January 2026

Powerlink 2027-32 Revenue Proposal

Project Pack

CP.02478 South Pine Transformer 5 Replacement

Project Status: Unapproved

Network Requirement

The South Pine Substation (H002) provides essential switching and injection of power from Central and Southwest Queensland to Southeast Queensland loads. South Pine 275/110kV Transformers T4 and T5 act as a bulk supply point for suburbs in north-west Brisbane as well as parts of Brisbane CBD.

South Pine Transformer T5 was commissioned in 1981 and is the smaller of the two transformers supplying South Pine's west bus with a rating of 250 MVA. Following a detailed condition assessment in 2020 and recent desktop update it has been determined that the winding clamping structure has low reliability and the winding hot spot insulation having reached statistical end of life [1].

If Transformer T5 is not replaced, the retirement of T5 will leave South Pine's west bus with a single transformer to support the current load, along with weak support from the 110kV feeders connected to Upper Kedron from Abermain, West Darra and the CBD. This 110kV injection is not sufficient to support the existing or forecast load. Replacement of T5 is necessary to maintain Powerlink's N-1-50MW/600MWh Transmission Authority reliability standard [2].

Powerlink is currently unaware of any feasible alternative options to minimise or eliminate the load at risk at South Pine 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.

Recommended Option

As this project is currently 'Unapproved', project need and options will be subjected to the public RIT-T consultation process to identify the preferred option closer to the time of investment.

The current recommended option given the poor condition of the winding hot spot insulation is to replace Transformer 5 at South Pine Substation by October 2030 [3].

Options considered but not proposed include:

- Do Nothing – rejected due to non-compliance with reliability standards and safety obligations;
- Decommission Transformer 5 – rejected due to non-compliance with reliability standards under the credible contingency of loss of the remaining transformer;
- Increasing network capacity into CBD West from Rocklea Substation – rejected due to the significantly higher cost of additional 110kV cable capacity from Rocklea and unable to support other loads supplied directly from South Pine West 110kV.
- Connecting the South Pine West and South Pine East 110kV buses – rejected due to fault levels exceeding equipment ratings within both the Powerlink and Energex networks; and
- Non-network option – no viable non-network options have been identified at this time.

Figure 1 shows the current recommended option reduces the forecast risk monetisation profile of the South Pine Substation T5 transformer from around $1.11 million per annum in 2031 to $0 from 2032 [5].

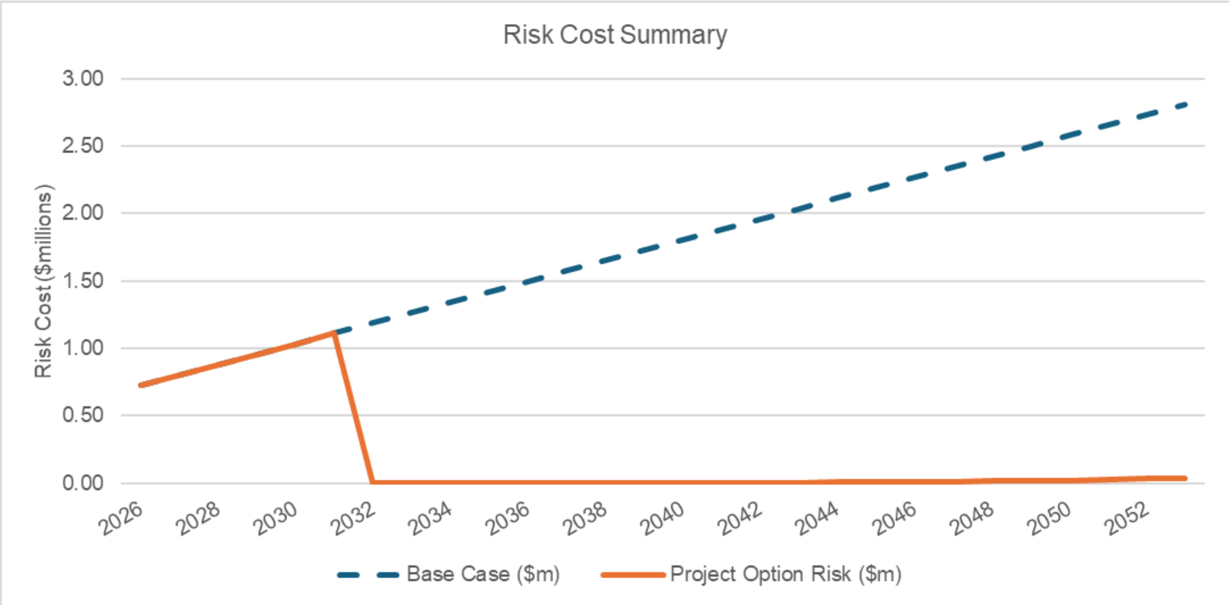

Figure 1 – Annual Risk Monetisation Profile ($ Real, 2025/26)

Cost and Timing

The estimated cost to replace T5 at South Pine substation is $16.3m ($2025/26) [4].

Target Commissioning Date: October 2030

Documents in CP.02478 Project Pack

Public Documents

1. H002 South Pine Transformer T5 Condition Assessment Report
2. CP.02478 South Pine -Transformer 5 Replacement – Planning Statement
3. CP.02478 South Pine -Transformer 5 Replacement – Project Scope Report
4. CP.02478 South Pine -Transformer 5 Replacement – Concept Estimate
5. CP.02478 South Pine -Transformer 5 Replacement – Risk Cost Summary Report

Transformer Condition Assessment H002 South Pine Substation

Asset Category	Power transformers	**Author**	[redacted]	**Authorisation**	[redacted]
Activity	Condition Assessment - Primary Substation Plant, Power Transformers.				
Reviewed by:	[redacted]	**Review Date:**	17/09/2025		
Document Type	Report	**Team**	Substation Strategies		
Issue date	20/05/2025	**Date of site visit**	Desktop only to update 2020 CA Report.		

Date	Version	Objective ID	Nature of Change	Author	Authorisation
20/05/2025	1.0	A5856589		[redacted]	

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 thorough condition assessment was performed on a 250 MVA 275/110 kV transformer T05 commissioned at H002 South Pine substation in 1981 and a report issued on the 10th March 2020.

A further desk top review of the condition of this same transformer has again been performed in May 2025 after 44 years of service and the original Condition Assessment Report has been updated.

No main tank internal inspection of the core and windings was performed. Reference was made to preliminary assessment work performed by Powerlink's *Operations and Service Delivery* (OSD) field staff, reference report OSD-PSS-REP-028 dated 13 August 2019.

This report does not attempt to cover any detailed economic analysis of the viability of rectifying the highlighted issues associated with the transformer.

In addition, the listed conclusions below do not consider the need for this transformer's functionality in the network so this aspect needs to be confirmed prior to finalising any decision in relation to extending the life of this transformer.

The Health Index shown in our SAP system at present is showing a 7 for this transformer but according to the findings of this investigation, that value should be changed to a 9 due to the localised winding hot spot cellulose insulation having reached statistically *"end of reliable service life".*

The internal mechanical reliability of the clamping structure of the windings has been assessed and is classified as **"LOW"** when looking at the risk category for withstanding through faults or even for significant step loading of the transformer

In summary, this transformer is in poor condition and should be scrapped within the next 3 to 4 years. Because of this, the following conclusion have been reached.

- Even though the HV bushings should be replaced due to exceeding their reliable service life which when combined with the bushing design creates a significant safety issue, due to the transformer internal insulation having reached "end of life", the bushing replacement is not considered an appropriate approach. Other methods for ensuring field staff safety are available for use over a short duration until this transformer can be decommissioned.

- Replace the **HV and LV surge arresters** if not already replaced.

- The existing oil leaks are considered minor and if the transformer is going to be scrapped within the next 3 to 4 years (or sooner), the oil leaks can be managed instead of performing full repairs to the leaking gaskets. The

internal oil leak between main tank and the Tap Changer diverter switch cylinder is not critical provided the Powerlink staff reviewing the dissolved gas in oil measurement data every two years for this transformer are aware of this main tank oil contamination.

- There will still be a need to continue to perform routine maintenance to keep the transformer operational until the transformer can be replaced but this action should be purely to “nurse” the transformer through to its decommissioning date.

2. INVESTIGATION:

A further desk top review of the condition of this transformer has again been performed in April 2025 and the original Condition Assessment Report has been updated. Any major findings which may impact the transformer's serviceability are discussed in this report.

The H002 South Pine substation Operating Diagram is shown in figure 1.

[redacted]

Figure 1: H002 South Pine 275/110kV Substation Operating Diagram. Transformer T05 identified by the "red" arrow.

As it can be seen from substation operating diagram shown above, this transformer is operated in parallel with T04.

2.1 H002 SOUTH PINE TRANSFORMER T05 CONDITION OBSERVATIONS:

2.1.1. Identification Details:

Transformer T05 details are shown below. It was originally commissioned at South Pine substation in July 1981.

- Manufacturer - Tyree Electrical Company Pty Ltd, Moorebank, Sydney.
- Specification - QEGB H124/78.
- YOM = September 1980 (45 years)

- Commissioned 1981 (44 years in service)
- 160 / 200 / 250 MVA ONAN / ODAN / ODAF.
- 275/110/19.1 kV.
- Serial No. 70927.
- SAP Equipment No. 20002429
- Reinhausen OLTC Model no. T III Y 1000-60/C, Serial No. 56044
- OLTC Counter Reading = 233907 on 28 January 2020.

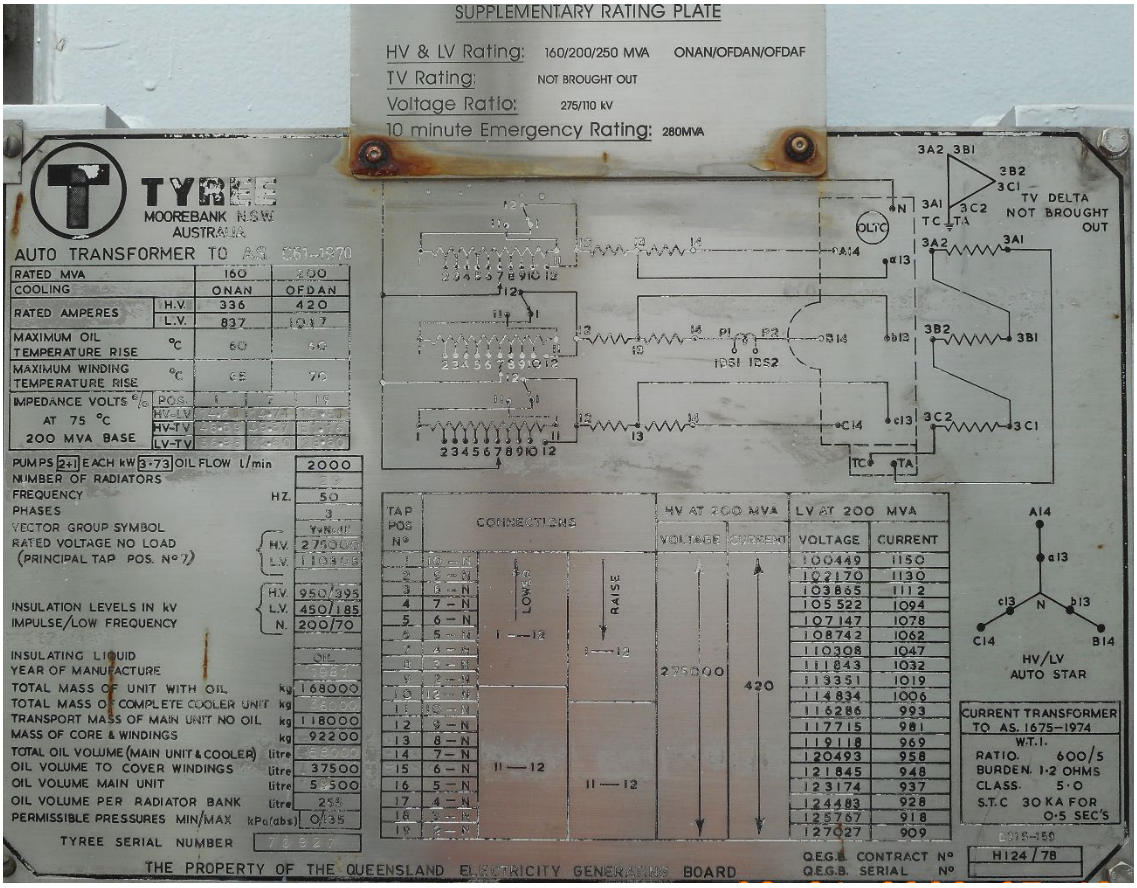

Figure 2: Transformer Name Plate Diagram with supplementary uprating plate due to the addition of fans.

2.1.2 External Physical Condition:

This Condition Assessment Report is intended as an update on the information provided in the Condition Assessment Report for South Pine T05 submitted in 2020. As such, only a few site photographs have been included in this report to show present physical condition. These photographs have been sourced via the substation remote camera system.

This transformer was refurbished and repainted in 2011 under project OR.01272 and whilst the paint has oxidised, its condition at present is still very serviceable with no signs of any significant corrosion. Previous localised areas of corrosion appear to have been rectified more recently. The base of the transformer could not be inspected on this occasion.

Figure 3: Transformer 110kV side showing overall condition. Photograph taken using the substation remote monitoring camera system.

Figure 4: Transformer 275kV side showing overall condition. Photograph taken using the substation remote monitoring camera system.

<u>This transformer has a welded lid to tank flange via a retro-fitted flat, steel strap and has been fitted with special Dome Nuts</u> to seal oil from leaking through the clearance holes around the original lid/tank clamping bolts.

