In need of drying if economic. Entering the "*At Risk*" zone.
5% - 6%	There is a risk of internal flashover under certain rapid temperature variations. Can also lead to insulation gassing problems.
7%	Failure is imminent.

Figure 23- Powerlink's guideline for managing moisture levels in power transformer insulation

The moisture in oil being below 20 deg C is also within acceptable limits, although there were some high readings prior to 2000 which is likely due to the moisture readings not being adjusted for different oil temperatures. Since 2000, Powerlink has adopted a methodology that involves moisture readings to be all adjusted to the equivalent measurements at 20 deg C to enable easy comparison and trending.

Oil tests show that oil was tested positive for corrosive sulphur most likely due to the different oil type being used for topping up oil level, as the original oil is unlikely to be positive to corrosive sulphur. As mentioned above, since 2016 this is managed by adding passivator so that copper corrosion is not progressing.

2.3.2 Transformer Loading

This transformer has only one cooling mode (ONAN) so it has no oil pumps nor radiator cooling fans.

The peak loading in MVA on the 132 kV side of this transformer over period 25/03/2007 to 26/03/2020 is 7 MVA and occurred in December 2014. While this exceeded transformer nameplate rating of 5 MVA, it was below emergency cyclic loading of 10 MVA. The data analysis indicates that transformer no. 4 was out of service during this period.

The average loading between 2007 and 2020 was 1MVA, which is 20% of the nameplate rating, suggesting very light loading over service life. This explains the relatively high calculated DP value of insulating paper and other cellulose containing materials.

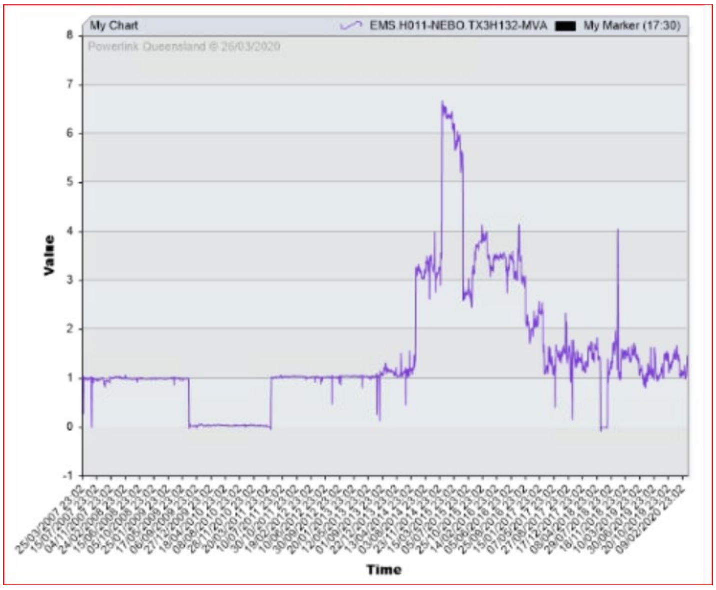


Figure 24 – Transformer 132 kV Loading History

2.3.3 Dissolved Gas Analysis:

There are a few “stand-out” aspects to note from the oil dissolved gas analysis (DGA) test data and they are as follows;

- There is obvious exchange of gasses between OLTC and main transformer tank in the common space of the conservator and possibly associated with leaks from the OLTC diverter switch cylinder (single column only) as acetylene is always present in the main tank oil samples.

It is also likely that records of oil samples taken from OLTC and main tank have not been separated in SAP.

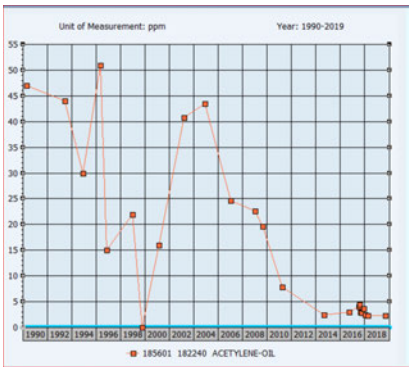


Figure 25- Acetylene in Oil

- Although the previous condition assessment report mentions the record of flashover in September 2009, the detailed examination of the record revealed that it was actually an 11 kV cable fault which occurred and post fault transformer test results confirmed that this through fault did not cause detectable damage to this transformer.
- The maintenance records indicate one more through fault due to moisture ingress in the 11 kV cable termination box in 2011.

2.3.4 Moisture in Insulation:

This is covered in Section 2.3.1 of this report. The percentage of moisture in the insulation was calculated and yielded approximately to be below 4% by dry weight using measured moisture in oil samples. It is likely that this is partially due to the quality of silica gel breather and unsealed transformer being operated at light load during most of its service life.

2.4 Estimated Residual Life of Transformer:

2.4.1 Anti-corrosion System Life

The surface paint on the main transformer tank although not completely free of corrosion is in relatively good condition considering the transformer's age. The majority of the corrosion could be addressed with good clean and touch up paint, besides that associated with the Buchholz relay and mating flanges for it and corrosion of the gate valve located above the Main Control Cubicle. If this transformer is to remain in service beyond 2025, then the Buchholz relay should be replaced together with mating flanges. The same applies for the gate valve. These recommendations are based on the relatively slow progression of this corrosion firstly observed and documented in 2015.

With the implementation of the above recommendations, it is expected that the anti-corrosion system could last until 2030.

2.4.2 Insulation Life

The insulation age of transformers T3 and T4 were calculated to be approximately 29-30 years as shown below in Figure 26. This indicates the localised winding hot spot insulation age whilst for insulation in other parts of the transformer it is just under 25 years. This is well below its nameplate age of 37 years.

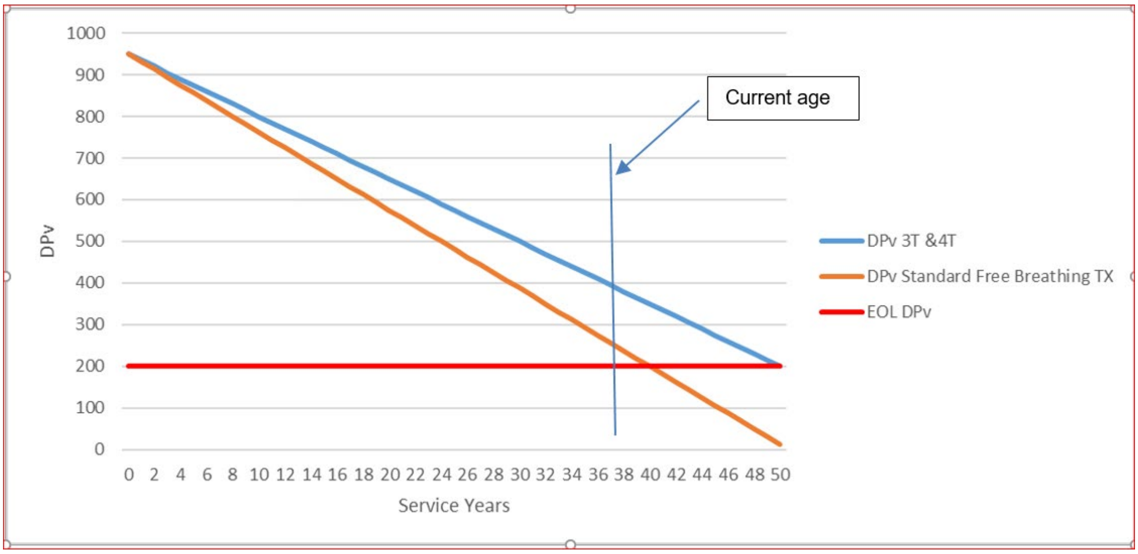


Figure 26- Calculation of cellulose insulation age using a number of indirect indicators

Since no actual paper samples were taken from the transformer for this assessment, using the Chendong formula a paper DP value was calculated based on the dissolved furans in oil and its estimated trend is shown in Figure 26, using an approximate value for the hot spot, considering that the furan data represents only an average of the total cellulose insulation mass. The DPv of the insulating paper is very dependent on the operating conditions (temperature, load and moisture).

Assuming that the transformer operating conditions remain the same, the trend shows that the transformer has 10-13 years (2030-33) of remaining service life (Refer Figure 26).

As shown above, for a typical free breathing transformer the estimated service life is 40 years in an n-1 operating context (operating below 50% capacity for most of time and allowing for higher ambient temperatures).

The average loading of T3 transformer being only 1 MVA (only 20% of its rated capacity), the expected service life based on paper aging only is significantly greater than the theoretical design life.

2.4.3 Mechanical Life

Because there was no internal active part inspection performed, there is no way of knowing the state of the winding clamping or winding mechanical stability. Apart from two through faults associated with the 11 kV cable failure in 2009 and the cable air insulated terminal box fault in 2011, there are no other records available of exposure to through faults.

Figure 27 – 11 kV Cable Air Termination Box

The fault level at Nebo is calculated to be just under 16 kA at 132 kV voltage and just over 3 kA at 11 kV voltage level. It is slightly decreased compared to last year due to changes in network configuration and changes in generation.

No internal inspection was performed on this transformer to review the condition of the core and coils. Without a complete removal of the main tank lid in the field or factory due to a lack of access to all clamping points it is not possible to inspect the outer windings themselves for displacement, twisting or tilting, checking of the block stability and residual clamping pressure. The cost of such an intrusive inspection would be prohibitive and hard to justify for a transformer of this age.

What can be stated about the mechanical stability of the windings is as follows:

(a) The top clamping structure for this old transformer design is known to be unacceptable by today’s standards.

(b) Even with a calculated 3% to 4% moisture content in the internal winding insulation system partially migrating in and out of the clamped structure due to changes in transformer load, there will be some loss of clamping pressure due to the phenomenon shown in the Figure 28. It is realised that load changes are not normally as sharp as in the diagram but the overall cyclic effect is the same.

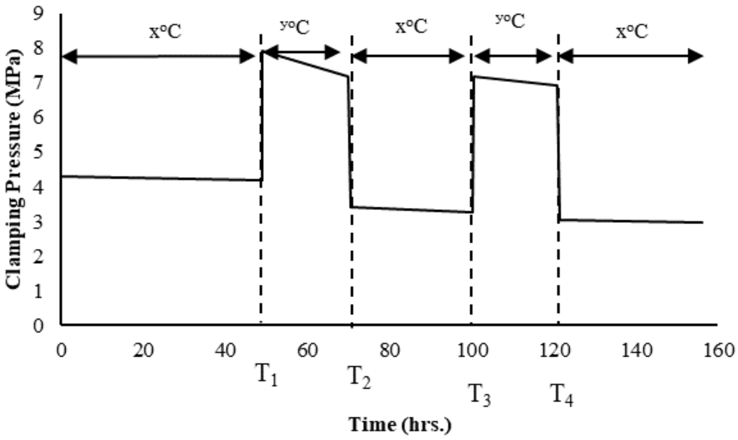


Figure 28 - Example of the effect of cyclic compression on a clamped insulation structure

Recent research into the loss of winding clamping shows that for the winding radial spacers alone, where the biggest axial thicknesses exists within the winding, a change of 1.5% moisture produces a change in clamping pressure of about 1%. The moisture in insulation of this transformer was not that stable so the effects of moisture migration in and out of the winding paper cannot be ignored and have certainly negatively impacted the mechanical stability of the windings.

(c) A drop in the internal cellulose insulation mass indicated by the change in DPv from 950 down to 390 will lower the winding residual clamping pressure but by how much is uncertain at this stage.

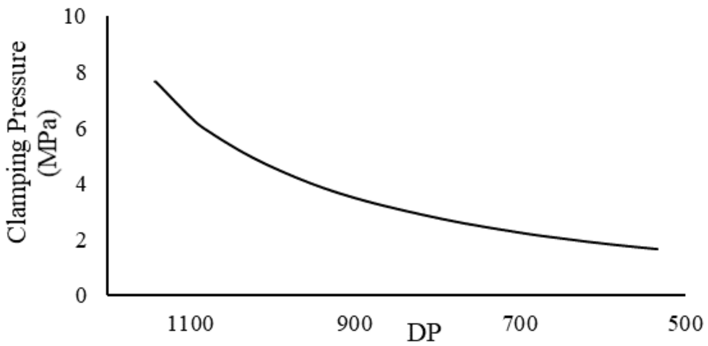


Figure 29 - Example of the effect of loss of DPv on Clamping Pressure

(d) A Low Voltage Leakage Reactance test along with a Sweeped Frequency Response Analysis (SFRA) test were not performed on this transformer. Both types of tests are designed to show potential winding displacements.

In summary, due to these four factors, the residual life expectancy of the core and coils (active part) is considered uncertain, especially if subjected to significant through faults. The electromechanical forces exerted on the winding structure due to periodic through faults often have a cumulative effect similarly to the effects of moisture and temperature cycling.

Considering the above aspects, the mechanical stability and through fault withstand capability of the winding structure would have to be in the medium risk category. In such a state, the structure could last for a further 10 years max unless a very significant event impacted the transformer (including but not limited to the multiple through faults).

3 H011 NEBO TRANSFORMER T4

3.1 Identification Details:

The SAP information indicates a start-up date at H011 Nebo of July 1983 for this transformer. This transformer has an on-board cooler bank consisting of only two radiator panels. Its general descriptive details are shown below.

- Manufacturer: Westralian Transformers Pty Ltd
- Contract: H409/82
- YOM: 1983 (37 years)
- Commissioned 1983
- Capacity: 5 MVA ONAN
- Voltage 132/11 kV
- Vector group: Star – delta with integral 11 kV earthing transformer
- Serial No. 47208
- SAP Equipment No. 20004063
- Reinhausen OLTC model no. MS111 300 60/13 12 23 3G (C/F), serial no. 88868
- OLTC counter reading = 81289 (Sept.2019)

3.2 Onsite Inspection:

3.2.1 Anti-corrosion System:

Due to a restricted access zone being in place at the time of site visit, this report relies on the information and photos provided in the condition assessment report from 2015. Maintenance records provide a single indication of a corrosion issue associated with tap changer drive shaft coupling (Figure 32 and 33), but visual inspection on site undertaken in 2015 and 2019 identified a number of other corroded parts with varying corrosion levels (Grade 1 to Grade 3). Below are photographs showing some of these. There are no records either indicating the transformer has been partially or fully painted, but there seems to be evidence of some painted parts. The original coating is oxidised in most locations and the paint is falling from radiators (Figure 30).