Despite the retrofitted welded tank to lid modification and the refurbishment performed in 2011, <u>this transformer remained unsealed with no conservator air cell installed</u>. This is obvious from the dissolved gas signature in the transformer oil.

Even with the retrofitted welded tank to lid modification in 2011, the LV side of the main tank in 2020 was showing oil leaks between the lid and main tank flange via the heat effected Dome Nut ‘O’-ring oil seals. These oil leaks roughly aligned with the centre line of each of the three phase internal windings where the windings are closest to the side of the main tank wall.

Extra heating in those regions is occurring due to stray flux and resulting currents passing through the Dome Nut bolts from lid to main tank. The localised heating accelerates the degradation of the neoprene ‘O’-ring seals on the Dome Nuts as well as causing the clamping bolts to elongate more in those regions which lowers the bolt’s clamping pressure. When this transformer was designed, flux shunts were not normally used on the tank walls but aluminium flux rejecters were favoured on the active part instead but this resulted in a loss of control over the final flux paths. Both effects over time will continue to allow oil to bypass degraded ‘O’-ring seals on the Dome Nuts.

Figure 5: Transformer 110kV side showing overall condition on the lid. Photograph taken using the substation remote monitoring camera system.

There seem to be no signs of oil leaks around the top of the HV and LV bushings or main conservator.

Figure 6: Transformer bushings and main oil conservator condition. Photograph taken using the substation remote monitoring camera system.

The type of corrosion between the radiator panel individual fins shown in the figure below was an issue for this transformer in 2020 and needs to be detected early if it returns. It is difficult to see via a remote substation camera system if the corrosion was properly removed and treated or is being covered by existing surface coatings.

Figure 7: Transformer cooler bank radiator panel corrosion from 2020. Need to confirm if that corrosion has reappeared.

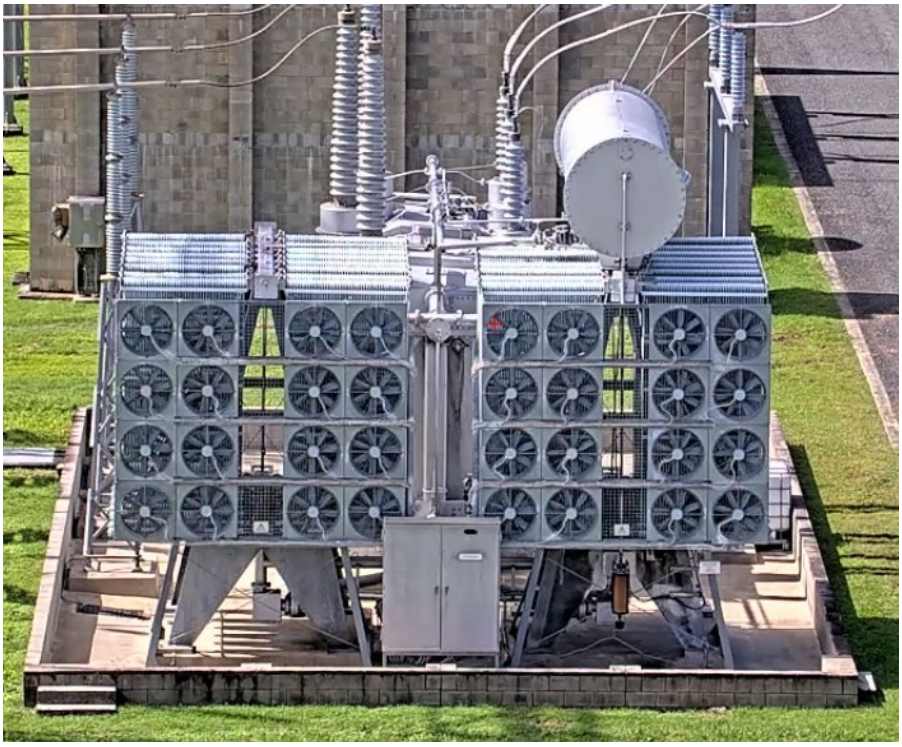

Figure 8: Overall view of the transformer from the cooler bank end showing clean concrete surfaces. Photograph taken using the substation remote monitoring camera system.

Figure 9: Close-up view under the cooler bank does not show any significant signs of oil leaks on the concrete surfaces. Photograph taken using the substation remote monitoring camera system.

Figure 10: Side view under cooler bank does not show any significant signs of oil leaks on the concrete surfaces. Photograph taken using the substation remote monitoring camera system.

Figure 11: The concrete plinth and surrounding apron of the transformer main tank also appears to be clean / dry from oil residue. Photograph taken using the substation remote monitoring camera system.

There is also a reasonable internal oil leak between the tap changer diverter switch cylinder and the main tank oil as observed during the last OLTC service. Main tank oil was leaking into the diverter switch cylinder while the switch was out being refurbished. It is highly likely that the seal on the cylinder drain plug has deteriorated. With the OLTC and main tank sharing a common conservator tank via a partial partition (common head/gas space), oil will therefore flow between the two in either direction depending on which oil level is higher. This needs to be considered when examining the dissolved gas in oil test data gathered from the main tank and OLTC oil samples. There is still signs of a mild mixing of OLTC diverter switch oil with main tank oil through to the last oil sample taken in June 2024.

This transformer main tank and associated oil pipe work has very little surface corrosion and while the surface paint may not be in the best of condition, it could still provide reliable service for another 5 to 10 years with only minor touch-ups as necessary. The original organic zinc rich primer applied to the parent steel surfaces still seems to be providing good galvanic protection.

2.1.2.2 Cooler bank:

The cooler bank radiator panels still appear to be in a reasonable overall condition. The cooling fans and their housings still appear to be in reasonable condition when viewed via the substation remote camera system.

Figure 12: Transformer Cooler Bank cooling fans. Photograph taken using the substation remote monitoring camera system.

2.1.2.3 Structural:

There were no signs of any structural issues associated with main galvanised supports for the cooler bank and the main tank oil conservator when examined closely in 2020 and when reviewed via the substation remote camera system, there was no evidence visible that would change this assessment. Refer to figures 3 to 10.

Only two holding down bolts are present in each galvanised foot plate of the cooler bank galvanised 'A' Frame support structures. The grouting between the foot plate and the top of the concrete foundation platform makes it impossible to assess the jacking / anchor bolt shank diameter for signs of corrosion.

Figure 13: Cooler bank 'A' Frame structure using only two bolts per foot pad. Note the grouting which is no longer specified. Photograph taken using the substation remote monitoring camera system.

2.1.3 Secondary Systems:

The external black PVC/PVC multi-core cables have been painted when the transformer was refurbished and this has provided some UV protection. This paint was not designed to adhere to the outer cable PVC surface and as such, some paint has been progressively delaminating. After 44 years, the cables are sure to have taken a set and any significant cable flexing could likely create significant insulation damage.

Figure 14: The original external multicore cabling was Black PVC/PVC and whilst being aged, the only cracking visible is in the paint coating. These cables would have taken a set and should not be subjected to any significant flexing.

From a review of the transformer maintenance history records stored in SAP, various secondary system componentry has needed to be replaced over the years due to failure (eg; relays, contactors, indication & cubicle lights, gauges, temperature monitoring instruments / parts, tap changer counter). This is considered normal expected maintenance of a transformer after 44 years of service.

There is no indication in the maintenance history / notifications that the WTI and OTI temperature monitoring instruments have been replaced as recommended in 2020 due to the poor visibility when looking through the viewing glass of the instruments.

Figure 15: Photograph taken in 2020 showing one AKM winding temperature measurement instrument (WTI) and one top oil temperature measuring instrument (OTI) installed.

The OSD-PSS-REP-028 - H002 *South Pine 5 Transformer Condition Assessment Report* in 2019 did mention insulation resistance issue(s) in the Main Control Cubicle and suggested the cubicle should be replace with a new one. The historical maintenance history records do not show this recommendation having been addressed.

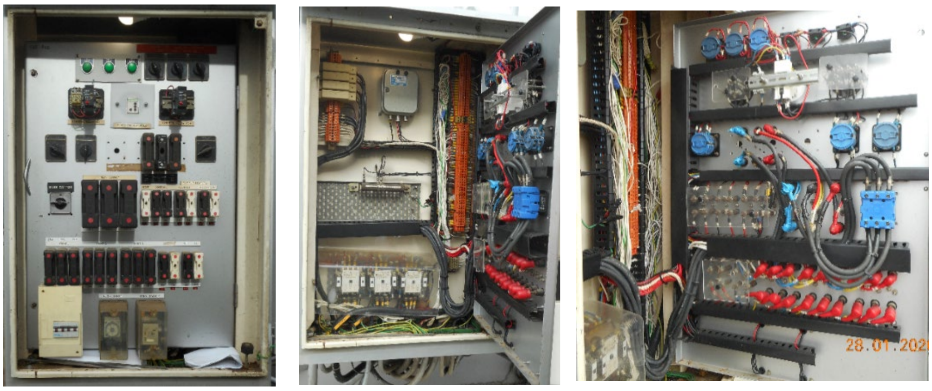

Figure 16: Year 2020 photographs (if still relevant) of the Main Control Cubicle internal views. Various componentry has been replaced over the years due to failure.

Due to the transformer being uprated from 200MVA to 250MVA later in its life (prior to 2000) by the addition of 32 forced draught cooling fans on the cooler bank, the Fan Control Cubicle is not as old as the original transformer and appears to be in reasonable condition.

Figure 17: Year 2020 photograph of the Fan Control Cubicle.

When this transformer was uprated, the fans were wired using multicore cables with orange outer PVC insulation. In 2009, it was noticed that the outer PVC of these cables was deteriorating / cracking due to the orange coloured PVC having worse natural UV stabilisation characteristics compared to black PVC.

The cables were eventually painted to help shield them from direct sunlight. Now there are extensive areas on these cables where the paint coating has flaked off exposing the faded and aged outer orange PVC. These cables would be very inflexible with PVC embrittlement and should be periodically visually checked during substation RSMs and the cables with the most outer physical damage / cracking should than be electrically tested for DC Insulation Resistance between cores and to earth.

Figure 18: Year 2020 photograph of the orange PVC multicore cables showing paint flaking off the already faded outer PVC insulation.

The transformer has a Reinhausen (MR) on-load tap changer (OLTC). The tap changer had 233,907 operations when inspected in 2020. Reinhausen stated the OLTC was in good condition when last serviced in 2019.

Figure 19: Reinhausen Tap Changer Control Cubicle.

Figure 20: Year 2020 photograph of the Reinhausen OLTC Control Cubicle internal view.

Apart from showing its age, there were no signs in 2020 of immediate issues within the Tap Changer (OLTC) Control Cubicle with the exception of electrical safety barriers that were not installed from new to protect workers from accidental contact with live terminals. The transformer maintenance history does not mention if the safety barriers have been installed.

The tap change motor gearbox oil level was correct and there were no signs of oil leaks collecting on the cubicle cable gland plate.

2.1.4 High Voltage (HV) and Low Voltage (LV) Bushings:

The HV and LV bushings still appear to be the original ones supplied with the Tyree transformer from new. The internal insulation of the 44 year old HV and LV bushings are a synthetic resin bonded paper (SRBP) design that has proven by visual inspections of many SRBP bushings over the years to be subject to progressive delamination of the concentric capacitive layers due to poor resin bonding of the paper layers during manufacture and the continual 100Hz vibration during operation working these incomplete adhesion bonds in shear. The potential consequences of a bushing failure can be catastrophic involving field personnel injury or death as well as an extended transformer outage or complete loss of the transformer. <u>These HV and LV bushings need to be replaced with a newer, safer design if this transformer is to remain in service, however, as discussed in the Summary, clause 1, this transformer has effectively reached statistical end of life and needs to be replaced within the next 4 to 5 years or sooner. It may therefore be more appropriate to take other safety measures to protect field staff rather than replace the bushings.</u>

Figure 21: View of transformer HV and LV SRBP bushings. Photograph taken using the substation remote monitoring camera system.

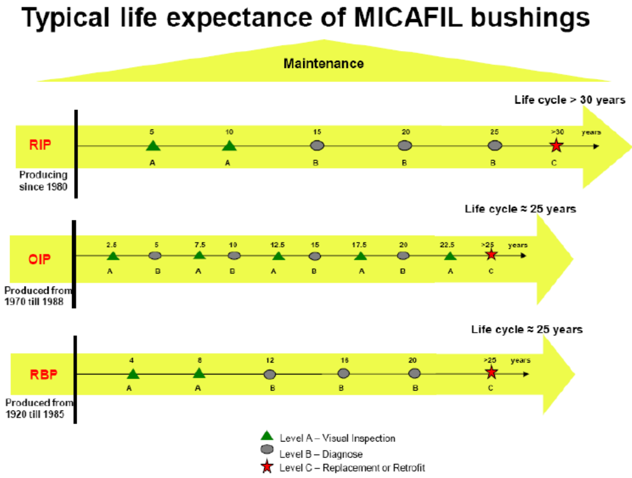

Figure 22: Bushing life expectancy provided by the bushing manufacturer.

2.1.5 Oil and Insulation Assessment:

A desktop assessment was performed on the transformer oil and paper sample test data supplied by Powerlink's Oil and Insulation Testing Laboratory. This data was further analysed to derive a more in depth understanding of the transformer's internal high voltage insulation system condition.

2.1.5.1 Oil Quality:

Because this transformer was designed and operated for quite a few years with the Drycol main conservator breather technology installed, the continuous dehumidifying of the air above the oil in the main conservator, as well as for new air entering the conservator, was very effective in maintaining the dryness of the transformer internal HV insulation system.

Unfortunately, these breathers were prone to failure due to the high summer ambient temperatures in Australia and were very expensive to repair and maintain. Eventually all of the Drycol breathers were replaced with conventional desiccant breathers on Powerlink's power transformers.

The original insulating oil would more than likely have been the old (original high quality) Diala 'B' which possessed good natural inhibitors and anti-oxidation stability. It is likely now to be a hybrid mix with other oil types such as Nynas '*Nitro 10GBN'* (corrosive) and Nynas '*Libra*' (non-corrosive) as different oils would have been used over time for topping up. Due to this, the oil has tested positive to corrosive sulphur and has been passivated.

When tested in July 2002, the oil in this transformer had 0.25 ppm PCB in oil and when tested in 2009, no PCB in oil was detectable. This test has not been repeated since. Based on the most recent oil test results, the oil is classified as "Non-Contaminated" for being less than 2 ppm.

The oil dielectric loss (DDF) and acidity level have not changed that significantly over the life of the transformer and are still considered acceptable for the transformer's age. The oil resistivity (G Ohm.m) has progressively reduced as expected over the transformer's life, in correlation with the changing DDF of the oil.

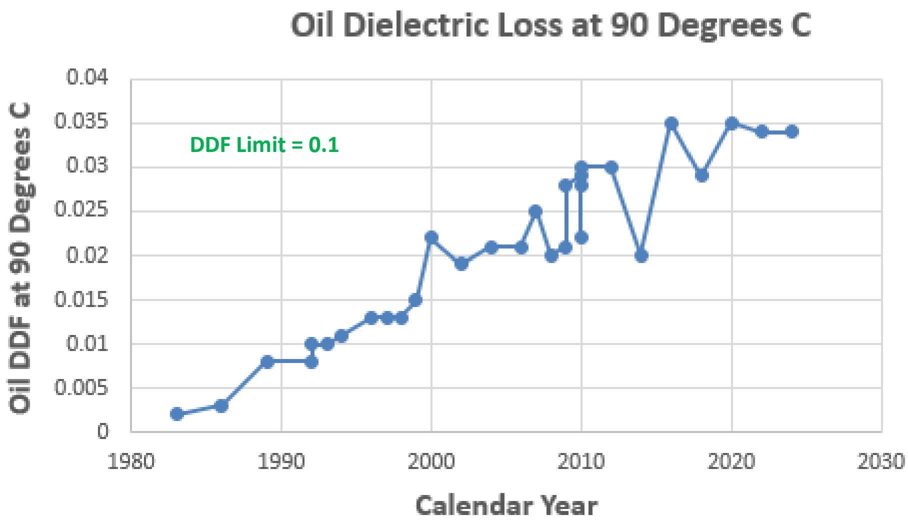

Figure 23: Transformer oil Dielectric Loss (DDF) characteristics over its service life. The DDF results are still well below the limit.

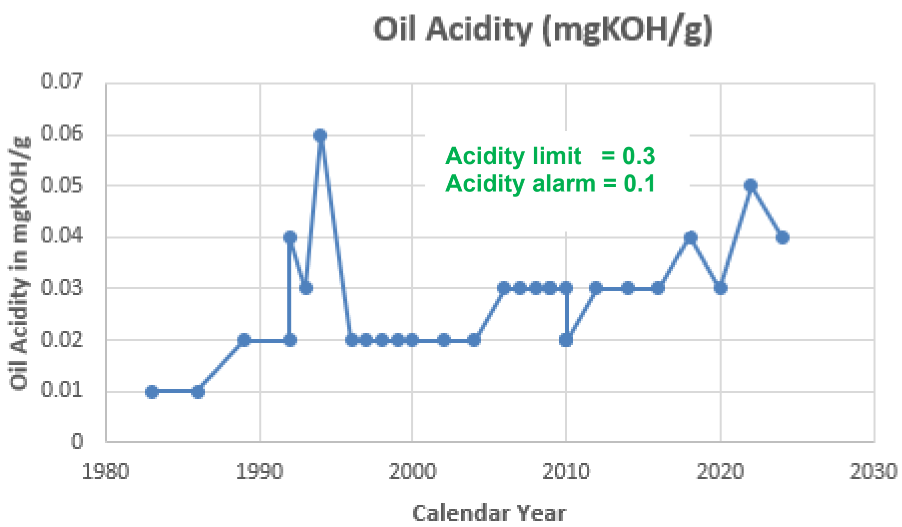

Figure 24: Transformer oil Acidity characteristics over its service life. The acidity level is still well below the limit.

2.1.5.2 Moisture in Insulation:

The moisture in the internal HV insulation system appears to be relatively dry for a free breathing transformer of this age, no doubt due to the effects of having a Drycol breather installed on this transformer from new.

When this transformer was manufactured in late 1980, the factory insulation dryout technology involved autoclaves that applied elevated temperature and vacuum to the transformer core & windings assembly over a set time period. This technology and associated factory drying process did not provide a reliable insulation dryness result. It can only be stated that the transformer high voltage cellulose insulation dryness from new would not have been much lower than 1%. Therefore any oil laboratory test data that when used for calculating the percent moisture in insulation and which gives results of less than 1% is considered in error.

The percentage of moisture in the cellulose insulation was measured by Powerlink's field staff in June 2019 using a "*Dirana*" test instrument for a *Dielectric Response Analysis* test. A figure of 1.5% by dry weight moisture in the cellulose insulation was determined by that test. A separate calculation using Powerlink's own software and Oil Laboratory test data provided a calculated result of 1.4% by dry weight as shown in the graph below.

This is good correlation between the two methods of calculation for the cellulose moisture content and gives more confidence in the moisture level being well below 2%. The 1.5% or even up to 2% is a very acceptable figure for the internal high voltage cellulose insulation system of an unsealed transformer after 44 years of service, especially considering it has had a number of oil leaks over time.

<u>The calculated moisture level in the high voltage cellulose insulation system of this transformer will not by itself be a factor that would limit the serviceability of this transformer if it remained in service for a further 10 to 15 years.</u>

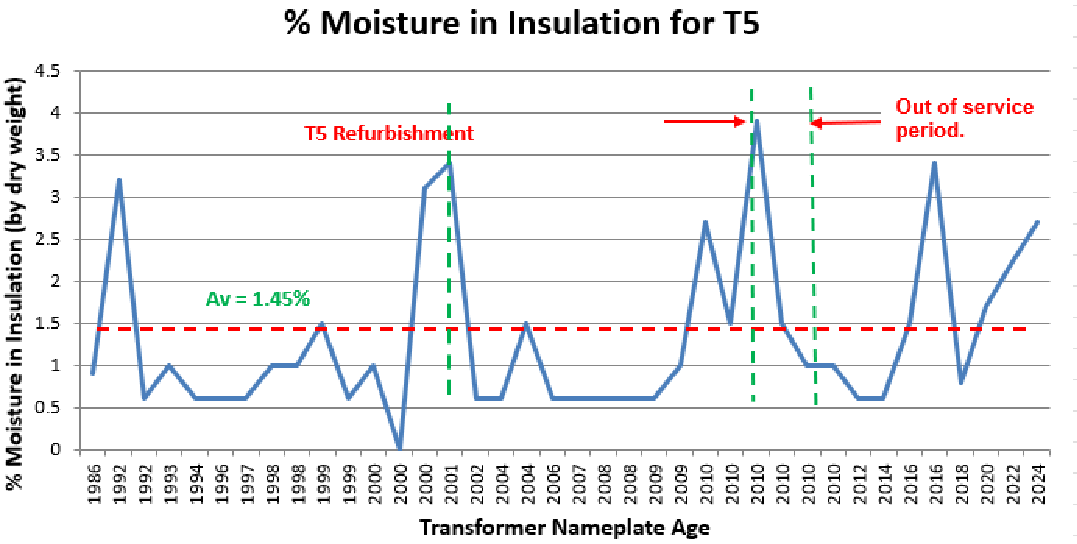

Figure 25: Transformer calculated % moisture in cellulose by dry weight based on Oil Laboratory test data. The moisture level is very acceptable for a transformer after 44 years of service.

2.1.5.3 Dissolved Gas Analysis:

It is important to recall the oil leak that exists between the OLTC diverter switch tank and the main tank oil volumes because this can introduce false dissolved gas-in-oil (DGA) signatures which if taken on face value, can lead to misinterpretation. Another source of misleading dissolved gases in the main tank oil sample in this case (refer to clause 2.1.7.2) is the use of a combined OLTC and Main Tank oil conservator (only a partial partition in the conservator) where there exists a common head space above the oil.

Throughout much of the transformer's life, the DGA data suggested on face value either a thermal in oil without really involving any cellulose material and as time progressed, this appeared to evolve into low level discharge / heating / flashover. <u>In actual fact, these apparent DGA signatures were due to oil from the OLTC diverter switch mixing with main tank oil.</u>

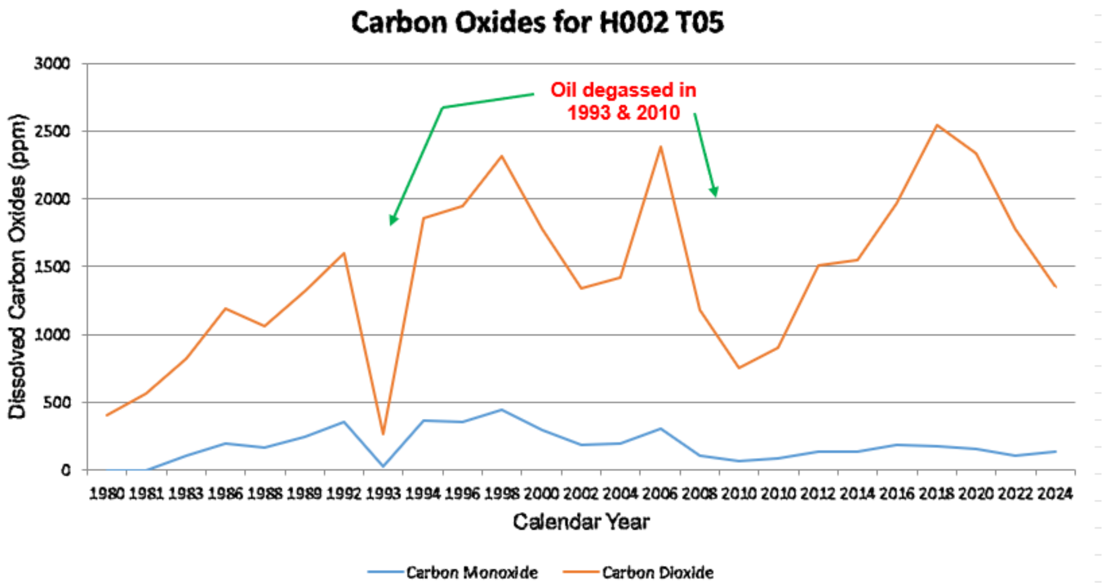

Figure 26: Carbon Monoxide and Carbon Dioxide dissolved gasses over the transformer's life.

If the contamination of the main tank oil from the OLTC oil is ignored, there are no signs of electrical issues associated with the core and coils of this transformer up to the date when the last oil sample was taken for analysis.

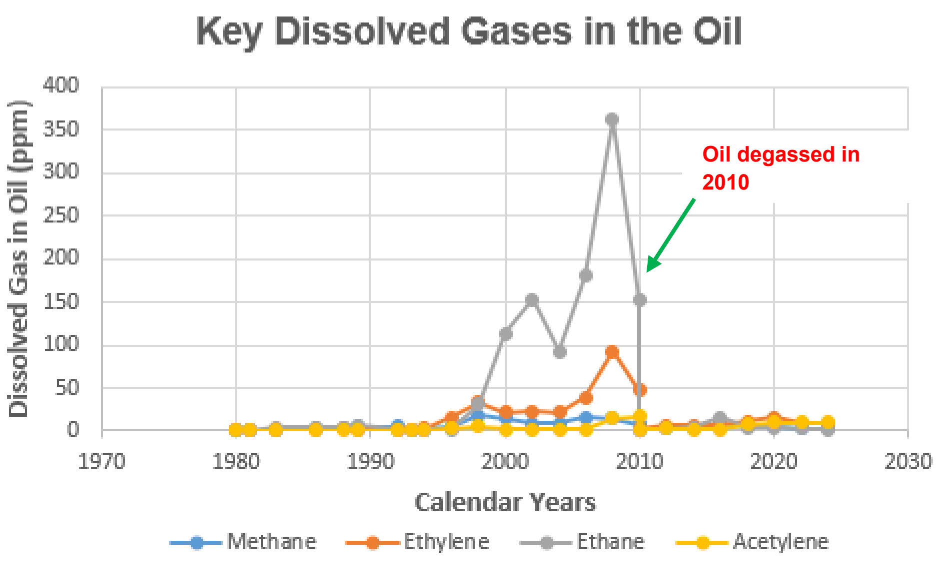

Figure 27: Key dissolved gas in oil activity. This data still reflects some distortion due to the mixing of OLTC oil with the main tank oil.

2.1.5.4 Winding Paper:

It needs to be emphasised that the life expectancy of a power transformer is dependent upon a number of factors, some of which are the internal oil, high voltage cellulose insulation, the design of the transformer's windings, the continued mechanical deformation of the winding clamping structure in service and the on-going mechanical stability of that clamping structure. It is not purely a function of the oil quality and residual cellulose degree of polymerisation (DPv) value although if these two parameters become sufficiently low enough, they can become dominant factors impacting residual transformer serviceability.

As the cellulose solid insulation and winding paper degrades chemically and becomes physically weaker, "*2 furfuraldehyde*" is one of the many degradation products. A somewhat linear relationship exists between the logarithm of the mass of furfuraldehyde (furan) produced and the resulting reduction in the degree of polymerisation (DP) or physical strength of the paper. When the DP falls, the paper insulation becomes more brittle and ultimately will fall away from the energised windings reducing the insulation level between adjacent turns. This is especially relevant when the windings are experiencing through faults causing, amongst other things, the adjacent winding turns will try and move closer together and even touch if the winding mechanical structure is weak.