Figure 30 – Peeling paint

Figure 31 –Transformer No. 4

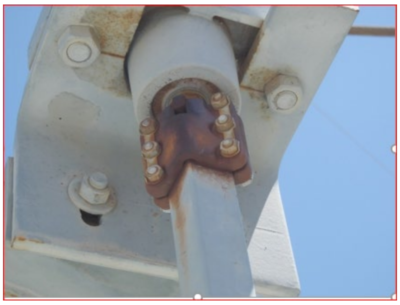


Figure 32–Tap Changer Drive Shaft Coupling (in 2015)

Figure 33 – Tap Changer Drive Shaft Coupling (2019)

Figure 34 – Earthing Transformer Attachment Flange

Figure 35 – Main Tank Lid

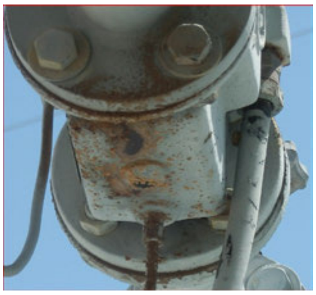


Figure 36– Buchholz Relay

Figure 37 - Plinth corrosion

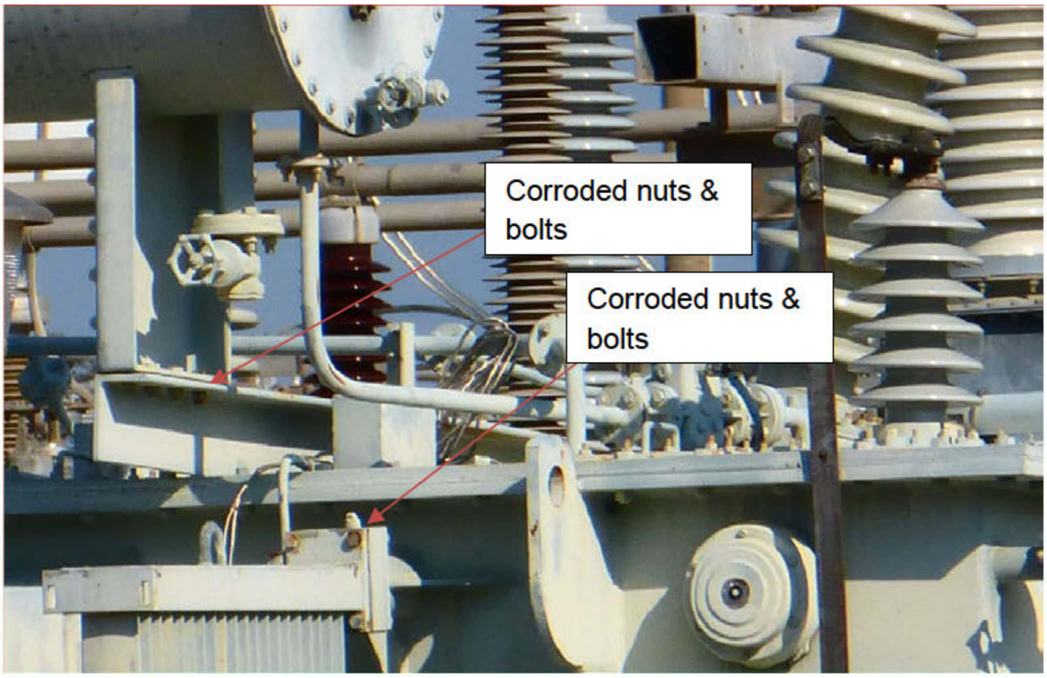


Figure 38 –Corroded Hardware

3.2.2 Structural:

Due to this transformer having an on-board cooler bank, there is no separate cooler bank 'A'-frame support structures to consider. The skid which supports the transformer appeared to be in sound condition as was the conservator support structure and radiator panel mounting points. There was no evidence of any deterioration of the original supports for the transformer and tap changer control cubicle and earthing transformer mounting. No changes to these were noted during limited site inspection in 2019.

3.2.3 Oil Leaks:

Despite corroded parts, only a few minor oil leaks are visible. It is expected that there could be more in the future, but it is likely they will be of minor nature.

3.2.4 Silica Gel Breather:

Similarly to transformer No.3 this transformer is also fitted with an in-house silica gel breather in 2016 and it has the same issue – no visibility of the condition of the oil bath and initial increase in moisture levels in oil after installation.

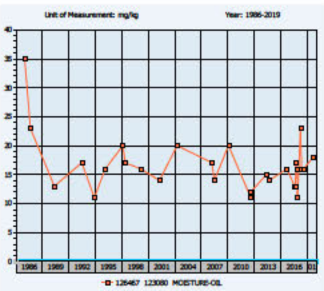


Figure 39 – Moisture in Oil

3.2.5 Temperature Indication Instruments:

Both OTI and WTI instruments were replaced in 2012 and are installed inside the main control cubicle. They are in good condition.

3.2.6 Control Cubicles:

There is a single control cubicle housing relevant equipment for OLTC and for the transformer itself. It is in poor condition with corroded parts and is non-compliant with current AS 3000 requirements. It is recommended to repair it and install additional protective covers or locks combined with warning signage.

3.2.7 Transformer Bushings:

High voltage bushings are oil impregnated paper (OIP) bushings in porcelain housing and have now being in service for 37 years. In accordance with maintenance practice the bushing capacitance and dielectric loss angle (DLA) are monitored every 6 years, but unfortunately only test results from 2000 are recorded in SAP. The next routine measurements are due in 2023. The bushing's manufacturer recommends 25 years as the expected OIP bushing's service life. There is insufficient data to calculate the probability of failure for this type of bushing for bushings older than 40 years, as historically, the majority of power transformers required replacement after 40 years in service.

Due to the bushing service age and aging mechanisms associated with oil impregnated paper, it is not sufficient to monitor their capacitance and DLA only every 6 years.

It is recommended to preventively replace these bushings within 3 years (2023) rather than leaving them in service and adopting an increased monitoring frequency of once a year. Whilst either option is acceptable, preventive bushing replacement is likely to be the lowest cost and safer option for personnel considering the costs and exposure of personnel necessary to switch the transformer out of service for these measurements to be undertaken. The previously used on-line DLA monitoring instruments did not perform reliably.

The LV bushings are hollow porcelain with no other insulation material subjected to the aging so they should last for many more years.

3.2.8 On Line Tap Changer (OLTC):

This OLTC has done a relatively small number of operations and has been maintained regularly. Apart from corroded tap changer shaft couplings (recommended to be replaced within 3 years (2023)), the issue of maintaining the 11 kV volts within their prescribed limits will have to continue to be managed operationally. Otherwise the OLTC is likely to perform satisfactorily within next 10-15 years, assuming the operational conditions do not change and it is regularly maintained.

3.2.9 Transformer Bund & Oil Separation System:

The transformer bunding is in an aged condition and will require detailed assessment once access is available, but it is most likely that re-sealing of the bund wall and repair of surface cracks will be required within 3 years (2023). At present the risk is relatively low, as there are very few minor oil leaks.

In addition, the oil separation tank functionality needs to be inspected, monitored and upgraded with 2nd stage separator (such as an above ground SPEL system). This recommendation can be re-assessed in 5 years.

Figure 40 –Transformer 4 Bund Wall

3.3 Oil and Insulation Assessment:

A desktop assessment was performed on the oil laboratory test data for this transformer and the following information is derived.

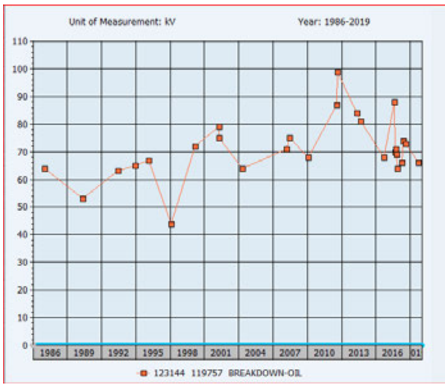
3.3.1 Oil Quality:

When last tested for polychlorinated biphenyl (PCB) content in 2014, 0 mg/kg of PCB was detected in oil. Based on this, this transformer is classified as "PCB free".

It has been tested positive to the presence of corrosive sulphur and has been passivated and the level of passivator maintained to prevent further copper corrosion.

As mentioned above, the oil sample test results indicate higher moisture levels potentially due to the lack of temperature corrections (prior to 2000) and then due to the silica gel breather replacement in 2016. This seems to be stabilised now and within acceptable limits.

The breakdown voltage of oil is also within acceptable limits.



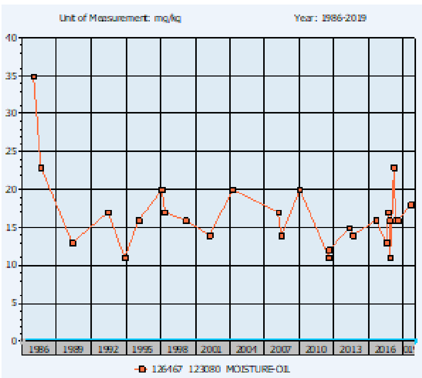


Figure 41 - Breakdown Voltage *Figure 42 – Moisture in Oil*

The oil acidity and oil resistivity measurements suggest that the oil is reaching the end of its service life. It is estimated that the oil will need to be replaced within 3-5 years (2023-25) if the transformer is to be left in service for a period longer than this. These levels of oil acidity and oil resistivity suggest there is a potential to have sludge on the bottom of the main tank. The oil processing will not assist with acidity and drying may cause damage to the already aged insulating paper.

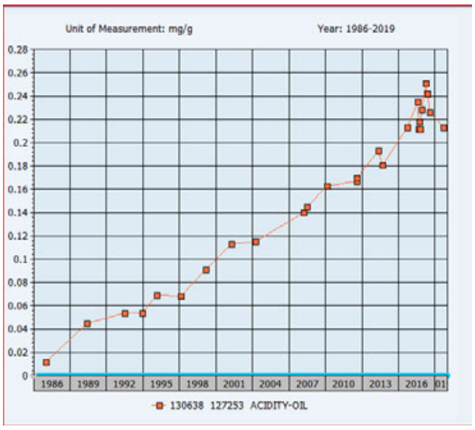


Figure 43 –Oil Acidity

Figure 44 – Oil Resistivity

3.3.2 Transformer Loading:

This transformer has only one cooling mode (ONAN) so it has no oil pumps nor radiator cooling fans.

The peak loading in MVA on the 132 kV side of this transformer over the period 25/03/2007 to 26/03/2020 is 7 MVA and occurred in December 2014. While this exceeded the transformer nameplate rating of 5 MVA, it was below the emergency cyclic loading of 10 MVA. It is not clear what caused this peak. The data also suggest that both transformers might be out of service for one-month period in 2000. There are no records suggesting this to be caused by defects.

The average loading between 2007 and 2020 was 1MVA, which is 20% of the nameplate rating, suggesting very light loading over its service life. This explains the relatively high calculated DP value of insulating paper and other cellulose containing materials.

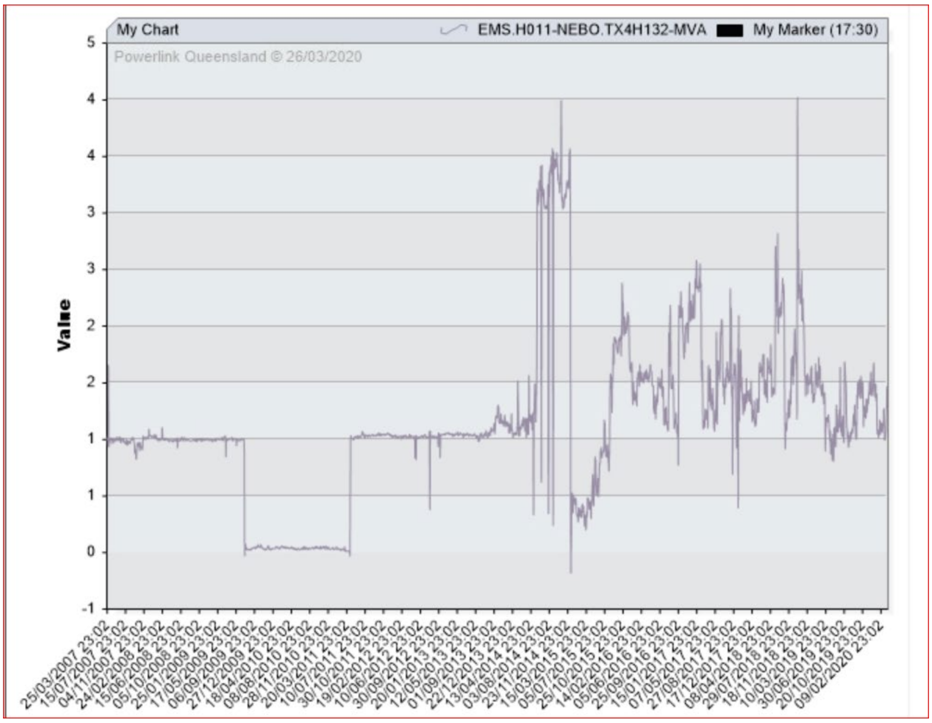


Figure 45 – Transformer No.4 Loading

3.3.3 Dissolved Gas Analysis:

There are a few “stand-out” aspects to note from the oil dissolved gas analysis (DGA) test data and they are as follows;

- There is obvious exchange of gasses between OLTC and main transformer tank in the common space of the conservator and possibly associated with leaks from the OLTC diverter switch cylinder (single column only) as acetylene is always present in the main tank oil samples.

It is also likely that records of oil samples taken from OLTC and main tank have not been separated in SAP.

- Although the previous condition assessment report does not mention the failure of the earthing transformer, it is worth noting that it failed once in July 2004 and was rewound (repaired) and re-installed. The records suggested this may have been its second failure. It is likely that this explains increase in acetylene and ethylene levels (Figure 46 & 47).
- This means that this transformer was exposed to at least one, possibly two very close through faults.

This transformer has only one cooling mode (ONAN) so it has no oil pumps nor radiator cooling fans.

Figure 46 Acetylene Level

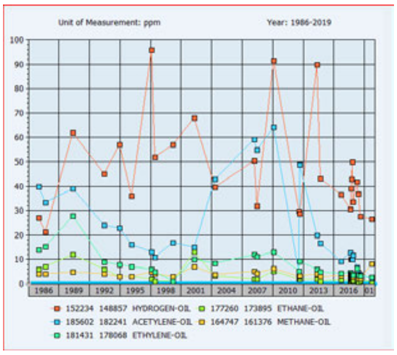


Figure 47 – Selection of Carbon Gases

3.3.4 Moisture In Insulation:

Assuming that all measurements are adjusted to 20 deg C temperature (unlikely for measurements prior to 2000) and using the SD Myers tool, Figure 48 shows moisture in solid insulation. When looking at these results, one should be reminded that due to light loading of this transformer, it is possible that moisture equilibrium is such that more moisture is in oil rather than in solid insulation. In any case, the measurements in the period 2000-2018 all show the moisture content to be below 4%. The calculated moisture in insulation for this transformer at present is still below 4% level beyond which the risks of insulation failure under the right combination of specific operating / environmental conditions is heightened.