As the transformer load fluctuates, the rate of generation of dissolved furan in the oil will also fluctuate in unison but imbedded / hidden within these fluctuations will be an obscure, increasing trend in the level of dissolved furan that correctly reflects the "real" chemical age of the cellulose insulation but with the fluctuations superimposed upon the upward trend. The art of determining the "real" cellulose insulation chemical age requires the separation of the fluctuations to reveal the "real" upward trend in dissolved furan. Corrections to the measured dissolved furan level in the oil may need to be made if the transformer internals and the oil have been subjected to vacuum treatment(s) at some stage in its life.

It is known that the original 275/110kV transformers at South Pine were fitted with temporary water sprinklers on the cooler banks and industrial fans positioned on the concrete foundation around the cooler bank at times of high substation loading.

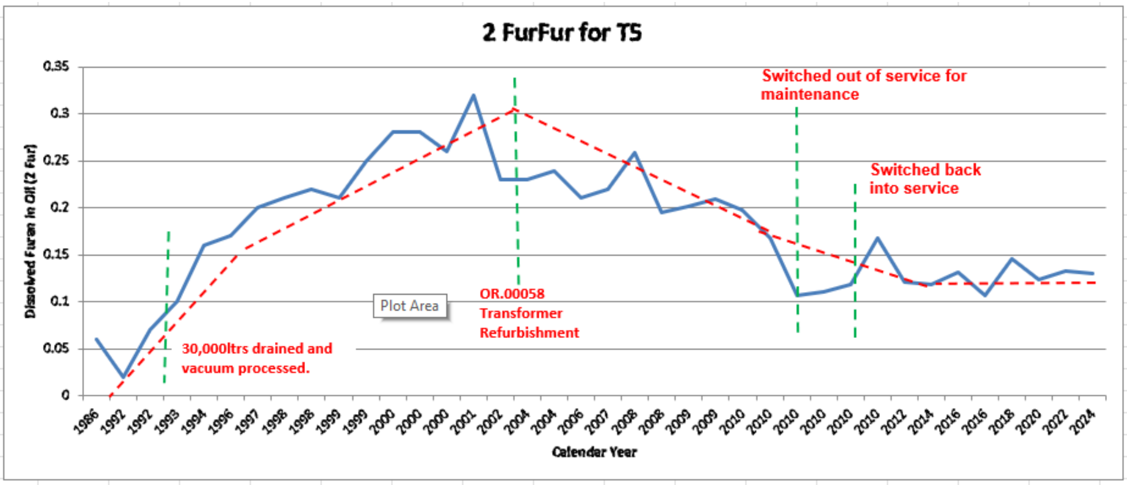

Figure 28: The dissolved 2-Furan in oil level over the life of the transformer.

The average dissolved Furan level appears to have remained fairly stable over the last few years which assists in identifying the "real" trend to date, however, previous cellulose insulation decomposition experienced during the transformer's service life up to approximately the year 2000 can't be reversed.

Because of the more localised nature of the winding hot spots, when the higher rate of dissolved Furan generation from the higher temperature locations is averaged out in the total transformer oil volume, the hot spot contribution to the dissolved furan level is not distinguishable from that generated by the bulk insulation mass.

A value of 0.32 ppm (parts per million) for the dissolved furan level has been used to calculate the <u>average</u> cellulose insulation and its chemical age discussed below.

The higher furan levels shown in the above figure for the transformer's earlier years <u>due to higher loading</u> represents the fluctuations discussed previously in this report and does not represent the "real" cellulose chemical age. This is because the "real" insulation chemical decomposition process can't reverse itself.

The <u>average</u> cellulose insulation *Degree of Polymerisation* (DPv) was calculated to provide a more tangible feel as to the residual mechanical strength of the winding paper insulation wraps. The <u>average</u> *Degree of Polymerisation* (DPv) of the bulk cellulose insulation system within the transformer is calculated to be approximately DPv = 462 with a chemical age of 22 years.

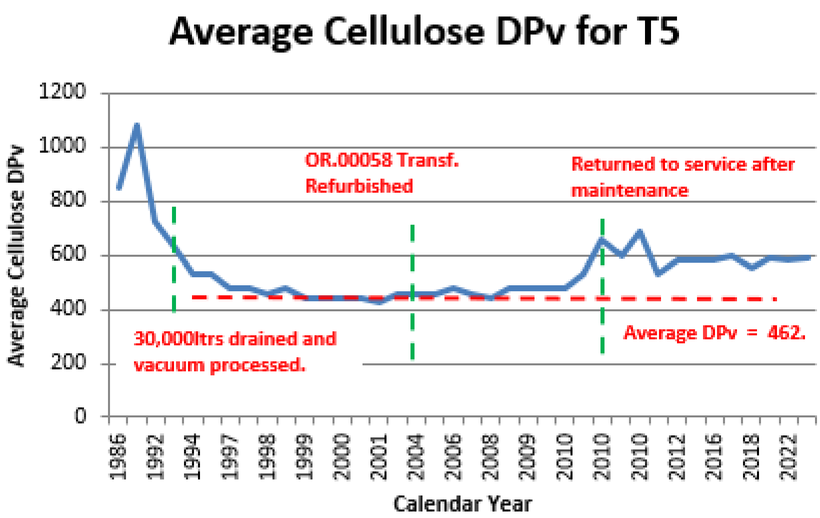

Figure 30: The calculated bulk cellulose insulation average DPv = 462. Cellulose decomposition sustained during its earlier years can't be reversed.

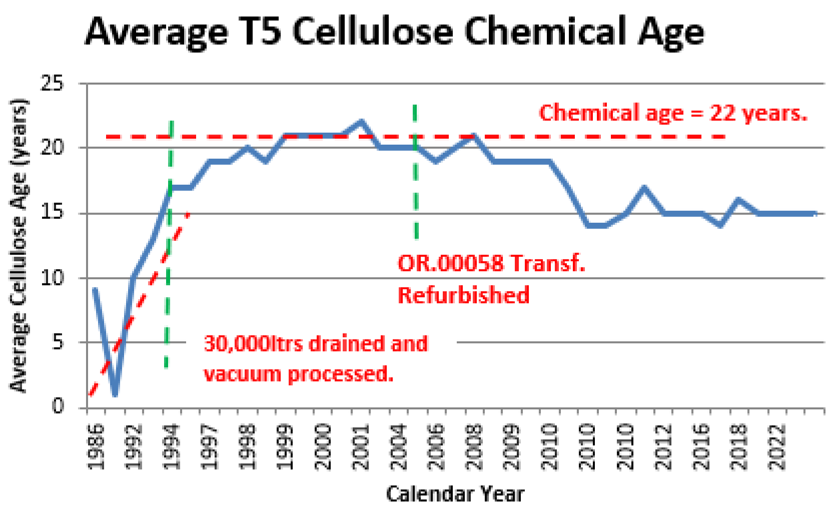

Figure 29: The calculated bulk cellulose insulation chemical age = 22 years. Cellulose decomposition sustained during its earlier years can't be reversed.

A new approach for calculating the winding hot spot DP has been utilised in this investigation and it is based upon the factory temperature rise test data (the thermal reference model for this specific transformer) and the historical average loading of this transformer in service. This determines what cooling mode the transformer has been predominantly operating in over the years and what the relationship has been between the corresponding average winding insulation operating temperature and winding hot spot insulation operating temperature when loaded.

<u>The calculation of the DPv for the **winding insulation hot spot** yields a DPv = 266 which corresponds to an insulation chemical age of only 36 years.</u> The calculation is based on the transformer operating predominately in ODAN cooling mode due to being in parallel with other transformers and this keeps the winding temperature gradients lower.

The table below provides a quick summary of the winding cellulose insulation calculated mechanical condition and apparent chemical age. Some allowance has been made to cater for calculation tolerances in the form of a range of DPv values and the corresponding chemical ages.

Table 2.1.5.4: DPv and Insulation Chemical Age.

Winding Zone	Calculated DPv	Possible Spread of Calculated DPv	Calculated Chemical Age (years)
Average Bulk Insulation	462	475 to 462	21 to 22
Winding Hot Spot Insulation	266	358 to 266	34 to 36

To estimate (extrapolate) the residual life of the cellulose insulation based on the DPv characteristics shown previously could be misleading due to some minor fluctuations in the rate of 2-Furan generation reflected in the calculated DPv characteristic.

A less scientific approach can be used for the residual insulation life calculation but it represents the worst case for aging. This simplified approach, which is based on the original DPv when new and the DPv at this point in time, is shown in the figure below. <u>Due to this transformer not being a fully sealed (eg; No conservator air cell from new or retrofitted), the transformer's "*IDEAL*" life has been shown over 40 years instead of 50</u> years but this is not of concern due to the real cellulose chemical age being well below unity as shown by the winding hot spot and average cellulose insulation ageing rate over its life in the graph below.

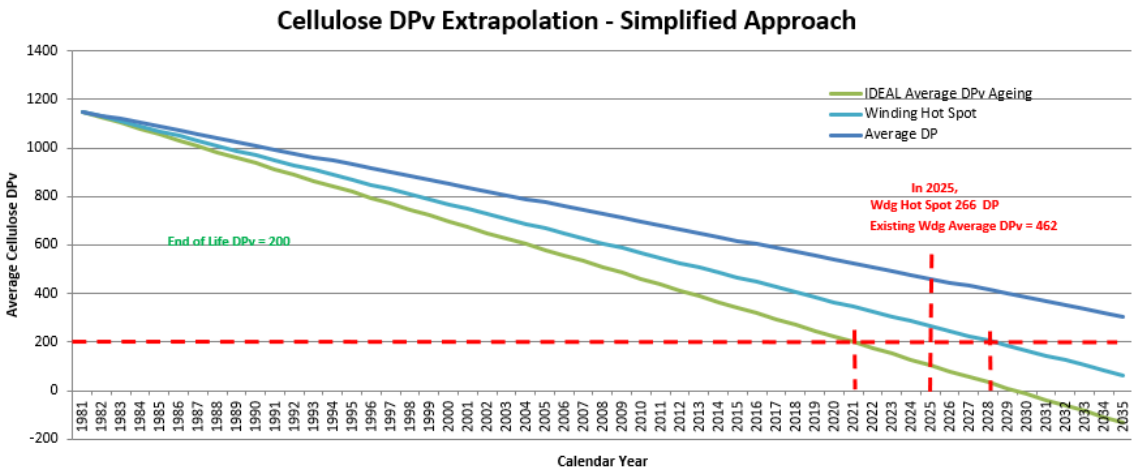

Figure 31: The simplified prediction of residual cellulose insulation life based on initial and present DPv.

A statistical figure adopted globally for the cellulose end of life is a DPv = 200 by which time the winding paper insulation has become very mechanically weak and brittle. By referring to the graph in the above figure, a DPv = 200 for the winding hot spot insulation would be reached in about 2028, another 3 years. This transformer winding Hot Spot cellulose insulation has effectively reached the end of its reliable service life and has a calculated chemical age of 36 years. This is still less than unity insulation ageing for a transformer of 44 years in service.

<u>The internal high voltage cellulose insulation DP property will in itself be a major factor that would limit the serviceability of this transformer beyond a further 3 years.</u>

2.1.6 Winding Dynamic Mechanical Stability

No internal inspection was performed on this transformer to review the condition of the core and coils. Due to the directed oil design of this transformer, it would not be possible to inspect the outer windings themselves for displacement, twisting or tilting and with a lack of lid access to all clamping points, checking of the blocking stability and residual clamping pressure would be impossible without a complete removal of the main tank lid in the field or factory. The cost of such an intrusive inspection would be prohibitively costly for a transformer of 44 years.

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

(a) The top clamping structure for this 1980 design is known to be unacceptable by today's standards.

(b) Even with a calculated 1.5% 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 slight loss of clamping pressure due to the type of phenomena shown in the figure below. It is realised that the load changes are not normally as sharp as in the diagram but the overall cyclic effect is the same. The electromechanical forces exerted on the winding structure due to periodic through faults can have the same accumulative effect.

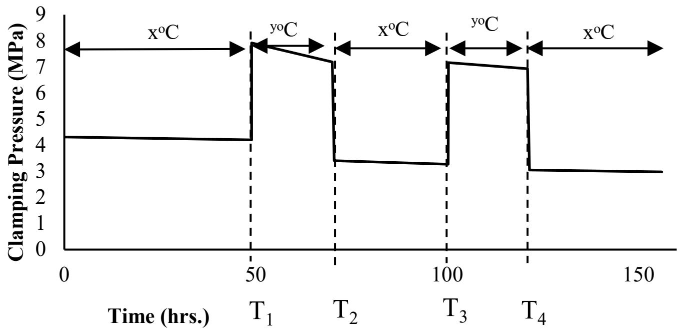

Figure 32: Example of the effect of cyclic compression on a clamped insulation structure.

(c) A drop in the internal cellulose average insulation mass indicated by the change in DPv from possibly 1150 down to an AVERAGE of about 462 will lower the winding residual clamping pressure but by how much is uncertain unless measured.

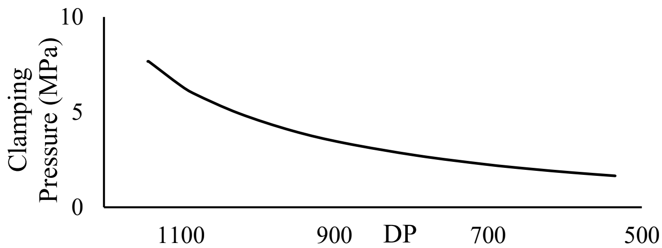

Figure 33: Example of the effect of loss of DPv on Clamping Pressure.

(d) The reliability of the windings clamping structure has also been analysed using a number of factors that can have a significant impact on residual winding clamping pressure, namely;

- Through fault accumulative energy in service verses the transformer's original design through fault withstand level.
- Cellulose winding insulation DPv.
- Calculated % moisture in insulation by dry weight.
- Transformer oil acidity level.

The analysis has provided a mechanical reliability of windings clamping structure result of 60% of the original design.

In summary, due to the factors discussed above, the residual mechanical reliability of the winding clamping and insulation (active part) is considered ***"LOW"*** when looking at the risk category for withstanding through faults. This estimation is purely statistical with the winding clamping structure failure being ultimately dependent upon its in-service operating environment and exposure to severe through faults.

2.1.7 General Interest Comments:

2.1.7.1 Drycol Breather:

This transformer was originally designed and manufactured with a Drycol refrigeration type breather mounted on the end of the main oil conservator tank. The Drycol unit was later replaced after a number of years by a conventional desiccant breather. Hence the pipe work on the end of the conservator which now bridges the top and lower internal pipes used by the Drycol unit.

Figure 34: High and low Drycol mounting points on the end of the conservator now used for a conventional desiccant breather.

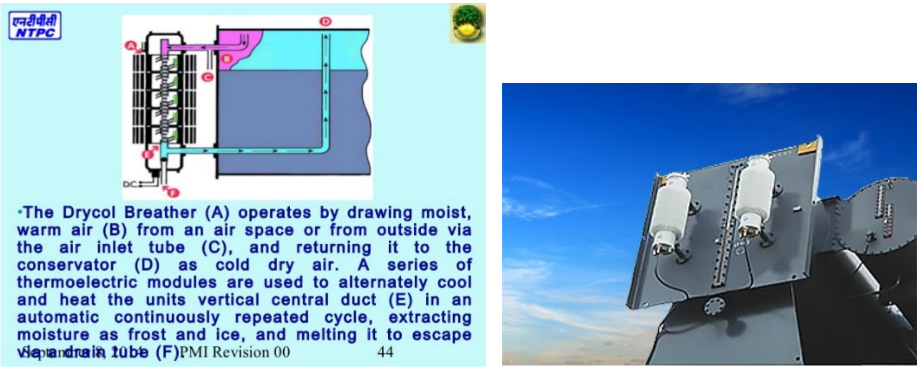

Figure 35: Operation of a Drycol breather and the typical physical mounting of such breathers on power transformer conservators.

2.1.7.2 Conservator Common Head Space:

The main tank oil conservator design appears to have incorporated a tap changer (OLTC) conservator compartment at one end with the OLTC oil and main tank oil volumes sharing the head space in the conservator (eg; only a partial partition between the two oil volumes). This is confirmed because there is no separate breather for the OLTC oil volume.

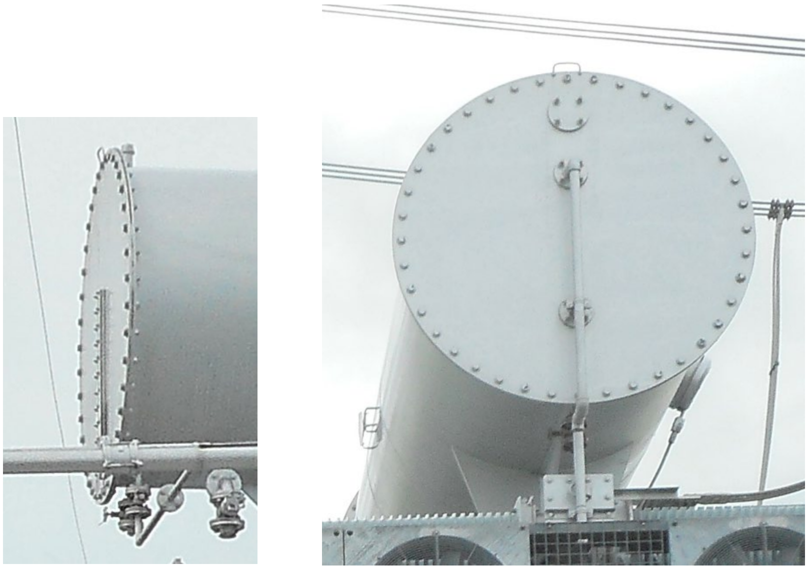

Figure 36: (LHS) Shows OLTC conservator end of the main conservator tank. (RHS) Main tank and cooler bank end of the main conservator tank. Note the single desiccant breather pipe.

3.0 CONCLUSIONS:

The following conclusions are based on the findings from this investigation into the physical, chemical and electrical condition of the T05 transformer at H002 South Pine substation. <u>These conclusions assume that Powerlink may choose to keep this transformer in service for only another 3 to 4 more years until it can be replaced.</u>

The Health Index shown in our SAP system at present is showing a 7 for this transformer but according to the findings of this investigation, that value should be changed to a 9 due to the localised winding hot spot cellulose insulation having reached statistically *"end of reliable service life".*

The internal mechanical reliability of the clamping structure of the windings has been assessed and is classified as **"LOW"** when looking at the risk category for withstanding through faults or even for significant step loading of the transformer

In summary, this transformer is in poor condition and should be scrapped within the next 3 to 4 years. Because of this, the following conclusion have been reached.

- Even though the HV bushings should be replaced due to exceeding their reliable service life which when combined with the bushing design creates a significant safety issue, due to the transformer internal insulation having reached "end of life", the bushing replacement is not considered an appropriate approach. Other methods for ensuring field staff safety are available for use over a short duration until this transformer can be decommissioned.

- Replace the **HV and LV surge arresters** if not already replaced.

- The existing oil leaks are considered minor and if the transformer is going to be scrapped within the next 3 to 4 years (or sooner), the oil leaks can be managed instead of performing full repairs to the leaking gaskets. The **internal oil leak** between main tank and the Tap Changer diverter switch cylinder is not critical provided the Powerlink staff reviewing the dissolved gas in oil measurement data every two years for this transformer are aware of this main tank oil contamination.

- There will still be a need to continue to perform routine maintenance to keep the transformer operational until the transformer can be replaced but this action should be purely to "nurse" the transformer through to its decommissioning date.

Planning Report	14 July 2025
Title	CP.02478 – H002 South Pine Substation Transformer T5 Replacement
Zone	Moreton
Need Driver	Emerging operational and safety risks arising from the condition of the 275/110kV transformer
Network Limitation	South Pine Transformer T5 is necessary to maintain power transfer capabilities to load centres in Brisbane and to meet Powerlink Queensland's N-1-50MW/600MWh Transmission Authority reliability standard.
Pre-requisites	None

Executive Summary

South Pine Substation services a number of significant load centres in Southeast Queensland. Transformer T4 (375MVA) and T5 (250MVA) are connected to South Pine's western 110kV bus.

The western 110kV bus supplies Energex's Stafford Substation and supports load in Brisbane's CBD via the western 110kV ring. This western South Pine 110kV bus is completely isolated from the eastern 110kV bus.

The 250MVA 275/110 kV transformer T5 transformer at H002 South Pine Substation was installed in July 1981. The condition assessment of the transformer [1] identified that the transformer has reached end of reliable service life.

The Central scenario load forecast confirms there is an enduring need to maintain electricity supply to the South Pine western 110kV bus. Removal of the transformer to address emerging condition and safety risks would violate Powerlink's N-1-50MW/600MWh Transmission Authority reliability standard.

The preferred network solution for Powerlink to continue to meet its statutory obligations is the replacement of the at-risk transformer with a new 375MVA transformer.

Table of Contents

1. Introduction

The South Pine Substation (H002) provides essential switching and injection of power from Central and Southwest Queensland to Southeast Queensland loads. South Pine 275/110kV Transformers T4 and T5 act as a bulk supply point for suburbs in north-west Brisbane as well as parts of Brisbane CBD.

South Pine Transformer T5 was commissioned in 1981 and is the smaller of the two transformers supplying South Pine's west bus with a rating of 250 MVA.

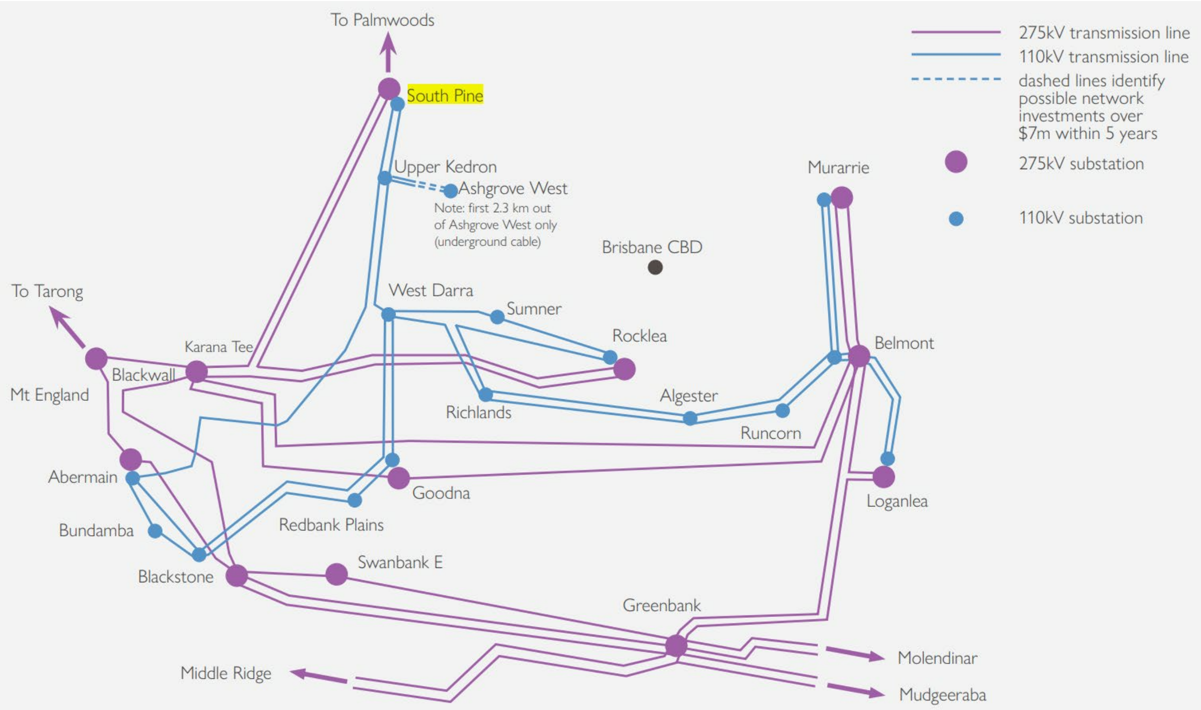

Figure 1. South Pine Substation in South East Queensland

2. South Pine Substation configuration

The operational diagram of the South Pine Substation is shown in Figure 2. The 275/110kV transformer T5 supplies (with T4) the western 110kV bus. This bus connects:

1. Two 275/110kV transformers (T4 & T5) from South Pine 275kV Substation.
2. A 110kV double circuit overhead line to Upper Kedron.
3. A 110kV double circuit overhead and underground cable to Energy Queensland's (EQL) Stafford Substation.
4. A 110kV 50MVAr capacitor bank.

[redacted]

Figure 2. H002 South Pine Substation Operational Diagram – Southeast Queensland

This report assesses the impact that removal of the at-risk South Pine 275/110kV transformer T5 would have on the network performance and Powerlink's statutory obligations. The report also establishes the indicative requirements of any potential alternative solutions to the current services provided by the transformer.

3. South Pine Substation Demand Forecast

The South Pine Substation forms part of an electrical ring supplying greater Brisbane made up of 275kV and 110kV circuits. South Pine Transformers T4 and T5 connect to the western 110kV bus, supporting delivery of power to loads in northern and inner west Brisbane. The loads supplied by the transformers include Stafford, Milton and Makerston Street in Brisbane's CBD West. A full breakdown of the loads in CBD West can be found in Appendix A.

The historical peak demand and forecast maximum demand for the loads supplied from the western South Pine 110kV bus are shown in Figure 3. The maximum demand for the Central scenario is forecast to increase by around 50MW over the 10-year forecast period.

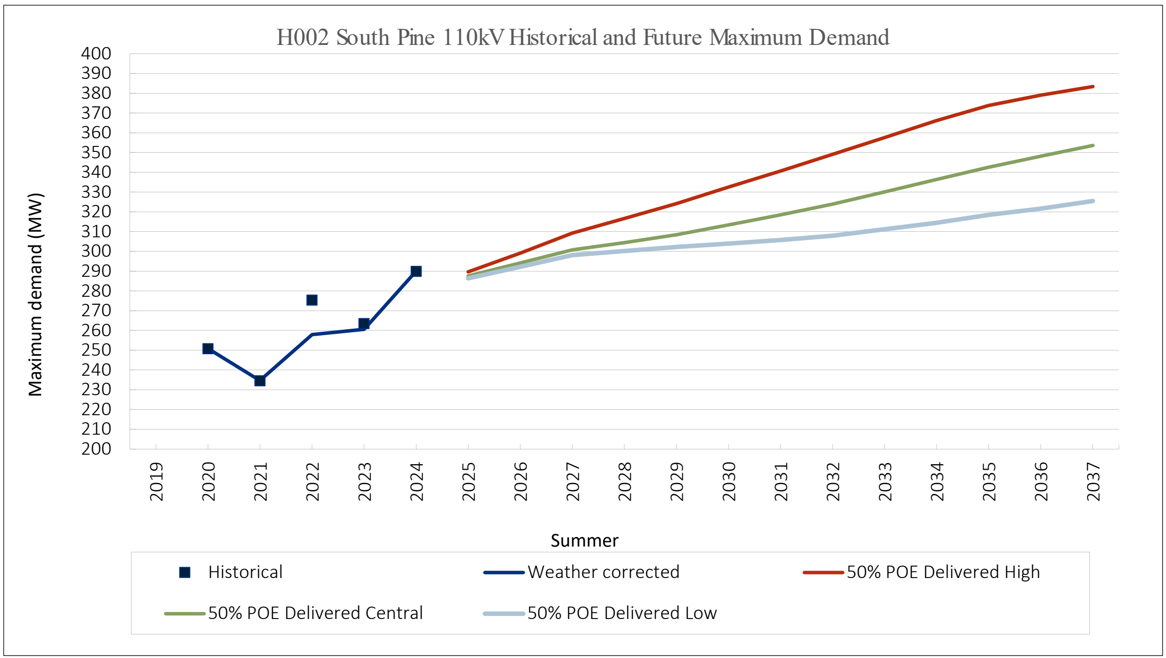

Figure 2. South Pine T4 & T5 Historical and Future Maximum Demand

The historical load duration curve for the loads connected to the 110kV network off South Pine transformers T4 and T5 between 2019 and 2025 is shown in Figure 4. The significant variation between 2019/20 and subsequent years is most likely related to COVID.