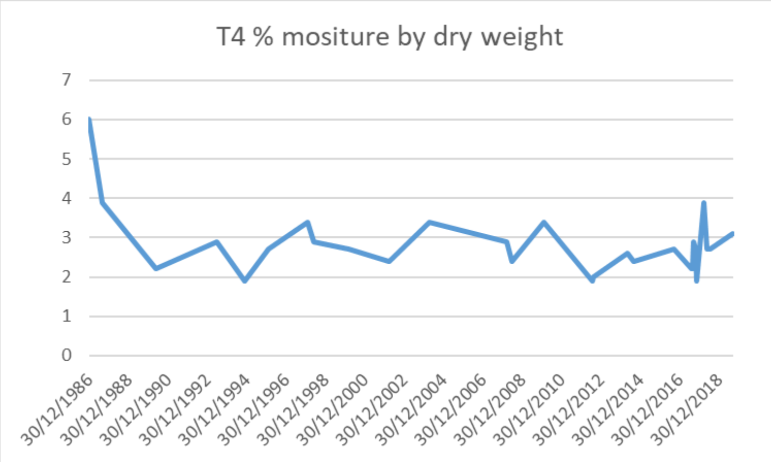


Figure 48 – Moisture in Insulation

Figure 23 shows Powerlink's approach towards managing changing moisture levels within transformer insulation. If oil is to be replaced within 3 years, then the moisture in oil will decrease significantly for at least a short period of time after which the moisture "stored" in solid insulation will migrate to the oil.

The only way of monitoring oil condition (rather than replacing it) is to install an on-line moisture and temperature probe in the main oil stream and monitor data under varying loads / temperatures.

3.4 Estimated Residual Life of Transformer

3.4.1 Anti-corrosion System Life:

Considering only minor corrosion is detected and assuming the Buchholz relay and couplings on the tap changer shaft are replaced, it is expected that the anticorrosion system can last for another 10-15 years.

3.4.2 Insulation Life:

Similarly to the insulation age of transformer T3, the insulation age for T4 was calculated to be approximately 29-30 years as shown above in Figure 26. This indicates a localised winding hot spot insulation age whilst it is most likely under 25 years for insulation in other parts of the transformer. This is well below its nameplate age of 37 years.

Since no actual paper samples were taken from the transformer for this assessment, using the Chendong formula a paper DP value was calculated based on the dissolved furans in oil and its estimated trend is shown in Figure 26, using an approximate value for hot spot considering that the furan data represents only an average of the total cellulose insulation mass. DPv of the insulating paper is very dependent on the operating conditions (temperature, load and moisture).

Assuming that the transformer operating conditions remain the same, the trend shows that the transformer has 10-13 years (2030-33) of remaining service life (Refer Figure 26).

As shown above, for a typical free breathing transformer the estimated service life is 40 years in an n-1 operating context (operating below 50% capacity for most of the time and allowing for higher ambient temperatures).

The average loading of T4 transformer being only 1 MVA (only 20% of its rated capacity), the expected service life based on the paper aging only is significantly greater than the theoretical design life.

3.4.2.1 Oil Life:

The insulating oil has almost reached its end of reliable service life. It is recommended to replace it within 3 years.

3.4.3 Mechanical Life:

As explained in Section 2.4.3 above, the winding clamping pressure is somewhat compromised due to the exposure to one, or possibly two very close through faults. It is not possible to predict if this transformer would remain in serviceable condition if it is exposed to another through fault in the future. Assuming this does not occur and based on the low fault levels at this site, it is expected that it can remain in service for up to 10 years (mid 2030).

3.4.4 Bushings Life:

As discussed above, the HV bushings require more frequent condition monitoring and this is unlikely to be economical (as it requires transformer outage and test and switching crews). It is recommended to preventively replace these within the next 3 years (2023).

3.4.5 OLTC Life:

Assuming the corroded couplings on the tap changer shaft are replaced, the OLTC should be serviceable for another 10-15 years.

Planning Statement	08/04/20
Title	CP.02360 - H011 Nebo Transformer 3 & 4 Replacement – Planning Statement [1]
Zone	North Queensland (NQ)
Need Driver	Emerging operational and safety risks arising from the condition of the 132/11kV transformers and 11kV switchgear.
Network Limitation	Necessary to meet Powerlink Queensland's transmission authority and N-1-50MW/600MWh reliability obligations. Under the scenario of a losing the transformers or 11kV switchgear due to end-of-life asset condition, the customer loss of supply would exceed 600 MWh.
Pre-requisites	None

Executive Summary

Energy Queensland's (EQ) forecasts confirm there is an enduring need to maintain electricity supply into the Nebo area.

Powerlink has recently reviewed the condition of the T3 & T4 (132/11kV, 5MVA Transformer) and 11kV switchgear at Nebo Substation and concludes they will reach end of technical service life within the next 3-5 years.

Removal of the transformer/s to address emerging condition risks would result in Powerlink breaching its N-1-50 MW/600 MWh reliability obligations. It will also allow EQ to meet its reliability standard (See Appendix A).

The preferred network solution for Powerlink to continue to meet its statutory obligations is the replacement/refit of the existing 2 x 5MVA transformers by December 2021.

[1] *This report contains confidential information, which is the property of Powerlink, and the Registered Participant mentioned in the report, and has commercial value. It qualifies as Confidential Information under the National Electricity Rules (NER). The NER provides that Confidential Information:*

- *must not be disclosed to any person except as permitted by the NER;*
- *must only be used or copied for the purpose intended in this report;*
- *must not be made available to unauthorised persons*

1. Contents

2. Introduction

H011 Nebo Substation was established in 1977 as a 275/132kV injection point for North Queensland supply to the EQ distribution network in the region and to provide a 132kV network to faciliate customer connections to the surrounding region.

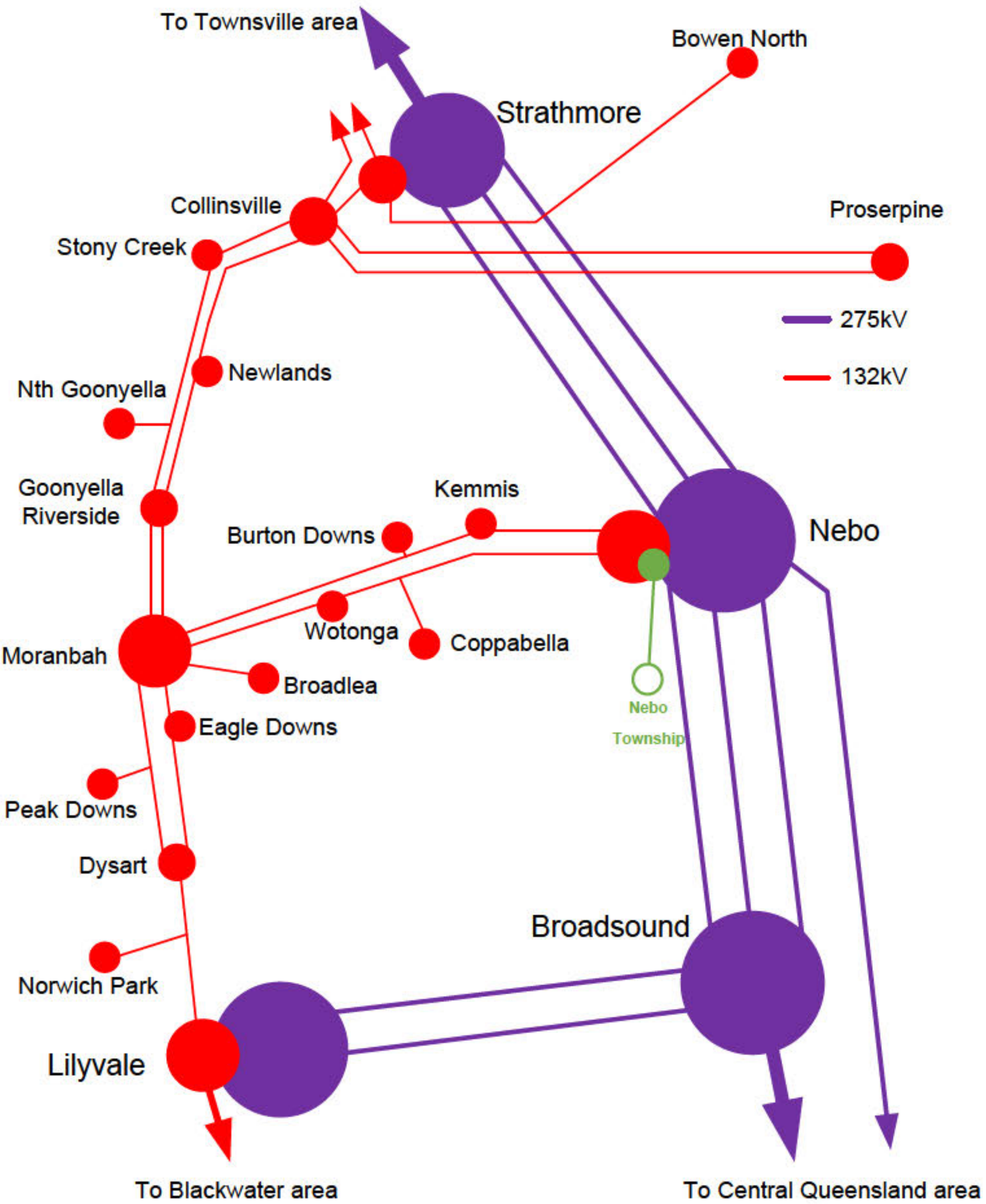


Figure 1: H011 Nebo Substation – North Queensland

H011 Nebo substation also plays a role in supplying the local Nebo Township. This is achieved via two (2) 132/11kV 5MVA transformers (T3 & T4) feeding local EQ 11kV distribution network. These two transformers were installed in this substation in 1983. The transformers and the associated 11kV switchgear are owned by Powerlink.

Transformers 3 and 4 at Nebo Substation are nearing 40 years old. A condition assessment estimated that both transformers require intervention within 3-5 years. Both are suitable for life extension, with a projected end of life in 2031 following selected refit works

The associated 11kV switchgear are SF6 circuit breakers with spring mechanisms, manufactured by Hitachi (model VG-35 HI VAC – no longer manufactured) with cable termination box all enclosed within one cabinet. Powerlink does not have any spare parts for this type of circuit breakers and there has been observed issues associated with the cable box such as corrosion and plastic components falling apart - possibly due to the impact of retained heat, etc. The 11kV switchgear requires replacement within 3-5 years.

Therefore there is a need to coordinate the replacement of transformer T3 & T4 along with the replacement of the 11kV switchgear units. The considerations towards retiring the at-risk transformers or deploying alternative solutions and the impact these would have on Powerlink's statutory obligations are also explored.

3. Demand Forecast

From historical data and previous discussions with EQ, the summer peak load has typically varied between 2-3MVA.

The current high level forecast has realistically assumed a flat 2.8 MW peak load to be used for power system simulation over the next 10 years, and the peak load is not expected to change materially in coming future years.

4. Statement of Investment Need

Retaining Nebo as a two 132/11kV transformer substation is necessary to maintain Powerlink's N-1-50MW/600MWh reliability standard.

If no investment is made, and either transformer is taken out of service, then following the credible contingency loss of the remaining transformer, the customer loss of supply would exceed 600MWh.

Two transformers also meets EQ's reliability standard (See Appendix A).

5. Network Risk

Table 4.1 summarises results of analysis to determine the maximum load at risk, as well as the energy at risk, if either transformer is decommissioned from service.

Table 4.1: Nebo Load at Risk

At Risk	Contingency	Metric	2026
Nebo Township	132/11kV Transformers (3T and 4T)	Max (MW)	3
		Average (MW)	2.5
		24h Energy Unserved Max (MWh)	50
		24h Energy Unserved Average (MWh)	40

Given that the mean time to repair or replace a transformer is 10 to 12 weeks, the 600 MWh limit of Powerlink's Transmission Authority would be exceeded.

6. Non Network Options

Potential non-network solutions would need to provide supply to the 11kV network at Nebo as per Table 4.1. That is, up to 3MW at peak and up to 50MWh per day. The non-network solution would be required for a contingency and able to operate on a continuous basis until normal supply is restored. Supply would also be required for planned outages. Such a solution consisting of generation would need to be capable of operating as an isolated network, with no connection to the transmission network.

Powerlink is not aware of any Demand Side Solutions (DSM) in the Nebo Township; the DSM would need to include all load connected to the transformers within the township and is therefore not considered feasible.

7. Network Options

7.1 Proposed Option to Address the Identified Need

Powerlink has identified three (3) credible options to address the identified need, as presented in Table 6.1 below.

Table 6.1: Options summary

Option	Description	Stage	Works
Option 1:	Staged replacement of Equipment	Stage 1	Replace 11kV switchgear by June 2022 Life extension of T3 & T4
		Stage 2	Replace the T3 & T4 transformers by Dec 2031
Option 2	Single stage replacement	Single-stage	Replace the transformers T3 & T4 and 11kV switchgear by June 2022
Option 3:	Staged replacement of Equipment	Stage 1	Replace 11kV switchgear by June 2022 Life extension of T4 Replace the T3 transformers by June 2022
		Stage 2	Replace the T4 transformers by Dec 2031

Ultimately the existing 2 x 5MVA transformers would be replaced with 2 new 132/11kV transformers of similar capacity. All presented options will provide adequate N-1 capacity during after construction and ensures that Powerlink's reliability obligations to maintain supply to existing customers under its Transmission Authority are met.

The assets replaced under this project are intended to be transferred to EQ per standard ownership arrangements.

7.2 Option Considered but Not Proposed

This section discusses alternative options that Powerlink has investigated but does not consider technically and/or economically feasible to address the above identified issues, and thus are not considered credible options.

7.2.1 Do Nothing

"Do Nothing" or run-to-fail would not be an acceptable option as the primary driver (plant condition) and associated safety, reliability and compliance risks would not be resolved. Furthermore, the "Do Nothing" option would not be consistent with good industry practice and would result in Powerlink breaching their obligations with the requirements of the System Standards of the National Electricity Rules and its Transmission Authority.

7.2.2 Establishing an Isolated Distribution System

As discussed in section 5, establishing an isolated distribution system would only be feasible via continuous utilisation of gas or diesel generators provided by a third party. For a shorter term usage such as for network fault management, this set up could work, however for daily use and over the longer period the running cost will quickly and significantly overtake the asset replacement cost and therefore was discounted.

8. Recommendations

Powerlink has reviewed the condition of the T3 & T4 132/11kV Transformer and 11kV switchgear at Nebo Substation and concludes that the switchgear will reach end of technical service life by end of 2021.

Retaining Nebo as a two 132/11kV transformer substation will allow Powerlink to continue maintaining its required obligation under the transmission authority license and the reliability obligations (N-1-50 MW/600 MWh). It will also allow EQ to meet its reliability standard (See Appendix A).

The present transformer condition may still be supportive of minor life extension, this would enable a staged replacement approach, which will facilitate a more efficient outage scheduling and work delivery hence the recommended project commencement in 2021 and by completed by 2031.