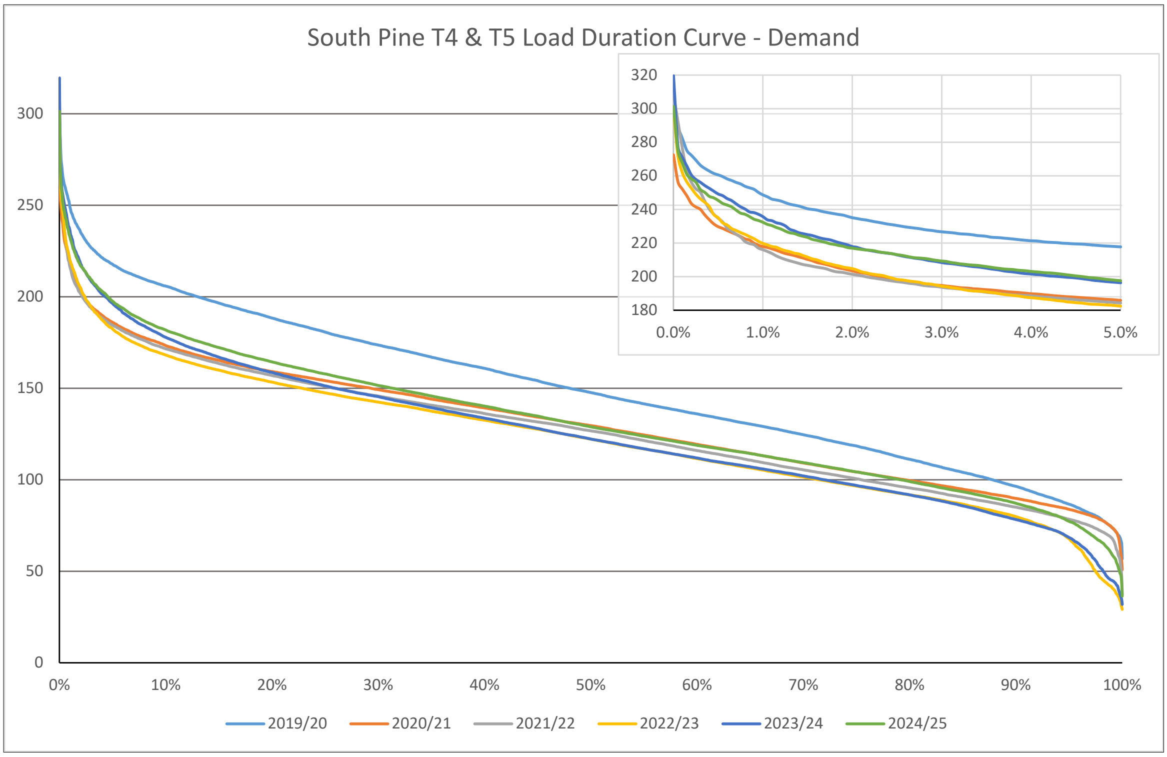

Figure 4. South Pine T4 and T5 Load Duration Curve

With consideration of rooftop PV within the Energex network supplied from the South Pine western 110kV bus, the maximum customer load is actually significantly higher. Figure 5 shows the difference between underlying load and delivered load can be up to 150MW during summer.

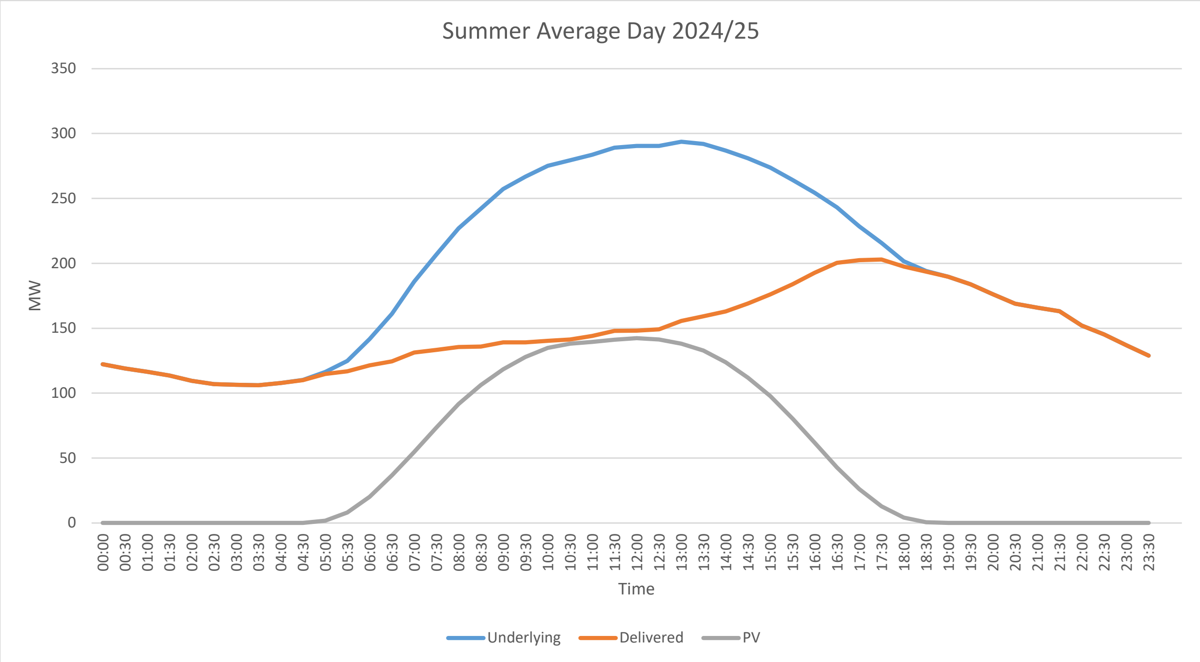

Figure 5. Average Rooftop PV during Summer 2024/25

4. Statement of Investment Need

As outlined in Section 2, South Pine transformers T4 (375MVA) and T5 (250MVA) form part of the electrical ring supplying greater Brisbane. If Transformer T5 is not replaced, the retirement of T5 will leave South Pine's west bus with a single transformer to support the current load, along with weak support from the 110kV feeders connected to Upper Kedron from Abermain, West Darra and the CBD. This 110kV injection is not sufficient to support the existing or forecast load.

Replacement of T5 is necessary to maintain Powerlink's N-1-50MW/600MWh Transmission Authority reliability standard.

5. Network Risk

Table 1 defines the maximum and average forecast load supplied (i.e. "Delivered") from the western 110kV bus at South Pine. The "Underlying" load values represent the actual customer load (i.e. exclude the contribution for rooftop PV).

Table 2 summarises the results of analysis to determine the load and energy at risk for loads supplied from the South Pine substation (west) at 110kV. The estimates take into account the expected level of rooftop PV connected to the Energex network supplied from the western 110kV bus. This level of rooftop PV is discounted to capture the total level of customer load at risk of not being supplied.

Table 1. Load Data

Measure	2025	2034
Max Underlying Load (MW)	413.5	633.1
Avg Underlying Load (MW)	171.8	233.2
Max Delivered Load (MW)	301.3	390.4
Avg Delivered Load (MW)	132.4	152.2

Table 2. South Pine 110kV (west) Load at Risk

At Risk	Contingency	Measure	2025	2034
South Pine 110kV West Bus	Loss of T4 (native load – adding back the contribution from rooftop PV)	Max Load > Contingency Capacity[1] (MW)	84.2	170.6
		Average Load > Contingency Capacity[1] (MW)	0.2	6.1
		24h Energy Constrained Max (MWh)	347.0	1508.8
		24h Energy Constrained Average (MWh)	5.250	146.7
	Loss of T4 (Delivered load)	Max Load > Contingency Capacity[1] (MW)	71.3	160.4
		Average Load > Contingency Capacity[1] (MW)	0.2	5.9
		24h Energy Constrained Max (MWh)	279.6	1284.1
		24h Energy Constrained Average (MWh)	4.5	141.5

[1]Contingency capacity limited by thermal rating of F905

With T5 out of service, a credible contingency on T4 would result in all the load connected to the west bus at South Pine being supported from Upper Kedron. Upper Kedron, itself would be back fed from Ashgrove West (CBD), Abermain (7258) and West Darra (776). Energex's CBD cable (F905) would be overloaded, and potentially trip resulting in cascading overloads and all loads being lost. This includes all rooftop PV that is connected to these loads.

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

6. Non-Network Options

Potential non-network solutions would need to provide supply to the bulk supply point Stafford, and the 110kV CBD west loads. To meet this demand, the non-network solution must be capable of delivering at up to 160MW and 1285MWh of energy per day (Refer Table 2). This is the load and energy above what rooftop PV delivers.

Powerlink is not aware of any Demand Side Solutions (DSM) in the area supplied by South Pine Substation 110kV west bus. However, Powerlink will consider any proposed solution that can contribute significantly to the requirements of ensuring that Powerlink continues to meet its required reliability of supply obligations as part of the RIT-T consultation process ahead of the actual investment decision.

7. Network Options

7.1 Proposed Option to address the identified need

To address the end of life of T5 Transformer at South Pine, it is recommended to replace the transformer. This ensures that reliability of supply and asset condition criteria are met.

Considering the forecasted load, Powerlink's standard specification transformer of 375MVA is recommended.

Powerlink considers the proposed network solution will not have a material inter-network impact, and as such does not need to formally consult with other Market Participants.

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 issues identified above and thus are not considered credible options.

7.2.1 Do Nothing

"Do Nothing" would not be an acceptable option as the transformer condition driver and associated safety, reliability and compliance risks are not addressed. 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 Increasing Network Capacity into CBD West from Rocklea Substation

Power is delivered to Brisbane's CBD West through Ashgrove West and West End substations. Ashgrove West is supplied from Upper Kedron Substation via a 110kV double circuit and West End Substation is supplied via a single 110kV cable from Rocklea Substation. Consequently, any interruption to the supply of electricity into Upper Kedron (or Rocklea) substation will significantly impact the capability to reliably supply the CBD West loads.

The cables between Rocklea, West End and Charlotte Street substations are at the greatest risk of overloading if South Pine Transformer T5 is retired from service. A second cable was modelled in parallel with F905 to reinforce the circuits carrying power into CBD West from Rocklea. The addition of the second cable is much more expensive, and unable to support the Stafford loads back at South Pine 110kV (west).

7.2.3 Closing the South Pine West and East 110kV buses

Due to the increasing demand in North Brisbane, the South Pine Substation was augmented with additional 275/110kV transformer capacity in 2009/10. Coincidently, to address fault level limitations, the South Pine 110kV bus was also physically split to create two 275/110kV switchyards.

Fault levels at South Pine Substation have not reduced. In fact, with the commitment of BESSs in south east Queensland (Brendale BESS, Supernode BESSs stages 1, 2 and 3, Swanbank BESS, Greenbank BESS and Woolooga BESS) fault levels have further increased. In addition to the BESS projects above, there is also a significant pipeline of BESSs (~2.5GW) within various stages of the Connection Application process in southern Queensland.

Therefore, reconnecting the two 110kV buses is not considered a viable option following retiring Transformer T5 from service due to fault level remediation works that would be required at South Pine 110kV and within Energy Queensland network supplied from South Pine.

8. Recommendations

Powerlink has reviewed the condition of the 275/110kV transformer T5 at H002 South Pine Substation and concludes it has reached end of technical service life.

It is recommended that the 275/110kV transformer T5 at South Pine Substation be replaced. Retaining two 275/110kV transformers on the South Pine west 110kV bus will allow Powerlink to continue to meet its N-1-50MW/600MWh Transmission Authority reliability standard.

Powerlink is currently unaware of any feasible alternative options to minimise or eliminate the load at risk at South Pine 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. References

1. H002 South Pine Transformer T5 Condition Assessment Report May 2025

2. 2025 Transmission Annual Planning Report (A6049612)

3. Asset Planning Criteria - Framework (ASM-FRA-A2352970)

4. Powerlink Queensland’s Transmission Authority T01/98

Appendix A – CBD West Loads

- T030 Ashgrove West
- SSKVG Kelvin Grove
- SSMLT Milton
- SSQRT QR Roma Street
- SSMST Makerston Street
- SSWED West End

Appendix B – Network Risk methodology

110kV Brisbane CBD West Loads

CBD West (with loads as described above) is supported by EQL 110kV cable from Rocklea, and 110kV circuits from Upper Kedron; the latter ultimately supplied from South Pine Substation transformers T4 and T5.

Stafford BSP

EQL's Stafford substation is also supplied from the western 110kV bus at South Pine.

Collective South Pine 110kV (west) Load at Risk

In the event of an outage of Transformer T4 with Transformer T5 retired, the power into CBD West would be delivered primarily from H016 Rocklea Substation through feeder F905, with some support Upper Kedron from Abermain and West Darra.

Stafford BSP would be completely supplied from Upper Kedron.

During higher load periods (nominally > 230MW), then feeder F905 is at the greatest risk of overloading in the event of an outage of transformers T4 (and T5) at South Pine Substation. Feeder F905 has a summer emergency cyclic rating of 124MVA. All load in excess of ~230MW is considered at risk. This is reflected in Table 2.

Project Scope Report

CP.02478

South Pine 5 Transformer Replacement

Concept – Version 1

Document Control

Change Record

Issue Date	Revision	Prepared by	Reviewed by	Approved by	Background
06/05/2025	1	[redacted]	[redacted]	[redacted]	Preliminary scope for revenue reset 2027 - 2032

Related Documents

Issue Date	Responsible Person	Objective Document Name
11/04/2025	[redacted]	PIF – South Pine 5 Transformer Replacement (A2851996)

Document Purpose

The purpose of this Project Scope Report is to define the business (functional) requirements that the project is intended to deliver. These functional requirements are subject to Powerlink's design and construction standards and prevailing asset strategies, which will be detailed in documentation produced during the detailed scoping and estimating undertaken by DTS (or OSD), i.e. it is not intended for this document to provide a detailed scope of works that is directly suitable for estimating.

Project Contacts

Project Sponsor	[redacted]
Connection & Development Manager	[redacted]
Strategist – HV/Digital Asset Strategies	[redacted]
Planner – Main/Regional Grid	[redacted]
Manager Projects	TBC
Project Manager	TBC
Design Manager	TBC

Project Details

1. Project Need & Objective

H002 South Pine substation consists of a 275kV and a 110kV yard. The 110kV yard is a bulk supply point for Energex to supply customers in an area that includes the north coast and the northern suburbs of Brisbane in Southern Queensland. The substation was established in 1963 and extended with load growth from the 1980s, 1990s and 2008.

The 250MVA 275/110 kV transformer T05 transformer at H002 South Pine Substation was originally installed in July 1981. The transformer is now over 40 years in service and is starting to display issues typical of transformers of this age, which indicate ageing of insulation and other components. A thorough condition assessment has determined that this transformer is not a candidate for life extension due to its age (45 years), low DPv value (<600) and free breathing type. Planning has confirmed the enduring need for No 5 Transformer.

The objective of this project is to replace 5 Transformer by 2030. This project is expected to follow the two (2) stage approval process.

2. Project Drawing

[redacted]

Figure 1: Site Layout

Figure 2: Aerial photo of existing T05

3. Deliverables

The following deliverables are to be provided for the purposes of Revenue Reset in response to this Project Scope Report. The requirement dates for these deliverables will be communicated separately.

1. A report (e.g. Concept Estimate Report) detailing the works to be delivered, high level staging, resource requirements and availability, and outage requirements and constraints;

2. A class 5 estimate (minimum);

3. Any existing assets to be removed and disposed of as part of this scope identified within the Proposal together with the forecast asset write off amounts at time of disposal; and

4. A basis of estimate document and risk table, detailing the key estimating assumptions and delivery risks.

4. Project Scope

4.1. Original Scope

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 7 Special Considerations*.

Briefly, the project consists of the replacement of 5 Transformer.

4.1.1. H002 South Pine Substation Works

Design, procure, construct and commission replacement of 5 Transformer. Within the scope of work:

- Procure and install a new 275/110kV 250MVA transformer, with on load tap changer and cooling facilities;
- Review and replace Transformer 5 foundations (if required);
- Review and modify transformer oil separation tank (if required);
- Modify protection, automation and communication systems as necessary to accommodate the new transformer;
- Decommission and dispose of existing 5 Transformer; and
- Decommission and recover all redundant equipment, and update drawing records, SAP records, config files, etc. accordingly

4.1.2. Telecoms Works

Not applicable

4.2. Key Scope Assumptions

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

- Replacement will be on a like for like basis; and
- The new transformer will be located in the existing 5 Transformer bay.

4.3. Variations to Scope (post project approval)

Not applicable

5. Key Asset Risks

Asset risk management shall be in accordance with the Asset Risk Management Process Guideline (A4870713).

6. Project Timing

6.1. Project Approval Date

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

6.2. Site Access Date

H002 South Pine Substation is an existing Powerlink site and access is available immediately.

6.3. Commissioning Date

The latest date for the commissioning of the new assets included in this scope is 30 June 2030.

7. Special Considerations

H002 South Pine Substation is one of the sites under CP.03107 Replace 275kV ABB IMB CTs – Metro. Overlapping impacts to access and delivery should be considered in the planning phases of this project.

8. 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 Network and Business Development including Asset Strategies & Planning.

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

9. Asset Ownership

The works detailed in this project will be Powerlink Queensland assets.

10. 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.

11. Options

Not applicable

12. Division of Responsibilities

Not applicable.

13. Related Projects

Project No.	Project Description	Planned Comm Date	Comment
Pre-requisite Projects			
Co-requisite Projects			
Other Related Projects			
CP.03107	Replace 275kV ABB IMB300 CTs - Metro		

CP.02478 South Pine 5 Transformer Replacement

Concept Estimate

Table of Contents

1. Executive Summary

H002 South Pine substation consists of a 275kV and a 110kV yard. The 110kV yard is a bulk supply point for Energex to supply customers in an area that includes the north coast and the northern suburbs of Brisbane in Southern Queensland. The substation was established in 1963 and extended with load growth from the 1980s, 1990s and 2008.

The 250MVA 275/110 kV transformer T05 transformer at H002 South Pine Substation was originally installed in July 1981. The transformer is now over 40 years in service and is starting to display issues typical of transformers of this age, which indicate ageing of insulation and other components. A thorough condition assessment has determined that this transformer is not a candidate for life extension due to its age (45 years), low DPv value (<600) and free breathing type. Planning has confirmed the enduring need for the capacity provided by No 5 Transformer.

The assessment behind this proposal has established that the project can be delivered by October 2030.

The project will follow the two (2) stage approval process.

1.1 Project Estimate

No escalation costs have been considered in this estimate.

		Total ($)
Estimate Class	5	
Base Estimate – Un-Escalated (2025/2026)		16,323,427
TOTAL		**16,323,427**

1.2 Project Financial Year Cash Flows

No escalation costs have been considered in this estimate.

DTS Cash Flow Table	Un-Escalated Cost ($)
To June 2026	95,485
To June 2027	2,619,901
To June 2028	483,613
To June 2029	2,815,703
To June 2030	10,224,452
To June 2031	84,273
TOTAL	**16,323,427**

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			
Interactions			
Other Related Projects			
CP.03107	Replace 275kV ABB IMB CTs – Metro.	2026	Overlapping impacts to access and delivery should be considered in the planning phases of this project.

2.2 Site Specific Issues

List items that are specific to the project, considering such things as:

- Site Location:
  - Located at 381 South Pine Rd in Brendale, Brisbane 4500.
  - Main access is via South Pine Road.
  - No accommodation required due to location in SEQ.
- Climate considerations:
  - Limited risks as located in Brisbane; wet season expected during summer months.
- Site Access:
  - No issues identified for building delivery or transport of equipment.
- Noise restrictions, Construction working times:
  - Located close to local housing, noise consideration required for local community.
  - 7 day a week access will not be restricted.
- Environmental and Cultural Heritage issues:
  - Any works will be undertaken within the existing substation fence line.
  - Standard Environmental requirements for the disposal of any material.
  - Cultural Heritage to be notified during the next stage of approvals.
- Services:
  - Electrical supply on site.
  - Potable water on site.
  - Toilets available on site.
- Rosters:
  - No roster anticipated as located in Brisbane.
  - Possible deliver and removal of Tx in the evening to recued traffic concerns.

3. Project Scope

3.1 Substations Works

Design, procure, construct and commission replacement of 5 Transformer. Within the scope of work:

- Procure and install a new 275/110kV 250MVA transformer, with on load tap changer and cooling facilities;
- Replacement of Transformer 5 foundations;
- Installation and connection of new oil separation system;
- Modify protection, automation and communication systems to accommodate the new transformer;
- Decommission and dispose of existing 5 Transformer; and
- Decommission and recover all redundant equipment, and update drawing records, SAP records, config files, etc. accordingly.

Figure 1 – Aerial photo of existing Transformer 5

[redacted]

Figure 2 – Site Layout

3.2 Major Scope Assumptions

The following key assumptions were made for this Project Estimate.

- Replacement will be on a like for like basis with a lead time of 4 years.
- H002 South Pine Substation is an existing Powerlink site and access is available immediately.
- The existing transformer 5T will be replaced in-situ with a new 250MVA unit.
- The transformer replacement works are to be performed under outage.
- An extended outage period of up to 6 months is required to replace the transformer in-situ.
- The existing foundation will be removed, and a new foundation is required to replace the existing foundation.
- New oil separation tank will be provided and installed. The transformer will be connected to the new oil separation tank.
- New surge arrestors are included for the transformer replacement.
- Commissioning works to re-energise and test the new transformer will be by MSP labour.

3.3 Scope Exclusions

The following exclusions apply.

- Removal of rock or unsuitable material, including asbestos and other contaminants.
- No modification and upgrading of the internal roads, lights, fences and gates.
- Live substation work.
- Construction of a new bay.

4. Project Execution

4.1 Project Schedule

This project will follow the two (2) stage approval process.

A High-Level Project Schedule has been developed for the project stages:

Milestones	High-Level Timing
Class 5 Project Proposal Submission	October 2025
Request for Class 3 Estimate, includes funds for design & procurement	November 2025
Place Transformer Order	December 2025
Class 3 Project Proposal Submission	August 2026
Stage 1 Approval (PAN1) includes funds for ITT preparation	November 2026
RIT-T (assumed 26 weeks)	November 2026 – May 2027
Project Development Phase 1 & Phase 2	December 2026 – August 2027

ITT Submission (8 Weeks)	August 2028 – October 2028
Evaluate Tender, Reconcile Estimate and Submit PMP for Stage 2 Approval	November 2028
Stage 2 Approval (PAN2)	January 2029
Execute Delivery (including award of SPA contract)	October 2029
Procurement Deliveries	December 2029
SPA Site Establishment	March 2030
SPA Civil Works and Construction	April 2030 – October 2030
MSP Site Establishment	October 2030
Staged Bay Commissioning	October 2030
Project Commissioning	November 2030

4.2 Network Impacts

There will be a requirement for a long outage to replace the transformer, the options for RTS can be reviewed to utilise alternate power e.g. bay on a skid or temporary generators

4.3 Resourcing

- Disconnection and re-connection will be performed by MSP labour.
- Live subs are included in the estimate.
- All works will be supervised by MSP labour.
- Commissioning works to re-energise and test the new transformer will be by MSP labour.

5. Project Asset Classification

Asset Class	Base ($)	Base (%)
Substation Primary Plant	15,329,965	93.9%
Substation Secondary Systems	993,461	6.1%
Telecommunications	0	0%
Overhead Transmission Line	0	0%
TOTAL	**16,323,427**	**100%**

6. References

Document name and hyperlink	Version	Date
Project Scope Report	1.0	06/05/2025

Risk Cost Summary Report

CP. 02478

South Pine Transformer 5 Replacement

Document Control

Change Record

Issue Date	Revision	Prepared by
22/12/2025	1.0	Asset Strategies

Related Documents

Issue Date	Responsible Person	Objective Document Name

Document Purpose

The purpose of this model is to quantify the base case and option risk cost profiles for the equipment at the South Pine Substation which is proposed for replacement under CP.02478. These risk cost profiles are then included as part of an overall cost-benefit analysis (CBA) to understand the economic benefit of the proposed upgrades. This process provides a benchmarking and internal gate process to support Powerlink in effectively identifying prioritised infrastructure upgrades.

The CBA was designed to demonstrate and quantify the value to be gained through specific infrastructure investments. To evaluate the CBA, an NPV is derived based on the present values of costs and benefits. The flow chart in Figure 4 below designates the methodology used in designing the CBA process.

Key Assumptions

In calculating the risk cost arising from a failure of the ageing equipment at the South Pine Substation, the following modelling assumptions have been made:

- The functionality of the equipment is assumed to decay according to decay curves calculated by Powerlink, and associated probability of failures (PoF).
- Where equipment in scope is replaced, its associated Health Index (HI) score is reverted to one.
- The likelihood of personnel within the substation in the event of explosive failure of equipment (used to calculate safety risk) is assumed to be 25% (based upon historic site entry averages), with the likelihood of resulting injury or death depending on the explosive radius of the equipment, its housing, and the total substation land area. The modelling also assumes that personnel are equally likely to be anywhere within the substation land area. No escalation to the likelihood has been made during construction even though more people will be present on site as it is assumed appropriate risk assessments and risk mitigation measures are completed by the project team.
- For the purposes of the cost-benefit analysis, the total useful asset life of 40 years has been applied.
- A site-specific value of customer reliability (VCR) of $25,750 has been applied when calculating network risks.

Base Case Risk Analysis

Risk Categories

Four main categories of risk are assessed as part of this project as consistent with Powerlink’s Asset Risk Management Framework:

- Financial Risk
- Safety Risk
- Network Risk (including market impact if applicable)

- Environmental

Table 1: Risk categories

Risk Category	Failure Types	Equipment in scope
Safety Risk	Explosive failure	All equipment with the potential to fail explosively
Financial Risk	Peaceful failure	All equipment
	Explosive failure	All equipment with the potential to fail explosively
Network Risk	Peaceful failure	All equipment related to network elements identified in the planning statement
Environmental Risk	Peaceful failure	None for this project

Base Case Risk Cost

The modelled and extrapolated total base case risk costs are shown in Figures 1 and 2 below.