Powerlink is currently unaware of any feasible alternative options to replace the 132/11kV grid-connected transformer supply arrangement at Nebo but will, as part of the formal RIT-T consultation process, seek non-network solutions that can contribute significantly to ensuring it continues to meet its reliability of supply obligations.

9. Relevant Documents

1. H011 Nebo Transformers T3 & T4 Condition Assessment Report 2020
2. Transmission Annual Planning Report 2020
3. Asset Planning Criteria_Framework

Appendix A: – Energy Queensland's Planning Standards

Area	Targets for restoration of supply following an N-1 Event
Regional Centre[13]	Following an N-1 Event, load not supplied must be: • Less than 20MVA (8000 customers) after 1 hour • Less than 15MVA (6000 customers) after 6 hours • Less than 5MVA (2000 customers) after 12 hours • Fully restored within 24 hours.
Rural Areas	Following an N-1 Event, load not supplied must be: • Less than 20MVA (8000 customers) after 1 hour • Less 15MVA (6000 customers) after 8 hours • Less 5MVA (2000 customers) after 18 hours • Fully restored within 48 hours.

Base Case Risk and Maintenance Costs Summary Report

CP.02360 Nebo Transformer T3 & T4 Replacement

Version Number	Objective ID	Date	Description
1.0		10/11/2020	Original document

1. Purpose

The purpose of this model is to quantify the base case risk cost profiles and maintenance costs for 132/11kV transformers T3 and T4 at Nebo Substation which are candidates for reinvestment under CP.02360.

Base case risk costs and maintenance costs have been analysed over a ten year study horizon.

2. Key Assumptions

In calculating the potential unserved energy (USE) arising from failure of transformers T3 and T4 at Nebo Substation, the following modelling assumptions have been made:

- Historical load profiles have been used when assessing the likelihood of unserved energy under concurrent failure events;
- Due to the network and substation configuration, unserved energy generally accrues under concurrent failure events and consideration has been given to potential feeder trip events within the wider transmission network supplying the substation;
- Nebo Substation predominantly supplies the township load The QLD Climate Zone 2 region average VCR value of $25,560/MWh has been used when evaluating network risk costs; and
- The applicable VCRs published within the AER's 2019 Value of Customer Reliability Review Final Report have been used within this risk cost assessment.

3. Base Case Risk Analysis

3.1 Risk Categories

Four main categories of risk are assessed within Powerlink's risk approach; safety, network, financial, and environmental. Network, Safety & Financial risk have been deemed relevant to transformers T3 & T4 at Nebo.

3.2 Transformer analysis

This section analyses the risks presented by the 132/11kV transformers T3 and T4 at Nebo Substation.

Table 1: Risks associated with at risk transformers

	Mode of failure	
Equipment	Peaceful	Explosive
Transformer	**Network risks** (unserved energy from concurrent outages). **Financial risks** to replace failed transformer(s) in an unplanned (emergency) manner.	**Network risks** (unserved energy) due to substation de-energisation to extinguish a transformer fire. **Safety risks** to personnel. **Financial risks** to replace the failed transformer in an unplanned manner, including clean-up and community engagement.

3.2.1 Transformer Risk Cost

The modelled and extrapolated total base case risk costs are shown in Figures 1 to 4.

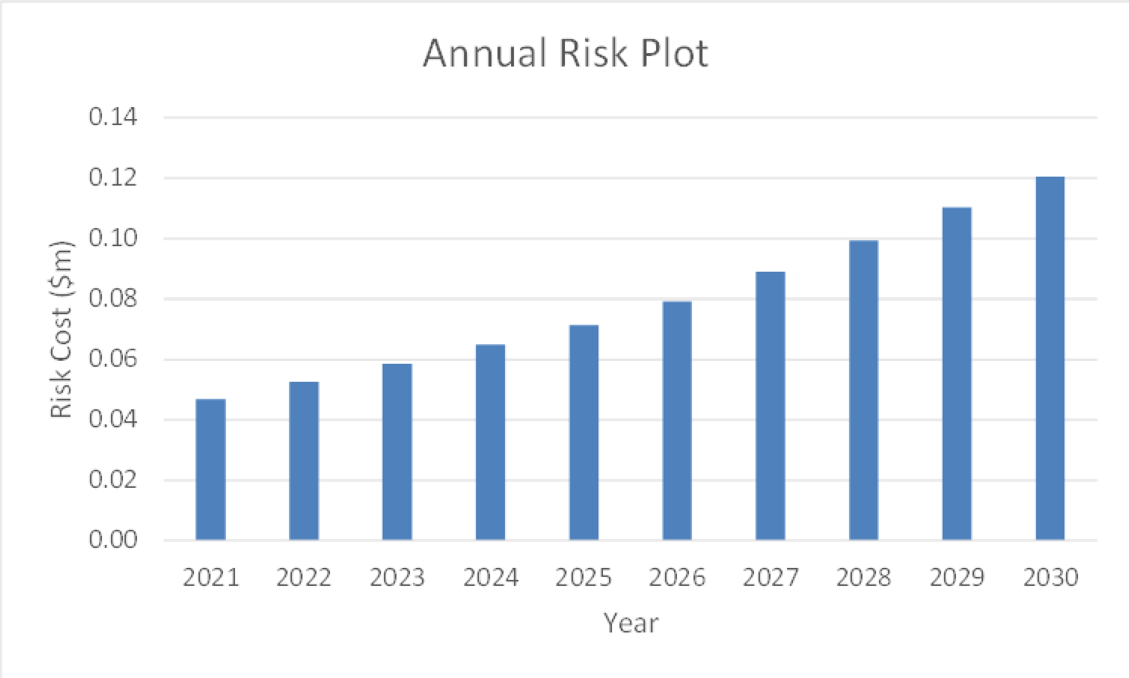


Figure 1 – Nebo T3 and T4 total risk cost (10 years)

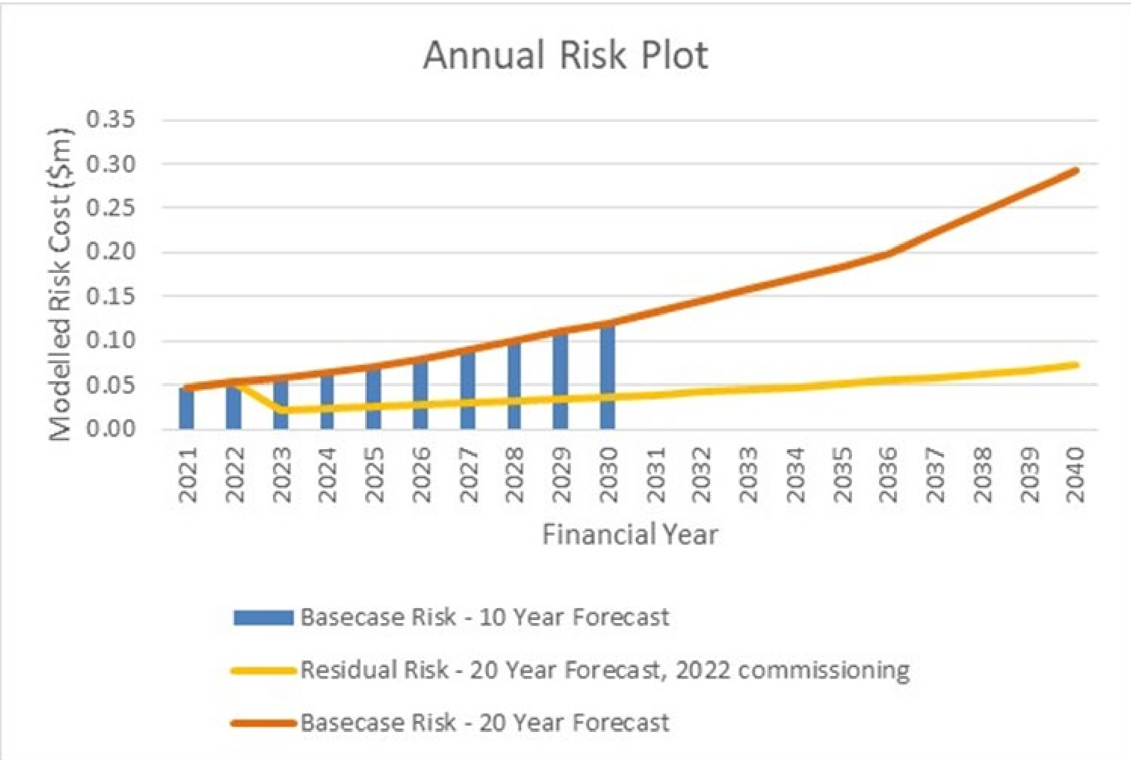


Figure 2 – Nebo T3 and T4 risk cost (calculated 10 years and extrapolated 20 years)

Figure 3 – Nebo T3 and T4 risk cost (10 years) by risk category

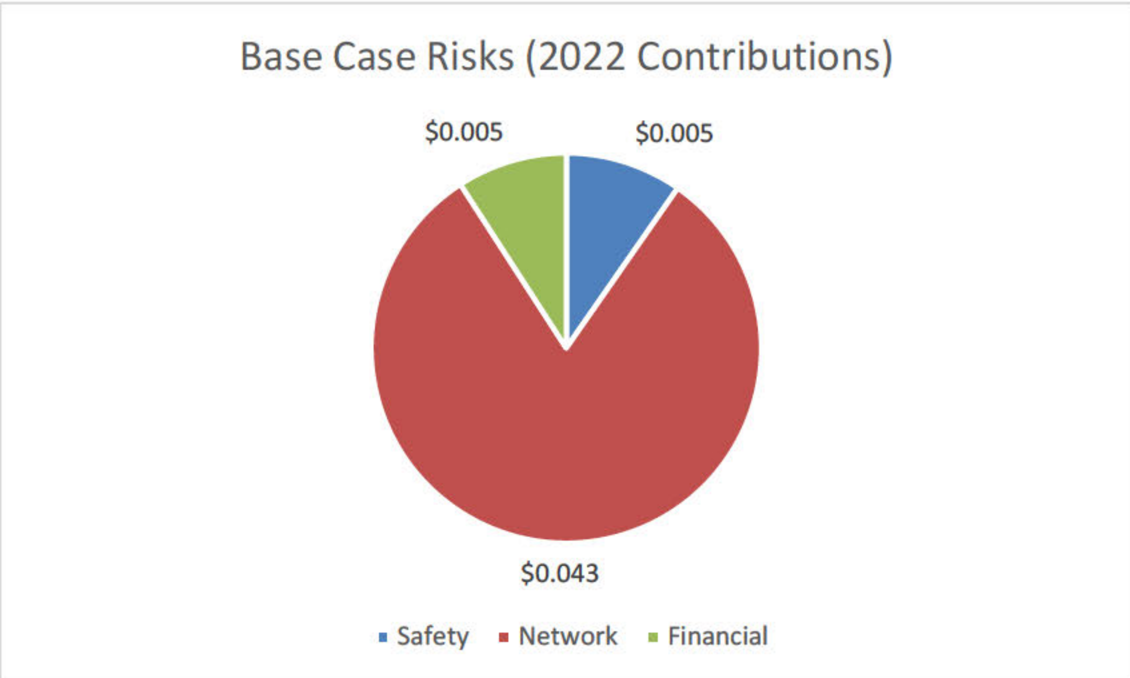


Figure 4 – Nebo T3 and T4 risk cost by risk category (year 2022)

3.2.2 Base case risk statement

The main base case risks for 132/11kV transformers T3 and T4 at Nebo Substation are network risk (unserved energy) due to concurrent outages of 132/11kV transformers T3 and T4 at Nebo, safety risks (injury to personnel on site) for explosive failures of the transformers, and financial risks due to costs associated with repairing failed plant.

4. Maintenance costs

Two categories of maintenance costs are included in Powerlink's base case approach; routine maintenance and corrective / condition based maintenance.

Maintenance costs are still being developed. For the purposes of this report, maintenance has been modelled as 1.5% of the project capital. This is consistent with historical maintenance costs as a proportion of capital cost.

The modelled total base case costs (maintenance plus risk) are shown in Figure 5 below.

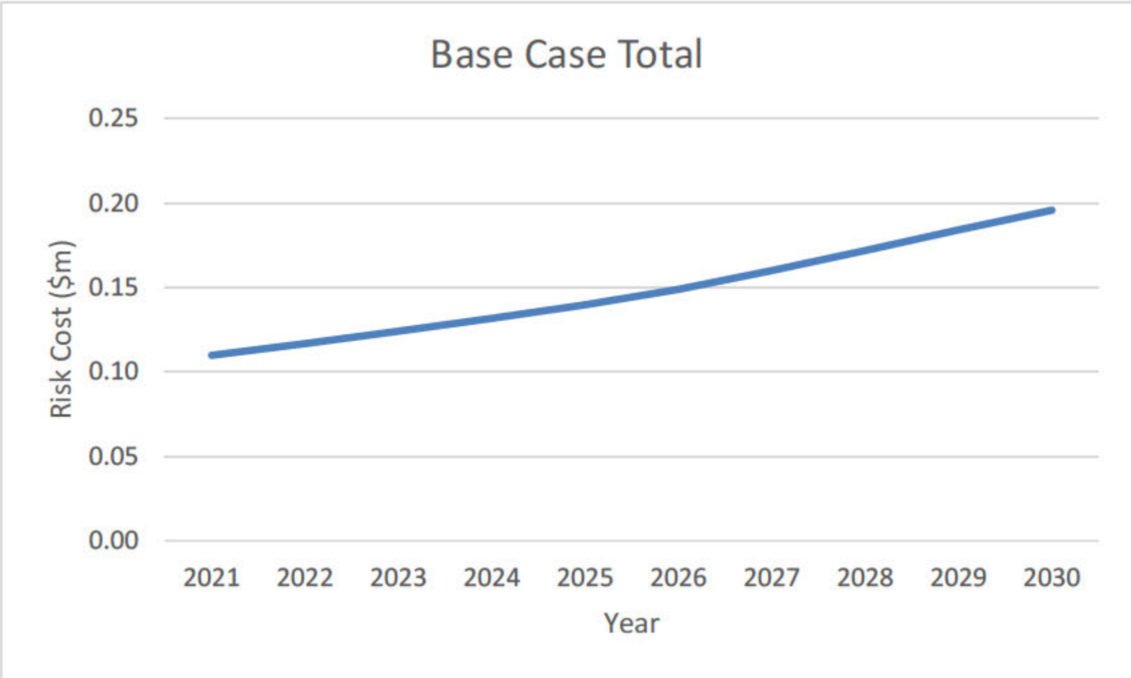


Figure 5: Base Case Total (Risk Cost + Maintenance) 2021 to 2030

5. Input participation

Sensitivity analysis was carried out on the model to determine the participation factors for key inputs to the risk models (i.e. which inputs affect the risk cost calculations the most). The year analysed was 2021.