Risk costs associated with the equipment in scope are expected to increase from $0.72 million in 2026 to $1.50 million in 2036 and $2.27 million by 2046. Key highlights of the analysis include:

- Financial risks forms approximately 99% of the base case risk in 2030. Of this, the majority is a result of peaceful failures modes.
- Network risk and safety risk accounts for approximately 1% of the total risk, and environmental risk is zero for this project.

Figure 1: Total risk cost

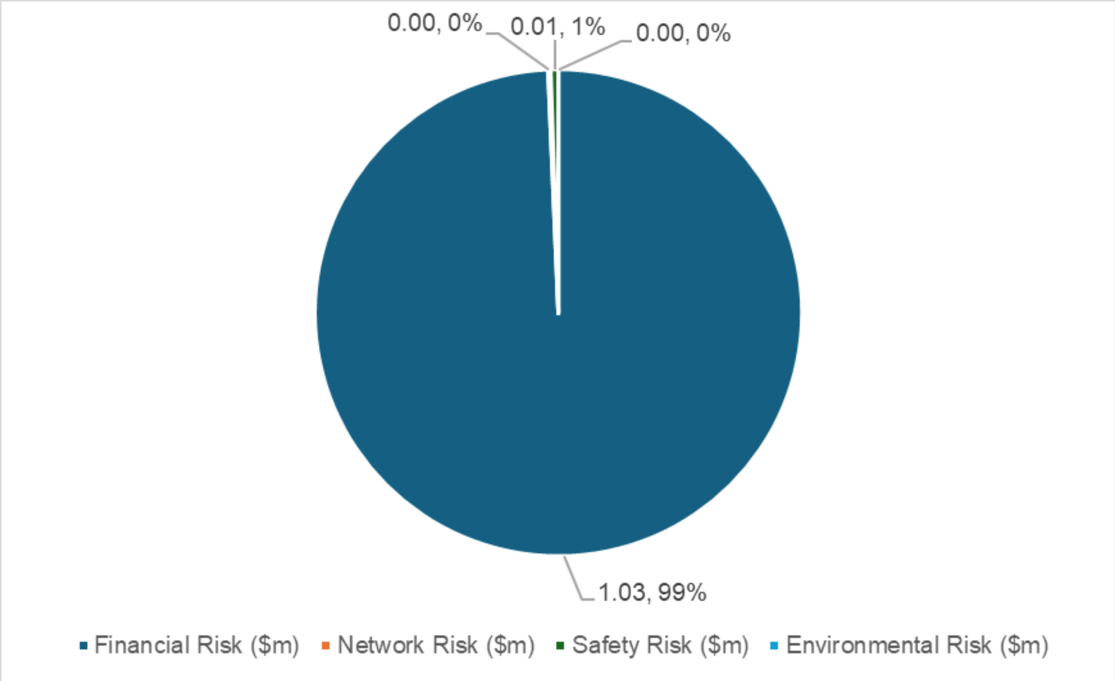

Figure 2: Base case risk cost by contributions (2030)

Option Risk Cost

For modelling purposes, effective HI scores have been reduced to one for equipment replaced under this project. Replacement of the equipment results in a lower probability of failure and therefore risk cost. Updated equipment strategies to preference polymer housed bushings also reduces the safety consequences associated with catastrophic failures.

The figures below set out the total project case risk cost, and associated risk cost savings incremental to the base case.

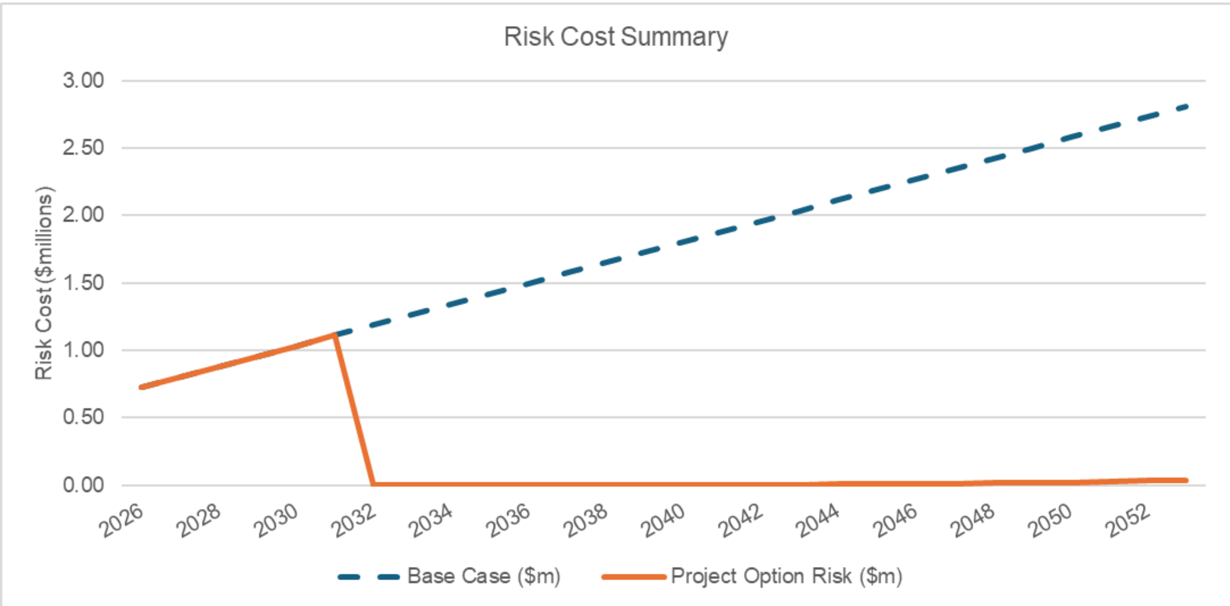

Figure 3: Project Option Risk Cost (compared to base case)

Following the year of investment (2031) the risk cost associated with the equipment in scope reduces close to $0. By 2044, the risk cost of the project option is approximately $.01 million, compared with the base case risk cost of $2.11 million.

Cost Benefit Analysis

The methodology designed for the cost benefit is set out as per Figure 4 below.

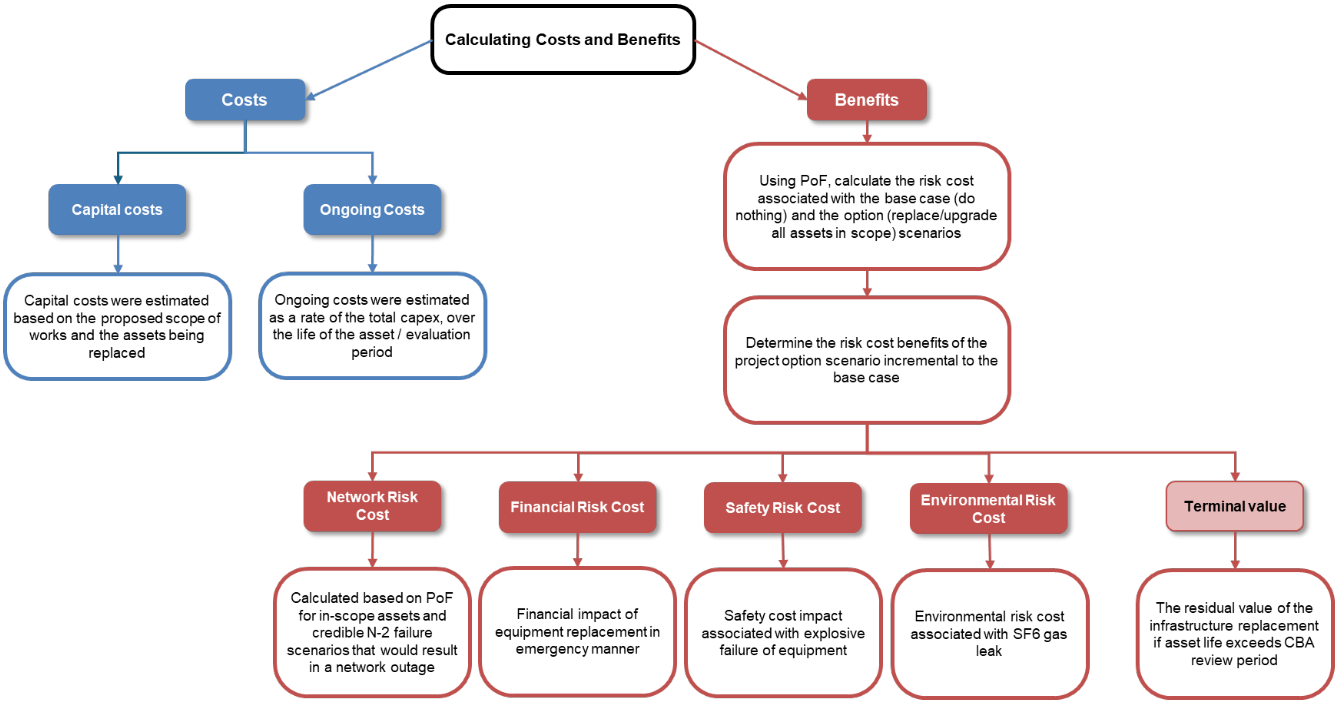

Figure 4: CBA methodology

The project is estimated to cost approximately $16.32 million. This represents a significant cost saving over the estimated financial risk cost of replacing assets individually in an emergency manner, due to the efficiencies associated with planned upgrades.

Based on a baseline discount factor of 7%, the project has a net present value (NPV) of $5.2 million over a 40-year period, and a benefit-cost ratio (BCR) of 1.48.

The project also has a positive NPV and BCR when a discount factor of 10% is applied.

Given this, the scope of work associated with the nominated assets within this project is considered appropriate.

Table 2: Net Present Value and Benefit-Cost Ratio

		Present Value Table ($m)		
Discount rate	%	**3%**	**7%**	**10%**
NPV of Net Gain/Loss	$m	$21.6	$5.2	$0.5
Benefit-Cost Ratio	ratio	2.58	1.48	1.05

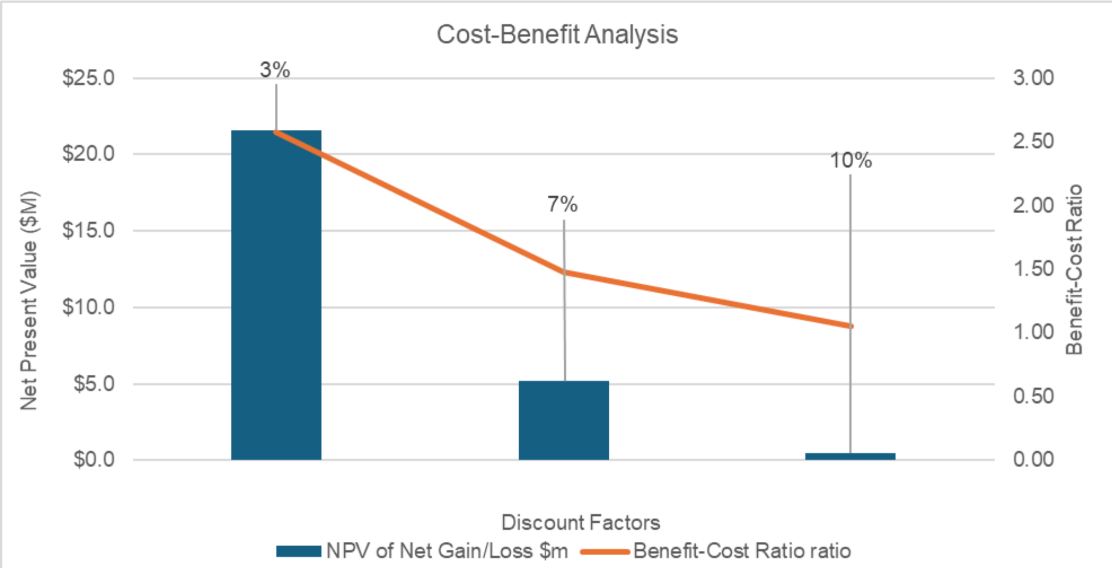

Figure 5: Cost benefit summary

Participation Factors

A sensitivity analysis was undertaken to determine the participation factors for key inputs to the risk cost models (i.e. to identify which inputs are most sensitive to overall risk cost).

The participation factor is defined as the ratio of percentage change in output (i.e. risk cost) to a percentage change in input (e.g. VCR). The participation factors for key model inputs are shown in the table below.

Due to the non-linear nature of the risk cost model (especially network risk costs, which are a function of concurrent failures), the participation factor can change depending on the magnitude of input percentage change.

The model is most sensitive to:

- **changes in emergency premium (peaceful failure)** results in a decrease in risk cost of $0.08 million, or approximately 7.76% of the original base risk.

Table 3: Participation Factors

Input	Baseline value	Sensitivity value (-50%)	Change in risk cost at 2030 ($m)	Participation (%)
Likelihood of personnel within substation	25%	12.5%	0.00	-0.25%
Cost consequence of multiple fatality	$11,400,000	$5,700,000	0.00	-0.08%
Cost consequence of single fatality	$5,700,000	$2,850,000	0.00	-0.07%
Cost consequence of multiple serious injury	$4,206,600	$2,103,300	0.00	-0.06%
Emergency premium (peaceful failure)	20%	10%	-0.08	-7.76%

Emergency premium (explosive failure)	100% (Pwr TX) 30% (Bushings)	50% (Pwr TX) 15% (Bushings)	-0.01	-1.37%
VCR ($/MWh)	25,750	12,875	0.00	-0.09%
Restoration Time (hrs)	720 (Pwr TX) 168 (Bushings)	360 (Pwr TX) 84 (Bushings)	0.00	-0.06%