Figure 6 and Figure 7 below show the input values and the percentage change of the total modelled risk for a 100% change in an individual input (for example if VCR in the transformer model is doubled the calculated risk will increase by ~81%).

Equivalent cost of serious injury	1	$M
ALARP disproportionality factor	3	Ratio
VCR (Climate Zone 2 - CBD and suburban)	25560	$/MWh
Emergency transformer replacement time without spare	12	Weeks
Likelihood of major fire given transformer explosion	0.2	Ratio
Time required to de-energise site during major fire	72	Hours
Emergency transformer replacement cost	0.5	$M
Media and communication costs	0.3	$M

Figure 6: Input values, transformer risk cost model

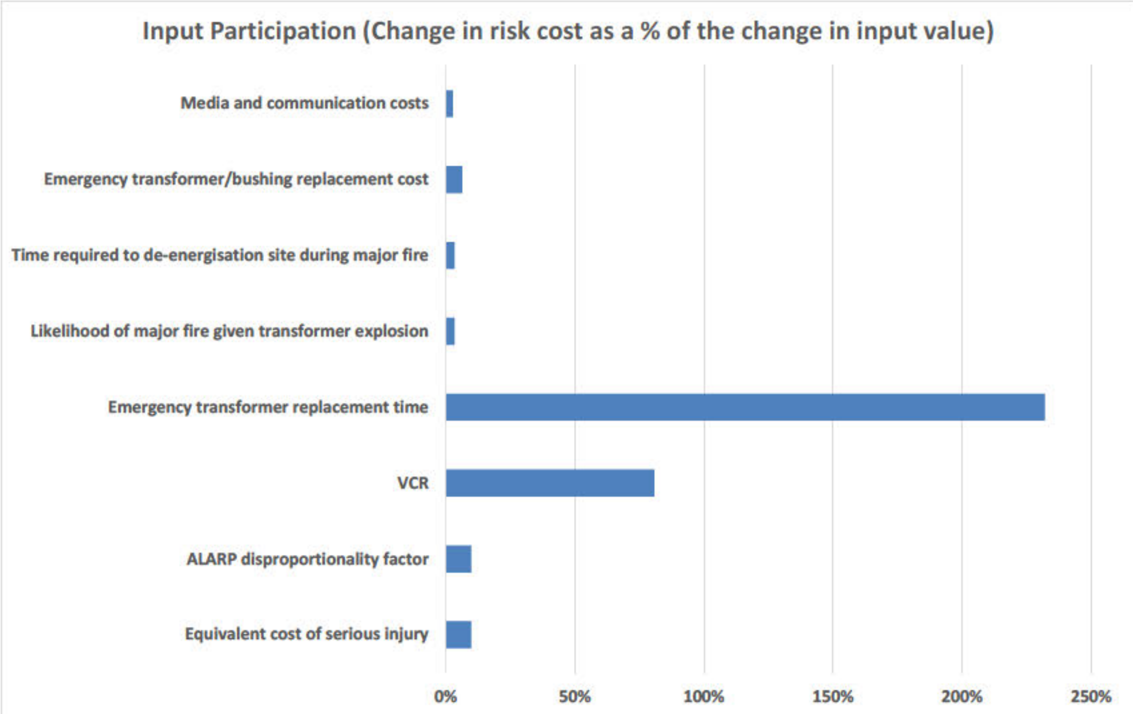


Figure 7: Participation factors, transformer risk cost model

Project Scope Report

CP.02360

Nebo Transformer 3 & 4 Replacement

Concept – Version 3

Document Control

Change Record

Issue Date	Responsible Person	Objective Document Name	Background
11/03/2019	[redacted]	Project Scope Report CP.02360 Nebo Transformer 3 & 4 Replacement	Initial Draft
14/02/2020	[redacted]	Project Scope Report CP.02360 Nebo Transformer 3 & 4 Replacement V2	Updated following meetings with Ergon
08/04/2020	[redacted]	Project Scope Report CP.02360 Nebo Transformer 3 & 4 Replacement V3	Updated following new Condition Assessment report

Related Documents

Issue Date	Responsible Person	Objective Document Name
13/03/2020	[redacted]	H011 Nebo Transformers T3 & T4 Condition Assessment Report

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Manager Projects	TBA	Ext.
Project Manager	TBA	Ext.
Design Coordinator	TBA	Ext.

Project Details

1. Project Need & Objective

Nebo Substation is an important node in the state-wide transmission network, connecting North and South Queensland whilst providing bulk supplies to several key areas, including Mackay and Pioneer Valley.

H011 Nebo Substation was established in 1977 as a 275/132kV injection point for North Queensland supply to the Energy Queensland (EQ) distribution network in the region and to provide a132kV generation connection point for Collinsville Power Station (which is now retired). The major later addition includes Static Var Compensator (SVC) assisting with voltage regulation in this relatively weak part of the network. Nebo Substation also supplies the local township via two (2) 132/11kV 5MVA transformers (3T and 4T) feeding the EQ 11kV distribution network.

Both transformers were installed at Nebo in 1983 and have now been in service for 37 years. Although they are displaying condition issues typical of transformers of this age, due to the low loading over service life, the insulating paper condition seems to be such that an additional 10 years of service life can be achieved with targeted intervention (life extension activities). However, the associated 11kV switchgear is at end of its technical life, with no spares available and deteriorating condition issues.

The objective of this project is to replace or life extend transformers T3 & T4, and replace the associated 11kV equipment, by June 2022.

2. Project Drawing

Figure 1: Aerial view of H11 Nebo Substation

[redacted]

Figure 2: Operational view of H011 Nebo Substation

3. Project Scope

Powerlink has identified three (3) credible options to address the identified need, as presented in Table 1 below. Concept estimates are required to inform feasibility and cost assessments for the options.

Each option describes a projected asset lifecycle scenario for the future development of the asset.

Table 1: Options summary

Option	Description	Stage	Works
Option 1:	Staged replacement of Equipment	Stage 1	Replace 11kV switchgear by June 2022 Life extension of T3 & T4
		Stage 2	Replace the T3 & T4 transformers by Dec 2031
Option 2	Single stage replacement	Single stage	Replace the transformers T3 & T4 and 11kV switchgear by June 2022
Option 3:	Staged replacement of Equipment	Stage 1	Replace 11kV switchgear by June 2022 Life extension of T4 Replace the T3 transformer by June 2022
		Stage 2	Replace the T4 transformers by Dec 2031

The scope requirements for each of the options are described in the following sections

3.1. Option 1 – Staged Replacement of Equipment

The following scope presents a functional overview of the desired outcomes of the project. The proposed solution presented in the estimate must be developed with reference to the remaining sections of this Project Scope Report, in particular *Section 5 Special Considerations*.

Briefly, this option consists of the staged replacement of equipment with work done in two stages.

3.1.1. Transmission Line Works

Not Applicable.

3.1.2. H011 Substation Works

Under stage 1 of this option, the 11kV ring main units are replaced by June 2022 and the transformers T3 & T4 are refitted to extend their life through to 2031, when they will be replaced under stage 2 by December 2031.

3.1.2.1. Stage 1 works

The following work is to be done under stage 1 of this project (by June 2022).

- Replace two (2) 11kV circuit breakers in-situ using outdoor type, SF6 or vacuum, circuit breakers, AIS disconnectors, and 11kV toroidal CTs installed on cables.

- For Transformer T3, implement the following life extension activities:
    - replace Oil;
    - replace HV Bushings;
    - replace Buchholz relay;
    - replace any parts with corrosion Grade 4;
    - repair and address minor oil leaks;
    - replace main tank and OLTC silica gel breather;
    - upgrade main control cubicle to AS3000 requirements, treat corrosion on cubicle and test/mange asbestos containing materials (it is considered feasible to do this without replacing the cubicle and without disturbing secondary cabling); and
    - inspect and reseal bund area cracks.
- For Transformer T4, implement the following life extension activities:
    - replace Oil;
    - replace HV Bushings;
    - replace Buchholz relay;
    - replace tap changer shaft couplings;
    - replace any parts with corrosion Grade 4;
    - replace main tank and OLTC silica gel breather;
    - upgrade main control cubicle to AS3000 requirements, treat corrosion on cubicle and test/manage asbestos containing materials (it is considered feasible to do this without replacing the cubicle and without disturbing secondary cabling); and
    - inspect and reseal bund area cracks.

3.1.2.2. Stage 2 works

The following work is to be done under Stage 2 of this project (by December 2031).

- Design, procure, supply and install two (2) 132/11kV 5MVA transformers, with on load tap changer and cooling facilities.
- Replace both transformer foundations and bunds as required.
- Review requirement for fire/blast wall and install if required.
- Review and upgrade metering as required and associated bay plant to comply with Rules' requirements (metering is currently on the LV side and should be moved to the HV side under this project).
- Modify protection, automation and communication systems as necessary to accommodate the new transformer and associated 11kV switchgear.
- Recover and dispose of old T3 & T4 transformer units.
- Provide comms path for EQ to communicate with their network.
- Update SAP and corporate data systems accordingly.

3.1.3. Telecoms Works

Review and adjust as required to support primary plant replacements.

3.1.4. Easement/Land Acquisition & Permits Works

Not applicable

3.2. Option 2 – Singe Staged Replacement of Equipment

The following scope presents a functional overview of the desired outcomes of the project. The proposed solution presented in the estimate must be developed with reference to the remaining sections of this Project Scope Report, in particular *Section 5 Special Considerations*.

Briefly, this option consists of the replacement of transformers T3 and T4, and associated 11kV switchgear in a single stage.

3.2.1. Transmission Line Works

Not Applicable.

3.2.2. H011 Substation Works

- Design, procure, supply and install two (2) 132/11kV 5 MVA transformers, with on load tap changer and cooling facilities.
- Review and replace both transformer foundations as required.
- Replace two (2) 11kV circuit breakers in-situ using outdoor type, SF6 or vacuum, circuit breakers, AIS disconnectors, and 11kV toroidal CTs installed on cables.
- Review and upgrade metering as required and associated bay plant to comply with Rules' requirements (metering is currently on the LV side and should be moved to the HV side under this project).
- Modify protection, automation and communication systems as necessary to accommodate the new transformer and associated 11kV switchgear.
- Modify protection, automation and communication systems as necessary to accommodate the new transformers and associated 11kV switchgear.
- Provide comms path for EQ to communicate with their network.
- Recover and dispose of old T3 & T4 transformer units.

3.2.3. Telecoms Works

Review and adjust as required to support primary plant replacements.

3.2.4. Easement/Land Acquisition & Permits Works

Not applicable

3.3. Option 3 – Alternative Staged Replacement of Equipment

The following scope presents a functional overview of the desired outcomes of the project. The proposed solution presented in the estimate must be developed with reference to the remaining sections of this Project Scope Report, in particular *Section 5 Special Considerations*.

Briefly, this option consists of the staged replacement of equipment with work done in two stages.

3.3.1. Transmission Line Works

Not Applicable.

3.3.2. H011 Substation Works

Under Stage 1 of this option, the 11kV switchgear and T3 are replaced by June 2022; transformer T4 is refitted to extend its life through to 2031 when it is replaced, when it will be replaced under stage 2 by December 2031

3.3.2.1. Stage 1 works

The following work is to be done under Stage 1 of this project (by June 2022).

- Replace two (2) 11kV circuit breakers in-situ using outdoor type, SF6 or vacuum, circuit breakers, AIS disconnectors, and 11kV toroidal CTs installed on cables.
- Design, procure, supply and install one (1) 132/11kV 5 MVA transformer, with on load tap changer and cooling facilities in place of T3.
- Review and replace transformer foundation as required.
- Review and upgrade metering as required and associated bay plant to comply with Rules' requirements (metering is currently on the LV side and should be moved to the HV side under this project).
- Modify protection, automation and communication systems as necessary to accommodate the new transformer and associated 11kV switchgear.
- Modify protection, automation and communication systems as necessary to accommodate the new transformer and associated 11kV switchgear.
- Provide comms path for EQ to communicate with their network.
- Recover and dispose of old T3 transformer unit.
- For Transformer T4 implement the following life extension activities:
    - replace oil;
    - replace HV bushings;
    - replace Buchholz relay;
    - replace tap changer shaft couplings;
    - replace any parts with corrosion Grade 4;
    - replace main tank and OLTC silica gel breather;
    - upgrade main control cubicle to AS3000 requirements, treat corrosion on cubicle and test/manage asbestos containing materials (it is considered feasible to do this without replacing the cubicle and without disturbing secondary cabling); and
    - inspect and reseal bund area cracks

3.3.2.2. Option 3 - Stage 2 works

The following work is to be done under Stage 2 of this project (by December 2031).

- Design, procure, supply and install one (1) 132/11kV 5 MVA transformer, with on load tap changer and cooling facilities in place of T4.
- Review and replace transformer foundation as required.
- Review and upgrade metering as required and associated bay plant to comply with Rules' requirements (metering is currently on the LV side and should be moved to the HV side under this project).
- Modify protection, automation and communication systems as necessary to accommodate the new transformer and associated 11kV switchgear.

- Modify protection, automation and communication systems as necessary to accommodate the new transformer and associated 11kV switchgear.
- Provide comms path for EQ to communicate with their network.
- Recover and dispose of old T4 transformer unit.

3.3.3. Telecoms Works

Review and adjust as required to support primary plant replacements.

3.3.4. Easement/Land Acquisition & Permits Works

Not applicable

3.4. Key Scope Assumptions

The following assumptions should be included in the estimating of this scope:

- The priority of this project is driven by the potential risk, which relates to safety, financial and network reliability. This is a high priority project due to the poor condition of 11kV switchgear.
- It is the intent that when these assets are replaced under this project they will be transferred to EQ and the asset boundary moved to reflect this change in ownership.
- Since transformers are planned to be transferred to EQ, due consideration should be given to protection and control requirements of these transformers. EQ preference is that all the secondary systems should comply with their standard.
- EQ preference is that all the primary plant and secondary systems including comms should comply with EQ standard.
- The transformers should comply with EQ standard and hence will be procured through EQ period contracts.
- There may be outage constraints on the length of time each transformer can be out of service. This needs to be confirmed with Operations as to the maximum length of the transformer outages;
- There are currently a number of projects happening on site at Nebo. This work will need to be coordinated with the other work happening on site;
- The upgrade of the oil separation tank with 2nd stage above ground puraceptor is being done under CP.02770 (*Upgrade of Oil Containment System Stage 2*). The work under this project needs to be coordinated with work under CP.02770 so that the upgrade is completed in a timely manner to align with works.
- This project will be delivered by Powerlink with EQ providing input regarding preferred design and equipment strategies. As part of this project a division of responsibility document to be developed to clearly demarcate the scope and deliverables.

3.5. Variations to Scope (post project approval)

Not applicable

4. Project Timing

4.1. Project Approval Date

The anticipated date by which the project will be approved is April 2021.

4.2. Site Access Date

As H011 is a Powerlink substation site access is immediately available.

4.3. Commissioning Date

The latest date for the commissioning of the new assets included in this scope and the decommissioning and removal of redundant assets, where applicable, is defined under each option and stage.

5. Special Considerations

The following issues are important to consider during the implementation of this project: -

- Any existing assets to be removed and disposed of as part of this scope must be identified within the estimate together with the residual asset values at time of disposal;
- Plant and equipment identified as suitable to be recovered for use as spares or returned to stores should be packaged and transported to an appropriate storage location, with a suitable allowance for the cost included in the estimate;
- A high level project implementation plan including staging and outage plans should be considered as part of the estimate; and
- As part of the estimate please provide a breakdown of costs in the three (3) options as follows:
    - PQ works excluding transformer works;
    - Transformer works; and
    - EQ works.

6. Asset Management Requirements

Equipment shall be in accordance with Powerlink equipment strategies.

Unless otherwise advised [redacted] will be the Project Sponsor for this project. The Project Sponsor must be included in any discussions with any other areas of Investment & Planning.

[redacted] will provide the primary customer interface with Ergon. The Project Sponsor should be kept informed of any discussions with the customer.

7. Asset Ownership

Following the replacement of transformers T3 & T4, the asset boundary with Ergon will be moved from the HV terminals to the LV terminals of the 132/11kV transformer.

8. System Operation Issues

Operational issues that should be considered as part of the scope and estimate include:

- interaction of project outage plan with other outage requirements;
- likely impact of project outages upon grid support arrangements; and
- likely impact of project outages upon the optical fibre network.

9. Options

Options discussed in section 3 above.

10. Division of Responsibilities

A division of responsibilities document will be required to cover the changes to the interface boundaries with Ergon. The Project Manager will be required to draft the document and consult with the Project Sponsor who will arrange sign-off between Powerlink and the relevant customer.

11. Related Projects

Project No.	Project Description	Planned Comm Date	Comment
Pre-requisite Projects			
Co-requisite Projects			
CP.02770	Upgrade of Oil Containment System Stage 2	October 2021	Reviewing Estimates
Other Related Projects			
CP.01016	Nebo Secondary Systems Replacement	August 2022	Progressing
CP.01396	Nebo 275/132kV No.2 Transformer Replacement	December 2018	Progressing
CP.02351	Nebo Primary Plant Replacement	August 2022	Progressing
OR.02334	H011 Nebo SVC Aux Tfmr Replacement	August 2020	Approved

Concept Estimate for CP.02360 - H011 Nebo Transformer 3 & 4 Replacement

Record ID	A3397052	
Policy stream	Asset Management	
Authored by	Project Manager	[redacted]
Reviewed by	Project Manager	[redacted]
Reviewed by	Team Leader Projects	[redacted]
Approved by	Manager Projects	[redacted]

Table of Contents

1. Executive Summary

H011 Nebo Substation was established in 1977 and is an important node in the state-wide transmission network, connecting North and South Queensland whilst providing bulk supplies to several key areas, including Mackay and Pioneer Valley.

Nebo Substation also supplies the local township via two (2) 132/11kV 5MVA transformers (3T and 4T) feeding the EQ 11kV distribution network. Both transformers were installed at Nebo in 1983 and have now been in service for 37 years. Although they are displaying condition issues typical of transformers of this age, due to the low loading over service life, the insulating paper condition seems to be such that an additional 10 years of service life can be achieved with targeted intervention (life extension activities). However, the associated 11kV switchgear is at end of its technical life, with no spares available and deteriorating condition issues.

Powerlink has identified three (3) credible options to address the identified need, as presented in Table 1.1 below. Concept estimates are required to inform feasibility and cost assessments for the options.

Table 1.1: Options summary

Option	Description	Stage	Works
Option 1:	Staged replacement of Equipment	Stage 1	Replace 11kV switchgear by June 2022 Life extension of T3 & T4
		Stage 2	Replace the T3 & T4 transformers by Dec 2031
Option 2	Single stage replacement	Single stage	Replace the transformers T3 & T4 and 11kV switchgear by June 2022
Option 3:	Staged replacement of Equipment	Stage 1	Replace 11kV switchgear by June 2022 Life extension of T4 Replace the T3 transformers by June 2022
		Stage 2	Replace the T4 transformers by Dec 2031

The objective of this estimate is to develop the most feasible economic options for replacement of transformer T3 & T4 along with the replacement of the 11kV switchgear units by June 2022.

In addition to the above options summary, scope clarification has confirmed for the following requirements.

1.1 Option 1: Stage 1: Replace 11kV switchgear by June 2022 & life extension of T3 & T4

The existing secondary systems will be reviewed, updated and retained until asset transfer occurs in 2031. Metering point to remain on the transformer LV until asset handover of the 132kV Transformers and its associated 11kV switchgear occurring in December 2031.

1.1.1 Project Estimate

Estimate Components		Base $	Escalated $
Estimate Class	5		
Estimate Accuracy	+100% / -50%		
Base Estimate		**4,211,822**	**4,271,996**
Mitigated Risk	[redacted]	[redacted]	[redacted]
Contingency Allowance	[redacted]	[redacted]	[redacted]
TOTAL		[redacted]	[redacted]

1.1.2 Project Financial Year Cash Flows

	June 2020 Base $	Escalated $
To June 2021	2,744,148	2,744,148
To June 2022	1,467,674	1,527,849
TOTAL	**4,211,822**	**4,271,996**

1.2 Option 1: Stage 2: Replace the T3 & T4 transformers by Dec 2031

Replace associated secondary system that conform to EQ standards by December 2031 in preparation for asset handover of the 132kV Transformers and associated 11kV switchgear.

1.2.1 Project Estimate

Estimate Components		Base $	Escalated $
Estimate Class	5		
Estimate Accuracy	+100% / -50%		
Base Estimate		**4,615,850**	**6,815,931**
Mitigated Risk	[redacted]	[redacted]	[redacted]
Contingency Allowance	[redacted]	[redacted]	[redacted]
TOTAL		[redacted]	[redacted]

1.2.2 Project Financial Year Cash Flows

	June 2020 Base $	Escalated $
To June 2030	1,795,712	2,543,208
To June 2031	1,874,955	2,802,194
To June 2032	945,183	1,470,530
TOTAL	**4,615,850**	**6,815,931**

1.3 Option 2: Replace transformers T3 & T4 and 11kV switchgear by June 2022

Replace associated secondary system with one that conforms with EQ standards by June 2022 in preparation for asset handover of the 132kV Transformers and associated 11kV switchgear.

1.3.1 Project Estimate

Estimate Components		Base $	Escalated $
Estimate Class	5		
Estimate Accuracy	+100% / -50%		
Base Estimate		**5,583,475**	**5,663,626**
Mitigated Risk	[redacted]	[redacted]	[redacted]
Contingency Allowance	[redacted]	[redacted]	[redacted]
TOTAL		[redacted]	[redacted]

1.3.2 Project Financial Year Cash Flows

	June 2020 Base $	Escalated $
To June 2021	3,628,573	3,628,573
To June 2022	1,954,902	2,035,053
TOTAL	**5,583,475**	**5,663,626**

1.4 Option 3: Stage 1: Replace 11kV switchgear by June 2022, life extension of T4, and replace T3 by June 2022

The existing secondary systems will be reviewed, updated and retained until asset transfer occurs in 2031. Metering point to remain on the transformer LV until asset handover of the 132kV Transformers and its associated 11kV CB occurring in December 2031.

1.4.1 Project Estimate

Estimate Components		Base $	Escalated $
Estimate Class	5		
Estimate Accuracy	+100% / -50%		
Base Estimate		**5,397,677**	**5,475,122**
Mitigated Risk	[redacted]	[redacted]	[redacted]
Contingency Allowance	[redacted]	[redacted]	[redacted]
TOTAL		[redacted]	[redacted]

1.4.2 Project Financial Year Cash Flows

	June 2020 Base $	Escalated $
To June 2021	3,508,772	3,508,772
To June 2022	1,888,905	1,966,350
TOTAL	**5,397,677**	**5,475,122**

1.5 Option 3: Stage 2: Replace the T4 transformers by Dec 2031

Replace associated secondary system that conform to EQ Standards by December 2031 in preparation for asset handover of the 132kV Transformers and its associated 11kV CB.

1.5.1 Project Estimate

Estimate Components		**Base $**	**Escalated $**
Estimate Class	5		
Estimate Accuracy	+100% / -50%		
Base Estimate		**3,197,571**	**4,709,726**
Mitigated Risk	[redacted]	[redacted]	[redacted]
Contingency Allowance	[redacted]	[redacted]	[redacted]
TOTAL		[redacted]	[redacted]

1.5.2 Project Financial Year Cash Flows

	June 2020 Base $	**Escalated $**
To June 2030	1,259,240	1,773,007
To June 2031	1,288,690	1,925,998
To June 2032	649,641	1,010,721
TOTAL	**3,197,571**	**4,709,726**

2. Project and Site Specific Information

2.1 Project Dependencies & Interactions

This project is dependent on the completion delivery of the following projects:

Project No.	Project Description	Planned Commissioning Date	Comment
Dependencies			
EQ Project	Option 2 requires an EQ project to be established to replace sec sys and commission the two 132/11kV transformers	TBA	EQ to design procure, install, test and commission the new Transformer and secondary systems by 2021. Powerlink to assist in construction only.
EQ Project	Option 1 Stage 2 and Option 3 Stage 2 requires an EQ project to be established to replace sec sys and commission the 132/11kV transformers	TBA	EQ to design procure, install, test and commission the new Transformer and secondary systems by 2031. Powerlink to assist in construction only.
Interactions			
CP.02351	Nebo Primary systems replacement	October 2024	Design, construction and testing resource to align with this project.
CP.01016	Nebo Secondary systems replacement	October 2024	Design, construction and testing resource to align with this project.
CP.02770	Upgrade of Oil Containment System Stage 2		The upgrade of the OST is to be completed prior to the Transformer replacement commence
Other Related Projects			
Nil			

2.2 Site Specific Issues

- Nebo Substation is a major node that connects the North and South Queensland transmission network.
- Nebo 132kV bays =D04 and =D05 replacement to rectify the RAZ needs to be completed successfully to allow a safe and easy replacement of the 132/11kV Transformer and 11kV CB.
- There is currently a Primary and Secondary systems replacement happening in the Nebo Substation under CP.02351 and CP.01016 projects. Coordination with these projects will be required in order to complete this project.
- The Nebo Substation site is 90km west of Mackay on Peak Downs Hwy.
- No major environmental or cultural heritage issues identified.
- All works done within a live substation; and most in close proximity to operational plant, this will influence efficiencies of works as well as construction and commissioning costs.

- The Nebo Township and surrounding mines receives 11kV supply from the two transformers being replaced under this project.
- The asset boundaries will move from the 11kV pole outside the substation to the HV bushing of the transformers as soon as the asset handover of the 132kV Transformers and its associated 11kV CB has been completed.
- It is difficult to obtain MSP resource for Nebo projects. There is a high likelihood that the target project commissioning date of June 2022 may not be met.

3. Option 1 - Stage 1: Replace 11kV switchgear by June 2022 Life extension of T3 & T4

3.1 Definition

3.1.1 Scope

Briefly, this project option consists of the staged replacement of equipment with work done in two stages where by the 11kV switchgear is replace by June 2022 followed by a delayed replacement of transformers T3 & T4 by December 2031.

For Stage 1 of Option 1 the project will replace the 11kV ring main unit with new outdoor type SF6 or vacuum circuit breakers with AIS disconnectors and 11kV toroidal CT's. The existing 132/11kV Transformer 3 and Transformer 4 will be refurbished in order to extend its operational life to 2030 then both will be completely replaced by December 2031. A review of the existing secondary systems and any relevant updates shall be implemented in order to maintain its operational status until the asset transfer on December 2031.

3.1.1.1 Substations Works

- Design, procure, erect and commission 2 x 132kV bays, as follows:
  - 2 x 11kV feeder bays (EQ sourced switchgear in bay);
  - New 33kV cable to connect the transformers to the 11kV switching bays; and
  - 1 x bus tie bay to connect the two 11kV feeders.
- Organise the life extension refurbishment of 2x 132/11kV 5 MVA Power Transformer;
- Provide footings for all plant and equipment required for the 11kV switchgear;
- Provide structures for all plant and equipment required for the 11kV switchgear;
- Reinstate existing road construction following trenching works for 11kV cables;
- Provide new cable trenches and conduits as required to suit the transformer refurbishment and associated 11kV cable and switchgear replaced;
- Demolition and removal of structures and foundations for all redundant plant;
- Support all necessary civil works and miscellaneous site works to facilitate the refurbishment of the transformer and replacement of associated 11kV switchgear;
- Secondary system design to replace two (2) 11kV circuit breakers in-situ with using outdoor type either SF6 or vacuum circuit breakers with AIS disconnectors;
- The existing (SDM8) Secondary systems panel will be reviewed, updated and retained until the asset transfer is completed on December 2031;
- For T3 and T4 Replace Buchholz relay and upgrade main control cubicle to AS 3000 requirements;
- Review and upgrade metering as required and associated bay plant utilising 11kV equipment; and
- Review existing T3 and T4 protection (under CP.01016) to use new CTs installed at the 11kV switchgear.

3.1.1.2 Transmission Line Works

Not applicable.

3.1.1.3 Telecommunication Works

Provide Telecommunications design for communications and network device configuration for metering over the MPLS network.

3.1.1.4 Easement/Land Acquisition & Permit Works

Not applicable

3.1.2 Major Scope Assumptions

- Another project will be set up on 2030 to replace the secondary system with an EQ compliant system prior to asset handover on December 2031.
- It is assume that procurement of the 11kV switchgear will be via the current EQ period contract.
- It is assume that the 11kV cables from the RMU to the EQ pole outside the sub is to be replaced. Cost to install and commission the cable is still unknown. As part of this Options estimate Powerlink assumes that we provide cost for the installation and testing.
- It is assume that an EQ project will be established to design and procure the 11kV cables between the RMU and the pole outside the sub.
- It is assume that procurement of long lead-time equipment will not pose a risk in the projects delivery schedule.
- It is assume that outage availability will not be an issue due to the constrained timeline for this option.
- It is assume that resources availability will not pose a risk in the projects delivery schedule.

3.1.3 Scope Exclusions

Design and procurement of the 11kV cables from the RMU to the EQ pole outside the substation.

3.2 Project Execution

3.2.1 Project Schedule

Task	Target Completion
Project Approval	Apr 21
Kick Off meeting	Apr 21
PMP	May 21
Design	May 21 – Sep 21
RFQ	May 21
ITT	May 21 – Jun 21
Procurement	Jun 21
EQ Design	Jun 21 – Sep 21
Contract Award	Jul 21
Stage 1a: Decommission 3T	Sep 21
Stage 1b: Rebuild 3T (including refurbishment of TX)	Oct 21 – Nov 21
Stage 1c: Commission 3T	Dec 21
Stage 2a: Decommission 4T	Mar 22
Stage 2b: Rebuild 4T (including refurbishment of TX)	Apr 22 – May 22
Stage 2c: Commission 4T	Jun 22

3.2.2 Network Impacts

An outage will be required for each of the transformer on a continuous period that is sufficient to complete the work.

During the outage, the Nebo township and surrounding mine will be supplied via the single operation Transformer that poses load at risk. Further contingencies may need to be in place such as temporary generation on standby if required. Cost for such contingency is not included within this estimate.

3.2.3 Project Staging

Stage	Name (of Stage)	Stage Description, Tasks & Principal Contractor
1a	Decommission 3T	1. MSP to disconnect between 3T and 132kV post insulator 2. MSP to disconnect 11kV cable at pole termination 3. Decommission 11kV CB
1b	Rebuild 3T	1. Remove redundant primary plant inc 11kV cable between 3T and 11kV CB, toroidal CTs 2. Rebuild 11kV bay and run new 11kV cable 3. Transformer vendor to perform life extension of 3T 4. Run all new secondary cables and terminate
1c	Commission 3T	1. Terminate remaining secondary cables 2. Perform changes to convert metering panel in +4 to IP metering 3. Perform panel mods to 3T panel in +4 4. Test new points to EMS 5. Primary inject 3T including new 11kV DTCB to prove diff stability 6. Re-connect 132kV and 11kV HV connections 7. Metering Clearance 8. Energise 3T and 11kV bay
2a	Decommission 4T	1. MSP to disconnect between 4T and 132kV post insulator 2. MSP to disconnect 11kV cable at pole termination 3. Decommission 11kV CB
2b	Rebuild 4T	1. Remove redundant primary plant inc 11kV cable between 4T and 11kV CB, toroidal CTs 2. Rebuild 11kV bay and run new 11kV cable 3. Transformer vendor to perform life extension of 4T 4. Run all new secondary cables and terminate 5. Restore switchyard road
2c	Commission 4T	1. Terminate remaining secondary cables 2. Perform changes to convert metering panel in +4 to IP metering 3. Perform panel mods to 4T panel in +4 4. Test new points to EMS 5. Primary inject 4T including new 11kV DTCB to prove diff stability 6. Re-connect 132kV and 11kV HV connections 7. Receive metering clearance 8. Energise 4T and 11kV bay

3.2.4 Resourcing

It is assumed that:

- All design works except for the 11kV cable will be done by Powerlink;
- Design of 11kV cables between the RMU and the pole will be done by EQ;
- Majority of construction works will be carried out by a contractor construction panel contractors;

- Final termination, testing and commissioning works will be carried out by EQ; and
- Live substation works will be carried out by MSP.

3.3 Project Estimate

Estimate Components		Base $	Escalated $
Estimate Class	5		
Estimate Accuracy	+100% / -50%		
Base Estimate		**4,211,822**	**4,271,996**
Mitigated Risk	[redacted]	[redacted]	[redacted]
Contingency Allowance	[redacted]	[redacted]	[redacted]
TOTAL		[redacted]	[redacted]

3.4 Project Financial Year Cash Flows

	June 2020 Base $	Escalated $
To June 2021	2,744,148	2,744,148
To June 2022	1,467,674	1,527,849
TOTAL	**4,211,822**	**4,271,996**

3.5 Project Asset Classification

Asset Class	Asset Life	Base $	Percentage
Secondary systems	15 years	768,672	18%
Communications	15 years	248,038	6%
Primary plant	40 years	3,195,112	76%
Transmission lines	50 years		
TOTAL		**4,211,822**	

4. Option 1 - Stage 2: Replace the T3 & T4 transformers by Dec 2031

4.1 Definition

4.1.1 Scope

For Stage 2 of Option 1 the project will replace the existing 132/11kV Transformer 3 and Transformer 4 by December 2031. An EQ design secondary systems will be required under this stage to allow asset transfer as soon as the Transformers are commissioned.

4.1.1.1 Substations Works

- Provide interface Electrical design for the two new 132/11kV 5MVA Power Transformer;
- Install Rules compliant revenue metering on the 132kV side of the transformers utilising metering units or turret CTs within the new transformers;
- Removal of the old toroidal CTs from the 11kV side of the existing transformers;
- Provide footings for all plant and equipment required for the transformer;
- EQ to provide structures for all plant and equipment required for the transformer replacements;
- Reinstate existing road construction following trenching works for 11kV cables;
- Provide new cable trenches and conduits as required to suit the transformer replacements;
- Demolition and removal of structures and foundations for all redundant plant;
- Support all necessary civil works and miscellaneous site works to facilitate the transformer replacements;
- Secondary system design modifications to support the new EQ designed secondary systems for Transformer 3 and 4; and
- Review and upgrade metering as required and associated bay plant utilising 132kV equipment.

4.1.1.2 Transmission Line Works

Not applicable.

4.1.1.3 Telecommunication Works

Telecommunications design to support EQ Protection and SCADA for their new Transformer 3, 4 and 11kV assets.

4.1.1.4 Easement/Land Acquisition & Permit Works

Not applicable.

4.1.2 Major Scope Assumptions

- To be compliant it is assume that all secondary systems for the two Transformers will be designed, fabricated and installed by EQ. Powerlink will assist in any interface and Civil design requirements
- It is assume that procurement of the 132/11kV Power Transformer will be via the EQ period contract.
- It is assume that the testing and commissioning of the new panels will be facilitated by EQ.

- It is assume that outage availability will not be an issue.
- It is assume that resources availability will not pose a risk in the projects delivery schedule.

4.1.3 Scope Exclusions

Scope as per PCR clarifications. All secondary system design will be done by EQ in order to conform to their standards and requirements for asset transfer.

4.2 Project Execution

4.2.1 Project Schedule

Task	Target Completion
Project Approval	Jul 2030
EQ Design	Sep 2030 - Mar 2031
Procurement	Jul 2030
Site access date	Apr-2031
Stage 1a: Decommission 3T	Apr-2031
Stage 1b: Replace 3T	May 2031 - Jun 2031
Stage 1c: Commission 3T	Jul-31
Stage 2a: Decommission 4T	Aug-31
Stage 2b: Replace 4T	Sep 2031 - Oct 2031
Stage 2c: Commission 4T	Dec-31

4.2.2 Network Impacts

An outage will be required for each of the transformer on a continuous period that is sufficient to complete the work.

During the outage, the Nebo township and surrounding mine will be supplied via the single operation Transformer that poses load at risk. Further contingencies may need to be in place such as temporary generation on standby if required. Cost for such contingency is not included within this estimate.

4.2.3 Project Staging

Stage	Name (of Stage)	Stage Description, Tasks & Principal Contractor
1a	Decommission 3T	1. MSP to disconnect between 3T and 132kV post insulator 2. MSP to disconnect 11kV cable at the Transformer cable junction
1b	Rebuild 3T	1. Remove redundant 3T primary plant and toroidal CTs 2. Construction to install the new 3T 3. Run all new secondary cables and terminate
1c	Commission 3T	1. Terminate remaining secondary cables 2. Perform changes to convert metering 3. EQ to install their new secondary systems panel 4. EQ to test new points via their SCADA network 5. Primary inject 3T including the 11kV DTCB to prove diff stability 6. Re-connect 132kV and 11kV HV connections 7. Metering Clearance 8. Energise 3T and 11kV bay
2a	Decommission 4T	1. MSP to disconnect between 4T and 132kV post insulator 2. MSP to disconnect 11kV cable at the Transformer cable junction
2b	Rebuild 4T	1. Remove redundant 4T primary plant and toroidal CTs 2. Construction to install the new 4T 3. Run all new secondary cables and terminate
2c	Commission 4T	1. Terminate remaining secondary cables 2. Perform changes to convert metering 3. EQ to install their new secondary systems panel 4. EQ to test new points via their SCADA network 5. Primary inject 4T including the 11kV DTCB to prove diff stability 6. Re-connect 132kV and 11kV HV connections 7. Metering Clearance 8. Energise 4T and 11kV bay

4.2.4 Resourcing

It is assumed that:

- All design work for the Transformer and associated secondary system will be done by EQ;
- Majority of construction works will be carried out by a contractor construction panel contractors;

- Final termination, testing and commissioning works will be carried out by EQ; and
- Live HV substation works will be carried out by a MSP.

4.3 Project Estimate

Estimate Components		Base $	Escalated $
Estimate Class	5		
Estimate Accuracy	+100% / -50%		
Base Estimate		**4,615,850**	**6,815,931**
Mitigated Risk	[redacted]	[redacted]	[redacted]
Contingency Allowance	[redacted]	[redacted]	[redacted]
TOTAL		[redacted]	[redacted]

4.4 Project Financial Year Cash Flows

	June 2020 Base $	Escalated $
To June 2030	1,795,712	2,543,208
To June 2031	1,874,955	2,802,194
To June 2032	945,183	1,470,530
TOTAL	**4,615,850**	**6,815,931**

4.5 Project Asset Classification

Asset Class	Asset Life	Base $	Percentage
Secondary systems	15 years	561,688	12%
Communications	15 years	169,727	4%
Primary plant	40 years	3,884,435	84%
Transmission lines	50 years		0%
TOTAL		**4,615,850**	

5. Option 2: Replace the transformers T3 & T4 and 11kV switchgear by June 2022

5.1 Definition

5.1.1 Scope

Briefly, this project option consists of the single staged replacement of the 11kV switchgear and transformers T3 & T4 at Nebo by June 2022.

Under Option 2 the project will replace the existing 132/11kV Transformer 3 and Transformer 4 as well as both 11kV circuit breaker and associated secondary systems by June 2022. An EQ design and compliant secondary systems will be required under this stage to allow asset transfer as soon as the Transformers are commissioned.

5.1.1.1 Substations Works

- Provide interface Electrical design for the two new 132/11kV 5 MVA Power Transformer;
- EQ to design, procure, erect and commission 2 x 132kV bays, as follows:
  - 2 x 11kV feeder bays (EQ sourced switchgear in bay);
  - New 33kV cable to connect the transformers to the 11kV switching bays;
  - Removal of the toroidal CTs from the 11kV side of the existing transformers; and
  - 1 x bus tie bay to connect the two 11kV feeders.
- EQ to provide structures for all plant and equipment required for the transformer replacements and associated 11kV switchgear;
- Install Rules compliant revenue metering on the 132kV side of the transformers utilising metering units or turret CTs within the new transformers;
- Provide footings for all plant and equipment required for the transformer replacements and associated 11kV switchgear;
- Reinstate existing road construction following trenching works for 11kV cables;
- Provide new cable trenches and conduits as required to suit the transformer replacements and associated 11kV switchgear;
- Demolition and removal of structures and foundations for all redundant plant;
- Support all necessary civil works and miscellaneous site works to facilitate the transformer replacements and associated 11kV switchgear;
- Secondary system design modifications to support the new EQ designed secondary systems for Transformer 3, 4, and 11kV CB; and
- Review and upgrade metering as required and associated bay plant utilising 132kV equipment.

5.1.1.2 Transmission Line Works

Not Applicable

5.1.1.3 Telecommunication Works

Telecommunications design to support EQ Protection and SCADA for their new Transformer 3, 4 and 11kV assets.

5.1.1.4 Easement/Land Acquisition & Permit Works

Not applicable

5.1.2 Major Scope Assumptions

- To be compliant it is assume that all secondary systems for the two Transformers will be designed, fabricated and installed by EQ. Powerlink will assist in any interface and Civil design requirements.
- It is assume that procurement of the 132/11kV Transformer and associated 11kV switchgear will be via the current EQ period contract.
- It is assume that the testing and commissioning of the new panels will be facilitated by EQ.
- It is assume that EQ will design and procure the 11kV cables from the RMU to the EQ pole outside the subs if required.
- It is assume that outage availability is not an issue due to the constrained timeline on this option.
- It is assume that resources availability will not pose a risk in the projects delivery schedule.

5.1.3 Scope Exclusions

Scope as per PCR clarifications. All design will be done by EQ in order to conform to their standards and requirements for asset transfer.

5.2 Project Execution

5.2.1 Project Schedule

Task	Target Completion
Project Approval	Apr 21
Kick Off meeting	Apr 21
PMP	May 21
Interface Meeting & DOR	May 21
RFQ	May 21
EQ Design	May 21 – Aug 21
Procurement	Jun 21
ITT	Jun 21 – Jul 21
Contract Award	Aug 21
Stage 1a: Decommission 3T	Sep 21
Stage 1b: Replace 3T and 11kV CB	Oct 21 – Nov 22
Stage 1c: Commission 3T	Dec 22
Stage 2a: Decommission 4T	Mar 22
Stage 2b: Replace 4T and 11kV CB	Apr 22 – May 22
Stage 2c: Commission 4T	Jun 22

5.2.2 Network Impacts

An outage will be required for each of the transformer on a continuous period that is sufficient to complete the work.

During the outage, the Nebo township and surrounding mine will be supplied via the single operation Transformer that poses load at risk. Further contingencies may need to be in place such as temporary generation on standby if required. Cost for such contingency is not included within this estimate.

5.2.3 Project Staging

3	Name (of Stage)	Stage Description, Tasks & Principal Contractor
1a	Decommission 3T	1. MSP to disconnect between 3T and 132kV post insulator 2. MSP to disconnect 11kV cable at pole termination 3. Decommission 3T and 11kV bay
1b	Rebuild 3T	1. Remove redundant primary plant inc 3T 2. Rebuild 11kV bay and run new 11kV cable and 3T 3. Install 132kV new metering unit 4. Run all new secondary cables and terminate
1c	Commission 3T	1. Terminate remaining secondary cables 2. Perform changes to convert metering panel in +4 to IP metering 3. Perform panel mods to 3T panel in +4 and install ENERGY QUEENSLANDSecSys 4. SAT new 3T and 11kV bay 5. Test new points to EMS & OCCN 6. Primary inject 3T including new 11kV DTCB to prove diff stability 7. Re-connect 132kV and 11kV HV connections 8. Metering Clearance 9. Energise 3T and 11kV bay
2a	Decommission 4T	1. MSP to disconnect between 4T and 132kV post insulator 2. MSP to disconnect 11kV cable at pole termination 3. Decommission 4T and 11kV bay
2b	Rebuild 4T	1. Remove redundant primary plant inc 4T 2. Rebuild 11kV bay and run new 11kV cable and 4T 3. Install 132kV new metering unit 4. Run all new secondary cables and terminate
2c	Commission 4T	1. Terminate remaining secondary cables 2. Perform changes to convert metering panel in +4 to IP metering 3. Perform panel mods to 4T panel in +4 and install EQ SecSys 4. SAT new 4T and 11kV bay 5. Test new points to EMS & OCCN 6. Primary inject 4T including new 11kV DTCB to prove diff stability 7. Re-connect 132kV and 11kV HV connections 8. Metering Clearance 9. Energise 4T and 11kV bay

5.2.4 Resourcing

It is assumed that:

- All design work for the Transformer and associated secondary system will be done by EQ;
- Interface, necessary Electrical and Civil design will be done by Powerlink;
- Majority of civil construction works will be carried out by a contractor construction panel contractors;
- Final termination, testing and commissioning works will be carried out by EQ MSP; and
- Live HV substation works will be carried out by a MSP.

5.3 Project Estimate

Estimate Components		Base $	Escalated $
Estimate Class	5		
Estimate Accuracy	+100% / -50%		
Base Estimate		**5,583,475**	**5,663,626**
Mitigated Risk	[redacted]	[redacted]	[redacted]
Contingency Allowance	[redacted]	[redacted]	[redacted]
TOTAL		[redacted]	[redacted]

5.4 Project Financial Year Cash Flows

	June 2020 Base $	Escalated $
To June 2021	3,628,573	3,628,573
To June 2022	1,954,902	2,035,053
TOTAL	**5,583,475**	**5,663,626**

5.5 Project Asset Classification

Asset Class	Asset Life	Base $	Percentage
Secondary systems	15 years	873,673	16%
Communications	15 years	248,062	4%
Primary plant	40 years	4,461,740	80%
Transmission lines	50 years		
TOTAL		**5,583,475**	

6. Option 3 - Stage 1: Replace 11kV switchgear by June 2022 Life extension of T4 Replace the T3 transformers by June 2022

6.1 Definition

6.1.1 Scope

Briefly, this project option consists of the staged replacement of equipment with work done in two stages where by the 11kV switchgear and Transformer T3 is replace by June 2022 followed by a delayed replacement of transformer T4 by December 2031.

For Stage 1 of Option 3 the project will replace the 11kV ring main unit with new outdoor type SF6 or vacuum circuit breakers with AIS disconnectors and 11kV toroidal CT's. One of the existing 132/11kV Transformer will also be replaced by June 2022. The remaining Transformer will be refurbished to extend it operational life to 2030 and will subsequently be replaced by December 2031. A review on the existing secondary systems and any relevant updates shall be implemented in order to maintain its operational status until the asset transfer on December 2031.

6.1.1.1 Substations Works

- Design, procure, erect and commission 2 x 132kV bays, as follows:
    - 2 x 11kV feeder bays (EQ sourced switchgear in bay);
    - New 33kV cable to connect the transformers to the 11kV switching bays;
    - 1 x bus tie bay to connect the two 11kV feeders;
- Provide Electrical design for the refurbished and new 132/11kV 5 MVA Power Transformer;
- Install Rules compliant Type 2 revenue metering on the replaced
- Organise the life extension refurbishment on one of the 132/11kV 5 MVA Power Transformer;
- Provide footings for all plant and equipment required for the transformer replacement and associated 11kV switchgear;
- Provide structures for all plant and equipment required for the transformer replacement and associated 11kV switchgear;
- Reinstate existing road construction following trenching works for 11kV cables;
- Provide new cable trenches and conduits as required to suit the transformers and associated 11kV switchgear replacement;
- Demolition and removal of structures and foundations for all redundant plant;
- Support all necessary civil works and miscellaneous site works to facilitate the refurbishment of one of the transformer, replacement of the other and replacement of associated 11kV switchgear;
- Secondary system design to replace two (2) 11kV circuit breakers in-situ with using outdoor type either SF6 or vacuum circuit breakers with AIS disconnectors;
- The existing (SDM8) Secondary systems panel will be reviewed, updated and retained until the asset transfer is completed on 2031;
- For the refurbished Transformer replace Buchholz relay and upgrade main control cubicle to AS 3000 requirements;
- For the new and refurbished Transformer review and upgrade metering as required and associated bay plant utilising 11kV equipment

- Review existing T3 and T4 protection (under CP.01016) to use new CTs installed at the 11kV switchgear.

6.1.1.2 Transmission Line Works

Not applicable.

6.1.1.3 Telecommunication Works

Provide Telecommunications design for communications and network device configuration for metering over the MPLS network.

6.1.1.4 Easement/Land Acquisition & Permit Works

Not applicable

6.1.2 Major Scope Assumptions

- The SDM8 (or similar) panels will be used for this stage up to the asset handover on December 2031. Another project will be set up to replace the secondary system with and EQ compliant system prior to asset handover.
- It is assume that procurement of the 132/11kV Transformer and associated 11kV switchgear will be via the current EQ period contract.
- It is assume that the 11kV cables from the RMU to the EQ pole outside the subs is to be replaced. Cost to install and commission the cable is still unknown. As part of this Options estimate Powerlink assumes that we provide cost for the installation and testing.
- It is assumed that an EQ project will be established to design and procure the 11kV cables.
- It is assume that procurement of long lead-time equipment will not pose a risk in the projects delivery schedule.
- It is assume that outage availability will not be an issue due to the constrained timeline for this option.
- It is assume that resources availability will not pose a risk in the projects delivery schedule.

6.1.3 Scope Exclusions

Design and procurement of the 11kV cables from the RMU to the EQ pole outside the substation.

6.2 Project Execution

6.2.1 Project Schedule

Task	Target Completion
Project Approval	Apr 21
Kick Off meeting	Apr 21
PMP	May 21
Design	May 21 – Sep 21
RFQ	May 21
ITT	May 21 – Jun 21
Procurement	Jun 21
EQ Design	Jun 21 – Sep 21
Contract Award	Jul 21
Stage 1a: Decommission 3T	Sep 21
Stage 1b: Replace 3T and 11kV CB	Oct 21 – Nov 21
Stage 1c: Commission 3T	Dec 21
Stage 2a: Decommission 4T	Mar 22
Stage 2b: Rebuild 4T (including refurbishment of TX)	Apr 22 – May 22
Stage 2c: Commission 4T	Jun 22

6.2.2 Network Impacts

An outage will be required for each of the transformer on a continuous period that is sufficient to complete the work.

During the outage, the Nebo township and surrounding mine will be supplied via the single operation Transformer that poses load at risk. Further contingencies may need to be in place such as temporary generation on standby if required. Cost for such contingency is not included within this estimate.

6.2.3 Project Staging

Stage	Name (of Stage)	Stage Description, Tasks & Principal Contractor
1a	Decommission 3T	1. MSP to disconnect between 3T and 132kV post insulator 2. MSP to disconnect 11kV cable at pole termination 3. Decommission 3T and 11kV bay
1b	Rebuild 3T	1. Remove redundant primary plant inc 3T 2. Rebuild 11kV bay and run new 11kV cable and 3T 3. Install 132kV new metering unit 4. Run all new secondary cables and terminate
1c	Commission 3T	1. Terminate remaining secondary cables 2. Perform changes to convert metering panel in +4 to IP metering 3. Perform panel mods to 3T panel in +4 4. SAT new 3T and 11kV bay 5. Test new points to EMS 6. Primary inject 3T including new 11kV DTCB to prove diff stability 7. Re-connect 132kV and 11kV HV connections 8. Metering Clearance 9. Energise 3T and 11kV bay
2a	Decommission 4T	1. MSP to disconnect between 4T and 132kV post insulator 2. MSP to disconnect 11kV cable at pole termination 3. Decommission 11kV bay
2b	Rebuild 4T	1. Remove redundant primary plant 2. Rebuild 11kV bay and run new 11kV cable 3. Transformer vendor life extension T4 4. Run all new secondary cables and terminate
2c	Commission 4T	1. Terminate remaining secondary cables 2. Perform changes to convert metering panel in +4 to IP metering 3. Perform panel mods to 4T panel in +4 4. SAT new 11kV bay 5. Test new points to EMS 6. Primary inject 4T including new 11kV DTCB to prove diff stability 7. Re-connect 132kV and 11kV HV connections 8. Metering Clearance 9. Energise 4T and 11kV bay

6.2.4 Resourcing

It is assumed that:

- All design works except for the 11kV cable will be done by Powerlink;
- Majority of construction works will be carried out by a contractor construction panel contractors;
- Final termination, testing and commissioning works will be carried out by EQ MSP;
- Live substation works will be carried out by a Powerlink MSP.

6.3 Project Estimate

Estimate Components		Base $	Escalated $
Estimate Class	5		
Estimate Accuracy	+100% / -50%		
Base Estimate		**5,397,677**	**5,475,122**
Mitigated Risk	[redacted]	[redacted]	[redacted]
Contingency Allowance	[redacted]	[redacted]	[redacted]
TOTAL		[redacted]	[redacted]

6.4 Project Financial Year Cash Flows

	June 2020 Base $	Escalated $
To June 2021	3,508,772	3,508,772
To June 2022	1,888,905	1,966,350
TOTAL	**5,397,677**	**5,475,122**

6.5 Project Asset Classification

Asset Class	Asset Life	Base $	Percentage
Secondary systems	15 years	1,037,206	25%
Communications	15 years	245,499	6%
Primary plant	40 years	4,114,972	98%
Transmission lines	50 years		
TOTAL		**5,397,677**	

7. Option 3 - Stage 2: Replace the T4 transformers by Dec 2031

7.1 Definition

7.1.1 Scope

Briefly, this project option consists of the staged replacement of equipment with work done in two stages where by the 11kV switchgear and Transformer T3 is replace by June 2022 followed by a delayed replacement of transformer T4 by December 2031.

For Stage 2 of Option 3 the project will replace the remaining 132/11kV Transformer by December 2031. An EQ design compliant secondary systems will be required for both transformer under this stage. This will to allow asset transfer as soon as the new Transformers is commissioned.

7.1.1.1 Substations Works

- Provide interface Electrical design for the new 132/11kV 5 MVA Power Transformer
- New 33kV cable to connect the new transformer to the 11kV switching bays.
- Removal of the toroidal CTs from the 11kV side of the existing transformers.
- Install Rules compliant revenue metering on the 132kV side of the transformers utilising metering units or turret CTs within the new transformers.
- Provide footings for all plant and equipment required for the new transformer;
- Provide structures for all plant and equipment required for the new transformer;
- Provide new cable trenches and conduits as required to suit the new transformer;
- Demolition and removal of structures and foundations for all redundant plant; and
- Support all necessary civil works and miscellaneous site works to facilitate the transformer replacements;
- Secondary system design to support the new EQ designed Secondary systems for both Transformer 3 and 4; and
- Review and upgrade metering as required and associated bay plant utilising 132kV equipment.

7.1.1.2 Transmission Line Works

Not applicable.

7.1.1.3 Telecommunication Works

Telecommunications design to support EQ Protection and SCADA for their Transformer 3, 4 and 11kV assets.

7.1.1.4 Easement/Land Acquisition & Permit Works

Not applicable.

7.1.2 Major Scope Assumptions

- To be compliant it is assume that all secondary systems for the two Transformers will be designed, fabricated and installed by EQ. Powerlink will assist in any to the interface and Civil design requirements.
- It is assume that procurement of the 132/11kV Transformer will be via the EQ period contract.
- It is assume that the testing and commissioning of the new panels will be facilitated by EQ.
- It is assume that outage availability will not be an issue.
- It is assume that resources availability will not pose a risk in the projects delivery schedule.

7.1.3 Scope Exclusions

Scope as per PCR clarifications. All secondary systems design will be done by EQ in order to conform to their standards and requirements for asset transfer.

7.2 Project Execution

7.2.1 Project Schedule

Task	Target Completion
Project Approval	Jul 30
EQ Design	Sep 30 - Mar 31
Procurement	Jul 30
Site access date	Apr-31
Stage 1a: Decommission 3T	Apr-31
Stage 1b: Replace 3T	May-31
Stage 1c: Commission 3T	Jun-31
Stage 2a: Decommission 4T	Jul-31
Stage 2b: Replace 4T	Aug 2031 - Oct 2031
Stage 2c: Commission 4T	Dec-31

7.2.2 Network Impacts

An outage will be required for each of the transformer on a continuous period that is sufficient to complete the work.

During the outage, the Nebo Township and surrounding mine will be supplied via the single operation Transformer that poses load at risk. Further contingencies may need to be in place such as temporary generation on standby if required. Cost for such contingency is not included within this estimate.

7.2.3 Project Staging

Stage	Name (of Stage)	Stage Description, Tasks & Principal Contractor
1a	Decommission and Upgrade 3T	1. MSP to disconnect and remove old secondary system
1b	Rebuild 3T	1. Construction to install interface panel/MK 2. Run all new secondary cables
1c	Commission 3T	1. Terminate remaining secondary cables 2. EQ to install their new secondary systems panel 3. EQ to test new points via their SCADA network 4. Primary inject 3T including the 11kV DTCB to prove diff stability 5. Re-connect 132kV and 11kV HV connections 6. Energise 3T and 11kV bay
2a	Decommission 4T	1. MSP to disconnect between 4T and 132kV post insulator 2. MSP to disconnect 11kV cable at the Transformer cable junction
2b	Rebuild 4T	1. Remove redundant 4T primary plant and toroidal CTs 2. Construction to install the new 4T 3. Run all new secondary cables and terminate
2c	Commission 4T	1. Terminate remaining secondary cables 2. Perform changes to convert metering 3. EQ to install their new secondary systems panel 4. EQ to test new points via their SCADA network 5. Primary inject 4T including the 11kV DTCB to prove diff stability 6. Re-connect 132kV and 11kV HV connections 7. Metering Clearance 8. Energise 4T and 11kV bay

7.2.4 Resourcing

It is assumed that:

- All design work for the secondary system will be done by EQ;
- Majority of civil construction works for the new Transformer will be carried out by a contractor construction panel contractors;
- Final termination, testing and commissioning works will be carried out by EQ; and
- Live HV substation works will be carried out by a MSP.

7.3 Project Estimate

Estimate Components		Base $	Escalated $
Estimate Class	5		
Estimate Accuracy	+100% / -50%		
Base Estimate		**3,197,571**	**4,709,726**
Mitigated Risk	[redacted]	[redacted]	[redacted]
Contingency Allowance	[redacted]	[redacted]	[redacted]
TOTAL		[redacted]	[redacted]

7.4 Project Financial Year Cash Flows

	June 2020 Base $	Escalated $
To June 2030	1,259,240	1,773,007
To June 2031	1,288,690	1,925,998
To June 2032	649,641	1,010,721
TOTAL	**3,197,571**	**4,709,726**

7.5 Project Asset Classification

Asset Class	Asset Life	Base $	Percentage
Secondary systems	15 years	554,738	12%
Communications	15 years	169,935	4%
Primary plant	40 years	2,472,898	54%
Transmission lines	50 years		
TOTAL		**3,197,571**	

8. References

Document name	Version	Date
Project Scope Report	3.0	08/04/2020